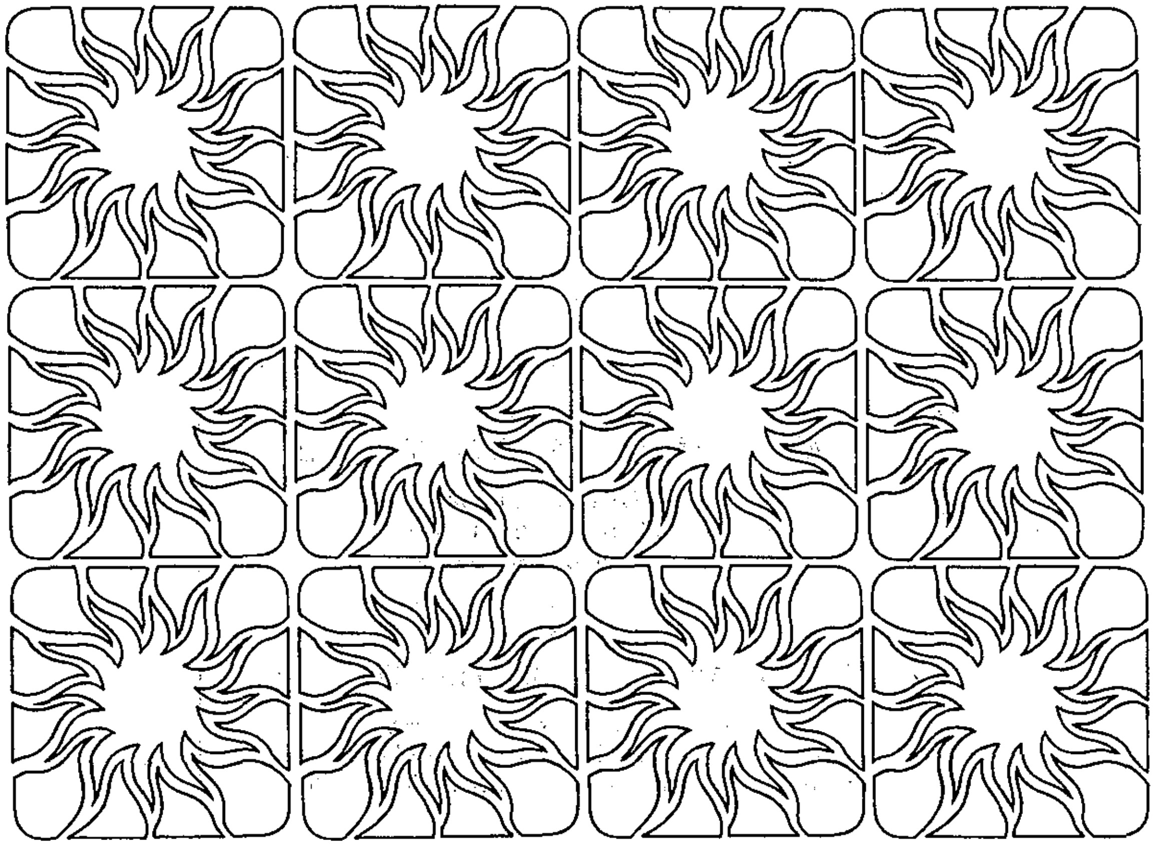
U.S. Energy Outlook

Oil and Gas Availability

National Petroleum Council



U.S. Energy Outlook

Oil and Gas Availability

A Report by the Oil & Gas Supply Task Groups of the Oil & Gas Subcommittees of the National Petroleum Council's Committee on U. S. Energy Outlook

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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 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.

In response to this request, the National Petroleum Council's Committee on U.S. Energy Outlook was established, with a coordinating subcommittee, four supporting subcommittees for oil, gas, other energy forms and government policy, and fourteen task groups. An organization chart appears as Appendix B. In July 1971, the Council issued an interim report entitled *U.S. Energy Outlook: An Initial Appraisal 1971-1985* which, along with associated task group reports, provided the groundwork for subsequent investigation of the U.S. energy situation.

Continuing investigation by the Committee and component subcommittees and task groups resulted in the publication in December 1972 of the NPC's summary report, *U.S. Energy Outlook*, as well as an expanded full report of the Committee. Individual task group reports have been prepared to include methodology, data, illustration and computer program descriptions for the particular area studied by the task group. This report is one of ten such detailed studies. Other fuel task group reports are available as listed on the order form included at the back of this volume.

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.

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Part One

A Summary of Oil and Gas Availability Studies

(Extracted from U. S. ENERGY OUTLOOK, A Report of the National Petroleum Council's Committee on U. S. Energy Outlook, published in December 1972)

Chapter One

Domestic Oil and Gas Availability

Chapter One
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-

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

Editors Note: This chapter appears as Chapter Four in the NPC report, *U.S. Energy Outlook, A Report of the National Petroleum Council's Committee on U.S. Energy Outlook*, published in December 1972.

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 1) 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.

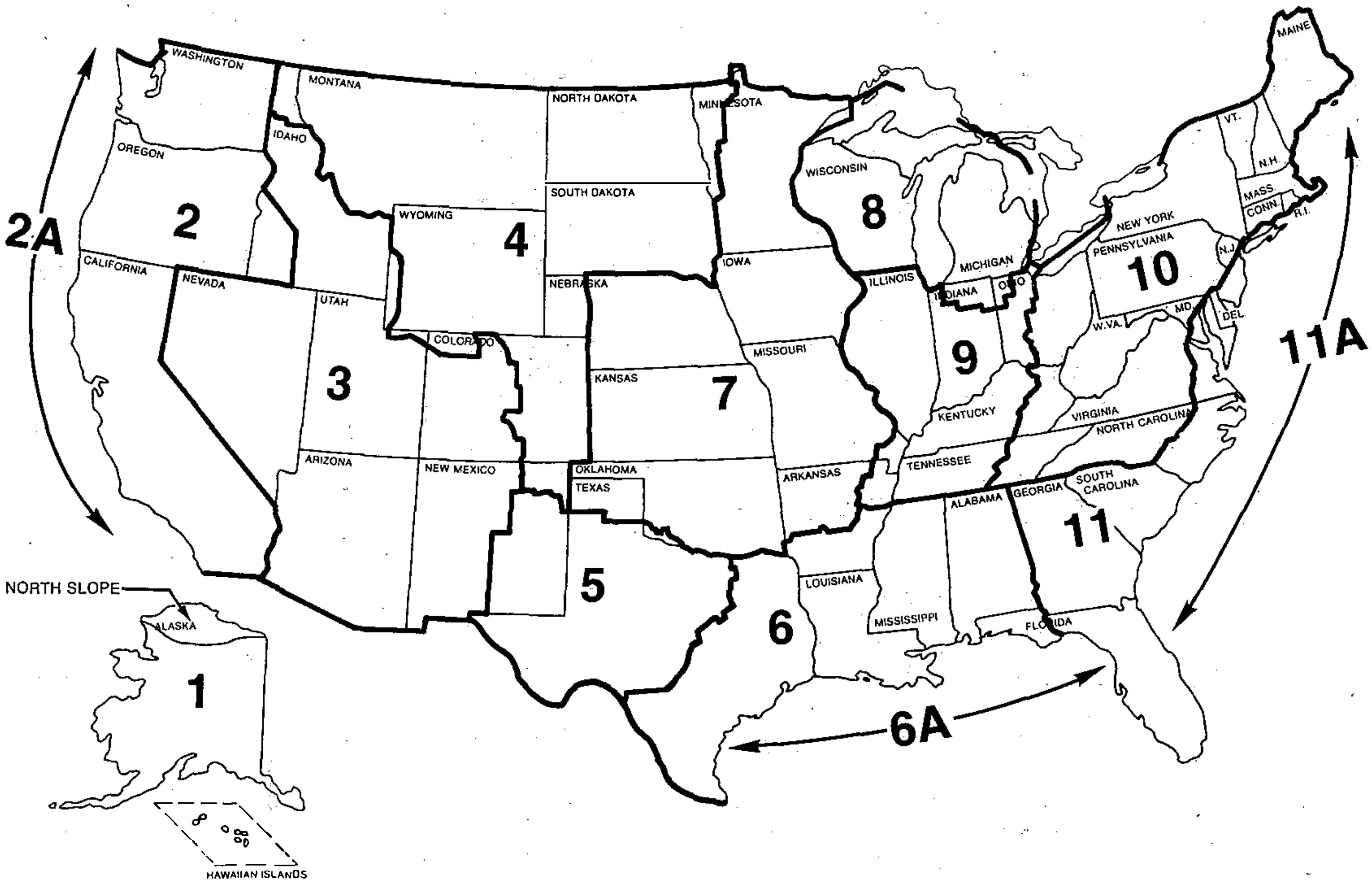
Cases Analyzed

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 1. 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 1.

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 2 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 1

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

* *U.S. Energy Outlook.*

TABLE 2

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 3 and 4 show the projected daily average production of petroleum liquids and the annual production of natural gas.

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 5. 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 5.

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

TABLE 3

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, U.S. Energy Outlook. Oil supply from all sources is shown in Table 51 in this report.

* 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.

TABLE 4

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 and coal were projected. Gas supply from all sources is shown in Table 52.

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 5

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

	Actual*	Projected (15% Return on Net Fixed Assets)					
		High Finding Rates			Low Finding Rates		
		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 method-

* Refer to Chapter Four, this report.

ology 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 2). 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-

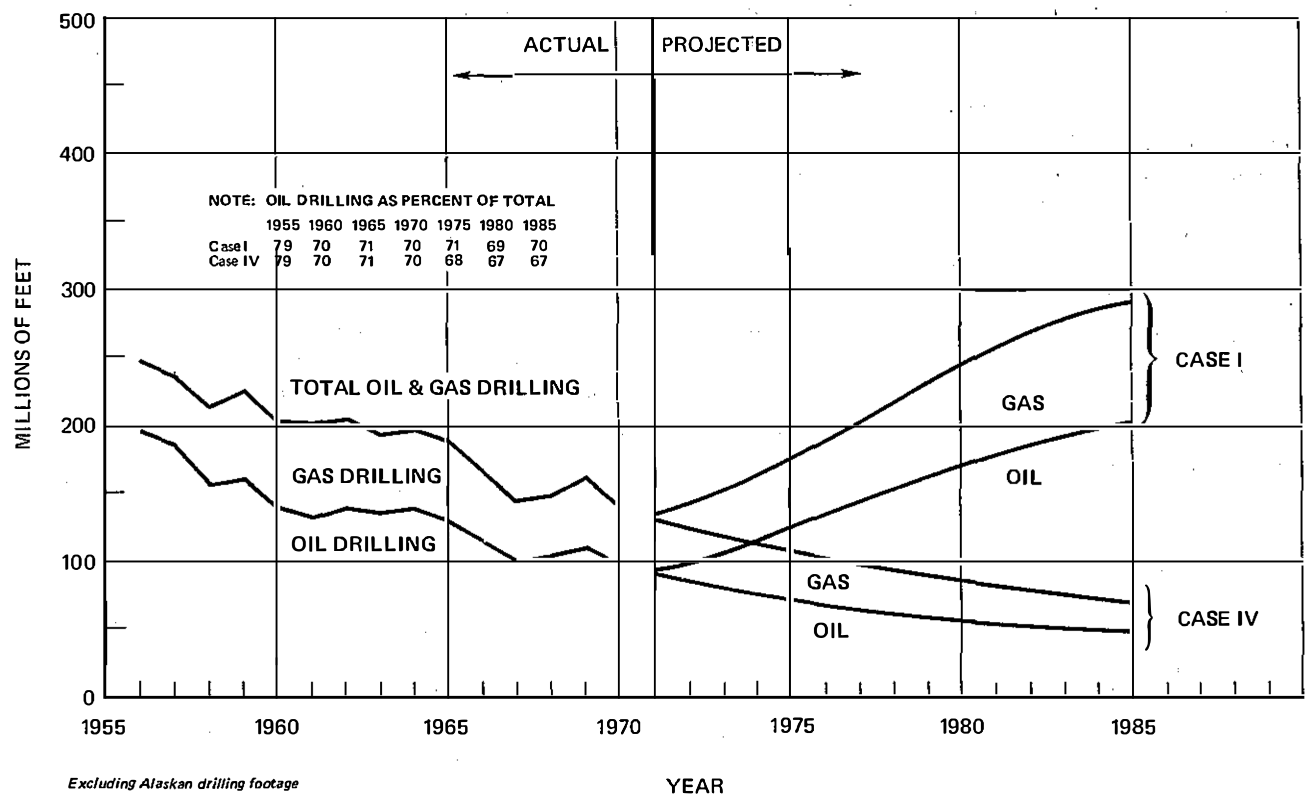


Figure 2. Oil and Gas Drilling Footage—Total United States (Million Feet).

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 3) 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

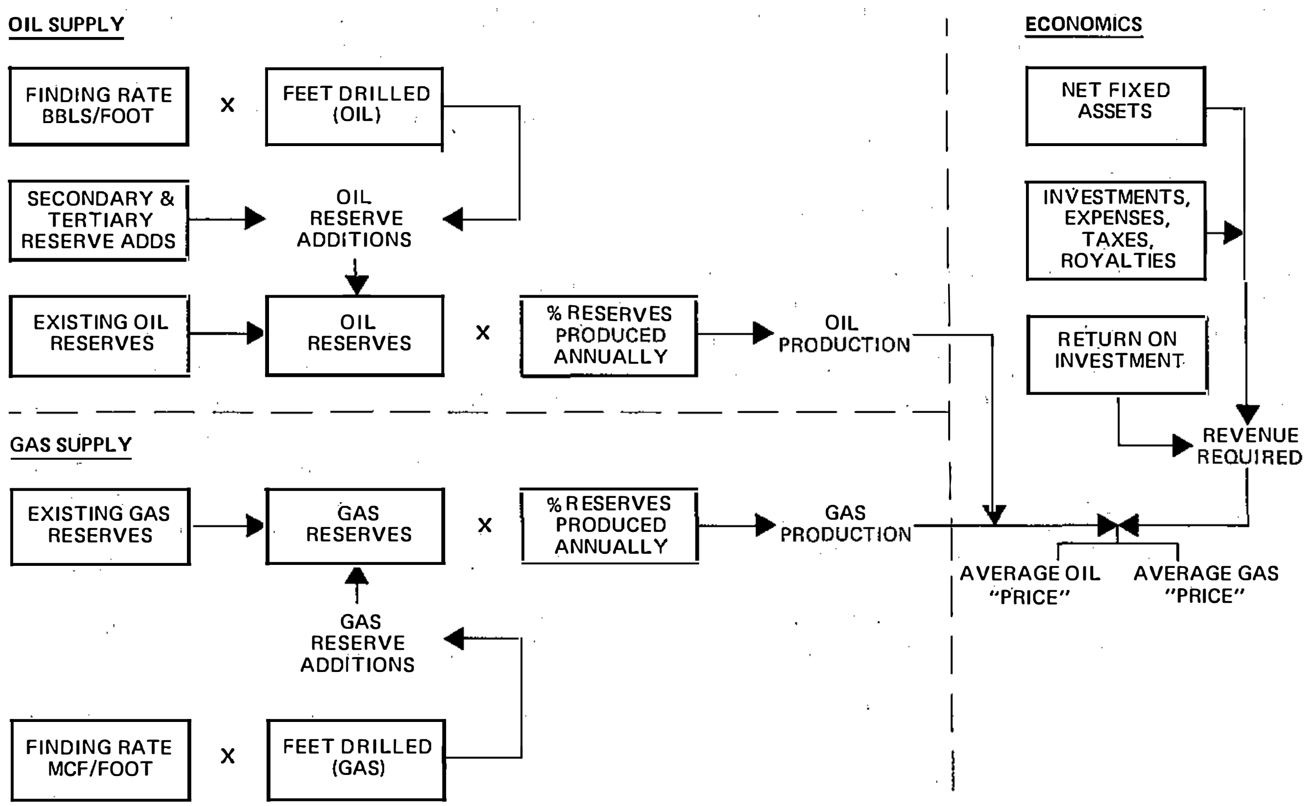


Figure 3. Oil and Gas Supply—Economic Methodology.

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 6) 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 7. 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.

* Refer to Chapter Five, Section I.

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

TABLE 6

DEPARTMENT OF THE INTERIOR SCHEDULE OF ANNOUNCED LEASE SALES*

Tentative Schedule—OSC Leasing†

1971

SALES	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.												

1972

SALES	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.												

1973

SALES	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.												

1974

SALES	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

1975

SALES	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 8.

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 7

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**

* Refer to Chapter Five, Section II.

TABLE 8

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	Not Estimated	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 4. 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.

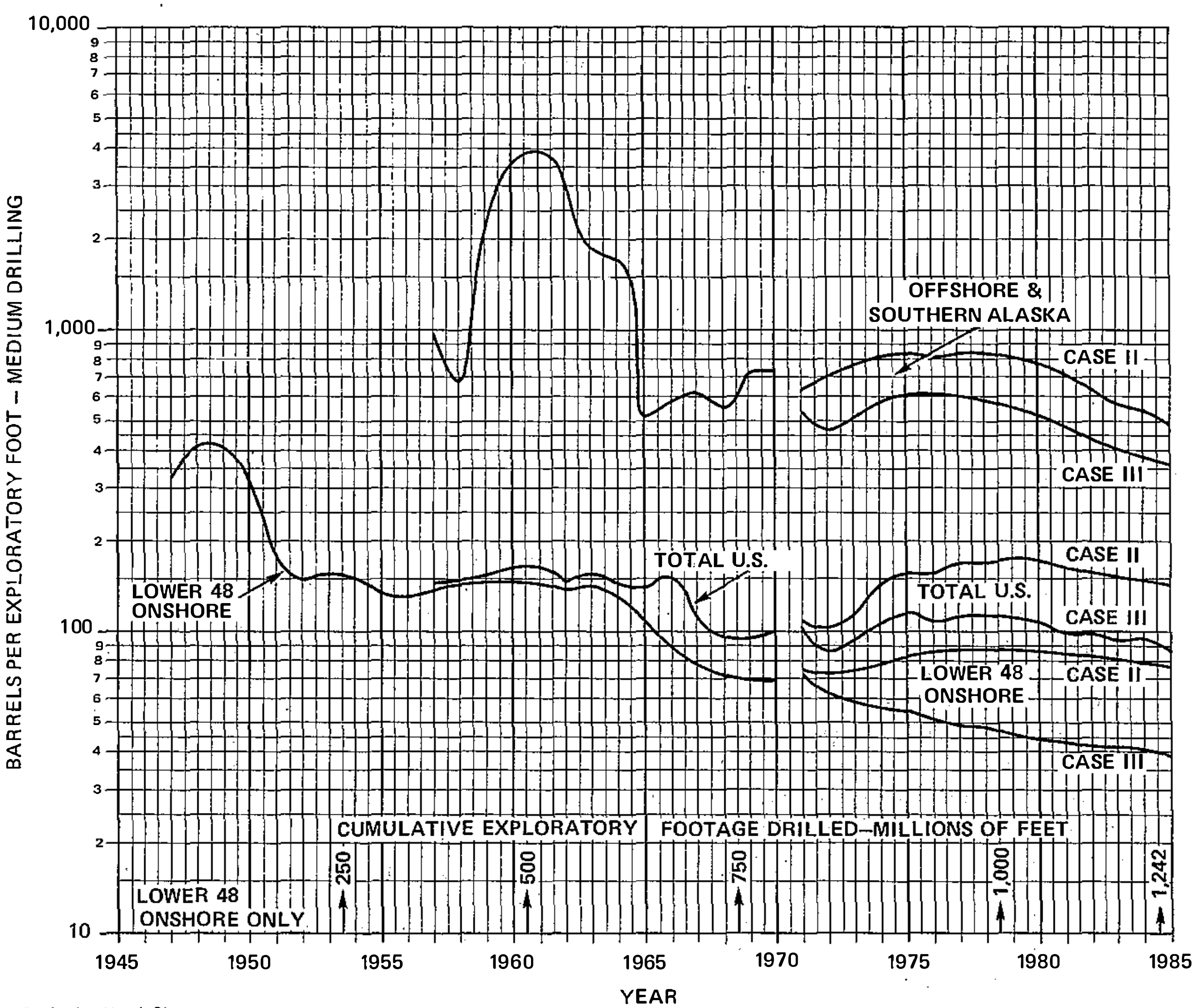
Oil Drilling Activity*

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 5). 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-

* Refer to Chapter Five, Section III.



Excluding North Slope.

Figure 4. Oil Finding Rates—Medium Drilling.

tribution used in the analysis is shown in Table 9.

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 5.

The number of wells resulting from these drilling footages are indicated in Figure 6. 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 9

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 7. 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 10 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 11.

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.

* Refer to Chapter Five, Section IV.

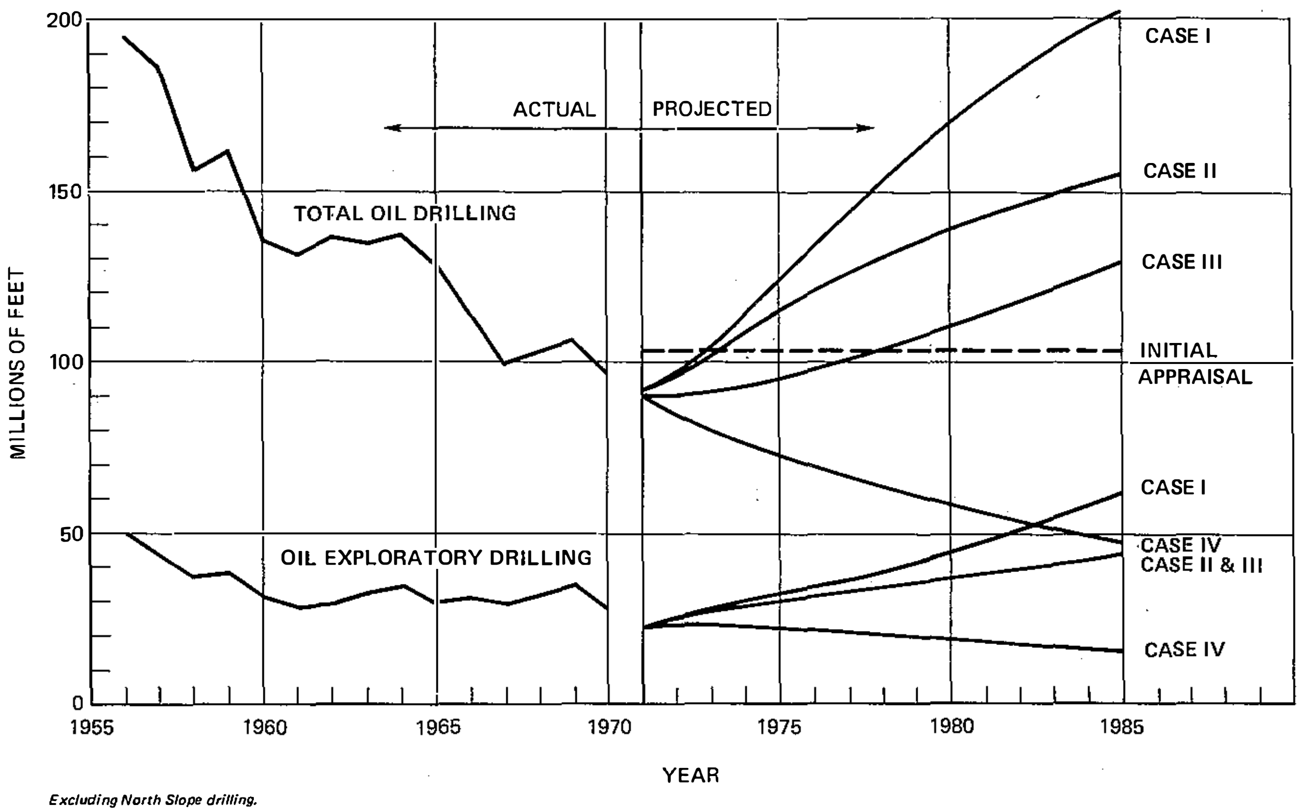


Figure 5. Oil Drilling Rate Projections—Million Feet Drilled.

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 12.

Oil Reserve Additions *

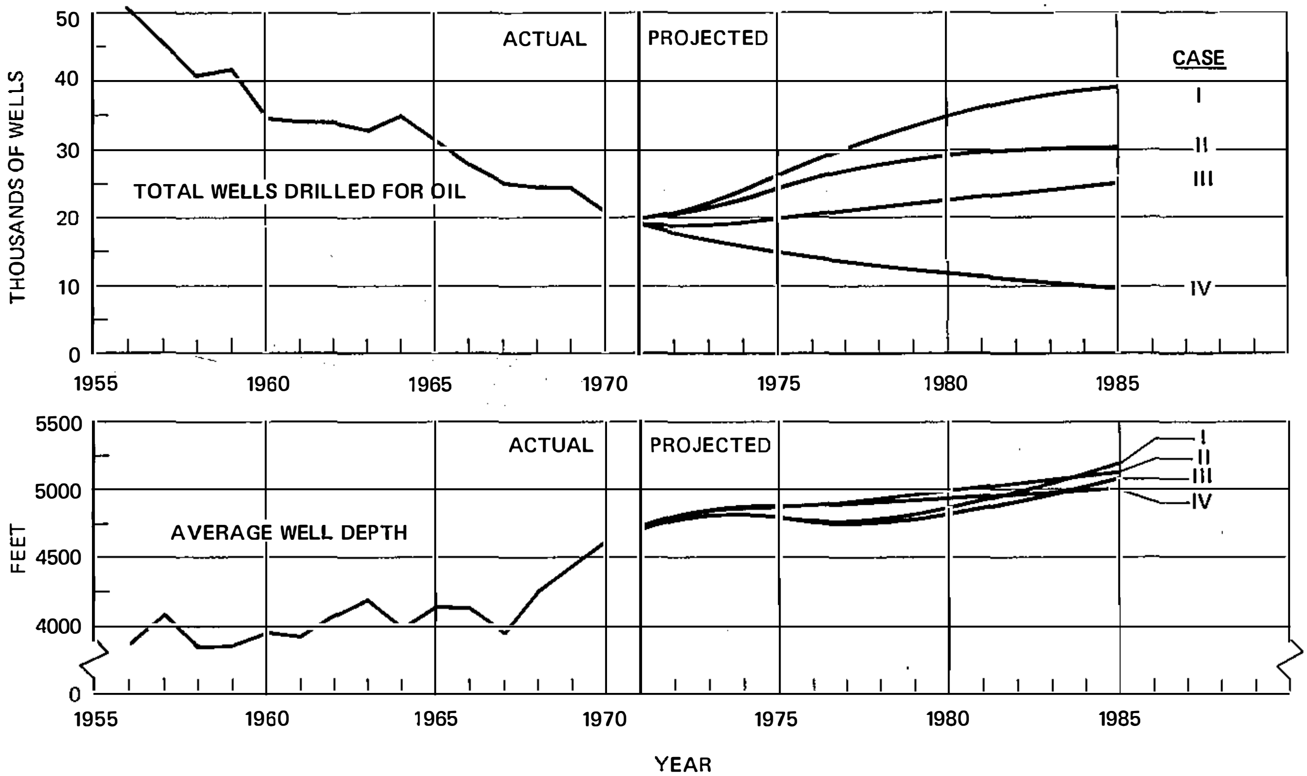
The procedure for determining annual oil reserve additions was as follows: Using the regional projections of oil-in-place found per year, primary reserve additions resulting from exploratory effort each year were calculated by applying the regional primary recovery factor to the oil-in-place discovered 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 8.

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 9. For the last 15 years, the reserve additions from

* Refer to Chapter Five, Section V.



Excluding North Slope drilling.

Figure 6. 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:

1956-1970 Actual	1971-1985 Projected (Billion Barrels) Case 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 13. 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 10 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

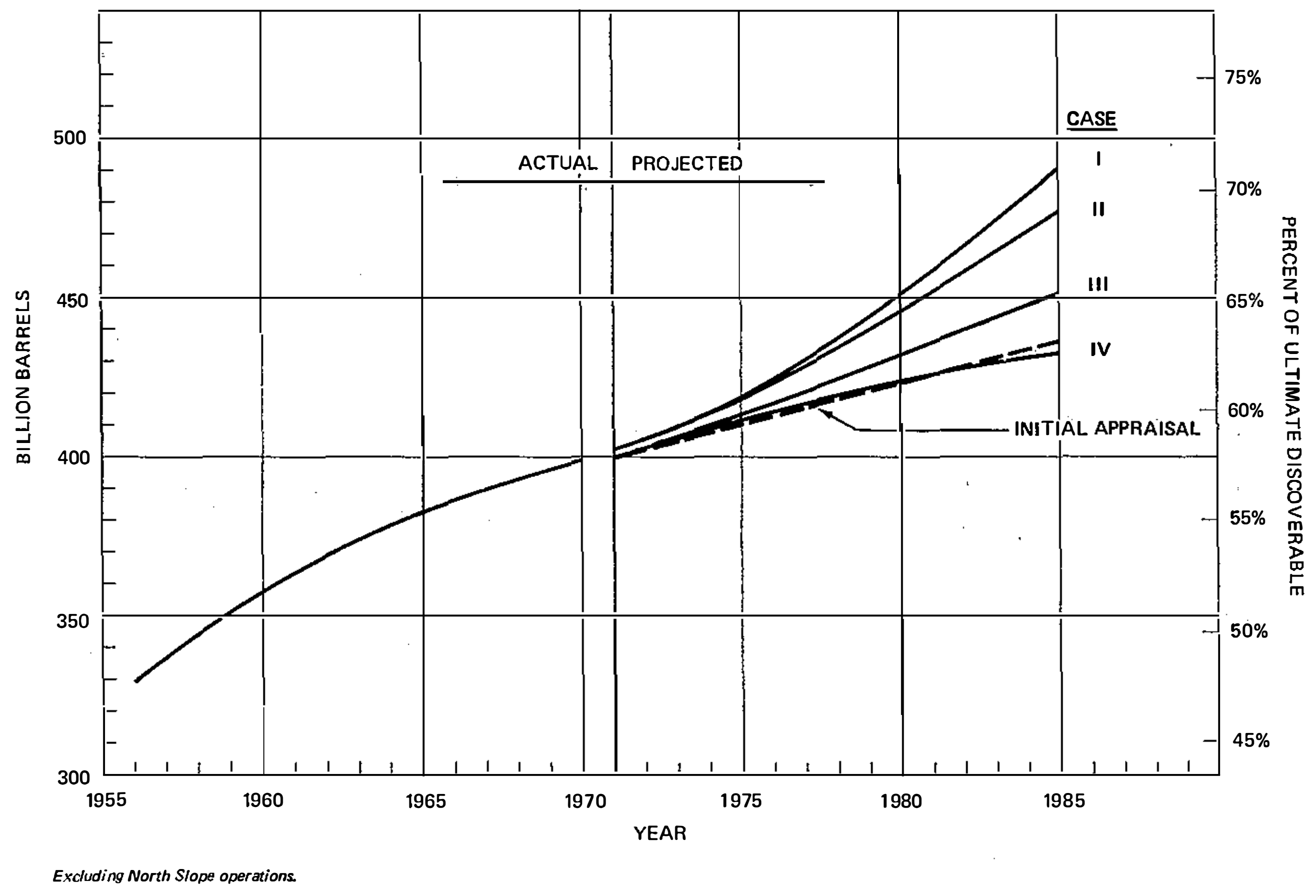


Figure 7. Cumulative Oil-in-Place Discovered.

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 14.

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 15 and Figures 11 and 12.

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

* Refer to Chapter Five, Section VI.

TABLE 10

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 13 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 11

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 14 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 15 and 16 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

* Refer to Chapter Five, Section VI.
† Refer to Chapter Six, Section I.

TABLE 12

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).

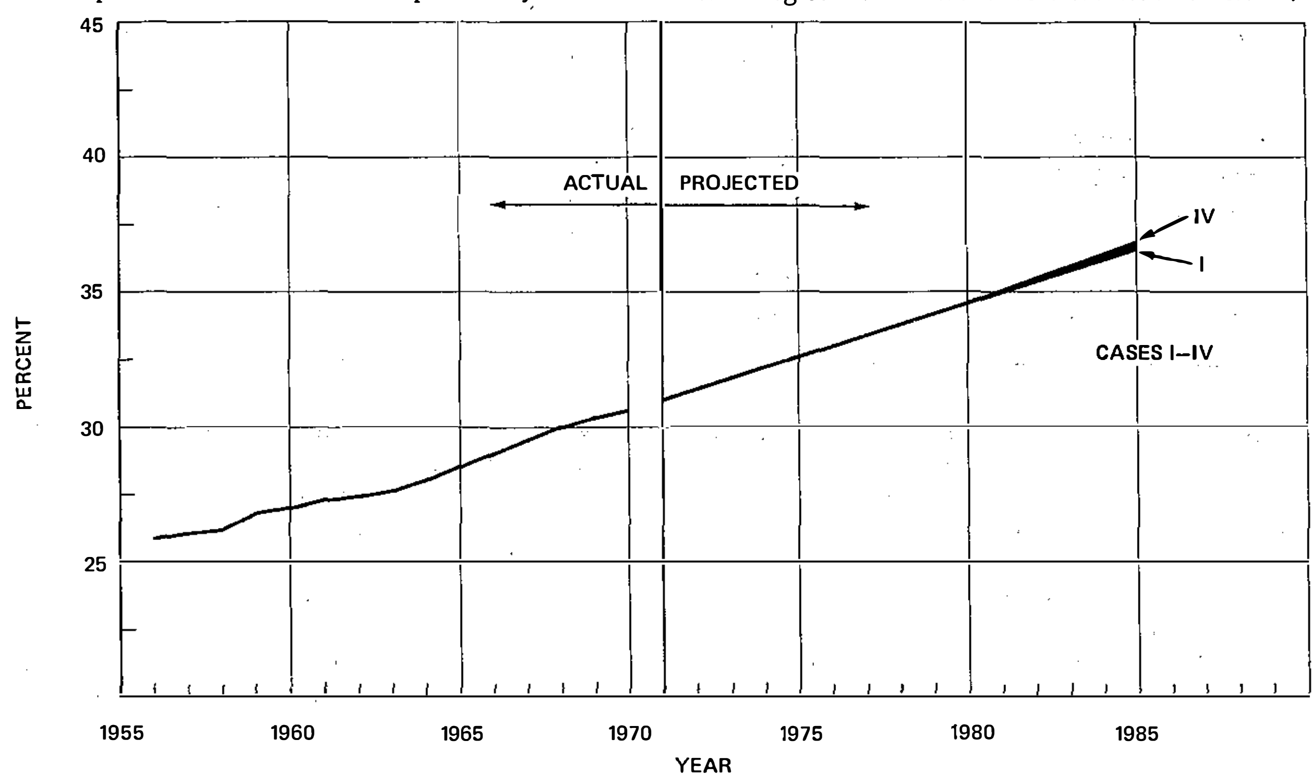
resources. These estimates of associated-dissolved potential gas were subtracted from the PGC estimates to arrive at non-associated potential gas. Table 16 shows non-associated gas potential, previously discovered gas, and ultimate recoverable gas (the sum of potential and discovered) by NPC region. 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 17.

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 8. Cumulative Oil Recovery Efficiency (Percent of Oil-in-Place).

* Refer to Chapter Six, Section II.

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 17 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.

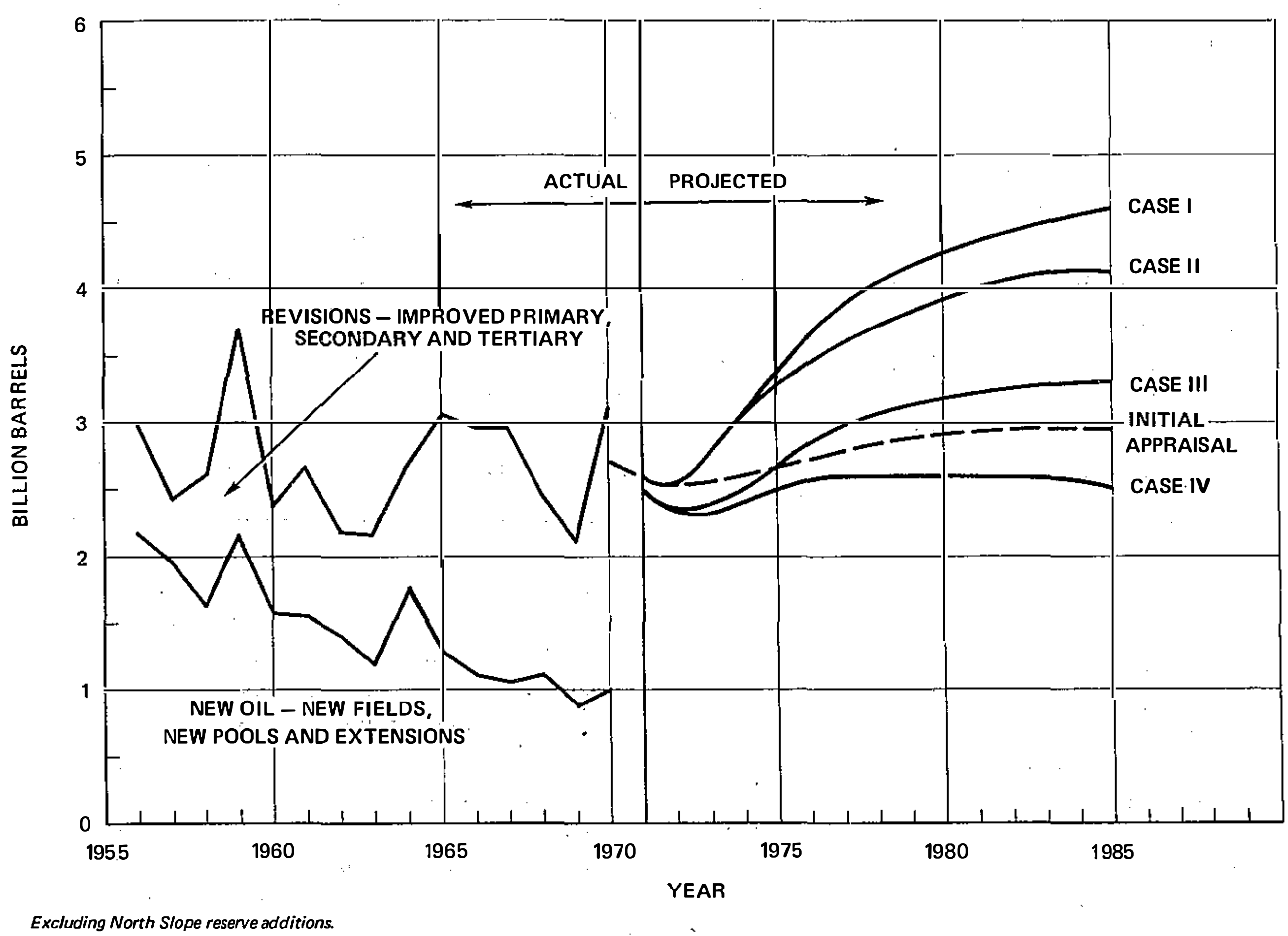


Figure 9. Oil Reserve Additions.

TABLE 13

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

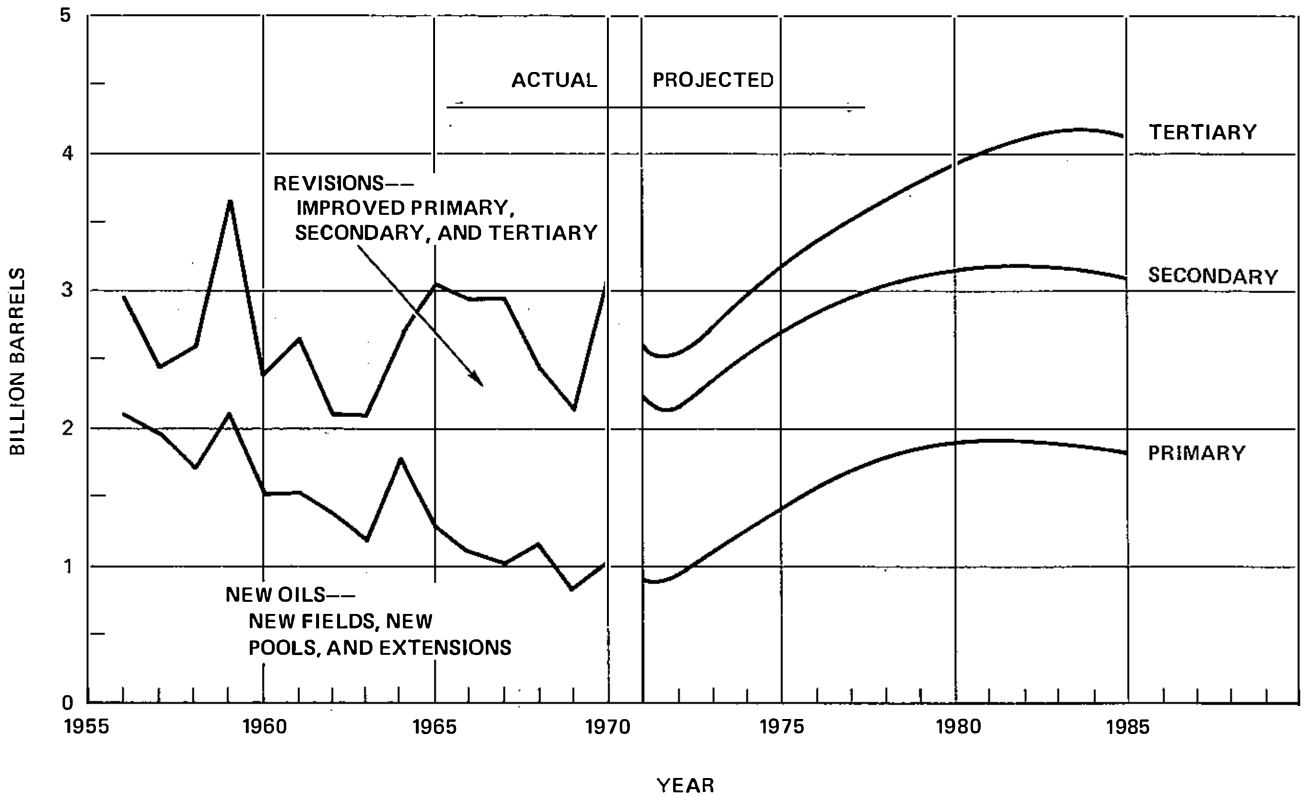
Region		Reserves Added 1956–1970	Reserves Added 1971–1985 Case I	II	III	IV	Initial Appraisal
Lower 48 Onshore							
2	Pacific Coast	4.8	4.6	4.5	4.4	4.2	5.1
3	Western Rocky Mtns.	1.1	0.6	0.6	0.4	0.4	0.5
4	Eastern Rocky Mtns.	2.9	3.1	2.7	1.6	1.3	2.4
5	West Texas Area	10.7	10.5	10.1	9.6	9.1	8.9
6	Western 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 18 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.

* Refer to Chapter Six, Section III.



Excluding North Slope Reserve Additions.

Figure 10. 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 19), 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 20 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 14

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

* Refer to Chapter Six, Section II.

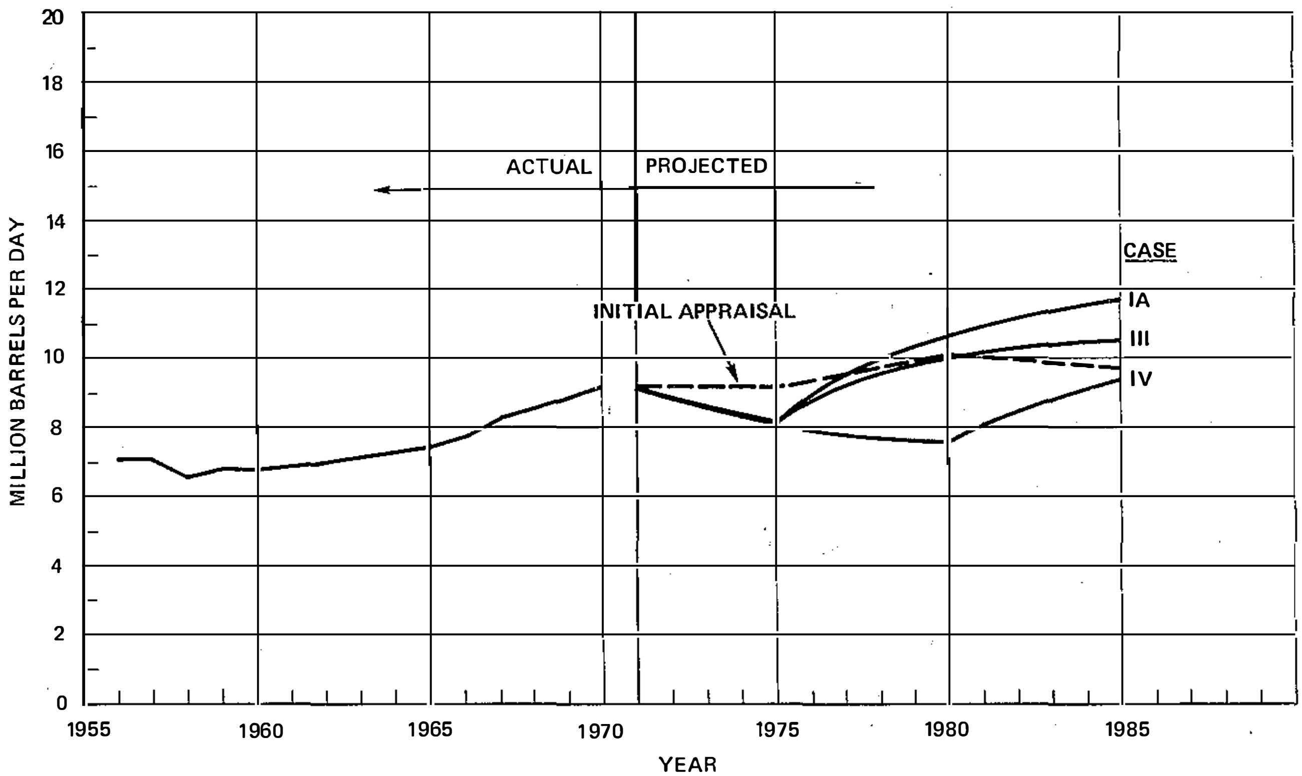


Figure 11. U.S. Crude Oil Production—Low Finding Rate.

distribution for the 3-year period 1968-1970, is shown in Table 18.

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 21, 22 and 23. Figure 24 shows historical annual gas reserve additions and projections for the lower 48 states. Figure 25 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 19 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 16, which includes Alaska, shows that 464.1 TCF of non-associated gas had been discovered prior to 1971. This is 30.9 percent of

* Refer to Chapter Six, Section IV.

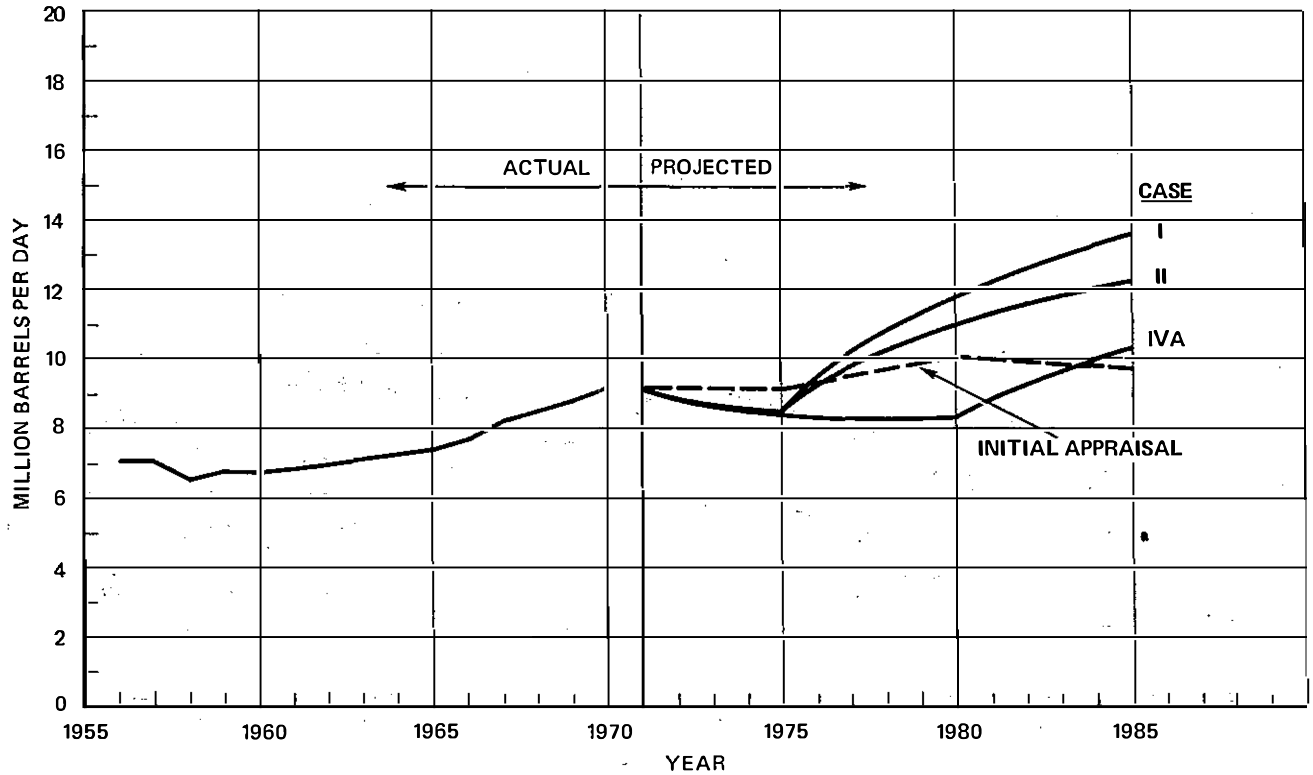


Figure 12. U.S. Crude Oil Production—High Finding Rate.

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 20 shows regionally the percent of ulti-

TABLE 15

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

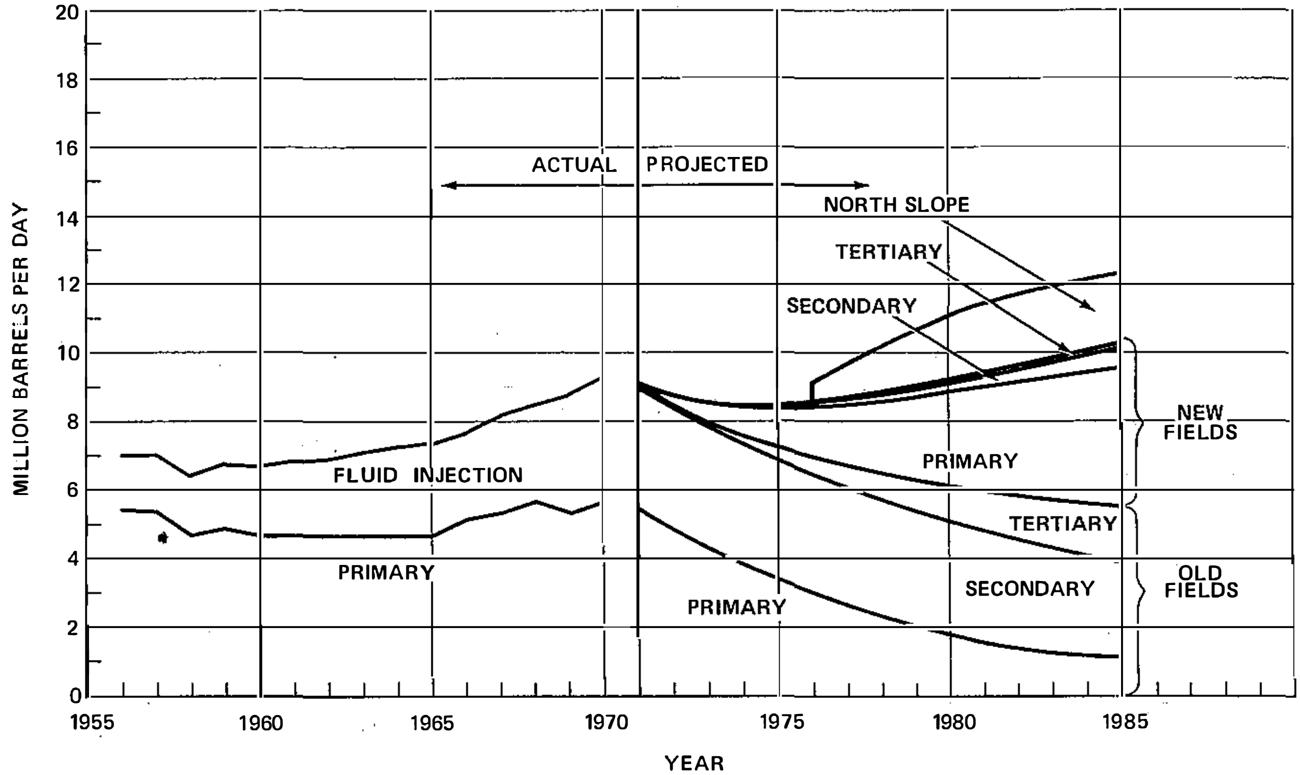


Figure 13. Daily Crude Oil Production (Case II)—Total United States.

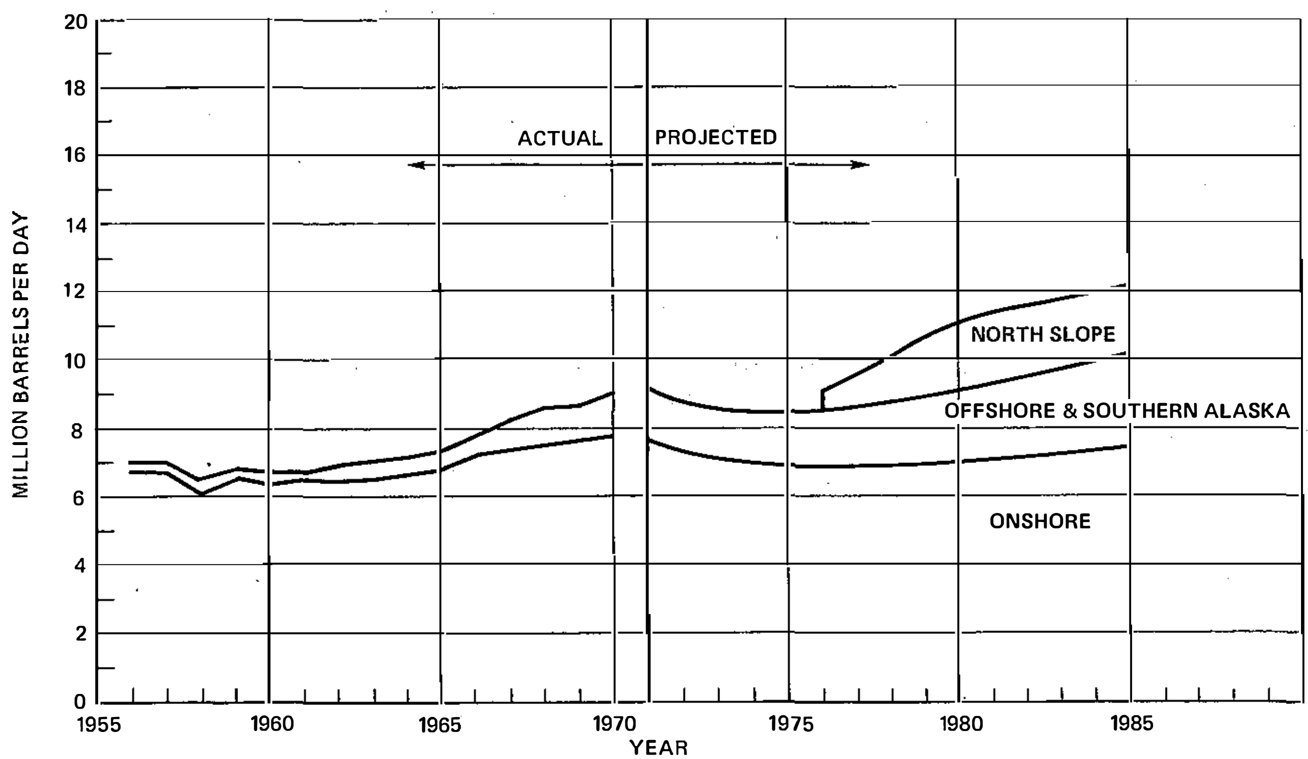


Figure 14. Daily Crude Oil Production (Case II)—Total United States.

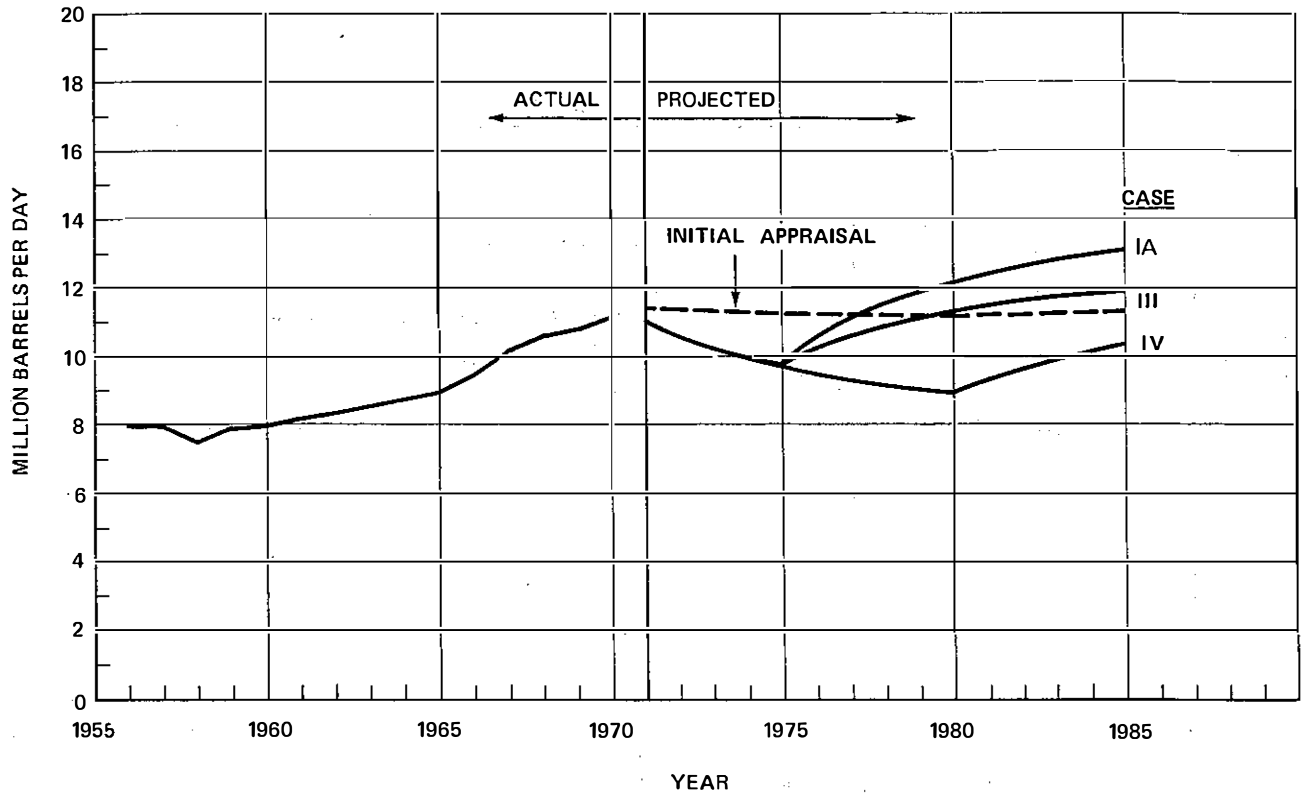


Figure 15. U.S. Total Liquids Production—Low Finding Rate.

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 21 shows 1970 wellhead production and year-end proved reserves of non-associated gas for the lower 48 states. Figure 26 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 26 also shows the effect that finding rates have on projected production by comparing Cases II and III. Projected pro-

* Refer to Chapter Six, Section V.

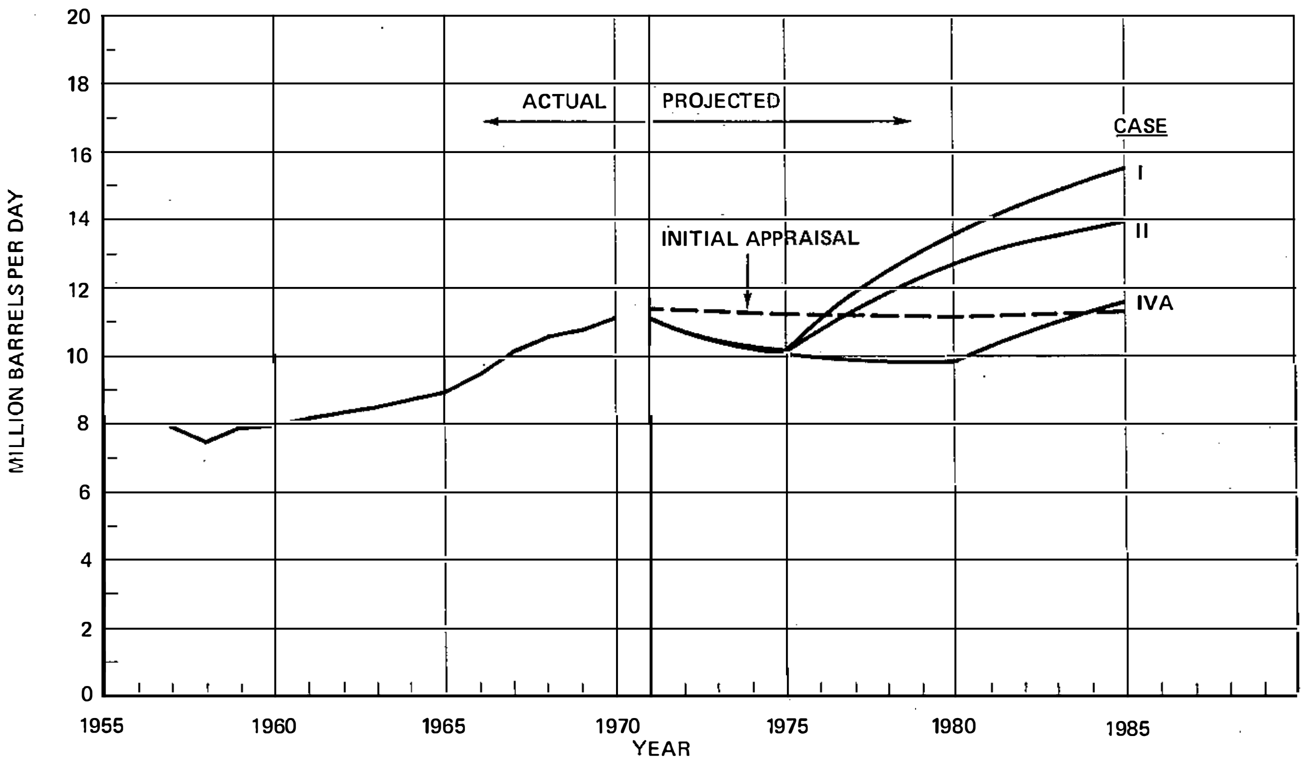


Figure 16. U.S. Total Liquids Production—High Finding Rate.

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 22 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 27 shows marketed gas for the United States projected in the cases utilizing the high finding rate (Cases I, II and IVA). Figure 28 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

* Refer to Chapter Six, Section VI.
† Refer to Chapter Six, Section VII.

TABLE 16

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 23 summarizes the annual NGL reserve additions, and Table 24 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.* Discussions 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

* *U.S. Energy Outlook.*

TABLE 17

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.

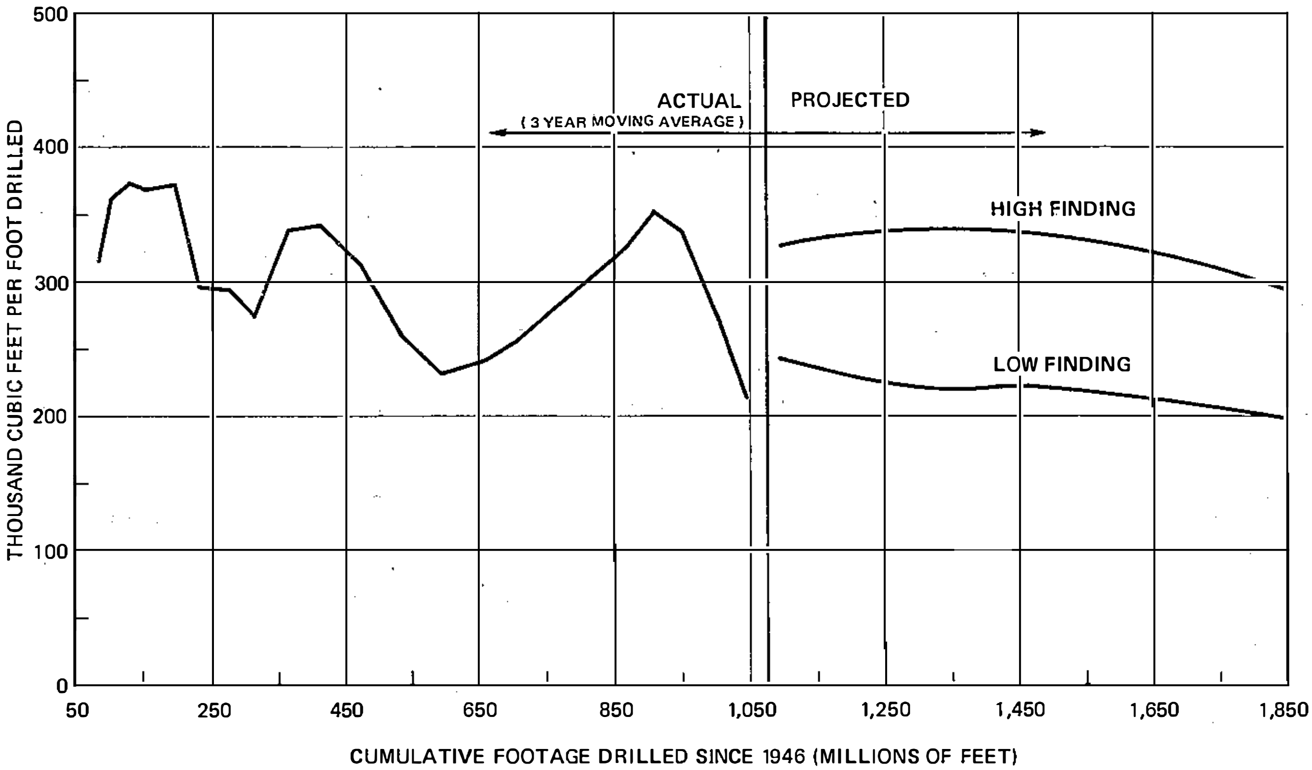
Most of the plant capacities announced assume construction in modules with total capacities ranging from 100 to 500 MCF per day. All plant components, with the exception of catalysts in some cases, are available in the United States. As a general rule, each 100 million cubic feet (MMCF) of plant output 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 17. 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.

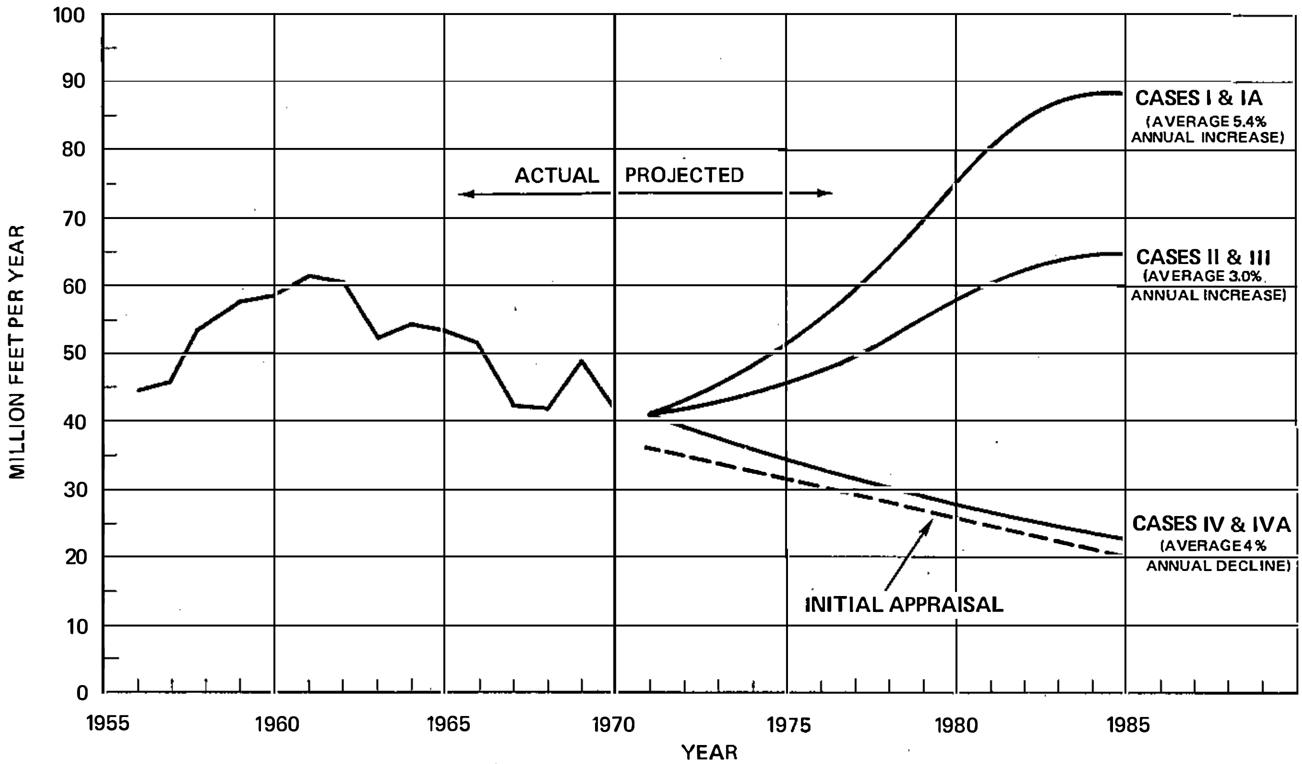
The import question concerns the willingness of the Department of the Interior to permit the import of light hydrocarbons. Approximately two-thirds of the light hydrocarbon feedstock required for these plants is anticipated to be foreign in nature. This has the effect of "exporting" refinery capacity 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 Three. 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 1) 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

* Refer to Chapter Six, Section IX.



Excluding Alaskan gas drilling.

Figure 18. 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.

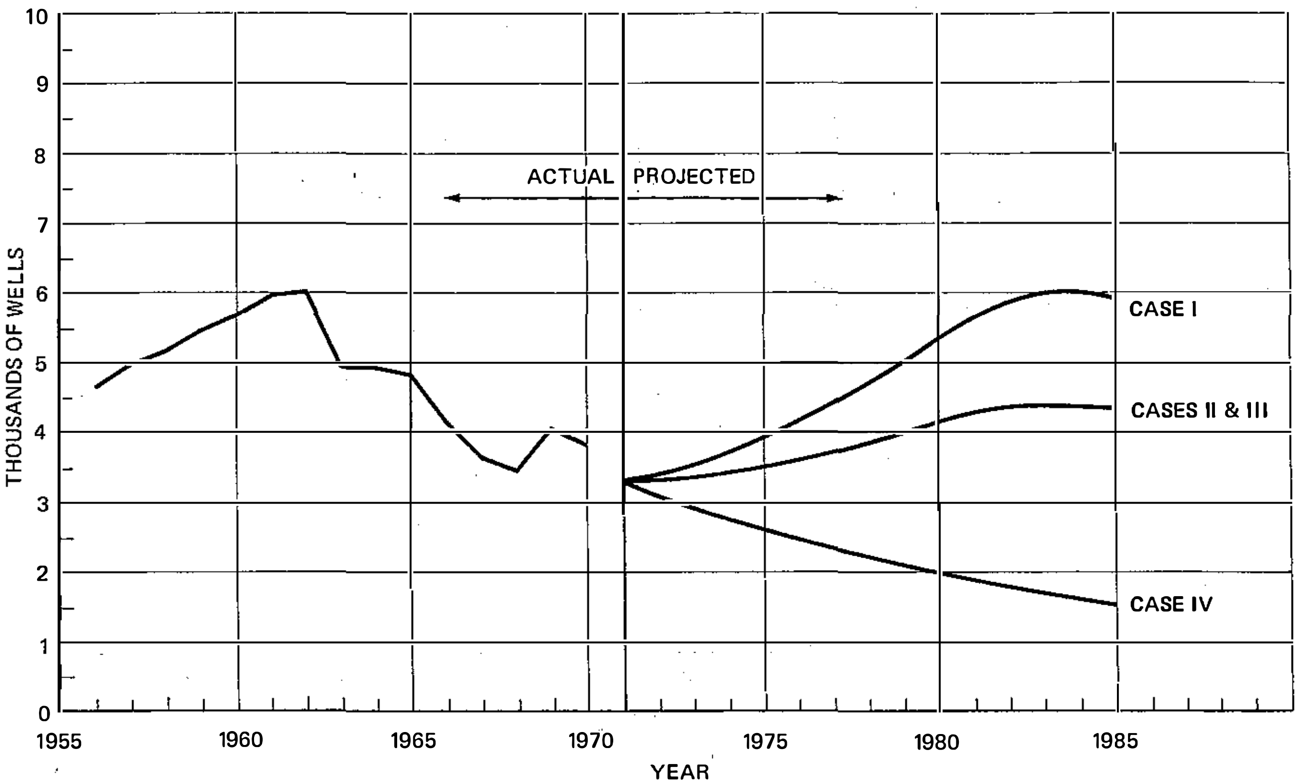
Technical feasibility has been established by the Gasbuggy experiment in northwest New Mexico and the Rulison experiment in Colorado. Two projects (Rio Blanco in Colorado, Wagon Wheel in Wyoming) have been designed which are expected to demonstrate production of about 20 billion cubic feet per well over 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 19. Productive Gas Wells Annually.

taining small amounts of radioactivity, and well-head 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 29 is a map of Alaska showing the pertinent features and locations.

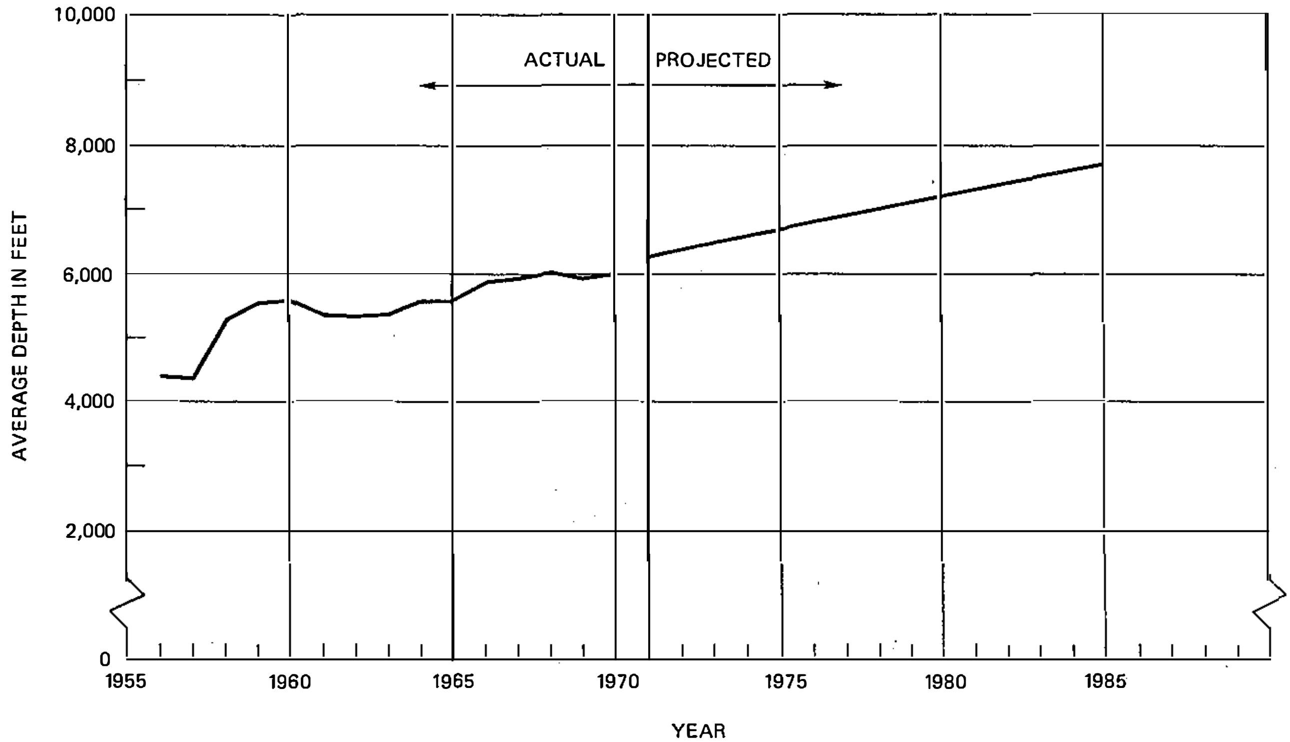
Southern Alaska

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

* Refer to Chapter Five, Section VII and Chapter Six, Section VIII.



Excluding Alaskan gas drilling.

Figure 20. 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 18

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

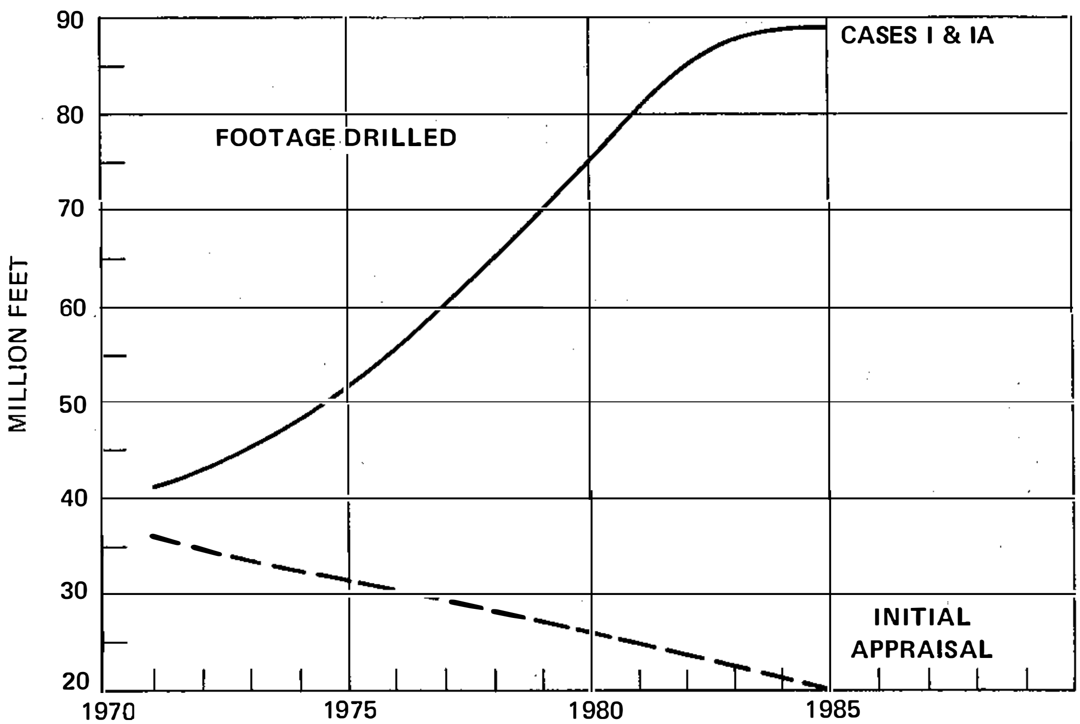
After the discovery at Prudhoe Bay, plans were made for the transportation of the oil to southern Alaska via an 800 mile, 48-inch pipeline. The pipe was ordered and delivered, and initial crude movement through the system was scheduled for 1973. However, governmental and environmental considerations 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.

* *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).

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).



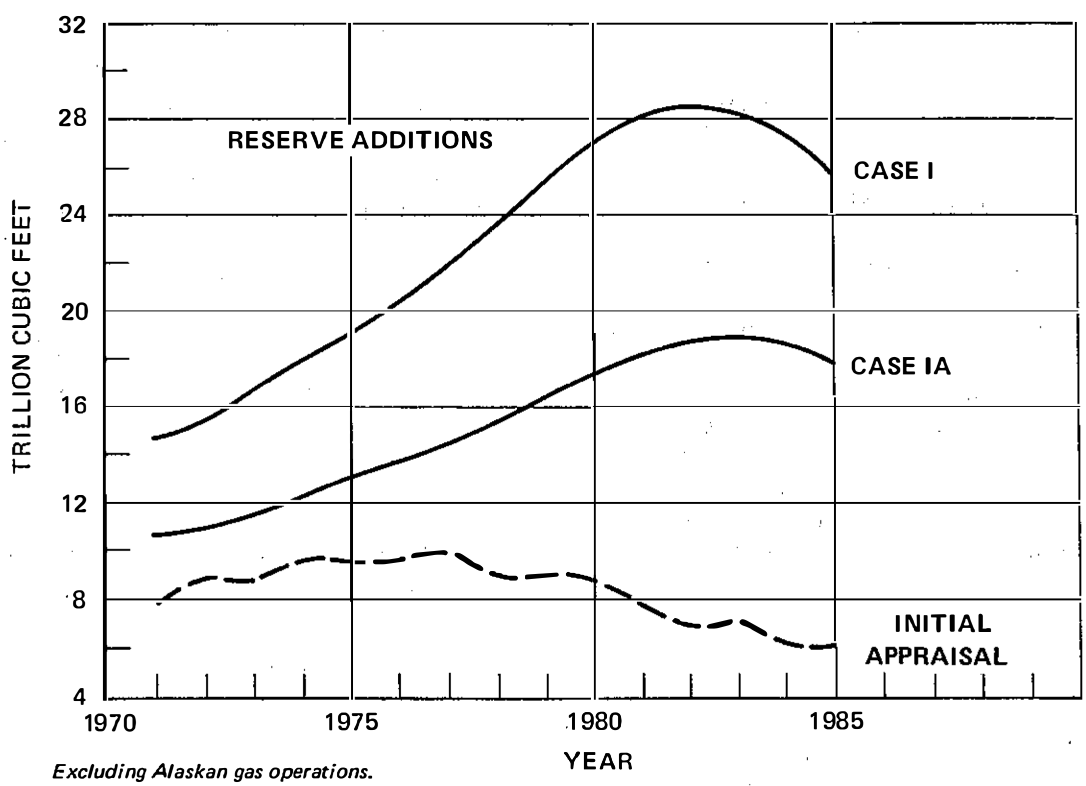
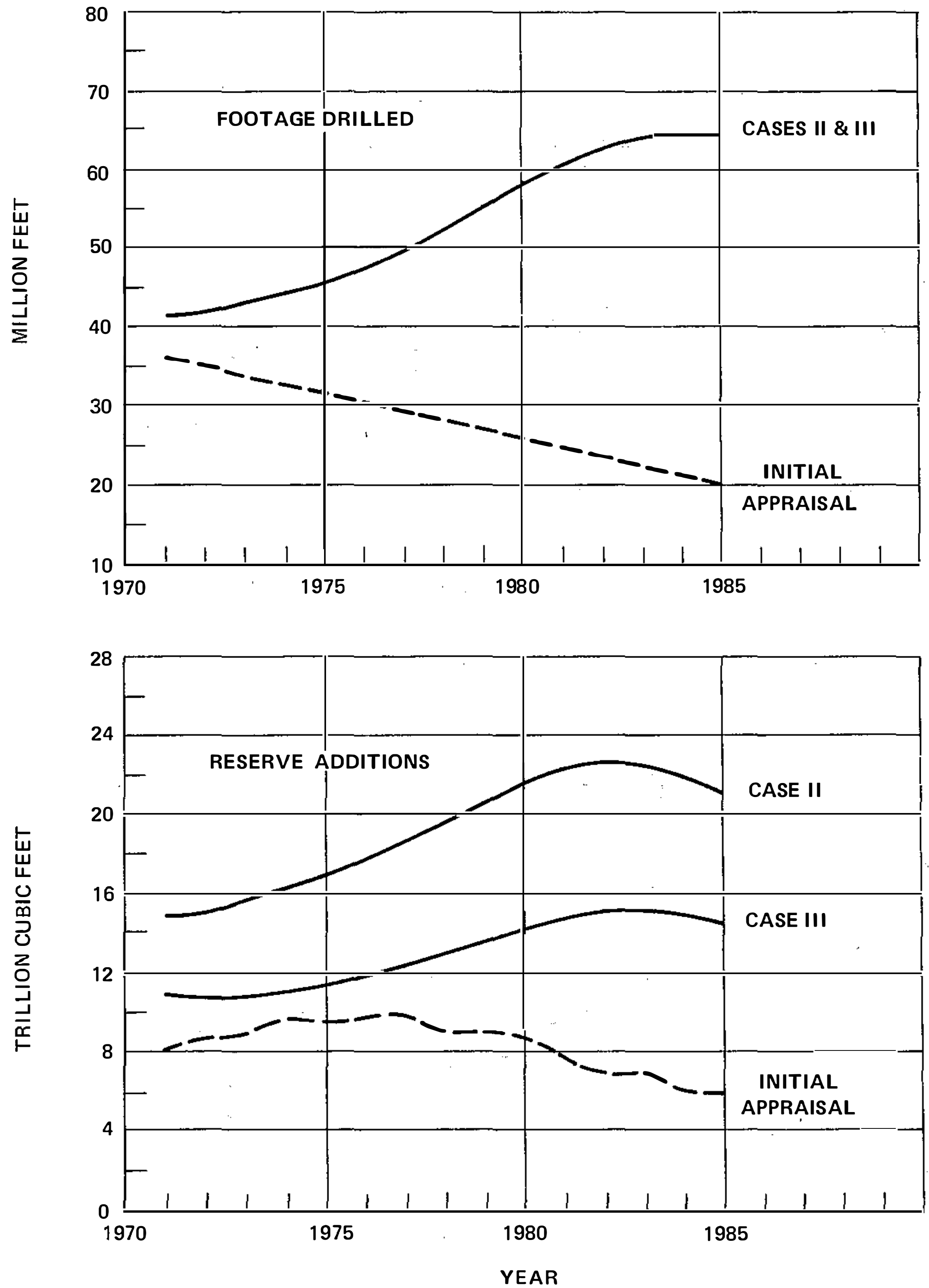


Figure 21. Gas Footage Drilled and Total Gas Reserve Additions (Cases I and IA).



Excluding Alaskan gas operations.

Figure 22. Gas Footage Drilled and Total Gas Reserve Additions (Cases II and III).

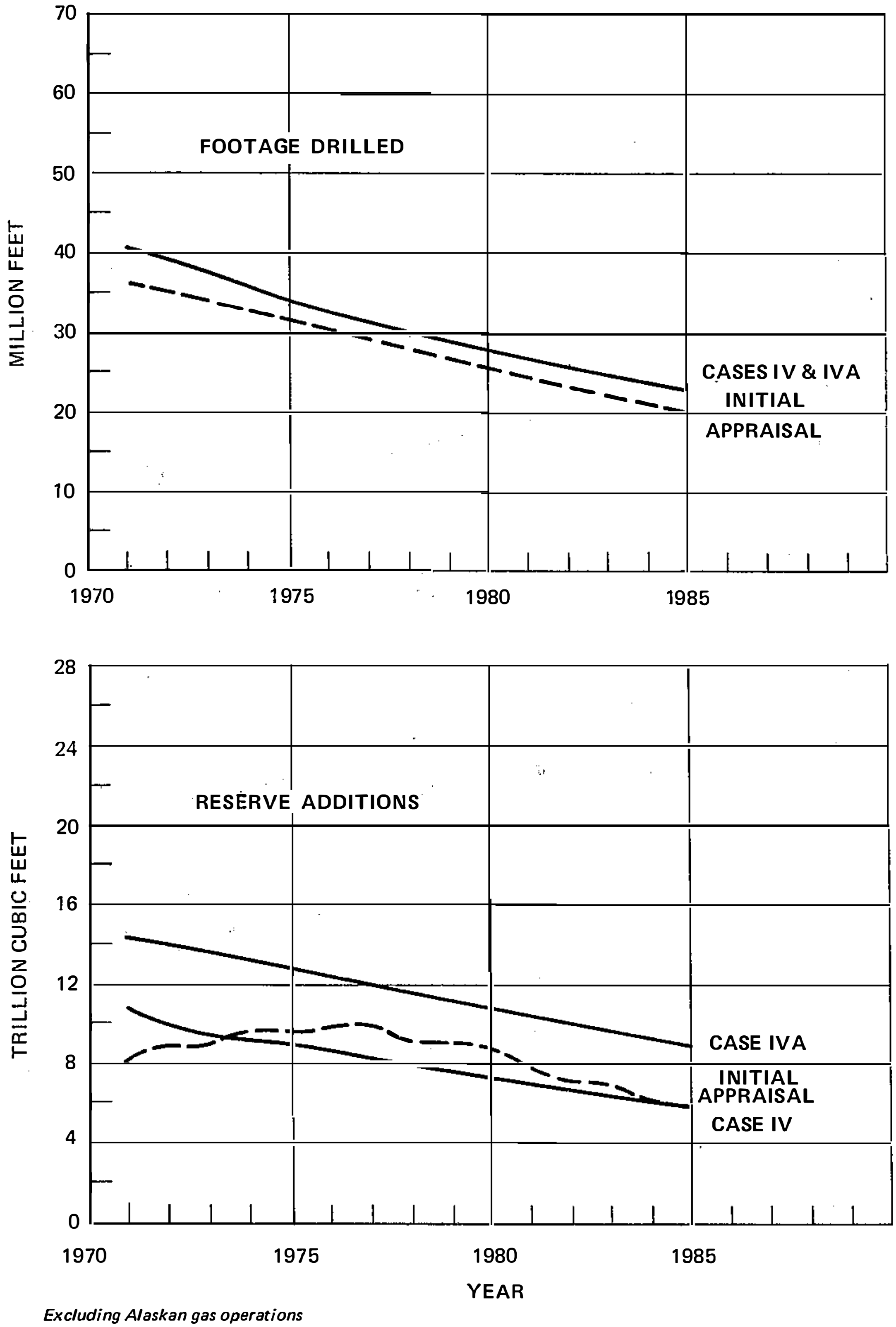
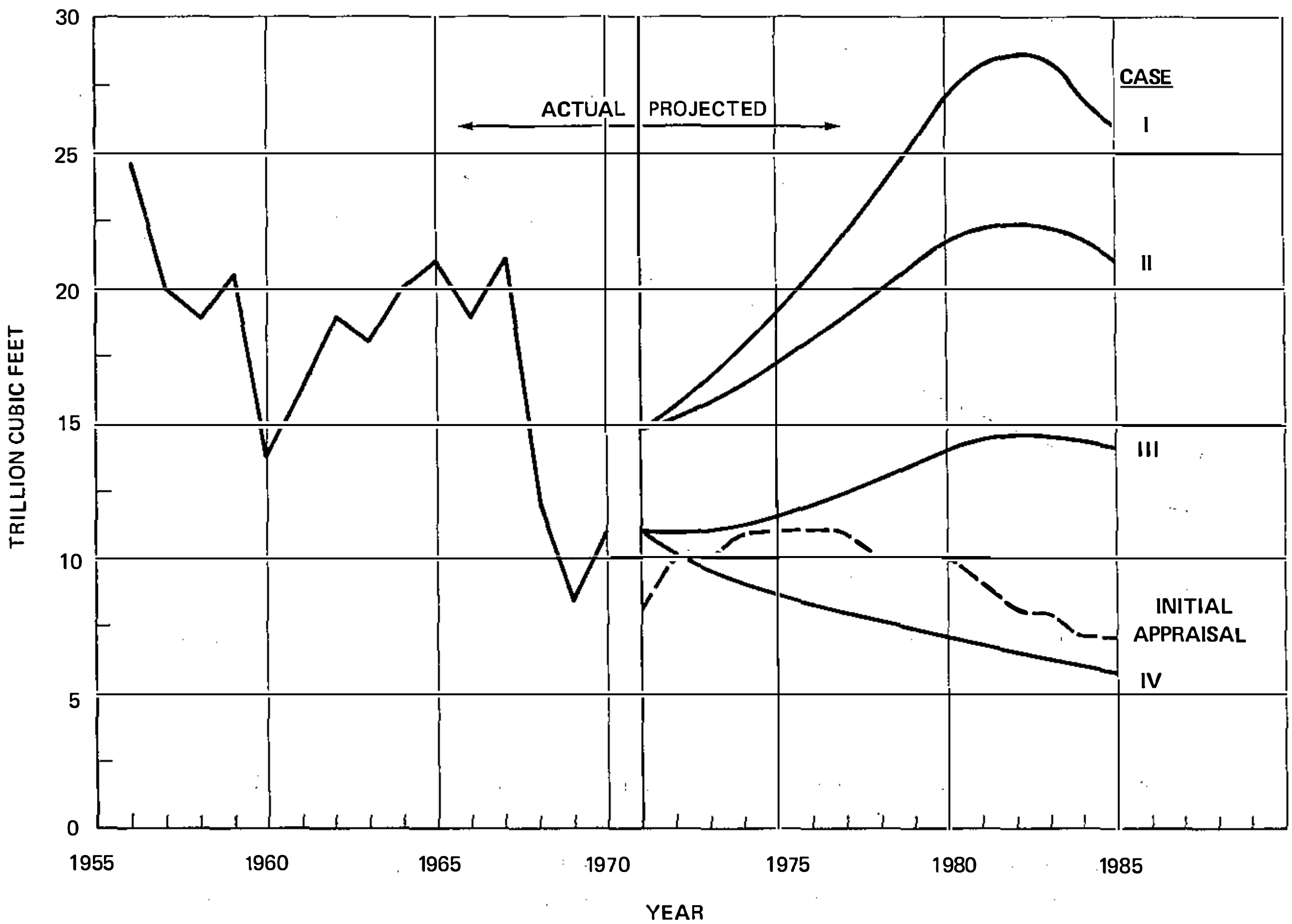


Figure 23. Gas Footage and Total Gas Reserve Additions (Cases IV and IVA).



Excluding Alaskan operations.

Figure 24. 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 25 and 26 summarize the estimated production schedules and exploration and development expenditures.

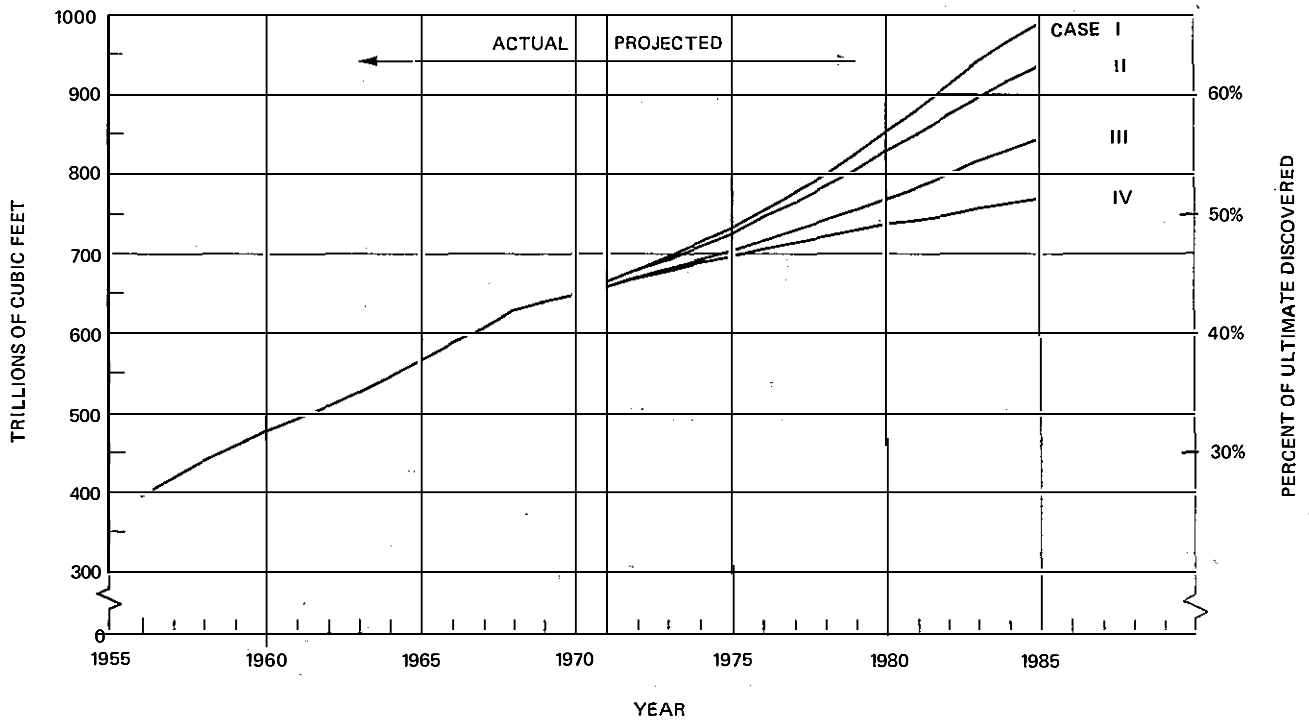
Operating costs for production and transportation for the North Slope cannot be projected with any accuracy until experience in additional drilling and actual production has been achieved. Since these costs and the timing of such activities enter into calculations of "price," the complete impact of Alaska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

* Refer to Chapter Seven.



Excluding Alaskan operations.

Figure 25. 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 30. 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

* Refer to Chapter Five, Section VII and Chapter Seven, Section III.

TABLE 19

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

			Projected 1971–1985					
			High Finding Rate			Low Finding Rate		
Region		Actual 1956–1970	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	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 27, 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 28 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 29.

The growing application of more secondary and

TABLE 20

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 31. 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 32. 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.

* Refer to Chapter Seven, Sections I and III.

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 32. 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 33 and 34 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 21

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).

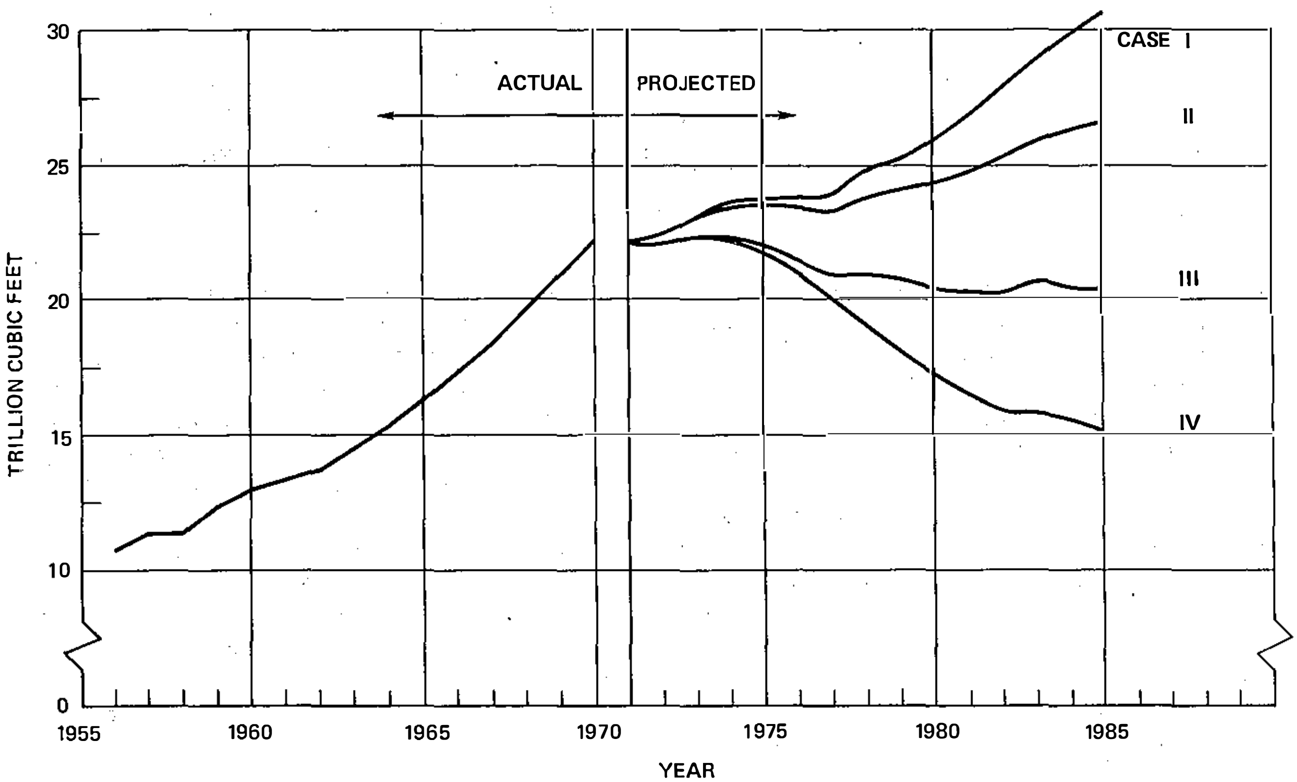


Figure 26. Wellhead Gas Production—Non-Associated and Associated-Dissolved United States (Including Alaska).

TABLE 22

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 33. 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

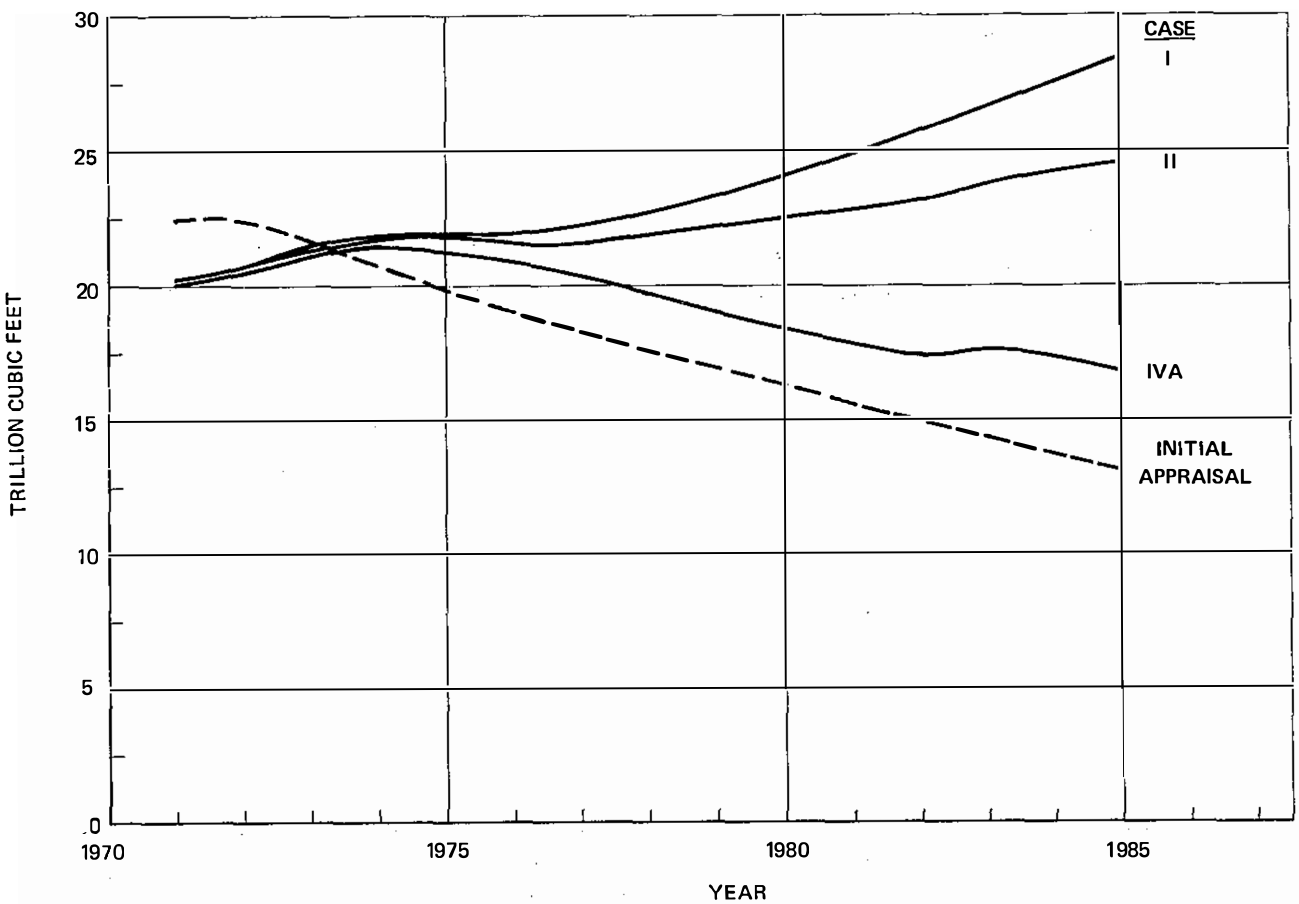


Figure 27. Total Marketed Gas Projections—Total United States (Including Alaska)—High Finding Rate.

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 34. 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 35. 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 36. 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

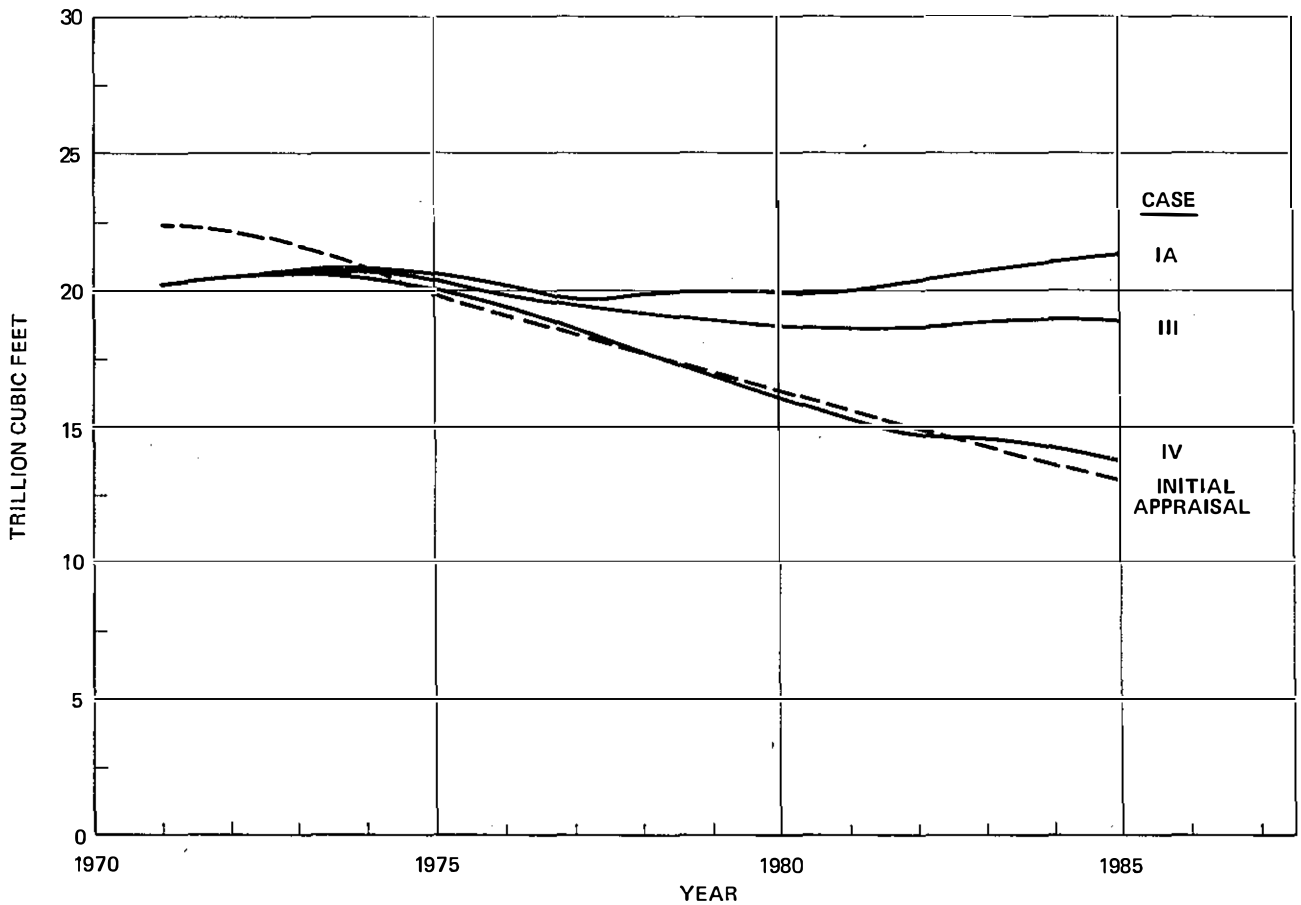


Figure 28. Total Marketed Gas Projections—Total United States—Low Finding Rate.

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.

* Refer to Chapter Seven, Section I.

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 23

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 24

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 37 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

* Refer to Chapter Seven, Sections II and III.

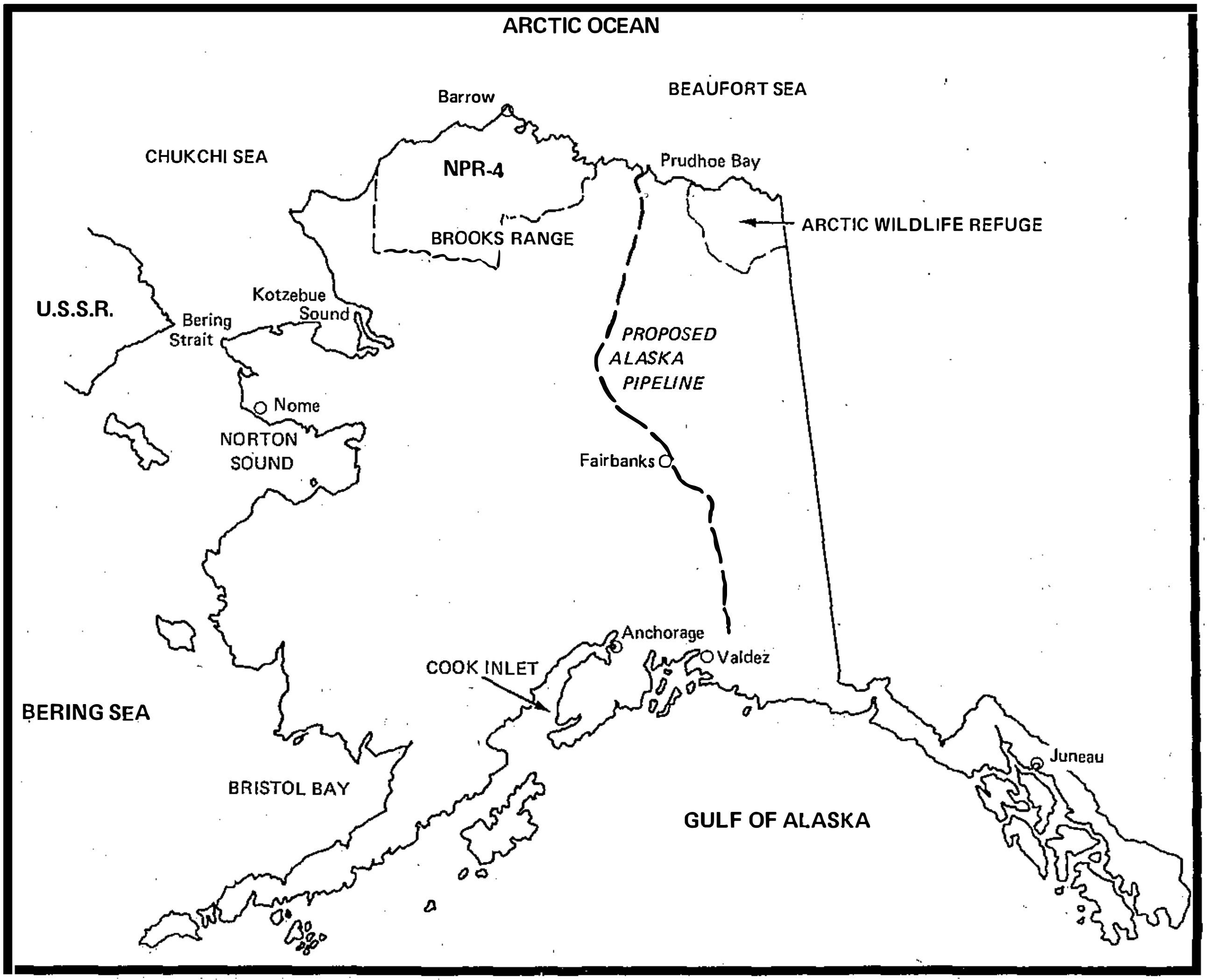


Figure 29. Area Map of Alaska.

drilling rate combined with the high finding rate (Case II) on Figure 38. Figure 39 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 38 and 39 indicate, current earnings from gas are substantially below the range of rates of return used in these studies.

Figure 40 shows the average unit gas revenues required for those cases which utilized the low finding rate (Cases IA, III and IV). Figure 41 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 40 and 41 clearly show the magnitude of the effect that finding rate has on required unit revenue. For example, Case II (see Figure 41), 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 40), 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 25

ALASKAN PRODUCTION*

	Crude Oil—North Slope (MB/D)			
	Case I	Case II	Case III	Case IV
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 38 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.

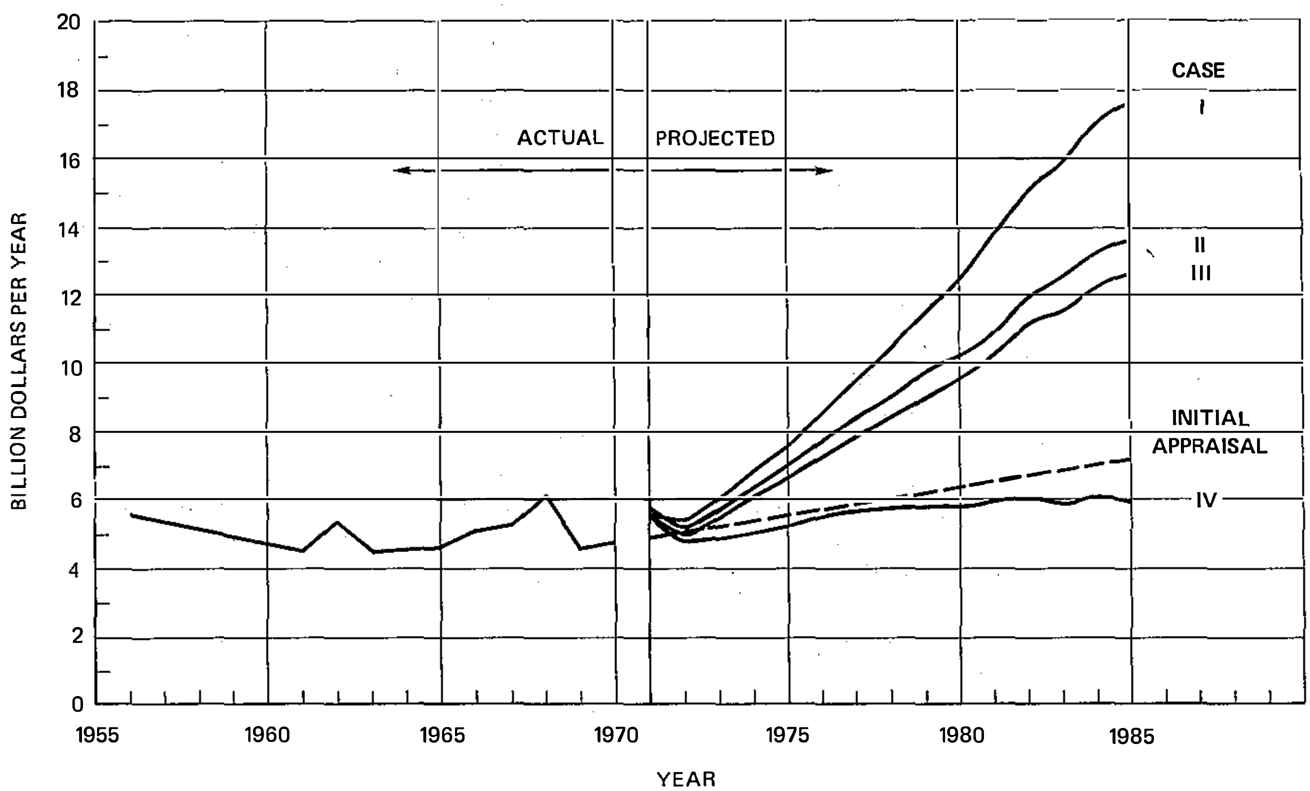
The level of unit revenue required from future gas sales at an assumed rate of return on total gas sales can be calculated by using data generated in the computer program. The program computes the total annual revenue required from gas sales. It also calculates the annual volume of marketed production 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 26

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 30. Exploration and Development Costs —Oil and Gas (Constant 1970 Dollars).

* Refer to Chapter Seven, Section III.

TABLE 27

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 30 shows marketed volumes of pre- and post-1970 discovered gas under Case III conditions. Table 31 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 31 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 31 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 31) increases the constant 1970 dollar price of 53.0 cents to 82.6 cents per MCF.

TABLE 28

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."

* Refer to Chapter Eight.

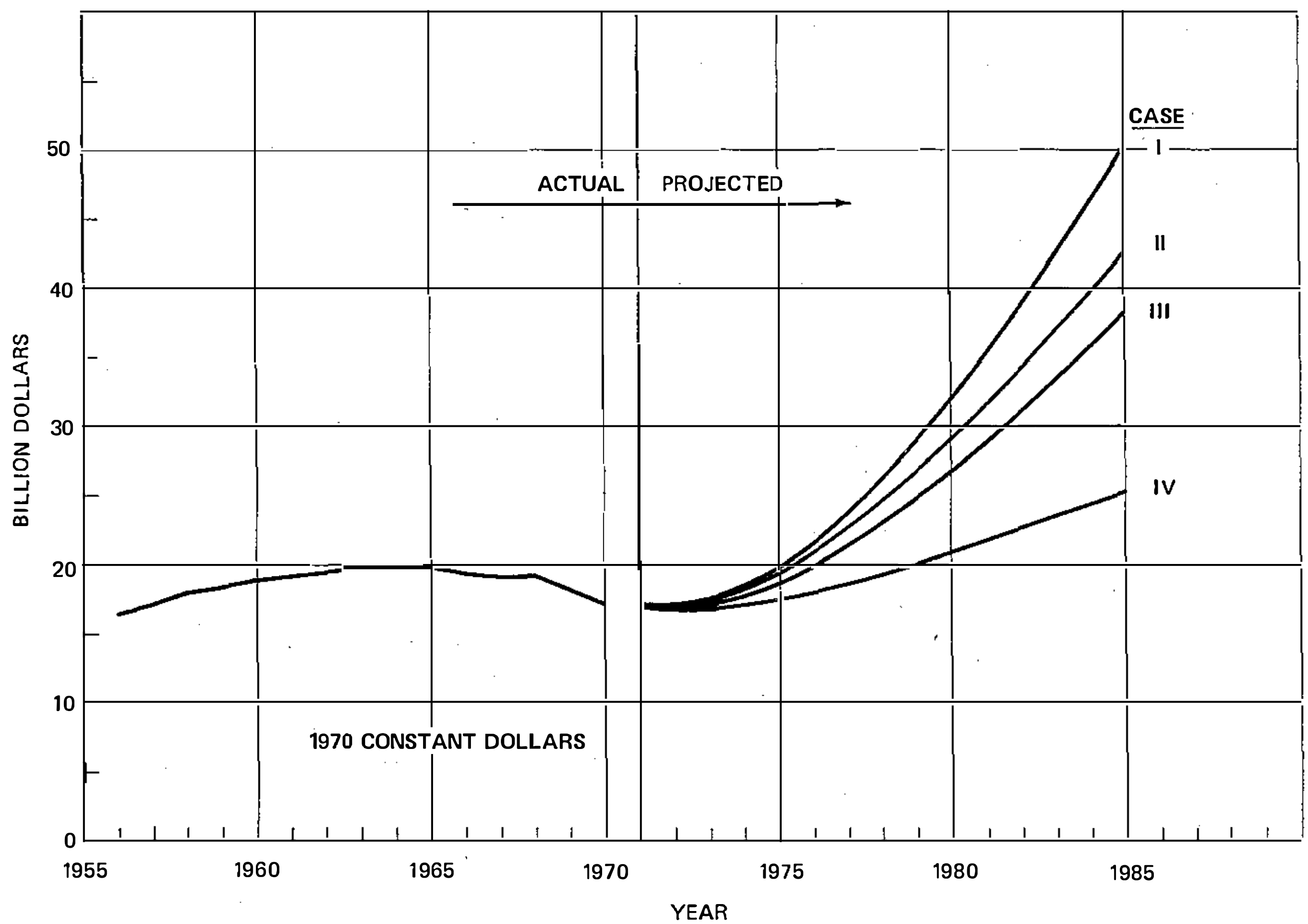
TABLE 29

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	

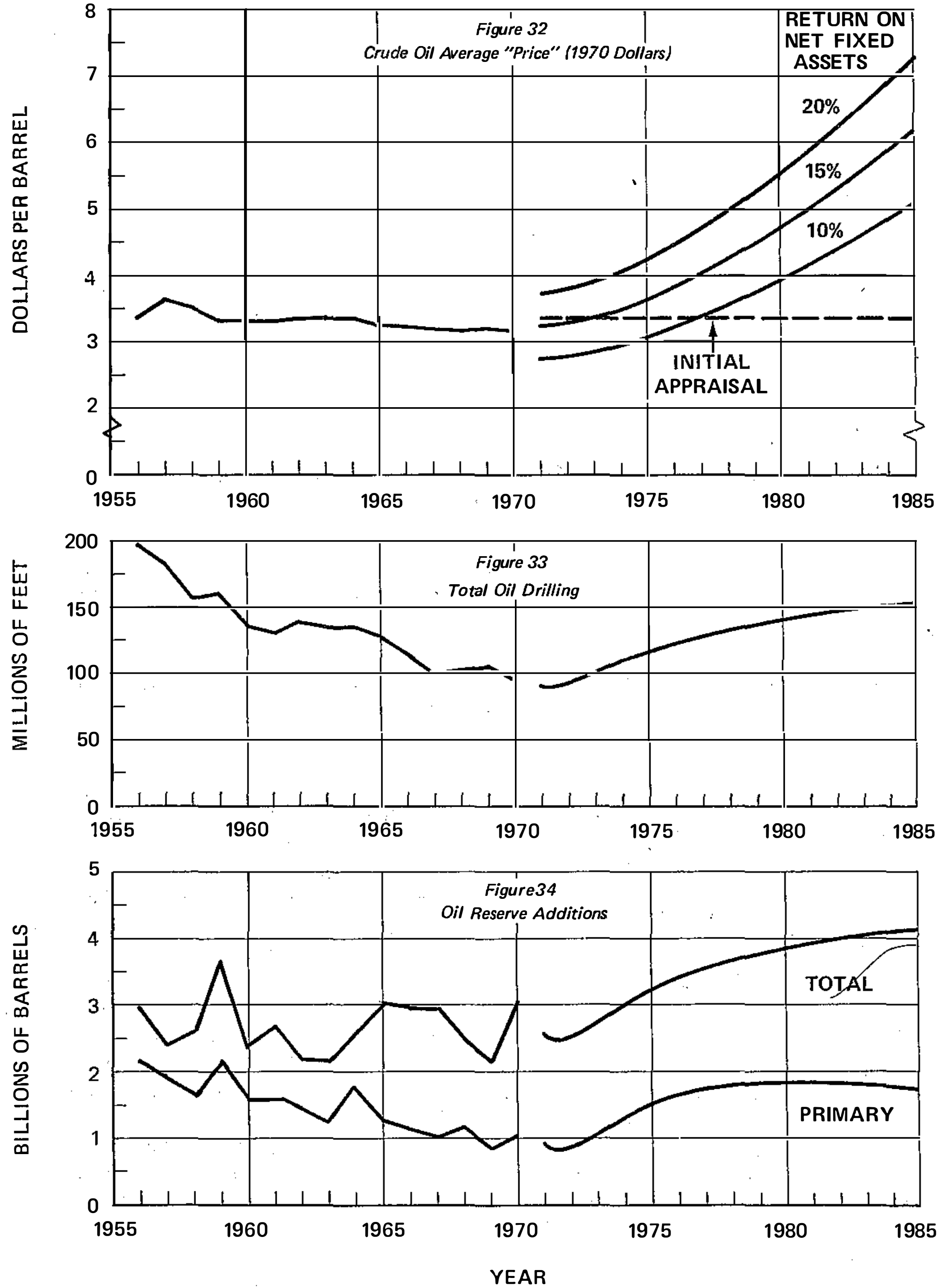
* Developed from *Joint Association Survey of the Oil and Gas Producing Industry,* Sponsored by the American Petroleum Institute, Independent Petroleum Association of America and Mid-Continent Oil and Gas Association (published yearly).

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.



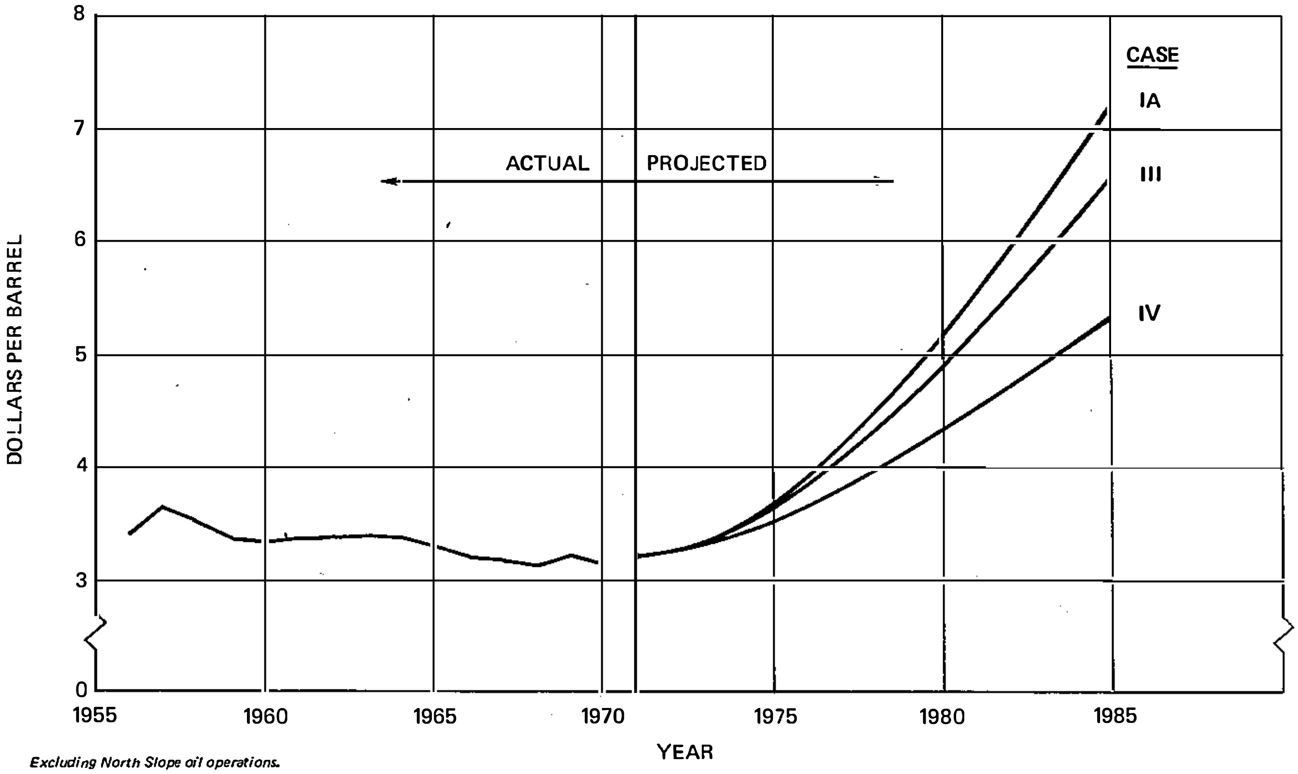
Excluding North Slope operations.

Figure 31. Net Fixed Assets—Oil Operations (Billion Dollars).



Excluding North Slope operations.

Figure 32-34. Oil Average "Price," Drilling and Reserve Additions.



Excluding North Slope oil operations.

Figure 35. 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 32. 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 32 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

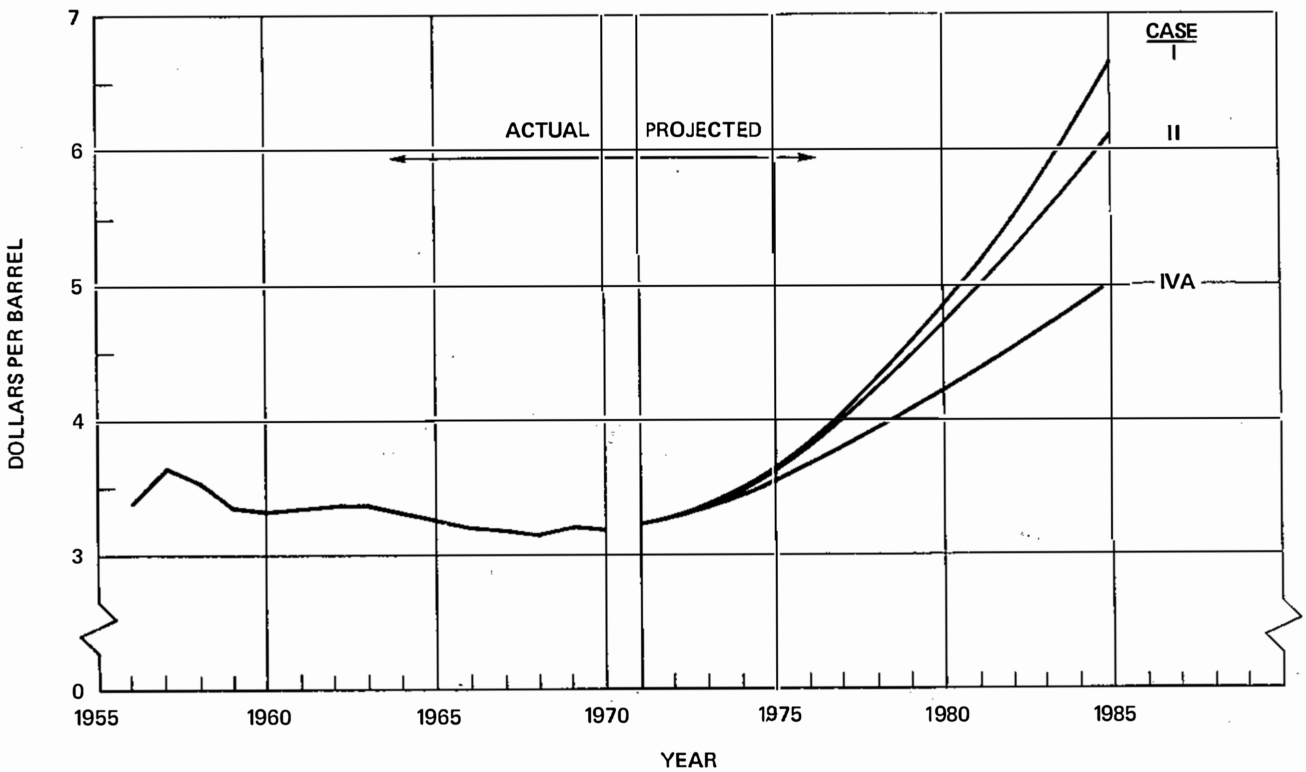


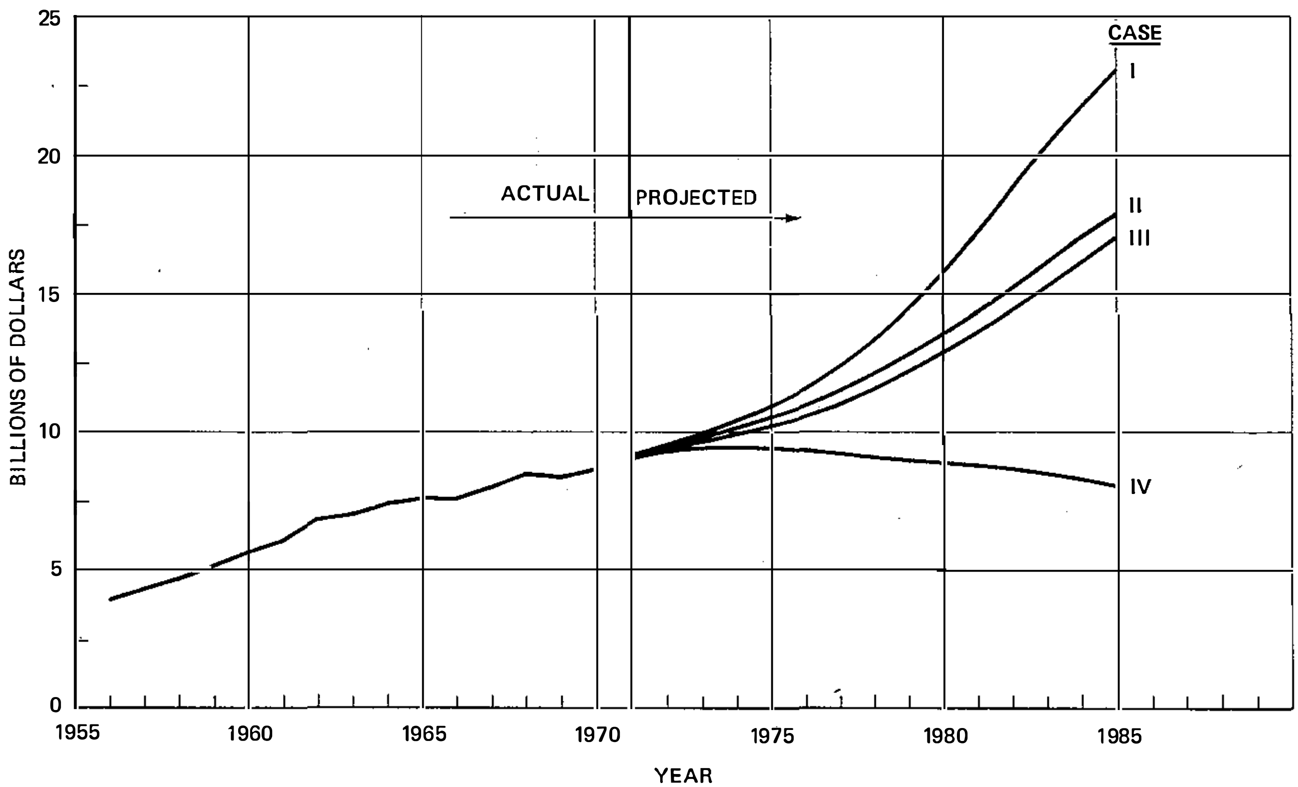
Figure 36. Required Crude Oil "Price"—High Finding Rate—15-Percent Return (Constant 1970 Dollars).

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 33. 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 34. 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 34. 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 37. Year-End Net Fixed Assets—Gas Operations.

through, additional recovery projects were implemented earlier and applied to more fields, production would be significantly increased. Studies were made against the highest and lowest supply cases (I and IV) in which implementation 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 35. 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 36). 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 37, 38 and 39.

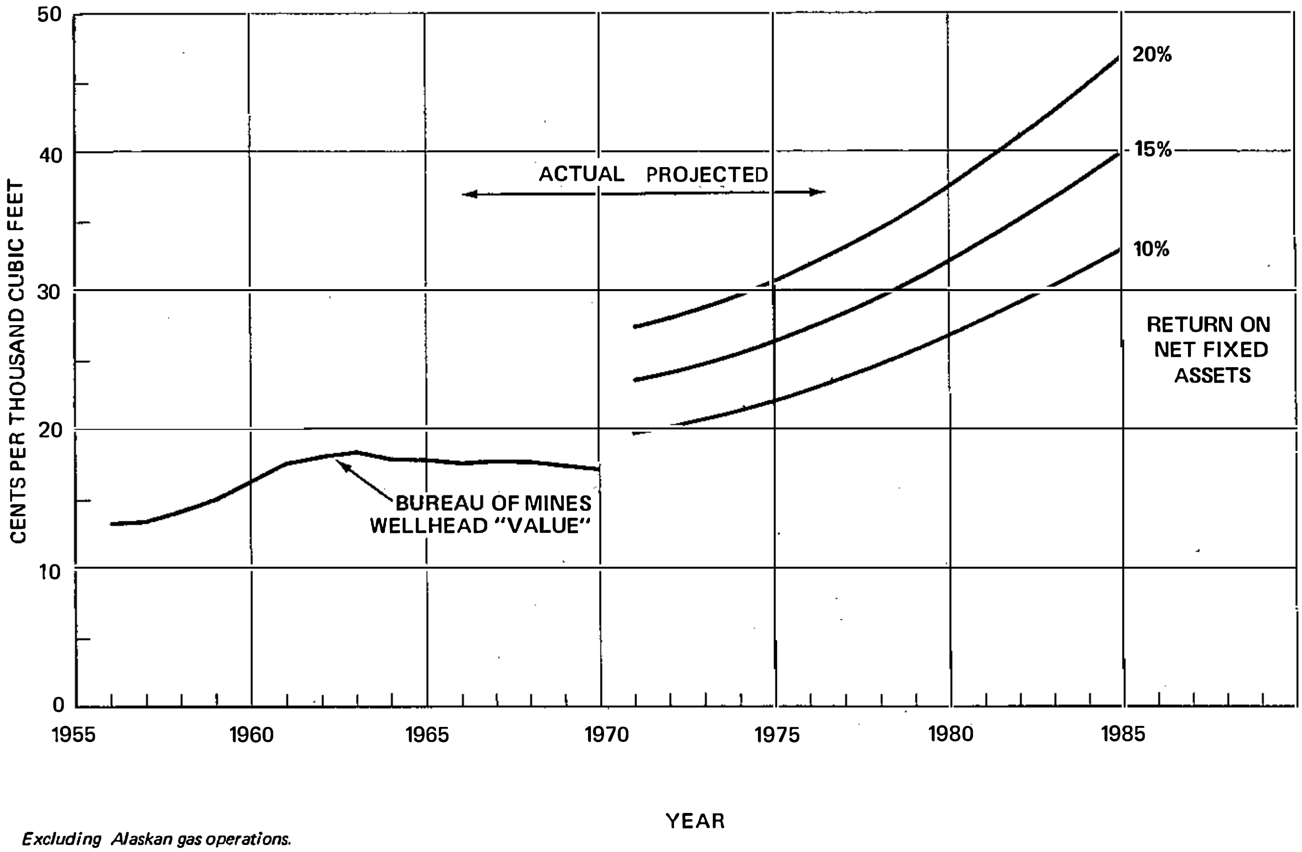


Figure 38. Required Average Gas "Prices"—Case II (Constant 1970 Dollars).

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.

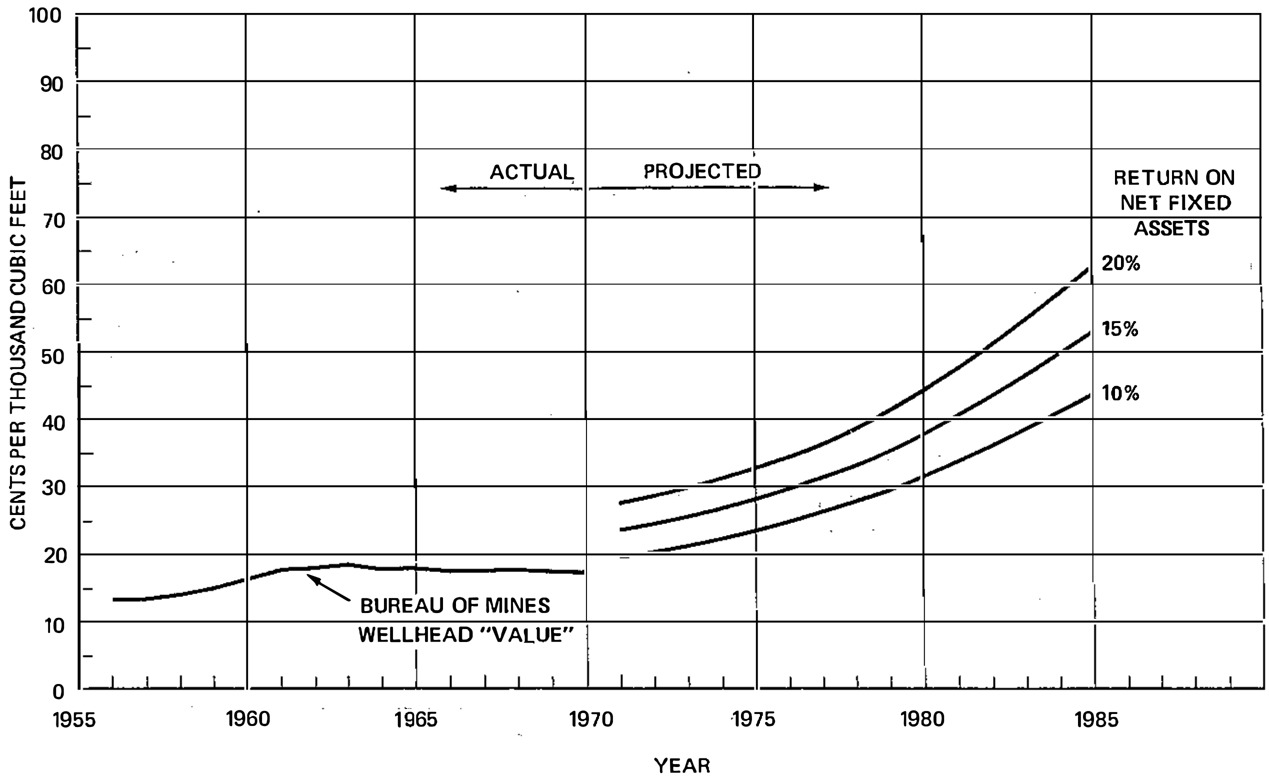
To determine the economic impact of further regulations of this nature, a parametric study was made in which these costs were arbitrarily doubled. The impact of this doubling on exploration and production economics is quite substantial, as shown in Table 40.

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 39. 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 41 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 42 shows the areas in which the oil production would be lost. Also shown on Figure 42 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 43. In this case, up to 35 percent of the 1985 gas supply would be eliminated.

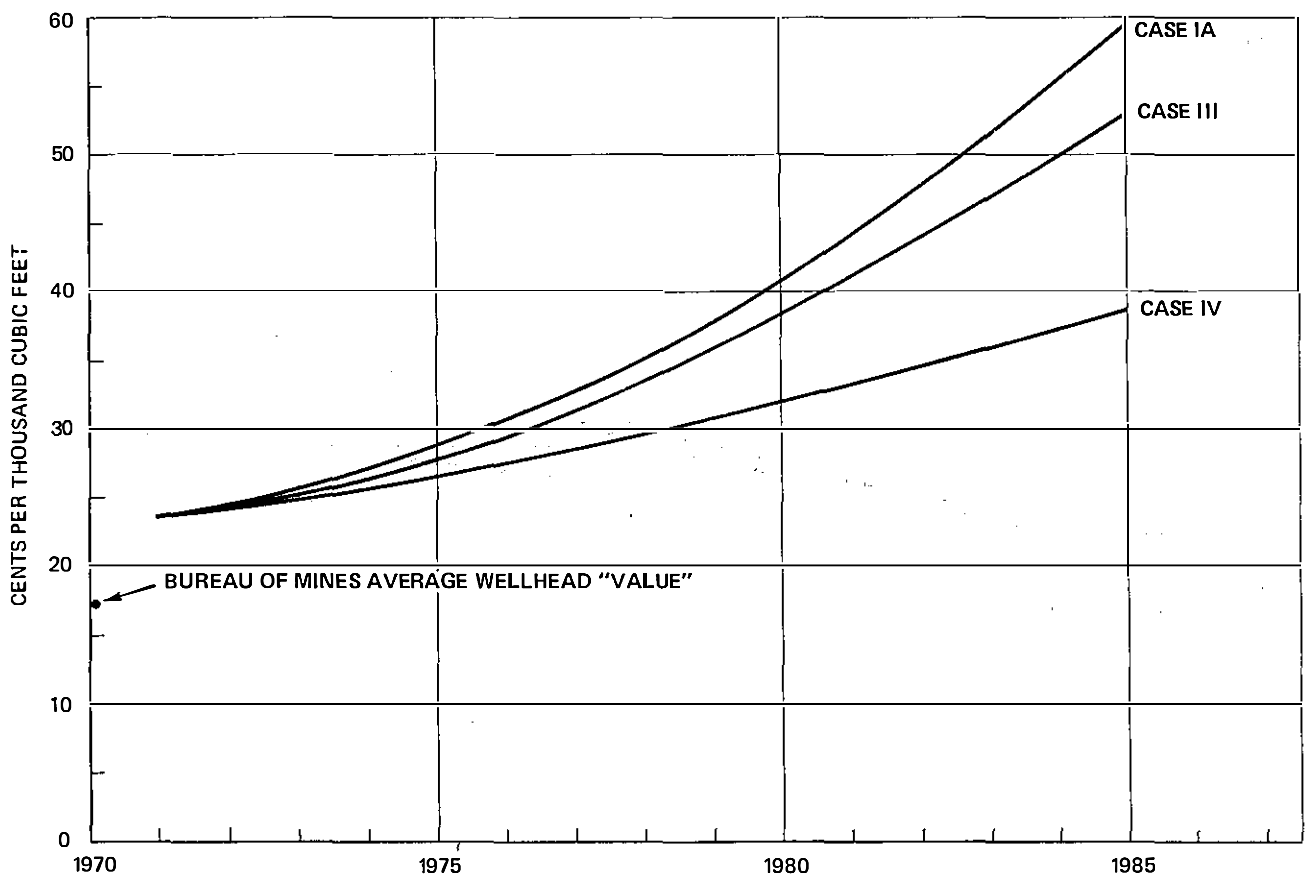
Table 42 shows the production cutback which would occur if new offshore leasing on the Gulf Coast were delayed until 1975 and eliminated in all the other areas. Under this condition, the country would be denied in excess of 1 MMB/D of oil and over 1 TCF of gas per year at the end of the period.

The effect on supply of delaying all offshore leasing for 5 years is shown in Table 43, while the effects of delaying only Pacific Coast offshore leasing for 5 years are depicted in Table 44.

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 45.

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-



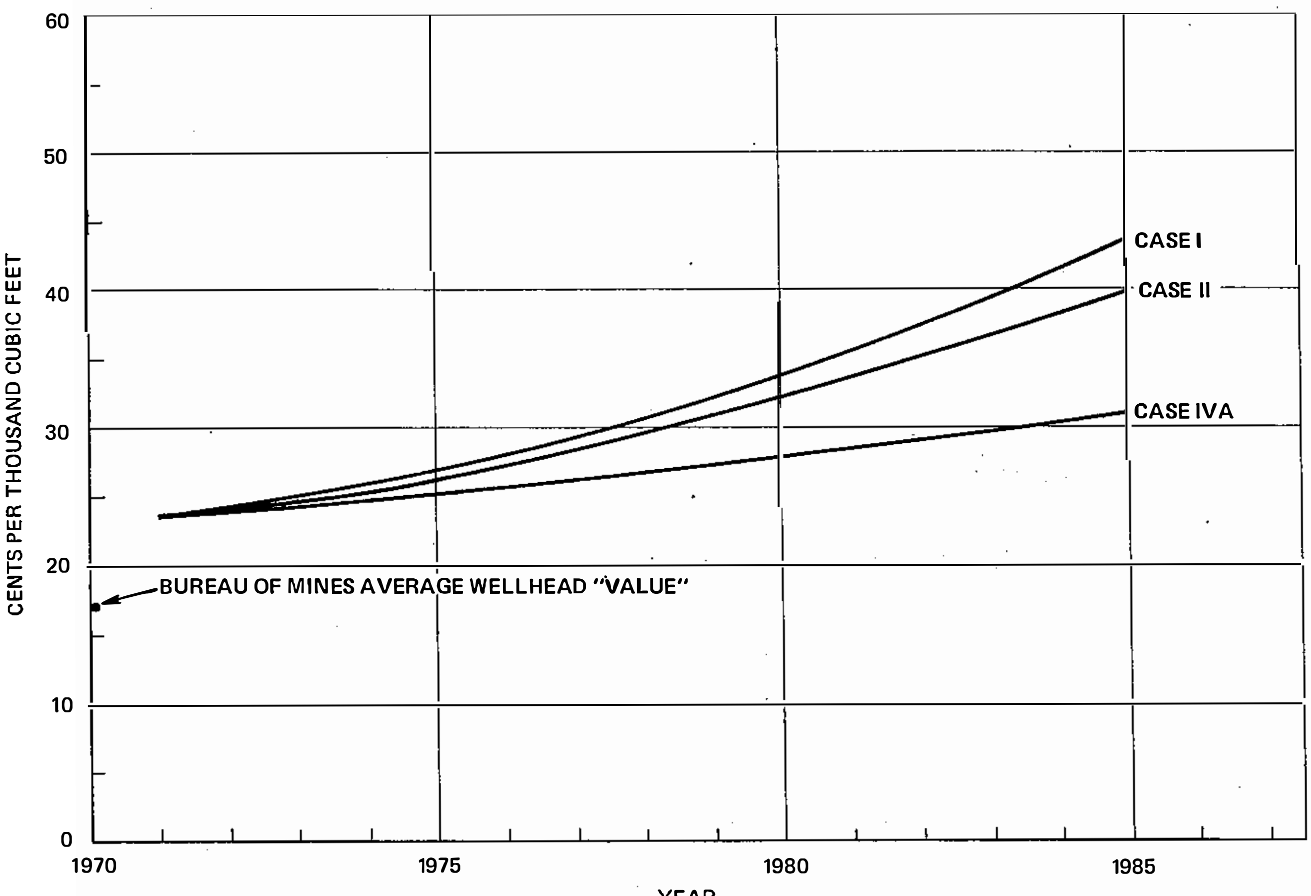
Excluding Alaskan gas operations.

Figure 40. 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 41. Required Average Gas "Price" Projections—15-Percent Return on Net Fixed Assets—High Finding Rate.

TABLE 30

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

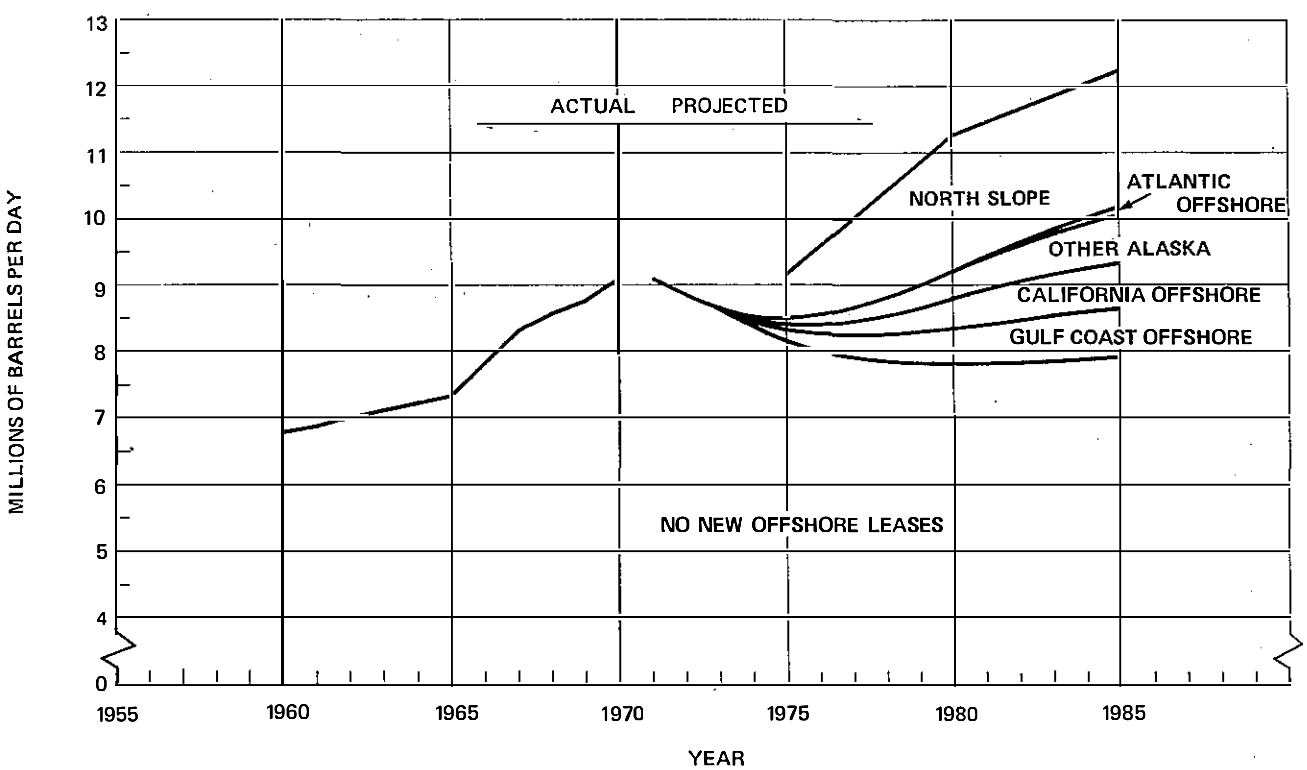


Figure 42. Effect of No New Offshore Leases or North Slope Production—Daily Oil Production (Case II).

TABLE 31

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

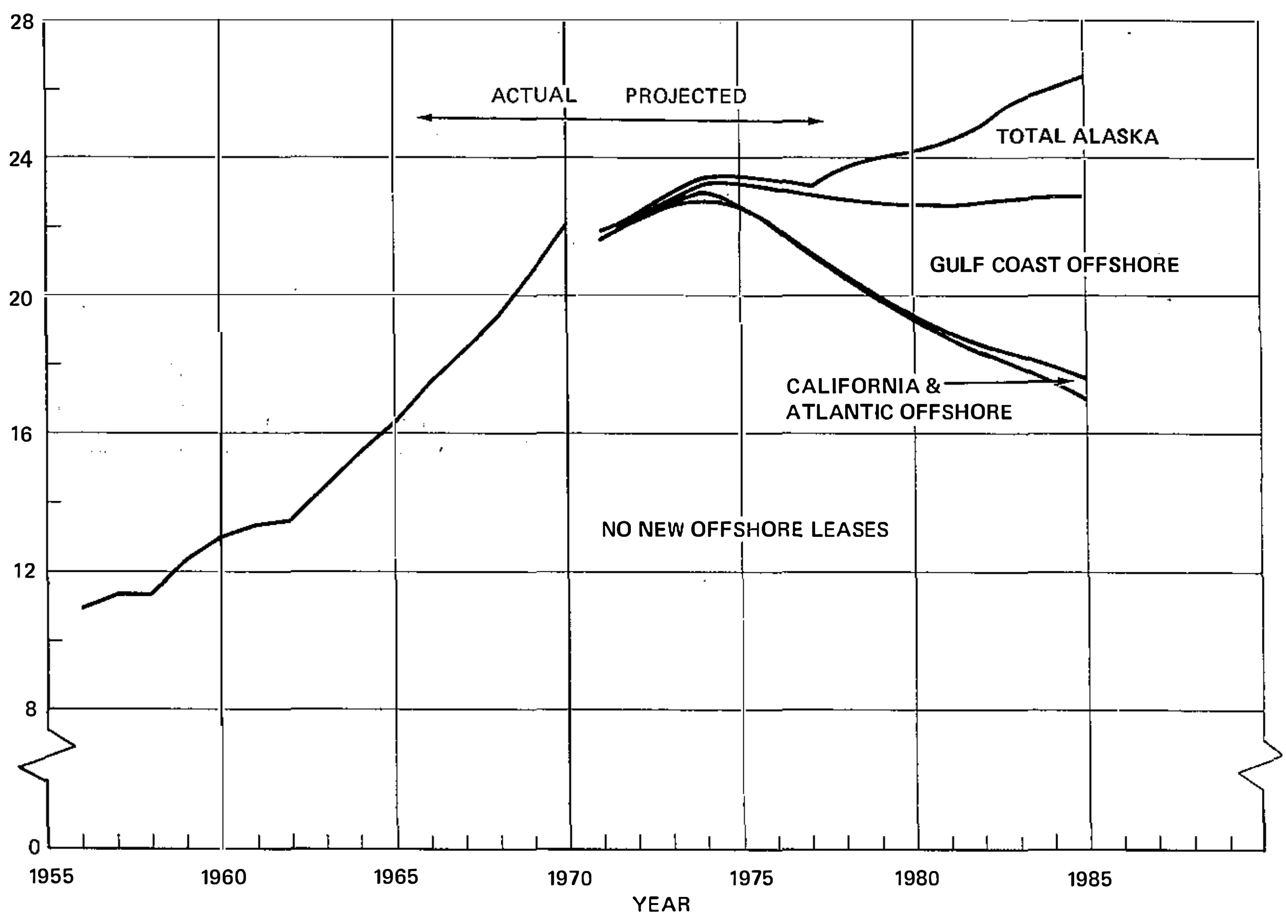


Figure 43. Effect of No New Offshore Leases or Alaskan Production—Wellhead Gas Production (Case II).

TABLE 32

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 33

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 46.

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 34

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 35

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 36

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 37

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 38

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 39

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 40

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 41

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 43

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 42

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 44

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 45

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 47.

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 48, 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 46

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 47

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 48

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 49.

TABLE 49

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 50

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 51

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 50 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 52

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 Two

Foreign Oil and Gas Availability

Chapter Two
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 53.

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 53 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 53

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

Editor's Note: This chapter appears as Chapter Twelve in the NPC's *U.S. Energy Outlook* report of December 1972.

* Refer to Chapter Eight of this report.

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 54).
- 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 54

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" in *U.S. Energy Outlook.*

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 55.

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 55

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 56.

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 56

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 57 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 58 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 58, discussions concerning imports from Russia suggest that LNG projects based on that source of supply should be considered a possibility.

* Refer to Chapter Six, Section XI, and Chapter Nine.

TABLE 57

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:		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 58

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 59 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 44. 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 59

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	–	–

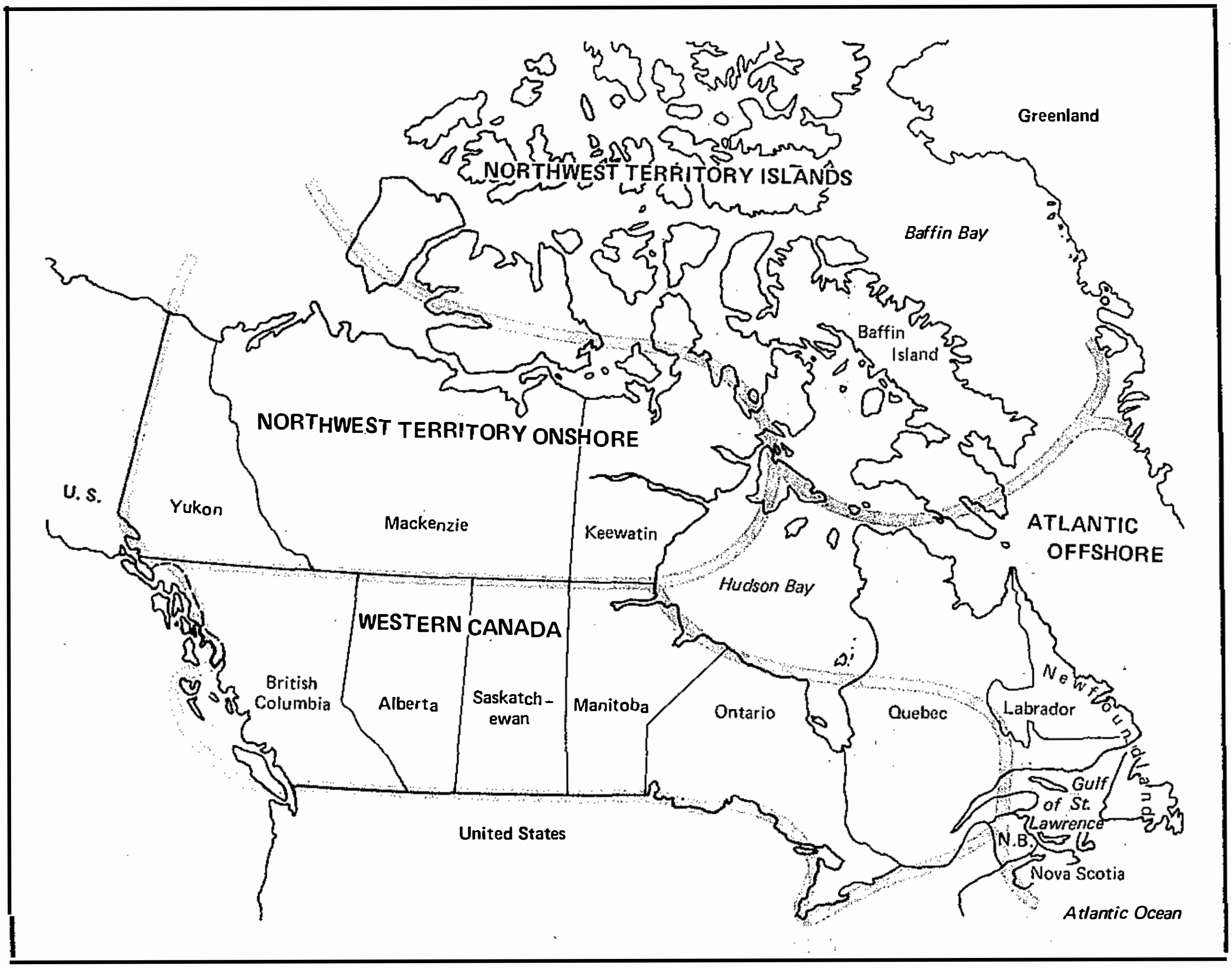


Figure 44. Area Map of Canada.

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 Three

Oil and Gas Logistics and Imports

Chapter Three
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 60 through 63 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 *U.S. Energy Outlook* which are based on BTU's.

Editor's Note: This chapter appears as Chapter Thirteen in the NPC's *U.S. Energy Outlook* report of December 1972.

TABLE 60

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 61

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 62

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 63

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 45 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 64 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 65 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 shown in Table 65, 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

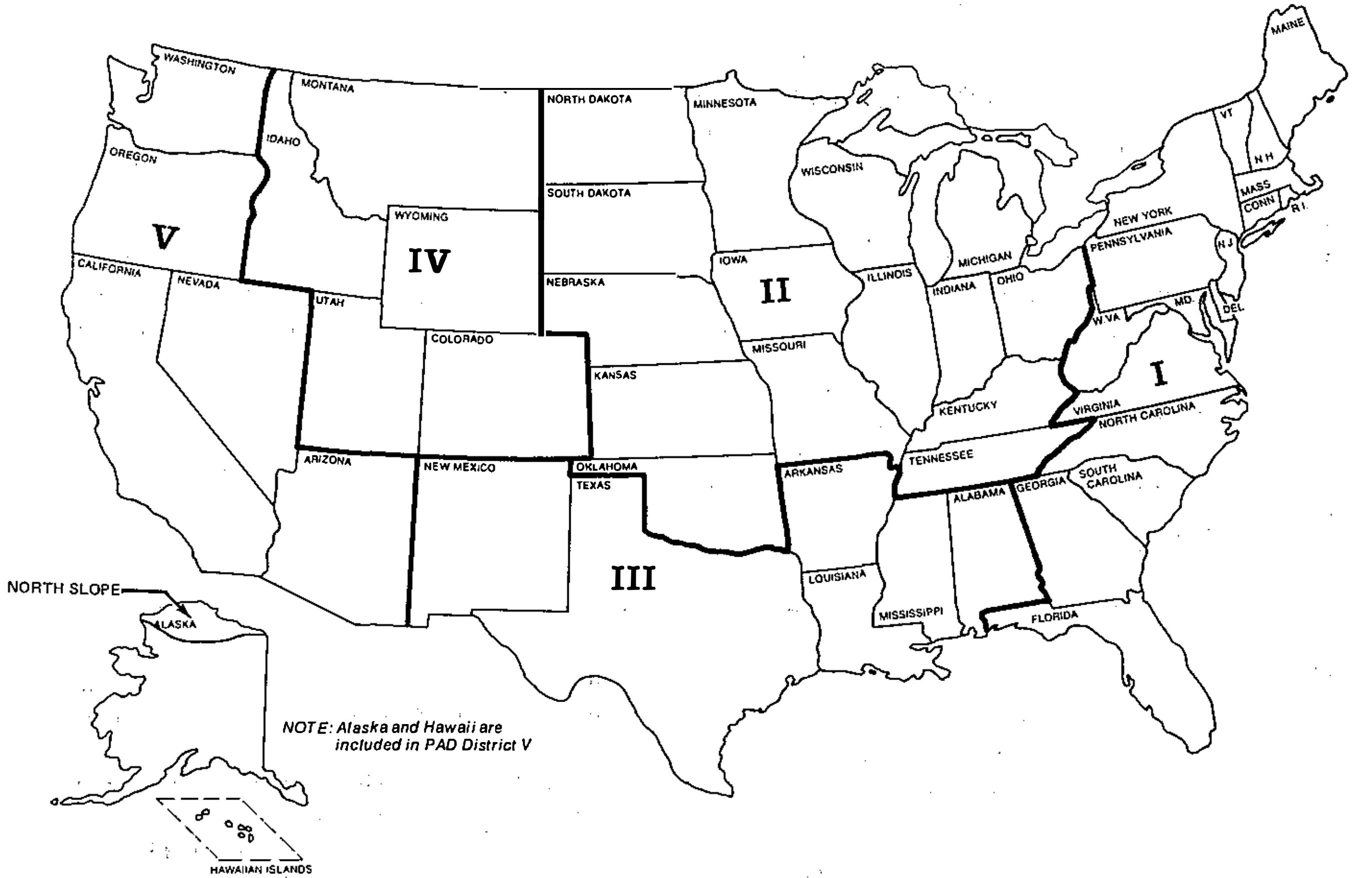


Figure 45. Petroleum Administration for Defense (PAD) Districts.

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 64

PETROLEUM SUPPLY/DEMAND SITUATION—ALL OILS—1970
(MB/D)

	PAD Districts					Total
	I	II	III	IV	V	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 65

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 66

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 66, 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 67).

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 67

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 46 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

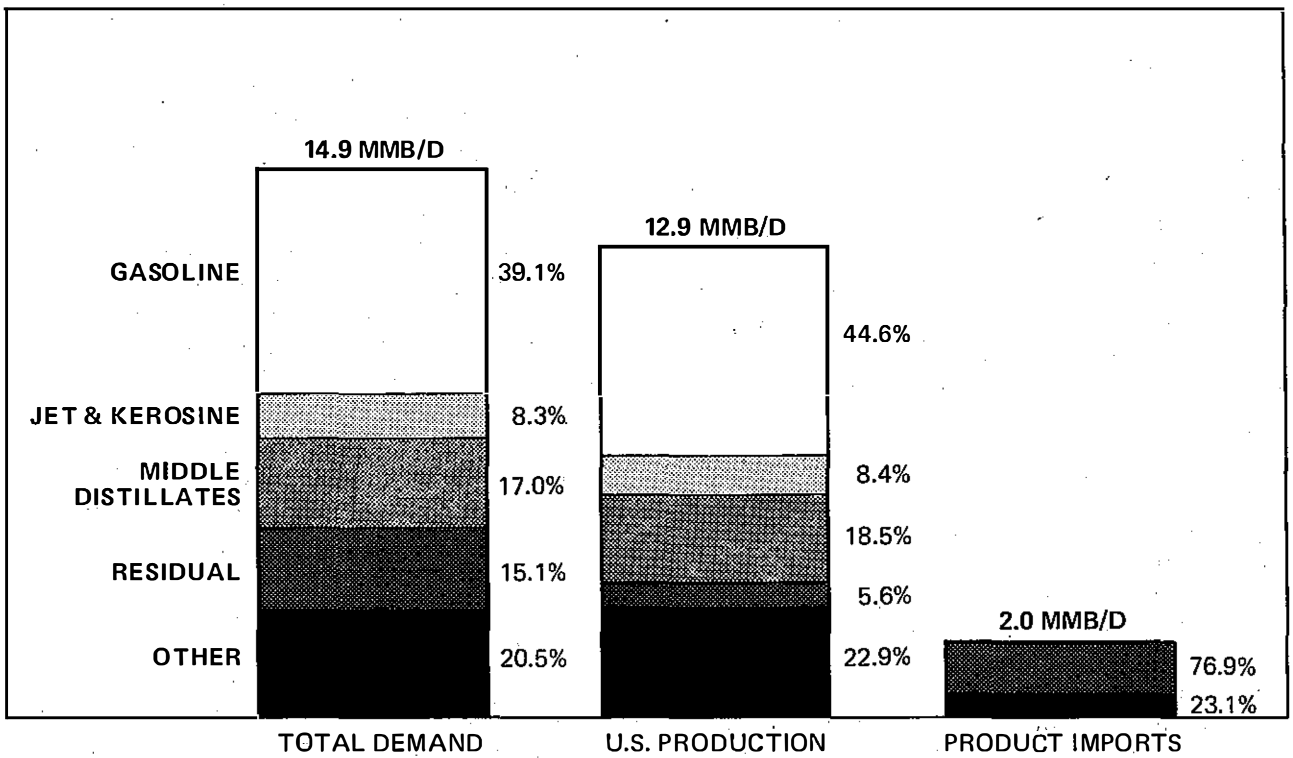


Figure 46. U.S. Petroleum Product Demand and Production.

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 68. 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 47 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 68

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 47 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 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.

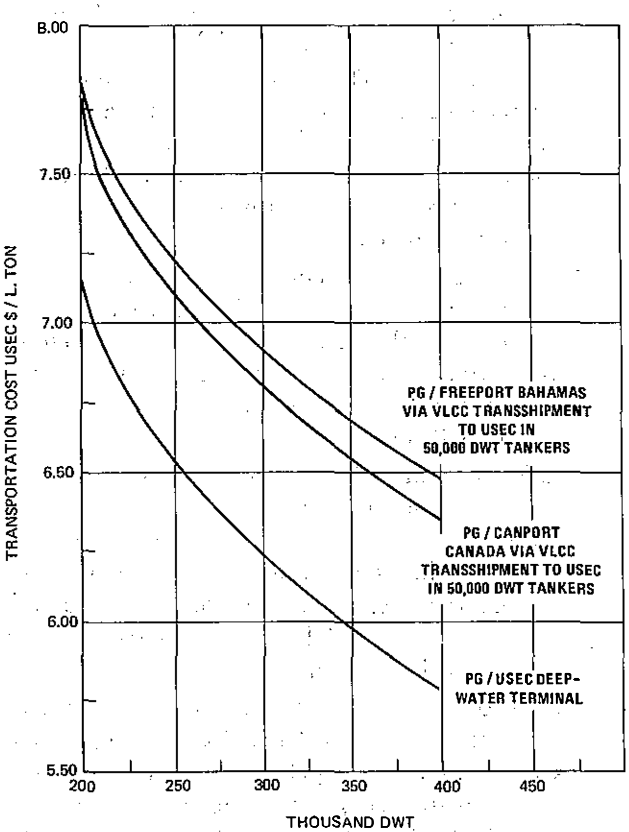


Figure 47. Transportation Costs to U.S. East Coast (USEC) from Middle East VLCC Transportation Costs Including Terminalling and Transshipment Costs, 1975-1985.

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 69.

TABLE 69

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

Editor's Note: This section on Gas Logistics is included in the extract from *U.S. Energy Outlook* for continuity. A separate task group report, *Gas Transportation*, gives detailed backup information on this subject.

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 70. Tables 71 to 74 summarize 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 government 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 70

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 & Transmission Lower 48	Transmission Alaska	Transmission Canada	Attachments-New Production Coal Gas, LNG & Syngas	Extraction 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 71

TOTAL U.S. NATURAL AND SYNTHETIC GAS REQUIREMENTS VERSUS GAS SUPPLY—CASE I*

	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	21.74	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 One.

† 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 70. 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 72

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 One.

† 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 71 through 74 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 73

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 One.

† 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 74

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 One.

† 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 79 were developed as discussed below.

TABLE 75

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 76

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 77

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 75 through 78 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 78

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 70.

TABLE 79

LNG CAPITAL REQUIREMENTS FOR LIQUEFACTION, TRANSPORTATION AND REGASIFICATION—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

Part Two

Findings of the Oil and Gas Supply Task Groups of the National Petroleum Council's Committee on U.S. Energy Outlook

Detailed Table of Contents
Part Two

Page

Chapter Four

NPC Methods of Analysis of Oil and Gas Supplies

Introduction

In January 1970, the National Petroleum Council was asked to undertake a study of the Nation's energy outlook. This request came from the Assistant Secretary of Mineral Resources in the Department of the Interior. The Secretary requested, among other things, that the Council study the petroleum (oil and gas) outlook, making projections as near to the end of the century as feasible. It was pointed out that the Council's final report should indicate ranges of probable outcome where appropriate, and that the report should also emphasize areas where federal oil and gas policies and programs can effectively and appropriately contribute to an optimum long-term national energy posture. In response to this request, the Council established a committee on U.S. Energy Outlook to carry out the study.

Projecting possible ranges of future domestic oil and natural gas production and evaluating the effect of federal policies and programs require the consideration of many variables. Because of this and the need for making a large number of repetitive calculations, a computer program was developed to facilitate processing the data. The purpose of this program is to describe the methodology developed by the study committee and used in the computer program to project future domestic oil and gas production under a wide variety of possible future situations.

Physical Factors Affecting Domestic Oil and Gas Production

The major physical factors that affect future domestic oil and gas production are shown on Table 80. The first factor is the quantity of new reserves that will be discovered in the future. This is primarily dependent upon five items. The first item is the amount of oil and gas remaining to be discovered. Several studies indicate that there are substantial undiscovered quantities of oil and gas in the United States, with a significant part of it located offshore and in Alaska. The next consideration is when and how much access will be provided to those potential areas. This refers to the lease sales held by state and federal agencies.

The next two items go together. New reserves discovered are very much dependent upon the annual level of exploration drilling and its success. Both of these independent variables will be heavily dependent upon the access granted to the potential areas. The fifth consideration is the time required to develop a field after it has been discovered. This includes securing permits, building platforms, drilling development wells and installing production facilities and pipelines.

TABLE 80

PHYSICAL FACTORS AFFECTING DOMESTIC OIL AND GAS PRODUCTION

New Reserves Discovered

- Remaining Discoverable Oil and Gas
- Access to the Potential Areas
- Level of Exploration Drilling
- Success of Exploration Drilling
- Time Required to Develop

Reserves in Existing Fields

Improvements in Recovery

Producing Capacity

Another major factor which affects future domestic oil and gas production is the current level of reserves in existing fields. This is the source of all of our production today. These reserves will continue to produce for several years, but at a declining rate until they are depleted.

Improvements in the recovery of oil from old and new fields provide another source for future production. Most frequently these improvements come from secondary recovery, which consists of injecting water or gas to drive more oil from the pores of the rock. Further improvements are expected from the use of heat or chemicals in some of the fields. These latter processes are referred to as tertiary recovery.

The last factor is the producing capacity, or the rate at which the oil and gas will flow from the reservoir into the well. Experience has shown that "a maximum of 10 to 12 percent of the country's developed reserves can be produced in one year." As reserves decline, the producing capacity also declines. The reciprocal of this relationship is the R/P or reserves-to-production ratio. This is discussed later in the chapter. Improvements in technology are also very important and are considered a part of each of the factors shown.

It was also recognized that each of these factors vary throughout the United States and require that the analysis be performed on a geographic region-by-region basis.

NPC Future Petroleum Provinces Study—Geographic Regions

Figure 48 shows the outline of each geographic region. As the title indicates, these regions were selected from the NPC study, *Future Petroleum Provinces of the United States*, published in July 1970. They represent areas of similar geology and operating conditions. The data required to project future production were developed for each region. This includes data such as the average depth of new wells, the amount of oil and gas found per unit of drilling, drilling costs, operating expenses and producing capacity. Dividing the offshore areas into separate regions also facilitated analysis of the different lease sale schedules.

Method of Analysis—Oil and Gas Supply (Flowchart)

Figure 49 shows a very simplified flowchart of the computer program and illustrates the overall method of analysis used. The computer program actually consists of 3 models that operate as a single program—the *oil model*, the *gas model* and the *economic model.*

The NPC used as a starting point an assumed level of future drilling activity for the entire United States. This drilling activity is divided into annual feet drilled for oil and annual feet drilled for gas. These footages are then allocated to each region on the basis of current trends in drilling, the remaining oil and gas potential and the availability of leases. All of these decisions are made outside the computer program. Therefore, the model is neither a predictive nor a forecasting model. It simply calculates the results of an assumed drilling activity.

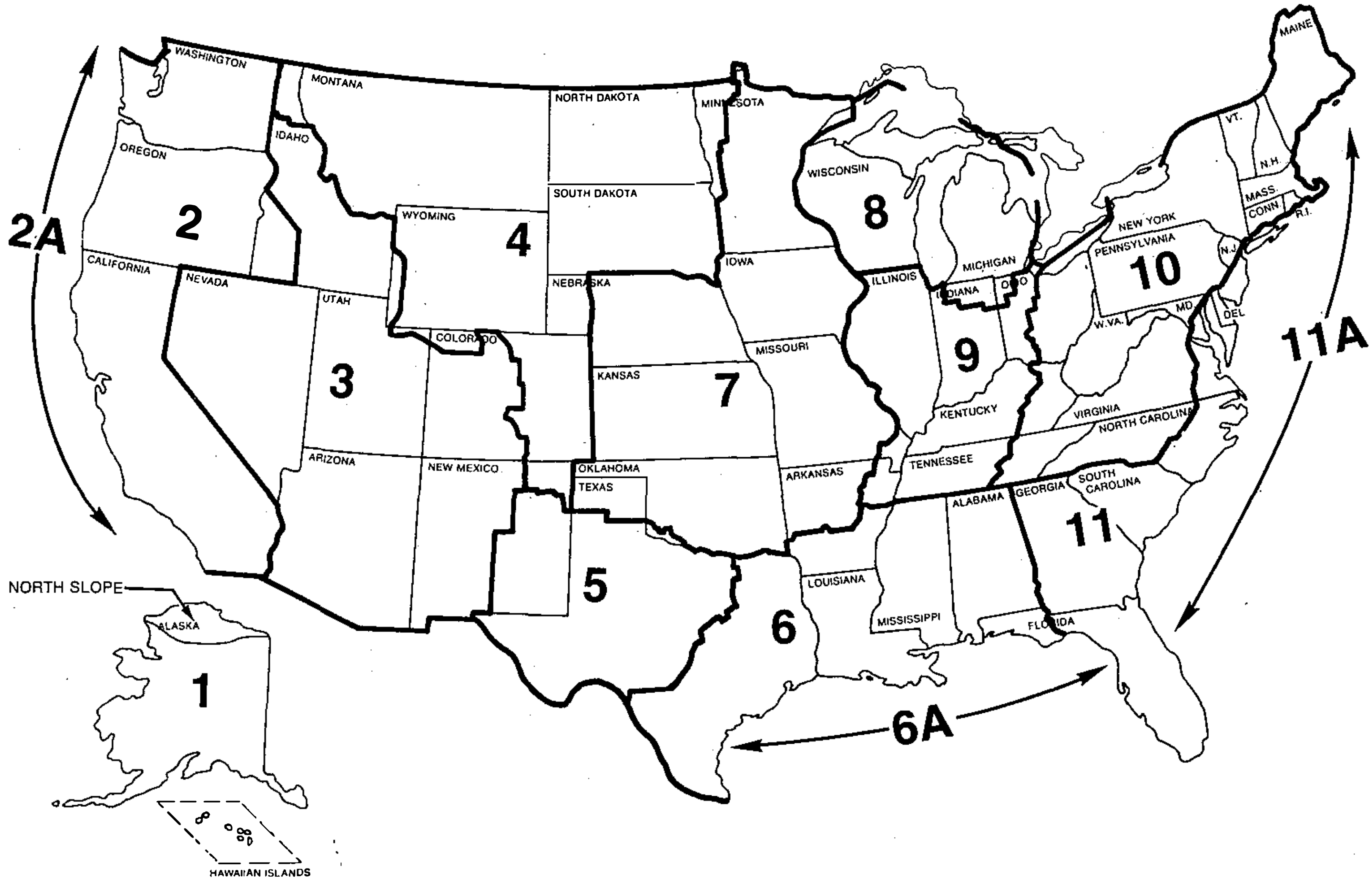
The purpose of the oil model is to calculate a schedule of annual oil production for the 15-year period (1971-1985) that would result from the assumed drilling. Likewise, the gas model calculates a schedule of future gas production. The economic model then calculates the capital requirement and the annual oil and gas prices required to provide a reasonable rate of return on the upstream investments.

Using the specified footage drilled for oil, the oil model calculates the new oil discovered annually in each region by multiplying the exploratory oil footage drilled by the average finding rate in that region. The finding rate is simply the barrels of oil discovered per foot of drilling. The model then applies a primary recovery factor to determine the reserves discovered. The amount of oil in existing fields, shown here as *old oil,* is read into the model. Anticipated improvements in recovery of oil are also read in and are shown as secondary and tertiary data. From these sources, the model determines the total oil reserves added annually in each region. The next step is to calculate annual production. This is shown in a simplified form as dividing the oil reserves at the beginning of each year by the R/P ratio. The R/P in this case corresponds to the maximum rate at which the reserves can be produced.

The gas model operates in a similar manner to develop the reserve additions and production for non-associated gas. Non-associated gas deposits are those that contain no crude oil. About 70 percent of the currently developed U.S. gas reserves are of this type. The balance is associated and dissolved gas, which is gas produced along with the oil. The number of total feet drilled for gas is multiplied by the average finding rate to determine the non-associated gas reserves that are discovered annually in each region. Existing gas reserves are read into the model and are shown as *old gas.* The next step is to calculate the annual gas production in each region. A high percent of the gas discovered is recoverable, therefore, secondary and tertiary recovery reserves are not included in the gas model.

There are two other important calculations not included on the diagram. The oil model calculates the amount of associated and dissolved gas and passes the volume to the gas model for inclusion in the gas production values. In addition, the gas model calculates the amount of natural gas liquids that are recovered from the gas. These both become a part of the total U.S. gas and liquid supplies.

With regard to the economic model, the oil and gas industry's current investment in net fixed assets, as allocated to oil activities and gas activities in the upstream functions, are read into the



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 48. NPC Future Petroleum Provinces Study—Geographic Regions.

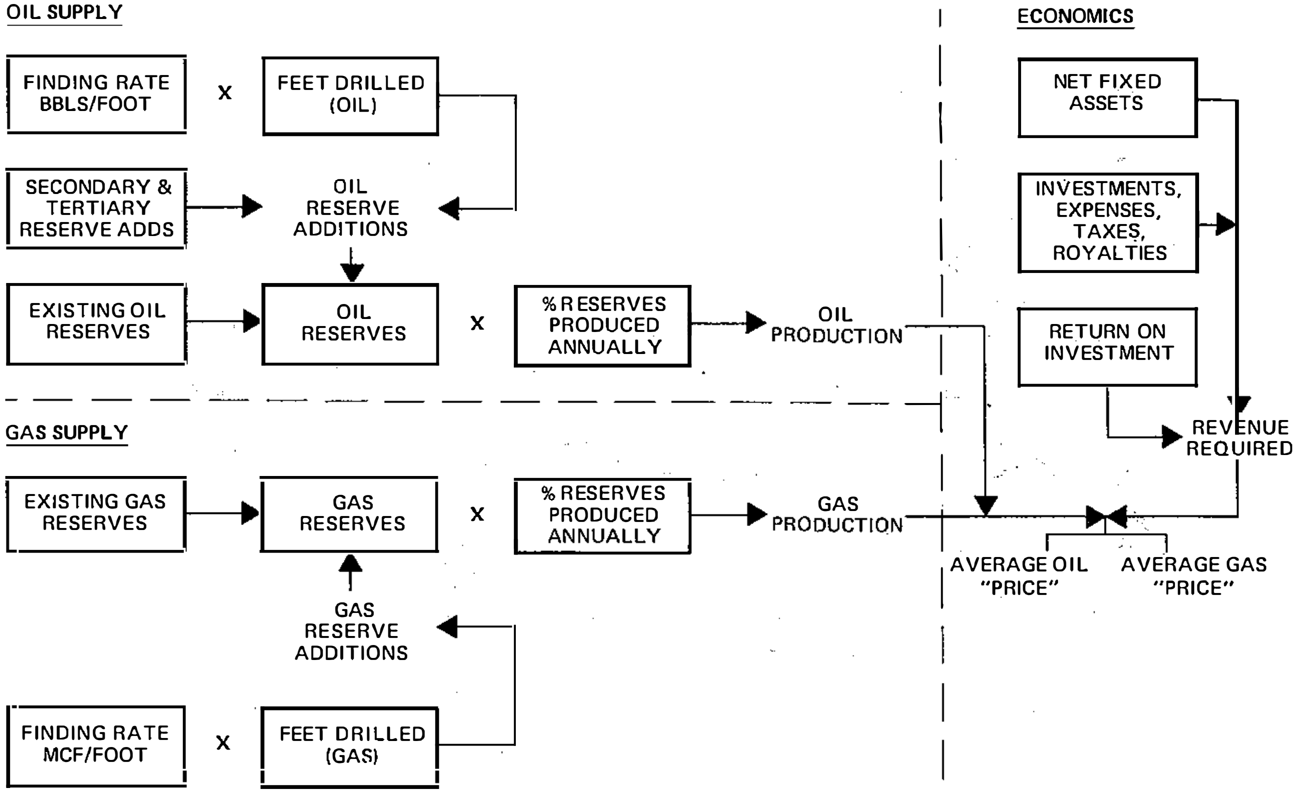


Figure 49. Method of Analysis—Oil and Gas Supply.

model. The next step is to calculate the investments and operating expenses required to conduct the annual activities being analyzed. Some of these values have already been determined by the oil and gas models. Estimated tax rates and a set of five rates of return to be earned on net fixed assets are read as data. The model then performs typical book accounting calculations to determine the annual revenue required to earn each of the five rates of return. The five schedules of calculated average oil and gas prices needed to provide the required revenues are printed. These are calculated cost-plus-return prices only and do not represent selling prices established between producers and purchasers or a future market value.

It should be emphasized that no attempt was made to forecast what prices would be required to actually elicit the drilling activity that was assumed. The primary purpose of the economic model is to assess the financial requirement and economic implications of conducting the assumed drilling activities and producing the calculated oil and gas volumes. The prices are calculated simply to indicate the direction that prices might have to go to provide a reasonable return to industry while carrying on the assumed activities. Obviously different prices would result from different assumed activities.

The following sections illustrate the methods used to develop some of the data and provide some additional details on the calculation procedures.

Annual Oil and Gas Well Drilling

Figure 50 demonstrates the basis for assuming future drilling activity. This diagram shows the amount of oil and gas well drilling in millions of feet per year. For the 1956-1970 period, total drilling has declined from about 240 million feet per year to about 140 million feet per year. Oil drilling represents about 70 percent of the total drilling during this time.

The NPC U.S. Energy Outlook study undertook to determine what future oil and gas production would result from reversing the drilling trend and what the result would be if the historical downward trends were continued. It was from such assumptions that the NPC selected several future

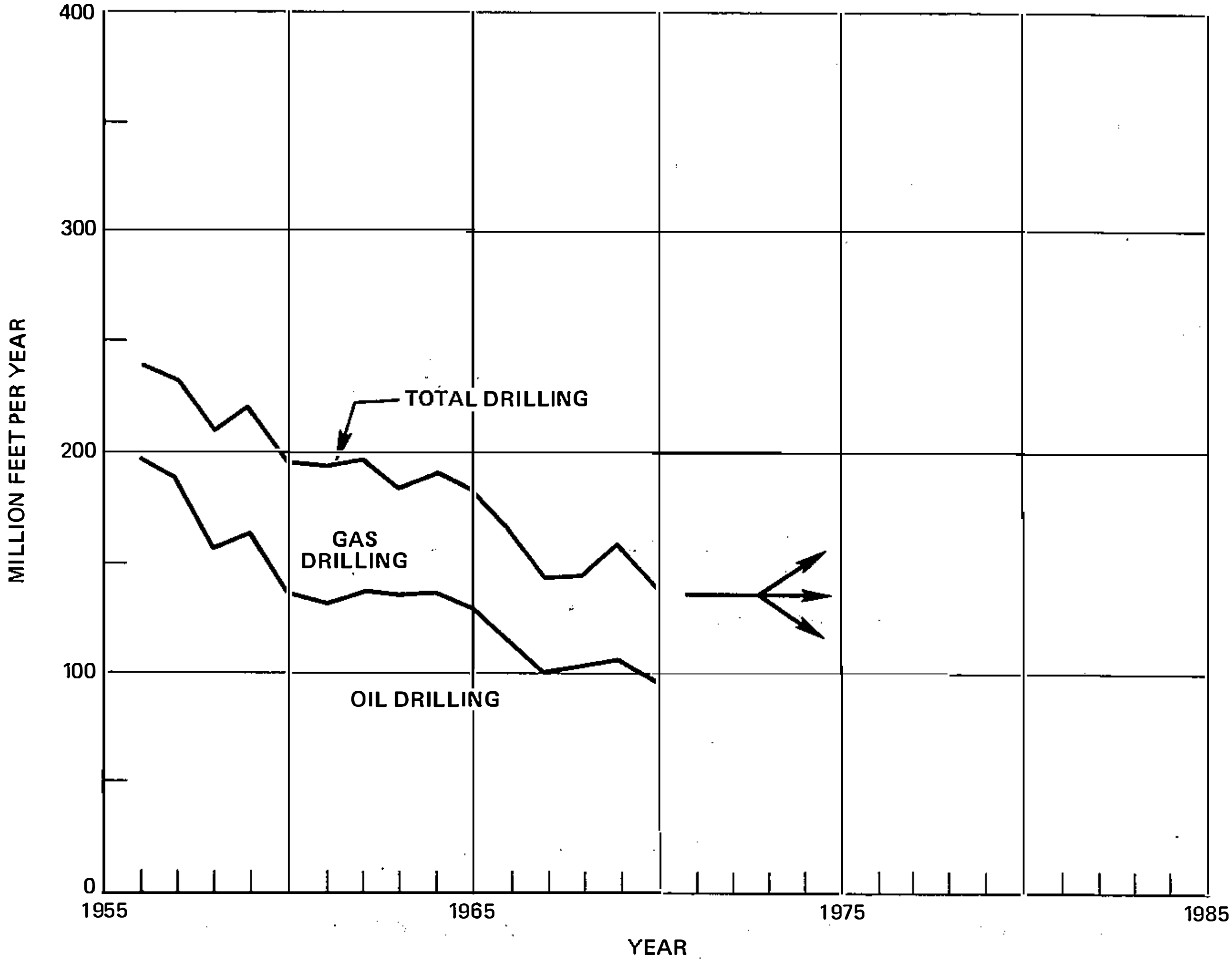


Figure 50. Annual Oil and Gas Well Drilling.

drilling schedules to establish a range of possible future production. As mentioned earlier, after the total drilling is projected, it is allocated to each of the NPC regions.

Annual Oil Well Drilling

Figure 51 shows total oil drilling and its relationship to oil exploratory drilling in millions of feet per year. The oil exploratory drilling curve indicates the footage drilled in search of new fields or deeper deposits in existing fields. The difference between the curves represents the drilling of development wells. Historically, the ratio of total to exploratory drilling has been about 4 to 1; however, it has varied significantly from region to region. Regional drilling activities are therefore analyzed in detail, with consideration given to the frequency of dry holes, trends in drilling depths and trends in drilling costs over a wide range of depths. It is the assumed exploratory oil footage that is read into the oil model and used to calculate new oil discovered in each region. The total oil drilling requirement is recalculated by the model as a function of the historic footage ratios and the exploratory activity for each of the regions.

Oil-in-Place (OIP) Finding Rate

After assuming the level of drilling, it must be related to the finding rate to establish the reserves added during the projection period. Figure 52 illustrates a typical, but hypothetical, finding rate curve for a region. Note that the amount of oil dis-

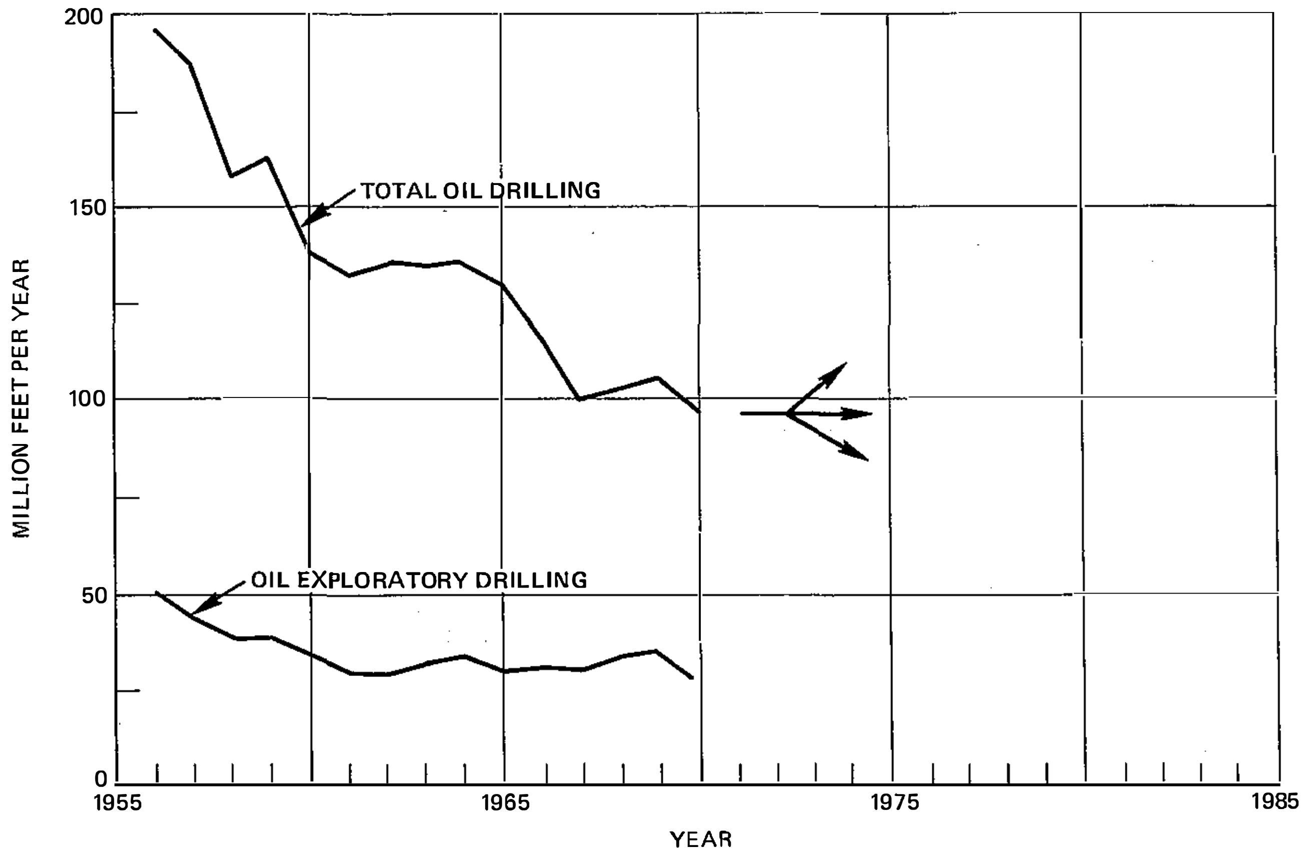


Figure 51. Annual Oil Well Drilling.

covered per foot of drilling decreases with cumulative exploration in that region. This is due to the fact that larger and shallower fields in an area are normally discovered early and emphasizes the need to explore in new regions to increase future supplies. The vertical axis shows the barrels of oil-in-place found per foot of oil exploratory drilling and the horizontal axis is the cumulative oil footage drilled in a region commencing at any point in history. The curve shown was sketched to illustrate variations and trends in the data.

The historical data indicates a band of results. There are numerous methods for extrapolating data of this type, and the best method varies from region to region. Therefore, the Oil Supply Task Group made two projections that represent a band of reasonable expectation. These projections are conveniently named the *high finding rate* and the *low finding rate*. Separate computer runs are made for each of the curves to calculate a range of possible future supply from each assumed drilling schedule.

Annual Oil Reserve Additions

Table 81 indicates some of the relationships used

TABLE 81

ANNUAL OIL RESERVE ADDITIONS

New Reserves Discovered

- O.I.P.* Added = Expl. Ft. X Finding Rate
- Reserves Added = O.I.P. Added X Primary Recovery Fraction

Revisions to Known Reserves

- Revisions in Old Fields = Original O.I.P X Increase in Recovery Fraction
- Revisions in New Fields = Original O.I.P X Increase in Recovery Fraction

* Oil-in-Place.

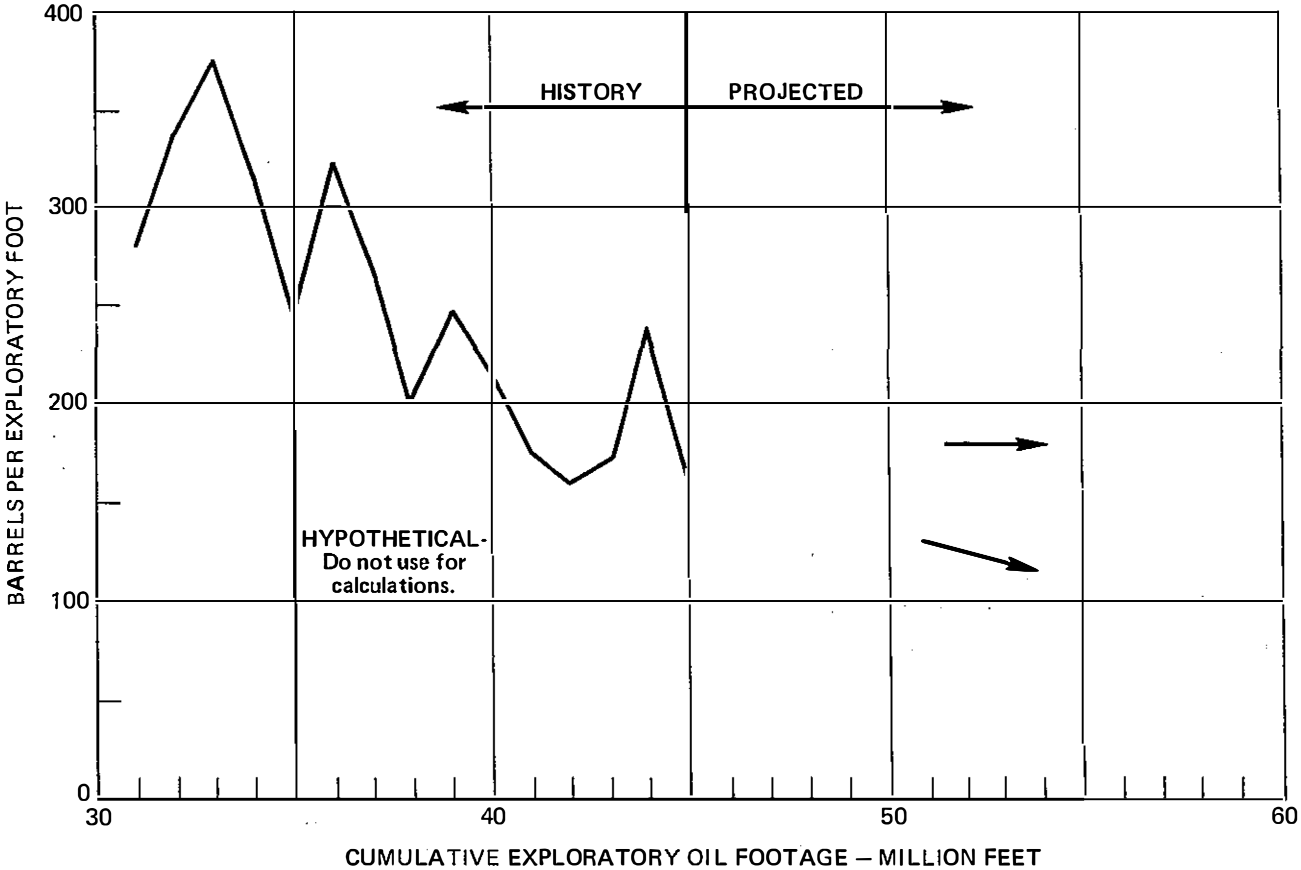


Figure 52. Oil-in-Place Finding Rate—Example Region.

to calculate annual oil reserve additions. As mentioned previously, oil reserves added annually are from two sources: (1) the new reserves discovered and (2) the revisions to known reserves.

The equation used to calculate the oil-in-place added or discovered is simply the oil exploratory feet drilled in a year times the annual average finding rate. All of the oil discovered cannot be produced; therefore, the reserves added is the product of the oil-in-place discovered and the primary recovery fraction.

Revisions to known reserves are calculated separately for old fields and new fields, although the same procedure is used for both. Revision in old fields is based upon a gradual annual improvement in recovery efficiency, and the annual revision is the product of the original oil-in-place in the old fields and the annual increase in recovery fraction.

Revisions in new fields are timed to coincide with the installation of secondary and tertiary recovery projects. If applied, these installations are typically scheduled to occur 5 years and 10 years after discovery. All of the equations shown are solved for each region in each year using values applicable to each region. Thus the procedure for estimating oil reserve additions was developed. The following sections review the procedure for gas reserves.

Gas Finding Rate

Figure 53 shows an example of a gas finding rate curve. This curve is analogous to the oil finding rate curve in that it is a typical, but hypothetical, curve for a region. The vertical axis represents the average volume of non-associated gas discovered in thousands of cubic feet per foot of gas drilling. The horizontal axis is cumulative gas footage drilled since some point in history. The oil curve was based on cumulative oil exploratory footage, but the gas curve shown here is based on total gas footage drilled. The reason for this is simply that the parameters which correlated best

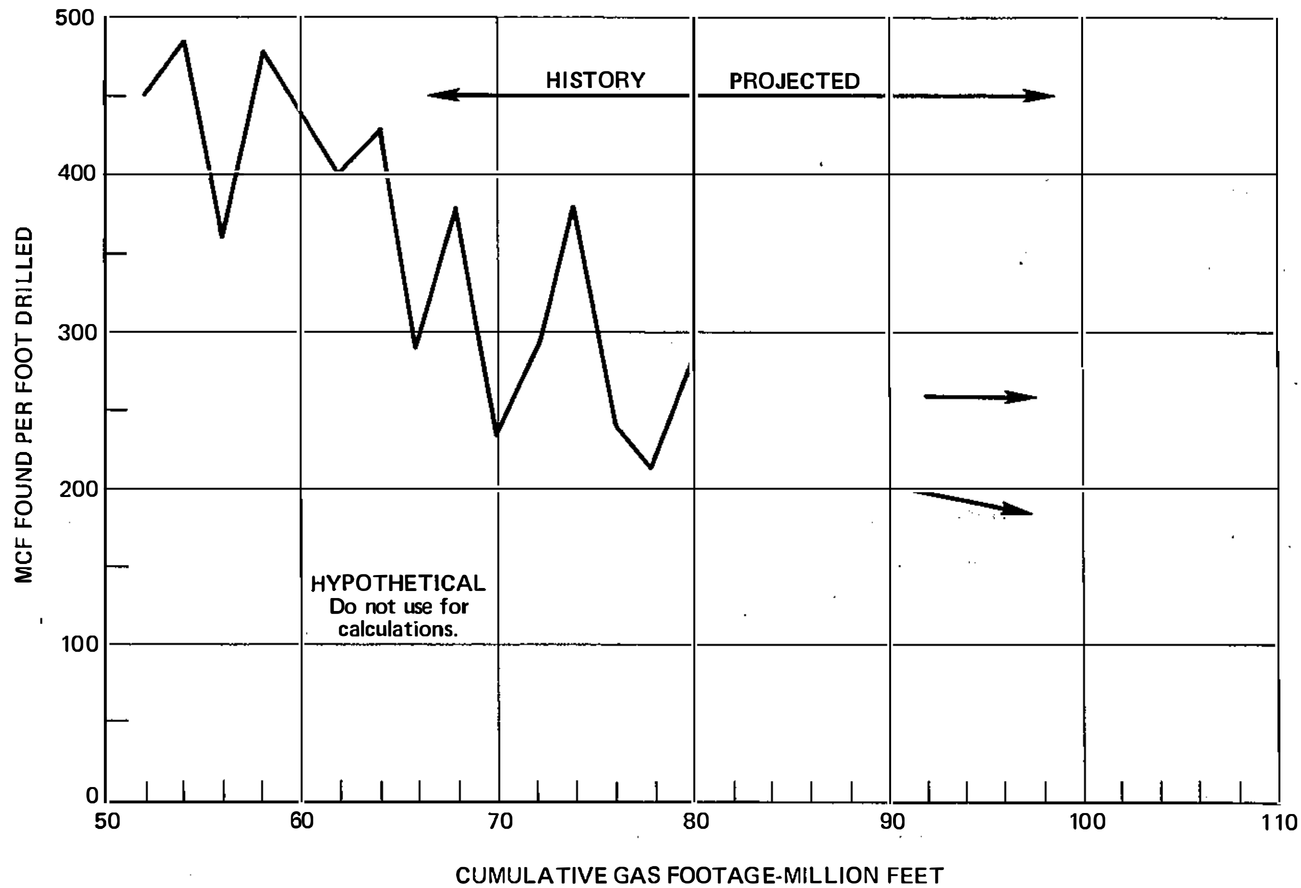


Figure 53. Gas Finding Rate—Example Region.

were selected for each. Like oil, a high and a low finding rate is projected to define a reasonable range for future discoveries. These both decline as cumulative gas footage drilled in a region increases.

A major limitation of the models is contained in the oil and gas finding rate curves. About 70 percent of the total footage drilled during the past 15 years has been oil footage. Therefore, the finding rate curves are based upon total U.S. drilling activities that are 70 percent oil and 30 percent gas. It is an established fact that some of the wells that were expected to find oil have discovered gas and vice versa. In the method used, wells have been classified on the basis of what they discovered, not what they were expected to discover. There is no doubt that the finding rate curves would be affected by a change in the percent of oil and gas footage drilled. The magnitude of the effect is unknown. Although this is a limitation of the model, it was not a limitation in the NPC Energy Study, since all cases analyzed assumed that the ratio between oil and gas drilling would remain essentially unchanged.

Annual Gas Reserve Additions

The equations used to calculate the volume of gas reserves added annually are shown on Table 82. The non-associated gas reserves added is the product of the total gas footage drilled in a year and the annual average finding rate. A recovery

TABLE 82

ANNUAL GAS RESERVE ADDITIONS

- N.A. Gas Reserves Added = Gas Footage Drilled X Finding Rate
- A.–D. Gas Reserves Added = Oil Reserves Added X Reserves G.O.R.

factor for gas has not been included as it was for oil because a high percent of gas discovered is recoverable, and all of the correlations and data in the model have been based on recoverable volumes.

In addition to the non-associated gas, there is associated and dissolved gas found along with crude oil. Historically, about 1,600 cubic feet of associated and dissolved (A&D) gas reserves have been added along with each barrel of oil reserves. The second equation shows that A&D gas reserves added as the product of the oil reserves added and the reserves gas/oil ratio. Actually this is an oversimplification of the calculation since the model considers how much of the oil reserves added comes from primary, secondary and tertiary reserves and uses a different gas/oil ratio for each category. Both of these equations are solved for each year and each region using pertinent regional data.

Annual Oil and Gas Production

Table 83 also shows the relationships used to calculate the annual oil and gas production after the reserves are calculated.

TABLE 83

ANNUAL OIL AND GAS PRODUCTION

- Oil Production = Remaining Oil Reserves ÷ R/P
- A.—D. Gas Production = Oil Production X Producing G.O.R.
- N.A. Gas Production = Original Gas Reserves X % Producible Annually
- Natural Gas Liquids Production = Gas Production X Liquid/Gas Ratio

Annual oil production is calculated by the first equation which divides the remaining reserves in the developed fields by the R/P ratio applicable to each region. In the second equation, the associated and dissolved gas produced annually is the product of the oil production and the producing gas/oil ratio in each region.

Annual non-associated gas production is calculated by multiplying original gas reserves discovered in each year by the percent of the reserves producible annually in each of the subsequent years. This is a different form of the equation shown on the model flowchart; however, the percent producible annually is directly related to the R/P ratio.

The last equation shows the calculation of natural gas liquids (NGL). Annual NGL production is the product of the gas production and the liquid to gas ratio. Different volumes of liquids are recovered from non-associated gas than from A&D gas. Therefore, this calculation is made separately for each type of gas. As with the other equations, each of these are solved separately for each region.

After the computer program has completed the projection of future oil and gas production for the assumed drilling activity, it switches to the economic calculations.

Annual Asset Accounting

The economic model performs book accounting calculations relating to the annual rate of return on net fixed assets. Table 84 shows the parameters considered by the asset accounting routine.

The first item is industry's beginning-of-year investment in net fixed assets for the upstream functions. The investments in oil activities and gas activities at the start of the study are read in as data. Using the assumed drilling activity and the calculated oil and gas production, the computer program determines all of the additions to the asset

TABLE 84

ANNUAL ASSET ACCOUNTING

	Oil Activity	Gas Activity
• B.O.Y. Net Fixed Assets	✓	✓
• Annual Additions		
Lease Acquisitions	✓	✓
Successful Wells and Platforms	✓	✓
Lease Equipment	✓	✓
Natural Gas Plants		✓
• Less Deprecitaion	✓	✓
• E.O.Y. Net Fixed Assets	✓	✓
• Average Net Fixed Assets	✓	✓

accounts. These are expenditures for lease acquisitions, successful wells and offshore platforms, lease equipment including all production facilities and natural gas plants. With the exception of the natural gas plants, each item has two accounts—one for oil activities and one for gas activities. All gas plants are placed in the gas activity account.

Depreciation, which includes all book write-offs, is calculated annually for both oil and gas activities. The end-of-year net fixed assets are calculated next by adding the annual additions to the beginning-of-year net fixed assets and subtracting the depreciation. Industry's annual average investment in net fixed assets is retained by the program, and is the base for the annual rate-of-return calculation.

Annual Net Income

The parameters used to calculate annual net income and return on net fixed assets are also shown on Table 85. Again, the split between oil and gas activity is indicated.

As an earlier discussion of the flowchart indicated, five specified rates of return are read into the computer program, and the average oil and gas prices required to yield these rates of return are calculated. Net revenue, the first item on this chart, is therefore one of the dependent variables to be computed. As mentioned previously, the model assumes an oil and gas price and calculates the revenue. This chart shows the remainder of the items considered in the annual net income statement used to iterate on the annual oil and gas prices required to attain the rate of return.

Once the economic model assumes an oil and a gas price, it calculates the net revenue from the oil activities and the gas activities. The next step is to determine the operating expenses. Each of the items shown are calculated, based on the assumed drilling activity and the calculated production rates. Depreciation, as calculated in the asset accounting routine, is also one of the book expenses. An income tax routine was developed as part of the economic model and is used to calculate the income tax liability generated by the upstream functions.

The annual net income is then computed by subtracting operating expenses, depreciation and income taxes from the net revenue. Finally, the annual rate of return on net fixed assets is determined by dividing the net income by the average net fixed assets. If the rate of return is not one of the specified rates read in, different prices are assumed by the model and the calculations are repeated.

TABLE 85

ANNUAL NET INCOME

	Oil Activity	Gas Activity
• Net Revenue	✓	✓
• Operating Expenses	✓	✓
Geological and Geophysical	✓	✓
Lease Rental	✓	✓
Dry Holes	✓	✓
Producing	✓	✓
Gas Plants		✓
Overhead	✓	✓
Ad. Val. & Production Tax	✓	✓
• Depreciation	✓	✓
• Income Tax	✓	✓
• Net Income	✓	✓
• % Return (Net Fixed Assets)	✓	✓

Price Iteration

Table 86 shows the procedure used in the price iteration. The price iteration starts by selecting the first of the five rates of return for which prices are to be calculated. Next, the model assumes the oil and gas prices in the year being analyzed are equal to the prices in the prior year. Using these assumed values, it calculates the *oil* economics for one year by going through the net income and rate-of-return calculations discussed previously. After the annual return has been calculated on the oil activities, it checks to determine if the oil return is equal to the rate of return specified. If they are not equal, it adjusts the oil price up or down as needed, and recalculates the oil economics. The oil loop is repeated until an oil price is found that will yield the specified return.

After the required oil price is determined, the model calculates the *gas* economics. It then checks to determine if the gas return is equal to the return specified. If the returns are not equal, it adjusts the gas price for that year and repeats the

TABLE 86

PRICE ITERATION

- Select Rate of Return
- Assume Oil & Gas Prices Equal Prior Year's
  - Calculate "Oil" Economics
  - Is "Oil" Return = Value Specified? — No / Yes
  - Adjust Oil Price
  - Calculate "Gas" Economics
  - Is "Gas" Return = Value Specified? — No / Yes
  - Adjust Gas Price
- Was Gas Price Same for "Oil"? — No / Yes
- Repeat for Each Year
- Repeat for Each Return

gas economics. The gas loop is repeated until a gas price is found that yields the specified return.

It should be pointed out that some of the revenue for the oil activities comes from sale of the associated-dissolved gas produced on the oil leases. Also, part of the gas revenue comes from sale of natural gas liquids. While making the oil price iteration, the price of A&D gas is assumed to be unchanged. Likewise, while calculating gas economics, the price of the heavier natural gas liquids are based on the crude oil price calculated in the oil loop. It is assumed that the price of these liquids remains constant during the gas iteration.

After completing both an oil price and gas price iteration, the model tests the question, "Was the gas price calculated the same as the gas price used in the oil economics?" If the answer is no, the calculated gas price is transferred to the oil economic calculation for recalculation of the oil price. The entire cycle is repeated until the gas prices and liquid prices in both economic calculations are in agreement. The model then repeats the entire process for each year of the study and for all five returns. In this way the five schedules of oil and gas prices required to yield the specified returns are attained. The model *does not* determine whether the prices would be adequate to elicit the activity that was assumed.

Sensitivity of Method

As listed on Table 87, the computer program has been used to analyze the sensitivity of future production to: (1) the availability of future off-

TABLE 87

METHOD PROVIDES SENSITIVITY

Of Future Production to:

- Lease Availability
- Drilling Activity
- Finding Rates
- Improved Recovery
- Imposed Delays

Of Expl.—Devel. Economics to:

- Lease Costs
- Taxation
- Wellhead Prices

shore leases, (2) future drilling activity both offshore and inland, (3) the variations in finding rates, (4) different levels of improved recovery and (5) imposed delays in exploring frontier areas.

The method is also useful in analyzing the effect on exploration and development economics of changes in lease acquisition costs, taxation and the wellhead prices of oil and gas.

Note: Major sources of basic data for this chapter include:

- NPC, *Future Petroleum Provinces of the United States* (July 1970).
- Potential Gas Committee, Colorado School of Mines, *Potential Supply of Natural Gas in the United States*, (October 1971).
- American Gas Association and American Petroleum Institute, *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States*, a joint report published annually.
- American Petroleum Institute, Quarterly and Annual Review of Drilling Statistics.
- American Association of Petroleum Geologists Exploratory Drilling Statistics.
- Joint Association Survey of U.S. Oil and Gas Producing Industry.
- Chase Manhattan Bank industry-cost studies.

Chapter Five

Oil Operations

Guide to Chapter Five
Oil Operations

SECTION I: Ultimately Discoverable Oil and Its Distribution

Discusses the statistical data concerning the Nation's oil resource base as of January 1, 1971, including its distribution by NPC region and offshore areas by water depth. Future potential reserves distribution by depth and pool size is discussed and documented.

SECTION II: Historical and Projected Regional Activity and Oil Finding Rate

Includes composition of the NPC regions and discussion of oil exploratory and development drilling activity statistics and trends. Describes methodology for establishing and projecting oil finding rate and contains historical data on U.S. reserves additions.

SECTION III: Drilling Activities for Oil

Presents historical U.S. exploratory and total drilling statistics since 1956 and various projections for future drilling. Establishes success ratios, projects future successful and dry wells and average well depths.

SECTION IV: Oil-In-Place Discovered

Tabulates future oil-in-place discovered annually to 1985 by NPC regions for all six cases.

SECTION V: Recovery Factors and Reserve Additions

Includes background data for establishing future reserves additions from primary, secondary and tertiary processes, and includes the actual projection of oil reserves additions by cases and NPC regions annually to 1985. Includes projections and the basis for establishing associated and dissolved gas reserve additions.

SECTION VI: Crude Oil, Natural Gas Liquids and Associated and Dissolved Gas Production

Presents supporting data on crude oil production, reserves-to-production ratios, producing wells, regional sources of produced oil and production summarized by primary, secondary and tertiary methods. Includes projections of future crude oil, natural gas liquids and associated and dissolved gas production.

SECTION VII: Alaskan North Slope Oil Operations

Discusses the general approach to the analysis of the North Slope and includes a description of the cases covered in the report. Provides the basis for developing the various pertinent factors, both physical and financial, needed to integrate this frontier producing province into the total U.S. picture.

SECTION VIII: Composition of PAD Districts from NPC Regions and Determination of Offshore Acreage Requirements

Relates NPC regions to PAD districts and describes the method of determining offshore leasing requirements.

Chapter Five—Section I

Ultimately Discoverable Oil and Its Distribution

Ultimately Discoverable Oil

The basic data used to define the future ultimate discoverable oil-in-place in the United States was from the NPC report, *Future Petroleum Provinces of the United States*. Future discoverable oil was categorized as probable, possible and speculative. The median estimate reported in the Petroleum Provinces study used all the probable and possible plus one-half of the speculative. This median estimate was used in this study.

To facilitate analysis of onshore and offshore discoverable oil, the original 11 NPC regions were expanded to 15 regions by subdividing Region 2 (West Coast) into Regions 2 and 2A, Region 6 (Gulf Coast) into Regions 6 and 6A and Region 11 (Atlantic Coast) into Regions 11 and 11A. Region 1 (Alaska) was subdivided into Regions 1S and 1N, with a further separation in Region 1N for the onshore and offshore portions. In view of recent developments on the North Slope of Alaska, the oil formerly considered as speculative is now probable and possible.

Estimates of oil-in-place were made for the frontier areas—Gulf of Alaska and Bristol Bay in Region 1S and the North Slope offshore. These estimates were based upon the estimate of the volume of rocks considered to be prospective multiplied by an estimate of the amount of recoverable oil anticipated per cubic mile and divided by an appropriate recovery factor. The result is the total speculative oil-in-place of which one-half is used in this study. For example, calculations for the Gulf of Alaska are:

Volume of sedimentary rocks considered prospective	50,000-75,000 cubic miles
Estimate of recoverable oil per cubic mile (Atlantic Coast estimate)	71,000 barrels
Recovery factor	23 percent

$75{,}000 \times 71{,}000 \div 0.23 = 23.2$ billion barrels of oil (all speculative)

$^1/_2\ (23.2) = 11.6$ billion barrels of oil (median estimate used in this study)

Similar calculations were made for Bristol Bay and the North Slope offshore (Beaufort shelf and the northern Chukchi basin).

To aid in determining directionality of future exploration, the future discoverable oil-in-place was assigned by geological age to three depth ranges (0 to 5,000 feet, 5,000 to 10,000 feet and 10,000 to 15,000 feet). It was assumed, based upon a review of domestic oil and gas fields, that below 15,000 feet, gas rather than oil would be the primary hydrocarbon discovered.

The authors of the NPC Future Petroleum Provinces report did not always quantify the oil-in-place estimates by geologic age and rarely by depth interval. Thus it was necessary to make assumptions as to age and depth based upon interpretations of their text. This involved study of the authors' maps and cross sections plus a general knowledge of the area to determine the probable depth to the various potentially productive formations. In those instances where a formation spanned two or more depth brackets, it was necessary to make a judgment. The final results were then reviewed with the authors and, where necessary, revisions were made. As it was not possible to assign the oil discovered since the Petroleum Provinces report was published to any specific age or depth bracket, the original estimates were used.

The future discoverable oil-in-place in the offshore areas was also subdivided by water depth (0 to 600 feet, 600 to 1,500 feet and over 1,500 feet) to help guide the timing of exploratory drilling in these areas. This information was developed from the authors' text, maps and cross sections, plus the "Tectonic Map of North America" (United States Geological Survey, 1969), which shows topographic contours in sub-sea areas.

Because of discoveries made since the Petroleum Provinces report was published, it was necessary to revise the regional estimates of future discoverable oil-in-place. This adjustment was made by dividing the annual new reserves for new fields, new pools and extensions (as reported by the API) by the appropriate primary recovery factor for each region to determine the annual new oil-in-place additions. These additions were subtracted from the Petroleum Provinces report estimate to determine the oil-in-place remaining on January 1, 1971. An example, using calculations for Region 7, is given below (in billions of barrels).

	New Reserves	Recovery Factor	OIP	Revised OIP Remaining
1967	—	—	5.6	5.6
1968	0.0643	0.25	0.2572	5.3
1969	0.0852	0.25	0.3408	5.0
1970	0.0899	0.25	0.3596	4.6

The breakdown of Region 7 for 1970 is shown below (in thousands of barrels).

New Reserves	New Fields	New Pools	Extensions	Total
Kansas	3,249	992	15,968	20,209
Oklahoma	13,206	1,772	52,319	67,297
Texas District 10	25	226	1,755	2,006
15% Nebraska	228	118	18	364
	16,708	3,108	70,060	89,876

The ultimate discoverable oil-in-place used in this report is the sum of the oil-in-place discovered to January 1, 1971 (as reported by the API) plus the remaining future oil-in-place as determined by the above calculations. This information is tabulated for each region on Table 7 in Chapter One. Approximately 52 percent (425.2 billion barrels) of the ultimate discoverable oil-in-place had been discovered by January 1, 1971, and about 91 percent of this amount was located in the Lower 48 States onshore. During the next 15 years, as shown by Tables 10, 11 and 12 in Chapter One, 12 percent to 31 percent of the remaining oil-in-place will be discovered with an increasing emphasis on the offshore and Alaskan areas.

Distribution of Future Potential Reserves

In order to gain insight into the optimum places to concentrate drilling effort and the probable changes in drilling depths with time, a study was made of the distribution of future potential reserves as to the proportion which could be expected to be found in large, medium and small fields in the various geologic horizons and in several depth ranges. To do this, the NPC median values for future discoverable oil-in-place were used. The values for each region were first distributed by the geologic horizons in which they are believed to occur. These, in turn, were separated into geologic areas and into three depth ranges—0 to 5,000 feet, 5,000 to 10,000 feet and deeper than 10,000 feet.

To estimate size distribution, the assumption was made that the distribution of reserves by field size would be in proportion to that found in the past. To determine the past distribution, the NPC tabulation of crude oil reserves by fields from 1860 to 1944 was used. This compilation had been made for the Petroleum Administration for War (PAW), and was the only source available with enough data for individual fields to provide statistically adequate results for the whole United States production to that time. It was inadequate for Regions 1, 3 and the offshore areas, the bulk of production from which has occurred since 1944. Offshore California and the Gulf Coast offshore areas are considered to be similar to the adjacent onshore. No available historical data were considered similar enough to be used for Regions 3 and 11A.

The historical field data were separated for each region into the three depth ranges and by geologic horizon for the major geologic basins. For each of these, log normal probability distributions by field size were made. Through these distributions, a straight, best-fitting line was drawn. This line was used to establish the distribution of future reserves. Typical data plots are shown on Figures 54 through 58. They indicate the wide divergence which occurs regionally and geologically. Note, for example, the large difference to be found in the size range of fields in the Pliocene and upper Miocene formations of the Los Angeles Basin, California, (see Figure 54) as contrasted with the lower Devonian fields of Oklahoma, or the upper Mississippian fields of Indiana (see Figures 55 and 56). Consider also the steepness of the curve for the fields of the Gulf Coast Eocene, (see Figure 57) when compared with the relatively flat distribution of the fields of the Mississippian of Region 5 (see Figure 58).

The straight line plot for the Gulf Coast Eocene fields is shown on Figure 59. In evaluating distribution curves the median (50 percentile) value and those at the standard deviations (15.87 and 84.13 percentiles) give useful insight into the nature of the distribution. The size of the field at the 50 percentile is that most frequently encountered. The standard deviation values determine the slope and hence relate to the range in size of the fields. A list of the values determined by the above procedures and used in this report are given by region and geologic horizon in Table 106.

From these data and the appropriate future oil in place values, a distribution of future potential reserves by field size was calculated. A typical calculation sheet is presented in Table 107. The oil in place value was multiplied by the regional recovery factor to establish the potential primary reserve. The reserve distribution was then summed to provide values for the ranges of field size of less than 10 million barrels, 10 to 50 million bar-

TABLE 88

MEDIAN FUTURE OIL-IN-PLACE (OIP)
(Millions of Barrels)

SUMMARY OF OFFSHORE AREAS BY WATER DEPTH

	Water Depth Ranges							
	0-600'		600-1500'		Over 1500'		Total OIP	As Of Year End
Region 1 N								
North Slope	47,900	(100%)	0		0		47,900	1970
Region 1 S								
Cook Inlet	6,450	(100%)	0		0		6,450	
Gulf of Alaska	11,600	(100%)	0		0		11,600	
Bristol Bay	5,440	(100%)	0		0		5,440	
Total	23,490	(100%)					23,490	1968
Region 2 A								
South Calif.	4,671	(13%)	3,034	(8%)	29,295	(79%)	37,000	
Santa Barbara	7,403	(59%)	2,677	(21%)	2,520	(20%)	12,600	
Total	12,074	(24%)	5,711	(12%)	31,815	(64%)	49,600	1968
Region 6 A								
	24,359	(83%)	478	(2%)	4,302	(15%)	29,139	1968
Region 11 A								
Atlantic Coast								
N. Lat. 33°	6,625	(62%)	207	(2%)	3,918	(36%)	10,750	
S. Lat. 33°	250	(14%)	74	(4%)	1,426	(82%)	1,750	
Florida Offshore	1,888	(100%)	0		0		1,888	
Total	8,763	(61%)	281	(2%)	5,344	(37%)	14,388	1968
Grand Total*	116,586	(71%)	6,470	(4%)	41,461	(25%)	164,517	

* Supporting studies were made over a period of time, and users should note that the time periods are not identical.

TABLE 89

MEDIAN FUTURE OIL-IN-PLACE
(Millions of Barrels)

REGION 1 N SUBDIVISION NORTH ALASKA
YEAR-END 1970

Geologic Horizon	Depth 0-5	Range 5-10	Thousand Feet 10-15	Total
North Slope	2,400	62,500	7,200	72,100
Frontier Areas				
Beauford Shelf and North Chukchi Basin	2,400	38,300	7,200	47,900
Grand Total	4,800	100,800	14,400	120,000

TABLE 90

MEDIAN FUTURE OIL-IN-PLACE
(Millions of Barrels)

REGION 1 S SUBDIVISION SOUTH ALASKA
YEAR-END 1968

Geologic Horizon	Depth 0-5	Range 5-10	Thousand Feet 10-15	Total
Cook Inlet				
Oligocene-Pliocene				
Kenai Group	0	500	4,500	5,000
Mesozoic	0	0	1,450	1,450
Total	0	500	5,950	6,450
Frontier Areas				
Gulf of Alaska				
Miocene-Pliocene	1,160	6,960	3,480	11,600
Bristol Bay				
Tertiary	0	460	4,160	4,620
Mesozoic	0	0	820	820
Total	0	460	4,980	5,440
Grand Total	1,160	7,920	14,410	23,490

TABLE 91

MEDIAN FUTURE OIL-IN-PLACE
(Millions of Barrels)

REGION 2 SUBDIVISION CALIFORNIA ONSHORE
YEAR-END 1968

Geologic Horizon	Depth 0-5	Range 5-10	Thousand Feet 10-15	Total
Ventura Basin				
Pliocene and Upper Miocene	560	470	420	1,450
Middle Miocene	300	400	150	850
Lower Miocene	100	300	200	600
Oligocene	125	175	275	575
Eocene and Older	150	255	70	475
Total	**1,235**	**1,600**	**1,115**	**3,950**
San Joaquin Valley				
Pliocene and Upper Miocene	175	1,034	743	1,952
Middle Miocene		467	470	937
Lower Miocene	117	982	1,725	2,824
Eocene and Older		475	3,178	3,653
Total	**292**	**2,958**	**6,116**	**9,366**
Los Angeles Basin				
Pliocene and Upper Miocene	100	1,500	2,400	4,000
Santa Maria Valley				
Pliocene and Upper Miocene	30	38		68
Middle Miocene		260	260	520
Lower Miocene and Cretaceous	6	6		12
Total	**36**	**304**	**260**	**600**
Central Coastal				
Pliocene and Upper Miocene	500	167		667
Middle Miocene	500	167		667
Lower Miocene	136	980		1,116
Eocene	25	25		50
Total	**1,161**	**1,339**		**2,500**
North Coastal Ranges				
Pliocene	5	2		7
Eocene	1	2		3
Cretaceous	1	2		3
Total	**7**	**6**		**13**
California Onshore	**2,831**	**7,707**	**9,891**	**20,429**

TABLE 92

MEDIAN FUTURE OIL-IN-PLACE
(Millions of Barrels)

REGION 2A SUBDIVISION CALIFORNIA OFFSHORE
YEAR-END 1968

Geologic Horizon	Depth 0-5	Range 5-10	Thousand Feet 10-15	Total
Santa Barbara Channel				
Northeast Side				
Pliocene, Upper and Middle Miocene	945	1,260	945	3,150
Northwest Side				
Lower Miocene and Oligocene	567	756	567	1,890
Eocene and Older	126	504	630	1,260
Total	**693**	**1,260**	**1,197**	**3,150**
Northeast and Northwest	1,638	2,520	2,142	6,300
South Side				
Pliocene, Upper and Middle Miocene	3,357	839		4,196
Lower Miocene and Oligocene	370	834	648	1,852
Eocene and Older	25	101	126	252
Total	**3,752**	**1,774**	**774**	**6,300**
Southern California (All Pliocene and Upper Miocene)				
Santa Cruz Basin	6,300			6,300
Santa Monica Basin	5,550			5,550
Los Angeles Basin, Southeast	3,150	3,150		6,300
San Nicholas Basin	5,150			5,150
San Diego Basin	3,700			3,700
Tanner Bank	2,950			2,950
San Pedro Basin	2,950			2,950
Santa Catalina Basin	2,600			2,600
San Clemente Basin	750			750
Los Angeles Basin, Northwest	750			750
Total	**33,850**	**3,150**		**37,000**
California Offshore	**39,240**	**7,444**	**2,916**	**49,600**

TABLE 93

MEDIAN FUTURE OIL-IN-PLACE
(Millions of Barrels)

REGION 3 SUBDIVISION WEST ROCKY MOUNTAINS
YEAR-END 1967

Geologic Horizon	Depth 0-5	Range 5-10	Thousand Feet 10-15	Total
Paradox Basin				
Permian	1,808	8,436	1,808	12,052
Pennsylvanian	1,326	6,187	1,326	8,839
Mississippian		723	1,687	2,410
Devonian		241	562	803
Total	3,134	15,587	5,383	24,104
Uinta-Piceance Basin				
Tertiary	420	1,680	2,100	4,200
Cretaceous	51	462	512	1,025
Jurassic	40	360	400	800
Permian, Pennsylvanian		1,020	2,380	3,400
Mississippian		104		520
Mississippian, Devonian			416	
Total	511	3,626	5,808	9,945
Idaho-Wyoming Overthrust				
Jurassic (Twin Creek)	3	67	105	175
Traissic (Nugget)	25	475	750	1,250
Triassic (Thaynes)	3	67	105	175
Permian (Weber-Wells), Pennsylvanian	25	475	750	1,250
Mississippian (Brazier-Madison)	25	475	750	1,250
Total	81	1,559	2,460	4,100
Western Rocky Mountains	3,726	20,772	13,651	38,149

TABLE94

MEDIAN FUTURE OIL-IN-PLACE
(Millions of Barrels)

REGION 4 SUBDIVISION NORTH ROCKY MOUNTAINS
YEAR-END 1968

Geologic Horizon	Depth 0-5	Range 5-10	Thousand Feet 10-15	Total
North Montana				
Mesozoic	425	425		850
Permo-Pennsylvanian	20			20
Pre-Pennsylvanian	614	1,432		2,046
Total	1,059	1,857		2,916
Powder River Basin				
Tertiary	450			450
Mesozoic	2,255	2,255	1,127	5,637

TABLE 94 (Continued)

Geologic Horizon	Depth 0-5	Range 5-10	Thousand Feet 10-15	Total
Permo-Pennsylvanian		1,710	1,140	2,850
Pre-Pennsylvanian		742		742
Total	2,705	4,707	2,267	9,679
Crazy Mt.—Bull Mt.-Basin				
Tertiary	50			50
Mesozoic		400		400
Permo-Pennsylvanian		111		111
Pre-Pennsylvanian		167		167
Total	50	678		728
Wind River Basin				
Tertiary	71	24		95
Mesozoic	22	315	113	450
Permo-Pennsylvanian	15	150	135	300
Pre-Pennsylvanian (Mississippian)	5	49	45	99
Total	113	538	293	944
Big Horn Basin				
Tertiary	150			150
Mesozoic	264	272	264	800
Permo-Pennsylvanian	150	1,500	1,350	3,000
Pre-Pennsylvanian	42	425	383	850
Total	606	2,197	1,997	4,800
Green River Basin				
Tertiary	225	225		450
Mesozoic	380	1,140	2,280	3,800
Permo-Pennsylvanian	200	400	400	1,000
Pre-Pennsylvanian	100	450	450	1,000
Total	905	2,215	3,130	6,250
East Colorado, West Nebraska, Southeast Wyoming, Northeast New Mexico				
Cretaceous		800		800
Jurassic-Traissic	30			30
Permian		280		280
Pennsylvanian	330			330
Pre-Pennsylvanian		295		295
Total	360	1,375		1,735
North Dakota				
Mesozoic	100			100
Permo-Pennsylvanian		80		80
Pre-Pennsylvanian (M-D)		1,143		1,143
Pre-Pennsylvanian (D)			762	762
Total	100	1,223	762	2,085
South Dakota				
Mesozoic				
Permo-Pennsylvanian	?	1		1
Pre-Pennsylvanian (D)		15		15
Total		16		16
North Rocky Mountains	5,898	14,806	8,449	29,153

TABLE 95

MEDIAN FUTURE OIL-IN-PLACE
(Millions of Barrels)

REGION 5 SUBDIVISION WEST TEXAS, EAST NEW MEXICO
YEAR-END 1967

Geologic Horizon	Depth 0-5	Range 5-10	Thousand Feet 10-15	Total
Northwestern Shelf				
Upper Guadalupe	750			750
Lower Guadalupe	5,152	2,208		7,360
Leonard		4,000		4,000
Wolfcamp		268	132	400
Cisco Canyon		1,803	257	2,060
Mississippian			90	90
Devonian-Silurian		72	108	180
Montoya	—	—	—	—
Simpson		30	20	50
Cambrian—Ordovician	—	—	—	—
Total	**5,902**	8,381	607	**14,890**
Eastern Shelf				
Lower Guadalupe	3,680			3,680
Leonard	800			800
Wolf Camp		107	53	160
Cisco Canyon Strawn	640	2,244		2,884
Lower Pennsylvanian (Pre-Strawn)	—	—	—	—
Mississippian	22	38		60
Simpson				
Cambrian-Ordovician	56	224		280
Total	**5,198**	**2,613**	53	**7,864**
Ft. Worth Basin				
Strawn	46	160		206
Lower Pennsylvanian (Pre-Strawn)	7	53		60
Mississippian		30		30
Montoya		5		5
Simpson		50		50
Cambrian-Ordovician		62	78	140
Total	53	360	78	491
Central Basin Platform				
Upper Guadalupe	450			450
Lower Guadalupe	2,576	1,104		3,680
Leonard	80	320		400
Wolfcamp		53	27	80

TABLE 95 (Continued)

Geologic Horizon	Depth 0-5	Range 5-10	Thousand Feet 10-15	Total
Cisco				
Canyon	114	401		515
Strawn				
Devonian-Silurian		90	135	225
Montoya		25	10	35
Simpson		105	70	175
Cambrian-Ordovician		311	389	700
Total	3,220	2,409	631	6,260
Palo Duro Basin				
Wolfcamp	23	137		160
Cisco				
Canyon	275	961		1,236
Strawn				
Lower Pennsylvanian (Pre-Strawn)		60		60
Mississippian		120		120
Cambrian-Ordovician		280		280
Total	298	1,558		1,856
Delaware Basin				
Upper Guadalupe	600	600		1,200
Lower Guadalupe	920			920
Leonard		400		400
Wolfcamp		107	53	160
Canyon		270	39	309
Total	1,520	1,377	92	2,989
Midland Basin				
Upper Guadalupe	150			150
Lower Guadalupe	920			920
Leonard		1,600		1,600
Wolfcamp		320	160	480
Cisco				
Canyon		1,082	154	1,236
Strawn				
Lower Pennsylvanian (Pre-Strawn)		187	53	240
Mississippian		43	17	60
Devonian-Silurian		90	135	225
Montoya		21	9	30
Simpson		60	40	100
Cambrian-Ordovician		249	311	560
Total	1,070	3,651	880	5,601
Ouachita Fold Belt				
Mississippian		30		30
Devonian-Silurian		36	54	90
Montoya		10		10
Simpson		50		50

TABLE 95 (Continued)

Geologic Horizon	Depth 0-5	Range 5-10	Thousand Feet 10-15	Total
Cambrian-Ordovician		140		140
Total		266	54	320
Bend Arch - North Texas				
Cisco, Canyon, Strawn	412	1,442		1,854
Lower Pennsylvanian (Pre-Strawn)	150			150
Mississippian	45	75		120
Cambrian-Ordovician	56	224		280
Total	663	1,741		2,404
Diablo Platform				
Upper Guadalupe	450			450
Lower Guadalupe	1,288	552		1,840
Leonard	800			800
Wolfcamp	23	137		160
Total	2,561	689		3,250
Kerr Basin				
Lower Pennsylvanian		90		90
Cambrian-Ordovician		140		140
Total		230		230
Marfa Basin				
Mississippian		30		30
Devonian-Silurian		72	108	180
Montoya		4	1	5
Simpson		15	10	25
Cambrian-Ordovician		140		140
Total		261	119	380
Hollis-Hardeman				
Mississippian		30		30
Montoya		5		5
Simpson		25		25
Cambrian-Ordovician		140		140
Total		200		200
Muenster Arch				
Montoya		10		10
Simpson		25		25
Total		35		35
Matador-Red River				
Mississippian	30			30
Total	30			30
West Texas-East New Mexico	20,515	23,771	2,514	46,800

TABLE 96

MEDIAN FUTURE OIL-IN-PLACE
(Millions of Barrels)

REGION 6 SUBDIVISION WEST GULF ONSHORE
YEAR-END 1968

Geologic Horizon	Depth 0-5	Range 5-10	Thousand Feet 10-15	Total
Pleistocene	1			1
Pliocene	71	215		286
Miocene	543	1,629	3,259	5,431
Oligocene	—	1,501	4,501	6,002
Eocene and Paleocene	428	1,284	2,568	4,280
Cretaceous	1,276	2,552	8,932	12,760
Jurassic		431	1,293	1,724
Pre-Jurassic	153	612	765	1,530
Total	2,472	8,224	21,318	32,014

TABLE 97

MEDIAN FUTURE OIL-IN-PLACE
(Millions of Barrels)

REGION 6A SUBDIVISION WEST GULF OFFSHORE
YEAR-END 1968

Geologic Horizon	Depth 0-5	Range 5-10	Thousand Feet 10-15	Total
Less than 200 Meters				
Pleistocene	713	2,138	713	3,564
Pliocene	577	1,731	0	2,308
Miocene	530	1,589	3,179	5,298
Lower Eocene	125	0	0	125
Paleocene	125	0	0	125
Cretaceous	769	3,970	7,906	12,645
Jurassic	0	0	281	281
Early Paleozoics	0	11	1	12
Total	2,839	9,439	12,080	24,358
Deeper than 200 Meters				
Pleistocene	115	346	116	577
Pliocene	410	1,231	0	1,641
Lower Cretaceous	0	769	1,794	2,563
Total	525	2,346	1,910	4,781
Grand Total	3,364	11,785	13,990	29,139

TABLE 98

MEDIAN FUTURE OIL-IN-PLACE
(Millions of Barrels)

REGION 7 SUBDIVISION MID-CONTINENT
MID-YEAR 1967

Geologic Horizon	Depth 0-5	Range 5-10	Thousand Feet 10-15	Total
Cretaceous	3			3
Permian	128			128
Pennsylvanian	1,040	441	360	1,841
Mississippian	366	164	245	775
Middle and Upper Devonian	106			106
Lower Devonian and Upper Silurian	6	559	373	938
Upper Middle Ordovician	327	49	33	409
Lower Middle Ordovician	246	347	150	743
Cambrian and Lower Ordovician	360	229	98	687
Mid-Continent	2,582	1,789	1,259	5,630

TABLE 99

MEDIAN FUTURE OIL-IN-PLACE
(Millions of Barrels)

REGION 8 SUBDIVISION MICHIGAN BASIN
YEAR-END 1967

Geologic Horizon	Depth 0-5	Range 5-10	Thousand Feet 10-15	Total
Middle Devonian	284	–	–	284
Silurian	94	284	–	378
Middle Ordovician	63	377	188	628
Michigan Basin	441	661	188	1,290

TABLE 100

MEDIAN FUTURE OIL-IN-PLACE
(Millions of Barrels)

REGION 9 SUBDIVISION EASTERN INTERIOR
YEAR-END 1969

Geologic Horizon	Depth 0-5	Range 5-10	Thousand Feet 10-15	Total
Pennsylvanian	41			41
Chester, Mississippian	624			624
Pre-Chester, Mississippian	234			234
Middle and Lower Devonian end Silurian	132	15		147
Upper and Middle Ordovician	49	5		54
Knox	448	1,792		2,240
Potsdam	96	576	288	960
Eastern Interior	1,624	2,388	288	4,300

TABLE 101

MEDIAN FUTURE OIL-IN-PLACE
(Millions of Barrels)

REGION 10 SUBDIVISION APPALACHIAN BASIN
YEAR-END 1968

Geologic Horizon	Depth 0-5	Range 5-10	Thousand Feet 10-15	Total
Lower Mississippian	90			90
Upper Devonian	60			60
Lower Devonian and Silurian	60			60
Middle Ordovician	30			30
Cambro-Ordovician	90	180	90	360
Appalachian Basin	**330**	**180**	**90**	**600**

TABLE 102

MEDIAN FUTURE OIL-IN-PLACE
(Millions of Barrels)

REGION 11 SUBDIVISION ATLANTIC COAST ONSHORE
YEAR-END 1968

Geologic Horizon	Depth 0-5	Range 5-10	Thousand Feet 10-15	Total
North of Cape Fear				
Upper Cretaceous	303			303
Lower Cretaceous	709			709
Total	**1,012**			**1,012**
Cape Fear to Florida				
Upper Cretaceous	109			109
Lower Cretaceous	254			254
Total	363			363
Florida Peninsula				
Lower Cretaceous Transitional Zone		656	281	937
Lower Cretaceous Carbonate Zone		112	263	375
Jurassic			938	938
Early Paleozoics	11	90	11	112
Total	**11**	858	1,493	2,362
Atlantic Coast Onshore	1,386	858	1,493	3,737

TABLE 103

MEDIAN FUTURE OIL-IN-PLACE
(Millions of Barrels)

REGION 11A SUBDIVISION EAST COAST OFFSHORE
YEAR-END 1968

Geologic Horizon	Depth 0-5	Range 5-10	Thousand Feet 10-15	Total
Less Than 200 Meters				
North of 33° Latitude				
Upper Cretaceous	795	1,192		1,987
Lower Cretaceous	398	1,988	1,590	3,976
Jurassic			662	662
Total	1,193	3,180	2,252	6,625
South of 33° Latitude to Florida				
Upper Cretaceous	30	45		75
Lower Cretaceous	15	75	60	150
Jurassic			25	25
Total	45	120	85	250
Florida Peninsula				
Lower Cretaceous Transitional		591	253	844
Lower Cretaceous Carbonate		304	709	1,013
Jurassic			31	31
Total		895	993	1,888
Subtotal	1,238	4,195	3,330	8,763
Water Deeper Than 200 Meters				
North of Latitude 33°				
Upper Cretaceous	495	742		1,237
Lower Cretaceous	247	1,238	990	2,475
Jurassic			413	413
Total	742	1,980	1,403	4,125
South of Latitude 33°				
Upper Cretaceous	180	270		450
Lower Cretaceous	90	450	360	900
Jurassic			150	150
Total	270	720	510	1,500
Subtotal	1,012	2,700	1,913	5,625
East Coast Offshore	2,250	6,895	5,243	14,388

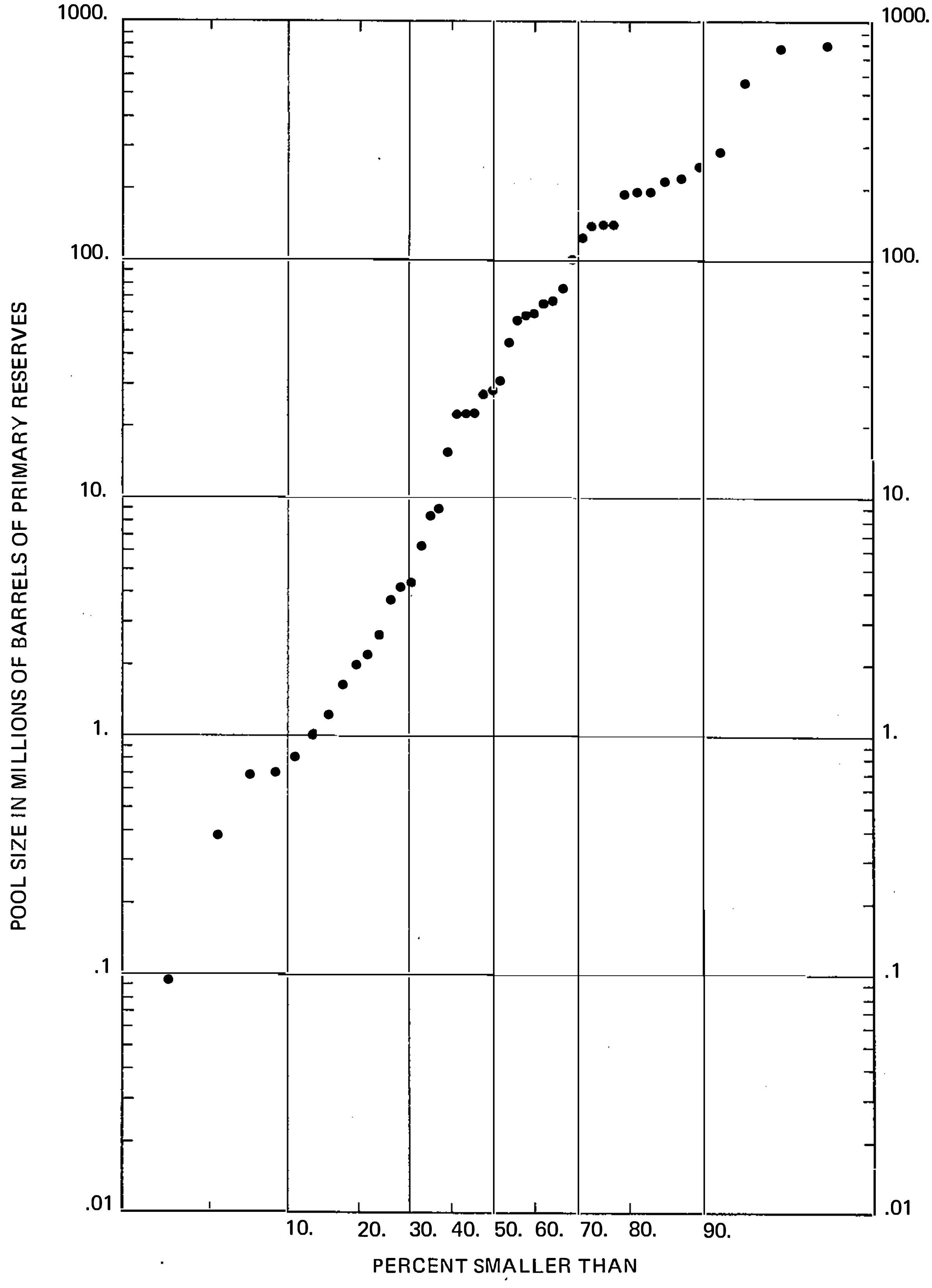


Figure 54. Pool Size—Los Angeles Basin (Pliocene and Upper Miocene).

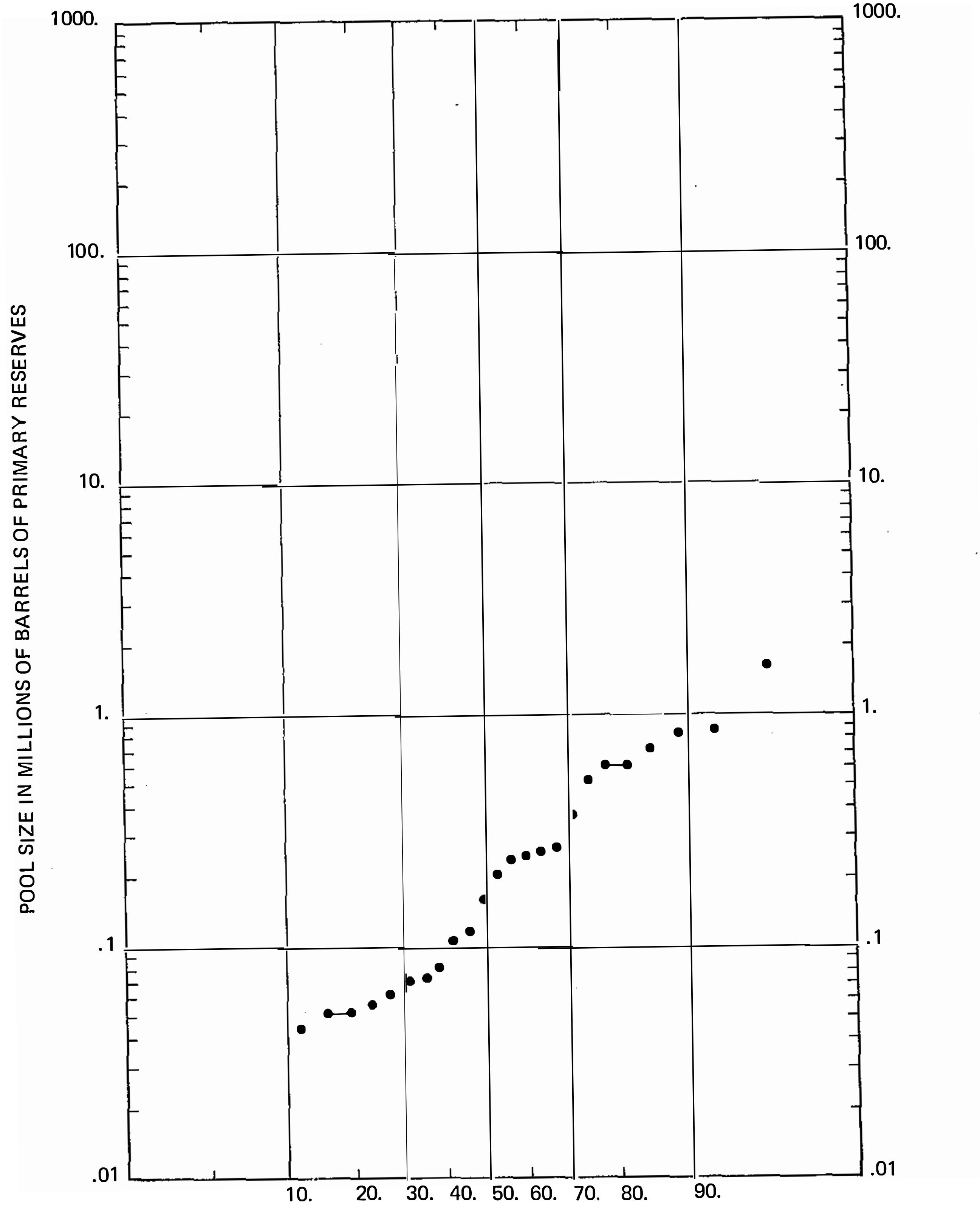


Figure 55. Pool Size—Oklahoma (Lower Devonian).

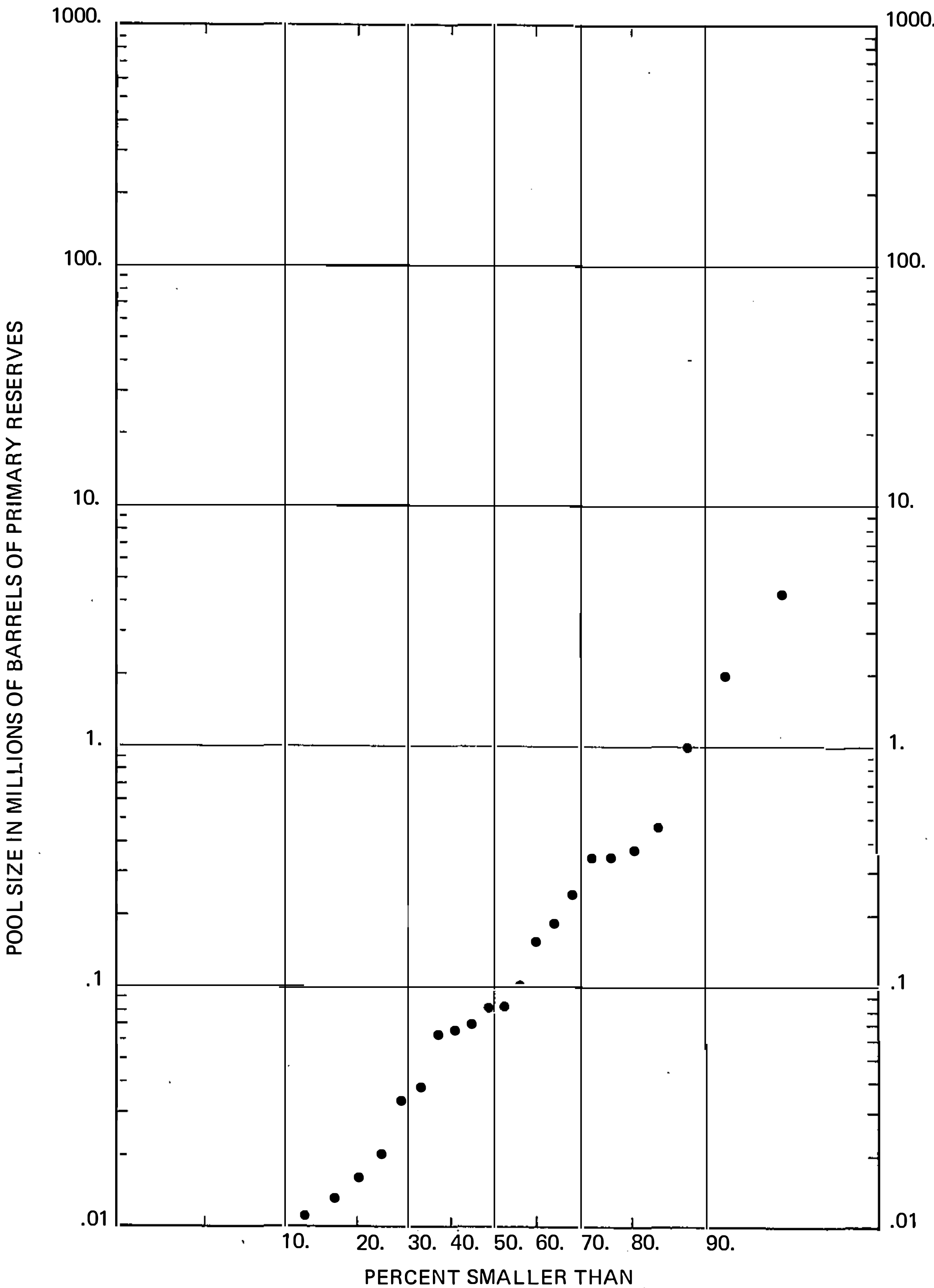


Figure 56. Pool Size—Indiana (Upper Mississippian).

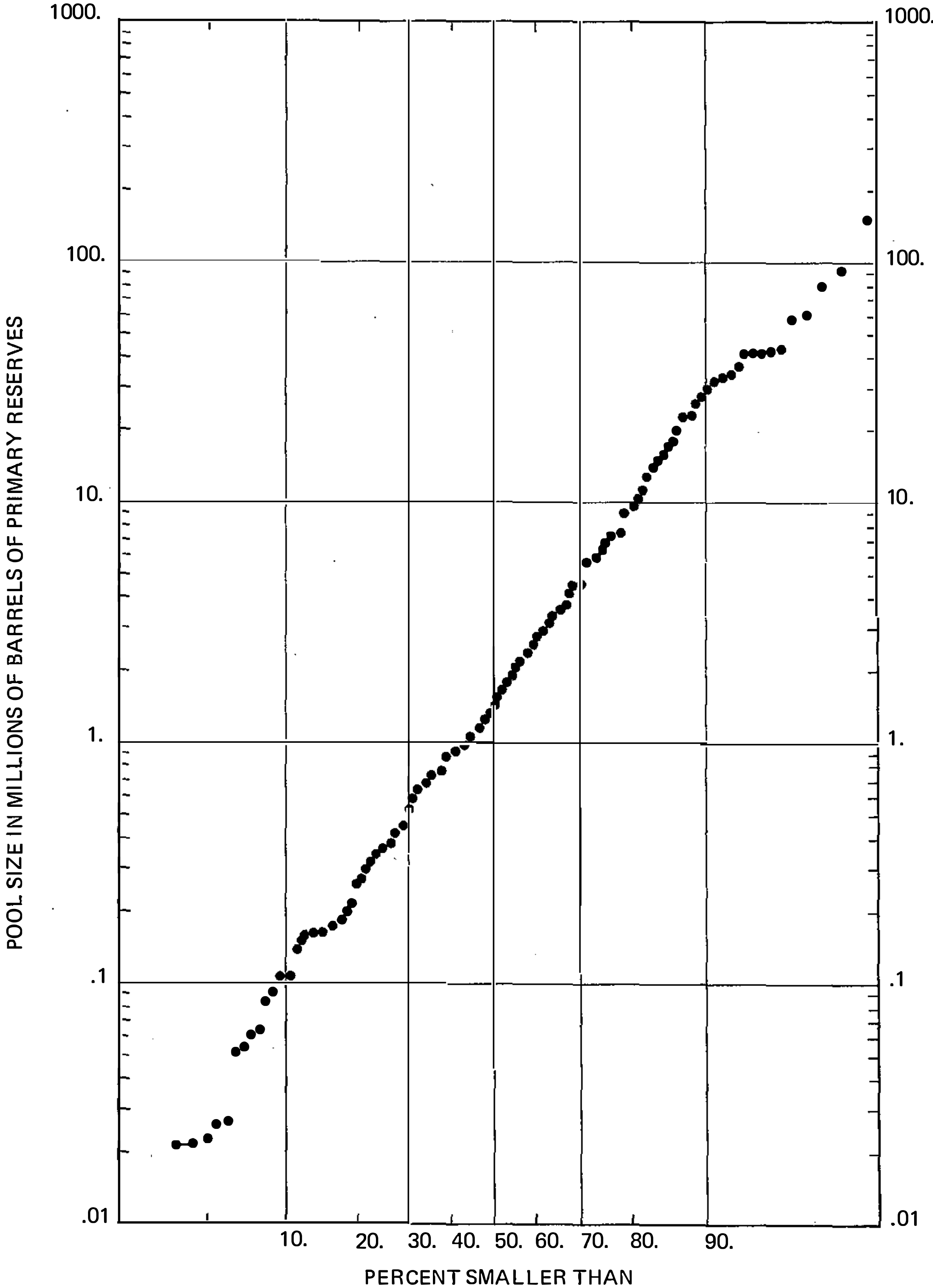


Figure 57. Pool Size—Gulf Coast (Eocene).

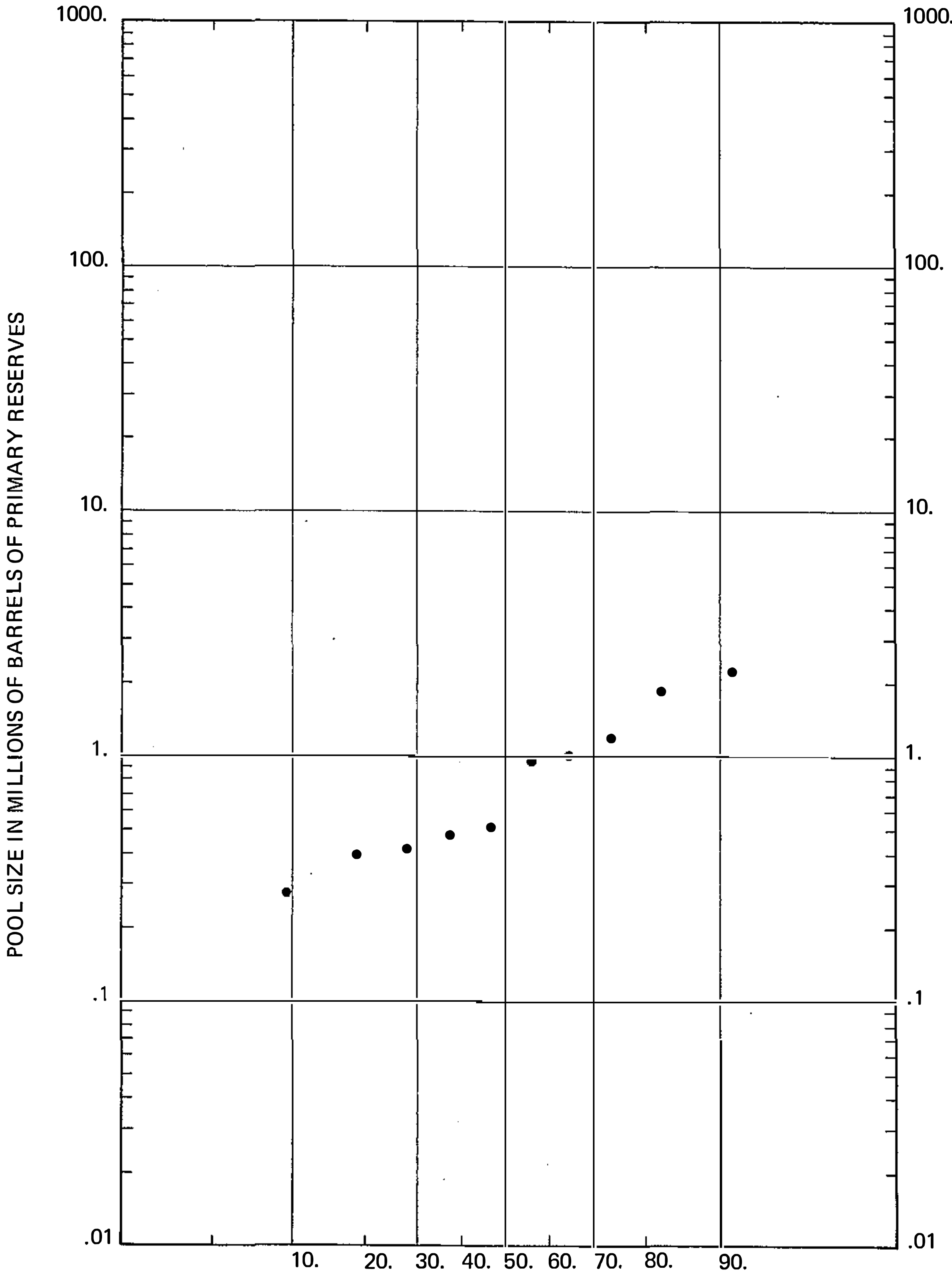


Figure 58. Pool Size—(Composite Mississippian).

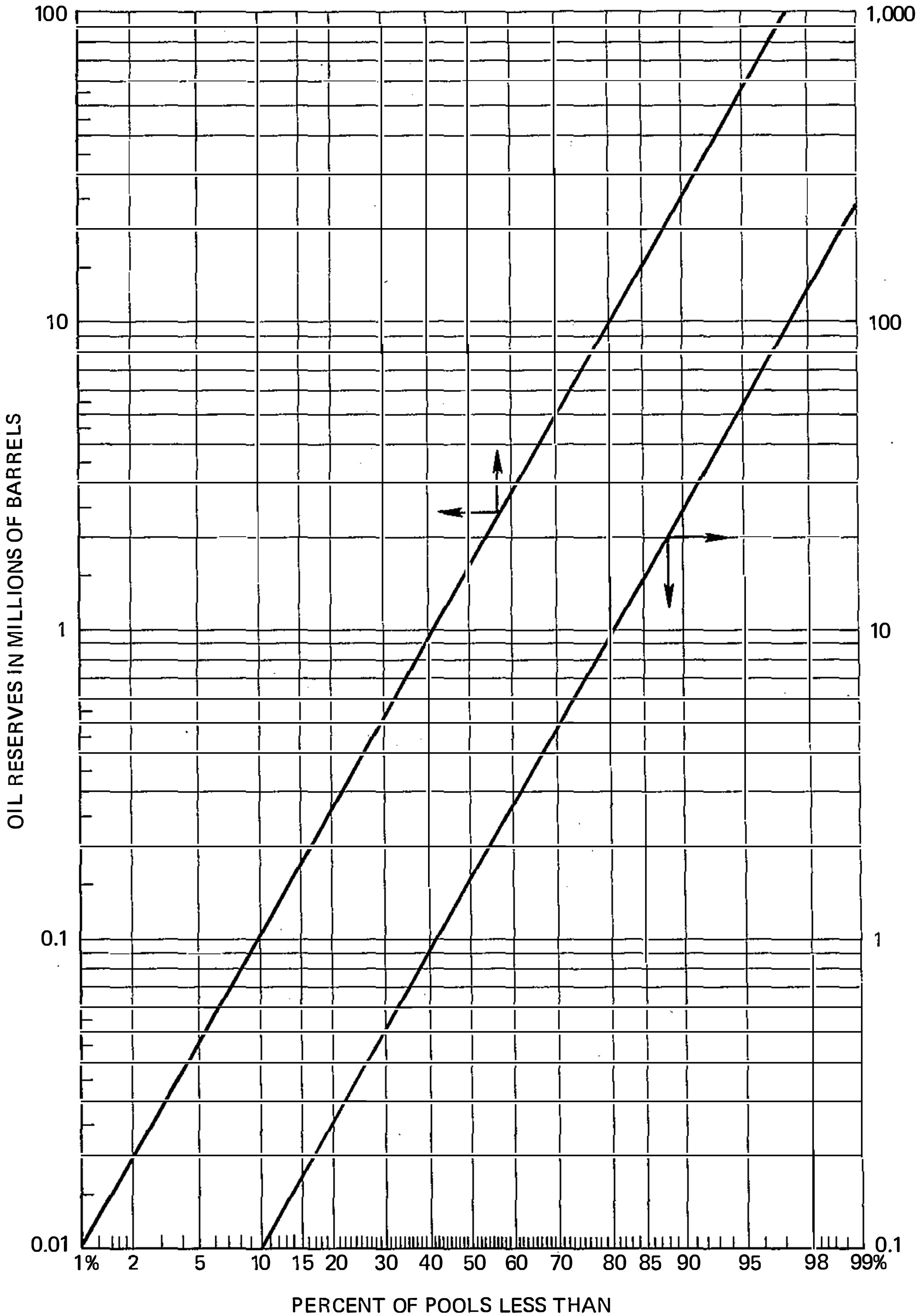


Figure 59. Size Distribution of Oil Pools—Gulf Coast (Eocene).

TABLE 104

DISTRIBUTION OF FUTURE DISCOVERABLE PRIMARY RESERVES BY DEPTH AND POOL SIZE – MM BARRELS

	0-5 M Feet					5-10 M Feet					10-15+ M Feet					0-15+ M Feet				
Region	<10	10-50	50-100	>100	Total	<10	10-50	50-100	>100	Total	<10	10-50	50-100	>100	Total	<10	10-50	50-100	>100	Total
1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
2	81	213	195	302	791	115	475	432	839	1,911	105	473	261	1,477	2,316	301	1,161	938	2,618	5,018
2A	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
3	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
4	172	296	58	874	1,400	403	876	–	2,840	4,119	203	520	–	1,670	2,393	778	1,692	58	5,384	7,912
5	442	536	735	3,102	4,865	1,418	1,412	329	1,237	4,396	119	125	79	275	598	1,979	2,123	1,143	4,614	9,859
6	115	224	216	592	1,147	391	905	613	1,902	3,811	851	1,752	1,468	5,814	9,395	1,357	2,891	2,297	8,308	14,853
6A	69	199	264	915	1,447	176	590	752	2,822	4,340	255	518	820	3,596	5,189	500	1,307	1,836	7,333	10,976
7	269	528	–	–	797	341	210	–	–	551	224	165	–	–	389	834	903	–	–	8,737
8	26	52	72	–	150	51	175	–	–	226	20	45	–	–	65	97	272	72	–	441
9 & 10	420	245	–	–	668	926	–	–	–	926	124	–	–	–	124	1,470	243	–	–	1,718
11	19	17	45	230	311	18	21	25	125	189	13	33	75	315	436	50	71	145	670	936
11A	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–

rels, 50 to 100 million barrels and greater than 100 million barrels.

For those places where the remaining future reserves were less than those already found, the assumption was made that all of the larger fields had already been found and that the future reserves were distributed in fields of sizes lying on the curve below the field size equivalent to that at which the total reserves in the sum of the fields remaining to be found equalled the estimated potential future reserves. A typical example showing such a calculation is given on Table 108.

The summarized results of these calculations are provided in Table 104 for those regions susceptible to calculation. For convenience in helping to establish appropriate probable regional drilling rates the percentage of future oil-in-place was determined as a function of depth. In addition, the number of potential productive horizons which might be encountered in each depth range was also determined for each region. These data are provided on Table 105.

TABLE 105

ESTIMATED PROBABLE FUTURE OIL-IN-PLACE
AND RELATIVE NUMBER OF POTENTIAL GEOLOGIC HORIZONS
BY REGION AND DEPTH RANGE

	Percent of Future Oil-In-Place			Relative Number of Potential Geologic Horizons		
	Depth (Thousands of Feet)			Depth (Thousands of Feet)		
Region	0-5	5-10	Over 10	0-5	5-10	Over 10
1	8	47	45	—	—	—
2	14	38	48	3+	4	4
2A	79	15	6	1+	2	2
3	10	54	36	2+	4+	5
4	20	21	29	3–	3	2+
5	44	51	5	3–	4	4–
6	8	26	66	6	7	7
6A	13	40	47	3+	3+	3–
7	46	32	22	9	7	7
8	34	51	15	3	2	1
9	38	56	6	7	4	1
10	55	30	15	5	1	1
11	37	28	40	2	2+	3+
11A	13	47	40	2	2+	3

TABLE 106

OIL FIELD SIZE
LOG NORMAL DISTRIBUTION FOR VARIOUS PERCENTILES

Region	Geologic Province	Geologic Horizon	Pool Size at Percentile Millions of Barrels of Primary Reserves 15.9%	50.0%	84.3%
1	–	–			
2,2A	Coastal and Santa Maria Valley	Pliocene and Upper Miocene	0.33	7.20	154
	Los Angeles Basin	Pliocene and Upper Miocene	3.20	20.50	136
	San Joaquin Valley	Pliocene and Upper Miocene	0.66	11.30	190
		Middle Miocene	0.63	8.40	112
		Lower Miocene	0.16	6.15	66
		Eocene and Older	0.19	4.10	90
	Ventura Basin	Pliocene and Upper Miocene	0.53	3.14	18.2
		Middle and Lower Miocene	0.07	1.83	51.0
		Oligocene and Older	1.18	6.80	39.0
3	–	–			
4	Green River	Mesozoic	0.28	2.98	34.5
	No. Rocky Mountains (excl. Green River)	Mesozoic	0.18	1.90	21.0
	No. Rocky Mountains Composite	Permo-Pennsylvanian	0.30	3.60	43.0
		Pre-Pennsylvanian	0.39	3.25	27.8
5	Midland Basin-Eastern Shelf	Guadalupe	0.01	0.43	17.0
	Northwest Shelf	Guadalupe	0.11	2.50	66.0
	Central Basin Platform, Delaware and Diablo Basin Composite	Guadalupe	0.87	7.20	61.5
	New Mexico-West Texas Composite	Lower Permian	0.03	0.48	8.60
		Cisco, Canyon and Strawn	0.13	0.80	5.0
		Lower Pennsylvanian	0.06	0.58	7.3
		Mississippian	0.33	0.77	1.85
		Ordovician	0.10	1.60	28.0
6,6A	Gulf Coast	Pleistocene, Pliocene and Upper Miocene	1.24	9.30	71.5
		Miocene	0.82	5.60	38.0
		Oligocene 0-5000'	0.45	1.48	15.1
		Oligocene 5000-15,000'	0.43	3.65	31.0
		Eocene	0.17	1.48	12.6
		Cretaceous	0.23	3.25	45.5
		Jurassic	0.24	4.20	72.0
		*Pre-Jurassic	0.02	0.21	2.30
7	Midcontinent	†Cretaceous	0.23	3.25	45.5
		Permian	0.03	0.48	8.60
		Pennsylvanian	0.04	0.47	5.0
		Mississippian	0.02	0.23	2.90
		Devonian-Silurian	0.04	0.16	0.62
		Upper Middle Ordovician	0.04	0.43	4.45
		Lower Middle Ordovician	0.10	0.92	8.30
		Lower Ordovician	0.02	0.16	1.90
8	Michigan Basin	Middle Devonian-Silurian	0.06	0.80	11.2
		Middle Ordovician	0.04	0.43	4.45
9	Eastern Interior	Mississippian	0.02	0.21	2.30
		Lower Mississippian	0.01	0.11	0.87
		Middle, Lower Devonian and Silurian	0.06	0.80	11.2
		‡Upper and Middle Ordovician	0.04	0.43	4.45
		Cambrian-Ordovician	0.02	0.16	1.90
10	Appalachian	Lower Mississippian	0.68	2.82	11.0
		Devonian-Silurian	1.16	4.95	21.1
		Middle Ordovician	0.04	0.43	4.45
		Cambrian-Ordovician	0.02	0.16	1.90
11, 11A	Atlantic Coast	§Cretaceous	0.23	3.25	45.5
		§Jurassic and Older	0.24	4.20	72.0

* Eastern Interior Basin Composite Mississippian data (closest geologically related information)

† Gulf Coast Cretaceous (closest geologically related information)

‡ Midcontinent Upper Middle Ordovician (closest geologically related information)

§ Gulf Coast Data used (closest similar geologic information)

TABLE 107

RESERVE DISTRIBUTION CALCULATION
(Millions of Barrels)

Region 5 | Subdivision New Mexico, West Texas | Location All

Geological Age Guadalupe | Depth Range 5-10 Thousands of Feet

Future OIP 2256 | Recov. Fact. 23.7% | Equiv. 100% | Recov. OIP 534.7

Distribution (Calculated on basis of PAW 1946 Data) | Curve No. 11

Average Field Size at: 50% 7.20 | 16% 0.87 | 84% 61.5

Percentile Range	Average Field Size, Millions of Barrels	Cumulative Average, Field Size Millions of Barrels	Future Allocable Reserves, Millions of Barrels
1-10	0.22	0.22	0.32
10-20	0.80	1.02	1.15
20-30	1.72	2.74	2.47
30-40	3.17	5.91	4.55
40-50	5.55	11.46	7.96
50-60	9.40	20.86	13.5
60-70	16.3	37.16	23.4
70-80	30.5	67.7	43.8
80-90	65.0	132.7	93.3
90-99	240.0	372.7	344.4
Total	372.7		534.9

Future Allocable Factor = $\frac{534.7}{372.7}$ = 1.435 Millions of Barrels

Future Reserves (Primary Recovery) in Fields of: Less than 10 30.0 | 10 - 50 67.2

(Millions of Barrels) 50 - 100 93.3 | Over 100 344.4

TABLE 108

RESERVE DISTRIBUTION CALCULATION
(Millions of Barrels)

Region 5 | Subdivision New Mexico, West Texas | Location All

Geological Age Comp. Ord. | Depth Range 0-5 Thousands of Feet

Future OIP 112 | Recov. Fact. 23.7% | Equiv. 83.4% | Recov. OIP 26.54

Distribution (Calculated on basis of PAW 1946 Data) | Curve No. 13

Average Field Size at: 50% 1.60 | 16% 0.097 | 84% 28.0

Percentile Range	Average Field Size, Millions of Barrels	Cumulative Average, Field Size Millions of Barrels	Future Allocable Reserves, Millions of Barrels
1-10	0.015	0.015	0.01
10-20	0.086	0.10	0.06
20-30	0.24	0.34	0.15
30-40	0.55	0.89	0.35
40-50	1.13	2.02	0.73
50-60	2.30	4.32	1.48
60-70	4.90	9.22	3.14
70-80	10.13	19.35	6.50
80-83.4	22.0	41.35	
80-90	31.8	51.15	14.12
90-99	183.0	234.2	
Total	41.35		26.54

Future Allocable Factor = $\frac{26.54}{41.35}$ = 0.6418 Millions of Barrels

Future Reserves (Primary Recovery) in Fields of: Less than 10 5.92 | 10 - 50 20.62

(Millions of Barrels) 50 - 100 – | Over 100 –

Chapter Five—Section II

Historical and Projected Regional Activity and Oil Finding Rate

TABLE 109

ALLOCATION OF STATES TO NPC REGIONS*

State or Area	NPC Region Assigned	Remarks
Alabama	6	
Alaska (South)	1	
Arkansas	6	All production in southern Arkansas
California	(All 2)	
Coastal	2	
Los Angeles Basin	2	
San Joaquin Valley	2	Includes Sacramento Valley
Colorado	3 (60%) & 4 (40%)	Could call it 59.6% and 40.4%
Illinois	9	Combined with Regions 8 & 10
Indiana	9	Combined with Regions 8 & 10
Kansas	7	
Kentucky	10	Combined with Regions 8 & 9
Louisiana	(All 6)	
North	6	
South	6	
Offshore	6A	Included with Gulf of Mexico
Michigan	8	Combined with Regions 9 & 10
Mississippi	6	
Montana	4	
Nebraska	4 (85%) & 7 (15%)	
New Mexico	(Split 3 & 5)	
Southeast	5	
Northwest	3	
New York	10	Combined with Regions 8 & 9
North Dakota	4	
Ohio	10	Combined with Regions 8 & 9
Oklahoma	7	
Pennsylvania	10	Combined with Regions 8 & 9
Texas	(Split 5, 6 & 7)	
District 1	6	
District 2	6	
District 3	6	
District 4	6	All production in eastern portion
District 5	6	
District 6	6	
District 7-B	5	
District 7-C	5	
District 8	5	
District 8A	5	
District 9	5	
District 10	7	Production in north half of District 10
Offshore	6A	Included with Gulf of Mexico
Utah	3	
West Virginia	10	Combined with Regions 8 & 9
Wyoming	4	
Miscellaneous	(Split as shown)	
Arizona	3	
Florida	11	New discoveries in Panhandle in 1970 were put in Region 6
Missouri	7	
Nevada	3	
South Dakota	4	
Tennessee	9	Combined with Regions 8 & 10 Carried in Region 9 to balance Virginia in Region 10
Virginia	10	Combined with Regions 8 & 9 Production in western portion of State

* All statistical data normally published by states was allocated as shown above to NPC regions on the basis of oil-in-place and reserves from "Future Petroleum Provinces of the United States".

TABLE 110

CROSS-REFERENCE SHOWING COMPOSITION OF NPC REGIONS

NPC Region 1 Alaska	**NPC Region 6 (Cont.)** Mississippi Texas RRC District 1 Texas RRC District 2 Texas RRC District 3 Texas RRC District 4 Texas RRC District 5 Texas RRC District 6 Florida Panhandle
NPC Region 2 California	**NPC Region 6A** Gulf of Mexico (Offshore)
NPC Region 2A California (Offshore)	**NPC Region 7** Kansas Missouri 15% Nebraska Oklahoma Texas RRC District 10
NPC Region 3 Arizona 60% Colorado Nevada Northwest New Mexico Utah	**NPC Regions 8, 9, 10** Illinois Indiana Kentucky Michigan New York Ohio Pennsylvania Tennessee Virginia West Virginia
NPC Region 4 40% Colorado Montana 85% Nebraska North Dakota South Dakota Wyoming	**NPC Region 11** Florida (Less Panhandle)
NPC Region 5 Southeast New Mexico Texas RRC District 7B Texas RRC District 7C Texas RRC District 8 Texas RRC District 8A Texas RRC District 9	**NPC Region 11A** Atlantic Coast (Offshore)
NPC Region 6 Alabama Arkansas North Louisiana South Louisiana	

Oil Drilling Activity

Drilling statistics for each NPC region were tabulated for the period 1956 through 1970 to determine trends of exploratory and development drilling, and to develop the relationship between drilling effort and oil-in-place discovered. The basic sources for this information were from API published data for the 1966-1969 period. Prior to 1966, the *Oil & Gas Journal* was used for development drilling data and the annual American Association of Petroleum Geologists (AAPG) bulletins were used for exploratory wells. The oil wells and footage drilled annually for each region were accumulated from the individual states and grouped as shown on Tables 139 through 149 in this section. In addition, this data was accumulated separately for oil wells and gas wells on all new field wildcats, other wildcats, development wells and stratigraphic and core tests. Service wells were not included. Dry holes were allocated between oil and gas on the basis of successful oil and gas wells. This was done separately for exploratory wells (including all the strat and core tests) and development wells. The same procedure was used to assign the annual footage drilled to the oil finding effort. A well completed from more than one formation was counted as an oil well if any of the completions were oil.

An exception to the above procedure was made in Regions 2 and 2A because of the unique split between onshore and offshore. The Oil Supply Task Group agreed to include five offshore fields located in the Los Angeles basin with onshore California because only a part of each field was located offshore and because it was virtually impossible to separate with confidence the offshore from the onshore oil reserves. These fields are the offshore portions of Huntington Beach, West Montalvo, Rincon, Torrance and Wilmington.

Development drilling statistics for the remaining offshore fields were obtained from the annual publications of the California State Division of Oil and Gas, the annual publications of the Conservation Committee of California Oil Production for state lands out to the three-mile limit, and from company files for federal acreage. Service wells were not included. Exploratory drilling statistics for offshore core holes and wells were obtained from the annual records of the California State Division of Oil and Gas for state acreage, and the United States Geological Survey for Federal lands.

The data were handled in the following manner:

- All drilling in Region 2A was considered to be part of the total oil effort and, therefore, included dry holes. (It was not possible to separate dry holes from producing wells.) Gas wells and gas footage drilled, as indicated by the allocated computer run (Total Drilling Effort for the Years 1950 to 1969 by NPC Region) was accepted without revision.
- Region 2 oil drilling statistics were obtained by subtracting Region 2A from the California total (Regions 2 and 2A) as indicated by the

allocated computer run. Gas drilling statistics for Region 2, as shown by the allocated computer run, were accepted without revision. Drilling statistics for 1970 were obtained from API published data.

Total drilling (which includes development drilling) reflects the success of the exploratory effort. Cases I, II and IVA have higher finding rates of barrels of oil per exploratory foot drilled than Cases IA, III and IV and, therefore, require more development drilling to produce the oil. Thus, the total footage drilled for Cases I and IA (high trend), Cases II and III (intermediate trend) and Cases IV and IVA (low trend) is different, even though the amount of exploratory drilling is the same.

Future exploratory drilling levels for each region (excluding the North Slope) were based upon the current percent of United States total exploratory drilling, future anticipated potential and costs. The distribution used in this analysis is shown in Table 9, Chapter One.

In addition, three exploration drilling trends in the United States were selected to cover the range of possible exploration activity. All trends used the estimated 1971 drilling level of about 22 million feet per year as the base point. The highest trend (Cases I and IA), which assumes a 7.5-percent increase in oil exploration drilling per year, reaches about 60 million feet by 1985. Although this trend exceeds the 1956 level by 21 percent, it is still consistent with the maximum increase in total oil drilling activity seen since World War II. The intermediate trend (Cases II and III) assumes a 5-percent annual growth, reaching about 44 million feet in 1985. The lowest trend (Cases IV and IVA), reflects a 3-percent-per-year decline in activity, which by 1985 results in a rate of about 15 million feet per year.

Case I reaches a total annual drilling rate of 202 million feet per year in 1985, which is about 2.0 percent more than the 1956 level of 198 million feet per year. Case IV, which is the opposite extreme, results in an annual total drilling level of about 47 million feet per year, or a 48 percent decline from the 1971 level of about 90 million feet per year. The intermediate cases represent possible variations within the two extremes.

Exploratory drilling discovers new oil-in-place and expands the reserve base to support future production levels. Thus the historical relationship between the annual new oil-in-place discovered and exploratory drilling (expressed in footage drilled per year) is a measure of success. The annual oil-in-place discovered per exploration foot plotted against cumulative exploration footage drilled establishes a trend which can be projected into the future to predict exploratory activity. The annual ratio of exploratory drilling to total drilling also establishes a trend which can be projected into the future to determine the total number of wells required to produce the oil discovered by the exploratory effort. Field size determines the number of development wells required (large fields—many wells; small fields—few wells). This information is necessary to determine the cost of finding and developing oil supplies. Each region was analyzed separately to obtain the above statistical data.

Methodology for Projection of Oil-In-Place Found and Reserves Added

The basic procedure used for making Reserve Additions projections is as follows:

- Oil-in-place found annually is related by geographic region to the *exploration drilling footage* necessary to find it.* This permits the establishment of trends for extrapolation into the future as a function of exploratory drilling.
- Using various assumed future drilling rates, the amount of OIP found per year is calculated using extrapolation of the regional historical trends.
- Primary recovery factors are then applied by region to the OIP found each year to obtain the annual primary reserve additions.
- Increases in recovery factor are accounted for by the addition of reserves for additional recovery (secondary and tertiary recovery).

Oil-in-Place Finding Trends

Oil-in-place is used as a basis because it is the

* In the NPC report, *U.S. Energy Outlook: An Initial Appraisal* (November 1971), oil finding rates were related to *total oil well drilling*. Subsequent investigation indicated that a large number of in-fill *oil* development wells were drilled, particularly during the last few years of the historical base period. These wells did not contribute to the discovery of new oil-in-place. Consequently, it was decided that the relationship between oil-in-place found and *exploratory drilling footage* was a more valid relationship between effort and result.

true resource base which the industry has to work with. This avoids the danger involved in simply extrapolating reserve additions during a time in which recovery factors are escalating, thereby masking the real resource base trend that will determine what oil is available for recovery in the future.

The starting point for this study is the OIP discovered as of January 1, 1970, as reported by the API. The future discoverable resource base is assumed to be established by the NPC Future Provinces Study's *Median Case* (*probable* and *possible* plus half of the *speculative*), with minor upward adjustments in Alaska.

In order to determine the historical OIP finding trend related to the exploratory drilling required to make the discoveries, it is necessary to calculate backwards from the API reserves additions data by dividing these data by the appropriate recovery factor.

Annual OIP additions are composed of four components: (1) new field discoveries, (2) new pool discoveries in old fields, (3) extensions to old pools caused by extending their areal limits and (4) changes in the earlier estimates of thickness, porosity and connate water in old pools. API reserve additions consist of *new field discoveries, new pool discoveries in old fields, extensions* and *revisions.*

Obviously, the API reserve categories of *new fields,* and *new pools* represent the reserves added as a result of new OIP found and these categories are included in the OIP determination.

However, the first-year estimates of reserves in new reservoirs are often only a small part of the total that will be ultimately assigned to the reservoir after subsequent extensions are made or estimates of thickness, porosity and connate water are revised. Most increases result from extensions, however, as estimates of reservoir parameters are usually not drastically altered. For this reason, *extensions* are also included in the annual OIP determination in the year in which they are booked. Even though these extensions were made in reservoirs not discovered in the year under consideration, they were the result of drilling done and money spent in that year and do provide a means to allow for OIP estimate *growth* that can be expected.

Since this method credits to the current year extensions which are really *appreciation* of new discoveries made previously, a time lag effect is introduced. When discovery trends are downward, as they have been in recent times, the future projections tend to be somewhat optimistic because current extensions are being made on a higher past resource base. Likewise, when finding trends are increasing, the future projections would tend to be somewhat pessimistic on OIP discovery per exploratory foot drilled.

While this method introduces some uncertainty, other techniques for accounting for OIP growth have similar difficulties. Use of an *appreciation factor* determined on a gross historical basis for multiplication by the current new discoveries can tend to be somewhat optimistic. This is because improvements in technology have undoubtedly led to an earlier definition of the ultimate OIP on recent discoveries than was possible in fields discovered prior to development of sophisticated well logging, well testing and completion techniques. Thus, any appreciation factor curves should tend to be decreasing with time. However, representative data for analyzing such a trend are not available.

The *revisions* category consists primarily of changes in recovery factor estimates resulting from improved primary performance over the previous estimate, additional recovery projects, or poorer performance than estimated. Also, changes in estimates by reservoir parameters such as thickness, porosity and connate water would be included in this category.

Since changes in the recovery factor do not affect the OIP estimate and revisions caused by revising reservoir parameter estimates are minimal, *revisions* are not included in the annual OIP determination. To the extent that any reserves added in this category are due to changes in OIP, then the historical OIP/foot drilled trend is slightly conservative. This effect has been estimated as ±5 percent by those knowledgeable in API reserve statistics. However, the part of these OIP revisions relating to OIP found prior to the historical period used to establish the trends for extrapolation would not influence these finding trends.

A partial offsetting factor in the methodology used on the revisions category is that, if some OIP increases are included in revisions, then the improved primary and secondary recovery assumed to constitute the revisions category is somewhat overstated. This implies that the recovery factors used for determining future reserve additions are slightly high and the additional recovery costs are somewhat overstated.

In summary, the OIP found each year during a 15-year historical period is determined by dividing the total API reserve additions from *new fields, new pools* and *extensions* by an engineering estimate of the primary recovery factor. This is done for each NPC region.

API and AAPG drilling statistics are analyzed by region to determine the total exploration footage each year allocated to oil, including a proportionate share of exploratory dry holes. The assumption used in this allocation is that oil and gas dry holes are in the same proportion as successful wells.

OIP per foot of oil exploration drilling is then determined by region for the historical period and plotted against the cumulative oil exploration footage drilled.

Next, based on these historical trends, projections of OIP per foot drilled are made into the future as a function of the cumulative exploration footage drilled.

Using several assumed drilling rates and an assumed allocation of drilling effort by geographic region, the annual OIP found can be estimated for each region.

Reserve Addition Trends

Based on the regional projections of the OIP found per year, the primary reserve additions resulting from the year's exploratory effort are generated by applying a suitable regional primary recovery factory to the OIP discovered that year.

Each region was treated separately, with the secondary and tertiary recovery factors designed to give each region ultimate recovery compatible with the rock and fluid characteristics of the region. For example, Region 1 was estimated to have a primary recovery factor of 23 percent. For *newly discovered oil* the Task Group believes secondary recovery would be applied to most of the reservoirs and would equal primary recovery. The secondary reserves were added in two equal increments of $11^1/_2$ percent. The first increment was added 5 years after the oil-in-place was discovered (or in the sixth year of the study). The second increment was added 10 years after discovery (or in the eleventh year of the study). In the case of *oil-in-place discovered in the past,* the additional recovery factors were applied to the entire volume of oil-in-place in each region at individually selected rates for each region that tied to the historical rate of addition. These rates ranged from one-tenth to one-half percent per year. Constraints are applied which limit the maximum recovery efficiency for secondary and then tertiary, which are unique for each region.

Totalling these reserves additions gives the base for determining the regional oil production as a function of remaining reserves.

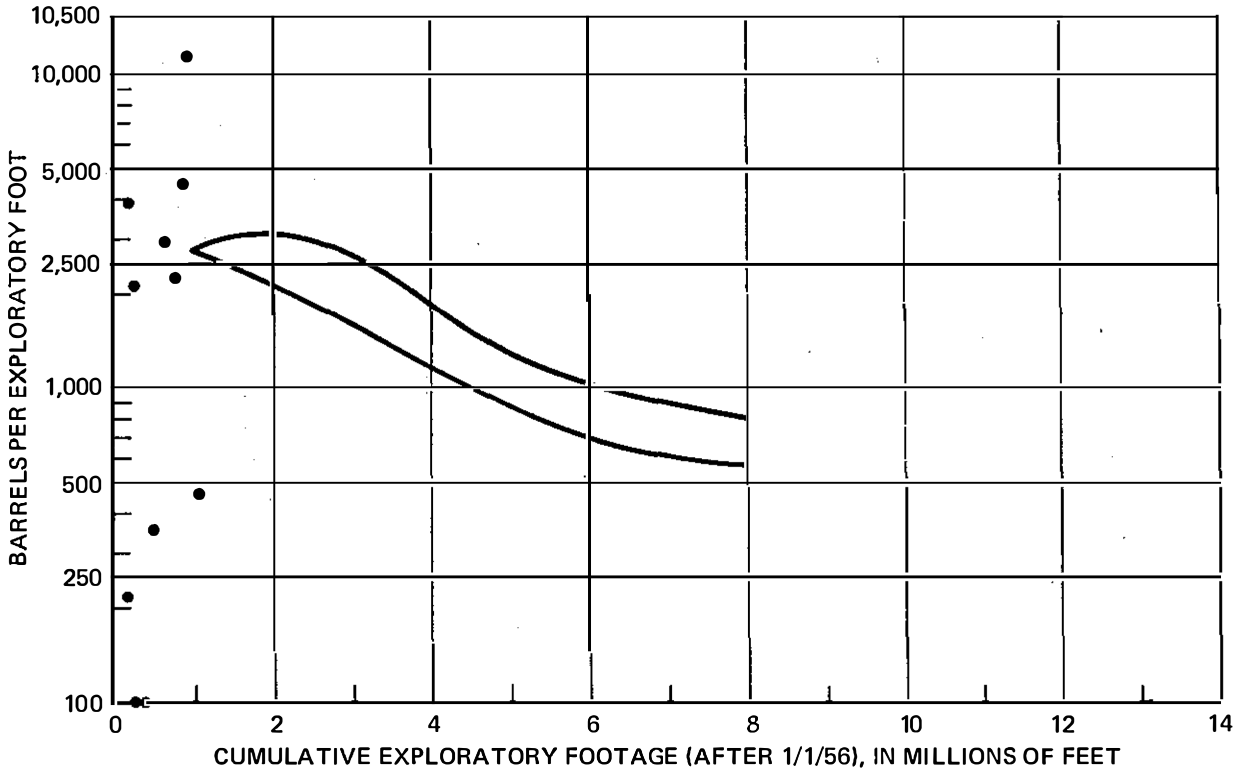


Figure 60. Oil Finding Rate Projections—Alaska (Excluding North Slope).

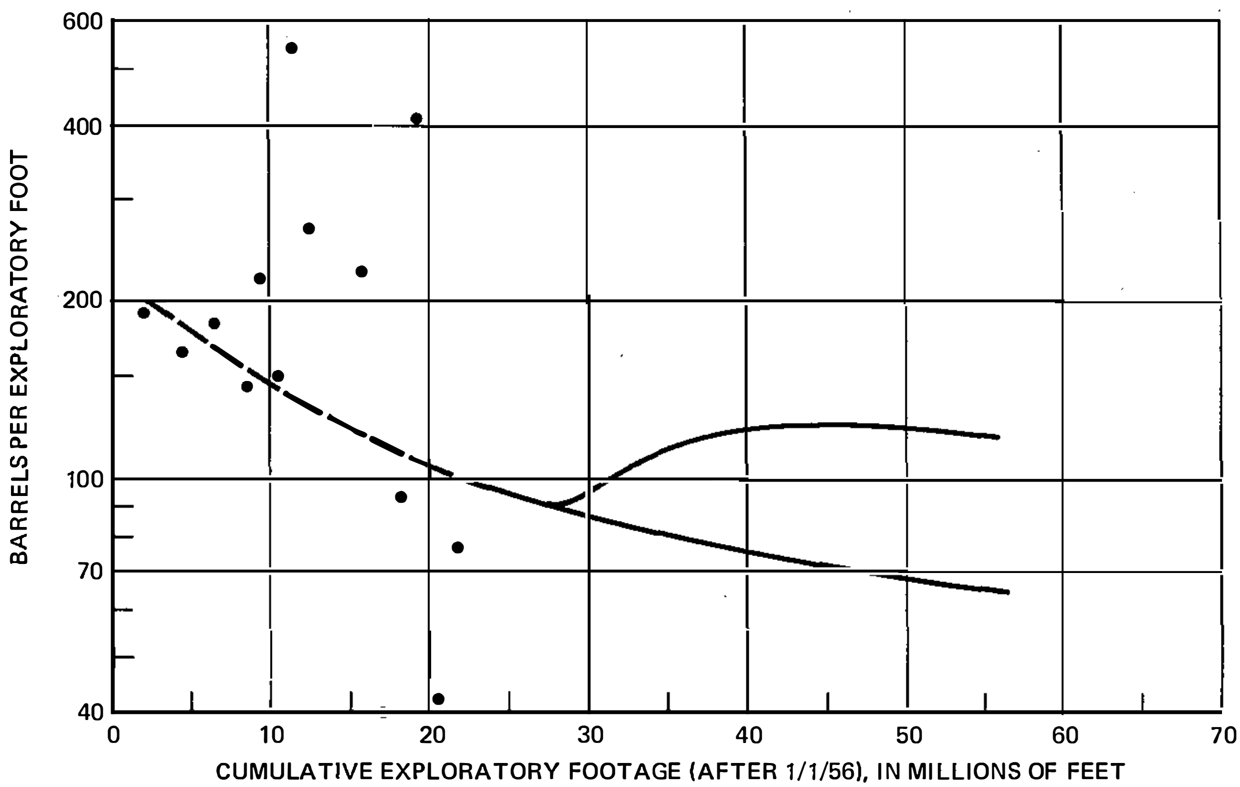


Figure 61. Oil Finding Rate Projections—California Onshore.

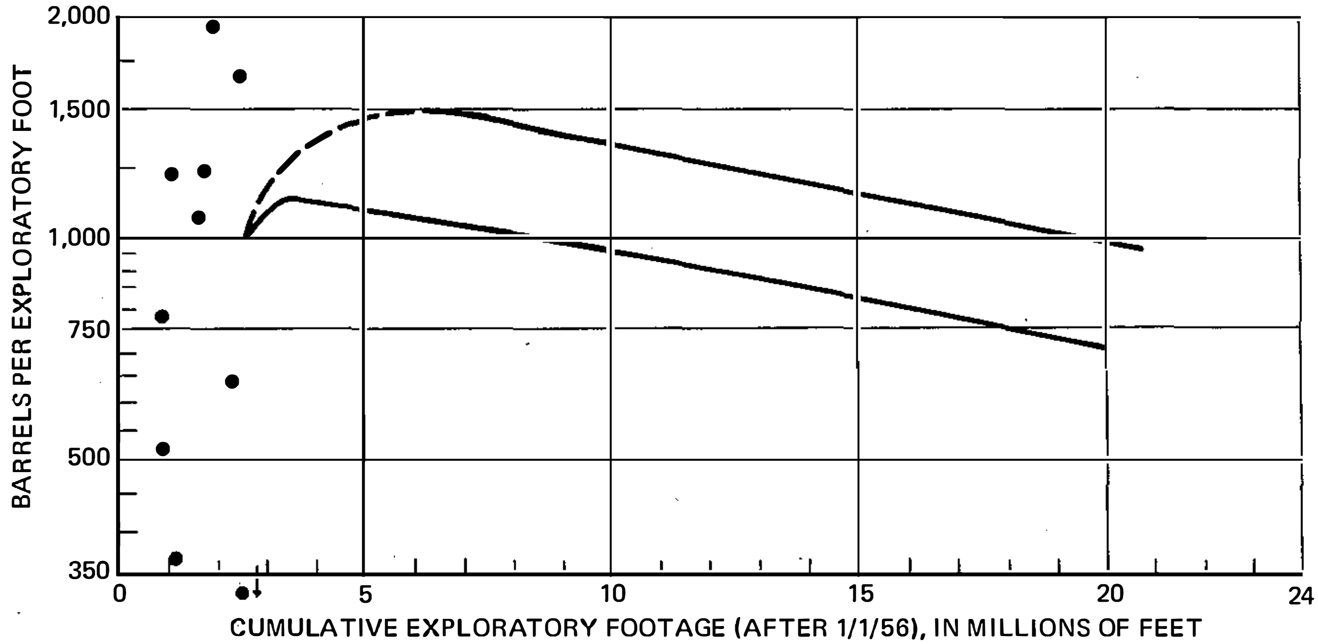


Figure 62. Oil Finding Rate Projections—California Offshore.

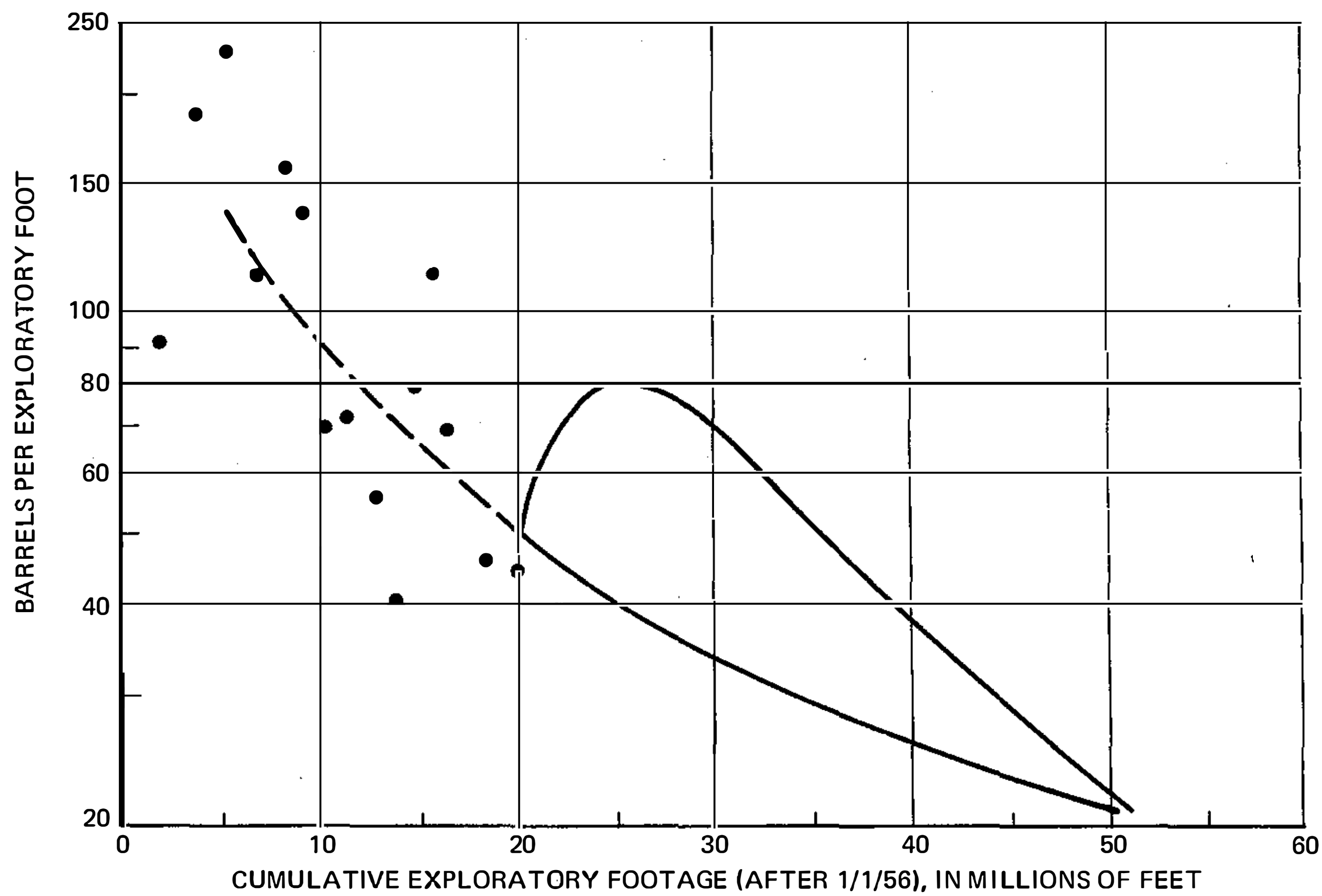


Figure 63. Oil Finding Rate Projections—Southern Rocky Mountains.

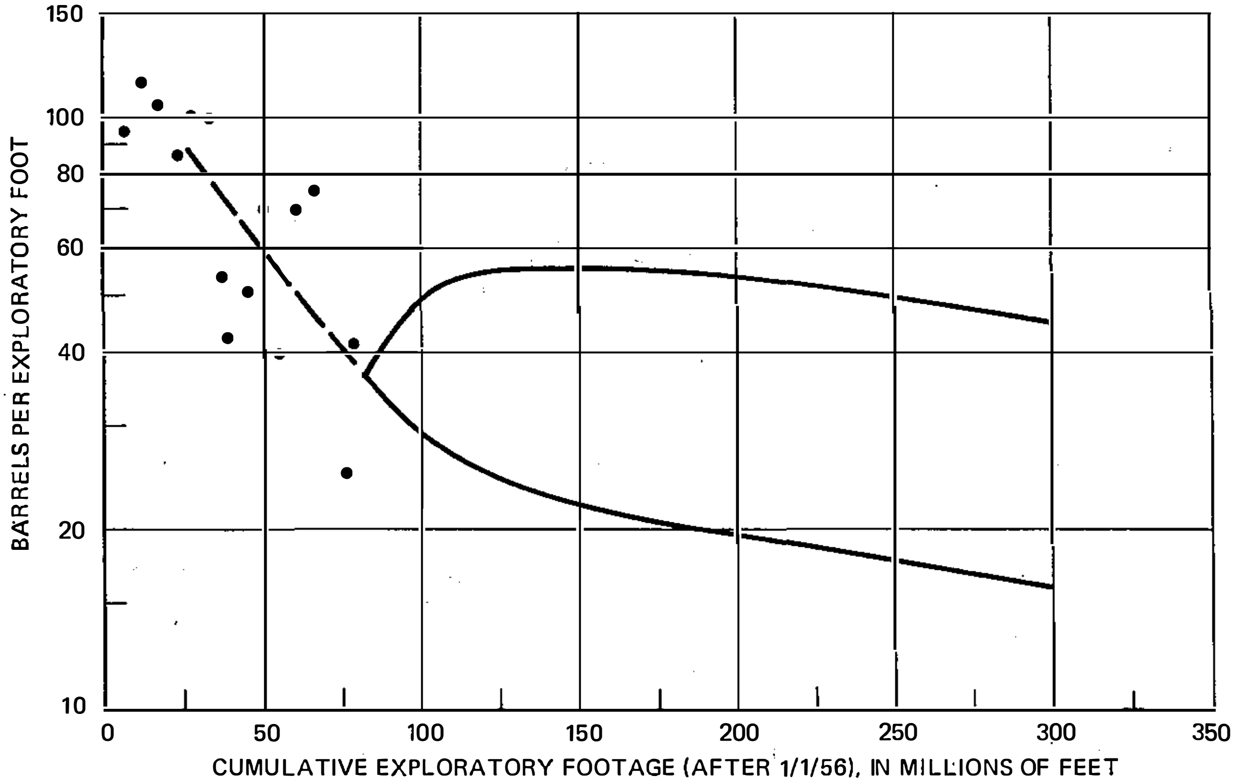


Figure 64. Oil Finding Rate Projections—Eastern Rocky Mountains.

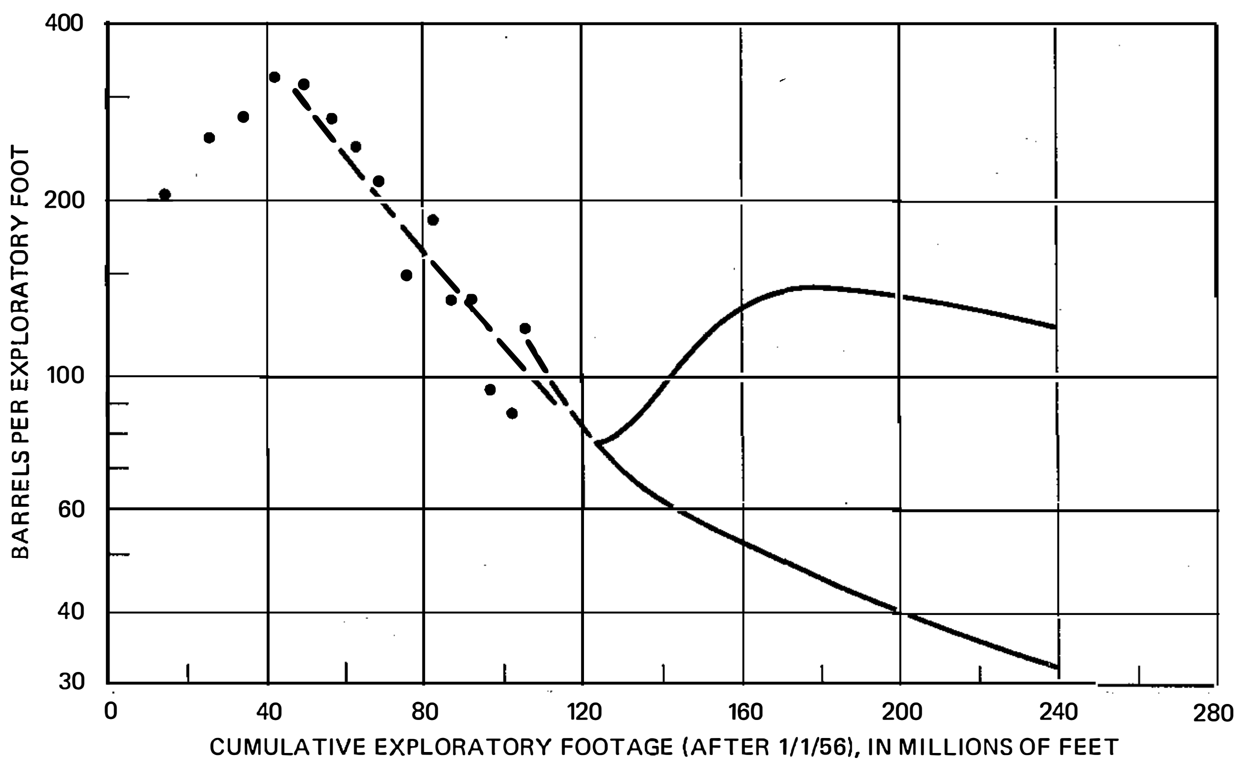


Figure 65. Oil Finding Rate Projections—West Texas.

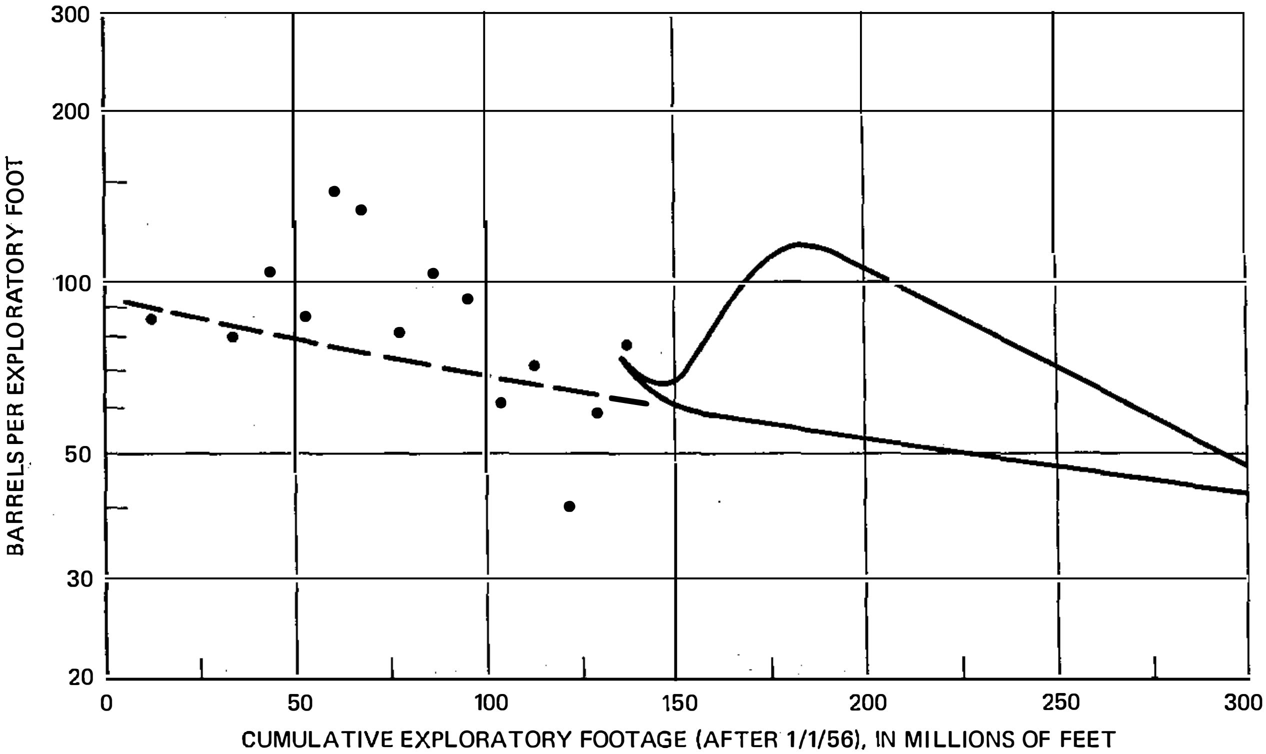


Figure 66. Oil Finding Rate Projections—Gulf Coast Onshore.

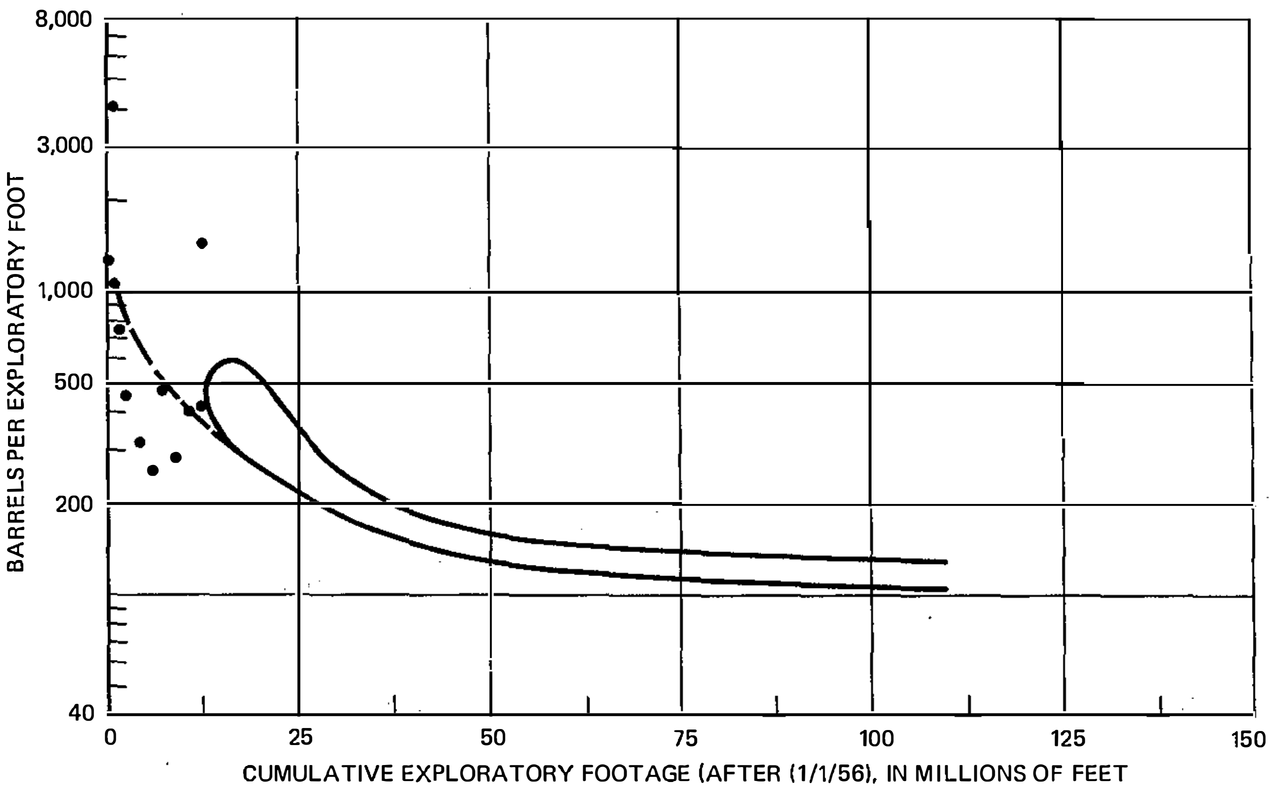


Figure 67. Oil Finding Rate Projections—Gulf Coast Offshore.

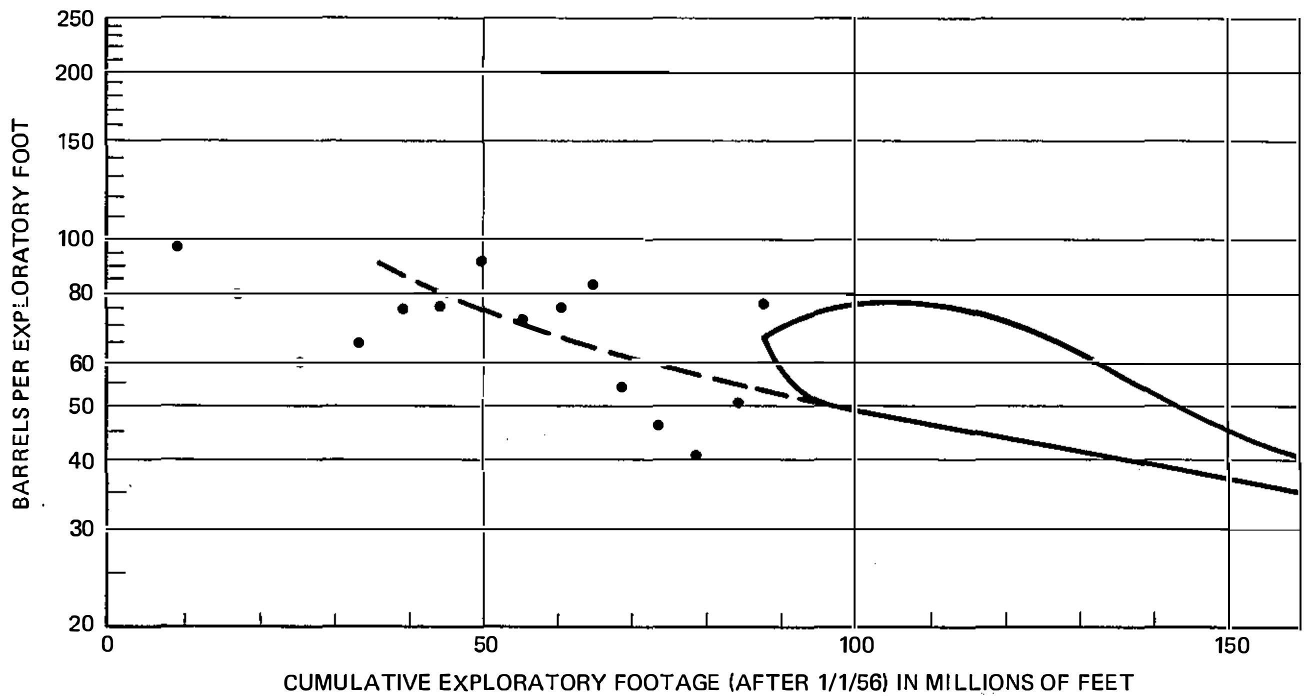


Figure 68. Oil Finding Rate Projections—Midcontinent.

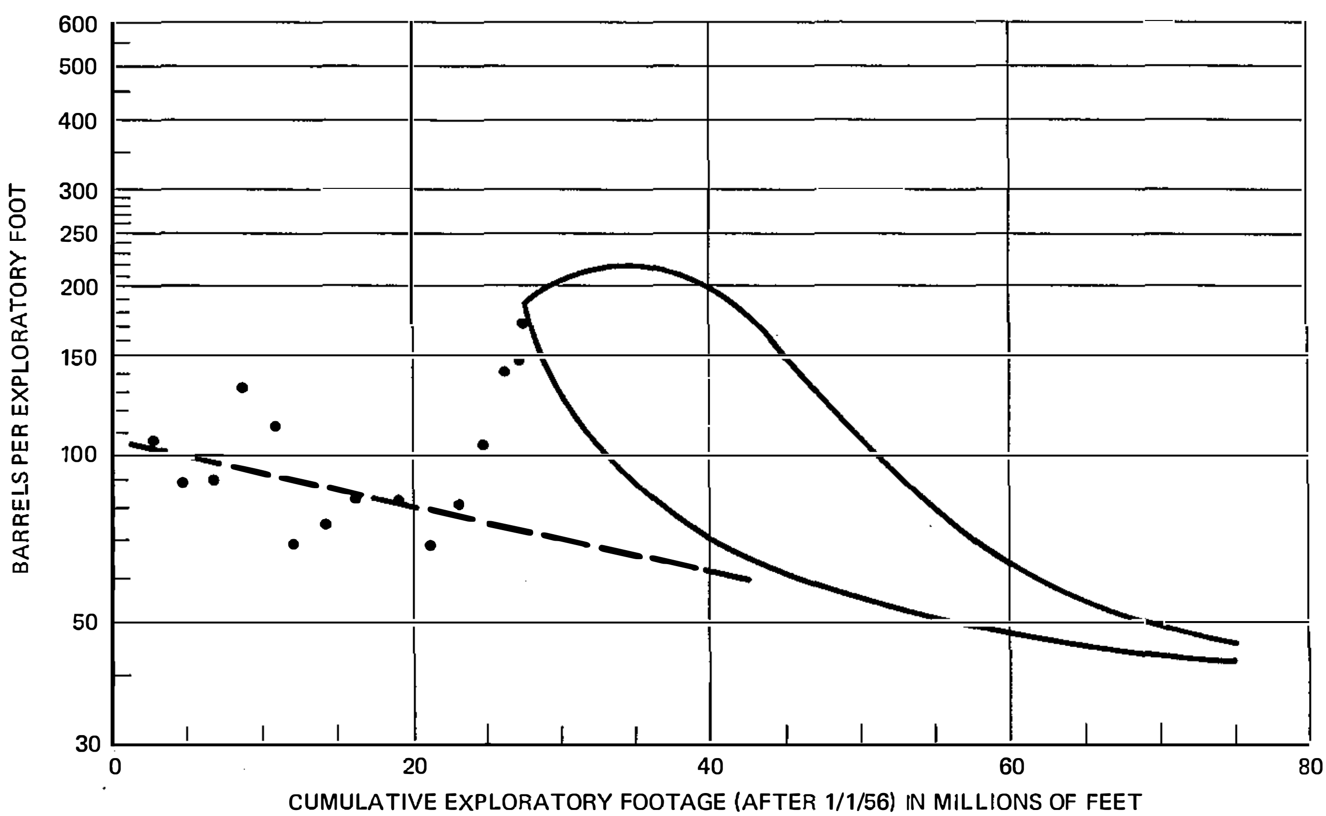


Figure 69. Oil Finding Rate Projections—Illinois, Michigan, Appalachian.

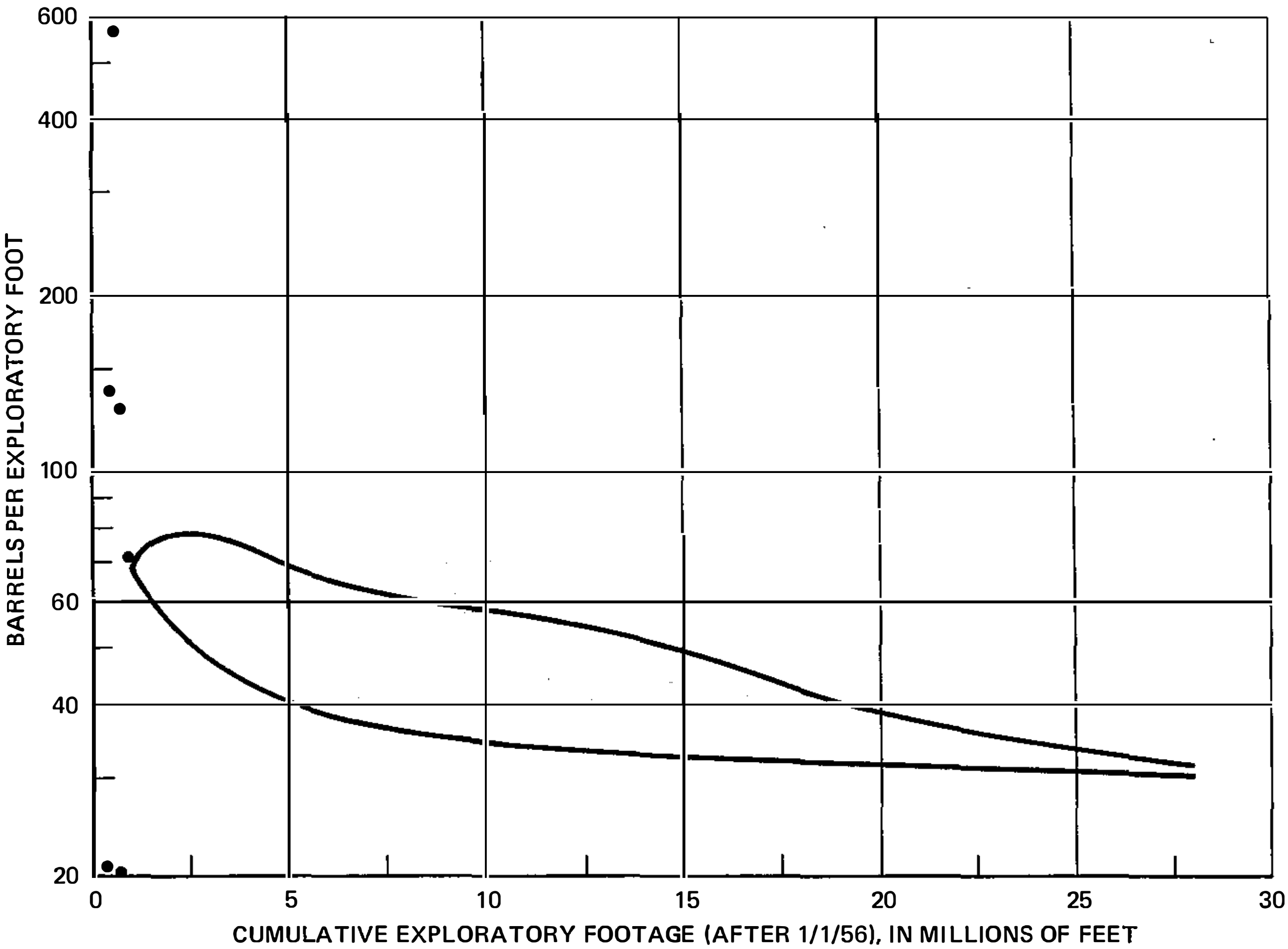


Figure 70. Oil Finding Rate Projections—Atlantic Coast Onshore.

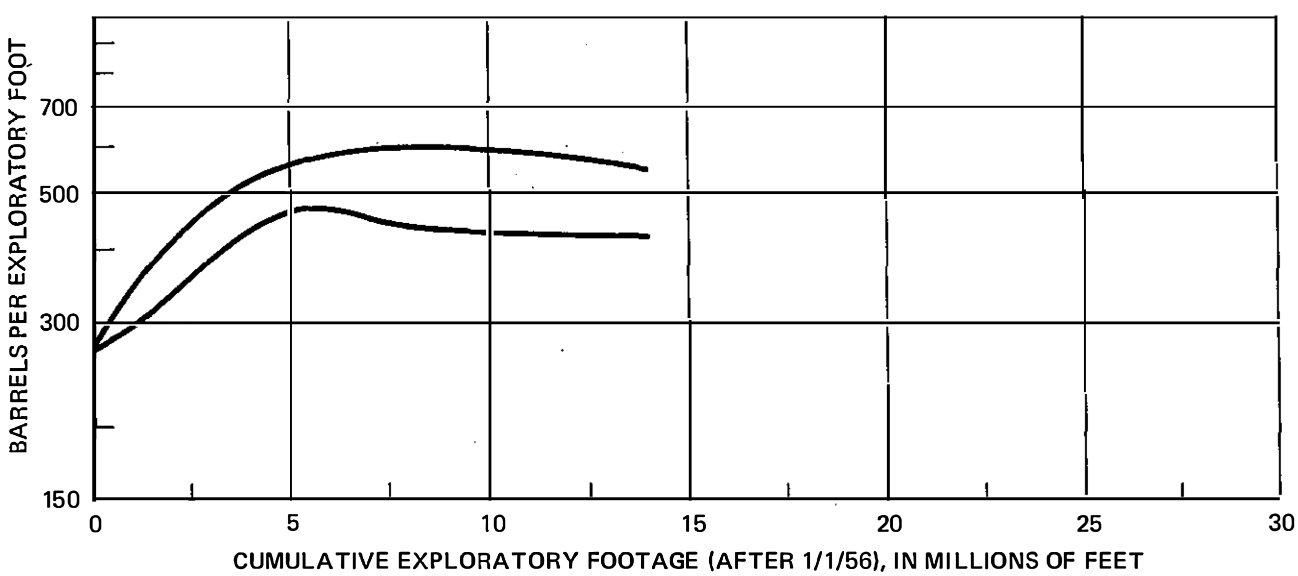


Figure 71. Oil Finding Rate Projections—Atlantic Coast Offshore.

TABLE 111

OIL EXPLORATORY DRILLING STATISTICS BY REGION

	Region 1		Region 2		Region 2A		Region 3		Region 4		Region 5		Region 6	
	% of U.S. Total	Feet	% of U.S. Total	Feet	% of U.S. Total	Feet	% of U.S. Total	Feet	% of U.S. Total	Feet	% of U.S. Total	Feet	% of U.S. Total	Feet
1956	0	0	4.83	2,393,000	0.34	166,295	3.94	1,951,243	10.95	5,425,986	29.77	14,744,485	24.93	12,347,604
1957	0.11	48,315	4.86	2,090,000	0.97	415,684	4.47	1,919,459	13.93	5,990,361	26.18	11,254,513	24.94	10,722,348
1958	0.11	43,115	5.39	2,012,000	0.38	142,826	4.05	1,514,873	12.54	4,686,439	22.80	8,516,606	27.14	10,137,900
1959	0.19	72,074	5.41	2,043,000	0.23	85,863	4.22	1,595,002	14.61	5,519,507	22.74	8,591,411	26.98	10,191,062
1960	0.08	26,642	3.19	999,000	0.25	77,767	3.94	1,234,624	16.67	5,226,910	22.67	7,105,859	27.71	8,686,161
1961	0.25	68,767	3.26	916,000	0.19	52,444	3.17	890,826	16.61	4,668,725	22.15	6,224,389	27.88	7,834,794
1962	0	0	3.71	1,060,000	0.39	111,323	4.16	1,189,810	16.66	4,762,573	22.77	6,512,503	27.01	7,723,067
1963	0.33	103,233	3.94	1,252,000	0.11	33,696	3.50	1,112,552	14.90	4,729,585	20.03	6,357,931	30.85	9,793,230
1964	0.36	120,213	5.32	1,800,000	0.73	248,698	3.53	1,194,063	13.92	4,711,021	20.82	7,044,922	25.65	8,677,571
1965	0.46	130,310	4.42	1,261,000	0.82	234,356	3.58	1,022,206	13.72	3,918,384	20.04	5,720,828	28.79	8,219,014
1966	0.57	169,879	3.51	1,054,000	0.66	197,390	3.46	1,040,316	15.52	4,658,387	19.21	5,766,362	30.82	9,253,572
1967	0.27	76,888	4.28	1,224,000	0.47	133,492	3.56	1,018,389	16.84	4,820,728	15.32	4,385,301	30.04	8,596,282
1968	0.08	26,275	4.00	1,284,000	1.21	389,672	2.54	816,766	23.48	7,543,301	14.41	4,630,918	28.64	9,202,617
1969	0.14	46,403	3.64	1,233,000	0.43	147,011	5.36	1,812,254	28.47	9,627,402	15.74	5,321,850	23.45	7,928,955
1970	0.50	133,340	4.16	1,114,810	0.46	124,502	6.01	1,612,570	28.00	7,511,539	14.38	3,856,118	27.70	7,428,463
Total	0.21	1,065,454	4.34	21,735,810	0.51	2,561,019	3.98	19,924,953	16.72	83,800,848	21.15	106,033,996	27.28	136,742,640

TABLE 112

OIL EXPLORATORY DRILLING STATISTICS BY REGION

	Region 6A		Region 7		Regions 8, 9, & 10		Region 11			
	% of U.S. Total	Feet	% of U.S. Total	Feet	% of U.S. Total	Feet	% of U.S. Total	Feet	% of U.S. Total	Total Feet
1956	1.11	552,222	18.40	9,113,778	5.56	2,751,547	0.17	84,948	100	49,531,108
1957	0.99	423,486	18.48	7,945,535	4.98	2,142,276	0.09	37,497	100	42,989,474
1958	0.28	104,039	22.08	8,249,349	5.12	1,913,225	0.11	39,360	100	37,359,732
1959	0.17	63,951	20.42	7,713,834	4.89	1,849,579	0.14	54,360	100	37,779,643
1960	0	0	19.28	6,042,857	6.21	1,947,352	0	0	100	31,347,172
1961	0	0	20.46	5,749,579	5.85	1,644,913	0.18	51,149	100	28,101,586
1962	1.41	402,272	17.43	4,985,209	6.39	1,827,804	0.07	20,677	100	28,595,238
1963	2.87	910,706	17.21	5,464,457	6.17	1,958,699	0.09	29,573	100	31,745,662
1964	4.92	1,664,220	15.29	5,172,485	9.23	3,122,254	0.23	78,660	100	33,834,107
1965	6.41	1,830,970	13.92	3,973,627	7.66	2,186,511	0.18	52,686	100	28,549,892
1966	5.02	1,506,839	14.95	4,488,465	6.04	1,815,301	0.24	70,862	100	30,021,373
1967	6.48	1,854,342	17.02	4,869,449	5.53	1,584,253	0.19	53,690	100	28,616,814
1968	5.62	1,806,839	15.77	5,066,782	4.11	1,321,820	0.14	44,154	100	32,133,144
1969	3.86	1,306,884	15.90	5,376,543	2.77	937,230	0.24	81,675	100	33,819,207
1970	2.06	553,061	13.96	3,745,486	2.31	619,506	0.46	123,208	100	26,822,603
Total	2.59	12,979,831	17.55	87,957,435	5.51	27,622,270	0.16	822,499	100	501,246,755

TABLE 113

TOTAL OIL DRILLING STATISTICS BY REGIONS

	Region 1		Region 2		Region 2A		Region 3		Region 4		Region 5		Region 6	
	% of U.S. Total	Feet	% of U.S. Total	Feet	% of U.S. Total	Feet	% of U.S. Total	Feet	% of U.S. Total	Feet	% of U.S. Total	Feet	% of U.S. Total	Feet
1956	0	0	5.04	9,967,000	0.12	233,523	1.71	3,377,317	7.34	14,491,709	28.91	57,106,416	24.56	48,528,128
1957	0.03	48,315	4.69	8,651,000	0.28	520,089	2.24	4,126,275	7.03	12,982,211	29.56	54,560,416	26.62	49,143,760
1958	0.03	43,115	4.50	7,020,000	0.11	172,349	3.34	5,219,260	7.74	12,087,310	27.90	43,565,936	25.31	39,529,168
1959	0.09	138,761	4.03	6,488,000	0.11	172,116	3.10	4,986,916	8.76	14,086,968	28.23	45,397,776	26.39	42,449,264
1960	0.12	159,469	4,32	5,931,000	0.16	223,982	2.36	3,248,584	9.39	12,899,512	25.95	35,647,856	28.85	39,639,600
1961	0.29	387,619	4.57	6,054,000	0.22	300,713	2.18	2,885,310	8.48	11,238,919	23.75	31,475,264	29.48	39,068,624
1962	0.07	99,954	5.67	7,813,000	0.21	289,929	1.94	2,672,051	7.39	10,190,939	23.36	32,198,048	30.88	42,575,440
1963	0.14	191,398	5.60	7,581,000	0.11	146,370	1.69	2,282,005	7.67	10,374,740	21.32	28,850,912	32.72	44,278,416
1964	0.12	166,222	5.82	8,006,000	0.21	295,975	1.43	1,960,535	7.44	10,230,335	21.34	29,347,056	29.83	41,019,520
1965	0.13	167,482	5.39	6,946,000	0.27	345,731	1.54	1,975,568	7.59	9,772,738	21.12	27,200,336	29.92	38,530,064
1966	0.25	271,911	4.86	5,364,000	0.49	536,683	1.67	1,840,884	8.41	9,280,414	22.72	25,069,424	27.71	30,576,752
1967	0.50	492,903	5.38	5,303,000	0.51	503,792	1.90	1,867,598	9.29	9,154,700	20.68	20,382,288	26.64	26,256,144
1968	0.87	903,729	6.20	6,403,000	0.72	746,990	1.49	1,535,518	13.41	13,841,473	19.50	20,132,544	24.72	25,516,272
1969	0.48	512,592	5.01	5,396,000	0.56	601,076	2.57	2,768,748	15.90	17,122,768	20.10	21,639,456	23.55	25,355,264
1970	0.32	312,822	5.79	5,556,048	0.15	139,420	2.59	2,481,495	15.28	14,657,688	20.95	20,097,274	26.03	24,969,303
Total	0.19	3,896,292	5.06	102,479,048	0.26	5,228,738	2.13	43,228,064	9.01	182,412,424	24.34	492,671,002	27.54	557,435,719

TABLE 114

TOTAL OIL DRILLING STATISTICS BY REGIONS

	Region 6A		Region 7		Regions 8, 9, & 10		Region 11			
	% of U.S. Total	Feet	% of U.S. Total	Feet	% of U.S. Total	Feet	% of U.S. Total	Feet	% of U.S. Total	Total Feet
1956	1.66	3,278,811	22.73	44,907,520	7.89	15,587,898	0.04	84,948	100	197,563,270
1957	2.65	4,892,893	20.54	37,917,488	6.34	11,703,261	0.02	37,497	100	184,583,205
1958	1.93	3,007,688	21.86	34,134,576	7.26	11,335,052	0.02	39,360	100	156,153,764
1959	1.85	2,972,077	20.44	32,881,728	6.97	11,214,046	0.03	54,360	100	160,842,012
1960	2.57	3,527,060	18.64	25,607,968	7.64	10,500,874	0	0	100	137,385,905
1961	2.81	3,727,799	21.20	28,104,128	6.98	9,249,644	0.04	51,149	100	132,543,169
1962	3.59	4,949,026	20.39	28,117,696	6.48	8,934,517	0.02	32,498	100	137,873,098
1963	3.91	5,284,711	19.72	26,688,720	7.09	9,600,153	0.03	41,224	100	135,319,649
1964	5.33	7,324,024	19.28	26,512,656	9.11	12,531,874	0.09	125,384	100	137,519,581
1965	6.59	8,482,173	19.20	24,730,576	8.03	10,343,726	0.22	287,704	100	128,782,098
1966	6.97	7,687,308	18.67	20,605,056	8.13	8,973,472	0.12	128,578	100	110,334,482
1967	6.58	6,486,759	19.17	18,890,000	9.30	9,165,196	0.05	53,690	100	98,556,070
1968	7.04	7,268,820	18.20	18,787,552	7.76	8,010,473	0.09	90,465	100	103,236,836
1969	5.61	6,039,583	19.54	21,044,048	6.55	7,057,782	0.13	140,046	100	107,677,363
1970	5.50	5,278,316	17.40	16,689,070	5.74	5,505,069	0.25	236,971	100	95,923,476
Total	3.96	**80,206,998**	20.04	405,618,782	7.40	**149,713,037**	0.07	1,403,874	100	**2,024,293,978**

TABLE 115

OIL AND GAS DRILLING FOOTAGE — TOTAL UNITED STATES*
(Million Feet)

History

	Total Oil Drilling	Total Gas Drilling	Total O&G Drilling	Oil Drilling as % of Total
1956	198	44	242	82
1957	185	46	231	80
1958	156	54	210	74
1959	161	58	219	74
1960	137	59	196	70
1961	133	61	193	68
1962	138	61	199	69
1963	135	52	187	72
1964	138	54	191	72
1965	129	53	182	71
1966	110	52	162	68
1967	99	42	140	70
1968	103	42	144	71
1969	108	49	156	69
1970	96	42	138	70

* Excluding Alaskan drilling footage.

Note: These numbers are correct; they differ slightly from those shown on Figure 6 in Chapter One.

TABLE 116

OIL AND GAS DRILLING FOOTAGE — TOTAL UNITED STATES*
(Million Feet)

Case I

	Total Oil Drilling	Total Gas Drilling	Total O&G Drilling	Oil Drilling as % of Total
1971	90	41	131	69
1972	93	43	136	68
1973	103	46	149	69
1974	113	48	161	70
1975	122	51	173	71
1976	131	55	186	70
1977	142	59	201	71
1978	151	64	215	70
1979	159	69	228	70
1980	167	76	243	69
1981	175	81	256	68
1982	180	85	265	68
1983	186	88	274	68
1984	191	88	279	68
1985	196	88	284	69

* Excluding Alaskan drilling footage.

TABLE 117

OIL AND GAS DRILLING FOOTAGE — TOTAL UNITED STATES*
(Million Feet)

Case IA

	Total Oil Drilling	Total Gas Drilling	Total O&G Drilling	Oil Drilling as % of Total
1971	89	41	130	68
1972	89	43	132	67
1973	93	46	139	67
1974	96	48	144	67
1975	101	51	152	66
1976	106	55	161	66
1977	112	59	171	65
1978	119	64	183	65
1979	126	69	195	65
1980	133	76	209	64
1981	140	81	221	63
1982	146	85	231	63
1983	153	88	241	63
1984	160	88	248	65
1985	168	88	256	66

* Excluding Alaskan drilling footage.

TABLE 118

OIL AND GAS DRILLING FOOTAGE — TOTAL UNITED STATES*
(Million Feet)

Case II

	Total Oil Drilling	Total Gas Drilling	Total O&G Drilling	Oil Drilling as % of Total
1971	90	41	131	69
1972	91	42	133	68
1973	100	43	143	70
1974	108	44	152	71
1975	113	46	159	71
1976	118	48	166	71
1977	125	50	175	71
1978	130	52	182	71
1979	133	55	188	71
1980	136	59	195	70
1981	139	61	200	70
1982	141	63	204	69
1983	144	64	208	69
1984	147	65	212	69
1985	150	65	215	70

* Excluding Alaskan drilling footage.

TABLE 119

OIL AND GAS DRILLING FOOTAGE – TOTAL UNITED STATES*
(Million Feet)

Case III

	Total Oil Drilling	Total Gas Drilling	Total O&G Drilling	Oil Drilling as % of Total
1971	89	41	130	68
1972	87	42	129	67
1973	90	43	133	68
1974	92	44	136	68
1975	94	46	140	67
1976	96	48	144	67
1977	99	50	149	66
1978	102	52	154	66
1979	105	55	160	66
1980	108	59	167	65
1981	111	61	172	65
1982	113	63	176	64
1983	117	64	181	65
1984	120	65	185	65
1985	124	65	189	66

* Excluding Alaskan drilling footage.

TABLE 120

OIL AND GAS DRILLING FOOTAGE – TOTAL UNITED STATES*
(Million Feet)

Case IV

	Total Oil Drilling	Total Gas Drilling	Total O&G Drilling	Oil Drilling as % of Total
1971	89	41	130	68
1972	82	39	121	68
1973	79	37	116	68
1974	75	36	111	68
1975	71	34	105	68
1976	68	33	101	67
1977	64	32	96	67
1978	63	31	94	67
1979	60	29	89	67
1980	57	28	85	67
1981	54	27	81	67
1982	51	26	77	66
1983	49	25	74	66
1984	47	24	71	66
1985	45	23	68	66

* Excluding Alaskan drilling footage.

TABLE 121

OIL AND GAS DRILLING FOOTAGE – TOTAL UNITED STATES*
(Million Feet)

Case IVA

	Total Oil Drilling	Total Gas Drilling	Total O&G Drilling	Oil Drilling as % of Total
1971	90	41	131	69
1972	86	39	125	69
1973	87	37	124	70
1974	87	36	123	71
1975	84	34	118	71
1976	82	33	115	71
1977	79	32	111	71
1978	79	31	110	72
1979	76	29	105	72
1980	72	28	100	72
1981	69	27	96	72
1982	65	26	91	71
1983	62	25	87	71
1984	59	24	83	71
1985	57	23	80	71

* Excluding Alaskan drilling footage.

TABLE 122

ANNUAL OIL-IN-PLACE DISCOVERED
(Region 1)

	Reserves Added (Thousand Barrels)					
	Extensions	New Fields	New Pools	Total	Recovery Factor	Annual Oil-in-Place Discovered
1956	0	0	0	0	22.7	0
1957	0	0	0	0	22.7	0
1958	0	0	0	0	22.7	0
1959	3,500	0	0	3,500	22.7	15,419
1960	4,000	20,000	0	24,000	22.7	105,727
1961	34,000	0	0	34,000	22.7	149,780
1962	0	0	0	0	22.7	0
1963	0	1,000	0	1,000	22.7	4,405
1964	10,000	0	0	10,000	22.7	44,053
1965	0	88,000	0	88,000	22.7	387,665
1966	15,000	72,000	0	87,000	22.7	383,260
1967	72,300	2,100	4,000	78,400	22.7	345,374
1968	67,000	0	0	67,000	22.7	295,154
1969	1,350	0	0	1,350	22.7	5,947
1970	10,000	4,000	0	14,000	22.7	61,674

TABLE 123

ANNUAL OIL-IN-PLACE DISCOVERED
(Regions 2 & 2A Combined [Total California])

	Reserves Added (Thousand Barrels)					
	Extensions	New Fields	New Pools	Total	Recovery Factor	Annual Oil-In-Place Discovered
1956	89,189	508	18,395	108,092	23.3	463,914
1957	65,572	3,060	12,000	80,632	23.3	346,060
1958	72,710	3,209	12,450	88,369	23.3	379,266
1959	61,120	725	7,355	69,200	23.3	296,996
1960	50,200	5,026	5,890	61,116	23.3	262,300
1961	20,745	10,170	10,690	41,605	23.3	178,562
1962	139,920	2,102	1,950	143,972	23.3	617,906
1963	74,565	4,180	7,525	86,270	23.3	370,258
1964	540,687	30,100	9,175	579,962	23.3	2,489,107
1965	76,570	1,005	46,830	124,405	23.3	533,927
1966	59,163	4,700	4,060	67,923	23.3	291,515
1967	52,470	1,460	30,717	84,647	23.3	363,292
1968	79,489	76,600	25,000	181,089	23.3	777,206
1969	61,887	685	8,040	70,612	23.3	303,056
1970	17,991	0	1,920	19,911	23.3	85,455

TABLE 124

ANNUAL OIL-IN-PLACE DISCOVERED
(Region 2)

	Reserves Added (Thousand Barrels)					
	Extensions	New Fields	New Pools	Total	Recovery Factor	Annual Oil-In-Place Discovered
1956	No category breakdown available by reserve additions between Regions 2 and 2A.				23.3	458,200
1957					23.3	340,560
1958					23.3	373,766
1959					23.3	291,496
1960					23.3	221,700
1961					23.3	137.962
1962					23.3	577,306
1963					23.3	329,658
1964					23.3	2,448,507
1965					23.3	284,727
1966					23.3	42,315
1967					23.3	114,092
1968					23.3	528,006
1969					23.3	52,997
1970	17,991	0	1,920	19,911	23.3	85,455

Note: The annual oil-in-place additions for NPC Region 2 were obtained by taking the API annual reserve additions for California, converting them to annual oil-in-place additions, and then subtracting the Region 2A annual oil-in-place additions.

TABLE 125

ANNUAL OIL-IN-PLACE DISCOVERED
(Region 2A)

	Reserves Added (Thousand Barrels) Extensions	New Fields	New Pools	Total	Recovery Factor	Annual Oil-In-Place Discovered
1956					23.3	5,500
1957					23.3	5,500
1958					23.3	5,500
1959					23.3	5,500
1960					23.3	40,600
1961					23.3	40,600
1962	No category breakdown available by reserve additions between Regions 2 and 2A.				23.3	40,600
1963					23.3	40,600
1964					23.3	40,600
1965					23.3	249,000
1966					23.3	249,000
1967					23.3	249,000
1968					23.3	249,000
1969					23.3	249,000
1970	0	0	0	0	23.3	0

Note: Reserve figures for Offshore California are not available from API sources. The annual oil-in-place-added figures for Offshore California were developed from estimates of the ultimate recovery cumulative to 1-1-55, 1-1-60, 1-1-65, and 1-1-70 for the following offshore fields: Alegria, Belmont, Carpenteria, Coal Oil, Conception, Cuarta, Dos Quadros, Elwood (Dev.), Pt. Conception, So. Elwood, Summerland, Venice, and West Newport. The near-offshore fields, such as Wilmington and Huntington Beach, are not included since their operating end development costs are more similar to onshore than offshore operations.

	Ultimate Recovery MBbls	Recovery Factor	Oil-In-Place	Increment Found	Years	Annual Oil-In-Place Discovered
1-1-56	108,570	23.3	465,000			
1-1-60	113,570	23.3	487,000	22,000	÷ 4 =	5,500
1-1-65	158,970	23.3	690,000	203,000	÷ 5 =	40,600
1-1-70	450,995	23.3	1,936,000	1,246,000	÷ 5 =	249,000

TABLE 126

ANNUAL OIL-IN-PLACE DISCOVERED
(Region 3)

	Reserves Added (Thousand Barrels) Extensions	New Fields	New Pools	Total	Recovery Factor	Annual Oil-in-Place Discovered
1956	18,256	30,928	541	49,725	27.4	181,478
1957	74,881	23,844	377	99,102	27.4	361,686
1958	88,826	3,677	1,866	94,369	27.4	344,412
1959	46,576	2,292	655	49,523	27.4	180,741
1960	49,802	3,262	609	53,673	27.4	195,887
1961	29,159	2,810	1,737	33,706	27.4	123,015
1962	18,716	2,945	954	22,615	27.4	82,536
1963	18,669	1,644	1,187	21,500	27.4	78,467
1964	12,774	4,077	1,312	18,163	27.4	66,288
1965	8,318	2,565	276	11,159	27.4	40,726
1966	17,202	4,346	1,136	22,684	27.4	82,788
1967	17,275	13,044	1,071	31,390	27.4	114,562
1968	14,209	993	55	15,257	27.4	55,682
1969	18,250	3,882	348	22,480	27.4	82,044
1970	13,596	100	5,787	19,483	27.4	71,106

TABLE 127

ANNUAL OIL-IN-PLACE DISCOVERED
(Region 4)

	Reserves Added (Thousand Barrels)					Annual
	Extensions	New Fields	New Pools	Total	Recovery Factor	Oil-In-Place Discovered
1956	110,045	20,905	13,898	144,848	28.3	511,830
1957	119,499	23,630	51,733	194,862	28.3	688,558
1958	117,337	18,999	5,346	141,682	28.3	500,643
1959	115,353	17,608	1,368	134,329	28.3	474,661
1960	120,712	18,155	9,223	148,090	28.3	523,286
1961	106,790	6,721	16,650	130,161	28.3	459,933
1962	52,652	13,133	6,667	72,452	28.3	256,014
1963	37,206	10,855	8,635	56,696	28.3	200,339
1964	41,653	20,388	6,743	68,784	28.3	243,053
1965	55,646	21,463	1,297	78,406	28.3	277,053
1966	42,066	9,632	747	52,445	28.3	185,318
1967	26,314	65,547	2,765	94,626	28.3	334,367
1968	131,954	24,067	3,880	159,901	28.3	565,021
1969	39,553	26,104	2,438	68,095	28.3	240,618
1970	74,969	1,760	10,753	87,482	28.3	309,124

TABLE 128

ANNUAL OIL-IN-PLACE DISCOVERED
(Region 5)

	Reserves Added (Thousand Barrels)					Annual
	Extensions	New Fields	New Pools	Total	Recovery Factor	Oil-In-Place Discovered
1956	598,212	63,576	39,090	700,878	23.6	2,969,822
1957	593,865	57,175	23,497	674,537	23.6	2,858,208
1958	491,274	33,220	26,310	550,804	23.6	2,333,915
1959	611,693	29,433	25,668	666,794	23.6	2,825,398
1960	465,271	39,573	21,635	526,479	23.6	2,230,843
1961	325,126	46,634	29,971	401,731	23.6	1,702,250
1962	321,379	29,219	32,404	383,002	23.6	1,622,890
1963	239,563	22,248	57,420	319,231	23.6	1,352,674
1964	214,713	22,154	10,841	247,708	23.6	1,049,610
1965	213,007	23,420	12,294	248,721	23.6	1,053,903
1966	133,120	17,476	31,770	182,366	23.6	772,737
1967	111,914	11,558	16,880	140,352	23.6	594,712
1968	82,049	9,281	11,947	103,277	23.6	437,614
1969	79,925	16,000	12,796	108,721	23.6	460,682
1970	80,393	10,947	18,568	109,908	23.6	465,712

TABLE 129

ANNUAL OIL-IN-PLACE DISCOVERED
(Regions 6 and 6A Combined)

	Reserves Added (Thousand Barrels)					
	Extensions	New Fields	New Pools	Total	Recovery Factory	Annual Oil-In-Place Discovered
1956	616,614	52,714	144,282	813,610	46.5	1,749,699
1957	488,621	57,740	116,952	663,313	46.5	1,426,480
1958	410,309	55,746	108,569	574,624	46.5	1,235,751
1959	773,563	69,080	163,134	1,005,777	46.5	2,162,961
1960	451,881	32,665	72,094	556,640	46.5	1,197,075
1961	552,883	23,050	185,050	760,983	46.5	1,636,523
1962	357,005	28,114	239,146	624,265	46.5	1,342,505
1963	350,603	35,870	176,052	562,525	46.5	1,209,731
1964	449,946	29,693	182,950	662,589	46.5	1,424,923
1965	327,471	77,123	169,677	574,271	46.5	1,234,991

TABLE 130

ANNUAL OIL-IN-PLACE DISCOVERED
(Region 6)

	Reserves Added (Thousand Barrels)					
	Extensions	New Fields	New Pools	Total	Recovery Factor	Annual Oil-In-Place Discovered
1956						1,065,699
1957						991,480
1958						815,751
1959						1,046,961
1960	No category breakdown available by reserve additions between Regions 6 and 6A.					758,075
1961						1,142,523
1962						1,040,505
1963						790,731
1964						887,923
1965						763,991
1966	170,368	27,514	67,722	265,604	46.5	571,191
1967	162,877	16,548	105,396	284,821	46.5	612,518
1968	113,591	20,951	39,637	174,179	46.5	374,578
1969	117,364	29,540	69,867	216,771	46.5	466,174
1970	127,288	71,852	66,897	266,037	46.5	572,122

TABLE 131

ANNUAL OIL-IN-PLACE DISCOVERED
(Region 6A)

	Reserves Added (Thousand Barrels)					
	Extensions	New Fields	New Pools	Total	Recovery Factor	Annual Oil-In-Place Discovered
1956						684,000
1957						435,000
1958						420,000
1959						1,116,000
1960	No category breakdown available by reserve additions between Regions 6 and 6A.					439,000
1961						494,000
1962						302,000
1963						419,000
1964						537,000
1965						471,000
1966	294,622	5,009	41,269	340,900	46.5	733,118
1967	185,118	1,909	56,530	243,557	46.5	523,778
1968	207,792	15,470	105,321	328,583	46.5	706,630
1969	193,650	5,040	53,286	251,976	46.5	541,884
1970	216,071	122,375	27,478	365,924	46.5	786,933

TABLE 132

ANNUAL OIL-IN-PLACE DISCOVERED
(Region 7)

	Reserves Added (Thousand Barrels)					
	Extensions	New Fields	New Pools	Total	Recovery Factor	Annual Oil-In-Place Discovered
1956	210,840	51,642	10,122	272,604	30.8	885,078
1957	160,485	32,684	1,320	194,489	30.8	631,458
1958	121,764	29,433	3,246	154,443	30.8	501,438
1959	116,749	33,001	3,761	153,511	30.8	498,412
1960	116,354	19,853	2,691	138,898	30.8	450,968
1961	112,511	15,707	5,859	134,077	30.8	435,315
1962	122,177	14,354	4,037	140,568	30.8	456,390
1963	107,024	13,602	1,385	122,011	30.8	396,140
1964	100,293	14,240	5,939	120,472	30.8	391,143
1965	86,783	11,019	3,186	100,988	30.8	327,883
1966	63,370	9,743	2,535	75,648	30.8	245,610
1967	56,459	11,606	1,155	69,220	30.8	224,740
1968	42,745	16,304	5,214	64,263	30.8	208,646
1969	74,026	7,701	3,441	85,168	30.8	276,519
1970	70,270	3,008	16,598	89,876	30.8	291,805

TABLE 133

ANNUAL OIL-IN-PLACE DISCOVERED
(Region 8)

	Reserves Added (Thousand Barrels)					
	Extensions	New Fields	New Pools	Total	Recovery Factor	Annual Oil-in-Place Discovered
1956	2,680	75	0	2,755	33.7	8,175
1957	0	2,182	0	2,182	33.7	6,475
1958	5,720	290	0	6,010	33.7	17,834
1959	9,027	4,213	0	13,240	33.7	39,288
1960	35,874	625	0	36,499	33.7	108,306
1961	10,590	1,425	0	12,015	33.7	35,653
1962	5,070	420	0	5,490	33.7	16,291
1963	5,286	363	0	5,649	33.7	16,763
1964	3,741	0	185	3,926	33.7	11,650
1965	1,708	440	0	2,148	33.7	6,374
1966	0	1,060	300	4,036	33.7	4,036
1967	316	710	0	1,026	33.7	3,045
1968	1,005	2,025	0	3,030	33.7	8,991
1969	3,743	995	0	4,738	33.7	14,059
1970	665	0	4,276	4,941	33.7	14,662

TABLE 134

ANNUAL OIL-IN-PLACE DISCOVERED
(Region 9)

	Reserves Added (Thousand Barrels)					
	Extensions	New Fields	New Pools	Total	Recovery Factor	Annual Oil-in-Place Discovered
1956	30,889	11,471	2,488	44,848	38.8	115,588
1957	21,755	6,116	1,297	29,168	38.8	75,175
1958	20,010	1,636	5,731	27,377	38.8	70,559
1959	22,032	2,214	1,603	25,849	38.8	66,621
1960	19,264	2,095	338	21,697	38.8	55,920
1961	8,464	906	1,309	10,679	38.8	27,523
1962	8,220	1,201	2,770	12,191	38.8	31,420
1963	7,111	1,880	955	9,946	38.8	25,634
1964	8,717	392	667	9,776	38.8	25,196
1965	4,599	490	92	5,181	38.8	13,353
1966	2,617	1,086	195	3,898	38.8	10,046
1967	2,510	91	656	3,257	38.8	8,394
1968	5,766	280	346	6,392	38.8	16,474
1969	2,695	3,873	435	7,003	38.8	18,049
1970	3,192	15	1,730	4,937	38.8	12,725

TABLE 135

ANNUAL OIL-IN-PLACE DISCOVERED
(Region 10)

	Reserves Added (Thousand Barrels)					
	Extensions	New Fields	New Pools	Total	Recovery Factor	Annual Oil-in-Place Discovered
1956	25,636	2,908	3,678	32,222	19.1	168,702
1957	18,504	957	1,584	21,045	19.1	110,183
1958	10,958	5,000	0	15,958	19.1	83,550
1959	19,092	7,129	123	26,344	19.1	137,927
1960	10,180	42	80	10,302	19.1	53,937
1961	8,833	0	585	9,418	19.1	49,309
1962	16,119	1,000	70	17,189	19.1	89,995
1963	18,142	5,090	0	23,232	19.1	121,634
1964	36,658	4,605	400	41,663	19.1	218,131
1965	12,089	11,810	961	24,860	19.1	130.157
1966	17,021	7,919	338	25,278	19.1	132,346
1967	28,914	532	411	29,857	19.1	156,319
1968	31,021	320	60	31,401	19.1	164,403
1969	20,316	115	48	20,479	19.1	107,220
1970	14,942	0	573	15,515	19.1	81,231

TABLE 136

ANNUAL OIL-IN-PLACE DISCOVERED
(Region 11)

	Reserves Added (Thousand Barrels)					
	Extensions	New Fields	New Pools	Total	Recovery Factor	Annual Oil-In-Place Discovered
1956	0	0	0	0	22.4	0
1957	0	0	0	0	22.4	0
1958	0	0	0	0	22.4	0
1959	0	0	0	0	22.4	0
1960	0	0	0	0	22.4	0
1961	0	0	0	0	22.4	0
1962	0	100	0	100	22.4	446
1963	0	0	0	0	22.4	0
1964	0	1,399	1,034	2,433	22.4	10,862
1965	6,711	0	0	6,711	22.4	29,960
1966	0	0	0	0	22.4	0
1967	0	0	0	0	22.4	0
1968	160	0	0	160	22.4	714
1969	2,153	0	200	2,353	22.4	10,504
1970	1,232	745	0	1,977	22.4	8,826

TABLE 137

ANNUAL OIL-IN-PLACE DISCOVERED
TOTAL UNITED STATES*

	Thousand Barrels
1956	7,054,286
1957	6,504,283
1958	5,467,368
1959	6,698,424
1960	5,184,249
1961	4,797,863
1962	4,516,393
1963	3,776,045
1964	5,974,016
1965	4,035,992
1966	3,411,965
1967	3,281,101
1968	3,611,113
1969	2,526,756
1970	2,761,375

* Calculated

Note: The oil-in-place found each year shown in this table results directly from the drilling activity for that particular year. This differs from the API oil-in-place figures which are related back to the year of original field discovery.

TABLE 138

TOTAL U.S. CRUDE OIL RESERVE ADDITIONS
(Thousand Barrels)

	Extensions	New Fields	New Pools	Total Oil From Drilling	Revisions	Total Reserve Additions
1956	1,702,311	234,727	232,495	2,169,533	804,803	2,974,336
1957	1,543,182	207,437	208,760	1,959,379	465,421	2,424,800
1958	1,338,908	151,210	163,519	1,653,637	954,605	2,608,242
1959	1,778,705	165,695	203,667	2,148,067	1,518,678	3,666,745
1960	1,323,538	141,296	112,560	1,577,394	787,934	2,365,328
1961	1,209,101	107,423	253,051	1,569,575	1,087,092	2,656,667
1962	1,041,257	92,488	288,098	1,421,843	759,053	2,180,896
1963	858,168	96,732	253,159	1,208,059	966,051	2,174,110
1964	1,419,182	126,682	219,611	1,765,475	899,292	2,664,767
1965	792,901	237,335	234,612	1,264,848	1,783,231	3,048,079
1966	814,249	160,384	150,038	1,124,671	1,839,307	2,963,978
1967	716,467	125,105	219,581	1,061,153	1,800,969	2,962,122
1968	776,780	166,291	191,455	1,134,526	1,320,109	2,454,635
1969	614,710	96,435	150,749	861,894	1,258,142	2,120,036
1970	631,354	252,512*	116,125	999,991	2,088,927	3,088,918

* Excludes 9.6 billion, North Slope.

TABLE 139

OIL DRILLING AND FINDING RATE STATISTICS
(NPC Region 1)

	Exploratory Effort				Annual New OIP Added		Cumulative OIP		Cum. OIP	Total Drilling Effort		Total	Annual
	Wells	Footage	Percent of Total	Avg. Depth	Million Barrels	DIP/ft	Million Barrels	Cumulative Exp. Footage	÷ Cum. Exp. Ftg.	Wells	Footage	Cumulative Footage	Tot. Footage / Exp. Footage
1956	–	0	0	0	0	0	0	0	0	0	0	0	0
1957	5	48,315	0.11	9,663	0	0	0	48,315	0	5	48,315	48,315	1.00
1958	5	43,115	0.11	8,623	0	0	0	91,430	0	5	43,115	91,430	1.00
1959	7	72,074	0.19	10,296	15,419	213.93	15,419	163,504	94.30	12	138,761	230,191	1.93
1960	3	26,642	0.08	8,881	105,727	3,968.43	121,146	190,146	637.12	15	159,469	389,660	5.99
1961	9	68,767	0.25	7,641	149,780	2,178.08	270,926	258,913	1,046.40	38	387,619	777,279	5.64
1962	0	0	0	0	0	0	270,926	258,913	1,046.40	9	99,954	877,233	–
1963	11	103,233	0.33	9,385	4,405	42.67	275,331	362,146	760.28	19	191,398	1,068,631	1.85
1964	11	120,213	0.36	10,928	44,053	366.46	319,384	482,359	662.13	15	166,222	1,234,853	1.38
1965	17	130,310	0.46	7,665	387,665	2,974.94	707,049	612,669	1,154.05	21	167,482	1,402,335	1.29
1966	19	169,879	0.57	8,941	383,260	2,256.08	1,090,309	782,548	1,393.28	30	271,911	1,674,246	1.60
1967	8	76,888	0.27	9,611	345,374	4,491.91	1,435,683	859,436	1,670.49	48	492,903	2,167,149	6.41
1968	6	26,275	0.08	4,379	295,154	11,233.26	1,730,837	885,711	1,954.18	88	903,729	3,070,878	34.40
1969	6	46,403	0.14	7,734	5,947	128.16	1,736,784	932,114	1,863.27	46	512,592	3,583,470	11.05
1970	13	133,340	0.50	10,257	61,674	462.53	1,798,458	1,065,454	1,687.97	32	312,822	3,896,292	2.35

TABLE 140

OIL DRILLING AND FINDING RATE STATISTICS
(NPC Region 2)

	Exploratory Effort				Annual New OIP Added		Cumulative DIP		Cum. OIP	Total Drilling Effort		Total	Annual
	Wells	Footage	Percent of Total	Avg. Depth	Million Barrels	OIP/ft	Million Barrels	Cumulative Exp. Footage	÷ Cum. Exp. Ftg.	Wells	Footage	Cumulative Footage	Tot. Footage / Exp. Footage
1956	325	2,393,000	4.83	7,363	458,200	191.48	458,200	2,393,000	191.48	2,038	9,967,000	9,967,000	4.17
1957	341	2,090,000	4.86	6,129	340,560	162.95	798,760	4,483,000	178.17	1,955	8,651,000	18,618,000	4.14
1958	344	2,012,000	5.39	5,849	373,766	185.77	1,172,526	6,495,000	180.53	1,389	7,020,000	25,638,000	3.49
1959	322	2,043,000	5.41	6,345	291,496	142.68	1,464,022	8,538,000	171.47	1,319	6,488,000	32,126,000	3.18
1960	153	999,000	3.19	6,529	221,700	221.92	1,685,722	9,537,000	176.76	1,426	5,931,000	38,057,000	5.94
1961	155	916,000	3.26	5,910	137,962	150.61	1,823,684	10,453,000	174.47	1,678	6,054,000	44,111,000	6.61
1962	216	1,060,000	3.71	4,907	577,306	544.63	2,400,990	11,513,000	208.55	2,212	7,813,000	51,924,000	7.37
1963	277	1,253,000	2.94	4,520	329,658	263.31	2,730,648	12,765,000	213.92	2,191	7,581,000	59,505,000	6.06
1964	382	1,800,000	5.32	4,712	2,448,507	1,360.28	5,179,155	14,565,000	355.59	2,186	8,006,000	67,511,000	4.45
1965	256	1,261,000	4.42	4,926	284,727	225.79	5,463,882	15,826,000	345.25	1,988	6,946,000	74,457,000	5.51
1966	220	1,054,000	3.51	4,791	42,315	40.15	5,506,197	16,880,000	326.20	2,080	5,364,000	79,821,000	5.09
1967	234	1,224,000	4.28	5,231	114,092	93.21	5,620,289	18,104,000	310.44	2,282	5,303,000	85,124,000	4.33
1968	244	1,284,000	4.00	5,262	528,006	411.22	6,148,295	19,388,000	317.12	2,452	6,403,000	91,527,000	4.99
1969	199	1,233,000	3.64	6,196	52,997	42.98	6,201,292	20,621,000	300.73	1,751	5,396,000	96,923,000	4.38
1970	188	1,114,810	4.16	5,930	85,455	76.65	6,286,747	21,735,810	289.23	1,961	5,556,048	102,479,048	4.98

TABLE 141

OIL DRILLING AND FINDING RATE STATISTICS
(NPC Region 2A)

	Exploratory Effort				Annual New OIP Added		Cumulative OIP			Total Drilling Effort			
	Wells	Footage	Percent of Total	Avg. Depth	Million Barrels	OIP/ft	Million Barrels	Cumulative Exp. Footage	Cum. OIP ÷ Cum. Exp. Ftg.	Wells	Footage	Total Cumulative Footage	Annual Tot. Footage Exp. Footage
1956	147	166,295	0.34	1,131	5,500	33.07	5,500	166,295	33.07	166	233,523	233,523	1.40
1957	147	415,684	0.97	2,828	5,500	13.23	11,000	581,979	18.90	181	520,089	753,612	1.25
1958	41	142,826	0.38	3,484	5,500	38.50	16,500	724,805	22.76	48	172,349	925,961	1.21
1959	15	85,863	0.23	5,724	5,500	34.06	22,000	810,668	27.14	30	172,116	1,098,077	2.00
1960	14	77,767	0.25	5,555	40,600	522.07	62,600	888,435	70.46	34	223,982	1,322,059	2.88
1961	22	52,444	0.19	2,384	40,600	774.16	103,200	940,879	109.68	69	300,713	1,622,772	5.73
1962	20	111,323	0.39	5,566	40,600	364.70	143,800	1,052,202	136.67	46	289,929	1,912,701	2.60
1963	11	33,696	0.11	3,063	40,600	1,205.87	184,400	1,085,898	169.81	30	146,370	2,059,071	4.34
1964	58	248,698	0.73	4,288	40,600	163.25	225,000	1,334,596	168.59	75	295,975	2,355,046	1.19
1965	49	234,356	0.82	4,783	249,200	1,063.34	474,200	1,568,952	302.24	84	345,731	2,700,777	1.48
1966	53	197,390	0.66	3,724	249,200	1,262,48	723,400	1,766,342	409.55	118	536,683	3,237,460	2.72
1967	25	133,492	0.47	5,340	249,200	1,866.78	972,600	1,899,834	511.94	102	503,792	3,741,252	3.77
1968	38	389,672	1.21	10,255	249,200	639.51	1,221,800	2,289,506	533.65	122	746,990	4,488,242	1.92
1969	17	147,011	0.43	8,648	249,200	1,695.11	1,471,000	2,436,517	603.73	120	601,076	5,089,318	4.09
1970	11	124,502	0.46	11,318	0	0	1,471,000	2,561,019	574.38	21	139,420	5,228,738	1.12

TABLE 142

OIL DRILLING AND FINDING RATE STATISTICS
(NPC Region 3)

	Exploratory Effort				Annual New OIP Added		Cumulative OIP			Total Drilling Effort		Total	Annual
	Wells	Footage	Percent of Total	Avg. Depth	Million Barrels	OIP/ft	Million Barrels	Cumulative Exp. Footage	Cum. OIP ÷ Cum. Exp. Ftg.	Wells	Footage	Cumulative Footage	Tot. Footage / Exp. Footage
1956	388	1,951,243	3.94	5,029	181,478	93.01	181,478	1,951,243	93.00	677	3,377,317	3,377,317	1.73
1957	376	1,919,459	4.47	5,105	361,686	188.43	543,164	3,870,702	140.33	810	4,126,275	7,503,592	2.15
1958	305	1,514,873	4.05	4,967	344,412	227.35	887,576	5,385,575	164.81	1,044	5,219,260	12,722,852	3.45
1959	322	1,595,002	4.22	4,953	180,741	113.32	1,068,317	6,980,577	153.04	1,093	4,986,916	17,709,768	3.13
1960	260	1,234,624	3.94	4,749	195,887	158.66	1,264,204	8,215,201	153.89	690	3,248,584	20,958,352	2.63
1961	229	890,826	3.17	3,890	123,015	138.09	1,387,219	9,106,027	152.34	663	2,885,310	23,843,662	3.24
1962	307	1,189,810	4.16	3,876	82,536	69.37	1,469,755	10,295,837	142.75	649	2,672,051	26,515,713	2.25
1963	235	1,112,552	3.50	4,734	78,467	70.53	1,548,222	11,408,389	135.71	524	2,282,005	28,797,718	2.05
1964	234	1,194,063	3.53	5,108	66,288	55.51	1,614,510	12,602,452	128.11	411	1,960,535	30,758,253	1.64
1965	201	1,022,206	3.58	5,036	40,726	40.23	1,655,236	13,624,658	121.58	413	1,975,568	32,733,821	1.95
1966	239	1,040,316	3.46	4,353	82,788	79.58	1,738,024	14,664,974	118.60	406	1,840,884	34,574,705	1.77
1967	216	1,018,389	3.56	4,715	114,562	112.49	1,852,586	15,683,363	118.20	442	1,867,598	36,442,303	1.83
1968	180	816,766	2.54	4,538	55,682	68.17	1,908,268	16,500,129	115.72	345	1,535,518	37,977,821	1.88
1969	360	1,812,254	5.36	5,034	82,044	45.27	1,990,312	18,312,383	108.75	589	2,768,748	40,746,569	1.53
1970	259	1,612,570	6.01	6,226	71,106	44.09	2,061,418	19,924,953	103.46	447	2,481,495	43,228,064	1.54

TABLE 143

OIL DRILLING AND FINDING RATE STATISTICS
(NPC Region 4)

	Exploratory Effort									Total Drilling Effort			
	Wells	Footage	Percent of Total	Avg. Depth	Annual New OIP Added Million Barrels	OIP/ft	Cumulative OIP Million Barrels	Cumulative Exp. Footage	Cum. OIP ÷ Cum. Exp. Ftg.	Wells	Footage	Total Cumulative Footage	Annual Tot. Footage Exp. Footage
1956	1,057	5,425,986	10.95	5133	511,830	94.33	511,830	5,425,986	94.33	2,739	14,491,709	14,491,709	2.67
1957	1,119	5,990,361	13.93	5353	688,558	114.94	1,200,388	11,416,347	105.15	2,426	12,982,211	27,473,920	2.17
1958	883	4,686,439	12.54	5307	500,643	106.83	1,701,031	16,102,786	105.64	2,225	12,087,310	39,561,230	2.58
1959	1,009	5,519,507	14.61	5470	474,661	86.00	2,175,692	21,622,293	100.62	2,595	14,086,968	53,648,198	2.55
1960	998	5,226,910	16.67	5237	523,286	100.11	2,698,978	26,849,203	100.52	2,450	12,899,512	66,547,710	2.47
1961	940	4,668,725	16.61	4967	459,933	98.51	3,158,911	31,517,928	100.23	2,301	11,238,919	77,786,629	2.41
1962	931	4,762,573	16.66	5116	256,014	53.76	3,414,925	36,280,501	94.13	1,967	10,190,939	87,977,568	2.14
1963	847	4,729,585	14.90	5584	200,339	42.36	3,615,264	41,010,086	88.16	1,949	10,374,740	98,352,308	2.19
1964	893	4,711,021	13.92	5275	243,053	51.59	3,858,317	45,721,107	84.39	2,111	10,230,335	108,582,643	2.17
1965	780	3,918,384	13.72	5024	277,053	70.71	4,135,370	49,639,491	83.31	2,030	9,772,738	118,355,381	2.49
1966	900	4,658,387	15.52	5176	185,318	39.78	4,320,688	54,297,878	79.57	1,884	9,280,414	127,635,795	1.99
1967	856	4,820,728	16.84	5632	334,367	69.36	4,655,055	59,118,606	78.74	1,797	9,154,700	136,790,495	1.90
1968	1,243	7,543,301	23.48	6069	565,021	74.90	5,220,076	66,661,907	78.31	2,378	13,841,473	150,631,968	1.83
1969	1,641	9,627,402	28.47	5867	240,618	24.99	5,460,694	76,289,309	71.58	2,946	17,122,768	167,754,736	1.78
1970	1,117	7,511,539	28.00	6725	309,124	41.15	5,769,818	83,800,848	68.85	2,181	14,657,688	182,412,424	1.95

TABLE 144

OIL DRILLING AND FINDING RATE STATISTICS

(NPC Region 5)

	Exploratory Effort				Annual New DIP Added		Cumulative DIP			Total Drilling Effort			
	Wells	Footage	Percent of Total	Avg. Depth	Million Barrels	DIP/ft	Million Barrels	Cumulative Exp. Footage	Cum. DIP ÷ Cum. Exp. Ftg.	Wells	Footage	Total Cumulative Footage	Annual Tot. Footage Exp. Footage
1956	3,307	14,744,485	29.77	4459	2,969,822	201.42	2,969,822	14,744,485	201.42	14,275	57,106,416	57,106,416	3.87
1957	2,745	11,254,513	26.18	4100	2,858,208	253.96	5,828,030	25,998,998	224.16	13,947	54,560,416	111,666,832	4.85
1958	2,089	8,516,606	22.80	4077	2,333,915	274.04	8,161,945	34,515,604	236.47	11,533	43,565,936	155,232,768	5.12
1959	1,985	8,591,411	22.74	4328	2,825,398	328.86	10,987,343	43,107,015	254.89	11,763	45,397,776	200,630,544	5.28
1960	1,594	7,105,859	22.67	4458	2,230,843	313.94	13,218,186	50,212,874	263.24	9,121	35,647,856	236,278,400	5.02
1961	1,282	6,224,389	22.15	4855	1,702,250	273.48	14,920,436	56,437,263	264.37	7,923	31,475,264	267,753,664	5.06
1962	1,369	6,512,503	22.77	4757	1,622,890	249.20	16,543,326	62,949,766	262.80	7,936	32,189,048	299,951,712	4.94
1963	1,418	6,357,931	20.03	4484	1,352,674	212.75	17,896,000	69,307,697	258.21	7,039	28,850,912	328,802,624	4.54
1964	1,370	7,044,922	20.82	5142	1,049,610	148.99	18,945,610	76,352,619	248.13	6,945	29,347,056	358,149,680	4.17
1965	1,165	5,720,828	20.04	4911	1,053,903	184.22	19,999,513	82,073,447	243.68	6,367	27,200,336	385,350,016	4.75
1966	1,176	5,766,362	19.21	4903	772,737	134.01	20,772,250	87,839,809	236.48	5,906	25,069,424	410,419,440	4.35
1967	919	4,385,301	15.32	4772	594,712	135.61	21,366,962	92,225,110	231.68	5,066	20,382,288	430,801,728	4.65
1968	1,431	4,630,918	14.41	3236	437,614	94.50	21,804,576	96,856,028	225.12	5,033	20,132,544	450,934,272	4.35
1969	1,191	5,321,850	15.74	4468	460,682	86.56	22,265,258	102,177,878	217.91	4,874	21,639,456	472,573,728	4.07
1970	818	3,856,118	14.38	4714	465,712	120.77	22,730,970	106,033,996	214.37	4,517	20,097,274	492,671,002	5.32

TABLE 145

OIL DRILLING AND FINDING RATE STATISTICS
(NPC Region 6)

	Exploratory Effort				Annual New DIP Added		Cumulative DIP		Cum. OIP	Total Drilling Effort		Total	Annual
	Wells	Footage	Percent of Total	Avg. Depth	Million Barrels	DIP/ft	Million Barrels	Cumulative Exp. Footage	÷ Cum. Exp. Ftg.	Wells	Footage	Cumulative Footage	Tot. Footage Exp. Footage
1956	2,344	12,347,604	24.93	5268	1,065,699	86.31	1,065,699	12,347,604	86.31	9,387	48,528,128	48,528,128	3.93
1957	1,877	10,722,348	24.94	5712	991,480	92.47	2,057,179	23,069,952	89.17	8,588	49,143,760	97,671,888	4.58
1958	1,697	10,137,900	27.14	5974	815,751	80.47	2,872,930	33,207,852	86.51	7,433	39,529,168	137,201,056	3.90
1959	1,608	10,191,062	26.98	6338	1,046,961	102.73	3,919,891	43,398,914	90.32	7,984	42,449,264	179,650,320	4.17
1960	1,213	8,686,161	27.71	7161	758,075	87.27	4,677,966	52,085,075	89.81	6,939	39,639,600	219,289,920	4.56
1961	1,237	7,834,794	27.88	6334	1,142,523	145.83	5,820,489	59,919,869	97.14	6,943	39,068,624	258,358,544	4.99
1962	1,156	7,723,067	27.01	6681	1,040,505	134.73	6,860,994	67,642,936	101.43	7,542	42,575,440	300,933,984	5.51
1963	1,469	9,793,230	30.85	6667	790,731	80.74	7,651,725	77,436,166	98.81	8,163	44,278,416	345,212,400	4.52
1964	1,386	8,677,571	25.65	6261	887,923	102.32	8,539,648	86,113,737	99.17	8,096	41,019,520	386,231,920	4.73
1965	1,323	8,219,014	28.79	6212	763,991	92.95	9,303,639	94,332,751	98.63	7,429	38,530,064	424,761,984	4.69
1966	1,457	9,253,572	30.82	6351	571,191	61.73	9,874,830	103,586,323	95.33	5,896	30,576,752	455,338,736	3.30
1967	1,278	8,596,282	30.04	6726	612,518	71.25	10,487,348	112,182,605	93.48	4,864	26,256,144	481,594,880	3.05
1968	1,261	9,202,617	28.64	7298	374,578	40.70	10,861,926	121,385,222	89.48	4,284	25,516,272	507,111,152	2.77
1969	1,125	7,928,955	23.45	7048	466,174	58.79	11,328,100	129,314,177	87.60	4,646	25,355,264	532,466,416	3.20
1970	1,006	7,428,463	27.70	7384	572,122	77.02	11,900,222	136,742,640	87.03	3,956	24,969,303	557,435,719	3.36

TABLE 146

OIL DRILLING AND FINDING RATE STATISTICS
(NPC Region 6A)

	Exploratory Effort				Annual New OIP Added		Cumulative OIP		Cum. OIP	Total Drilling Effort		Total	Annual
	Wells	Footage	Percent of Total	Avg. Depth	Million Barrels	OIP/ft	Million Barrels	Cumulative Exp. Footage	÷ Cum. Exp. Ftg.	Wells	Footage	Cumulative Footage	Tot. Footage / Exp. Footage
1956	46	552,222	1.11	12,005	684,000	1,238.63	648,000	552,222	1,238.63	344	3,278,811	3,278,811	5.94
1957	33	423,486	0.99	12,833	435,000	1,027.19	1,119,000	975,708	1,146.88	528	4,892,893	8,171,704	11.57
1958	10	104,039	0.28	10,404	420,000	4,036.95	1,539,000	1,079,747	1,425.36	323	3,007,638	11,179,342	28.92
1959	5	63,951	0.17	12,790	1,116,000	17,450.86	2,655,000	1,143,698	2,321.45	299	2,972,077	14,151,419	46.44
1960	0	0	0	0	439,000	–	3,094,000	1,143,698	–	351	3,527,060	17,678,479	–
1961	0	0	0	0	494,000	–	3,588,000	1,143,698	–	370	3,727,799	21,406,278	–
1962	38	402,272	1.41	10,586	302,000	750.74	3,890,000	1,545,970	2,516.25	483	4,949,026	26,355,304	12.31
1963	83	910,706	2.87	10,972	419,000	460.08	4,309,000	2,456,676	1,754.01	512	5,284,711	31,640,015	5.80
1964	163	1,664,220	4.92	10,210	537,000	322.67	4,846,000	4,120,896	1,175.96	726	7,324,024	38,964,039	4.40
1965	176	1,830,970	6.41	10,403	471,000	257.24	5,317,000	5,951,866	893.34	831	8,482,173	47,446,212	4.63
1966	161	1,506,839	5.02	9,359	733,118	486.53	6,050,118	7,458,705	811.15	762	7,687,308	55,133,520	5.10
1967	176	1,854,342	6.48	10,536	523,778	282.46	6,573,896	9,313,047	705.88	629	6,486,759	61,620,279	3.50
1968	169	1,806,839	5.62	10,691	706,630	391.09	7,280,526	11,119,886	654.73	705	7,268,820	68,889,099	4.02
1969	123	1,306,884	3.86	10,625	541,884	414.64	7,822,410	12,426,770	629.48	578	6,039,583	74,928,682	4.62
1970	57	553,061	2.06	9,703	786,933	1,422.87	8,609,343	12,979,831	663.29	566	5,278,316	80,206,998	9.55

TABLE 147

OIL DRILLING AND FINDING RATE STATISTICS (NPC Region 7)

	Exploratory Effort				Annual New OIP Added		Cumulative OIP		Cum. OIP	Total Drilling Effort		Total	Annual
	Wells	Footage	Percent of Total	Avg. Depth	Million Barrels	OIP/ft	Million Barrels	Cumulative Exp. Footage	÷ Cum. Exp. Ftg.	Wells	Footage	Cumulative Footage	Tot. Footage / Exp. Footage
1956	2,432	9,113,778	18.40	3,747	885,078	97.11	885,078	9,113,778	97.11	13,099	44,907,520	44,907,520	4.93
1957	2,176	7,945,535	18.48	3,651	631,458	79.47	1,516,536	17,059,313	88.90	10,821	37,917,488	82,825,008	4.77
1958	2,327	8,249,349	22.08	3,545	501,438	60.79	2,017,974	25,308,662	79.73	10,373	34,134,576	116,959,584	4.14
1959	2,125	7,713,834	20.42	3,630	498,412	64.61	2,516,386	33,022,496	76.20	9,429	32,881,728	149,841,312	4.26
1960	1,530	6,042,857	19.28	3,950	450,968	74.63	2,967,354	39,065,353	75.96	7,944	25,607,968	175,449,280	4.24
1961	1,439	5,749,579	20.46	3,996	435,315	75.71	3,402,669	44,314,932	75.93	8,950	28,104,128	203,553,408	4.89
1962	1,280	4,985,209	17.43	3,895	456,390	91.55	3,859,059	49,800,141	77.49	7,981	28,117,696	231,671,104	5.64
1963	1,324	5,464,457	17.21	4,127	396,140	72.49	4,255,199	55,264,598	77.00	7,695	26,688,720	258,359,824	4.88
1964	1,171	5,172,485	15.29	4,417	391,143	75.62	4,646,342	60,437,083	76.88	7,804	26,512,656	284,872,480	5.13
1965	956	3,973,627	13.92	4,157	327,883	82.51	4,974,225	64,410,710	77.23	6,514	24,730,576	309,603,056	6.22
1966	1,108	4,488,465	14.95	4,051	245,610	54.72	5,219,835	68,899,175	75.76	5,478	20,605,056	330,208,112	4.59
1967	1,291	4,869,449	17.02	3,772	224,740	46.15	5,444,575	73,768,624	73.81	5,205	18,890,000	349,098,112	3.88
1968	1,351	5,066,782	15.77	3,750	208,646	41.18	5,653,221	78,835,406	71.71	5,127	18,787,552	367,885,664	3.71
1969	1,336	5,376,543	15.90	4,024	276,519	51.43	5,929,740	84,211,949	70.41	5,373	21,044,048	388,929,712	3.91
1970	968	3,745,486	13.96	3,869	291,805	77.91	6,221,545	87,957,435	70.73	4,377	16,689,070	405,618,782	4.46

TABLE 148

OIL DRILLING AND FINDING RATE STATISTICS

(NPC Regions 8, 9, 10 Combined)

	Exploratory Effort				Annual New OIP Added		Cumulative OIP			Total Drilling Effort			Annual
	Wells	Footage	Percent of Total	Avg. Depth	Million Barrels	OIP/ft	Million Barrels	Cumulative Exp. Footage	Cum. OIP ÷ Cum. Exp. Ftg.	Wells	Footage	Total Cumulative Footage	Tot. Footage / Exp. Footage
1956	1,617	2,751,547	5.56	1,702	292,465	106.29	292,465	2,751,547	106.29	7,746	15,587,898	15,587,898	5.67
1957	1,273	2,142,276	4.98	1,683	191,833	89.55	484,298	4,893,823	98.96	6,134	11,703,261	27,291,159	5.46
1958	1,090	1,913,225	5.12	1,755	171,943	89.87	656,241	6,807,048	96.41	6,429	11,335,052	38,626,211	5.92
1959	1,281	1,849,579	4.89	1,444	243,836	131.83	900,077	8,656,627	103.98	7,326	11,214,046	49,840,257	6.06
1960	1,352	1,947,352	6.21	1,440	218,163	112.03	1,118,240	10,603,979	105.45	5,841	10,500,874	60,341,131	5.39
1961	1,115	1,644,913	5.85	1,475	112,485	68.38	1,230,725	12,248,892	100.48	4,977	9,249,644	69,590,775	5.62
1962	1,176	1,827,804	6.39	1,554	137,706	75.34	1,368,431	14,076,696	97.21	5,077	8,934,517	78,525,292	4.89
1963	1,248	1,958,699	6.17	1,569	164,031	83.74	1,532,462	16,035,395	95.57	5,497	9,600,153	88,125,445	4.90
1964	1,562	3,122,254	9.23	1,999	254,977	81.66	1,787,439	19,157,649	93.30	6,232	12,531,874	100,651,319	4.01
1965	1,178	2,186,511	7.66	1,856	149,884	68.55	1,937,323	21,344,160	90.77	5,476	10,343,726	111,001,045	4.73
1966	1,443	1,815,301	6.04	1,258	146,428	80.66	2,083,751	23,159,461	89.97	5,250	8,973,472	119,974,517	4.94
1967	924	1,584,253	5.53	1,715	167,758	105.89	2,251,509	24,743,714	90.99	4,554	9,165,196	129,139,713	5.79
1968	720	1,321,820	4.11	1,836	189,868	143.64	2,441,377	26,065,534	93.66	3,788	8,010,473	137,150,186	6.06
1969	535	937,230	2.77	1,752	139,328	148.66	2,580,705	27,002,764	95.57	3,419	7,057,782	144,207,968	7.53
1970	364	619,506	2.31	1,702	108,618	175.33	2,689,323	27,622,270	97.36	2,713	5,505,069	149,713,037	8.89

TABLE 149

OIL DRILLING AND FINDING RATE STATISTICS
(NPC Region 11)

	Exploratory Effort				Annual New OIP		Cumulative			Total		Total	Annual
	Wells	Footage	Percent of Total	Avg. Depth	Added Million Barrels	OIP/ft	OIP Million Barrels	Cumulative Exp. Footage	Cum.OIP ÷ Cum. Exp. Ftg.	Drilling Effort Wells	Drilling Effort Footage	Cumulative Footage	Tot. Footage Exp. Footage
1956	17	84,948	0.17	4,997	0	0	0	84,948	0	17	84,948	84,948	1.00
1957	7	37,497	0.09	5,357	0	0	0	122,445	0	7	37,497	122,445	1.00
1958	5	39,360	0.11	7,872	0	0	0	161,805	0	5	39,360	161,805	1.00
1959	12	54,360	0.14	4,530	0	0	0	216,165	0	12	54,360	216,165	1.00
1960	0	0	0	0	0	0	0	216,165	0	0	0	216,165	0
1961	8	51,149	0.18	6,394	0	0	0	267,314	0	8	51,149	267,314	1.00
1962	3	20,677	0.07	6,892	446	21.58	446	287,991	1.55	4	32,498	299,812	1.57
1963	7	29,573	0.09	4,225	0	0	446	317,564	1.40	8	41,224	341,036	1.39
1964	10	78,660	0.23	7,866	10,862	138.09	11,308	396,224	28.54	14	125,384	466,420	1.59
1965	8	52,686	0.18	6,586	29,960	568.65	41,268	448,910	91.93	30	287,704	754,124	5.46
1966	9	70,862	0.24	7,874	0	0	41,268	519,772	79.40	14	128,578	882,702	1.81
1967	6	53,690	0.19	8,948	0	0	41,268	573,462	71.96	6	53,690	936,392	1.00
1968	5	44,154	0.14	8,831	714	16.17	41,982	617,616	67.97	9	90,465	1,026,857	2.05
1969	10	81,675	0.24	8,168	10,504	128.61	52,486	699,291	75.06	15	140,046	1,166,903	1.71
1970	13	123,208	0.46	9,478	8,826	71.63	61,312	822,499	74.54	24	236,971	1,403,874	1.92

TABLE 150

PROJECTION OF FINDING RATES AND TOTAL/EXPLORATORY DRILLING RATIOS

Cumulative Exploratory M Ft. Drilled	High Finding OIP/Ft	High Finding "R"*	Low Finding OIP/Ft	Low Finding "R"*	Cumulative Exploratory M Ft. Drilled	High Finding OIP/Ft	High Finding "R"*	Low Finding OIP/Ft	Low Finding "R"*
REGION 1					**REGION 2**				
1,065	2750	13.69	2750	13.69	21,736	100	4.98	100	4.98
1,815	3200	6.80	2120	8.00	26,836	91	4.00	91	4.00
2,815	2820	6.70	1680	6.00	30,036	95	4.03	88	3.90
3,815	2000	6.55	1022	5.45	34,036	109	4.20	82	3.70
4,815	1370	6.40	880	5.30	38,036	120	4.42	78	3.58
5,815	1070	6.20	710	5.15	42,036	122	4.55	74	3.42
8,015	805	5.90	575	4.90	56,036	118	4.02	64	3.10
REGION 2A					**REGION 3**				
2,561	1015	1.16	1015	1.16	19,925	48	1.54	48	1.54
3,401	1300	2.60	1120	3.00	21,925	68	2.02	44	1.54
4,601	1410	4.10	1100	3.60	23,925	80	2.40	42	1.50
5,801	1500	5.00	1080	4.00	25,925	79	2.50	38.5	1.50
7,001	1500	3.00	1040	4.00	29,925	70	2.25	34	1.50
11,001	1300	4.90	940	3.70	34,925	51	1.77	29.5	1.50
20,001	980	4.70	710	3.70	49,925	22	1.50	21	1.50
REGION 4					**REGION 5**				
83,801	37	1.95	37	1.95	106,034	115	5.32	115	5.32
91,801	43	2.07	31.6	1.03	124,034	76	4.10	76	4.10
105,801	52	2.20	27	1.80	132,034	80	4.20	69	4.05
127,801	55	2.30	22	1.60	150,034	112	4.40	57	3.95
189,801	54	2.20	20	1.55	172,034	140	4.60	48	3.85
239,801	51	2.00	18	1.50	190,034	138	4.50	45	3.80
299,801	45	1.92	16	1.50	240,034	120	4.40	32	3.70

* "R" is the ratio of total footage drilled per exploratory foot.

TABLE 150 (Continued)

PROJECTION OF FINDING RATES AND TOTAL/EXPLORATORY DRILLING RATIOS

Cumulative Exploratory M Ft. Drilled	High Finding OIP/Ft	High Finding "R"*	Low Finding OIP/Ft	Low Finding "R"*
REGION 6				
136,743	73	3.36	73	3.36
149,743	66	3.32	59.5	3.32
155,743	72	4.15	58	3.30
167,743	98	4.20	57	3.26
185,743	115	4.50	55	3.20
239,743	78	3.70	48	3.05
299,743	48	2.98	43	2.87
REGION 7				
87,957	67	4.60	67	4.60
95,957	74	4.60	50.5	4.60
99,957	76	4.85	49.5	4.60
107,957	78	4.90	47	4.60
119,957	71	4.90	44	4.60
139,957	53	4.80	40	4.60
159,957	41	4.70	34	4.60
REGION 11				
822	69	1.93	69	1.93
2,022	79	2.50	54	1.85
6,022	65	1.94	38	1.75
10,022	58	1.85	35	1.69
13,022	54	1.80	33	1.65
24,022	34	1.55	31	1.50
28,022	31	1.50	30	1.50

Cumulative Exploratory M Ft. Drilled	High Finding OIP/Ft	High Finding "R"*	Low Finding OIP/Ft	Low Finding "R"*
REGION 6A				
12,980	485	9.50	485	9.50
13,780	535	8.40	390	8.00
14,780	580	7.40	335	6.50
16,580	600	6.30	305	5.00
23,780	375	4.50	230	4.00
47,780	160	3.40	132	3.00
71,780	140	2.60	116	2.60
REGIONS 8, 9, 10				
27,622	185	8.89	185	8.89
30,122	208	8.90	128	6.40
35,122	220	8.90	90	5.00
45,122	152	7.10	60	4.30
55,122	79	4.90	50	4.20
65,122	54	4.40	45	4.03
75,122	46	4.20	42	4.00
REGION 11A				
0	270	1.00	270	1.00
2,000	420	2.60	330	2.40
4,000	530	4.20	430	3.60
6,000	590	5.00	465	4.00
8,000	600	4.80	430	3.95
10,000	600	4.45	426	3.70
14,000	545	3.75	415	3.05

* "R" is the ratio of total footage drilled per exploratory foot.

TABLE 151

OIL-IN-PLACE FOUND PER FOOT OF EXPLORATORY DRILLING IN THE UNITED STATES*

(Case I)

	History — 3 Year Running Average				Projection		
	Original 48 States	Offshore & Alaska	Total U.S.		Original 48 States	Offshore & Alaska	Total U.S.
1947	330	–	330	1971	76	641	122
1948	439	–	439	1972	73	702	109
1949	417	–	417	1973	75	778	128
1950	334	–	334	1974	79	825	146
1951	172	–	172	1975	83	848	162
1952	150	–	150	1976	86	825	162
1953	154	–	154	1977	88	841	176
1954	153	–	153	1978	88	817	173
1955	136	–	136	1979	87	784	174
1956	131	–	131	1980	85	728	166
1957	137	975	147	1981	83	661	155
1958	143	688	149	1982	81	583	152
1959	144	2,391	152	1983	78	524	141
1960	147	3,784	160	1984	74	481	137
1961	147	3,973	164	1985	71	447	129
1962	135	3,648	149				
1963	143	1,801	151				
1964	130	1,747	146				
1965	118	513	144				
1966	89	592	153				
1967	78	611	112				
1968	71	545	99				
1969	69	709	95				
1970	69	732	100				

* Excluding North Slope drilling.

TABLE 152

OIL-IN-PLACE FOUND PER FOOT OF EXPLORATORY DRILLING IN THE UNITED STATES*

(Case IA)

	History — 3 Year Running Average				Projection		
	Original 48 States	Offshore & Alaska	Total U.S.		Original 48 States	Offshore & Alaska	Total U.S.
1947	330	–	330	1971	73	538	111
1948	439	–	439	1972	64	475	88
1949	417	–	417	1973	59	537	95
1950	334	–	334	1974	56	591	104
1951	172	–	172	1975	53	619	112
1952	150	–	150	1976	51	599	107
1953	154	–	154	1977	49	601	113
1954	153	–	153	1978	47	572	108
1955	136	–	136	1979	46	543	108
1956	131	–	131	1980	44	502	101
1957	137	975	147	1981	42	455	94
1958	143	688	149	1982	40	406	92
1959	144	2,391	152	1983	39	378	87
1960	147	3,784	160	1984	38	354	87
1961	147	3,973	164	1985	37	333	83
1962	135	3,648	149				
1963	143	1,801	151				
1964	130	1,747	146				
1965	118	513	144				
1966	89	592	153				
1967	78	611	112				
1968	71	545	99				
1969	69	709	95				
1970	69	732	100				

* Excluding North Slope drilling.

TABLE 153

OIL-IN-PLACE FOUND PER FOOT OF EXPLORATORY DRILLING IN THE UNITED STATES*

(Case II)

	History — 3 Year Running Average				Projection		
	Original 48 States	Offshore & Alaska	Total U.S.		Original 48 States	Offshore & Alaska	Total U.S.
1947	330	—	330	1971	76	641	122
1948	439	—	439	1972	73	701	109
1949	417	—	417	1973	75	779	128
1950	334	—	334	1974	79	827	146
1951	172	—	172	1975	82	851	162
1952	150	—	150	1976	85	830	162
1953	154	—	154	1977	88	847	176
1954	153	—	153	1978	89	829	175
1955	136	—	136	1979	88	806	178
1956	131	—	131	1980	86	763	171
1957	137	975	147	1981	85	712	163
1958	143	688	149	1982	83	641	162
1959	144	2,391	152	1983	81	589	153
1960	147	3,784	160	1984	79	541	151
1961	147	3,973	164	1985	77	498	142
1962	135	3,648	149				
1963	143	1,801	151				
1964	130	1,747	146				
1965	118	513	144				
1966	89	592	153				
1967	78	611	112				
1968	71	545	99				
1969	69	709	95				
1970	69	732	100				

* Excluding North Slope drilling.

TABLE 154

OIL-IN-PLACE FOUND PER FOOT OF EXPLORATORY DRILLING IN THE UNITED STATES*

(Case III)

	History — 3 Year Running Average				Projection		
	Original 48 States	Offshore & Alaska	Total U.S.		Original 48 States	Offshore & Alaska	Total U.S.
1947	330	—	330	1971	73	538	111
1948	439	—	439	1972	64	475	88
1949	417	—	417	1973	59	537	96
1950	334	—	334	1974	56	591	104
1951	172	—	172	1975	54	621	112
1952	150	—	150	1976	51	603	108
1953	154	—	154	1977	49	607	114
1954	153	—	153	1978	48	583	110
1955	136	—	136	1979	46	559	110
1956	131	—	131	1980	45	527	105
1957	137	975	147	1981	43	491	99
1958	143	688	149	1982	42	441	99
1959	144	2,391	152	1983	41	410	93
1960	147	3,784	160	1984	40	387	94
1961	147	3,973	164	1985	39	366	89
1962	135	3,648	149				
1963	143	1,801	151				
1964	130	1,747	146				
1965	118	513	144				
1966	89	592	153				
1967	78	611	112				
1968	71	545	99				
1969	69	709	95				
1970	69	732	100				

* Excluding North Slope drilling.

TABLE 155

OIL-IN-PLACE FOUND PER FOOT OF EXPLORATORY DRILLING IN THE UNITED STATES*
(Case IV)

	History — 3 Year Running Average				Projection		
	Original 48 States	Offshore & Alaska	Total U.S.		Original 48 States	Offshore & Alaska	Total U.S.
1947	330	–	330	1971	73	538	111
1948	439	–	439	1972	64	476	88
1949	417	–	417	1973	60	538	96
1950	334	–	334	1974	57	594	105
1951	172	–	172	1975	55	627	114
1952	150	–	150	1976	53	614	111
1953	154	–	154	1977	51	626	118
1954	153	–	153	1978	50	612	115
1955	136	–	136	1979	49	602	118
1956	131	–	131	1980	48	585	115
1957	137	975	147	1981	47	569	113
1958	143	688	149	1982	47	541	117
1959	144	2,391	152	1983	46	525	114
1960	147	3,784	160	1984	45	511	117
1961	147	3,973	164	1985	45	490	114
1962	135	3,648	149				
1963	143	1,801	151				
1964	130	1,747	146				
1965	118	513	144				
1966	89	592	153				
1967	78	611	112				
1968	71	545	99				
1969	69	709	95				
1970	69	732	100				

* Excluding North Slope drilling.

TABLE 156

OIL-IN-PLACE FOUND PER FOOT OF EXPLORATORY DRILLING IN THE UNITED STATES*
(Case IVA)

	History — 3 Year Running Average				Projection		
	Original 48 States	Offshore & Alaska	Total U.S.		Original 48 States	Offshore & Alaska	Total U.S.
1947	330	–	330	1971	76	641	122
1948	439	–	439	1972	73	701	109
1949	417	–	417	1973	75	780	128
1950	334	–	334	1974	78	833	146
1951	172	–	172	1975	81	862	162
1952	150	–	150	1976	83	848	162
1953	154	–	154	1977	86	866	176
1954	153	–	153	1978	87	855	176
1955	136	–	136	1979	89	851	184
1956	131	–	131	1980	90	837	183
1957	137	975	147	1981	89	820	180
1958	143	688	149	1982	88	779	186
1959	144	2,391	152	1983	87	760	183
1960	147	3,784	160	1984	87	747	189
1961	147	3,973	164	1985	86	719	184
1962	135	3,648	149				
1963	143	1,801	151				
1964	130	1,747	146				
1965	118	513	144				
1966	89	592	153				
1967	78	611	112				
1968	71	545	99				
1969	69	709	95				
1970	69	732	100				

* Excluding North Slope drilling.

TABLE 157

OIL-IN-PLACE FOUND PER FOOT OF EXPLORATORY DRILLING IN THE UNITED STATES*
(Case I by NPC Regions)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	All Regions
1971	2,768	99	1,036	56	39	111	71	528	69	189	69	0	122
1972	2,802	98	1,078	69	42	104	68	581	72	197	70	0	109
1973	2,845	96	1,154	77	46	95	70	582	74	205	71	0	128
1974	2,917	94	1,268	79	50	87	82	543	76	210	74	271	146
1975	3,023	92	1,363	77	53	80	96	479	77	213	77	275	162
1976	3,137	92	1,432	73	54	78	106	409	78	216	77	279	162
1977	3,134	94	1,482	68	55	82	111	361	77	215	75	286	176
1978	3,019	97	1,485	62	55	89	110	336	75	206	71	295	173
1979	2,870	102	1,439	55	55	99	103	308	73	191	68	307	174
1980	2,596	108	1,374	49	54	109	97	277	70	175	65	323	166
1981	2,216	114	1,309	45	54	117	89	244	67	158	62	340	155
1982	1,826	118	1,251	41	54	126	82	207	63	138	59	378	152
1983	1,466	121	1,195	36	53	134	75	171	59	115	57	431	141
1984	1,180	122	1,136	31	53	139	70	145	55	90	53	486	137
1985	1,005	121	1,073	25	52	139	64	124	51	73	49	538	129

* Excluding North Slope drilling.

TABLE 158

OIL-IN-PLACE FOUND PER FOOT OF EXPLORATORY DRILLING IN THE UNITED STATES*
(Case IA by NPC Regions)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	All Regions
1971	2,724	99	1,023	47	36	111	70	416	63	174	69	0	111
1972	2,678	98	1,038	44	33	104	63	332	56	154	67	0	88
1973	2,617	96	1,067	42	30	95	59	310	51	136	65	0	95
1974	2,516	94	1,101	39	28	87	58	299	49	122	61	270	104
1975	2,368	92	1,109	37	26	79	57	292	49	113	56	272	112
1976	2,195	90	1,095	35	24	73	56	283	48	101	52	274	107
1977	2,044	89	1,074	34	22	69	55	271	47	91	49	276	113
1978	1,911	87	1,042	32	22	65	54	253	46	84	45	280	108
1979	1,745	85	1,010	30	21	62	53	234	45	77	41	285	108
1980	1,500	82	977	29	21	58	52	213	44	70	38	291	101
1981	1,195	80	942	28	21	55	50	190	43	63	37	298	94
1982	988	78	905	26	20	53	49	165	42	58	36	313	92
1983	890	76	865	25	20	50	48	140	41	55	34	343	87
1984	773	74	822	24	19	48	47	120	40	52	33	390	87
1985	677	72	777	22	18	46	46	105	39	49	33	433	83

* Excluding North Slope drilling.

TABLE 159

OIL-IN-PLACE FOUND PER FOOT OF EXPLORATORY DRILLING IN THE UNITED STATES*
(Case II by NPC Regions)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	All Regions
1971	2,768	99	1,036	56	39	111	71	528	69	189	69	0	122
1972	2,801	98	1,078	69	42	104	68	581	72	197	70	0	109
1973	2,843	96	1,152	77	46	96	70	583	74	204	71	0	128
1974	2,913	94	1,264	79	50	87	81	547	76	210	74	271	146
1975	3,012	92	1,357	77	53	80	95	487	77	213	77	274	162
1976	3,129	92	1,421	74	54	77	104	421	77	216	77	279	162
1977	3,149	93	1,476	70	55	80	111	372	77	217	75	285	176
1978	3,059	95	1,497	65	55	86	112	346	76	211	73	292	175
1979	2,942	99	1,468	59	55	94	107	322	74	199	69	302	178
1980	2,761	104	1,415	53	55	102	101	297	72	185	66	316	171
1981	2,492	109	1,360	49	54	110	96	270	70	172	64	329	163
1982	2,152	113	1,306	45	54	117	90	242	67	156	62	358	162
1983	1,812	118	1,259	42	54	124	84	212	64	140	59	402	153
1984	1,488	120	1,215	38	54	130	79	179	61	121	57	448	151
1985	1,219	121	1,169	33	53	137	74	154	58	100	54	495	142

* Excluding North Slope drilling.

TABLE 160

OIL-IN-PLACE FOUND PER FOOT OF EXPLORATORY DRILLING IN THE UNITED STATES*
(Case III by NPC Regions)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	All Regions
1971	2,724	99	1,023	46	36	111	70	416	63	174	69	0	111
1972	2,678	98	1,038	44	33	104	64	332	56	155	67	0	88
1973	2,619	96	1,065	42	30	96	59	310	51	137	65	0	96
1974	2,522	94	1,100	40	28	87	58	299	50	123	61	270	104
1975	2,383	92	1,110	37	26	79	57	292	49	114	56	272	112
1976	2,219	91	1,097	36	24	74	56	285	48	103	52	274	108
1977	2,076	89	1,080	34	22	70	55	275	47	93	50	276	114
1978	1,957	88	1,053	33	22	67	55	260	46	86	47	279	110
1979	1,822	86	1,024	31	21	64	53	244	45	81	43	283	110
1980	1,643	84	998	30	21	61	52	226	45	75	39	288	105
1981	1,417	82	970	29	21	58	51	208	44	69	37	294	99
1982	1,154	80	941	28	21	55	50	189	43	63	37	305	99
1983	980	79	911	27	20	53	49	168	42	58	35	324	93
1984	898	77	879	26	20	51	48	145	42	56	34	355	94
1985	794	75	846	24	19	49	47	127	41	53	33	398	89

* Excluding North Slope drilling.

TABLE 161

OIL-IN-PLACE FOUND PER FOOT OF EXPLORATORY DRILLING IN THE UNITED STATES*
(Case IV by NPC Regions)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	All Regions
1971	2,724	99	1,023	47	36	111	70	416	63	174	69	0	111
1972	2,679	98	1,038	44	33	104	64	333	56	155	68	0	88
1973	2,627	96	1,062	42	30	97	59	311	51	138	66	0	96
1974	2,546	95	1,099	40	28	90	58	301	50	125	62	270	105
1975	2,439	93	1,114	39	27	83	57	296	49	118	58	271	114
1976	2,322	92	1,105	37	25	78	57	290	49	111	54	273	111
1977	2,196	91	1,095	36	24	74	56	285	48	103	52	274	118
1978	2,090	90	1,085	35	23	72	56	279	47	95	50	276	115
1979	2,009	89	1,070	34	22	69	55	270	47	89	48	278	118
1980	1,926	88	1,051	33	22	68	55	261	46	86	46	281	115
1981	1,846	88	1,035	32	22	66	54	252	46	83	44	284	113
1982	1,762	86	1,022	32	21	65	54	243	46	80	42	289	117
1983	1,662	85	1,009	31	21	63	53	234	45	77	39	297	114
1984	1,529	85	997	30	21	62	53	226	45	74	38	305	117
1985	1,376	84	986	30	21	60	52	217	45	71	37	314	114

* Excluding North Slope drilling.

TABLE 162

OIL-IN-PLACE FOUND PER FOOT OF EXPLORATORY DRILLING IN THE UNITED STATES*
(Case IVA by NPC Regions)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	All Regions
1971	2,768	99	1,036	56	39	111	71	528	69	189	69	0	122
1972	2,800	98	1,077	68	42	104	68	580	72	197	70	0	109
1973	2,838	96	1,142	77	46	97	69	587	74	204	71	0	128
1974	2,896	95	1,249	80	49	90	77	561	75	209	73	271	146
1975	2,972	93	1,334	78	52	83	88	515	76	211	77	273	162
1976	3,056	92	1,383	76	53	78	98	468	77	214	78	277	162
1977	3,146	92	1,431	74	54	77	104	421	77	216	77	280	176
1978	3,168	93	1,477	72	55	79	108	382	78	218	75	285	176
1979	3,105	94	1,500	70	55	80	112	361	78	217	74	291	184
1980	3,032	94	1,500	67	55	84	113	347	77	211	72	298	183
1981	2,963	96	1,488	64	55	88	111	334	76	204	70	305	180
1982	2,891	99	1,464	60	55	92	108	321	75	197	68	318	186
1983	2,791	101	1,439	57	55	96	106	308	74	190	66	336	183
1984	2,632	103	1,415	54	55	99	104	296	73	183	65	357	189
1985	2,441	105	1,392	52	55	103	102	283	72	176	63	381	184

* Excluding North Slope drilling.

Chapter Five—Section III

Drilling Activities for Oil

TABLE 163

TOTAL OIL DRILLING RATE PROJECTIONS IN THE UNITED STATES*
(Thousand Feet Drilled)

History		Projection						
			Case I	Case IA	Case II	Case III	Case IV	Case IVA
1956	197,563	1971	91,249	89,633	91,249	89,633	89,633	91,249
1957	184,583	1972	93,724	89,579	91,666	87,632	82,406	86,147
1958	156,154	1973	104,430	93,902	101,209	91,073	79,791	88,142
1959	160,842	1974	115,091	98,178	110,056	93,992	76,025	88,301
1960	137,386	1975	124,012	103,512	115,249	96,467	72,507	85,787
1961	132,543	1976	133,058	108,184	120,024	98,128	69,068	83,006
1962	137,873	1977	143,553	114,151	126,833	101,126	65,658	80,333
1963	135,320	1978	153,059	121,168	131,438	103,853	64,429	80,263
1964	137,520	1979	161,869	128,537	135,539	107,361	61,327	77,532
1965	128,782	1980	169,764	135,474	138,619	110,223	58,135	73,729
1966	110,334	1981	177,934	142,948	141,820	113,266	55,175	69,862
1967	98,556	1982	183,575	149,046	144,389	115,933	52,404	66,214
1968	103,237	1983	190,025	156,535	147,583	119,534	49,809	62,833
1969	107,677	1984	196,359	164,780	150,738	123,448	48,149	60,675
1970	95,923	1985	201,991	172,656	153,746	127,619	46,540	58,541

* Excluding North Slope drilling.

Distribution of Drilling Effort

The total exploratory drilling effort selected for the country was distributed to each of the various NPC regions as shown on Table 164.

Year one was established on the basis of recent history. Changes were made in subsequent years to account for shifts in drilling emphasis as opportunities develop. Factors taken into consideration in making this allocation were the relative potential oil yet to be found in each region, the expected success in finding for each region, the drilling cost for each region and the availability of drilling equipment to move in the trends projected.

TABLE 164

DISTRIBUTION OF EXPLORATORY DRILLING (FRACTION)— EXCLUDING NORTH SLOPE

NPC Region	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
1	.0028	.0020	.0035	.0050	.0065	.0065	.0080	.0080	.0100	.0100	.0100	.0120	.0120	.0150	.0150
2	.0305	.0400	.0400	.0400	.0400	.0400	.0400	.0400	.0400	.0400	.0400	.0400	.0400	.0400	.0400
2A	.0057	.0050	.0120	.0190	.0250	.0250	.0300	.0300	.0300	.0300	.0300	.0300	.0300	.0300	.0300
3	.0687	.0630	.0600	.0560	.0500	.0500	.0460	.0460	.0450	.0450	.0450	.0480	.0480	.0510	.0510
4	.1862	.2370	.2480	.2620	.2660	.2660	.2650	.2650	.2590	.2580	.2580	.2530	.2530	.2460	.2460
5	.1535	.1500	.1450	.1400	.1350	.1350	.1320	.1320	.1300	.1300	.1300	.1280	.1280	.1250	.1250
6	.2607	.2815	.2690	.2533	.2451	.2451	.2354	.2354	.2298	.2298	.2298	.2082	.2082	.1964	.1964
6A	.0726	.0505	.0600	.0650	.0700	.0700	.0750	.0750	.0800	.0800	.0800	.0850	.0850	.0900	.0900
7	.1723	.1360	.1190	.1037	.0969	.0969	.0926	.0926	.0892	.0892	.0892	.0858	.0858	.0816	.0816
8, 9, 10	.0442	.0300	.0350	.0400	.0450	.0450	.0500	.0500	.0550	.0550	.0550	.0600	.0600	.0650	.0650
11	.0028	.0050	.0085	.0150	.0185	.0185	.0230	.0230	.0280	.0280	.0280	.0350	.0350	.0400	.0400
11A	.0000	.0000	.0000	.0010	.0020	.0020	.0030	.0030	.0050	.0050	.0050	.0150	.0150	.0200	.0200
Total U.S.	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000

Note: The projections shown on this table are extrapolations of the trends in the historical distribution of drilling presented in Tables 139 through 149 taking into account the amount of oil left to be discovered, the field size and pool depth distribution, and drilling costs.

TABLE 165

OIL EXPLORATORY DRILLING RATE PROJECTIONS IN THE UNITED STATES*
(Thousand Feet Drilled)

History		Case			
			I & I A	II & III	IV & IV A
1956	49,531	1971	21,900	21,900	21,900
1957	42,989	1972	24,747	24,199	22,732
1958	37,360	1973	26,974	26,135	22,823
1959	37,780	1974	29,267	27,965	22,458
1960	31,347	1975	31,608	29,363	21,762
1961	28,102	1976	33,979	30,685	21,196
1962	28,595	1977	36,358	32,065	20,412
1963	31,746	1978	39,084	33,348	20,330
1964	33,834	1979	41,862	34,717	19,455
1965	28,550	1980	44,748	36,069	18,561
1966	30,021	1981	47,880	37,512	17,726
1967	28,617	1982	50,753	39,012	17,017
1968	32,133	1983	53,798	40,573	16,268
1969	33,819	1984	57,026	42,196	15,796
1970	26,823	1985	60,162	43,884	15,338

* Excluding North Slope drilling.

TABLE 166

CUMULATIVE OIL EXPLORATORY DRILLING PROJECTIONS IN THE UNITED STATES*
(Thousand Feet Drilled)

History		Case			
			I & I A	II & III	IV & IV A
1956	49,531	1971	21,900	21,900	21,900
1957	92,520	1972	46,647	46,099	44,632
1958	129,880	1973	73,621	72,235	67,455
1959	167,660	1974	102,888	100,200	89,913
1960	199,007	1975	134,497	129,563	111,675
1961	227,109	1976	168,476	160,248	132,871
1962	255,704	1977	204,833	192,313	153,283
1963	287,450	1978	243,918	225,661	173,613
1964	321,284	1979	285,780	260,377	193,068
1965	349,834	1980	330,527	296,447	211,629
1966	379,855	1981	378,407	333,958	229,354
1967	408,472	1982	429,160	372,971	246,371
1968	440,605	1983	482,958	413,544	262,639
1969	474,424	1984	539,984	455,739	278,435
1970	501,247	1985	600,147	499,623	293,773

* Excluding North Slope drilling.

TABLE 167

OIL EXPLORATORY DRILLING RATE PROJECTIONS IN THE UNITED STATES*
(Cases I & IA by NPC Regions – Thousand Feet Drilled)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	Total
1971	61	668	125	1,505	4,078	3,362	5,709	1,590	3,773	968	61	–	21,900
1972	49	990	124	1,559	5,865	3,712	6,966	1,250	3,366	742	124	–	24,747
1973	94	1,079	324	1,618	6,690	3,911	7,256	1,618	3,210	944	229	–	26,974
1974	146	1,171	556	1,639	7,668	4,097	7,413	1,902	3,035	1,171	439	29	29,267
1975	205	1,264	790	1,580	8,408	4,267	7,747	2,213	3,063	1,422	585	63	31,608
1976	221	1,359	849	1,699	9,038	4,587	8,328	2,379	3,293	1,529	629	68	33,979
1977	291	1,454	1,091	1,672	9,635	4,799	8,559	2,727	3,367	1,818	836	109	36,358
1978	313	1,563	1,173	1,798	10,357	5,159	9,200	2,931	3,619	1,954	899	117	39,084
1979	418	1,673	1,255	1,882	10,831	5,437	9,610	3,346	3,730	2,300	1,171	209	41,862
1980	447	1,790	1,342	2,014	11,545	5,817	10,283	3,580	3,991	2,461	1,253	224	44,748
1981	479	1,915	1,436	2,155	12,353	6,224	11,003	3,830	4,271	2,633	1,341	239	47,880
1982	609	2,030	1,523	2,436	12,840	6,496	10,567	4,314	4,355	3,045	1,776	761	50,753
1983	646	2,152	1,614	2,582	13,611	6,886	11,201	4,573	4,616	3,228	1,883	807	53,798
1984	855	2,281	1,711	2,908	14,028	7,128	11,200	5,132	4,653	3,707	2,281	1,141	57,026
1985	902	2,406	1,805	3,068	14,800	7,520	11,816	5,415	4,909	3,911	2,406	1,203	60,162

* Excluding North Slope drilling.

Note: Totals may not agree due to rounding.

TABLE 168

OIL EXPLORATORY DRILLING RATE PROJECTIONS IN THE UNITED STATES*
(Cases II and III by NPC Regions – Thousand Feet Drilled)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	Total
1971	61	668	125	1,505	4,078	3,362	5,709	1,590	3,773	968	61	–	21,900
1972	48	968	121	1,525	5,735	3,630	6,812	1,222	3,291	726	121	–	24,199
1973	91	1,045	314	1,568	6,482	3,790	7,030	1,568	3,110	915	222	–	26,135
1974	140	1,119	531	1,566	7,327	3,915	7,084	1,818	2,900	1,119	419	28	27,965
1975	191	1,175	734	1,468	7,811	3,964	7,197	2,055	2,845	1,321	543	59	29,363
1976	199	1,227	767	1,534	8,162	4,142	7,521	2,148	2,973	1,381	568	61	30,685
1977	257	1,283	962	1,475	8,497	4,233	7,548	2,405	2,969	1,603	738	96	32,065
1978	267	1,334	1,000	1,534	8,837	4,402	7,850	2,501	3,088	1,667	767	100	33,348
1979	347	1,387	1,040	1,561	8,983	4,509	7,970	2,775	3,094	1,908	971	173	34,717
1980	361	1,443	1,082	1,623	9,306	4,689	8,289	2,886	3,217	1,984	1,010	180	36,069
1981	375	1,500	1,125	1,688	9,678	4,877	8,620	3,001	3,346	2,063	1,050	188	37,512
1982	468	1,560	1,170	1,873	9,870	4,994	8,122	3,316	3,347	2,341	1,365	585	39,012
1983	487	1,623	1,217	1,947	10,265	5,193	8,447	3,449	3,481	2,434	1,420	609	40,573
1984	633	1,688	1,266	2,152	10,380	5,274	8,287	3,798	3,443	2,743	1,688	844	42,196
1985	658	1,755	1,317	2,238	10,795	5,485	8,619	3,950	3,581	2,852	1,755	878	43,884

* Excluding North Slope drilling.

Note: Totals may not agree due to rounding.

TABLE 169

OIL EXPLORATORY DRILLING RATE PROJECTIONS IN THE UNITED STATES*
(Cases IV and IVA by NPC Regions – Thousand Feet Drilled)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	Total
1971	61	668	125	1,505	4,078	3,362	5,709	1,590	3,773	968	61	–	21,900
1972	45	909	114	1,432	5,388	3,410	6,399	1,148	3,092	682	114	–	22,732
1973	80	913	274	1,369	5,660	3,309	6,139	1,369	2,716	799	194	–	22,823
1974	112	898	427	1,258	5,884	3,144	5,689	1,460	2,329	898	337	22	22,458
1975	141	870	544	1,088	5,789	2,938	5,334	1,523	2,109	979	403	44	21,762
1976	138	848	530	1,060	5,638	2,861	5,195	1,484	2,054	954	392	42	21,196
1977	163	816	612	939	5,409	2,694	4,805	1,531	1,890	1,021	469	61	20,412
1978	163	813	610	935	5,387	2,684	4,786	1,525	1,883	1,017	468	61	20,330
1979	194	777	583	875	5,034	2,527	4,466	1,555	1,734	1,069	544	97	19,455
1980	186	742	557	835	4,789	2,413	4,265	1,485	1,656	1,021	520	93	18,561
1981	177	709	532	798	4,573	2,304	4,073	1,418	1,581	975	496	89	17,726
1982	204	681	511	817	4,305	2,178	3,543	1,446	1,460	1,021	596	255	17,017
1983	195	651	488	781	4,116	2,082	3,387	1,383	1,396	976	569	244	16,268
1984	237	632	474	806	3,886	1,975	3,102	1,422	1,289	1,027	632	316	15,796
1985	230	614	460	782	3,773	1,917	3,012	1,380	1,252	997	614	307	15,338

* Excluding North Slope drilling.

Note: Totals may not agree due to rounding.

TABLE 170

CUMULATIVE OIL EXPLORATORY DRILLING PROJECTIONS IN THE UNITED STATES*

(Cases I & IA by NPC Regions – Thousand Feet Drilled)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	Total
1971	61	668	125	1,505	4,078	3,362	5,709	1,590	3,773	968	61	–	21,900
1972	111	1,658	249	3,064	9,943	7,074	12,676	2,840	7,139	1,710	185	–	46,647
1973	205	2,737	572	4,682	16,632	10,985	19,932	4,458	10,349	2,654	414	–	73,621
1974	352	3,907	1,128	6,321	24,300	15,082	27,345	6,360	13,384	3,825	853	29	102,888
1975	557	5,172	1,919	7,901	32,708	19,349	35,092	8,573	16,447	5,248	1,438	92	134,497
1976	778	6,531	2,768	9,600	41,747	23,937	43,420	10,952	19,739	6,777	2,067	160	168,476
1977	1,069	7,985	3,859	11,273	51,381	28,736	51,979	13,678	23,106	8,594	2,903	270	204,833
1978	1,381	9,549	5,031	13,071	61,739	33,895	61,180	16,610	26,725	10,549	3,802	387	243,918
1979	1,800	11,221	6,286	14,953	72,570	39,332	70,790	19,955	30,456	12,849	4,973	596	285,780
1980	2,247	13,011	7,628	16,966	84,115	45,149	81,073	23,535	34,447	15,310	6,226	820	330,527
1981	2,726	14,927	9,065	19,121	96,468	51,373	92,076	27,366	38,718	17,943	7,566	1,059	378,407
1982	3,335	16,957	10,587	21,557	109,309	57,870	102,642	31,680	43,073	20,989	9,343	1,820	429,160
1983	3,981	19,109	12,201	24,139	122,920	64,756	113,843	36,252	47,688	24,216	11,226	2,627	482,958
1984	4,836	21,390	13,912	27,048	136,948	71,884	125,043	41,385	52,342	27,923	13,507	3,768	539,984
1985	5,738	23,796	15,717	30,116	151,748	79,404	136,859	46,799	57,251	31,834	15,913	4,971	600,147

* Excluding North Slope drilling.

Note: Totals may not agree due to rounding.

TABLE 171

CUMULATIVE OIL EXPLORATORY DRILLING PROJECTIONS IN THE UNITED STATES*

(Cases II & III by NPC Regions – Thousand Feet Drilled)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	Total
1971	61	668	125	1,505	4,078	3,362	5,709	1,590	3,773	968	61	–	21,900
1972	110	1,636	246	3,029	9,813	6,992	12,521	2,812	7,065	1,694	182	–	46,099
1973	201	2,681	559	4,597	16,295	10,781	19,552	4,380	10,175	2,609	404	–	72,235
1974	341	3,800	1,091	6,163	23,621	14,696	26,635	6,198	13,075	3,727	824	28	100,200
1975	532	4,974	1,825	7,631	31,432	18,660	33,832	8,253	15,920	5,049	1,367	87	129,563
1976	731	6,202	2,592	9,166	39,594	22,803	41,353	10,401	18,893	6,429	1,935	148	160,248
1977	988	7,484	3,554	10,641	48,091	27,035	48,901	12,806	21,862	8,033	2,672	244	192,313
1978	1,255	8,818	4,554	12,175	56,929	31,437	56,751	15,307	24,950	9,700	3,439	344	225,661
1979	1,601	10,206	5,595	13,735	65,911	35,946	64,721	18,082	28,044	11,608	4,410	518	260,377
1980	1,962	11,648	6,677	15,358	75,217	40,635	73,010	20,967	31,261	13,591	5,420	698	296,447
1981	2,337	13,149	7,802	17,046	84,895	45,511	81,630	23,968	34,608	15,655	6,471	886	333,958
1982	2,805	14,709	8,973	18,919	94,765	50,505	89,753	27,284	37,955	17,995	7,836	1,471	372,971
1983	3,292	16,332	10,190	20,867	105,030	55,698	98,200	30,733	41,436	20,430	9,256	2,079	413,544
1984	3,925	18,020	11,456	23,019	115,410	60,973	106,487	34,531	44,879	23,172	10,944	2,923	455,739
1985	4,583	19,775	12,772	25,257	126,206	66,458	115,106	38,480	48,460	26,025	12,699	3,801	499,623

* Excluding North Slope drilling.

Note: Totals may not agree due to rounding.

TABLE 172

CUMULATIVE OIL EXPLORATORY DRILLING PROJECTIONS IN THE UNITED STATES*

(Cases IV & IVA by NPC Regions – Thousand Feet Drilled)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	Total
1971	61	668	125	1,505	4,078	3,362	5,709	1,590	3,773	968	61	–	21,900
1972	107	1,577	238	2,937	9,465	6,771	12,108	2,738	6,865	1,650	175	–	44,632
1973	187	2,490	512	4,306	15,125	10,081	18,248	4,107	9,581	2,449	369	–	67,455
1974	299	3,388	939	5,564	21,009	13,225	23,936	5,567	11,910	3,347	706	22	89,913
1975	440	4,259	1,483	6,652	26,798	16,163	29,270	7,090	14,019	4,326	1,108	66	111,675
1976	578	5,107	2,013	7,712	32,436	19,024	34,465	8,574	16,072	5,280	1,501	108	132,871
1977	741	5,923	2,625	8,651	37,845	21,719	39,270	10,105	17,963	6,301	1,970	170	153,283
1978	904	6,736	3,235	9,586	43,233	24,402	44,056	11,630	19,845	7,317	2,438	231	173,613
1979	1,098	7,514	3,818	10,460	48,267	26,929	48,522	13,185	21,579	8,386	2,982	328	193,068
1980	1,284	8,256	4,375	11,296	53,055	29,342	52,788	14,669	23,234	9,407	3,502	421	211,629
1981	1,461	8,965	4,907	12,093	57,629	31,646	56,861	16,088	24,815	10,382	3,998	509	229,354
1982	1,666	9,646	5,417	12,910	61,934	33,824	60,404	17,534	26,276	11,403	4,593	764	246,371
1983	1,861	10,297	5,905	13,691	66,050	35,906	63,791	18,917	27,671	12,379	5,163	1,008	262,639
1984	2,098	10,929	6,379	14,496	69,935	37,881	66,893	20,338	28,960	13,406	5,795	1,324	278,435
1985	2,328	11,542	6,839	15,279	73,709	39,798	69,906	21,719	30,212	14,403	6,408	1,631	293,773

* Excluding North Slope drilling.

Note: Totals may not agree due to rounding.

TABLE 173

TOTAL OIL DRILLING RATE PROJECTIONS IN THE UNITED STATES*
(Case I by NPC Regions – Thousand Feet Drilled)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	Total
1971	822	3,284	158	2,589	8,076	17,501	19,133	13,602	17,358	8,607	119	–	91,249
1972	638	4,708	183	3,214	12,021	18,435	23,210	8,982	15,482	6,604	246	–	93,724
1973	1,155	4,918	603	3,768	14,176	18,414	27,119	10,399	15,001	8,401	475	–	104,430
1974	1,629	5,083	1,418	4,027	16,719	18,178	30,909	11,124	14,576	10,419	979	30	115,091
1975	1,955	5,203	2,730	3,841	18,746	17,953	32,744	11,800	14,911	12,659	1,404	66	124,012
1976	1,697	5,446	3,650	3,955	20,510	19,016	36,125	11,357	16,094	13,609	1,523	75	133,058
1977	1,973	5,847	5,261	3,682	22,053	20,168	37,927	12,081	16,494	16,000	1,940	128	143,553
1978	2,111	6,340	5,854	3,670	23,612	21,973	40,369	12,607	17,734	16,664	1,976	148	153,059
1979	2,808	6,890	6,235	3,510	24,508	23,475	40,828	13,908	18,279	18,733	2,405	291	161,869
1980	2,980	7,512	6,628	3,462	25,914	25,475	42,171	14,313	19,534	18,989	2,436	350	169,764
1981	3,155	8,220	7,043	3,460	27,490	27,628	43,388	14,665	20,830	19,088	2,550	419	177,934
1982	3,964	8,918	7,414	3,712	28,263	29,211	39,980	15,711	21,144	20,304	3,317	1,638	183,575
1983	4,137	9,633	7,802	3,873	29,393	31,383	40,744	15,764	22,309	19,295	3,449	2,243	190,025
1984	5,364	10,288	8,207	4,362	29,519	32,633	39,230	16,762	22,382	19,462	4,091	4,058	196,359
1985	5,529	10,741	8,588	4,602	30,290	34,190	39,756	15,733	23,496	18,697	4,194	5,176	201,991

* Excluding North Slope drilling.

Note: Totals may not agree due to rounding.

TABLE 174

TOTAL OIL DRILLING RATE PROJECTIONS IN THE UNITED STATES*
(Case IA by NPC Regions – Thousand Feet Drilled)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	Total
1971	825	3,284	162	2,317	7,827	17,501	19,133	12,970	17,358	8,139	118	–	89,633
1972	645	4,708	194	2,384	10,893	18,435	23,210	7,779	15,482	5,610	238	–	89,579
1973	1,179	4,918	666	2,443	12,166	18,414	24,010	8,509	14,766	6,393	438	–	93,902
1974	1,694	5,083	1,545	2,458	13,766	18,178	24,349	9,034	13,961	7,250	829	30	98,178
1975	2,105	5,201	2,641	2,371	14,637	17,899	25,250	9,875	14,089	8,292	1,087	66	103,512
1976	1,922	5,405	3,135	2,548	15,018	18,703	26,921	9,874	15,146	8,282	1,154	74	108,184
1977	2,226	5,719	4,277	2,509	15,486	19,431	27,432	10,735	15,487	9,204	1,520	125	114,151
1978	2,204	6,056	4,664	2,697	16,467	20,742	29,248	11,195	16,648	9,488	1,615	144	121,168
1979	2,658	6,350	4,904	2,823	17,128	21,698	30,300	12,339	17,160	10,825	2,073	281	128,537
1980	2,618	6,652	5,116	3,020	18,152	23,038	32,136	12,687	18,361	11,172	2,187	335	135,474
1981	2,679	6,990	5,358	3,232	19,304	24,466	34,061	12,983	19,646	11,520	2,312	397	142,948
1982	3,297	7,283	5,634	3,654	19,931	25,347	32,394	13,891	20,031	13,034	3,022	1,528	149,046
1983	3,430	7,555	5,972	3,873	20,959	26,658	33,986	13,960	21,233	13,715	3,155	2,038	156,535
1984	4,450	7,827	6,330	4,362	21,408	27,406	33,607	15,053	21,405	15,616	3,758	3,557	164,780
1985	4,592	8,104	6,678	4,602	22,372	28,752	35,048	15,405	22,583	16,266	3,888	4,365	172,656

* Excluding North Slope drilling.

Note: Totals may not agree due to rounding.

TABLE 175

TOTAL OIL DRILLING RATE PROJECTIONS IN THE UNITED STATES*

(Case II by NPC Regions – Thousand Feet Drilled)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	Total
1971	822	3,284	158	2,589	8,076	17,501	19,133	13,602	17,358	8,607	119	–	91,249
1972	625	4,606	179	3,138	11,752	18,038	22,698	8,794	15,139	6,458	241	–	91,666
1973	1,122	4,773	580	3,642	13,721	17,878	26,272	10,104	14,518	8,140	460	–	101,209
1974	1,566	4,874	1,337	3,852	15,952	17,448	29,517	10,684	13,909	9,956	932	28	110,056
1975	1,848	4,859	2,476	3,588	17,380	16,713	30,331	11,086	13,844	11,760	1,303	61	115,249
1976	1,573	4,931	3,201	3,606	18,458	17,125	32,414	10,456	14,521	12,289	1,383	67	120,024
1977	1,763	5,151	4,576	3,312	19,431	17,717	33,480	10,831	14,539	14,192	1,730	111	126,833
1978	1,804	5,385	5,001	3,244	20,204	18,646	34,868	10,882	15,131	14,430	1,718	124	131,438
1979	2,335	5,662	5,186	3,069	20,408	19,322	34,479	11,736	15,159	15,894	2,057	233	135,539
1980	2,414	5,975	5,364	2,956	21,005	20,334	34,860	11,831	15,765	15,835	2,013	268	138,619
1981	2,491	6,316	5,548	2,878	21,697	21,399	35,174	11,899	16,374	15,717	2,020	306	141,820
1982	3,079	6,694	5,737	3,013	21,972	22,154	32,136	12,669	16,330	16,881	2,589	1,137	144,389
1983	3,167	7,103	5,933	2,978	22,684	23,280	32,384	12,641	16,924	16,367	2,648	1,473	147,583
1984	4,061	7,508	6,136	3,228	22,649	23,895	30,784	31,289	16,679	16,878	3,097	2,533	150,738
1985	4,146	7,907	6,343	3,357	23,110	25,101	31,083	13,211	17,284	15,798	3,168	3,238	153,746

* Excluding North Slope drilling.

Note: Totals may not agree due to rounding.

TABLE 176

TOTAL OIL DRILLING RATE PROJECTIONS IN THE UNITED STATES*

(Case III by NPC Regions – Thousand Feet Drilled)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	Total
1971	825	3,284	162	2,317	7,827	17,501	19,133	12,970	17,358	8,139	118	–	89,633
1972	631	4,606	189	2,332	10,653	18,038	22,698	7,621	15,139	5,492	233	–	87,632
1973	1,144	4,773	640	2,367	11,791	17,878	23,269	8,271	14,307	6,208	424	–	91,073
1974	1,627	4,874	1,464	2,349	13,179	17,448	23,279	8,662	13,340	6,950	792	28	93,992
1975	1,981	4,859	2,429	2,202	13,667	16,688	23,480	9,242	13,088	7,758	1,011	61	96,467
1976	1,775	4,903	2,791	2,301	13,689	16,913	24,352	9,031	13,677	7,585	1,044	66	98,128
1977	2,009	5,061	3,744	2,213	13,752	17,172	24,252	9,586	13,659	8,227	1,344	109	101,126
1978	1,936	5,202	3,997	2,301	14,079	17,749	25,037	9,665	14,205	8,178	1,383	121	103,853
1979	2,304	5,326	4,112	2,341	14,246	18,067	25,244	10,417	14,231	9,116	1,730	226	107,361
1980	2,197	5,437	4,191	2,435	14,690	18,670	26,066	10,493	14,800	9,211	1,776	257	110,223
1981	2,168	5,557	4,265	2,532	15,203	19,291	26,907	10,545	15,392	9,287	1,826	292	113,266
1982	2,603	5,698	4,358	2,809	15,427	19,634	25,164	11,216	15,397	10,211	2,349	1,068	115,933
1983	2,632	5,848	4,504	2,921	15,961	20,299	25,976	11,178	16,013	10,426	2,414	1,362	119,534
1984	3,368	5,983	4,684	3,228	16,044	20,490	25,288	11,736	15,839	11,676	2,832	2,279	123,448
1985	3,439	6,102	4,871	3,357	16,573	21,178	26,086	11,750	16,472	12,063	2,905	2,824	127,619

* Excluding North Slope drilling.

Note: Totals may not agree due to rounding.

TABLE 177

TOTAL OIL DRILLING RATE PROJECTIONS IN THE UNITED STATES*
(Case IV by NPC Regions – Thousand Feet Drilled)

Year	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	Total
1971	825	3,284	162	2,317	7,827	17,501	19,133	12,970	17,358	8,139	118	–	89,633
1972	593	4,332	177	2,192	10,009	16,969	21,326	7,194	14,221	5,174	218	–	82,406
1973	1,005	4,190	543	2,069	10,306	15,716	20,338	7,291	12,493	5,471	371	–	79,791
1974	1,330	3,966	1,138	1,886	10,641	14,243	18,733	7,048	10,713	5,666	638	23	76,025
1975	1,540	3,695	1,733	1,632	10,299	12,703	17,466	7,039	9,700	5,901	753	45	72,507
1976	1,354	3,460	1,830	1,590	9,758	11,901	16,921	6,546	9,448	5,489	725	45	69,068
1977	1,418	3,255	2,260	1,408	9,090	11,007	15,570	6,434	8,695	5,591	862	67	65,658
1978	1,281	3,222	2,377	1,403	8,789	10,918	15,431	6,146	8,660	5,279	853	70	64,429
1979	1,457	3,060	2,332	1,312	8,063	10,239	14,332	6,115	7,975	5,339	986	116	61,327
1980	1,321	2,905	2,227	1,253	7,636	9,744	13,630	5,746	7,616	5,004	935	117	58,135
1981	1,197	2,754	2,118	1,196	7,275	9,275	12,969	5,402	7,273	4,711	887	117	55,175
1982	1,301	2,620	2,014	1,225	6,834	8,740	11,242	5,423	6,716	4,863	1,056	369	52,404
1983	1,182	2,483	1,907	1,171	6,519	8,331	10,715	5,103	6,421	4,580	1,001	395	49,809
1984	1,392	2,391	1,835	1,208	6,142	7,877	9,787	5,164	5,929	4,746	1,103	574	48,149
1985	1,322	2,303	1,766	1,173	5,952	7,628	9,477	4,933	5,757	4,538	1,065	624	46,540

* Excluding North Slope drilling.

Note: Totals may not agree due to rounding.

TABLE 178

TOTAL OIL DRILLING RATE PROJECTIONS IN THE UNITED STATES*
(Case IVA by NPC Regions – Thousand Feet Drilled)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	Total
1971	822	3,284	158	2,589	8,076	17,501	19,133	13,602	17,358	8,607	119	–	91,249
1972	587	4,332	167	2,935	11,030	16,969	21,326	8,287	14,221	6,066	226	–	86,147
1973	986	4,190	494	3,159	11,942	15,716	22,620	8,901	12,628	7,108	399	–	88,142
1974	1,287	3,966	1,016	3,077	12,730	14,243	23,370	8,745	11,112	7,995	736	23	88,301
1975	1,456	3,695	1,667	2,686	12,771	12,703	22,304	8,558	10,235	8,716	950	45	85,787
1976	1,242	3,460	1,979	2,571	12,599	11,928	21,951	7,778	10,000	8,489	964	45	83,006
1977	1,246	3,269	2,635	2,219	12,223	11,127	20,651	7,448	9,226	9,083	1,138	68	80,333
1978	1,111	3,262	2,908	2,156	12,306	11,172	20,950	6,965	9,212	9,047	1,103	71	80,263
1979	1,317	3,124	2,914	1,960	11,552	10,600	19,896	6,882	8,494	9,428	1,245	119	77,532
1980	1,254	2,989	2,784	1,809	10,963	10,192	19,057	6,469	8,113	8,829	1,151	121	73,729
1981	1,194	2,867	2,656	1,665	10,435	9,793	17,979	6,084	7,748	8,257	1,064	122	69,862
1982	1,372	2,772	2,543	1,642	9,792	9,311	15,437	6,110	7,154	8,463	1,231	385	66,214
1983	1,307	2,669	2,425	1,510	9,334	8,951	14,584	5,752	6,839	7,916	1,130	417	62,833
1984	1,579	2,608	2,349	1,496	8,787	8,532	13,210	5,822	6,316	8,141	1,223	611	60,675
1985	1,526	2,549	2,276	1,398	8,509	8,326	12,690	5,565	6,133	7,724	1,178	669	58,541

* Excluding North Slope drilling.

Note: Totals may not agree due to rounding.

TABLE 179

OIL DRILLING RATE PROJECTIONS IN THE UNITED STATES*
(Case I—Thousand Feet Drilled)

	Oil Exploratory Drilling			Total Oil Drilling		
	Original 48 States†	Offshore & Alaska	Total	Original 48 States†	Offshore & Alaska	Total
1971	20,124	1,776	21,900	76,667	14,582	91,249
1972	23,324	1,423	24,747	83,920	9,804	93,724
1973	24,938	2,037	26,974	92,272	12,157	104,430
1974	26,633	2,634	29,267	100,890	14,201	115,091
1975	28,337	3,271	31,608	107,460	16,552	124,012
1976	30,462	3,517	33,979	116,278	16,780	133,058
1977	32,140	4,217	36,358	124,110	19,443	143,553
1978	34,551	4,534	39,084	132,339	20,721	153,059
1979	36,635	5,228	41,862	138,627	23,242	161,869
1980	39,154	5,593	44,748	145,493	24,271	169,764
1981	41,895	5,985	47,880	152,652	25,282	177,934
1982	43,546	7,207	50,753	154,848	28,726	183,575
1983	46,159	7,639	53,798	160,079	29,946	190,025
1984	48,187	8,839	57,026	161,967	34,392	196,359
1985	50,837	9,325	60,162	165,966	36,025	201,991

* Excluding North Slope drilling.

† Onshore only.

Note: Totals may not agree due to rounding.

TABLE 180

OIL DRILLING RATE PROJECTIONS IN THE UNITED STATES*
(Case I A — Thousand Feet Drilled)

	Oil Exploratory Drilling			Total Oil Drilling		
	Original 48 States†	Offshore & Alaska	Total	Original 48 States†	Offshore & Alaska	Total
1971	20,124	1,776	21,900	75,676	13,957	89,633
1972	23,324	1,423	24,747	80,960	8,618	89,579
1973	24,938	2,037	26,974	83,548	10,354	93,902
1974	26,633	2,634	29,267	85,875	12,303	98,178
1975	28,337	3,271	31,608	88,826	14,686	103,512
1976	30,462	3,517	33,979	93,177	15,006	108,184
1977	32,140	4,217	36,358	96,787	17,364	114,151
1978	34,551	4,534	39,084	102,960	18,207	121,168
1979	36,635	5,228	41,862	108,355	20,182	128,537
1980	39,154	5,593	44,748	114,719	20,775	135,474
1981	41,895	5,985	47,880	121,530	21,417	142,948
1982	43,546	7,207	50,753	124,697	24,349	149,046
1983	46,159	7,639	53,798	131,135	25,400	156,535
1984	48,187	8,839	57,026	135,390	29,390	164,780
1985	50,837	9,325	60,162	141,615	31,040	172,656

* Excluding North Slope drilling.

† Onshore only.

Note: Totals may not agree due to rounding.

TABLE 181

OIL DRILLING RATE PROJECTIONS IN THE UNITED STATES*
(Case II—Thousand Feet Drilled)

	Oil Exploratory Drilling			Total Oil Drilling		
	Original 48 States†	Offshore & Alaska	Total	Original 48 States†	Offshore & Alaska	Total
1971	20,124	1,776	21,900	76,667	14,582	91,249
1972	22,808	1,391	24,199	82,069	9,597	91,666
1973	24,162	1,973	26,135	89,404	11,806	101,209
1974	25,448	2,517	27,965	96,440	13,615	110,056
1975	26,324	3,039	29,363	99,778	15,471	115,249
1976	27,509	3,176	30,685	104,727	15,298	120,024
1977	28,346	3,720	32,065	109,551	17,282	126,833
1978	29,480	3,868	33,348	113,628	17,810	131,438
1979	30,381	4,335	34,717	116,049	19,490	135,539
1980	31,560	4,509	36,069	118,742	19,877	138,619
1981	32,823	4,689	37,512	121,575	20,245	141,820
1982	33,473	5,540	39,012	121,767	22,622	144,389
1983	34,812	5,761	40,573	124,368	23,214	147,583
1984	35,655	6,540	42,196	124,719	26,019	150,738
1985	37,082	6,802	43,884	126,807	26,939	153,746

* Excluding North Slope drilling.

† Onshore only.

Note: Totals may not agree due to rounding.

TABLE 182

OIL DRILLING RATE PROJECTIONS IN THE UNITED STATES*
(Case III—Thousand Feet Drilled)

	Oil Exploratory Drilling			Total Oil Drilling		
	Original 48 States†	Offshore & Alaska	Total	Original 48 States†	Offshore & Alaska	Total
1971	20,124	1,776	21,900	75,676	13,957	89,633
1972	22,808	1,391	24,199	79,190	8,441	87,632
1973	24,162	1,973	26,135	81,017	10,055	91,073
1974	25,448	2,517	27,965	82,211	11,781	93,992
1975	26,324	3,039	29,363	82,753	13,713	96,467
1976	27,509	3,176	30,685	84,465	13,663	98,128
1977	28,346	3,720	32,065	85,678	15,448	101,126
1978	29,480	3,868	33,348	88,133	15,719	103,853
1979	30,381	4,335	34,717	90,302	17,059	107,361
1980	31,560	4,509	36,069	93,085	17,138	110,223
1981	32,823	4,689	37,512	95,996	17,270	113,266
1982	33,473	5,540	39,012	96,689	19,244	115,933
1983	34,812	5,761	40,573	99,858	19,676	119,534
1984	35,655	6,540	42,196	101,381	22,067	123,448
1985	37,082	6,802	43,884	104,736	22,883	127,619

* Excluding North Slope drilling.

† Onshore only.

Note: Totals may not agree due to rounding.

TABLE 183

OIL DRILLING RATE PROJECTIONS IN THE UNITED STATES*
(Case IV—Thousand Feet Drilled)

	Oil Exploratory Drilling			Total Oil Drilling		
	Original 48 States†	Offshore & Alaska	Total	Original 48 States†	Offshore & Alaska	Total
1971	20,124	1,776	21,900	75,676	13,957	89,633
1972	21,425	1,307	22,732	74,442	7,965	82,406
1973	21,100	1,723	22,823	70,953	8,838	79,791
1974	20,437	2,021	22,458	66,486	9,539	76,025
1975	19,509	2,252	21,762	62,150	10,357	72,507
1976	19,002	2,194	21,196	59,292	9,775	69,068
1977	18,044	2,368	20,412	55,479	10,179	65,658
1978	17,972	2,358	20,330	54,555	9,874	64,429
1979	17,026	2,429	19,455	51,307	10,020	61,327
1980	16,241	2,320	18,561	48,723	9,412	58,135
1981	15,510	2,216	17,726	46,341	8,834	55,175
1982	14,600	2,416	17,017	43,296	9,108	52,404
1983	13,958	2,310	16,268	41,221	8,588	49,809
1984	13,348	2,448	15,796	39,184	8,964	48,149
1985	12,961	2,377	15,338	37,895	8,645	46,540

* Excluding North Slope drilling.

† Onshore only.

Note: Totals may not agree due to rounding.

TABLE 184

OIL DRILLING RATE PROJECTIONS IN THE UNITED STATES*
(Case IV A—Thousand Feet Drilled)

	Oil Exploratory Drilling			Total Oil Drilling		
	Original 48 States†	Offshore & Alaska	Total	Original 48 States†	Offshore & Alaska	Total
1971	20,124	1,776	21,900	76,667	14,582	91,429
1972	21,425	1,307	22,732	77,106	9,041	86,147
1973	21,100	1,723	22,823	77,761	10,381	88,142
1974	20,437	2,021	22,458	77,231	11,070	88,301
1975	19,509	2,252	21,762	74,061	11,726	85,787
1976	19,002	2,194	21,196	71,962	11,044	83,006
1977	18,044	2,368	20,412	68,937	11,396	80,333
1978	17,972	2,358	20,330	69,209	11,055	80,263
1979	17,026	2,429	19,455	66,300	11,232	77,532
1980	16,241	2,320	18,561	63,102	10,628	73,729
1981	15,510	2,216	17,726	59,807	10,055	69,862
1982	14,600	2,416	17,017	55,803	10,411	66,214
1983	13,958	2,310	16,268	52,932	9,901	62,833
1984	13,348	2,448	15,796	50,314	10,362	60,675
1985	12,961	2,377	15,338	48,506	10,035	58,541

* Excluding North Slope drilling.

† Onshore only.

Note: Totals may not agree due to rounding.

TABLE 185

CUMULATIVE OIL EXPLORATORY DRILLING PROJECTIONS IN THE UNITED STATES*
(Original 48 States, Offshore & Alaska by Cases—Thousand Feet Drilled)

	Cases I & I A			Cases II & III			Cases IV & IV A		
	Original 48 States†	Offshore & Alaska	Total	Original 48 States†	Offshore & Alaska	Total	Original 48 States†	Offshore & Alaska	Total
1971	20,124	1,776	21,900	20,124	1,776	21,900	20,124	1,776	21,900
1972	43,448	3,199	46,647	42,932	3,168	46,099	41,549	3,083	44,632
1973	68,386	5,236	73,621	67,094	5,141	72,235	62,649	4,806	67,455
1974	95,019	7,870	102,888	92,542	7,658	100,200	83,086	6,828	89,913
1975	123,356	11,141	134,497	118,866	10,697	129,563	102,595	9,080	111,675
1976	153,818	14,658	168,476	146,375	13,873	160,248	121,597	11,274	132,871
1977	185,958	18,875	204,833	174,721	17,592	192,313	139,641	13,641	153,283
1978	220,508	23,409	243,918	204,200	21,461	225,661	157,613	16,000	173,613
1979	257,143	28,637	285,780	234,582	25,796	260,377	174,639	18,429	193,068
1980	296,297	34,230	330,527	266,142	30,304	296,447	190,879	20,749	211,629
1981	338,192	40,215	378,407	298,965	34,993	333,958	206,389	22,965	229,354
1982	381,738	47,422	429,160	332,438	40,533	372,971	220,990	25,381	246,371
1983	427,897	55,061	482,958	367,249	46,294	413,544	234,948	27,691	262,639
1984	476,084	63,900	539,984	402,905	52,835	455,739	248,295	30,140	278,435
1985	526,921	73,226	600,147	439,986	59,637	499,623	261,256	32,517	293,773

* Excluding North Slope drilling.
† Onshore only

Note: Totals may not agree due to rounding.

TABLE 186

DRY HOLE FACTORS*

	Region 1		Region 2		Region 2A		Region 3		Region 4		Region 5	
	Expl.	Dev.	Expl.	Dev.	Expl.	Dev.	Expl.	Dev.	Expl.	Dev.	Expl.	Dev.
1950	0	0	84.11	7.11	–	–	63.57	15.20	76.96	26.40	71.68	15.48
1951	0	0	84.11	5.65	–	–	77.57	16.59	79.21	27.95	73.93	14.57
1952	0	0	83.08	4.00	–	–	80.41	16.52	80.19	25.23	74.29	16.19
1953	0	0	82.38	4.47	–	–	80.01	12.40	80.96	17.65	76.26	18.49
1954	0	0	82.56	6.92	–	–	86.24	20.86	82.07	19.39	70.37	16.22
1955	0	0	83.05	8.99	–	–	84.65	24.97	86.13	33.08	68.33	14.59
1956	0	0	79.28	5.85	–	–	81.77	20.48	88.64	30.93	72.11	14.27
1957	74.37	0	80.77	9.43	–	–	80.99	12.16	85.51	25.72	71.60	15.42
1958	72.06	0	80.70	16.80	–	–	85.45	14.16	82.41	33.35	70.81	16.68
1959	57.20	29.54	81.35	19.88	–	–	83.41	17.22	85.45	33.18	73.32	17.58
1960	57.53	7.78	80.95	14.39	–	13.67	80.78	13.42	89.16	31.71	73.93	18.65
1961	68.29	10.33	85.29	15.20	–	7.99	84.75	15.15	90.13	31.25	72.21	18.94
1962	0	33.41	87.97	10.88	80.99	0	81.61	18.29	88.19	32.51	70.14	15.64
1963	84.74	0	86.02	13.75	0	12.50	87.76	20.59	89.92	38.23	71.00	16.41
1964	63.58	28.12	87.75	16.52	91.66	18.44	85.06	21.27	88.16	39.38	72.69	17.52
1965	39.75	0	86.54	11.62	79.83	5.56	87.01	21.61	92.60	40.22	68.92	18.82
1966	78.40	3.22	91.22	10.24	91.14	0	84.20	17.32	86.20	35.79	74.61	18.03
1967	84.67	10.13	86.93	9.91	92.52	6.21	85.11	17.73	84.67	30.51	76.61	18.63
1968	87.99	6.14	92.90	10.71	93.12	0.47	89.93	21.25	87.51	26.82	76.85	18.66
1969	100.00	3.46	90.70	14.36	64.65	6.76	85.91	21.85	86.93	30.37	73.29	19.69
Avg.	70.08	8.48	84.01	10.15	87.49	5.13	83.81	17.40	86.30	30.27	72.49	16.65
Use	70.1	8.5	86.0	10.0	87.5	5.1	86.0	18.0	86.3	30.3	72.5	18.0

* $\frac{\text{Dry Hole Footage}}{\text{Total Footage}}$ x 100 separately for exploratory and development wells.

TABLE 187

DRY HOLE FACTORS*

	Region 6		Region 6A		Region 7		Regions 8,9,10		Region 11		Region 11A	
	Expl.	Dev.	Expl.	Dev.	Expl.	Dev.	Expl.	Dev.	Expl.	Dev.	Expl.	Dev.
1950	75.55	21.78	–	–	80.71	22.00	84.91	30.50	–	66.67		
1951	78.41	24.59	–	–	80.35	28.47	83.43	34.43	–	–		
1952	78.49	26.30	–	–	80.53	32.70	82.87	37.54	100.00	–		
1953	77.53	25.90	–	–	77.40	30.49	78.98	31.10	–	–		
1954	76.67	23.95	–	–	77.12	26.57	78.88	30.92	89.39	100.00		
1955	77.26	25.20	–	–	76.29	27.12	79.18	31.85	–	100.00		
1956	79.69	25.74	48.12	29.11	75.02	27.37	84.63	34.64	100.00	–		
1957	77.76	28.45	53.18	28.35	76.52	27.98	80.34	32.87	100.00	–		
1958	77.31	31.89	70.42	25.06	74.78	30.61	81.93	31.33	100.00	–		
1959	74.17	29.30	77.22	26.24	76.07	29.38	85.68	27.60	100.00	–		
1960	76.50	29.16	–	25.45	73.10	28.01	85.10	29.19	–	–		
1961	80.04	29.14	–	23.00	72.98	25.92	82.24	29.64	100.00	–		
1962	80.13	31.33	73.60	33.82	71.95	26.83	83.73	27.03	100.00	–		
1963	81.68	32.84	87.86	29.72	71.94	28.76	83.74	28.37	100.00	–		
1964	81.19	33.43	79.87	32.34	72.80	28.43	87.64	32.56	85.40	25.04		
1965	82.35	33.96	81.15	37.94	80.44	28.87	86.87	31.30	78.08	31.45		
1966	83.10	32.37	76.15	22.27	74.43	30.86	81.76	24.85	83.52	40.08		
1967	80.74	29.85	73.45	20.18	75.78	30.16	83.88	21.54	100.00	–		
1968	83.20	33.31	75.46	14.84	78.77	32.65	74.68	18.77	100.00	25.02		
1969	80.19	33.11	80.07	20.21	74.21	29.81	75.49	18.64	85.32	–		
Avg.	79.02	28.72	76.00	26.53	76.23	28.44	82.79	30.04	92.97	30.21		
Use	82.0	33.0	76.0	26.5	76.2	29.0	82.8	30.0	93.0	30.2	78.5	24.36
											Total	37.51

* $\frac{\text{Dry Hole Footage}}{\text{Total Footage}}$ x 100 separately for exploratory and development wells.

TABLE 188

TOTAL WELLS (PRODUCTIVE & DRY) DRILLED FOR OIL IN THE UNITED STATES*

History		Projection						
			Case I	Case IA	Case II	Case III	Case IV	Case IVA
1956	50,488	1971	19,352	19,000	19,352	19,000	19,000	19,352
1957	45,402	1972	19,570	18,695	19,140	18,290	17,202	17,989
1958	40,817	1973	21,692	19,428	21,024	18,846	16,524	18,316
1959	41,862	1974	23,873	20,147	22,831	19,295	15,630	18,328
1960	34,811	1975	25,835	21,173	24,009	19,742	14,868	17,872
1961	33,920	1976	27,771	22,052	25,054	20,023	14,133	17,316
1962	33,906	1977	30,061	23,178	26,594	20,566	13,425	16,873
1963	33,627	1978	31,851	24,468	27,430	21,015	13,135	16,872
1964	34,615	1979	33,584	25,844	28,238	21,648	12,464	16,337
1965	31,183	1980	34,931	27,095	28,692	22,136	11,789	15,480
1966	27,824	1981	36,268	28,419	29,144	22,640	11,167	14,619
1967	24,995	1982	37,023	29,415	29,477	23,007	10,570	13,853
1968	24,331	1983	37,763	30,744	29,812	23,614	10,026	13,098
1969	24,357	1984	38,334	32,083	30,077	24,238	9,651	12,630
1970	20,795	1985	38,920	33,376	30,239	24,938	9,303	12,133

* Excluding North Slope Drilling.

TABLE 189

TOTAL U.S. WELLS DRILLED FOR OIL

Case I

	Total Wells Drilled		
	Successful	Dry Holes	Total
1971	11,802.31	7,549.94	19,352.25
1972	11,742.31	7,827.30	19,569.61
1973	13,034.00	8,658.05	21,692.05
1974	14,364.82	9,508.61	23,873.44
1975	15,556.74	10,278.46	25,835.20
1976	16,737.91	11,033.46	27,771.37
1977	18,215.58	11,845.52	30,061.11
1978	19,286.78	12,564.36	31,851.15
1979	20,322.51	13,261.03	33,583.54
1980	21,079.26	13,851.82	34,931.08
1981	21,817.46	14,450.80	36,268.26
1982	22,226.05	14,797.18	37,023.23
1983	22,569.56	15,193.93	37,763.49
1984	22,809.99	15,524.36	38,334.35
1985	23,023.08	15,896.81	38,919.90

Case IA

	Total Wells Drilled		
	Successful	Dry Holes	Total
1971	11,547.98	7,452.07	19,000.05
1972	11,109.22	7,586.10	18,695.33
1973	11,436.50	7,991.53	19,428.04
1974	11,761.97	8,385.19	20,147.16
1975	12,295.83	8,876.83	21,172.66
1976	12,721.87	9,330.09	22,051.96
1977	13,360.65	9,817.12	23,177.78
1978	14,057.53	10,410.25	24,467.78
1979	14,810.28	11,033.30	25,843.58
1980	15,459.48	11,635.05	27,094.52
1981	16,145.80	12,273.09	28,418.89
1982	16,674.86	12,740.23	29,415.09
1983	17,385.32	13,358.74	30,744.06
1984	18,123.13	13,960.14	32,083.27
1985	18,812.39	14,563.55	33,375.95

Case II

	Total Wells Drilled		
	Successful	Dry Holes	Total
1971	11,802.31	7,549.94	19,352.25
1972	11,485.24	7,655.21	19,140.45
1973	12,633.75	8,390.28	21,024.03
1974	13,740.66	9,090.04	22,830.70
1975	14,457.40	9,552.06	24,009.45
1976	15,092.92	9,961.34	25,054.26
1977	16,115.11	10,478.82	26,593.93
1978	16,624.35	10,805.41	27,429.76
1979	17,110.80	11,126.79	28,237.59
1980	17,346.15	11,345.45	28,691.60
1981	17,576.40	11,567.52	29,143.92
1982	17,762.97	11,714.51	29,477.48
1983	17,909.32	11,902.99	29,812.31
1984	18,030.97	12,046.25	30,077.22
1985	18,053.36	12,185.47	30,238.83

Case III

	Total Wells Drilled		
	Successful	Dry Holes	Total
1971	11,547.98	7,452.07	19,000.05
1972	10,869.46	7,420.58	18,290.05
1973	11,096.80	7,749.02	18,845.82
1974	11,270.59	8,023.97	19,294.56
1975	11,474.06	8,268.01	19,742.07
1976	11,562.01	8,460.69	20,022.71
1977	11,866.88	8,698.66	20,565.54
1978	12,089.40	8,925.67	21,015.07
1979	12,432.78	9,215.39	21,648.18
1980	12,666.82	9,469.28	22,136.10
1981	12,906.30	9,733.31	22,639.60
1982	13,084.74	9,922.60	23,007.34
1983	13,395.97	10,218.00	23,613.96
1984	13,739.33	10,498.82	24,238.15
1985	14,110.41	10,827.54	24,937.95

Case IV

	Total Wells Drilled		
	Successful	Dry Holes	Total
1971	11,547.98	7,452.07	19,000.05
1972	10,225,56	6,976.48	17,202.04
1973	9,738.67	6,785.51	16,524.18
1974	9,149.39	6,480.72	15,630.10
1975	8,675.53	6,192.95	14,868.48
1976	8,197.48	5,935.39	14,132.87
1977	7,778.84	5,646.35	13,425.20
1978	7,588.11	5,546.49	13,134.60
1979	7,196.22	5,267.35	12,463.57
1980	6,795.06	4,993.60	11,788.66
1981	6,425.51	4,741.49	11,167.00
1982	6,078.82	4,491.31	10,570.13
1983	5,755.10	4,270.65	10,025.75
1984	5,537.69	4,113.18	9,650.86
1985	5,329.29	3,973.44	9,302.73

Case IVA

	Total Wells Drilled		
	Successful	Dry Holes	Total
1971	11,802.31	7,549.94	19,352.25
1972	10,795.69	7,193.76	17,989.45
1973	11,005.37	7,310.75	18,316.12
1974	11,034.97	7,293.18	18,328.15
1975	10,772.46	7,099.63	17,872.09
1976	10,427.81	6,888.61	17,316.43
1977	10,202.43	6,670.30	16,872.74
1978	10,222.82	6,649.61	16,872.43
1979	9,929.66	6,407.08	16,336.73
1980	9,403.12	6,077.15	15,480.27
1981	8,869.33	5,749.49	14,618.82
1982	8,411.55	5,441.09	13,852.64
1983	7,943.96	5,154.27	13,098.23
1984	7,665.92	4,964.07	12,629.99
1985	7,355.79	4,777.65	12,133.45

TABLE 190

TOTAL WELLS (PRODUCTIVE & DRY) DRILLED IN THE UNITED STATES*
(Case I)

	Original 48 States†	Offshore & Alaska	Total
1971	17,968	1,385	19,352
1972	18,632	939	19,570
1973	20,490	1,202	21,692
1974	22,392	1,481	23,873
1975	23,989	1,846	25,835
1976	25,801	1,971	27,771
1977	27,667	2,395	30,061
1978	29,277	2,574	31,851
1979	30,742	2,842	33,584
1980	31,958	2,974	34,931
1981	33,163	3,105	36,268
1982	33,549	3,474	37,023
1983	34,134	3,631	37,763
1984	34,233	4,102	38,334
1985	34,615	4,305	38,920

* Excluding North Slope drilling.
† Onshore only.

Note: Totals may not agree due to rounding.

TABLE 191

TOTAL WELLS (PRODUCTIVE & DRY) DRILLED IN THE UNITED STATES*
(Case I A)

	Original 48 States†	Offshore & Alaska	Total
1971	17,674	1,326	19,000
1972	17,868	828	18,695
1973	18,389	1,040	19,428
1974	18,830	1,317	20,147
1975	19,513	1,660	21,173
1976	20,308	1,745	22,052
1977	21,090	2,088	23,178
1978	22,262	2,206	24,468
1979	23,434	2,410	25,844
1980	24,613	2,482	27,095
1981	25,854	2,564	28,419
1982	26,538	2,876	29,415
1983	27,732	3,012	30,744
1984	28,650	3,434	32,083
1985	29,746	3,630	33,376

* Excluding North Slope drilling.
† Onshore only.

Note: Totals may not agree due to rounding.

TABLE 192

TOTAL WELLS (PRODUCTIVE & DRY) DRILLED IN THE UNITED STATES*
(Case II)

	Original 48 States†	Offshore & Alaska	Total
1971	17,968	1,385	19,352
1972	18,222	918	19,140
1973	19,858	1,167	21,024
1974	21,413	1,418	22,831
1975	22,293	1,717	24,009
1976	23,272	1,783	25,054
1977	24,475	2,119	26,594
1978	25,218	2,211	27,430
1979	25,856	2,382	28,238
1980	26,259	2,433	28,692
1981	26,662	2,482	29,144
1982	26,748	2,730	29,477
1983	27,006	2,806	29,812
1984	26,982	3,096	30,077
1985	27,028	3,211	30,239

* Excluding North Slope drilling.
† Onshore only.

Note: Totals may not agree due to rounding.

TABLE 193

TOTAL WELLS (PRODUCTIVE & DRY) DRILLED IN THE UNITED STATES*
(Case III)

	Original 48 States†	Offshore & Alaska	Total
1971	17,674	1,326	19,000
1972	17,479	810	18,290
1973	17,838	1,009	18,846
1974	18,036	1,259	19,295
1975	18,197	1,546	19,742
1976	18,442	1,582	20,023
1977	18,714	1,852	20,566
1978	19,112	1,902	21,015
1979	19,613	2,035	21,648
1980	20,088	2,049	22,136
1981	20,574	2,066	22,640
1982	20,740	2,267	23,007
1983	21,291	2,323	23,614
1984	21,666	2,572	24,238
1985	22,265	2,674	24,938

* Excluding North Slope drilling.
† Onshore only.

Note: Totals may not agree due to rounding.

TABLE 194

TOTAL WELLS (PRODUCTIVE & DRY) DRILLED IN THE UNITED STATES*
(Case IV)

	Original 48 States†	Offshore & Alaska	Total
1971	17,674	1,326	19,000
1972	16,437	765	17,202
1973	15,640	885	16,524
1974	14,616	1,014	15,630
1975	13,712	1,156	14,868
1976	13,020	1,113	14,133
1977	12,227	1,198	13,425
1978	11,952	1,182	13,135
1979	11,274	1,189	12,464
1980	10,668	1,120	11,789
1981	10,113	1,054	11,167
1982	9,499	1,071	10,570
1983	9,015	1,011	10,026
1984	8,612	1,039	9,651
1985	8,301	1,002	9,303

* Excluding North Slope drilling.
† Onshore only.

Note: Totals may not agree due to rounding.

TABLE 195

TOTAL WELLS (PRODUCTIVE & DRY) DRILLED IN THE UNITED STATES*
(Case IV A)

	Original 48 States†	Offshore & Alaska	Total
1971	17,968	1,385	19,352
1972	17,124	865	17,989
1973	17,292	1,024	18,316
1974	17,183	1,145	18,328
1975	16,594	1,278	17,872
1976	16,067	1,250	17,316
1977	15,517	1,356	16,873
1978	15,518	1,354	16,872
1979	14,967	1,369	16,337
1980	14,183	1,297	15,480
1981	13,390	1,229	14,619
1982	12,602	1,252	13,853
1983	11,908	1,191	13,098
1984	11,405	1,226	12,630
1985	10,946	1,187	12,133

* Excluding North Slope drilling.
† Onshore only.

Note: Totals may not agree due to rounding.

TABLE 196

TOTAL WELLS (PRODUCTIVE & DRY) DRILLED FOR OIL IN THE UNITED STATES*
(Case I by NPC Regions)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	Total
1971	69	683	33	483	1,301	3,643	3,813	1,282	4,311	3,725	10	0	19,352
1972	54	976	38	592	1,934	3,833	4,605	846	3,822	2,847	22	0	19,570
1973	98	1,017	125	687	2,276	3,824	5,356	978	3,683	3,606	41	0	21,692
1974	138	1,047	294	727	2,680	3,770	6,076	1,046	3,560	4,447	85	3	23,873
1975	165	1,069	566	686	2,998	3,719	6,406	1,108	3,623	5,367	122	7	25,835
1976	144	1,114	753	700	3,273	3,934	7,031	1,064	3,888	5,728	133	9	27,771
1977	168	1,191	1,082	645	3,511	4,165	7,343	1,130	3,962	6,677	170	14	30,061
1978	180	1,287	1,201	639	3,748	4,532	7,772	1,178	4,234	6,891	174	16	31,851
1979	239	1,392	1,274	606	3,880	4,833	7,814	1,297	4,337	7,664	214	32	33,584
1980	253	1,511	1,349	592	4,091	5,237	8,021	1,331	4,604	7,683	219	39	34,931
1981	269	1,645	1,428	588	4,326	5,668	8,198	1,360	4,876	7,632	231	47	36,268
1982	338	1,776	1,498	625	4,433	5,981	7,507	1,454	4,914	8,008	304	185	37,023
1983	353	1,908	1,571	648	4,595	6,413	7,599	1,455	5,146	7,503	321	252	37,763
1984	458	2,026	1,645	726	4,599	6,655	7,268	1,542	5,124	7,449	386	456	38,334
1985	473	2,102	1,715	762	4,701	6,957	7,315	1,535	5,337	7,037	403	581	38,920

* Excluding North Slope drilling.

Note: Totals may not agree due to rounding.

TABLE 197

TOTAL WELLS (PRODUCTIVE & DRY) DRILLED FOR OIL IN THE UNITED STATES*
(Case IA by NPC Regions)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	Total
1971	70	683	34	433	1,261	3,643	3,813	1,223	4,311	3,522	10	0	19,000
1972	55	976	41	439	1,753	3,833	4,605	733	3,822	2,419	21	0	18,695
1973	100	1,017	138	445	1,954	3,824	4,742	800	3,625	2,744	38	0	19,428
1974	143	1,047	320	444	2,206	3,770	4,786	840	3,410	3,095	72	3	20,147
1975	178	1,069	547	423	2,341	3,708	4,940	927	3,423	3,515	95	7	21,173
1976	163	1,106	647	451	2,397	3,869	5,240	926	3,659	3,486	101	9	22,052
1977	189	1,165	880	440	2,465	4,013	5,311	1,004	3,721	3,841	133	14	23,178
1978	188	1,229	957	469	2,614	4,278	5,630	1,046	3,975	3,923	142	16	24,468
1979	226	1,283	1,002	487	2,712	4,467	5,799	1,150	4,071	4,429	184	31	25,844
1980	223	1,338	1,041	516	2,866	4,736	6,113	1,180	4,328	4,520	197	37	27,095
1981	228	1,399	1,087	549	3,038	5,020	6,436	1,204	4,599	4,606	209	45	28,419
1982	281	1,450	1,139	615	3,126	5,190	6,082	1,285	4,655	5,141	277	172	29,415
1983	292	1,496	1,202	648	3,277	5,448	6,339	1,289	4,898	5,333	293	229	30,744
1984	380	1,541	1,269	726	3,336	5,589	6,227	1,385	4,900	5,976	354	399	32,083
1985	393	1,586	1,333	762	3,472	5,850	6,449	1,414	5,129	6,122	373	490	33,376

* Excluding North Slope drilling.

Note: Totals may not agree due to rounding.

TABLE 198

TOTAL WELLS (PRODUCTIVE & DRY) DRILLED FOR OIL IN THE UNITED STATES*
(Case II by NPC Regions)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	Total
1971	69	683	33	483	1,301	3,643	3,813	1,282	4,311	3,725	10	0	19,352
1972	53	956	37	579	1,891	3,750	4,504	828	3,739	2,785	20	0	19,140
1973	95	987	120	664	2,204	3,713	5,190	951	3,566	3,495	40	0	21,024
1974	133	1,005	277	696	2,558	3,619	5,805	1,004	3,399	4,252	80	3	22,831
1975	157	998	513	642	2,781	3,462	5,939	1,041	3,367	4,991	113	7	24,009
1976	134	1,010	662	639	2,947	3,543	6,317	980	3,513	5,181	121	8	25,054
1977	150	1,052	943	583	3,096	3,662	6,494	1,014	3,500	5,938	152	13	26,594
1978	154	1,095	1,027	567	3,212	3,848	6,731	1,017	3,624	5,990	152	14	27,430
1979	198	1,147	1,062	532	3,237	3,982	6,623	1,095	3,611	6,540	182	26	28,238
1980	205	1,206	1,095	508	3,323	4,185	6,663	1,102	3,735	6,457	180	30	28,692
1981	212	1,270	1,129	493	3,425	4,398	6,688	1,106	3,858	6,348	181	34	29,144
1982	262	1,341	1,164	512	3,459	4,547	6,081	1,176	3,826	6,748	235	128	29,477
1983	269	1,417	1,200	503	3,562	4,770	6,096	1,170	3,943	6,472	243	165	29,812
1984	346	1,491	1,237	542	3,548	4,888	5,766	1,228	3,865	6,593	288	285	30,077
1985	354	1,563	1,275	561	3,610	5,127	5,793	1,218	3,982	6,096	298	364	30,239

* Excluding North Slope drilling.

Note: Totals may not agree due to rounding.

TABLE 199

TOTAL WELLS (PRODUCTIVE & DRY) DRILLED FOR OIL IN THE UNITED STATES*

(Case III by NPC Regions)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	Total
1971	70	683	34	433	1,261	3,643	3,813	1,223	4,311	3,522	10	0	19,000
1972	53	956	39	430	1,714	3,750	4,504	718	3,739	2,368	20	0	18,290
1973	97	987	133	432	1,894	3,713	4,597	779	3,514	2,665	36	0	18,846
1974	138	1,005	304	424	2,113	3,619	4,578	814	3,260	2,968	68	3	19,295
1975	168	998	503	394	2,187	3,457	4,597	868	3,183	3,292	88	7	19,742
1976	151	1,004	577	408	2,185	3,499	4,746	846	3,309	3,197	92	8	20,023
1977	171	1,033	771	390	2,191	3,549	4,704	897	3,288	3,442	118	12	20,566
1978	165	1,058	821	402	2,238	3,663	4,833	904	3,402	3,395	122	13	21,015
1979	195	1,079	842	406	2,260	3,724	4,849	972	3,390	3,751	153	25	21,648
1980	187	1,097	856	419	2,324	3,843	4,982	978	3,507	3,756	158	29	22,136
1981	185	1,118	868	433	2,400	3,965	5,116	980	3,627	3,751	164	33	22,640
1982	222	1,142	884	477	2,429	4,029	4,761	1,041	3,608	4,082	213	120	23,007
1983	224	1,167	911	493	2,507	4,159	4,890	1,035	3,731	4,123	221	153	23,614
1984	287	1,188	944	542	2,513	4,192	4,737	1,085	3,670	4,561	263	256	24,238
1985	293	1,206	979	561	2,589	4,325	4,861	1,083	3,795	4,655	273	318	24,938

* Excluding North Slope drilling.

Note: Totals may not agree due to rounding.

TABLE 200

TOTAL WELLS (PRODUCTIVE & DRY) DRILLED FOR OIL IN THE UNITED STATES*

(Case IV by NPC Regions)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	Total
1971	70	683	34	433	1,261	3,643	3,813	1,223	4,311	3,522	10	0	19,000
1972	50	899	37	404	1,611	3,528	4,233	677	3,513	2,231	19	0	17,202
1973	85	867	113	378	1,655	3,264	4,021	686	3,072	2,350	32	0	16,524
1974	113	818	237	342	1,707	2,955	3,691	662	2,623	2,423	55	3	15,630
1975	131	761	360	294	1,650	2,634	3,429	661	2,366	2,513	65	5	14,868
1976	115	711	379	285	1,561	2,466	3,312	614	2,297	2,326	63	5	14,133
1977	120	667	467	251	1,452	2,279	3,039	604	2,107	2,359	75	8	13,425
1978	109	659	490	249	1,402	2,258	3,002	576	2,092	2,217	75	8	13,135
1979	124	625	480	231	1,285	2,116	2,781	573	1,921	2,231	87	13	12,464
1980	112	592	457	220	1,215	2,012	2,637	537	1,829	2,080	83	13	11,789
1981	102	560	434	209	1,156	1,915	2,503	504	1,742	1,949	79	13	11,167
1982	110	532	413	213	1,084	1,802	2,165	506	1,605	2,003	94	42	10,570
1983	101	503	390	203	1,034	1,717	2,060	476	1,531	1,878	89	44	10,026
1984	118	484	375	209	973	1,623	1,877	481	1,411	1,937	99	65	9,651
1985	113	465	360	202	942	1,571	1,815	460	1,367	1,844	96	70	9,303

* Excluding North Slope drilling.

Note: Totals may not agree due to rounding.

TABLE 201

TOTAL WELLS (PRODUCTIVE & DRY) DRILLED FOR OIL IN THE UNITED STATES*
(Case IVA by NPC Regions)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	Total
1971	70	683	33	483	1,301	3,643	3,813	1,282	4,311	3,725	10	0	19,352
1972	50	899	35	541	1,775	3,528	4,233	780	3,513	2,616	20	0	17,989
1973	84	867	103	577	1,918	3,264	4,472	838	3,105	3,054	35	0	18,316
1974	110	818	211	558	2,042	2,955	4,604	822	2,721	3,420	64	3	18,328
1975	123	761	346	484	2,046	2,634	4,379	804	2,496	3,711	83	5	17,872
1976	106	711	410	460	2,015	2,471	4,296	730	2,431	3,598	84	5	17,316
1977	106	670	545	395	1,952	2,303	4,030	699	2,236	3,832	99	8	16,873
1978	94	667	600	382	1,963	2,311	4,076	653	2,225	3,798	97	8	16,872
1979	112	638	600	345	1,840	2,190	3,861	645	2,046	3,939	110	13	16,337
1980	107	609	572	318	1,744	2,104	3,687	605	1,949	3,670	102	13	15,480
1981	101	583	545	291	1,659	2,022	3,470	568	1,856	3,416	94	14	14,619
1982	116	562	521	286	1,554	1,920	2,973	570	1,710	3,486	109	44	13,853
1983	112	541	496	261	1,481	1,845	2,803	537	1,631	3,245	101	46	13,098
1984	134	528	480	258	1,393	1,758	2,534	542	1,503	3,323	110	69	12,630
1985	130	515	465	241	1,347	1,714	2,430	519	1,456	3,138	106	75	12,133

* Excluding North Slope drilling.

Note: Totals may not agree due to rounding.

TABLE 202

AVERAGE DEPTH OF TOTAL WELLS DRILLED FOR OIL IN THE UNITED STATES*

History			Projection					
			Case I	Case IA	Case II	Case III	Case IV	Case IVA
1956	3,913	1971	4,715	4,718	4,715	4,718	4,718	4,715
1957	4,066	1972	4,789	4,792	4,789	4,791	4,790	4,789
1958	3,826	1973	4,814	4,833	4,814	4,832	4,829	4,812
1959	3,842	1974	4,821	4,873	4,820	4,871	4,864	4,818
1960	3,947	1975	4,800	4,889	4,800	4,886	4,877	4,800
1961	3,908	1976	4,791	4,906	4,791	4,901	4,887	4,794
1962	4,066	1977	4,775	4,925	4,769	4,917	4,891	4,761
1963	4,024	1978	4,805	4,952	4,792	4,942	4,905	4,757
1964	3,973	1979	4,820	4,974	4,800	4,959	4,920	4,746
1965	4,130	1980	4,860	5,000	4,831	4,979	4,931	4,763
1966	3,965	1981	4,906	5,030	4,866	5,003	4,941	4,779
1967	3,943	1982	4,958	5,067	4,898	5,039	4,958	4,780
1968	4,243	1983	5,032	5,092	4,950	5,062	4,968	4,797
1969	4,421	1984	5,122	5,136	5,012	5,093	4,989	4,804
1970	4,613	1985	5,190	5,173	5,084	5,117	5,003	4,825

* Excluding North Slope drilling.

TABLE 203

AVERAGE DEPTH OF TOTAL WELLS DRILLED FOR OIL IN THE UNITED STATES*

(Case I)

	Original 48 States†	Offshore & Alaska	Total U.S.
1971	4,267	10,529	4,715
1972	4,504	10,441	4,789
1973	4,503	10,114	4,814
1974	4,506	9,589	4,821
1975	4,480	8,966	4,800
1976	4,507	8,513	4,791
1977	4,486	8,118	4,775
1978	4,520	8,050	4,805
1979	4,509	8,178	4,820
1980	4,553	8,161	4,860
1981	4,603	8,142	4,906
1982	4,616	8,269	4,958
1983	4,690	8,247	5,032
1984	4,731	8,384	5,122
1985	4,795	8,368	5,190

* Excluding North Slope drilling.
† Onshore only.

TABLE 204

AVERAGE DEPTH OF TOTAL WELLS DRILLED FOR OIL IN THE UNITED STATES*
(Case IA)

	Original 48 States†	Offshore & Alaska	Total U.S.
1971	4,282	10,526	4,718
1972	4,531	10,408	4,792
1973	4,543	9,956	4,833
1974	4,561	9,342	4,873
1975	4,552	8,847	4,889
1976	4,588	8,599	4,906
1977	4,589	8,316	4,925
1978	4,625	8,253	4,952
1979	4,624	8,374	4,974
1980	4,661	8,370	5,000
1981	4,701	8,353	5,030
1982	4,699	8,466	5,067
1983	4,729	8,433	5,092
1984	4,726	8,559	5,136
1985	4,761	8,551	5,173

* Excluding North Slope drilling.
† Onshore only.

TABLE 205

AVERAGE DEPTH OF TOTAL WELLS DRILLED FOR OIL IN THE UNITED STATES*
(Case II)

	Original 48 States†	Offshore & Alaska	Total U.S.
1971	4,267	10,529	4,715
1972	4,504	10,454	4,789
1973	4,502	10,117	4,814
1974	4,504	9,602	4,820
1975	4,476	9,010	4,800
1976	4,500	8,580	4,791
1977	4,476	8,156	4,769
1978	4,506	8,055	4,792
1979	4,488	8,182	4,800
1980	4,522	8,170	4,831
1981	4,560	8,157	4,866
1982	4,552	8,286	4,898
1983	4,605	8,273	4,950
1984	4,622	8,404	5,012
1985	4,692	8,390	5,084

* Excluding North Slope drilling.
† Onshore only.

TABLE 206

AVERAGE DEPTH OF TOTAL WELLS DRILLED FOR OIL IN THE UNITED STATES*
(Case III)

	Original 48 States†	Offshore & Alaska	Total U.S.
1971	4,282	10,526	4,718
1972	4,531	10,421	4,791
1973	4,542	9,965	4,832
1974	4,558	9,357	4,871
1975	4,548	8,870	4,886
1976	4,580	8,637	4,901
1977	4,578	8,341	4,917
1978	4,611	8,264	4,942
1979	4,604	8,383	4,959
1980	4,634	8,364	4,979
1981	4,666	8,359	5,003
1982	4,662	8,489	5,039
1983	4,690	8,470	5,062
1984	4,679	8,580	5,093
1985	4,704	8,558	5,117

* Excluding North Slope drilling.
† Onshore only.

TABLE 207

AVERAGE DEPTH OF TOTAL WELLS DRILLED FOR OIL IN THE UNITED STATES*
(Case IV)

	Original 48 States†	Offshore & Alaska	Total U.S.
1971	4,282	10,526	4,718
1972	4,529	10,412	4,790
1973	4,537	9,986	4,829
1974	4,549	9,407	4,864
1975	4,533	8,959	4,877
1976	4,554	8,783	4,887
1977	4,537	8,497	4,891
1978	4,565	8,354	4,905
1979	4,551	8,427	4,920
1980	4,567	8,404	4,931
1981	4,582	8,381	4,941
1982	4,558	8,504	4,958
1983	4,572	8,495	4,968
1984	4,550	8,628	4,989
1985	4,565	8,628	5,003

* Excluding North Slope drilling.
† Onshore only.

TABLE 208

AVERAGE DEPTH OF TOTAL WELLS DRILLED FOR OIL IN THE UNITED STATES*
(Case IV A)

	Original 48 States†	Offshore & Alaska	Total U.S.
1971	4,267	10,529	4,725
1972	4,503	10,452	4,789
1973	4,497	10,138	4,812
1974	4,495	9,668	4,818
1975	4,463	9,175	4,800
1976	4,479	8,835	4,794
1977	4,443	8,404	4,761
1978	4,460	8,165	4,757
1979	4,430	8,205	4,746
1980	4,449	8,194	4,763
1981	4,467	8,181	4,779
1982	4,428	8,315	4,780
1983	4,445	8,313	4,797
1984	4,412	8,452	4,804
1985	4,431	8,454	4,825

* Excluding North Slope drilling
† Onshore only

TABLE 209

AVERAGE DEPTH OF TOTAL OIL DRILLING IN THE UNITED STATES*

(Case I by NPC Regions)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	All Regions
1971	11,913	4,808	4,788	5,360	6,208	4,804	5,018	10,610	4,026	2,311	11,900	0	4,715
1972	11,815	4,824	4,816	5,429	6,316	4,810	5,040	10,617	4,051	2,320	11,182	0	4,789
1973	11,786	4,836	4,824	5,485	6,228	4,815	5,063	10,633	4,073	2,330	11,585	0	4,814
1974	11,804	4,855	4,823	5,539	6,238	4,822	5,087	10,635	4,094	2,343	11,518	10,000	4,821
1975	11,848	4,867	4,823	5,599	6,253	4,827	5,111	10,650	4,116	2,359	11,508	9,429	4,800
1976	11,785	4,889	4,847	5,650	6,266	4,834	5,138	10,674	4,139	2,376	11,451	8,333	4,791
1977	11,744	4,909	4,862	5,709	6,281	4,842	5,165	10,691	4,163	2,396	11,412	9,143	4,775
1978	11,728	4,926	4,874	5,743	6,300	4,848	5,194	10,702	4,188	2,418	11,356	9,250	4,805
1979	11,749	4,950	4,894	5,792	6,316	4,857	5,225	10,723	4,215	2,444	11,238	9,094	4,820
1980	11,779	4,972	4,913	5,848	6,334	4,864	5,258	10,754	4,243	2,472	11,123	8,974	4,860
1981	11,729	4,997	4,932	5,884	6,355	4,874	5,293	10,783	4,272	2,501	11,039	8,915	4,906
1982	11,728	5,021	4,949	5,939	6,376	4,884	5,326	10,805	4,303	2,535	10,911	8,854	4,958
1983	11,720	5,049	4,966	5,977	6,397	4,894	5,362	10,834	4,335	2,572	10,745	8,901	5,032
1984	11,712	5,078	4,989	6,008	6,419	4,904	5,398	10,870	4,368	2,613	10,598	8,899	5,122
1985	11,689	5,110	5,008	6,039	6,443	4,914	5,435	10,901	4,402	2,657	10,407	8,909	5,190

* Excluding North Slope drilling.

TABLE 210

AVERAGE DEPTH OF TOTAL OIL DRILLING IN THE UNITED STATES*
(Case IA by NPC Regions)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	All Regions
1971	11,786	4,808	4,765	5,351	6,207	4,804	5,018	10,605	4,026	2,311	11,800	0	4,718
1972	11,727	4,824	4,732	5,431	6,214	4,810	5,040	10,613	4,051	2,319	11,333	0	4,792
1973	11,790	4,836	4,826	5,490	6,226	4,815	5,063	10,636	4,073	2,330	11,526	0	4,833
1974	11,846	4,855	4,828	5,536	6,240	4,822	5,088	10,641	4,094	2,342	11,514	10,000	4,873
1975	11,826	4,865	4,828	5,605	6,252	4,827	5,111	10,653	4,116	2,359	11,442	9,429	4,889
1976	11,791	4,887	4,845	5,650	6,265	4,834	5,138	10,663	4,139	2,376	11,426	8,222	4,906
1977	11,778	4,909	4,860	5,702	6,282	4,842	5,165	10,692	4,162	2,396	11,429	8,929	4,925
1978	11,723	4,928	4,874	5,751	6,300	4,849	5,195	10,703	4,188	2,419	11,373	9,000	4,952
1979	11,761	4,949	4,894	5,797	6,316	4,857	5,225	10,730	4,215	2,444	11,266	9,065	4,974
1980	11,740	4,972	4,915	5,853	6,334	4,864	5,257	10,752	4,242	2,472	11,102	9,054	5,000
1981	11,750	4,996	4,929	5,887	6,354	4,874	5,292	10,783	4,272	2,501	11,062	8,822	5,030
1982	11,733	5,023	4,946	5,941	6,376	4,884	5,326	10,810	4,303	2,535	10,910	8,884	5,067
1983	11,747	5,050	4,968	5,977	6,396	4,893	5,361	10,830	4,335	2,572	10,768	8,900	5,092
1984	11,711	5,079	4,988	6,008	6,417	4,904	5,397	10,869	4,368	2,613	10,616	8,915	5,136
1985	11,684	5,110	5,010	6,039	6,444	4,915	5,435	10,895	4,403	2,657	10,424	8,908	5,173

* Excluding North Slope drilling.

TABLE 211

AVERAGE DEPTH OF TOTAL OIL DRILLING IN THE UNITED STATES*
(Case II by NPC Regions)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	All Regions
1971	11,913	4,808	4,788	5,360	6,208	4,804	5,018	10,610	4,026	2,311	11,900	0	4,715
1972	11,792	4,818	4,838	5,420	6,215	4,810	5,040	10,621	4,049	2,319	12,050	0	4,789
1973	11,811	4,836	4,833	5,485	6,225	4,815	5,062	10,625	4,071	2,329	11,500	0	4,814
1974	11,774	4,850	4,827	5,534	6,236	4,821	5,085	10,641	4,092	2,341	11,650	9,333	4,820
1975	11,771	4,869	4,827	5,589	6,250	4,828	5,107	10,649	4,112	2,356	11,531	8,714	4,800
1976	11,739	4,882	4,835	5,643	6,263	4,833	5,131	10,669	4,134	2,372	11,430	8,375	4,791
1977	11,753	4,896	4,853	5,681	6,276	4,838	5,156	10,681	4,154	2,390	11,382	8,538	4,769
1978	11,714	4,918	4,870	5,721	6,290	4,846	5,180	10,700	4,175	2,409	11,303	8,857	4,792
1979	11,793	4,936	4,883	5,769	6,305	4,852	5,206	10,718	4,198	2,430	11,302	8,962	4,800
1980	11,776	4,954	4,899	5,819	6,321	4,859	5,232	10,736	4,221	2,452	11,183	8,933	4,831
1981	11,750	4,973	4,914	5,838	6,335	4,866	5,259	10,759	4,244	2,476	11,160	9,000	4,866
1982	11,752	4,992	4,929	5,885	6,352	4,872	5,285	10,773	4,268	2,502	11,017	8,883	4,898
1983	11,773	5,013	4,944	5,920	6,368	4,881	5,312	10,804	4,292	2,529	10,897	8,927	4,950
1984	11,737	5,036	4,960	5,956	6,384	4,889	5,339	10,822	4,315	2,560	10,753	8,888	5,012
1985	11,712	5,059	4,975	5,984	6,402	4,896	5,366	10,846	4,341	2,592	10,631	8,896	5,084

* Excluding North Slope drilling.

TABLE 212

AVERAGE DEPTH OF TOTAL OIL DRILLING IN THE UNITED STATES*
(Case III by NPC Regions)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	All Regions
1971	11,786	4,808	4,765	5,351	6,207	4,804	5,018	10,605	4,026	2,311	11,800	0	4,718
1972	11,906	4,818	4,846	5,423	6,215	4,810	5,040	10,614	4,049	2,319	11,650	0	4,791
1973	11,794	4,836	4,812	5,479	6,225	4,815	5,062	10,617	4,071	2,329	11,778	0	4,832
1974	11,790	4,850	4,816	5,540	6,237	4,821	5,085	10,641	4,092	2,342	11,647	9,333	4,871
1975	11,792	4,869	4,829	5,589	6,249	4,827	5,108	10,647	4,112	2,357	11,489	8,714	4,886
1976	11,755	4,883	4,837	5,640	6,265	4,834	5,131	10,675	4,133	2,373	11,348	8,250	4,901
1977	11,749	4,899	4,856	5,674	6,277	4,839	5,156	10,687	4,154	2,390	11,390	9,083	4,917
1978	11,733	4,917	4,868	5,724	6,291	4,845	5,180	10,691	4,175	2,409	11,336	9,308	4,942
1979	11,815	4,936	4,884	5,766	6,304	4,852	5,206	10,717	4,198	2,430	11,307	9,040	4,959
1980	11,749	4,956	4,896	5,811	6,321	4,858	5,232	10,729	4,220	2,452	11,241	8,862	4,979
1981	11,719	4,970	4,914	5,848	6,335	4,865	5,259	10,760	4,244	2,476	11,134	8,848	5,003
1982	11,725	4,989	4,930	5,889	6,351	4,873	5,285	10,774	4,267	2,501	11,028	8,900	5,039
1983	11,750	5,011	4,944	5,925	6,367	4,881	5,312	10,800	4,292	2,529	10,923	8,902	5,062
1984	11,735	5,036	4,962	5,956	6,384	4,888	5,338	10,817	4,316	2,560	10,768	8,902	5,093
1985	11,737	5,060	4,975	5,984	6,401	4,897	5,366	10,849	4,340	2,591	10,641	8,881	5,117

* Excluding North Slope drilling.

TABLE 213

AVERAGE DEPTH OF TOTAL OIL DRILLING IN THE UNITED STATES*
(Case IV by NPC Regions)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	All Regions
1971	11,786	4,808	4,765	5,351	6,207	4,804	5,018	10,605	4,026	2,311	11,800	0	4,718
1972	11,860	4,819	4,784	5,426	6,213	4,810	5,038	10,626	4,048	2,319	11,474	0	4,790
1973	11,824	4,833	4,805	5,474	6,227	4,815	5,058	10,628	4,067	2,328	11,594	0	4,829
1974	11,770	4,848	4,802	5,515	6,234	4,820	5,075	10,647	4,084	2,338	11,600	7,667	4,864
1975	11,756	4,855	4,814	5,551	6,242	4,823	5,094	10,649	4,100	2,348	11,585	9,000	4,877
1976	11,774	4,866	4,828	5,579	6,251	4,826	5,109	10,661	4,113	2,360	11,508	9,000	4,887
1977	11,817	4,880	4,839	5,610	6,260	4,830	5,123	10,652	4,127	2,370	11,493	8,375	4,891
1978	11,752	4,889	4,851	5,635	6,269	4,835	5,140	10,670	4,140	2,381	11,373	8,750	4,905
1979	11,750	4,896	4,858	5,680	6,275	4,839	5,154	10,672	4,151	2,393	11,333	8,923	4,920
1980	11,795	4,907	4,873	5,695	6,285	4,843	5,169	10,700	4,164	2,406	11,265	9,000	4,931
1981	11,735	4,918	4,880	5,722	6,293	4,843	5,181	10,718	4,175	2,417	11,228	9,000	4,941
1982	11,827	4,925	4,877	5,751	6,304	4,850	5,193	10,717	4,184	2,428	11,234	8,786	4,958
1983	11,703	4,936	4,890	5,768	6,305	4,852	5,201	10,721	4,194	2,439	11,247	8,977	4,968
1984	11,797	4,940	4,893	5,780	6,312	4,853	5,214	10,736	4,202	2,450	11,141	8,831	4,989
1985	11,699	4,953	4,906	5,807	6,318	4,856	5,221	10,724	4,211	2,461	11,094	8,914	5,003

* Excluding North Slope drilling.

TABLE 214

AVERAGE DEPTH OF TOTAL OIL DRILLING IN THE UNITED STATES*
(Case IVA by NPC Regions)

	Region 1	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-10	Region 11	Region 11A	All Regions
1971	11,743	4,808	4,788	5,360	6,208	4,804	5,018	10,610	4,026	2,311	11,900	0	4,715
1972	11,740	4,819	4,771	5,425	6,214	4,810	5,038	10,624	4,048	2,319	11,300	0	4,789
1973	11,738	4,833	4,796	5,475	6,226	4,815	5,058	10,622	4,067	2,327	11,400	0	4,812
1974	11,700	4,848	4,815	5,514	6,234	4,820	5,076	10,639	4,084	2,338	11,500	7,667	4,818
1975	11,837	4,855	4,818	5,550	6,242	4,823	5,093	10,644	4,101	2,349	11,446	9,000	4,800
1976	11,717	4,866	4,827	5,589	6,253	4,827	5,110	10,655	4,114	2,359	11,476	9,000	4,794
1977	11,755	4,879	4,835	5,618	6,262	4,832	5,124	10,655	4,126	2,370	11,495	8,500	4,761
1978	11,819	4,891	4,847	5,644	6,269	4,834	5,140	10,666	4,140	2,382	11,371	8,875	4,757
1979	11,759	4,897	4,857	5,681	6,278	4,840	5,153	10,670	4,152	2.394	11,318	9,154	4,746
1980	11,720	4,908	4,867	5,689	6,286	4,844	5,169	10,693	4,163	2,406	11,284	9,308	4,763
1981	11,822	4,918	4,873	5,722	6,290	4,843	5,181	10,711	4,175	2,417	11,319	8,714	4,779
1982	11,828	4,932	4,881	5,741	6,301	4,849	5,192	10,719	4,184	2,428	11,294	8,750	4,780
1983	11,670	4,933	4,889	5,785	6,302	4,851	5,203	10,711	4,193	2,439	11,188	9,065	4,797
1984	11,784	4,939	4,894	5,798	6,308	4,853	5,213	10,742	4,202	2,450	11,118	8,855	4,804
1985	11,738	4,950	4,895	5,801	6,317	4,858	5,222	10,723	4,212	2,461	11,113	8,920	4,825

* Excluding North Slope drilling.

Chapter Five—Section IV

Oil-in-Place Discovered

TABLE 215

OIL-IN-PLACE DISCOVERED
(Million Barrels)

This Is the High Drilling and High Finding Case

Case I

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48--Onshore															
2	66.4	97.0	103.7	110.2	116.4	125.0	136.3	151.6	171.1	193.5	217.5	240.1	260.1	277.3	292.0
3	83.5	107.1	124.7	129.4	120.9	123.7	113.8	111.0	103.0	99.0	97.2	99.1	92.5	88.8	76.3
4	157.1	247.2	310.4	386.7	444.7	488.8	527.9	567.6	591.7	628.6	670.2	693.1	726.7	737.4	765.1
5	374.3	384.9	373.3	355.5	339.2	357.0	393.1	461.5	537.5	631.6	730.9	815.4	923.0	990.0	1,044.8
6	408.0	474.1	508.6	608.3	743.5	881.1	953.0	1,010.3	993.3	992.8	982.1	865.0	844.7	781.5	756.5
7	259.0	241.6	238.2	229.9	235.0	255.3	259.4	271.9	272.3	280.8	285.6	274.3	272.1	255.2	252.0
8-10	183.4	146.5	193.1	245.6	302.8	330.9	391.6	402.4	440.4	431.3	415.6	419.2	370.4	335.3	285.7
11	4.2	8.7	16.4	32.6	45.1	48.4	62.3	64.2	79.4	80.8	83.2	105.4	106.5	121.9	119.0
Totals	1,536.1	1,707.0	1,868.4	2,098.2	2,347.7	2,610.1	2,837.3	3,040.5	3,188.8	3,338.5	3,482.3	3,511.6	3,596.0	3,587.3	3,591.3
Offshore and South Alaska															
1	169.8	138.7	268.6	426.9	621.0	692.8	911.6	944.1	1,200.1	1,161.6	1,061.1	1,111.9	946.5	1,009.6	907.2
2A	129.3	133.4	373.6	705.0	1,076.8	1,216.2	1,616.8	1,741.5	1,805.5	1,844.7	1,880.5	1,904.3	1,928.6	1,943.2	1,937.3
6A	839.1	726.2	942.5	1,033.9	1,060.2	973.1	985.5	985.2	1,030.3	991.4	933.7	894.2	782.8	742.1	673.5
11A	.0	.0	.0	7.9	17.4	19.0	31.2	34.5	64.2	72.3	81.5	287.7	347.4	554.1	647.6
Totals	1,138.2	998.2	1,584.7	2,173.6	2,775.3	2,901.1	3,545.1	3,705.3	4,100.1	4,070.0	3,956.8	4,198.1	4,005.4	4,249.0	4,165.5
Totals U.S. Ex North Slope	2,674.3	2,705.3	3,453.1	4,271.9	5,123.0	5,511.3	6,382.5	6,745.8	7,288.9	7,408.5	7,439.1	7,709.8	7,601.4	7,836.3	7,756.8
Northern Alaska															
Onshore	100.0	300.0	300.0	900.0	1,000.0	2,500.0	3,000.0	3,000.0	3,100.0	4,300.0	4,400.0	3,500.0	1,200.0	600.0	600.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	100.0	300.0	300.0	900.0	1,000.0	2,500.0	3,000.0	3,000.0	3,100.0	4,300.0	4,400.0	3,500.0	1,200.0	600.0	600.0
Totals All U.S.	2,774.3	3,005.3	3,753.1	5,171.9	6,123.0	8,011.3	9,382.5	9,745.8	10,388.9	11,708.5	11,839.1	11,209.8	8,801.4	8,436.3	8,356.8

TABLE 216

OIL-IN-PLACE DISCOVERED
(Million Barrels)

This Is the High Drilling and Low Finding Case

Case IA

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	66.4	97.0	103.7	110.2	116.3	122.7	129.4	136.3	142.0	147.6	153.9	159.1	164.1	169.3	174.1
3	70.0	68.5	67.8	64.7	58.9	60.2	56.3	57.6	57.2	58.3	59.8	64.5	64.7	68.3	67.0
4	145.3	191.2	199.8	211.8	214.6	212.8	213.3	223.7	230.2	241.2	253.3	257.9	266.7	267.1	273.3
5	374.3	384.9	373.3	355.5	335.3	334.0	331.1	337.7	336.7	339.3	343.9	342.1	343.7	340.5	348.9
6	399.9	442.0	427.2	427.1	441.0	467.1	471.7	497.0	507.4	529.7	551.6	514.9	532.8	522.2	539.6
7	238.1	187.6	164.0	150.2	148.8	156.7	157.1	165.7	167.3	175.4	184.0	183.9	190.7	187.9	192.3
8-10	168.4	114.7	128.8	143.3	160.1	154.9	165.6	163.7	178.0	172.9	166.1	176.7	177.2	191.0	190.9
11	4.2	8.3	15.0	26.8	32.6	32.6	40.9	40.8	48.3	47.7	49.2	63.2	64.5	75.7	78.3
Totals	1,466.6	1,494.3	1,479.5	1,489.6	1,507.5	1,540.9	1,565.3	1,622.5	1,667.1	1,712.1	1,761.8	1,762.3	1,804.6	1,822.1	1,864.4
Offshore and South Alaska															
1	167.1	132.5	247.1	368.2	486.6	484.8	594.4	597.5	729.7	671.3	572.4	602.0	574.5	661.0	611.0
2A	127.7	128.5	345.2	612.2	876.0	930.1	1,171.0	1,222.1	1,266.6	1,311.7	1,353.3	1,377.3	1,395.3	1,406.3	1,402.6
6A	661.1	415.0	501.5	568.3	645.1	674.1	738.0	742.2	782.4	760.7	726.5	709.8	637.9	617.3	568.0
11A	.0	.0	.0	7.9	17.2	18.6	30.2	32.8	59.5	65.2	71.4	238.4	276.8	444.7	520.6
Totals	955.8	676.1	1,093.7	1,556.5	2,024.9	2,107.6	2,533.7	2,594.7	2,838.2	2,808.8	2,723.5	2,927.5	2,884.4	3,129.3	3,102.2
Totals U.S. Ex North Slope	2,422.3	2,170.4	2,573.2	3,046.1	3,532.5	3,648.5	4,099.0	4,217.2	4,505.3	4,520.9	4,485.4	4,689.8	4,689.0	4,951.4	4,966.6
Northern Alaska															
Onshore	100.0	300.0	300.0	900.0	1,000.0	2,500.0	3,000.0	3,000.0	3,100.0	4,300.0	4,400.0	3,500.0	1,200.0	600.0	600.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	100.0	300.0	300.0	900.0	1,000.0	2,500.0	3,000.0	3,000.0	3,100.0	4,300.0	4,400.0	3,500.0	1,200.0	600.0	600.0
Totals All U.S.	2,522.3	2,470.4	2,873.2	3,946.1	4,532.5	6,148.5	7,099.0	7,217.2	7,605.3	8,820.9	8,885.4	8,189.8	5,889.0	5,551.4	5,566.6

TABLE 217

OIL-IN-PLACE DISCOVERED
(Million Barrels)

This Is the Low Drilling and High Finding Case

Case II

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	66.4	94.8	100.6	105.5	108.4	112.7	119.5	127.3	137.7	150.3	163.6	177.1	191.2	203.3	212.9
3	83.5	104.6	120.6	124.0	113.0	112.9	102.8	99.2	91.7	86.1	82.2	84.7	80.9	80.9	74.6
4	157.1	241.5	299.8	368.4	412.0	439.5	464.5	484.8	491.5	507.8	526.7	535.6	555.3	557.7	573.4
5	374.3	376.7	362.8	342.2	316.1	320.5	339.1	377.5	422.3	477.6	536.3	584.8	641.8	687.0	750.3
6	408.0	463.9	490.2	572.8	680.9	783.9	840.4	881.5	852.4	840.4	824.1	729.9	711.1	652.8	638.7
7	259.0	236.1	230.6	219.5	218.0	230.0	229.6	234.7	229.6	232.8	234.4	224.8	223.1	209.9	207.0
8-10	183.4	143.2	187.0	234.5	280.8	297.9	347.8	351.3	378.7	367.6	354.0	366.2	339.6	330.8	285.8
11	4.2	8.5	15.9	31.1	41.9	43.9	55.4	55.6	67.5	66.8	66.9	84.1	84.0	95.9	95.5
Totals	1,536.1	1,669.3	1,807.5	1,997.8	2,171.2	2,341.3	2,499.2	2,612.0	2,671.5	2,729.6	2,788.0	2,787.1	2,827.0	2,818.1	2,838.0
Offshore and South Alaska															
1	169.8	135.6	260.1	407.3	574.8	624.1	807.8	816.1	1,020.5	996.0	934.9	1,007.3	882.1	941.7	802.2
2A	129.3	130.4	361.2	671.6	995.9	1,089.9	1,419.6	1,497.8	1,527.7	1,531.4	1,530.5	1,529.1	1,533.0	1,538.4	1,539.5
6A	839.1	709.9	914.9	994.7	1,000.4	904.3	895.2	864.9	893.9	856.5	811.7	803.1	730.7	681.4	608.8
11A	.0	.0	.0	7.6	16.1	17.1	27.4	29.2	52.4	56.9	61.8	209.7	244.9	377.7	434.4
Totals	1,138.2	975.9	1,536.2	2,081.1	2,587.2	2,635.4	3,150.0	3,208.0	3,494.5	3,440.8	3,338.9	3,549.2	3,390.6	3,539.2	3,384.9
Totals U.S. Ex North Slope	2,674.3	2,645.2	3,343.6	4,078.9	4,758.4	4,976.7	5,649.2	5,820.0	6,166.0	6,170.3	6,126.8	6,336.3	6,217.6	6,357.4	6,222.9
Northern Alaska															
Onshore	100.0	300.0	300.0	700.0	700.0	1,800.0	2,400.0	2,700.0	2,700.0	3,500.0	3,400.0	2,800.0	900.0	500.0	500.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	100.0	300.0	300.0	700.0	700.0	1,800.0	2,400.0	2,700.0	2,700.0	3,500.0	3,400.0	2,800.0	900.0	500.0	500.0
Totals All U.S.	2,774.3	2,945.2	3,643.6	4,778.9	5,458.4	6,776.7	8,049.2	8,520.0	8,866.0	9,670.3	9,526.8	9,136.3	7,117.6	6,857.4	6,722.9

TABLE 218

OIL-IN-PLACE DISCOVERED
(Million Barrels)

This Is the Low Drilling and Low Finding Case

Case III

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	66.4	94.8	100.6	105.5	108.4	111.2	114.6	117.4	119.6	121.3	123.1	125.4	127.9	130.2	132.4
3	70.0	67.1	65.8	62.1	55.0	54.9	50.4	50.2	48.9	48.6	48.6	52.1	52.1	55.0	54.4
4	145.3	187.1	194.1	203.3	201.1	195.3	190.6	192.0	192.6	196.8	201.7	202.6	207.3	205.8	209.5
5	374.3	376.7	362.8	342.2	314.3	304.9	296.5	294.2	288.0	285.1	281.9	276.4	276.7	269.7	268.7
6	399.9	432.8	414.6	408.4	410.4	423.2	418.4	427.9	426.2	434.5	442.5	408.1	415.4	399.2	408.1
7	238.1	183.7	159.2	143.7	138.6	142.2	139.4	142.5	140.4	143.5	146.7	144.4	147.8	143.8	147.1
8-10	168.4	112.3	125.1	137.5	150.2	142.8	149.5	143.2	153.6	148.2	141.6	146.3	141.9	152.8	150.9
11	4.2	8.2	14.5	25.7	30.4	29.6	36.6	35.7	41.9	39.9	39.3	49.9	50.4	58.1	58.6
Totals	1,466.6	1,462.7	1,436.7	1,428.4	1,408.4	1,404.1	1,396.1	1,403.1	1,411.1	1,417.9	1,425.4	1,405.2	1,419.4	1,414.5	1,429.7
Offshore and South Alaska															
1	167.1	129.6	239.6	352.7	454.9	442.7	532.4	522.0	631.8	592.6	531.5	540.2	476.9	568.1	522.8
2A	127.7	125.6	334.1	584.7	814.6	841.7	1,039.1	1,053.8	1,065.6	1,079.5	1,091.6	1,101.5	1,108.7	1,112.8	1,113.9
6A	661.1	406.1	486.5	543.7	601.0	612.4	660.2	650.1	676.0	652.7	624.3	625.3	578.4	552.1	503.4
11A	.0	.0	.0	7.6	16.0	16.8	26.5	27.9	49.1	52.0	55.1	178.7	197.2	299.6	349.4
Totals	955.8	661.4	1,060.2	1,488.6	1,886.5	1,913.5	2,258.2	2,253.8	2,422.4	2,376.7	2,302.6	2,445.7	2,361.2	2,532.7	2,489.6
Totals U.S. Ex North Slope	2,422.3	2,124.1	2,496.9	2,917.1	3,294.9	3,317.6	3,654.3	3,656.9	3,833.5	3,794.6	3,728.0	3,850.9	3,780.5	3,947.2	3,919.2
Northern Alaska															
Onshore	100.0	300.0	300.0	700.0	700.0	1,800.0	2,400.0	2,700.0	2,700.0	3,500.0	3,400.0	2,800.0	900.0	500.0	500.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	100.0	300.0	300.0	700.0	700.0	1,800.0	2,400.0	2,700.0	2,700.0	3,500.0	3,400.0	2,800.0	900.0	500.0	500.0
Totals All U.S.	2,522.3	2,424.1	2,796.9	3,617.1	3,994.9	5,117.6	6,054.3	6,356.9	6,533.5	7,294.6	7,128.0	6,650.9	4,680.5	4,447.2	4,419.2

TABLE 219

OIL-IN-PLACE DISCOVERED
(Million Barrels)

This Is the Low Declining Drilling and Low Finding Case

Case IV

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	66.4	89.1	88.0	85.2	81.2	77.8	74.0	73.1	69.3	65.6	62.1	58.9	55.6	53.4	51.3
3	70.0	63.1	57.9	50.8	41.9	39.4	33.8	32.7	29.8	27.7	25.9	25.9	24.2	24.4	23.2
4	145.3	176.1	170.9	166.5	154.1	142.5	129.9	122.8	110.8	104.3	98.9	92.5	87.9	82.5	79.6
5	374.3	354.7	320.2	282.2	244.3	221.9	199.2	192.1	175.3	163.1	152.1	140.5	131.4	121.9	115.9
6	399.9	407.9	364.1	329.3	306.0	295.5	270.7	267.1	247.0	233.7	221.0	190.4	180.5	164.1	158.1
7	238.1	173.2	139.8	116.0	103.7	99.7	90.6	89.1	81.2	76.8	72.7	66.6	63.2	57.9	55.8
8-10	168.4	105.8	110.5	112.6	115.4	105.4	105.1	96.8	95.5	87.6	80.7	81.5	75.0	75.8	70.6
11	4.2	7.7	12.7	21.0	23.2	21.2	24.3	23.4	26.1	23.8	21.7	24.8	22.4	23.9	22.9
Totals	1,466.6	1,377.6	1,264.0	1,163.5	1,069.8	1,003.3	927.7	897.1	835.0	782.6	735.2	681.2	640.2	603.9	577.4
Offshore and South Alaska															
1	167.1	121.8	209.8	285.9	345.1	319.9	358.6	339.9	390.5	357.5	327.2	359.8	324.5	362.3	316.5
2A	127.7	117.9	290.8	468.8	606.0	585.5	670.7	661.8	624.1	585.5	550.5	521.7	492.7	472.7	453.6
6A	661.1	382.2	426.3	439.0	450.2	430.7	436.4	424.9	419.9	387.1	357.0	351.4	323.9	320.7	299.4
11A	.0	.0	.0	6.1	11.8	11.6	16.8	16.8	27.1	26.1	25.2	73.8	72.4	96.4	96.4
Totals	955.8	622.0	927.0	1,199.7	1,413.0	1,347.7	1,482.5	1,443.4	1,461.7	1,356.2	1,259.9	1,306.7	1,213.4	1,252.0	1,165.9
Totals U.S. Ex North Slope	2,422.3	1,999.6	2,191.0	2,363.2	2,482.8	2,351.0	2,410.2	2,340.5	2,296.6	2,138.8	1,995.1	1,987.9	1,853.6	1,855.9	1,743.3
Northern Alaska															
Onshore	100.0	100.0	100.0	200.0	200.0	200.0	200.0	300.0	300.0	400.0	1,800.0	2,400.0	2,700.0	2,700.0	3,500.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	100.0	100.0	100.0	200.0	200.0	200.0	200.0	300.0	300.0	400.0	1,800.0	2,400.0	2,700.0	2,700.0	3,500.0
Totals All U.S.	2,522.3	2,099.6	2,291.0	2,563.2	2,682.8	2,551.0	2,610.2	2,640.5	2,596.6	2,538.8	3,795.1	4,387.9	4,553.6	4,555.9	5,243.3

TABLE 220

OIL-IN-PLACE DISCOVERED
(Million Barrels)

This Is the Trend Drilling and High Finding Case

Case IVA

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	66.4	89.1	88.0	85.2	81.2	77.8	74.7	75.3	72.7	70.1	68.2	67.1	65.6	65.1	64.6
3	83.5	97.9	105.1	100.0	85.3	80.9	69.6	67.3	60.9	55.7	50.7	49.4	44.9	43.9	40.4
4	157.1	226.3	259.0	291.1	301.1	299.0	291.0	293.8	276.4	262.9	250.7	235.7	225.0	212.2	205.8
5	374.3	354.7	320.2	282.2	244.3	223.9	208.0	210.7	203.2	202.2	202.8	200.3	199.4	196.2	197.1
6	408.0	436.4	422.8	437.9	471.9	507.9	497.5	517.2	502.2	484.0	452.2	384.0	359.1	322.0	306.4
7	259.0	221.5	200.7	175.5	160.7	157.7	146.0	146.3	134.4	126.8	119.6	109.2	103.2	94.3	90.6
8-10	183.4	134.4	162.8	187.6	206.8	203.7	220.3	221.9	231.7	214.9	198.6	201.1	185.6	188.2	175.9
11	4.2	8.0	13.8	24.8	30.8	30.6	36.2	35.3	40.1	37.3	34.8	40.6	37.7	40.8	38.9
Totals	1,536.1	1,568.3	1,572.4	1,584.2	1,582.1	1,581.5	1,543.3	1,567.8	1,521.6	1,453.9	1,377.5	1,287.4	1,220.5	1,162.8	1,119.8
Offshore and South Alaska															
1	169.8	127.3	226.7	325.2	420.4	421.0	513.7	515.3	603.4	562.8	525.3	590.3	544.8	623.6	561.5
2A	129.3	122.4	312.9	532.9	725.8	733.0	876.1	900.7	874.5	835.2	791.4	747.3	702.3	670.5	640.3
6A	839.1	666.4	804.2	819.4	784.1	694.0	643.9	582.7	560.7	515.2	473.6	464.5	426.6	420.7	391.2
11A	.0	.0	.0	6.1	11.9	11.7	17.2	17.4	28.3	27.7	27.0	81.1	82.1	112.9	116.8
Totals	1,138.2	916.1	1,343.8	1,683.6	1,942.1	1,859.7	2,050.9	2,016.0	2,066.8	1,941.0	1,817.4	1,883.3	1,755.7	1,827.8	1,709.8
Totals U.S. Ex North Slope	2,674.3	2,484.3	2,916.2	3,267.8	3,524.3	3,441.1	3,594.2	3,583.9	3,588.4	3,394.9	3,194.9	3,170.6	2,976.2	2,990.5	2,829.6
Northern Alaska															
Onshore	100.0	100.0	100.0	200.0	200.0	200.0	200.0	300.0	300.0	400.0	1,800.0	2,400.0	2,700.0	2,700.0	3,500.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	100.0	100.0	100.0	200.0	200.0	200.0	200.0	300.0	300.0	400.0	1,800.0	2,400.0	2,700.0	2,700.0	3,500.0
Totals All U.S.	2,774.3	2,584.3	3,016.2	3,467.8	3,724.3	3,641.1	3,794.2	3,883.9	3,888.4	3,794.9	4,994.9	5,570.6	5,676.2	5,690.5	6,329.6

Chapter Five—Section V

Recovery Factors and Reserve Additions

TABLE 221

INITIAL OIL-IN-PLACE

Region	M Bbls
1	2,912
2	80,005
2A	1,936
3	5,807
4	23,915
5	106,437
6	79,656
6A	11,509
7	58,216
10	30,524
11	155

Source: Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity, produced jointly by the American Gas Association, the American Petroleum Institute and the Canadian Petroleum Association, published annually.

TABLE 222

PRIMARY RECOVERY FACTORS

Region	M Bbls
1	.230
2	.233
2A	.233
3	.220
4	.240
5	.200
6	.465
6A	.476
7	.250
10	.274
11	.330
11A	.330

Note: Primary recovery factors were developed on the basis of the judgment of the Gas Transportation Task Group.

TABLE 223

INITIAL OIL RESERVES

Region	M Bbls
1	549
2	3,786
2A	198
3	445
4	1,642
5	7,875
6	9,220
6A	2,924
7	2,114
10	617
11	31
11A	0

Source: Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United Sttaes and Canada and United States Productive Capacity, produced jointly by the American Gas Association, the American Petroleum Institute and the Canadian Petroleum Association, published annually.

TABLE 224

CUMULATIVE OIL RECOVERY EFFICIENCY— UNITED STATES*

ACTUAL

	Oil-in-Place Year-End	Cum. Production Plus Year-End Reserve	% Recovery
1956	329.5	85.2	25.9
1957	336	87.7	26.1
1958	344	90.2	26.2
1959	350	93.9	26.8
1960	356	96.3	27.0
1961	363	99.0	27.3
1962	369	101.2	27.4
1963	374	103.4	27.6
1964	329	106.0	28.0
1965	383	109.1	28.5
1966	386	112.1	29.0
1967	390	115.0	29.5
1968	392	117.5	30.0
1969	395	119.6	30.3
1970	401.2	122.7	30.6

PROJECTED

	Case IV	Case I
1971	.3100	.3100
1972	.3141	.3143
1973	.3181	.3184
1974	.3220	.3225
1975	.3259	.3264
1976	.3303	.3307
1977	.3347	.3349
1978	.3390	.3389
1979	.3433	.3427
1980	.3476	.3465
1981	.3522	.3505
1982	.3567	.3544
1983	.3612	.3582
1984	.3656	.3620
1985	.3700	.3657

* Excluding North Slope.

Application of Secondary and Tertiary Recovery

One of the very important factors influencing the results of this study is the extent to which advanced recovery processes are applied in the projection. This study continues to use the procedure developed in the Initial Appraisal to provide this analysis.* The rate of application of these factors was determined on a judgmental basis, taking into consideration the following factors.

Reservoir Characteristics of Each Region: The reservoir rock and fluid characteristics, together with the driving mechanism, determine the primary recovery expected from the reservoir and also provide a basis for estimating the increase in recovery obtainable by secondary and tertiary methods. This was used primarily to set the absolute limit of recovery that could be expected in each region. During the 15-year projection only Regions 6 and 6A were limited by this absolute cut-off. These factors were also used to help in determining the rate of application of secondary and tertiary processes to each region.

Maturity of Each Region: The application of advanced recovery processes was applied separately as secondary and tertiary. Additionally, different rates of application were made for old fields and new fields in each region. The application in old fields followed the historical trend as described in the Initial Appraisal. For the *old fields*, secondary and tertiary reserves were added by applying additional recovery factors for each region to the original oil-in-place discovered at the beginning of the projection period. For the *new fields*, it was applied to the new oil discovered. Additional recovery factors were applied for each of three 5-year intervals as was done in the Initial Appraisal. To simplify the computer calculation there was a change from the Initial Appraisal in the rate of application of advanced recovery processes to the new oil found in this study. In effect, the calculations were as follows:

> No additional recovery was applied until 5 years after the discovery, except in Region 7. During the sixth year, a portion of the discovery in the first year was added as an increased secondary reserve and in some cases as a tertiary reserve. In the eleventh year an additional increment of recovery was applied to the discovery in the first year. Region 7 (Mid-Continent Region) was an exception to this where the committee felt there was frequently no delay between the discovery of reserve and the application of advanced recovery processes to that reserve.

Although it is recognized that field operations will not actually follow this procedure, it is believed that the overall results obtained by applying this procedure will be very similar to what actually occurs in the future. The individual rates of application of secondary and tertiary recovery are shown on Table 225 which follows. The improvement in recovery percentages shown on this table were applied each year to *old fields* and a maximum of once in each five year period to the *new fields*.

The cost of adding secondary and tertiary reserves was considered as a one-time *investment* type charge at the time a project was initiated and the reserve credited. Table 547 in Chapter Seven shows the values used. A linear extrapolation was applied to obtain costs for the intervening years.

* NPC, *U.S. Energy Outlook: An Initial Appraisal* (November 1971).

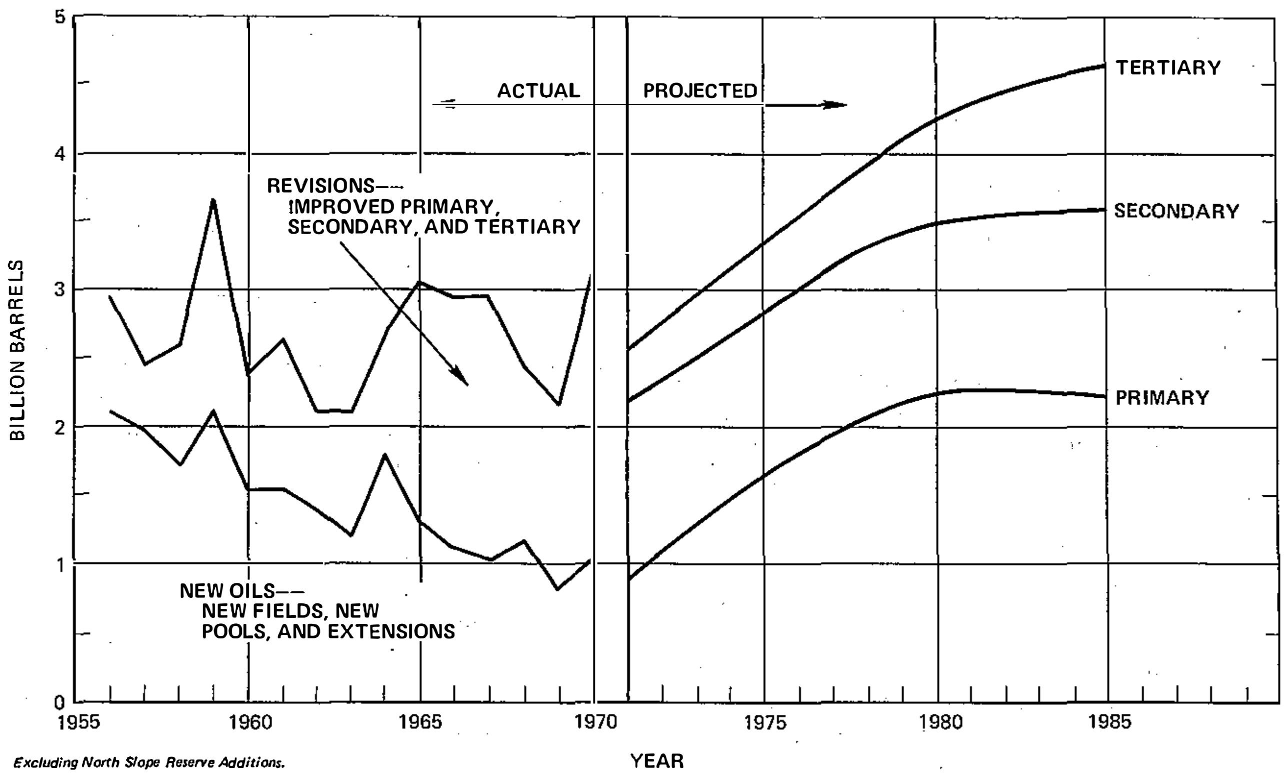


Figure 72. Oil Reserve Additions—Case I.

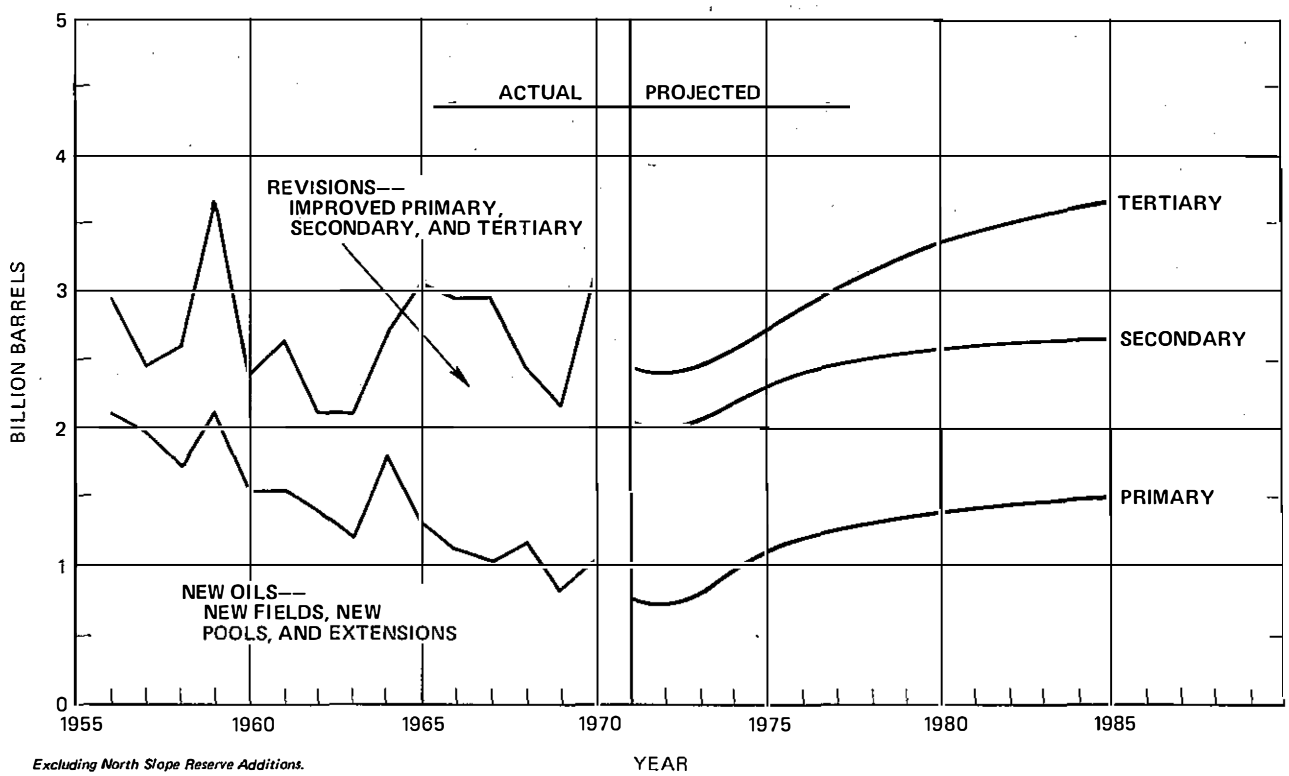


Figure 73. Oil Reserve Additions—Case I-A.

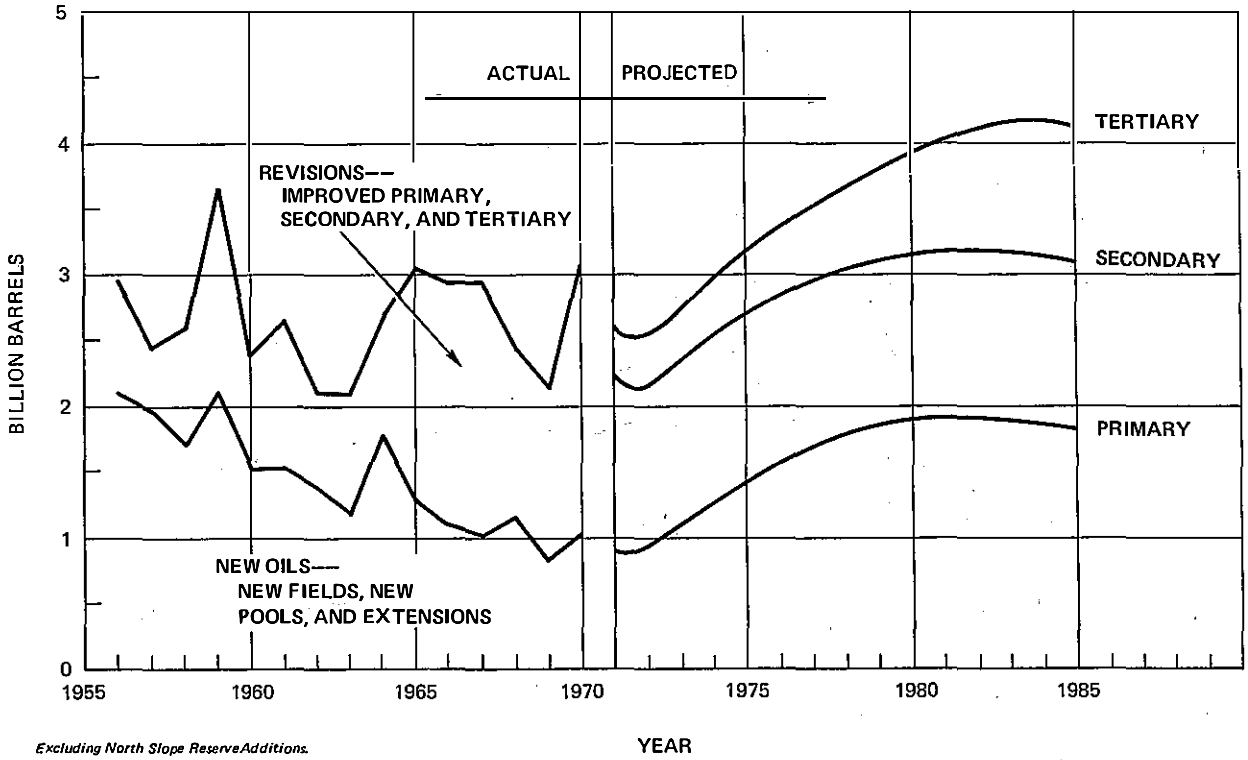


Figure 74. Oil Reserve Additions—Case II.

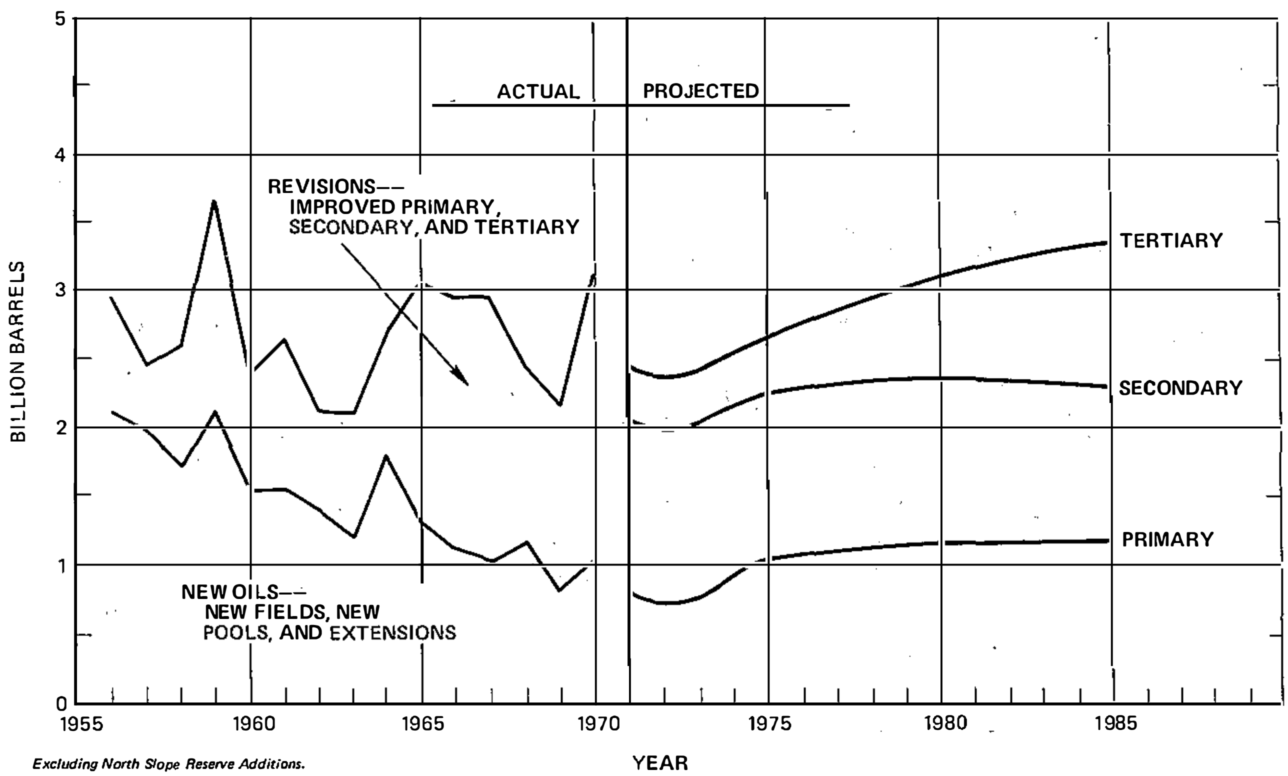


Figure 75. Oil Reserve Additions—Case III.

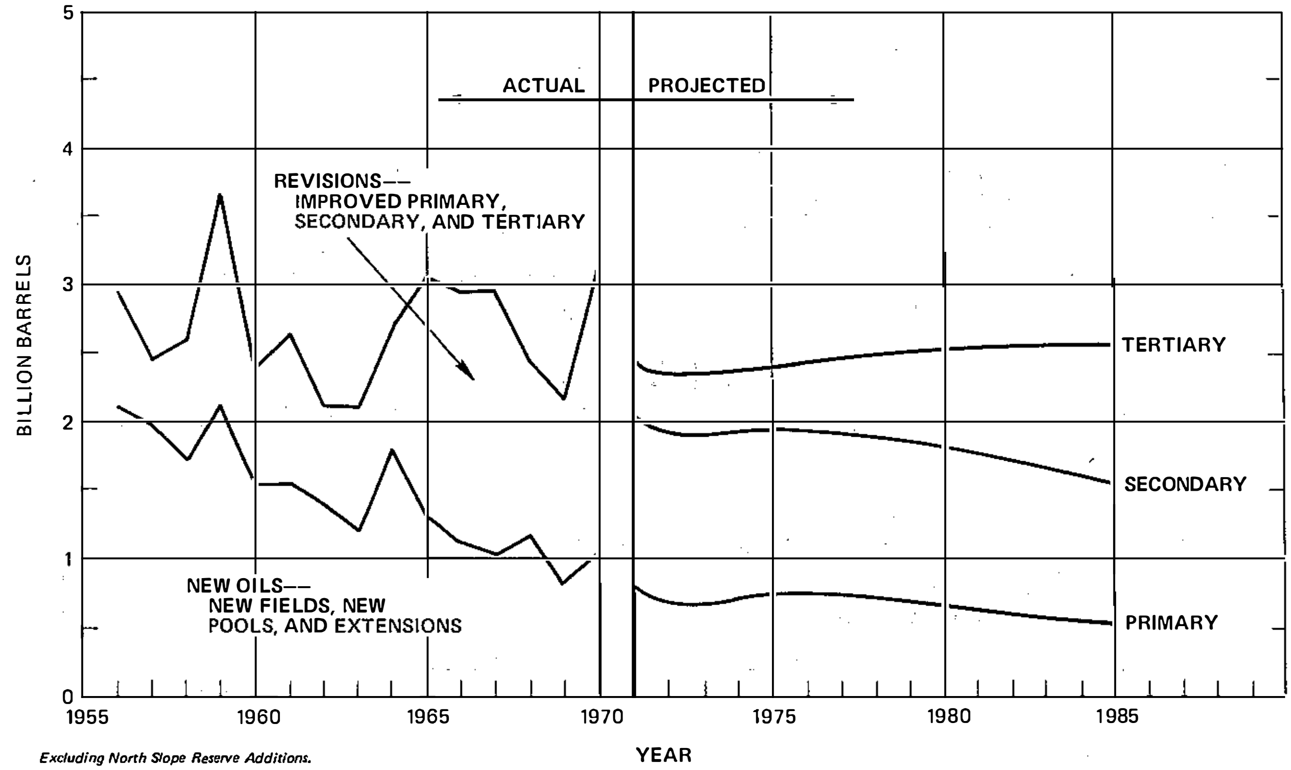


Figure 76. Oil Reserve Additions—Case IV.

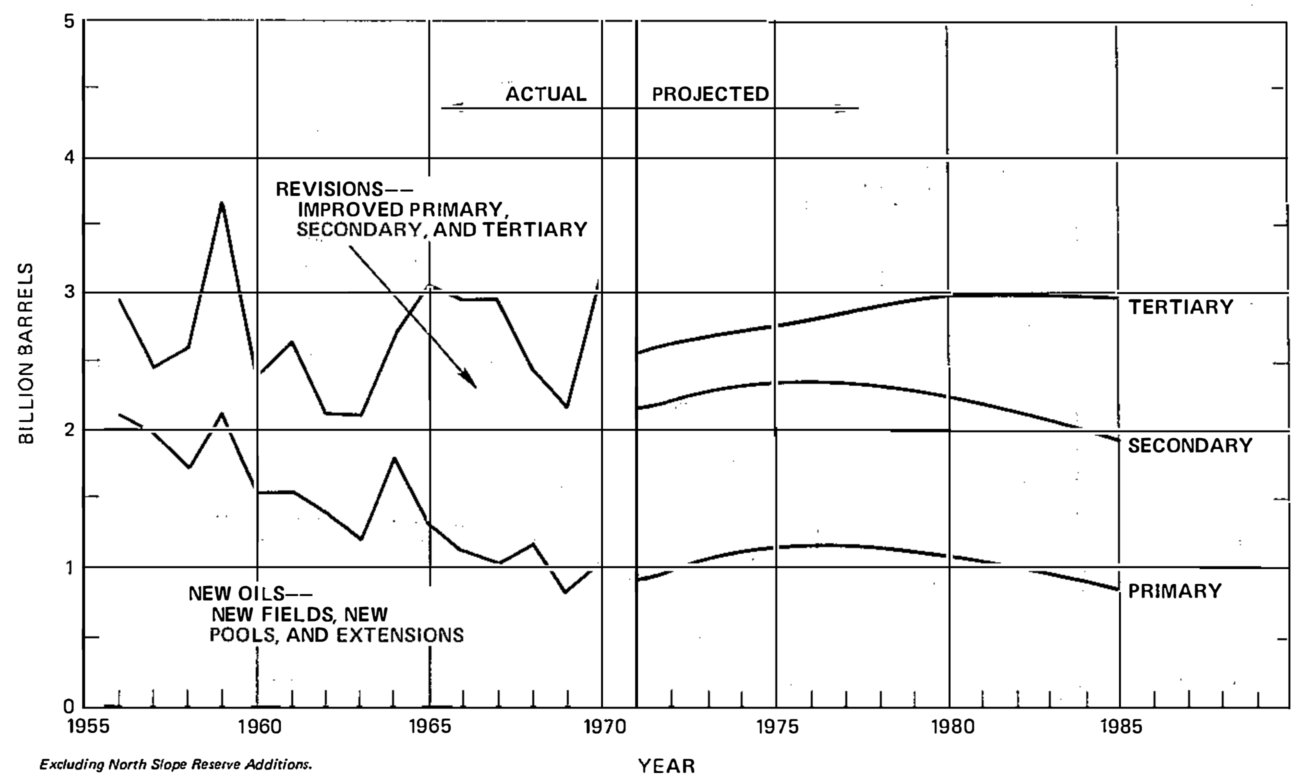


Figure 77.—Oil Reserve Additions—Case IVA.

TABLE 225

SECONDARY AND TERTIARY RECOVERY FACTORS

	Period	Secondary New* %	Secondary Old† %	Tertiary New* %	Tertiary Old† %
Region 1	1971-75	0	0.88	0	0
	1976-80	11.50	0.50	0	0
	1981-85	11.50	0	0	0
Region 2	1971-75	0	0.12	0	0.226
	1976-80	13.30	0.12	2.7	0.226
	1981-85	8.10	0.10	3.7	0.148
Region 2A	1971-75	0	0.10	0	0
	1976-80	0.80	0.20	0	0.10
	1981-85	1.16	0.40	0.54	0.10
Region 3	1971-75	0	0.30	0	0
	1976-80	7.30	0.20	0	0
	1981-85	7.30	0.08	0	0.02
Region 4	1971-75	0	0.18	0	0.02
	1976-80	6.90	0.15	1.00	0.05
	1981-85	5.86	0.10	2.34	0.10
Region 5	1971-75	0	0.30	0	0.20
	1976-80	10.00	0.20	5.00	0.30
	1981-85	4.50	0.10	4.50	0.40
Region 6	1971-75	0	0.594	0	0.006
	1976-80	1.50	0.60	0.30	0.20
	1981-85	0.45	0.60	0.15	0.40
Region 6A	1971-75	0	0.094	0	0
	1976-80	1.62	0.146	0	0
	1981-85	1.62	0.242	0	0
Region 7	1971-75	9.00	0.30	1.00	0.02
	1976-80	8.00	0.225	2.00	0.06
	1981-85	6.00	0.14	4.00	0.10
Regions 8, 9, 10	1971-75	0	0.123	0	0.011
	1976-80	8.451	0.094	0.285	0.046
	1981-85	5.57	0.062	1.32	0.078
Region 11	1971-75	0	0	0	0
	1976-80	3.30	0	0	0
	1981-85	0	0	0	0
Region 11A	1971-75	0	0	0	0
	1976-80	0	0	0	0
	1981-85	0	0	0	0

* New fields after January 1, 1971. (Percent applied one time to annual oil-in-place discovered per time delay, discussed earlier in this section).

† Old fields prior to 1971. (Percent per year applied to cumulative oil-in-place on January 1, 1971).

TABLE 226

CRUDE OIL RESERVES ADDED
(Million Barrels)

This Is the High Drilling and High Finding Case

Case I

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48–Onshore															
2	292.3	299.4	301.0	302.5	303.9	316.6	324.1	328.7	334.3	340.5	276.9	287.6	295.5	303.4	311.1
3	35.8	41.0	44.8	45.9	44.0	44.9	44.5	45.1	43.7	42.2	42.3	43.7	43.4	42.3	38.6
4	85.5	107.2	122.3	140.6	154.5	177.5	194.0	208.6	220.4	233.8	260.2	276.1	292.5	303.3	317.6
5	607.1	609.2	606.8	603.3	600.0	659.7	668.5	680.5	693.0	709.4	765.6	788.9	819.6	842.8	866.4
6	667.7	698.4	714.4	760.8	823.7	1,054.3	1,088.9	1,116.2	1,110.1	1,112.3	1,271.5	1,218.8	1,210.6	1,181.5	1,170.7
7	277.6	271.5	270.3	267.4	269.2	255.8	257.3	261.7	261.8	264.8	240.2	236.2	235.4	229.5	228.4
8-10	91.2	81.0	93.8	108.2	123.9	149.4	162.8	169.9	184.8	187.4	198.2	201.9	192.7	190.0	179.6
11	1.4	2.9	5.4	10.8	14.9	16.1	20.8	21.7	27.3	28.2	29.0	36.8	37.3	42.9	41.9
Totals	2,058.5	2,110.5	2,159.0	2,239.5	2,334.2	2,674.5	2,761.0	2,832.4	2,875.5	2,918.5	3,083.9	3,090.1	3,127.0	3,135.6	3,154.3
Offshore and South Alaska															
1	64.7	57.5	87.4	123.8	168.5	193.4	240.2	262.6	339.7	353.1	343.2	376.5	357.2	419.3	413.7
2A	32.1	33.0	89.0	166.2	252.8	290.2	383.6	414.6	432.1	444.2	459.8	468.6	479.3	488.9	494.1
6A	410.2	356.5	459.5	502.9	515.5	493.6	497.7	501.0	524.0	505.9	501.6	481.2	431.7	414.5	372.5
11A	.0	.0	.0	2.6	5.7	6.3	10.3	11.4	21.2	23.9	26.9	95.0	114.6	182.9	213.7
Totals	507.0	447.0	635.9	795.6	942.5	983.5	1,131.7	1,189.6	1,317.0	1,327.1	1,331.5	1,421.3	1,382.8	1,505.6	1,494.0
Totals U.S. Ex North Slope	2,565.5	2,557.5	2,794.8	3,035.0	3,276.6	3,658.0	3,892.8	4,021.9	4,192.4	4,245.7	4,415.5	4,511.4	4,509.8	4,641.2	4,648.3
Northern Alaska															
Onshore	30.0	100.0	100.0	300.0	340.0	840.0	1,010.0	1,010.0	1,040.0	1,440.0	1,470.0	1,240.0	400.0	200.0	200.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	30.0	100.0	100.0	300.0	340.0	840.0	1,010.0	1,010.0	1,040.0	1,440.0	1,470.0	1,240.0	400.0	200.0	200.0
Totals All U.S.	2,595.5	2,657.5	2,894.8	3,335.0	3,616.6	4,498.0	4,902.8	5,031.9	5,232.4	5,685.7	5,885.5	5,751.4	4,909.8	4,841.2	4,848.3

TABLE 227

CRUDE OIL RESERVES ADDED
(Million Barrels)

This Is the High Drilling and Low Finding Case

Case IA

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48–Onshore															
2	292.3	299.4	301.0	302.5	303.9	316.0	322.5	325.2	327.5	329.8	261.7	267.6	270.7	273.6	276.3
3	32.8	32.5	32.3	31.7	30.4	30.0	29.0	29.2	28.9	28.7	28.5	29.1	29.2	29.7	29.1
4	82.7	93.7	95.8	98.7	99.3	110.4	114.1	117.3	119.8	122.7	137.3	142.3	145.9	147.5	150.1
5	607.1	609.2	606.8	603.3	599.2	655.1	656.1	655.7	652.8	650.3	684.8	684.9	685.2	682.8	683.0
6	663.9	683.5	676.6	676.5	683.0	861.6	864.6	876.0	880.9	891.5	1,063.8	1,047.1	1,055.8	1,051.1	1,059.7
7	270.3	252.6	244.3	239.5	239.0	221.3	221.5	224.5	225.0	227.9	204.6	204.5	207.0	206.0	207.5
8-10	87.0	72.3	76.2	80.2	84.8	99.9	98.1	98.8	104.0	104.1	113.4	113.5	114.5	120.5	121.2
11	1.4	2.8	4.9	8.8	10.7	10.9	13.8	14.0	16.8	16.8	17.3	22.2	22.6	26.6	27.4
Totals	2,037.4	2,046.0	2,038.0	2,041.1	2,050.4	2,305.2	2,319.7	2,340.7	2,355.9	2,371.8	2,511.5	2,511.3	2,530.9	2,537.7	2,554.3
Offshore and South Alaska															
1	64.0	56.1	82.5	110.3	137.5	145.3	166.5	180.4	224.7	224.9	206.6	222.1	229.3	278.3	273.7
2A	31.7	31.9	82.4	144.6	206.1	223.5	279.7	293.3	305.8	318.4	334.6	342.1	350.4	357.9	361.9
6A	325.5	208.4	249.5	281.3	317.9	348.4	374.8	378.2	398.4	389.4	395.3	384.4	351.7	343.6	311.8
11A	.0	.0	.0	2.6	5.7	6.1	10.0	10.8	19.6	21.5	23.6	78.7	91.3	146.7	171.8
Totals	421.2	296.4	414.3	538.8	667.2	723.3	831.0	862.8	948.6	954.2	960.0	1,027.3	1,022.7	1,126.5	1,119.2
Totals U.S. Ex North Slope	2,458.6	2,342.3	2,452.3	2,579.9	2,717.6	3,028.6	3,150.6	3,203.5	3,304.5	3,326.0	3,471.5	3,538.6	3,553.5	3,664.2	3,673.5
Northern Alaska															
Onshore	30.0	100.0	100.0	300.0	340.0	840.0	1,010.0	1,010.0	1,040.0	1,440.0	1,470.0	1,240.0	400.0	200.0	200.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	30.0	100.0	100.0	300.0	340.0	840.0	1,010.0	1,010.0	1,040.0	1,440.0	1,470.0	1,240.0	400.0	200.0	200.0
Totals All U.S.	2,488.6	2,442.3	2,552.3	2,879.9	3,057.6	3,868.6	4,160.6	4,213.5	4,344.5	4,766.0	4,941.5	4,778.6	3,953.5	3,864.2	3,873.5

TABLE 228

CRUDE OIL RESERVES ADDED
(Million Barrels)

This Is the Low Drilling and High Finding Case

Case II

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	292.3	298.9	300.2	301.4	302.1	313.7	319.8	322.6	325.8	329.2	262.4	270.0	275.2	280.2	284.9
3	35.8	40.4	44.0	44.7	42.3	42.6	41.9	42.2	40.8	38.8	38.2	39.6	39.7	39.3	36.8
4	85.5	105.8	119.8	136.2	146.7	165.7	178.4	187.9	194.9	202.3	221.8	232.9	244.0	250.7	259.3
5	607.1	607.5	604.8	600.6	595.4	652.4	656.5	662.1	668.0	675.1	721.2	733.9	749.8	763.7	782.3
6	667.7	693.6	705.9	744.3	794.6	1,009.1	1,036.4	1,056.0	1,043.9	1,040.3	1,196.3	1,153.9	1,146.0	1,118.9	1,112.8
7	277.6	269.6	267.6	263.7	263.2	247.0	246.8	248.6	246.8	248.0	222.2	218.9	218.3	213.7	212.6
8-10	91.2	80.1	92.1	105.1	117.8	140.4	150.5	155.3	167.0	168.0	178.4	183.3	179.4	182.6	172.5
11	1.4	2.8	5.2	10.3	13.8	14.6	18.6	18.9	23.3	23.4	23.5	29.6	29.6	33.9	33.7
Totals	2,058.5	2,098.8	2,139.6	2,206.4	2,275.9	2,585.5	2,649.0	2,693.6	2,710.6	2,725.1	2,864.1	2,862.0	2,881.9	2,883.1	2,894.9
Offshore and South Alaska															
1	64.7	56.8	85.4	119.3	157.8	177.6	216.0	232.2	296.1	309.7	306.3	340.2	326.6	380.8	365.2
2A	32.1	32.3	86.1	158.4	234.0	260.8	337.6	357.7	367.1	370.6	377.2	379.5	385.0	391.8	397.6
6A	410.2	348.7	446.3	484.3	487.0	460.9	454.4	443.3	458.4	440.7	442.5	436.1	404.5	382.8	338.6
11A	.0	.0	.0	2.5	5.3	5.6	9.0	9.6	17.3	18.8	20.4	69.2	80.8	124.6	143.3
Totals	507.0	437.9	617.8	764.5	881.1	904.9	1,017.0	1,042.8	1,139.0	1,139.8	1,146.4	1,225.0	1,196.9	1,280.0	1,244.6
Totals U.S. Ex North Slope	2,565.5	2,536.7	2,757.5	2,970.9	3,160.1	3,490.4	3,666.0	3,736.5	3,849.5	3,864.9	4,010.5	4,087.0	4,078.8	4,163.0	4,139.5
Northern Alaska															
Onshore	30.0	100.0	100.0	230.0	230.0	600.0	800.0	900.0	900.0	1,170.0	1,140.0	940.0	300.0	170.0	170.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	30.0	100.0	100.0	230.0	230.0	600.0	800.0	900.0	900.0	1,170.0	1,140.0	940.0	300.0	170.0	170.0
Totals All U.S.	2,595.5	2,636.7	2,857.5	3,200.9	3,390.1	4,090.4	4,466.0	4,636.5	4,749.5	5,034.9	5,150.5	5,027.0	4,378.8	4,333.0	4,309.5

TABLE 229

CRUDE OIL RESERVES ADDED
(Million Barrels)

This Is the Low Drilling and Low Finding Case

Case III

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	292.3	298.9	300.2	301.4	302.1	313.3	318.7	320.3	321.5	322.4	252.7	257.2	258.8	260.3	261.4
3	32.8	32.2	31.9	31.1	29.5	28.8	27.6	27.5	26.9	26.3	25.6	25.8	25.7	26.0	25.4
4	82.7	92.7	94.4	96.6	96.1	106.2	108.4	109.2	110.1	110.9	123.6	126.8	128.7	129.1	130.1
5	607.1	607.5	604.8	600.6	595.0	649.3	648.0	645.5	641.1	636.4	668.0	665.9	664.3	660.1	657.0
6	663.9	679.2	670.7	667.9	668.8	841.2	839.6	843.7	842.8	846.7	1,012.3	996.5	999.9	992.3	996.6
7	270.3	251.2	242.7	237.2	235.4	216.2	215.3	216.4	215.6	216.7	191.5	190.7	191.9	190.5	191.7
8-10	87.0	71.7	75.2	78.6	82.0	96.6	93.5	92.9	96.8	96.5	105.6	103.6	102.7	107.5	107.4
11	1.4	2.7	4.8	8.5	10.0	9.9	12.3	12.3	14.7	14.2	14.0	17.7	17.8	20.5	20.6
Totals	2,037.4	2,036.1	2,024.7	2,021.9	2,019.0	2,261.6	2,263.4	2,267.6	2,269.6	2,270.0	2,393.3	2,384.2	2,389.9	2,386.4	2,390.2
Offshore and South Alaska															
1	64.0	55.4	80.7	106.7	130.3	135.6	151.9	162.2	200.4	203.2	192.4	200.4	197.3	243.9	240.7
2A	31.7	31.2	79.8	138.2	191.7	202.9	248.9	254.0	258.8	263.8	272.9	276.8	282.1	287.4	291.7
6A	325.5	204.1	242.4	269.6	296.9	319.0	337.6	334.1	347.4	337.2	345.7	342.8	321.6	310.4	278.6
11A	.0	.0	.0	2.5	5.3	5.5	8.8	9.2	16.2	17.2	18.2	59.0	65.1	98.9	115.3
Totals	421.2	290.8	402.9	517.0	624.2	663.1	747.2	759.5	822.8	821.4	829.2	878.9	866.0	940.6	926.3
Totals U.S. Ex North Slope	2,458.6	2,326.9	2,427.6	2,538.9	2,643.2	2,924.7	3,010.6	3,027.1	3,092.4	3,091.4	3,222.5	3,263.1	3,256.0	3,327.0	3,316.6
Northern Alaska															
Onshore	30.0	100.0	100.0	230.0	230.0	600.0	800.0	900.0	900.0	1,170.0	1,140.0	940.0	300.0	170.0	170.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	30.0	100.0	100.0	230.0	230.0	600.0	800.0	900.0	900.0	1,170.0	1,140.0	940.0	300.0	170.0	170.0
Totals All U.S.	2,488.6	2,426.9	2,527.6	2,768.9	2,873.2	3,524.7	3,810.6	3,927.1	3,992.4	4,261.4	4,362.5	4,203.1	3,556.0	3,497.0	3,486.6

TABLE 230

CRUDE OIL RESERVES ADDED
(Million Barrels)

This Is the Low Declining Drilling and Low Finding Case

Case IV

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	292.3	297.6	297.3	296.7	295.7	305.6	308.3	307.9	306.6	305.1	233.2	234.5	233.5	232.0	230.4
3	32.8	31.3	30.2	28.6	26.6	25.4	23.7	23.0	21.9	20.8	19.5	18.6	17.8	17.1	16.0
4	82.7	90.1	88.8	87.8	84.8	93.5	92.9	90.8	87.6	85.0	94.7	94.7	92.6	90.0	87.8
5	607.1	603.1	596.2	588.6	581.0	632.7	625.2	618.6	609.6	601.4	629.6	622.1	616.1	608.3	601.8
6	663.9	667.6	647.2	631.1	620.2	781.9	770.5	768.0	758.0	751.4	907.0	892.4	887.5	879.3	876.1
7	270.3	247.6	235.9	227.5	223.2	201.4	198.2	197.7	194.9	193.4	165.7	163.5	162.3	160.5	159.7
8-10	87.0	69.9	71.2	71.8	72.5	86.3	80.8	78.9	78.7	76.8	85.7	81.5	79.3	79.6	77.7
11	1.4	2.5	4.2	6.9	7.7	7.1	8.3	8.1	9.3	8.6	7.9	9.0	8.2	8.8	8.3
Totals	2,037.4	2,009.7	1,971.0	1,938.9	1,911.9	2,133.8	2,107.9	2,093.1	2,066.6	2,042.6	2,143.2	2,116.4	2,097.2	2,075.4	2,057.9
Offshore and South Alaska															
1	64.0	53.6	73.9	91.4	105.0	107.4	111.0	116.9	137.3	136.5	131.3	138.0	137.8	161.1	153.6
2A	31.7	29.4	69.7	111.2	143.1	143.2	163.0	162.3	155.0	147.1	144.8	138.6	134.7	132.8	130.4
6A	325.5	192.8	213.7	219.8	225.1	232.5	230.7	225.9	223.8	208.4	215.5	208.4	195.8	194.4	174.8
11A	.0	.0	.0	2.0	3.9	3.8	5.5	5.6	8.9	8.6	8.3	24.4	23.9	31.8	31.8
Totals	421.2	275.8	357.3	424.3	477.1	487.0	510.3	510.7	525.0	500.5	499.9	509.3	492.2	520.1	490.5
Totals U.S. Ex North Slope	2,458.6	2,285.5	2,328.3	2,363.3	2,389.0	2,620.8	2,618.2	2,603.8	2,591.6	2,543.1	2,643.0	2,625.7	2,589.5	2,595.5	2,548.5
Northern Alaska															
Onshore	30.0	30.0	30.0	70.0	70.0	70.0	70.0	100.0	100.0	130.0	600.0	800.0	900.0	900.0	1,170.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	30.0	30.0	30.0	70.0	70.0	70.0	70.0	100.0	100.0	130.0	600.0	800.0	900.0	900.0	1,170.0
Totals All U.S.	2,488.6	2,315.5	2,358.3	2,433.3	2,459.0	2,690.8	2,688.2	2,703.8	2,691.6	2,673.1	3,243.0	3,425.7	3,489.5	3,495.5	3,718.5

TABLE 231

CRUDE OIL RESERVES ADDED
(Million Barrels)

This Is the Trend Drilling and High Finding Case

Case IVA

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	292.3	297.6	297.3	296.7	295.7	305.6	308.5	308.4	307.4	306.1	234.6	236.5	236.1	235.3	234.3
3	35.8	39.0	40.5	39.4	36.2	35.5	34.1	34.1	32.3	30.1	29.0	28.9	28.3	27.2	25.0
4	85.5	102.1	110.0	117.7	120.1	132.0	135.5	138.8	137.2	134.7	144.5	145.9	146.3	144.5	142.7
5	607.1	603.1	596.2	588.6	581.0	633.1	627.0	622.4	615.2	609.3	640.0	635.4	632.5	627.3	623.9
6	667.7	680.9	674.5	681.5	697.4	880.8	876.4	885.4	878.6	870.8	1,018.4	986.7	975.4	958.0	950.6
7	277.6	264.5	257.2	248.4	243.2	221.7	217.6	217.7	213.5	210.9	182.1	178.4	176.3	173.2	171.9
8-10	91.2	77.7	85.5	92.3	97.6	114.6	114.8	117.8	122.6	119.7	127.6	126.3	124.2	127.5	124.0
11	1.4	2.6	4.6	8.2	10.2	10.2	12.2	12.1	14.1	13.3	12.5	14.6	13.6	14.8	14.1
Totals	2,058.5	2,067.5	2,065.9	2,072.8	2,081.4	2,333.4	2,326.2	2,336.6	2,320.8	2,294.9	2,388.6	2,352.8	2,332.7	2,307.7	2,286.4
Offshore and South Alaska															
1	64.7	54.9	77.8	100.4	122.3	130.9	147.4	159.1	190.7	192.4	188.7	209.5	210.6	250.2	242.2
2A	32.1	30.4	74.8	126.1	171.0	177.6	210.9	218.2	213.8	206.2	202.2	192.9	185.8	182.0	177.9
6A	410.2	328.0	393.6	400.9	384.0	360.7	334.1	307.2	297.0	274.8	278.1	270.2	253.4	250.5	225.9
11A	.0	.0	.0	2.0	3.9	3.9	5.7	5.7	9.3	9.1	8.9	26.8	27.1	37.3	38.6
Totals	507.0	413.4	546.2	629.4	681.3	673.1	698.1	690.2	710.9	682.5	677.9	699.3	676.9	719.9	684.6
Total U.S. Ex North Slope	2,565.5	2,480.9	2,612.1	2,702.2	2,762.7	3,006.6	3,024.2	3,026.8	3,031.7	2,977.4	3,066.5	3,052.1	3,009.6	3,027.6	2,971.0
Northern Alaska															
Onshore	30.0	30.0	30.0	70.0	70.0	70.0	70.0	100.0	100.0	130.0	600.0	800.0	900.0	900.0	1,170.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	30.0	30.0	30.0	70.0	70.0	70.0	70.0	100.0	100.0	130.0	600.0	800.0	900.0	900.0	1,170.0
Totals All U.S.	2,595.5	2,510.9	2,642.1	2,772.2	2,832.7	3,076.6	3,094.2	3,126.8	3,131.7	3,107.4	3,666.5	3,852.1	3,909.6	3,927.6	4,141.0

TABLE 232

RESERVES ADDED BY TYPE AND YEAR-END RESERVE POSITION—TOTAL U.S. BY CASES

Case I

	Primary	Secondary		Tertiary		Total Add.	Cum Res.	Cum Oil	Remaining
	New Fields Thous Bbls	Old Fields Thous Bbls	New Fields Thous Bbls	Old Fields Thous Bbls	New Fields Thous Bbls	Reserves Thous Bbls	Developed Thous Bbls	Production Thous Bbls	Reserves Thous Bbls
1971	921,166	1,200,114	23,314	418,288	2,590	2,565,473	31,966,472	3,320,061	28,646,412
1972	914,934	1,200,114	21,741	418,288	2,416	2,557,493	34,523,965	6,551,938	27,972,028
1973	1,152,599	1,200,114	21,439	418,288	2,382	2,794,823	37,318,788	9,703,430	27,615,359
1974	1,393,609	1,200,114	20,694	418,288	2,299	3,035,004	40,353,792	12,816,586	27,537,207
1975	1,634,738	1,200,114	21,151	418,288	2,350	3,276,642	43,630,433	15,927,356	27,703,077
1976	1,737,409	1,029,666	139,534	722,418	28,933	3,657,961	47,288,394	19,066,752	28,221,643
1977	1,963,730	1,029,666	145,577	722,418	31,365	3,892,756	51,181,149	22,272,446	28,908,703
1978	2,060,728	1,029,666	177,027	722,418	32,083	4,021,922	55,203,071	25,566,424	29,636,648
1979	2,197,215	1,029,666	210,551	722,418	32,587	4,192,438	59,395,509	28,953,336	30,442,173
1980	2,213,511	1,029,666	246,817	722,418	33,262	4,245,675	63,641,183	32,447,773	31,193,411
1981	2,202,018	829,242	344,355	972,016	67,832	4,415,464	68,056,647	36,041,465	32,015,182
1982	2,247,662	829,242	388,835	972,016	73,621	4,511,376	72,568,022	39,738,978	32,829,044
1983	2,191,743	829,242	435,676	972,016	81,135	4,509,812	77,077,834	43,543,169	33,534,665
1984	2,239,481	829,242	511,519	972,016	88,939	4,641,197	81,719,031	47,437,043	34,281,988
1985	2,204,018	820,081	553,900	972,016	98,283	4,648,299	86,367,330	51,430,921	34,936,407

Case IA

	Primary	Secondary		Tertiary		Total Add.	Cum Res.	Cum Oil	Remaining
	New Fields Thous Bbls	Old Fields Thous Bbls	New Fields Thous Bbls	Old Fields Thous Bbls	New Fields Thous Bbls	Reserves Thous Bbls	Developed Thous Bbls	Production Thous Bbls	Reserves Thous Bbls
1971	816,424	1,200,114	21,432	418,288	2,381	2,458,640	31,859,640	3,320,061	28,539,579
1972	705,159	1,200,114	16,886	418,288	1,876	2,342,324	34,201,963	6,537,566	27,664,397
1973	817,519	1,200,114	14,761	418,288	1,640	2,452,322	36,654,285	9,647,937	27,006,348
1974	946,525	1,200,114	13,518	418,288	1,502	2,579,948	39,234,232	12,680,224	26,554,009
1975	1,084,276	1,200,114	13,394	418,288	1,488	2,717,561	41,951,793	15,661,660	26,290,134
1976	1,124,463	1,029,666	125,242	722,418	26,777	3,028,566	44,980,359	18,616,737	26,363,623
1977	1,248,247	1,029,666	121,741	722,418	28,570	3,150,643	48,131,001	21,582,054	26,548,948
1978	1,282,823	1,029,666	140,192	722,418	28,424	3,203,524	51,334,524	24,572,282	26,762,243
1979	1,365,743	1,029,666	158,773	722,418	27,904	3,304,505	54,639,030	27,590,973	27,048,057
1980	1,369,847	1,029,666	176,772	722,418	27,338	3,326,042	57,965,071	30,650,076	27,314,996
1981	1,359,146	829,242	253,540	972,016	57,558	3,471,502	61,436,572	33,745,781	27,690,791
1982	1,412,178	829,242	265,499	972,016	59,677	3,538,612	64,975,184	36,887,895	28,087,290
1983	1,402,753	829,242	287,632	972,016	61,904	3,553,548	68,528,732	40,081,672	28,447,060
1984	1,474,118	829,242	325,461	972,016	63,382	3,664,219	72,192,952	43,322,100	28,870,851
1985	1,477,315	820,081	338,991	972,016	65,050	3,673,453	75,866,403	46,621,560	29,244,844

TABLE 232 (CONT'D)

RESERVES ADDED BY TYPE AND YEAR-END RESERVE POSITION—TOTAL U.S. BY CASES

Case II

	Primary	Secondary		Tertiary		Total Add.	Cum Res.	Cum Oil	Remaining
	New Fields Thous Bbls	Old Fields Thous Bbls	New Fields Thous Bbls	Old Fields Thous Bbls	New Fields Thous Bbls	Reserves Thous Bbls	Developed Thous Bbls	Production Thous Bbls	Reserves Thous Bbls
1971	921,166	1,200,114	23,314	418,288	2,590	2,565,473	31,966,472	3,320,061	28,646,412
1972	894,652	1,200,114	21,250	418,288	2,361	2,536,666	34,503,138	6,551,938	27,951,200
1973	1,116,013	1,200,114	20,751	418,288	2,306	2,757,472	37,260,611	9,700,795	27,559,816
1974	1,330,548	1,200,114	19,752	418,288	2,195	2,970,897	40,231,507	12,806,903	27,424,604
1975	1,519,868	1,200,114	19,622	418,288	2,180	3,160,072	43,391,579	15,903,390	27,488,190
1976	1,572,396	1,029,666	137,513	722,418	28,428	3,490,422	46,882,001	19,015,461	27,866,540
1977	1,743,269	1,029,666	140,427	722,418	30,203	3,665,984	50,547,984	22,176,158	28,371,827
1978	1,784,584	1,029,666	169,229	722,418	30,553	3,736,450	54,284,433	25,402,037	28,882,398
1979	1,867,980	1,029,666	198,833	722,418	30,618	3,849,516	58,133,949	28,693,223	29,440,727
1980	1,855,522	1,029,666	226,940	722,418	30,351	3,864,898	61,998,846	32,060,000	29,938,847
1981	1,829,072	829,242	317,383	972,016	62,746	4,010,459	66,009,306	35,494,028	30,515,279
1982	1,868,497	829,242	350,528	972,016	66,734	4,087,017	70,096,323	39,001,872	31,094,451
1983	1,819,871	829,242	385,731	972,016	71,943	4,078,803	74,175,126	42,587,488	31,587,638
1984	1,838,722	829,242	445,779	972,016	77,282	4,163,042	78,338,167	46,237,516	32,100,651
1985	1,788,555	820,081	476,009	972,016	82,845	4,139,506	82,477,673	49,958,491	32,519,183

Case III

	Primary	Secondary		Tertiary		Total Add.	Cum Res.	Cum Oil	Remaining
	New Fields Thous Bbls	Old Fields Thous Bbls	New Fields Thous Bbls	Old Fields Thous Bbls	New Fields Thous Bbls	Reserves Thous Bbls	Developed Thous Bbls	Production Thous Bbls	Reserves Thous Bbls
1971	816,424	1,200,114	21,432	418,288	2,381	2,458,640	31,859,640	3,320,061	28,539,579
1972	690,151	1,200,114	16,535	418,288	1,837	2,326,926	34,186,565	6,537,566	27,648,999
1973	793,234	1,200,114	14,329	418,288	1,592	2,427,558	36,614,123	9,646,024	26,968,098
1974	906,140	1,200,114	12,935	418,288	1,437	2,538,915	39,153,037	12,673,514	26,479,524
1975	1,010,943	1,200,114	12,476	418,288	1,386	2,643,208	41,796,245	15,645,534	26,150,712
1976	1,022,024	1,029,666	124,078	722,418	26,485	2,924,671	44,720,916	18,582,869	26,138,046
1977	1,112,849	1,029,666	117,982	722,418	27,674	3,010,589	47,731,505	21,519,497	26,212,008
1978	1,113,173	1,029,666	134,633	722,418	27,248	3,027,139	50,758,644	24,466,821	26,291,823
1979	1,163,186	1,029,666	150,675	722,418	26,414	3,092,360	53,851,003	27,425,678	26,425,326
1980	1,150,545	1,029,666	163,629	722,418	25,180	3,091,438	56,942,442	30,405,462	26,536,980
1981	1,130,333	829,242	236,941	972,016	53,958	3,222,490	60,164,932	33,402,536	26,762,396
1982	1,164,518	829,242	242,388	972,016	54,934	3,263,099	63,428,030	36,428,129	26,999,902
1983	1,140,341	829,242	258,304	972,016	56,072	3,255,975	66,684,005	39,485,579	27,198,426
1984	1,179,980	829,242	289,107	972,016	56,665	3,327,010	70,011,015	42,569,123	27,441,892
1985	1,168,777	820,081	298,738	972,016	56,961	3,316,573	73,327,588	45,688,244	27,639,344

TABLE 232 (CONT'D)

RESERVES ADDED BY TYPE AND YEAR-END RESERVE POSITION—TOTAL U.S. BY CASES

Case IV

	Primary	Secondary		Tertiary		Total Add.	Cum Res.	Cum Oil	Remaining
	New Fields Thous Bbls	Old Fields Thous Bbls	New Fields Thous Bbls	Old Fields Thous Bbls	New Fields Thous Bbls	Reserves Thous Bbls	Developed Thous Bbls	Production Thous Bbls	Reserves Thous Bbls
1971	816,424	1,200,114	21,432	418,288	2,381	2,458,640	31,859,640	3,320,061	28,539,579
1972	649,798	1,200,114	15,590	418,288	1,732	2,285,522	34,145,162	6,537,566	27,607,596
1973	695,948	1,200,114	12,582	418,288	1,398	2,328,331	36,473,493	9,640,880	26,832,612
1974	733,251	1,200,114	10,441	418,288	1,160	2,363,255	38,836,747	12,651,349	26,185,398
1975	760,210	1,200,114	9,337	418,288	1,037	2,388,987	41,225,734	15,586,106	25,639,627
1976	722,395	1,029,666	120,682	722,418	25,637	2,620,798	43,846,531	18,458,360	25,388,172
1977	733,095	1,029,666	107,783	722,418	25,240	2,618,202	46,464,733	21,299,613	25,165,120
1978	713,003	1,029,666	115,446	722,418	23,283	2,603,817	49,068,549	24,113,680	24,954,869
1979	698,350	1,029,666	120,122	722,418	21,006	2,591,564	51,660,113	26,902,556	24,757,557
1980	650,277	1,029,666	121,996	722,418	18,732	2,543,089	54,203,201	29,669,686	24,533,515
1981	606,320	829,242	190,518	972,016	44,928	2,643,024	56,846,225	32,411,387	24,434,838
1982	601,367	829,242	180,004	972,016	43,056	2,625,685	59,471,910	35,141,403	24,330,507
1983	560,790	829,242	185,772	972,016	41,645	2,589,465	62,061,374	37,860,297	24,201,078
1984	559,322	829,242	195,627	972,016	39,331	2,595,539	64,656,913	40,564,729	24,092,184
1985	526,539	820,081	192,830	972,016	37,009	2,548,475	67,205,387	43,259,222	23,946,166

Case IVA

	Primary	Secondary		Tertiary		Total Add.	Cum Res.	Cum Oil	Remaining
	New Fields Thous Bbls	Old Fields Thous Bbls	New Fields Thous Bbls	Old Fields Thous Bbls	New Fields Thous Bbls	Reserves Thous Bbls	Developed Thous Bbls	Production Thous Bbls	Reserves Thous Bbls
1971	921,166	1,200,114	23,314	418,288	2,590	2,565,473	31,966,472	3,320,061	28,646,412
1972	840,305	1,200,114	19,937	418,288	2,215	2,480,861	34,447,332	6,551,938	27,895,395
1973	973,622	1,200,114	18,063	418,288	2,007	2,612,095	37,059,428	9,693,734	27,365,693
1974	1,066,209	1,200,114	15,798	418,288	1,755	2,702,165	39,761,592	12,775,140	26,986,453
1975	1,128,201	1,200,114	14,467	418,288	1,607	2,762,678	42,524,271	15,815,804	26,708,466
1976	1,095,785	1,029,666	131,727	722,418	26,981	3,006,578	45,530,847	18,828,466	26,702,382
1977	1,118,778	1,029,666	126,344	722,418	27,017	3,024,224	48,555,071	21,841,218	26,713,853
1978	1,105,995	1,029,666	143,133	722,418	25,633	3,026,845	51,581,916	24,856,680	26,725,236
1979	1,099,907	1,029,666	155,851	722,418	23,856	3,031,699	54,613,614	27,874,843	26,738,772
1980	1,038,534	1,029,666	164,797	722,418	21,960	2,977,376	57,590,991	30,898,213	26,692,779
1981	973,393	829,242	242,008	972,016	49,884	3,066,544	60,657,533	33,918,758	26,738,776
1982	955,266	829,242	246,125	972,016	49,456	3,052,104	63,709,638	36,945,961	26,763,677
1983	894,174	829,242	264,126	972,016	50,016	3,009,574	66,719,210	39,979,618	26,739,593
1984	890,534	829,242	286,295	972,016	49,498	3,027,585	69,746,795	43,013,163	26,733,633
1985	842,024	820,081	288,140	972,016	48,722	2,970,983	72,717,777	46,051,839	26,665,939

TABLE 233

GAS/OIL RATIOS—Discovery by Regions

	Gas/Oil Ratio (CF/Bbl)
Region 1	435
Region 2	963
Region 2A	872
Region 3	686
Region 4	1,051
Region 5	2,109
Region 6	1,302
Region 6A	1,425
Region 7	3,260
Regions 8, 9, 10	739
Region 11*	800
Region 11A*	800

* Direct estimate.

Note: These figures were obtained by dividing the annual gas reserves added from drilling for each region by the oil reserves added by drilling for that same region. Gas reserves were obtained from Table III 6A the "Report of the Committee on Natural Gas Reserves of the American Gas Association." Oil reserves were obtained from Table I the "Report of the Committee on Reserves and Productive Capacity of the American Petroleum Institute." These reports appear in the joint publication, Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas In the United States and Canada and United States Production Capacity, published annually (latest edition released as Volume 27, May 1973). Both oil and associated and dissolved gas reserves that were considered to be added from drilling are (1) extensions, (2) new field discoveries and (3) new pools discovered in old fields.

TABLE 234

ASSOCIATED AND DISSOLVED GAS RESERVES ADDED
(Billion Cubic Feet)

This Is the High Drilling and High Finding Case

Case I

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48–Onshore															
2	14.9	21.8	23.3	24.7	26.1	28.0	30.6	34.0	38.4	43.4	48.8	53.9	58.4	62.2	65.5
3	12.6	16.2	18.8	19.5	18.2	18.7	17.2	16.8	15.6	14.9	14.7	15.0	14.0	13.4	11.5
4	39.6	62.4	78.3	97.5	112.2	123.3	133.1	143.2	149.2	158.6	169.0	174.8	183.3	186.0	193.0
5	157.9	162.4	157.4	149.9	143.1	150.6	165.8	194.7	226.7	266.4	308.3	343.9	389.3	417.6	440.7
6	247.0	287.0	307.9	368.3	450.2	533.5	576.9	611.6	601.4	601.1	594.6	523.7	511.4	473.1	458.0
7	211.1	196.9	194.1	187.4	191.5	208.0	211.4	221.6	221.9	228.9	232.8	223.6	221.8	208.0	205.3
8-10	37.1	29.7	39.1	49.7	61.3	67.0	79.3	81.5	89.2	87.3	84.2	84.9	75.0	67.9	57.8
11	1.1	2.3	4.3	8.6	11.9	12.8	16.4	17.0	21.0	21.3	22.0	27.8	28.1	32.2	31.4
Totals	721.4	778.5	823.3	905.7	1,014.5	1,141.8	1,230.8	1,320.3	1,363.4	1,421.9	1,474.3	1,447.6	1,481.2	1,460.4	1,463.3
Offshore and South Alaska															
1	17.0	13.9	26.9	42.7	62.1	69.3	91.2	94.5	120.1	116.2	106.2	111.2	94.7	101.0	90.8
2A	26.3	27.1	75.9	143.2	218.8	247.1	328.5	353.8	366.8	374.8	382.1	386.9	391.8	394.8	393.6
6A	569.2	492.5	639.3	701.3	719.1	660.1	668.5	668.2	698.9	672.5	633.3	606.5	531.0	503.4	456.8
11A	.0	.0	.0	2.1	4.6	5.0	8.2	9.1	16.9	19.1	21.5	76.0	91.7	146.3	171.0
Totals	612.4	533.5	742.1	889.3	1,004.6	981.5	1.096.4	1,125.6	1,202.7	1,182.6	1,143.1	1,180.7	1,109.3	1,145.5	1,112.1
Totals U.S. Ex North Slope	1,333.9	1,312.0	1,565.4	1,795.0	2,019.1	2,123.3	2,327.3	2,445.9	2,566.1	2,604.5	2,617.4	2,628.2	2,590.5	2,605.9	2,575.5
Northern Alaska															
Onshore	42.0	140.0	140.0	418.0	474.0	1,170.0	1.410.0	1,410.0	1,450.0	2,010.0	2,050.0	1,730.0	558.0	279.0	279.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	42.0	140.0	140.0	418.0	474.0	1,170.0	1,410.0	1,410.0	1,450.0	2,010.0	2,050.0	1,730.0	558.0	279.0	279.0
Totals All U.S.	1,375.9	1,452.0	1,705.4	2,213.0	2,493.1	3,293.3	3,737.3	3,855.9	4,016.1	4,614.5	4,667.4	4,358.2	3,148.5	2,884.9	2,854.5

TABLE 235

ASSOCIATED AND DISSOLVED GAS RESERVES ADDED
(Billion Cubic Feet)

This Is the High Drilling and Low Finding Case

Case IA

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48–Onshore															
2	14.9	21.8	23.3	24.7	26.1	27.5	29.0	30.6	31.9	33.1	34.5	35.7	36.8	38.0	39.1
3	10.6	10.3	10.2	9.8	8.9	9.1	8.5	8.7	8.6	8.8	9.0	9.7	9.8	10.3	10.1
4	36.6	48.2	50.4	53.4	54.1	53.7	53.8	56.4	58.1	60.8	63.9	65.1	67.3	67.4	68.9
5	157.9	162.4	157.4	149.9	141.4	140.9	139.7	142.4	142.0	143.1	145.1	144.3	145.0	143.6	147.2
6	242.1	267.6	258.7	258.6	267.0	282.8	285.6	300.9	307.2	320.7	333.9	311.8	322.6	316.2	326.7
7	194.1	152.9	133.7	122.4	121.3	127.7	128.0	135.0	136.4	143.0	150.0	149.8	155.5	153.1	156.7
8-10	34.1	23.2	26.1	29.0	32.4	31.4	33.5	33.2	36.1	35.0	33.6	35.8	35.9	38.7	38.6
11	1.1	2.2	3.9	7.1	8.6	8.6	10.8	10.8	12.8	12.6	13.0	16.7	17.0	20.0	20.7
Totals	691.4	688.7	663.7	654.9	659.8	681.6	688.9	718.0	732.9	757.1	783.0	768.8	789.8	787.3	808.0
Offshore and South Alaska															
1	16.7	13.3	24.7	36.8	48.7	48.5	59.5	59.8	73.0	67.2	57.3	60.2	57.5	66.1	61.1
2A	25.9	26.1	70.1	124.4	178.0	189.0	237.9	248.3	257.3	266.5	275.0	279.8	283.5	285.7	285.0
6A	448.4	281.5	340.1	385.5	437.6	457.2	500.6	503.5	530.7	516.0	492.8	481.5	432.7	418.7	385.3
11A	.0	.0	.0	2.1	4.5	4.9	8.0	8.7	15.7	17.2	18.8	62.9	73.1	117.4	137.4
Totals	491.1	320.9	435.0	548.8	668.8	699.6	806.0	820.2	876.8	866.9	843.8	884.5	846.7	888.0	868.8
Totals U.S. Ex North Slope	1,182.4	1,009.5	1,098.7	1,203.7	1,328.6	1,381.2	1,494.9	1,538.2	1,609.7	1,624.0	1,626.9	1,653.3	1,636.6	1,675.3	1,676.8
Northern Alaska															
Onshore	42.0	140.0	140.0	418.0	474.0	1,170.0	1,410.0	1,410.0	1,450.0	2,010.0	2,050.0	1,730.0	558.0	279.0	279.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	42.0	140.0	140.0	418.0	474.0	1,170.0	1,410.0	1,410.0	1,450.0	2,010.0	2,050.0	1,730.0	588.0	279.0	279.0
Totals All U.S.	1,224.4	1,149.5	1,238.7	1,621.7	1,802.6	2,551.2	2,904.9	2,948.2	3,059.7	3,634.0	3,676.9	3,383.3	2,194.6	1,954.3	1,955.8

TABLE 236

ASSOCIATED AND DISSOLVED GAS RESERVES ADDED
(Billion Cubic Feet)

This Is the Low Drilling and High Finding Case

Case II

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	14.9	21.3	22.6	23.7	24.3	25.3	26.8	28.6	30.9	33.7	36.7	39.7	42.9	45.6	47.8
3	12.6	15.8	18.2	18.7	17.1	17.0	15.5	15.0	13.8	13.0	12.4	12.8	12.2	12.2	11.3
4	39.6	60.9	75.6	92.9	103.9	110.9	117.2	122.3	124.0	128.1	132.8	135.1	140.1	140.7	144.6
5	157.9	158.9	153.0	144.3	133.3	135.2	143.0	159.2	178.1	201.4	226.2	246.7	270.7	289.8	316.5
6	247.0	280.8	296.8	346.8	412.2	474.6	508.8	533.7	516.1	508.8	498.9	441.9	430.5	395.2	386.7
7	211.1	192.4	187.9	178.9	177.7	187.4	187.1	191.3	187.1	189.8	191.0	183.2	181.8	171.1	168.7
8-10	37.1	29.0	37.9	47.5	56.9	60.3	70.4	71.1	76.7	74.4	71.7	74.2	68.8	67.0	57.9
11	1.1	2.2	4.2	8.2	11.1	11.6	14.6	14.7	17.8	17.6	17.7	22.2	22.2	25.3	25.2
Totals	721.4	761.4	796.2	861.0	936.5	1,022.3	1,083.5	1,135.9	1,144.6	1,166.9	1,187.4	1,155.7	1,169.2	1,146.8	1,158.5
Offshore and South Alaska															
1	17.0	13.6	26.0	40.7	57.5	62.4	80.8	81.6	102.1	99.6	93.5	100.8	88.3	94.2	80.3
2A	26.3	26.5	73.4	136.4	202.3	221.5	288.4	304.3	310.4	311.1	311.0	310.7	311.5	312.6	312.8
6A	569.2	481.5	620.6	674.7	678.6	613.4	607.2	586.7	606.4	581.0	550.6	544.7	495.6	462.2	413.0
11A	.0	.0	.0	2.0	4.3	4.5	7.2	7.7	13.8	15.0	16.3	55.4	64.6	99.7	114.7
Totals	612.4	521.6	720.0	853.9	942.7	901.8	983.7	980.4	1,032.7	1,006.8	971.4	1,011.6	960.0	968.7	920.7
Totals U.S. Ex North Slope	1,333.9	1,283.0	1,516.2	1,714.9	1,879.1	1,924.1	2,067.2	2,116.2	2,177.2	2,173.7	2,158.8	2,167.2	2,129.2	2,115.5	2,079.2
Northern Alaska															
Onshore	42.0	140.0	140.0	321.0	321.0	837.0	1,116.0	1,255.0	1,255.0	1,633.0	1,590.0	1,311.0	418.0	237.0	237.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	42.0	140.0	140.0	321.0	321.0	837.0	1,116.0	1,255.0	1,255.0	1,633.0	1,590.0	1,311.0	418.0	237.0	237.0
Totals All U.S.	1,375.9	1,423.0	1,656.2	2,035.9	2,200.1	2,761.1	3,183.2	3,371.2	3,432.2	3,806.7	3,748.8	3,478.2	2,547.2	2,352.5	2,316.2

TABLE 237

ASSOCIATED AND DISSOLVED GAS RESERVES ADDED
(Billion Cubic Feet)

This Is the Low Drilling and Low Finding Case

Case III

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	14.9	21.3	22.6	23.7	24.3	24.9	25.7	26.3	26.8	27.2	27.6	28.1	28.7	29.2	29.7
3	10.6	10.1	9.9	9.4	8.3	8.3	7.6	7.6	7.4	7.3	7.3	7.9	7.9	8.3	8.2
4	36.6	47.2	48.9	51.3	50.7	49.3	48.1	48.4	48.6	49.6	50.9	51.1	52.3	51.9	52.8
5	157.9	158.9	153.0	144.3	132.6	128.6	125.1	124.1	121.5	120.3	118.9	116.6	116.7	113.8	113.4
6	242.1	262.0	251.0	247.3	248.5	256.2	253.3	259.0	258.0	263.1	267.9	247.1	251.5	241.7	247.1
7	194.1	149.7	129.8	117.1	113.0	115.9	113.6	116.1	114.4	116.9	119.5	117.7	120.5	117.2	119.8
8-10	34.1	22.7	25.3	27.8	30.4	28.9	30.3	29.0	31.1	30.0	28.7	29.6	28.7	30.9	30.6
11	1.1	2.2	3.8	6.8	8.0	7.8	9.7	9.4	11.0	10.5	10.4	13.2	13.3	15.3	15.5
Totals	691.4	674.2	644.4	627.7	615.8	619.9	613.3	620.1	618.9	625.0	631.2	611.3	619.5	608.3	617.1
Offshore and South Alaska															
1	16.7	13.0	24.0	35.3	45.5	44.3	53.3	52.2	63.2	59.3	53.2	54.0	47.7	56.8	52.3
2A	25.9	25.5	67.9	118.8	165.5	171.0	211.1	214.1	216.5	219.3	221.8	223.8	225.3	226.1	226.3
6A	448.4	275.5	330.0	368.8	407.7	415.4	447.8	440.9	458.5	442.7	423.5	424.1	392.3	374.5	341.5
11A	.0	.0	.0	2.0	4.2	4.4	7.0	7.4	13.0	13.7	14.5	47.2	52.1	79.1	92.2
Totals	491.1	314.0	421.8	524.9	622.9	635.1	719.2	714.6	751.2	735.1	713.0	749.2	717.4	736.5	712.3
Totals U.S. Ex North Slope	1,182.4	988.1	1,066.3	1,152.6	1,238.7	1,255.0	1,332.5	1,334.7	1,370.1	1,360.0	1.344.2	1,360.4	1,336.9	1,344.8	1,329.4
Northern Alaska															
Onshore	42.0	140.0	140.0	321.0	321.0	837.0	1,116.0	1,255.0	1,255.0	1,633.0	1,590.0	1,311.0	418.0	237.0	237.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	42.0	140.0	140.0	321.0	321.0	837.0	1,116.0	1,255.0	1,255.0	1,633.0	1,590.0	1,311.0	418.0	237.0	237.0
Totals All U.S.	1,224.4	1,128.1	1,206.3	1,473.6	1,559.7	2,092.0	2,448.5	2,589.7	2,625.1	2,993.0	2,934.2	2,671.4	1,754.9	1,581.8	1,566.4

TABLE 238

ASSOCIATED AND DISSOLVED GAS RESERVES ADDED
(Billion Cubic Feet)

This Is the Low Declining Drilling and Low Finding Case

Case IV

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	14.9	20.0	19.7	19.1	18.2	17.5	16.6	16.4	15.5	14.7	13.9	13.2	12.5	12.0	11.5
3	10.6	9.5	8.7	7.7	6.3	5.9	5.1	4.9	4.5	4.2	3.9	3.9	3.7	3.7	3.5
4	36.6	44.4	43.1	42.0	38.9	35.9	32.8	31.0	28.0	26.3	25.0	23.3	22.2	20.8	20.1
5	157.9	149.6	135.0	119.0	103.1	93.6	84.0	81.0	74.0	68.8	64.2	59.3	55.4	51.4	48.9
6	242.1	247.0	220.4	199.4	185.3	178.9	163.9	161.7	149.5	141.5	133.8	115.3	109.3	99.3	95.7
7	194.1	141.2	113.9	94.5	84.5	81.3	73.8	72.6	66.2	62.6	59.3	54.3	51.5	47.2	45.5
8-10	34.1	21.4	22.4	22.8	23.4	21.3	21.3	19.6	19.3	17.7	16.3	16.5	15.2	15.3	14.3
11	1.1	2.0	3.4	5.5	6.1	5.6	6.4	6.2	6.9	6.3	5.7	6.5	5.9	6.3	6.0
Totals	691.4	635.1	566.7	510.1	465.8	440.0	404.0	393.4	363.9	342.1	322.1	292.3	275.6	256.1	245.5
Offshore and South Alaska															
1	16.7	12.2	21.0	28.6	34.5	32.0	35.9	34.0	39.1	35.8	32.7	36.0	32.5	36.3	31.7
2A	25.9	24.0	59.1	95.3	123.1	119.0	136.3	134.5	126.8	119.0	111.9	106.0	100.1	96.0	92.2
6A	448.4	259.3	289.2	297.7	305.4	292.2	296.0	288.2	284.8	262.6	242.2	238.3	219.7	217.5	203.1
11A	.0	.0	.0	1.6	3.1	3.1	4.4	4.4	7.1	6.9	6.6	19.5	19.1	25.4	25.5
Totals	491.1	295.4	369.2	423.2	466.1	446.2	472.6	461.1	457.9	424.2	393.4	399.8	371.3	375.2	352.4
Totals U.S. Ex North Slope	1,182.4	930.6	936.0	933.3	931.9	886.2	876.6	854.6	821.7	766.3	715.5	692.2	646.9	631.3	597.9
Northern Alaska															
Onshore	42.0	42.0	42.0	98.0	98.0	98.0	98.0	140.0	140.0	181.0	837.0	1,116.0	1,255.0	1,255.0	1,633.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	42.0	42.0	42.0	98.0	98.0	98.0	98.0	140.0	140.0	181.0	837.0	1,116.0	1,255.0	1,255.0	1,633.0
Totals All U.S.	1,224.4	972.6	978.0	1,031.3	1,029.9	984.2	974.6	994.6	961.7	947.3	1,552.5	1,808.2	1,901.9	1,886.3	2,230.9

TABLE 239

ASSOCIATED AND DISSOLVED GAS RESERVES ADDED
(Billion Cubic Feet)

This Is the Trend Drilling and High Finding Case

Case IVA

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48--Onshore															
2	14.9	20.0	19.7	19.1	18.2	17.5	16.8	16.9	16.3	15.7	15.3	15.0	14.7	14.6	14.5
3	12.6	14.8	15.9	15.1	12.9	12.2	10.5	10.2	9.2	8.4	7.7	7.5	6.8	6.6	6.1
4	39.6	57.1	65.3	73.4	75.9	75.4	73.4	74.1	69.7	66.3	63.2	59.5	56.8	53.5	51.9
5	157.9	149.6	135.0	119.0	103.1	94.4	87.7	88.9	85.7	85.3	85.5	84.5	84.1	82.8	83.2
6	247.0	264.2	256.0	265.1	285.7	307.5	301.2	313.1	304.0	293.0	273.8	232.5	217.4	195.0	185.5
7	211.1	180.5	163.6	143.1	131.0	128.5	119.0	119.3	109.5	103.4	97.5	89.0	84.1	76.8	73.9
8-10	37.1	27.2	33.0	38.0	41.9	41.2	44.6	44.9	46.9	43.5	40.2	40.7	37.6	38.1	35.6
11	1.1	2.1	3.6	6.5	8.1	8.1	9.6	9.3	10.6	9.9	9.2	10.7	9.9	10.8	10.3
Totals	721.4	715.5	692.1	679.3	676.8	684.8	662.8	676.7	652.0	625.5	592.4	539.4	511.4	478.2	460.9
Offshore and South Alaska															
1	17.0	12.7	22.7	32.5	42.1	42.1	51.4	51.6	60.4	56.3	52.6	59.1	54.5	62.4	56.2
2A	26.3	24.9	63.6	108.3	147.5	148.9	178.0	183.0	177.7	169.7	160.8	151.8	142.7	136.2	130.1
6A	569.2	452.0	545.5	555.8	531.9	470.7	436.8	395.2	380.3	349.5	321.2	315.1	289.3	285.4	265.3
11A	.0	.0	.0	1.6	3.1	3.1	4.5	4.6	7.5	7.3	7.1	21.4	21.7	29.8	30.8
Totals	612.4	489.6	631.8	698.2	724.5	664.9	670.7	634.4	625.8	582.8	541.7	547.4	508.2	513.8	482.4
Totals U.S. Ex North Slope	1,333.9	1,205.1	1,323.9	1,377.6	1,401.3	1,349.7	1,333.5	1,311.0	1,277.8	1,208.3	1,134.1	1,086.8	1,019.6	992.0	943.4
Northern Alaska															
Onshore	42.0	42.0	42.0	98.0	98.0	98.0	98.0	140.0	140.0	181.0	837.0	1,116.0	1,255.0	1,255.0	1,633.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	42.0	42.0	42.0	98.0	98.0	98.0	98.0	140.0	140.0	181.0	837.0	1,116.0	1,255.0	1,255.0	1,633.0
Totals All U.S.	1,375.9	1,247.1	1,365.9	1,475.6	1,499.3	1,447.7	1,431.5	1,451.0	1,417.8	1,389.3	1,971.1	2,202.8	2,274.6	2,247.0	2,576.4

Chapter Five—Section VI

Crude Oil, Natural Gas Liquids and Associated and Dissolved Gas Production

TABLE 240

CRUDE OIL PRODUCTION AND RESERVE STATISTICS–UNITED STATES*

	Annual Crude Production	Reserves at Beginning of Year	Production as a Function of Reserves: R/P	Production as a Function of Reserves: Production as a % of Remaining Reserves
	(Billions of Barrels)			
1955	2.425	29.561	12.20	8.20
1956	2.559	30.012	11.72	8.53
1957	2.559	30.435	11.89	8.41
1958	2.376	30.300	12.76	7.84
1959	2.493	30.536	12.25	8.16
1960	2.472	31.719	12.83	7.78
1961	2.507	31.613	12.61	7.93
1962	2.552	31.759	12.44	8.04
1963	2.613	31.389	12.02	8.32
1964	2.645	30.970	11.71	8.54
1965	2.699	30.991	11.48	8.71
1966	2.864	31.352	10.95	9.13
1967	3.048	31.452	10.32	9.69
1968	3.161	31.377	9.93	10.07
1969	3.185	30.707	9.64	10.37
1970	3.319	29.632	8.93	11.20

* Exluding North Slope

Source: *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity as of December 31, 1970.* API *Vol. 25, May 1971, pp. 25-122*

Future Production By Recovery Method

The components which make up the total daily crude oil production are discussed in Part I of this report (see Chapter One, pp.44 46). It was found important for two reasons to distinguish the components which derive from different recovery mechanisms. First, the relative contribution resulting from each mechanism is changing and can be expected to change markedly in the future. Second, the relative costs associated with each recovery mechanism vary widely. It is therefore necessary to separately account for them in attempting to evaluate the future production alternatives. An example of how the total production is allocated by recovery mechanisms is given for Case II in Table 257 in this section.

For the purposes of this study it was found to be desirable and adequate to separate production into three major categories: namely, those resulting from primary, secondary and tertiary recovery mechanisms.

Primary production is that which results from the flow of oil from the reservoir into the well-bore solely as a result of the innate energy naturally available. The three principal sources of such natural energy are (1) the energy stored in the gas dissolved in the oil supplemented by energy stored in any undissolved gas if present, (2) the energy stored in the water present in the reservoir and in the formation contiguous to the oil bearing part and (3) the energy resulting from the force of gravity. All of these vary in relative importance from reservoir to reservoir.

Secondary and tertiary recovery processes provide mechanisms by which additional energy is added to supplement naturally available energy. Secondary recovery is that which results principally from waterflooding. Tertiary recovery includes all other methods such as the use of heat or additives which result in increasing the recovery by addition of supplemental energy to the reservoir.

TABLE 241

NUMBER OF PRODUCING WELLS
(As of January 1, 1971)*

Region	
1	161
2	38,670†
2A	398†
3	3,097
4	16,241
5	114,859
6	89,903
6A	5,125
7	136,225
10	112,439
11	59
11A	0

* Excluding North Slope
† *World Oil* total for California onshore and offshore using Conservation Committee of California Oil Producers.

Source: Initial wells are from World Oil, *(January 1, 1971).*

Historical Data

It will be noted that past production is allocated between that from primary recovery and that from fluid injection. There is no complete reliable source of statistics separating primary, secondary and tertiary recovery as a function of time prior to 1971. Therefore, it was necessary to construct a history based upon such information as is available in the literature. During the period 1956 to 1971, by far the greater part of recovery other than primary resulted from waterflooding. While many tertiary recovery methods have been developed and have been experimented with, the economic climate has not been such as to encourage their commercialization at present. In view of the relatively small contribution resulting so far from tertiary methods and the difficulty of acquiring reliable statistics regarding them, no effort was made to segregate the production ascribed to fluid injection into categories for the historical data.

A number of sources provide incomplete evaluations of past production resulting from fluid injection. Since a number of these were incorporated into a study made by the National Petroleum Council, *Factors Affecting U.S. Exploration and Production 1946-1965*, published in 1967, this report was used as a basis for establishing past history. From it the following tabulation has been made.

Oil Production from Fluid Injection

Year	Daily Barrels per Day	Annual Millions of Barrels per Year	Percent of U.S. Total
1946	684,900	250	14.4
1952	1,115,000	407	17.8
1960	2,007,000	733	28.5
1965	2,684,900	980	34.4

Using these data, it was possible to construct a graph (see Figure 78) showing annual production from fluid injection *versus* time. A logarithmic extrapolation of this curve to 1970 yields a value of 1.31 billion barrels per year.

To check this extrapolation, API figures for revisions from 1950 to 1970 were related to the production from fluid injection. As mentioned in Section II of this report, it has been established that within a margin of ±5 percent on the average, the portion of API reserves allocated to revision for the period 1956 to present results from fluid injection operations. To make the check, a 5-year running average of revisions was made for this period. From these data a plot as a function of time was derived. This is also plotted on Figure 78. Values from each curve for identical times were then plotted, one *versus* the other, and extrapolated. A value of 1.305 billion barrels of production for 1970 revisions provided exceptionally good agreement with the previously obtained value; 1.3 billion barrels is equal to 39.3 percent of total 1970 production. By means of the above procedure, production values from 1956 to 1970 were derived (see Table 256).

Future Oil Production

Besides dividing future production into the three categories—primary, secondary and tertiary—it is necessary to distinguish between those portions of these three categories which result from fields found prior to 1971 (old fields) and from the

TABLE 242

SUMMARY OF WELLS AND DAILY PRODUCTION FOR ALL REGIONS*

THIS IS THE HIGH DRILLING AND HIGH FINDING CASE
SECONDARY AND TERTIARY EFFORTS NOT INTENSIFIED BY 50 PERCENT

CASE I

INITIAL WELL COUNT- 517177. WELLS

	PRODUCTIVE WELLS AT END OF YEAR			ABANDONMENTS		
TIME FRACTION	OLD FIELDS WELLS	NEW FIELDS WELLS	ALL FIELDS WELLS	OLD FIELDS WELLS	NEW FIELDS WELLS	ALL FIELDS WELLS
1971	489046.	11802.	500848.	28131.	0.	28131.
1972	464516.	23486.	488002.	24530.	59.	24589.
1973	443117.	36343.	479461.	21399.	176.	21575.
1974	424442.	50350.	474792.	18676.	358.	19034.
1975	408135.	65297.	473432.	16307.	610.	16917.
1976	394435.	81098.	475533.	13700.	936.	14637.
1977	382520.	98031.	480551.	11915.	1283.	13198.
1978	372152.	115662.	487814.	10367.	1656.	12023.
1979	363127.	133932.	497060.	9025.	2052.	11077.
1980	355268.	152542.	507809.	7860.	2470.	10330.
1981	346583.	171453.	518035.	8685.	2906.	11591.
1982	339025.	190321.	529346.	7557.	3358.	10916.
1983	332445.	209071.	541515.	6580.	3820.	10400.
1984	326711.	227594.	554305.	5734.	4287.	10020.
1985	321696.	245862.	567558.	5015.	4755.	9770.

*EXCLUDING NORTH SLOPE.

TABLE 243

SUMMARY OF WELLS AND DAILY PRODUCTION FOR ALL REGIONS*

THIS IS THE HIGH DRILLING AND LOW FINDING CASE
SECONDARY AND TERTIARY ARE NOT ACCELERATED OR INTENSIFIED

CASE IA

INITIAL WELL COUNT- 517177. WELLS

	PRODUCTIVE WELLS AT END OF YEAR			ABANDONMENTS		
TIME FRACTION	OLD FIELDS WELLS	NEW FIELDS WELLS	ALL FIELDS WELLS	OLD FIELDS WELLS	NEW FIELDS WELLS	ALL FIELDS WELLS
1971	489046.	11548.	500594.	28131.	0.	28131.
1972	464516.	22599.	487116.	24530.	58.	24587.
1973	443117.	33865.	476983.	21399.	171.	21569.
1974	424442.	45287.	469729.	18676.	340.	19016.
1975	408135.	57016.	465152.	16307.	566.	16873.
1976	394435.	68887.	463322.	13700.	852.	14552.
1977	382520.	81109.	463629.	11915.	1138.	13054.
1978	372152.	93736.	465888.	10367.	1431.	11798.
1979	363127.	106816.	469943.	9025.	1730.	10755.
1980	355268.	120238.	475505.	7860.	2038.	9898.
1981	346583.	134029.	480612.	8685.	2354.	11039.
1982	339025.	148025.	487050.	7557.	2680.	10237.
1983	332445.	162396.	494841.	6580.	3014.	9595.
1984	326711.	177161.	503873.	5734.	3358.	9091.
1985	321696.	192265.	513961.	5015.	3709.	8724.

*EXCLUDING NORTH SLOPE.

TABLE 244

SUMMARY OF WELLS AND DAILY PRODUCTION FOR ALL REGIONS*

THIS IS THE LOW DRILLING AND HIGH FINDING CASE
SECONDARY AND TERTIARY EFFORTS NOT INTENSIFIED BY 50 PERCENT
CASE II
INITIAL WELL COUNT- 517177. WELLS

	PRODUCTIVE WELLS AT END OF YEAR			ABANDONMENTS		
TIME	OLD FIELDS WELLS FRACTION	NEW FIELDS WELLS	ALL FIELDS WELLS	OLD FIELDS WELLS	NEW FIELDS WELLS	ALL FIELDS WELLS
1971	489046.	11802.	500848.	28131.	0.	28131.
1972	464516.	23229.	487745.	24530.	59.	24589.
1973	443117.	35687.	478805.	21399.	175.	21574.
1974	424442.	49074.	473516.	18676.	354.	19029.
1975	408135.	62933.	471068.	16307.	599.	16906.
1976	394435.	77112.	471547.	13700.	914.	14614.
1977	382520.	91987.	474507.	11915.	1240.	13155.
1978	372152.	107027.	479180.	10367.	1584.	11951.
1979	363127.	122197.	485325.	9025.	1941.	10965.
1980	355268.	137237.	492505.	7860.	2306.	10166.
1981	346583.	152136.	498718.	8685.	2678.	11363.
1982	339025.	166846.	505871.	7557.	3053.	10610.
1983	332445.	181328.	513773.	6580.	3427.	10008.
1984	326711.	195560.	522271.	5734.	3799.	9532.
1985	321696.	209448.	531144.	5015.	4166.	9181.

*EXCLUDING NORTH SLOPE.

TABLE 245

SUMMARY OF WELLS AND DAILY PRODUCTION FOR ALL REGIONS*

THIS IS THE LOW DRILLING AND LOW FINDING CASE
SECONDARY AND TERTIARY ARE NOT ACCELERATED OR INTENSIFIED
CASE III
INITIAL WELL COUNT- 517177. WELLS

	PRODUCTIVE WELLS AT END OF YEAR			ABANDONMENTS		
TIME	OLD FIELDS WELLS FRACTION	NEW FIELDS WELLS	ALL FIELDS WELLS	OLD FIELDS WELLS	NEW FIELDS WELLS	ALL FIELDS WELLS
1971	489046.	11548.	500594.	28131.	0.	28131.
1972	464516.	22360.	486876.	24530.	58.	24587.
1973	443117.	33287.	476404.	21399.	170.	21568.
1974	424442.	44222.	468663.	18676.	336.	19012.
1975	408135.	55139.	463274.	16307.	557.	16864.
1976	394435.	65868.	460303.	13700.	833.	14533.
1977	382520.	76630.	459150.	11915.	1104.	13020.
1978	372152.	87344.	459496.	10367.	1376.	11743.
1979	363127.	98131.	461258.	9025.	1646.	10671.
1980	355268.	108882.	464150.	7860.	1916.	9775.
1981	346583.	119604.	466187.	8685.	2184.	10869.
1982	339025.	130236.	469261.	7557.	2453.	10010.
1983	332445.	140911.	473356.	6580.	2721.	9301.
1984	326711.	151661.	478372.	5734.	2989.	8722.
1985	321696.	162515.	484211.	5015.	3256.	8271.

*EXCLUDING NORTH SLOPE.

TABLE 246

SUMMARY OF WELLS AND DAILY PRODUCTION FOR ALL REGIONS*

THIS IS THE LOW DECLINING DRILLING AND LOW FINDING CASE
SECONDARY AND TERTIARY ARE NOT ACCELERATED OR INTENSIFIED
CASE IV
INITIAL WELL COUNT- 517177. WELLS

	PRODUCTIVE WELLS AT END OF YEAR			ABANDONMENTS		
TIME FRACTION	OLD FIELDS WELLS	NEW FIELDS WELLS	ALL FIELDS WELLS	OLD FIELDS WELLS	NEW FIELDS WELLS	ALL FIELDS WELLS
1971	489046.	11548.	500594.	28131.	0.	28131.
1972	464516.	21716.	486232.	24530.	58.	24587.
1973	443117.	31288.	474406.	21399.	166.	21565.
1974	424442.	40115.	464557.	18676.	323.	18998.
1975	408135.	48267.	456402.	16307.	523.	16830.
1976	394435.	55700.	450135.	13700.	765.	14465.
1977	382520.	62493.	445013.	11915.	985.	12901.
1978	372152.	68892.	441044.	10367.	1189.	11557.
1979	363127.	74711.	437838.	9025.	1377.	10402.
1980	355268.	79956.	435223.	7860.	1550.	9410.
1981	346583.	84672.	431255.	8685.	1709.	10394.
1982	339025.	88898.	427923.	7557.	1854.	9411.
1983	332445.	92667.	425112.	6580.	1986.	8566.
1984	326711.	96100.	422811.	5734.	2105.	7838.
1985	321696.	99218.	420914.	5015.	2211.	7226.

*EXCLUDING NORTH SLOPE.

TABLE 247

SUMMARY OF WELLS AND DAILY PRODUCTION FOR ALL REGIONS*

THIS IS THE TREND DRILLING AND HIGH FINDING CASE
SECONDARY AND TERTIARY EFFORTS NOT INTENSIFIED BY 50 PERCENT
CASE IVA
INITIAL WELL COUNT- 517177. WELLS

	PRODUCTIVE WELLS AT END OF YEAR			ABANDONMENTS		
TIME FRACTION	OLD FIELDS WELLS	NEW FIELDS WELLS	ALL FIELDS WELLS	OLD FIELDS WELLS	NEW FIELDS WELLS	ALL FIELDS WELLS
1971	489046.	11802.	500848.	28131.	0.	28131.
1972	464516.	22539.	487055.	24530.	59.	24589.
1973	443117.	33373.	476490.	21399.	172.	21570.
1974	424442.	44069.	468511.	18676.	339.	19014.
1975	408135.	54283.	462418.	16307.	559.	16866.
1976	394435.	63880.	458315.	13700.	830.	14531.
1977	382520.	72992.	455512.	11915.	1091.	13006.
1978	372152.	81872.	454024.	10367.	1343.	11710.
1979	363127.	90216.	453343.	9025.	1585.	10610.
1980	355268.	97803.	453070.	7860.	1816.	9676.
1981	346583.	104638.	451221.	8685.	2034.	10719.
1982	339025.	110812.	449837.	7557.	2238.	9795.
1983	332445.	116329.	448774.	6580.	2427.	9007.
1984	326711.	121396.	448108.	5734.	2599.	8333.
1985	321696.	125997.	447693.	5015.	2755.	7770.

*EXCLUDING NORTH SLOPE.

TABLE 248

AVERAGE DAILY OIL PRODUCTION PER WELL

	Lower 48 Onshore					
	Case I	Case IA	Case II	Case III	Case IV	Case IVA
1971	15.5	15.5	15.5	15.5	15.5	15.5
1972	15.4	15.4	15.4	15.4	15.5	15.4
1973	15.3	15.3	15.3	15.3	15.4	15.4
1974	15.2	15.2	15.2	15.2	15.3	15.3
1975	15.0	15.0	15.0	15.0	15.1	15.1
1976	14.8	14.8	14.9	14.8	14.9	15.0
1977	14.8	14.7	14.9	14.7	14.9	15.0
1978	14.8	14.6	14.8	14.6	14.9	15.0
1979	14.7	14.4	14.8	14.5	14.8	15.0
1980	14.6	14.2	14.7	14.4	14.7	14.9
1981	14.6	14.1	14.7	14.3	14.7	14.9
1982	14.6	14.0	14.7	14.2	14.7	15.0
1983	14.5	13.9	14.6	14.1	14.7	15.0
1984	14.4	13.8	14.6	14.0	14.7	15.0
1985	14.4	13.6	14.5	13.9	14.7	15.0
	Offshore					
1971	243.8	245.6	243.8	245.6	245.6	243.8
1972	242.4	242.0	242.9	242.5	243.8	244.4
1973	227.9	222.9	228.7	223.7	227.0	232.1
1974	217.8	205.2	218.9	206.5	212.3	224.3
1975	207.4	188.6	209.4	190.7	198.4	216.6
1976	200.3	178.3	202.9	180.7	188.5	210.4
1977	187.4	165.9	190.6	168.6	177.7	200.6
1978	178.6	157.7	182.0	160.4	168.8	191.9
1979	169.2	149.2	172.6	151.9	160.4	182.7
1980	163.3	144.0	166.8	146.5	154.4	176.4
1981	156.2	137.9	160.0	140.6	147.9	169.4
1982	147.3	130.3	152.0	133.8	141.7	162.3
1983	140.6	124.6	146.2	128.7	137.1	157.5
1984	131.6	117.4	138.4	122.1	131.9	151.7
1985	125.5	112.7	132.9	117.9	128.9	148.5
	Total U.S.*					
	Case I	Case IA	Case II	Case III	Case IV	Case IVA
1971	18.2	18.2	18.2	18.2	18.2	18.2
1972	18.1	18.1	18.2	18.1	18.1	18.2
1973	18.0	17.9	18.0	17.9	18.0	18.1
1974	18.0	17.7	18.0	17.7	17.8	18.0
1975	18.0	17.6	18.0	17.6	17.6	18.0
1976	18.1	17.5	18.0	17.5	17.5	18.0
1977	18.3	17.5	18.2	17.5	17.5	18.1
1978	18.5	17.6	18.4	17.6	17.5	18.2
1979	18.7	17.6	18.6	17.6	17.5	18.2
1980	18.9	17.6	18.7	17.6	17.4	18.3
1981	19.0	17.6	18.9	17.6	17.4	18.3
1982	19.1	17.7	19.0	17.7	17.5	18.4
1983	19.2	17.7	19.1	17.7	17.5	18.5
1984	19.2	17.6	19.1	17.7	17.5	18.5
1985	19.3	17.6	19.1	17.6	17.5	18.6

* Excluding North Slope.

TABLE 249

CRUDE OIL PRODUCTION
(Million Barrels/Day)

This Is the High Drilling and High Finding Case

Case I

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48–Onshore															
2	.886	.879	.874	.869	.866	.863	.863	.866	.869	.873	.878	.868	.861	.856	.854
3	.118	.116	.115	.116	.117	.117	.118	.118	.119	.119	.119	.118	.118	.119	.118
4	.619	.566	.529	.502	.486	.477	.479	.486	.498	.512	.530	.555	.583	.613	.643
5	2.298	2.230	2.170	2.116	2.067	2.022	1.999	1.981	1.969	1.961	1.959	1.974	1.994	2.021	2.052
6	2.640	2.555	2.488	2.432	2.396	2.381	2.434	2.492	2.551	2.602	2.649	2.736	2.799	2.853	2.893
7	.855	.841	.827	.814	.802	.793	.779	.768	.761	.754	.750	.736	.723	.712	.699
8-10	.228	.231	.229	.233	.242	.255	.276	.299	.321	.346	.369	.392	.414	.429	.441
11	.019	.015	.014	.014	.017	.023	.027	.034	.040	.047	.054	.060	.069	.076	.085
Totals	7.662	7.433	7.246	7.098	6.993	6.931	6.976	7.043	7.126	7.215	7.307	7.439	7.561	7.679	7.786
Offshore and South Alaska															
1	.287	.266	.245	.244	.262	.300	.344	.404	.464	.553	.632	.691	.756	.799	.865
2A	.060	.064	.067	.086	.127	.191	.258	.346	.434	.518	.596	.670	.738	.803	.862
6A	1.087	1.092	1.076	1.101	1.138	1.176	1.200	1.222	1.242	1.268	1.284	1.297	1.300	1.284	1.264
11A	.000	.000	.000	.000	.001	.003	.005	.009	.012	.019	.026	.033	.067	.105	.164
Totals	1.434	1.421	1.388	1.431	1.529	1.670	1.807	1.981	2.153	2.359	2.539	2.691	2.862	2.990	3.156
Totals U.S. Ex North Slope	9.096	8.854	8.634	8.529	8.523	8.601	8.783	9.025	9.279	9.574	9.846	10.130	10.422	10.668	10.942
Northern Alaska															
Onshore	.000	.000	.000	.000	.000	.750	1.400	1.780	2.050	2.190	2.340	2.460	2.570	2.620	2.600
Offshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Total No. Alaska	.000	.000	.000	.000	.000	.750	1.400	1.780	2.050	2.190	2.340	2.460	2.570	2.620	2.600
Totals All U.S.	9.096	8.854	8.634	8.529	8.523	9.351	10.183	10.805	11.329	11.764	12.186	12.590	12.992	13.288	13.542

Note: Table 3 in Chapter One summarizes production in a little different manner than is generally used throughout the report. The production shown in Table 3 for the Lower 48 States includes the offshore areas of California, the Gulf of Mexico and the East Coast. Alaska in that table includes South Alaska (NPC Region 1) plus the North Slope.

TABLE 250

CRUDE OIL PRODUCTION
(Million Barrels/Day)

This Is the High Drilling and Low Finding Case

Case IA

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	.886	.879	.874	.869	.866	.863	.863	.865	.867	.879	.873	.859	.849	.840	.832
3	.118	.115	.112	.110	.108	.105	.103	.101	.099	.097	.095	.094	.092	.091	.090
4	.619	.565	.523	.487	.457	.432	.414	.400	.389	.381	.375	.375	.377	.380	.383
5	2.298	2.230	2.170	2.116	2.067	2.022	1.998	1.976	1.957	1.939	1.922	1.917	1.913	1.909	1.905
6	2.640	2.554	2.483	2.417	2.358	2.307	2.313	2.319	2.327	2.336	2.347	2.407	2.455	2.501	2.540
7	.855	.838	.817	.795	.775	.757	.735	.716	.701	.688	.679	.661	.647	.635	.624
8-10	.228	.229	.225	.223	.222	.224	.230	.236	.240	.246	.252	.260	.266	.273	.281
11	.019	.015	.014	.014	.016	.019	.021	.025	.028	.032	.035	.038	.043	.047	.053
Totals	**7.662**	**7.426**	**7.217**	**7.031**	**6.869**	**6.729**	**6.677**	**6.637**	**6.609**	**6.590**	**6.578**	**6.611**	**6.642**	**6.675**	**6.708**
Offshore and South Alaska															
1	.287	.266	.244	.241	.253	.276	.300	.329	.361	.410	.449	.471	.498	.522	.568
2A	.060	.063	.066	.084	.119	.168	.218	.279	.338	.393	.447	.499	.548	.594	.637
6A	1.087	1.060	.994	.952	.927	.920	.924	.938	.952	.971	.984	.997	1.005	.999	.991
11A	.000	.000	.000	.000	.001	.003	.005	.009	.012	.018	.024	.030	.058	.087	.135
Totals	**1.434**	**1.389**	**1.304**	**1.277**	**1.300**	**1.368**	**1.447**	**1.555**	**1.662**	**1.792**	**1.904**	**1.998**	**2.109**	**2.203**	**2.331**
Totals U.S. Ex North Slope	**9.096**	**8.815**	**8.522**	**8.308**	**8.168**	**8.096**	**8.124**	**8.192**	**8.270**	**8.381**	**8.481**	**8.609**	**8.750**	**8.878**	**9.040**
Northern Alaska															
Onshore	.000	.0000	.000	.000	.000	.750	1.400	1.780	2.050	2.190	2.340	2.460	2.570	2.620	2.600
Offshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Total No. Alaska	**.000**	**.000**	**.000**	**.000**	**.000**	**.750**	**1.400**	**1.780**	**2.050**	**2.190**	**2.340**	**2.460**	**2.570**	**2.620**	**2.600**
Totals All U.S.	**9.096**	**8.815**	**8.522**	**8.308**	**8.168**	**8.846**	**9.524**	**9.972**	**10.320**	**10.571**	**10.821**	**11.069**	**11.320**	**11.498**	**11.640**

Note: Table 3 in Chapter One summarizes production in a little different manner than is generally used throughout the report. The production shown in Table 3 for the Lower 48 States includes the offshore areas of California, the Gulf of Mexico and the East Coast. Alaska in that table includes South Alaska (NPC Region 1) plus the North Slope.

TABLE 251

CRUDE OIL PRODUCTION
(Million Barrels/Day)

This Is the Low Drilling and High Finding Case

Case II

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	.886	.879	.873	.869	.865	.862	.862	.863	.865	.867	.870	.857	.847	.839	.833
3	.118	.116	.115	.116	.116	.116	.116	.116	.116	.116	.115	.114	.113	.113	.112
4	.619	.566	.528	.501	.483	.472	.469	.472	.478	.486	.495	.511	.528	.547	.567
5	2.298	2.230	2.170	2.115	2.065	2.019	1.994	1.974	1.957	1.943	1.933	1.938	1.945	1.957	1.971
6	2.640	2.555	2.486	2.429	2.388	2.366	2.408	2.453	2.499	2.537	2.569	2.643	2.697	2.744	2.777
7	.855	.841	.826	.812	.799	.788	.771	.757	.746	.736	.727	.710	.694	.679	.666
8-10	.228	.231	.229	.232	.240	.251	.269	.288	.307	.327	.345	.364	.383	.398	.411
11	.019	.015	.014	.014	.017	.022	.026	.031	.036	.042	.047	.051	.057	.063	.069
Totals	7.662	7.433	7.242	7.088	6.974	6.896	6.916	6.955	7.003	7.053	7.102	7.188	7.266	7.340	7.407
Offshore and South Alaska															
1	.287	.266	.245	.243	.259	.292	.329	.379	.428	.501	.568	.620	.679	.720	.782
2A	.060	.064	.066	.085	.124	.182	.241	.317	.391	.460	.522	.579	.630	.678	.722
6A	1.087	1.092	1.073	1.093	1.125	1.153	1.168	1.179	1.184	1.193	1.195	1.198	1.197	1.185	1.167
11A	.000	.000	.000	.000	.001	.003	.005	.008	.011	.016	.022	.027	.051	.077	.117
Totals	1.434	1.421	1.385	1.422	1.509	1.630	1.744	1.883	2.014	2.171	2.306	2.423	2.558	2.660	2.787
Totals U.S. Ex North Slope	9.096	8.854	8.627	8.510	8.484	8.526	8.659	8.838	9.017	9.224	9.408	9.611	9.824	10.000	10.194
Northern Alaska															
Onshore	.000	.000	.000	.000	.000	.600	.950	1.300	1.650	2.000	2.000	2.000	2.000	2.000	2.000
Offshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Total No. Alaska	.000	.000	.000	.000	.000	.600	.950	1.300	1.650	2.000	2.000	2.000	2.000	2.000	2.000
Totals All U.S.	9.096	8.854	8.627	8.510	8.484	9.126	9.609	10.138	10.667	11.224	11.408	11.611	11.824	12.000	12.194

Note: Table 3 in Chapter One summarizes production in a little different manner than is generally used throughout the report. The production shown in Table 3 for the Lower 48 States includes the offshore areas of California, the Gulf of Mexico and the East Coast. Alaska in that table includes South Alaska (NPC Region 1) plus the North Slope.

TABLE 252

CRUDE OIL PRODUCTION
(Million Barrels/Day)

This Is the Low Drilling and Low Finding Case

Case III

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	.886	.879	.873	.869	.865	.862	.862	.863	.864	.866	.867	.852	.840	.828	.819
3	.118	.115	.112	.110	.108	.105	.102	.100	.097	.095	.093	.091	.089	.087	.086
4	.619	.565	.522	.486	.456	.429	.410	.395	.381	.370	.361	.358	.357	.356	.356
5	2.298	2.230	2.170	2.115	2.065	2.019	1.993	1.970	1.949	1.928	1.909	1.900	1.892	1.884	1.876
6	2.640	2.554	2.481	2.414	2.353	2.299	2.299	2.299	2.301	2.301	2.303	2.353	2.392	2.428	2.459
7	.855	.838	.816	.794	.773	.754	.730	.709	.692	.677	.665	.644	.626	.611	.598
8-10	.228	.229	.225	.222	.221	.222	.227	.231	.234	.239	.242	.248	.253	.257	.262
11	.019	.015	.014	.014	.016	.018	.020	.023	.026	.029	.031	.033	.036	.039	.043
Totals	7.662	7.426	7.214	7.024	6.856	6.708	6.645	6.591	6.544	6.505	6.471	6.479	6.485	6.492	6.498
Offshore and South Alaska															
1	.287	.266	.244	.240	.250	.270	.290	.314	.339	.379	.413	.435	.456	.472	.510
2A	.060	.063	.066	.083	.116	.162	.206	.259	.307	.352	.394	.433	.469	.503	.535
6A	1.087	1.060	.992	.948	.919	.905	.901	.904	.906	.912	.914	.918	.921	.916	.907
11A	.000	.000	.000	.000	.001	.003	.005	.008	.010	.016	.020	.025	.045	.065	.096
Totals	1.434	1.389	1.302	1.270	1.286	1.340	1.401	1.484	1.562	1.658	1.740	1.810	1.892	1.957	2.048
Totals U.S. Ex North Slope	9.096	8.815	8.516	8.294	8.143	8.047	8.046	8.075	8.106	8.164	8.211	8.289	8.377	8.448	8.546
Northern Alaska															
Onshore	.000	.000	.000	.000	.000	.600	.950	1.300	1.650	2.000	2.000	2.000	2.000	2.000	2.000
Offshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Total No. Alaska	.000	.000	.000	.000	.000	.600	.950	1.300	1.650	2.000	2.000	2.000	2.000	2.000	2.000
Totals All U.S.	9.096	8.815	8.516	8.294	8.143	8.647	8.996	9.375	9.756	10.164	10.211	10.289	10.377	10.448	10.546

Note: Table 3 in Chapter One summarizes production in a little different manner than is generally used throughout the report. The production shown in Table 3 for the Lower 48 States includes the offshore areas of California, the Gulf of Mexico and the East Coast. Alaska in that table includes South Alaska (NPC Region 1) plus the North Slope.

TABLE 253

CRUDE OIL PRODUCTION
(Million Barrels/Day)

This Is the Low Declining Drilling and Low Finding Case

Case IV

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	.886	.879	.873	.868	.863	.859	.857	.856	.855	.854	.852	.834	.818	.802	.788
3	.118	.115	.112	.109	.106	.103	.100	.096	.093	.090	.087	.084	.080	.077	.074
4	.619	.565	.521	.483	.450	.420	.397	.378	.360	.343	.328	.319	.311	.303	.295
5	2.298	2.230	2.169	2.112	2.059	2.009	1.980	1.951	1.924	1.897	1.870	1.855	1.839	1.823	1.806
6	2.640	2.554	2.478	2.404	2.334	2.268	2.254	2.239	2.225	2.210	2.194	2.224	2.247	2.267	2.282
7	.855	.838	.815	.790	.765	.743	.714	.689	.667	.648	.630	.604	.581	.561	.543
8-10	.228	.229	.224	.220	.217	.214	.217	.218	.218	.217	.217	.219	.220	.219	.219
11	.019	.015	.014	.013	.014	.016	.017	.018	.019	.020	.021	.021	.022	.022	.022
Totals	7.662	7.426	7.206	7.000	6.808	6.631	6.537	6.446	6.361	6.279	6.199	6.160	6.117	6.074	6.030
Offshore and South Alaska															
1	.287	.266	.243	.235	.238	.248	.257	.266	.276	.295	.310	.320	.331	.340	.359
2A	.060	.063	.065	.079	.104	.137	.165	.196	.224	.247	.264	.279	.290	.299	.306
6A	1.087	1.060	.988	.933	.888	.852	.823	.797	.773	.751	.727	.708	.689	.669	.650
11A	.000	.000	.000	.000	.001	.002	.004	.005	.007	.009	.012	.013	.021	.028	.037
Totals	1.434	1.389	1.296	1.248	1.232	1.238	1.248	1.264	1.280	1.302	1.312	1.320	1.332	1.335	1.352
Totals U.S. Ex North Slope	9.096	8.815	8.502	8.248	8.040	7.869	7.784	7.710	7.641	7.581	7.512	7.479	7.449	7.409	7.382
Northern Alaska															
Onshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.600	.950	1.300	1.650	2.000
Offshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Total No. Alaska	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.600	.950	1.300	1.650	2.000
Totals All U.S.	9.096	8.515	8.502	8.248	8.040	7.869	7.784	7.710	7.641	7.581	8.112	8.429	8.749	9.059	9.382

Note: Table 3 in Chapter One summarizes production in a little different manner than is generally used throughout the report. The production shown in Table 3 for the Lower 48 States includes the offshore areas of California, the Gulf of Mexico and the East Coast. Alaska in that table includes South Alaska (NPC Region 1) plus the North Slope.

TABLE 254

CRUDE OIL PRODUCTION
(Million Barrels/Day)

This Is the Trend Drilling and High Finding Case

Case IVA

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	.886	.879	.873	.868	.863	.859	.857	.856	.855	.854	.853	.835	.819	.804	.790
3	.118	.116	.115	.114	.114	.112	.111	.109	.108	.106	.104	.101	.099	.097	.095
4	.619	.566	.527	.496	.472	.452	.440	.430	.423	.417	.410	.408	.407	.406	.405
5	2.298	2.230	2.169	2.112	2.059	2.009	1.980	1.952	1.925	1.900	1.875	1.862	1.849	1.837	1.824
6	2.640	2.555	2.483	2.416	2.359	2.312	2.323	2.331	2.341	2.348	2.352	2.398	2.430	2.455	2.473
7	.855	.841	.824	.806	.788	.770	.746	.724	.705	.687	.671	.646	.622	.602	.583
8-10	.228	.231	.228	.229	.232	.237	.247	.256	.265	.275	.282	.291	.298	.304	.310
11	.019	.015	.014	.013	.015	.018	.020	.023	.025	.028	.030	.031	.033	.034	.035
Totals	7.662	7.433	7.232	7.056	6.902	6.770	6.724	6.682	6.648	6.615	6.577	6.572	6.558	6.539	6.516
Offshore and South Alaska															
1	.287	.266	.244	.238	.245	.262	.281	.304	.329	.366	.397	.420	.449	.474	.514
2A	.060	.064	.066	.081	.111	.151	.188	.232	.272	.307	.336	.360	.379	.394	.405
6A	1.087	1.092	1.065	1.067	1.071	1.069	1.058	1.039	1.012	.985	.953	.928	.902	.874	.848
11A	.000	.000	.000	.000	.001	.002	.004	.005	.007	.010	.012	.014	.023	.031	.041
Totals	1.434	1.421	1.375	1.387	1.428	1.484	1.530	1.580	1.621	1.668	1.699	1.722	1.753	1.772	1.809
Totals U.S. Ex North Slope	9.096	8.854	8.608	8.442	8.331	8.254	8.254	8.262	8.269	8.283	8.275	8.294	8.311	8.311	8.325
Northern Alaska															
Onshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.600	.950	1.300	1.650	2.000
Offshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Total No. Alaska	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.600	.950	1.300	1.650	2.000
Totals All U.S.	9.096	8.854	8.608	8.442	8.331	8.254	8.254	8.262	8.269	8.283	8.875	9.244	9.611	9.961	10.325

Note: Table 3 in Chapter One summarizes production in a little different manner than is generally used throughout the report. The production shown in Table 3 for the Lower 48 States includes the offshore areas of California, the Gulf of Mexico and the East Coast. Alaska in that table includes South Alaska (NPC Region 1) plus the North Slope.

TABLE 255

CRUDE OIL ANNUAL PRODUCTION PROJECTION BY SOURCES
TOTAL U.S. FOR EACH CASE

Summary of Production for All Regions

Case I

	Primary Oil Prod Thous Bbls	Secondary Oil Prod Thous Bbls	Tertiary Oil Prod Thous Bbls	Associated Gas Prod MMSCF	Yrly Total Oil Prod Thous Bbls
1971	3,320,061	0	0	4,812,431	3,320,061
1972	3,049,835	140,211	41,831	4,568,584	3,231,877
1973	2,808,549	263,554	79,389	4,335,481	3,151,492
1974	2,627,713	372,305	113,138	4,154,605	3,113,156
1975	2,499,116	468,187	143,468	4,011,606	3,110,771
1976	2,415,696	552,949	170,751	3,898,943	3,139,395
1977	2,351,965	621,892	231,838	3,832,947	3,205,695
1978	2,324,176	683,163	286,640	3,784,700	3,293,978
1979	2,308,799	742,434	335,680	3,743,174	3,386,912
1980	2,314,692	800,189	379,557	3,709,871	3,494,437
1981	2,317,873	856,969	418,850	3,670,015	3,593,692
1982	2,314,871	895,443	487,201	3,648,176	3,697,514
1983	2,319,982	935,657	548,551	3,621,013	3,804,191
1984	2,312,594	977,352	603,928	3,578,580	3,893,874
1985	2,314,042	1,025,818	654,020	3,538,310	3,993,879

Case 1A

	Primary Oil Prod Thous Bbls	Secondary Oil Prod Thous Bbls	Tertiary Oil Prod Thous Bbls	Associated Gas Prod MMSCF	Yrly Total Oil Prod Thous Bbls
1971	3,320,061	0	0	4,812,431	3,320,061
1972	3,035,772	139,933	41,801	4,544,316	3,217,505
1973	2,768,488	262,600	79,283	4,269,143	3,110,371
1974	2,548,843	370,506	112,938	4,030,602	3,032,287
1975	2,372,662	465,594	143,180	3,825,214	2,981,436
1976	2,235,107	549,593	170,378	3,651,452	2,955,077
1977	2,117,090	617,023	231,204	3,531,824	2,965,317
1978	2,028,779	675,752	285,697	3,429,868	2,990,228
1979	1,953,297	731,036	334,359	3,334,714	3,018,692
1980	1,898,162	783,161	377,780	3,250,545	3,059,103
1981	1,846,955	832,224	416,527	3,166,333	3,095,706
1982	1,797,232	861,050	483,832	3,106,963	3,142,113
1983	1,761,702	888,223	543,853	3,048,769	3,193,778
1984	1,727,396	915,569	597,464	2,984,303	3,240,429
1985	1,708,168	945,994	645,297	2,926,307	3,299,460

TABLE 255 (CONT'D)

CRUDE OIL ANNUAL PRODUCTION PROJECTION BY SOURCES
TOTAL U.S. FOR EACH CASE

Summary of Production for All Regions

Case II

	Primary Oil Prod Thous Bbls	Secondary Oil Prod Thous Bbls	Tertiary Oil Prod Thous Bbls	Associated Gas Prod MMSCF	Yrly Total Oil Prod Thous Bbls
1971	3,320,061	0	0	4,812,431	3,320,061
1972	3,049,835	140,211	41,831	4,568,584	3,231,877
1973	2,805,995	263,482	79,381	4,331,728	3,148,857
1974	2,620,847	372,142	113,120	4,145,123	3,106,108
1975	2,485,142	467,909	143,437	3,993,603	3,096,487
1976	2,388,887	552,485	170,699	3,866,821	3,112,071
1977	2,307,779	621,199	231,719	3,782,570	3,160,697
1978	2,257,615	681,875	286,389	3,711,765	3,225,879
1979	2,215,663	740,255	335,269	3,643,420	3,291,186
1980	2,191,155	796,670	378,953	3,581,115	3,366,778
1981	2,164,955	851,103	417,970	3,512,989	3,434,027
1982	2,135,462	886,585	485,798	3,465,571	3,507,845
1983	2,116,513	922,605	546,498	3,416,792	3,585,616
1984	2,089,834	959,143	601,052	3,357,470	3,650,029
1985	2,069,959	1,000,860	650,155	3,298,001	3,720,974

Case III

	Primary Oil Prod Thous Bbls	Secondary Oil Prod Thous Bbls	Tertiary Oil Prod Thous Bbls	Associated Gas Prod MMSCF	Yrly Total Oil Prod Thous Bbls
1971	3,320,061	0	0	4,812,431	3,320,061
1972	3,035,772	139,933	41,801	4,544,316	3,217,505
1973	2,766,633	262,549	79,277	4,266,525	3,108,458
1974	2,544,167	370,398	112,926	4,024,417	3,027,490
1975	2,363,444	465,415	143,160	3,813,747	2,972,019
1976	2,217,685	549,305	170,346	3,630,863	2,937,336
1977	2,088,888	616,606	231,134	3,499,274	2,936,628
1978	1,986,899	674,897	285,527	3,382,722	2,947,324
1979	1,895,248	729,543	334,067	3,270,639	2,958,858
1980	1,821,693	780,746	377,345	3,167,868	2,979,784
1981	1,752,894	828,289	415,892	3,065,352	2,997,075
1982	1,687,408	855,354	482,832	2,989,082	3,025,593
1983	1,634,971	880,073	542,407	2,915,072	3,057,451
1984	1,583,583	904,458	595,504	2,836,468	3,083,544
1985	1,545,048	931,287	642,787	2,762,101	3,119,122

TABLE 255 (CONT'D)

CRUDE OIL ANNUAL PRODUCTION PROJECTION BY SOURCES
TOTAL U.S. FOR EACH CASE

Summary of Production for All Regions

Case IV

	Primary Oil Prod Thous Bbls	Secondary Oil Prod Thous Bbls	Tertiary Oil Prod Thous Bbls	Associated Gas Prod MMSCF	Yrly Total Oil Prod Thous Bbls
1971	3,320,061	0	0	4,812,431	3,320,061
1972	3,035,772	139,933	41,801	4,544,316	3,217,505
1973	2,761,644	262,409	79,261	4,259,484	3,103,314
1974	2,527,565	370,021	112,884	4,002,562	3,010,470
1975	2,326,948	464,726	143,083	3,768,620	2,934,757
1976	2,153,770	548,254	170,229	3,555,427	2,872,253
1977	1,995,136	615,208	230,909	3,390,968	2,841,254
1978	1,856,681	672,350	285,036	3,235,678	2,814,067
1979	1,730,928	724,772	333,175	3,087,657	2,788,875
1980	1,618,774	772,417	375,940	2,945,643	2,767,131
1981	1,512,536	815,247	413,918	2,804,777	2,741,701
1982	1,412,306	837,696	480,014	2,692,850	2,730,017
1983	1,324,230	856,128	538,536	2,582,889	2,718,894
1984	1,240,282	873,736	590,415	2,472,308	2,704,432
1985	1,166,666	891,525	636,302	2,366,307	2,694,494

Case IVA

	Primary Oil Prod Thous Bbls	Secondary Oil Prod Thous Bbls	Tertiary Oil Prod Thous Bbls	Associated Gas Prod MMSCF	Yrly Total Oil Prod Thous Bbls
1971	3,320,061	0	0	4,812,431	3,320,061
1972	3,049,835	140,211	41,831	4,568,584	3,231,877
1973	2,799,150	263,288	79,359	4,321,674	3,141,797
1974	2,596,768	371,579	113,058	4,112,000	3,081,405
1975	2,430.501	466,846	143,319	3,923,426	3,040,665
1976	2,291,329	550,818	170,514	3,749,169	3,012,661
1977	2,162,482	618,923	231,348	3,615,270	3,012,752
1978	2,051,775	678,025	285,663	3,483,982	3,015,463
1979	1,950,717	733,406	334,039	3,355,413	3,018,163
1980	1,861,493	784,804	377,072	3,230,166	3,023,369
1981	1,773,195	832,024	415,327	3,102,097	3,020,545
1982	1,685,818	859,486	481,900	2,999,110	3,027,204
1983	1,608,208	884,434	541,016	2,895,682	3,033,657
1984	1,530,575	909,316	593,655	2,789,104	3,033,546
1985	1,462,986	935,268	640,423	2,686,602	3,038,677

Note: On this table primary oil production includes all production from known reserves existing on 1/1/71 plus the primary production from oil-in-place discovered after 1/1/71. Secondary oil production includes production from all secondary recovery projects initiated after 1/1/71 in both new fields and fields discovered prior to 1/1/71. Tertiary oil production includes production from all tertiary recovery projects initiated after 1/1/71 in both new fields discovered after 1/1/71 and fields discovered prior to 1/1/71. The following text is devoted to correcting these figures to reflect actual current production levels from primary, secondary, and tertiary sources regardless of the time the projects were initiated.

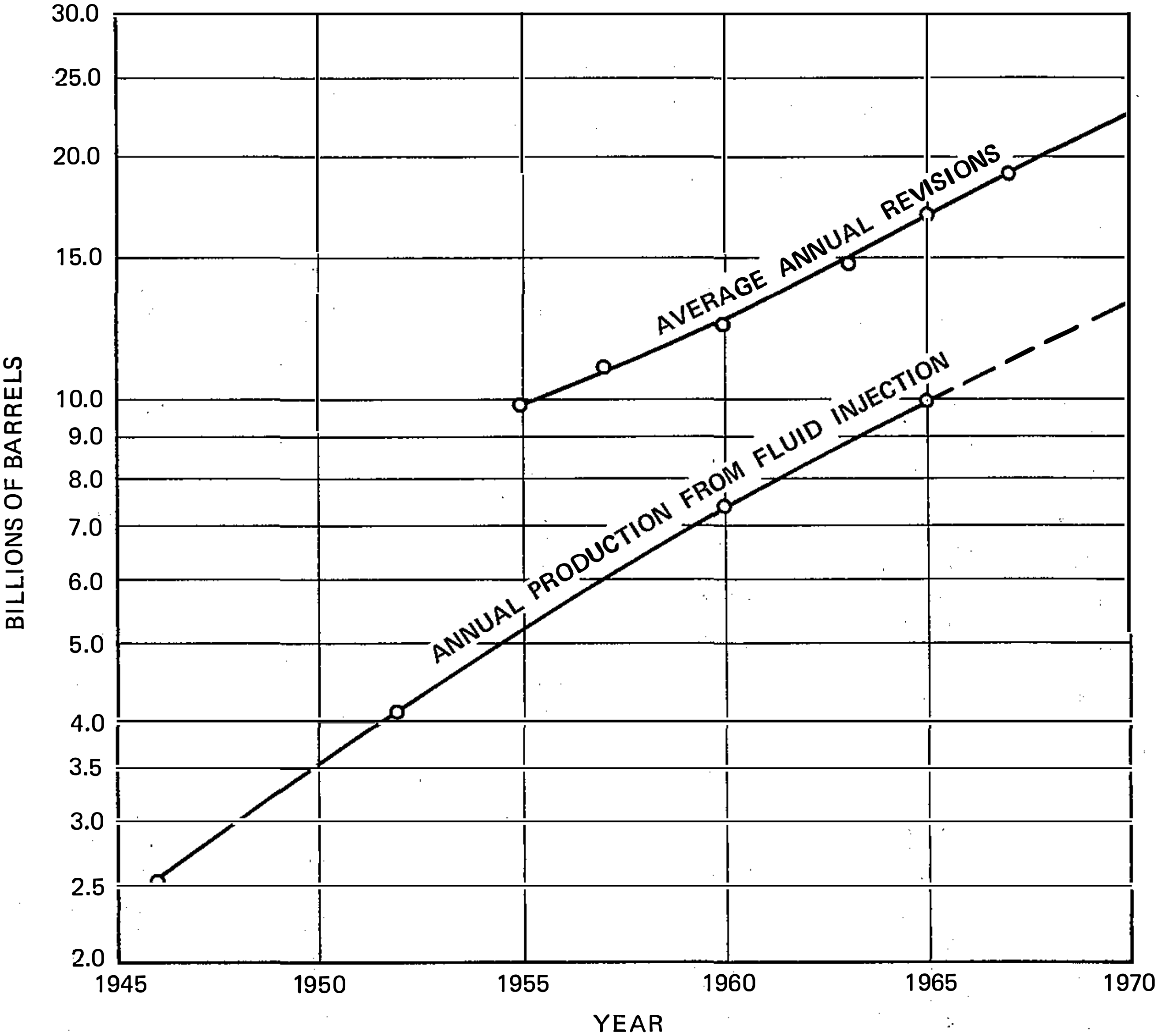


Figure 78. Fluid Injection Revisions As a Function of Time.

new fields subsequently found. Future production from old fields will arise from two sources. The first of these is a continuation of primary, secondary and tertiary activities already underway. The second will result from secondary and tertiary activities not yet applied to old fields but which will be started in the future when conditions are appropriate. Of course, for new fields yet to be found all three methods will be initiated at the appropriate times. It is expected that secondary and tertiary methods will be applied much earlier in the life of new fields than for old fields. Even so, because of the time required to find and develop new fields, the contribution to production by secondary and tertiary methods from new fields will be a relatively small part of the total production to be had in the period to 1985. On the other hand, the contribution from these sources from old fields can be expected to be the major part of the contribution during the period.

As of January 1, 1971, 39.3 percent of the total domestic production is attributable to fluid injection. This equals 3.58 million barrels per day. On the basis of the best information available, it was

TABLE 256

U.S. PRODUCTION (1956-1970)*

	Primary		By Fluid Injection		Total		
	Annual MMB	Daily MB	Annual MMB	Daily MB	Annual MMB	Daily MB	Percent of Total
1956	1984	5436	575	1576	2559	7012	22.5
1957	1944	5327	615	1685	2559	7012	24.0
1958	1720	4713	656	1797	2376	6510	27.6
1959	1792	4927	695	1904	2493	6831	27.9
1960	1732	4745	740	2028	2472	6773	29.9
1961	1722	4718	785	2151	2507	6869	31.3
1962	1722	4718	830	2274	2552	6992	32.5
1963	1733	4749	880	2411	2613	7160	33.7
1964	1715	4699	930	2548	2645	7247	35.2
1965	1719	4710	980	2685	2699	7395	36.3
1966	1824	5096	1040	2849	2864	7847	36.3
1967	1948	5338	1100	3014	3048	8352	36.1
1968	2001	5483	1160	3178	3161	8661	36.7
1969	1965	5384	1220	3343	3185	8727	38.3
1970	2014	5518	1305	3576	3319	9094	39.3

* Excluding North Slope.

estimated that, as of this date, 100,000 barrels per day of this amount could be ascribed to tertiary recovery. In establishing future production from activities under way as of January 1, 1971, it was assumed that the contribution from these sources would decline in a constant manner throughout the period to 1985. The values so derived are applicable to all cases considered and are tabulated in Table 257 which provides complete data for Case II.*

To establish secondary and tertiary recovery factors for production subsequent to January 1, 1971, each region was considered separately. A recovery factor is the fraction of original oil-in-place which will be produced as a result of a particular recovery mechanism. In evaluating secondary and tertiary recovery factors a number of pertinent items were considered. Among the more impotant were the relative amount of reserves to be found in each of several kinds of reservoirs, the relative depths, the nature of the major reservoir and fluid parameters such as porosity, permeability, oil viscosity, associated gas, reservoir pressure, etc. A very important item is the primary recovery factor, for it governs how much oil is left to be recovered by secondary or tertiary methods. The regional primary recovery factors used are tabulated below:

* It should be noted that all of these calculations exclude the North Slope for which no effort was made to differentiate the production by type of recovery. Further information is given in Table 284.

Primary Recovery Factors Fraction of Original Oil-in-Place Recovered

Region	The Initial Appraisal	Currently Being Used
1	0.23	0.23
2	0.233	0.233
2A	0.233	0.233
3	0.22	0.22
4	0.24	0.24
5	0.20	0.20
6	0.465	0.465
6A	0.476	0.476
7	0.25	0.25
8-10	0.274	0.274
11	0.23	0.33*
11A	——	0.33*

* Based upon anticipation as to the nature of the reservoirs and fluids expected to be found.

TABLE 257

CRUDE OIL PRODUCTION PROJECTED 1971-1985 – CASE II*
ALLOCATED BY TYPE OF RECOVERY MECHANISM
(Millions of Barrels Per Day)

		1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	Total
From Old Fields																	
From operations under way as of 1-1-71	Primary	5.52	4.87	4.31	3.81	3.37	2.99	2.65	2.34	2.08	1.85	1.64	1.46	1.29	1.15	1.03	40.36
	Secondary	3.48	3.07	2.71	2.41	2.14	1.88	1.67	1.48	1.32	1.16	1.04	0.92	0.83	0.74	0.66	25.51
	Tertiary	0.10	0.09	0.08	0.06	0.05	0.05	0.04	0.04	0.03	0.03	0.02	0.02	0.01	0.01	0	0.63
	Total	9.10	8.03	7.10	6.28	5.56	4.92	4.36	3.86	3.43	3.04	2.70	2.40	2.13	1.90	1.69	66.50
From operations after 1-1-71	Primary	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
	Secondary	0	0.37	0.71	1.00	1.25	1.48	1.63	1.75	1.87	1.97	2.06	2.07	2.09	2.10	2.11	22.46
	Tertiary	0	0.11	0.22	0.31	0.39	0.46	0.62	0.76	0.89	1.00	1.11	1.28	1.43	1.56	1.68	11.82
	Total	0	0.48	0.93	1.31	1.64	1.94	2.25	2.51	2.76	2.97	3.17	3.35	3.52	3.66	3.79	34.28
Sub Total	Primary	5.52	4.87	4.31	3.81	3.37	2.99	2.65	2.34	2.08	1.85	1.64	1.46	1.29	1.15	1.03	40.36
	Secondary	3.48	3.44	3.42	3.41	3.39	3.36	3.30	3.23	3.19	3.13	3.10	2.99	2.92	2.84	2.77	47.97
	Tertiary	0.10	0.20	0.30	0.37	0.44	0.51	0.66	0.80	0.92	1.03	1.13	1.30	1.44	1.57	1.68	12.45
Old Fields	Total	9.10	8.51	8.03	7.59	7.20	6.86	6.61	6.37	6.19	6.01	5.87	5.75	5.65	5.56	5.48	100.78
From New Fields																	
	Primary	0	0.32	0.59	0.90	1.25	1.63	1.96	2.32	2.64	2.96	3.23	3.45	3.67	3.83	3.98	32.73
	Secondary	0	0.01	0.02	0.02	0.03	0.03	0.08	0.11	0.16	0.21	0.27	0.36	0.44	0.53	0.63	2.90
	Tertiary	0	0	0	0	0	0	0.01	0.02	0.03	0.03	0.04	0.05	0.07	0.08	0.10	.43
New Fields	Total	0	0.33	0.61	0.92	1.28	1.66	2.05	2.45	2.83	3.20	3.54	3.86	4.18	4.44	4.71	36.06
Totals	Primary	5.52	5.19	4.90	4.71	4.62	4.62	4.61	4.66	4.72	4.81	4.87	4.91	4.96	4.98	5.01	73.09
	Secondary	3.48	3.45	3.44	3.43	3.42	3.39	3.38	3.34	3.35	3.34	3.37	3.35	3.36	3.37	3.40	50.87
	Tertiary	0.10	0.20	0.30	0.37	0.44	0.51	0.67	0.82	0.95	1.06	1.17	1.35	1.51	1.65	1.78	12.88
Grand Total		9.10	8.84	8.64	8.51	8.48	8.52	8.66	8.82	9.02	9.21	9.41	9.61	9.83	10.00	10.19	136.84

* Excluding North Slope.

The selected regional factors for secondary and tertiary recovery represent the collective judgment of the committee in light of the considerations enumerated above. In addition to the effect of primary recovery on secondary or tertiary factors, if tertiary recovery follows secondary recovery rather than primary—as it will in a number of cases, particularly for fields found prior to January 1, 1973—the factor for tertiary recovery must be further modified to allow for the oil already produced by both primary and secondary activities. These considerations were felt to be best handled by placing certain constraints in the calculation procedure to provide the necessary adjustments. The restraints are set forth below.

Secondary Recovery Constraints

	Old Oil	New Oil
First Limitation	Don't exceed 75% of primary. For example, if primary = 25%, secondary additions cannot exceed 18.75%.	Don't exceed primary recovery efficiency. For example, if primary = 20%, secondary additions cannot exceed 20%.
Second Limitation	Don't exceed 50% for primary + secondary in all regions except 6 and 6A. In Regions 6 and 6A, don't exceed 60%.	Don't exceed 50% for primary + secondary in all regions except 6 and 6A. In Regions 6 and 6A, don't exceed 60%.

Tertiary Recovery Constraints

Old Oil	New Oil
Don't exceed 50% for primary + secondary in all regions except 6 and 6A. For example, if primary + secondary add up to 50%, no tertiary would apply. For Regions 6 and 6A, the constraint is don't exceed 60% (primary + secondary).	Don't exceed 60% for primary + secondary. This applies to all regions. For example, if primary + secondary = 50%, tertiary can generate 10% additional recovery.

In addition to the above constraints, delay factors for each region were developed to provide for appropriate time intervals subsequent to discovery before secondary and tertiary operations are initiated (see Section V of Chapter Five). The relative magnitudes of production to be expected from the several sources of primary, secondary and tertiary production are given in Table 257 for Case II and are presented graphically for all six cases considered.

Offshore Oil Production History

In the past and at present, only three U.S. regions have provided offshore oil—Regions 1, Alaska; 2A, Pacific Coast (all from offshore California, so far); and 6A, Gulf of Mexico. Exclusive of the North Slope, essentially all of Alaskan production has come from offshore in the Cook Inlet. As a consequence, the production statistics used for Alaska offshore are those given for Alaska in Table III-2 of the API Reserves Statistics as of December 31, 1970. Similarly, the production figures for Region 6A, Gulf of Mexico, are those of Table III-45 of the API Statistics.*

Statistics for California Offshore oil are not treated separately by the API. Therefore, it was necessary to resort to other sources. The figures provided by the Conservation Committee of California Oil Producers' report, *Annual Review of California Oil and Gas Production*, were used. Several California fields underlie both the land and the ocean and have been produced for many years with little effort to segregate the production from the land and sea portions. A number of these fields are well past their prime, and the preponderance of their produced oil has been from the portion beneath the land. In view of the desire to relate recent past offshore history to expected future history, the Task Group judged that such fields should be omitted from its offshore figures unless the greater part of the production was from offshore, as is the case for the Elwood Field, or unless some new segments of a field had been found offshore for which separate figures were available. The fields included are given, together with their cumulative production, in Table 259.

In order to provide smoothed yearly figures, average annual figures were developed from the differences between the 5-year cumulative numbers. These, together with offshore production fig-

* API, *Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada and U.S. Productive Capacity* (May 1971).

ures for Alaska and the Gulf of Mexico, are given in Table 260. The sums of these annual figures result in the historical values for domestic offshore oil used in this report.

TABLE 258

DAILY AVERAGE CRUDE OIL PRODUCTION*
(Million Barrels)

	Case I				Case IA			
	1971	1975	1980	1985	1971	1975	1980	1985
Old Primary	5.52	3.37	1.85	1.03	5.52	3.37	1.85	1.03
New Primary	0	1.29	3.30	4.65	0	0.95	2.16	2.99
Old Field Secondary	3.48	3.39	3.13	2.77	3.48	3.39	3.13	2.77
New Field Secondary	0	0.03	0.22	0.70	0	0.02	0.18	0.48
Old Field Tertiary	0.10	0.44	1.03	1.68	0.10	0.44	1.03	1.68
New Field Tertiary	0	0	0.04	0.11	0	0	0.03	0.09
Total	9.10	8.52	9.57	10.94	9.10	8.17	8.38	9.04
	Case II				Case III			
Old Primary	5.52	3.37	1.85	1.03	5.52	3.37	1.85	1.03
New Primary	0	1.25	2.96	3.98	0	0.92	1.95	2.55
Old Field Secondary	3.48	3.39	3.13	2.77	3.48	3.39	3.13	2.77
New Field Secondary	0	0.03	0.21	0.63	0	0.02	0.17	0.44
Old Field Tertiary	0.10	0.44	1.03	1.68	0.10	0.44	1.03	1.68
New Field Tertiary	0	0	0.03	0.10	0	0	0.03	0.08
Total	9.10	8.48	9.21	10.19	9.10	8.14	8.16	8.55
	Case IV				Case IVA			
Old Primary	5.52	3.37	1.85	1.03	5.52	3.37	1.85	1.03
New Primary	0	0.82	1.39	1.51	0	1.10	2.06	2.82
Old Field Secondary	3.48	3.39	3.13	2.77	3.48	3.39	3.13	2.77
New Field Secondary	0	0.02	0.15	0.33	0	0.02	0.18	0.45
Old Field Tertiary	0.10	0.44	1.03	1.68	0.10	0.44	1.03	1.68
New Field Tertiary	0	0	0.03	0.06	0	0	0.03	0.07
Total	9.10	8.04	7.58	7.38	9.10	8.32	8.28	8.32

* Excluding North Slope.

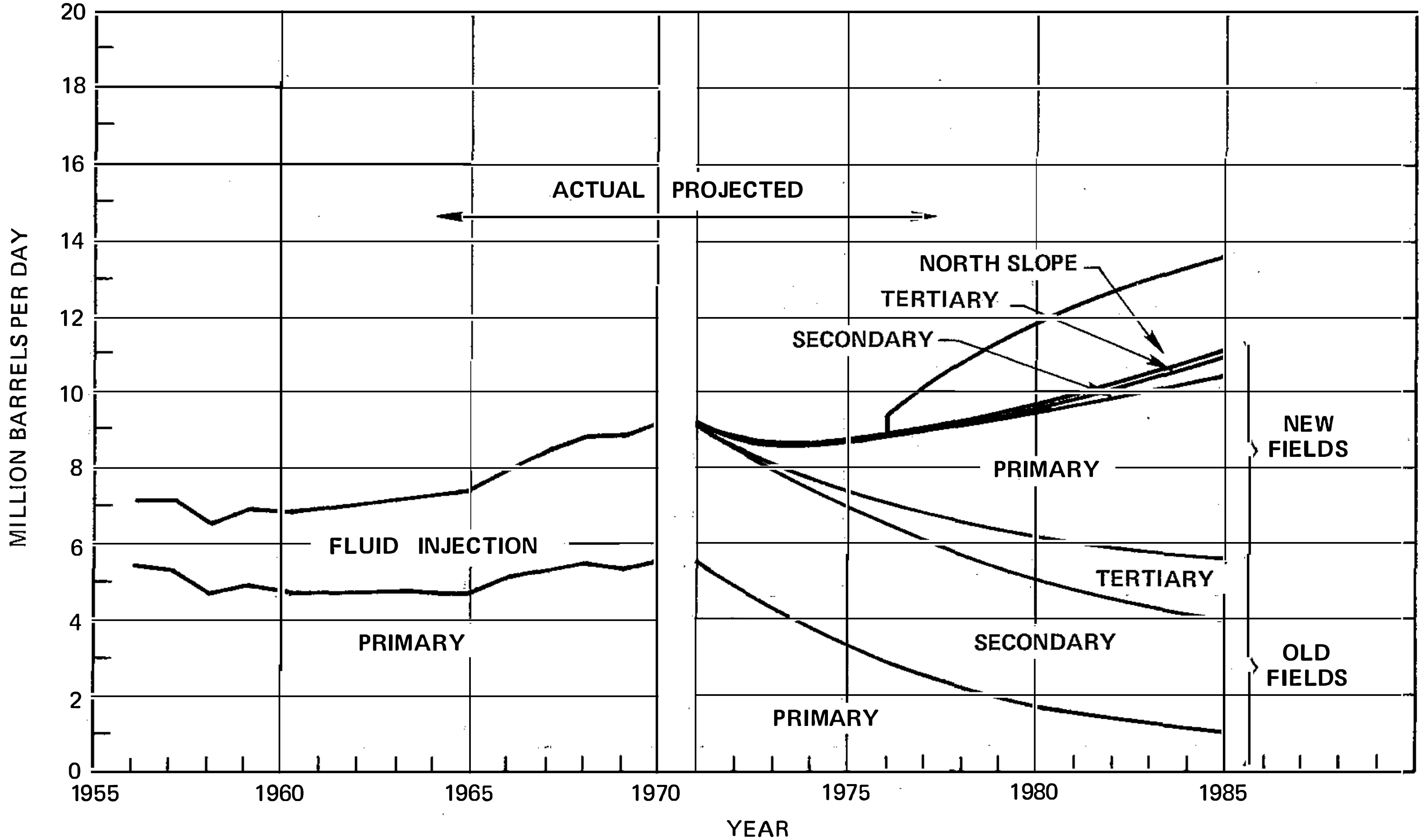


Figure 79. Production by Recovery Method—Case I.

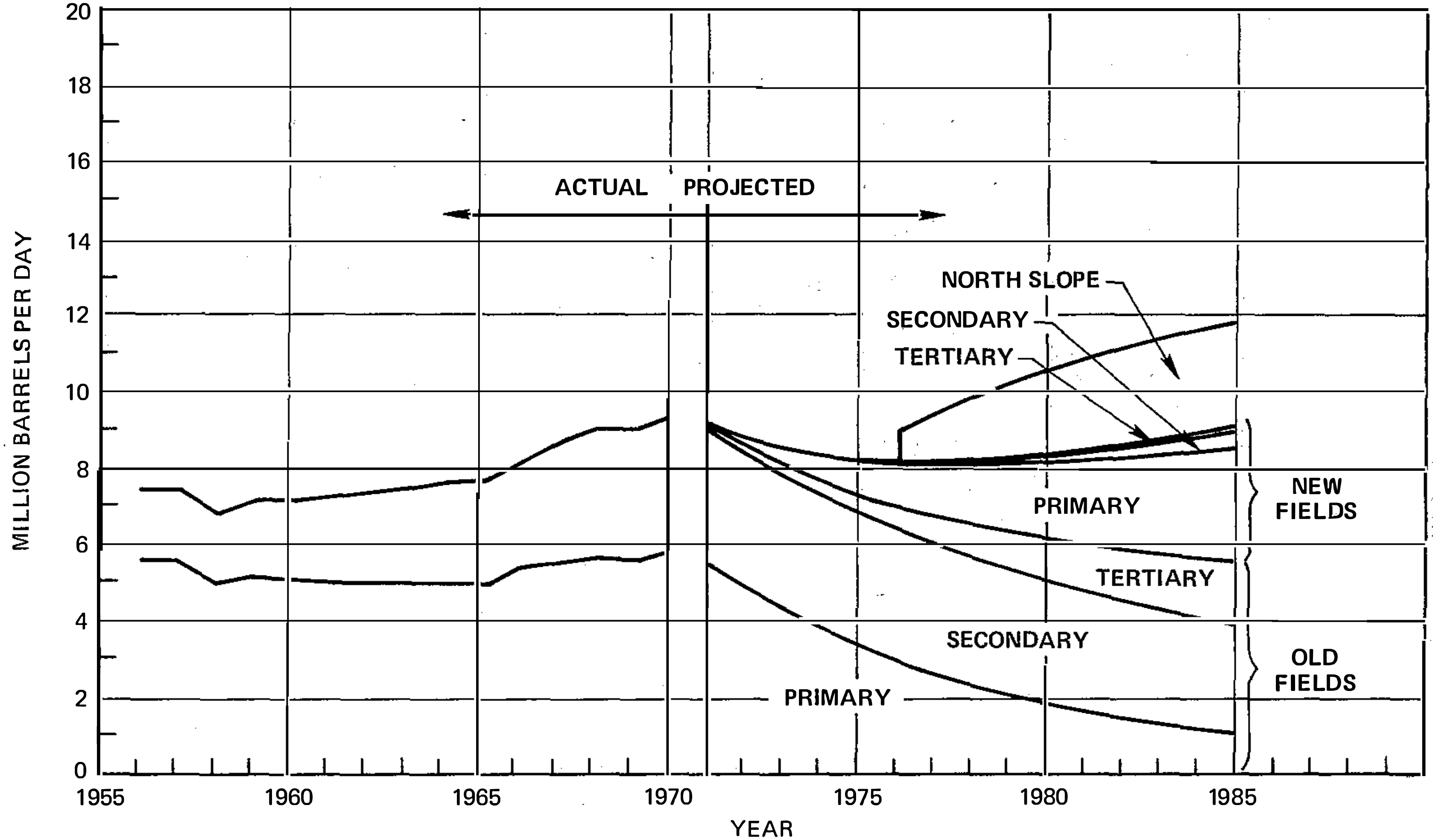


Figure 80. Production by Recovery Method—Case IA.

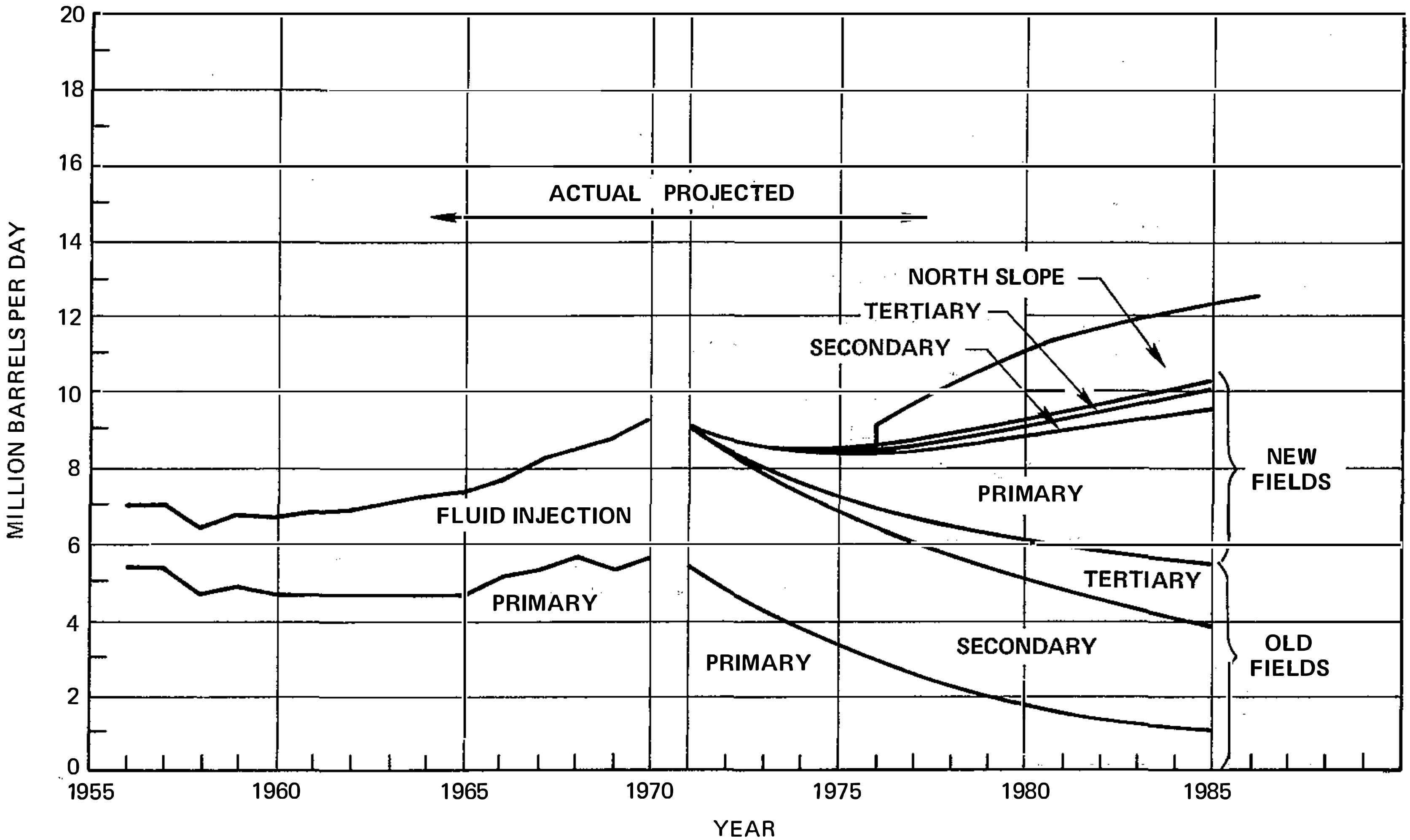


Figure 81. Production by Recovery Method—Case II.

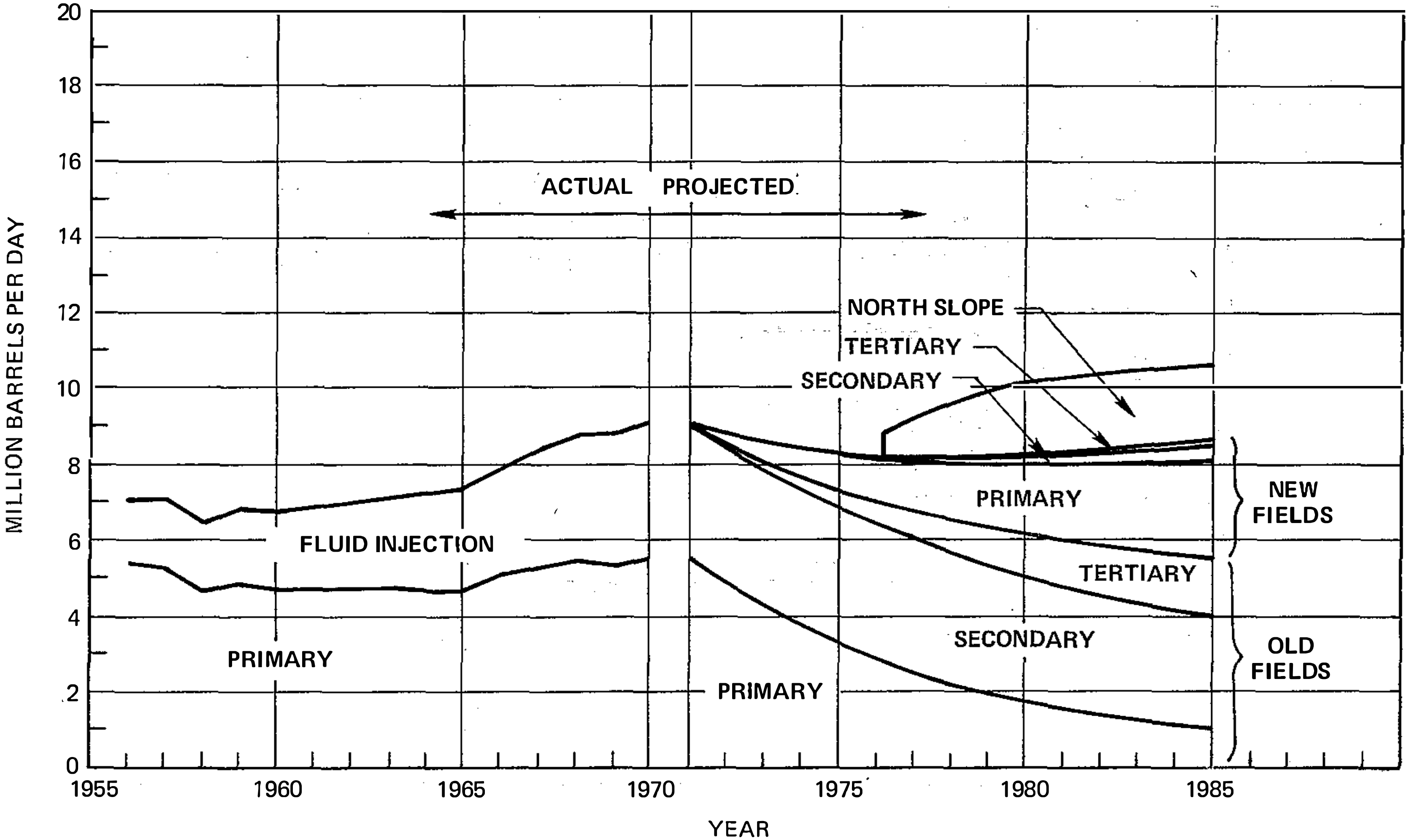


Figure 82. Production by Recovery Method—Case III.

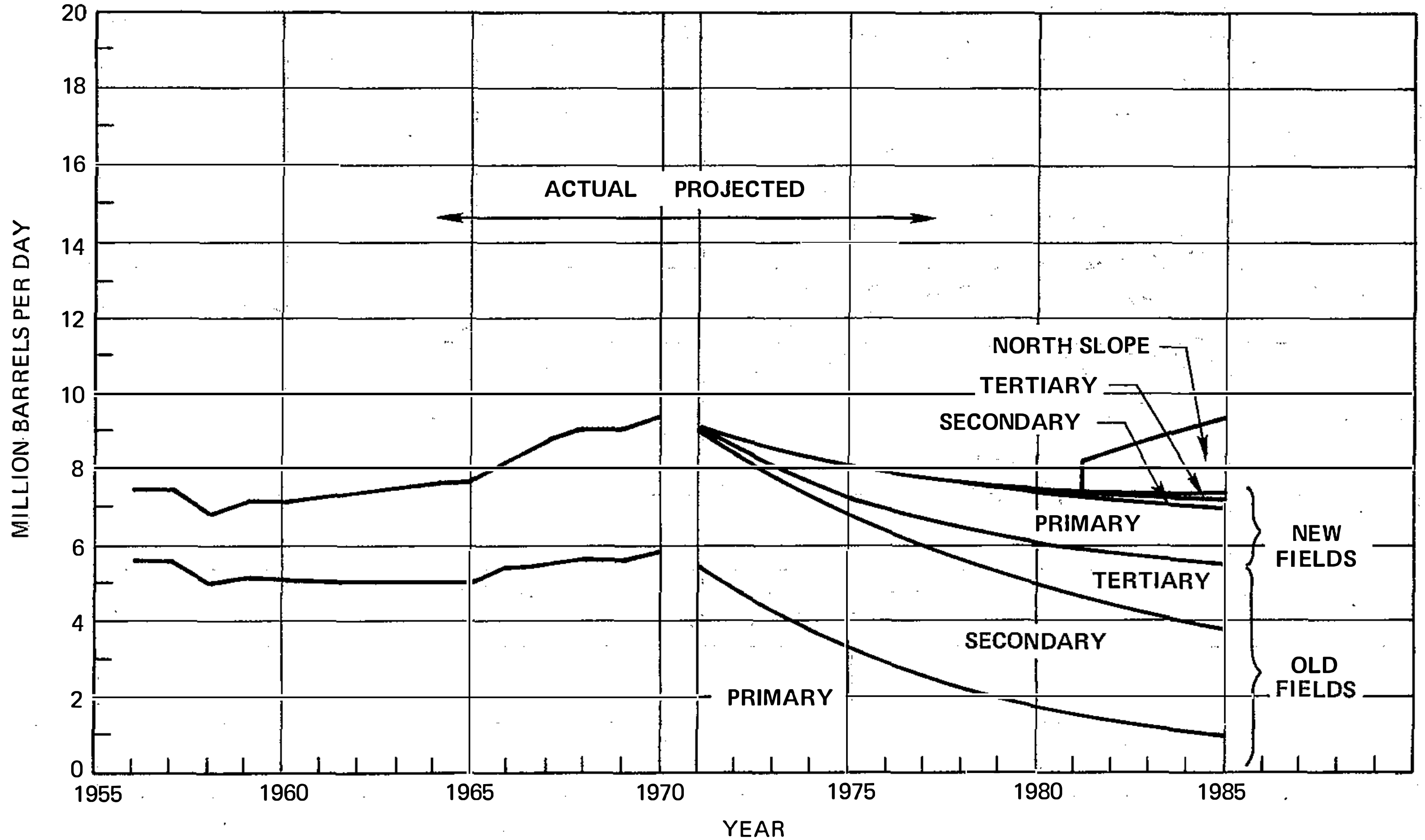


Figure 83. Production by Recovery Method—Case IV.

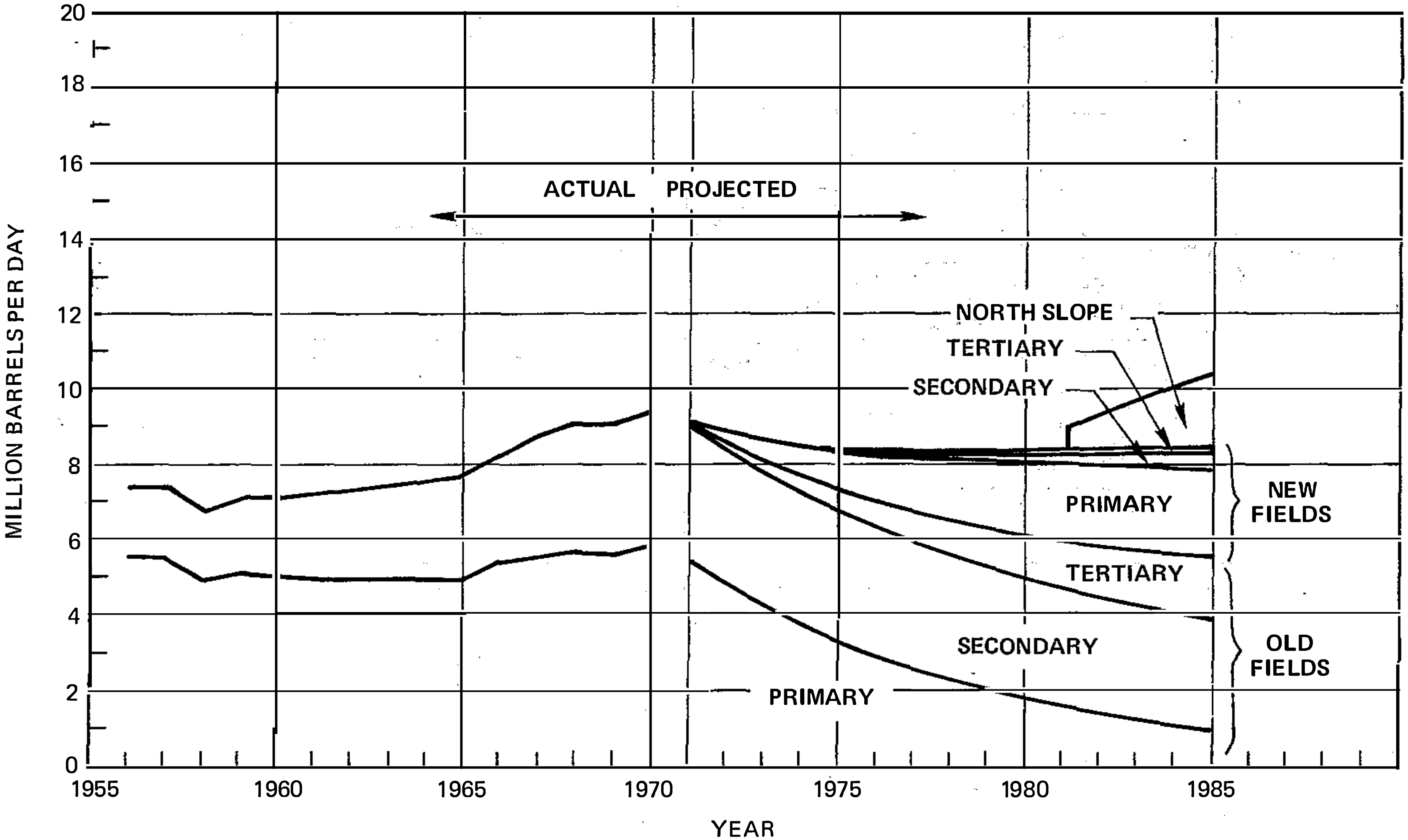


Figure 84. Production by Recovery Method—Case IVA.

TABLE 259

CALIFORNIA OFFSHORE PRODUCTION SINCE 1955

Field	Cumulative Production (Thousands of Barrels)			
	1-1-55	1-1-60	1-1-65	1-1-70
Alegria			49	154
Belmont				12,059
Carpenteria				20,359
Coal Oil Point			282	1,075
Conception			12,699	19,726
Cuarta			495	600
Dos Quadros				6,817
Elwood	94,609	99,807	101,864	102,988
Point Conception				155
South Elwood				3,993
Summerland (New)		78	15,192	21,845
Venice				1,452
West Newport	282	1,637	2,675	3,302
Total	94,891	101,522	133,256	194,525

TABLE 260

UNITED STATES OFFSHORE OIL PRODUCTION

	Annual Production (Thousands of Barrels)			
	Alaska	California*	Gulf of Mexico	Total
1956		1,080	35,822	36,902
1957		1,320	47,901	49,221
1958	36	1,650	52,051	53,737
1959	187	2,050	67,810	70,047
1960	578	2,505	81,603	84,686
1961	6,327	3,170	95,189	104,686
1962	10,259	3,920	117,180	131,359
1963	10,740	4,900	135,170	150,810
1964	11,054	6,100	155,287	172,441
1965	11,130	7,700	183,728	202,558
1966	14,362	9,700	225,806	249,868
1967	28,917	10,240	269,322	308,479
1968	66,146	15,500	306,176	387,822
1969	74,101	19,700	336,478	430,279
1970	82,989	25,500	372,890	481,379

* From curve shown on Figure 85.

Source: API Reserve Volume 1970, Tables III-2 and III-45.

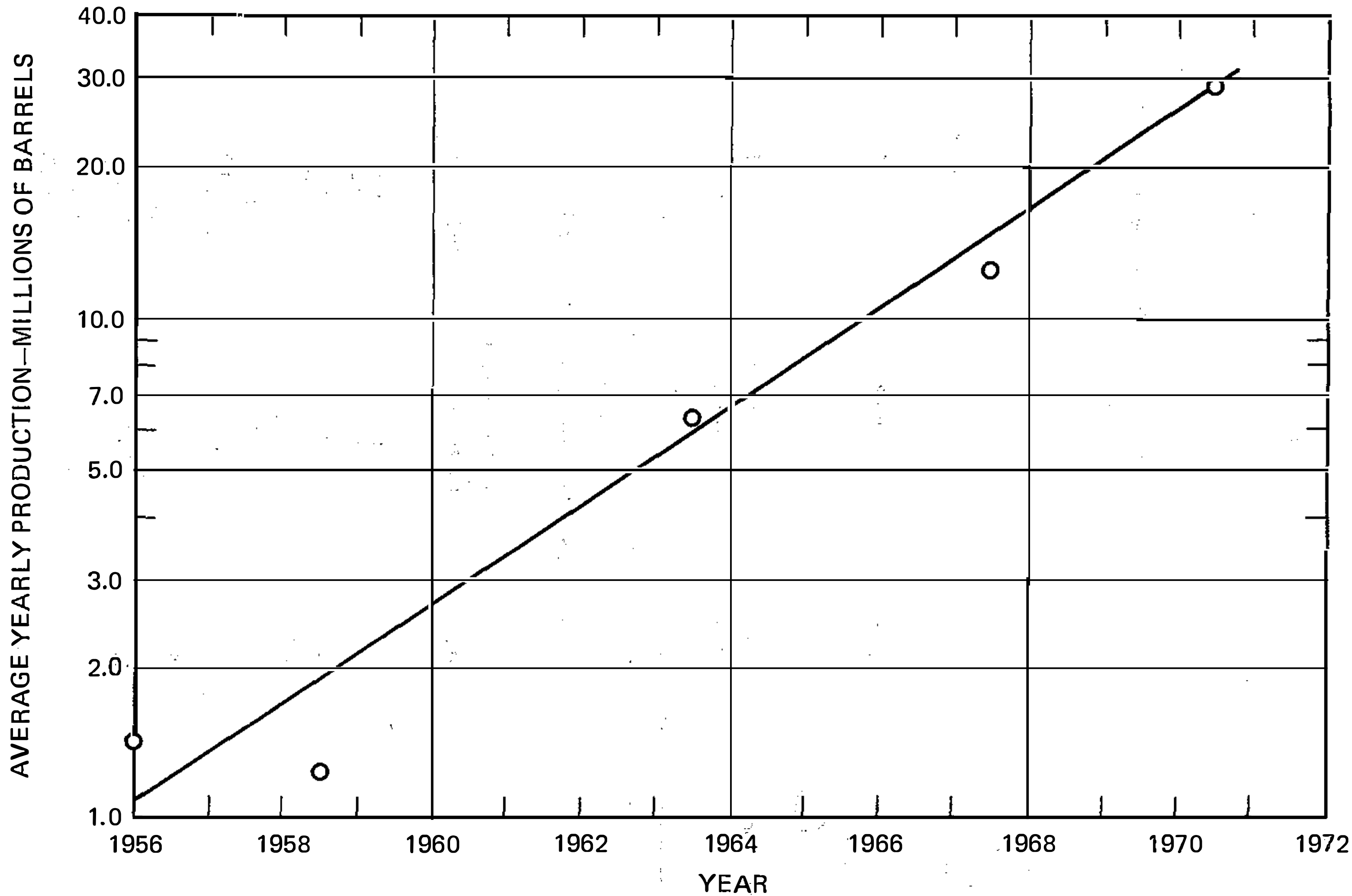


Figure 85. California Offshore Production History for Selected Fields.

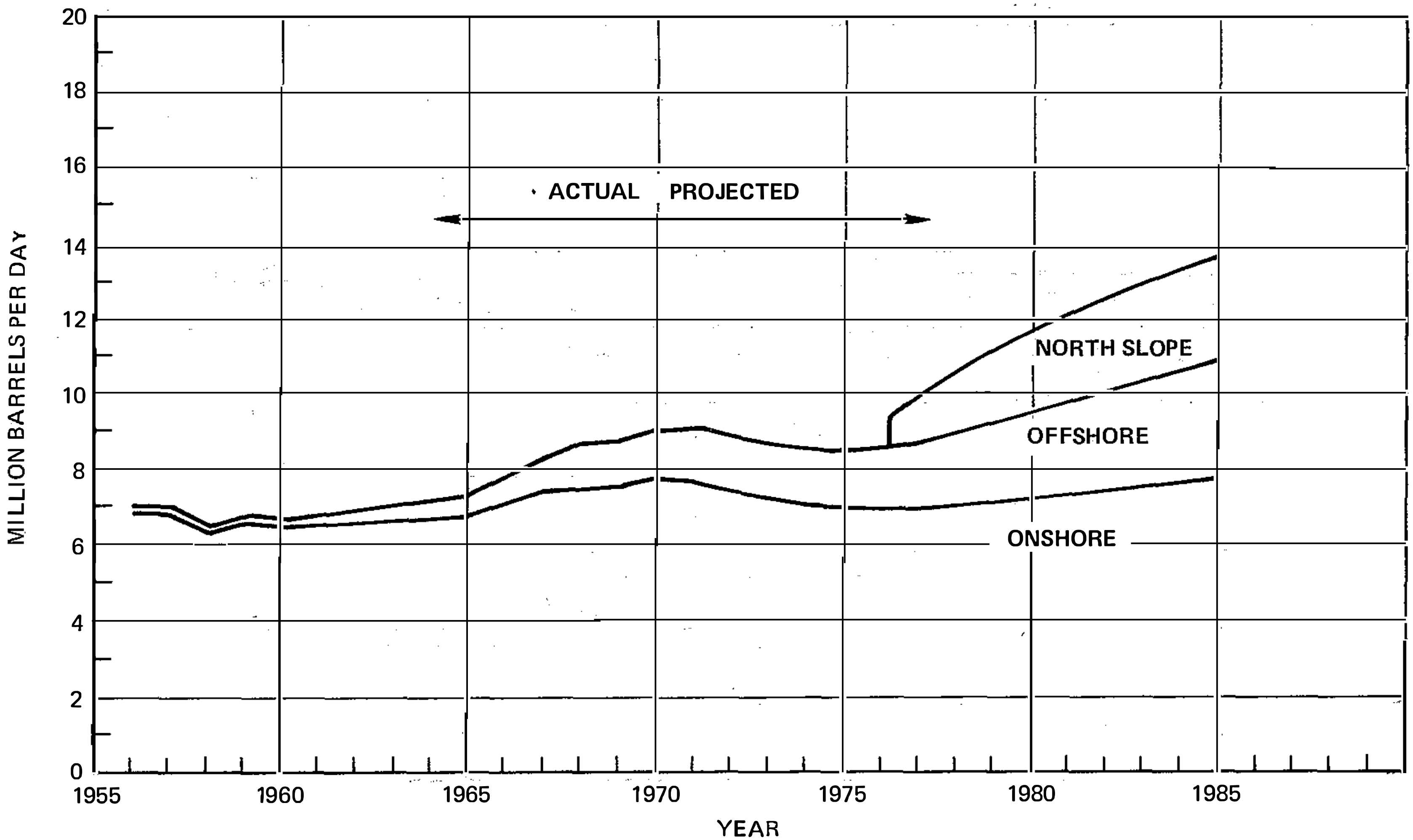


Figure 86. Offshore Production—Case I.

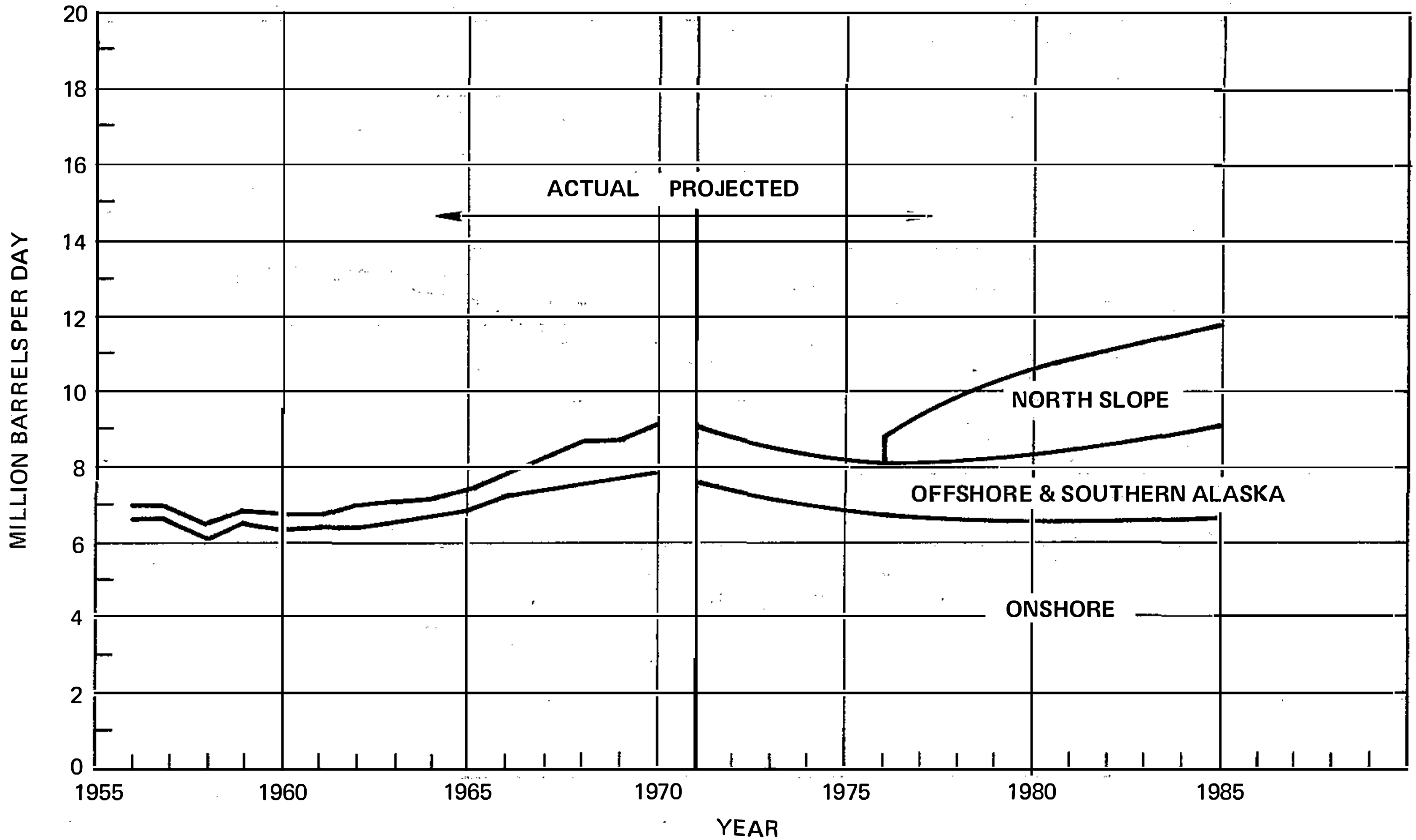


Figure 87. Offshore Production—Case IA.

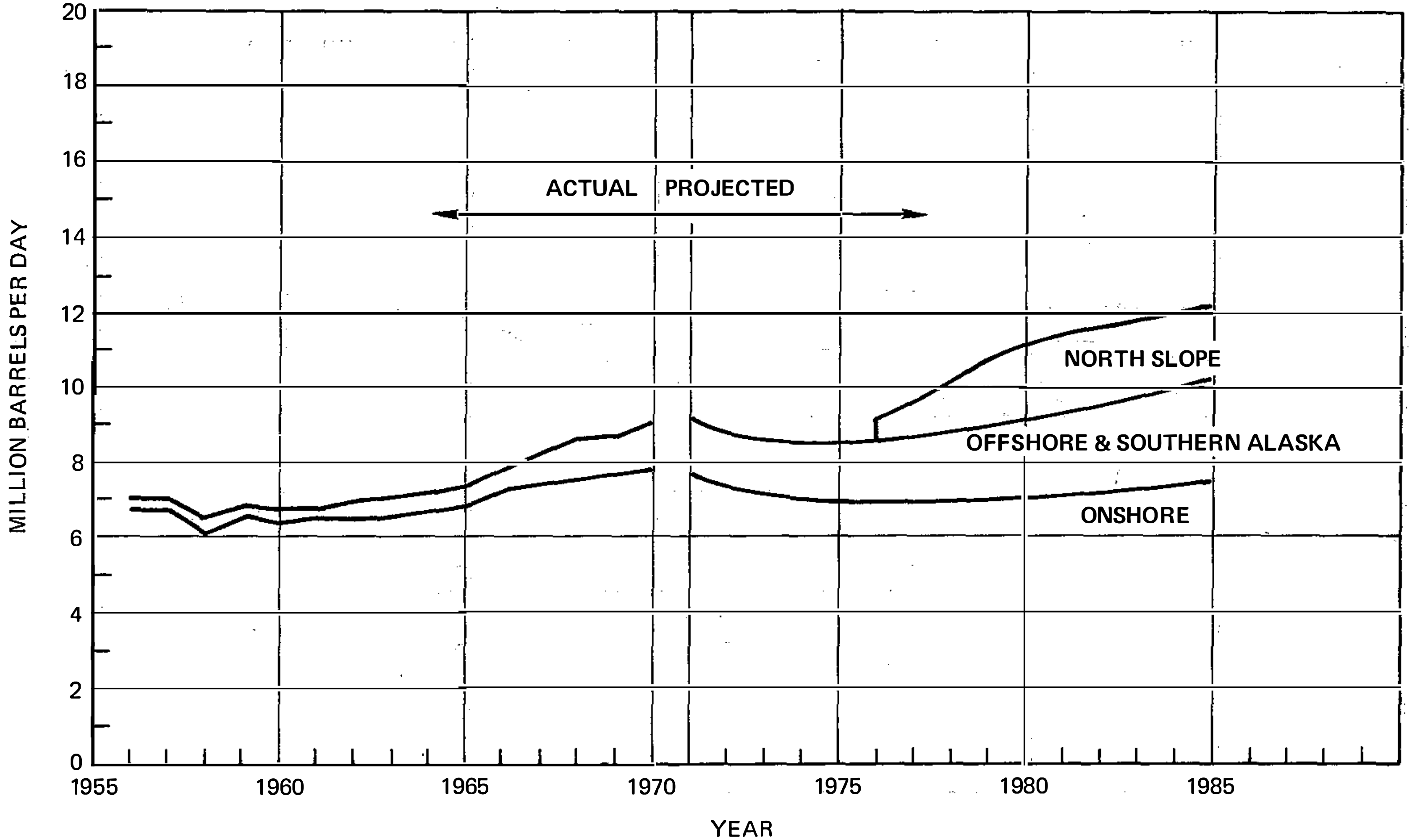


Figure 88. Offshore Production—Case II.

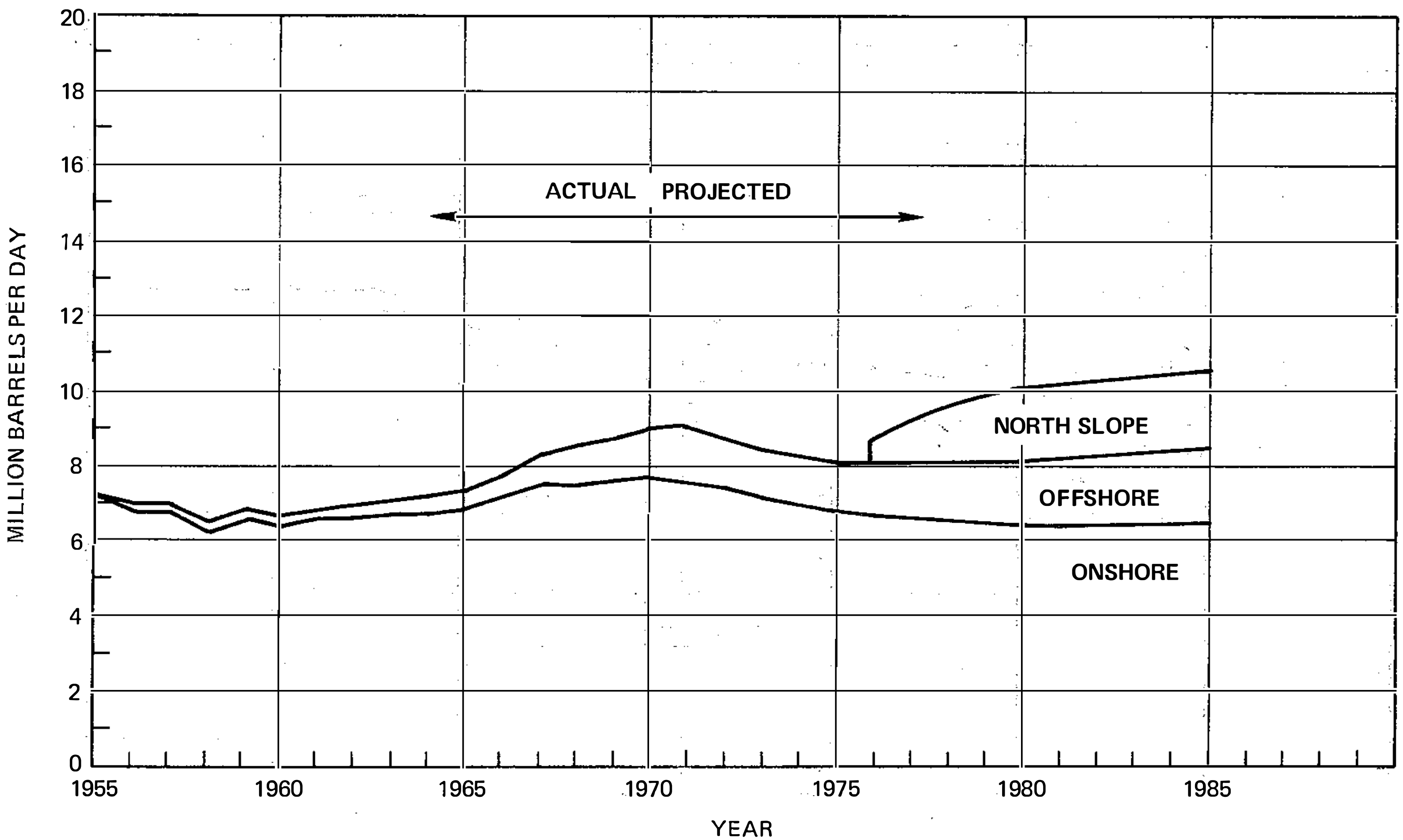


Figure 89. Offshore Production—Case III.

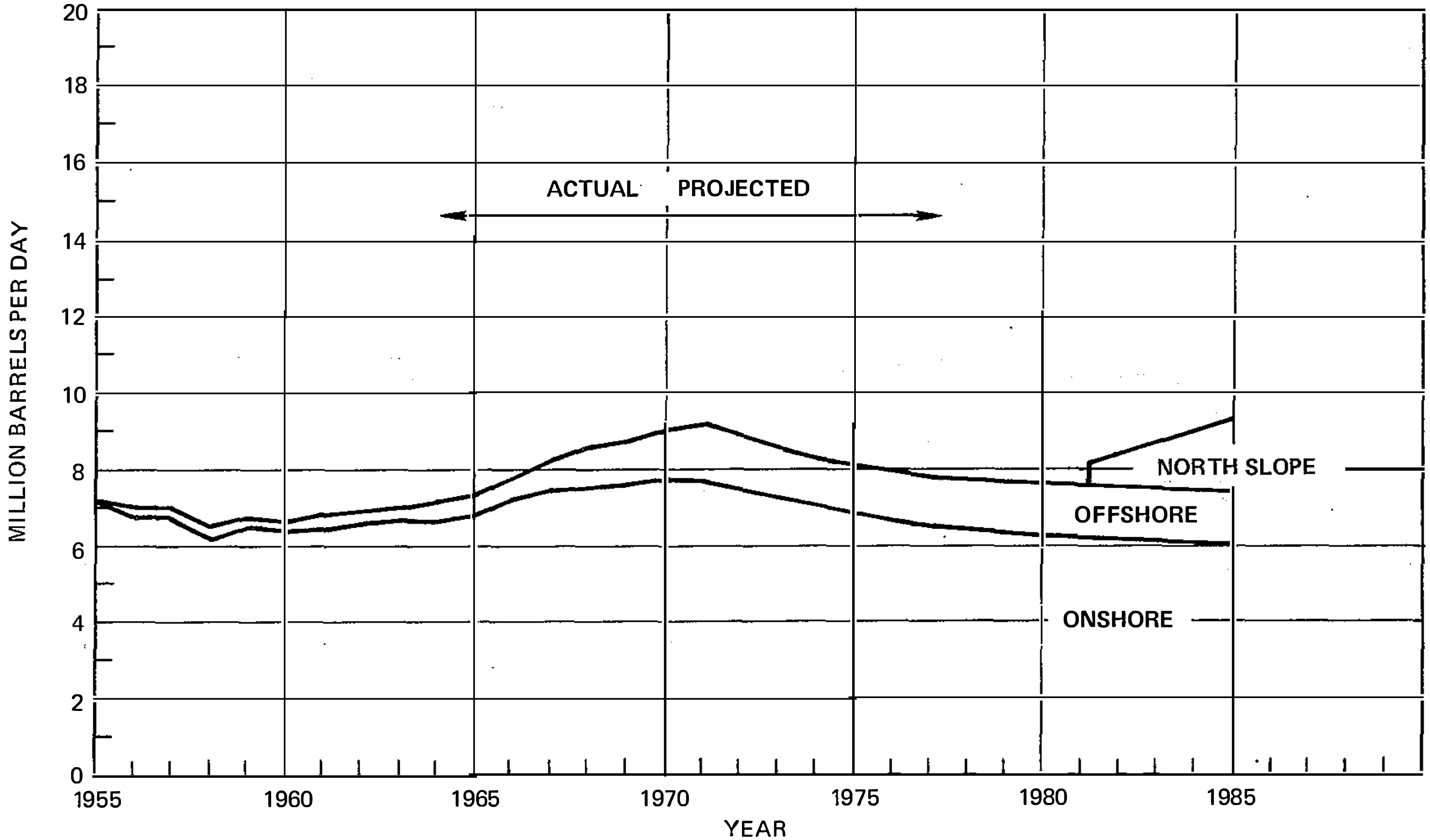


Figure 90. Offshore Production—Case IV.

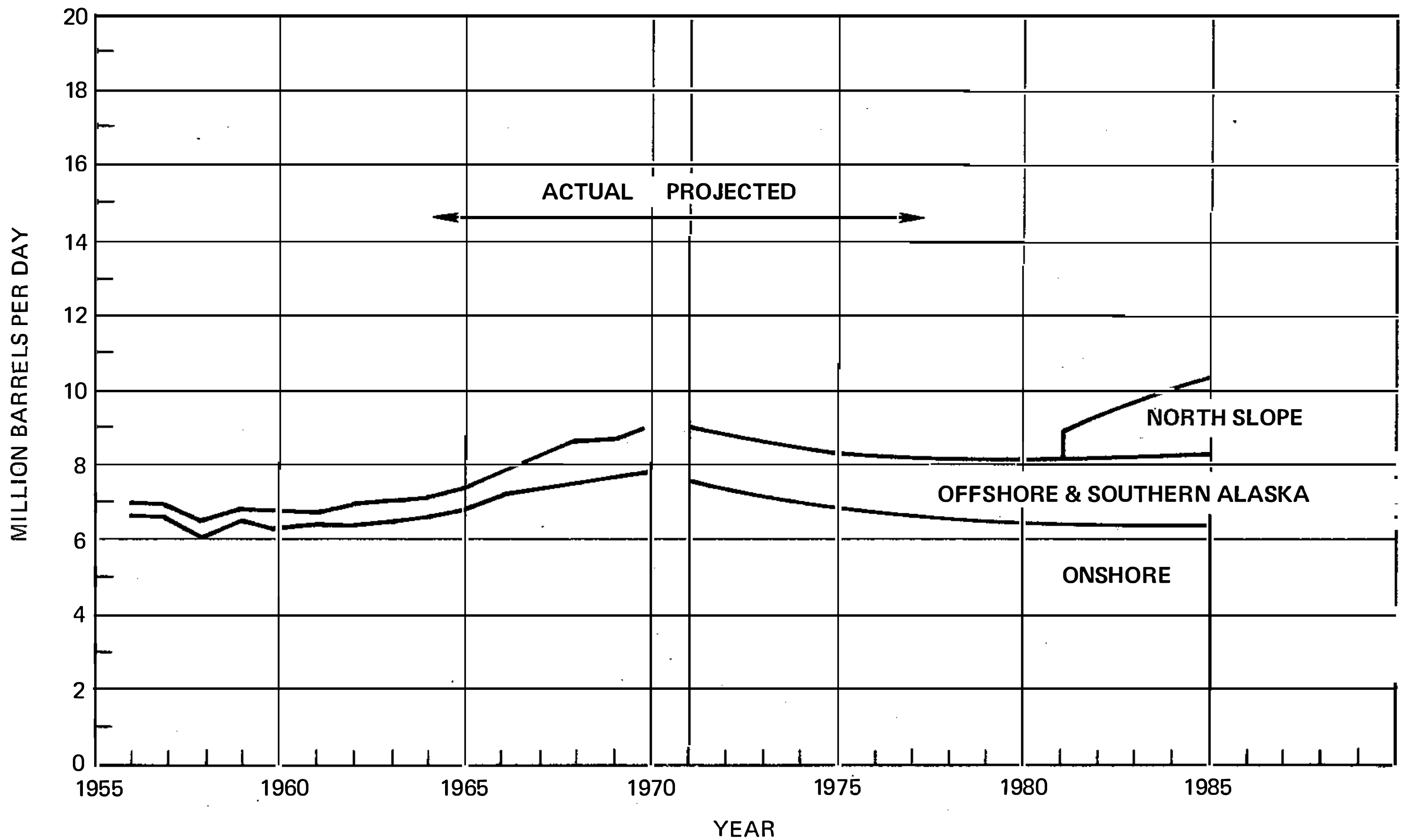


Figure 91. Offshore Production—Case IVA.

TABLE 261

NATURAL GAS LIQUIDS PRODUCTION*
(Million Barrels/Day)

This Is the High Drilling and High Finding Case

Case I

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48–Onshore															
2	.039	.035	.031	.028	.025	.023	.022	.022	.020	.019	.019	.018	.017	.015	.014
3	.050	.055	.061	.065	.070	.069	.060	.056	.054	.052	.050	.050	.049	.048	.048
4	.038	.034	.034	.037	.038	.041	.043	.044	.046	.046	.046	.048	.052	.055	.058
5	.421	.378	.332	.287	.266	.228	.222	.277	.277	.273	.271	.269	.268	.265	.261
6	.927	.875	.807	.738	.692	.665	.688	.709	.722	.725	.716	.713	.714	.704	.690
7	.277	.276	.263	.256	.248	.238	.228	.218	.209	.202	.198	.193	.189	.185	.182
8-10	.026	.030	.036	.043	.047	.047	.046	.043	.044	.046	.048	.050	.053	.054	.054
11	.000	.000	.000	.000	.000	.000	.001	.001	.001	.001	.002	.002	.003	.003	.004
Totals	1.778	1.684	1.565	1.455	1.388	1.311	1.309	1.371	1.373	1.365	1.350	1.345	1.343	1.330	1.313
Offshore and South Alaska															
1	.002	.002	.002	.002	.002	.002	.003	.004	.004	.006	.007	.008	.009	.010	.011
2A	.002	.002	.002	.003	.004	.005	.007	.011	.013	.016	.019	.022	.024	.027	.029
6A	.194	.216	.259	.299	.323	.340	.350	.374	.400	.428	.452	.479	.505	.525	.537
11A	.000	.000	.000	.000	.000	.000	.000	.001	.001	.002	.004	.009	.016	.023	.031
Totals	.198	.220	.263	.304	.328	.348	.361	.389	.419	.451	.482	.518	.554	.584	.608
Totals U.S. Ex North Slope	1.975	1.904	1.827	1.758	1.717	1.659	1.670	1.760	1.792	1.816	1.831	1.863	1.897	1.914	1.922
Northern Alaska															
Onshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Offshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Total No. Alaska	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Totals All U.S.	1.975	1.904	1.827	1.758	1.717	1.659	1.670	1.760	1.792	1.816	1.831	1.863	1.897	1.914	1.922

* *NGL is commingled with the crude for transportation by pipeline and is reported as part of the crude volume. For additional discussion, see Chapter Six, Section VIII.*

TABLE 262

NATURAL GAS LIQUIDS PRODUCTION*
(Million Barrels/Day)

This Is the High Drilling and Low Finding Case

Case IA

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	.039	.035	.031	.028	.025	.023	.022	.022	.021	.019	.020	.018	.017	.015	.014
3	.050	.055	.061	.066	.072	.070	.061	.058	.058	.058	.058	.059	.061	.062	.063
4	.038	.034	.034	.036	.037	.038	.039	.039	.039	.038	.037	.039	.040	.042	.045
5	.421	.376	.327	.281	.258	.221	.213	.258	.254	.247	.242	.237	.233	.227	.222
6	.927	.867	.784	.704	.646	.606	.609	.610	.601	.585	.557	.537	.522	.498	.470
7	.277	.275	.259	.249	.239	.226	.212	.199	.186	.175	.167	.159	.150	.141	.133
8-10	.026	.030	.036	.042	.046	.045	.045	.041	.042	.044	.046	.048	.049	.051	.052
11	.000	.000	.000	.000	.000	.000	.000	.001	.001	.001	.001	.002	.002	.002	.003
Totals	1.778	1.672	1.533	1.406	1.322	1.229	1.203	1.228	1.201	1.168	1.128	1.099	1.074	1.038	1.003
Offshore and South Alaska															
1	.002	.002	.002	.002	.002	.002	.003	.003	.003	.004	.005	.005	.006	.006	.007
2A	.002	.002	.002	.003	.003	.005	.006	.009	.010	.012	.014	.016	.018	.020	.021
6A	.194	.212	.246	.274	.286	.290	.290	.300	.311	.323	.331	.344	.358	.368	.375
11A	.000	.000	.000	.000	.000	.000	.000	.001	.001	.001	.003	.006	.011	.016	.022
Totals	.198	.216	.250	.279	.291	.297	.299	.312	.325	.340	.353	.372	.392	.409	.425
Totals U.S. Ex North Slope	1.975	1.888	1.782	1.685	1.613	1.527	1.502	1.540	1.527	1.509	1.482	1.471	1.466	1.448	1.428
Northern Alaska															
Onshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Offshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Total No. Alaska	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Totals All U.S.	1.975	1.888	1.782	1.685	1.613	1.527	1.502	1.540	1.527	1.509	1.482	1.471	1.466	1.448	1.428

* *NGL is commingled with the crude for transportation by pipeline and is reported as part of the crude volume. For additional discussion, see Chapter Six, Section VIII.*

TABLE 263

NATURAL GAS LIQUIDS PRODUCTION*
(Million Barrels/Day)

This Is the Low Drilling and High Finding Case

Case II

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	.039	.035	.031	.028	.025	.023	.022	.021	.020	.019	.019	.018	.016	.015	.013
3	.050	.055	.061	.065	.070	.068	.059	.055	.052	.050	.048	.047	.046	.044	.044
4	.038	.034	.034	.037	.038	.040	.042	.043	.044	.043	.042	.044	.046	.048	.051
5	.421	.378	.332	.287	.264	.227	.219	.271	.267	.261	.255	.250	.245	.239	.233
6	.927	.875	.806	.735	.688	.658	.675	.691	.697	.693	.675	.665	.658	.641	.621
7	.277	.276	.263	.256	.247	.236	.225	.213	.202	.193	.186	.180	.173	.165	.160
8-10	.026	.030	.036	.043	.047	.046	.045	.041	.041	.043	.044	.045	.046	.046	.046
11	.000	.000	.000	.000	.000	.000	.000	.001	.001	.001	.001	.002	.002	.003	.003
Totals	1.778	1.684	1.564	1.451	1.380	1.297	1.287	1.336	1.325	1.303	1.272	1.250	1.231	1.201	1.171
Offshore and South Alaska															
1	.002	.002	.002	.002	.002	.002	.003	.003	.004	.005	.006	.007	.008	.009	.010
2A	.002	.002	.002	.003	.004	.005	.007	.010	.012	.014	.017	.019	.021	.022	.024
6A	.194	.216	.258	.297	.317	.330	.336	.354	.372	.391	.406	.424	.442	.455	.463
11A	.000	.000	.000	.000	.000	.000	.000	.001	.001	.002	.003	.008	.012	.018	.024
Totals	.198	.220	.262	.301	.323	.338	.346	.367	.389	.412	.432	.457	.483	.504	.521
Totals U.S. Ex North Slope	1.975	1.904	1.826	1.752	1.703	1.635	1.633	1.703	1.714	1.715	1.704	1.707	1.714	1.705	1.693
Northern Alaska															
Onshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Offshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Total No. Alaska	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Totals All U.S.	1.975	1.904	1.826	1.752	1.703	1.635	1.633	1.703	1.714	1.715	1.704	1.707	17.14	1.705	1.693

* *NGL is commingled with the crude for transportation by pipeline and is reported as part of the crude volume. For additional discussion, see Chapter Six, Section VIII.*

TABLE 264

NATURAL GAS LIQUIDS PRODUCTION*
(Million Barrels/Day)

This Is the Low Drilling and Low Finding Case

Case III

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48–Onshore															
2	.039	.035	.031	.028	.025	.023	.022	.022	.020	.019	.019	.018	.016	.015	.013
3	.050	.055	.061	.066	.071	.069	.061	.057	.056	.055	.055	.055	.055	.055	.056
4	.038	.034	.034	.036	.036	.038	.039	.038	.038	.037	.035	.036	.037	.038	.039
5	.421	.376	.327	.280	.257	.220	.211	.253	.247	.238	.230	.223	.216	.208	.201
6	.927	.867	.784	.702	.643	.602	.603	.601	.589	.571	.540	.517	.499	.473	.444
7	.277	.275	.259	.249	.238	.224	.210	.196	.182	.170	.161	.151	.142	.131	.123
8-10	.026	.030	.036	.042	.046	.044	.043	.039	.040	.041	.042	.043	.043	.043	.044
11	.000	.000	.000	.000	.000	.000	.000	.001	.001	.001	.001	.001	.002	.002	.002
Totals	1.778	1.672	1.532	1.404	1.317	1.221	1.190	1.207	1.172	1.131	1.083	1.043	1.009	.965	.923
Offshore and South Alaska															
1	.002	.002	.002	.002	.002	.002	.003	.003	.003	.004	.004	.005	.005	.006	.006
2A	.002	.002	.002	.003	.003	.005	.006	.008	.010	.011	.013	.014	.015	.017	.018
6A	.194	.212	.245	.273	.282	.284	.281	.287	.293	.300	.303	.310	.317	.321	.324
11A	.000	.000	.000	.000	.000	.000	.000	.000	.001	.001	.002	.005	.009	.012	.016
Totals	.198	.216	.249	.277	.287	.291	.289	.298	.307	.316	.322	.344	.346	.356	.365
Totals U.S. Ex North Slope	1.975	1.888	1.781	1.681	1.604	1.512	1.479	1.505	1.479	1.447	1.405	1.377	1.356	1.321	1.287
Northern Alaska															
Onshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Offshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Total No. Alaska	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Totals All U.S.	1.975	1.888	1.781	1.681	1.604	1.512	1.479	1.505	1.479	1.447	1.405	1.377	1.356	1.321	1.287

* *NGL is commingled with the crude for transportation by pipeline and is reported as part of the crude volume. For additional discussion, see Chapter Six, Section VIII.*

TABLE 265

NATURAL GAS LIQUIDS PRODUCTION*
(Million Barrels/Day)

This Is the Low Declining Drilling and Low Finding Case

Case IV

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48–Onshore															
2	.039	.035	.031	.028	.025	.023	.022	.021	.020	.019	.019	.017	.016	.014	.012
3	.050	.055	.061	.066	.070	.068	.059	.055	.051	.049	.046	.045	.043	.042	.041
4	.038	.034	.034	.036	.036	.037	.037	.036	.035	.033	.030	.030	.029	.029	.029
5	.421	.376	.326	.279	.254	.217	.207	.242	.232	.218	.206	.194	.182	.169	.158
6	.927	.867	.783	.699	.637	.592	.588	.580	.563	.538	.500	.471	.448	.417	.384
7	.277	.275	.259	.248	.236	.221	.205	.189	.173	.160	.148	.136	.124	.112	.102
8-10	.026	.030	.035	.041	.045	.042	.041	.036	.035	.035	.034	.033	.032	.030	.029
11	.000	.000	.000	.000	.000	.000	.000	.000	.000	.001	.001	.001	.001	.001	.001
Totals	1.778	1.672	1.529	1.397	1.304	1.200	1.159	1.160	1.110	1.051	.984	.927	.875	.814	.756
Offshore and South Alaska															
1	.002	.002	.002	.002	.002	.002	.002	.002	.003	.003	.003	.004	.004	.004	.005
2A	.002	.002	.002	.002	.003	.004	.005	.006	.007	.008	.008	.009	.010	.010	.010
6A	.194	.212	.244	.269	.273	.270	.260	.258	.255	.252	.244	.239	.234	.227	.218
11A	.000	.000	.000	.000	.000	.000	.000	.000	.000	.001	.001	.003	.004	.006	.008
Totals	.198	.216	.248	.273	.278	.276	.267	.267	.265	.263	.257	.254	.252	.247	.241
Totals U.S. Ex North Slope	1.975	1.888	1.777	1.669	1.582	1.476	1.426	1.427	1.375	1.315	1.241	1.181	1.127	1.061	.997
Northern Alaska															
Onshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Offshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Total No. Alaska	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Totals All U.S.	1.975	1.888	1.777	1.669	1.582	1.476	1.426	1.427	1.375	1.315	1.241	1.181	1.127	1.061	.997

* *NGL is commingled with the crude for transportation by pipeline and is reported as part of the crude volume. For additional discussion, see Chapter Six, Section VIII.*

TABLE 266

NATURAL GAS LIQUIDS PRODUCTION*
(Million Barrels/Day)

This Is the Trend Drilling and High Finding Case

Case IV A

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48–Onshore															
2	.039	.035	.031	.028	.025	.023	.022	.021	.020	.019	.019	.017	.015	.014	.012
3	.050	.055	.061	.065	.070	.067	.057	.053	.050	.047	.044	.041	.039	.037	.035
4	.038	.034	.034	.037	.037	.039	.040	.039	.039	.037	.035	.035	.035	.035	.035
5	.421	.378	.331	.285	.261	.223	.214	.256	.248	.235	.223	.212	.200	.188	.176
6	.927	.875	.804	.730	.677	.640	.647	.650	.642	.624	.591	.566	.544	.514	.481
7	.277	.276	.262	.254	.244	.230	.217	.202	.188	.175	.164	.153	.141	.129	.120
8-10	.026	.030	.036	.042	.046	.044	.042	.037	.036	.036	.036	.035	.034	.032	.030
11	.000	.000	.000	.000	.000	.000	.000	.000	.001	.001	.001	.001	.001	.001	.001
Totals	1.778	1.683	1.560	1.441	1.360	1.265	1.238	1.261	1.223	1.173	1.112	1.059	1.009	.950	.892
Offshore and South Alaska															
1	.002	.002	.002	.002	.002	.002	.002	.003	.003	.004	.004	.005	.005	.006	.007
2A	.002	.002	.002	.003	.003	.004	.005	.007	.008	.010	.011	.012	.012	.013	.014
6A	.194	.216	.256	.291	.305	.309	.304	.309	.313	.315	.311	.310	.309	.304	.298
11A	.000	.000	.000	.000	.000	.000	.000	.000	.001	.001	.002	.004	.006	.009	.011
Totals	.198	.220	.260	.295	.310	.315	.312	.320	.325	.329	.328	.331	.333	.332	.329
Totals U.S. Ex North Slope	1.975	1.903	1.820	1.736	1.669	1.580	1.551	1.580	1.548	1.503	1.441	1.390	1.324	1.281	1.220
Northern Alaska															
Onshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Offshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Total No. Alaska	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Totals All U.S.	1.975	1.903	1.820	1.736	1.669	1.580	1.551	1.580	1.548	1.503	1.441	1.390	1.342	1.281	1.220

* *NGL is commingled with the crude for transportation by pipeline and is reported as part of the crude volume. For additional discussion, see Chapter Six, Section VIII.*

TABLE 267

TOTAL LIQUID PRODUCTION
(Million Barrels/Day)

This Is the High Drilling and High Finding Case

Case I

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	.925	.913	.905	.898	.891	.886	.885	.887	.889	.892	.897	.886	.877	.872	.868
3	.168	.170	.176	.182	.187	.186	.178	.174	.172	.171	.169	.168	.167	.167	.167
4	.657	.601	.563	.539	.524	.518	.522	.530	.544	.558	.576	.604	.634	.668	.701
5	2.719	2.608	2.503	2.404	2.333	2.250	2.221	2.259	2.246	2.235	2.230	2.243	2.262	2.286	2.313
6	3.566	3.430	3.295	3.170	3.088	3.047	3.122	3.201	3.273	3.328	3.365	3.449	3.513	3.558	3.583
7	1.132	1.117	1.090	1.070	1.051	1.031	1.007	.986	.969	.956	.947	.930	.912	.896	.882
8-10	.253	.261	.265	.276	.289	.301	.322	.341	.365	.392	.417	.442	.466	.483	.497
11	.019	.016	.014	.014	.018	.023	.028	.035	.041	.049	.056	.062	.071	.079	.089
Totals	9.440	9.117	8.811	8.553	8.381	8.242	8.285	8.414	8.499	8.580	8.656	8.784	8.904	9.008	9.100
Offshore and South Alaska															
1	.289	.268	.247	.246	.264	.303	.347	.408	.469	.559	.639	.699	.765	.808	.876
2A	.063	.066	.069	.089	.131	.196	.265	.357	.448	.534	.615	.692	.763	.829	.891
6A	1.280	1.308	1.335	1.400	1.461	1.515	1.549	1.596	1.643	1.696	1.736	1.776	1.805	1.808	1.800
11A	.000	.000	.000	.000	.001	.003	.006	.009	.013	.021	.030	.043	.083	.127	.196
Totals	1.632	1.641	1.651	1.735	1.858	2.017	2.168	2.370	2.572	2.810	3.020	3.209	3.416	3.573	3.764
Totals U.S. Ex North Slope	11.071	10.758	10.462	10.288	10.239	10.260	10.452	10.784	11.071	11.390	11.677	11.993	12.320	12.582	12.864
Northern Alaska															
Onshore	.000	.000	.000	.000	.000	.750	1.400	1.780	2.050	2.190	2.340	2.460	2.570	2.620	2.600
Offshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Total No. Alaska	.000	.000	.000	.000	.000	.750	1.400	1.780	2.050	2.190	2.340	2.460	2.570	2.620	2.600
Totals All U.S.	11.071	10.758	10.462	10.288	10.239	11.010	11.852	12.564	13.121	13.580	14.017	14.453	14.890	15.202	15.464

Note: Table 3 in Chapter One summarizes production in a little different manner than is generally used throughout the report. The production shown in Table 3 for the Lower 48 States includes the offshore areas of California, the Gulf of Mexico and the East Coast. Alaska in that table includes South Alaska (NPC Region 1) plus the North Slope.

TABLE 26B

TOTAL LIQUID PRODUCTION
(Million Barrels/Day)

This Is the High Drilling and Low Finding Case

Case IA

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	.925	.913	.905	.898	.891	.886	.885	.887	.888	.889	.892	.878	.865	.855	.846
3	.168	.170	.174	.176	.179	.176	.165	.159	.157	.155	.153	.153	.153	.153	.153
4	.657	.600	.557	.523	.494	.470	.453	.439	.428	.419	.412	.414	.417	.422	.428
5	2.719	2.606	2.497	2.397	2.325	2.243	2.211	2.234	2.211	2.186	2.164	2.155	2.146	2.137	2.128
6	3.566	3.421	3.267	3.120	3.004	2.913	2.922	2.928	2.928	2.922	2.905	2.944	2.977	2.998	3.010
7	1.132	1.113	1.076	1.044	1.013	.982	.947	.915	.887	.864	.846	.820	.796	.776	.758
8-10	.253	.259	.261	.265	.269	.269	.275	.277	.282	.290	.297	.307	.316	.324	.332
11	.019	.016	.014	.014	.016	.019	.022	.026	.029	.033	.036	.039	.045	.050	.056
Totals	9.440	9.098	8.750	8.437	8.191	7.958	7.880	7.865	7.810	7.758	7.706	7.709	7.715	7.713	7.711
Offshore and South Alaska															
1	.289	.267	.246	.243	.255	.279	.302	.332	.364	.414	.454	.477	.503	.529	.575
2A	.063	.066	.068	.086	.122	.173	.224	.288	.348	.406	.461	.515	.566	.614	.659
6A	1.280	1.272	1.240	1.226	1.213	1.210	1.214	1.238	1.262	1.293	1.315	1.341	1.362	1.367	1.366
11A	.000	.000	.000	.000	.001	.003	.006	.009	.013	.019	.027	.037	.069	.103	.156
Totals	1.632	1.605	1.554	1.555	1.591	1.665	1.746	1.867	1.987	2.132	2.257	2.370	2.501	2.612	2.756
Totals U.S. Ex North Slope	11.071	10.703	10.304	9.993	9.782	9.623	9.626	9.732	9.797	9.890	9.963	10.079	10.216	10.326	10.468
Northern Alaska															
Onshore	.000	.000	.000	.000	.000	.750	1.400	1.780	2.050	2.190	2.340	2.460	2.570	2.620	2.600
Offshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Total No. Alaska	.000	.000	.000	.000	.000	.750	1.400	1.780	2.050	2.190	2.340	2.460	2.570	2.620	2.600
Totals All U.S.	11.071	10.703	10.304	9.993	9.782	10.373	11.026	11.512	11.847	12.080	12.303	12.539	12.786	12.946	13.068

Note: Table 3 in Chapter One summarizes production in a little different manner than is generally used throughout the report. The production shown in Table 3 for the Lower 48 States includes the offshore areas of California, the Gulf of Mexico and the East Coast. Alaska in that table includes South Alaska (NPC Region 1) plus the North Slope.

TABLE 269

TOTAL LIQUID PRODUCTION
(Million Barrels/Day)

This Is the Low Drilling and High Finding Case

Case II

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48–Onshore															
2	.925	.913	.905	.897	.891	.885	.884	.885	.885	.887	.889	.875	.864	.854	.847
3	.168	.170	.176	.181	.187	.184	.175	.171	.168	.166	.163	.161	.159	.157	.156
4	.657	.601	.562	.538	.521	.512	.512	.515	.522	.529	.537	.555	.574	.596	.617
5	2.719	2.608	2.502	2.402	2.330	2.246	2.214	2.244	2.224	2.204	2.188	2.188	2.190	2.196	2.204
6	3.566	3.430	3.293	3.164	3.076	3.024	3.083	3.143	3.196	3.229	3.245	3.308	3.355	3.385	3.398
7	1.132	1.117	1.089	1.068	1.046	1.023	.996	.970	.948	.928	.914	.889	.866	.845	.826
8-10	.253	.261	.265	.275	.287	.297	.314	.329	.348	.370	.389	.409	.429	.444	.458
11	.019	.016	.014	.014	.017	.022	.026	.032	.037	.043	.048	.052	.060	.065	.072
Totals	9.440	9.117	8.086	8.539	8.354	8.193	8.203	8.291	8.328	8.356	8.374	8.437	8.497	8.541	8.579
Offshore and South Alaska															
1	.289	.268	.247	.245	.261	.294	.332	.383	.432	.507	.574	.626	.687	.729	.792
2A	.063	.066	.068	.088	.128	.187	.248	.327	.403	.474	.538	.598	.651	.700	.746
6A	1.280	1.308	1.331	1.390	1.443	1.484	1.504	1.532	1.556	1.584	1.601	1.622	1.639	1.640	1.630
11A	.000	.000	.000	.000	.001	.003	.005	.009	.012	.018	.025	.034	.064	.095	.141
Totals	1.632	1.641	1.647	1.723	1.832	1.968	2.089	2.251	2.403	2.583	2.738	2.880	3.041	3.164	3.309
Totals U.S. Ex North Slope	11.071	10.758	10.453	10.262	10.186	10.161	10.292	10.541	10.731	10.939	11.112	11.317	11.537	11.705	11.887
Northern Alaska															
Onshore	.000	.000	.000	.000	.000	.600	.950	1.300	1.650	2.000	2.000	2.000	2.000	2.000	2.000
Offshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Total No. Alaska	.000	.000	.000	.000	.000	.600	.950	1.300	1.650	2.000	2.000	2.000	2.000	2.000	2.000
Totals All U.S.	11.071	10.758	10.453	10.262	10.186	10.761	11.242	11.841	12.381	12.939	13.112	13.317	13.537	13.705	13.887

Note: Table 3 in Chapter One summarizes production in a little different manner than is generally used throughout the report. The production shown in Table 3 for the Lower 48 States includes the offshore areas of California, the Gulf of Mexico and the East Coast. Alaska in that table includes South Alaska (NPC Region 1) plus the North Slope.

TABLE 270

TOTAL LIQUID PRODUCTION
(Million Barrels/Day)

This Is the Low Drilling and Low Finding Case

Case III

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48--Onshore															
2	.925	.913	.905	.897	.891	.885	.884	.884	.884	.885	.886	.870	.856	.843	.832
3	.168	.170	.174	.176	.179	.174	.163	.157	.153	.150	.148	.146	.144	.142	.142
4	.657	.600	.556	.522	.492	.467	.449	.433	.419	.407	.396	.394	.393	.394	.395
5	2.719	2.606	2.497	2.395	2.322	2.239	2.205	2.223	2.195	2.166	2.139	2.123	2.108	2.092	2.077
6	3.566	3.421	3.265	3.116	2.996	2.901	2.902	2.900	2.890	2.872	2.843	2.869	2.891	2.901	2.903
7	1.132	1.113	1.075	1.043	1.011	.978	.940	.905	.874	.847	.826	.795	.768	.743	.722
8-10	.253	.259	.260	.264	.267	.266	.271	.271	.274	.279	.284	.291	.296	.300	.306
11	.019	.016	.014	.014	.016	.019	.021	.024	.026	.030	.032	.034	.038	.041	.045
Totals	9.440	9.098	8.746	8.428	8.173	7.929	7.834	7.797	7.717	7.637	7.554	7.522	7.494	7.457	7.420
Offshore and South Alaska															
1	.289	.267	.246	.241	.252	.272	.292	.317	.342	.383	.417	.439	.462	.478	.516
2A	.063	.066	.068	.085	.119	.166	.211	.267	.317	.363	.406	.447	.485	.520	.553
6A	1.280	1.272	1.238	1.221	1.201	1.189	1.181	1.191	1.199	1.212	1.216	1.228	1.238	1.237	1.230
11A	.000	.000	.000	.000	.001	.003	.005	.008	.011	.017	.023	.030	.054	.078	.113
Totals	1.632	1.605	1.551	1.547	1.573	1.631	1.690	1.782	1.869	1.974	2.062	2.144	2.238	2.313	2.412
Totals U.S. Ex North Slope	11.071	10.703	10.297	9.975	9.747	9.559	9.524	9.580	9.585	9.611	9.616	9.667	9.732	9.769	9.833
Northern Alaska															
Onshore	.000	.000	.000	.000	.000	.600	.950	1.300	1.650	2.000	2.000	2.000	2.000	2.000	2.000
Offshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Total No. Alaska	.000	.000	.000	.000	.000	.600	.950	1.300	1.650	2.000	2.000	2.000	2.000	2.000	2.000
Totals All U.S.	11.071	10.703	10.297	9.975	9.747	10.159	10.474	10.880	11.235	11.611	11.616	11.667	11.732	11.769	11.833

Note: Table 3 in Chapter One summarizes production in a little different manner than is generally used throughout the report. The production shown in Table 3 for the Lower 48 States includes the offshore areas of California, the Gulf of Mexico and the East Coast. Alaska in that table includes South Alaska (NPC Region 1) plus the North Slope.

TABLE 271

TOTAL LIQUID PRODUCTION
(Million Barrels/Day)

This Is the Low Declining Drilling and Low Finding Case

Case IV

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48–Onshore															
2	.925	.913	.905	.896	.889	.882	.879	.877	.875	.873	.871	.851	.833	.816	.801
3	.168	.170	.173	.175	.177	.171	.159	.151	.145	.139	.133	.129	.124	.119	.115
4	.657	.600	.555	.519	.486	.456	.434	.414	.395	.376	.358	.349	.340	.332	.324
5	2.719	2.606	2.495	2.390	2.313	2.226	2.187	2.193	2.156	2.115	2.076	2.049	2.021	1.992	1.964
6	3.566	3.421	3.261	3.103	2.971	2.860	2.843	2.820	2.788	2.747	2.694	2.696	2.695	2.683	2.666
7	1.132	1.113	1.073	1.038	1.001	.963	.920	.879	.841	.807	.778	.740	.705	.673	.645
8-10	.253	.259	.259	.261	.261	.257	.258	.254	.253	.252	.251	.252	.252	.250	.248
11	.019	.016	.014	.013	.015	.016	.017	.018	.019	.021	.022	.022	.023	.023	.024
Totals	9.440	9.097	8.735	8.396	8.112	7.831	7.696	7.606	7.471	7.330	7.184	7.087	6.993	6.888	6.786
Offshore and South Alaska															
1	.289	.267	.245	.237	.240	.250	.259	.268	.279	.298	.313	.323	.335	.344	.364
2A	.063	.066	.067	.082	.108	.140	.170	.202	.231	.254	.272	.288	.300	.309	.316
6A	1.280	1.272	1.232	1.202	1.162	1.121	1.082	11.055	1.028	1.003	.970	.947	.924	.896	.869
11A	.000	.000	.000	.000	.001	.002	.004	.006	.007	.010	.013	.016	.026	.034	.044
Totals	1.632	1.605	1.544	1.521	1.510	1.514	1.515	1.531	1.545	1.565	1.569	1.574	1.584	1.582	1.593
Totals U.S. Ex North Slope	11.071	10.703	10.279	9.917	9.622	9.345	9.211	9.137	9.016	8.896	8.753	8.661	8.576	8.470	8.379
Northern Alaska															
Onshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.600	.950	1.300	1.650	2.000
Offshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Total No. Alaska	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.600	.950	1.300	1.650	2.000
Totals All U.S.	11.071	10.703	10.279	9.917	9.622	9.345	9.211	9.137	9.016	8.896	9.353	9.611	9.876	10.120	10.379

Note: Table 3 in Chapter One summarizes production in a little different manner than is generally used throughout the report. The production shown in Table 3 for the Lower 48 States includes the offshore areas of California, the Gulf of Mexico and the East Coast. Alaska in that table includes South Alaska (NPC Region 1) plus the North Slope.

TABLE 272

TOTAL LIQUID PRODUCTION
(Million Barrels/Day)

This Is the Trend Drilling and High Finding Case

Case IVA

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	.925	.913	.905	.896	.889	.882	.879	.877	.875	.873	.871	.852	.834	.818	.803
3	.168	.170	.176	.180	.183	.180	.168	.162	.157	.152	.147	.143	.138	.134	.130
4	.657	.601	.561	.532	.509	.491	.480	.470	.463	.454	.445	.443	.442	.441	.440
5	2.719	2.608	2.500	2.397	2.320	2.232	2.193	2.208	2.173	2.135	2.099	2.074	2.049	2.025	2.000
6	3.566	3.430	3.287	3.146	3.036	2.952	2.970	2.981	2.983	2.972	2.943	2.963	2.974	2.969	2.954
7	1.132	1.117	1.086	1.061	1.032	1.000	.963	.926	.893	.862	.835	.798	.764	.731	.703
8-10	.253	.261	.264	.271	.278	.280	.289	.293	.302	.311	.317	.326	.332	.336	.341
11	.019	.016	.014	.014	.016	.018	.021	.024	.026	.029	.031	.032	.034	.035	.037
Totals	9.440	9.116	8.792	8.496	8.262	8.035	7.962	7.942	7.872	7.788	7.689	7.631	7.567	7.489	7.408
Offshore and South Alaska															
1	.289	.268	.246	.240	.247	.265	.283	.307	.333	.370	.401	.425	.455	.479	.521
2A	.063	.066	.068	.084	.114	.155	.194	.239	.281	.317	.347	.372	.392	.407	.419
6A	1.230	1.308	1.322	1.358	1.376	1.377	1.362	1.348	1.325	1.300	1.265	1.238	1.211	1.178	1.146
11A	.000	.000	.000	.000	.001	.002	.004	.006	.008	.011	.014	.018	.029	.039	.052
Totals	1.632	1.641	1.635	1.682	1.738	1.799	1.843	1.900	1.946	1.998	2.027	2.052	2.086	2.103	2.138
Totals U.S. Ex North Slope	11.071	10.757	10.428	10.178	10.000	9.834	9.805	9.842	9.817	9.786	9.716	9.684	9.654	9.592	9.545
Northern Alaska															
Onshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.600	.950	1.300	1.650	2.000
Offshore	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
Total No. Alaska	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.600	.950	1.300	1.650	2.000
Totals All U.S.	11.071	10.757	10.428	10.178	10.000	9.834	9.805	9.842	9.817	9.786	10.316	10.634	10.954	11.242	11.545

Note: Table 3 in Chapter One summarizes production in a little different manner than is generally used throughout the report. The production shown in Table 3 for the Lower 48 States includes the offshore areas of California, the Gulf of Mexico and the East Coast. Alaska in that table includes South Alaska (NPC Region 1) plus the North Slope.

TABLE 273

HISTORICAL PRODUCING GAS/OIL RATIOS

						Projected	
	1966	1967	1968	1969	1970	1971	1985
Region 1	–	–	–	143	176	176	435
Region 2	1075	1011	1000	985	920	920	360
Region 2A	725	795	770	756	697	697	872
Region 3	1673	1087	969	1019	859	859	686
Region 4	648	628	662	709	726	726	900
Region 5	1879	1817	1811	1764	1710	1710	670
Region 6	1817	1803	1663	1645	1622	1622	1302
Region 6A	2043	2043	1862	1831	1874	1874	1425
Region 7	1785	2058	2124	2348	2045	2045	400
Regions 8, 9, and 10	385	360	365	388	447	400	400
Region 11	110	NA	110	100	NA	100	800
Region 11A	–	–	–	–	–	800	800

Note: Developed by dividing the total associated and dissolved gas produced annually in each region by the oil production produced in the same year for the same region. Gas production figures were obtained from Table III of the "Report of the Committee on Natural Gas Reserves of the American Gas Association." Oil production figures were taken from Table I of the "Report of the Committee on Reserves and Productive Capacity of the American Petroleum Institute." These reports appear in the joint publication, Reserves of Crude Oil, National Gas Liquids, and Natural Gas, in the United States and Canada and United States Production Capacity, published annually (latest edition released as Volume 27, May 1973.)

TABLE 274

ASSOCIATED AND DISSOLVED GAS PRODUCTION
(Billion Cubic Feet/Year)

This Is the High Drilling and High Finding Case

Case I

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	285.4	271.1	257.6	244.6	231.8	219.3	207.6	196.3	185.1	174.1	163.2	149.5	136.6	124.2	112.3
3	36.4	35.3	34.7	34.4	34.2	33.8	33.5	33.1	32.8	32.3	31.7	31.1	30.7	30.2	29.6
4	166.7	154.8	146.8	141.5	139.1	138.6	141.0	145.2	150.8	157.4	165.1	175.3	186.5	198.8	211.2
5	1,376.0	1,279.1	1,189.9	1,106.7	1,028.6	955.0	893.6	835.5	780.4	727.8	677.5	632.7	588.6	545.3	501.7
6	1,542.1	1,472.8	1,414.7	1,364.3	1,325.2	1,298.6	1,308.6	1,320.0	1,331.5	1,338.0	1,341.2	1,364.1	1,373.8	1,378.1	1,374.9
7	604.3	560.7	518.0	477.4	438.2	401.3	363.2	327.4	293.7	261.0	229.6	195.9	163.5	132.4	102.1
8-10	33.2	33.7	33.5	34.0	35.3	37.2	40.2	43.6	46.9	50.5	53.8	57.2	60.4	62.6	64.4
11	1.0	1.1	.12	.15	2.1	3.1	4.3	5.9	7.5	9.8	12.1	14.4	17.7	20.9	24.9
Totals	4,045.1	3,808.6	3,596.5	3,404.4	3,234.5	3,087.0	2,992.0	2,906.9	2,828.7	2,751.0	2,674.2	2,620.2	2,557.7	2,492.5	2,421.2
Offshore and South Alaska															
1	20.3	20.5	20.4	21.9	25.1	30.7	37.3	46.3	56.2	70.4	84.5	96.7	110.5	121.8	137.4
2A	15.6	16.7	17.8	23.4	35.1	53.3	73.3	99.9	127.2	153.8	179.5	204.7	228.7	252.0	274.5
6A	731.4	722.9	700.8	704.9	716.5	727.0	728.8	728.9	727.6	729.1	724.2	716.9	704.3	681.7	657.3
11A	.0	.0	.0	.0	.3	1.0	1.6	2.6	3.6	5.6	7.6	9.7	19.7	30.5	48.0
Totals	767.3	760.0	739.0	750.2	777.1	812.0	840.9	877.8	914.5	958.9	995.8	1,028.0	1,063.3	1,086.1	1,117.2
Totals U.S. Ex North Slope	4,812.4	4,568.6	4,335.5	4,154.6	4,011.6	3,898.9	3,832.9	3,784.7	3,743.2	3,709.9	3,670.0	3,648.2	3,621.0	3,578.6	3,538.3
Northern Alaska															
Onshore	.0	.0	.0	.0	.0	.0	.0	600.0	700.0	800.0	900.0	1,300.0	1,400.0	1,700.0	1,800.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	.0	.0	.0	.0	.0	.0	.0	600.0	700.0	800.0	900.0	1,300.0	1,400.0	1,700.0	1,800.0
Totals All U.S.	4,812.4	4,568.6	4,335.5	4,154.6	4,011.6	3,898.9	3,832.9	4,384.7	4,443.2	4,509.9	4,570.0	4,948.2	5,021.0	5,278.6	5,338.3

TABLE 275

ASSOCIATED AND DISSOLVED GAS PRODUCTION
(Billion Cubic Feet/Year)

This Is the High Drilling and Low Finding Case

Case IA

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48–Onshore															
2	285.4	271.1	257.6	244.6	231.8	219.3	207.6	196.2	184.9	173.6	162.2	148.1	134.6	121.8	109.3
3	36.4	35.1	33.8	32.7	31.6	30.4	29.3	28.2	27.3	26.3	25.5	24.6	23.9	23.2	22.6
4	166.7	154.6	145.2	137.3	130.8	125.3	121.9	119.5	117.9	117.0	116.7	118.4	120.6	123.2	125.9
5	1,376.0	1,279.1	1,189.9	1,106.7	1,028.6	954.9	892.9	833.4	775.8	719.6	664.7	614.5	564.7	515.2	465.9
6	1,542.1	1,472.1	1,411.8	1,355.6	1,304.2	1,258.1	1,243.1	1,228.2	1,214.6	1,201.1	1,188.6	1,199.9	1,204.8	1,207.8	1,207.2
7	604.3	558.7	511.6	466.1	423.1	383.2	342.5	305.1	270.7	238.3	207.8	176.0	146.2	118.1	91.2
8-10	33.2	33.4	32.8	32.5	32.5	32.7	33.6	34.4	35.1	36.0	36.7	37.9	38.9	39.8	41.0
11	1.0	1.1	1.2	1.4	1.9	2.6	3.3	4.3	5.3	6.6	7.8	9.1	11.1	13.0	15.4
Totals	4,045.1	3,805.2	3,584.0	3,376.9	3,184.4	3,006.4	2,874.3	2,749.3	2,631.5	2,518.5	2,410.1	2,328.4	2,244.8	2,162.1	2,078.4
Offshore and South Alaska															
1	20.3	20.4	20.3	21.5	24.2	28.2	32.5	37.8	43.7	52.1	60.0	65.9	72.7	79.7	90.2
2A	15.6	16.7	17.7	22.8	32.7	47.2	61.9	80.5	98.8	116.8	134.6	152.5	169.8	186.5	202.8
6A	731.4	702.0	647.2	609.4	583.6	568.7	561.5	559.7	557.3	557.8	554.6	551.3	544.5	530.6	515.6
11A	.0	.0	.0	.0	.3	1.0	1.5	2.5	3.4	5.3	7.1	8.9	17.0	25.5	39.3
Totals	767.3	739.1	685.2	653.7	640.8	645.0	657.5	680.5	703.2	732.0	756.2	778.6	804.0	822.2	847.9
Totals U.S. Ex North Slope	4,812.4	4,544.3	4,269.1	4,030.6	3,825.2	3,651.5	3,531.8	3,429.9	3,334.7	3,250.5	3,166.3	3,107.0	3,048.8	2,984.3	2,926.3
Northern Alaska															
Onshore	.0	.0	.0	.0	.0	.0	.0	600.0	700.0	800.0	900.0	1,300.0	1,400.0	1,700.0	1,800.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	.0	.0	.0	.0	.0	.0	.0	600.0	700.0	800.0	900.0	1,300.0	1,400.0	1,700.0	1,800.0
Totals All U.S.	4,812.4	4,544.3	4,269.1	4,030.6	3,825.2	3,651.5	3,531.8	4,029.9	4,034.7	4,050.5	4,066.3	4,407.0	4,448.8	4,684.3	4,726.3

TABLE 276

ASSOCIATED AND DISSOLVED GAS PRODUCTION
(Billion Cubic Feet/Year)

This Is the Low Drilling and High Finding Case

Case II

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	285.4	271.1	257.6	244.5	231.6	219.0	207.2	195.8	184.4	173.1	161.8	147.7	134.4	121.7	109.5
3	36.4	35.3	34.7	34.3	34.0	33.5	33.1	32.5	32.0	31.4	30.7	29.9	29.3	28.7	28.1
4	166.7	154.8	146.7	141.2	138.3	137.1	138.3	141.1	144.9	149.3	154.3	161.3	169.0	177.5	186.1
5	1,376.0	1,279.1	1,189.6	1,106.2	1,027.7	953.6	891.5	832.2	775.6	721.1	668.4	621.0	574.2	528.1	482.1
6	1,542.1	1,472.8	1,414.0	1,362.2	1,320.8	1,290.2	1,294.1	1,299.3	1,304.2	1,304.2	1,301.0	1,317.9	1,323.9	1,325.2	1,319.8
7	604.3	560.7	517.5	476.4	436.6	398.8	359.6	322.7	288.1	254.7	222.7	188.9	156.8	126.4	97.2
8-10	33.2	33.7	33.4	33.9	35.0	36.6	39.3	42.1	44.8	47.7	50.4	53.2	55.9	58.0	60.1
11	1.0	1.1	1.2	1.5	2.1	3.0	4.0	5.4	6.8	8.7	10.5	12.2	14.8	17.2	20.2
Totals	4,045.1	3,808.6	3,594.7	3,400.1	3,226.1	3,071.8	2,967.1	2,871.2	2,780.7	2,690.1	2,599.7	2,532.1	2,458.4	2,383.0	2,303.2
Offshore and South Alaska															
1	20.3	20.5	20.4	21.7	24.8	29.8	35.7	43.5	51.8	63.8	75.8	86.7	99.3	109.8	124.2
2A	15.6	16.7	17.7	23.1	34.2	50.9	68.6	91.6	114.6	136.6	157.2	176.9	195.2	212.8	229.7
6A	731.4	722.9	698.9	700.2	708.1	713.4	709.8	703.2	693.2	685.9	673.9	662.2	648.9	629.4	606.8
11A	.0	.0	.0	.0	.3	.9	1.4	2.3	3.1	4.7	6.3	7.8	15.0	22.5	34.1
Totals	767.3	760.0	737.0	745.0	767.5	795.0	815.4	840.6	862.7	891.0	913.3	933.5	958.4	974.5	994.8
Totals U.S. Ex North Slope	4,812.4	4,568.6	4,331.7	4,145.1	3,993.6	3,866.8	3,782.6	3,711.8	3,643.4	3,581.1	3,513.0	3,465.6	3,416.8	3,357.5	3,298.0
Northern Alaska															
Onshore	.0	.0	.0	.0	.0	.0	.0	500.0	700.0	800.0	800.0	900.0	1,300.0	1,400.0	1,500.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	.0	.0	.0	.0	.0	.0	.0	500.0	700.0	800.0	800.0	900.0	1,300.0	1,400.0	1,500.0
Totals All U.S.	4,812.4	4,568.6	4,331.7	4,145.1	3,993.6	3,866.8	3,782.6	4,211.8	4,343.4	4,381.1	4,313.0	4,365.6	4,716.8	4,757.5	4,798.0

TABLE 277

ASSOCIATED AND DISSOLVED GAS PRODUCTION
(Billion Cubic Feet/Year)

This Is the Low Drilling and Low Finding Case

Case III

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	285.4	271.1	257.6	244.5	231.6	219.0	207.2	195.7	184.2	172.7	161.2	146.8	133.2	120.1	107.6
3	36.4	35.1	33.8	32.6	31.5	30.3	29.1	27.9	26.9	25.8	24.8	23.9	23.0	22.2	21.4
4	166.7	154.6	145.1	137.0	130.4	124.6	120.8	117.9	115.6	113.8	112.6	113.1	114.2	115.5	116.9
5	1,376.0	1,279.1	1,189.6	1,106.2	1,027.7	953.6	891.1	830.8	772.4	715.5	659.9	609.0	558.5	508.5	458.9
6	1,542.1	1,472.1	1,411.1	1,354.0	1,301.5	1,253.5	1,235.9	1,218.1	1,200.8	1,183.3	1,166.4	1,172.9	1,174.0	1,172.9	1,168.4
7	604.3	558.7	511.3	465.5	422.1	381.6	340.3	302.3	267.3	234.4	203.5	171.4	141.5	113.7	87.3
8-10	33.2	33.4	32.8	32.4	32.3	32.4	33.2	33.8	34.2	34.8	35.3	36.3	37.0	37.5	38.3
11	1.0	1.1	1.2	1.4	1.9	2.5	3.2	4.0	4.8	6.0	6.9	7.9	9.3	10.7	12.5
Totals	4,045.1	3,805.2	3,582.5	3,373.6	3,178.9	2,997.5	2,860.8	2,730.5	2,606.2	2,486.4	2,370.7	2,281.2	2,190.6	2,101.1	2,011.2
Offshore and South Alaska															
1	20.3	20.4	20.3	21.4	23.9	27.6	31.4	36.0	41.0	48.2	55.1	60.8	66.7	72.0	80.9
2A	15.6	16.7	17.6	22.5	32.0	45.2	58.4	74.6	90.0	104.6	118.6	132.3	145.4	158.0	170.2
6A	731.4	702.0	646.2	606.8	578.6	559.7	547.3	539.4	530.4	524.1	515.1	507.6	499.1	486.2	471.6
11A	.0	.0	.0	.0	.3	.9	1.4	2.3	3.0	4.5	5.9	7.2	13.2	19.1	28.1
Totals	767.3	739.1	684.1	650.8	634.8	633.4	638.5	652.2	664.4	681.4	694.7	707.9	724.4	735.3	750.9
Totals U.S. Ex North Slope	4,812.4	4,544.3	4,266.5	4,024.4	3,813.7	3,630.9	3,499.3	3,382.7	3,270.6	3,167.9	3,065.4	2,989.1	2,915.1	2,836.5	2,762.1
Northern Alaska															
Onshore	.0	.0	.0	.0	.0	.0	.0	500.0	700.0	800.0	800.0	900.0	1,300.0	1,400.0	1,500.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	.0	.0	.0	.0	.0	.0	.0	500.0	700.0	800.0	800.0	900.0	1,300.0	1,400.0	1,500.0
Totals All U.S.	4,812.4	4,544.3	4,266.5	4,024.4	3,813.7	3,630.9	3,499.3	3,882.7	3,970.6	3,967.9	3,865.4	3,889.1	4,215.1	4,236.5	4,262.1

TABLE 278

ASSOCIATED AND DISSOLVED GAS PRODUCTION
(Billion Cubic Feet/Year)

This Is the Low Declining Drilling and Low Finding Case

Case IV

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	285.4	271.1	257.5	244.2	231.1	218.2	206.0	194.1	182.2	170.3	158.4	143.7	129.7	116.4	103.6
3	36.4	35.1	33.7	32.4	31.1	29.7	28.4	27.0	25.7	24.4	23.2	22.0	20.8	19.7	18.6
4	166.7	154.6	144.8	136.2	128.7	121.9	117.0	112.9	109.1	105.5	102.2	100.7	99.4	98.2	96.9
5	1,376.0	1,279.1	1,188.9	1,104.3	1,024.4	948.8	884.9	822.8	762.6	703.9	646.7	594.4	542.7	491.9	441.7
6	1,542.1	1,472.1	1,409.2	1,348.6	1,290.8	1,236.5	1,211.8	1,186.3	1,161.5	1,136.2	1,111.0	1,109.1	1,103.0	1,094.8	1,084.3
7	604.3	558.7	510.3	463.1	418.1	375.9	333.1	293.7	257.7	224.2	192.9	160.8	131.4	104.4	79.3
8-10	33.2	33.4	32.7	32.1	31.7	31.3	31.7	31.8	31.8	31.7	31.6	32.0	32.1	32.0	32.0
11	1.0	1.1	1.2	1.4	1.8	2.2	2.6	3.1	3.6	4.2	4.7	5.1	5.7	6.1	6.6
Totals	4,045.1	3,805.2	3,578.4	3,362.3	3,157.6	2,964.6	2,815.5	2,671.7	2,534.2	2,400.5	2,270.8	2,167.6	2,064.8	1,963.4	1,862.9
Offshore and South Alaska															
1	20.3	20.4	20.2	21.1	22.8	25.3	27.8	30.5	33.4	37.6	41.4	44.7	48.3	51.8	57.0
2A	15.6	16.7	17.5	21.5	28.8	38.2	46.9	56.7	65.6	73.2	79.5	85.2	89.8	93.8	97.4
6A	731.4	702.0	643.4	597.7	559.2	526.7	499.7	475.3	452.5	431.6	409.6	391.5	373.7	355.1	338.2
11A	.0	.0	.0	.0	.2	.7	1.0	1.5	2.0	2.8	3.4	3.9	6.2	8.2	10.8
Totals	767.3	739.1	661.1	640.3	611.0	590.9	575.5	564.0	553.5	545.2	534.0	525.2	518.1	508.9	503.4
Totals U.S. Ex North Slope	4,812.4	4,544.3	4,259.5	4,002.6	3,768.6	3,555.4	3,391.0	3,235.7	3,087.7	2,945.6	2,804.8	2,692.9	2,582.9	2,472.3	2,366.3
Northern Alaska															
Onshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	500.0	700.0	800.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	500.0	700.0	800.0
Totals All U.S.	4,812.4	4,544.3	4,259.5	4,002.6	3,768.6	3,555.4	3,391.0	3,235.7	3,087.7	2,945.6	2,804.8	2,692.9	3,082.9	3,172.3	3,166.3

TABLE 279

ASSOCIATED AND DISSOLVED GAS PRODUCTION
(Billion Cubic Feet/Year)

This Is the Trend Drilling and High Finding Case

Case IV A

Regions	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Lower 48—Onshore															
2	285.4	271.1	257.5	244.2	231.1	218.2	206.0	194.1	182.3	170.4	158.5	143.8	129.9	116.6	103.9
3	36.4	35.3	34.6	34.0	33.3	32.4	31.5	30.6	29.7	28.7	27.7	26.6	25.7	24.7	23.8
4	166.7	154.8	146.3	139.8	135.0	131.3	129.6	128.6	128.4	128.1	127.8	129.0	130.3	131.7	133.0
5	1,376.0	1,279.1	1,188.9	1,104.3	1,024.4	948.8	884.9	823.0	763.2	705.0	648.4	596.8	545.9	495.7	446.2
6	1,542.1	1,472.8	1,411.9	1,355.4	1,304.8	1,260.9	1,248.5	1,234.8	1,221.8	1,207.1	1,190.9	1,195.4	1,192.4	1,185.8	1,175.1
7	604.3	560.7	516.2	472.9	430.4	389.8	347.8	308.5	272.2	237.9	205.4	171.8	140.7	112.0	85.1
8-10	33.2	33.7	33.3	33.4	33.9	34.6	36.1	37.4	38.7	40.1	41.2	42.5	43.6	44.4	45.3
11	1.0	1.1	1.2	1.4	1.9	2.5	3.2	4.0	4.8	5.9	6.7	7.5	8.5	9.3	10.3
Totals	4,045.1	3,808.6	3,589.9	3,385.3	3,194.8	3,018.5	2,887.6	2,761.1	2,641.2	2,523.3	2.406.7	2,313.4	2,217.0	2,120.2	2,022.6
Offshore and South Alaska															
1	20.3	20.5	20.3	21.3	23.5	26.8	30.4	34.9	39.8	46.6	53.0	58.7	65.7	72.2	81.6
2A	15.6	16.7	17.6	22.1	30.5	42.2	53.5	66.8	79.8	91.3	101.3	110.1	117.4	123.6	129.0
6A	731.4	722.9	693.9	683.4	674.4	661.0	642.7	619.6	592.6	566.1	537.6	512.8	488.9	464.1	441.3
11A	.0	.0	.0	.0	.2	.7	1.0	1.6	2.0	2.8	3.5	4.1	6.7	8.9	12.1
Totals	767.3	760.0	731.7	726.7	728.6	730.7	727.7	722.9	714.2	706.9	695.4	685.7	678.7	668.9	664.0
Totals U.S. Ex North Slope	4,812.4	4,568.6	4,321.7	4,112.0	3,923.4	3,749.2	3,615.3	3,484.0	3,355.4	3,230.2	3,102.1	2,999.1	2,895.7	2,789.1	2,686.6
Northern Alaska															
Onshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	500.0	700.0	800.0
Offshore	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total No. Alaska	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	500.0	700.0	800.0
Totals All U.S.	4,812.4	4,568.6	4,321.7	4,112.0	3,923.4	3,749.2	3,615.3	3,484.0	3,355.4	3,230.2	3,102.1	2,999.1	3,395.7	3,489.1	3,486.6

Chapter Five—Section VII

Alaskan North Slope Oil Operations

General Approach

The ground rules for inclusion of North Slope oil operations in the study were as follows:

- Cases I and IA: Oil production initiated in 1976; oil transportation facilities are not a limiting factor.
- Cases II and III: Oil production initiated in 1976; production limited to planned oil pipeline capacity.
- Cases IV and IVA: Oil production initiated in 1981; production limited to planned oil pipeline capacity.

Because only very limited published data were available on the North Slope (one reported discovery and no actual producing operations), the following approach was used to obtain estimates for inclusions in this study.

Cases I and IA

A survey was made of several members of the Task Group who had some familiarity with North Slope operations. These members were asksed to submit their estimates of industry performance in exploration for and production of oil and associated-dissolved gas (excluding non-associated gas operations) under the guidelines for these cases. (The request was actually made on the basis of a 1975 startup, and the responses subsequently adjusted to a 1976 date.) This request included estimates of future oil-in-place discovered and reserves added, oil and associated-dissolved gas production schedules and capital requirements. The responses received were then arithmetically averaged to establish the Task Group's projections for Cases I and IA.

Cases II and III

The Task Group estimates for Cases I and IA were adjusted downward to arrive at projections for these pipeline-capacity limited cases. In general, this was done by assuming that exploration and development efforts would be proportional to the oil-production rates achieved and would lead production by 2 years. The only exception to this procedure was in developing an associated-dissolved gas volume projection which was adjusted on the basis of cumulative oil production. Table 280 shows the derivation of the factors used to adjust discoveries and capital requirements from Cases I and IA to Cases II and III.

TABLE 280

ALASKAN NORTH SLOPE—OIL OPERATIONS
DERIVATION OF FACTORS FOR CONVERTING
CASES I/IA TO CASES II/III

	Oil Production (MMB/D)			
	Cases I/IA*	Cases II/III†	Ratio II/III to I/IA	Adjustment Factor Used‡
1971	—	—	—	1.00
1972	—	—	—	1.00
1973	—	—	—	1.00
1974	—	—	—	.80
1975	—	—	—	.68
1976	.75	.60	.80	.73
1977	1.40	.95	.68	.81
1978	1.78	1.30	.73	.91
1979	2.05	1.65	.81	.86
1980	2.19	2.00	.91	.81
1981	2.34	2.00	.86	.78
1982	2.46	2.00	.81	.76
1983	2.57	2.00	.78	.77
1984	2.62	2.00	.76	.77
1985	2.60	2.00	.77	.77
1986§	2.60	2.00	.77	—
1987§	2.60	2.00	.77	—

* Arithmetic average of survey responses assuming no transportation facility limitations.

‡ Estimated oil pipeline capacity, starting at 600 MB/D in 1976 and growing linearly to 2,000 MB/D in 1980.

† Based on production ratio with 2-year lead time.

§ 1986 and 1987 production assumed to remain constant at 1985 level.

Cases IV and IVA

The projections for these cases were developed by delaying the Case II and III estimates by 5 years. Since such a delay would probably occur gradually with some low level of exploration and development activity continuing in the interim and accelerating as startup became imminent, the procedure used was as follows: Case II and III activity (1971 through 1975) was allocated one-third to 1971 through 1975 and two-thirds to 1976

TABLE 281

ALASKAN NORTH SLOPE—OIL OPERATIONS
OIL-IN-PLACE DISCOVERED
(Billion Barrels)

	Cases I/IA	Cases II/III	Cases IV/IVA
1971	.1	.1	.1
1972	.3	.3	.1
1973	.3	.3	.1
1974	.9	.7	.2
1975	1.0	.7	.2
5-Year Total	2.6	2.1	.7
1976	2.5	1.8	.2
1977	3.0	2.4	.2
1978	3.0	2.7	.3
1979	3.1	2.7	.3
1980	4.3	3.5	.4
5-Year Total	15.9	13.1	1.4
1981	4.4	3.4	1.8
1982	3.5	2.8	2.4
1983	1.2	.9	2.7
1984	.6	.5	2.7
1985	.6	.5	3.5
5-Year Total	10.5	8.1	13.1
15-Year Total	29.0	23.3	15.2
Area Ultimate Potential = 72.1			
Found pre-1971 = 24.0			
1/1/71 Remaining = 48.1			
Percentage of Ultimate found by 1985	74%	66%	54%
Percentage of 1/1/71 Remaining found by 1985	60%	48%	32%

TABLE 282

ALASKAN NORTH SLOPE—OIL OPERATIONS
OIL RESERVE ADDITIONS*
(Billion Barrels)

	Cases I/IA	Cases II/III	Cases IV/IVA
1971	.03	.03	.03
1972	.10	.10	.03
1973	.10	.10	.03
1974	.30	.23	.07
1975	.34	.23	.07
5-Year Total	.87	.69	.23
1976	.84	.60	.07
1977	1.01	.80	.07
1978	1.01	.90	.10
1979	1.04	.90	.10
1980	1.44	1.17	.13
5-Year Total	5.34	4.37	.47
1981	1.47	1.14	.60
1982	1.24	.94	.80
1983	.40	.30	.90
1984	.20	.17	.90
1985	.20	.17	1.17
5-Year Total	3.51	2.72	4.37
15-Year Total	9.72	7.78	5.07

* Calculated using 33.5-percent recovery factor for total of primary and secondary recovery (from average of responses submitted).

TABLE 283

ALASKAN NORTH SLOPE—OIL OPERATIONS
ASSOCIATED-DISSOLVED GAS RESERVES ADDED (TCF)*

	Cases I/IA	Cases II/III	Cases IV/IVA
1971	.04	.04	.04
1972	.14	.14	.04
1973	.14	.14	.04
1974	.42	.32	.10
1975	.47	.32	.10
5-Year Total	1.21	.96	.32
1976	1.17	.84	.10
1977	1.41	1.12	.10
1978	1.41	1.26	.14
1979	1.45	1.26	.14
1980	2.01	1.63	.18
5-Year Total	7.45	6.11	.66
1981	2.05	1.59	.84
1982	1.73	1.31	1.12
1983	.56	.42	1.26
1984	.28	.24	1.26
1985	.28	.24	1.63
5-Year Total	4.90	3.80	6.11
15-Year Total	13.56	10.87	7.09

* Calculated using ratio of associated and dissolved gas reserves added to oil reserves added of 1395 cubic feet/barrel (from average of estimates submitted).

TABLE 284

ALASKAN NORTH SLOPE—OIL OPERATIONS
OIL PRODUCTION (MMB/D)

	Cases I/IA	Cases II/III	Cases IV/IVA
1971	—	—	—
1972	—	—	—
1973	—	—	—
1974	—	—	—
1975	—	—	—
1976	.75	.60	—
1977	1.40	.95	—
1978	1.78	1.30	—
1979	2.05	1.65	—
1980	2.19	2.00	—
1981	2.34	2.00	.60
1982	2.46	2.00	.95
1983	2.57	2.00	1.30
1984	2.62	2.00	1.65
1985	2.60	2.00	2.00

TABLE 285

ALASKAN NORTH SLOPE—OIL OPERATIONS
DETERMINATION OF CASE II/III ASSOCIATED-DISSOLVED GAS VOLUMES

	Case I/IA*		Case II/III	
	A-D Gas Production (BCF/D)	Cumulative Oil Production (Billion Barrels)	Cumulative Oil Production† (Billion Barrels)	A-D Gas Production‡ (BCF/D)
1976	(.14)	274	219	—
1977	(.94)	783	566	—
1978	1.6	1,434	1,040	1.4
1979	1.9	2,182	1,643	1.9
1980	2.2	2,980	2,373	2.2
1981	2.5	3,833	3,103	2.2
1982	3.6	4,732	3,833	2.4
1983	3.8	5,668	4,563	3.6
1984	4.7	6,625	5,293	3.8
1985	4.9	7,524	6,023	4.1

* From arithmetic average of responses submitted; these data plotted on Figure 92.

† From adjusted oil production schedule.

‡ Values read from Figure 92 at the appropriate cumulative oil production levels.

TABLE 286

ALASKAN NORTH SLOPE—OIL OPERATIONS
ASSOCIATED-DISSOLVED GAS PRODUCTION (BCF/DAY)*

	Cases I/IA	Cases II/III	Cases IV/IVA
1978	1.6	1.4	—
1979	1.9	1.9	—
1980	2.2	2.2	—
1981	2.5	2.2	—
1982	3.6	2.4	—
1983	3.8	3.6	1.4
1984	4.7	3.8	1.9
1985	4.9	4.1	2.2

* Based on projected 2-year interval between completion of oil-transportation facilities in 1976 and completion of a gas sales line in 1978; all gas produced in 1976-1977 was assumed to be reinjected.

TABLE 287

ALASKAN NORTH SLOPE—OIL OPERATIONS
CAPITAL REQUIREMENTS—CASE I AND IA
(Million 1970 Dollars)

	Producing Well* Investment	Lease* Equipment	Lease Bonus	Dry Hole* Costs	Geological, Geophysical and Lease Rental Costs†	Total Capital Requirements
1971	39	57	—	10	6	112
1972	26	46	—	8	4	84
1973	27	46	—	8	4	85
1974	48	118	—	24	8	198
1975	79	238	—	26	13	356
5-Year Total	219	505	—	76	35	835
1976	102	377	—	29	16	524
1977	110	362	—	36	18	526
1978	113	307	—	38	18	476
1979	106	261	—	39	17	423
1980	98	311	—	38	16	463
5-Year Total	529	1,618	—	180	85	2,412
1981	94	335	63	37	15	544
1982	78	298	57	35	13	481
1983	67	120	52	31	11	281
1984	52	78	52	32	8	222
1985	44	43	46	28	7	168
5-Year Total	335	874	270	163	54	1,696
15-Year Total	1,083	2,997	270	419	174	4,943

* From average of estimates submitted.
† Estimated at 16 percent of producing well costs (from experience in Lower 48 States).

TABLE 288

ALASKAN NORTH SLOPE—OIL OPERATIONS
CAPITAL REQUIREMENTS—CASES II AND III
(Million 1970 Dollars)

	Producing Well* Investment	Lease* Equipment	Lease Bonus	Dry Hole* Costs	Geological, Geophysical and Lease Rental Costs†	Total Capital Requirements
1971	39	57	—	10	6	112
1972	26	46	—	8	4	84
1973	27	46	—	8	4	85
1974	38	94	—	19	6	157
1975	54	162	—	18	9	243
5-Year Total	184	405	—	63	29	681
1976	74	275	—	21	12	382
1977	89	293	—	29	14	425
1978	102	279	—	35	16	432
1979	91	224	—	34	15	364
1980	99	252	—	31	16	398
5-Year Total	455	1,323	—	150	73	2,001
1981	73	261	51	29	12	426
1982	59	226	45	27	10	367
1983	52	92	42	24	8	218
1984	40	60	42	25	6	173
1985	34	33	35	22	5	129
5-Year Total	258	672	214	127	41	1,313
15-Year Total	897	2,400	215	340	143	3,995

* Case I/IA numbers adjusted by production ratio.
† Estimated at 16 percent of producing well costs (from experience in Lower 48 States).

TABLE 289

ALASKAN NORTH SLOPE—OIL OPERATIONS
CAPITAL REQUIREMENTS—CASES IV AND IVA
(Million 1970 Dollars)

	Producing Well* Investment	Lease* Equipment	Lease Bonus	Dry Hole* Costs	Geological, Geophysical and Lease Rental Costs†	Total Capital Requirements
1971	39	57	—	10	6	112
1972	4	13	—	2	1	20
1973	4	13	—	2	1	20
1974	7	26	—	3	1	37
1975	7	26	—	4	1	38
5-Year Total	**61**	**135**	**—**	**21**	**10**	**227**
1976	18	38	—	6	3	65
1977	18	39	—	6	3	66
1978	26	58	—	9	4	97
1979	26	58	—	9	4	97
1980	35	77	—	12	6	130
5-Year Total	**123**	**270**	**—**	**42**	**20**	**455**
1981	74	275	—	21	12	382
1982	89	293	—	29	14	425
1983	102	279	—	35	16	432
1984	91	224	—	34	15	364
1985	99	252	—	31	16	398
5-Year Total	**455**	**1,323**	**—**	**150**	**73**	**2,001**
15-Year Total	**639**	**1,728**	**—**	**213**	**103**	**2,683**

* Case II/III projections delayed as indicated in general approach section.
† Estimated at 16 percent of producing well costs (from experience in Lower 48 States).

through 1980; Case II and III patterns within each 5-year period were used to distribute the 5-year totals by year (1971 estimates were not changed since this activity has already occurred); and Case II and III activity (1976 through 1985) was delayed by 5 years.

These procedures were used to arrive at the results shown in Tables 281 through 289.

Associated-Dissolved Gas Production Projection

Associated-dissolved gas production is normally a function of the cumulative oil produced from a field. For this reason, the following procedure was used to develop projections of associated-dissolved gas volumes for Cases II and III and Cases IV and IVA from the data submitted for Cases I and IA.

The arithmetic average of Case I and IA submissions was plotted in the form of daily gas production as a function of cumulative oil production (see Table 285 and Figure 92) and using Case II and III oil production schedule, cumulative oil production volumes were calculated. Daily gas production volumes by year for Cases II and III were then read off of Figure 92 at the appropriate cumulative production.

Case IV and IVA production was projected by simply delaying Cases II and III estimates by 5 years. The resulting associated-dissolved gas production rates are shown in Table 286. In all cases, gas production was assumed to be reinjected for the first 2 years of oil production pending completion of a gas transmission pipeline.

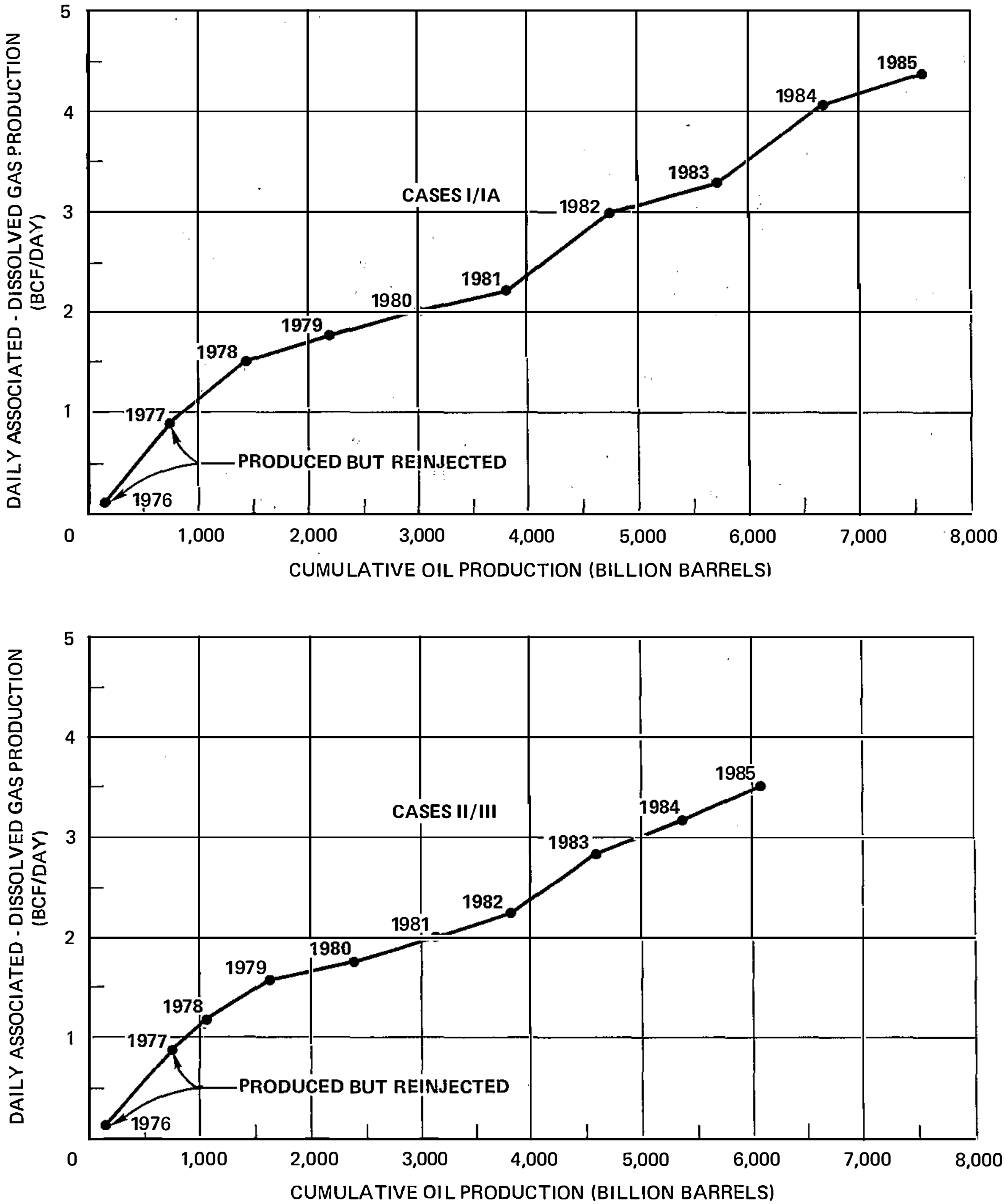


Figure 92. Alaska North Slope—Oil Operations
(Determination of A&D Gas Volumes for Cases II and III).

Lease Bonus Cost Projection

Cases I and IA

The following assumptions were employed in determining the lease bonus cost projection:

- No new acreage will need to be leased prior to 1981 because all but about 100 townships between NPR-4 and the Arctic Wildlife Refuge have already been leased.
- Forty-seven exploratory wells will be drilled on the North Slope during the 1981-1985 period (from average of submissions).
- Half of these exploratory wells will be drilled on new leases and half on existing leases.
- Each new lease will be a township in size (36 square miles or 23,000 acres).
- Lease bonuses for wildcat acreage on the North Slope will be \$500/acre (1970 dollars).

Using these assumptions, the total lease bonus costs were calculated for the 1981-1985 period as follows:

Lease Bonus Cost = 47 exploratory wells
(.5 wells on new leases)
= 23 thousand acres per lease
(\$500/acre)
= \$270 million

This total was then allocated by year according to the number of exploratory wells drilled each year (from average of submissions).

Cases II and III

The Cases I and IA projection was reduced by the factors developed in Table 280.

Cases IV and IVA

The assumption of a 5-year delay results in no new leases being granted during the 1971-1985 period.

Chapter Five—Section VIII

Composition of PAD Districts from NPC Regions and Determination of Offshore Acreage Requirements

TABLE 290

COMPOSITION OF PAD DISTRICTS

PAD District I		
NPC Regions		
	100.00%	11
	18.64%	10
	100.00%	11A
PAD District II		
NPC Regions		
	81.36%	10
	100.00%	7
	1.17%	4
PAD District III		
NPC Regions		
	100.00%	6
	100.00%	6A
	100.00%	5
	5.17%	3
PAD District IV		
NPC Regions		
	93.26%	3
	98.83%	4
PAD District V		
NPC Regions		
	100.00%	1
	100.00%	2
	100.00%	2A
	1.57%	3

Note: Map of NPC regions shown in chapter one.

The number of offshore lease acres evaluated by a wildcat well can vary significantly, depending upon the type of structure involved and the location of the structure on the offshore lease grid. For example, one extreme (1 well per 20,000 acres) is where a single well could evaluate 20,000 acres if a large anticline was more or less centered at the common corner of four 5,000-acre lease blocks. The opposite extreme (1 well per 500 acres) would be a salt dome centered inside one lease block which would require an excess of 10 wells for geological evaluation. In view of the wide differences possible, a statistical analysis was made for the Gulf of Mexico (Region 6A) where the bulk of offshore drilling has occurred.

For Region 6A

Total acreage leased 1954-1970—5,850,000 acres

Total exploratory wells drilled 1954-1970—2,750

Estimated unprocessed acreage on January 1, 1971—550,000 acres

Acreage required is

$$\frac{5{,}850{,}000-550{,}000}{2{,}750} = 1{,}927 \text{ acres per exploratory well.}$$

For purposes of this study, the acreage requirement was rounded off to 2,000 acres per exploratory well. Using this factor, future lease requirements were calculated from the total number of offshore oil and gas exploratory wells to be drilled in any given year as developed in the oil and gas drilling models. The number of offshore exploratory oil wells was obtained by dividing the total offshore exploratory oil footage by the average offshore exploratory oil well depth. The number of offshore exploratory gas wells was determined by multiplying the total offshore gas footage drilled by 44.1 percent to obtain the offshore exploratory gas footage drilled and dividing the result by the average offshore gas well depth. Historically, 44.1 percent of gas well drilling offshore has been exploratory. The information for both oil and gas is calculated by individual offshore regions and then accumulated.

Chapter Six

Gas Operations

Guide to Chapter Six
Gas Operations

SECTION I: **Recoverable Gas Resources**

Presents detailed data concerning cumulative production, proved reserves, potential supply and ultimately discovered natural gas in the United States as of December 31, 1970. Includes potential non-associated gas supply by drilling and offshore water depths.

SECTION II: **Finding Rates**

Presents additional explanation of the methodology used by the Gas Supply Task Group in arriving at their projections of future regional finding rates. Includes the historical data relied on by the Task Group, as well as the projections of finding rates in the various regions through 1985.

SECTION III: **Gas Drilling—Footage and Wells**

Presents the historical and projected relationship of oil to gas drilled footage in the Lower 48 States. Includes the historical footage drilled for gas from 1956 through 1970 for each region. This footage is further classified between productive gas footage and dry hole footage allocated to gas. Annual footage drilled for gas as well as cumulative footage drilled for gas in each region is also shown.

The historical and projected gas wells drilled annually are shown for each region, as well as the gas wells producing at year-end. Data concerning the average depth of gas wells and the success ratio of gas drilling is also included.

SECTION IV: **Gas Reserves**

Presents the historical and projected annual gas reserves additions for the various regions. Cumulative gas discovered and the percent of ultimate supply found over the projection period is also presented. This section includes the year-end remaining reserves, reserves-to-production ratios and findings-to-production ratios, both historically and for the projection period.

SECTION V: **Wellhead Gas Production**

Presents the historical and projected annual wellhead gas production by region. Includes the regional production schedules used by the Task Group in their forecast of production from non-associated gas reserves discovered prior to 1971 and the schedules for production from non-associated reserves found after 1970.

SECTION VI: **Marketed Gas Production**

Presents the projections of non-associated and total gas production from the various regions. The production from reserves found prior to 1971 and the production from reserves found after 1970 are shown separately.

SECTION VII: **Natural Gas Liquids—Reserves and Production**

Includes a discussion of the methodology, as well as the basic data used in the projections. Also presented by region are the projected reserves additions and production of condensate, pentanes and heavier, LPG and total non-associated gas liquids.

SECTION VIII: **Alaska**

Discusses the methodology used by the Task Group in its projections relating to frontier areas. (The Atlantic Offshore area 11-A is considered a frontier area.) Projections of gas footage drilled, reserves additions, wellhead and marketed production for both North and South Alaska as well as the Alaska total are included. Also included are the estimates of expenditures for exploration, development and production of non-associated gas which would necessarily accompany the various projections of activity in Alaska.

SECTION IX: Nuclear Stimulation

Presents potential field development and projected production following nuclear stimulation for the cases studied. Also included are the potential growth of pipeline gas from nuclear stimulation and a map showing the location of present and future planned projects.

SECTION X: Foreign Gas Supply

Contains detailed data relied on by the Task Group in its projections for foreign gas supply.

SECTION XI: Summary

Presents summaries of projections of gas footage drilled, reserves additions, wellhead and marketed gas production for all six cases by geographical area. Annual reserves additions and production are presented separately for non-associated and associated-dissolved gas. The geographical areas shown are the Lower 48 States Onshore, Lower 48 States Offshore, Alaska and the total United States. Also included is the total available gas for Cases IA and IVA which is not shown on Table 52 in Chapter One.

Chapter Six—Section I

Recoverable Gas Resources

TABLE 291

RECOVERABLE RESOURCES OF NON-ASSOCIATED AND ASSOCIATED-DISSOLVED NATURAL GAS IN UNITED STATES (AS OF DECEMBER 31, 1970)

	Trillion Cubic Feet				
	Cumulative Production	Proved Reserves	Total Discovered	Potential Supply	Ultimately Discoverable
Non-Associated Gas					
Onshore 48 States	245.9	167.2	413.1	550.0	963.1
Offshore 48 States	13.6	32.3	45.9	214.2	260.1
Total 48 States	259.5	199.5	459.0	764.2	1,223.2
Alaska	.4	4.7	5.1	272.3	277.4
Total U.S.	259.9	204.2	464.1	1,036.5	1,500.6
Associated-Dissolved Gas					
Onshore 48 States	128.4	50.2	178.6	63.0	241.6
Offshore 48 States	4.2	6.1	10.3	23.8	34.1
Total 48 States	132.6	56.3	188.9	86.8	275.7
Alaska	(.1)	26.4	26.3	54.7	81.0
Total U.S.	132.5	82.7	215.2	141.5	356.7
Total Non-Associated & Associated-Dissolved Gas					
Onshore 48 States	674.3	217.4	591.7	613.0	1,204.7
Offshore 48 States	17.8	38.4	56.2	238.0	294.2
Total 48 States	392.1	255.8	647.9	851.0	1,498.9
Alaska	.3	31.1	31.4	327.0	358.4
Total U.S.	392.4	286.9	679.3	1,178.0	1,857.3

TABLE 292

RECOVERABLE RESOURCES OF NON-ASSOCIATED NATURAL GAS IN UNITED STATES (AS OF DECEMBER 31, 1970)

		Trillion Cubic Feet				
	NPC Region	Cumulative Production	Proved Reserves	Total Discovered	Potential Supply	Ultimately Discoverable
2	Onshore Pacific	5.7	2.4	8.1	17.6	25.7
3	Southwest Rocky Mountains	7.8	10.1	17.9	32.3	50.2
4	Northwest Rocky Mountains	5.2	4.8	10.0	41.6	51.6
5	West Texas & East New Mexico	10.1	17.1	27.2	74.3	101.5
6	Onshore Gulf Coast	121.7	90.0	211.7	186.1	397.8
7	Midcontinent	66.3	38.5	104.8	118.5	223.3
8-9	Michigan & East Interior	.2	.2	.4	12.1	12.5
10	Appalachian	28.9	4.1	33.0	62.9	95.9
11	Onshore Atlantic	—	—	—	4.6	4.6
2A	Offshore Pacific	.3	.2	.5	3.3	3.8
6A	Offshore Gulf Coast	13.3	32.1	45.4	156.4	201.8
11A	Offshore Atlantic	—	—	—	54.5	54.5
1N	Alaska North of Brooks Range	—	—	—	117.1	117.1
1S	Alaska South of Brooks Range	.4	4.7	5.1	155.2	160.3
	Total United States	259.9	204.2	464.1	1,036.5	1,500.6
	Onshore 48 States	245.9	167.2	413.1	550.0	963.1
	Offshore 48 States	13.6	32.3	45.9	214.2	260.1
	Total 48 States	259.5	199.5	459.0	764.2	1,223.2
	Alaska	.4	4.7	5.1	272.3	277.4
	Total United States*	259.9	204.2	464.1	1,036.5	1,500.6

* Totals may not agree due to rounding.

TABLE 293

POTENTIAL RECOVERABLE NON-ASSOCIATED GAS SUPPLY (TCF)

	Shallower than 15,000 Feet	Deeper than 15,000 Feet	Total
Lower 48 States — Onshore			
2	14.6	3.0	17.6
3	30.2	2.0	32.2
4	36.6	5.0	41.6
5	35.3	39.0	74.3
6	123.2	63.0	186.2
7	80.5	38.0	118.5
8&9	10.1	2.0	12.1
10	56.9	6.0	62.9
11	.6	4.0	4.6
Total	**388.0**	**162.0**	**550.0**
	Water Depth 0-600 Feet	**Water Depth 601-1500 Feet**	**Total**
Lower 48 States — Offshore			
2A	–	3.3	3.3
6A	131.4	25.0	156.4
11A	45.5	9.0	54.5
Total	176.9	37.3	**214.2**
Alaska	–	–	272.3
Total United States			**1,036.5**

Chapter Six—Section II

Gas Finding Rates

The finding rate (defined as the amount of gas found per foot drilled) is one of the most important considerations in the gas supply projections. The finding rates used by the Gas Supply Task Group are based on historical data for the individual NPC regions.

In some instances, historical data on production, reserves, wells and footage drilled are reported by geographical areas which can be fitted to coincide with NPC regions. In other instances, the data must be allocated between two NPC regions. Allocations, when necessary, were based on the judgment of the Task Group members, with primary reliance placed on members with substantial knowledge of operations in the particular area under consideration.

The following tabulation describes the geographical makeup of the NPC regions. For those states where allocations were necessary, the percentage allocation is also shown. The percentage factor would apply to the drilling footage, reserves additions and production reported for the entire state.

NPC Region	Description
1N	Alaska, north of the Brooks Range
1S	Alaska, south of the Brooks Range
2	Onshore portions of Washington, Oregon and California. The allocation of data between offshore and onshore areas was based on the judgment of the Gas Supply Task Group
2A	Offshore area adjoining Washington, Oregon and California (see Region 2 above)
3	Idaho, Arizona, Utah, Nevada, northwest New Mexico and western Colorado (60 percent of Colorado)
4	Montana, Wyoming, North Dakota, South Dakota, eastern Colorado (40 percent of Colorado) and western Nebraska (85 percent of Nebraska)
5	Texas Railroad Commission Districts 7B, 7C, 8, 8A and 9; and southeast New Mexico
6	Onshore Louisiana, Mississippi, Alabama, Florida Panhandle, southern Arkansas (considered to be 0 percent of Arkansas for gas), and Texas Railroad Commission Districts 1, 2, 3, 4, 5 and 6. The allocation of data where necessary was based on the judgment of the Gas Supply Task Group
7	Oklahoma, Kansas, Iowa, Missouri, Minnesota, Texas Railroad Commission District 10, eastern Nebraska (15 percent of Nebraska) and northern Arkansas (considered to be 100 percent of Arkansas for gas)
8 & 9	Wisconsin, Michigan, Illinois, Indiana and Tennessee
10	Ohio, Pennsylvania, New York, West Virginia, Virginia, North Carolina, Kentucky, Maryland and the other New England States
11	Onshore Georgia, South Carolina, Delaware, New Jersey and Peninsular Florida
11A	Offshore Atlantic Coast.

The primary sources of historical data used as a basis for finding rate projections are as follows:

API—Quarterly Review of Drilling Statistics for the United States (1966-1970)

AAPG—Reports of the Committee on Statistics of Drilling (1956-1970)

Oil and Gas Journal—U.S. Drilling Statistics (Development—1956-1966)

AGA—Reports of the Committee on Proved Gas Reserves (1956-1970).

Exploratory dry hole footage, as well as stratigraphic and core test footage, was allocated between oil and non-associated gas on the basis of successful oil exploratory footage and successful gas exploratory footage. Developmental dry hole footage was allocated between oil and non-associated gas on the basis of successful oil developmental footage and successful gas developmental footage.

For the years 1966 through 1970, the AGA Committee reported non-associated gas separately from associated-dissolved gas. For the years prior to 1966, the Gas Supply Task Group used the following method to estimate the non-associated portion of total gas reserves additions.

The AGA Committee reported year-end remaining reserves of non-associated gas separately from associated-dissolved gas. However, annual gas production and reserves additions were reported on a combined basis prior to 1966. The Bureau of Mines Minerals Yearbook reports annual gas production from gas wells separately from gas production from oil wells. The relative proportion of gas production from gas wells, as reported by the Bureau of Mines, was then used to estimate the non-associated portion of total AGA preliminary net gas production. Once the non-associated production was established, the annual reserves additions could be calculated by differences in the year-end remaining reserves of non-associated gas reported by the AGA. This was done for each State.

Non-associated new gas reserve additions were determined for each region by projecting a finding rate in millions of cubic feet (MCF) found per foot drilled for gas, and then multiplying that finding rate by the footage projected to be drilled.

Two finding rates were developed for each region using different mathematical techniques. One is designated *high finding rate* and the other is designated *low finding rate*. Three drilling rates were projected for each region and these have been designated *high drilling rate*, *medium drilling rate* and *low drilling rate*. Application of three drilling rates to two finding rates results in six projections of non-associated new gas reserve additions.

High Finding of Non-Associated Natural Gas

The high finding rate of non-associated gas per foot of hole drilled for gas was estimated mathematically for each geologic region in the United States with the exception of Alaska where relatively few wells have been drilled for gas.

In principle, the high finding rate (MCF) was derived by taking the first derivative of the cumulative gas found — cumulative footage drilled growth equation. This growth equation was developed by fitting an S-shaped growth curve, by the method of least squares, to the historical relationship between the cumulative volume of non-associated gas found and cumulative footage drilled for gas during the 15-year period 1956 through 1970.

The S-shaped growth curve, fitted to the historical cumulative data was of the Gompertz type which is one of the broad class of S-curves, approaching zero to left and rising monotonically to a positive asymptote on the right. For this study, the upper asymptote was the volume of gas which has been estimated would ultimately be found in each region.

The cumulative volume of non-associated gas found at a given date is the sum of cumulative past production plus proved recoverable reserves at such date. The volume of gas which has been estimated and would ultimately be found is the sum of cumulative past production plus proved recoverable reserves at a given date plus estimated potential future gas supply at such date.

The Gompertz type S-shaped growth equation employed in projecting the relationship between the cumulative volume of non-associated gas found and cumulative footage drilled for gas is in the following form:

$$Q = U \cdot A^{[B^{(x)}]}$$

where:

$Q =$ Cumulative volume of non-associated gas found for corresponding values of cumulative footage drilled for gas from January 1, 1956

$U =$ Ultimate volume of non-associated gas to be found

$A =$ Ratio of cumulative volume of non-associated gas found at January 1, 1956 to ultimate volume of non-associated gas to be found

$B =$ Ratio of the differences between the natural logarithms of the cumulative volumes of non-associated gas found (Q) for corresponding values of cumulative footage drilled for gas (X). For increasing sequential *units* of X, for example from 1 to 2 to 3, with $X_3 - X_2 = X_2 - X_1 = 1$, and corresponding increasing sequential values of Q from 1 to 2 to 3, then

$$B = \frac{\ln Q_3 - \ln Q_2}{\ln Q_2 - \ln Q_1}$$

$X =$ Cumulative footage drilled for gas from January 1, 1956.

The first derivative of the Gompertz type S-shaped growth curve employed in projecting the high rate of non-associated gas found per foot of hole drilled for gas in the following form:

$dQ = Y_f$

$$Y_f = Q \cdot B^{(X)} \cdot \ln A \cdot \ln B$$

where:

Y_f = Volume of non-associated gas found per foot of hole drilled for gas, for corresponding values of cumulative footage drilled for gas from January 1, 1956

Q = Cumulative volume of non-associated gas found for corresponding values of cumulative footage drilled for gas from January 1, 1956

B = Ratio of the differences between the natural logarithms of the cumulative volumes of non-associated gas found (Q) for corresponding values of cumulative footage drilled for gas (X). For increasing sequential *units* of X, for example from a selected point 1 to 2 to 3, with $X_3 - X_2 = X_2 - X_1 = 1$, and corresponding increasing sequential values of Q from 1 to 2 to 3, then

$$B = \frac{\ln Q_3 - \ln Q_2}{\ln Q_2 - \ln Q_1}$$

X = Cumulative footage drilled for gas from January 1, 1956

A = Ratio of cumulative volume of non-associated gas found at January 1, 1956 to ultimate volume of non-associated gas to be found

$\ln$ = Natural logarithm.

The first derivative of the Gompertz type S-shaped growth curve was then extended for the three levels of cumulative footage, measured from January 1, 1956, which were considered would be drilled for gas during the 15-year period 1971 through 1985. From the extended first derivative curve, the future high finding rate of non-associated gas per foot of hole drilled for gas was determined for each year during the 15-year period 1971 through 1985.

In certain regions where historical gas finding data of major statistical significance has not been established or where such historical data is erratic, the finding rates developed by application of the foregoing methodology were adjusted to levels deemed compatible with finding rates for areas where historical gas finding data was of major statistical significance.

Low Finding Rate of Non-Associated Natural Gas

The low finding rate of non-associated gas per foot of hole drilled for gas was estimated for each geologic region in the United States in which the historical volumes of gas per foot of hole drilled have been established as being of major statistical significance. For those geologic regions where such historical gas finding data of major statistical significance has not been established, several regions were combined and the low finding rate of non-associated gas was estimated for the combined entity.

In principle, the low finding rate of non-associated gas per foot of hole drilled for gas was estimated for each geologic region or combined regions by fitting a modified exponential curve, by the method of least squares, to the historical relationship between the annual rate of non-associated gas found per foot of hole drilled for gas, and cumulative footage drilled for gas, during the 15-year period 1956 through 1970.

The annual rate of non-associated gas found per foot of hole drilled for gas, during the 15-year period 1956 through 1970, was determined by dividing gross additions of non-associated gas reserves for a given year by the footage drilled for gas during the same year. Gross additions of non-associated gas reserves are comprised of new field discoveries, new reservoir discoveries in old fields, extensions and revisions of prior estimates.

The modified exponential equation employed in projecting the low finding rate of non-associated gas per foot of hole drilled for gas is in the following form:

$$\ln Y_f = R \cdot X \div Y_0$$

where:

$\ln$ = Natural logarithm

Y_f = Volume of non-associated gas found per foot of hole drilled for gas, for corresponding values of cumulative footage drilled for gas from January 1, 1956

R = Rate of change of natural logarithm of volume of non-associated gas found per foot of hole drilled for gas, per unit of footage drilled.

X = Cumulative footage drilled for gas from January 1, 1956

Y_0 = Natural logarithm of volume of non-associated gas found per foot of hole drilled for gas at January 1, 1956.

The modified exponential curve for the period 1956 through 1970 was then extended for the three levels of cumulative footage (measured from January 1, 1956) which it was considered would be drilled for gas during the 15-year period 1971 through 1985. From the extended modified exponential curve, the future low finding rate of non-associated gas per foot of hole drilled for gas was determined for each year during the 15-year period 1971 through 1985.

It may be observed for Regions 2, 3, 4, and 2A, during the 15-year period 1971 through 1985, that somewhat greater volumes of new reserves were projected to be added for the low finding rate cases than for the high finding rate cases. This results from application of the previously mentioned different mathematical techniques to the reported historical data involving quantities of gas found and footage drilled.

The methodology for developing the finding rates used in Region 11A (Offshore Atlantic) are discussed in Chapter Six, Section VIII.

TABLE 294

HISTORICAL LOWER 48 STATES NON-ASSOCIATED GAS FINDING RATE
(1946-1970)

	Annual Gas Footage Drilled (000,000')	Annual N-A Gas Reserves Additions (BCF)	N-A Gas Added Per Foot Drilled (MCF)	3-Year Moving Average N-A Gas Added Per Foot Drilled (MCF)	Cumulative Gas Footage Drilled (000,000')
1946	19.6				19.6
1947	21.5	6,463	301		41.1
1948	22.5	7,485	333		63.6
1949	22.1	6,846	310	315	85.7
1950	20.1	9,065	451	362	105.8
1951	23.3	8,470	364	372	129.1
1952	30.2	9,621	319	369	159.3
1953	36.3	15,368	423	373	195.6
1954	37.8	5,632	149	294	233.4
1955	41.1	12,747	310	293	274.5
1956	44.5	15,427	347	274	319.0
1957	46.0	16,333	355	338	365.0
1958	53.9	17,505	325	341	418.9
1959	57.9	15,245	263	311	476.8
1960	58.8	11,646	198	260	535.6
1961	61.5	14,524	236	232	597.1
1962	60.7	17,490	288	241	657.8
1963	52.2	12,537	240	256	710.0
1964	54.4	17,371	319	283	764.4
1965	53.4	18,416	345	302	817.8
1966	51.8	16,136	312	325	869.6
1967	42.3	17,284	409	351	911.9
1968	42.0	12,334	294	336	953.9
1969	49.0	6,875	140	274	1,002.9
1970	42.2	9,351	222	214	1,045.1

TABLE 295

DRILLING AND FINDING RATE STATISTICS–NON-ASSOCIATED GAS

NPC Region 2

	Total Non-Associated Gas Drilling Effort*		Percent of Lower 48 Gas Ftg.	Average Depth	Annual Reserves Additions	Reserves Added Per Foot Drilled	Cumulative Reserves Added	Cumulative Footage Drilled	Cumulative Reserves ÷ Cumulative Footage
	Wells	Footage (1,000′)		(Feet)	(BCF)	(MCF)	(BCF)	(1,000′)	(MCF)
1956	181	717	1.6	3,961	49.6	69	49.6	717	69
1957	154	746	1.6	4,844	313.0	420	362.6	1,463	248
1958	134	539	1.0	4,022	(15.8)	(29)	346.8	2,002	173
1959	221	946	1.6	4,281	(40.3)	(43)	306.6	2,948	104
1960	366	1,942	3.3	5,306	400.6	206	707.2	4,890	145
1961	389	2,492	4.1	6,406	423.9	170	1,131.1	7,382	153
1962	335	2,296	3.8	6,854	465.6	203	1,596.7	9,678	165
1963	264	1,913	3.7	7,246	(39.7)	(21)	1,557.0	11,591	134
1964	246	1,649	3.0	6,703	190.6	116	1,747.6	13,240	132
1965	188	1,092	2.0	5,809	32.0	29	1,779.6	14,332	124
1966	190	1,416	2.7	7,453	293.8	207	2,073.4	15,748	132
1967	187	1,242	2.9	6,642	185.8	150	2,259.2	16,990	133
1968	176	1,150	2.7	6,534	266.3	232	2,525.5	18,140	139
1969	137	821	1.7	5,993	123.1	150	2,648.6	18,961	140
1970	109	660	1.6	6,055	(11.5)	(17)	2,637.1	19,621	134

* Includes allocated dry holes.

TABLE 296

DRILLING AND FINDING RATE STATISTICS–NON-ASSOCIATED GAS

NPC Region 2A

	Total Non-Associated Gas Drilling Effort*		Percent of Lower 48 Gas Ftg.	Average Depth	Annual Reserves Additions	Reserves Added Per Foot Drilled	Cumulative Reserves Added	Cumulative Footage Drilled	Cumulative Reserves ÷ Cumulative Footage
	Wells	Footage (1,000')		(Feet)	(BCF)	(MCF)	(BCF)	(1,000')	(MCF)
1956	–	–	–	–	–	–	–	–	–
1957	–	–	–	–	–	–	–	–	–
1958	–	–	–	–	–	–	–	–	–
1959	–	–	–	–	–	–	–	–	–
1960	–	–	–	–	62.2	–	62.2	–	–
1961	15	91	.1	6,067	67.8	745	130.0	91	1,429
1962	15	92	.2	6,133	53.3	579	183.3	183	1,002
1963	20	113	.2	5,650	110.0	973	293.3	296	991
1964	1	7	–	7,000	225.2	32,171	518.5	303	1,711
1965	–	–	–	–	17.8	–	536.3	303	1,770
1966	1	7	–	7,000	(19.1)	(2,729)	517.2	310	1,668
1967	–	–	–	–	13.6	–	530.8	310	1,712
1968	1	13	–	13,000	(1.8)	(138)	529.0	323	1,638
1969	1	5	–	5,000	–	–	529.0	328	1,638
1970	–	–	–	–	–	–	529.0	328	1,638

* Includes allocated dry holes.

TABLE 297

DRILLING AND FINDING RATE STATISTICS—NON-ASSOCIATED GAS

NCP Region 3

	Total Non-Associated Gas Drilling Effort*		Percent of Lower 48 Gas Ftg.	Average Depth	Annual Reserves Additions	Reserves Added Per Foot Drilled	Cumulative Reserves Added	Cumulative Footage Drilled	Cumulative Reserves ÷ Cumulative Footage
	Wells	Footage (1,000')		(Feet)	(BCF)	(MCF)	(BCF)	(1,000')	(MCF)
1956	1,163	4,826	10.9	4,150	4,436.4	919	4,436.4	4,826	919
1957	931	4,101	8.9	4,405	180.2	44	4,616.6	8,927	517
1958	829	3,795	7.0	4,578	(233.5)	(62)	4,383.1	12,722	345
1959	665	2,770	4.8	4,165	(2,582.9)	(932)	1,800.2	15,492	116
1960	714	3,777	6.4	5,290	(1,273.9)	(337)	526.3	19,269	27
1961	819	4,473	7.3	5,462	759.6	170	1,285.9	23,742	54
1962	865	4,676	7.7	5,406	58.2	12	1,344.1	28,418	47
1963	584	2,981	5.7	5,104	511.1	171	1,855.2	31,399	59
1964	613	3,139	5.8	5,121	479.8	153	2,335.0	34,538	68
1965	524	2,725	5.1	5,200	518.8	190	2,853.8	37,263	77
1966	493	2,469	4.8	5,008	10.3	4	2,864.1	39,732	72
1967	402	2,077	4.9	5,167	1,079.8	520	3,943.9	41,809	94
1968	262	1,475	3.5	5,630	151.0	102	4,094.9	43,284	95
1969	514	2,307	4.7	4,488	66.4	29	4,161.3	45,591	91
1970	303	1,468	3.5	4,845	181.0	123	4,342.3	47,059	92

* Includes allocated dry holes.

TABLE 298

DRILLING AND FINDING RATE STATISTICS–NON-ASSOCIATED GAS

NPC Region 4

	Total Non-Associated Gas Drilling Effort*								
	Wells	Footage (1,000')	Percent of Lower 48 Gas Ftg.	Average Depth (Feet)	Annual Reserves Additions (BCF)	Reserves Added Per Foot Drilled (MCF)	Cumulative Reserves Added (BCF)	Cumulative Footage Drilled (1,000')	Cumulative Reserves ÷ Cumulative Footage (MCF)
1956	463	2,100	4.7	4,536	159.9	76	159.9	2,100	76
1956	374	1,772	3.9	4,738	365.5	206	525.4	3,872	136
1958	344	2,023	3.8	5,881	754.3	373	1,279.7	5,895	217
1959	370	2,216	3.8	5,989	50.3	23	1,330.0	8,111	164
1960	348	1,960	3.3	5,632	(50.7)	(26)	1,279.3	10,071	127
1961	473	2,693	4.4	5,693	591.1	219	1,870.4	12,764	147
1962	465	2,679	4.4	5,761	138.5	52	2,008.9	15,443	130
1963	345	1,639	3.1	4,751	69.4	42	2,078.3	17,082	122
1964	274	1,456	2.7	5,314	(77.0)	(53)	2,001.3	18,538	108
1965	240	1,268	2.4	5,283	165.9	131	2,167.2	18,806	109
1966	272	1,402	2.7	5,154	179.1	128	2,346.3	21,208	111
1967	254	884	2.1	3,480	591.7	669	2,938.0	22,092	133
1968	341	1,371	3.3	4,021	353.1	258	3,291.1	23,463	140
1969	392	1,874	3.8	4,781	520.2	278	3,811.3	25,337	150
1970	506	1,717	4.1	3,393	397.7	232	4,209.0	27,054	156

* Includes allocated dry holes.

TABLE 299

DRILLING AND FINDING RATE STATISTICS—NON-ASSOCIATED GAS

NPC Region 5

	Total Non-Associated Gas Drilling Effort*								
	Wells	Footage (1,000')	Percent of Lower 48 Gas Ftg.	Average Depth (Feet)	Annual Reserves Additions (BCF)	Reserves Added Per Foot Drilled (MCF)	Cumulative Reserves Added (BCF)	Cumulative Footage Drilled (1,000')	Cumulative Reserves ÷ Cumulative Footage (MCF)
1956	440	1,807	4.1	4,107	(1,519.5)	(841)	(1,519.5)	1,807	(841)
1957	707	3,147	6.8	4,451	1,166.7	371	(352.8)	4,954	71
1958	869	4,732	8.8	5,445	2,485.3	525	2,132.5	9,686	220
1959	974	5,142	8.9	5,279	725.0	141	2,857.5	14,828	193
1960	994	5,474	9.3	5,507	1,142.4	209	3,999.9	20,302	197
1961	786	4,672	7.6	5,944	(17.1)	(4)	3,982.8	24,974	159
1962	681	3,778	6.2	5,548	328.8	87	4,311.6	28,752	150
1963	822	4,806	9.2	5,847	967.4	201	5,279.0	33,558	157
1964	703	4,032	7.4	5,735	2,765.8	686	8,044.8	37,590	214
1965	820	4,762	8.9	5,807	2,809.0	590	10,853.8	42,352	256
1966	783	4,910	9.5	6,271	4,400.1	896	15,253.9	47,262	323
1967	633	4,456	10.5	7,039	2,570.9	577	17,824.8	51,718	345
1968	639	4,069	9.7	6.368	1,324.7	326	19,149.5	55,787	343
1969	543	3,936	8.0	7,249	(76.6)	(19)	19,072.9	59,723	319
1970	467	3,778	8.9	8,090	374.7	99	19,447.6	63,501	306

* Includes allocated dry holes.

TABLE 300

DRILLING AND FINDING RATE STATISTICS—NON-ASSOCIATED GAS

NPC Region 6

	Total Non-Associated Gas Drilling Effort*		Percent of Lower 48 Gas Ftg.	Average Depth	Annual Reserves Additions	Reserves Added Per Foot Drilled	Cumulative Reserves Added	Cumulative Footage Drilled	Cumulative Reserves ÷ Cumulative Footage
	Wells	Footage (1,000')		(Feet)	(BCF)	(MCF)	(BCF)	(1,000')	(MCF)
1956	3,076	21,750	48.9	7,071	8,480.0	390	8,480.0	21,750	390
1957	3,407	20,191	43.9	5,926	9,704.3	481	18,184.3	41,941	434
1958	3,370	25,152	46.6	7,464	8,312.1	330	26,496.4	67,093	395
1959	3,610	28,206	48.7	7,813	11,827.2	419	38,323.6	95,299	402
1960	3,573	26,592	25.2	7,442	7,729.2	291	46,052.8	121,891	378
1961	3,524	26,413	43.0	7,495	9,524.8	361	55,577.6	148,304	375
1962	3,511	25,854	42.6	7,364	7,943.2	307	63,520.8	174,158	365
1963	3,224	23,314	44.7	7,231	6,797.2	292	70,318.0	194,472	362
1964	3,061	24,042	44.2	7,854	5,854.3	244	76,172.3	221,514	344
1965	3,169	24,338	45.6	7,680	7,414.1	305	83,586.4	245,852	340
1966	2,648	21,277	41.1	8,035	5,126.2	241	88,712.6	267,129	332
1967	2,176	17,017	40.2	7,820	5,503.8	323	94,216.4	284,146	332
1968	2,034	16,538	39.4	8,131	6,903.4	417	101,119.8	300,684	336
1969	2,579	21,283	43.4	8,252	3,212.9	151	104,332.7	321,967	324
1970	2,014	16,201	38.4	8,044	1,358.2	84	105,690.9	338,168	313

* Includes allocated dry holes.

TABLE 301

DRILLING AND FINDING RATE STATISTICS —NON-ASSOCIATED GAS

NPC Region 6A

	Total Non-Associated Gas Drilling Effort*									
	Wells	Footage (1,000′)	Percent of Lower 48 Gas Ftg.	Average Depth (Feet)	Annual Reserves Additions (BCF)	Reserves Added Per Foot Drilled (MCF)	Cumulative Reserves Added (BCF)	Cumulative Footage Drilled (1,000′)	Cumulative Reserves ÷ Cumulative Footage (MCF)
1956	82	844	1.9	10,293	737.9	874	737.9	844	874
1957	143	1,559	3.4	10,902	1,216.5	780	1,954.4	2,403	813
1958	95	1,114	2.1	11,726	532.5	478	2,486.9	3,517	707
1959	109	1,285	2.2	11,789	2,390.2	1,860	4,877.1	4,802	1,016
1960	138	1,708	2.9	12,377	1,472.4	862	6,349.5	6,510	975
1961	153	1,749	2.8	11,431	1,756.0	1,004	8,105.5	8,259	981
1962	230	2,535	4.2	11,022	5,665.0	2,235	13,770.5	10,794	1,276
1963	183	2,109	4.0	11,525	2,034.9	965	15,805.4	12,903	1,225
1964	282	3,409	6.3	12,089	4,601.5	1,350	20,406.9	16,312	1,251
1965	191	2,241	4.2	11,733	4,664.3	2,081	25,071.2	18,553	1,351
1966	364	3,798	7.3	10,434	3,392.0	893	28,463.2	22,351	1,273
1967	331	3,590	8.5	10,846	4,561.5	1,271	33,024.7	25,941	1,273
1968	404	4,596	11.0	11,376	2,942.8	640	35,967.5	30,537	1,178
1969	362	3,886	7.9	10,735	1,498.5	386	37,466.0	34,423	1,088
1970	332	3,683	8.7	11,093	4,649.8	1,263	42,115.8	38,106	1,105

* Includes allocated dry holes.

TABLE 302

DRILLING AND FINDING RATE STATISTICS—NON-ASSOCIATED GAS

NPC Region 7

	Total Non-Associated Gas Drilling Effort*		Percent of Lower 48 Gas Ftg.	Average Depth (Feet)	Annual Reserves Additions (BCF)	Reserves Added Per Foot Drilled (MCF)	Cumulative Reserves Added (BCF)	Cumulative Footage Drilled (1,000')	Cumulative Reserves ÷ Cumulative Footage (MCF)
	Wells	Footage (1,000')							
1956	1,943	7,749	17.4	3,988	2,730.7	352	2,730.7	7,749	352
1957	2,016	8,558	18.6	4,245	2,923.6	342	5,654.3	16,307	347
1958	2,303	10,813	20.1	4,695	5,403.8	500	11,058.1	27,120	408
1959	2,198	10,668	18.4	4,854	2,431.5	228	13,489.6	37,788	357
1960	2,059	10,202	17.4	4,955	1,473.4	144	14,963.0	47,990	312
1961	2,483	11,538	18.8	4,647	940.7	82	15,903.7	59,528	267
1962	2,130	11,061	18.2	5,193	2,438.4	220	18,342.1	70,589	260
1963	1,577	8,416	16.1	5,337	1,457.0	173	19,799.1	79,005	251
1964	1,514	8,357	15.4	5,520	2,927.1	350	22,726.2	87,362	260
1965	1,641	9,185	17.2	5,597	2,259.6	246	24,985.8	96,547	259
1966	1,646	10,014	19.4	6,084	2,191.3	219	27,177.1	106,561	255
1967	1,476	8,263	19.5	5,598	2,370.0	287	29,547.1	114,824	257
1968	1,195	7,235	17.2	6,054	21.3	3	29,568.4	122,059	242
1969	1,324	8,050	16.4	6,080	1,249.4	155	30,817.8	130,109	237
1970	1,107	7,341	17.4	6,631	1,736.9	237	32,554.7	137,450	237

* Includes allocated dry holes.

TABLE 303

DRILLING AND FINDING RATE STATISTICS—NON-ASSOCIATED GAS

NPC Regions 8&9

	Total Non-Associated Gas Drilling Effort*								
	Wells	Footage (1,000')	Percent of Lower 48 Gas Ftg.	Average Depth (Feet)	Annual Reserves Additions (BCF)	Reserves Added Per Foot Drilled (MCF)	Cumulative Reserves Added (BCF)	Cumulative Footage Drilled (1,000')	Cumulative Reserves ÷ Cumulative Footage (MCF)
1956	272	418	.9	1,537	7.7	18	7.7	418	18
1957	243	381	.8	1,568	45.7	120	53.4	799	67
1958	298	351	.7	1,178	58.6	167	112.0	1,150	97
1959	245	556	1.0	2,269	8.0	14	120.0	1,706	70
1960	268	543	.9	2,026	16.9	31	136.9	2,249	61
1961	448	938	1.5	2,094	37.3	40	174.2	3,187	55
1962	405	937	1.5	2,314	4.1	4	178.3	4,124	43
1963	331	718	1.4	2,169	8.8	12	187.1	4,842	39
1964	338	843	1.6	2,494	59.8	71	246.9	5,685	43
1965	299	730	1.4	2,441	(18.0)	(25)	228.9	6,415	36
1966	221	444	.9	2,009	(22.9)	(52)	206.0	6,859	30
1967	128	275	.6	2,148	33.1	120	239.1	7,134	34
1968	193	368	.9	1,907	9.2	25	248.3	7,502	33
1969	162	367	.7	2,265	15.4	42	263.7	7,869	34
1970	172	446	1.1	2,593	157.5	353	421.2	8,315	51

* Includes allocated dry holes.

TABLE 304

DRILLING AND FINDING RATE STATISTICS—NON-ASSOCIATED GAS

NPC Region 10

	Total Non-Associated Gas Drilling Effort*								
	Wells	Footage (1,000')	Percent of Lower 48 Gas Ftg.	Average Depth (Feet)	Annual Reserves Additions (BCF)	Reserves Added Per Foot Drilled (MCF)	Cumulative Reserves Added (BCF)	Cumulative Footage Drilled (1,000')	Cumulative Reserves ÷ Cumulative Footage (MCF)
1956	1,779	4,149	9.3	2,332	341.5	82	341.5	4,149	82
1957	1,888	5,493	11.9	2,909	417.6	76	759.1	9,642	79
1958	1,885	5,365	9.9	2,846	207.1	39	966.2	15,007	64
1959	2,048	6,041	10.4	2,950	434.7	72	1,400.9	21,048	67
1960	2,335	6,513	11.1	2,789	674.0	103	2,074.9	27,561	75
1961	2,411	6,381	10.4	2,647	440.2	69	2,515.1	33,942	74
1962	2,567	6,731	11.1	2,622	394.3	59	2,909.4	40,673	72
1963	2,201	6,154	11.8	2,796	620.9	101	3,530.3	46,827	75
1964	2,661	7,432	13.7	2,793	344.2	46	3,874.5	54,259	71
1965	2,297	7,050	13.2	3,069	553.0	78	4,427.5	61,309	72
1966	2,111	5,909	11.4	2,799	585.3	99	5,012.8	67,218	75
1967	1,604	4,472	10.6	2,788	374.0	84	5,386.8	71,690	75
1968	1,719	5,101	12.2	2,967	364.1	71	5,750.9	76,791	75
1969	1,981	6,510	13.3	3,286	265.4	41	6,016.3	83,301	72
1970	2,080	6,943	16.4	3,338	507.1	73	6,523.4	90,244	72

* Includes allocated dry holes.

TABLE 305

DRILLING AND FINDING RATE STATISTICS–NON-ASSOCIATED GAS

NPC Region 11

	Total Non-Associated Gas Drilling Effort*								
	Wells	Footage (1,000')	Percent of Lower 48 Gas Ftg.	Average Depth (Feet)	Annual Reserves Additions (BCF)	Reserves Added Per Foot Drilled (MCF)	Cumulative Reserves Added (BCF)	Cumulative Footage Drilled (1,000')	Cumulative Reserves ÷ Cumulative Footage (MCF)
1956	19	93	.2	4,895	2.8	30	2.8	93	30
1957	6	32	.1	5,333	(.2)	(6)	2.6	125	21
1958	6	40	.1	6,667	.2	5	2.8	165	17
1959	13	59	.1	4,538	1.0	17	3.8	224	17
1960	12	74	.1	6,167	(.7)	(9)	3.1	298	10
1961	8	51	.1	6,375	(.2)	(4)	2.9	349	8
1962	3	21	–	7,000	.1	5	3.0	370	8
1963	7	30	.1	4,286	–	–	3.0	400	8
1964	–	–	–	–	–	–	3.0	400	8
1965	8	39	.1	4,875	(.3)	(8)	2.7	439	6
1966	18	105	.2	5,833	(.1)	(1)	2.6	544	5
1967	5	45	.1	9,000	(.1)	(2)	2.5	589	4
1968	4	35	.1	8,750	.2	6	2.7	624	4
1969	–	–	–	–	–	–	2.7	624	4
1970	–	–	–	–	–	–	2.7	624	4

* Includes allocated dry holes.

TABLE 306

DRILLING AND FINDING RATE STATISTICS—NON-ASSOCIATED GAS

Lower 48 States

	Total Non-Associated Gas Drilling Effort*		Percent of Lower 48 Gas Ftg.	Average Depth	Annual Reserves Additions	Reserves Added Per Foot Drilled	Cumulative Reserves Added	Cumulative Footage Drilled	Cumulative Reserves ÷ Cumulative Footage
	Wells	Footage (1,000′)		(Feet)	(BCF)	(MCF)	(BCF)	(1,000′)	(MCF)
1956	9,418	44,453	100	4,720	15,426.9	347	15,426.9	44,453	347
1957	9,869	45,980	100	4,659	16,332.9	355	31,759.8	90,433	351
1958	10,133	53,924	100	5,322	17,504.5	325	49,264.3	144,357	341
1959	10,453	57,889	100	5,538	15,244.8	263	64,509.1	202,246	319
1960	10,807	58,785	100	5,440	11,645.9	198	76,155.0	261,031	292
1961	11,509	61,491	100	5,343	14,524.2	236	90,679.2	322,522	281
1962	11,207	60,660	100	5,413	17,489.5	288	108,168.7	383,182	282
1963	9,558	52,193	100	5,461	12,536.8	240	120,705.5	435,375	277
1964	9,693	54,366	100	5,609	17,371.4	320	138,076.9	489,741	282
1965	9,377	53,430	100	5,698	18,416.1	345	156,493.0	543,171	288
1966	8,747	51,757	100	5,916	16,136.1	312	172,629.1	594,922	290
1967	7,196	42,327	100	5,881	17,284.1	408	189,913.2	637,243	298
1968	6,968	41,951	100	6,021	12,334.3	294	202,247.5	679,194	298
1969	7,995	49,037	100	6,134	6,874.7	140	209,122.2	728,233	287
1970	7,090	42,237	100	5,957	9,351.3	221	218,473.5	770,470	284

* Includes allocated dry holes.

Note: Lower 48 totals may not check total of regions due to rounding.

TABLE 307

PROJECTED NON-ASSOCIATED GAS RESERVES ADDED PER FOOT DRILLED–LOWER 48 STATES (MCF)

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	132	122	117	146	473	281	1,112	216	59	74	–	–	327
1972	132	116	114	147	478	276	1,144	215	63	75	–	–	330
1973	133	109	114	149	482	272	1,171	214	66	75	–	–	333
1974	132	125	114	150	484	267	1,191	213	68	75	42	1,063	335
1975	133	118	114	152	484	262	1,203	211	72	75	39	1,078	336
1976	132	127	114	154	482	256	1,206	210	75	75	45	1,055	334
1977	133	136	114	156	477	250	1,198	208	80	75	51	1,056	333
1978	133	141	114	159	470	244	1,177	206	85	75	52	1,061	333
1979	133	151	114	161	459	237	1,143	204	88	74	54	1,061	334
1980	133	159	113	163	445	229	1,095	202	95	74	58	1,061	326
1981	133	173	113	165	427	221	1,032	199	101	74	66	1,061	318
1982	133	184	112	167	406	213	956	196	108	74	74	1,061	307
1983	132	202	112	169	383	205	872	193	114	74	84	1,061	294
1984	132	215	111	170	357	197	784	189	121	74	95	1,061	280
1985	132	230	111	171	331	189	697	186	129	73	109	1,061	263

Note: Totals may not agree due to rounding.

TABLE 308

PROJECTED NON-ASSOCIATED GAS RESERVES ADDED PER FOOT DRILLED—LOWER 48 STATES (MCF)

Case I A

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	143	146	143	143	332	175	885	160	69	69	–	–	241
1972	147	140	146	146	336	167	866	155	69	69	–	–	236
1973	149	152	149	149	340	158	846	150	69	68	–	–	233
1974	153	146	153	153	344	150	826	145	68	69	63	708	229
1975	157	157	157	157	349	141	804	140	69	69	78	706	225
1976	162	164	162	161	354	133	781	135	67	69	73	709	220
1977	166	169	166	167	360	125	757	129	67	69	68	708	217
1978	173	172	237	173	360	117	731	124	69	69	68	707	219
1979	179	180	230	179	352	109	705	118	68	69	68	707	218
1980	186	185	223	187	343	101	677	112	68	69	69	707	211
1981	195	193	215	195	333	93	648	106	69	69	68	707	207
1982	205	204	207	205	323	86	617	100	69	69	69	707	202
1983	199	213	199	215	313	79	588	94	69	69	69	707	197
1984	191	226	191	226	303	73	558	88	68	69	69	707	191
1985	183	238	183	238	294	68	530	83	68	69	69	707	184

Note: Totals may not agree due to rounding.

TABLE 309

PROJECTED NON-ASSOCIATED GAS RESERVES ADDED PER FOOT DRILLED—LOWER 48 STATES (MCF)

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	132	122	117	146	473	281	1,112	216	59	74	–	–	327
1972	132	119	114	147	478	276	1,143	215	61	75	–	–	330
1973	132	116	114	149	482	272	1,169	214	66	75	–	–	333
1974	132	114	114	150	484	267	1,189	213	68	75	45	1,068	335
1975	133	130	114	152	484	263	1,201	212	72	75	43	1,065	336
1976	133	126	114	154	483	258	1,206	210	75	75	53	1,063	335
1977	133	130	114	155	480	253	1,203	209	77	75	50	1,060	335
1978	133	143	114	157	474	247	1,191	207	82	75	51	1,062	336
1979	133	145	114	159	467	242	1,169	206	85	75	54	1,061	339
1980	133	154	114	161	458	236	1,138	204	90	74	58	1,061	334
1981	133	164	113	163	446	230	1,097	202	94	74	60	1,060	330
1982	133	176	113	165	432	224	1,047	200	100	74	66	1,061	324
1983	133	182	113	166	416	218	990	197	105	74	74	1,061	316
1984	133	196	112	168	399	212	928	195	111	74	82	1,061	306
1985	133	206	112	169	381	206	862	193	115	74	93	1,061	294

Note: Totals may not agree due to rounding.

TABLE 310

PROJECTED NON-ASSOCIATED GAS RESERVES ADDED PER FOOT DRILLED—LOWER 48 STATES (MCF)

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	143	146	143	143	332	175	885	160	69	69	–	–	241
1972	146	143	146	146	336	167	867	155	68	69	–	–	237
1973	150	140	149	149	340	159	848	151	70	69	–	–	233
1974	152	159	152	153	344	151	829	155	68	69	68	705	229
1975	156	152	156	156	348	144	809	142	69	69	65	696	226
1976	160	158	160	160	352	136	789	137	69	69	74	708	222
1977	164	160	164	164	357	129	769	132	69	69	70	707	220
1978	169	171	241	169	362	122	748	128	68	68	70	707	223
1979	174	173	236	174	359	116	726	123	70	69	68	707	224
1980	179	179	230	180	351	109	703	118	68	69	68	707	219
1981	186	186	223	186	344	103	680	113	68	69	68	707	215
1982	192	191	217	192	336	97	657	108	68	69	68	707	212
1983	199	198	211	199	329	91	633	103	69	69	68	707	208
1984	205	206	205	207	321	86	610	99	69	69	69	707	204
1985	199	216	199	214	314	81	588	94	69	69	68	707	199

Note: Totals may not agree due to rounding.

TABLE 311

PROJECTED NON-ASSOCIATED GAS RESERVES ADDED PER FOOT DRILLED—LOWER 48 STATES (MCF)

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	143	146	143	144	332	176	885	160	67	69	–	–	241
1972	146	154	146	146	336	168	868	155	70	68	–	–	237
1973	148	162	149	149	339	161	852	152	69	68	–	–	234
1974	152	139	151	151	342	154	836	148	68	69	56	694	231
1975	154	147	154	154	345	148	821	144	71	68	59	706	229
1976	157	152	156	157	348	143	807	141	69	69	76	697	227
1977	159	156	159	159	351	138	794	138	68	69	63	705	226
1978	162	164	162	162	354	134	781	135	70	69	65	705	227
1979	164	169	165	165	357	130	769	132	68	69	68	706	230
1980	167	161	243	167	359	126	758	130	66	69	71	708	233
1981	169	173	240	170	362	123	746	128	69	69	68	707	233
1982	172	167	238	172	362	120	736	125	66	69	66	707	233
1983	175	173	236	174	359	117	725	123	69	69	70	707	233
1984	176	181	232	176	356	115	715	121	66	68	70	707	232
1985	179	174	230	179	353	113	706	119	69	69	70	707	229

Note: Totals may not agree due to rounding.

TABLE 312

PROJECTED NON-ASSOCIATED GAS RESERVES ADDED PER FOOT DRILLED—LOWER 48 STATES (MCF)

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	132	122	117	145	473	281	1,112	216	60	74	–	–	327
1972	132	128	114	147	478	277	1,142	215	62	74	–	–	330
1973	132	108	114	149	481	273	1,166	214	65	75	–	–	333
1974	132	111	114	150	483	269	1,184	213	68	75	56	1,056	335
1975	132	118	114	151	484	265	1,196	212	71	75	59	1,088	337
1976	133	121	114	152	484	262	1,204	211	73	75	45	1,061	337
1977	132	125	114	153	483	258	1,207	210	77	75	47	1,063	338
1978	133	131	114	155	481	255	1,206	209	75	75	43	1,058	342
1979	133	136	114	156	479	252	1,201	209	78	75	51	1,060	348
1980	133	143	114	157	476	249	1,195	208	81	75	50	1,062	347
1981	133	148	114	158	473	247	1,186	207	85	74	56	1,061	349
1982	133	154	113	159	469	244	1,174	206	83	74	55	1,061	350
1983	133	147	113	160	465	242	1,161	205	86	74	60	1,061	349
1984	134	153	113	161	461	240	1,147	204	90	74	60	1,060	348
1985	133	159	114	162	456	237	1,132	204	88	74	66	1,061	344

Note: Totals may not agree due to rounding.

Chapter Six—Section III

Gas Drilling—Footage and Wells

TABLE 313

HISTORICAL OIL AND GAS DRILLING FOOTAGE–LOWER 48 STATES
INCLUDING ALLOCATED DRY HOLE FOOTAGE
(Million Feet)

History	Total Oil Drilling	Total Gas Drilling	Total Oil and Gas Drilling	Gas Drilling as Percentage of Total
1956	198	44	242	18
1957	185	46	231	20
1958	156	54	210	26
1959	161	58	219	26
1960	137	59	196	30
1961	132	61	193	32
1962	138	61	199	31
1963	135	52	187	28
1964	137	54	191	28
1965	129	53	182	29
1966	110	52	162	32
1967	98	42	140	30
1968	102	42	144	29
1969	107	49	156	31
1970	96	42	138	30

TABLE 314

PROJECTED OIL AND GAS DRILLING FOOTAGE—LOWER 48 STATES INCLUDING ALLOCATED DRY HOLE FOOTAGE
(Million Feet)

Case I

	Total Oil Drilling	Total Gas Drilling	Total Oil and Gas Drilling	Gas Drilling as Percentage of Total
1971	90	41	131	31
1972	93	43	136	32
1973	103	46	149	31
1974	113	48	161	30
1975	122	51	173	29
1976	131	55	186	30
1977	142	59	201	29
1978	151	64	215	30
1979	159	69	228	30
1980	167	76	243	31
1981	175	81	256	32
1982	180	85	265	32
1983	186	88	274	32
1984	191	88	279	32
1985	196	88	284	31

TABLE 315

PROJECTED OIL AND GAS DRILLING FOOTAGE—LOWER 48 STATES INCLUDING ALLOCATED DRY HOLE FOOTAGE
(Million Feet)

Case IA

	Total Oil Drilling	Total Gas Drilling	Total Oil and Gas Drilling	Gas Drilling as Percentage of Total
1971	89	41	130	32
1972	89	43	132	33
1973	93	46	139	33
1974	96	48	144	33
1975	101	51	152	34
1976	106	55	161	34
1977	112	59	171	35
1978	119	64	183	35
1979	126	69	195	35
1980	133	76	209	36
1981	140	81	221	37
1982	146	85	231	37
1983	153	88	241	37
1984	160	88	248	35
1985	168	88	256	34

TABLE 316

PROJECTED OIL AND GAS DRILLING FOOTAGE—LOWER 48 STATES INCLUDING ALLOCATED DRY HOLE FOOTAGE (Million Feet)

Case II

	Total Oil Drilling	Total Gas Drilling	Total Oil and Gas Drilling	Gas Drilling as Percentage of Total
1971	90	41	131	31
1972	91	42	133	32
1973	100	43	143	30
1974	108	44	152	29
1975	113	46	159	29
1976	118	48	166	29
1977	125	50	175	29
1978	130	52	182	29
1979	133	55	188	29
1980	136	59	195	30
1981	139	61	200	30
1982	141	63	204	31
1983	144	64	208	31
1984	147	65	212	31
1985	150	65	215	30

TABLE 317

PROJECTED OIL AND GAS DRILLING FOOTAGE—LOWER 48 STATES INCLUDING ALLOCATED DRY HOLE FOOTAGE (Million Feet)

Case III

	Total Oil Drilling	Total Gas Drilling	Total Oil and Gas Drilling	Gas Drilling as Percentage of Total
1971	89	41	130	32
1972	87	42	129	33
1973	90	43	133	32
1974	92	44	136	32
1975	94	46	140	33
1976	96	48	144	33
1977	99	50	149	34
1978	102	52	154	34
1979	105	55	160	34
1980	108	59	167	35
1981	111	61	172	35
1982	113	63	176	36
1983	117	64	181	35
1984	120	65	185	35
1985	124	65	189	34

TABLE 318

PROJECTED OIL AND GAS DRILLING FOOTAGE—LOWER 48 STATES INCLUDING ALLOCATED DRY HOLE FOOTAGE (Million Feet)

Case IV

	Total Oil Drilling	Total Gas Drilling	Total Oil and Gas Drilling	Gas Drilling as Percentage of Total
1971	89	41	130	32
1972	82	39	121	32
1973	79	37	116	32
1974	75	36	111	32
1975	71	34	105	32
1976	68	33	101	33
1977	64	32	96	33
1978	63	31	94	33
1979	60	29	89	33
1980	57	28	85	33
1981	54	27	81	33
1982	51	26	77	34
1983	49	25	74	34
1984	47	24	71	34
1985	45	23	68	34

TABLE 319

PROJECTED OIL AND GAS DRILLING FOOTAGE—LOWER 48 STATES INCLUDING ALLOCATED DRY HOLE FOOTAGE (Million Feet)

Case IVA

	Total Oil Drilling	Total Gas Drilling	Total Oil and Gas Drilling	Gas Drilling as Percentage of Total
1971	90	41	131	31
1972	86	39	125	31
1973	87	37	124	30
1974	87	36	123	29
1975	84	34	118	29
1976	82	33	115	29
1977	79	32	111	29
1978	79	31	110	28
1979	76	29	105	28
1980	72	28	100	28
1981	69	27	96	28
1982	65	26	91	29
1983	62	25	87	29
1984	59	24	83	29
1985	57	23	80	29

TABLE 320

PRODUCTIVE GAS WELL FOOTAGE DRILLED HISTORICALLY—LOWER 48 STATES

(1,000 Feet)

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-9	Region 10	Region 11	Region 11A	Total Lower 48 States
1956	293	–	2,968	554	806	8,739	524	3,698	186	2,754	9	–	20,531
1957	335	–	2,865	566	1,456	7,376	951	4,142	161	3,919	–	–	21,769
1958	224	–	2,446	716	2,641	11,228	741	5,843	106	3,785	4	–	27,734
1959	335	–	1,708	766	2,858	13,785	886	5,460	162	4,489	5	–	30,454
1960	741	–	2,689	648	2,939	13,197	1,009	5,729	121	4,557	8	–	31,637
1961	1,022	54	3,006	863	2,815	12,039	940	6,710	212	4,472	–	–	32,134
1962	1,073	18	3,059	888	2,155	12,040	1,229	6,424	202	5,012	–	–	32,102
1963	831	31	1,890	588	2,486	10,454	847	4,962	219	4,228	–	–	26,534
1964	777	7	2,097	535	2,293	10,787	1,377	4,877	195	4,390	–	–	27,333
1965	429	–	1,839	475	2,987	10,403	937	5,329	161	4,254	9	–	26,823
1966	393	7	1,770	478	2,729	7,718	1,626	5,504	127	4,020	17	–	24,390
1967	479	–	1,473	366	2,559	6,874	1,842	4,552	67	3,321	–	–	21,533
1968	459	13	941	438	2,378	6,307	2,313	3,740	106	3,971	–	–	20,665
1969	368	5	1,354	566	2,162	7,693	2,267	4,399	76	5,174	–	–	24,064
1970	319	–	818	545	2,246	7,053	1,876	3,709	96	6,191	–	–	22,852
Total	8,078	135	30,923	8,992	35,510	145,693	19,365	75,078	2,197	64,537	52	–	390,555

Note: Totals may not agree due to rounding.

TABLE 321

DRY HOLE FOOTAGE ALLOCATED TO GAS DRILLED HISTORICALLY—LOWER 48 STATES
(1,000 Feet)

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-9	Region 10	Region 11	Region 11A	Total Lower 48 States
1956	424	–	1,858	1,546	1,001	13,011	320	4,051	232	1,395	84	–	23,922
1957	411	–	1,236	1,206	1,691	12,815	608	4,416	220	1,574	32	–	24,209
1958	315	–	1,349	1,307	2,091	13,924	373	4,970	245	1,580	36	–	26,190
1959	611	–	1,062	1,450	2,284	14,421	399	5,208	394	1,552	54	–	27,435
1960	1,201	–	1,088	1,312	2,535	13,395	699	4,473	422	1,956	66	–	27,147
1961	1,470	37	1,467	1,830	1,857	14,374	809	4,828	726	1,909	51	–	29,358
1962	1,223	74	1,617	1,791	1,623	13,814	1,306	4,637	735	1,719	21	–	28,560
1963	1,082	82	1,091	1,051	2,320	12,860	1,262	3,454	499	1,926	30	–	25,657
1964	872	–	1,042	921	1,739	13,255	2,032	3,480	648	3,042	–	–	27,031
1965	663	–	886	793	1,775	13,935	1,304	3,856	569	2,796	30	–	26,607
1966	1,023	–	699	924	2,181	13,559	2,172	4,510	317	1,889	88	–	27,362
1967	763	–	604	518	1,897	10,143	1,748	3,711	208	1,151	45	–	20,788
1968	691	–	534	933	1,691	10,231	2,283	3,495	262	1,130	35	–	21,285
1969	453	–	953	1,308	1,774	13,590	1,619	3,651	291	1,336	–	–	24,975
1970	341	–	650	1,172	1,532	9,148	1,807	3,632	350	752	–	–	19,384
Total	11,543	193	16,136	18,062	27,991	192,475	18,741	62,372	6,118	25,707	572	–	379,910

Note: Totals may not agree due to rounding.

TABLE 322

TOTAL GAS WELL FOOTAGE DRILLED HISTORICALLY—LOWER 48 STATES INCLUDING DRY HOLE FOOTAGE ALLOCATED TO GAS (1,000 Feet)

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8-9	Region 10	Region 11	Region 11A	Total Lower 48 States
1956	717	–	4,826	2,100	1,807	21,750	844	7,749	418	4,149	93	–	44,453
1957	746	–	4,101	1,772	3,147	20,191	1,559	8,558	381	5,493	32	–	45,980
1958	539	–	3,795	2,023	4,732	25,152	1,114	10,813	351	5,365	40	–	53,924
1959	946	–	2,770	2,216	5,142	28,206	1,285	10,668	556	6,041	59	–	57,889
1960	1,942	–	3,777	1,960	5,474	26,592	1,708	10,202	543	6,513	74	–	58,785
1961	2,492	91	4,473	2,693	4,672	26,413	1,749	11,538	938	6,381	51	–	61,491
1962	2,296	92	4,676	2,679	3,778	25,854	2,535	11,061	937	6,731	21	–	60,660
1963	1,913	113	2,981	1,639	4,806	23,314	2,109	8,416	718	6,154	30	–	52,193
1964	1,649	7	3,139	1,456	4,032	24,042	3,409	8,357	843	7,432	–	–	54,366
1965	1,092	–	2,725	1,268	4,762	24,338	2,241	9,185	730	7,050	39	–	53,430
1966	1,416	7	2,469	1,402	4,910	21,277	3,798	10,014	444	5,909	105	–	51,751
1967	1,242	–	2,077	884	4,456	17,017	3,590	8,263	275	4,472	45	–	42,321
1968	1,150	13	1,475	1,371	4,069	16,538	4,596	7,235	368	5,101	35	–	41,951
1969	821	5	2,307	1,874	3,936	21,283	3,886	8,050	367	6,510	–	–	49,039
1970	660	–	1,468	1,717	3,778	16,201	3,683	7,341	446	6,943	–	–	42,237
Total	19,621	328	47,059	27,054	63,501	338,168	38,106	137,450	8,315	90,244	624	–	770,470

Note: Totals may not agree due to rounding.

TABLE 323

TOTAL GAS FOOTAGE PROJECTION—LOWER 48 STATES INCLUDING DRY HOLE FOOTAGE (1,000 Feet)

Cases I & IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	823	41	2,017	1,729	3,952	16,673	4,117	6,175	288	5,352	—	—	41,168
1972	865	43	2,118	1,859	4,236	17,291	4,366	6,527	303	5,619	—	—	43,226
1973	912	46	2,235	1,961	4,515	18,105	4,697	6,886	319	5,929	—	—	45,604
1974	967	48	2,417	2,127	4,834	18,853	5,027	7,348	338	6,284	48	48	48,340
1975	1,030	51	2,574	2,420	5,200	19,718	5,457	7,877	360	6,693	51	51	51,482
1976	1,102	110	2,754	2,644	5,619	20,822	5,894	8,428	386	7,161	110	55	55,086
1977	1,184	118	2,961	3,198	6,040	21,910	6,395	9,060	415	7,639	118	178	59,217
1978	1,279	128	3,198	3,581	6,523	23,088	6,971	9,785	448	8,186	192	576	63,955
1979	1,388	139	3,539	3,886	7,078	24,148	7,494	10,825	486	8,743	278	1,388	69,391
1980	1,513	151	3,857	4,311	7,715	26,019	8,320	11,799	529	9,530	378	1,513	75,636
1981	1,619	243	4,127	4,613	8,417	27,193	9,064	12,625	567	10,197	486	1,780	80,931
1982	1,700	255	4,334	4,844	8,923	28,042	9,687	13,256	595	10,707	595	2,039	84,977
1983	1,751	263	4,464	5,252	9,278	28,184	10,153	13,654	613	11,028	700	2,188	87,526
1984	1,768	265	4,508	5,393	9,459	27,935	10,431	13,879	619	11,139	796	2,210	88,402
1985	1,768	265	4,508	5,481	9,371	27,581	10,431	13,967	619	11,315	884	2,210	88,402

Note: Totals may not agree due to rounding.

TABLE 324

TOTAL GAS FOOTAGE PROJECTION—LOWER 48 STATES
INCLUDING DRY HOLE FOOTAGE
(1,000 Feet)

Cases II & III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	823	41	2,017	1,729	3,952	16,673	4,117	6,175	288	5,352	—	—	41,168
1972	840	42	2,058	1,806	4,115	16,797	4,241	6,341	294	5,459	—	—	41,991
1973	861	43	2,109	1,851	4,261	17,087	4,433	6,499	301	5,595	—	—	43,041
1974	887	44	2,217	1,951	4,433	17,290	4,611	6,739	310	5,763	44	44	44,332
1975	918	46	2,294	2,157	4,634	17,574	4,864	7,020	321	5,965	46	46	45,884
1976	954	95	2,386	2,291	4,867	18,038	5,106	7,301	334	6,204	95	48	47,719
1977	997	100	2,493	2,693	5,086	18,451	5,386	7,630	349	6,433	100	150	49,867
1978	1,047	105	2,618	2,932	5,341	18,902	5,707	8,011	367	6,702	157	471	52,360
1979	1,105	110	2,817	3,093	5,634	19,223	5,966	8,617	387	6,960	221	1,105	55,240
1980	1,171	117	2,986	3,338	5,973	20,243	6,441	9,134	410	7,378	293	1,171	58,554
1981	1,218	183	3,106	3,471	6,333	20,461	6,820	9,500	426	7,673	365	1,340	60,896
1982	1,254	188	3,199	3,575	6,586	20,699	7,150	9,785	439	7,903	439	1,505	62,723
1983	1,280	192	3,263	3,839	6,782	20,601	7,421	9,981	448	8,061	512	1,599	63,978
1984	1,292	194	3,295	3,942	6,914	20,419	7,625	10,145	452	8,142	582	1,615	64,618
1985	1,292	194	3,295	4,006	6,849	20,161	7,625	10,210	452	8,271	646	1,615	64,618

Note: Totals may not agree due to rounding.

TABLE 325

TOTAL GAS FOOTAGE PROJECTION–LOWER 48 STATES INCLUDING DRY HOLE FOOTAGE (1,000 Feet)

Cases IV & IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	812	41	1,989	1,705	3,898	16,443	4,060	6,090	284	5,278	–	–	40,599
1972	780	39	1,910	1,676	3,820	15,590	3,937	5,885	273	5,067	–	–	38,975
1973	748	37	1,833	1,609	3,704	14,854	3,854	5,650	262	4,864	–	–	37,416
1974	718	36	1,796	1,580	3,592	14,009	3,736	5,460	251	4,670	36	36	35,920
1975	690	34	1,724	1,621	3,483	13,207	3,655	5,276	241	4,483	34	34	34,483
1976	662	66	1,655	1,589	3,377	12,513	3,542	5,065	232	4,303	66	33	33,104
1977	636	64	1,589	1,716	3,242	11,758	3,432	4,862	222	4,100	64	95	31,779
1978	610	61	1,525	1,708	3,112	11,013	3,325	4,668	214	3,905	92	275	30,508
1979	586	59	1,494	1,640	2,987	10,192	3,163	4,569	205	3,690	117	586	29,288
1980	562	56	1,434	1,603	2,868	9,672	3,093	4,386	197	3,543	141	562	28,116
1981	540	81	1,377	1,539	2,807	9,069	3,023	4,211	189	3,401	162	594	26,992
1982	518	78	1,322	1,477	2,721	8,551	2,954	4,042	181	3,265	181	622	25,912
1983	498	75	1,269	1,493	2,637	8,010	2,886	3,881	174	3,134	199	622	24,876
1984	478	72	1,218	1,457	2,555	7,546	2,818	3,749	167	3,009	215	597	23,881
1985	459	69	1,169	1,421	2,430	7,153	2,705	3,622	160	2,934	229	573	22,925

Note: Totals may not agree due to rounding.

TABLE 326

PROJECTED CUMULATIVE GAS FOOTAGE DRILLED—LOWER 48 STATES
(1,000 Feet)

Case I & IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1956-1970	19,621	328	47,059	27,054	63,501	338,168	38,106	137,450	8,315	90,244	624	–	770,470
1971	20,444	369	49,076	28,783	67,453	354,841	42,223	143,625	8,603	95,596	624	–	811,638
1972	21,309	412	51,194	30,642	71,689	372,132	46,589	150,152	8,906	101,215	624	–	854,864
1973	22,221	458	53,429	32,603	76,204	390,237	51,286	157,038	9,225	107,144	624	–	900,468
1974	23,188	506	55,846	34,730	81,038	409,090	56,313	164,386	9,563	113,428	672	48	948,808
1975	24,218	557	58,420	37,150	86,238	428,808	61,770	172,263	9,923	120,121	723	99	1,000,290
1976	25,320	667	61,174	39,794	91,857	449,630	67,664	180,691	10,309	127,282	833	154	1,055,376
1977	26,504	785	64,135	42,992	97,897	471,540	74,059	189,751	10,724	134,921	951	332	1,114,593
1978	27,783	913	67,333	46,573	104,420	494,628	81,030	199,536	11,172	143,107	1,143	908	1,178,548
1979	29,171	1,052	70,872	50,459	111,498	518,776	88,524	210,361	11,658	151,850	1,421	2,296	1,247,939
1980	30,684	1,203	74,729	54,770	119,213	544,795	96,844	222,160	12,187	161,380	1,799	3,809	1,323,575
1981	32,303	1,446	78,856	59,383	127,630	571,988	105,908	234,785	12,754	171,577	2,285	5,589	1,404,506
1982	34,003	1,701	83,190	64,227	136,553	600,030	115,595	248,041	13,349	182,284	2,880	7,628	1,489,483
1983	35,754	1,964	87,654	69,479	145,831	628,214	125,748	261,695	13,962	193,312	3,580	9,816	1,577,009
1984	37,522	2,229	92,162	74,872	155,290	656,149	136,179	275,574	14,581	204,451	4,376	12,026	1,665,411
1985	39,290	2,494	96,670	80,353	164,661	683,730	146,610	289,541	15,200	215,766	5,260	14,236	1,753,813

Note: Totals may not agree due to rounding.

TABLE 327

PROJECTED CUMULATIVE GAS FOOTAGE DRILLED—LOWER 48 STATES
(1,000 Feet)

Cases II & III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1956-1970	19,621	328	47,059	27,054	63,501	338,168	38,106	137,450	8,315	90,244	624	—	770,470
1971	20,444	369	49,076	28,783	67,453	354,841	42,223	143,625	8,603	95,596	624	—	811,638
1972	21,284	411	51,134	30,589	71,568	371,638	46,464	149,966	8,897	101,055	624	—	853,629
1973	22,145	454	53,243	32,440	75,829	388,725	50,897	156,465	9,198	106,650	624	—	896,670
1974	23,032	498	55,460	34,391	80,262	406,015	55,508	163,204	9,508	112,413	668	44	941,002
1975	23,950	544	57,754	36,548	84,896	423,589	60,372	170,224	9,829	118,378	714	90	986,886
1976	24,904	639	60,140	38,839	89,763	441,627	65,478	177,525	10,163	124,582	809	138	1,034,605
1977	25,901	739	62,633	41,532	94,849	460,078	70,864	185,155	10,512	131,015	909	288	1,084,472
1978	26,948	844	65,251	44,464	100,190	478,980	76,571	193,166	10,879	137,717	1,066	759	1,136,832
1979	28,053	954	68,068	47,557	105,824	498,203	82,537	201,783	11,266	144,677	1,287	1,864	1,192,072
1980	29,224	1,071	71,054	50,895	111,797	518,346	88,978	210,917	11,676	152,055	1,580	3,035	1,250,626
1981	30,442	1,254	74,160	54,366	118,130	538,807	95,798	220,417	12,102	159,728	1,945	4,375	1,311,522
1982	31,696	1,442	77,359	57,941	124,716	559,506	102,948	230,202	12,541	167,631	2,384	5,880	1,374,245
1983	32,976	1,634	80,622	61,780	131,498	580,107	110,369	240,183	12,989	175,692	2,896	7,479	1,438,223
1984	34,268	1,828	83,917	65,722	138,412	600,526	117,994	250,328	13,441	183,834	3,478	9,094	1,502,841
1985	35,560	2,022	87,212	69,728	145,261	620,687	125,619	260,538	13,893	192,105	4,124	10,709	1,567,459

Note: Totals may not agree due to rounding.

TABLE 328

PROJECTED CUMULATIVE GAS FOOTAGE DRILLED–LOWER 48 STATES
(1,000 Feet)

Case IV & IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1956-1970	19,621	328	47,059	27,054	63,501	338,168	38,106	137,450	8,315	90,244	624	–	770,470
1971	20,433	369	49,048	28,759	67,399	354,611	42,166	143,540	8,599	95,522	624	–	811,069
1972	21,213	408	50,958	30,435	71,219	370,201	46,103	149,425	8,872	100,589	624	–	850,044
1973	21,961	445	52,791	32,044	74,923	385,055	49,957	155,075	9,134	105,453	624	–	887,460
1974	22,679	481	54,587	33,624	78,515	399,064	53,693	160,535	9,385	110,123	660	36	923,380
1975	23,369	515	56,311	35,245	81,998	412,271	57,348	165,811	9,626	114,606	694	70	957,863
1976	24,031	581	57,966	36,834	85,375	424,784	60,890	170,876	9,858	118,909	760	103	990,967
1977	24,667	645	59,555	38,550	88,617	436,542	64,322	175,738	10,080	123,009	824	198	1,022,746
1978	25,277	706	61,080	40,258	91,729	447,555	67,647	180,406	10,294	126,914	916	473	1,053,254
1979	25,863	765	62,574	41,898	94,716	457,747	70,810	184,975	10,499	130,604	1,033	1,059	1,082,542
1980	26,425	821	64,008	43,501	97,584	467,419	73,903	189,361	10,696	134,147	1,174	1,621	1,110,658
1981	26,965	902	65,385	45,040	100,391	476,488	76,926	193,572	10,885	137,548	1,336	2,215	1,137,650
1982	27,483	980	66,707	46,517	103,112	485,039	79,880	197,614	11,066	140,813	1,517	2,837	1,163,562
1983	27,981	1,055	67,976	48,010	105,749	493,049	82,766	201,495	11,240	143,947	1,716	3,459	1,188,438
1984	28,459	1,127	69,194	49,467	108,304	500,595	85,584	205,244	11,407	146,956	1,931	4,056	1,212,319
1985	28,918	1,196	70,363	50,888	110,734	507,748	88,289	208,866	11,567	149,890	2,160	4,629	1,235,244

Note: Totals may not agree due to rounding.

TABLE 329

PRODUCTIVE GAS WELLS DRILLED HISTORICALLY—LOWER 48 STATES

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1956	67	–	743	114	182	1,254	52	999	87	1,145	2	–	4,645
1957	61	–	661	111	306	1,397	88	1,059	90	1,212	–	–	4,985
1958	44	–	556	112	425	1,404	64	1,235	90	1,258	1	–	5,189
1959	73	–	444	126	456	1,667	74	1,050	79	1,500	1	–	5,470
1960	131	–	487	115	482	1,671	84	1,097	52	1,554	1	–	5,674
1961	157	8	520	156	447	1,545	81	1,378	102	1,584	–	–	5,978
1962	164	3	523	147	363	1,648	111	1,176	95	1,793	–	–	6,023
1963	126	6	328	112	399	1,463	71	934	107	1,428	–	–	4,974
1964	128	1	365	98	372	1,379	112	880	80	1,524	–	–	4,939
1965	71	–	309	88	463	1,397	77	932	57	1,431	1	–	4,826
1966	59	1	332	83	388	940	133	872	59	1,293	2	–	4,162
1967	72	–	270	80	328	882	160	748	33	1,082	–	–	3,655
1968	76	1	162	99	290	778	194	580	49	1,220	–	–	3,449
1969	58	1	284	107	266	930	208	706	34	1,478	–	–	4,072
1970	56	–	165	141	252	868	168	539	32	1,614	–	–	3,835
Total	1,343	21	6,149	1,689	5,419	19,223	1,677	14,185	1,046	21,116	8	–	72,876

Note: Totals may not agree due to rounding.

TABLE 330

PROJECTED PRODUCTIVE GAS WELLS DRILLED ANNUALLY--LOWER 48 STATES

Cases I & IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	47	3	224	118	262	780	177	480	25	1,203	–	–	3,318
1972	48	3	231	126	272	800	187	493	26	1,244	–	–	3,432
1973	50	3	241	131	282	829	201	507	27	1,294	–	–	3,565
1974	52	3	257	141	294	855	214	527	28	1,352	3	4	3,729
1975	55	3	269	159	308	885	232	551	29	1,419	3	4	3,918
1976	58	7	284	172	324	925	250	576	31	1,497	6	4	4,134
1977	62	7	302	206	340	964	270	605	32	1,575	6	12	4,380
1978	66	7	321	229	358	1,005	294	638	35	1,665	9	40	4,667
1979	70	8	351	246	379	1,041	315	690	37	1,754	13	95	5,000
1980	75	8	377	270	404	1,111	348	735	40	1,887	18	103	5,377
1981	80	13	399	286	431	1,150	378	770	42	1,993	23	120	5,684
1982	83	13	413	298	446	1,175	403	792	43	2,065	27	136	5,894
1983	84	13	420	320	454	1,170	421	799	44	2,100	32	144	6,001
1984	84	13	419	325	453	1,148	431	795	44	2,095	35	144	5,988
1985	83	13	414	328	440	1,123	430	785	43	2,101	38	143	5,941

Note: Totals may not agree due to rounding.

TABLE 331

PROJECTED PRODUCTIVE GAS WELLS DRILLED ANNUALLY—LOWER 48 STATES

Cases II & III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	47	3	224	118	262	780	177	480	25	1,203	–	–	3,318
1972	47	3	225	122	265	778	182	479	25	1,209	–	–	3,334
1973	47	3	227	124	266	783	190	479	25	1,221	–	–	3,365
1974	48	3	235	129	270	784	197	484	25	1,240	2	3	3,420
1975	49	3	240	142	274	789	207	491	26	1,265	2	3	3,492
1976	50	6	246	149	281	801	216	499	27	1,297	5	3	3,581
1977	52	6	254	173	286	812	228	509	27	1,326	5	11	3,689
1978	54	6	263	187	293	823	240	522	28	1,363	8	33	3,821
1979	56	6	279	195	302	829	250	549	29	1,397	11	76	3,980
1980	58	6	292	209	313	860	270	569	31	1,461	14	80	4,163
1981	60	10	300	215	324	865	285	579	31	1,499	17	90	4,277
1982	61	10	305	220	330	867	297	584	32	1,524	20	100	4,351
1983	61	10	307	234	332	855	308	584	32	1,535	23	106	4,386
1984	61	10	307	238	331	839	315	581	32	1,531	26	106	4,377
1985	60	9	303	239	321	821	314	574	32	1,536	28	105	4,342

Note: Totals may not agree due to rounding.

TABLE 332

PROJECTED PRODUCTIVE GAS WELLS DRILLED ANNUALLY—LOWER 48 STATES

Cases IV & IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	46	3	220	117	258	769	175	473	24	1,186	–	–	3,272
1972	44	3	209	114	246	722	169	445	23	1,122	–	–	3,095
1973	41	3	197	108	232	681	165	416	22	1,061	–	–	2,925
1974	39	2	191	105	218	635	159	392	21	1,004	2	3	2,771
1975	37	2	180	106	206	593	155	369	19	950	2	2	2,624
1976	35	4	171	103	195	556	150	346	18	900	3	2	2,484
1977	33	4	162	111	182	517	145	324	17	845	3	7	2,351
1978	31	4	153	109	171	480	140	304	16	794	5	19	2,226
1979	30	3	148	104	160	440	133	291	16	740	6	40	2,110
1980	28	3	140	100	150	413	129	273	15	701	7	38	1,999
1981	27	4	133	95	144	384	126	257	14	665	8	40	1,896
1982	25	4	126	91	136	358	123	241	13	630	8	41	1,797
1983	24	4	119	91	129	332	120	227	13	597	9	41	1,705
1984	23	4	113	88	122	310	116	215	12	566	10	39	1,617
1985	21	3	107	85	114	291	111	203	11	545	10	37	1,541

Note: Totals may not agree due to rounding.

TABLE 333

GAS WELLS PRODUCING AT YEAR-END—LOWER 48 STATES

Case I & IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1970*	865	115	7,999	1,942	7,223	18,493	2,600	24,526	1,308	52,374	–	–	117,445
1971	903	117	8,143	2,041	7,412	19,088	2,751	24,760	1,320	53,053	–	–	119,588
1972	942	119	8,293	2,146	7,611	19,698	2,911	25,006	1,332	53,767	–	–	121,825
1973	983	121	8,450	2,256	7,817	20,330	3,083	25,263	1,345	54,523	–	–	124,172
1974	1,026	123	8,622	2,375	8,033	20,982	3,267	25,538	1,359	55,329	3	4	126,659
1975	1,070	125	8,805	2,510	8,260	21,657	3,466	25,834	1,375	56,195	5	7	129,311
1976	1,107	129	8,914	2,632	8,419	22,149	3,647	25,893	1,378	56,569	11	11	130,858
1977	1,146	133	9,037	2,785	8,591	22,670	3,844	25,980	1,383	57,012	17	23	132,621
1978	1,189	138	9,177	2,958	8,777	23,222	4,061	26,098	1,390	57,537	26	63	134,636
1979	1,235	143	9,345	3,145	8,981	23,798	4,294	26,266	1,399	58,141	39	157	136,943
1980	1,286	149	9,535	3,352	9,205	24,434	4,557	26,476	1,410	58,865	56	257	139,581
1981	1,327	157	9,648	3,537	9,360	24,851	4,798	26,452	1,410	59,091	77	369	141,078
1982	1,370	166	9,772	3,729	9,526	25,280	5,057	26,450	1,411	59,384	102	494	142,740
1983	1,413	174	9,899	3,936	9,694	25,691	5,326	26,455	1,413	59,703	130	623	144,458
1984	1,454	182	10,022	4,143	9,856	26,069	5,598	26,457	1,414	60,006	162	749	146,112
1985	1,493	189	10,135	4,347	10,000	26,410	5,859	26,448	1,415	60,307	195	870	147,670

* 1970 data from Bureau of Mines, Minerals Yearbook.

Note: Totals may not agree due to rounding.

TABLE 334

GAS WELLS PRODUCING AT YEAR-END—LOWER 48 STATES

Cases II & III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1970*	865	115	7,999	1,942	7,223	18,493	2,600	24,526	1,308	52,374	—	—	117,445
1971	903	117	8,143	2,041	7,412	19,088	2,751	24,760	1,320	53,053	—	—	119,588
1972	941	119	8,286	2,143	7,603	19,675	2,906	24,992	1,331	53,732	—	—	121-727
1973	979	120	8,430	2,245	7,793	20,261	3,067	25,221	1,343	54,415	—	—	123,874
1974	1,017	122	8,581	2,352	7,985	20,842	3,233	25,452	1,355	55,111	2	3	126,056
1975	1,056	124	8,735	2,471	8,179	21,423	3,407	25,689	1,367	55,824	5	6	128,287
1976	1,085	127	8,807	2,570	8,297	21,796	3,555	25,674	1,366	56,005	10	10	129,302
1977	1,115	130	8,885	2,692	8,417	22,171	3,712	25,670	1,366	56,211	14	20	130,405
1978	1,147	134	8,970	2,826	8,542	22,551	3,878	25,679	1,367	56,450	22	52	131,617
1979	1,180	137	9,070	2,965	8,673	22,929	4,051	25,714	1,369	56,717	32	127	132,965
1980	1,214	141	9,181	3,114	8,812	23,330	4,240	25,770	1,373	57,044	46	204	134,469
1981	1,238	147	9,205	3,236	8,872	23,496	4,397	25,576	1,363	56,832	61	289	134,712
1982	1,262	152	9,234	3,359	8,936	23,658	4,562	25,393	1,354	56,651	80	380	135,021
1983	1,285	157	9,265	3,491	8,999	23,803	4,733	25,215	1,346	56,487	100	474	135,357
1984	1,308	162	9,293	3,624	9,061	23,928	4,906	25,040	1,337	56,323	123	566	135,673
1985	1,329	167	9,317	3,755	9,110	24,032	5,073	24,862	1,329	56,170	147	653	135,945

* 1970 data from Bureau of Mines, Minerals Yearbook.

Note: Totals may not agree due to rounding.

TABLE 335

GAS WELLS PRODUCING AT YEAR-END—LOWER 48 STATES

Cases IV & IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1970*	865	115	7,999	1,942	7,223	18,493	2,600	24,526	1,308	52,374	—	—	117,445
1971	902	117	8,140	2,039	7,509	19,077	2,749	24,754	1,319	53,037	—	—	119,543
1972	937	118	8,267	2,132	7,580	19,608	2,890	24,951	1,329	53,628	—	—	121,442
1973	969	120	8,381	2,219	7,736	20,093	3,026	25,118	1,338	54,153	—	—	123,153
1974	998	121	8,488	2,302	7,877	20,527	3,156	25,258	1,345	54,616	2	3	124,692
1975	1,025	122	8,584	2,385	8,005	20,915	3,279	25,375	1,351	55,021	4	5	126,069
1976	1,039	123	8,583	2,441	8,039	21,052	3,364	25,214	1,342	54,820	7	7	126,032
1977	1,051	125	8,573	2,503	8,061	21,148	3,442	25,034	1,333	54,569	10	14	125,862
1978	1,062	126	8,555	2,562	8,071	21,205	3,513	24,838	1,323	54,272	14	33	125,571
1979	1,070	127	8,532	2,614	8,069	21,220	3,576	24,632	1,312	53,927	20	72	125,170
1980	1,077	127	8,502	2,662	8,058	21,209	3,633	24,413	1,300	53,550	26	109	124,666
1981	1,071	128	8,380	2,678	7,960	20,956	3,651	23,937	1,275	52,608	33	146	122,821
1982	1,064	128	8,254	2,688	7,857	20,686	3,664	23,460	1,250	51,659	40	183	120,934
1983	1,056	128	8,126	2,698	7,751	20,398	3,674	22,984	1,225	50,706	48	218	119,011
1984	1,047	128	7,996	2,705	7,641	20,096	3,680	22,509	1,200	49,751	56	251	117,059
1985	1,037	127	7,863	2,709	7,525	19,784	3,681	22,037	1,175	48,803	64	280	115,087

* 1970 data from Bureau of Mines, Minerals Yearbook.

Note: Totals may not agree due to rounding.

TABLE 336

AVERAGE DEPTH OF PRODUCTIVE GAS WELLS DRILLED ANNUALLY
LOWER 48 STATES

Historical	Productive Gas Wells	Productive Gas Well Footage (000')	Average Depth Per Productive Gas Well (Feet)
1956	4,645	20,531	4,420
1957	4,985	21,769	4,367
1958	5,189	27,734	5,345
1959	5,470	30,454	5,567
1960	5,674	31,637	5,576
1961	5,978	32,134	5,375
1962	6,023	32,102	5,330
1963	4,974	26,534	5,335
1964	4,939	27,333	5,534
1965	4,826	26,823	5,558
1966	4,162	24,390	5,860
1967	3,655	21,533	5,891
1968	3,449	20,665	5,992
1969	4,072	24,064	5,910
1970	3,835	22,852	5,959
Projection			
1971	3,318	20,659	6,226
1975	3,492	23,135	6,625
1980	4,163	29,819	7,163
1985	3,342	33,205	7,647

TABLE 337

AVERAGE DEPTH IN FEET OF PRODUCTIVE GAS WELLS—LOWER 48 STATES

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Regions 8 & 9	Region 10
1956	4,400	–	4,000	4,900	4,400	7,000	10,100	3,700	2,200	2,400
1957	5,500	–	4,300	5,100	4,800	5,300	10,800	3,900	1,800	3,200
1958	5,100	–	4,400	6,400	6,200	8,000	11,600	4,700	1,200	3,000
1959	4,600	–	3,800	6,100	6,300	8,300	12,000	5,200	2,100	3,000
1960	5,700	–	5,500	5,600	6,100	7,900	12,000	5,200	2,300	2,900
1961	6,500	6,800	5,800	5,500	6,300	7,800	11,600	4,900	2,100	2,800
1962	6,500	6,000	5,800	6,000	5,900	7,300	11,100	5,500	2,100	2,800
1963	6,600	5,200	5,800	5,300	6,200	7,100	11,900	5,300	2,000	3,000
1964	6,100	7,000	5,700	5,500	6,200	7,800	12,300	5,500	2,400	2,900
1965	6,000	–	6,000	5,400	6,500	7,400	12,200	5,700	2,800	3,000
1966	6,700	7,000	5,300	5,800	7,000	8,200	12,200	6,300	2,200	3,100
1967	6,700	–	5,500	4,600	7,800	7,800	11,500	6,100	2,000	3,100
1968	6,000	13,000	5,800	4,400	8,200	8,100	11,900	6,400	2,200	3,300
1969	6,300	5,000	4,800	5,300	8,100	8,300	10,900	6,200	2,200	3,500
1970	5,700	–	5,100	3,900	8,900	8,100	11,200	6,900	3,000	3,800
1970 Trend Value	6,603	8,829	5,778	4,772	8,361	8,247	11,800	6,763	2,869	3,418
Projected Annual Increase in Average Depth	101	319	86	50	253	89	39	190	47	52

TABLE 338

GAS DRILLING SUCCESS RATIO
TOTAL UNITED STATES*

	1966-1970 Average (Percent)
1N	50
1S	50
2	38
2A	66
3	65
4	33
5	57
6	39
6A	51
7	54
8 & 9	25
10	78
11	50
11A	66

* Based on 5 year average (1966-70) where data was available.

Chapter Six—Section IV

Gas Reserves

TABLE 339

HISTORICAL ANNUAL NON-ASSOCIATED GAS RESERVE ADDITIONS–LOWER 48 STATES (BCF)

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1956	49.6	–	4436.4	159.9	(1519.5)	8480.0	737.9	2730.7	7.7	341.5	2.8	–	15426.9
1957	313.0	–	180.2	365.5	1166.7	9704.3	1216.5	2923.6	45.7	417.6	(.2)	–	16332.9
1958	(15.8)	–	(233.5)	754.3	2485.3	8312.1	532.5	5403.8	58.6	207.1	.2	–	17504.5
1959	(40.3)	–	(2582.9)	50.3	725.0	11827.2	2390.2	2431.5	8.0	434.7	1.0	–	15244.8
1960	400.6	62.2	(1273.9)	(50.7)	1142.4	7729.2	1472.4	1473.4	16.9	674.0	(.7)	–	11645.9
1961	423.9	67.8	759.6	591.1	(17.1)	9524.8	1756.0	940.7	37.3	440.2	(.2)	–	14524.2
1962	465.6	53.3	58.2	138.5	328.8	7943.2	5665.0	2438.4	4.1	394.3	.1	–	17489.5
1963	(39.7)	110.0	511.1	69.4	967.4	6797.2	2034.9	1457.0	8.8	620.9	–	–	12536.8
1964	190.6	225.2	479.8	(77.0)	2765.8	5854.3	4601.5	2927.1	59.8	344.2	–	–	17371.4
1965	32.0	17.8	518.8	165.9	2809.0	7414.1	4664.3	2259.6	(18.0)	553.0	(.3)	–	18416.1
1966	293.8	(19.1)	10.3	179.1	4400.1	5126.2	3392.0	2191.3	(22.9)	585.3	(.1)	–	16136.1
1967	185.8	13.6	1079.8	591.7	2570.9	5503.8	4561.5	2370.0	33.1	374.0	(.1)	–	17284.1
1968	266.3	(1.8)	151.0	353.1	1324.7	6903.4	2942.8	21.3	9.2	364.1	.2	–	12334.3
1969	123.1	–	66.4	520.2	(76.6)	3212.9	1498.5	1249.4	15.4	265.4	–	–	6874.7
1970	(11.5)	–	181.0	397.7	374.7	1358.2	4649.8	1736.9	157.5	507.1	–	–	9351.3

Note: Totals may not agree due to rounding.

TABLE 340

NON-ASSOCIATED GAS RESERVES PROJECTED ADDITIONS–LOWER 48 STATES
(BCF)

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	109	5	236	252	1,870	4,678	4,578	1,332	17	398	–	–	13,475
1972	114	5	242	273	2,025	4,777	4,994	1,402	19	419	–	–	14,270
1973	121	5	255	292	2,175	4,920	5,498	1,472	21	442	–	–	15,201
1974	128	6	276	320	2,338	5,032	5,986	1,562	23	469	2	51	16,193
1975	137	6	294	368	2,516	5,160	6,565	1,663	26	499	2	55	17,292
1976	146	14	314	408	2,707	5,332	7,108	1,767	29	534	5	58	18,424
1977	157	16	337	500	2,883	5,478	7,661	1,885	33	570	6	188	19,714
1978	170	18	364	568	3,065	5,623	8,206	2,018	38	610	10	611	21,300
1979	185	21	402	625	3,250	5,715	8,567	2,209	43	651	15	1,472	23,156
1980	201	24	437	703	3,434	5,967	9,108	2,380	50	709	22	1,605	24,641
1981	215	42	466	762	3,598	6,023	9,352	2,512	57	757	32	1,889	25,705
1982	226	47	487	809	3,625	5,983	9,264	2,598	64	793	44	2,164	26,105
1983	232	53	500	886	3,549	5,781	8,855	2,633	70	814	59	2,322	25,754
1984	234	57	502	917	3,378	5,503	8,180	2,630	75	820	76	2,345	24,717
1985	234	61	499	937	3,104	5,214	7,275	2,599	80	829	96	2,345	23,271

Note: Totals may not agree due to rounding.

TABLE 341

NON-ASSOCIATED GAS RESERVES PROJECTED ADDITIONS–LOWER 48 STATES
(BCF)

Case IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	118	6	289	248	1,314	2,923	3,642	986	20	367	–	–	9,912
1972	127	6	310	272	1,424	2,883	3,780	1,012	21	385	–	–	10,220
1973	136	7	334	293	1,536	2,864	3,975	1,035	22	406	–	–	10,609
1974	148	7	370	326	1,665	2,824	4,150	1,068	23	431	3	34	11,051
1975	162	8	404	380	1,815	2,789	4,386	1,105	25	359	4	36	11,574
1976	178	18	445	427	1,991	2,773	4,603	1,139	26	491	8	39	12,137
1977	197	20	493	533	2,174	2,738	4,840	1,175	28	524	8	126	12,857
1978	221	22	759	618	2,351	2,699	5,099	1,214	31	561	13	407	13,994
1979	249	25	815	696	2,490	2,632	5,284	1,280	33	599	19	981	15,102
1980	282	28	859	805	2,644	2,629	5,632	1,323	36	653	26	1,069	15,987
1981	316	47	886	900	2,803	2,540	5,869	1,337	39	699	33	1,259	16,728
1982	348	52	896	991	2,883	2,414	5,981	1,323	41	734	41	1,442	17,145
1983	348	56	887	1,128	2,904	2,236	5,965	1,281	42	756	48	1,547	17,199
1984	337	60	860	1,218	2,867	2,044	5,823	1,223	42	764	55	1,563	16,856
1985	324	63	826	1,302	2,751	1,863	5,533	1,156	42	776	61	1,563	16,259

Note: Totals may not agree due to rounding.

TABLE 342

NON-ASSOCIATED GAS RESERVES PROJECTED ADDITIONS–LOWER 48 STATES
(BCF)

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	109	5	236	252	1,870	4,678	4,578	1,332	17	398	—	—	13,475
1972	111	5	235	265	1,967	4,642	4,849	1,362	18	407	—	—	13,861
1973	114	5	241	275	2,052	4,648	5,184	1,389	20	417	—	—	14,345
1974	117	5	253	293	2,144	4,625	5,481	1,433	21	430	2	47	14,852
1975	122	6	262	327	2,243	4,619	5,843	1,485	23	445	2	49	15,425
1976	127	12	272	352	2,350	4,652	6,159	1,535	25	463	5	51	16,001
1977	133	13	284	418	2,439	4,664	6,478	1,593	27	480	5	159	16,694
1978	139	15	298	461	2,534	4,678	6,795	1,661	30	500	8	500	17,617
1979	147	16	320	493	2,632	4,651	6,974	1,772	33	519	12	1,172	18,741
1980	156	18	339	538	2,734	4,758	7,329	1,861	37	549	17	1,243	19,578
1981	162	30	352	566	2,824	4,712	7,481	1,917	40	571	22	1,421	20,099
1982	167	33	362	589	2,845	4,641	7,488	1,954	44	587	29	1,597	20,335
1983	170	35	368	638	2,823	4,494	7,348	1,971	47	598	38	1,697	20,226
1984	172	38	370	661	2,759	4,331	7,073	1,980	50	603	48	1,714	19,797
1985	172	40	369	677	2,609	4,156	6,576	1,968	52	611	60	1,714	19,002

Note: Totals may not agree due to rounding.

TABLE 343

NON-ASSOCIATED GAS RESERVES PROJECTED ADDITIONS—LOWER 48 STATES
(BCF)

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	118	6	289	248	1,314	2,923	3,642	986	20	367	–	–	9,912
1972	123	6	301	264	1,383	2,805	3,675	984	20	374	–	–	9,935
1973	129	6	315	276	1,448	2,715	3,758	979	21	384	–	–	10,031
1974	135	7	338	298	1,524	2,613	3,821	985	21	395	3	31	10,172
1975	143	7	358	337	1,612	2,524	3,936	994	22	409	3	32	10,379
1976	153	15	381	366	1,715	2,459	4,030	1,001	23	425	7	34	10,609
1977	164	16	409	442	1,816	2,384	4,140	1,010	24	441	7	106	10,960
1978	177	18	632	495	1,934	2,312	4,267	1,023	25	459	11	333	11,685
1979	192	19	664	538	2,021	2,224	4,331	1,059	27	477	15	781	12,348
1980	210	21	686	600	2,099	2,198	4,531	1,077	28	506	20	828	12,804
1981	226	34	694	645	2,178	2,104	4,640	1,073	29	526	25	947	13,122
1982	241	36	695	687	2,215	2,004	4,697	1,058	30	542	30	1,064	13,301
1983	255	38	689	765	2,229	1,879	4,701	1,032	31	553	35	1,131	13,337
1984	265	40	675	815	2,220	1,756	4,653	1,002	31	558	40	1,142	13,196
1985	257	42	655	859	2,148	1,635	4,482	963	31	567	44	1,142	12,827

Note: Totals may not agree due to rounding.

TABLE 344

NON-ASSOCIATED GAS RESERVES PROJECTED ADDITIONS—LOWER 48 STATES
(BCF)

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	116	6	285	245	1,296	2,885	3,592	972	19	362	—	—	9,779
1972	114	6	279	245	1,283	2,614	3,417	915	19	347	—	—	9,238
1973	111	6	273	239	1,256	2,386	3,282	857	18	333	—	—	8,761
1974	109	5	272	239	1,229	2,160	3,124	808	17	320	2	25	8,311
1975	106	5	265	249	1,203	1,960	3,002	762	17	307	2	24	7,904
1976	104	10	259	249	1,176	1,791	2,859	715	16	295	5	23	7,502
1977	101	10	253	273	1,139	1,627	2,725	672	15	281	4	67	7,167
1978	99	10	247	276	1,102	1,476	2,597	631	15	268	6	194	6,921
1979	96	10	246	270	1,066	1,326	2,432	605	14	253	8	414	6,740
1980	94	9	349	267	1,031	1,223	2,343	570	13	243	10	398	6,551
1981	91	14	331	261	1,017	1,117	2,256	537	13	233	11	420	6,301
1982	89	13	315	254	985	1,028	2,173	506	12	224	12	440	6,050
1983	87	13	299	260	946	941	2,093	477	12	215	14	440	5,795
1984	84	13	283	257	909	867	2,016	454	11	206	15	422	5,537
1985	82	12	269	254	857	805	1,909	431	11	201	16	405	5,254

Note: Totals may not agree due to rounding.

TABLE 345

NON-ASSOCIATED GAS RESERVES PROJECTED ADDITIONS—LOWER 48 STATES
(BCF)

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	107	5	233	248	1,844	4,614	4,514	1,313	17	393	–	–	13,288
1972	103	5	218	246	1,825	4,312	4,496	1,264	17	377	–	–	12,863
1973	99	4	209	239	1,782	4,051	4,493	1,209	17	363	–	–	12,466
1974	95	4	205	237	1,736	3,767	4,422	1,163	17	348	2	38	12,034
1975	91	4	197	245	1,686	3,504	4,372	1,119	17	334	2	37	11,607
1976	88	8	189	242	1,634	3,276	4,263	1,070	17	321	3	35	11,145
1977	84	8	181	263	1,565	3,039	4,141	1,022	17	306	3	101	10,731
1978	81	8	174	264	1,497	2,811	4,009	977	16	291	4	291	10,420
1979	78	8	170	256	1,430	2,571	3,800	953	16	275	6	621	10,180
1980	75	8	163	252	1,365	2,413	3,695	911	16	264	7	597	9,760
1981	72	12	157	243	1,327	2,238	3,583	871	16	253	9	630	9,410
1982	69	12	150	235	1,276	2,088	3,468	833	15	243	10	660	9,060
1983	66	11	144	239	1,226	1,937	3,351	796	15	233	12	660	8,690
1984	64	11	138	234	1,178	1,808	3,231	766	15	224	13	633	8,310
1985	61	11	133	230	1,109	1,698	3,061	738	14	218	15	608	7,890

Note: Totals may not agree due to rounding.

TABLE 346

PROJECTED TOTAL GAS RESERVES ADDITIONS—NON-ASSOCIATED AND ASSOCIATED AND DISSOLVED—LOWER 48 STATES (BCF)

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	124	31	249	292	2,028	4,925	5,147	1,543	54	398	1	–	14,792
1972	136	32	258	335	2,187	5,064	5,487	1,599	49	419	2	–	15,568
1973	144	81	274	370	2,332	5,228	6,137	1,666	60	442	4	–	16,739
1974	153	149	296	418	2,488	5,400	6,687	1,749	73	469	11	53	17,945
1975	163	225	312	480	2,659	5,610	7,284	1,855	87	499	14	60	19,249
1976	174	261	333	531	2,858	5,865	7,768	1,975	96	534	18	63	20,478
1977	188	344	354	633	3,049	6,055	8,329	2,096	112	570	22	196	21,950
1978	204	372	381	711	3,260	6,235	8,874	2,240	119	610	27	620	23,652
1979	223	388	418	774	3,477	6,316	9,266	2,431	132	651	36	1,489	25,602
1980	244	399	452	862	3,700	6,568	9,780	2,609	137	709	43	1,624	27,130
1981	264	424	481	931	3,906	6,618	9,985	2,745	141	757	54	1,911	28,216
1982	280	434	502	984	3,969	6,507	9,871	2,822	149	793	72	2,240	28,622
1983	290	445	514	1,069	3,938	6,292	9,386	2,855	145	814	87	2,414	28,249
1984	296	452	515	1,103	3,796	5,976	8,683	2,838	143	820	108	2,491	27,222
1985	300	455	511	1,130	3,545	5,672	7,732	2,804	138	829	127	2,516	25,755

Note: Totals may not agree due to rounding.

TABLE 347

PROJECTED TOTAL GAS RESERVES ADDITIONS –NON-ASSOCIATED AND ASSOCIATED AND DISSOLVED–LOWER 48 STATES (BCF)

Case IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	133	32	300	285	1,472	3,165	4,090	1,180	54	367	1	–	11,077
1972	149	32	320	320	1,586	3,151	4,062	1,165	44	385	2	–	11,217
1973	159	77	344	343	1,693	3,123	4,315	1,169	48	406	4	–	11,683
1974	173	131	380	379	1,815	3,083	4,535	1,190	52	431	10	36	12,218
1975	188	186	413	434	1,956	3,056	4,824	1,226	57	459	13	41	12,854
1976	206	207	454	481	2,132	3,056	5,060	1,267	57	491	17	44	13,469
1977	226	258	501	587	2,314	3,024	5,341	1,303	62	524	19	134	14,293
1978	252	270	768	674	2,493	3,000	5,602	1,349	64	561	24	416	15,472
1979	281	282	824	754	2,632	2,939	5,815	1,416	69	599	32	997	16,639
1980	315	294	868	866	2,787	2,950	6,148	1,466	71	653	39	1,086	17,544
1981	351	322	895	964	2,948	2,874	6,362	1,487	73	699	46	1,278	18,298
1982	384	332	906	1,056	3,027	2,726	6,462	1,473	77	734	58	1,505	18,738
1983	385	339	897	1,195	3,049	2,559	6,398	1,436	78	756	65	1,620	18,779
1984	375	346	870	1,285	3,011	2,360	6,242	1,376	81	764	75	1,680	18,465
1985	363	348	836	1,371	2,898	2,190	5,918	1,313	81	776	82	1,700	17,875

Note: Totals may not agree due to rounding.

TABLE 348

PROJECTED TOTAL GAS RESERVES ADDITIONS—NON-ASSOCIATED AND ASSOCIATED AND DISSOLVED—LOWER 48 STATES (BCF)

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	124	31	249	292	2,028	4,925	5,147	1,543	54	398	1	–	14,792
1972	132	31	251	326	2,126	4,923	5,331	1,554	47	407	2	–	15,130
1973	137	78	259	351	2,205	4,945	5,805	1,577	58	417	4	–	15,835
1974	141	141	272	386	2,288	4,972	6,156	1,612	68	430	10	49	16,526
1975	146	208	279	431	2,376	5,031	6,522	1,663	80	445	13	53	17,246
1976	152	233	289	463	2,485	5,127	6,772	1,722	85	463	17	56	17,863
1977	160	301	300	535	2,582	5,173	7,085	1,780	97	480	20	166	18,680
1978	168	319	313	583	2,693	5,212	7,382	1,852	101	500	23	508	19,651
1979	178	326	334	617	2,810	5,167	7,580	1,959	110	519	30	1,186	20,816
1980	190	329	352	666	2,935	5,267	7,910	2,051	111	549	35	1,258	21,652
1981	199	341	364	699	3,050	5,211	8,032	2,108	112	571	40	1,437	22,164
1982	207	344	375	724	3,092	5,083	8,033	2,137	118	587	51	1,652	22,401
1983	213	346	380	778	3,094	4,925	7,844	2,153	116	598	60	1,762	22,267
1984	218	351	382	802	3,049	4,726	7,535	2,151	117	603	73	1,814	21,819
1985	220	353	380	822	2,925	4,543	6,989	2,137	110	611	85	1,829	21,001

Note: Totals may not agree due to rounding.

TABLE 349

PROJECTED TOTAL GAS RESERVES ADDITIONS–NON-ASSOCIATED AND ASSOCIATED AND DISSOLVED–LOWER 48 STATES
(BCF)

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	133	32	300	285	1,472	3,165	4,090	1,180	54	367	1	–	11,077
1972	144	32	311	311	1,542	3,067	3,950	1,134	43	374	2	–	10,910
1973	152	74	325	325	1,601	2,966	4,088	1,109	46	384	4	–	11,073
1974	159	126	347	349	1,668	2,860	4,190	1,102	49	395	10	33	11,290
1975	167	173	366	388	1,745	2,772	4,344	1,107	52	409	11	36	11,572
1976	178	186	389	415	1,844	2,715	4,445	1,117	52	425	15	38	11,820
1977	190	227	417	490	1,941	2,637	4,588	1,124	54	441	17	113	12,239
1978	203	232	640	543	2,058	2,571	4,708	1,139	54	459	20	340	12,968
1979	219	235	671	587	2,142	2,482	4,790	1,173	58	477	26	794	13,655
1980	237	240	693	650	2,219	2,461	4,974	1,194	58	506	31	841	14,105
1981	254	256	701	696	2,297	2,372	5,063	1,193	58	526	35	962	14,607
1982	269	260	703	738	2,332	2,251	5,121	1,176	60	542	43	1,111	14,413
1983	284	263	697	817	2,346	2,130	5,093	1,152	60	553	48	1,183	14,626
1984	294	266	683	867	2,334	1,998	5,027	1,119	62	558	55	1,221	14,484
1985	287	268	663	912	2,261	1,882	4,823	1,083	62	567	59	1,234	14,104

Note: Totals may not agree due to rounding.

TABLE 350

PROJECTED TOTAL GAS RESERVES ADDITIONS–NON-ASSOCIATED AND ASSOCIATED AND DISSOLVED--LOWER 48 STATES (BCF)

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	131	32	296	282	1,454	3,127	4,040	1,166	53	362	1	–	10,944
1972	134	30	289	289	1,433	2,861	3,676	1,056	40	347	2	–	10,157
1973	131	65	282	282	1,391	2,606	3,571	971	40	333	3	–	9,676
1974	128	100	280	281	1,348	2,359	3,422	903	40	320	8	27	9,215
1975	124	128	271	288	1,306	2,145	3,307	847	40	307	8	27	8,801
1976	121	129	265	285	1,270	1,970	3,151	796	37	295	11	26	8,356
1977	118	146	258	306	1,223	1,791	3,021	746	36	281	10	71	8,008
1978	115	144	252	307	1,183	1,638	2,885	704	35	268	12	198	7,742
1979	112	137	250	298	1,140	1,476	2,717	671	33	253	15	421	7,523
1980	109	128	353	293	1,100	1,364	2,606	633	31	243	16	405	7,281
1981	105	126	335	286	1,081	1,251	2,498	596	29	233	17	427	6,983
1982	102	119	319	277	1,044	1,143	2,411	560	29	224	19	459	6,706
1983	99	113	303	282	1,001	1,050	2,313	528	27	215	20	459	6,410
1984	96	109	287	278	963	966	2,234	501	26	206	21	447	6,132
1985	94	104	273	274	906	901	2,112	476	25	201	22	430	5,820

Note: Totals may not agree due to rounding.

TABLE 351

PROJECTED TOTAL GAS RESERVES ADDITIONS–NON-ASSOCIATED AND ASSOCIATED AND DISSOLVED–LOWER 48 STATES (BCF)

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	122	31	246	288	2,002	4,861	5,083	1,524	54	393	1	–	14,605
1972	123	30	233	303	1,975	4,576	4,948	1,445	44	377	2	–	14,055
1973	119	68	225	304	1,917	4,307	5,039	1,373	50	363	4	–	13,767
1974	114	112	220	310	1,855	4,032	4,978	1,306	55	348	9	40	13,379
1975	109	151	210	321	1,789	3,790	4,904	1,250	59	334	10	40	12,966
1976	105	157	201	317	1,728	3,583	4,734	1,198	58	321	11	38	12,453
1977	101	186	191	336	1,653	3,340	4,578	1,141	62	306	13	106	12,013
1978	98	191	184	338	1,586	3,124	4,404	1,096	61	291	13	296	11,685
1979	94	186	179	326	1,516	2,875	4,180	1,063	63	275	17	628	11,403
1980	91	178	171	318	1,450	2,706	4,044	1,014	60	264	17	604	10,917
1981	87	173	165	306	1,413	2,512	3,904	968	56	253	18	637	10,492
1982	84	164	157	294	1,360	2,321	3,783	922	56	243	21	681	10,088
1983	81	154	151	296	1,310	2,154	3,640	880	53	233	22	682	9,656
1984	79	147	145	288	1,261	2,003	3,516	843	53	224	24	663	9,247
1985	75	141	139	282	1,192	1,883	3,326	812	50	218	25	639	8,784

Note: Totals may not agree due to rounding.

TABLE 352

HISTORICAL TOTAL GAS RESERVES ADDITIONS
LOWER 48 STATES
NON-ASSOCIATED AND ASSOCIATED-DISSOLVED

	Annual Gas Additions (BCF)
1956	24,716
1957	20,008
1958	18,897
1959	20,621
1960	13,844
1961	16,350
1962	18,768
1963	18,104
1964	20,105
1965	21,158
1966	19,246
1967	21,093
1968	12,038
1969	8,338
1970	11,123

TABLE 353

CUMULATIVE NON-ASSOCIATED AND ASSOCIATED-DISSOLVED RECOVERABLE GAS DISCOVERED—LOWER 48 STATES
(1956-1970)

	Cumulative Gas Discovered (TCF)
1956	394.6
1957	419.3
1958	439.3
1959	458.2
1960	478.8
1961	492.6
1962	509.0
1963	527.8
1964	545.9
1965	566.0
1966	587.2
1967	606.4
1968	627.5
1969	639.5
1970	647.8

TABLE 354

PROJECTED CUMULATIVE NON-ASSOCIATED AND ASSOCIATED-DISSOLVED GAS DISCOVERED—LOWER 48 STATES
(1971-1985)

	Case I (TCF)	Case IA (TCF)	Case II (TCF)	Case III (TCF)	Case IV (TCF)	Case IVA (TCF)
1971	662.6	658.9	662.6	658.9	658.8	662.4
1972	678.2	670.1	677.8	669.8	668.9	676.5
1973	695.0	681.8	693.6	680.9	678.6	690.2
1974	713.0	694.0	710.2	692.3	687.8	703.6
1975	732.2	706.9	727.4	703.9	696.6	716.6
1976	752.6	720.3	745.2	715.8	705.0	729.0
1977	774.5	734.6	763.9	728.1	713.1	741.0
1978	798.1	750.1	783.5	741.0	720.9	752.7
1979	823.8	766.7	804.3	754.6	728.3	764.1
1980	850.9	784.3	826.0	768.7	735.7	775.0
1981	879.1	802.6	848.2	783.0	742.6	785.5
1982	907.7	821.3	870.6	797.6	749.2	795.6
1983	936.0	840.1	892.8	812.2	755.6	805.3
1984	963.2	858.5	914.6	826.6	761.6	814.5
1985	989.0	876.4	935.6	840.6	767.4	823.3

TABLE 355

CUMULATIVE NON-ASSOCIATED GAS DISCOVERED–LOWER 48 STATES (BCF)

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1970	8,144	527	17,879	9,981	27,193	211,718	45,430	104,777	370	32,989	9	–	459,017
1971	8,253	532	18,115	10,233	29,063	216,396	50,008	106,109	387	33,387	9	–	472,492
1972	8,367	537	18,357	10,506	31,088	221,173	55,002	107,511	406	33,806	9	–	486,762
1973	8,488	542	18,612	10,798	33,263	226,093	60,500	108,983	427	34,248	9	–	501,963
1974	8,616	548	18,888	11,118	35,601	231,125	66,486	110,545	450	34,717	11	51	518,156
1975	8,753	554	19,182	11,486	38,117	236,285	73,051	112,208	476	35,216	13	106	535,448
1976	8,899	568	19,496	11,894	40,824	241,617	80,159	113,975	505	35,750	18	164	553,872
1977	9,056	584	19,833	12,394	43,707	247,095	87,820	115,860	538	36,320	24	352	573,586
1978	9,226	602	20,197	12,962	46,772	252,718	96,026	117,878	576	36,930	34	963	594,886
1979	9,411	623	20,599	13,587	50,022	258,433	104,593	120,087	619	37,581	49	2,435	618,042
1980	9,612	647	21,036	14,290	53,456	264,400	113,701	122,467	669	38,290	71	4,040	642,683
1981	9,827	689	21,502	15,052	57,054	270,423	123,053	124,979	726	39,047	103	5,929	668,388
1982	10,053	736	21,989	15,861	60,679	276,406	132,317	127,577	790	39,840	147	8,093	694,493
1983	10,285	789	22,489	16,747	64,228	282,187	141,172	130,210	860	40,654	206	10,415	720,247
1984	10,519	846	22,991	17,664	67,606	287,690	149,352	132,840	935	41,474	282	12,760	744,964
1985	10,753	907	23,490	18,601	70,710	292,904	156,627	135,439	1,015	42,303	378	15,105	768,235

Note: Totals may not agree due to rounding.

TABLE 356

CUMULATIVE NON-ASSOCIATED GAS DISCOVERED—LOWER 48 STATES (BCF)

Case IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1970	8,144	527	17,879	9,981	27,193	211,718	45,430	104,777	370	32,989	9	–	459,017
1971	8,262	533	18,168	10,229	28,507	214,641	49,072	105,763	390	33,356	9	–	468,929
1972	8,389	539	18,478	10,501	29,931	217,524	52,852	106,775	411	33,741	9	–	479,149
1973	8,525	546	18,812	10,794	31,467	220,388	56,827	107,810	433	34,147	9	–	489,758
1974	8,673	553	19,182	11,120	33,132	223,212	60,977	108,878	456	34,578	12	34	500,809
1975	8,835	561	19,586	11,500	34,947	226,001	65,363	109,983	481	35,037	16	70	512,383
1976	9,013	579	20,031	11,927	36,938	228,774	69,966	111,122	507	35,528	24	109	524,520
1977	9,210	599	20,524	12,460	39,112	231,512	74,806	112,297	535	36,052	32	235	537,377
1978	9,431	621	21,283	13,078	41,463	234,211	79,905	113,511	566	36,613	45	642	551,371
1979	9,680	646	22,098	13,774	43,953	236,843	85,189	114,791	599	37,212	64	1,623	566,473
1980	9,962	674	22,957	14,579	46,597	239,472	90,821	116,114	635	37,865	90	2,692	582,460
1981	10,278	721	23,843	15,479	49,400	242,012	96,690	117,451	674	38,564	123	3,951	599,188
1982	10,626	773	24,739	16,470	52,283	244,426	102,671	118,774	715	39,298	164	5,393	616,333
1983	10,974	829	25,626	17,598	55,187	246,662	108,636	120,055	757	40,054	212	6,940	633,532
1984	11,311	889	26,486	18,816	58,054	248,706	114,459	121,278	799	40,818	267	8,503	650,388
1985	11,635	952	27,312	20,118	60,805	250,569	119,992	122,434	841	41,594	328	10,066	666,647

Note: Totals may not agree due to rounding.

TABLE 357

CUMULATIVE NON-ASSOCIATED GAS DISCOVERED – LOWER 48 STATES (BCF)

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1970	8,144	527	17,879	9,981	27,193	211,718	45,430	104,777	370	32,989	9	–	459,017
1971	8,253	532	18,115	10,233	29,063	216,396	50,008	106,109	387	33,387	9	–	472,492
1972	8,364	537	18,350	10,498	31,030	221,038	54,857	107,471	405	33,794	9	–	486,353
1973	8,478	542	18,591	10,773	33,082	225,686	60,041	108,860	425	34,211	9	–	500,698
1974	8,595	547	18,844	11,066	35,226	230,311	65,522	110,293	446	34,641	11	47	515,550
1975	8,717	553	19,106	11,393	34,469	234,930	71,365	111,778	469	35,086	13	96	530,975
1976	8,844	565	19,378	11,745	39,818	239,582	77,524	113,313	494	35,549	18	147	546,976
1977	8,977	578	19,662	12,163	42,258	244,246	84,002	114,906	521	36,029	23	306	563,670
1978	9,116	593	19,960	12,624	44,792	248,924	90,797	116,567	551	36,529	31	806	581,287
1979	9,263	609	20,280	13,117	47,424	253,575	97,771	118,339	584	37,048	43	1,978	600,028
1980	9,419	627	20,619	13,655	50,158	258,333	105,100	120,200	621	37,597	60	3,221	619,606
1981	9,581	657	20,971	14,221	52,982	263,045	112,581	122,117	661	38,168	82	4,642	639,705
1982	9,748	690	21,333	14,810	55,827	267,686	120,069	124,071	705	38,755	111	6,239	660,040
1983	9,918	725	21,701	15,448	58,650	272,180	127,417	126,042	752	39,353	149	7,936	680,266
1984	10,090	763	22,071	16,109	61,409	276,511	134,490	128,022	802	39,956	197	9,650	700,063
1985	10,262	803	22,440	16,786	64,018	280,667	141,066	129,990	854	40,567	257	11,364	719,065

Note: Totals may not agree due to rounding.

TABLE 358

CUMULATIVE NON-ASSOCIATED GAS DISCOVERED — LOWER 48 STATES
(BCF)

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1970	8,144	527	17,879	9,981	27,193	211,718	45,430	104,777	370	32,989	9	—	459,017
1971	8,262	533	18,168	10,229	28,507	214,641	49,072	105,763	390	33,356	9	—	468,929
1972	8,385	539	18,469	10,493	29,890	217,446	52,747	106,747	410	33,730	9	—	478,864
1973	8,514	545	18,784	10,769	31,338	220,161	56,505	107,726	431	34,114	9	—	488,895
1974	8,649	552	19,122	11,067	32,862	222,774	60,326	108,711	452	34,509	12	31	499,067
1975	8,792	559	19,480	11,404	34,474	225,298	64,262	109,705	474	34,918	15	63	509,446
1976	8,945	574	19,861	11,770	36,189	227,757	68,292	110,706	497	35,343	22	97	520,055
1977	9,109	590	20,270	12,212	38,005	230,141	72,432	111,716	521	35,784	29	203	531,015
1978	9,286	608	20,902	12,707	39,939	232,453	76,699	112,739	546	36,243	40	536	542,700
1979	9,478	627	21,566	13,245	41,960	234,677	81,030	113,798	573	36,720	55	1,317	555,048
1980	9,688	648	22,252	13,845	44,059	236,875	85,561	114,875	601	37,226	75	2,145	567,852
1981	9,914	682	22,946	14,490	46,237	238,979	90,201	115,948	630	37,752	100	3,092	580,974
1982	10,155	718	23,641	15,177	48,452	240,983	94,898	117,006	660	38,294	130	4,156	594,275
1983	10,410	756	24,330	15,942	50,681	242,862	99,599	118,038	691	38,847	165	5,287	607,612
1984	10,675	796	25,005	16,757	52,901	244,618	104,252	119,040	722	39,405	205	6,429	620,808
1985	10,932	838	25,660	17,616	55,049	246,253	108,734	120,003	753	39,972	249	7,571	633,635

Note: Totals may not agree due to rounding.

TABLE 359

CUMULATIVE NON-ASSOCIATED GAS DISCOVERED – LOWER 48 STATES (BCF)

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total /Lower 48 States
1970	8,144	527	17,879	9,981	27,193	211,718	45,430	104,777	370	32,989	9	–	459,017
1971	8,260	533	18,164	10,226	28,489	214,603	49,022	105,749	389	33,351	9	–	468,796
1972	8,374	539	18,443	10,471	29,772	217,217	52,439	106,664	408	33,698	9	–	478,034
1973	8,485	545	18,716	10,710	31,028	219,603	55,721	107,521	426	34,031	9	–	486,795
1974	8,594	550	18,988	10,949	32,257	221,763	58,845	108,329	443	34,351	11	25	495,106
1975	8,700	555	19,253	11,198	33,460	223,723	61,847	109,091	460	34,658	13	49	503,010
1976	8,804	565	19,512	11,447	34,636	225,514	64,706	109,806	476	34,953	18	72	510,512
1977	8,905	575	19,765	11,720	35,775	227,141	67,431	110,478	491	35,234	22	139	517,679
1978	9,004	585	20,012	11,996	36,877	228,617	70,028	111,109	506	35,502	28	333	524,600
1979	9,100	595	20,258	12,266	37,943	229,943	72,460	111,714	520	35,755	36	747	531,340
1980	9,194	604	20,607	12,533	38,974	231,166	74,803	112,284	533	35,998	46	1,145	537,891
1981	9,285	618	20,938	12,794	39,991	232,283	77,059	112,821	546	36,231	57	1,565	544,192
1982	9,374	631	21,253	13,048	40,976	233,311	79,232	113,327	558	36,455	69	2,005	550,242
1983	9,461	644	21,552	13,308	41,922	234,252	81,325	113,804	570	36,670	83	2,445	556,037
1984	9,545	657	21,835	13,565	42,831	235,119	83,341	114,258	581	36,876	98	2,867	561,574
1985	9,627	669	22,104	13,819	43,688	235,924	85,250	114,689	592	37,077	114	3,272	566,828

Note: Totals may not agree due to rounding.

TABLE 360

CUMULATIVE NON-ASSOCIATED GAS DISCOVERED—LOWER 48 STATES
(BCF)

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1970	8,144	527	17,879	9,981	27,193	211,718	45,430	104,777	370	32,989	9	–	459,017
1971	8,251	532	18,112	10,229	29,037	216,332	49,944	106,090	387	33,382	9	–	472,305
1972	8,354	537	18,330	10,475	30,862	220,644	54,440	107,354	404	33,759	9	–	485,168
1973	8,453	541	18,539	10,714	32,644	224,695	58,933	108,563	421	34,122	9	–	497,634
1974	8,548	545	18,744	10,951	34,380	228,462	63,355	109,726	438	34,470	11	38	509,668
1975	8,639	549	18,941	11,196	36,066	231,966	67,727	110,845	455	34,804	13	75	521,275
1976	8,727	557	19,130	11,438	37,700	235,242	71,990	111,915	472	35,125	16	110	532,420
1977	8,811	565	19,311	11,701	39,265	238,281	76,131	112,937	489	35,431	19	211	543,151
1978	8,892	573	19,485	11,965	40,762	241,092	80,140	113,914	505	35,722	23	502	553,577
1979	8,970	581	19,655	12,221	42,192	243,663	83,940	114,867	521	35,997	29	1,123	563,762
1980	9,045	589	19,818	12,473	43,557	246,076	87,635	115,778	537	36,261	36	1,720	573,527
1981	9,117	601	19,975	12,716	44,884	248,314	91,218	116,649	553	36,514	45	2,350	582,938
1982	9,186	613	20,125	12,951	46,160	250,402	94,686	117,482	568	36,757	55	3,010	591,998
1983	9,252	624	20,269	13,190	47,386	252,339	98,037	118,278	583	36,990	67	3,670	600,689
1984	9,316	635	20,407	13,424	48,564	254,147	101,268	119,044	598	37,214	80	4,303	609,006
1985	9,377	646	20,540	13,654	49,673	255,845	104,329	119,782	612	37,432	95	4,911	616,903

Note: Totals may not agree due to rounding.

TABLE 361

PERCENT OF ULTIMATE NON-ASSOCIATED GAS DISCOVERED – LOWER 48 STATES

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1970	31.7	13.9	35.7	19.3	26.8	53.2	22.5	46.9	3.0	34.4	0.2	0.0	37.5
Case I													
1975	34.1	14.6	38.3	22.3	37.6	59.4	36.2	50.3	3.8	36.7	0.3	0.2	43.8
1980	37.4	17.1	42.0	27.7	52.7	66.5	56.3	54.8	5.3	39.9	1.5	7.4	52.5
1985	41.9	24.0	46.9	36.0	69.7	73.6	77.6	60.7	8.1	44.1	8.2	27.7	62.8
Case IA													
1975	34.4	14.8	39.1	22.3	34.4	56.8	32.4	49.3	3.8	36.5	0.3	0.1	41.9
1980	38.8	17.8	45.8	28.2	45.9	60.2	45.0	52.0	5.1	39.5	2.0	4.9	47.6
1985	45.3	25.2	54.5	39.0	59.9	63.0	59.5	54.8	6.7	43.4	7.1	18.5	54.5
Case II													
1975	33.9	14.6	38.1	22.1	36.9	59.0	35.4	50.1	3.7	36.6	0.3	0.2	43.4
1980	36.7	16.6	41.1	26.5	49.4	64.9	52.1	53.8	5.0	39.2	1.3	5.9	50.7
1985	40.0	21.2	44.8	32.5	63.1	70.5	69.9	58.2	6.8	42.3	5.6	20.9	58.8
Case III													
1975	34.2	14.8	38.9	22.1	34.0	56.6	31.8	49.1	3.8	36.4	0.3	0.1	41.7
1980	37.7	17.1	44.4	26.8	43.4	59.5	42.4	51.4	4.8	38.8	1.6	3.9	46.4
1985	42.6	22.1	51.2	34.1	54.3	61.9	53.9	53.7	6.0	41.7	5.4	13.9	51.8
Case IV													
1975	33.9	14.7	38.4	21.7	33.0	56.2	30.6	48.9	3.7	36.1	0.3	0.1	41.1
1980	35.8	16.0	41.1	24.3	38.4	58.1	37.1	50.3	4.3	37.5	1.0	2.1	44.0
1985	37.5	17.7	44.1	26.8	43.1	59.3	42.2	51.4	4.7	38.7	2.5	6.0	46.3
Case IVA													
1975	33.6	14.5	37.8	21.7	35.5	58.3	33.6	49.6	3.6	36.3	0.3	0.1	42.6
1980	35.2	15.6	39.5	24.2	42.9	61.8	43.4	51.9	4.3	37.8	0.8	3.2	46.9
1985	36.5	17.1	41.0	26.5	49.0	64.3	51.7	53.6	4.9	39.0	2.1	9.0	50.4
Note: Ultimate Non-Associated Gas (BCF)	25,676	3,784	50,129	51,613	101,453	397,862	201,826	223,289	12,513	95,913	4,609	54,488	1,223,155

TABLE 362

CUMULATIVE NON-ASSOCIATED GAS RESERVES DISCOVERED OFFSHORE REGIONS 2A, 6A AND 11A

	Case I (BCF)	Case IA (BCF)	Case II (BCF)	Case III (BCF)	Case IV (BCF)	Case IVA (BCF)
1970	45,957	45,957	45,957	45,957	45,957	45,957
1971	50,540	49,605	50,540	49,605	49,555	50,476
1972	55,539	53,391	55,394	53,286	52,978	54,977
1973	61,042	57,373	60,583	57,050	56,266	59,474
1974	67,085	61,564	66,116	60,909	59,420	63,938
1975	73,711	65,994	72,014	64,884	62,451	68,351
1976	80,891	70,654	78,236	68,963	65,343	72,657
1977	88,756	75,640	84,886	73,225	68,145	76,907
1978	97,591	81,168	92,196	77,843	70,946	81,215
1979	107,651	87,458	100,358	82,974	73,802	85,644
1980	118,388	94,187	108,948	88,354	76,552	89,944
1981	129,671	101,362	117,880	93,975	79,242	94,169
1982	141,146	108,837	126,998	99,772	81,868	98,309
1983	152,376	116,405	136,078	105,642	84,414	102,331
1984	162,958	123,851	144,903	111,477	86,865	106,206
1985	172,639	131,010	153,233	117,143	89,191	109,886

TABLE 363

PERCENT OF ULTIMATE NON-ASSOCIATED GAS DISCOVERED—OFFSHORE REGIONS 2A, 6A AND 11A

(Percent)

	1970	17.7			
Case I			Case III		
	1975	28.3		1975	24.9
	1980	45.5		1980	34.0
	1985	66.4		1985	45.0
Case IA			Case IV		
	1975	25.4		1975	24.0
	1980	36.2		1980	29.4
	1985	50.4		1985	34.3
Case II			Case IVA		
	1975	27.7		1975	26.3
	1980	41.9		1980	34.6
	1985	58.9		1985	42.2

Note: Ultimate Non-Associated Gas (BCF) 260,098.

TABLE 364

CUMULATIVE NON-ASSOCIATED GAS RESERVES DISCOVERED LOWER 48 STATES—ONSHORE

	Case I (BCF)	Case IA (BCF)	Case II (BCF)	Case III (BCF)	Case IVA (BCF)	Case IV (BCF)
1970	413,060	413,060	413,060	413,060	413,060	413,060
1971	421,952	419,324	421,952	419,324	421,829	419,241
1972	431,223	425,758	430,959	425,578	430,191	425,056
1973	440,921	432,385	440,115	431,845	438,160	430,529
1974	451,071	439,245	449,434	438,158	445,730	435,686
1975	461,737	446,389	458,961	444,562	452,924	440,559
1976	472,981	453,866	468,740	451,092	459,763	445,169
1977	484,830	461,737	478,784	457,790	466,244	449,534
1978	497,295	470,203	489,091	464,857	472,362	453,654
1979	510,391	479,015	499,670	472,074	478,118	457,538
1980	524,295	488,273	510,658	479,498	483,583	461,339
1981	538,717	497,826	521,825	486,999	488,769	464,950
1982	553,347	507,496	533,042	494,503	493,689	468,374
1983	567,871	517,127	544,188	501,970	498,358	471,623
1984	582,006	526,537	555,160	509,331	502,800	474,709
1985	595,596	535,637	565,832	516,492	507,017	477,637

TABLE 365

PERCENT OF ULTIMATE NON-ASSOCIATED GAS DISCOVERED ONSHORE LOWER 48 STATES

(Percent)

1970	42.9		
Case I		**Case III**	
1975	47.9	1975	46.2
1980	54.4	1980	49.8
1985	61.8	1985	53.6
Case IA		**Case IV**	
1975	46.4	1975	45.7
1980	50.7	1980	47.9
1985	55.6	1985	49.6
Case II		**Case IVA**	
1975	47.7	1975	47.0
1980	53.0	1980	50.2
1985	58.8	1985	52.6

Note: Ultimate Non-Associated Gas (BCF) 963,057.

TABLE 366

CUMULATIVE NON-ASSOCIATED GAS RESERVES DISCOVERED TOTAL UNITED STATES

	Case I (BCF)	Case IA (BCF)	Case II (BCF)	Case III (BCF)	Case IV (BCF)	Case IVA (BCF)
1970	464,118	464,118	464,118	464,118	464,118	464,118
1971	478,037	474,326	478,037	474,326	473,189	477,843
1972	492,773	484,857	492,351	484,563	483,707	491,126
1973	508,465	495,795	507,160	494,903	492,737	503,995
1974	525,179	507,193	522,490	505,394	501,307	516,416
1975	543,519	519,466	538,849	516,397	509,679	528,725
1976	563,064	532,352	555,823	527,655	517,631	540,544
1977	585,970	547,341	575,210	540,411	525,943	552,988
1978	611,024	563,843	595,906	554,149	534,060	565,205
1979	638,253	581,666	617,896	568,662	541,949	577,109
1980	667,333	600,619	640,917	583,762	549,602	588,524
1981	697,788	620,524	664,600	599,274	556,962	599,519
1982	728,880	641,004	688,627	615,037	564,029	610,100
1983	761,345	662,691	713,774	631,654	571,100	620,698
1984	792,840	684,080	738,540	648,164	577,861	630,846
1985	822,889	704,872	762,511	664,305	584,290	640,501

TABLE 367

PERCENT OF ULTIMATE NON-ASSOCIATED GAS DISCOVERED—TOTAL UNITED STATES

(Percent)

	1970	30.9		
Case I			Case III	
	1975	36.2	1975	34.4
	1980	44.5	1980	38.9
	1985	54.8	1985	44.3
Case IA			Case IV	
	1975	34.6	1975	34.0
	1980	40.0	1980	36.6
	1985	47.0	1985	38.9
Case II			Case IVA	
	1975	35.9	1975	35.2
	1980	42.7	1980	37.2
	1985	50.8	1985	42.7

Note: Ultimate Non-Associated Gas (BCF) 1,500,556.

TABLE 368

CUMULATIVE TOTAL GAS RESERVES DISCOVERED
NON-ASSOCIATED & ASSOCIATED DISSOLVED
UNITED STATES

	Case I (BCF)	Case IA (BCF)	Case II (BCF)	Case III (BCF)	Case IV (BCF)	Case IVA (BCF)
1970	679,300	679,300	679,300	679,300	679,300	679,300
1971	694,595	690,732	694,595	690,732	690,595	694,401
1972	710,783	702,413	710,332	702,097	701,086	708,932
1973	728,180	714,590	726,797	713,643	711,094	723,166
1974	747,108	727,611	744,163	725,608	720,695	737,063
1975	767,941	741,687	762,722	738,171	730,097	750,871
1976	790,781	757,126	782,457	751,521	739,033	764,135
1977	817,423	775,019	805,027	766,725	748,320	778,013
1978	846,332	794,468	829,095	783,054	757,432	791,681
1979	877,578	815,352	854,518	800,193	766,283	805,003
1980	911,272	837,938	881,345	818,285	774,883	817,807
1981	946,395	861,521	908,777	836,731	783,795	830,773
1982	981,845	885,384	936,282	855,165	792,670	843,557
1983	1,017,458	909,266	963,977	873,538	801,644	856,431
1984	1,051,838	932,609	991,096	891,630	810,292	868,827
1985	1,084,741	955,357	1,017,383	909,337	818,951	881,057

TABLE 369

PERCENT OF ULTIMATE TOTAL GAS DISCOVERED
NON-ASSOCIATED & ASSOCIATED DISSOLVED
UNITED STATES
(Percent)

	1970	36.6			
Case I			Case III		
	1975	41.3		1975	39.7
	1980	49.1		1980	44.1
	1985	58.4		1985	49.0
Case IA			Case IV		
	1975	39.9		1975	39.3
	1980	45.1		1980	41.7
	1985	51.4		1985	44.1
Case II			Case IVA		
	1975	41.1		1975	40.4
	1980	47.5		1980	44.0
	1985	54.8		1985	47.4

Note: Ultimate Total Gas (Non-Associated & Assoc. Dissolved) (BCF) 1,857,300.

TABLE 370

HISTORICAL NON-ASSOCIATED GAS RESERVES REMAINING AT YEAR-END—LOWER 48 STATES (BCF)

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1956	2,220	–	17,363	3,729	5,714	79,937	4,132	43,834	55	3,485	–	–	160,421
1957	2,443	–	17,116	3,956	6,599	85,138	5,233	44,815	94	3,519	–	–	168,862
1958	2,345	–	16,452	4,590	8,753	88,770	5,593	48,341	141	3,343	–	–	178,278
1959	2,212	–	13,479	4,491	9,098	95,382	7,704	48,713	132	3,376	–	–	184,538
1960	2,504	12	11,764	4,277	9,788	97,599	8,834	48,082	129	3,635	–	–	186,625
1961	2,800	74	12,079	4,660	9,279	101,101	10,212	46,866	147	3,691	–	–	190,910
1962	3,142	115	11,704	4,623	9,118	103,227	15,392	47,076	132	3,723	–	–	198,253
1963	2,947	198	11,791	4,514	9,568	103,599	16,847	46,103	116	3,966	–	–	199,651
1964	2,973	386	11,720	4,230	11,673	103,131	20,788	46,445	156	3,928	–	–	205,431
1965	2,845	363	11,664	4,151	13,782	103,828	24,637	46,022	113	4,088	–	–	211,494
1966	2,863	299	11,103	4,063	17,481	102,218	26,906	45,460	78	4,269	–	–	214,740
1967	2,816	268	11,588	4,393	19,322	100,827	29,964	44,927	96	4,217	–	–	218,417
1968	2,813	226	11,073	4,481	19,653	100,550	31,014	42,014	83	4,152	–	–	216,060
1969	2,675	192	10,514	4,715	18,337	96,155	30,214	40,152	83	4,002	–	–	207,040
1970	2,397	166	10,093	4,817	17,108	89,976	32,093	38,466	222	4,069	–	–	199,407

Note: Totals may not agree due to rounding.

TABLE 371

PROJECTED NON-ASSOCIATED GAS RESERVES REMAINING AT YEAR-END—LOWER 48 STATES
(BCF)

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	2,242	148	9,653	4,746	17,421	87,186	34,007	36,298	220	4,061	—	—	195,982
1972	2,087	133	9,206	4,684	17,796	84,262	36,108	34,133	219	4,085	—	—	192,713
1973	1,927	121	8,757	4,622	18,246	81,007	38,235	32,170	220	4,122	—	—	189,428
1974	1,801	111	8,312	4,569	18,753	77,606	40,436	30,359	223	4,174	2	51	186,397
1975	1,703	102	7,876	4,549	19,337	74,380	42,897	28,718	229	4,246	5	106	184,148
1976	1,630	102	7,463	4,554	20,032	71,500	45,617	27,293	237	4,338	10	164	182,940
1977	1,578	104	7,122	4,659	20,810	68,929	48,563	26,088	249	4,453	15	350	182,921
1978	1,548	108	6,849	4,831	21,676	66,653	51,689	25,121	264	4,590	23	956	184,310
1979	1,534	115	6,645	5,052	22,638	64,624	54,786	24,452	284	4,755	36	2,420	187,341
1980	1,539	125	6,494	5,335	23,678	62,945	58,015	24,016	309	4,955	56	4,009	191,475
1981	1,556	151	6,391	5,657	24,757	61,537	61,125	23,732	339	5,178	83	5,851	196,356
1982	1,582	181	6,316	6,000	25,741	60,144	63,731	23,551	372	5,416	120	7,897	201,051
1983	1,610	213	6,260	6,392	26,536	58,548	65,528	23,424	409	5,654	168	10,025	204,766
1984	1,638	246	6,213	6,784	27,067	56,797	66,348	23,321	448	5,879	229	12,092	207,064
1985	1,664	279	6,162	7,161	27,243	54,937	66,061	23,185	487	6,100	305	14,065	207,649

Note: Totals may not agree due to rounding.

TABLE 372

PROJECTED NON-ASSOCIATED GAS RESERVES REMAINING AT YEAR-END—LOWER 48 STATES
(BCF)

Case IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	2,251	149	9,706	4,742	16,865	85,431	33,071	35,952	222	4,029	—	—	192,420
1972	2,108	135	9,326	4,679	16,667	80,700	34,005	33,414	223	4,022	—	—	185,279
1973	1,963	124	8,949	4,620	16,563	75,660	34,763	31,069	224	4,028	—	—	177,963
1974	1,853	115	8,586	4,573	16,539	70,501	35,410	28,856	227	4,050	3	34	170,748
1975	1,777	108	8,243	4,565	16,619	65,531	36,120	26,788	231	4,091	7	71	164,150
1976	1,728	111	7,935	4,588	16,844	60,891	36,927	24,906	237	4,154	14	110	158,445
1977	1,708	115	7,717	4,725	17,212	56,564	37,834	23,210	244	4,239	21	233	153,821
1978	1,716	122	7,796	4,943	17,711	52,546	38,844	21,707	252	4,346	32	637	150,653
1979	1,751	132	7,940	5,228	18,300	48,821	39,878	20,429	263	4,481	49	1,613	148,883
1980	1,817	144	8,121	5,601	18,976	45,396	41,082	19,317	275	4,649	70	2,671	148,120
1981	1,909	174	8,321	6,044	19,728	42,298	42,392	18,306	289	4,842	98	3,899	148,297
1982	2,024	206	8,512	6,542	20,474	39,331	43,620	17,370	303	5,051	130	5,262	148,825
1983	2,125	239	8,677	7,139	21,159	36,380	44,622	16,488	317	5,263	166	6,680	149,257
1984	2,206	272	8,801	7,781	21,735	33,541	45,325	15,655	331	5,468	206	8,058	149,378
1985	2,265	305	8,870	8,453	22,120	30,855	45,621	14,831	342	5,671	248	9,372	148,954

Note: Totals may not agree due to rounding.

TABLE 373

PROJECTED NON-ASSOCIATED GAS RESERVES REMAINING AT YEAR-END–LOWER 48 STATES
(BCF)

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	2,242	148	9,653	4,746	17,421	87,186	34,007	36,298	220	4,061	–	–	195,982
1972	2,084	133	9,199	4,676	17,738	84,126	35,964	34,093	218	4,073	–	–	192,304
1973	1,918	121	8,736	4,598	18,067	80,607	37,783	32,050	218	4,086	–	–	188,184
1974	1,781	110	8,269	4,520	18,392	76,826	39,509	30,118	219	4,101	2	47	183,895
1975	1,670	100	7,805	4,462	18,731	73,119	41,318	28,317	222	4,124	4	96	179,966
1976	1,580	99	7,353	4,416	19,117	69,662	43,215	26,691	227	4,155	8	146	176,670
1977	1,507	98	6,967	4,449	19,528	66,433	45,179	25,245	234	4,194	13	303	174,150
1978	1,452	99	6,639	4,529	19,975	63,430	47,185	23,994	242	4,242	19	798	172,604
1979	1,409	102	6,367	4,638	20,469	60,626	49,088	22,986	254	4,303	30	1,963	172,237
1980	1,380	107	6,139	4,784	21,005	58,108	51,059	22,164	268	4,381	44	3,191	172,630
1981	1,358	122	5,946	4,950	21,557	55,847	52,950	21,454	284	4,467	62	4,574	173,570
1982	1,344	139	5,778	5,123	22,060	53,661	54,566	20,839	301	4,560	86	6,075	174,534
1983	1,332	158	5,630	5,332	22,480	51,420	55,766	20,304	321	4,654	117	7,619	175,133
1984	1,325	176	5,499	5,547	22,789	49,223	56,485	19,849	341	4,750	155	9,116	175,254
1985	1,320	195	5,372	5,757	22,898	47,097	56,561	19,420	362	4,851	201	10,544	174,577

Note: Totals may not agree due to rounding.

TABLE 374

PROJECTED NON-ASSOCIATED GAS RESERVES REMAINING AT YEAR-END—LOWER 48 STATES
(BCF)

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	2,251	149	9,706	4,742	16,865	85,431	33,071	35,952	222	4,029	–	–	192,420
1972	2,105	135	9,316	4,671	16,626	80,621	33,900	33,386	222	4,011	–	–	184,993
1973	1,952	124	8,921	4,595	16,436	75,436	34,446	30,986	223	3,995	–	–	177,114
1974	1,830	114	8,527	4,522	16,280	70,082	34,785	28,696	224	3,983	3	31	169,077
1975	1,736	106	8,142	4,473	16,176	64,879	35,094	26,529	225	3,980	6	64	161,409
1976	1,666	107	7,776	4,441	16,161	59,979	35,411	24,530	228	3,985	12	98	154,394
1977	1,618	108	7,485	4,496	16,228	55,375	35,746	22,701	231	4,001	18	202	148,208
1978	1,589	111	7,453	4,607	16,393	51,076	36,106	21,052	235	4,026	27	532	143,207
1979	1,579	116	7,469	4,757	16,630	47,079	36,431	19,612	240	4,065	40	1,308	139,325
1980	1,588	122	7,510	4,957	16,912	43,387	36,852	18,329	246	4,121	57	2,126	136,208
1981	1,610	140	7,561	5,189	17,229	40,049	37,330	17,145	253	4,185	77	3,048	133,816
1982	1,646	160	7,607	5,445	17,540	36,897	37,758	16,054	259	4,258	100	4,048	131,772
1983	1,690	179	7,640	5,757	17,827	33,839	38,071	15,050	266	4,334	126	5,077	129,857
1984	1,741	197	7,658	6,098	18,077	30,981	38,262	14,137	272	4,414	155	6,074	128,066
1985	1,781	215	7,646	6,449	18,218	28,349	38,238	13,272	278	4,502	185	7,026	126,158

Note: Totals may not agree due to rounding.

TABLE 375

PROJECTED NON-ASSOCIATED GAS RESERVES REMAINING AT YEAR-END—LOWER 48 STATES
(BCF)

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	2,250	149	9,702	4,739	16,847	85,393	33,022	35,939	222	4,024	–	–	192,286
1972	2,094	135	9,291	4,649	16,508	80,394	33,595	33,305	221	3,979	–	–	184,169
1973	1,924	122	8,854	4,536	16,133	74,893	33,684	30,787	218	3,915	–	–	175,067
1974	1,778	111	8,398	4,408	15,703	69,125	33,379	28,334	216	3,833	2	25	165,313
1975	1,651	101	7,927	4,279	15,234	63,434	32,863	25,964	213	3,740	5	50	155,460
1976	1,539	98	7,453	4,142	14,757	57,987	32,193	23,726	209	3,634	9	73	145,820
1977	1,439	93	7,027	4,048	14,265	52,799	31,386	21,627	205	3,518	13	139	136,558
1978	1,348	90	6,641	3,970	13,768	47,895	30,459	19,681	200	3,391	18	331	127,791
1979	1,263	87	6,291	3,894	13,282	43,293	29,394	17,911	196	3,259	24	742	119,636
1980	1,184	84	6,075	3,823	12,800	38,986	28,277	16,277	191	3,120	32	1,133	111,981
1981	1,109	86	5,866	3,751	12,334	35,088	27,179	14,748	186	2,977	40	1,536	104,899
1982	1,039	87	5,656	3,677	11,874	31,454	26,061	13,332	181	2,835	49	1,940	98,184
1983	972	87	5,446	3,614	11,418	28,013	24,917	12,037	176	2,697	58	2,325	91,760
1984	913	87	5,242	3,554	10,976	24,875	23,792	10,869	170	2,568	67	2,675	85,789
1985	859	86	5,033	3,492	10,521	22,065	22,677	9,797	165	2,453	77	2,989	80,214

Note: Totals may not agree due to rounding.

TABLE 376

PROJECTED NON-ASSOCIATED GAS RESERVES REMAINING AT YEAR-END—LOWER 48 STATES
(BCF)

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	2,240	148	9,649	4,742	17,395	87,122	33,943	36,280	220	4,055	–	–	195,795
1972	2,074	133	9,179	4,653	17,571	83,735	35,549	33,978	217	4,038	–	–	191,128
1973	1,894	120	8,686	4,540	17,641	79,641	36,702	31,761	214	3,999	–	–	185,197
1974	1,736	108	8,174	4,409	17,587	75,071	37,444	29,580	211	3,939	2	38	178,299
1975	1,599	97	7,650	4,275	17,430	70,386	37,941	27,454	209	3,863	3	75	170,982
1976	1,475	92	7,125	4,132	17,208	65,779	38,216	25,434	206	3,772	6	110	163,557
1977	1,364	86	6,652	4,028	16,907	61,258	38,265	23,525	204	3,669	9	209	156,174
1978	1,263	82	6,221	3,940	16,545	56,846	38,086	21,740	201	3,552	12	497	148,985
1979	1,167	78	5,829	3,852	16,144	52,561	37,629	20,115	199	3,427	17	1,113	142,131
1980	1,079	75	5,462	3,768	15,704	48,450	37,017	18,602	196	3,294	23	1,700	135,371
1981	995	75	5,124	3,683	15,248	44,635	36,327	17,172	194	3,156	30	2,306	128,943
1982	917	75	4,805	3,595	14,774	40,991	35,522	15,836	191	3,017	37	2,911	122,673
1983	843	76	4,506	3,516	14,293	37,459	34,600	14,602	188	2,881	46	3,490	116,499
1984	776	75	4,229	3,441	13,814	34,163	33,613	13,482	185	2,753	55	4,014	110,601
1985	717	75	3,964	3,364	13,307	31,147	32,538	12,443	181	2,638	65	4,486	104,924

Note: Totals may not agree due to rounding.

TABLE 377

HISTORICAL NON-ASSOCIATED GAS RESERVES TO PRODUCTION RATIOS LOWER 48 STATES

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1956	24.1	–	49.5	36.2	23.9	18.7	40.1	23.2	6.9	8.8	–	–	21.5
1957	27.1	–	40.1	28.5	23.4	18.9	45.1	23.1	13.4	9.2	–	–	21.4
1958	28.6	–	38.3	38.3	26.4	19.0	32.3	25.7	11.8	8.7	–	–	22.0
1959	23.8	–	34.6	30.1	23.9	18.3	27.6	23.6	7.8	8.4	–	–	20.5
1960	23.0	12.0	26.7	26.2	21.7	17.7	25.8	22.9	6.5	8.8	–	–	19.5
1961	21.9	12.3	27.1	22.4	18.9	16.8	27.0	21.7	7.7	9.6	–	–	18.6
1962	25.3	9.6	27.0	26.3	18.6	17.7	31.7	21.1	6.9	10.3	–	–	19.5
1963	19.0	7.3	27.8	25.4	18.5	16.1	29.0	19.0	4.6	10.5	–	–	17.9
1964	18.0	10.4	21.3	20.4	17.7	16.3	31.4	18.0	7.8	10.3	–	–	17.7
1965	17.8	8.9	20.3	16.9	19.7	15.5	30.2	17.2	4.5	10.4	–	–	17.1
1966	10.4	6.6	19.4	15.2	24.9	15.2	24.0	16.5	6.5	10.6	–	–	16.7
1967	12.1	6.0	19.5	16.8	26.5	14.6	19.9	15.5	6.4	9.9	–	–	16.1
1968	10.5	5.7	16.6	16.9	19.8	14.0	16.4	14.3	3.8	9.7	–	–	14.7
1969	10.2	5.6	16.8	16.5	14.8	12.6	13.1	12.9	5.5	9.6	–	–	13.0
1970	9.0	6.4	16.8	16.3	10.7	11.9	11.6	11.2	11.7	9.2	–	–	11.7

Note: Totals may not agree due to rounding.

TABLE 378

PROJECTED NON-ASSOCIATED GAS RESERVES TO PRODUCTION RATIOS
LOWER 48 STATES

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	8.5	6.5	14.3	14.7	11.2	11.7	12.8	10.4	10.8	10.0	–	–	11.6
1972	7.8	6.7	13.4	14.0	10.8	10.9	12.5	9.6	10.8	10.4	–	–	11.0
1973	6.9	6.8	12.4	13.1	10.6	9.9	11.3	9.4	11.0	10.2	–	–	10.2
1974	7.1	6.7	11.5	12.3	10.2	9.2	10.7	9.0	11.2	10.0	–	–	9.7
1975	7.3	6.8	10.8	11.7	10.0	8.9	10.5	8.7	11.4	9.9	–	–	9.4
1976	7.4	7.3	10.3	11.3	10.0	8.7	10.4	8.5	11.4	9.8	–	–	9.3
1977	7.6	6.9	10.5	11.8	9.9	8.6	10.3	8.4	11.7	9.8	20.4	136.6	9.3
1978	7.7	7.9	10.8	12.2	9.9	8.4	10.2	8.4	11.7	9.7	19.0	184.1	9.3
1979	7.7	8.3	11.0	12.5	9.9	8.3	10.0	8.5	12.0	9.8	19.1	308.2	9.3
1980	7.8	8.5	11.1	12.7	9.9	8.2	9.9	8.5	12.1	9.7	18.5	237.3	9.3
1981	7.8	9.6	11.2	12.9	9.8	8.3	9.8	8.5	12.2	9.7	17.8	125.4	9.4
1982	7.9	10.2	11.2	12.9	9.7	8.2	9.6	8.5	12.2	9.8	17.0	66.8	9.4
1983	7.9	10.3	11.3	12.9	9.6	7.9	9.3	8.5	12.2	9.8	16.4	52.0	9.3
1984	8.0	10.2	11.3	12.9	9.5	7.8	9.0	8.5	12.2	9.9	15.7	43.5	9.2
1985	8.0	10.1	11.2	12.8	9.3	7.8	8.7	8.5	12.0	10.0	15.1	37.7	9.2

Note: Totals may not agree due to rounding.

TABLE 379

PROJECTED NON-ASSOCIATED GAS RESERVES TO PRODUCTION RATIOS LOWER 48 STATES

Case IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	8.5	6.5	14.4	14.7	10.8	11.4	12.4	10.3	11.0	9.9	–	–	11.4
1972	7.8	6.7	13.5	14.0	10.3	10.6	11.9	9.4	10.9	10.2	–	–	10.7
1973	7.0	7.0	12.6	13.1	10.1	9.6	10.8	9.2	11.0	10.1	–	–	9.9
1974	7.2	6.8	11.7	12.3	9.8	8.8	10.1	8.8	11.2	9.9	–	–	9.3
1975	7.5	7.0	11.0	11.7	9.6	8.4	9.8	8.4	11.3	9.8	–	–	9.0
1976	7.6	7.7	10.5	11.4	9.5	8.2	9.7	8.2	11.2	9.7	17.0		8.9
1977	7.9	7.3	10.9	11.9	9.5	8.0	9.6	8.1	11.4	9.7	20.2	136.6	8.8
1978	8.1	8.3	11.5	12.4	9.6	7.8	9.5	8.0	11.3	9.6	18.5	184.1	8.8
1979	8.2	8.6	11.8	12.7	9.6	7.7	9.4	8.0	11.5	9.6	18.2	308.2	8.8
1980	8.4	8.8	12.0	13.0	9.6	7.5	9.3	7.9	11.5	9.6	17.3	237.3	8.8
1981	8.5	9.9	12.1	13.2	9.6	7.5	9.3	7.8	11.6	9.6	16.2	125.4	9.0
1982	8.7	10.4	12.1	13.3	9.6	7.3	9.2	7.7	11.4	9.6	15.2	66.8	9.0
1983	8.6	10.3	12.0	13.4	9.5	7.0	9.0	7.6	11.4	9.7	14.4	52.0	8.9
1984	8.6	10.2	12.0	13.5	9.5	6.9	8.9	7.6	11.3	9.8	13.7	43.5	8.9
1985	8.6	10.0	11.7	13.4	9.3	6.8	8.7	7.5	11.2	9.9	13.1	37.7	8.9

Note: Totals may not agree due to rounding.

TABLE 380

PROJECTED NON-ASSOCIATED GAS RESERVES TO PRODUCTION RATIOS
LOWER 48 STATES

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	8.5	6.5	14.3	14.7	11.2	11.7	12.8	10.4	10.8	10.0	–	–	11.6
1972	7.7	6.7	13.4	13.9	10.7	10.9	12.4	9.6	10.8	10.3	–	–	11.0
1973	6.8	6.8	12.4	13.0	10.5	9.9	11.2	9.3	10.9	10.1	–	–	10.2
1974	7.0	6.6	11.5	12.2	10.1	9.1	10.5	9.0	11.1	9.9	–	–	9.6
1975	7.2	6.7	10.7	11.6	9.8	8.8	10.2	8.6	11.2	9.8	–	–	9.3
1976	7.3	7.1	10.2	11.1	9.7	8.6	10.1	8.4	11.2	9.6	–	–	9.2
1977	7.4	6.6	10.4	11.5	9.6	8.4	10.0	8.3	11.4	9.5	19.8	128.7	9.1
1978	7.5	7.5	10.6	11.9	9.6	8.3	9.9	8.2	11.4	9.4	18.3	170.1	9.0
1979	7.4	7.7	10.8	12.1	9.6	8.1	9.7	8.3	11.6	9.4	18.3	281.1	9.0
1980	7.5	7.9	10.8	12.2	9.6	8.0	9.5	8.3	11.6	9.3	17.6	218.9	9.0
1981	7.4	8.7	10.9	12.4	9.5	8.0	9.5	8.2	11.7	9.2	16.8	117.5	9.1
1982	7.4	9.1	10.9	12.3	9.4	7.9	9.3	8.1	11.6	9.2	16.1	63.4	9.0
1983	7.3	9.3	10.9	12.4	9.4	7.6	9.1	8.1	11.6	9.2	15.5	49.7	8.9
1984	7.4	9.2	11.0	12.4	9.3	7.5	8.9	8.2	11.6	9.4	15.0	42.0	8.9
1985	7.5	9.2	10.8	12.3	9.2	7.5	8.7	8.1	11.6	9.5	14.5	36.8	8.9

Note: Totals may not agree due to rounding.

TABLE 381

PROJECTED NON-ASSOCIATED GAS RESERVES TO PRODUCTION RATIOS
LOWER 48 STATES

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	8.5	6.5	14.4	14.7	10.8	11.4	12.4	10.3	11.0	9.9	–	–	11.4
1972	7.8	6.7	13.5	13.9	10.2	10.6	11.9	9.4	10.9	10.2	–	–	10.7
1973	6.9	6.9	12.6	13.0	10.0	9.5	10.7	9.2	11.0	10.0	–	–	9.9
1974	7.1	6.8	11.7	12.2	9.7	8.8	10.0	8.8	11.1	9.8	–	–	9.3
1975	7.3	6.9	10.9	11.6	9.4	8.4	9.7	8.4	11.1	9.7	–	–	8.9
1976	7.5	7.4	10.4	11.2	9.3	8.2	9.5	8.2	11.0	9.5	–	–	8.8
1977	7.6	7.0	10.7	11.6	9.3	7.9	9.4	8.0	11.2	9.4	19.7	128.7	8.6
1978	7.8	7.9	11.2	12.0	9.3	7.7	9.2	7.9	11.1	9.3	17.9	170.1	8.6
1979	7.8	8.1	11.5	12.2	9.3	7.6	9.1	7.8	11.2	9.3	17.6	281.1	8.6
1980	7.9	8.2	11.6	12.4	9.3	7.4	9.0	7.8	11.2	9.2	16.7	218.9	8.6
1981	7.9	9.0	11.8	12.6	9.3	7.4	9.0	7.6	11.2	9.1	15.7	117.5	8.6
1982	8.0	9.4	11.7	12.6	9.2	7.2	8.8	7.5	11.1	9.1	14.8	63.4	8.6
1983	8.0	9.4	11.7	12.7	9.2	6.9	8.7	7.4	11.0	9.1	14.0	49.7	8.5
1984	8.2	9.3	11.6	12.8	9.2	6.7	8.6	7.4	11.0	9.2	13.4	42.0	8.5
1985	8.2	9.1	11.5	12.7	9.1	6.6	8.5	7.3	10.9	9.4	12.9	36.8	8.6

Note: Totals may not agree due to rounding.

TABLE 382

PROJECTED NON-ASSOCIATED GAS RESERVES TO PRODUCTION RATIOS LOWER 48 STATES

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	8.5	6.5	14.3	14.7	10.8	11.4	12.4	10.3	10.9	9.9	–	–	11.4
1972	7.8	6.7	13.5	13.9	10.2	10.6	11.8	9.4	10.8	10.1	–	–	10.6
1973	6.8	6.9	12.5	12.9	9.9	9.5	10.5	9.1	10.8	9.8	–	–	9.8
1974	7.0	6.7	11.5	12.0	9.5	8.7	9.7	8.7	10.8	9.5	–	–	9.2
1975	7.1	6.7	10.8	11.3	9.1	8.3	9.3	8.3	10.8	9.3	–	–	8.8
1976	7.1	7.0	10.2	10.7	8.9	8.0	9.1	8.0	10.6	9.1	–	–	8.5
1977	7.1	6.3	10.3	11.0	8.7	7.7	8.9	7.8	10.7	8.9	18.3	109.7	8.3
1978	7.1	7.0	10.5	11.2	8.6	7.5	8.6	7.6	10.5	8.6	16.4	135.8	8.1
1979	7.0	6.9	10.6	11.3	8.6	7.3	8.4	7.5	10.6	8.5	16.0	212.9	8.0
1980	6.9	6.8	10.7	11.3	8.5	7.0	8.2	7.4	10.4	8.2	15.0	169.5	7.9
1981	6.6	7.0	10.9	11.3	8.3	7.0	8.1	7.1	10.4	7.9	14.1	95.5	7.8
1982	6.6	7.1	10.8	11.2	8.2	6.7	7.9	6.9	10.2	7.8	13.4	53.8	7.7
1983	6.3	7.0	10.7	11.2	8.1	6.4	7.7	6.8	10.2	7.6	12.8	42.9	7.5
1984	6.3	6.8	10.7	11.2	8.1	6.2	7.6	6.7	10.1	7.7	12.3	36.9	7.5
1985	6.3	6.6	10.5	11.1	8.0	6.1	7.5	6.5	10.0	7.7	12.0	32.8	7.4

Note: Totals may not agree due to rounding.

TABLE 383

PROJECTED NON-ASSOCIATED GAS RESERVES TO PRODUCTION RATIOS
LOWER 48 STATES

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	8.5	6.5	14.3	14.7	11.2	11.7	12.7	10.4	10.8	10.0	–	–	11.6
1972	7.7	6.6	13.3	13.9	10.7	10.9	12.3	9.5	10.7	10.3	–	–	10.9
1973	6.8	6.8	12.4	12.9	10.3	9.8	11.0	9.3	10.8	9.9	–	–	10.1
1974	6.9	6.6	11.4	12.0	9.8	9.0	10.2	8.8	10.8	9.6	–	–	9.4
1975	7.0	6.6	10.6	11.3	9.5	8.6	9.8	8.5	10.9	9.4	–	–	9.0
1976	7.0	6.8	10.0	10.7	9.3	8.3	9.6	8.2	10.7	9.2	–	–	8.8
1977	7.0	6.0	10.2	11.0	9.1	8.1	9.4	8.0	10.8	9.0	–	109.7	8.6
1978	6.9	6.7	10.3	11.2	8.9	7.9	9.1	7.9	10.7	8.7	16.5	135.8	8.5
1979	6.7	6.6	10.4	11.2	8.8	7.7	8.8	7.8	10.7	8.6	16.2	212.9	8.3
1980	6.6	6.5	10.3	11.2	8.7	7.4	8.6	7.7	10.6	8.3	15.4	169.5	8.2
1981	6.4	6.7	10.4	11.2	8.6	7.4	8.5	7.5	10.6	8.0	14.6	95.5	8.1
1982	6.3	6.7	10.2	11.1	8.4	7.2	8.3	7.3	10.4	7.9	13.9	53.8	8.0
1983	6.0	6.7	10.2	11.1	8.4	6.8	8.1	7.2	10.4	7.8	13.4	42.9	7.8
1984	6.0	6.5	10.2	11.1	8.3	6.7	8.0	7.1	10.4	7.8	13.0	36.9	7.8
1985	5.9	6.3	10.0	11.0	8.2	6.6	7.9	7.0	10.2	7.9	12.6	32.8	7.7

Note: Totals may not agree due to rounding.

TABLE 384

HISTORICAL TOTAL GAS RESERVES TO PRODUCTION RATIOS AND YEAR-END RESERVES—NON-ASSOCIATED AND ASSOCIATED-DISSOLVED—LOWER 48 STATES

	Reserves to Production Ratios	Reserves Remaining At Year End (BCF)
1956	21.80	236,483
1957	21.44	245,230
1958	22.13	252,762
1959	21.11	261,170
1960	20.14	262,219
1961	19.84	265,352
1962	19.85	270,645
1963	18.87	274,461
1964	18.21	279,420
1965	17.51	284,484
1966	16.39	286,386
1967	15.76	289,272
1968	14.59	282,098
1969	13.08	269,907
1970	11.90	259,616

TABLE 385

PROJECTED TOTAL GAS RESERVES REMAINING AT YEAR-END NON-ASSOCIATED & ASSOCIATED DISSOLVED —LOWER 48 STATES (BCF)

	Case I	Case IA	Case II	Case III	Case IV	Case IVA
1971	249,647	245,934	249,647	245,934	245,800	249,460
1972	243,122	235,258	242,684	234,951	234,069	241,430
1973	237,067	224,772	235,748	223,872	221,644	232,501
1974	231,676	214,730	229,029	212,963	208,820	222,869
1975	227,435	205,635	222,986	202,720	196,131	213,030
1976	224,451	197,660	217,747	193,329	183,821	203,205
1977	222,927	190,999	213,511	184,976	172,045	193,540
1978	222,977	185,939	210,370	177,927	160,897	184,179
1979	224,831	182,444	208,537	172,144	150,476	175,247
1980	227,859	180,055	207,522	167,220	140,642	166,465
1981	231,688	178,692	207,108	163,107	131,470	158,069
1982	235,363	177,767	206,774	159,434	122,755	149,887
1983	238,047	176,787	206,085	155,941	114,395	141,837
1984	239,372	175,598	204,964	152,658	106,583	134,142
1985	238,995	173,925	203,068	149,317	99,239	126,721

TABLE 386

PROJECTED TOTAL GAS RESERVES TO PRODUCTION RATIOS
NON-ASSOCIATED & ASSOCIATED DISSOLVED —
LOWER 48 STATES

	Case I	Case IA	Case II	Case III	Case IV	Case IVA
1971	11.5	11.3	11.5	11.3	11.3	11.5
1972	11.0	10.7	11.0	10.7	10.7	10.9
1973	10.4	10.1	10.4	10.1	10.0	10.2
1974	9.9	9.6	9.8	9.6	9.5	9.7
1975	9.7	9.4	9.6	9.3	9.1	9.3
1976	9.6	9.2	9.4	9.1	8.9	9.1
1977	9.5	9.1	9.3	9.0	8.7	8.9
1978	9.4	9.0	9.2	8.9	8.5	8.7
1979	9.4	9.0	9.2	8.8	8.4	8.6
1980	9.4	9.0	9.1	8.8	8.2	8.4
1981	9.5	9.1	9.2	8.8	8.1	8.4
1982	9.4	9.0	9.1	8.7	8.0	8.2
1983	9.3	9.0	9.0	8.6	7.8	8.0
1984	9.3	8.9	8.9	8.6	7.7	7.9
1985	9.2	8.9	8.9	8.6	7.6	7.8

TABLE 387

HISTORICAL NON-ASSOCIATED GAS
FINDING TO PRODUCTION RATIO
(ANNUAL RESERVES ADDITIONS ÷ ANNUAL
PRODUCTION)—LOWER 48 STATES

	Finding to Production Ratio
1956	2.07
1957	2.07
1958	2.16
1959	1.70
1960	1.22
1961	1.42
1962	1.72
1963	1.13
1964	1.50
1965	1.49
1966	1.25
1967	1.27
1968	.84
1969	.43
1970	.55

TABLE 388

PROJECTED NON-ASSOCIATED GAS FINDING TO PRODUCTION RATIO (ANNUAL RESERVES ADDITIONS ÷ ANNUAL PRODUCTION)— LOWER 48 STATES

	Case I	Case IA	Case II	Case III	Case IV	Case IVA
1971	.80	.59	.80	.59	.58	.79
1972	.81	.59	.79	.57	.53	.73
1973	.82	.59	.78	.56	.49	.68
1974	.84	.61	.78	.56	.46	.64
1975	.88	.64	.80	.58	.45	.61
1976	.94	.68	.83	.60	.44	.60
1977	1.00	.74	.87	.64	.44	.59
1978	1.07	.82	.92	.70	.44	.59
1979	1.15	.90	.98	.76	.45	.60
1980	1.20	.95	1.02	.80	.46	.59
1981	1.23	1.01	1.05	.85	.47	.59
1982	1.22	1.03	1.05	.87	.47	.59
1983	1.17	1.03	1.03	.87	.47	.58
1984	1.10	1.01	1.01	.88	.48	.59
1985	1.03	.97	.97	.87	.49	.58

Chapter Six—Section V

Wellhead Gas Production

TABLE 389

HISTORICAL WELLHEAD PRODUCTION
NON-ASSOCIATED AND ASSOCIATED DISSOLVED
TOTAL UNITED STATES INCLUDING ALASKA

	Wellhead Production (BCF)
1956	10,849
1957	11,440
1958	11,423
1959	12,373
1960	13,019
1961	13,378
1962	13,638
1963	14,546
1964	15,347
1965	16,279
1966	17,435
1967	18,379
1968	19,683
1969	20,975
1970	22,296

TABLE 390

PERCENTAGE OF PRE-1971 NON-ASSOCIATED GAS RESERVES PRODUCED ANNUALLY

All Cases

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A
1971	11.0	13.8	6.7	6.7	9.1	8.3	8.3	9.1	9.1	10.0	12.3	–
1972	11.0	11.9	6.7	6.7	9.1	8.3	8.3	9.1	8.7	9.2	11.1	–
1973	11.0	10.2	6.7	6.7	8.4	8.3	8.3	8.4	7.8	8.5	10.0	–
1974	9.5	9.2	6.7	6.7	7.9	8.1	8.1	7.9	7.0	7.9	9.1	–
1975	8.2	8.0	6.6	6.6	7.4	7.6	7.6	7.4	6.3	7.3	8.3	–
1976	7.2	7.1	6.4	6.4	6.8	7.0	7.0	6.8	5.8	6.8	7.5	–
1977	6.3	7.2	5.7	5.7	6.2	6.4	6.4	6.2	5.2	6.3	6.9	–
1978	5.5	5.6	5.1	5.1	5.6	5.8	5.8	5.6	4.8	5.9	6.3	–
1979	4.9	4.9	4.6	4.6	5.0	5.2	5.2	5.0	4.3	5.4	5.8	–
1980	4.3	4.4	4.2	4.2	4.5	4.7	4.7	4.5	4.0	5.1	5.3	–
1981	3.9	4.0	3.8	3.8	4.1	4.1	4.1	4.1	3.6	4.8	4.9	–
1982	3.4	3.6	3.5	3.5	3.7	3.7	3.7	3.7	3.4	4.4	4.5	–
1983	3.1	3.2	3.2	3.2	3.3	3.4	3.4	3.3	3.1	4.0	4.2	–
1984	2.6	2.9	2.9	2.9	2.9	3.0	3.0	2.9	2.8	3.5	3.8	–
1985	2.2	2.7	2.7	2.7	2.6	2.6	2.6	2.6	2.6	3.0	–	–

TABLE 391

PERCENTAGE OF POST-1970 NON-ASSOCIATED GAS RESERVES PRODUCED ANNUALLY

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A
T+1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	—
T+2	10.0	10.0	6.7	6.7	10.0	10.0	10.0	10.0	9.5	9.5	10.0	—
T+3	9.0	9.0	6.7	6.7	9.0	9.0	9.0	9.0	8.4	8.4	9.0	5.0
T+4	8.0	8.0	6.7	6.7	8.0	8.0	8.0	8.0	7.5	7.5	8.0	4.8
T+5	7.0	7.0	6.6	6.6	7.0	7.0	7.0	7.0	6.7	6.7	7.0	4.5
T+6	7.0	7.0	6.4	6.4	7.0	7.0	7.0	7.0	6.0	6.0	7.0	4.3
T+7	7.0	7.0	5.8	5.8	6.3	7.0	7.0	6.3	5.4	5.4	6.3	4.1
T+8	6.7	6.7	5.2	5.2	5.5	6.7	6.7	5.5	4.8	4.8	5.5	3.9
T+9	5.8	5.8	4.7	4.7	4.9	5.8	5.8	4.9	4.4	4.4	4.9	3.7
T+10	5.0	5.0	4.3	4.3	4.4	5.0	5.0	4.4	4.0	4.0	4.4	3.5
T+11	4.4	4.4	3.9	3.9	3.9	4.4	4.4	3.9	3.6	3.6	3.9	3.4
T+12	3.8	3.8	3.6	3.6	3.5	3.8	3.8	3.5	3.3	3.3	3.5	3.2
T+13	3.5	3.5	3.2	3.2	3.1	3.5	3.5	3.1	3.0	3.0	3.1	3.0
T+14	3.0	3.0	3.0	3.0	2.8	3.0	3.0	2.8	2.8	2.8	2.8	2.9
T+15	2.6	2.6	2.7	2.7	2.6	2.6	2.6	2.6	2.5	2.5	2.6	2.7

Note: T = Year of Reserves Addition.

TABLE 392

HISTORICAL NON-ASSOCIATED GAS WELLHEAD PRODUCTION–LOWER 48 STATES
(BCF)

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1956	92	–	351	103	239	4,267	103	1,887	8	397	–	–	7,447
1957	90	–	427	139	282	4,503	116	1,943	7	384	–	–	7,892
1958	82	–	430	120	331	4,680	173	1,878	12	383	–	–	8,089
1959	93	–	390	149	380	5,215	279	2,060	17	402	–	–	8,985
1960	109	1	441	163	452	5,512	342	2,104	20	415	–	–	9,559
1961	128	6	445	208	492	6,023	378	2,157	19	384	–	–	10,239
1962	124	12	433	176	490	5,817	485	2,228	19	362	–	–	10,146
1963	155	27	424	178	517	6,425	580	2,430	25	378	–	–	11,139
1964	165	37	551	207	661	6,322	661	2,585	20	382	–	–	11,591
1965	160	41	575	245	700	6,717	815	2,683	25	393	–	–	12,353
1966	276	45	571	267	701	6,736	1,123	2,753	12	404	–	–	12,890
1967	233	45	595	262	730	6,895	1,504	2,903	15	426	–	–	13,607
1968	269	40	666	265	994	7,180	1,893	2,934	22	429	–	–	14,691
1969	261	34	625	286	1,239	7,608	2,229	3,111	15	415	–	–	15,895
1970	266	26	602	296	1,604	7,537	2,771	3,423	19	440	–	–	16,984

Note: Totals may not agree due to rounding.

TABLE 393

NON-ASSOCIATED GAS WELLHEAD PRODUCTION PROJECTION—LOWER 48 STATES (BCF)

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	264	23	676	323	1,557	7,468	2,664	3,500	20	407	–	–	16,902
1972	269	20	688	335	1,650	7,702	2,893	3,567	20	394	–	–	17,539
1973	280	18	704	353	1,725	8,175	3,371	3,434	20	405	–	–	18,486
1974	255	17	721	372	1,831	8,433	3,786	3,373	20	417	–	–	19,224
1975	234	15	729	389	1,932	8,386	4,104	3,304	20	427	–	–	19,541
1976	220	14	728	403	2,012	8,212	4,388	3,193	21	441	–	–	19,632
1977	209	15	677	395	2,105	8,049	4,715	3,089	21	455	1	3	19,733
1978	201	14	637	395	2,198	7,899	5,080	2,985	23	473	1	5	19,910
1979	198	14	607	404	2,288	7,745	5,470	2,879	24	486	2	8	20,125
1980	196	15	587	420	2,395	7,646	5,879	2,815	26	509	3	17	20,507
1981	199	16	570	439	2,519	7,431	6,242	2,796	28	533	5	47	20,823
1982	200	18	562	466	2,641	7,376	6,658	2,779	31	555	7	118	21,410
1983	205	21	556	494	2,755	7,377	7,059	2,760	34	577	10	193	22,039
1984	205	24	548	524	2,847	7,253	7,361	2,733	37	594	15	278	22,420
1985	208	28	550	560	2,928	7,075	7,561	2,735	40	609	20	373	22,686

Note: Totals may not agree due to rounding.

TABLE 394

NON-ASSOCIATED GAS WELLHEAD PRODUCTION PROJECTION—LOWER 48 STATES
(BCF)

Case IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	264	23	676	323	1,557	7,468	2,664	3,500	20	407	–	–	16,902
1972	270	20	691	335	1,623	7,614	2,846	3,550	20	393	–	–	17,361
1973	282	18	711	353	1,640	7,904	3,217	3,380	20	400	–	–	17,925
1974	258	17	733	372	1,689	7,983	3,504	3,281	20	409	–	–	18,266
1975	238	15	747	389	1,736	7,759	3,676	3,173	21	417	–	–	18,172
1976	226	14	753	403	1,765	7,413	3,796	3,021	21	428	1	–	17,842
1977	217	16	711	397	1,806	7,066	3,934	2,871	21	439	1	2	17,481
1978	213	15	680	399	1,852	6,717	4,088	2,717	22	454	2	3	17,162
1979	214	15	671	411	1,901	6,356	4,250	2,558	23	465	3	5	16,872
1980	216	16	678	432	1,967	6,055	4,427	2,435	24	485	4	11	16,749
1981	225	18	686	457	2,052	5,638	4,559	2,349	25	506	6	31	16,551
1982	233	20	705	492	2,136	5,381	4,753	2,259	27	525	9	79	16,617
1983	247	23	722	531	2,219	5,188	4,963	2,162	28	544	12	129	16,767
1984	256	27	736	576	2,291	4,883	5,120	2,057	29	559	15	185	16,735
1985	265	31	756	630	2,366	4,548	5,237	1,980	31	572	19	248	16,683

Note: Totals may not agree due to rounding.

TABLE 395

NON-ASSOCIATED GAS WELLHEAD PRODUCTION PROJECTION—LOWER 48 STATES
(BCF)

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	264	23	676	323	1,557	7,468	2,664	3,500	20	407	–	–	16,902
1972	269	20	688	335	1,650	7,702	2,893	3,567	20	394	–	–	17,539
1973	280	18	704	353	1,722	8,168	3,364	3,432	20	404	–	–	18,465
1974	254	16	720	371	1,819	8,406	3,756	3,364	20	414	–	–	19,141
1975	232	15	726	386	1,905	8,326	4,034	3,286	20	422	–	–	19,353
1976	217	14	723	397	1,963	8,109	4,262	3,160	20	432	–	–	19,298
1977	205	15	670	386	2,028	7,893	4,514	3,039	21	440	1	2	19,214
1978	195	13	626	381	2,088	7,681	4,788	2,912	21	451	1	5	19,163
1979	190	13	592	384	2,137	7,455	5,071	2,779	22	457	2	7	19,109
1980	185	14	568	391	2,199	7,276	5,358	2,684	23	471	2	15	19,185
1981	184	14	544	401	2,273	6,973	5,591	2,628	24	485	4	39	19,159
1982	181	15	530	415	2,342	6,826	5,871	2,569	26	494	5	96	19,371
1983	182	17	516	430	2,403	6,734	6,147	2,505	28	503	8	153	19,627
1984	178	19	501	446	2,450	6,528	6,354	2,435	29	507	10	217	19,675
1985	176	21	496	467	2,499	6,282	6,501	2,397	31	510	14	286	19,679

Note: Totals may not agree due to rounding.

TABLE 396

NON-ASSOCIATED GAS WELLHEAD PRODUCTION PROJECTION—LOWER 48 STATES
(BCF)

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	264	23	676	323	1,557	7,468	2,664	3,500	20	407	–	–	16,902
1972	270	20	691	335	1,623	7,614	2,846	3,550	20	393	–	–	17,361
1973	282	18	711	353	1,638	7,901	3,212	3,379	20	399	–	–	17,911
1974	257	17	732	371	1,681	7,967	3,483	3,275	20	407	–	–	18,209
1975	237	15	744	386	1,717	7,727	3,628	3,161	20	412	–	–	18,046
1976	223	14	747	398	1,729	7,359	3,713	3,000	21	420	–	–	17,623
1977	212	15	701	387	1,750	6,987	3,806	2,839	21	426	1	2	17,146
1978	205	14	664	384	1,768	6,611	3,907	2,672	21	434	2	3	16,686
1979	203	14	648	389	1,785	6,221	4,006	2,499	21	438	2	5	16,230
1980	201	15	645	399	1,816	5,890	4,110	2,360	22	450	3	10	15,921
1981	204	16	643	412	1,862	5,442	4,163	2,257	23	462	5	26	15,514
1982	205	17	650	432	1,904	5,156	4,269	2,149	23	469	7	64	15,345
1983	212	19	655	453	1,941	4,937	4,388	2,036	24	476	9	102	15,252
1984	213	21	658	476	1,970	4,613	4,461	1,915	25	478	12	145	14,988
1985	218	24	667	506	2,007	4,268	4,507	1,828	25	479	14	191	14,734

Note: Totals may not agree due to rounding.

TABLE 397

NON-ASSOCIATED GAS WELLHEAD PRODUCTION PROJECTION—LOWER 48 STATES
(BCF)

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	264	23	676	323	1,557	7,468	2,664	3,500	20	407	–	–	16,902
1972	269	20	690	335	1,622	7,612	2,843	3,549	20	392	–	–	17,354
1973	281	18	709	351	1,631	7,887	3,194	3,374	20	398	–	–	17,863
1974	255	17	728	367	1,659	7,928	3,429	3,261	20	402	–	–	18,065
1975	233	15	736	379	1,672	7,651	3,518	3,133	20	401	–	–	17,757
1976	216	14	733	385	1,653	7,238	3,529	2,953	20	401	–	–	17,142
1977	202	15	679	368	1,631	6,814	3,532	2,770	19	397	1	1	16,429
1978	189	13	633	354	1,599	6,380	3,524	2,578	19	395	1	2	15,688
1979	181	13	595	345	1,552	5,928	3,497	2,375	19	385	2	3	14,895
1980	172	12	566	339	1,513	5,530	3,460	2,204	18	382	2	7	14,205
1981	167	12	540	332	1,483	5,015	3,355	2,066	18	376	3	16	13,383
1982	158	12	525	328	1,445	4,662	3,291	1,922	18	365	4	36	12,766
1983	154	13	508	323	1,402	4,382	3,237	1,773	17	353	5	54	12,219
1984	144	13	488	317	1,351	4,004	3,140	1,621	17	335	5	73	11,508
1985	136	13	478	315	1,312	3,615	3,025	1,504	16	317	6	91	10,828

Note: Totals may not agree due to rounding.

TABLE 398

NON-ASSOCIATED GAS WELLHEAD PRODUCTION PROJECTION—LOWER 48 STATES
(BCF)

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	264	23	676	323	1,557	7,468	2,664	3,500	20	407	–	–	16,902
1972	269	20	688	335	1,649	7,699	2,889	3,566	20	394	–	–	17,530
1973	280	18	703	352	1,713	8,145	3,340	3,426	20	402	–	–	18,397
1974	253	16	717	368	1,789	8,337	3,680	3,344	20	408	–	–	18,932
1975	229	15	721	379	1,843	8,189	3,875	3,244	19	410	–	–	18,924
1976	211	14	713	385	1,857	7,883	3,987	3,090	19	412	–	–	18,571
1977	196	14	655	367	1,867	7,561	4,092	2,932	19	409	–	2	18,114
1978	182	12	605	353	1,859	7,223	4,187	2,762	19	408	1	4	17,615
1979	173	12	563	343	1,831	6,857	4,258	2,578	19	400	1	5	17,039
1980	163	11	529	336	1,805	6,523	4,306	2,424	19	397	2	10	16,525
1981	156	11	495	328	1,783	6,053	4,274	2,300	18	392	2	24	15,838
1982	146	11	469	323	1,750	5,732	4,273	2,169	18	381	3	54	15,331
1983	141	11	443	317	1,708	5,470	4,272	2,031	18	369	3	81	14,865
1984	130	12	416	310	1,657	5,104	4,218	1,886	18	352	4	109	14,215
1985	121	12	398	307	1,616	4,714	4,136	1,776	18	334	5	137	13,573

Note: Totals may not agree due to rounding.

TABLE 399

PROJECTED TOTAL WELLHEAD GAS PRODUCTION—NON-ASSOCIATED AND ASSOCIATED DISSOLVED
LOWER 48 STATES
(BCF)

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	549	39	712	490	2,933	9,010	3,395	4,104	53	407	1	–	21,694
1972	540	37	723	490	2,929	9,175	3,616	4,128	54	394	1	–	22,087
1973	538	36	739	500	2,915	9,590	4,072	3,952	53	405	1	–	22,801
1974	500	40	755	514	2,938	9,797	4,491	3,850	54	417	1	–	23,357
1975	466	50	763	528	2,961	9,711	4,821	3,742	55	427	2	–	23,527
1976	439	67	762	542	2,967	9,511	5,115	3,594	58	441	3	1	23,500
1977	417	88	710	536	2,999	9,358	5,444	3,452	61	455	5	5	23,529
1978	397	114	670	540	3,033	9,219	5,809	3,312	67	473	7	8	23,648
1979	383	141	640	555	3,068	9,076	6,198	3,173	71	486	10	12	23,812
1980	370	169	619	577	3,123	8,984	6,608	3,076	77	509	13	23	24,146
1981	362	196	602	604	3,197	8,772	6,966	3,026	82	533	17	55	24,409
1982	349	223	593	641	3,274	8,740	7,375	2,975	88	555	21	128	24,962
1983	342	250	587	681	3,344	8,751	7,763	2,923	94	577	28	213	25,549
1984	329	276	578	723	3,392	8,631	8,043	2,865	100	594	36	309	25,877
1985	320	302	580	771	3,430	8,450	8,218	2,837	104	609	45	421	26,087

Note: Totals may not agree due to rounding.

TABLE 400

PROJECTED TOTAL WELLHEAD GAS PRODUCTION—NON-ASSOCIATED AND ASSOCIATED DISSOLVED—LOWER 48 STATES
(BCF)

Case IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	549	39	712	490	2,933	9,010	3,395	4,104	53	407	1	–	21,694
1972	541	37	726	490	2,902	9,086	3,548	4,109	53	393	1	–	21,885
1973	540	36	745	498	2,830	9,316	3,864	3,892	53	400	1	–	22,173
1974	503	40	766	509	2,796	9,339	4,113	3,747	53	409	1	–	22,275
1975	470	48	779	520	2,765	9,063	4,260	3,596	53	417	2	–	21,973
1976	445	61	783	528	2,720	8,671	4,365	3,404	54	428	4	1	21,465
1977	425	78	740	519	2,699	8,309	4,496	3,214	55	439	4	4	20,980
1978	409	96	708	519	2,685	7,945	4,648	3,022	56	454	6	6	20,554
1979	399	114	697	529	2,677	7,571	4,807	2,829	58	465	8	8	20,163
1980	390	133	704	549	2,687	7,256	4,985	2,673	60	485	11	16	19,947
1981	387	153	711	574	2,717	6,827	5,114	2,557	62	506	14	38	19,657
1982	381	173	730	610	2,750	6,581	5,304	2,435	65	525	18	88	19,658
1983	382	193	746	652	2,784	6,393	5,508	2,308	67	544	23	146	19,743
1984	378	214	759	699	2,806	6,091	5,651	2,175	69	559	28	210	19,640
1985	374	234	779	756	2,832	5,755	5,753	2,071	72	572	34	287	19,519

Note: Totals may not agree due to rounding.

TABLE 401

PROJECTED TOTAL WELLHEAD GAS PRODUCTION–NON-ASSOCIATED AND ASSOCIATED DISSOLVED–LOWER 48 STATES (BCF)

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	549	39	712	490	2,933	9,010	3,395	4,104	53	407	1	–	21,694
1972	540	37	723	490	2,929	9,175	3,616	4,128	54	394	1	–	22,087
1973	538	36	739	500	2,912	9,582	4,063	3,949	53	404	1	–	22,776
1974	498	39	754	512	2,925	9,768	4,456	3,840	54	414	1	–	23,260
1975	464	49	760	524	2,933	9,647	4,742	3,723	55	422	2	–	23,322
1976	436	65	757	534	2,917	9,399	4,975	3,559	57	432	3	1	23,135
1977	412	84	703	524	2,920	9,187	5,224	3,399	60	440	5	3	22,961
1978	391	105	659	522	2,920	8,980	5,491	3,235	63	451	6	7	22,831
1979	374	128	624	529	2,913	8,759	5,764	3,067	67	457	9	10	22,701
1980	358	151	599	540	2,920	8,580	6,044	2,939	71	471	11	20	22,702
1981	346	171	575	555	2,941	8,274	6,265	2,851	74	485	15	45	22,596
1982	329	192	560	576	2,963	8,144	6,533	2,758	79	494	17	104	22,750
1983	316	212	545	599	2,977	8,058	6,796	2,662	84	503	23	168	22,945
1984	300	232	530	624	2,978	7,853	6,983	2,561	87	507	27	239	22,923
1985	285	251	524	653	2,981	7,602	7,108	2,494	91	510	34	320	22,853

Note: Totals may not agree due to rounding.

TABLE 402

PROJECTED TOTAL WELLHEAD GAS PRODUCTION—NON-ASSOCIATED AND ASSOCIATED DISSOLVED—LOWER 48 STATES (BCF)

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	549	39	712	490	2,933	9,010	3,395	4,104	53	407	1	–	21,694
1972	541	37	726	490	2,902	9,086	3,548	4,109	53	393	1	–	21,885
1973	539	36	745	498	2,828	9,312	3,858	3,890	53	399	1	–	22,157
1974	501	40	765	508	2,787	9,321	4,090	3,740	52	407	1	–	22,212
1975	469	47	775	516	2,745	9,028	4,207	3,583	52	412	2	–	21,836
1976	442	59	777	523	2,683	8,612	4,273	3,382	53	420	3	1	21,226
1977	419	73	730	508	2,641	8,223	4,353	3,179	54	426	4	3	20,614
1978	401	89	692	502	2,599	7,829	4,446	2,974	55	434	6	5	20,033
1979	387	104	675	505	2,557	7,422	4,536	2,766	55	438	7	8	19,460
1980	374	120	671	513	2,532	7,073	4,634	2,594	57	450	9	15	19,041
1981	365	135	668	525	2,522	6,608	4,678	2,460	58	462	12	32	18,524
1982	352	149	674	545	2,513	6,329	4,777	2,320	59	469	15	71	18,273
1983	345	164	678	567	2,499	6,111	4,887	2,178	61	476	18	115	18,100
1984	333	179	680	591	2,479	5,786	4,947	2,029	63	478	23	164	17,752
1985	326	194	688	623	2,466	5,436	4,979	1,915	63	479	26	219	17,415

Note: Totals may not agree due to rounding.

TABLE 403

PROJECTED TOTAL WELLHEAD GAS PRODUCTION–NON-ASSOCIATED AND ASSOCIATED DISSOLVED–LOWER 48 STATES
(BCF)

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	549	39	712	490	2,933	9,010	3,395	4,104	53	407	1	–	21,694
1972	540	37	725	490	2,901	9,084	3,545	4,108	53	392	1	–	21,878
1973	539	35	743	496	2,820	9,296	3,837	3,884	53	398	1	–	22,102
1974	499	39	760	503	2,763	9,277	4,027	3,724	52	402	1	–	22,047
1975	464	44	767	508	2,696	8,942	4,077	3,551	52	401	2	–	21,503
1976	434	52	763	507	2,602	8,474	4,056	3,329	51	401	2	1	20,672
1977	408	62	707	485	2,516	8,026	4,032	3,103	51	397	4	2	19,792
1978	383	70	660	467	2,422	7,566	3,999	2,872	51	395	4	4	18,893
1979	363	79	621	454	2,315	7,089	3,949	2,633	51	385	6	5	17,949
1980	342	85	590	444	2,217	6,666	3,892	2,428	50	382	6	10	17,113
1981	325	92	563	434	2,130	6,126	3,765	2,259	50	376	8	19	16,146
1982	302	97	547	429	2,039	5,771	3,682	2,083	50	365	9	40	15,414
1983	284	103	529	422	1,945	5,485	3,611	1,904	49	353	11	60	14,754
1984	260	107	508	415	1,843	5,099	3,495	1,725	49	335	11	81	13,929
1985	240	110	497	412	1,754	4,699	3,363	1,583	48	317	13	102	13,137

Note: Totals may not agree due to rounding.

TABLE 404

PROJECTED TOTAL WELLHEAD GAS PRODUCTION–NON-ASSOCIATED AND ASSOCIATED DISSOLVED–LOWER 48 STATES
(BCF)

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	549	39	712	490	2,933	9,010	3,395	4,104	53	407	1	–	21,694
1972	540	37	723	490	2,928	9,172	3,612	4,127	54	394	1	–	22,078
1973	538	36	738	498	2,902	9,557	4,034	3,942	53	402	1	–	22,698
1974	497	38	751	508	2,893	9,692	4,363	3,817	53	408	1	–	23,023
1975	460	46	754	514	2,867	9,494	4,549	3,674	53	410	2	–	22,824
1976	429	56	745	516	2,806	9,144	4,648	3,480	54	412	3	1	22,293
1977	402	67	687	497	2,752	8,810	4,736	3,280	55	409	3	3	21,699
1978	376	79	636	482	2,682	8,458	4,807	3,070	56	408	5	6	21,064
1979	355	92	593	471	2,594	8,079	4,851	2,850	58	400	6	7	20,355
1980	334	102	558	464	2,510	7,730	4,872	2,662	59	397	8	13	19,709
1981	315	112	523	456	2,431	7,244	4,812	2,505	59	392	9	28	18,887
1982	290	121	496	452	2,347	6,927	4,786	2,341	60	381	10	58	18,271
1983	271	128	469	447	2,254	6,662	4,761	2,172	62	369	12	88	17,695
1984	247	136	441	442	2,153	6,290	4,682	1,998	62	352	13	118	16,932
1985	225	141	422	440	2,062	5,889	4,577	1,861	63	334	15	149	16,178

Note: Totals may not agree due to rounding.

Chapter Six—Section VI

Marketed Gas Production

TABLE 405

PROJECTED NON-ASSOCIATED GAS-MARKETED PRODUCTION
LOWER 48 STATES
(BCF)

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	247	21	632	302	1,456	6,983	2,491	3,273	19	380	–	–	15,803
1972	252	19	643	314	1,543	7,201	2,705	3,335	19	369	–	–	16,399
1973	262	17	658	330	1,613	7,643	3,152	3,211	19	378	–	–	17,284
1974	238	15	674	348	1,712	7,885	3,540	3,153	19	390	–	–	17,974
1975	219	14	682	363	1,807	7,841	3,837	3,090	19	400	–	–	18,271
1976	206	13	681	376	1,881	7,678	4,103	2,985	19	413	–	–	18,355
1977	195	14	633	369	1,968	7,526	4,408	2,888	20	425	1	2	18,451
1978	188	13	595	370	2,055	7,386	4,750	2,791	21	442	1	5	18,616
1979	186	13	567	378	2,139	7,241	5,115	2,692	22	455	2	7	18,817
1980	183	14	549	393	2,239	7,149	5,497	2,632	24	476	3	16	19,174
1981	186	15	533	411	2,355	6,948	5,837	2,614	26	498	4	44	19,470
1982	187	16	526	436	2,469	6,897	6,225	2,599	29	519	7	110	20,019
1983	192	19	520	462	2,576	6,897	6,600	2,581	31	540	10	180	20,607
1984	192	22	513	490	2,662	6,782	6,882	2,556	34	556	14	260	20,963
1985	194	26	515	524	2,738	6,615	7,069	2,557	38	570	19	348	21,212

Note: Totals may not agree due to rounding.

TABLE 406

PROJECTED NON-ASSOCIATED GAS-MARKETED PRODUCTION
LOWER 48 STATES
(BCF)

Case IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	247	21	632	302	1,456	6,983	2,491	3,273	19	380	–	–	15,803
1972	252	19	646	313	1,517	7,119	2,661	3,319	19	367	–	–	16,232
1973	263	17	665	330	1,533	7,391	3,008	3,161	19	374	–	–	16,760
1974	241	16	685	348	1,579	7,464	3,276	3,067	19	383	–	–	17,078
1975	223	14	699	363	1,623	7,255	3,437	2,967	19	390	–	–	16,991
1976	211	14	704	377	1,650	6,931	3,549	2,825	20	400	–	–	16,682
1977	203	15	665	371	1,689	6,606	3,678	2,685	20	410	1	2	16,345
1978	199	14	636	373	1,732	6,280	3,823	2,540	21	424	2	3	16,047
1979	200	14	627	384	1,777	5,943	3,974	2,391	21	435	2	5	15,775
1980	202	15	634	404	1,840	5,661	4,139	2,276	22	453	4	11	15,661
1981	210	16	641	427	1,918	5,271	4,263	2,196	23	473	6	29	15,475
1982	217	19	659	460	1,997	5,031	4,444	2,112	25	491	8	74	15,537
1983	231	22	675	497	2,075	4,850	4,640	2,022	26	509	11	120	15,677
1984	239	25	689	539	2,142	4,566	4,787	1,923	27	523	14	173	15,647
1985	248	29	707	589	2,213	4,253	4,896	1,851	29	535	18	232	15,599

Note: Totals may not agree due to rounding.

TABLE 407

PROJECTED NON-ASSOCIATED GAS-MARKETED PRODUCTION
LOWER 48 STATES
(BCF)

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	247	21	632	302	1,456	6,983	2,491	3,273	19	380	–	–	15,803
1972	252	19	643	314	1,543	7,201	2,705	3,335	19	369	–	–	16,399
1973	262	17	658	330	1,610	7,637	3,145	3,209	19	378	–	–	17,265
1974	238	15	673	347	1,701	7,859	3,512	3,146	19	387	–	–	17,897
1975	217	14	679	361	1,781	7,785	3,772	3,073	19	395	–	–	18,095
1976	203	13	676	371	1,835	7,582	3,985	2,955	19	404	–	–	18,044
1977	191	14	627	361	1,896	7,380	4,221	2,841	19	412	1	2	17,965
1978	182	12	586	357	1,952	7,181	4,477	2,723	20	422	1	4	17,917
1979	178	12	553	359	1,999	6,970	4,741	2,599	20	428	2	7	17,867
1980	173	13	531	366	2,056	6,803	5,010	2,509	22	440	2	14	17,938
1981	172	13	509	375	2,125	6,520	5,227	2,457	23	453	3	36	17,914
1982	169	14	496	388	2,189	6,383	5,489	2,402	24	462	5	90	18,112
1983	170	16	482	402	2,247	6,297	5,748	2,342	26	471	7	143	18,351
1984	167	18	468	417	2,291	6,103	5,941	2,277	27	474	10	203	18,396
1985	165	20	463	436	2,337	5,874	6,078	2,241	29	477	13	268	18,400

Note: Totals may not agree due to rounding.

TABLE 408

PROJECTED NON-ASSOCIATED GAS-MARKETED PRODUCTION
LOWER 48 STATES
(BCF)

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	247	21	632	302	1,456	6,983	2,491	3,273	19	380	–	–	15,803
1972	252	19	646	313	1,517	7,119	2,661	3,319	19	367	–	–	16,232
1973	263	17	664	330	1,531	7,387	3,003	3,159	19	373	–	–	16,747
1974	240	16	684	347	1,571	7,449	3,256	3,062	19	381	–	–	17,025
1975	221	14	695	361	1,605	7,224	3,392	2,956	19	385	–	–	16,873
1976	208	13	698	372	1,617	6,881	3,471	2,805	19	392	–	–	16,478
1977	198	14	655	362	1,636	6,533	3,558	2,655	19	398	1	1	16,031
1978	192	13	621	359	1,653	6,181	3,653	2,499	20	406	1	3	15,602
1979	190	13	606	363	1,669	5,817	3,745	2,336	20	410	2	4	15,175
1980	188	14	603	373	1,698	5,507	3,843	2,206	21	421	3	9	14,886
1981	191	15	601	385	1,741	5,089	3,892	2,110	21	432	5	24	14,505
1982	192	16	607	404	1,780	4,821	3,992	2,009	22	439	6	60	14,348
1983	198	18	612	423	1,815	4,616	4,103	1,903	23	445	8	96	14,261
1984	200	20	615	445	1,842	4,313	4,171	1,791	23	447	11	135	14,014
1985	203	22	624	473	1,877	3,990	4,214	1,709	24	448	13	178	13,776

Note: Totals may not agree due to rounding.

TABLE 409

PROJECTED NON-ASSOCIATED GAS-MARKETED PRODUCTION
LOWER 48 STATES
(BCF)

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	247	21	632	302	1,456	6,983	2,491	3,273	19	380	–	–	15,803
1972	252	19	646	313	1,516	7,117	2,659	3,318	19	367	–	–	16,226
1973	263	17	663	329	1,525	7,374	2,986	3,155	19	372	–	–	16,702
1974	239	16	680	344	1,551	7,413	3,206	3,049	19	375	–	–	16,891
1975	218	14	688	354	1,563	7,153	3,290	2,929	18	375	–	–	16,603
1976	202	13	686	360	1,545	6,768	3,300	2,761	18	375	–	–	16,028
1977	189	14	635	344	1,525	6,371	3,302	2,590	18	371	1	1	15,361
1978	177	12	592	331	1,495	5,965	3,295	2,410	18	369	1	2	14,668
1979	170	12	556	323	1,452	5,542	3,270	2,221	17	360	1	3	13,927
1980	161	12	529	317	1,415	5,171	3,235	2,061	17	357	2	6	13,282
1981	156	11	505	310	1,386	4,689	3,137	1,932	17	352	3	15	12,513
1982	148	11	491	307	1,351	4,359	3,077	1,797	17	341	3	34	11,936
1983	144	12	475	302	1,310	4,097	3,026	1,658	16	330	4	51	11,425
1984	135	12	457	297	1,263	3,744	2,936	1,515	16	313	5	68	10,760
1985	127	12	447	295	1,227	3,380	2,828	1,406	15	296	6	85	10,124

Note: Totals may not agree due to rounding.

TABLE 410

PROJECTED NON-ASSOCIATED GAS-MARKETED PRODUCTION
LOWER 48 STATES
(BCF)

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	247	21	632	302	1,456	6,983	2,491	3,273	19	380	–	–	15,803
1972	252	19	643	313	1,542	7,198	2,702	3,334	19	368	–	–	16,390
1973	261	17	657	329	1,601	7,616	3,123	3,203	19	376	–	–	17,201
1974	236	15	670	344	1,673	7,795	3,441	3,127	18	382	–	–	17,701
1975	214	14	674	354	1,723	7,657	3,623	3,034	18	383	–	–	17,694
1976	198	13	667	360	1,736	7,370	3,728	2,889	18	385	–	–	17,364
1977	183	13	612	343	1,745	7,069	3,826	2,742	18	383	–	2	16,937
1978	170	11	565	330	1,738	6,754	3,915	2,582	18	382	1	3	16,470
1979	162	11	526	321	1,712	6,411	3,981	2,411	17	374	1	5	15,932
1980	152	11	495	314	1,688	6,099	4,026	2,266	17	371	1	9	15,451
1981	146	11	463	307	1,667	5,660	3,996	2,151	17	367	2	23	14,809
1982	137	10	439	302	1,636	5,359	3,996	2,028	17	357	3	51	14,334
1983	132	11	414	297	1,597	5,114	3,994	1,899	17	345	3	76	13,899
1984	122	11	389	290	1,549	4,772	3,944	1,764	17	329	4	102	13,291
1985	113	11	372	287	1,511	4,408	3,868	1,661	17	312	5	128	12,691

Note: Totals may not agree due to rounding.

TABLE 411

PROJECTED NON-ASSOCIATED GAS-MARKETED PRODUCTION FROM PRE-1971 RESERVES
LOWER 48 STATES
(BCF)

All Cases

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	247	21	632	302	1,456	6,983	2,491	3,273	19	380	–	–	15,803
1972	247	18	632	302	1,456	6,983	2,491	3,273	18	350	–	–	15,769
1973	247	16	632	302	1,344	6,983	2,491	3,021	16	323	–	–	15,374
1974	213	14	632	302	1,264	6,814	2,431	2,841	15	301	–	–	14,826
1975	184	12	623	297	1,184	6,394	2,281	2,662	13	278	–	–	13,927
1976	161	11	604	288	1,088	5,889	2,100	2,446	12	259	–	–	12,858
1977	141	11	538	257	992	5,384	1,920	2,230	11	240	–	–	11,724
1978	123	9	481	230	896	4,879	1,740	2,014	10	224	–	–	10,607
1979	110	8	434	207	800	4,375	1,560	1,798	9	205	–	–	9,506
1980	96	7	396	189	720	3,954	1,410	1,618	8	194	–	–	8,594
1981	87	6	359	171	656	3,449	1,230	1,475	8	183	–	–	7,623
1982	76	6	330	158	592	3,113	1,110	1,331	7	167	–	–	6,890
1983	69	5	302	144	528	2,860	1,020	1,187	6	152	–	–	6,275
1984	58	5	274	131	464	2,524	900	1,043	6	133	–	–	5,537
1985	49	4	255	122	416	2,187	780	935	5	114	–	–	4,868

Note: Totals may not agree due to rounding.

TABLE 412

PROJECTED NON-ASSOCIATED GAS-MARKETED PRODUCTION FROM POST-1970 RESERVES
LOWER 48 STATES
(BCF)

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	–	–	–	–	–	–	–	–	–	–	–	–	–
1972	5	–	11	12	87	219	214	62	1	19	–	–	630
1973	15	1	26	29	270	661	661	190	2	55	–	–	1,910
1974	25	1	42	47	448	1,070	1,109	312	4	89	–	–	3,148
1975	35	2	59	66	623	1,447	1,557	428	6	122	–	–	4,344
1976	44	2	77	88	793	1,789	2,002	540	7	154	–	–	5,497
1977	54	3	95	112	976	2,142	2,488	659	9	186	1	2	6,727
1978	65	4	114	140	1,160	2,506	3,009	777	11	217	1	5	8,009
1979	76	5	133	171	1,340	2,867	3,554	893	13	249	2	7	9,311
1980	87	7	153	204	1,519	3,195	4,087	1,014	16	282	3	16	10,581
1981	99	8	174	240	1,699	3,498	4,606	1,140	18	316	4	44	11,846
1982	110	11	196	278	1,877	3,784	5,115	1,268	21	351	7	110	13,129
1983	122	14	218	318	2,048	4,037	5,580	1,394	25	387	10	180	14,332
1984	134	18	239	360	2,198	4,258	5,982	1,513	29	422	14	260	15,426
1985	145	22	260	402	2,322	4,427	6,289	1,622	32	455	19	348	16,344

Note: Totals may not agree due to rounding.

TABLE 413

PROJECTED NON-ASSOCIATED GAS-MARKETED PRODUCTION FROM POST-1970 RESERVES
LOWER 48 STATES
(BCF)

Case 1A

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	–	–	–	–	–	–	–	–	–	–	–	–	–
1972	6	–	14	12	61	137	170	46	1	17	–	–	463
1973	17	1	33	28	189	408	517	139	3	51	–	–	1,386
1974	28	1	53	46	316	649	846	226	4	82	–	–	2,252
1975	39	2	76	66	440	861	1,156	306	6	112	–	–	3,064
1976	50	3	100	89	562	1,042	1,449	379	8	142	–	–	3,824
1977	62	4	127	114	697	1,222	1,758	455	9	171	1	2	4,621
1978	75	5	154	144	836	1,401	2,082	526	11	200	2	3	5,440
1979	90	7	193	177	977	1,568	2,414	593	12	229	2	5	6,269
1980	106	8	237	214	1,120	1,707	2,729	658	14	259	4	11	7,067
1981	123	10	283	256	1,262	1,822	3,033	721	16	291	6	29	7,852
1982	141	13	328	303	1,406	1,918	3,334	781	18	323	8	74	8,647
1983	161	17	373	353	1,547	1,990	3,620	835	20	357	11	120	9,403
1984	181	21	415	408	1,679	2,042	3,887	880	21	390	14	173	10,110
1985	198	24	452	468	1,797	2,065	4,116	916	23	421	18	232	10,731

Note: Totals may not agree due to rounding.

TABLE 414

PROJECTED NON-ASSOCIATED GAS-MARKETED PRODUCTION FROM POST-1970 RESERVES
LOWER 48 STATES
(BCF)

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	–	–	–	–	–	–	–	–	–	–	–	–	–
1972	5	–	11	12	87	219	214	62	1	19	–	–	630
1973	15	1	26	28	267	654	655	188	2	54	–	–	1,891
1974	25	1	41	45	437	1,045	1,081	304	4	87	–	–	3,070
1975	34	2	56	63	597	1,391	1,491	411	5	117	–	–	4,169
1976	42	2	72	83	748	1,693	1,884	509	7	145	–	–	5,185
1977	50	3	89	104	905	1,996	2,300	611	8	172	1	2	6,241
1978	59	4	104	127	1,056	2,302	2,737	709	10	198	1	4	7,310
1979	68	5	119	151	1,199	2,596	3,181	800	12	222	2	7	8,361
1980	76	6	135	177	1,336	2,849	3,600	891	13	246	2	14	9,345
1981	85	7	150	203	1,469	3,071	3,997	982	15	271	3	36	10,290
1982	93	9	165	231	1,598	3,270	4,379	1,071	17	295	5	90	11,222
1983	101	11	180	258	1,719	3,436	4,727	1,156	19	318	7	143	12,077
1984	108	13	195	286	1,827	3,580	5,041	1,234	22	341	10	203	12,859
1985	115	16	209	315	1,921	3,687	5,298	1,306	24	362	13	268	13,532

Note: Totals may not agree due to rounding.

TABLE 415

PROJECTED NON-ASSOCIATED GAS-MARKETED PRODUCTION FROM POST-1970 RESERVES
LOWER 48 STATES
(BCF)

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	–	–	–	–	–	–	–	–	–	–	–	–	–
1972	6	–	14	12	61	137	170	46	1	17	–	–	463
1973	17	1	32	28	188	404	512	138	3	50	–	–	1,373
1974	27	1	52	45	308	635	826	221	4	80	–	–	2,199
1975	38	2	73	63	421	831	1,112	294	6	108	–	–	2,947
1976	47	2	94	84	529	992	1,371	359	7	134	–	–	3,619
1977	57	3	117	105	644	1,149	1,638	425	9	158	1	1	4,307
1978	68	5	140	130	758	1,302	1,912	485	10	182	1	3	4,995
1979	80	6	172	156	869	1,442	2,185	538	11	204	2	4	5,669
1980	91	7	207	184	978	1,553	2,433	588	12	227	3	9	6,293
1981	103	8	242	214	1,085	1,640	2,662	636	14	249	5	24	6,882
1982	116	10	277	246	1,188	1,708	2,881	679	15	271	6	60	7,458
1983	128	13	310	279	1,287	1,758	3,083	716	16	293	8	96	7,986
1984	141	15	341	315	1,378	1,790	3,271	748	17	314	11	135	8,477
1985	154	18	369	352	1,461	1,803	3,434	774	18	334	13	178	8,908

Note: Totals may not agree due to rounding.

TABLE 416

PROJECTED NON-ASSOCIATED GAS-MARKETED PRODUCTION FROM POST-1970 RESERVES LOWER 48 STATES (BCF)

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	–	–	–	–	–	–	–	–	–	–	–	–	–
1972	5	–	13	11	61	135	168	45	1	17	–	–	457
1973	16	1	31	27	181	392	496	134	3	48	–	–	1,328
1974	26	1	48	42	288	599	775	207	4	75	–	–	2,065
1975	34	2	65	57	380	760	1,009	268	5	97	–	–	2,676
1976	41	2	82	72	458	879	1,199	315	6	116	–	–	3,170
1977	47	3	97	87	534	987	1,382	360	7	132	1	1	3,637
1978	54	3	111	102	599	1,086	1,555	396	8	145	1	2	4,061
1979	60	4	122	115	652	1,168	1,709	422	8	155	1	3	4,421
1980	65	5	133	128	695	1,217	1,824	442	9	163	2	6	4,688
1981	69	5	147	139	731	1,240	1,906	457	9	169	3	15	4,890
1982	72	6	161	149	759	1,246	1,967	466	9	174	3	34	5,046
1983	74	7	173	158	783	1,236	2,006	471	10	178	4	51	5,151
1984	76	7	183	166	800	1,220	2,036	472	10	180	5	68	5,223
1985	78	8	192	173	811	1,193	2,048	471	10	182	6	85	5,256

Note: Totals may not agree due to rounding.

TABLE 417

PROJECTED NON-ASSOCIATED GAS-MARKETED PRODUCTION FROM POST-1970 RESERVES
LOWER 48 STATES
(BCF)

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	–	–	–	–	–	–	–	–	–	–	–	–	–
1972	5	–	11	12	86	216	211	61	1	18	–	–	621
1973	15	1	25	27	258	633	632	182	2	53	–	–	1,827
1974	23	1	38	42	409	981	1,010	285	4	81	–	–	2,875
1975	30	1	51	57	539	1,263	1,343	372	5	106	–	–	3,767
1976	36	2	63	72	648	1,481	1,628	443	6	126	–	–	4,506
1977	42	2	74	86	754	1,685	1,906	512	7	143	–	2	5,213
1978	47	3	84	101	842	1,874	2,175	568	8	157	1	3	5,863
1979	52	3	92	114	913	2,036	2,421	612	8	168	1	5	6,425
1980	56	4	99	125	968	2,145	2,616	648	9	177	1	9	6,857
1981	59	4	104	136	1,011	2,211	2,766	676	10	184	2	23	7,185
1982	61	5	109	145	1,044	2,247	2,885	697	10	189	3	51	7,444
1983	62	6	112	152	1,069	2,254	2,974	712	10	193	3	76	7,624
1984	63	6	115	159	1,085	2,248	3,044	721	11	196	4	102	7,754
1985	64	7	117	165	1,095	2,220	3,087	726	11	198	5	128	7,823

Note: Totals may not agree due to rounding.

TABLE 418

PROJECTED TOTAL MARKETED GAS PRODUCTION—NON-ASSOCIATED AND ASSOCIATED DISSOLVED—LOWER 48 STATES (BCF)

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	495	35	664	447	2,653	8,324	3,127	3,799	48	380	1	–	19,972
1972	487	33	674	448	2,656	8,483	3,333	3,823	48	369	1	–	20,356
1973	486	32	689	458	2,648	8,874	3,762	3,662	48	378	1	–	21,038
1974	451	36	704	471	2,675	9,072	4,153	3,569	49	390	1	–	21,570
1975	420	45	711	484	2,702	8,994	4,460	3,471	50	400	2	–	21,739
1976	396	59	710	497	2,712	8,808	4,735	3,334	51	413	3	1	21,720
1977	376	78	662	492	2,745	8,665	5,042	3,204	55	425	4	4	21,754
1978	359	100	624	496	2,782	8,534	5,384	3,076	59	442	6	7	21,869
1979	347	124	596	509	2,818	8,400	5,748	2,947	63	455	8	10	22,025
1980	335	148	577	530	2,872	8,313	6,131	2,859	68	476	11	21	22,341
1981	328	171	560	554	2,944	8,114	6,467	2,814	73	498	15	50	22,590
1982	317	195	553	588	3,020	8,084	6,849	2,769	79	519	19	119	23,109
1983	310	218	546	624	3,088	8,092	7,213	2,723	84	540	25	198	23,661
1984	300	242	539	663	3,136	7,981	7,476	2,671	89	556	32	286	23,970
1985	292	265	540	707	3,174	7,811	7,641	2,646	94	570	40	390	24,170

Note: Totals may not agree due to rounding.

TABLE 419

PROJECTED TOTAL MARKETED GAS PRODUCTION–NON-ASSOCIATED AND ASSOCIATED DISSOLVED–LOWER 48 STATES (BCF)

Case IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	495	35	664	447	2,653	8,324	3,127	3,799	48	380	1	–	19,972
1972	488	33	676	448	2,630	8,400	3,272	3,805	48	367	1	–	20,168
1973	488	32	694	456	2,568	8,619	3,571	3,606	48	374	1	–	20,456
1974	454	35	714	467	2,542	8,643	3,806	3,473	47	383	1	–	20,566
1975	425	43	726	477	2,518	8,389	3,944	3,335	47	390	2	–	20,297
1976	402	55	731	486	2,481	8,026	4,044	3,158	48	400	3	1	19,834
1977	384	69	690	477	2,466	7,688	4,167	2,983	49	410	4	3	19,389
1978	369	84	660	477	2,457	7,349	4,310	2,806	51	424	5	5	18,998
1979	361	100	651	487	2,452	7,000	4,459	2,627	52	435	7	8	18,638
1980	353	117	657	505	2,466	6,706	4,624	2,484	53	453	10	15	18,444
1981	351	134	664	529	2,496	6,306	4,745	2,377	54	473	12	35	18,178
1982	346	151	680	563	2,532	6,075	4,924	2,265	58	491	16	81	18,183
1983	348	169	696	602	2,566	5,899	5,114	2,149	60	509	20	135	18,266
1984	345	187	709	646	2,591	5,616	5,249	2,026	62	523	25	195	18,174
1985	343	205	727	699	2,618	5,303	5,345	1,931	65	535	31	266	18,067

Note: Totals may not agree due to rounding.

TABLE 420

PROJECTED TOTAL MARKETED GAS PRODUCTION—NON-ASSOCIATED AND ASSOCIATED DISSOLVED—LOWER 48 STATES (BCF)

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	495	35	664	447	2,653	8,324	3,127	3,799	48	380	1	–	19,972
1972	487	33	674	448	2,656	8,483	3,333	3,823	48	369	1	–	20,356
1973	486	32	688	458	2,645	8,867	3,753	3,660	48	378	1	–	21,016
1974	450	36	703	470	2,663	9,044	4,121	3,560	48	387	1	–	21,484
1975	419	44	709	481	2,675	8,934	4,388	3,452	49	395	2	–	21,548
1976	394	57	706	491	2,665	8,704	4,605	3,302	51	404	3	1	21,382
1977	372	73	655	481	2,672	8,506	4,838	3,154	53	412	4	3	21,225
1978	352	92	614	479	2,676	8,312	5,089	3,004	57	422	6	6	21,108
1979	338	112	581	485	2,673	8,105	5,344	2,849	59	428	7	9	20,992
1980	323	132	558	496	2,683	7,938	5,607	2,731	64	440	10	18	20,998
1981	313	150	535	509	2,706	7,652	5,814	2,651	67	453	13	42	20,904
1982	298	168	522	529	2,730	7,529	6,065	2,566	70	462	16	96	21,052
1983	287	186	508	549	2,746	7.449	6,312	2,479	75	471	20	156	21,238
1984	273	203	493	571	2,751	7,256	6,489	2,387	77	474	25	222	21,221
1985	260	220	488	598	2,756	7,022	6,606	2,325	81	477	31	297	21,161

Note: Totals may not agree due to rounding.

TABLE 421

PROJECTED TOTAL MARKETED GAS PRODUCTION–NON-ASSOCIATED AND ASSOCIATED DISSOLVED–LOWER 48 STATES (BCF)

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	495	35	664	447	2,653	8,324	3,127	3,799	48	380	1	–	19,972
1972	488	33	676	448	2,630	8,400	3,272	3,805	48	367	1	–	20,168
1973	487	32	694	456	2,566	8,615	3,565	3,604	48	373	1	–	20,441
1974	453	35	712	466	2,534	8,627	3,784	3,467	47	381	1	–	20,507
1975	423	42	723	474	2,499	8,357	3,896	3,323	47	385	2	–	20,170
1976	399	53	725	480	2,447	7,971	3,958	3,137	47	392	3	1	19,613
1977	379	65	680	467	2,411	7,608	4,035	2,951	48	398	4	3	19,048
1978	362	78	645	462	2,376	7,241	4,122	2,762	49	406	5	5	18,514
1979	350	92	629	464	2,341	6,861	4,207	2,569	50	410	6	7	17,984
1980	338	105	626	472	2,321	6,536	4,299	2,410	51	421	8	13	17,600
1981	331	118	623	483	2,315	6,103	4,340	2,287	52	432	11	29	17,124
1982	320	131	628	502	2,310	5,842	4,433	2,158	54	439	13	66	16,896
1983	314	144	632	523	2,301	5,638	4,537	2,026	55	445	17	107	16,739
1984	304	157	634	546	2,285	5,334	4,594	1,890	56	447	20	152	16,419
1985	297	170	643	575	2,276	5,007	4,624	1,785	57	448	24	203	16,109

Note: Totals may not agree due to rounding.

TABLE 422

PROJECTED TOTAL MARKETED GAS PRODUCTION—NON-ASSOCIATED AND ASSOCIATED DISSOLVED—LOWER 48 STATES
(BCF)

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	495	35	664	447	2,653	8,324	3,127	3,799	48	380	1	—	19,972
1972	488	33	676	448	2,629	8,398	3,269	3,805	48	367	1	—	20,162
1973	487	32	693	454	2,559	8,600	3,546	3,599	47	372	1	—	20,390
1974	451	34	709	462	2,512	8,586	3,726	3,452	47	375	1	—	20,355
1975	419	39	715	466	2,455	8,277	3,776	3,293	46	375	2	—	19,862
1976	392	46	711	466	2,371	7,843	3,758	3,088	45	375	2	1	19,099
1977	368	55	660	446	2,295	7,426	3,737	2,880	46	371	3	2	18,287
1978	346	61	615	430	2,210	6,998	3,709	2,666	46	369	4	4	17,457
1979	328	69	579	418	2,115	6,553	3,663	2,445	45	360	5	5	16,584
1980	309	75	550	409	2,027	6,159	3,610	2,256	45	357	6	9	15,812
1981	294	81	525	399	1,949	5,656	3,493	2,099	45	352	7	18	14,917
1982	273	86	510	395	1,868	5,324	3,417	1,937	45	341	8	37	14,240
1983	257	90	493	389	1,783	5,056	3,351	1,772	44	330	9	56	13,630
1984	236	94	474	382	1,691	4,697	3,245	1,606	44	313	10	75	12,866
1985	217	97	463	379	1,611	4,323	3,122	1,475	43	296	12	94	12,133

Note: Totals may not agree due to rounding.

TABLE 423

PROJECTED TOTAL MARKETED GAS PRODUCTION—NON-ASSOCIATED AND ASSOCIATED DISSOLVED—LOWER 48 STATES (BCF)

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	495	35	664	447	2,653	8,324	3,127	3,799	48	380	1	–	19,972
1972	487	33	674	448	2,655	8,480	3,330	3,822	48	368	1	–	20,347
1973	485	32	687	456	2,636	8,844	3,726	3,652	48	376	1	–	20,943
1974	449	35	700	465	2,634	8,974	4,035	3,538	47	382	1	–	21,260
1975	415	40	703	472	2,614	8,792	4,210	3,408	47	383	2	–	21,087
1976	387	49	695	474	2,561	8,467	4,303	3,228	48	385	2	1	20,603
1977	362	60	640	456	2,515	8,155	4,385	3,044	49	383	3	3	20,056
1978	339	70	592	442	2,454	7,828	4,454	2,851	51	382	4	5	19,471
1979	320	80	552	433	2,376	7,474	4,497	2,647	51	374	5	7	18,816
1980	300	90	520	426	2,301	7,149	4,519	2,473	52	371	7	12	18,220
1981	284	99	487	418	2,231	6,696	4,464	2,330	53	367	8	26	17,461
1982	262	106	462	415	2,155	6,399	4,442	2,177	54	357	9	54	16,892
1983	245	113	437	410	2,072	6,152	4,419	2,021	55	345	11	82	16,361
1984	223	118	410	404	1,980	5,803	4,348	1,861	56	329	12	110	15,655
1985	203	123	392	403	1,899	5,430	4,251	1,735	56	312	14	138	14,957

Note: Totals may not agree due to rounding.

TABLE 424

PROJECTED MARKETED GAS PRODUCTION FROM PRE-1971 RESERVES—NON-ASSOCIATED AND ASSOCIATED DISSOLVED—LOWER 48 STATES (BCF)

All Cases

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	495	35	664	447	2,653	8,325	3,127	3,799	48	380	1	—	19,972
1972	482	30	661	433	2,558	8,237	3,034	3,740	45	350	1	—	19,571
1973	469	27	659	421	2,359	8,159	2,955	3,436	41	323	1	—	18,850
1974	422	24	658	411	2,200	7,919	2,828	3,211	39	301	1	—	18,013
1975	381	22	647	397	2,047	7,436	2,620	2,991	35	278	1	—	16,854
1976	347	20	627	380	1,884	6,874	2,390	2,740	33	259	1	—	15,553
1977	315	19	559	342	1,725	6,338	2,170	2,488	31	240	1	—	14,228
1978	286	17	500	309	1,571	5,805	1,955	2,240	30	224	—	—	12,939
1979	262	16	452	281	1,420	5,275	1,746	1,995	28	205	—	—	11,681
1980	238	14	413	258	1,289	4,830	1,571	1,789	27	194	—	—	10,625
1981	218	13	375	237	1,177	4,302	1,369	1,622	26	183	—	—	9,520
1982	194	13	344	220	1,066	3,964	1,233	1,453	25	167	—	—	8,679
1983	175	12	315	203	958	3,707	1,129	1,286	23	152	—	—	7,964
1984	152	12	286	188	852	3,367	997	1,122	23	133	—	—	7,132
1985	133	11	266	177	763	3,024	867	995	22	114	—	—	6,372

Note: Totals may not agree due to rounding.

TABLE 425

PROJECTED TOTAL MARKETED GAS PRODUCTION FROM POST-1970 RESERVES NON-ASSOCIATED AND ASSOCIATED DISSOLVED—LOWER 48 STATES (BCF)

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	—	—	—	—	—	—	—	—	—	—	—	—	—
1972	6	2	12	15	98	246	300	83	3	19	—	—	785
1973	17	5	29	37	290	716	806	226	6	55	—	—	2,188
1974	28	11	46	61	475	1,152	1,326	358	10	89	—	—	3,557
1975	39	23	65	87	655	1,558	1,841	480	14	122	1	—	4,885
1976	49	40	84	117	828	1,934	2,344	596	18	154	2	1	6,167
1977	60	58	103	150	1,020	2,326	2,872	717	24	186	4	3	7,524
1978	73	83	124	187	1,212	2,728	3,428	836	29	217	6	7	8,930
1979	85	108	144	228	1,399	3,125	4,001	952	35	249	8	10	10,344
1980	97	134	164	272	1,583	3,483	4,561	1,070	41	282	11	21	11,717
1981	110	157	186	318	1,768	3,812	5,097	1,193	47	316	14	51	13,068
1982	122	182	209	368	1,953	4,120	5,616	1,317	53	351	19	118	14,429
1983	135	206	232	421	2,130	4,385	6,084	1,437	60	387	25	197	15,697
1984	148	230	253	476	2,285	4,614	6,478	1,549	67	422	32	287	16,839
1985	159	253	275	531	2,411	4,786	6,774	1,651	71	455	41	390	17,798

Note: Totals may not agree due to rounding.

TABLE 426

PROJECTED TOTAL MARKETED GAS PRODUCTION FROM POST-1970 RESERVES
NON-ASSOCIATED AND ASSOCIATED DISSOLVED—LOWER 48 STATES
(BCF)

Case IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	–	–	–	–	–	–	–	–	–	–	–	–	–
1972	7	2	15	15	72	164	237	66	3	17	–	–	597
1973	19	5	35	35	209	461	616	169	6	51	–	–	1,607
1974	31	10	56	56	343	723	979	262	9	82	–	–	2,554
1975	43	21	79	80	472	954	1,324	345	12	112	1	–	3,444
1976	55	35	104	106	597	1,152	1,653	419	15	142	2	1	4,281
1977	68	50	132	135	741	1,349	1,997	495	18	171	3	3	5,161
1978	83	67	159	169	886	1,543	2,354	566	21	200	5	5	6,059
1979	99	85	199	206	1,031	1,724	2,713	631	23	229	6	8	6,957
1980	115	102	243	246	1,177	1,876	3,054	695	27	259	9	16	7,819
1981	133	120	290	292	1,320	2,003	3,376	755	30	291	13	35	8,658
1982	152	139	335	344	1,466	2,111	3,690	812	33	323	16	82	9,503
1983	172	157	381	398	1,608	2,191	3,985	863	37	357	20	135	10,303
1984	193	176	423	458	1,739	2,250	4,251	904	39	390	25	195	11,043
1985	210	193	461	523	1,855	2,279	4,478	935	42	421	31	266	11,694

Note: Totals may not agree due to rounding.

TABLE 427

PROJECTED TOTAL MARKETED GAS PRODUCTION FROM POST-1970 RESERVES NON-ASSOCIATED AND ASSOCIATED DISSOLVED—LOWER 48 STATES (BCF)

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	—	—	—	—	—	—	—	—	—	—	—	—	—
1972	6	2	12	15	98	246	300	83	3	19	—	—	785
1973	17	5	29	36	287	709	799	223	6	54	—	—	2,166
1974	28	11	45	59	464	1,125	1,293	349	10	87	—	—	3,471
1975	38	22	62	83	628	1,498	1,768	461	13	117	1	—	4,695
1976	47	38	79	110	782	1,831	2,214	562	18	145	2	1	5,828
1977	56	54	97	139	947	2,167	2,668	666	22	172	4	3	6,996
1978	66	76	113	171	1,105	2,506	3,134	764	27	198	5	6	8,169
1979	76	97	129	203	1,253	2,830	3,598	854	32	222	7	10	9,311
1980	85	117	146	237	1,394	3,108	4,036	942	36	246	9	18	10,375
1981	95	137	161	272	1,530	3,350	4,444	1,029	41	271	12	41	11,383
1982	103	156	177	309	1,664	3,566	4,832	1,114	46	295	15	97	12,372
1983	112	174	193	346	1,788	3,740	5,182	1,193	50	318	20	156	13,274
1984	120	191	208	383	1,899	3,890	5,491	1,265	56	341	25	223	14,090
1985	127	208	223	422	1,993	3,999	5,739	1,331	60	362	30	298	14,789

Note: Totals may not agree due to rounding

TABLE 428

PROJECTED TOTAL MARKETED GAS PRODUCTION FROM POST-1970 RESERVES
NON-ASSOCIATED AND ASSOCIATED DISSOLVED–LOWER 48 STATES
(BCF)

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	–	–	–	–	–	–	–	–	–	–	–	–	–
1972	7	2	15	15	72	164	237	66	3	17	–	–	597
1973	19	5	34	35	208	456	610	168	6	50	–	–	1,591
1974	30	10	55	55	335	708	957	256	8	80	–	–	2,496
1975	42	20	76	77	452	922	1,276	332	12	108	1	–	3,317
1976	52	33	98	100	563	1,098	1,568	397	14	134	2	1	4,059
1977	63	46	122	125	686	1,270	1,864	463	17	158	3	2	4,820
1978	75	62	145	153	806	1,435	2,166	522	20	182	4	5	5,575
1979	88	77	177	183	921	1,586	2,461	573	22	204	6	7	6,304
1980	100	91	213	214	1,031	1,707	2,728	621	24	227	8	13	6,976
1981	112	104	248	246	1,139	1,802	2,971	666	27	249	11	29	7,604
1982	126	118	284	282	1,243	1,878	3,199	706	29	271	13	66	8,216
1983	138	132	317	319	1,343	1,930	3,408	740	31	293	16	108	8,775
1984	151	145	348	358	1,432	1,968	3,597	768	33	314	20	152	9,288
1985	164	159	377	399	1,513	1,983	3,757	790	35	334	24	202	9,736

Note: Totals may not agree due to rounding.

TABLE 429

PROJECTED TOTAL MARKETED GAS PRODUCTION FROM POST-1970 RESERVES NON-ASSOCIATED AND ASSOCIATED DISSOLVED—LOWER 48 STATES (BCF)

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	–	–	–	–	–	–	–	–	–	–	–	–	–
1972	6	2	14	14	72	162	235	65	3	17	–	–	591
1973	18	5	33	34	200	442	592	163	6	48	–	–	1,540
1974	29	9	51	52	313	667	898	240	8	75	–	–	2,343
1975	38	18	68	69	408	841	1,156	302	10	97	1	–	3,008
1976	45	27	85	86	488	970	1,367	349	12	116	1	1	3,546
1977	52	36	101	104	571	1,087	1,567	392	14	132	3	2	4,059
1978	60	44	115	121	640	1,192	1,753	426	16	145	3	3	4,517
1979	66	53	126	136	695	1,278	1,917	449	17	155	4	5	4,903
1980	72	61	138	150	738	1,330	2,039	466	18	163	5	8	5,188
1981	76	67	152	162	773	1,354	2,123	478	18	169	7	18	5,397
1982	79	73	166	174	802	1,360	2,184	484	19	174	7	37	5,561
1983	81	78	178	185	825	1,348	2,222	486	21	178	9	56	5,667
1984	83	81	188	194	840	1,330	2,248	484	21	180	10	75	5,734
1985	85	85	197	202	848	1,300	2,255	480	21	182	12	94	5,761

Note: Totals may not agree due to rounding.

TABLE 430

PROJECTED TOTAL MARKETED GAS PRODUCTION FROM POST-1970 RESERVES
NON-ASSOCIATED AND ASSOCIATED DISSOLVED—LOWER 48 STATES
(BCF)

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	—	—	—	—	—	—	—	—	—	—	—	—	—
1972	6	2	12	15	97	243	297	82	3	18	—	—	776
1973	17	5	28	35	277	686	771	216	6	53	—	—	2,093
1974	26	10	42	55	434	1,055	1,208	327	9	81	—	—	3,248
1975	34	18	56	75	567	1,356	1,590	417	12	106	1	—	4,232
1976	40	30	69	94	678	1,593	1,913	489	15	126	2	1	5,050
1977	47	40	81	114	791	1,817	2,215	557	18	143	2	3	5,827
1978	53	53	91	134	883	2,022	2,499	611	21	157	4	4	6,532
1979	58	65	100	152	957	2,199	2,751	652	23	168	5	7	7,134
1980	63	76	107	167	1,012	2,319	2,948	684	25	177	6	11	7,597
1981	66	85	113	182	1,055	2,394	3,094	708	28	184	8	26	7,941
1982	68	94	118	195	1,089	2,436	3,208	725	29	189	9	55	8,212
1983	69	101	121	206	1,114	2,444	3,290	735	31	193	10	82	8,397
1984	70	106	125	217	1,128	2,437	3,350	740	33	196	12	110	8,524
1985	71	112	127	226	1,136	2,406	3,384	740	34	198	14	139	8,585

Note: Totals may not agree due to rounding.

Chapter Six—Section VII

Natural Gas Liquids—Reserves and Production

TABLE 431

NATURAL GAS LIQUIDS—HISTORICAL DATA
UNITED STATES
(MMB)

	Reserve Additions*	Production†	Remaining Reserve‡
1946	—	129.3	316.3
1947	251.5	160.8	325.4
1948	470.6	183.7	354.1
1949	386.8	198.5	372.9
1950	766.1	227.4	426.8
1951	724.0	267.1	472.5
1952	556.8	284.8	499.7
1953	744.0	302.7	543.8
1954	107.4	300.8	524.4
1955	514.5	320.4	543.9
1956	809.8	346.1	590.2
1957	137.4	352.4	568.7
1958	858.2	341.5	620.4
1959	703.4	385.2	652.2
1960	725.1	431.4	681.6
1961	694.7	461.6	704.9
1962	732.5	470.1	731.2
1963	878.1	515.7	767.4
1964	608.7	536.1	774.7
1965	832.3	555.4	802.4
1966	894.1	588.7	832.9
1967	929.8	644.5	861.4
1968	685.7	701.8	859.8
1969	281.0	736.0	814.3
1970	307.6	747.8	770.3

* *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity,* Part II, Report of the Committee on Natural Gas Reserves of the American Gas Association, Table X (May 1973).

† Ibid.

‡ Ibid., Table XIII-1.

Natural Gas Liquids—Non-Associated Gas

Using December 31, 1969 natural gas and natural gas liquids (NGL) reserves, liquid reserve ratios were calculated for each NPC region. These values were multiplied by gas reserve additions to develop NGL reserve additions by years by regions.

Production ratios were calculated, using 1969 production of NGL and natural gas. For each region where the reserve ratio differed from the production ratio, the production ratio was adjusted over a period of years to make liquids production conform to liquids reserves. Table 432 shows the production ratios used by year and by region.

Recent history indicates about 29 percent of total NGL from non-associated gas is condensate. This percentage was held constant for all projections. The split of plant liquids between LPG and pentanes and heavier was based on 1969 experience.

Total natural gas liquids production from both non-associated and associated-disolved gas is shown in Tables 261 through 266 in Section VI of Chapter Five.

TABLE 432

NON-ASSOCIATED NATURAL GAS LIQUIDS (BARREL/MMCF)

NPC Region	2	2A	3	4	5	6	6A	7	8&9	10
Reserve Additions	2.5	2.5	28.5	12.3	20.8	29.7	24.4	23.1	13.7	32.4
Production:										
1971	4.5	4.5	24.0	22.4	34.3	36.4	23.6	23.1	20.5	22.1
1972	3.5	3.5	26.0	15.0	29.0	34.0	24.0	23.1	15.0	27.0
1973	2.5	2.5	28.5	10.0	23.0	30.0	24.4	23.1	10.0	32.0
1974	2.0	2.0	30.0	9.8	17.3	27.0	24.8	23.1	11.0	37.4
1975	1.5	1.5	32.0	8.0	15.0	26.0	24.9	23.1	11.0	40.0
1976	1.7	1.5	31.0	8.6	10.0	26.0	24.8	23.1	12.3	38.0
1977	1.8	1.5	28.5	12.0	10.0	27.5	24.4	23.1	13.7	36.6
1978	1.8	1.5	28.5	12.3	20.0	29.0	24.4	23.1	13.7	32.4
1979	1.9	1.7	28.5	12.3	20.8	29.7	24.4	23.1	13.7	32.4
1980	2.1	1.9	28.5	12.3	20.8	29.7	24.4	23.1	13.7	32.4
1981	2.3	2.5	28.5	12.3	20.8	29.7	24.4	23.1	13.7	32.4
1982	2.5	2.5	28.5	12.3	20.8	29.7	24.4	23.1	13.7	32.4
1983	2.5	2.5	28.5	12.3	20.8	29.7	24.4	23.1	13.7	32.4
1984	2.5	2.5	28.5	12.3	20.8	29.7	24.4	23.1	13.7	32.4
1985	2.5	2.5	28.5	12.3	20.8	29.7	24.4	23.1	13.7	32.4
Fraction C_5+	.43	.43	.25	.27	.24	.38	.38	.25	.37	.14

Associated and Dissolved Natural Gas Liquids (Barrels/MMCF)

NPC Region	2	2A	3	4	5	6	6A	7	8&9	10
Reserve Additions	46.8	46.8	75.8	78.4	78.8	34.8	20.0	37.6	0	8.6
Production:										
1971	52.6	52.6	65.2	45.9	83.9	49.5	12.3	38.2	36.6	0.4
1972	50.0	50.0	68.0	56.0	81.0	45.0	15.0	37.6	36.6	0.4
1973	48.0	48.0	72.0	70.0	78.8	40.0	20.0	37.0	36.6	0.4
1974	46.0	46.0	76.0	80.0	76.0	35.0	25.0	37.6	36.6	0.4
1975	44.0	44.0	80.0	90.0	76.0	30.0	25.0	37.6	36.6	0.4
1976	42.0	42.0	84.0	95.0	76.0	26.0	23.9	37.6	36.6	0.4
1977	42.0	42.0	84.0	90.0	77.0	26.0	20.0	37.6	36.6	0.4
1978	44.0	44.0	80.0	90.0	78.8	26.0	20.0	37.6	36.6	0.4
1979	44.0	44.0	80.0	90.0	78.8	29.0	20.0	37.6	36.6	0.4
1980	44.0	44.0	75.8	85.0	78.8	32.4	20.0	37.6	36.6	0.4
1981	46.8	44.0	75.8	78.4	78.8	34.8	20.0	37.6	36.6	0.4
1982	46.8	44.0	75.8	78.4	78.8	34.8	20.0	37.6	36.6	0.4
1983	46.8	44.0	75.8	78.4	78.8	34.8	20.0	37.6	36.6	0.4
1984	46.8	44.0	75.8	78.4	78.8	34.8	20.0	37.6	36.6	0.4
1985	46.8	44.0	75.8	78.4	78.8	34.8	20.0	37.6	36.6	0.4
Fraction C_5+	.43	.43	.25	.27	.24	.38	.38	.25	.37	.14

TABLE 433
NATURAL GAS LIQUID PRODUCTION FROM NATURAL GAS PROCESSING PLANTS
UNITED STATES–1969

NPC Region	State and PAD District		Percent or Segment of State	1,000 Barrels Ethane	Propane	Butanes	Pentanes & Heavier	Total
1	Alaska-Hawaii		–	–	–	–	–	–
2	California-Washington	V	100*	–	6,973	5,186	9,096	21,255
				0	33%	24%	43%	100%
3	Colorado (W)	IV	45†	–	488	392	407	1,286
	New Mexico (NW)	III	53†	1,003	6,856	5,816	4,330	18,006
	Utah (Cent.)	IV	79‡	–	951	762	495	2,208
	Wyoming (SW)	IV	13†	–	369	254	281	904
	Subtotal			1,003	8,664	7,224	5,513	22,404
				4%	39%	32%	25%	100%
4	Montana-Utah (NE)	IV	21‡	–	253	203	131	587
	Nebraska (W)	II	100	–	250	178	108	536
	N. Dakota	II	100	–	1,192	840	427	2,459
	Wyoming (Cent.)	IV	87†	–	2,466	1,697	1,884	6,047
	Colorado (NW & E)	IV	55†	–	596	478	497	1,572
	Subtotal			–	4,757	3,396	3,047	11,201
				0	43%	30%	27%	100%
5	Texas (W)	III	100	7,669	41,229	22,454	23,428	94,780
	New Mexico (SE)	III	47†	890	6,080	5,158	3,840	15,967
	Subtotal			8,559	47,309	27,612	27,268	110,747
				8%	43%	25%	24%	100%
6	Arkansas (S)	III	43†	–	342	232	273	848
	Alabama-Mississippi	III	100	–	344	345	575	1,254
	Louisiana	III	100	18,034	31,653	25,807	49,938	125,432
	Texas Gulf	III	100	12,647	16,621	11,199	19,634	60,101
	East	III	100	122	2,824	1,954	1,488	6,388
	Other	III	100	12,416	25,311	18,529	34,631	90,887
	Subtotal			43,219	77,095	58,066	106,539	284,910
				15%	27%	20%	38%	100%
7	Arkansas (N)	III	57†	–	454	307	363	1,123
	Kansas	II	100	–	12,613	7,729	4,087	24,429
	Oklahoma (Cent.)	II	100	452	17,736	11,251	12,484	41,925
	Texas (Panhandle)	III	100	937	14,542	13,512	10,087	39,078
	Subtotal			1,389	45,345	32,799	27,021	106,555
				1%	43%	31%	25%	100%
8	Michigan	II	100	–	771	571	776	2,118
				0	36%	27%	37%	100%
9	Illinois-Kentucky (W)	II	14§	1,137	571	181	102	1,992
				57%	29%	9%	5%	100%
10	Pennsylvania	I	100	–	25	10	22	57
	West Virginia	I	100‖	734	2,684	1,376	1,973	6,767
	Kentucky (E)	II	86§	6,984	3,511	1,113	628	12,235
	Subtotal			7,718	6,220	2,499	2,623	19,059
				40%	33%	13%	14%	100%
11	Atlantic Coast	I	–	–	–	–	–	–
	Total USA		–	63,025	197,705	137,534	181,985	580,241
				11%	34%	24%	31%	100%

* Assumes all of PAD District V gas processing is in California and Washington.

† Divided on basis of gas liquid reserves for each segment of state.

‡ Percent of combined Utah and Montana gas liquid reserves.

§ Percent of combined Illinois and Kentucky gas liquid reserves.

‖ 100 percent of liquids assigned to Georgia, Florida and West Virginia are in West Virginia.

Source: U.S. Bureau of Mines, "Crude Petroleum, Petroleum Products, and Natural Gas Liquids: 1969 (Final Summary)," Mineral Industry Surveys (Annual Petroleum Statement, published December 15, 1970), p. 29.

TABLE 434

PROJECTED ADDITIONS NON-ASSOCIATED CONDENSATE RESERVES—LOWER 48 STATES
(MMB)

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.08	–	1.95	.90	11.28	40.29	32.39	8.92	.07	3.74	–	–	99.63
1972	.08	–	2.00	.97	12.22	41.15	35.34	9.39	.08	3.93	–	–	105.16
1973	.09	–	2.11	1.04	13.12	42.38	38.90	9.86	.08	4.15	–	–	111.74
1974	.09	–	2.28	1.14	14.11	43.34	42.36	10.46	.09	4.40	.02	.38	118.67
1975	.10	–	2.43	1.31	15.18	44.44	46.46	11.14	.10	4.69	.02	.41	126.28
1976	.11	.01	2.60	1.45	16.33	45.92	50.30	11.84	.12	5.02	.04	.43	134.16
1977	.11	.01	2.79	1.78	17.39	47.18	54.21	12.63	.13	5.35	.04	1.40	143.02
1978	.12	.01	3.01	2.02	18.49	48.43	58.07	13.52	.15	5.73	.07	4.53	154.16
1979	.13	.02	3.32	2.23	19.60	49.23	60.62	14.80	.17	6.12	.11	10.93	167.28
1980	.15	.02	3.61	2.51	20.72	51.39	64.45	15.94	.20	6.66	.17	11.92	177.72
1981	.16	.03	3.85	2.72	21.70	51.87	66.18	16.83	.23	7.11	.24	14.02	184.94
1982	.16	.03	4.03	2.89	21.87	51.53	65.55	17.41	.25	7.45	.32	16.06	187.57
1983	.17	.04	4.13	3.16	21.41	49.79	62.66	17.64	.28	7.65	.43	17.24	184.60
1984	.17	.04	4.15	3.27	20.38	47.39	57.88	17.62	.30	7.70	.56	17.41	176.88
1985	.17	.04	4.12	3.34	18.73	44.91	51.48	17.41	.32	7.79	.71	17.41	166.43

Note: Totals may not agree due to rounding.

TABLE 435

PROJECTED ADDITIONS NON-ASSOCIATED C_5+ RESERVES—LOWER 48 STATES
(MMB)

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.08	–	1.19	.59	6.63	37.49	30.14	5.46	.06	1.28	–	–	82.93
1972	.09	–	1.22	.64	7.18	38.28	32.87	5.75	.07	1.35	–	–	87.46
1973	.09	–	1.29	.69	7.71	39.43	36.19	6.03	.08	1.42	–	–	92.94
1974	.10	–	1.40	.75	8.29	40.32	39.41	6.40	.08	1.51	–	–	98.26
1975	.10	–	1.49	.87	8.92	41.35	43.22	6.82	.09	1.61	–	–	104.47
1976	.11	.01	1.59	.96	9.60	42.73	46.79	7.25	.11	1.72	–	–	110.86
1977	.12	.01	1.71	1.18	10.22	43.90	50.43	7.73	.12	1.83	–	–	117.24
1978	.13	.01	1.84	1.34	10.86	45.06	54.02	8.27	.14	1.96	–	–	123.64
1979	.14	.02	2.03	1.47	11.52	45.80	56.40	9.06	.16	2.10	–	–	128.69
1980	.15	.02	2.21	1.66	12.17	47.81	59.96	9.76	.18	2.28	–	–	136.21
1981	.16	.03	2.36	1.80	12.75	48.26	61.57	10.30	.21	2.44	–	–	139.87
1982	.17	.04	2.47	1.91	12.85	47.94	60.99	10.65	.23	2.55	–	–	139.80
1983	.18	.04	2.53	2.09	12.58	46.32	58.30	10.80	.25	2.62	–	–	135.71
1984	.18	.04	2.54	2.16	11.97	44.09	53.85	10.78	.27	2.64	–	–	128.54
1985	.18	.05	2.52	2.21	11.00	41.78	47.89	10.66	.29	2.67	–	–	119.24

Note: Totals may not agree due to rounding.

TABLE 436

PROJECTED ADDITIONS NON-ASSOCIATED LPG RESERVES–LOWER 48 STATES
(MMB)

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.11	.01	3.58	1.60	20.99	61.16	49.17	16.38	.11	7.88	–	–	160.99
1972	.12	.01	3.67	1.74	22.73	62.46	53.64	17.24	.12	8.28	–	–	170.00
1973	.12	.01	3.87	1.86	24.41	64.33	59.05	18.10	.13	8.74	–	–	180.62
1974	.13	.01	4.19	2.04	26.25	65.79	64.30	19.21	.14	9.27	.04	.93	192.28
1975	.14	.01	4.46	2.35	28.24	67.46	70.52	20.46	.16	9.87	.04	.99	204.70
1976	.15	.01	4.77	2.60	30.39	69.71	76.35	21.74	.18	10.57	.10	1.06	217.61
1977	.16	.02	5.12	3.18	32.35	71.62	82.28	23.19	.20	11.27	.11	3.43	232.92
1978	.17	.02	5.52	3.62	34.40	73.52	88.14	24.82	.23	12.07	.18	11.10	253.78
1979	.19	.02	6.10	3.98	36.48	74.72	92.02	27.17	.27	12.88	.27	26.76	280.86
1980	.20	.02	6.63	4.48	38.55	78.01	97.83	29.27	.31	14.02	.41	29.17	298.90
1981	.22	.04	7.07	4.86	40.38	78.74	100.45	30.90	.35	14.97	.58	34.34	312.90
1982	.23	.05	7.40	5.16	40.69	78.22	99.50	31.96	.39	15.69	.79	39.33	319.42
1983	.24	.05	7.58	5.65	39.84	75.58	95.12	32.39	.43	16.11	1.06	42.20	316.25
1984	.24	.06	7.62	5.84	37.92	71.94	87.87	32.35	.46	16.22	1.38	42.62	304.51
1985	.24	.06	7.57	5.97	34.84	68.16	78.14	31.97	.49	16.41	1.74	42.62	288.21

Note: Totals may not agree due to rounding.

TABLE 437

PROJECTED ADDITIONS NON-ASSOCIATED GAS LIQUID RESERVES–LOWER 48 STATES (MMB)

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11.	Region 11A	Total Lower 48 States
1971	.27	.01	6.72	3.09	38.90	138.94	111.70	30.76	.24	12.90	–	–	343.55
1972	.29	.01	6.89	3.35	42.13	141.89	121.85	32.38	.27	13.56	–	–	362.62
1973	.30	.01	7.27	3.59	45.24	146.14	134.14	33.99	.29	14.31	–	–	385.28
1974	.32	.01	7.87	3.93	48.65	149.45	146.07	36.07	.31	15.18	.06	1.31	409.21
1975	.34	.01	8.38	4.53	52.34	153.25	160.20	38.42	.35	16.17	.06	1.40	435.45
1976	.37	.03	8.96	5.01	56.32	158.36	173.44	40.83	.41	17.31	.14	1.49	462.63
1977	.39	.04	9.62	6.14	59.96	162.70	186.92	43.55	.45	18.45	.15	4.83	493.18
1978	.42	.04	10.37	6.98	63.75	167.01	200.23	46.61	.52	19.76	.25	15.63	531.58
1979	.46	.06	11.45	7.68	67.60	169.75	209.04	51.03	.60	21.10	.38	37.69	576.83
1980	.50	.06	12.45	8.65	71.44	177.21	222.24	54.97	.69	22.96	.58	41.09	612.83
1981	.54	.10	13.28	9.38	74.83	178.87	228.20	58.03	.79	24.52	.82	48.36	637.71
1982	.56	.12	13.90	9.96	75.41	177.69	226.04	60.02	.87	25.69	1.11	55.39	646.79
1983	.59	.13	14.24	10.90	73.83	171.69	216.08	60.83	.96	26.38	1.49	59.44	636.56
1984	.59	.14	14.31	11.27	70.27	163.42	199.60	60.75	1.03	26.56	1.94	60.03	609.93
1985	.59	.15	14.21	11.52	64.57	154.85	177.51	60.04	1.10	26.87	2.45	60.03	573.88

Note: Totals may not agree due to rounding.

TABLE 438

PROJECTED ADDITIONS NON-ASSOCIATED CONDENSATE RESERVES—LOWER 48 STATES
(MMB)

Case IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.09	—	2.39	.88	7.93	25.18	25.77	6.60	.08	3.45	—	—	72.37
1972	.09	—	2.56	.97	8.59	24.83	26.75	6.78	.08	3.62	—	—	74.28
1973	.10	—	2.76	1.05	9.26	24.67	28.12	6.93	.09	3.82	—	—	76.81
1974	.11	.01	3.06	1.16	10.04	24.32	29.37	7.16	.09	4.05	.02	.25	79.64
1975	.12	.01	3.34	1.36	10.95	24.02	31.04	7.40	.10	4.31	.03	.27	82.95
1976	.13	.01	3.68	1.52	12.01	23.88	32.57	7.63	.11	4.61	.06	.29	86.50
1977	.14	.01	4.08	1.90	13.11	23.59	34.25	7.87	.11	4.92	.06	.93	90.98
1978	.16	.02	6.27	2.20	14.18	23.24	36.08	8.14	.12	5.27	.10	3.02	98.80
1979	.18	.02	6.73	2.48	15.02	22.67	37.39	8.57	.13	5.63	.14	7.28	106.25
1980	.20	.02	7.10	2.87	15.95	22.65	39.85	8.86	.14	6.14	.19	7.94	111.91
1981	.23	.03	7.32	3.21	16.91	21.87	41.53	8.96	.15	6.57	.25	9.35	116.38
1982	.25	.04	7.41	3.53	17.39	20.80	42.32	8.86	.16	6.90	.30	10.70	118.66
1983	.25	.04	7.33	4.02	17.52	19.26	42.21	8.58	.17	7.10	.36	11.49	118.33
1984	.24	.04	7.11	4.34	17.30	17.60	41.20	8.20	.17	7.18	.40	11.60	115.39
1985	.23	.05	6.82	4.64	16.60	16.05	39.15	7.75	.17	7.29	.45	11.60	110.79

Note: Totals may not agree due to rounding.

TABLE 439

PROJECTED ADDITIONS NON-ASSOCIATED C_5 + RESERVES–LOWER 48 STATES
(MMB)

Case I A

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.09	–	1.46	.58	4.66	23.42	23.97	4.04	.07	1.18	–	–	59.49
1972	.10	–	1.57	.64	5.05	23.10	24.89	4.15	.07	1.24	–	–	60.81
1973	.10	.01	1.69	.69	5.44	22.95	26.17	4.24	.08	1.31	–	–	62.68
1974	.11	.01	1.87	.77	5.90	22.63	27.32	4.38	.08	1.39	–	–	64.46
1975	.12	.01	2.05	.90	6.43	22.35	28.88	4.53	.09	1.48	–	–	66.83
1976	.14	.01	2.25	1.01	7.06	22.22	30.30	4.67	.10	1.58	–	–	69.33
1977	.15	.02	2.50	1.26	7.70	21.94	31.86	4.82	.10	1.69	–	–	72.04
1978	.17	.02	3.84	1.46	8.33	21.62	33.57	4.98	.11	1.81	–	–	75.90
1979	.19	.02	4.12	1.64	8.83	21.09	34.78	5.25	.12	1.93	–	–	77.96
1980	.22	.02	4.34	1.90	9.37	21.07	37.07	5.42	.13	2.10	–	–	81.65
1981	.24	.04	4.48	2.12	9.93	20.35	38.63	5.48	.14	2.25	–	–	83.68
1982	.27	.04	4.53	2.34	10.22	19.35	39.38	5.42	.15	2.36	–	–	84.05
1983	.27	.04	4.49	2.66	10.29	17.92	39.27	5.25	.15	2.44	–	–	82.77
1984	.26	.05	4.35	2.87	10.16	16.38	38.33	5.02	.15	2.46	–	–	80.03
1985	.25	.05	4.18	3.07	9.75	14.93	36.42	4.74	.15	2.50	–	–	76.04

Note: Totals may not agree due to rounding.

TABLE 440

PROJECTED ADDITIONS NON-ASSOCIATED LPG RESERVES—LOWER 48 STATES
(MMB)

Case IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.12	.01	4.39	1.58	14.75	38.21	39.12	12.12	.12	7.26	–	–	117.68
1972	.13	.01	4.71	1.73	15.98	37.69	40.60	12.44	.13	7.62	–	–	121.05
1973	.14	.01	5.07	1.87	17.24	37.45	42.69	12.73	.13	8.04	–	–	125.37
1974	.15	.01	5.62	2.08	18.69	36.92	44.58	13.14	.14	8.52	.06	.62	130.53
1975	.16	.01	6.14	2.42	20.38	36.47	47.11	13.60	.15	9.08	.06	.66	136.24
1976	.18	.02	6.75	2.72	22.34	36.25	49.44	14.01	.16	9.71	.14	.71	142.43
1977	.20	.02	7.49	3.40	24.40	35.80	51.99	14.45	.17	10.36	.15	2.28	150.71
1978	.22	.02	11.52	3.94	26.38	35.28	54.76	14.94	.19	11.10	.24	7.40	166.00
1979	.25	.03	12.36	4.44	27.95	34.41	56.75	15.74	.20	11.86	.35	17.83	182.16
1980	.29	.03	13.03	5.13	29.67	34.38	60.49	16.27	.22	12.93	.47	19.44	192.34
1981	.32	.05	13.45	5.74	31.46	33.20	63.04	16.45	.24	13.83	.61	22.88	201.26
1982	.35	.05	13.60	6.31	32.35	31.57	64.25	16.27	.25	14.52	.74	26.21	206.47
1983	.35	.06	13.46	7.19	32.60	29.24	64.07	15.76	.26	14.96	.87	28.12	206.92
1984	.34	.06	13.05	7.76	32.18	26.72	62.54	15.05	.26	15.11	.99	28.40	202.47
1985	.33	.06	12.53	8.30	30.88	24.36	59.43	14.22	.26	15.35	1.10	28.40	195.22

Note: Totals may not agree due to rounding.

TABLE 441

PROJECTED ADDITIONS NON-ASSOCIATED GAS LIQUID RESERVES—LOWER 48 STATES (MMB)

Case IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.30	.01	8.24	3.04	27.34	86.81	88.86	22.76	.27	11.89	—	—	249.54
1972	.32	.01	8.84	3.34	29.62	85.62	92.24	23.37	.28	12.48	—	—	256.14
1973	.34	.02	9.52	3.61	31.94	85.07	96.98	23.90	.30	13.17	—	—	264.86
1974	.37	.03	10.55	4.01	34.63	83.87	101.27	24.68	.31	13.96	.08	.87	274.63
1975	.40	.03	11.53	4.68	37.76	82.84	107.03	25.53	.34	14.87	.09	.90	286.02
1976	.45	.04	12.68	5.25	41.41	82.35	112.31	26.31	.37	15.90	.20	1.00	298.26
1977	.49	.05	14.07	6.56	45.21	81.33	118.10	27.14	.38	16.97	.21	3.21	313.73
1978	.55	.06	21.63	7.60	48.89	80.14	124.41	28.06	.42	18.18	.34	10.42	340.70
1979	.62	.07	23.21	8.56	51.80	78.17	128.92	29.56	.45	19.42	.49	25.11	366.37
1980	.71	.07	24.47	9.90	54.99	78.10	137.41	30.55	.49	21.17	.66	27.38	385.90
1981	.79	.12	25.25	11.07	58.30	75.42	143.20	30.89	.53	22.65	.86	32.23	401.32
1982	.87	.13	25.54	12.18	59.96	71.72	145.95	30.55	.56	23.78	1.04	36.91	409.18
1983	.87	.14	25.28	13.87	60.41	66.42	145.55	29.59	.58	24.50	1.23	39.61	408.02
1984	.84	.15	24.51	14.97	59.64	60.70	142.07	28.27	.58	24.75	1.39	40.00	397.89
1985	.81	.16	23.53	16.01	57.23	55.34	135.00	26.71	.58	25.14	1.55	40.00	382.05

Note: Totals may not agree due to rounding.

TABLE 442

PROJECTED ADDITIONS NON-ASSOCIATED CONDENSATE RESERVES—LOWER 48 STATES (MMB)

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.08	—	1.95	.90	11.28	40.29	32.39	8.92	.07	3.74	—	—	99.63
1972	.08	—	1.94	.95	11.87	39.98	34.31	9.12	.07	3.82	—	—	102.15
1973	.08	—	1.99	.98	12.38	40.04	36.68	9.31	.08	3.92	—	—	105.45
1974	.09	—	2.09	1.04	12.93	39.84	38.78	9.60	.08	4.04	.02	.35	108.86
1975	.09	—	2.16	1.17	13.53	39.78	41.35	9.95	.09	4.18	.02	.36	112.67
1976	.09	.01	2.25	1.25	14.17	40.07	43.58	10.28	.10	4.35	.03	.38	116.57
1977	.10	.01	2.35	1.49	14.71	40.17	45.84	10.67	.11	4.51	.04	1.18	121.17
1978	.10	.01	2.46	1.65	15.28	40.29	48.08	11.12	.12	4.69	.06	3.71	127.58
1979	.11	.01	2.65	1.76	15.88	40.06	49.35	11.87	.13	4.87	.09	8.70	135.47
1980	.11	.01	2.80	1.92	16.49	40.98	51.86	12.47	.15	5.16	.12	9.22	141.30
1981	.12	.02	2.91	2.02	17.04	40.58	52.94	12.84	.16	5.36	.17	10.55	144.70
1982	.12	.02	2.99	2.10	17.16	39.97	52.98	13.09	.17	5.51	.22	11.86	146.20
1983	.12	.03	3.04	2.28	17.03	38.70	51.99	13.20	.19	5.62	.28	12.60	145.07
1984	.12	.03	3.06	2.36	16.64	37.30	50.05	13.26	.20	5.66	.36	12.72	141.76
1985	.12	.03	3.05	2.41	15.73	35.80	46.53	13.18	.21	5.74	.44	12.72	135.98

Note: Totals may not agree due to rounding.

TABLE 443

PROJECTED ADDITIONS NON-ASSOCIATED C_5 + RESERVES—LOWER 48 STATES
(MMB)

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.08	–	1.19	.59	6.63	37.49	30.14	5.46	.06	1.28	–	–	82.93
1972	.08	–	1.19	.63	6.97	37.20	31.92	5.58	.07	1.31	–	–	84.95
1973	.09	–	1.22	.65	7.27	37.25	34.12	5.70	.07	1.34	–	–	87.71
1974	.09	–	1.28	.69	7.60	37.06	36.08	5.88	.08	1.38	–	–	90.14
1975	.09	–	1.32	.77	7.95	37.01	38.47	6.09	.08	1.43	–	–	93.22
1976	.10	.01	1.38	.83	8.33	37.28	40.55	6.29	.09	1.49	–	–	96.34
1977	.10	.01	1.44	.99	8.65	37.37	42.65	6.53	.10	1.54	–	–	99.38
1978	.11	.01	1.51	1.09	8.98	37.48	44.73	6.81	.11	1.61	–	–	102.43
1979	.11	.01	1.62	1.16	9.33	37.27	45.91	7.27	.12	1.67	–	–	104.47
1980	.12	.01	1.71	1.27	9.69	38.13	48.25	7.63	.13	1.77	–	–	108.71
1981	.12	.02	1.78	1.33	10.01	37.75	49.25	7.86	.15	1.84	–	–	110.12
1982	.13	.02	1.83	1.39	10.09	37.19	49.29	8.01	.16	1.89	–	–	109.99
1983	.13	.03	1.86	1.51	10.01	36.01	48.37	8.08	.17	1.92	–	–	108.08
1984	.13	.03	1.87	1.56	9.78	34.70	46.56	8.12	.18	1.94	–	–	104.87
1985	.13	.03	1.87	1.60	9.25	33.30	43.29	8.07	.19	1.97	–	–	99.69

Note: Totals may not agree due to rounding.

TABLE 444

PROJECTED ADDITIONS NON-ASSOCIATED LPG RESERVES—LOWER 48 STATES
(MMB)

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.11	.01	3.58	1.60	20.99	61.16	49.17	16.38	.11	7.88	–	–	160.99
1972	.11	.01	3.56	1.69	22.08	60.69	52.09	16.75	.11	8.05	–	–	165.13
1973	.12	.01	3.65	1.75	23.03	60.77	55.68	17.09	.12	8.25	–	–	170.47
1974	.12	.01	3.84	1.87	24.06	60.47	58.87	17.63	.13	8.50	.04	.85	176.39
1975	.12	.01	3.97	2.09	25.18	60.38	62.76	18.26	.14	8.80	.04	.88	182.64
1976	.13	.01	4.13	2.24	26.37	60.82	66.16	18.88	.15	9.15	.08	.92	189.05
1977	.13	.01	4.31	2.67	27.38	60.98	69.58	19.60	.17	9.49	.09	2.89	197.29
1978	.14	.01	4.52	2.94	28.44	61.15	72.98	20.43	.18	9.88	.14	9.09	209.92
1979	.15	.02	4.86	3.14	29.54	60.81	74.91	21.80	.20	10.26	.21	21.31	227.21
1980	.16	.02	5.14	3.43	30.68	62.21	78.72	22.90	.23	10.87	.30	22.58	237.23
1981	.16	.03	5.34	3.61	31.70	61.60	80.36	23.58	.25	11.29	.41	25.84	244.16
1982	.17	.03	5.49	3.75	31.94	60.67	80.42	24.03	.27	11.61	.54	29.03	247.96
1983	.17	.04	5.58	4.07	31.68	58.75	78.92	24.24	.29	11.82	.69	30.84	247.10
1984	.17	.04	5.62	4.22	30.96	56.62	75.97	24.35	.30	11.92	.88	31.15	242.20
1985	.17	.04	5.60	4.32	29.28	54.34	70.64	24.20	.32	12.08	1.09	31.15	233.22

Note: Totals may not agree due to rounding.

TABLE 445

PROJECTED ADDITIONS NON-ASSOCIATED GAS LIQUID RESERVES—LOWER 48 STATES
(MMB)

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.27	.01	6.72	3.09	38.90	138.94	111.70	30.76	.24	12.90	—	—	343.55
1972	.27	.01	6.69	3.27	40.92	137.87	118.32	31.45	.25	13.18	—	—	352.23
1973	.29	.01	6.86	3.38	42.68	138.06	126.48	32.10	.27	13.51	—	—	363.63
1974	.30	.01	7.21	3.60	44.59	137.37	133.73	33.11	.29	13.92	.06	1.20	375.39
1975	.30	.01	7.45	4.03	46.66	137.17	142.58	34.30	.31	14.41	.06	1.24	388.53
1976	.32	.03	7.76	4.32	48.87	138.17	150.29	35.45	.34	14.99	.11	1.30	401.96
1977	.33	.03	8.10	5.15	50.74	138.52	158.07	36.80	.38	15.54	.13	4.07	417.84
1978	.35	.03	8.49	5.68	52.70	138.92	165.79	38.36	.41	16.18	.20	12.80	439.93
1979	.37	.04	9.13	6.06	54.75	138.14	170.17	40.94	.45	16.80	.30	30.01	467.15
1980	.39	.04	9.65	6.62	56.86	141.32	178.83	43.00	.51	17.80	.42	31.80	487.24
1981	.40	.07	10.03	6.96	58.75	139.93	182.55	44.28	.56	18.49	.58	36.39	498.98
1982	.42	.07	10.31	7.24	59.19	137.83	182.69	45.13	.60	19.01	.76	40.89	504.15
1983	.42	.10	10.48	7.86	58.72	133.46	179.28	45.52	.65	19.36	.97	43.44	500.25
1984	.42	.10	10.55	8.14	57.38	128.62	172.58	45.73	.68	19.52	1.24	43.87	488.83
1985	.42	.10	10.52	8.33	54.26	123.44	160.46	45.45	.72	19.79	1.53	43.87	468.89

Note: Totals may not agree due to rounding.

TABLE 446

PROJECTED ADDITIONS NON-ASSOCIATED CONDENSATE RESERVES–LOWER 48 STATES
(MMB)

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.09	–	2.39	.88	7.93	25.18	25.77	6.60	.08	3.45	–	–	72.37
1972	.09	–	2.49	.94	8.34	24.16	26.00	6.59	.08	3.52	–	–	72.21
1973	.09	–	2.60	.99	8.73	23.39	26.59	6.56	.08	3.60	–	–	72.65
1974	.10	–	2.80	1.06	9.19	22.51	27.04	6.60	.08	3.71	.02	.23	73.35
1975	.10	.01	2.96	1.20	9.73	21.74	27.85	6.66	.09	3.84	.02	.24	74.44
1976	.11	.01	3.15	1.31	10.35	21.18	28.52	6.70	.09	4.00	.05	.25	75.71
1977	.12	.01	3.38	1.58	10.96	20.53	29.30	6.77	.10	4.14	.05	.79	77.72
1978	.13	.01	5.22	1.77	11.66	19.91	30.19	6.85	.10	4.32	.08	2.47	82.72
1979	.14	.01	5.49	1.92	12.19	19.15	30.65	7.09	.11	4.48	.11	5.80	87.14
1980	.15	.02	5.67	2.14	12.66	18.93	32.06	7.22	.11	4.75	.15	6.15	90.00
1981	.16	.02	5.74	2.30	13.14	18.12	32,83	7.19	.12	4.94	.19	7.03	91.79
1982	.17	.03	5.75	2.45	13.36	17.26	33.24	7.09	.12	5.09	.22	7.90	92.69
1983	.18	.03	5.69	2.73	13.44	16.19	33.27	6.91	.12	5.19	.26	8.40	92.41
1984	.19	.03	5.58	2.91	13.39	15.12	32.92	6.71	.12	5.24	.30	8.48	91.00
1985	.19	.03	5.42	3.07	12.96	14.08	31.72	6.45	.12	5.33	.33	8.48	88.17

Note: Totals may not agree due to rounding.

TABLE 447

PROJECTED ADDITIONS NON-ASSOCIATED C_5 + RESERVES—LOWER 48 STATES
(MMB)

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.09	–	1.46	.58	4.66	23.42	23.97	4.04	.07	1.18	–	–	59.49
1972	.09	–	1.54	.62	4.90	22.47	24.19	4.03	.07	1.21	–	–	59.12
1973	.10	–	1.59	.65	5.13	21.76	24.74	4.01	.07	1.24	–	–	59.30
1974	.10	.01	1.71	.70	5.40	20.94	25.16	4.04	.08	1.27	–	–	59.41
1975	.11	.01	1.81	.79	5.72	20.22	25.91	4.08	.08	1.32	–	–	60.05
1976	.12	.01	1.93	.86	6.08	19.70	26.53	4.10	.08	1.37	–	–	60.79
1977	.12	.01	2.07	1.04	6.44	19.10	27.26	4.14	.09	1.42	–	–	61.69
1978	.13	.01	3.20	1.17	6.85	18.53	28.09	4.20	.09	1.48	–	–	63.75
1979	.15	.01	3.36	1.27	7.16	17.82	28.51	4.34	.10	1.54	–	–	64.26
1980	.16	.02	3.47	1.41	7.44	17.61	29.83	4.42	.10	1.63	–	–	66.09
1981	.17	.03	3.51	1.52	7.72	16.86	30.55	4.40	.11	1.69	–	–	66.56
1982	.18	.03	3.52	1.62	7.85	16.06	30.92	4.34	.11	1.75	–	–	66.38
1983	.19	.03	3.48	1.80	7.90	15.06	30.95	4.23	.11	1.78	–	–	65.54
1984	.20	.03	3.42	1.92	7.87	14.07	30.63	4.11	.11	1.80	–	–	64.15
1985	.20	.03	3.32	2.03	7.61	13.10	29.51	3.95	.11	1.83	–	–	61.68

Note: Totals may not agree due to rounding.

TABLE 448

PROJECTED ADDITIONS NON-ASSOCIATED LPG RESERVES—LOWER 48 STATES
(MMB)

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.12	.01	4.39	1.58	14.75	38.21	39.12	12.12	.12	7.26	—	—	117.68
1972	.12	.01	4.57	1.68	15.52	36.67	39.47	12.10	.12	7.40	—	—	117.67
1973	.13	.01	4.78	1.76	16.25	35.50	40.37	12.04	.13	7.59	—	—	118.56
1974	.14	.01	5.13	1.90	17.11	34.16	41.05	12.11	.13	7.82	.06	.57	120.17
1975	.14	.01	5.43	2.15	18.10	33.00	42.28	12.23	.13	8.09	.06	.59	122.21
1976	.15	.02	5.79	2.33	19.25	32.14	43.29	12.31	.14	8.41	.12	.61	124.57
1977	.17	.02	6.21	2.82	20.38	31.17	44.47	12.43	.15	8.73	.12	1.92	128.58
1978	.18	.02	9.59	3.16	21.70	30.23	45.83	12.59	.15	9.09	.20	6.06	138.78
1979	.19	.02	10.08	3.43	22.68	29.07	46.52	13.02	.16	9.44	.28	14.20	149.10
1980	.21	.02	10.41	3.82	23.56	28.73	48.67	13.25	.17	10.01	.36	15.05	154.27
1981	.23	.03	10.53	4.11	24.45	27.51	49.84	13.20	.18	10.41	.46	17.22	158.16
1982	.24	.04	10.55	4.38	24.86	26.21	50.45	13.01	.18	10.72	.55	19.34	160.54
1983	.26	.04	10.45	4.88	25.02	24.57	50.50	12.69	.19	10.93	.64	20.55	160.71
1984	.27	.04	10.25	5.20	24.91	22.95	49.98	12.32	.19	11.04	.72	20.76	158.63
1985	.26	.04	9.95	5.48	24.11	21.37	48.14	11.85	.19	11.22	.81	20.76	154.18

Note: Totals may not agree due to rounding.

TABLE 449

PROJECTED ADDITIONS NON-ASSOCIATED GAS LIQUID RESERVES—LOWER 48 STATES
(MMB)

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.30	.01	8.24	3.04	27.34	86.81	88.86	22.76	.27	11.89	—	—	249.54
1972	.30	.01	8.58	3.24	28.76	83.30	89.66	22.72	.27	12.13	—	—	249.00
1973	.32	.02	8.97	3.40	30.11	80.65	91.70	22.61	.28	12.43	—	—	250.51
1974	.34	.02	9.64	3.66	31.70	77.61	93.25	22.75	.29	12.80	.08	.80	252.93
1975	.35	.03	10.20	4.14	33.55	74.96	96.04	22.97	.30	13.25	.08	.83	256.70
1976	.38	.04	10.87	4.50	35.68	73.02	98.34	23.11	.31	13.78	.17	.86	261.07
1977	.41	.04	11.66	5.44	37.78	70.80	101.03	23.34	.34	14.29	.17	2.71	267.99
1978	.44	.04	18.01	6.10	40.21	68.67	104.11	23.64	.34	14.89	.28	8.53	285.25
1979	.48	.04	18.93	6.62	42.03	66.04	105.68	24.45	.37	15.46	.39	20.00	300.50
1980	.52	.06	19.55	7.37	43.66	65.27	110.56	24.89	.38	16.39	.51	21.20	310.36
1981	.56	.08	19.78	7.93	45.31	62.49	113.22	24.79	.41	17.04	.65	24.25	316.51
1982	.59	.10	19.82	8.45	46.07	59.53	114.61	24.44	.41	17.56	.77	27.24	319.61
1983	.63	.10	19.62	9.41	46.36	55.82	114.72	23.83	.42	17.90	.90	28.95	318.66
1984	.66	.10	19.25	10.03	46.17	52.14	113.53	23.14	.42	18.08	1.02	29.24	313.78
1985	.65	.10	18.69	10.58	44.68	48.55	109.37	22.25	.42	18.38	1.14	29.24	304.03

Note: Totals may not agree due to rounding.

TABLE 450

PROJECTED ADDITIONS NON-ASSOCIATED CONDENSATE RESERVES—LOWER 48 STATES (MMB)

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.08	—	2.36	.87	7.82	24.84	25.42	6.51	.08	3.40	—	—	71.39
1972	.08	—	2.31	.87	7.74	22.51	24.18	6.13	.07	3.26	—	—	67.16
1973	.08	—	2.25	.85	7.58	20.55	23.23	5.74	.07	3.13	—	—	63.48
1974	.08	—	2.25	.85	7.41	18.61	22.11	5.41	.07	3.01	.02	.19	60.00
1975	.08	—	2.19	.89	7.25	16.88	21.24	5.11	.07	2.89	.02	.18	56.80
1976	.08	.01	2.14	.89	7.10	15.43	20.23	4.79	.06	2.77	.03	.17	53.70
1977	.07	.01	2.09	.97	6.87	14.01	19.28	4.50	.06	2.64	.03	.50	51.04
1978	.07	.01	2.04	.99	6.65	12.71	18.38	4.23	.06	2.52	.05	1.44	49.13
1979	.07	.01	2.03	.96	6.43	11.42	17.21	4.06	.06	2.38	.06	3.07	47.75
1980	.07	.01	2.89	.95	6.22	10.54	16.58	3.82	.05	2.28	.07	2.95	46.43
1981	.07	.01	2.74	.93	6.13	9.62	15.96	3.60	.05	2.19	.08	3.12	44.50
1982	.06	.01	2.60	.91	5.94	8.85	15.37	3.39	.05	2.10	.09	3.26	42.64
1983	.06	.01	2.47	.93	5.71	8.10	14.81	3.20	.05	2.02	.10	3.26	40.71
1984	.06	.01	2.34	.92	5.48	7.47	14.26	3.04	.05	1.94	.11	3.13	38.81
1985	.06	.01	2.23	.91	5.17	6.93	13.51	2.89	.04	1.89	.12	3.01	36.76

Note: Totals may not agree due to rounding.

TABLE 451

PROJECTED ADDITIONS NON-ASSOCIATED C_5+ RESERVES LOWER 48 STATES (MMB)

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.09	–	1.44	.58	4.59	23.11	23.65	3.99	.07	1.17	–	–	58.69
1972	.09	–	1.41	.58	4.55	20.95	22.49	3.75	.07	1.12	–	–	55.00
1973	.08	–	1.38	.56	4.45	19.12	21.61	3.51	.06	1.07	–	–	51.86
1974	.08	–	1.37	.56	4.36	17.31	20.57	3.31	.06	1.03	–	–	48.66
1975	.08	–	1.34	.59	4.26	15.71	19.77	3.12	.06	.99	–	–	45.92
1976	.08	.01	1.31	.59	4.17	14.35	18.82	2.93	.06	.95	–	–	43.27
1977	.08	.01	1.28	.64	4.04	13.03	17.94	2.75	.05	.91	–	–	40.73
1978	.08	.01	1.25	.65	3.91	11.82	17.10	2.59	.05	.86	–	–	38.31
1979	.07	.01	1.24	.64	3.78	10.62	16.01	2.48	.05	.81	–	–	35.72
1980	.07	.01	1.77	.63	3.66	9.80	15.42	2.34	.05	.78	–	–	34.52
1981	.07	.01	1.68	.61	3.60	8.95	14.85	2.20	.05	.75	–	–	32.78
1982	.07	.01	1.59	.60	3.49	8.23	14.30	2.07	.04	.75	–	–	31.14
1983	.07	.01	1.51	.61	3.35	7.54	13.78	1.96	.04	.69	–	–	29.56
1984	.06	.01	1.43	.61	3.22	6.95	13.27	1.86	.04	.66	–	–	28.12
1985	.06	.01	1.36	.60	3.04	6.45	12.57	1.77	.04	.65	–	–	26.55

Note: Totals may not agree due to rounding.

TABLE 452

PROJECTED ADDITIONS NON-ASSOCIATED LPG RESERVES
LOWER 48 STATES
(MMB)

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.12	.01	4.33	1.56	14.54	37.71	38.59	11.96	.12	7.16	–	–	116.09
1972	.12	.01	4.23	1.56	14.39	34.18	36.70	11.26	.11	6.87	–	–	109.43
1973	.11	.01	4.14	1.53	14.10	31.19	35.26	10.54	.11	6.60	–	–	103.56
1974	.11	.01	4.12	1.52	13.80	28.24	33.55	9.93	.11	6.33	.04	.46	98.24
1975	.11	.01	4.03	1.59	13.50	25.63	32.25	9.37	.10	6.08	.04	.44	93.15
1976	.10	.01	3.93	1.59	13.20	23.41	30.71	8.80	.10	5.84	.08	.43	88.20
1977	.10	.01	3.84	1.74	12.78	21.26	29.26	8.26	.09	5.56	.08	1.23	84.22
1978	.10	.01	3.75	1.76	12.37	19.29	27.89	7.77	.09	5.30	.11	3.53	81.97
1979	.10	.01	3.73	1.72	11.97	17.33	26.13	7.45	.09	5.01	.15	7.53	81.19
1980	.09	.01	5.30	1.71	11.58	15.99	25.16	7.01	.08	4.81	.18	7.23	79.14
1981	.09	.01	5.03	1.66	11.41	14.61	24.23	6.60	.08	4.61	.20	7.63	76.18
1982	.09	.01	4.77	1.62	11.05	13.44	23.34	6.22	.08	4.43	.23	7.99	73.27
1983	.09	.01	4.53	1.66	10.62	12.30	22.48	5.87	.07	4.25	.25	7.99	70.12
1984	.09	.01	4.30	1.64	10.20	11.33	21.65	5.58	.07	4.08	.27	7.67	66.89
1985	.08	.01	4.09	1.62	9.62	10.52	20.51	5.30	.07	3.98	.29	7.37	63.46

Note: Totals may not agree due to rounding.

TABLE 453

PROJECTED ADDITIONS NON-ASSOCIATED GAS LIQUID RESERVES
LOWER 48 STATES
(MMB)

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.27	.01	8.13	3.01	26.95	85.66	87.66	22.46	.27	11.73	–	–	246.17
1972	.29	.01	7.95	3.01	26.68	77.64	83.37	21.14	.25	11.25	–	–	231.59
1973	.27	.01	7.77	2.94	26.13	70.86	80.10	19.79	.24	10.80	–	–	218.90
1974	.27	.01	7.74	2.93	25.57	64.16	76.23	18.65	.24	10.37	.06	.65	206.90
1975	.27	.01	7.56	3.07	25.01	58.22	73.26	17.60	.23	9.96	.06	.62	195.87
1976	.26	.03	7.38	3.07	24.47	53.19	69.76	16.52	.22	9.56	.11	.60	185.17
1977	.25	.03	7.21	3.35	23.69	48.30	66.48	15.51	.20	9.11	.11	1.73	175.99
1978	.25	.03	7.04	3.40	22.93	43.82	63.37	14.59	.20	8.68	.16	4.97	169.41
1979	.24	.03	7.00	3.32	22.18	39.37	59.35	13.99	.20	8.20	.21	10.60	164.66
1980	.23	.03	9.96	3.29	21.46	36.33	57.16	13.17	.18	7.87	.25	10.18	160.09
1981	.23	.03	9.45	3.20	21.14	33.18	55.04	12.40	.18	7.55	.28	10.75	153.46
1982	.22	.03	8.96	3.13	20.48	30.52	53.01	11.68	.17	7.25	.32	11.25	147.05
1983	.22	.03	8.51	3.20	19.68	27.94	51.07	11.03	.16	6.96	.35	11.25	140.39
1984	.21	.03	8.07	3.17	18.90	25.75	49.18	10.48	.16	6.68	.38	10.80	133.82
1985	.20	.03	7.68	3.13	17.83	23.90	46.59	9.96	.15	6.52	.41	10.38	126.77

Note: Totals may not agree due to rounding.

TABLE 454

PROJECTED ADDITIONS NON-ASSOCIATED CONDENSATE RESERVES
LOWER 48 STATES
(MMB)

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.08	–	1.92	.88	11.12	39.74	31.94	8.80	.07	3.69	–	–	98.25
1972	.07	–	1.80	.88	11.01	37.14	31.81	8.47	.07	3.55	–	–	94.80
1973	.07	–	1.73	.85	10.75	34.89	31.79	8.10	.07	3.41	–	–	91.66
1974	.07	–	1.69	.84	10.47	32.45	31.29	7.79	.07	3.27	.01	.28	88.24
1975	.07	–	1.63	.87	10.17	30.18	30.93	7.50	.07	3.14	.01	.27	84.84
1976	.06	.01	1.56	.86	9.86	28.22	30.16	7.17	.07	3.02	.02	.26	81.26
1977	.06	.01	1.50	.94	9.44	26.18	29.30	6.85	.07	2.87	.02	.75	77.98
1978	.06	.01	1.44	.94	9.03	24.22	28.37	6.55	.07	2.74	.03	2.16	75.60
1979	.06	.01	1.41	.91	8.63	22.15	26.89	6.38	.06	2.59	.04	4.61	73.74
1980	.05	.01	1.35	.90	8.23	20.78	26.14	6.10	.06	2.48	.05	4.43	70.60
1981	.05	.01	1.29	.87	8.00	19.28	25.36	5.83	.06	2.38	.06	4.68	67.88
1982	.05	.01	1.24	.84	7.70	17.99	24.54	5.58	.06	2.29	.08	4.90	65.27
1983	.05	.01	1.19	.85	7.40	16.68	23.71	5.33	.06	2.19	.09	4.90	62.46
1984	.05	.01	1.14	.84	7.10	15.57	22.87	5.13	.06	2.11	.10	4.70	59.67
1985	.04	.01	1.10	.82	6.69	14.63	21.66	4.94	.06	2.05	.11	4.51	56.62

Note: Totals may not agree due to rounding.

TABLE 455

PROJECTED ADDITIONS NON-ASSOCIATED C_5+ RESERVES
LOWER 48 STATES
(MMB)

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.08	–	1.18	.58	6.54	36.97	29.71	5.38	.06	1.27	–	–	81.78
1972	.08	–	1.10	.58	6.47	34.55	29.60	5.18	.06	1.22	–	–	78.84
1973	.08	–	1.06	.56	6.32	32.46	29.58	4.96	.06	1.17	–	–	76.24
1974	.07	–	1.04	.56	6.15	30.19	29.11	4.77	.06	1.12	–	–	73.07
1975	.07	–	1.00	.58	5.98	28.08	28.78	4.59	.06	1.08	–	–	70.20
1976	.07	.01	.96	.57	5.79	26.25	28.06	4.39	.06	1.03	–	–	67.18
1977	.06	.01	.92	.62	5.55	24.35	27.26	4.19	.06	.98	–	–	64.00
1978	.06	.01	.88	.62	5.31	22.53	26.39	4.01	.06	.94	–	–	60.80
1979	.06	.01	.86	.60	5.07	20.60	25.02	3.91	.06	.89	–	–	57.07
1980	.06	.01	.83	.59	4.84	19.33	24.32	3.73	.06	.85	–	–	54.62
1981	.05	.01	.79	.57	4.70	17.93	23.59	3.57	.06	.82	–	–	52.10
1982	.05	.01	.76	.55	4.52	16.73	22.83	3.41	.06	.78	–	–	49.72
1983	.05	.01	.73	.56	4.35	15.52	22.06	3.27	.05	.75	–	–	47.35
1984	.05	.01	.70	.55	4.17	14.49	21.27	3.14	.05	.72	–	–	45.16
1985	.05	.01	.67	.54	3.93	13.61	20.15	3.02	.05	.70	–	–	42.74

Note: Totals may not agree due to rounding.

TABLE 456

PROJECTED ADDITIONS NON-ASSOCIATED LPG RESERVES
LOWER 48 STATES
(MMB)

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.11	.01	3.53	1.58	20.70	60.33	48.48	16.15	.10	7.77	–	–	158.76
1972	.10	–	3.31	1.57	20.48	56.37	48.29	15.55	.10	7.47	–	–	153.25
1973	.10	–	3.17	1.52	20.00	52.96	48.26	14.87	.10	7.17	–	–	148.17
1974	.10	–	3.11	1.51	19.48	49.25	47.50	14.31	.10	6.89	.03	.69	142.97
1975	.09	–	2.99	1.56	18.92	45.81	46.96	13.76	.10	6.61	.03	.66	137.50
1976	.09	.01	2.87	1.54	18.34	42.83	45.78	13.16	.10	6.35	.06	.64	131.76
1977	.09	.01	2.75	1.68	17.57	39.73	44.47	12.58	.10	6.05	.06	1.84	126.92
1978	.08	.01	2.64	1.69	16.81	36.76	43.06	12.02	.10	5.76	.08	5.30	124.30
1979	.08	.01	2.58	1.63	16.06	33.62	40.82	11.72	.10	5.44	.11	11.30	123.46
1980	.08	.01	2.48	1.61	15.32	31.54	39.68	11.20	.10	5.23	.13	10.84	118.22
1981	.07	.01	2.38	1.55	14.89	29.26	38.49	10.71	.10	5.01	.16	11.45	114.09
1982	.07	.01	2.28	1.50	14.32	27.30	37.25	10.24	.09	4.81	.19	11.99	110.07
1983	.07	.01	2.19	1.52	13.76	25.33	35.99	9.80	.09	4.62	.21	11.99	105.58
1984	.06	.01	2.10	1.49	13.22	23.64	34.71	9.43	.09	4.43	.24	11.51	100.94
1985	.06	.01	2.01	1.47	12.45	22.20	32.87	9.07	.09	4.32	.27	11.05	95.89

Note: Totals may not agree due to rounding.

TABLE 457

PROJECTED ADDITIONS NON-ASSOCIATED GAS LIQUID RESERVES
LOWER 48 STATES
(MMB)

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.27	.01	6.63	3.04	38.36	137.04	110.13	30.33	.23	12.73	–	–	338.79
1972	.25	–	6.21	3.03	37.96	128.06	109.70	29.20	.23	12.24	–	–	326.89
1973	.25	–	5.96	2.93	37.07	120.31	109.63	27.93	.23	11.75	–	–	316.07
1974	.24	–	5.84	2.91	36.10	111.89	107.90	26.87	.23	11.28	.04	.97	304.28
1975	.23	–	5.62	3.01	35.07	104.07	106.67	25.85	.23	10.83	.04	.93	292.54
1976	.22	.03	5.39	2.97	33.99	97.30	104.00	24.72	.23	10.40	.08	.90	280.20
1977	.21	.03	5.17	3.24	32.56	90.26	101.03	23.62	.23	9.90	.08	2.59	268.90
1978	.20	.03	4.96	3.25	31.15	83.51	97.82	22.58	.23	9.44	.11	7.46	260.70
1979	.20	.03	4.85	3.14	29.76	76.37	92.73	22.01	.22	8.92	.15	15.91	254.27
1980	.19	.03	4.66	3.10	28.39	71.65	90.14	21.03	.22	8.56	.18	15.27	243.34
1981	.17	.03	4.46	2.99	27.59	66.47	87.44	20.11	.22	8.21	.22	16.13	234.07
1982	.17	.03	4.28	2.89	26.54	62.02	84.62	19.23	.21	7.88	.27	16.89	225.06
1983	.17	.03	4.11	2.93	25.51	57.53	81.76	18.40	.20	7.56	.30	16.89	215.39
1984	.16	.03	3.94	2.88	24.49	53.70	78.85	17.70	.20	7.26	.34	16.21	205.77
1985	.15	.03	3.78	2.83	23.07	50.44	74.68	17.03	.20	7.07	.38	15.56	195.25

Note: Totals may not agree due to rounding.

TABLE 458

PROJECTED NON-ASSOCIATED CONDENSATE PRODUCTION
LOWER 48 STATES
(MMB)

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.3	–	4.7	2.1	15.5	78.8	18.2	23.4	.1	2.6	–	–	145.9
1972	.3	–	5.2	1.5	13.9	75.9	20.1	23.9	.1	3.1	–	–	144.0
1973	.2	–	5.8	1.0	11.5	71.1	23.9	23.0	.1	3.8	–	–	140.4
1974	.1	–	6.3	1.1	9.2	66.0	27.2	22.6	.1	4.5	–	–	137.1
1975	.1	–	6.8	.9	8.4	63.2	29.6	22.1	.1	5.0	–	–	136.2
1976	.1	–	6.5	1.0	5.8	61.9	31.6	21.4	.1	4.9	–	–	133.3
1977	.1	–	5.6	1.4	6.1	64.2	33.4	20.7	.1	4.8	–	–	136.4
1978	.1	–	5.3	1.4	12.7	66.4	35.9	20.0	.1	4.4	–	–	146.5
1979	.1	–	5.0	1.4	13.8	66.7	38.7	19.3	.1	4.6	–	.1	149.8
1980	.1	–	4.9	1.5	14.4	65.9	41.6	18.9	.1	4.8	–	.1	152.3
1981	.1	–	4.7	1.6	15.2	64.0	44.2	18.7	.1	5.0	–	.3	154.0
1982	.1	–	4.6	1.7	15.9	63.5	47.1	18.6	.1	5.2	.1	.9	157.9
1983	.1	–	4.6	1.8	16.6	63.5	49.9	18.5	.1	5.4	.1	1.4	162.2
1984	.1	–	4.5	1.9	17.2	62.5	52.1	18.3	.1	5.6	.1	2.1	164.5
1985	.2	–	4.5	2.0	17.7	60.9	53.5	18.3	.2	5.7	.1	2.8	165.9

Note: Totals may not agree due to rounding.

TABLE 459

PROJECTED NON-ASSOCIATED C_5+ PRODUCTION
LOWER 48 STATES
(MMB)

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.4	–	2.9	1.4	9.1	73.3	17.0	14.4	.1	.9	–	–	119.4
1972	.3	–	3.2	1.0	8.2	70.7	18.7	14.6	.1	1.1	–	–	117.7
1973	.2	–	3.6	.7	6.8	66.2	22.2	14.1	.1	1.3	–	–	115.0
1974	.2	–	3.8	.7	5.4	61.4	25.3	13.8	.1	1.5	–	–	112.3
1975	.1	–	4.1	.6	4.9	58.8	27.6	13.5	.1	1.7	–	–	111.5
1976	.1	–	4.0	.7	3.4	57.6	29.4	13.1	.1	1.7	–	–	110.0
1977	.1	–	3.4	.9	3.6	59.7	31.0	12.7	.1	1.7	–	–	113.2
1978	.1	–	3.2	.9	7.5	61.8	33.4	12.2	.1	1.5	–	–	120.8
1979	.1	–	3.1	1.0	8.1	62.1	36.0	11.8	.1	1.6	–	–	123.8
1980	.1	–	3.0	1.0	8.5	61.3	38.7	11.5	.1	1.6	–	–	125.8
1981	.1	–	2.9	1.0	8.9	59.5	41.1	11.5	.1	1.7	–	–	126.9
1982	.2	–	2.8	1.1	9.4	59.1	43.8	11.4	.1	1.8	–	–	129.7
1983	.2	–	2.8	1.2	9.8	59.1	46.5	11.3	.1	1.9	–	–	132.8
1984	.2	–	2.8	1.2	10.1	58.1	48.5	11.2	.1	1.9	–	–	134.1
1985	.2	–	2.8	1.3	10.4	56.7	49.8	11.2	.1	2.0	–	–	134.4

Note: Totals may not agree due to rounding.

TABLE 460

PROJECTED NON-ASSOCIATED LPG PRODUCTION
LOWER 48 STATES
(MMB)

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.5	–	8.6	3.7	28.8	119.7	27.7	43.1	.2	5.5	–	–	237.8
1972	.4	–	9.5	2.6	25.8	115.3	30.6	43.9	.1	6.5	–	–	234.7
1973	.3	–	10.7	1.8	21.4	108.0	36.2	42.2	.1	7.9	–	–	228.6
1974	.2	–	11.5	1.9	17.1	100.2	41.3	41.5	.1	9.4	–	–	223.3
1975	.1	–	12.4	1.6	15.6	96.0	45.0	40.6	.1	10.4	–	–	222.0
1976	.2	–	12.0	1.8	10.9	94.0	47.9	39.3	.1	10.2	–	–	216.4
1977	.2	–	10.3	2.5	11.4	97.4	50.6	38.0	.1	10.2	–	–	220.7
1978	.1	–	9.7	2.5	23.7	100.8	54.6	36.7	.1	9.3	–	.1	237.8
1979	.2	–	9.2	2.6	25.7	101.3	58.8	35.4	.1	9.6	–	.1	243.0
1980	.2	–	8.9	2.7	26.9	100.0	63.1	34.6	.2	10.1	.1	.3	247.0
1981	.2	–	8.6	2.8	28.3	97.1	67.0	34.4	.2	10.5	.1	.8	250.2
1982	.2	–	8.5	3.0	29.6	96.4	71.5	34.2	.2	11.0	.1	2.1	256.9
1983	.2	–	8.4	3.1	30.9	96.4	75.8	34.0	.2	11.4	.2	3.5	264.3
1984	.2	–	8.3	3.3	32.0	94.8	79.1	33.6	.2	11.8	.3	5.1	268.7
1985	.2	–	8.4	3.6	32.9	92.5	81.2	33.6	.2	12.1	.4	6.8	271.8

Note: Totals may not agree due to rounding.

TABLE 461

PROJECTED TOTAL NON-ASSOCIATED GAS LIQUIDS PRODUCTION
LOWER 48 STATES
(MMB)

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	1.2	.1	16.2	7.2	53.4	271.8	62.9	80.9	.4	9.0	–	–	503.1
1972	.9	.1	17.9	5.0	47.9	261.9	69.4	82.4	.3	10.6	–	–	496.4
1973	.7	–	20.1	3.5	39.7	245.2	82.3	79.3	.2	12.9	–	–	484.0
1974	.5	–	21.6	3.7	31.7	227.7	93.9	77.9	.2	15.4	–	–	472.6
1975	.4	–	23.3	3.1	29.0	218.0	102.2	76.3	.2	17.1	–	–	469.7
1976	.4	–	22.6	3.5	20.1	213.5	108.8	73.8	.3	16.8	–	–	459.7
1977	.4	–	19.3	4.7	21.0	221.4	115.0	71.4	.3	16.7	–	.1	470.3
1978	.4	–	18.1	4.9	44.0	229.1	123.9	68.9	.3	15.3	–	.1	505.1
1979	.4	–	17.3	5.0	47.6	230.0	133.5	66.5	.3	15.8	–	.2	516.6
1980	.4	–	16.7	5.2	49.8	227.1	143.4	65.0	.4	16.5	.1	.4	525.1
1981	.5	–	16.2	5.4	52.4	220.7	152.3	64.6	.4	17.3	.1	1.2	531.1
1982	.5	–	16.0	5.7	54.9	219.1	162.5	64.2	.4	18.0	.2	3.0	544.6
1983	.5	.1	15.8	6.1	57.3	219.1	172.2	63.8	.5	18.7	.3	4.9	559.2
1984	.5	.1	15.6	6.5	59.2	215.4	179.6	63.1	.5	19.3	.4	7.1	567.3
1985	.5	.1	15.7	6.9	60.9	210.1	184.5	63.2	.6	19.7	.5	9.5	572.2

Note: Totals may not agree due to rounding.

TABLE 462

PROJECTED NON-ASSOCIATED CONDENSATE PRODUCTION
LOWER 48 STATES
(MMB)

Case IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.3	–	4.7	2.1	15.5	78.8	18.2	23.4	.1	2.6	–	–	145.9
1972	.3	–	5.2	1.5	13.6	75.1	19.8	23.8	.1	3.1	–	–	142.4
1973	.2	–	5.9	1.0	10.9	68.8	22.8	22.6	.1	3.7	–	–	136.0
1974	.1	–	6.4	1.1	8.5	62.5	25.2	22.0	.1	4.4	–	–	130.2
1975	.1	–	6.9	.9	7.6	58.5	26.5	21.3	.1	4.8	–	–	126.7
1976	.1	–	6.8	1.0	5.1	55.9	27.3	20.2	.1	4.7	–	–	121.2
1977	.1	–	5.9	1.4	5.2	56.3	27.8	19.2	.1	4.7	–	–	120.8
1978	.1	–	5.6	1.4	10.7	56.5	28.9	18.2	.1	4.3	–	–	125.9
1979	.1	–	5.5	1.5	11.5	54.7	30.1	17.1	.1	4.4	–	–	125.1
1980	.1	–	5.6	1.5	11.9	52.1	31.3	16.3	.1	4.6	–	.1	123.7
1981	.1	–	5.7	1.6	12.4	48.6	32.3	15.7	.1	4.8	–	.2	121.5
1982	.2	–	5.8	1.8	12.9	46.3	33.6	15.1	.1	4.9	.1	.6	121.4
1983	.2	–	6.0	1.9	13.4	44.7	35.1	14.5	.1	5.1	.1	1.0	122.0
1984	.2	–	6.1	2.1	13.8	42.1	36.2	13.8	.1	5.3	.1	1.4	121.1
1985	.2	–	6.2	2.2	14.3	39.2	37.1	13.3	.1	5.4	.1	1.8	120.0

Note: Totals may not agree due to rounding.

TABLE 463

PROJECTED NON-ASSOCIATED C_5+ PRODUCTIONS
LOWER 48 STATES
(MMB)

Case IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.4	–	2.9	1.4	9.1	73.3	17.0	14.4	.1	.9	–	–	119.4
1972	.3	–	3.2	1.0	8.0	69.8	18.4	14.6	.1	1.1	–	–	116.4
1973	.2	–	3.6	.7	6.4	64.0	21.2	13.9	.1	1.3	–	–	111.3
1974	.2	–	3.9	.7	5.0	58.2	23.4	13.5	.1	1.5	–	–	106.4
1975	.1	–	4.2	.6	4.4	54.4	24.7	13.0	.1	1.7	–	–	103.2
1976	.1	–	4.1	.7	3.0	52.0	25.4	12.4	.1	1.6	–	–	99.4
1977	.1	–	3.6	.9	3.1	52.4	25.9	11.8	.1	1.6	–	–	99.5
1978	.1	–	3.4	.9	6.3	52.6	26.9	11.1	.1	1.5	–	–	103.0
1979	.1	–	3.4	1.0	6.7	50.9	28.0	10.5	.1	1.5	–	–	102.2
1980	.1	–	3.4	1.0	7.0	48.5	29.1	10.0	.1	1.6	–	–	100.9
1981	.2	–	3.5	1.1	7.3	45.2	30.0	9.6	.1	1.6	–	–	98.5
1982	.2	–	3.6	1.2	7.6	43.1	31.3	9.3	.1	1.7	–	–	97.9
1983	.2	–	3.7	1.3	7.9	41.6	32.7	8.9	.1	1.8	–	–	97.9
1984	.2	–	3.7	1.4	8.1	39.1	33.7	8.4	.1	1.8	–	–	96.6
1985	.2	–	3.8	1.5	8.4	36.4	34.5	8.1	.1	1.8	–	–	94.9

Note: Totals may not agree due to rounding.

TABLE 464

PROJECTED NON-ASSOCIATED LPG PRODUCTION
LOWER 48 STATES
(MMB)

Case IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.5	–	8.6	3.7	28.8	119.7	27.7	43.1	.2	5.5	–	–	237.8
1972	.4	–	9.6	2.6	25.4	114.0	30.1	43.7	.1	6.5	–	–	232.3
1973	.3	–	10.8	1.8	20.3	104.4	34.6	41.6	.1	7.8	–	–	221.7
1974	.2	–	11.7	1.9	15.8	94.9	38.3	40.4	.1	9.2	–	–	212.4
1975	.1	–	12.7	1.6	14.1	88.8	40.3	39.0	.1	10.2	–	–	207.0
1976	.2	–	12.4	1.8	9.5	84.8	41.4	37.2	.1	9.9	–	–	197.4
1977	.2	–	10.8	2.5	9.7	85.5	42.3	35.3	.1	9.8	–	–	196.3
1978	.2	–	10.3	2.5	20.0	85.7	43.9	33.4	.1	9.0	–	.1	205.3
1979	.2	–	10.2	2.6	21.3	83.1	45.7	31.5	.1	9.2	–	.1	204.0
1980	.2	–	10.3	2.8	22.1	79.2	47.5	29.9	.1	9.6	.1	.2	202.0
1981	.2	–	10.4	2.9	23.0	73.7	49.0	28.9	.2	10.0	.1	.6	199.0
1982	.2	–	10.7	3.1	24.0	70.3	51.1	27.8	.2	10.4	.2	1.4	199.4
1983	.2	–	11.0	3.4	24.9	67.8	53.3	26.6	.2	10.8	.2	2.3	200.7
1984	.3	–	11.2	3.7	25.7	63.8	55.0	25.3	.2	11.1	.3	3.4	199.9
1985	.3	–	11.5	4.0	26.6	59.5	56.2	24.4	.2	11.3	.3	4.5	198.8

Note: Totals may not agree due to rounding.

TABLE 465

PROJECTED TOTAL NON-ASSOCIATED GAS LIQUIDS PRODUCTION
LOWER 48 STATES
(MMB)

Case IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	1.2	.1	16.2	7.2	53.4	271.8	62.9	80.9	.4	9.0	–	–	503.1
1972	.9	.1	18.0	5.0	47.1	258.9	68.3	82.0	.3	10.6	–	–	491.1
1973	.7	–	20.3	3.5	37.7	237.1	78.5	78.1	.2	12.8	–	–	469.0
1974	.5	–	22.0	3.6	29.2	215.5	86.9	75.8	.2	15.1	–	–	449.0
1975	.4	–	23.9	3.1	26.0	201.7	91.5	73.3	.2	16.7	–	–	436.9
1976	.4	–	23.4	3.5	17.6	192.7	94.1	69.8	.3	16.3	–	–	418.1
1977	.4	–	20.3	4.8	18.1	194.3	96.0	66.3	.3	16.1	–	–	416.5
1978	.4	–	19.4	4.9	37.0	194.8	99.8	62.8	.3	14.7	–	.1	434.2
1979	.4	–	19.1	5.1	39.5	188.8	103.7	59.1	.3	15.1	.1	.1	431.3
1980	.5	–	19.3	5.3	40.9	179.8	108.0	56.2	.3	15.7	.1	.3	426.5
1981	.5	–	19.6	5.6	42.7	167.4	111.2	54.3	.3	16.4	.2	.8	419.0
1982	.6	–	20.1	6.1	44.4	159.8	116.0	52.2	.4	17.0	.2	2.0	418.8
1983	.6	.1	20.6	6.5	46.2	154.1	121.1	49.9	.4	17.6	.3	3.3	420.7
1984	.6	.1	21.0	7.1	47.7	145.0	124.9	47.5	.4	18.1	.4	4.7	417.5
1985	.7	.1	21.6	7.8	49.2	135.1	127.8	45.7	.4	18.5	.5	6.4	413.7

Note: Totals may not agree due to rounding.

TABLE 466

PROJECTED NON-ASSOCIATED CONDENSATE PRODUCTION
LOWER 48 STATES
(MMB)

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.3	–	4.7	2.1	15.5	78.8	18.2	23.4	.1	2.6	–	–	145.9
1972	.3	–	5.2	1.5	13.9	75.9	20.1	23.9	.1	3.1	–	–	144.0
1973	.2	–	5.8	1.0	11.5	71.1	23.8	23.0	.1	3.7	–	–	140.2
1974	.1	–	6.3	1.1	9.1	65.8	27.0	22.5	.1	4.4	–	–	136.5
1975	.1	–	6.7	.9	8.3	62.8	29.1	22.0	.1	4.9	–	–	134.9
1976	.1	–	6.5	1.0	5.7	61.1	30.6	21.2	.1	4.8	–	–	131.1
1977	.1	–	5.5	1.3	5.9	63.0	31.9	20.4	.1	4.7	–	–	132.9
1978	.1	–	5.2	1.4	12.1	64.6	33.9	19.5	.1	4.2	–	–	141.1
1979	.1	–	4.9	1.4	12.9	64.2	35.9	18.6	.1	4.3	–	.1	142.4
1980	.1	–	4.7	1.4	13.3	62.7	37.9	18.0	.1	4.4	–	.1	142.7
1981	.1	–	4.5	1.4	13.7	60.1	39.6	17.6	.1	4.6	–	.3	142.0
1982	.1	–	4.4	1.5	14.1	58.8	41.5	17.2	.1	4.6	–	.7	143.2
1983	.1	–	4.3	1.5	14.5	58.0	43.5	16.8	.1	4.7	.1	1.1	144.8
1984	.1	–	4.1	1.6	14.8	56.2	45.0	16.3	.1	4.8	.1	1.6	144.7
1985	.1	–	4.1	1.7	15.1	54.1	46.0	16.1	.1	4.8	.1	2.1	144.3

Note: Totals may not agree due to rounding.

TABLE 467

PROJECTED NON-ASSOCIATED C_5+ PRODUCTION
LOWER 48 STATES
(MMB)

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.4	–	2.9	1.4	9.1	73.3	17.0	14.4	.1	.9	–	–	119.4
1972	.3	–	3.2	1.0	8.2	70.7	18.7	14.6	.1	1.1	–	–	117.7
1973	.2	–	3.6	.7	6.8	66.1	22.1	14.1	.1	1.3	–	–	114.9
1974	.2	–	3.8	.7	5.4	61.2	25.1	13.8	.1	1.5	–	–	111.8
1975	.1	–	4.1	.6	4.9	58.4	27.1	13.5	.1	1.7	–	–	110.4
1976	.1	–	4.0	.7	3.3	56.9	28.5	13.0	.1	1.6	–	–	108.2
1977	.1	–	3.4	.9	3.5	58.6	29.7	12.5	.1	1.6	–	–	110.3
1978	.1	–	3.2	.9	7.1	60.1	31.5	11.9	.1	1.5	–	–	116.4
1979	.1	–	3.0	.9	7.6	59.7	33.4	11.4	.1	1.5	–	–	117.7
1980	.1	–	2.9	.9	7.8	58.3	35.3	11.0	.1	1.5	–	–	117.9
1981	.1	–	2.8	.9	8.1	55.9	36.8	10.8	.1	1.6	–	–	117.0
1982	.1	–	2.7	1.0	8.3	54.7	38.6	10.5	.1	1.6	–	–	117.7
1983	.1	–	2.6	1.0	8.5	54.0	40.5	10.3	.1	1.6	–	–	118.7
1984	.1	–	2.5	1.1	8.7	52.3	41.8	10.0	.1	1.6	–	–	118.3
1985	.1	–	2.5	1.1	8.9	50.3	42.8	9.8	.1	1.6	–	–	117.3

Note: Totals may not agree due to rounding.

TABLE 468

PROJECTED NON-ASSOCIATED LPG PRODUCTION
LOWER 48 STATES
(MMB)

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.5	–	8.6	3.7	28.8	119.7	27.7	43.1	.2	5.5	–	–	237.8
1972	.4	–	9.5	2.6	25.8	115.3	30.6	43.9	.1	6.5	–	–	234.7
1973	.3	–	10.7	1.8	21.4	107.9	36.1	42.2	.1	7.9	–	–	228.4
1974	.2	–	11.5	1.9	17.0	99.9	41.0	41.4	.1	9.4	–	–	222.3
1975	.1	–	12.4	1.6	15.4	95.3	44.2	40.4	.1	10.3	–	–	219.9
1976	.1	–	11.9	1.8	10.6	92.8	46.5	38.9	.1	10.0	–	–	212.8
1977	.1	–	10.2	2.4	10.9	95.6	48.5	37.4	.1	9.8	–	–	215.1
1978	.1	–	9.5	2.4	22.5	98.0	51.4	35.8	.1	8.9	–	.1	229.1
1979	.1	–	9.0	2.4	24.0	97.5	54.5	34.2	.1	9.0	–	.1	231.0
1980	.2	–	8.6	2.5	24.7	95.1	57.6	33.0	.1	9.3	–	.3	231.4
1981	.2	–	8.3	2.6	25.5	91.2	60.0	32.3	.1	9.6	.1	.7	230.6
1982	.2	–	8.0	2.6	26.3	89.2	63.1	31.6	.2	9.8	.1	1.7	232.9
1983	.2	–	7.8	2.7	27.0	88.0	66.0	30.8	.2	10.0	.1	2.8	235.7
1984	.2	–	7.6	2.8	27.5	85.3	68.2	30.0	.2	10.0	.2	3.9	236.0
1985	.2	–	7.5	3.0	28.0	82.1	69.8	29.5	.2	10.1	.3	5.2	235.9

Note: Totals may not agree due to rounding.

TABLE 469

PROJECTED TOTAL NON-ASSOCIATED GAS LIQUIDS PRODUCTION
LOWER 48 STATES
(MMB)

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	1.2	.1	16.2	7.2	53.4	271.8	62.9	80.9	.4	9.0	–	–	503.1
1972	.9	.1	17.9	5.0	47.9	261.9	69.4	82.4	.3	10.6	–	–	496.4
1973	.7	–	20.1	3.5	39.6	245.0	82.1	79.3	.2	12.9	–	–	483.5
1974	.5	–	21.6	3.6	31.5	227.0	93.1	77.7	.2	15.3	–	–	470.6
1975	.3	–	23.2	3.1	28.6	216.5	100.4	75.9	.2	16.9	–	–	465.2
1976	.4	–	22.4	3.4	19.6	210.8	105.7	73.0	.2	16.4	–	–	452.1
1977	.4	–	19.1	4.6	20.3	217.1	110.1	70.2	.3	16.1	–	.1	458.3
1978	.4	–	17.8	4.7	41.8	222.7	116.8	67.3	.3	14.6	–	.1	486.6
1979	.4	–	16.9	4.7	44.5	221.4	123.7	64.2	.3	14.8	–	.2	491.1
1980	.4	–	16.2	4.8	45.7	216.1	130.7	62.0	.3	15.3	.1	.4	492.0
1981	.4	–	15.5	4.9	47.3	207.1	136.4	60.7	.3	15.7	.1	1.0	489.5
1982	.5	–	15.1	5.1	48.7	202.7	143.3	59.3	.4	16.0	.1	2.5	493.7
1983	.5	–	14.7	5.3	50.0	200.0	150.0	57.9	.4	16.3	.2	3.9	499.2
1984	.4	–	14.3	5.5	51.0	193.9	155.0	56.2	.4	16.4	.3	5.6	499.0
1985	.4	.1	14.1	5.7	52.0	186.6	158.6	55.4	.4	16.5	.4	7.3	497.5

Note: Totals may not agree due to rounding.

TABLE 470

PROJECTED NON-ASSOCIATED CONDENSATE PRODUCTION—LOWER 48 STATES
(MMB)

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.3	—	4.7	2.1	15.5	78.8	18.2	23.4	.1	2.6	—	—	145.9
1972	.3	—	5.2	1.5	13.6	75.1	19.8	23.8	.1	3.1	—	—	142.4
1973	.2	—	5.9	1.0	10.9	68.7	22.7	22.6	.1	3.7	—	—	135.9
1974	.1	—	6.4	1.1	8.4	62.4	25.0	21.9	.1	4.4	—	—	129.8
1975	.1	—	6.9	.9	7.5	58.3	26.2	21.2	.1	4.8	—	—	125.9
1976	.1	—	6.7	1.0	5.0	55.5	26.7	20.1	.1	4.6	—	—	119.8
1977	.1	—	5.8	1.3	5.1	55.7	26.9	19.0	.1	4.5	—	—	118.6
1978	.1	—	5.5	1.4	10.3	55.6	27.6	17.9	.1	4.1	—	—	122.6
1979	.1	—	5.4	1.4	10.8	53.6	28.3	16.7	.1	4.1	—	—	120.5
1980	.1	—	5.3	1.4	11.0	50.7	29.1	15.8	.1	4.2	—	.1	117.9
1981	.1	—	5.3	1.5	11.2	46.9	29.5	15.1	.1	4.3	—	.2	114.3
1982	.1	—	5.4	1.5	11.5	44.4	30.2	14.4	.1	4.4	.1	.5	112.6
1983	.2	—	5.4	1.6	11.7	42.5	31.1	13.6	.1	4.5	.1	.8	111.5
1984	.2	—	5.4	1.7	11.9	39.7	31.6	12.8	.1	4.5	.1	1.1	109.1
1985	.2	—	5.5	1.8	12.1	36.8	31.9	12.2	.1	4.5	.1	1.4	106.6

Note: Totals may not agree due to rounding.

TABLE 471

PROJECTED NON-ASSOCIATED C_5+ PRODUCTION—LOWER 48 STATES
(MMB)

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.4	–	2.9	1.5	9.1	73.3	17.0	14.4	.1	.9	–	–	119.4
1972	.3	–	3.2	1.0	8.0	69.8	18.4	14.6	.1	1.1	–	–	116.4
1973	.2	–	3.6	.7	6.4	63.9	21.1	13.9	.1	1.3	–	–	111.2
1974	.2	–	3.9	.7	5.0	58.0	23.3	13.4	.1	1.5	–	–	106.0
1975	.1	–	4.2	.6	4.4	54.2	24.4	13.0	.1	1.6	–	–	102.6
1976	.1	–	4.1	.7	2.9	51.6	24.8	12.3	.1	1.6	–	–	98.2
1977	.1	–	3.5	.9	3.0	51.8	25.1	11.6	.1	1.5	–	–	97.7
1978	.1	–	3.4	.9	6.0	51.7	25.7	11.0	.1	1.4	–	–	100.3
1979	.1	–	3.3	.9	6.3	49.8	26.4	10.2	.1	1.4	–	–	98.6
1980	.1	–	3.3	.9	6.4	47.2	27.1	9.7	.1	1.4	–	–	96.2
1981	.1	–	3.3	1.0	6.6	43.6	27.4	9.3	.1	1.5	–	–	92.8
1982	.2	–	3.3	1.0	6.7	41.3	28.1	8.8	.1	1.5	–	–	91.1
1983	.2	–	3.3	1.1	6.9	39.6	28.9	8.3	.1	1.5	–	–	89.9
1984	.2	–	3.3	1.1	7.0	37.0	29.4	7.9	.1	1.5	–	–	87.4
1985	.2	–	3.4	1.2	7.1	34.2	29.7	7.5	.1	1.5	–	–	84.9

Note: Totals may not agree due to rounding.

TABLE 472

PROJECTED NON-ASSOCIATED LPG PRODUCTION—LOWER 48 STATES
(MMB)

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.5	–	8.6	3.7	28.8	119.7	27.7	43.1	.2	5.5	–	–	237.8
1972	.4	–	9.6	2.6	25.4	114.0	30.1	43.7	.1	6.5	–	–	232.3
1973	.3	–	10.8	1.8	20.3	104.3	34.5	41.6	.1	7.8	–	–	221.5
1974	.2	–	11.7	1.9	15.7	94.7	38.0	40.3	.1	9.2	–	–	211.8
1975	.1	–	12.7	1.6	13.9	88.4	39.8	38.9	.1	10.1	–	–	205.6
1976	.2	–	12.3	1.8	9.3	84.2	40.5	36.9	.1	9.7	–	–	195.1
1977	.2	–	10.6	2.4	9.4	84.6	40.9	34.9	.1	9.5	–	–	192.7
1978	.1	–	10.1	2.5	19.1	84.4	42.0	32.9	.1	8.6	–	.1	199.8
1979	.2	–	9.8	2.5	20.0	81.3	43.0	30.7	.1	8.7	–	.1	196.5
1980	.2	–	9.8	2.5	20.4	77.0	44.1	29.0	.1	8.9	.1	.2	192.4
1981	.2	–	9.8	2.6	20.9	71.2	44.7	27.8	.1	9.1	.1	.5	186.9
1982	.2	–	9.9	2.8	21.4	67.4	45.9	26.4	.1	9.3	.1	1.2	184.6
1983	.2	–	9.9	2.9	21.8	64.5	47.1	25.0	.1	9.4	.2	1.9	183.2
1984	.2	–	10.0	3.0	22.1	60.3	47.9	23.6	.2	9.5	.2	2.6	179.6
1985	.2	–	10.1	3.2	22.5	55.8	48.4	22.5	.2	9.5	.3	3.5	176.2

Note: Totals may not agree due to rounding.

TABLE 473

PROJECTED TOTAL NON-ASSOCIATED GAS LIQUIDS PRODUCTION—LOWER 48 STATES
(MMB)

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	1.2	.1	16.2	7.2	53.4	271.8	62.9	80.9	.4	9.0	–	–	503.1
1972	.9	.1	18.0	5.0	47.1	258.9	68.3	82.0	.3	10.6	–	–	491.1
1973	.7	–	20.3	3.5	37.7	237.0	78.4	78.1	.2	12.8	–	–	468.6
1974	.5	–	21.9	3.6	29.1	215.1	86.4	75.7	.2	15.1	–	–	447.6
1975	.4	–	23.8	3.1	25.7	200.9	90.3	73.0	.2	16.5	–	–	434.0
1976	.4	–	23.2	3.4	17.3	191.3	92.1	69.3	.3	15.9	–	–	413.2
1977	.4	–	20.0	4.6	17.5	192.1	92.9	65.6	.3	15.6	–	–	409.0
1978	.4	–	18.9	4.7	35.4	191.7	95.3	61.7	.3	14.1	–	.1	422.7
1979	.4	–	18.5	4.8	37.1	184.8	97.7	57.7	.3	14.2	.1	.1	415.7
1980	.4	–	18.4	4.9	37.8	174.9	100.3	54.5	.3	14.6	.1	.2	406.5
1981	.5	–	18.3	5.1	38.7	161.6	101.6	52.1	.3	15.0	.1	.7	394.0
1982	.5	–	18.5	5.3	39.6	153.1	104.2	49.6	.3	15.2	.2	1.6	388.3
1983	.5	–	18.7	5.6	40.4	146.6	107.1	47.0	.3	15.4	.2	2.6	384.5
1984	.5	.1	18.7	5.9	41.0	137.0	108.9	44.2	.3	15.5	.3	3.7	376.1
1985	.5	.1	19.0	6.2	41.7	126.7	110.0	42.2	.3	15.5	.4	4.9	367.7

Note: Totals may not agree due to rounding.

TABLE 474

PROJECTED NON-ASSOCIATED CONDENSATE PRODUCTION—LOWER 48 STATES
(MMB)

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.3	–	4.7	2.1	15.5	78.8	18.2	23.4	.1	2.6	–	–	145.9
1972	.3	–	5.2	1.5	13.6	75.1	19.8	23.8	.1	3.1	–	–	142.4
1973	.2	–	5.9	1.0	10.9	68.6	22.6	22.6	.1	3.7	–	–	135.5
1974	.1	–	6.3	1.0	8.3	62.1	24.7	21.8	.1	4.3	–	–	128.8
1975	.1	–	6.8	.9	7.3	57.7	25.4	21.0	.1	4.7	–	–	123.9
1976	.1	–	6.6	1.0	4.8	54.6	25.4	19.8	.1	4.4	–	–	116.7
1977	.1	–	5.6	1.3	4.7	54.3	25.0	18.6	.1	4.2	–	–	113.9
1978	.1	–	5.2	1.3	9.3	53.7	24.9	17.3	.1	3.7	–	–	115.5
1979	.1	–	4.9	1.2	9.4	51.1	24.7	15.9	.1	3.6	–	–	111.1
1980	.1	–	4.7	1.2	9.1	47.6	24.5	14.8	.1	3.6	–	–	105.7
1981	.1	–	4.5	1.2	8.9	43.2	23.7	13.8	.1	3.5	–	.1	99.2
1982	.1	–	4.3	1.2	8.7	40.2	23.3	12.9	.1	3.4	–	.3	94.5
1983	.1	–	4.2	1.2	8.5	37.7	22.9	11.9	.1	3.3	–	.4	90.3
1984	.1	–	4.0	1.1	8.2	34.5	22.2	10.9	.1	3.1	–	.5	84.8
1985	.1	–	3.9	1.1	7.9	31.1	21.4	10.1	.1	3.0	–	.7	79.5

Note: Totals may not agree due to rounding.

TABLE 475

PROJECTED NON-ASSOCIATED C_5+ PRODUCTION—LOWER 48 STATES
(MMB)

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.4	–	2.9	1.4	9.1	73.3	17.0	14.4	.1	.9	–	–	119.4
1972	.3	–	3.2	1.0	8.0	69.8	18.4	14.6	.1	1.1	–	–	116.4
1973	.2	–	3.6	.7	6.4	63.8	21.0	13.8	.1	1.3	–	–	110.9
1974	.2	–	3.9	.7	4.9	57.8	22.9	13.4	.1	1.5	–	–	105.2
1975	.1	–	4.2	.6	4.3	53.7	23.6	12.8	.1	1.6	–	–	100.9
1976	.1	–	4.0	.6	2.8	50.8	23.6	12.1	.1	1.5	–	–	95.7
1977	.1	–	3.4	.8	2.8	50.6	23.2	11.4	.1	1.4	–	–	93.9
1978	.1	–	3.2	.8	5.4	49.9	23.2	10.6	.1	1.3	–	–	94.6
1979	.1	–	3.0	.8	5.5	47.5	23.0	9.7	.1	1.2	–	–	91.0
1980	.1	–	2.9	.8	5.4	44.3	22.8	9.0	.1	1.2	–	–	86.6
1981	.1	–	2.7	.8	5.3	40.2	22.1	8.5	.1	1.2	–	–	80.9
1982	.1	–	2.7	.8	5.1	37.4	21.7	7.9	.1	1.2	–	–	76.8
1983	.1	–	2.6	.8	5.0	35.1	21.3	7.3	.1	1.1	–	–	73.3
1984	.1	–	2.5	.7	4.8	32.1	20.7	6.6	.1	1.1	–	–	68.7
1985	.1	–	2.4	.7	4.7	29.0	19.9	6.2	.1	1.0	–	–	64.0

Note: Totals may not agree due to rounding.

TABLE 476

PROJECTED NON-ASSOCIATED LPG PRODUCTION—LOWER 48 STATES
(MMB)

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.5	–	8.6	3.7	28.8	119.7	27.7	43.1	.2	5.5	–	–	237.8
1972	.4	–	9.6	2.6	25.4	113.9	30.0	43.7	.1	6.5	–	–	232.2
1973	.3	–	10.8	1.8	20.2	104.2	34.3	41.5	.1	7.8	–	–	221.0
1974	.2	–	11.6	1.9	15.5	94.2	37.4	40.1	.1	9.1	–	–	210.1
1975	.1	–	12.5	1.6	13.5	87.6	38.6	38.5	.1	9.8	–	–	202.4
1976	.1	–	12.1	1.7	8.9	82.8	38.5	36.3	.1	9.3	–	–	190.0
1977	.1	–	10.3	2.3	8.8	82.5	37.9	34.1	.1	8.9	–	–	185.1
1978	.1	–	9.6	2.3	17.3	81.4	37.9	31.7	.1	7.8	–	–	188.3
1979	.1	–	9.0	2.2	17.4	77.5	37.6	29.2	.1	7.6	–	.1	180.9
1980	.1	–	8.6	2.2	17.0	72.3	37.2	27.1	.1	7.6	–	.1	172.3
1981	.2	–	8.2	2.1	16.6	65.6	36.0	25.4	.1	7.4	.1	.3	162.0
1982	.2	–	8.0	2.1	16.2	60.9	35.3	23.6	.1	7.2	.1	.7	154.4
1983	.2	–	7.7	2.1	15.7	57.3	34.8	21.8	.1	7.0	.1	1.0	147.7
1984	.1	–	7.4	2.0	15.2	52.4	33.7	19.9	.1	6.6	.1	1.3	138.9
1985	.1	–	7.2	2.0	14.7	47.3	32.5	18.5	.1	6.3	.1	1.7	130.5

Note: Totals may not agree due to rounding.

TABLE 477

PROJECTED TOTAL NON-ASSOCIATED GAS LIQUIDS PRODUCTION—LOWER 48 STATES
(MMB)

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	1.2	.1	16.2	7.2	53.4	271.8	62.9	80.9	.4	9.0	–	–	503.1
1972	.9	.1	18.0	5.0	47.0	258.8	68.2	82.0	.3	10.6	–	–	491.0
1973	.7	–	20.2	3.5	37.5	236.6	77.9	77.9	.2	12.7	–	–	467.4
1974	.5	–	21.8	3.6	28.7	214.1	85.0	75.3	.2	14.9	–	–	444.2
1975	.3	–	23.5	3.0	25.1	198.9	87.6	72.4	.2	16.0	–	–	427.2
1976	.4	–	22.7	3.3	16.5	188.2	87.5	68.2	.2	15.2	–	–	402.4
1977	.4	–	19.4	4.4	16.3	187.4	86.2	64.0	.3	14.5	–	–	392.9
1978	.3	–	18.0	4.4	32.0	185.0	86.0	59.5	.3	12.8	–	.1	398.4
1979	.3	–	17.0	4.2	32.3	176.1	85.3	54.9	.3	12.5	–	.1	383.0
1980	.4	–	16.1	4.2	31.5	164.2	84.4	50.9	.3	12.4	.1	.2	364.6
1981	.4	–	15.4	4.1	30.8	149.0	81.9	47.7	.2	12.2	.1	.4	342.2
1982	.4	–	15.0	4.0	30.1	138.5	80.3	44.4	.2	11.8	.1	.9	325.7
1983	.4	–	14.5	4.0	29.2	130.1	79.0	41.0	.2	11.4	.1	1.4	311.3
1984	.4	–	13.9	3.9	28.1	118.9	76.6	37.4	.2	10.9	.1	1.9	292.4
1985	.3	–	13.6	3.9	27.3	107.4	73.8	34.7	.2	10.3	.2	2.3	274.0

Note: Totals may not agree due to rounding.

TABLE 478

PROJECTED NON-ASSOCIATED CONDENSATE PRODUCTION—LOWER 48 STATES
(MMB)

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.3	–	4.7	2.1	15.5	78.8	18.2	23.4	.1	2.6	–	–	145.9
1972	.3	–	5.2	1.5	13.9	75.9	20.1	23.9	.1	3.1	–	–	143.9
1973	.2	–	5.8	1.0	11.4	70.9	23.6	22.9	.1	3.7	–	–	139.7
1974	.1	–	6.2	1.0	9.0	65.3	26.5	22.4	.1	4.4	–	–	135.0
1975	.1	–	6.7	.9	8.0	61.7	28.0	21.7	.1	4.8	–	–	132.0
1976	.1	–	6.4	1.0	5.4	59.4	28.7	20.7	.1	4.5	–	–	126.3
1977	.1	–	5.4	1.3	5.4	60.3	29.0	19.6	.1	4.3	–	–	125.5
1978	.1	–	5.0	1.3	10.8	60.7	29.6	18.5	.1	3.8	–	–	130.0
1979	.1	–	4.6	1.2	11.0	59.1	30.1	17.3	.1	3.8	–	–	127.4
1980	.1	–	4.4	1.2	10.9	56.2	30.5	16.2	.1	3.7	–	.1	123.3
1981	.1	–	4.1	1.2	10.8	52.1	30.2	15.4	.1	3.7	–	.2	117.9
1982	.1	–	3.9	1.2	10.6	49.4	30.2	14.5	.1	3.6	–	.4	113.9
1983	.1	–	3.7	1.1	10.3	47.1	30.2	13.6	.1	3.5	–	.6	110.3
1984	.1	–	3.4	1.1	10.0	44.0	29.8	12.6	.1	3.3	–	.8	105.3
1985	.1	–	3.3	1.1	9.7	40.6	29.3	11.9	.1	3.1	–	1.0	100.3

Note: Totals may not agree due to rounding.

TABLE 479

PROJECTED NON-ASSOCIATED C_5+ PRODUCTION—LOWER 48 STATES
(MMB)

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.4	–	2.9	1.4	9.1	73.3	17.0	14.4	.1	.9	–	–	119.4
1972	.3	–	3.2	1.0	8.1	70.6	18.7	14.6	.1	1.1	–	–	117.7
1973	.2	–	3.6	.7	6.7	65.9	22.0	14.0	.1	1.3	–	–	114.5
1974	.2	–	3.8	.7	5.3	60.7	24.6	13.7	.1	1.5	–	–	110.6
1975	.1	–	4.1	.6	4.7	57.4	26.0	13.3	.1	1.6	–	–	108.0
1976	.1	–	3.9	.6	3.2	55.3	26.7	12.7	.1	1.6	–	–	104.1
1977	.1	–	3.3	.8	3.2	56.1	26.9	12.0	.1	1.5	–	–	104.1
1978	.1	–	3.1	.8	6.3	56.5	27.6	11.3	.1	1.3	–	–	107.1
1979	.1	–	2.8	.8	6.5	54.9	28.0	10.6	.1	1.3	–	–	105.2
1980	.1	–	2.7	.8	6.4	52.3	28.3	9.9	.1	1.3	–	–	101.9
1981	.1	–	2.5	.8	6.3	48.5	28.1	9.4	.1	1.3	–	–	97.1
1982	.1	–	2.4	.8	6.2	45.9	28.1	8.9	.1	1.2	–	–	93.7
1983	.1	–	2.2	.7	6.1	43.8	28.1	8.3	.1	1.2	–	–	90.7
1984	.1	–	2.1	.7	5.9	40.9	27.8	7.7	.1	1.1	–	–	86.4
1985	.1	–	2.0	.7	5.7	37.8	27.2	7.3	.1	1.1	–	–	82.0

Note: Totals may not agree due to rounding.

TABLE 480

PROJECTED NON-ASSOCIATED LPG PRODUCTION—LOWER 48 STATES (MMB)

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	.5	–	8.6	3.7	28.8	119.7	27.7	43.1	.2	5.5	–	–	237.8
1972	.4	–	9.5	2.6	25.8	115.2	30.5	43.9	.1	6.5	–	–	234.6
1973	.3	–	10.7	1.8	21.3	107.6	35.9	42.1	.1	7.9	–	–	227.6
1974	.2	–	11.5	1.9	16.7	99.1	40.2	41.1	.1	9.2	–	–	220.0
1975	.1	–	12.3	1.6	14.9	93.7	42.5	39.9	.1	10.0	–	–	215.1
1976	.1	–	11.8	1.7	10.0	90.2	43.5	38.0	.1	9.5	–	–	205.1
1977	.1	–	9.9	2.3	10.1	91.5	44.0	36.1	.1	9.2	–	–	203.3
1978	.1	–	9.2	2.3	20.1	92.2	45.0	34.0	.1	8.1	–	.1	211.1
1979	.1	–	8.5	2.2	20.6	89.6	45.7	31.7	.1	7.9	–	.1	206.6
1980	.1	–	8.0	2.1	20.3	85.3	46.3	29.8	.1	7.9	–	.2	200.1
1981	.1	–	7.5	2.1	20.0	79.1	45.9	28.3	.1	7.8	–	.4	191.5
1982	.1	–	7.1	2.1	19.6	74.9	45.9	26.7	.1	7.5	–	1.0	185.2
1983	.1	–	6.7	2.0	19.2	71.5	45.9	25.0	.1	7.3	.1	1.5	179.4
1984	.1	–	6.3	2.0	18.6	66.7	45.3	23.2	.1	7.0	.1	2.0	171.4
1985	.1	–	6.0	2.0	18.1	61.6	44.4	21.8	.1	6.6	.1	2.5	163.5

Note: Totals may not agree due to rounding.

TABLE 481

PROJECTED TOTAL NON-ASSOCIATED GAS LIQUIDS PRODUCTION—LOWER 48 STATES
(MMB)

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	1.2	.1	16.2	7.2	53.4	271.8	62.9	80.9	.4	9.0	–	–	503.1
1972	.9	.1	17.9	5.0	47.8	261.8	69.3	82.4	.3	10.6	–	–	496.2
1973	.7	–	20.0	3.5	39.4	244.4	81.5	79.1	.2	12.9	–	–	481.7
1974	.5	–	21.5	3.6	31.0	225.1	91.3	77.2	.2	15.1	–	–	465.5
1975	.3	–	23.1	3.0	27.6	212.9	96.5	74.9	.2	16.4	–	–	455.1
1976	.4	–	22.1	3.3	18.6	205.0	98.9	71.4	.2	15.6	–	–	435.5
1977	.4	–	18.7	4.4	18.7	207.9	99.9	67.7	.3	15.0	–	–	432.9
1978	.3	–	17.2	4.3	37.2	209.5	102.2	63.8	.3	13.2	–	.1	448.1
1979	.3	–	16.0	4.2	38.1	203.6	103.9	59.6	.3	12.9	–	.1	439.2
1980	.3	–	15.1	4.1	37.5	193.7	105.1	56.0	.3	12.9	–	.3	425.3
1981	.4	–	14.1	4.0	37.1	179.8	104.3	53.1	.3	12.7	.1	.6	406.5
1982	.4	–	13.4	4.0	36.4	170.2	104.3	50.1	.3	12.4	.1	1.4	392.8
1983	.4	–	12.6	3.9	35.5	162.5	104.2	46.9	.2	12.0	.1	2.1	380.4
1984	.3	–	11.8	3.8	34.5	151.6	102.9	43.6	.2	11.4	.1	2.8	363.1
1985	.3	–	11.3	3.8	33.6	140.0	100.9	41.0	.2	10.8	.1	3.5	345.7

Note: Totals may not agree due to rounding.

Chapter Six—Section VIII

Alaska

Development of Frontier Area Projections Of Non-Associated Gas Reserve Additions, Production and Drilling Data

The frontier areas under consideration are the offshore Atlantic (Region 11A) and Alaska (Region 1). Alaska has been subdivided into the area north of the Brooks Range (Region 1N) and the area south of the Brooks Range (Region 1S). Since little or no drilling or production has occurred in these areas, a statistical approach based on local history cannot be applied to project the future. Therefore, these frontier areas were treated differently than the other regions.

Several members of the Task Group who had some familiarity with these areas were asked to make independent estimates for the frontier areas on an annual basis (1971 to 1985) for the following factors:

- Reserve additions
- Number of wells drilled
- Average well depth
- Annual production
- Average number of producing wells
- Average daily production per well.

An estimate was also made of the ultimate recoverable non-associated gas for each region, even though only a small portion of the ultimate will be produced by 1985.

The results of these independent projections were combined arithmetically without attempting to adjust for obvious differences of opinion on such items as initiation of exploration or production. These averaged results were then presented to the complete Task Group. Each member was given the opportunity to study the preliminary figures and make individual adjustments based on:

- Federal leasing schedules
- Initial proved reserves required to justify transportation facilities
- Date of first gas sales
- Annual rate of reserve depletion
- Minimum economic producing rate per well
- Ultimate reserves for each area.

Since these areas are characterized by high drilling and operating costs and do not have significant gas transportation facilities, they must achieve high threshold levels of reserves and productive capacity before production may be initiated. Economies of scale for individual wells, fields and transportation systems are extremely important for these frontier areas and may well be the controlling factors.

After study the Task Group selected certain basic parameters for each area. The most important are:

Alaska (1N)

- Average reserve additions of 101 BCF per successful well
- Success ratio of 50 percent for total wells drilled
- Producing depletion rate the same as that used for new gas reserves in Region 6, tabulated on Table 391 (Chapter Six, Section V)
- Well depth of 10,000 to 11,800 feet (increasing with time)
- Gas sales begin in 1978
- Drilling activity as shown on Tables 482 and 499 in this section.

Alaska (1S)

- Average reserve additions of 101 BCF per successful well
- Success ratio of 50 percent for total wells drilled
- Producing depletion rate of 4 percent per year
- Well depth of 8,500 to 9,200 feet (increasing with time)
- Gas sales begin in 1981
- Drilling activity as shown on Tables 482 and 499 in this section.

Alaska (General)

- The estimated ultimate recovery of non-associated gas for Alaska is projected to be 277 trillion cubic feet (TCF). This is comprised of 5 TCF discovered prior to 1971 and 272 TCF of future potentially discoverable gas. In this study the ultimate recovery has been divided with 117 TCF projected for North Alaska and 160 TCF for South Alaska. Future discoveries of 272 TCF are in agreement with the estimates of the Potential Gas Committee.
- A separate projection of non-associated gas liquids has not been made for Alaska. Industry plans have been announced which provide for construction of a chilled, high pressure gas line from the North Slope. This line will be capable of carrying high BTU gas to the markets. Similarly, in South Alaska it is expected

that the gas will be transported as LNG. In this form a high BTU gas stream could be transported. Since the Alaskan gas will enter the market as a high value fuel it is anticipated that processing to remove the liquids will not be economically attractive.

Atlantic (11A)

- Average reserve additions of 21 BCF per successful well
- Success ratio of 66 percent based on South Louisiana experience
- Estimated ultimate recovery of 55 TCF (same as Potential Gas Committee's forecast)
- Producing depletion rate of 5 percent per year
- Well depth of 8,900 to 10,200 feet (increasing with time)
- Gas sales begin in 1977
- Drilling activity as shown on Tables 314 and 328 (Chapter Six, Section III).

These conditions formed the basis for projections of high drilling—high finding case. For the low finding case reserve additions per successful well were decreased to 67 BCF for Alaska and 14 BCF for Atlantic offshore.

The tables in this section tabulate gas reserves and gas production for Alaska. For Atlantic offshore gas reserves and gas production, see Chapter Six, Section IV and V (Region 11A).

TABLE 482

PROJECTIONS FOR ALASKA

Case I

	Gas Footage Drilled Annually (000′)	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	82	444	59	503	200	20	220	187	18	205
1972	86	466	154	620	200	20	220	187	18	205
1973	92	491	167	658	200	20	220	187	18	205
1974	96	521	462	983	200	21	221	187	19	206
1975	205	1,048	536	1,584	200	25	225	187	22	209
1976	220	1,121	1,241	2,362	200	31	231	187	27	214
1977	592	3,192	1,500	4,692	200	36	236	187	32	219
1978	704	3,754	1,503	5,257	400	645	1,045	374	562	936
1979	763	4,073	1,571	5,644	600	755	1,355	561	658	1,219
1980	832	4,439	2,125	6,564	800	869	1,669	748	757	1,505
1981	891	4,750	2,157	6,907	1,200	982	2,182	1,123	856	1,979
1982	935	4,987	1,841	6,828	1,600	1,395	2,995	1,496	1,215	2,711
1983	1,225	6,711	653	7,364	1,800	1,508	3,308	1,684	1,314	2,998
1984	1,237	6,778	380	7,158	2,200	1,820	4,020	2,058	1,585	3,643
1985	1,237	6,778	370	7,148	2,600	1,936	4,536	2,432	1,686	4,118
Total	9,197	49,553	14,719	64,272	12,600	10,083	22,683	11,785	8,787	20,572

TABLE 483

PROJECTIONS FOR NORTH ALASKA
(NORTH OF BROOKS RANGE)

Case I

	Gas Footage Drilled Annually (000′)	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	41	197	42	239	—	—	—	—	—	—
1972	43	207	140	347	—	—	—	—	—	—
1973	46	218	140	358	—	—	—	—	—	—
1974	48	231	419	650	—	—	—	—	—	—
1975	154	739	474	1,213	—	—	—	—	—	—
1976	165	791	1,172	1,963	—	—	—	—	—	—
1977	296	1,416	1,409	2,825	—	—	—	—	—	—
1978	384	1,836	1,409	3,245	200	600	800	187	522	709
1979	416	1,992	1,451	3,443	400	700	1,100	374	609	983
1980	454	2,171	2,009	4,180	600	800	1,400	561	696	1,257
1981	486	2,323	2,051	4,374	700	900	1,600	655	783	1,438
1982	510	2,439	1,730	4,169	1,000	1,300	2,300	935	1,131	2,066
1983	525	2,512	558	3,070	1,100	1,400	2,500	1,029	1,218	2,247
1984	530	2,537	279	2,816	1,300	1,700	3,000	1,216	1,479	2,695
1985	530	2,537	279	2,816	1,500	1,800	3,300	1,403	1,566	2,969
Total	4,628	22,146	13,562	35,708	6,800	9,200	16,000	6,360	8,004	14,364

TABLE 484

PROJECTIONS FOR SOUTH ALASKA
(SOUTH OF BROOKS RANGE)

Case I

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	41	247	17	264	200	20	220	187	18	205
1972	43	259	14	273	200	20	220	187	18	205
1973	46	273	27	300	200	20	220	187	18	205
1974	48	290	43	333	200	21	221	187	19	206
1975	51	309	62	371	200	25	225	187	22	209
1976	55	330	69	399	200	31	231	187	27	214
1977	296	1,776	91	1,867	200	36	236	187	32	219
1978	320	1,918	94	2,012	200	45	245	187	40	227
1979	347	2,081	120	2,201	200	55	255	187	49	236
1980	378	2,268	116	2,384	200	69	269	187	61	248
1981	405	2,427	106	2,533	500	82	582	468	73	541
1982	425	2,548	111	2,659	600	95	695	561	84	645
1983	700	4,199	95	4,294	700	108	808	655	96	751
1984	707	4,241	101	4,342	900	120	1,020	842	106	948
1985	707	4,241	91	4,332	1,100	136	1,236	1,029	120	1,149
Total	4,569	27,407	1,157	28,564	5,800	883	6,683	5,425	783	6,208

TABLE 485

PROJECTIONS FOR ALASKA

Case IA

	Gas Footage Drilled Annually (000′)	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	82	296	59	355	200	20	220	187	18	205
1972	86	311	153	464	200	20	220	187	18	205
1973	92	329	165	494	200	20	220	187	18	205
1974	96	347	456	803	200	21	221	187	19	206
1975	205	699	523	1,222	200	24	224	187	21	208
1976	220	749	1,221	1,970	200	28	228	187	25	212
1977	592	2,132	1,468	3,600	200	32	232	187	28	215
1978	704	2,508	1,469	3,977	410	637	1,047	383	555	938
1979	763	2,721	1,524	4,245	512	743	1,255	479	647	1,126
1980	832	2,966	2,076	5,042	622	851	1,473	582	741	1,323
1981	891	3,177	2,108	5,285	937	959	1,896	876	835	1,711
1982	935	3,335	1,790	5,125	1,151	1,364	2,515	1,077	1,188	2,265
1983	1,225	4,488	615	5,103	1,263	1,471	2,734	1,181	1,281	2,462
1984	1,237	4,533	345	4,878	1,470	1,778	3,248	1,374	1,548	2,922
1985	1,237	4,533	340	4,873	1,670	1,888	3,558	1,562	1,644	3,206
Total	9,197	33,124	14,312	47,436	9,435	9,856	19,291	8,823	8,586	17,409

TABLE 486

PROJECTIONS FOR NORTH ALASKA
(NORTH OF BROOKS RANGE)

Case IA

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	41	131	42	173	–	–	–	–	–	–
1972	43	138	140	278	–	–	–	–	–	–
1973	46	146	140	286	–	–	–	–	–	–
1974	48	154	419	573	–	–	–	–	–	–
1975	154	493	474	967	–	–	–	–	–	–
1976	165	528	1,172	1,700	–	–	–	–	–	–
1977	296	946	1,409	2,355	–	–	–	–	–	–
1978	384	1,227	1,409	2,636	210	600	810	196	522	718
1979	416	1,331	1,451	2,782	312	700	1,012	292	609	901
1980	454	1,451	2,009	3,460	422	800	1,222	395	696	1,091
1981	486	1,554	2,051	3,605	537	900	1,437	502	783	1,285
1982	510	1,631	1,730	3,361	651	1,300	1,951	609	1,131	1,740
1983	525	1,680	558	2,238	763	1,400	2,163	713	1,218	1,931
1984	530	1,697	279	1,976	870	1,700	2,570	813	1,479	2,292
1985	530	1,697	279	1,976	970	1,800	2,770	907	1,566	2,473
Total	4,628	14,804	13,562	28,366	4,735	9,200	13,935	4,427	8,004	12,431

TABLE 487

PROJECTIONS FOR SOUTH ALASKA
(SOUTH OF BROOKS RANGE)

Case IA

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	41	165	17	182	200	20	220	187	18	205
1972	43	173	13	186	200	20	220	187	18	205
1973	46	183	25	208	200	20	220	187	18	205
1974	48	193	37	230	200	21	221	187	19	206
1975	51	206	49	255	200	24	224	187	21	208
1976	55	221	49	270	200	28	228	187	25	212
1977	296	1,186	59	1,245	200	32	232	187	28	215
1978	320	1,281	60	1,341	200	37	237	187	33	220
1979	347	1,390	73	1,463	200	43	243	187	38	225
1980	378	1,515	67	1,582	200	51	251	187	45	232
1981	405	1,623	57	1,680	400	59	459	374	52	426
1982	425	1,704	60	1,764	500	64	564	468	57	525
1983	700	2,808	57	2,865	500	71	571	468	63	531
1984	707	2,836	66	2,902	600	78	678	561	69	630
1985	707	2,836	61	2,897	700	88	788	655	78	733
Total	4,569	18,320	750	19,070	4,700	656	5,356	4,396	582	4,978

TABLE 488

PROJECTIONS FOR ALASKA

Case II

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	82	444	59	503	200	20	220	187	18	205
1972	84	453	154	607	200	20	220	187	18	205
1973	86	464	166	630	200	20	220	187	18	205
1974	88	478	362	840	200	21	221	187	19	206
1975	184	934	379	1,313	200	25	225	187	22	209
1976	191	973	899	1,872	200	29	229	187	26	213
1977	500	2,693	1,197	3,890	200	35	235	187	31	218
1978	577	3,079	1,338	4,417	500	543	1,043	468	473	941
1979	609	3,249	1,358	4,607	600	751	1,351	561	654	1,215
1980	645	3,443	1,732	5,175	700	863	1,563	655	752	1,407
1981	671	3,584	1,684	5,268	1,100	875	1,975	1,029	762	1,791
1982	692	3,692	1,412	5,104	1,200	985	2,185	1,123	858	1,981
1983	898	4,921	507	5,428	1,500	1,397	2,897	1,403	1,217	2,620
1984	907	4,969	331	5,300	1,700	1,508	3,208	1,590	1,314	2,904
1985	907	4,969	317	5,286	2,100	1,622	3,722	1,964	1,413	3,377
Total	**7,121**	38,345	**11,895**	**50,240**	**10,800**	8,714	**19,514**	**10,102**	7,595	**17,697**

TABLE 489

PROJECTIONS FOR NORTH ALASKA
(NORTH OF BROOKS RANGE)

Case II

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	41	197	42	239	–	–	–	–	–	–
1972	42	201	140	341	–	–	–	–	–	–
1973	43	206	140	346	–	–	–	–	–	–
1974	44	212	321	533	–	–	–	–	–	–
1975	138	659	321	980	–	–	–	–	–	–
1976	143	686	837	1,523	–	–	–	–	–	–
1977	250	1,195	1,116	2,311	–	–	–	–	–	–
1978	315	1,506	1,256	2,762	300	500	800	281	435	716
1979	332	1,589	1,256	2,845	400	700	1,100	374	609	983
1980	352	1,684	1,632	3,316	500	800	1,300	468	696	1,164
1981	366	1,753	1,590	3,343	600	800	1,400	561	696	1,257
1982	377	1,806	1,311	3,117	700	900	1,600	655	783	1,438
1983	385	1,842	419	2,261	900	1,300	2,200	842	1,131	1,973
1984	389	1,860	237	2,097	1,000	1,400	2,400	935	1,218	2,153
1985	389	1,860	237	2,097	1,200	1,500	2,700	1,122	1,305	2,427
Total	3,606	17,256	10,855	28,111	5,600	7,900	13,500	5,238	6,873	12,111

TABLE 490

PROJECTIONS FOR SOUTH ALASKA
(SOUTH OF BROOKS RANGE)

Case II

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	41	247	17	264	200	20	220	187	18	205
1972	42	252	14	266	200	20	220	187	18	205
1973	43	258	26	284	200	20	220	187	18	205
1974	44	266	41	307	200	21	221	187	19	206
1975	46	275	58	333	200	25	225	187	22	209
1976	48	287	62	349	200	29	229	187	26	213
1977	250	1,498	81	1,579	200	35	235	187	31	218
1978	262	1,573	82	1,655	200	43	243	187	38	225
1979	277	1,660	102	1,762	200	51	251	187	45	232
1980	293	1,759	100	1,859	200	63	263	187	56	243
1981	305	1,831	94	1,925	500	75	575	468	66	534
1982	315	1,886	101	1,987	500	85	585	468	75	543
1983	513	3,079	88	3,167	600	97	697	561	86	647
1984	518	3,109	94	3,203	700	108	808	655	96	751
1985	518	3,109	80	3,189	900	122	1,022	842	108	950
Total	**3,515**	**21,089**	**1,040**	**22,129**	**5,200**	**814**	**6,014**	**4,864**	**722**	**5,586**

TABLE 491

PROJECTIONS FOR ALASKA

Case III

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	82	296	59	355	200	20	220	187	18	205
1972	84	302	153	455	200	20	220	187	18	205
1973	86	309	164	473	200	20	220	187	18	205
1974	88	319	356	675	200	21	221	187	19	206
1975	184	624	367	991	200	24	224	187	21	208
1976	191	649	881	1,530	200	27	227	187	24	211
1977	500	1,796	1,169	2,965	200	31	231	187	27	214
1978	577	2,053	1,308	3,361	300	535	835	281	466	747
1979	609	2,165	1,319	3,484	500	741	1,241	468	645	1,113
1980	645	2,296	1,691	3,987	500	847	1,347	468	738	1,206
1981	671	2,390	1,643	4,033	800	854	1,654	748	744	1,492
1982	692	2,462	1,365	3,827	900	960	1,860	842	836	1,678
1983	898	3,280	467	3,747	1,000	1,366	2,366	935	1,189	2,124
1984	907	3,314	294	3,608	1,100	1,471	2,571	1,029	1,281	2,310
1985	907	3,314	289	3,603	1,300	1,579	2,879	1,216	1,375	2,591
Total	7,121	25,569	11,525	37,094	7,800	8,516	16,316	7,296	7,419	14,715

TABLE 492

PROJECTIONS FOR NORTH ALASKA
(NORTH OF BROOKS RANGE)

Case III

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	41	131	42	173	–	–	–	–	–	–
1972	42	134	140	274	–	–	–	–	–	–
1973	43	137	140	277	–	–	–	–	–	–
1974	44	142	321	463	–	–	–	–	–	–
1975	138	440	321	761	–	–	–	–	–	–
1976	143	458	837	1,295	–	–	–	–	–	–
1977	250	797	1,116	1,913	–	–	–	–	–	–
1978	315	1,004	1,256	2,260	100	500	600	94	435	529
1979	332	1,059	1,256	2,315	300	700	1,000	281	609	890
1980	352	1,123	1,632	2,755	300	800	1,100	281	696	977
1981	366	1,169	1,590	2,759	400	800	1,200	374	696	1,070
1982	377	1,204	1,311	2,515	500	900	1,400	468	783	1,251
1983	385	1,228	419	1,647	600	1,300	1,900	561	1,131	1,692
1984	389	1,241	237	1,478	600	1,400	2,000	561	1,218	1,779
1985	389	1,241	237	1,478	700	1,500	2,200	655	1,305	1,960
Total	3,606	11,508	10,855	22,363	3,500	7,900	11,400	3,275	6,873	10,141

TABLE 493

PROJECTIONS FOR SOUTH ALASKA
(SOUTH OF BROOKS RANGE)

Case III

	Gas Footage Drilled Annually (000′)	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	41	165	17	182	200	20	220	187	18	205
1972	42	168	13	181	200	20	220	187	18	205
1973	43	172	24	196	200	20	220	187	18	205
1974	44	177	35	212	200	21	221	187	19	206
1975	46	184	46	230	200	24	224	187	21	208
1976	48	191	44	235	200	27	227	187	24	211
1977	250	99	53	1,052	200	31	231	187	27	214
1978	262	1,049	52	1,101	200	35	235	187	31	218
1979	277	1,106	63	1,169	200	41	241	187	36	223
1980	293	1,173	59	1,232	200	47	247	187	42	229
1981	305	1,221	53	1,274	400	54	454	374	48	422
1982	315	1,258	54	1,312	400	60	460	374	53	427
1983	513	2,052	48	2,100	400	66	466	374	58	432
1984	518	2,073	57	2,130	500	71	571	468	63	531
1985	518	2,073	52	2,125	600	79	679	561	70	631
Total	3,515	14,061	670	14,731	4,300	616	4,916	4,021	546	4,567

TABLE 494

PROJECTIONS FOR ALASKA

Case IV

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	82	292	59	351	200	20	220	187	18	205
1972	78	280	54	334	200	20	220	187	18	205
1973	74	269	63	332	200	20	220	187	18	205
1974	72	259	127	386	200	20	220	187	18	205
1975	139	468	133	601	200	23	223	187	20	207
1976	133	450	130	580	200	25	225	187	22	209
1977	318	1,145	134	1,279	200	27	227	187	24	211
1978	336	1,196	174	1,370	200	29	229	187	26	213
1979	323	1,149	179	2,328	200	33	233	187	29	216
1980	310	1,102	217	1,319	200	37	237	187	33	220
1981	297	1,059	870	1,929	300	41	341	281	36	317
1982	286	1,017	1,152	2,169	300	44	344	281	39	320
1983	350	1,276	1,288	2,564	500	547	1,047	468	477	945
1984	336	1,224	1,292	2,516	700	751	1,451	655	654	1,309
1985	322	1,175	1,664	2,839	900	857	1,757	842	746	1,588
Total	3,456	12,361	7,536	19,897	4,700	2,494	7,194	4,397	2,178	6,575

TABLE 495

PROJECTIONS FOR NORTH ALASKA
(NORTH OF BROOKS RANGE)

Case IV

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	41	130	42	172	—	—	—	—	—	—
1972	39	124	42	166	—	—	—	—	—	—
1973	37	119	42	161	—	—	—	—	—	—
1974	36	115	98	213	—	—	—	—	—	—
1975	104	330	98	428	—	—	—	—	—	—
1976	100	317	98	415	—	—	—	—	—	—
1977	159	508	98	606	—	—	—	—	—	—
1978	183	585	140	725	—	—	—	—	—	—
1979	176	562	140	702	—	—	—	—	—	—
1980	169	539	181	720	—	—	—	—	—	—
1981	162	518	837	1,355	—	—	—	—	—	—
1982	156	497	1,116	1,613	—	—	—	—	—	—
1983	150	478	1,256	1,734	200	500	700	187	435	622
1984	144	458	1,256	1,714	400	700	1,100	374	609	983
1985	138	440	1,632	2,072	500	800	1,300	468	696	1,164
Total	**1,794**	**5,720**	**7,076**	**12.796**	**1,100**	**2,000**	**3,100**	**1,029**	**1,740**	**2,769**

TABLE 496

PROJECTIONS FOR SOUTH ALASKA
(SOUTH OF BROOKS RANGE)

Case IV

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Market Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	41	162	17	179	200	20	220	187	18	205
1972	39	156	12	168	200	20	187	18	205	205
1973	37	150	21	171	200	20	220	187	18	205
1974	36	144	29	173	200	20	220	187	18	205
1975	35	138	35	173	200	23	223	187	20	207
1976	33	133	32	165	200	25	225	187	22	209
1977	159	637	36	673	200	27	227	187	24	211
1978	153	611	34	645	200	29	229	187	26	213
1979	147	587	39	626	200	33	233	187	29	216
1980	141	563	36	599	200	37	237	187	33	220
1981	135	541	33	574	300	41	341	281	36	317
1982	130	520	36	556	300	44	344	281	39	320
1983	200	798	32	830	300	47	347	281	42	323
1984	192	766	36	802	300	51	351	281	45	326
1985	184	735	32	767	400	57	457	374	50	424
Total	1,662	6,641	460	7,101	3,600	494	4,094	3,368	438	3,806

TABLE 497

PROJECTIONS FOR ALASKA

Case IVA

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	82	437	59	496	200	20	220	187	18	205
1972	78	420	55	475	200	20	220	187	18	205
1973	74	403	65	468	200	20	220	187	18	205
1974	72	387	131	518	200	21	221	187	19	206
1975	137	702	140	842	200	23	223	187	20	207
1976	132	674	140	814	200	26	226	187	23	210
1977	318	1,713	149	1,862	200	29	229	187	26	213
1978	336	1,791	192	1,983	200	34	234	187	30	217
1979	322	1,719	200	1,919	200	40	240	187	35	222
1980	310	1,650	237	1,887	200	46	246	187	41	228
1981	297	1,584	890	2,474	400	52	452	374	46	420
1982	285	1,521	1,175	2,696	400	58	458	374	51	425
1983	348	1,907	1,311	3,218	1,000	564	1,564	935	492	1,427
1984	334	1,831	1,318	3,149	1,000	771	1,771	935	672	1,607
1985	321	1,758	1,688	3,446	1,200	880	2,080	1,123	767	1,890
Total	3,446	18,497	7,750	26,247	6,000	2,604	8,604	5,611	2,276	7,887

TABLE 498

PROJECTIONS FOR NORTH ALASKA
(NORTH OF BROOKS RANGE)

Case IVA

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	41	194	42	236	–	–	–	–	–	–
1972	39	186	42	228	–	–	–	–	–	–
1973	37	179	42	221	–	–	–	–	–	–
1974	36	172	98	270	–	–	–	–	–	–
1975	103	495	98	593	–	–	–	–	–	–
1976	99	475	98	573	–	–	–	–	–	–
1977	159	760	98	858	–	–	–	–	–	–
1978	183	876	140	1,016	–	–	–	–	–	–
1979	176	841	140	981	–	–	–	–	–	–
1980	169	807	181	988	–	–	–	–	–	–
1981	162	775	837	1,612	–	–	–	–	–	–
1982	155	744	1,116	1,860	–	–	–	–	–	–
1983	149	714	1,256	1,970	600	500	1,100	561	435	996
1984	143	685	1,256	1,941	600	700	1,300	561	609	1,170
1985	138	658	1,632	2,290	700	800	1,500	655	696	1,351
Total	1,789	8,561	7,076	15,637	1,900	2,000	3,900	1,777	1,740	3,517

TABLE 499

PROJECTIONS FOR SOUTH ALASKA
(SOUTH OF BROOKS RANGE)

Case IVA

	Gas Footage Drilled Annually (000')	Gas Reserves Additions Non-Assoc. (BCF)	Gas Reserves Additions A&D (BCF)	Gas Reserves Additions Total (BCF)	Wellhead Gas Production Non-Assoc. (BCF)	Wellhead Gas Production A&D (BCF)	Wellhead Gas Production Total (BCF)	Marketed Gas Production Non-Assoc. (BCF)	Marketed Gas Production A&D (BCF)	Marketed Gas Production Total (BCF)
1971	41	243	17	260	200	20	220	187	18	205
1972	39	234	13	247	200	20	220	187	18	205
1973	37	224	23	247	200	20	220	187	18	205
1974	36	215	33	248	200	21	221	187	19	206
1975	34	207	42	249	200	23	223	187	20	207
1976	33	199	42	241	200	26	226	187	23	210
1977	159	953	51	1,004	200	29	229	187	26	213
1978	153	915	52	967	200	34	234	187	30	217
1979	146	878	60	938	200	40	240	187	35	222
1980	141	843	56	899	200	46	246	187	41	228
1981	135	809	53	862	400	52	452	374	46	420
1982	130	177	59	836	400	58	458	374	51	425
1983	199	1,193	55	1,248	400	64	464	374	57	431
1984	191	1,146	62	1,208	400	71	471	374	63	437
1985	183	1,100	56	1,156	500	80	580	468	71	539
Total	1,657	9,936	674	10,610	4,100	604	4,704	3,834	536	4,370

TABLE 500

CUMULATIVE NON-ASSOCIATED GAS RESERVES DISCOVERED ALASKA

	Case I (BCF)	Case IA (BCF)	Case II (BCF)	Case III (BCF)	Case IV (BCF)	Case IVA (BCF)
1970	5,101	5,101	5,101	5,101	5,101	5,101
1971	5,545	5,397	5,545	5,397	5,393	5,538
1972	6,011	5,708	5,998	5,699	5,673	5,958
1973	6,502	6,037	6,462	6,008	5,942	6,361
1974	7,023	6,384	6,940	6,327	6,201	6,748
1975	8,071	7,083	7,874	6,951	6,669	7,450
1976	9,192	7,832	8,847	7,600	7,119	8,124
1977	12,384	9,964	11,540	9,396	8,264	9,873
1978	16,138	12,472	14,619	11,449	9,460	11,628
1979	20,211	15,193	17,868	13,614	10,609	13,347
1980	24,650	18,159	21,311	15,910	11,711	14,997
1981	29,400	21,336	24,895	18,300	12,770	16,581
1982	34,387	24,671	28,587	20,762	13,787	18,102
1983	41,098	29,159	33,508	24,042	15,063	20,009
1984	47,876	33,692	38,477	27,356	16,287	21,840
1985	54,654	38,225	43,446	30,670	17,462	23,598

TABLE 501

CUMULATIVE NON-ASSOCIATED GAS RESERVES DISCOVERED NORTH ALASKA—NORTH OF BROOKS RANGE

	Case I (BCF)	Case IA (BCF)	Case II (BCF)	Case III (BCF)	Case IV (BCF)	Case IVA (BCF)
1970	—	—	—	—	—	—
1971	197	131	197	131	130	194
1972	404	269	398	265	254	380
1973	622	415	604	402	373	559
1974	853	569	816	544	488	731
1975	1,592	1,062	1,475	984	818	1,226
1976	2,383	1,590	2,161	1,442	1,135	1,701
1977	3,799	2,536	3,356	2,239	1,643	2,461
1978	5,635	3,763	4,862	3,243	2,228	3,337
1979	7,627	5,094	6,451	4,302	2,790	4,178
1980	9,789	6,545	8,135	5,425	3,329	4,985
1981	12,121	8,099	9.888	6,594	3,847	5,760
1982	14,560	9,730	11,694	7,798	4,344	6,504
1983	17,072	11,410	13,536	9,026	4,822	7,218
1984	19,609	13,107	15,396	10,267	5,280	7,903
1985	22,146	14,804	17,256	11,508	5,720	8,561

TABLE 502

CUMULATIVE NON-ASSOCIATED GAS RESERVES DISCOVERED SOUTH ALASKA—SOUTH OF BROOKS RANGE

	Case I (BCF)	Case IA (BCF)	Case II (BCF)	Case III (BCF)	Case IV (BCF)	Case IVA (BCF)
1970	5,101	5,101	5,101	5,101	5,101	5,101
1971	5,348	5,266	5,348	5,266	5,263	5,344
1972	5,607	5,439	5,600	5,434	5,419	5,578
1973	5,880	5,622	5,858	5,606	5,569	5,802
1974	6,170	5,815	6,124	5,783	5,713	6,017
1975	6,479	6,021	6,399	5,967	5,851	6,224
1976	6,809	6,242	6,686	6,158	5,984	6,423
1977	8,585	7,428	8,184	7,157	6,621	7,376
1978	10,503	8,709	9,757	8,206	7,232	8,291
1979	12,584	10,099	11,417	9,312	7,819	9,169
1980	14,852	11,614	13,176	10,485	8,382	10,012
1981	17,279	13,237	15,007	11,706	8,923	10,821
1982	19,827	14,941	16,893	12,964	9,443	11,598
1983	24,026	17,749	19,972	15,016	10,241	12,791
1984	28,267	20,585	23,081	17,089	11,007	13,937
1985	32,508	23,421	26,190	19,162	11,742	15,037

TABLE 503

PERCENT OF ULTIMATE NON-ASSOCIATED GAS DISCOVERED—ALASKA

	Percent				Percent		
	North Alaska	South Alaska	Alaska Total		North Alaska	South Alaska	Alaska Total
1970	—	3.2	1.8				
Case I				Case III			
1975	1.4	4.0	2.9	1975	0.8	3.7	2.5
1980	8.4	9.3	8.9	1980	4.6	6.5	5.7
1985	18.9	20.3	19.7	1985	9.8	12.0	11.1
Case IA				Case IV			
1975	0.9	3.8	2.6	1975	0.7	3.7	2.4
1980	5.6	7.2	6.5	1980	2.8	5.2	4.2
1985	12.6	14.6	13.8	1985	4.9	7.3	6.3
Case II				Case IVA			
1975	1.3	4.0	2.8	1975	1.0	3.9	2.7
1980	6.9	8.2	7.7	1980	4.3	6.2	5.4
1985	14.7	16.3	15.7	1985	7.3	9.4	8.5
Ultimate Non-Associated Gas				117,100	160,301		277,401

TABLE 504

ALASKAN EXPLORATION AND DEVELOPMENT EXPENDITURES
(Millions of Dollars)

	Case I	Case IA	Case II	Case III	Case IV	Case IVA
			Non-Associated Gas—All Alaska			
1971-1975	207	207	192	192	164	164
1976-1980	1,226	1,210	991	978	543	545
1981-1985	2,282	2,232	1,688	1,648	663	687
Total	3,715	3,649	2,871	2,818	1,370	1,396
			Oil—North Slope			
1971-1975	835	835	681	681	227	227
1976-1980	2,412	2,412	2,001	2,001	455	455
1981-1985	1,696	1,696	1,313	1,313	2,001	2,001
Total	4,943	4,943	3,995	3,995	2,683	2,683

TABLE 505

CAPITAL REQUIREMENTS FOR ALASKA—GAS OPERATIONS
(Millions of 1970 Dollars)

Case I

	Producing Well Investment	Lease Equipment	Lease Bonus	Dry Hole Costs	Geological, Geophysical and Lease Rental Costs	Requirements
1971	8.3	3.9	6.7	7.8	3.1	29.8
1972	8.7	3.3	6.7	8.3	3.2	30.2
1973	9.3	3.5	8.3	8.8	3.4	33.3
1974	9.8	3.7	9.2	9.5	3.6	35.8
1975	21.5	8.1	19.0	21.7	7.4	77.7
5-Year Total	57.6	22.5	49.9	56.1	20.7	206.8
1976	23.1	8.7	21.9	23.5	8.0	85.2
1977	60.8	22.8	59.3	59.5	19.8	222.2
1978	72.8	27.3	86.3	72.3	24.1	282.8
1979	79.3	29.7	87.0	79.1	26.8	301.9
1980	86.7	32.5	97.6	87.0	29.7	333.5
5-Year Total	322.7	121.0	352.1	321.4	108.4	1,225.6
1981	94.1	35.3	136.4	96.2	32.9	394.9
1982	99.2	37.2	111.3	101.2	35.0	383.9
1983	128.7	48.3	145.3	128.6	45.0	495.9
1984	130.3	48.8	148.5	130.1	46.3	504.0
1985	130.6	49.0	146.4	130.3	47.1	503.4
5-Year Total	582.9	218.6	687.9	586.4	206.3	2,282.1
15-Year Total	963.2	362.1	1,089.9	963.9	335.4	3,714.5

TABLE 506

CAPITAL REQUIREMENTS FOR ALASKA—GAS OPERATIONS
(Millions of 1970 Dollars)

Case IA

	Producing Well Investment	Lease Equipment	Lease Bonus	Dry Hole Costs	Geological, Geophysical and Lease Rental Costs	Requirements
1971	8.3	3.9	6.7	7.8	3.1	29.8
1972	8.8	3.3	6.7	8.3	3.2	30.3
1973	9.3	3.5	8.3	8.9	3.4	33.4
1974	9.8	3.7	9.1	9.5	3.6	35.7
1975	21.6	8.1	18.8	21.7	7.4	77.6
5-Year Total	57.8	22.5	49.6	56.2	20.7	206.8
1976	23.2	8.7	21.3	23.5	8.0	84.7
1977	60.9	22.8	58.3	59.6	19.9	221.5
1978	73.0	27.3	80.1	72.4	24.2	277.0
1979	79.4	29.7	82.9	79.3	26.8	298.1
1980	86.9	32.6	92.4	87.2	29.8	328.9
5-Year Total	323.4	121.1	335.0	322.0	108.7	1,210.2
1981	94.4	35.4	118.5	96.5	33.0	377.8
1982	99.5	37.4	102.9	101.5	35.2	376.5
1983	129.0	48.4	136.0	129.0	45.1	487.5
1984	130.7	49.0	138.6	130.5	46.4	495.2
1985	131.0	49.1	136.7	130.7	47.2	494.7
5-Year Total	584.6	219.3	632.7	588.2	206.9	2,231.7
15-Year Total	965.8	362.9	1,017.3	966.4	336.3	3,648.7

TABLE 507

CAPITAL REQUIREMENTS FOR ALASKA–GAS OPERATIONS
(Millions of 1970 Dollars)

Case II

	Producing Well Investment	Lease Equipment	Lease Bonus	Dry Hole Costs	Geological, Geophysical and Lease Rental Costs	Requirements
1971	8.3	3.9	6.7	7.9	3.1	29.9
1972	8.5	3.2	6.7	8.1	3.1	29.6
1973	8.7	3.3	6.7	8.4	3.2	30.3
1974	9.0	3.4	9.1	8.7	3.3	33.5
1975	19.2	7.2	16.7	19.4	6.6	69.1
5-Year Total	53.7	21.0	45.9	52.5	19.3	192.4
1976	20.1	7.5	19.6	20.4	7.1	74.7
1977	51.3	19.2	49.6	50.2	16.8	187.1
1978	59.7	22.4	69.8	59.3	19.9	231.1
1979	63.2	23.7	68.2	63.1	21.4	239.6
1980	67.3	25.2	75.7	67.5	23.2	258.9
5-Year Total	261.6	98.0	282.9	260.5	88.4	991.4
1981	71.1	26.7	105.5	72.6	25.0	300.9
1982	73.4	27.5	81.3	74.9	26.2	283.3
1983	94.3	35.3	106.4	94.3	33.2	363.5
1984	95.5	35.9	108.8	95.4	34.2	369.8
1985	95.8	35.9	108.6	95.5	34.8	370.6
5-Year Total	430.1	161.3	510.6	432.7	153.4	1,688.1
15-Year Total	745.4	280.3	839.4	745.7	261.1	2,871.9

TABLE 508

CAPITAL REQUIREMENTS FOR ALASKA–GAS OPERATIONS
(Millions of 1970 Dollars)

Case III

	Producing Well Investment	Lease Equipment	Lease Bonus	Dry Hole Costs	Geological, Geophysical and Lease Rental Costs	Requirements
1971	8.3	3.9	6.7	7.9	3.1	29.9
1972	8.5	3.2	6.7	8.1	3.1	29.6
1973	8.7	3.3	6.7	8.4	3.2	30.3
1974	9.0	3.4	9.0	8.7	3.3	33.4
1975	19.2	7.2	16.4	19.4	6.6	68.8
5-Year Total	53.7	21.0	45.5	52.5	19.3	192.0
1976	20.1	7.5	19.1	20.4	7.1	74.2
1977	51.3	19.2	48.8	50.2	16.8	186.3
1978	59.7	22.4	64.4	59.3	19.9	225.7
1979	63.2	23.7	65.2	63.1	21.4	236.6
1980	67.3	25.2	72.1	67.5	23.2	255.3
5-Year Total	261.6	98.0	269.6	260.5	88.4	978.1
1981	71.1	26.7	91.8	72.6	25.0	287.2
1982	73.4	27.5	75.6	74.9	26.2	277.6
1983	94.3	35.3	99.9	94.3	33.2	357.0
1984	95.5	35.9	101.7	95.4	34.2	362.7
1985	95.8	35.9	101.2	95.5	34.8	363.2
5-Year Total	430.1	161.3	470.2	432.7	153.4	1,647.7
15-Year Total	745.4	280.3	785.3	745.7	261.1	2,817.8

TABLE 509

CAPITAL REQUIREMENTS FOR ALASKA—GAS OPERATIONS
(Millions of 1970 Dollars)

Case IV

	Producing Well Investment	Lease Equipment	Lease Bonus	Dry Hole Costs	Geological, Geophysical and Lease Rental Costs	Requirements
1971	8.2	3.9	6.7	7.7	3.0	29.5
1972	7.9	3.0	6.7	7.5	2.9	28.0
1973	7.6	2.9	6.7	7.3	2.9	27.4
1974	7.3	2.7	7.3	7.0	2.8	27.1
1975	14.4	5.4	12.9	14.5	5.0	52.2
5-Year Total	45.4	17.9	40.3	44.0	16.6	164.2
1976	13.9	5.2	13.4	14.1	5.0	51.6
1977	32.7	12.3	30.3	32.0	10.9	118.2
1978	34.8	13.1	33.1	34.5	11.9	127.4
1979	33.5	12.6	32.3	33.5	11.7	123.6
1980	32.3	12.1	33.7	32.4	11.6	122.1
5-Year Total	147.2	55.3	142.8	146.5	51.1	542.9
1981	31.5	11.9	41.7	32.2	11.6	128.9
1982	30.3	11.3	45.4	31.0	11.3	129.3
1983	36.7	13.8	38.5	36.7	13.5	139.2
1984	35.3	13.2	37.3	35.2	13.2	134.2
1985	34.0	12.8	37.5	33.9	13.0	131.2
5-Year Total	167.8	63.0	200.4	169.0	62.6	662.8
15-Year Total	360.4	136.2	383.5	359.5	130.3	1,369.9

TABLE 510

CAPITAL REQUIREMENTS FOR ALASKA—GAS OPERATIONS
(Millions of 1970 Dollars)

Case IVA

	Producing Well Investment	Lease Equipment	Lease Bonus	Dry Hole Costs	Geological, Geophysical and Lease Rental Costs	Requirements
1971	8.2	3.9	6.7	7.7	3.0	29.5
1972	7.9	3.0	6.7	7.5	2.9	28.0
1973	7.6	2.9	6.7	7.3	2.9	27.4
1974	7.3	2.7	7.4	7.0	2.8	27.2
1975	14.4	5.4	13.0	14.5	5.0	52.3
5-Year Total	45.4	17.9	40.5	44.0	16.6	164.4
1976	13.9	5.2	13.7	14.1	5.0	51.9
1977	32.6	12.3	30.7	31.9	10.9	118.4
1978	34.7	13.0	33.8	34.5	11.9	127.9
1979	33.5	12.6	33.1	33.4	11.7	124.3
1980	32.2	12.1	34.8	32.3	11.4	122.8
5-Year Total	146.9	55.2	146.1	146.2	50.9	545.3
1981	31.4	11.8	48.8	32.1	11.6	135.7
1982	30.2	11.3	54.2	30.9	11.3	137.9
1983	36.6	13.8	41.2	36.6	13.4	141.6
1984	35.2	13.2	40.5	35.1	13.1	137.1
1985	33.9	12.7	40.8	33.8	13.0	134.2
5-Year Total	167.3	62.8	225.5	168.5	62.4	686.5
15-Year Total	359.6	135.9	412.1	358.7	129.9	1,396.2

Chapter Six—Section IX

Nuclear Stimulation

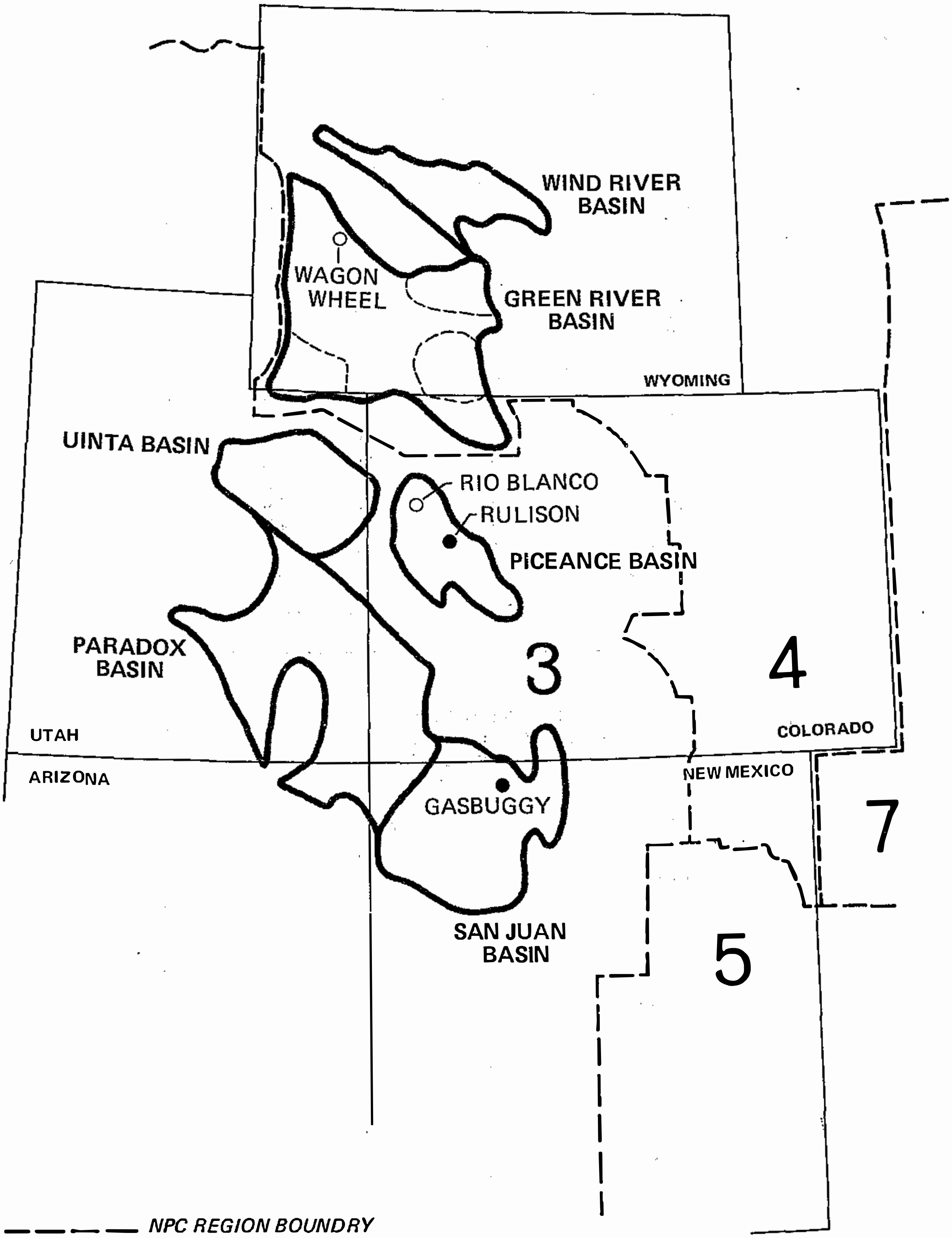


Figure 93. Major Basins of the Rocky Mountain States.

TABLE 511

POTENTIAL FIELD DEVELOPMENT WITH NUCLEAR STIMULATION
(Case I)

Year of Detonation	Number of Wells Stimulated: Identified Area	New Areas	Total
1972, 1973	2		2
1974, 1975, 1976	6	2	8
1977	10		10
1978	20	6	26
1979	40		40
1980	60	10	70
1981	80	20	100
1982	80	40	120
1983	80	60	140
1984	80	80	160
1985	80	80	160
Total	538	298	836

TABLE 512

POTENTIAL FIELD DEVELOPMENT WITH NUCLEAR STIMULATION
(Cases II and III)

Year of Detonation	Number of Wells Stimulated: Identified Areas	New Areas	Total
1973), 1974)	2		2
1975), 1976), 1977)	9	2	11
1978	9		9
1979	15	6	21
1980	25	12	37
1981	35	20	55
1982	45	30	75
1983	50	40	90
1984	50	50	100
1985	50	50	100
Total	290	210	500

TABLE 513

POTENTIAL PRODUCTION FOLLOWING NUCLEAR STIMULATION
(Case I)

Year		1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
No. of Wells Added		2	4	4	10	26	40	70	100	120	140	160
1975		16.	13.	9.2	7.8	7.0	6.4	6.2	6.0	6.0	5.8	5.6
1976			32.	26.	18.4	15.6	14.0	12.8	12.4	12.0	12.0	11.6
1977				32.	26.	18.4	15.6	14.0	12.8	12.4	12.0	12.0
1978					80.	65.	46.	39.	45.	32.	31.	30.
1979	Production from wells					208.	169.	119.6	101.4	91.0	83.2	80.6
1980	going on line:						320.	260.	184.	156.	140.	128.
1981								560.	455.	322.	273.	245.
1982									800.	650.	460.	390.
1983										960.	780.	522.
1984											1120.	910.
1985												1280.
Daily Production (M^2CF per day)		16.	45.	67.2	132.2	314.0	571.0	1011.6	1606.6	2241.4	2917.0	3644.8
Annual Production (BCF per year)		5.8	16.4	24.5	48.3	114.6	208.4	369.2	586.4	818.1	1064.7	1330.4
Total Wells Producing		2	6	10	20	46	86	156	256	376	516	676

TABLE 514

POTENTIAL PRODUCTION FOLLOWING NUCLEAR STIMULATION
(Cases II and III)

Year		1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
No. of Wells Added		1	1	4	5	11	21	37	55	75	90	100
1975		8.	6.5	4.6	3.9	3.5	3.2	3.1	3.0	3.0	2.9	2.8
1976			8.0	6.5	4.6	3.9	3.5	3.2	3.1	3.0	3.0	2.9
1977				32.	26.	18.4	15.6	14.0	12.8	12.4	12.0	12.0
1978					40.	32.5	23.0	19.5	17.5	16.0	15.5	15.0
1979	Production from wells					88.	71.5	50.6	42.9	38.5	35.2	34.1
1980	going on line:						168.	136.5	96.6	81.9	73.5	67.2
1981								296.	240.5	170.2	144.3	129.5
1982									440.	357.5	253.	214.5
1983										600.	487.5	345.0
1984											720.	585.
1985												800.
Daily Production (M^2CF per day)		8.0	14.5	43.1	74.5	146.3	284.8	522.9	856.4	1282.5	1746.9	2208.0
Annual Production (BCF per year)		2.9	5.3	15.7	27.2	53.4	104.0	190.9	312.6	468.1	637.6	805.9
Total Wells Producing		1	2	6	11	22	43	80	135	210	300	400

TABLE 515

POTENTIAL GROWTH OF PIPELINE GAS FROM NUCLEAR STIMULATION

Case I

	No. of Wells Producing	Annual Investment*	Annual Production	Total Production	Annual Sales†
1975	22	$ 5 million	.006 TCF	.006 TCF	.005 TCF
1980	86	215 million	.208 TCF	.418 TCF	.187 TCF
1985	676	1690 million	1.330 TCF	4.587 TCF	1.197 TCF
1990	1476	3690 million	2.296 TCF	14.261 TCF	2.066 TCF
1995	2276	5690 million	3.099 TCF	28.184 TCF	2.789 TCF
2000	3076	7690 million	3.811 TCF	45.846 TCF	3.430 TCF

Cases II and III

	No. of Wells Producing	Annual Investment*	Annual Production	Total Production	Annual Sales†
1975	1	$ 2.5 million	.003 TCF	.003 TCF	.003 TCF
1980	43	107.5 million	.014 TCF	.209 TCF	.094 TCF
1985	400	1000 million	.806 TCF	2.624 TCF	.725 TCF
1990	900	2250 million	1.411 TCF	8.549 TCF	1.270 TCF
1995	1400	3500 million	1.916 TCF	17.143 TCF	1.724 TCF
2000	1900	4750 million	2.365 TCF	28.091 TCF	2.129 TCF

* Assuming $2.5 million per well and not including exploration or R&D costs.

† Ten percent of production deducted for field use.

Chapter Six—Section X

Foreign Gas Supply

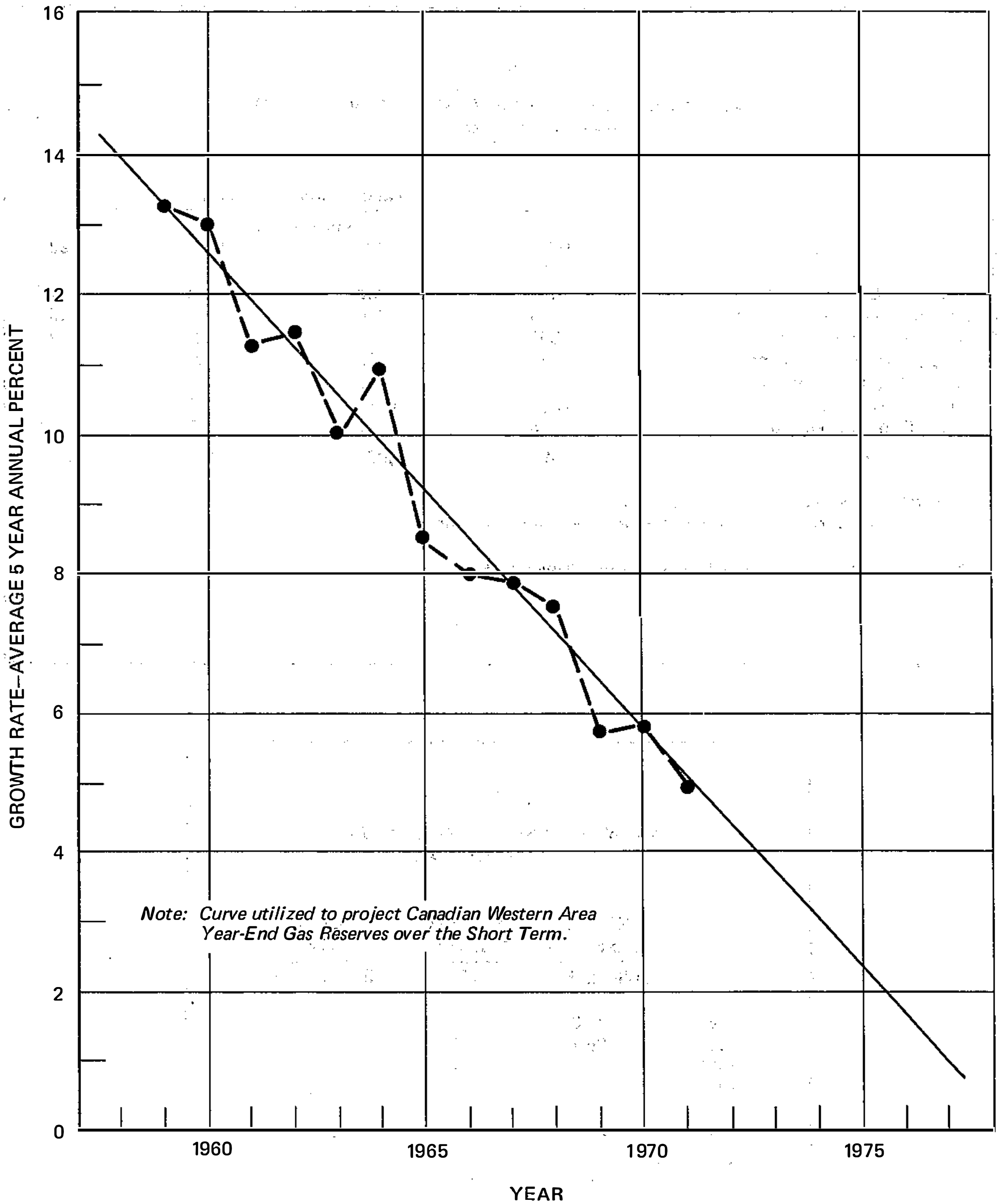


Figure 94. Canadian Year-End Gas Reserves—Five-Year Rolling Growth Rate.

TABLE 516

STATUS OF CANADIAN NATURAL GAS EXPORT PERMITS
(Issued as of November 1971)

	Maximum Permitted Volumes			
	Annual — BCF			
Exporter	1972	1973	1975	1982
Trans-Canada Pipelines, Ltd.	258	258	258	184
Alberta & Southern Gas, Ltd.	374	374	374	374
Westcoast Transmission Co., Ltd.	306	332	332	281
Canadian Montana Pipeline Co.	49	49	29	29
Niagara Gas Transmission	6	6	6	6
Patrick T. Buckley	Neg.	Neg.	0	0
I.C.G. Transmission, Ltd.	8	8	8	8
Total	1,001	1,027	1,007	882

Note: (1) Does not include any gas exported for reimport.
(2) Volumes dropped out in year following expiration date of license.

Source: Canadian National Energy Board data, issued November 1971.

TABLE 517

CANADIAN NATURAL GAS LIQUID DATA—HISTORICAL

	NGL & LPG Production (Millions Bbls)	Net (Dry) Gas Production (TCF)	Liquid Yield (Bbls/MMCF)
1966	49.6	1.1	44.1
1967	56.7	1.2	46.6
1968	61.3	1.4	43.9
1969	66.3	1.6	42.6
1970	78.9	1.8	43.9
1971	80.1	1.8	44.5

Source: Canadian Petroleum Association.

TABLE 518

GAS RESERVES ESTIMATES
(TCF)

Area	World Oil Data 12/31/61	World Oil Data 12/31/67	World Oil Data 12/31/69	World Oil Data 12/31/70	Oil & Gas Journal Data 12/31/70	Oil & Gas Journal Data 12/31/71
North America	322.2	351.9	342.1	360.7	339.0	340.5
Canada	36.0	45.7	52.0	53.4	60.5	54.4
Trinidad	1.2	1.5	3.0	4.5	3.5	5.0
U.S.A.	275.0	292.9	275.1	290.7	265.0	269.6
Others	10.0	11.8	12.0	12.1	10.0	11.5
South America	43.6	48.9	948.6	45.2	59.6	56.2
Brazil	0.4	1.0	903.0†	0.9	6.0	5.0
Ecuador	0.1	0.1	0.2	1.3	5.0	6.0
Venezuela	33.0	27.8	26.5	25.4	27.0	25.4
Others	10.1	20.0	18.9	17.6	21.6	19.8
Western Europe	19.0	118.4	475.0	146.4	146.5	161.5
Austria	0.9	1.0	339.0†	0.5	0.4	0.6
Netherlands	2.6	18.0	85.5	87.5	83.0	83.0
United Kingdom	—	25.0	27.0	33.0	36.0	40.0
Others	15.5	24.4	23.5	25.4	27.1	37.9
Africa	54.4	116.0	179.1	179.3	191.5	193.0
Algeria	50.0	100.0	145.0	145.0	141.0	106.5
Nigeria	0.3	3.0	5.0	5.4	6.0	40.0
Others	4.1	13.0	29.1	28.9	44.5	46.5
Middle East	178.3	228.2	237.9	275.9	354.3	343.9
Iran	65.0	100.0	107.0	110.0	214.0	200.0
Kuwait	33.0	35.0	40.0	40.0	38.0	35.0
Saudi Arabia	45.0	50.0	45.7	83.2	49.5	52.0
Others	35.3	43.2	45.2	42.7	52.8	56.9
Far East & Oceania	21.6	43.5	42.0	48.5	56.3	69.8
Australia	—	7.5	15.1	15.0	12.6	24.8
Pakistan	15.0	20.5	18.9	21.0	20.0	19.5
Others	6.6	15.5	8.0	12.5	23.7	25.5
Sino-Soviet Bloc*	82.4	165.0	326.7	425.7	441.2	559.8
U.S.S.R.	75.0	150.0	322.0	423.0	426.0	546.0
Others	7.4	15.0	4.7	2.7	15.2	13.8
Total Free World	639.1	906.9	2,224.7	1,056.0	1,147.2	1,164.9
Total World	721.5	1,071.9	2,551.4	1,481.7	1,588.4	1,724.7

* Includes Yugoslavia.

† As published, but assumed decimal off by 10^3.

Note: The data on this table, in conjunction with production data, were utilized to obtain the annual reserve additions shown on Table 157, (p. 265) of the NPC report, U.S. Energy Outlook *(December 1972).*

TABLE 519

CANADIAN NATURAL GAS DATA – HISTORICAL

	Gross Gas Production (BCF)	Losses, Gas Shrinkage, Flared, Etc. Volume (BCF)	Losses, Gas Shrinkage, Flared, Etc. Production (Percent)	Gas Exports Volume (BCF)	Gas Exports Production (Percent)	Canadian Internal Gas Demand Volume (BCF)	Canadian Internal Gas Demand Growth (%/Year)	Year End Reserves Proved Volume	Year End Reserves Proved 5 Year Growth (%/Year)	Reserve Adds Discoveries & Extensions Volume (BCF)	Reserve Adds Revisions (BCF)	Reserve Adds Total (BCF)
1958	393	132	34	90	23	203		20,500				2,587
1959	471	120	25	84	18	280	37.6	23,400	13.2			3,359
1960	565	138	24	110	20	322	15.3	27,000	13.0			4,041
1961	713	176	25	170	24	373	15.6	29,500	11.3			3,236
1962	989	236	24	345	35	414	11.1	31,200	11.4			2,518
1963	1,081	273	25	362	33	454	9.6	33,000	10.0	2,697	(44)	2,653
1964	1,218	326	27	394	32	507	11.7	39,300	10.9	4,156	3,153	7,309
1965	1,328	363	27	407	31	576	13.6	40,400	8.4	2,602	(472)	2,130
1966	1,428	400	28	434	30	639	10.9	43,500	8.0	2,044	2,159	4,203
1967	1,567	419	27	516	33	702	9.9	45,700	7.9	1,872	1,572	3,444
1968	1,790	494	28	608	34	770	9.7	47,700	7.6	3,150	230	3,380
1969	2,076	580	28	684	33	848	10.1	52,000	5.7	3,805	2,044	5,839
1970	2,379	683	29	784	33	923	8.8	53,400	5.8	2,710	494	3,204
1971	2,700	800	30	900	33	1,027	11.3	55,500	5.0	3,056	983	4,039

Source: *Canadian Petroleum Association.*

Note: Utilized to prepare Table 159 (p. 267), U.S. Energy Outlook.

TABLE 520

FREE WORLD GAS PRODUCTION DATA EXCLUDING UNITED STATES
(BCF)

Area	1-1-62 Cumulative	Annual Production 1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	1-1-72 Cumulative
North America & Caribbean	12,490	1,460	1,582	1,814	1,913	2,076	2,280	2,518	2,823	3,156	3,300	35,413
Reported Data*	–	1,560	1,682	1,914	2,013	2,176	2,380	2,618	2,923	3,256	–	–
Estimated	12,990	–	–	–	–	–	–	–	–	–	3,400	–
Gas Injection†	500	100	100	100	100	100	100	100	100	100	100	–
South America	13,325	1,243	1,304	1,415	1,452	1,453	1,416	1,435	1,496	1,587	1,645	27,771
Reported Data	–	1,825	1,873	2,007	2,072	2,100	2,347	2,408	2,480	2,537	–	–
Estimated	17,700	5	5	6	6	5	–	–	–	–	2,545	–
Gas Injection	4,375	587	574	598	626	652	931	973	984	950	900	–
Western Europe	6,000	610	647	711	770	894	1,120	1,541	2,082	3,050	4,800	22,223
Reported Data	–	610	647	711	770	894	1,120	1,541	2,082	3,050	–	–
Estimated	6,000	–	–	–	–	–	–	–	–	–	4,800	–
Gas Injection	–	–	–	–	–	–	–	–	–	–	–	–
Africa	1,370	200	328	496	658	815	866	1,066	1,341	1,605	1,650	10,395
Reported Data	–	31	38	328	490	607	615	765	1,017	1,187	–	–
Estimated	1,370	169	290	168	168	208	251	301	324	418	1,650	–
Gas Injection	–	–	–	–	–	–	–	–	–	–	–	–
Middle East	10,981	1,354	1,507	1,701	1,930	2,235	2,320	2,707	2,913	3,356	4,200	35,205
Reported Data	–	325	738	837	920	1,094	1,213	1,360	1,742	2,740	–	–
Estimated	10,981	1,029	769	864	1,010	1,141	1,152	1,397	1,292	816	4,500	–
Gas Injection	–	–	–	–	–	–	45	50	121	200	300	–
Far East & Oceania	3,320	250	272	299	348	329	386	460	501	687	850	7,701
Reported Data	–	243	265	290	338	317	300	439	485	626	–	–
Estimated	3,320	7	7	9	10	12	86	21	16	61	850	–
Gas Injection	–	–	–	–	–	–	–	–	–	–	–	–
Free World Total	47,486	5,117	5,640	6,436	7,071	7,801	8,388	9,727	11,156	13,441	16,445	138,708
Reported Data‡	–	4,594	5,243	6,087	6,603	7,187	7,976	9,131	10,729	13,396	–	–
Estimated	52,361	1,210	1,071	1,047	1,194	1,366	1,489	1,718	1,632	1,295	17,745	–
Gas Injection	4,875	687	674	698	726	752	1,077	1,122	1,205	1,250	1,300	–

* Canadian data from Canadian Petroleum Association. They report net after deducting gas injected.

† Mexico gas injection only.

‡ Sources: USBM, CPA, *World Oil*, miscellaneous.

Note: On Table 157 (p. 265) of U.S. Energy Outlook, the production growth rates were obtained from the gross production above before deducting gas injection volumes. The cumulative production and gas/oil ratios were also obtained from the above data. Totals may not add due to rounding.

TABLE 521

SUMMARY PETROLEUM AND SELECTED MINERAL STATISTICS FOR 120 COUNTRIES
(Natural Gas Proved Reserves and Potential Resources, Onshore, Offshore and Total)

Continent and country	Reserves (Billions of Cubic Meters) Onshore	Offshore	Total	Resources Category Onshore	Offshore	Total
Oceania:						
Australia	440.0	260.0	700.0	2	2	2
Fiji	.0	.0	.0	5	5	5
New Zealand	.0	170.0	170.0	4	3	3
Total	440.0	430.0	870.0			
Europe:						
Albania	200.0	0.0	200.0	4	4	3
Austria	16.0	–	16.0	4	–	4
Belgium	.0	.0	.0	5	4	4
Bulgaria	30.0	.0	30.0	4	4	4
Czechoslovakia	11.0	–	11.0	4	–	4
Denmark	.0	14.0	14.0	4	4	4
Finland	.0	.0	.0	0	5	5
France	190.0	.0	190.0	3	4	3
Germany, Federal Republic of (West)	390.0	.0	390.0	3	4	3
Greece	.0	NA	NA	5	4	4
Hungary	85.0	–	85.0	4	–	4
Iceland	.0	.0	.0	0	0	0
Ireland	.0	NA	NA	4	4	3
Italy	80.0	90.0	170.0	4	3	3
Malta	.0	.0	.0	6	4	4
Netherlands	2,350.0	NA	2,350.0	2	3	2
Norway	.0	280.0	280.0	0	3	3
Poland	140.0	.0	140.0	4	5	4
Portugal	.0	.0	.0	5	5	5
Romania	277.0	.0	277.0	3	4	3
Spain	4.0	11.0	15.0	4	5	4
Sweden	.0	.0	.0	6	5	5
Switzerland	.0	–	.0	5	–	5
United Kingdom	200.0	900.0	1,100.0	5	3	3
Yogoslavia	50.0	.0	50.0	4	4	4
Total	4,023.0	1,295.0	5,318.0			
North America:						
Bahamas (U.K.)	0.0	0.0	0.0	6	4	4
Barbados	NA	.0	NA	5	5	4
Canada	1,570.0	NA	1,570.0	2	3	2
Costa Rica	.0	.0	.0	6	4	4
Dominican Republic	.0	.0	.0	5	5	5
El Salvador	.0	.0	.0	0	5	5
Guatemala	.0	.0	.0	4	4	4
Haiti	.0	.0	.0	5	5	5
Honduras	.0	.0	.0	5	4	4
Jamaica	.0	.0	.0	5	4	4
Martinique and Guadeloupe	.0	.0	.0	0	0	0
Mexico	NA	NA	326.0	2	3	2
Nicaragua	.0	.0	.0	5	4	4
Panama	.0	.0	.0	5	4	4
United States of America	6,777.0	1,118.0	7,895.0	1	1	1
Total	8,347.0	1,118.0	9,791.0			
South America:						
Argentina	215.0	NA	215.0	3	3	3
Bolivia	140.0	–	140.0	2	–	2
Brazil	140.0	NA	140.0	2	3	2
Chile	62.0	.0	62.0	4	3	3
Colombia	70.0	.0	70.0	3	3	3
Ecuador	157.0	13.0	170.0	3	3	3
Guyana	.0	.0	.0	4	5	4
Peru	NA	NA	70.0	3	4	3
Trinidad and Tobago	.0	140.0	140.0	4	3	3
Uruguay	.0	.0	.0	4	4	4
Venezuela	720.0	NA	720.0	2	2	2
Total	1,504.0	153.0	1,727.0			
120 country total	39,976.9	3,656.0	50,445.9			

Source: Geological Survey Professional Paper 817, entitled "Summary Petroleum and Selected Mineral Statistics for 120 Countries, Including Offshore Areas" by John P. Albers, M. Devereux Carter, Allen L. Clark, Anny B. Coury and Stanley P. Schweinfurth.

Chapter Six—Section XI

Summary

TABLE 522

PROJECTED ANNUAL GAS FOOTAGE DRILLED—NON-ASSOCIATED AND ASSOCIATED-DISSOLVED—TOTAL OFFSHORE REGIONS 2A, 6A & 11A

Case I

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	4,158	4,583	595	5,178	2,687	747	3,434	2,512	650	3,162
1972	4,409	4,999	520	5,519	2,913	740	3,653	2,724	642	3,366
1973	4,743	5,503	715	6,218	3,389	719	4,108	3,169	625	3,794
1974	5,123	6,043	846	6,889	3,804	728	4,532	3,555	634	4,189
1975	5,559	6,626	943	7,569	4,119	752	4,871	3,851	654	4,505
1976	6,059	7,180	912	8,092	4,402	781	5,183	4,116	679	4,795
1977	6,691	7,865	1,004	8,869	4,733	804	5,537	4,424	700	5,124
1978	7,675	8,835	1,031	9,866	5,099	832	5,931	4,768	723	5,491
1979	9,021	10,060	1,083	11,143	5,492	859	6,351	5,135	747	5,882
1980	9,984	10,737	1,066	11,803	5,911	889	6,800	5,527	773	6,300
1981	11,087	11,283	1,037	12,320	6,305	912	7,217	5,896	792	6,688
1982	11,981	11,475	1,070	12,545	6,794	932	7,726	6,351	812	7,163
1983	12,604	11,230	1,015	12,245	7,273	953	8,226	6,799	830	7,629
1984	12,906	10,582	1,044	11,626	7,663	965	8,628	7,164	840	8,004
1985	12,906	9,681	1,022	10,703	7,962	979	8,941	7,443	853	8,296
Total	124,906	126,682	13,903	140,585	78,546	12,592	91,138	73,434	10,954	84,388

TABLE 523

PROJECTED ANNUAL GAS FOOTAGE DRILLED—NON-ASSOCIATED AND ASSOCIATED-DISSOLVED—TOTAL OFFSHORE REGIONS2A, 6A & 11A

Case IA

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	4,158	3,648	474	4,122	2,687	747	3,434	2,512	650	3,162
1972	4,409	3,786	308	4,094	2,866	719	3,585	2,680	625	3,305
1973	4,743	3,982	410	4,392	3,235	665	3,900	3,025	578	3,603
1974	5,123	4,191	511	4,702	3,521	632	4,153	3,292	549	3,841
1975	5,559	4,430	621	5,051	3,691	617	4,308	3,451	536	3,987
1976	6,059	4,660	651	5,311	3,810	617	4,427	3,563	537	4,100
1977	6,691	4,986	747	5,733	3,952	626	4,578	3,695	544	4,239
1978	7,675	5,528	760	6,288	4,106	644	4,750	3,840	559	4,399
1979	9,021	6,290	804	7,094	4,270	659	4,929	3,993	574	4,567
1980	9,984	6,729	799	7,528	4,454	680	5,134	4,165	591	4,756
1981	11,087	7,175	787	7,962	4,608	697	5,305	4,308	606	4,914
1982	11,981	7,475	824	8,299	4,852	713	5,565	4,537	619	5,156
1983	12,604	7,568	789	8,357	5,115	732	5,847	4,782	636	5,418
1984	12,906	7,446	822	8,268	5,332	743	6,075	4,985	646	5,631
1985	12,906	7,159	807	7,966	5,516	758	6,274	5,157	659	5,816
Total	124,906	85,053	10,114	95,167	62,015	10,249	72,264	57,985	8,909	66,894

TABLE 524

PROJECTED ANNUAL GAS FOOTAGE DRILLED—NON-ASSOCIATED AND ASSOCIATED-DISSOLVED—TOTAL OFFSHORE REGIONS 2A, 6A & 11A

Case II

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	4,158	4,583	595	5,178	2,687	747	3,434	2,512	650	3,162
1972	4,283	4,854	508	5,362	2,913	740	3,653	2,724	642	3,366
1973	4,476	5,189	694	5,883	3,382	717	4,099	3,162	623	3,785
1974	4,699	5,533	813	6,346	3,772	723	4,495	3,527	630	4,157
1975	4,956	5,898	885	6,783	4,049	742	4,791	3,786	646	4,432
1976	5,249	6,222	839	7,061	4,276	765	5,041	3,998	665	4,663
1977	5,636	6,650	902	7,552	4,531	780	5,311	4,237	677	4,914
1978	6,283	7,310	899	8,209	4,806	797	5,603	4,493	694	5,187
1979	7,181	8,162	930	9,092	5,091	811	5,902	4,760	705	5,465
1980	7,729	8,590	907	9,497	5,387	828	6,215	5,037	720	5,757
1981	8,343	8,932	878	9,810	5,644	837	6,481	5,276	730	6,006
1982	8,843	9,418	611	10,029	5,982	847	6,829	5,593	736	6,329
1983	9,212	9,080	872	9,952	6,317	859	7,176	5,907	747	6,654
1984	9,434	8,825	875	9,700	6,590	864	7,454	6,162	752	6,914
1985	9,434	8,330	841	9,171	6,808	871	7,679	6,366	757	7,123
Total	99,916	107,576	12,049	119,625	72,235	11,928	84,163	67,540	10,374	77,914

TABLE 525

PROJECTED ANNUAL GAS FOOTAGE DRILLED—NON-ASSOCIATED AND ASSOCIATED-DISSOLVED—TOTAL OFFSHORE REGIONS 2A, 6A & 11A

Case III

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	4,158	3,648	474	4,122	2,687	747	3,434	2,512	650	3,162
1972	4,283	3,681	301	3,982	2,866	719	3,585	2,680	625	3,305
1973	4,476	3,764	398	4,162	3,230	664	3,894	3,020	577	3,597
1974	4,699	3,859	490	4,349	3,500	630	4,130	3,272	547	3,819
1975	4,956	3,975	578	4,553	3,643	611	4,254	3,406	532	3,938
1976	5,249	4,079	590	4,669	3,727	606	4,333	3,484	528	4,012
1977	5,636	4,262	666	4,928	3,823	606	4,429	3,573	530	4,103
1978	6,283	4,618	662	5,280	3,924	616	4,540	3,669	536	4,205
1979	7,181	5,131	688	5,819	4,025	623	4,648	3,762	544	4,306
1980	7,729	5,380	675	6,055	4,135	634	4,769	3,866	551	4,417
1981	8,343	5,621	660	6,281	4,205	640	4,845	3,931	556	4,487
1982	8,843	5,797	695	6,492	4,350	647	4,997	4,068	562	4,630
1983	9,212	5,870	669	6,539	4,509	657	5,166	4,217	571	4,788
1984	9,434	5,835	679	6,514	4,627	663	5,290	4,326	577	4,903
1985	9,434	5,666	659	6,325	4,722	670	5,392	4,414	583	4,997
Total	99,916	71,186	8,884	80,070	57,973	9,733	67,706	54,200	8,469	62,669

TABLE 526

PROJECTED ANNUAL GAS FOOTAGE DRILLED—NON-ASSOCIATED AND ASSOCIATED-DISSOLVED—TOTAL OFFSHORE REGIONS 2A, 6A & 11A

Case IV

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	4,101	3,598	474	4,072	2,687	747	3,434	2,512	650	3,162
1972	3,976	3,423	283	3,706	2,863	719	3,582	2,678	624	3,302
1973	3,891	3,288	348	3,636	3,212	660	3,872	3,003	575	3,578
1974	3,808	3,154	395	3,549	3,446	620	4,066	3,222	538	3,760
1975	3,723	3,031	431	3,462	3,533	588	4,121	3,304	511	3,815
1976	3,641	2,892	414	3,306	3,543	566	4,109	3,313	492	3,805
1977	3,591	2,802	436	3,238	3,548	548	4,096	3,317	477	3,794
1978	3,661	2,801	426	3,227	3,539	534	4,073	3,309	465	3,774
1979	3,808	2,856	419	3,275	3,513	520	4,033	3,285	452	3,737
1980	3,711	2,750	389	3,139	3,479	508	3,987	3,253	441	3,694
1981	3,698	2,690	361	3,051	3,383	439	3,876	3,163	429	3,592
1982	3,654	2,626	363	2,989	3,339	480	3,819	3,122	418	3,540
1983	3,583	2,546	339	2,885	3,304	470	3,774	3,089	408	3,497
1984	3,487	2,451	339	2,790	3,226	457	3,683	3,016	398	3,414
1985	3,347	2,326	320	2,646	3,129	446	3,575	2,925	388	3,313
Total	55,680	43,234	5,737	48,971	49,744	8,356	58,100	46,511	7,266	53,777

TABLE 527

PROJECTED ANNUAL GAS FOOTAGE DRILLED—NON-ASSOCIATED AND ASSOCIATED-DISSOLVED—TOTAL OFFSHORE REGIONS 2A, 6A & 11A

Case IVA

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	4,101	4,519	595	5,114	2,687	747	3,434	2,512	650	3,162
1972	3,976	4,501	477	4,978	2,909	740	3,649	2,721	642	3,363
1973	3,891	4,497	610	5,107	3,358	712	4,070	3,140	618	3,758
1974	3,808	4,464	666	5,130	3,696	705	4,401	3,456	614	4,070
1975	3,723	4,413	682	5,095	3,890	705	4,595	3,637	613	4,250
1976	3,641	4,306	623	4,929	4,001	704	4,705	3,741	612	4,353
1977	3,591	4,250	620	4,870	4,108	698	4,806	3,841	607	4,448
1978	3,661	4,308	583	4,891	4,203	689	4,892	3,929	600	4,529
1979	3,808	4,429	565	4,994	4,275	675	4,950	3,997	587	4,584
1980	3,711	4,300	526	4,826	4,327	660	4,987	4,046	575	4,621
1981	3,698	4,225	489	4,714	4,309	643	4,952	4,030	559	4,589
1982	3,654	4,140	488	4,628	4,338	627	4,965	4,057	545	4,602
1983	3,583	4,022	454	4,476	4,364	613	4,977	4,081	533	4,614
1984	3,487	3,875	451	4,326	4,339	597	4,936	4,057	519	4,576
1985	3,347	3,680	426	4,106	4,285	582	4,867	4,007	505	4,512
Total	55,680	63,929	8,255	72,184	59,089	10,097	69,186	55,252	8,779	64,031

TABLE 528

PROJECTED ANNUAL GAS FOOTAGE DRILLED—NON-ASSOCIATED AND ASSOCIATED-DISSOLVED—TOTAL ONSHORE REGIONS 2, 3, 4, 5, 6, 7, 8, 9, 10 & 11

Case I

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	37,010	8,892	722	9,614	14,215	4,045	18,260	13,291	3,519	16,810
1972	38,817	9,271	778	10,049	14,626	3,808	18,434	13,675	3,315	16,990
1973	40,861	9,698	823	10,521	15,097	3,596	18,693	14,115	3,129	17,244
1974	43,217	10,150	906	11,056	15,420	3,405	18,825	14,419	2,962	17,381
1975	45,923	10,666	1,014	11,680	15,422	3,234	18,656	14,420	2,814	17,234
1976	49,027	11,244	1,142	12,386	15,230	3,087	18,317	14,239	2,687	16,926
1977	52,526	11,849	1,232	13,081	15,000	2,992	17,992	14,027	2,602	16,629
1978	56,280	12,465	1,321	13,786	14,811	2,906	17,717	13,848	2,530	16,378
1979	60,370	13,096	1,363	14,459	14,633	2,828	17,461	13,682	2,461	16,143
1980	65,652	13,904	1,423	15,327	14,596	2,750	17,346	13,647	2,394	16,041
1981	69,844	14,420	1,476	15,896	14,518	2,674	17,192	13,574	2,328	15,902
1982	72,996	14,630	1,447	16,077	14,616	2,620	17,236	13,668	2,278	15,946
1983	74,922	14,524	1,480	16,004	14,766	2,557	17,323	13,808	2,224	16,032
1984	75,496	14,135	1,461	15,596	14,757	2,492	17,249	13,799	2,167	15,966
1985	75,496	13,536	1,516	15,052	14,724	2,422	17,146	13,769	2,105	15,874
Total	858,437	182,480	18,104	200,584	222,431	45,416	267,847	207,981	39,515	247,496

TABLE 529

PROJECTED ANNUAL GAS FOOTAGE DRILLED—NON-ASSOCIATED AND ASSOCIATED-DISSOLVED—TOTAL ONSHORE REGIONS 2, 3, 4, 5, 6, 7, 8, 9, 10 & 11

Case IA

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	37,010	6,264	691	6,955	13,405	4,855	18,260	13,291	3,519	16,810
1972	38,817	6,434	689	7,123	14,495	3,805	18,300	13,552	3,311	16,863
1973	40,861	6,627	664	7,291	14,690	3,583	18,273	13,735	3,118	16,853
1974	43,217	6,860	656	7,516	14,745	3,377	18,122	13,786	2,939	16,725
1975	45,923	7,144	659	7,803	14,481	3,184	17,665	13,540	2,770	16,310
1976	49,027	7,477	681	8,158	14,032	3,006	17,038	13,119	2,615	15,734
1977	52,526	7,871	689	8,560	13,529	2,873	16,402	12,650	2,500	15,150
1978	56,280	8,466	718	9,184	13,056	2,748	15,804	12,207	2,392	14,599
1979	60,370	8,812	733	9,545	12,602	2,632	15,234	11,782	2,289	14,071
1980	65,652	9,258	758	10,016	12,295	2,518	14,813	11,496	2,192	13,688
1981	69,844	9,553	783	10,336	11,943	2,409	14,352	11,176	2,088	13,264
1982	72,996	9,670	769	10,439	11,765	2,328	14,093	11,000	2,027	13,027
1983	74,922	9,631	791	10,422	11,652	2,244	13,896	10,895	1,954	12,849
1984	75,496	9,410	787	10,197	11,403	2,162	13,565	10,662	1,881	12,543
1985	75,496	9,100	809	9,909	11,167	2,078	13,245	10,442	1,809	12,251
Total	858,437	122,577	10,877	133,454	195,260	43,802	239,062	183,333	37,404	220,737

TABLE 530

PROJECTED ANNUAL GAS FOOTAGE DRILLED—NON-ASSOCIATED AND ASSOCIATED-DISSOLVED—TOTAL ONSHORE REGIONS 2, 3, 4, 5, 6, 7, 8, 9, 10 & 11

Case II

	Gas Footage Drilled Annually (000′)	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	37,010	8,892	722	9,614	14,215	4,045	18,260	13,291	13,519	16,810
1972	37,708	9,007	761	9,768	14,626	3,808	18,434	13,675	3,315	16,990
1973	38,565	9,156	796	9,952	15,083	3,594	18,677	14,103	3,128	17,231
1974	39,633	9,319	861	10,180	15,369	3,396	18,765	14,370	2,957	17,327
1975	40,928	9,527	936	10,463	15,304	3,227	18,531	14,309	2,807	17,116
1976	42,470	9,779	1,023	10,802	15,022	3,072	18,094	14,046	2,673	16,719
1977	44,231	10,044	1,084	11,128	14,683	2,967	17,650	13,728	2,583	16,311
1978	46,077	10,307	1,135	11,442	14,357	2,871	17,228	13,424	2,497	15,921
1979	48,059	10,579	1,145	11,724	14,018	2,781	16,799	13,107	2,420	15,527
1980	50,825	10,988	1,167	12,155	13,798	2,689	16,487	12,901	2,340	15,241
1981	52,553	11,167	1,187	12,354	13,515	2,600	16,115	12,638	2,260	14,898
1982	53,880	10,917	1,455	12,372	13,389	2,532	15,921	12,519	2,204	14,723
1983	54,766	11,146	1,169	12,315	13,310	2,459	15,769	12,444	2,140	14,584
1984	55,184	10,972	1,147	12,119	13,085	2,384	15,469	12,234	2,073	14,307
1985	55,184	10,672	1,158	11,830	12,871	2,303	15,174	12,034	2,004	14,038
Total	697,073	152,472	15,746	168,218	212,645	44,728	257,373	198,823	38,920	237,743

TABLE 531

PROJECTED ANNUAL GAS FOOTAGE DRILLED—NON-ASSOCIATED AND ASSOCIATED-DISSOLVED—TOTAL ONSHORE REGIONS 2, 3, 4, 5, 6, 7, 8, 9, 10 & 11

Case III

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	37,010	6,264	691	6,955	14,215	4,045	18,260	13,291	3,519	16,810
1972	37,708	6,254	674	6,928	14,495	3,805	18,300	13,552	3,311	16,863
1973	38,565	6,267	644	6,911	14,681	3,582	18,263	13,727	3,117	16,844
1974	39,633	6,313	628	6,941	14,709	3,373	18,082	13,753	2,936	16,689
1975	40,928	6,404	615	7,019	14,403	3,179	17,582	13,467	2,765	16,232
1976	42,470	6,530	621	7,151	13,896	2,997	16,893	12,994	2,607	15,601
1977	44,231	6,698	613	7,311	13,323	2,862	16,185	12,458	2,488	14,946
1978	46,077	7,067	621	7,688	12,762	2,731	15,493	11,933	2,376	14,309
1979	48,059	7,217	619	7,836	12,205	2,607	14,812	11,413	2,266	13,679
1980	50,825	7,424	626	8,050	11,786	2,486	14,272	11,020	2,163	13,183
1981	52,553	7,501	631	8,132	11,309	2,370	13,679	10,574	2,063	12,637
1982	53,880	7,504	611	8,115	10,995	2,281	13,276	10,280	1,985	12,265
1983	54,766	7,467	620	8,087	10,743	2,191	12,934	10,044	1,907	11,951
1984	55,184	7,361	609	7,970	10,361	2,101	12,462	9,688	1,827	11,515
1985	55,184	7,161	618	7,779	10,012	2,011	12,023	9,362	1,750	11,112
Total	**697,073**	**103,432**	9,441	112,873	189,895	42,621	232,516	**177,556**	**37,080**	**214,636**

TABLE 532

PROJECTED ANNUAL GAS FOOTAGE DRILLED—NON-ASSOCIATED AND ASSOCIATED-DISSOLVED—TOTAL ONSHORE REGIONS 2, 3, 4, 5, 6, 7, 8, 9, 10 & 11

Case IV

	Gas Footage Drilled Annually (000′)	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	36,498	6,181	691	6,872	14,215	4,045	18,260	13,291	3,519	16,810
1972	34,999	5,815	636	6,451	14,491	3,805	18,296	13,548	3,312	16,860
1973	33,525	5,473	567	6,040	14,651	3,579	18,230	13,698	3,114	16,812
1974	32,112	5,157	509	5,666	14,619	3,362	17,981	13,669	2,926	16,595
1975	30,760	4,873	466	5,339	14,224	3,158	17,382	13,299	2,748	16,047
1976	29,463	4,610	440	5,050	13,599	2,964	16,563	12,715	2,579	15,294
1977	28,188	4,365	405	4,770	12,881	2,815	15,696	12,044	2,449	14,493
1978	26,847	4,120	395	4,515	12,149	2,671	14,820	11,359	2,324	13,683
1979	25,480	3,884	364	4,248	11,382	2,534	13,916	10,642	2,205	12,847
1980	24,405	3,801	341	4,142	10,726	2,400	13,126	10,029	2,089	12,118
1981	23,294	3,611	321	3,932	10,000	2,270	12,270	9,350	1,975	11,325
1982	22,258	3,424	293	3,717	9,427	2,168	11,595	8,814	1,886	10,700
1983	21,293	3,249	276	3,525	8,915	2,065	10,980	8,336	1,797	10,133
1984	20,394	3,086	256	3,342	8,282	1,964	10,246	7,744	1,708	9,452
1985	19,578	2,928	246	3,174	7,699	1,863	9,562	7,199	1,621	8,820
Total	409,094	64,577	6,206	70,783	177,260	41,663	218,923	165,737	36,252	201,989

TABLE 533

PROJECTED ANNUAL GAS FOOTAGE DRILLED—NON-ASSOCIATED AND ASSOCIATED-DISSOLVED—TOTAL ONSHORE REGIONS 2, 3, 4, 5, 6, 7, 8, 9, 10 & 11

Case IVA

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	36,498	8,769	722	9,491	14,215	4,045	18,260	13,291	3,517	16,808
1972	34,999	8,362	715	9,077	14,621	3,808	18,429	13,669	3,315	16,984
1973	33,525	7,969	691	8,660	15,039	3,589	18,628	14,061	3,124	17,185
1974	32,112	7,570	679	8,249	15,236	3,386	18,622	14,245	2,945	17,190
1975	30,760	7,194	677	7,871	15,034	3,195	18,229	14,057	2,780	16,837
1976	29,463	6,839	685	7,524	14,570	3,018	17,588	13,623	2,627	16,250
1977	28,188	6,481	662	7,143	14,006	2,887	16,893	13,096	2,512	15,608
1978	26,847	6,118	676	6,794	13,412	2,760	16,172	12,541	2,401	14,942
1979	25,480	5,756	653	6,409	12,764	2,641	15,405	11,935	2,297	14,232
1980	24,405	5,465	626	6,091	12,198	2,524	14,722	11,405	2,194	13,599
1981	23,294	5,186	592	5,778	11,529	2,406	13,935	10,779	2,093	12,872
1982	22,258	4,920	540	5,460	10,993	2,313	13,306	10,277	2,013	12,290
1983	21,293	4,669	511	5,180	10,501	2,217	12,718	9,818	1,929	11,747
1984	20,374	4,442	479	4,921	9,876	2,120	11,996	9,234	1,845	11,079
1985	19,578	4,217	461	4,678	9,288	2,023	11,311	8,684	1,761	10,445
Total	409,094	93,957	9,369	103,326	193,282	42,932	236,214	180,715	37,353	218,068

TABLE 534

PROJECTIONS FOR ALASKA

Case I

	Gas Footage Drilled Annually (000')	Gas Reserves Additions Non-Assoc. (BCF)	Gas Reserves Additions A&D (BCF)	Gas Reserves Additions Total (BCF)	Wellhead Gas Production Non-Assoc. (BCF)	Wellhead Gas Production A&D (BCF)	Wellhead Gas Production Total (BCF)	Marketed Gas Production Non-Assoc. (BCF)	Marketed Gas Production A&D (BCF)	Marketed Gas Production Total (BCF)
1971	82	444	59	503	200	20	220	187	18	205
1972	86	466	154	620	200	20	220	187	18	205
1973	92	491	167	658	200	20	220	187	18	205
1974	96	521	462	983	200	21	221	187	19	206
1975	205	1,048	536	1,584	200	25	225	187	22	209
1976	220	1,121	1,241	2,362	200	31	231	187	27	214
1977	592	3,192	1,500	4,692	200	36	236	187	32	219
1978	704	3,754	1,503	5,257	400	645	1,045	374	562	936
1979	763	4,073	1,571	5,644	600	755	1,355	561	658	1,219
1980	832	4,439	2,125	6,564	800	869	1,669	748	757	1,505
1981	891	4,750	2,157	6,907	1,200	982	2,182	1,123	856	1,979
1982	935	4,987	1,841	6,828	1,600	1,395	2,995	1,496	1,215	2,711
1983	1,225	6,711	653	7,364	1,800	1,508	3,308	1,684	1,314	2,998
1984	1,237	6,778	380	7,158	2,200	1,820	4,020	2,058	1,585	3,643
1985	1,237	6,778	370	7,148	2,600	1,936	4,536	2,432	1,686	4,118
Total	9,197	49,553	14,719	64,272	12,600	10,083	22,683	11,785	8,787	20,572

TABLE 535

PROJECTIONS FOR ALASKA

Case IA

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	82	296	59	355	200	20	220	187	18	205
1972	86	311	153	464	200	20	220	187	18	205
1973	92	329	165	494	200	20	220	187	18	205
1974	96	347	456	803	200	21	221	187	19	206
1975	205	699	523	1,222	200	24	224	187	21	208
1976	220	749	1,221	1,970	200	28	228	187	25	212
1977	592	2,132	1,468	3,600	200	32	232	187	28	215
1978	704	2,508	1,469	3,977	410	637	1,047	383	555	938
1979	763	2,721	1,524	4,245	512	743	1,255	479	647	1,126
1980	832	2,966	2,076	5,042	622	851	1,473	582	741	1,323
1981	891	3,177	2,108	5,285	937	959	1,896	876	835	1,711
1982	935	3,335	1,790	5,125	1,151	1,364	2,515	1,077	1,188	2,265
1983	1,225	4,488	615	5,103	1,263	1,471	2,734	1,181	1,281	2,462
1984	1,237	4,533	345	4,878	1,470	1,778	3,248	1,374	1,548	2,922
1985	1,237	4,533	340	4,873	1,670	1,888	3,558	1,562	1,644	3,206
Total	9,197	33,124	14,312	47,436	9,435	9,856	19,291	8,823	8,586	17,409

TABLE 536

PROJECTIONS FOR ALASKA

Case II

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	82	444	59	503	200	20	220	187	18	205
1972	84	453	154	607	200	20	220	187	18	205
1973	86	464	166	630	200	20	220	187	18	205
1974	88	478	362	840	200	21	221	187	19	206
1975	184	934	379	1,313	200	25	225	187	22	209
1976	191	973	899	1,872	200	29	229	187	26	213
1977	500	2,693	1,197	3,890	200	35	235	187	31	218
1978	577	3,079	1,338	4,417	500	543	1,043	468	473	941
1979	609	3,249	1,358	4,607	600	751	1,351	561	654	1,215
1980	645	3,443	1,732	5,175	700	863	1,563	655	752	1,407
1981	671	3,584	1,684	5,268	1,100	875	1,975	1,029	762	1,791
1982	692	3,692	1,412	5,104	1,200	985	2,185	1,123	858	1,981
1983	898	4,921	507	5,428	1,500	1,397	2,897	1,403	1,217	2,620
1984	907	4,969	331	5,300	1,700	1,508	3,208	1,590	1,314	2,904
1985	907	4,969	317	5,286	2,100	1,622	3,722	1,964	1,413	3,377
Total	**7,121**	38,345	11,895	50,240	**10,800**	8,714	19,514	**10,102**	**7,595**	**17,697**

TABLE 537

PROJECTIONS FOR ALASKA

Case III

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	82	296	59	355	200	20	220	187	18	205
1972	84	302	153	455	200	20	220	187	18	205
1973	86	309	164	473	200	20	220	187	18	205
1974	88	319	356	675	200	21	221	187	19	206
1975	184	624	367	991	200	24	224	187	21	208
1976	191	649	881	1,530	200	27	227	187	24	211
1977	500	1,796	1,169	2,965	200	31	231	187	27	214
1978	577	2,053	1,308	3,361	300	535	835	281	466	747
1979	609	2,165	1,319	3,484	500	741	1,241	468	645	1,113
1980	645	2,296	1,691	3,987	500	847	1,347	468	738	1,206
1981	671	2,390	1,643	4,033	800	854	1,654	748	744	1,492
1982	692	2,462	1,365	3,827	900	960	1,860	842	836	1,678
1983	898	3,280	467	3,747	1,000	1,366	2,366	935	1,189	2,124
1984	907	3,314	294	3,608	1,100	1,471	2,571	1,029	1,281	2,310
1985	907	3,314	289	3,603	1,300	1,579	2,879	1,216	1,375	2,591
Total	7,121	25,569	11,525	37,094	7,800	8,516	16,316	7,296	7,419	14,715

TABLE 538

PROJECTIONS FOR ALASKA

Case IV

	Gas Footage Drilled Annually (000')	Gas Reserves Additions Non-Assoc. (BCF)	Gas Reserves Additions A&D (BCF)	Gas Reserves Additions Total (BCF)	Wellhead Gas Production Non-Assoc. (BCF)	Wellhead Gas Production A&D (BCF)	Wellhead Gas Production Total (BCF)	Marketed Gas Production Non-Assoc. (BCF)	Marketed Gas Production A&D (BCF)	Marketed Gas Production Total (BCF)
1971	82	292	59	351	200	20	220	187	18	205
1972	78	280	54	334	200	20	220	187	18	205
1973	74	269	63	332	200	20	220	187	18	205
1974	72	259	127	386	200	20	220	187	18	205
1975	139	468	133	601	200	23	223	187	20	207
1976	133	450	130	580	200	25	225	187	22	109
1977	318	1,145	134	1,279	200	27	227	187	24	211
1978	336	1,196	174	1,370	200	29	229	187	26	213
1979	323	1,149	179	1,328	200	33	233	187	29	216
1980	310	1,102	217	1,319	200	37	237	187	33	220
1981	297	1,059	870	1,929	300	41	341	281	36	317
1982	286	1,017	1,152	2,169	300	44	344	281	39	320
1983	350	1,276	1,288	2,564	500	547	1,047	468	477	945
1984	336	1,224	1,292	2,516	700	751	1,451	655	654	1,309
1985	322	1,175	1,664	2,839	900	857	1,757	842	746	1,588
Total	3,456	12,361	7,536	19,897	4,700	2,494	7,194	4,397	2,178	6,575

TABLE 539

PROJECTIONS FOR ALASKA

Case IVA

	Gas Footage Drilled Annually (000')	Gas Resreves Additions Non-Assoc. (BCF)	Gas Resreves Additions A&D (BCF)	Gas Resreves Additions Total (BCF)	Wellhead Gas Production Non-Assoc. (BCF)	Wellhead Gas Production A&D (BCF)	Wellhead Gas Production Total (BCF)	Marketed Gas Production Non-Assoc. (BCF)	Marketed Gas Production A&D (BCF)	Marketed Gas Production Total (BCF)
1971	82	437	59	496	200	20	220	187	18	205
1972	78	420	55	475	200	20	220	187	18	205
1973	74	403	65	468	200	20	220	187	18	205
1974	72	387	131	518	200	21	221	187	19	206
1975	137	702	140	842	200	23	223	187	20	207
1976	132	674	140	814	200	26	226	187	23	210
1977	318	1,713	149	1,862	200	29	229	187	26	213
1978	336	1,791	192	1,983	200	34	234	187	30	217
1979	322	1,719	200	1,919	200	40	240	187	35	222
1980	310	1,650	237	1,887	200	46	246	187	41	228
1981	297	1,584	890	2,474	400	52	452	374	46	420
1982	285	1,521	1,175	2,696	400	58	458	374	51	425
1983	348	1,907	1,311	3,218	1,000	564	1,564	935	492	1,427
1984	334	1,831	1,318	3,149	1,000	771	1,771	935	672	1,607
1985	321	1,758	1,688	3,446	1,200	880	2,080	1,123	767	1,890
Total	3,446	18,497	7,750	26,247	6,000	2,604	8,604	5,611	2,276	7,887

TABLE 540

PROJECTIONS FOR TOTAL UNITED STATES, INCLUDING ALASKA
NON-ASSOCIATED AND ASSOCIATED-DISSOLVED

Case I

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	41,250	13,919	1,376	15,295	17,102	4,812	21,914	15,990	4,187	20,177
1972	43,312	14,736	1,452	16,188	17,739	4,568	22,307	16,586	3,975	20,561
1973	45,696	15,692	1,705	17,397	18,686	4,335	23,021	17,471	3,772	21,243
1974	48,436	16,714	2,214	18,928	19,424	4,154	23,578	18,161	3,615	21,776
1975	51,687	18,340	2,493	20,833	19,741	4,011	23,752	18,458	3,490	21,948
1976	55,306	19,545	3,295	22,840	19,832	3,899	23,731	18,542	3,392	21,934
1977	59,809	22,906	3,736	26,642	19,933	3,832	23,765	18,638	3,335	21,973
1978	64,659	25,054	3,855	28,909	20,310	4,383	24,693	18,990	3,815	22,805
1979	70,154	27,229	4,017	31,246	20,725	4,442	25,167	19,378	3,866	23,244
1980	76,468	29,080	4,614	33,694	21,307	4,508	25,815	19,922	3,924	23,846
1981	81,822	30,455	4,668	35,123	22,023	4,568	26,591	20,593	3,976	24,569
1982	85,912	31,092	4,358	35,450	23,010	4,947	27,957	21,515	4,305	25,820
1983	88,751	32,465	3,148	35,613	23,839	5,018	28,857	22,291	4,368	26,659
1984	89,639	31,495	2,885	34,380	24,620	5,277	29,897	23,021	4,592	27,613
1985	89,639	30,049	2,854	32,903	25,286	5,337	30,623	23,644	4,644	28,288
Total	992,540	358,771	46,670	405,441	313,577	68,091	381,668	293,200	59,256	352,456

TABLE 541

PROJECTIONS FOR TOTAL UNITED STATES, INCLUDING ALASKA
NON-ASSOCIATED AND ASSOCIATED-DISSOLVED

Case IA

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	41,250	10,208	1,224	11,432	17,102	4,812	21,914	15,990	4,187	20,177
1972	43,312	10,531	1,150	11,681	17,561	4,544	22,105	16,419	3,954	20,373
1973	45,696	10,938	1,239	12,177	18,125	4,268	22,393	16,947	3,714	20,661
1974	48,436	11,398	1,623	13,021	18,466	4,030	22,496	17,265	3,507	20,772
1975	51,687	12,273	1,803	14,076	18,372	3,825	22,197	17,178	3,327	20,505
1976	55,306	12,886	2,553	15,439	18,042	3,651	21,693	16,869	3,177	20,046
1977	59,809	14,989	2,904	17,893	17,681	3,531	21,212	16,532	3,072	19,604
1978	64,659	16,502	2,947	19,449	17,572	4,029	21,601	16,430	3,506	19,936
1979	70,154	17,823	3,061	20,884	17,384	4,034	21,418	16,254	3,510	19,764
1980	76,468	18,953	3,633	22,586	17,371	4,049	21,420	16,243	3,524	19,767
1981	81,822	19,905	3,678	23,583	17,488	4,065	21,553	16,351	3,538	19,889
1982	85,912	20,480	3,383	23,863	17,768	4,405	22,173	16,614	3,834	20,448
1983	88,751	21,687	2,195	23,882	18,030	4,447	22,477	16,858	3,870	20,728
1984	89,639	21,389	1,954	23,343	18,205	4,683	22,888	17,021	4,075	21,096
1985	89,639	20,792	1,956	22,748	18,353	4,724	23,077	17,161	4,112	21,273
Total	992,540	240,754	35,303	276,057	267,520	63,097	330,617	250,132	54,907	305,039

TABLE 542

PROJECTIONS FOR TOTAL UNITED STATES, INCLUDING ALASKA
NON-ASSOCIATED AND ASSOCIATED-DISSOLVED

Case II

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	41,250	13,919	1,376	15,295	17,102	4,812	21,914	15,990	4,187	20,177
1972	42,075	14,314	1,423	15,737	17,739	4,568	22,307	16,586	3,975	20,561
1973	43,127	14,809	1,656	16,465	18,665	4,331	22,996	17,452	3,769	21,221
1974	44,420	15,330	2,036	17,366	19,341	4,140	23,481	18,084	3,606	21,690
1975	46,068	16,359	2,200	18,559	19,553	3,994	23,547	18,282	3,475	21,757
1976	47,910	16,974	2,761	19,735	19,498	3,866	23,364	18,231	3,364	21,595
1977	50,367	19,387	3,183	22,570	19,414	3,782	23,196	18,152	3,291	21,443
1978	52,937	20,696	3,372	24,068	19,663	4,211	23,874	18,385	3,664	22,049
1979	55,849	21,990	3,433	25,423	19,709	4,343	24,052	18,428	3,779	22,207
1980	59,199	23,021	3,806	26,827	19,885	4,380	24,265	18,593	3,812	22,405
1981	61,567	23,683	3,749	27,432	20,259	4,312	24,571	18,943	3,752	22,695
1982	63,415	24,027	3,478	27,505	20,571	4,364	24,935	19,235	3,798	23,033
1983	64,876	25,147	2,548	27,695	21,127	4,715	25,842	19,754	4,104	23,858
1984	65,525	24,766	2,353	27,119	21,375	4,756	26,131	19,986	4,139	24,125
1985	65,525	23,971	2,316	26,287	21,779	4,796	26,575	20,364	4,174	24,538
Total	804,110	298,393	39,690	338,083	295,680	65,370	361,050	276,465	56,889	333,354

TABLE 543

PROJECTIONS FOR TOTAL UNITED STATES, INCLUDING ALASKA
NON-ASSOCIATED AND ASSOCIATED-DISSOLVED

Case III

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	41,250	10,208	1,224	11,432	17,102	4,812	21,914	15,990	4,187	20,177
1972	42,075	10,237	1,128	11,365	17,561	4,544	22,105	16,419	3,954	20,373
1973	43,127	10,340	1,206	11,546	18,111	4,266	22,377	16,934	3,712	20,646
1974	44,420	10,491	1,474	11,965	18,409	4,024	22,433	17,212	3,501	20,713
1975	46,068	11,003	1,560	12,563	18,246	3,814	22,060	17,060	3,318	20,378
1976	47,910	11,258	2,092	13,350	17,823	3,630	21,453	16,665	3,159	19,824
1977	50,367	12,756	2,448	15,204	17,346	3,499	20,845	16,218	3,044	19,262
1978	52,937	13,738	2,591	16,329	16,986	3,882	20,868	15,883	3,378	19,261
1979	55,849	14,513	2,626	17,139	16,730	3,971	20,701	15,643	3,454	19,097
1980	59,199	15,100	2,992	18,092	16,421	3,967	20,388	15,354	3,452	18,806
1981	61,567	15,512	2,934	18,446	16,314	3,864	20,178	15,253	3,363	18,616
1982	63,415	15,763	2,671	18,434	16,245	3,888	20,133	15,190	3,384	18,574
1983	64,876	16,617	1,756	18,373	16,252	4,214	20,466	15,196	3,667	18,863
1984	65,525	16,510	1,582	18,092	16,088	4,235	20,323	15,043	3,686	18,729
1985	65,525	16,141	1,566	17,707	16,034	4,260	20,294	14,992	3,708	18,700
Total	804,110	200,187	29,850	230,037	255,668	60,870	316,538	239,052	52,967	292,019

TABLE 544

PROJECTIONS FOR TOTAL UNITED STATES, INCLUDING ALASKA
NON-ASSOCIATED AND ASSOCIATED-DISSOLVED

Case IV

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	40,681	10,071	1,224	11,295	17,102	4,812	21,914	15,990	4,187	20,177
1972	39,053	9,518	973	10,491	17,554	4,544	22,098	16,413	3,954	20,367
1973	37,490	9,030	978	10,008	18,063	4,259	22,322	16,889	3,706	20,595
1974	35,992	8,570	1,031	9,601	18,265	4,002	22,267	17,078	3,482	20,560
1975	34,622	8,372	1,030	9,402	17,957	3,769	21,726	16,790	3,279	20,069
1976	33,237	7,952	984	8,936	17,342	3,555	20,897	16,215	3,093	19,308
1977	32,097	8,312	975	9,287	16,629	3,390	20,019	15,548	2,950	18,498
1978	30,844	8,117	995	9,112	15,888	3,234	19,122	14,855	2,815	17,670
1979	29,611	7,889	962	8,851	15,095	3,087	18,182	14,114	2,686	16,800
1980	28,426	7,653	947	8,600	14,405	2,945	17,350	13,469	2,563	16,032
1981	27,289	7,360	1,552	8,912	13,683	2,804	16,487	12,794	2,440	15,234
1982	26,198	7,067	1,808	8,875	13,066	2,692	15,758	12,217	2,343	14,560
1983	25,226	7,071	1,903	8,974	12,719	3,082	15,801	11,893	2,682	14,575
1984	24,217	6,761	1,887	8,648	12,208	3,172	15,380	11,415	2,760	14,175
1985	23,247	6,429	2,230	8,659	11,728	3,166	14,894	10,966	2,755	13,721
Total	468,230	120,172	19,479	139,651	231,704	52,513	284,217	216,646	48,695	262,341

TABLE 545

PROJECTIONS FOR TOTAL UNITED STATES, INCLUDING ALASKA
NON-ASSOCIATED AND ASSOCIATED-DISSOLVED

Case IVA

	Gas Footage Drilled Annually (000')	Gas Reserves Additions			Wellhead Gas Production			Marketed Gas Production		
		Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)	Non-Assoc. (BCF)	A&D (BCF)	Total (BCF)
1971	40,681	13,725	1,376	15,101	17,102	4,812	21,914	15,990	4,187	20,177
1972	39,053	13,283	1,247	14,530	17,730	4,568	22,298	16,577	3,975	20,552
1973	37,490	12,869	1,366	14,235	18,597	4,321	22,918	17,388	3,760	21,148
1974	35,992	12,421	1,476	13,897	19,132	4,112	23,244	17,888	3,578	21,466
1975	34,622	12,309	1,499	13,808	19,124	3,923	23,047	17,881	3,413	21,294
1976	33,237	11,819	1,448	13,267	18,771	3,748	22,519	17,551	3,262	20,813
1977	32,097	12,444	1,431	13,875	18,314	3,614	21,928	17,124	3,145	20,269
1978	30,844	12,217	1,451	13,668	17,815	3,483	21,298	16,657	3,031	19,688
1979	29,611	11,904	1,418	13,322	17,239	3,356	20,595	16,119	2,919	19,038
1980	28,426	11,415	1,389	12,804	16,725	3,230	19,955	15,638	2,810	18,448
1981	27,289	10,995	1,971	12,966	16,238	3,101	19,339	15,183	2,698	17,881
1982	26,198	10,581	2,203	12,784	15,731	2,998	18,729	14,708	2,609	17,317
1983	25,226	10,598	2,276	12,874	15,865	3,394	19,259	14,834	2,954	17,788
1984	24,217	10,148	2,248	12,396	15,215	3,488	18,703	14,226	3,036	17,262
1985	23,247	9,655	2,575	12,230	14,773	3,485	18,258	13,814	3,033	16,847
Total	468,230	176,383	25,374	201,757	258,371	55,633	314,004	241,578	48,410	289,988

TABLE 546

PROJECTED TOTAL AVAILABLE GAS
(TCF/Year)

	Case IA			Case IVA		
	1975	1980	1985	1975	1980	1985
Lower 48						
Onshore	17.7	14.8	13.2	18.2	14.7	11.3
Offshore	4.3	5.1	6.3	4.6	5.0	4.9
Alaska, North Slope	—	1.2	2.8	—	—	1.5
Alaska, South	.2	.3	.8	.2	.2	.6
Total Conventional (Wellhead Production)	22.2	21.4	23.1	23.0	20.0	18.3
Synthetic Gas						
From Coal	—	.6	2.5	—	.2	.5
From Liquids	.6	1.3	1.3	.6	1.3	1.3
Gas from Nuclear Stimulation	—	.2	1.3	—	—	—
Imports						
LNG	.2	2.3	3.2	.2	2.3	3.9
Pipeline	1.0	1.6	2.7	1.0	1.6	2.7
Total Supply	24.0	27.4	34.0	24.8	25.4	26.7

Note: Totals may not agree due to rounding.

Chapter Seven

Economics — Oil and Gas

Guide to Chapter Seven
Economics—Oil and Gas

SECTION I: Oil Operations

Discusses economic factors developed by the oil supply model, including operating expenses for oil wells, the cost of adding secondary and tertiary reserves, drilling costs, future well depths and escalation of future costs exclusive of inflation. Presents history and projection of net fixed assets for oil operations and the cash flow on new oil well drilling from 1971 to 1985, and depletion of the reserves developed by drilling during that period by years to 2000, and in a lump sum from 2000 to 2015.

SECTION II: Gas Operations

Discusses economic factors developed by the gas supply model, including operating expenses for gas wells, drilling costs, gas plant investments and operating expenses. Presents history and projection of net fixed assets for gas operations and the effects of various unit revenue assumptions for old gas on the required unit revenue required for new gas.

SECTION III: Economic Model Support and Results

Describes and supports individually the various historical and projected parameters used in making the economic calculations. Describes the calculation procedure for projected expenses and investments and the profit and loss statements. Tabulates exploration and development costs, net fixed assets and expenses. Presents historical oil and gas prices and tabulates the projected oil and gas revenues for various rates of return for all the cases analyzed.

Chapter Seven—Section I

Oil Operations

Allocation of Total Well Operating Expense Between Oil and Gas Wells

The following statistical information was obtained from testimony given to the Federal Power Commission in South Louisiana Rate Case AR61-2 by Clark Gillespie. The operating cost data is for 1960:

- 53,859 oil wells with an average operating cost of $3,300 per year
- 75,472 oil wells selling solution gas with an average operating cost of $3,840 per year
- 6,500 dry gas wells with an average operating cost of $1,272 per year
- 5,335 gas condensate wells with an average operating cost of $9,120 per year

This information was used to determine relative costs of operating the average gas well in relationship to the cost of operating the average oil well as follows:

	53,859 oil wells @ $3,300 per year	= $177,735,000
	75,472 oil wells selling solution gas @ $3,840 per year	= 288,812,000
129,331	Total Oil Well Cost	= $467,547,000

$$\text{Average oil well cost} = \frac{467{,}547{,}000}{129{,}331} = \$3{,}616 \text{ per year}$$

	6,500 gas wells @ $1,272 per year	= $ 8,268,000
	5,335 gas condensate wells @ $9,120 per year	= 48,655,000
11,835	Total Gas Well Cost	= $ 56,923,000

$$\text{Average gas well cost} = \frac{56{,}923{,}000}{11{,}835} = \$4{,}810 \text{ per year}$$

$$\text{Ratio gas well cost/oil well cost} = \frac{4{,}810}{3{,}616} = 1.33$$

Gas wells cost 1.33 times oil wells to operate.

Since 1960 there has been a trend toward more oil wells producing from secondary recovery projects, which are more expensive, but during this same period the number of higher-operating-cost gas condensate wells has also increased. It is assumed these trends offset and the cost split developed for 1960 is applicable for 1969.

According to Joint Association Survey (JAS) figures for 1969, well operating costs were $2,985,000,000. Producing well count from the Bureau of Mines Mineral Yearbook was 542,000 oil wells and 114,000 gas wells.

Operating cost per oil well =

$$\frac{\$2{,}985\text{MM}}{542\text{M oil wells} + 1.33\ (114\text{M gas wells})} = \$4{,}301 \text{ per year}$$

Total cost for oil wells =

542M wells x $4,301 per year = $2,331MM

Total Cost	$2,985MM	
Less: Oil well cost	2,331MM	
Gas well cost	654MM	

$$\text{\% Total costs allocated to oil} = \frac{\$2{,}331\text{MM}}{2{,}985\text{MM}} = 78 \text{ percent}$$

$$\text{\% Total costs allocated to gas} = \frac{\$\ 654\text{MM}}{2{,}985\text{MM}} = 22 \text{ percent}$$

Oil Well Operating Costs

Well operating costs are generally based on a per-barrel or per-well figure. For the intended purpose of this study, the Task Group concluded the per-well cost would be most representative. Although in some instances lifting costs are a function of the amount of fluid being produced, costs are more frequently controlled by labor and other field costs which are more a function of the number of wells being operated than a function of the amount of fluid being produced.

Operating costs include all costs directly associated with the daily operation of oil wells, except overhead costs to support offices and operating levels above the base field office frequently allocated to producing wells. Costs normally include equipment and materials, both and subsurface, required for replacement and maintenance, corrosion and scale treatment, flowlines and other costs required to keep wells on production in the current producing interval; stimulation, cleanouts and pulling jobs, plugbacks in the same reservoir and recompletion costs from one reservoir to a separate reservoir. A large number of operators were polled to obtain basic well cost information by NPC regions. These operators were requested to furnish lifting cost data in addition to cleanout and workover expense on an average per-well basis for whatever operating unit of their company such information was available. These geographic operating units were then assigned as closely as possible to the appropriate NPC region. The following tabulation presents this information.

Well Operating Costs
(Dollars per Well per Year)

Region	1	2	3	4	5	6	6A	7	9
Operator A	127,435	5,250	10,806	7,015	4,147		38,789	4,990	0
Operator B	113,187	6,552		5,067	3,826	4,248	33,548	2,639	2,527
Operator C			37,012	4,206	2,233	6,212	22,672	3,229	
Operator D	119,598			7,092	5,858	5,220	44,027	4,147	
Cost Used	107,920	4,942	15,563	4,942	3,510	4,942	31,470	3,510	897
Total Wells	104	9,650	570	3,382	14,662	10,332	535	8,878	2,245

The costs developed from this survey represent an adequately sized sample and, with the exception of Region 3, the levels of costs are fairly consistent. Starting with these raw numbers, the 14 NPC regions were placed into six groups with similar operating cost characteristics as follows:

Cost Group I — Region 1
Cost Group II — Regions 2, 4, 6
Cost Group III — Regions 2A, 6A, 11A
Cost Group IV — Regions 3, 11
Cost Group V — Regions 5, 7
Cost Group VI — Regions 8, 9, 10

This grouping was to simplify well costing and to extend the cost coverage into regions where no data are available by matching it with a region with similar conditions.

The Region 8, 9, 10 group was estimated using the information in the tabulation, and a cost for Region 10 developed by assuming that stripper wells which average one-third barrel per day are being operated profitably with a posted crude price of $4.50 per barrel. Total income to these wells would be about $550 per year, which would be the upper limit of well costs for this region. An estimate of $1,000 per well per year was used for combining Regions 8, 9, and 10.

The final operating costs for each group of wells was determined by adjusting each cost group proportionally so that the product of the number of

TABLE 547
OILWELL OPERATING COST FACTORS

Region	New Fields Dollars Per Well Per Year	Dollars Per Barrel Reserves Added: Secondary Investment 1970	Secondary Investment 1985	Tertiary Investment 1970	Tertiary Investment 1985
1	107,920	.50	1.00	.875	1.625
2	4,942	.25	.75	.625	1.375
2A	31,467	.50	1.00	.875	1.625
3	15,563	.25	.75	.625	1.375
4	4,942	.25	.75	.625	1.375
5	3,510	.25	.75	.625	1.375
6	4,942	.25	.75	.625	1.375
6A	31,470	.50	1.00	.875	1.625
7	3,510	.25	.75	.625	1.375
10	897	.25	.75	.625	1.375
11	15,563	.25	.75	.625	1.375
11A	31,467	.50	1.00	.875	1.625

wells in each region and the operating cost for wells in the region would total the value given in the Joint Association Survey for total oil well operating costs for 1970. Operating costs were split 78 percent to oil and 22 percent to gas as developed at the beginning of this section. The adjusted values are shown as *cost used* on the bottom line in the above table for comparison with the actual numbers submitted by various operators.

Oil Well Operating Cost Escalation Due to Increased Application and Complexity of Fluid Injection Processes

In preparation of the Initial Appraisal the Task Group estimated the following schedule of increased field operating costs that would be occasioned by secondary and tertiary recovery operations over those attributed to primary operations.

	Increased Operating Costs per Barrel Over 1965-1969 Trends
Waterflooding	15¢-20¢
Miscible—Carbon Dioxide	20¢-25¢
Miscible—Hydrocarbon	10¢
Miscible—Water Miscible	15¢-20¢
Thermal	30¢-45¢

The overall average operating cost per barrel for 1970 was determined from the JAS cost for all operating oil and gas wells—$2,379 million. As shown elsewhere in this report, 78 percent of this would apply to oil wells so the total expenditure for oil wells was .78 x $2,379 = $1,856 million.

Total production from the API was 3,319 million barrels. The cost per barrel was:

$$\frac{\$1{,}856\text{ MM}}{3{,}319\text{ MB}} = \$0.56 \text{ per barrel}$$

The production mix for 1971 was:

	MMB/D	%
Primary	5.52	61
Secondary	3.48	38
Tertiary	.10	1
	9.10	100

If P = cost of producing a barrel of primary oil, and using the lower end of the price range from the cost table, the cost of secondary = $(P + .15) and tertiary = $(P + .20). The present cost of primary using the above prices and production mix is:

$$\begin{aligned} .61P + .38(P + .15) + .01(P + .20) &= \$0.56 \\ 1.0P + .057 + .002 &= \$0.56 \\ P &= \$0.50 \end{aligned}$$

The production mix in 1985 for Case II is projected to be:

	MMB/D	%
Primary	5.01	50
Secondary	3.40	33
Tertiary	1.78	17
	10.19	100

Then, using the upper range of production costs which will likely be applicable 15 years in the future after the cheaper feasible prospects have been completed, the new composite price (NCP) can be calculated as follows:

$$\begin{aligned} .5P + .33(P + .2) + .17(P + .40) &= \text{NCP} \\ .5 \times .50 + .33(.50 + .2) + .17(.50 + .40) &= \text{NCP} \\ .25 + .231 + .153 = \$.634 &= \text{NCP} \end{aligned}$$

The multiplier needed to adjust 1971 operating cost to reflect the change in mix in 1985 is .634/.56 = $1.13.

The calculations assumed the 13-percent increase accumulated linearly with time.

Drilling Costs

Drilling cost information was developed from the Joint Association Survey of the U. S. Oil and Gas Producing Industry for the year 1969. The JAS shows for each of the major oil and gas producing states the number of wells drilled, the total footage drilled and the total cost separately for oil wells, gas wells and dry holes in depth increments of 1,250 feet down to 5,000 feet, and 2,500-foot increments from 5,000 feet to 20,000 feet or over. The wells, footage and costs were accumulated by NPC regions and average depth versus cost per foot for wells in each depth bracket were found for each depth bracket in each region. These data are shown in Table 548. A smooth curve was drawn through the data for each region and values picked from the curve were input to the program.

TABLE 548
DRILLING COST VERSUS DEPTH

	Dry Holes		Producers	
	Average Depth	Cost ($/Foot)	Average Depth	Cost ($/Foot)
Region 1	2,205	122.00	9,682	262.70
	3,960	108.83	11,162	206.65
	6,654	101.68	13,405	201.19
	8,852	124.45	15,835	93.00
	11,047	190.62		
	13,145	231.96		
	15,552	216.05		
Region 2	898	7.38	968	17.64
	1,851	7.93	1,635	15.57
	3,058	8.61	3,031	17.88
	4,485	10.15	4,339	22.43
	6,134	12.99	6,205	29.52
	8,633	14.51	8,832	33.84
	10,886	17.29	10,975	32.73
	13,653	32.96	13,743	30.08
			16,114	40.79
Region 2A	4,945	80.90	734	145.07
	6,750	61.10	1,956	91.07
	7,856	26.60	3,253	55.62
	11,225	114.31	4,432	48.61
	13,254	155.93	5,969	48.41
	15,352	139.77	8,843	51.98
Region 3	737	13.27	385	12.00
	1,790	11.76	1,342	18.85
	2,998	13.04	3,269	18.00
	4,521	11.73	4,659	25.66
	6.018	19.25	5,818	20.12
	8,378	22.31	8,229	23.74
	11,472	36.02	11,317	33.37
			15,800	45.78
			17,910	88.31
Region 4	918	13.30	955	15.96
	1,802	9.74	1,851	13.16
	3,156	7.82	3,237	12.92
	4,477	6.44	4,509	16.04
	6,061	6.82	6,512	14.24
	8,379	9.00	8,773	14.65
	10,763	14.43	10,970	20.06
	13,139	24.03	12,773	33.47
	16,471	50.55		
	19,149	82.32		
Region 5	766	5.08	786	9.02
	1,814	4.76	1,852	8.53
	3,136	6.84	3,195	12.92
	4,416	7.25	4,816	11.20
Region 6	785	9.74	683	12.23
	2,041	6.80	1,962	9.92
	3,090	6.00	2,982	9.99
	4,359	6.37	4,366	12.21
	6,291	6.48	6,268	12.87
	8,611	10.21	8,671	16.12
	11,168	15.75	11,040	21.07
	13,543	21.95	13,405	24.70
	15,354	32.38	15,985	31.53
	18,225	43.15	18,628	57.84
	20,424	70.02	20,878	68.87
Region 6A	595	106.17	4,439	60.05
	2,414	40.81	6,636	74.75
	3,038	69.75	8,882	50.39
	4,115	77.34	11,231	44.01
	6,352	44.74	13,337	46.37
	8,823	33.11	15,746	62.96
	11,179	39.99	19,479	81.22
	13,589	45.48		
	15,910	53.98		
	19,784	107.73		
Region 7	775	5.35	837	8.04
	1,933	5.28	1,973	9.19
	3,302	4.99	3,240	9.69
	4,279	5.80	4,227	10.86
	6,172	8.80	6,567	12.81
	8,563	11.38	8,426	14.73
	10,808	15.22	10,478	19.33
	13,361	21.12	14,392	35.82
	16,184	33.62	15,715	45.20
	18,692	71.15		
	20,330	161.68		
Regions 8, 9 & 10	683	6.15	769	8.98
	1,874	5.88	1,847	9.53
	3,053	5.95	3,056	9.37
	4,333	7.74	4,516	11.35
	6,070	11.52	5,282	11.64
	8,480	15.56	7,849	15.44
	10,176	19.15		
Region 11		Used Region 6		
Region 11A		Used Region 6A		

* Includes platform costs for offshore regions.

Future Average Well Depth

Future well depths were obtained from historical plots of the average well depths for producers and dry holes separately for each region, extrapolated for each region as a function of cumulative exploratory footage, extrapolated into the future toward the weighted average depth of the oil reserve yet to be discovered. Depth distribution was obtained from Table 105 (Chapter Five, Section I).

TABLE 549

AVERAGE DRILLING DEPTHS—OIL

Region	Cumulative* Exploratory (Thousand Feet)	Average Well Depth (Feet) Exploratory Dry Holes	Producers	Development Dry Holes
1	0	7,980	11,000	8,000
	23,000	9,290	11,300	9,300
	46,000	10,600	10,600	10,600
2	0	7,500	4,800	5,300
	50,000	6,425	5,425	5,925
	120,000	7,150	6,150	6,650
2A	0	7,500	4,800	5,100
	15,000	6,000	5,000	5,500
	80,000	6,000	5,000	5,500
3	0	5,500	5,300	3,600
	22,500	6,050	5,950	4,800
	45,000	6,600	6,000	6,300
4	0	5,700	6,200	5,300
	169,000	6,470	6,470	6,120
	338,000	7,240	6,740	6,940
5	0	4,100	4,800	3,700
	173,000	4,950	5,050	4,150
	345,000	5,600	5,300	4,600
6	0	6,900	5,000	5,400
	283,000	7,800	5,900	6,300
	565,000	8,700	6,800	7,200
6A	0	10,400	10,600	10,000
	70,000	11,450	11,050	10,800
	140,000	12,500	11,500	11,600
7	0	3,800	4,000	3,800
	136,000	5,100	4,950	4,750
	275,000	6,400	5,900	5,700
10	0	1,700	2,300	1,800
	165,000	3,950	4,150	3,800
	330,000	6,200	6,000	5,800
11	0	7,700	11,600	11,600
	25,000	8,250	9,730	9,800
	50,000	8,800	7,850	8,000
11A	0	9,900	8,900	9,400
	16,000	9,900	8,900	9,400
	32,000	9,900	8,900	9,400

* From 1/1/71 to points in the future, the last being beyond the 15-year projection to permit extrapolation of average well depths.

Escalation of Offshore Drilling Costs As a Result of Operations Moving Further Offshore Into Progressively Deeper Water Depths

The cost per foot for offshore drilling is more a function of the depth of water and the resulting platform cost than drilling depth per se. The tabulation below develops a multiplier for adjusting offshore drilling costs that will be occasioned by moving progressively into deeper water. The average depth of water projected is based upon trends in both the Louisiana-Texas offshore and the California offshore. It was assumed for this estimate that each platform would serve 10 wells and that well depths would be 10,000 feet, or that each platform would support 100,000 feet of drilling.

Offshore drilling costs in the calculations were developed by increasing the base cost per foot factors by 3 percent per year (45 percent for the 15-year period) to account for the effect of increased water depth.

	Approximate Platform Cost			Total Cost per Foot Drilled		
	Average Water Depth Feet	For a 10-Well Base (MM$)	Per Foot Drilled (100,000 Feet per Platform)	Total Excluding Platform	Total Including Platform	Ratio of Total Cost to Base
1967-1969, Incl. (Base)	170	$1,450	$14.50	42.74*	57.24	1.00
1970-1974, Incl.	230	2,000	20.00	42.74	62.74	1.10
1975-1979, Incl.	300	2,600	26.00	42.74	68.74	1.20
1980-1984, Incl.	400	3,900	39.00	42.74	81.74	1.43

* Weighted average cost for 10,000-foot well using $34.00 per foot for dry holes and $45.00 per foot for producers and a 76 percent success factor.

TABLE 550

SUMMARY OF COSTS AND INVESTMENTS FOR ALL REGIONS*

THIS IS THE HIGH DRILLING AND HIGH FINDING CASE
SECONDARY AND TERTIARY EFFORTS NOT INTENSIFIED BY 50 PERCENT
CASE I

TIME	OPERATING COSTS			DRILLING COSTS		
	OLD WELLS THOUS DOLS	NEW WELLS THOU DOLS	ALL WELLS THOUS DOLS	PROD WELLS THOUS DOLS	DRY HOLES THOUS DOLS	ALL WELLS THOUS DOLS
1971	1954930.	0.	1954930.	1120812.	390106.	1510918.
1972	1856357.	74204.	1930561.	1018089.	370670.	1388759.
1973	1770642.	142975.	1913617.	1237283.	434356.	1671639.
1974	1696201.	225351.	1921552.	1446638.	495722.	1942360.
1975	1631651.	321319.	1952970.	1632668.	553591.	2186259.
1976	1575785.	430257.	2006042.	1685303.	586865.	2272168.
1977	1530672.	544956.	2075628.	1899610.	651205.	2550815.
1978	1492201.	674349.	2166549.	2048043.	699229.	2747272.
1979	1459536.	812057.	2271593.	2296831.	768169.	3065000.
1980	1431952.	961022.	2392974.	2431400.	816103.	3247503.
1981	1408814.	1115837.	2524651.	2571330.	867330.	3438660.
1982	1382060.	1276605.	2658666.	2852129.	951444.	3803573.
1983	1359609.	1449019.	2808628.	2998391.	1003092.	4001483.
1984	1340915.	1627324.	2968239.	3394513.	1105438.	4499951.
1985	1325507.	1823317.	3148824.	3556710.	1161772.	4718482.

TIME	SECONDARY RECOVERY INVESTMENTS			TERTIARY RECOVERY INVESTMENTS		
	OLD FIELDS THOUS DOLS	NEW FIELDS THOUS DOLS	ALL FIELDS THOUS DOLS	OLD FIELDS THOUS DOLS	NEW FIELDS THOUS DOLS	ALL FIELDS THOUS DOLS
1971	353436.	5829.	359264.	271888.	1684.	273571.
1972	353436.	5435.	358871.	292802.	1691.	294493.
1973	353436.	5360.	358795.	313716.	1787.	315503.
1974	353436.	5173.	358609.	334631.	1839.	336470.
1975	353436.	5288.	358723.	355545.	1998.	357543.
1976	523642.	43421.	567063.	650661.	26040.	676700.
1977	523642.	43589.	567230.	686781.	29797.	716578.
1978	523642.	56543.	580185.	722902.	32083.	754985.
1979	523642.	70507.	594149.	759023.	34217.	793240.
1980	523642.	86005.	609647.	795144.	36588.	831732.
1981	610385.	163133.	773517.	1118303.	78181.	1196484.
1982	610385.	181474.	791858.	1166904.	88525.	1255429.
1983	610385.	214169.	824553.	1215505.	101923.	1317427.
1984	610385.	262403.	872788.	1264105.	116573.	1380678.
1985	601223.	295282.	896506.	1312706.	134136.	1446842.

*EXCLUDING NORTH SLOPE.

TABLE 551

SUMMARY OF COSTS AND INVESTMENTS FOR ALL REGIONS*

THIS IS THE HIGH DRILLING AND LOW FINDING CASE
SECONDARY AND TERTIARY ARE NOT ACCELERATED OR INTENSIFIED
CASE IA

TIME	OPERATING COSTS			DRILLING COSTS		
	OLD WELLS THOUS DOLS	NEW WELLS THOU DOLS	ALL WELLS THOUS DOLS	PROD WELLS THOUS DOLS	DRY HOLES THOUS DOLS	ALL WELLS THOUS DOLS
1971	1954930.	0.	1954930.	1090442.	382469.	1472911.
1972	1856357.	71922.	1928279.	947236.	353893.	1301130.
1973	1770642.	135196.	1905838.	1095816.	400126.	1495943.
1974	1696201.	206725.	1902926.	1253339.	447579.	1700918.
1975	1631651.	287982.	1919634.	1417809.	499595.	1917404.
1976	1575785.	380183.	1955968.	1438753.	527353.	1966106.
1977	1530672.	474689.	2005361.	1601077.	583562.	2184640.
1978	1492201.	579685.	2071886.	1683497.	625182.	2308679.
1979	1459536.	689343.	2148879.	1858967.	688768.	2547736.
1980	1431952.	807095.	2239047.	1927794.	733213.	2661008.
1981	1408814.	927694.	2336508.	2019350.	782058.	2801408.
1982	1382060.	1052179.	2434239.	2242899.	864258.	3107157.
1983	1359609.	1186386.	2545995.	2367876.	917348.	3285225.
1984	1340915.	1326068.	2666984.	2713559.	1020395.	3733954.
1985	1325507.	1481693.	2807200.	2876496.	1081706.	3958202.

TIME	SECONDARY RECOVERY INVESTMENTS			TERTIARY RECOVERY INVESTMENTS		
	OLD FIELDS THOUS DOLS	NEW FIELDS THOUS DOLS	ALL FIELDS THOUS DOLS	OLD FIELDS THOUS DOLS	NEW FIELDS THOUS DOLS	ALL FIELDS THOUS DOLS
1971	353436.	5358.	358794.	271888.	1548.	273435.
1972	353436.	4221.	357657.	292802.	1313.	294115.
1973	353436.	3690.	357126.	313716.	1230.	314946.
1974	353436.	3380.	356815.	334631.	1202.	335832.
1975	353436.	3348.	356784.	355545.	1265.	356810.
1976	523642.	39046.	562688.	650661.	24099.	674760.
1977	523642.	36183.	559825.	686781.	27142.	713923.
1978	523642.	44873.	568515.	722902.	28424.	751326.
1979	523642.	53805.	577447.	759023.	29299.	788322.
1980	523642.	62548.	586189.	795144.	30072.	825216.
1981	610385.	128975.	739359.	1118303.	66364.	1184667.
1982	610385.	131268.	741653.	1166904.	71786.	1238690.
1983	610385.	150418.	760803.	1215505.	77846.	1293351.
1984	610385.	178012.	788397.	1264105.	83223.	1347328.
1985	601223.	193321.	794545.	1312706.	89000.	1401706.

*EXCLUDING NORTH SLOPE.

TABLE 552

SUMMARY OF COSTS AND INVESTMENTS FOR ALL REGIONS*

THIS IS THE LOW DRILLING AND HIGH FINDING CASE
SECONDARY AND TERTIARY EFFORTS NOT INTENSIFIED BY 50 PERCENT
CASE II

TIME	OPERATING COSTS			DRILLING COSTS		
	OLD WELLS THOUS DOLS	NEW WELLS THOU DOLS	ALL WELLS THOUS DOLS	PROD WELLS THOUS DOLS	DRY HOLES THOUS DOLS	ALL WELLS THOUS DOLS
1971	1954930.	0.	1954930.	1120812.	390106.	1510918.
1972	1856357.	74204.	1930561.	995979.	362536.	1358515.
1973	1770642.	141482.	1912124.	1200062.	421002.	1621064.
1974	1696201.	221350.	1917551.	1385674.	474008.	1859682.
1975	1631651.	313175.	1944826.	1524155.	514947.	2039103.
1976	1575785.	414511.	1990296.	1530167.	530662.	2060830.
1977	1530672.	518018.	2048690.	1684169.	575086.	2259255.
1978	1492201.	632198.	2124399.	1759248.	597658.	2356906.
1979	1459536.	750138.	2209674.	1923809.	638904.	2562713.
1980	1431952.	874396.	2306347.	1986631.	660309.	2646940.
1981	1408814.	1000100.	2408914.	2051296.	682874.	2734170.
1982	1382060.	1127244.	2509304.	2240724.	735789.	2976513.
1983	1359609.	1261269.	2620877.	2322211.	762274.	3084485.
1984	1340915.	1397454.	2738369.	2585171.	823673.	3408844.
1985	1325507.	1544410.	2869917.	2686613.	854628.	3541241.

TIME	SECONDARY RECOVERY INVESTMENTS			TERTIARY RECOVERY INVESTMENTS		
	OLD FIELDS THOUS DOLS	NEW FIELDS THOUS DOLS	ALL FIELDS THOUS DOLS	OLD FIELDS THOUS DOLS	NEW FIELDS THOUS DOLS	ALL FIELDS THOUS DOLS
1971	353436.	5829.	359264.	271888.	1684.	273571.
1972	353436.	5312.	358748.	292802.	1653.	294455.
1973	353436.	5188.	358623.	313716.	1729.	315446.
1974	353436.	4938.	358373.	334631.	1756.	336386.
1975	353436.	4905.	358341.	355545.	1853.	357398.
1976	523642.	42916.	566558.	650661.	25585.	676246.
1977	523642.	42141.	565782.	686781.	28693.	715475.
1978	523642.	54212.	577854.	722902.	30553.	753456.
1979	523642.	66789.	59[illegible]430.	759023.	32149.	791173.
1980	523642.	79305.	602947.	795144.	33386.	828531.
1981	610385.	153882.	764267.	1118303.	72333.	1190636.
1982	610385.	167019.	777404.	1166904.	80257.	1247161.
1983	610385.	194818.	805203.	1215505.	90417.	1305921.
1984	610385.	235620.	846005.	1264105.	101374.	1365479.
1985	601223.	261619.	862842.	1312706.	113185.	1425892.

*EXCLUDING NORTH SLOPE.

TABLE 553

SUMMARY OF COSTS AND INVESTMENTS FOR ALL REGIONS*

THIS IS THE LOW DRILLING AND LOW FINDING CASE
SECONDARY AND TERTIARY ARE NOT ACCELERATED OR INTENSIFIED
CASE III

TIME	OPERATING COSTS			DRILLING COSTS		
	OLD WELLS THOUS DOLS	NEW WELLS THOU DOLS	ALL WELLS THOUS DOLS	PROD WELLS THOUS DOLS	DRY HOLES THOUS DOLS	ALL WELLS THOUS DOLS
1971	1954930.	0.	1954930.	1090442.	382469.	1472911.
1972	1856357.	71922.	1928279.	926982.	346198.	1273180.
1973	1770642.	133849.	1904491.	1063421.	387946.	1451367.
1974	1696201.	203243.	1899444.	1201087.	428036.	1629123.
1975	1631651.	281034.	1912685.	1325682.	464921.	1790603.
1976	1575785.	367002.	1942787.	1311765.	477424.	1789190.
1977	1530672.	452699.	1983371.	1426586.	515559.	1942145.
1978	1492201.	545677.	2037878.	1455005.	533885.	1988890.
1979	1459536.	639794.	2099331.	1574810.	572308.	2147118.
1980	1431952.	738608.	2170559.	1590976.	592142.	2183118.
1981	1408814.	837018.	2245831.	1622072.	613742.	2235814.
1982	1382060.	935625.	2317686.	1765892.	664752.	2430644.
1983	1359609.	1039553.	2399162.	1825382.	691439.	2516821.
1984	1340915.	1145209.	2486124.	2043771.	751538.	2795308.
1985	1325507.	1260187.	2585694.	2134163.	784363.	2918526.

TIME	SECONDARY RECOVERY INVESTMENTS			TERTIARY RECOVERY INVESTMENTS		
	OLD FIELDS THOUS DOLS	NEW FIELDS THOUS DOLS	ALL FIELDS THOUS DOLS	OLD FIELDS THOUS DOLS	NEW FIELDS THOUS DOLS	ALL FIELDS THOUS DOLS
1971	353436.	5358.	358794.	271888.	1548.	273435.
1972	353436.	4134.	357569.	292802.	1286.	294088.
1973	353436.	3582.	357018.	313716.	1194.	314910.
1974	353436.	3234.	356669.	334631.	1150.	335781.
1975	353436.	3119.	356555.	355545.	1178.	356723.
1976	523642.	38755.	562397.	650661.	23837.	674498.
1977	523642.	35118.	558760.	686781.	26290.	713072.
1978	523642.	43185.	566827.	722902.	27248.	750151.
1979	523642.	51180.	574822.	759023.	27735.	786758.
1980	523642.	58049.	581691.	795144.	27698.	822842.
1981	610385.	123187.	733572.	1118303.	62224.	1180527.
1982	610385.	122211.	732595.	1166904.	66091.	1232994.
1983	610385.	138549.	748934.	1215505.	70542.	1286046.
1984	610385.	162363.	772748.	1264105.	74454.	1338559.
1985	601223.	174615.	775838.	1312706.	77997.	1390704.

*EXCLUDING NORTH SLOPE.

TABLE 554

SUMMARY OF COSTS AND INVESTMENTS FOR ALL REGIONS*

THIS IS THE LOW DECLINING DRILLING AND LOW FINDING CASE
SECONDARY AND TERTIARY ARE NOT ACCELERATED OR INTENSIFIED
CASE 1V

TIME	OPERATING COSTS			DRILLING COSTS		
	OLD WELLS THOUS DOLS	NEW WELLS THOU DOLS	ALL WELLS THOUS DOLS	PROD WELLS THOUS DOLS	DRY HOLES THOUS DOLS	ALL WELLS THOUS DOLS
1971	1954930.	0.	1954930.	1090442.	382469.	1472911.
1972	1856357.	71922.	1928279.	872545.	325543.	1198089.
1973	1770642.	130229.	1900871.	933204.	339458.	1272662.
1974	1696201.	191069.	1887269.	975111.	344833.	1319943.
1975	1631651.	253948.	1885600.	1007908.	347018.	1354926.
1976	1575785.	318556.	1894341.	945884.	333591.	1279475.
1977	1530672.	378948.	1909620.	948792.	331597.	1280390.
1978	1492201.	438904.	1931104.	920043.	327083.	1247126.
1979	1459536.	496598.	1956135.	933001.	322482.	1255483.
1980	1431952.	552997.	1984949.	880973.	306944.	1187917.
1981	1408814.	604891.	2013704.	832369.	292325.	1124693.
1982	1382060.	652470.	2034530.	838679.	292022.	1130701.
1983	1359609.	698317.	2057926.	794779.	278583.	1073362.
1984	1340915.	740216.	2081131.	829030.	282071.	1111101.
1985	1325507.	782155.	2107662.	806123.	273812.	1079935.

TIME	SECONDARY RECOVERY INVESTMENTS			TERTIARY RECOVERY INVESTMENTS		
	OLD FIELDS THOUS DOLS	NEW FIELDS THOUS DOLS	ALL FIELDS THOUS DOLS	OLD FIELDS THOUS DOLS	NEW FIELDS THOUS DOLS	ALL FIELDS THOUS DOLS
1971	353436.	5358.	358794.	271888.	1548.	273435.
1972	353436.	3897.	357333.	292802.	1213.	294014.
1973	353436.	3145.	356581.	313716.	1048.	314765.
1974	353436.	2610.	356046.	334631.	928.	335559.
1975	353436.	2334.	355770.	355545.	882.	356427.
1976	523642.	37906.	561548.	650661.	23073.	673734.
1977	523642.	32232.	555874.	686781.	23978.	710759.
1978	523642.	37202.	560844.	722902.	23283.	746185.
1979	523642.	40965.	564607.	759023.	22057.	781080.
1980	523642.	43455.	567097.	795144.	20605.	815749.
1981	610385.	106805.	717189.	1118303.	51840.	1170143.
1982	610385.	97511.	707895.	1166904.	51826.	1218730.
1983	610385.	106849.	717233.	1215505.	52448.	1267953.
1984	610385.	117561.	727945.	1264105.	51764.	1315869.
1985	601223.	120458.	721681.	1312706.	50781.	1363487.

*EXCLUDING NORTH SLOPE.

TABLE 555

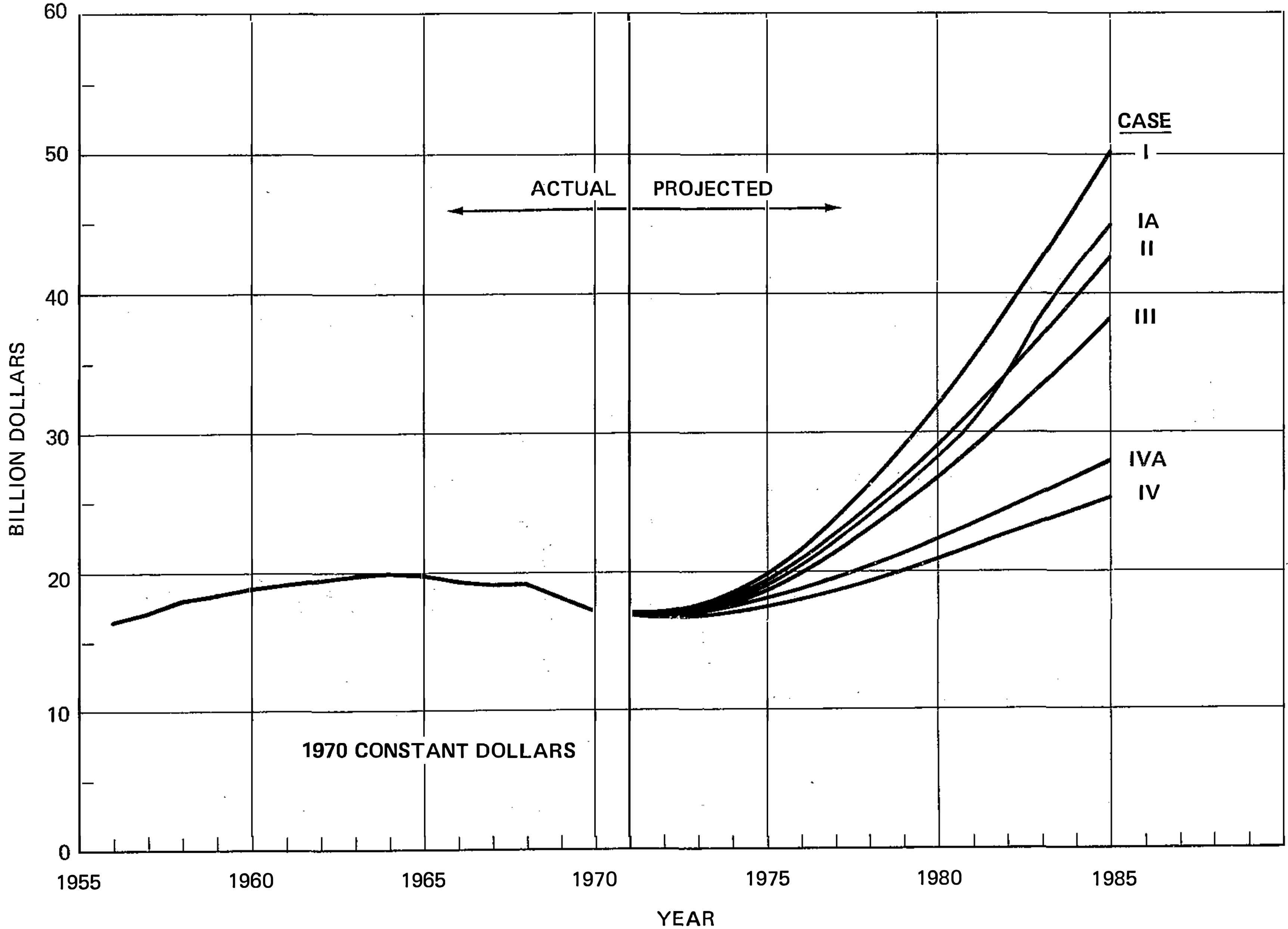
SUMMARY OF COST SUMMARY OF COSTS AND INVESTMENTS FOR ALL REGIONS*

THIS IS THE TREND DRILLING AND HIGH FINDING CASE
SECONDARY AND TERTIARY EFFORTS NOT INTENSIFIED BY 50 PERCENT
CASE IVA

TIME	OPERATING COSTS OLD WELLS THOUS DOLS	OPERATING COSTS NEW WELLS THOU DOLS	OPERATING COSTS ALL WELLS THOUS DOLS	DRILLING COSTS PROD WELLS THOUS DOLS	DRILLING COSTS DRY HOLES THOUS DOLS	DRILLING COSTS ALL WELLS THOUS DOLS
1971	1954930.	0.	1954930.	1120812.	390106.	1510918.
1972	1856357.	74204.	1930561.	936634.	340721.	1277355.
1973	1770642.	137476.	1908118.	1048902.	367400.	1416302.
1974	1696201.	207162.	1903363.	1120137.	380980.	1501116.
1975	1631651.	280968.	1912620.	1152360.	383788.	1536147.
1976	1575785.	356458.	1932243.	1093248.	369881.	1463129.
1977	1530672.	428469.	1959141.	1095729.	367628.	1463357.
1978	1492201.	500433.	1992634.	1079944.	364072.	1444016.
1979	1459536.	571189.	2030725.	1103256.	360031.	1463288.
1980	1431952.	640949.	2072901.	1058113.	343350.	1401462.
1981	1408814.	705993.	2114807.	1012842.	326963.	1339805.
1982	1382060.	766277.	2148338.	1027221.	325490.	1352711.
1983	1359609.	824584.	2184193.	986662.	310502.	1297164.
1984	1340915.	878561.	2219476.	1030685.	313561.	1344246.
1985	1325507.	932548.	2258055.	1007593.	304191.	1311784.

TIME	SECONDARY RECOVERY INVESTMENTS OLD FIELDS THOUS DOLS	SECONDARY RECOVERY INVESTMENTS NEW FIELDS THOUS DOLS	SECONDARY RECOVERY INVESTMENTS ALL FIELDS THOUS DOLS	TERTIARY RECOVERY INVESTMENTS OLD FIELDS THOUS DOLS	TERTIARY RECOVERY INVESTMENTS NEW FIELDS THOUS DOLS	TERTIARY RECOVERY INVESTMENTS ALL FIELDS THOUS DOLS
1971	353436.	5829.	359264.	271888.	1684.	273571.
1972	353436.	4984.	358420.	292802.	1551.	294353.
1973	353436.	4516.	357951.	313716.	1505.	315222.
1974	353436.	3950.	357385.	334631.	1404.	336035.
1975	353436.	3617.	357052.	355545.	1366.	356912.
1976	523642.	41469.	565111.	650661.	24283.	674944.
1977	523642.	38190.	561832.	686781.	25666.	712447.
1978	523642.	46184.	569826.	722902.	25633.	748536.
1979	523642.	52696.	576337.	759023.	25049.	784072.
1980	523642.	57912.	581554.	795144.	24156.	819300.
1981	610385.	127634.	738019.	1118303.	57542.	1175845.
1982	610385.	127319.	737704.	1166904.	59512.	1226416.
1983	610385.	144732.	755117.	1215505.	62943.	1278447.
1984	610385.	163765.	774150.	1264105.	65067.	1329172.
1985	601223.	171611.	772835.	1312706.	66754.	1379460.

*EXCLUDING NORTH SLOPE.



Excluding North Slope operations.

Figure 95. Net Fixed Assets—Oil Operations.

TABLE 556

NET FIXED ASSETS* – OIL OPERATIONS
(Million Dollars)

	Case IA	Case IVA
1971	17,133	17,184
1972	16,871	16,889
1973	17,084	16,982
1974	17,730	17,320
1975	18,777	17,795
1976	20,364	18,682
1977	22,281	19,593
1978	24,254	20,449
1979	26,520	21,328
1980	28,783	22,068
1981	31,517	23,155
1982	34,625	24,255
1983	37,706	25,211
1984	41,316	26,248
1985	44,864	27,157

*Excluding North *Slope.*

Note: End of year Net Fixed Assets.

TABLE 557

NET FIXED ASSETS – OIL OPERATIONS
(Million Dollars)

	NFA Current $	Price Deflater	1970 $
1956	13,544	.825	16,417
1957	14,489	.848	17,086
1958	15,230	.851	17,890
1959	15,851	.866	18,303
1960	16,259	.866	18,774
1961	16,456	.862	19,020
1962	16,755	.862	19,340
1963	16,938	.861	19,663
1964	17,209	.865	19,888
1965	17,290	.876	19,732
1966	17,308	.895	19,335
1967	17,275	.909	19,000
1968	17,723	.932	19,011
1969	17,451	.964	18,098
1970	17,074	1.000	17,074

TABLE 558

CASH FLOW – NEW OIL DRILLING
(Case II)

	Oil Production (MMB)	A&D Gas Production (MMCF)	Revenue* MM Dollars	Costs MM Dollars	Net Income After FIT†	Cumulative Net Income After FIT†
1971	–	–	–	3,107	(2,623)	(2,623)
1972	122	179	357	2,801	(1,991)	(4,614)
1973	222	319	658	3,467	(2,168)	(6,782)
1974	338	466	1,031	4,122	(2,301)	(9,083)
1975	468	614	1,483	4,698	(2,342)	(11,425)
1976	606	755	2,005	4,985	(2,102)	(13,527)
1977	749	891	2,604	5,636	(2,142)	(15,669)
1978	896	1,019	3,283	6,034	(1,940)	(17,609)
1979	1,033	1,132	3,968	6,689	(1,910)	(19,519)
1980	1,171	1,237	4,735	7,092	(1,645)	(21,164)
1981	1,293	1,322	5,479	7,565	(1,361)	(22,525)
1982	1,409	1,400	6,282	8,371	(1,495)	(24,020)
1983	1,524	1,468	7,175	8,822	(1,192)	(25,212)
1984	1,621	1,518	8,013	9,784	(1,324)	(26,536)
1985	1,720	1,564	8,979	10,302	(1,013)	(27,549)
1986	1,885	1,604	9,813	2,265	6,700	(20,849)
1987	1,744	1,432	9,066	2,153	6,000	(14,849)
1988	1,623	1,285	8,425	2,054	5,411	(9,438)
1989	1,521	1,158	7,884	1,971	4,916	(4,522)
1990	1,431	1,049	7,408	1,276	5,114	592
1991	1,355	954	7,005	1,492	4,507	5,099
1992	1,249	820	6,441	1,408	4,066	9,165
1993	1,156	708	5,950	1,360	3,658	12,823
1994	1,082	617	5,557	1,300	3,355	16,178
1995	1,018	540	5,218	1,242	3,104	19,282
1996	963	475	4,928	1,169	2,914	22,196
1997	914	420	4,670	1,132	2,724	24,920
1998	871	370	4,442	1,096	2,560	27,480
1999	829	324	4,221	1,065	2,399	29,879
2000	792	286	4,027	1,034	2,263	32,142
	31,605	25,926	151,107	115,492	32,142	
2000-2015	5,794	1,655	29,459	10,542	14,188	46,330
Total	37,399	27,581	180,566	126,034	46,330	

*Revenue less royalty and mineral taxes.

†Federal income taxes.

Chapter Seven—Section II

Gas Operations

Gas Well and Lease Operating Expense

Well and lease operating expenses are assumed to be a function of the number of producing wells. The Task Group, using their expertise and experience, estimated the annual cost of operating a well in each region. These regional cost per well figures were then multiplied by the number of producing wells in each region in 1969 and summed to yield a national operating expense. The 1969 operating expense, as reported by the Joint Association Survey, was allocated between oil and gas (78 percent to oil; 22 percent to gas)* and the regional operating costs normalized to force the calculated national operating expense equal to the allocated JAS figure. The normalized regional costs were then divided by the number of producing wells to yield a cost per well for each region. These cost per well figures were then escalated 10 percent over the 15-year projection period to account for the greater costs of reworking deeper wells, operating in increasing water depths offshore, etc. The projected cost per well was then multiplied by the projected number of producing wells in each region to determine the lease and well operating expense for each year of the projection period.

TABLE 559

GAS WELL AND LEASE OPERATING EXPENSE

Region	1970 Annual Expense Per Well
2	$ 3,600
2A	30,000
3	5,100
4	6,100
5	9,650
6	6,100
6A	30,000
7	4,500
8-9	1,000
10	1,000
11	6,100
11A	30,000

The number of producing wells in each region was projected by taking the number of producing wells at the beginning of the year, adding the number of successful wells completed during the year, and substracting the number of abandonments to arrive at number of producing wells at the end of the year. The number of producing wells was then assumed to be the average of the beginning and end of year producing wells. The number of successful wells completed was determined by dividing productive footage for the year by average depth for the year. Abandonments for the year (for each region) was assumed to be 1 percent of beginning of year producing wells for 1971 through 1975; 2 percent for 1976 through 1980, and 3 percent for 1981 through 1985.

Drilling Costs

Drilling costs are calculated for each NPC region by classifying total footage drilled in that region into dry hole and productive footage, then multiplying each category by the appropriate drilling cost per foot. Productive footage projected is based on the average gas footage success ratios of 1966-1970.

Drilling cost per foot depends on well depth, whether productive or dry, and the region in which it is drilled. Productive well cost per foot *vs.* depth, and dry hole cost per foot *vs.* depth curves were developed from 1970 Joint Association Survey data for each region except 1N, 11, and 11A (Alaska North Slope, Atlantic Coast and Offshore Atlantic). Little or no data was available for these three regions. The Task Group used Region 1S (South Alaska) curves for 1N; Region 6 and 6A (Gulf Coast) curves were used for Region 11 and 11A, respectively.

The productive cost per foot *vs.* depth curves were developed from 1970 Joint Association Survey drilling cost data. For each depth interval, the cost per foot of successful gas wells in the interval were plotted at the midpoint of the depth interval. The resulting data points were then connected by straight lines to approximate the cost per foot *vs.* depth curve. The average cost per foot in a region is not equal to the cost per foot at the average depth due to the disproportionately high cost of deep wells. To adjust for this difference, the average cost per foot and the cost per foot at the average depth were both calculated and the difference between the two was added to each point of the curve. Essentially the same procedure was used to develop dry hole costs.

* First page of Section I, this chapter for details of this allocation.

TABLE 560

GAS WELL AND LEASE OPERATING EXPENSE—LOWER 48 STATES
(Millions of 1970 Dollars)

Cases I & IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	3.5	3.9	45.6	13.5	78.2	126.9	88.9	122.8	1.5	58.4	—	—	543.0
1972	3.7	3.9	46.7	14.2	80.8	131.9	94.7	124.8	1.5	59.5	—	—	561.8
1973	3.9	4.0	47.9	15.1	83.5	137.0	100.9	126.9	1.5	60.8	—	—	581.4
1974	4.1	4.1	49.2	16.0	86.4	142.3	107.6	129.1	1.5	62.0	—	.1	602.3
1975	4.3	4.2	50.5	16.9	89.4	147.8	114.8	131.4	1.6	63.4	—	.2	624.5
1976	4.5	4.3	51.7	17.9	92.1	152.8	122.1	133.1	1.6	64.5	.1	.3	645.0
1977	4.7	4.5	52.7	19.0	94.5	157.4	129.4	134.4	1.6	65.4	.1	.6	664.2
1978	4.9	4.7	53.8	20.3	97.1	162.2	137.4	135.8	1.6	66.4	.2	1.5	685.7
1979	5.1	4.9	55.1	21.7	99.9	167.2	146.1	137.4	1.6	67.4	.2	3.8	710.6
1980	5.3	5.1	56.5	23.2	103.0	172.6	155.8	139.2	1.6	68.6	.3	7.3	738.7
1981	5.6	5.4	57.8	24.8	105.8	177.5	165.7	140.6	1.7	69.6	.5	11.1	765.9
1982	5.8	5.8	58.8	26.3	108.3	181.6	175.6	141.4	1.7	70.4	.6	15.4	791.7
1983	6.0	6.1	60.0	27.9	110.8	185.8	186.2	142.3	1.7	71.2	.8	20.0	818.9
1984	6.2	6.4	61.1	29.6	113.4	189.9	197.1	143.2	1.7	72.0	1.1	24.8	846.4
1985	6.4	6.7	62.2	31.3	115.9	193.7	207.9	144.0	1.7	72.8	1.3	29.4	873.5

Note: Totals may not agree due to rounding.

TABLE 561

GAS WELL AND LEASE OPERATING EXPENSE—LOWER 48 STATES
(Millions of 1970 Dollars)

Cases II & III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	3.5	3.9	45.6	13.5	78.2	126.9	88.9	122.8	1.5	58.4	—	—	543.0
1972	3.7	3.9	46.7	14.2	80.8	131.8	94.6	124.8	1.5	59.5	—	—	561.5
1973	3.9	4.0	47.8	15.0	83.3	136.7	100.5	126.8	1.5	60.7	—	—	580.2
1974	4.1	4.1	49.0	15.8	86.0	141.6	106.7	128.8	1.5	61.8	—	.1	599.4
1975	4.2	4.2	50.2	16.7	88.7	146.5	113.2	130.8	1.5	63.0	—	.2	619.3
1976	4.4	4.3	51.2	17.6	90.9	150.8	119.5	132.2	1.6	64.0	.1	.3	636.8
1977	4.6	4.4	51.9	18.5	92.8	154.4	125.5	133.0	1.6	64.6	.1	.5	652.0
1978	4.7	4.6	52.8	19.5	94.8	158.0	131.9	133.9	1.6	65.3	.1	1.3	668.4
1979	4.9	4.7	53.6	20.6	96.9	161.7	138.7	134.8	1.6	66.0	.2	3.1	686.9
1980	5.1	4.9	54.6	21.8	99.0	165.5	145.9	135.9	1.6	66.7	.3	5.8	707.2
1981	5.2	5.1	55.4	22.9	100.7	168.6	153.0	136.4	1.6	67.2	.4	8.7	725.2
1982	5.3	5.3	55.9	23.9	102.1	170.9	159.7	136.2	1.6	67.4	.5	11.9	740.7
1983	5.5	5.5	56.4	25.0	103.4	173.0	166.7	136.1	1.6	67.6	.7	15.3	756.9
1984	5.6	5.8	56.9	26.1	104.8	175.1	173.9	136.0	1.6	67.8	.8	18.8	773.2
1985	5.7	6.0	57.4	27.2	106.1	177.0	181.1	135.9	1.6	68.1	1.0	22.1	789.2

Note: Totals may not agree due to rounding.

TABLE 562

GAS WELL AND LEASE OPERATING EXPENSE–LOWER 48 STATES
(Millions of 1970 Dollars)

Cases IV & IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	3.5	3.9	45.6	13.4	78.2	126.9	88.8	122.8	1.5	58.4	–	–	542.9
1972	3.7	3.9	46.6	14.2	80.6	131.5	94.3	124.7	1.5	59.4	–	–	560.4
1973	3.8	4.0	47.6	14.9	82.9	135.9	99.6	126.4	1.5	60.5	–	–	577.1
1974	4.0	4.1	48.6	15.6	85.1	139.9	104.7	128.0	1.5	61.4	–	–	592.9
1975	4.1	4.1	49.5	16.2	87.1	143.7	109.7	129.5	1.5	62.3	–	.1	608.0
1976	4.3	4.2	50.1	16.8	88.6	146.4	114.0	130.2	1.5	62.8	–	.2	619.2
1977	4.3	4.3	50.4	17.4	89.4	148.2	117.5	130.2	1.5	63.0	.1	.4	626.6
1978	4.4	4.4	50.6	17.9	90.2	149.7	120.9	130.0	1.5	63.1	.1	.8	633.5
1979	4.5	4.4	50.8	18.4	90.8	150.9	124.0	129.8	1.5	63.1	.1	1.8	640.1
1980	4.5	4.5	51.0	18.9	91.3	151.8	126.9	129.5	1.5	63.1	.2	3.2	646.3
1981	4.6	4.5	50.8	19.2	91.3	151.8	129.0	128.4	1.5	62.7	.2	4.5	648.6
1982	4.6	4.6	50.4	19.4	90.7	150.9	130.3	126.7	1.5	61.9	.3	5.9	647.1
1983	4.6	4.6	49.9	19.6	90.0	149.8	131.6	124.9	1.5	61.2	.3	7.2	645.2
1984	4.6	4.6	49.4	19.8	89.3	148.5	132.7	123.1	1.5	60.4	.4	8.5	642.7
1985	4.5	4.6	48.9	20.0	88.5	147.2	133.6	121.3	1.4	59.6	.4	9.6	639.8

Note: Totals may not agree due to rounding.

Gas Plant Investment and Operating Expense

Analysis by the Gas Supply Task Group indicated that it costs approximately 1.5 cents per MCF to gather and process non-associated gas and 6.9 cents per MCF to gather and process associated-dissolved gas. A check of the Bureau of Mines figures on the amount of gas processed through gas plants indicates that approximately 93.5 percent of marketed gas is processed, except in Region 6 where only 75 percent of marketed gas is processed. Thus, gas plant operating expenses are calculated by determining, separately for non-associated and for associated-dissolved gas, the amount of gas processed, then multiplying by $0.015 for non-associated gas and by $0.069 for associated-dissolved gas, then summing the products.

It was the judgment of the Task Group that gas plant investment would be $30 for each incremental MCF per day of non-associated gas, and $175 for each incremental MCF per day of associated-dissolved gas. The calculation procedure is: (1) Determine incremental production (non-associated and associated-dissolved gas separately) over the prior year for the region. If the increment is not positive there will be 0 investment. (2) If the increment is positive, multiply by .75 for Region 6; by .935 for all other regions to determine incremental processed gas. (3) Divide by 365 to get average daily rate of the increment, then multiply by 1.20 to provide for maximum daily throughput. (4) Multiply non-associated gas incremental maximum daily throughput by $30, associated-dissolved by $175, and add the two results to obtain regional gas plant investment for that year.

Tables 590 through 595 in this section show the data necessary to make the computation of the required unit revenue for gas produced from reserves added after 1970. Also shown is an additional assumption concerning the average price of gas produced from reserves discovered prior to 1971—a one cent per year escalation is assumed to begin in 1971 rather than 1973.

Tables 596 and 597 show the same information for all cases as shown on Table 31, Chapter One, for Case III only.

TABLE 563

AVERAGE DRILLING COST FOR GAS WELLS

	Average Depth (Feet)	Producties (Dollars Per Feet)	Dry Hole (Dollars Per Feet)
Region 2	6250	16.77	11.21
	8750	17.04	13.61
Region 2A	8750	248.00	128.32
	11250	258.50	135.27
	13750	270.50	141.47
Region 3	4375	12.93	6.87
	6250	13.93	7.42
	8750	15.28	14.65
Region 4	4375	23.40	14.34
	6250	26.37	16.09
Region 5	6250	36.58	26.96
	8750	39.24	31.47
	11250	49.09	34.55
	13750	54.13	38.96
Region 6	6250	21.65	16.50
	8750	28.24	20.24
	11250	36.80	26.65
Region 6A	11250	63.77	49.77
	13750	75.77	55.97
Region 7	6250	22.02	12.85
	8750	22.80	15.64
	11250	28.90	20.28
Region 8 & 9	1875	13.23	9.13
	3125	16.04	10.19
	4375	20.59	12.12
Region 10	3125	12.68	10.47
	4375	12.67	11.90
Region 11	8750	28.24	20.24
	11250	36.80	26.65
Region 11A	8750	53.22	42.82
	11250	63.77	49.77

TABLE 564

PROJECTED SUCCESSFUL NON-ASSOCIATED GAS WELL COSTS—LOWER 48 STATES

(Millions of 1970 Dollars)

Cases I & IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	5.3	6.8	18.0	13.8	88.1	176.5	151.0	74.2	1.1	52.9	–	–	587.6
1972	5.5	7.2	19.0	14.8	95.9	184.6	161.5	78.6	1.2	55.6	–	–	623.9
1973	5.8	7.6	20.1	15.7	104.7	195.0	175.3	83.1	1.3	58.6	–	–	667.2
1974	6.2	8.1	21.8	17.1	114.9	204.8	189.3	88.9	1.3	62.1	0.7	1.9	717.1
1975	6.6	8.7	23.3	19.5	126.5	215.9	207.2	95.6	1.4	66.2	0.8	2.1	773.8
1976	7.1	18.6	25.0	21.4	139.9	230.1	225.7	102.6	1.6	70.8	1.7	2.2	846.7
1977	7.6	20.1	26.9	25.9	153.8	244.7	247.0	110.5	1.7	75.5	1.9	7.3	923.2
1978	8.2	21.9	29.2	29.1	169.8	260.6	271.5	119.7	1.8	80.9	3.2	24.1	1,020.1
1979	8.9	23.9	32.4	31.7	188.2	275.4	294.4	132.8	2.0	86.4	4.7	58.9	1,139.8
1980	9.7	26.2	35.5	35.3	209.6	299.9	329.6	145.1	2.2	94.2	6.5	65.0	1,258.7
1981	10.4	42.3	38.1	37.9	233.4	316.6	362.1	157.2	2.4	100.8	8.5	77.5	1,387.1
1982	10.9	44.6	40.1	39.9	251.1	329.8	390.2	168.3	2.6	105.8	10.6	90.0	1,484.0
1983	11.3	46.2	41.4	43.4	263.8	334.8	412.3	176.8	2.7	109.0	12.7	97.8	1,552.2
1984	11.4	47.0	42.0	44.7	271.7	335.2	427.1	183.2	2.7	110.1	14.7	100.0	1,589.8
1985	11.4	47.2	42.1	45.6	271.9	334.2	430.7	187.9	2.7	111.8	16.7	101.3	1,603.4

Note: Totals may not agree due to rounding.

TABLE 565

PROJECTED SUCCESSFUL NON-ASSOCIATED GAS WELL COSTS—LOWER 48 STATES
(Millions of 1970 Dollars)

Cases II & III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	5.3	6.8	18.0	13.8	88.1	176.5	151.0	74.2	1.1	52.9	–	–	587.6
1972	5.4	7.0	18.4	14.4	93.1	179.4	156.9	76.4	1.2	54.0	–	–	606.0
1973	5.5	7.2	18.9	14.8	98.8	184.0	165.5	78.5	1.2	55.3	–	–	629.7
1974	5.7	7.4	20.0	15.7	105.3	187.8	173.6	81.6	1.2	57.0	0.7	1.8	657.7
1975	5.9	7.7	20.7	17.4	112.7	192.5	184.7	85.2	1.3	59.0	0.7	1.8	689.6
1976	6.1	16.1	21.6	18.5	121.2	199.3	195.5	88.8	1.3	61.3	1.5	1.9	733.5
1977	6.4	17.0	22.7	21.8	129.5	206.1	208.0	93.1	1.4	63.6	1.6	6.2	777.4
1978	6.7	17.9	23.9	23.9	139.0	213.4	222.3	98.0	1.5	66.3	2.6	19.7	835.2
1979	7.1	19.0	25.8	25.3	149.9	219.3	234.4	105.7	1.6	68.8	3.7	46.9	907.3
1980	7.5	20.3	27.5	27.3	162.2	232.1	255.1	112.3	1.7	72.9	5.0	50.3	974.4
1981	7.8	31.8	28.6	28.5	175.6	238.2	272.4	118.3	1.8	75.8	6.4	58.3	1,043.7
1982	8.1	32.9	29.6	29.5	185.4	243.4	288.0	124.2	1.9	78.1	7.8	66.4	1,095.3
1983	8.2	33.8	30.3	31.7	192.8	244.7	301.4	129.2	1.9	79.7	9.3	71.5	1,134.6
1984	8.3	34.3	30.7	32.7	198.6	245.0	312.2	133.9	2.0	80.5	10.8	73.1	1,162.0
1985	8.3	34.5	30.8	33.3	198.7	244.3	314.8	137.3	2.0	81.7	12.2	74.0	1,172.0

Note: Totals may not agree due to rounding.

TABLE 566

PROJECTED SUCCESSFUL NON-ASSOCIATED GAS WELL COSTS—LOWER 48 STATES
(Millions of 1970 Dollars)

Cases IV & IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	5.2	6.7	17.7	13.6	86.9	174.1	148.9	73.1	1.1	52.2	–	–	579.5
1972	5.0	6.5	17.1	13.4	86.4	166.5	145.7	70.9	1.1	50.1	–	–	562.5
1973	4.8	6.2	16.5	12.9	85.9	160.0	143.8	68.2	1.0	48.1	–	–	547.4
1974	4.6	6.0	16.2	12.7	85.4	152.1	140.6	66.1	1.0	46.2	0.5	1.4	532.9
1975	4.4	5.8	15.6	13.1	84.7	144.6	138.8	64.0	1.0	44.3	0.5	1.4	518.3
1976	4.2	11.2	15.0	12.8	84.1	138.3	135.7	61.6	0.9	42.5	1.0	1.4	508.8
1977	4.1	10.8	14.5	13.9	82.5	131.3	132.6	59.3	0.9	40.5	1.0	3.9	495.4
1978	3.9	10.4	13.9	13.9	81.0	124.3	129.5	57.1	0.9	38.6	1.5	11.5	486.6
1979	3.8	10.1	13.7	13.4	79.5	116.3	124.3	56.0	0.9	36.5	2.0	24.8	481.1
1980	3.6	9.7	13.2	13.1	77.9	111.5	122.5	53.9	0.8	35.0	2.4	24.2	467.9
1981	3.5	14.1	12.7	12.6	77.8	105.6	120.8	52.4	0.8	33.6	2.8	25.9	462.6
1982	3.3	13.6	12.2	12.2	76.6	100.6	119.0	51.3	0.8	32.3	3.2	27.4	452.5
1983	3.2	13.1	11.8	12.3	75.0	95.2	117.2	50.2	0.8	31.0	3.6	27.8	441.2
1984	3.1	12.7	11.3	12.1	73.4	90.5	115.4	49.5	0.7	29.7	4.0	27.0	429.5
1985	3.0	12.2	10.9	11.8	70.5	86.7	111.7	48.7	0.7	29.0	4.3	26.3	415.8

Note: Totals may not agree due to rounding.

TABLE 567

PROJECTED DRY HOLE COSTS ALLOCATED TO NON-ASSOCIATED GAS–LOWER 48 STATES

(Millions of 1970 Dollars)

Cases I & IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	5.9	1.8	5.2	17.1	53.1	199.5	111.6	38.7	2.2	12.8	–	–	447.9
1972	6.3	1.9	5.4	18.4	57.6	208.3	119.3	41.6	2.3	13.5	–	–	474.7
1973	6.7	2.0	5.8	19.5	62.0	219.6	129.3	44.5	2.4	14.3	–	–	506.2
1974	7.2	2.2	6.2	21.2	67.0	230.2	139.5	48.2	2.6	15.3	0.5	0.8	540.9
1975	7.7	2.3	6.7	24.2	72.8	242.4	152.6	52.5	2.7	16.3	0.6	0.9	581.6
1976	8.3	5.0	7.3	26.6	79.4	258.0	166.1	57.0	3.0	17.6	1.2	0.9	630.3
1977	9.0	5.4	8.1	32.2	86.1	274.5	181.6	62.1	3.2	18.9	1.4	3.0	685.6
1978	9.8	5.9	9.0	36.2	93.9	292.5	199.4	68.1	3.5	20.3	2.3	9.9	750.7
1979	10.7	6.4	10.3	39.4	102.8	309.3	216.0	76.3	3.8	21.8	3.4	24.1	824.4
1980	11.7	7.1	11.5	43.8	113.1	336.8	241.6	84.4	4.2	23.9	4.7	26.6	909.5
1981	12.7	11.4	12.7	47.1	124.5	355.8	265.2	91.9	4.5	25.7	6.1	31.7	989.3
1982	13.4	12.0	13.7	49.6	133.5	370.8	285.6	98.7	4.8	27.1	7.7	36.7	1053.5
1983	13.9	12.5	14.5	53.9	140.6	376.5	301.5	103.9	4.9	28.1	9.2	39.9	1099.4
1984	14.2	12.7	15.1	55.5	145.2	377.1	312.1	107.8	5.0	28.5	10.7	40.7	1124.5
1985	14.3	12.7	15.5	56.6	145.6	376.1	314.4	110.8	5.0	29.1	12.1	41.2	1133.4

Note: Totals may not agree due to rounding.

TABLE 568

PROJECTED DRY HOLE COSTS ALLOCATED TO NON-ASSOCIATED GAS—LOWER 48 STATES

(Millions of 1970 Dollars)

Cases II & III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	5.9	1.8	5.2	17.1	53.1	199.5	111.6	38.7	2.2	12.8	—	—	447.9
1972	6.1	1.9	5.3	17.9	55.9	202.4	115.9	40.4	2.2	13.1	—	—	461.1
1973	6.3	1.9	5.4	18.4	58.4	207.3	122.1	42.0	2.3	13.5	—	—	477.8
1974	6.6	2.0	5.7	19.5	61.4	211.1	127.9	44.2	2.4	14.0	0.5	0.7	496.1
1975	6.8	2.1	5.9	21.6	64.9	216.0	136.0	46.8	2.4	14.6	0.5	0.8	518.4
1976	7.2	4.3	6.3	23.0	68.8	223.5	143.9	49.4	2.6	15.2	1.1	0.8	546.0
1977	7.6	4.6	6.8	27.1	72.5	231.2	152.9	52.3	2.7	15.9	1.2	2.5	577.3
1978	8.0	4.8	7.4	29.6	76.9	239.4	163.3	55.7	2.9	16.6	1.9	8.1	614.6
1979	8.5	5.1	8.2	31.4	81.9	246.2	172.0	60.8	3.0	17.4	2.7	19.2	656.3
1980	9.1	5.5	8.9	33.9	87.6	260.7	187.1	65.3	3.2	18.5	3.6	20.6	704.1
1981	9.5	8.6	9.6	35.4	93.7	267.7	199.6	69.2	3.4	19.3	4.6	23.8	744.4
1982	9.9	8.9	10.1	36.6	98.5	273.7	210.8	72.8	3.5	20.0	5.7	27.1	777.6
1983	10.2	9.1	10.6	39.4	102.8	275.2	220.4	75.9	3.6	20.5	6.7	29.1	803.6
1984	10.3	9.3	11.0	40.6	106.1	275.6	228.1	78.8	3.7	20.9	7.8	29.8	821.9
1985	10.4	9.3	11.3	41.4	106.4	274.9	229.8	81.0	3.7	21.3	8.8	30.1	828.4

Note: Totals may not agree due to rounding.

TABLE 569

PROJECTED DRY HOLE COSTS ALLOCATED TO NON-ASSOCIATED GAS--LOWER 48 STATES
(Millions of 1970 Dollars)

Cases IV & IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	5.9	1.8	5.1	16.9	52.3	196.8	110.1	38.2	2.1	12.6	–	–	441.7
1972	5.7	1.7	4.9	16.6	51.9	187.8	107.6	37.5	2.1	12.2	–	–	428.0
1973	5.5	1.7	4.7	16.0	50.8	180.2	106.1	36.5	2.0	11.8	–	–	415.3
1974	5.3	1.6	4.6	15.8	49.8	171.1	103.7	35.8	1.9	11.3	0.4	0.6	401.9
1975	5.1	1.6	4.5	16.2	48.7	162.3	102.2	35.1	1.8	11.0	0.4	0.6	389.6
1976	5.0	3.0	4.4	16.0	47.7	155.0	99.8	34.2	1.8	10.6	0.8	0.6	378.8
1977	4.8	2.9	4.3	17.3	46.2	147.3	97.5	33.3	1.7	10.1	0.7	1.6	367.9
1978	4.7	2.8	4.3	17.3	44.8	139.5	95.1	32.5	1.7	9.7	1.1	4.7	358.1
1979	4.5	2.7	4.3	16.6	43.4	130.5	91.2	32.2	1.6	9.2	1.4	10.2	347.9
1980	4.4	2.6	4.3	16.3	42.1	125.2	89.8	31.4	1.6	8.9	1.7	9.9	338.1
1981	4.2	3.4	4.2	15.7	41.5	118.7	88.5	30.7	1.5	8.6	2.0	10.6	330.0
1982	4.1	3.7	4.2	15.1	40.7	113.1	87.1	30.1	1.5	8.3	2.3	11.2	321.3
1983	4.0	3.5	4.1	15.3	40.0	107.0	85.7	29.5	1.4	8.0	2.6	11.3	312.5
1984	3.8	3.4	4.1	15.0	39.2	101.9	84.3	29.1	1.4	7.7	2.9	11.0	303.8
1985	3.7	3.3	4.0	14.7	37.8	97.5	81.5	28.7	1.3	7.6	3.1	10.7	293.9

Note: Totals may not agree due to rounding.

TABLE 570

GAS PLANT INVESTMENT—LOWER 48 STATES
(Millions of 1970 Dollars)

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	3.5	1.8	2.8	4.8	26.8	49.2	84.9	30.0	.2	5.6	.1	—	209.6
1972	2.6	1.5	2.5	4.6	24.8	48.1	80.6	25.2	.2	5.0	.1	—	195.2
1973	1.7	1.1	2.3	4.3	22.9	47.1	76.4	20.4	.2	4.4	.1	—	180.8
1974	1.6	3.2	2.4	4.9	21.4	43.9	82.4	17.4	.2	4.4	.2	—	181.9
1975	1.5	6.0	2.4	5.7	19.9	42.5	80.5	14.7	.2	4.5	.4	.1	178.3
1976	1.4	9.0	2.4	6.2	18.6	41.7	75.2	13.0	.2	4.7	.5	.3	173.1
1977	1.6	9.7	2.6	7.2	22.9	44.7	70.5	13.2	.2	5.0	.6	.5	178.6
1978	1.7	12.8	2.5	7.9	22.2	45.2	70.1	12.1	.2	5.1	.8	.7	181.3
1979	1.7	13.1	2.4	8.4	21.3	44.1	69.0	11.5	.2	5.0	.9	.7	178.4
1980	1.7	12.8	2.4	8.7	20.7	39.0	66.7	11.9	.2	5.2	1.2	1.8	172.3
1981	1.6	12.3	2.4	9.2	20.3	35.2	60.5	12.4	.3	5.2	1.2	3.7	164.4
1982	1.8	12.0	2.6	10.3	21.4	32.0	55.5	12.6	.3	5.3	1.3	7.6	162.8
1983	1.7	11.6	2.6	10.7	19.9	25.1	47.4	12.4	.3	5.2	1.9	11.6	150.5
1984	1.6	11.3	2.5	11.1	17.4	21.2	39.7	11.7	.4	4.7	1.9	12.9	136.3
1985	1.3	10.9	2.3	11.1	13.7	14.8	30.3	10.8	.4	4.3	2.4	16.9	119.1

Note: Totals may not agree due to rounding.

TABLE 571

GAS PLANT INVESTMENT—LOWER 48 STATES
(Millions of 1970 Dollars)

Case IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	3.5	1.8	2.8	4.6	25.0	44.4	76.5	28.2	.2	5.4	.1	—	192.4
1972	2.7	1.4	2.6	4.1	21.3	38.5	63.8	21.5	.2	4.7	.1	—	160.9
1973	1.8	1.1	2.4	3.7	17.5	32.7	51.2	14.9	.2	3.9	.1	—	129.5
1974	1.7	3.0	2.5	3.7	16.2	28.4	51.0	11.6	.2	3.7	.1	—	122.1
1975	1.6	5.2	2.6	3.8	14.9	24.8	49.4	9.3	.2	3.6	.3	.1	115.9
1976	1.5	7.2	2.7	3.9	13.8	21.7	48.2	7.9	.2	3.6	.4	.3	111.4
1977	1.9	7.2	3.0	4.6	17.9	21.6	48.9	7.7	.2	3.8	.4	.4	117.6
1978	2.0	9.0	3.0	5.0	17.2	20.6	49.7	7.1	.2	3.6	.6	.6	118.7
1979	2.0	8.9	4.1	5.3	16.3	19.4	47.4	6.6	.2	3.6	.6	.6	115.0
1980	2.0	8.8	4.6	5.6	15.4	16.5	44.8	6.4	.2	3.7	.8	1.4	110.0
1981	2.0	8.6	4.7	6.1	14.5	14.3	40.0	6.3	.2	3.7	.8	2.7	103.8
1982	2.2	8.7	4.8	7.1	15.5	12.7	36.9	5.9	.2	4.0	.8	5.2	104.1
1983	2.3	8.4	4.7	7.5	14.3	9.0	32.5	5.3	.2	4.0	1.2	8.4	97.9
1984	2.1	8.2	4.4	8.0	13.0	7.3	26.3	4.5	.2	3.8	1.2	9.2	88.2
1985	1.7	8.0	3.9	8.2	11.6	4.2	22.6	3.6	.2	3.7	1.5	12.3	81.6

Note: Totals may not agree due to rounding.

TABLE 572

GAS PLANT INVESTMENT—LOWER 48 STATES
(Millions of 1970 Dollars)

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	3.5	1.8	2.8	4.8	26.7	48.9	84.3	29.8	.2	5.5	.1	—	208.4
1972	2.6	1.5	2.5	4.5	24.6	47.6	79.6	24.9	.2	4.9	.1	—	192.9
1973	1.7	1.1	2.2	4.2	22.5	46.3	74.8	19.9	.2	4.3	.1	—	177.4
1974	1.5	3.1	2.3	4.7	20.4	41.9	78.9	16.6	.2	4.2	.1	—	173.9
1975	1.4	5.7	2.3	5.3	18.3	39.2	75.1	13.5	.1	4.2	.3	.1	165.6
1976	1.2	8.3	2.1	5.6	16.3	37.0	67.5	11.3	.1	4.1	.5	.3	154.5
1977	1.4	8.6	2.3	6.4	20.0	38.5	61.1	11.0	.1	4.3	.5	.5	154.8
1978	1.5	11.1	2.1	6.8	18.5	38.2	58.6	9.6	.2	4.3	.7	.6	152.1
1979	1.4	11.0	2.0	7.0	16.9	36.4	55.0	9.0	.2	4.0	.7	.6	144.2
1980	1.3	10.6	1.9	7.0	15.6	30.6	51.4	8.9	.2	4.1	1.0	1.5	134.0
1981	1.2	9.9	1.8	7.0	14.6	26.3	45.1	9.0	.2	3.9	1.0	3.0	123.0
1982	1.2	9.4	1.9	7.7	15.3	22.9	40.9	8.8	.2	3.9	1.0	5.9	119.2
1983	1.1	8.8	1.9	7.9	13.8	16.9	35.6	8.3	.2	3.8	1.4	8.7	108.5
1984	1.0	8.4	1.7	8.1	11.9	13.9	30.9	7.7	.2	3.4	1.4	9.4	98.0
1985	.8	8.2	1.6	8.0	9.6	9.0	25.4	7.1	.2	3.2	1.7	11.8	86.6

Note: Totals may not agree due to rounding.

TABLE 573

GAS PLANT INVESTMENT—LOWER 48 STATES
(Millions of 1970 Dollars)

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	3.5	1.8	2.8	4.5	24.9	44.2	76.1	28.1	.2	5.4	.1	—	191.6
1972	2.6	1.4	2.6	4.1	21.1	38.2	63.2	21.3	.2	4.6	.1	—	159.3
1973	1.8	1.1	2.3	3.6	17.2	32.1	50.2	14.6	.2	3.9	.1	—	127.0
1974	1.6	2.9	2.3	3.5	15.5	27.3	48.8	11.1	.2	3.6	.1	—	116.8
1975	1.5	4.9	2.4	3.6	13.7	23.1	45.9	8.5	.1	3.4	.3	.1	107.6
1976	1.4	6.7	2.4	3.6	12.1	19.4	43.0	6.8	.1	3.2	.4	.3	99.3
1977	1.6	6.5	2.6	4.1	15.7	18.8	42.3	6.5	.1	3.3	.4	.4	102.3
1978	1.7	7.9	2.5	4.2	14.3	17.5	41.9	5.9	.1	3.0	.5	.5	100.2
1979	1.6	7.5	3.4	4.3	13.0	15.9	38.5	5.3	.1	2.8	.5	.5	93.4
1980	1.5	7.1	3.7	4.3	11.8	12.8	35.0	4.9	.1	2.8	.7	1.2	85.8
1981	1.4	6.8	3.6	4.5	10.6	10.4	29.9	4.7	.1	2.7	.6	2.1	77.5
1982	1.5	6.6	3.7	5.2	11.2	8.7	26.9	4.2	.1	2.9	.6	4.1	75.8
1983	1.4	6.4	3.5	5.3	9.9	5.6	23.4	3.7	.1	2.7	.9	6.4	69.3
1984	1.4	6.2	3.3	5.4	9.0	4.3	18.9	3.1	.1	2.5	.9	6.6	61.7
1985	1.3	6.0	2.9	5.4	8.1	1.9	16.1	2.5	.1	2.5	1.1	8.5	56.4

Note: Totals may not agree due to rounding.

TABLE 574

GAS PLANT INVESTMENT–LOWER 48 STATES
(Millions of 1970 Dollars)

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	3.5	1.8	2.8	4.5	24.6	43.7	75.2	27.8	.2	5.3	.1	–	189.4
1972	2.6	1.4	2.5	3.9	20.5	37.1	61.4	20.8	.2	4.5	.1	–	154.9
1973	1.7	1.0	2.2	3.4	16.3	30.6	47.5	13.8	.2	3.7	.1	–	120.4
1974	1.4	2.5	2.0	3.1	13.6	24.0	42.5	9.5	.1	3.1	.1	–	102.0
1975	1.2	3.9	1.9	2.9	10.9	18.4	36.0	6.4	.1	2.7	.2	.1	84.8
1976	.9	4.9	1.8	2.6	8.5	13.6	29.9	4.7	.1	2.3	.3	.2	69.8
1977	1.1	4.4	1.8	2.9	11.2	12.3	27.1	4.4	.1	2.2	.3	.3	68.1
1978	1.1	4.8	1.5	2.7	8.7	10.4	24.2	3.5	.1	1.7	.3	.3	59.4
1979	.9	4.4	1.3	2.4	6.4	8.4	20.4	2.6	.1	1.3	.3	.3	48.8
1980	.6	3.8	1.1	2.0	4.4	5.0	15.1	2.0	–	1.1	.4	.7	36.0
1981	.4	3.1	1.4	1.7	3.5	2.3	9.3	1.4	–	.8	.3	1.2	25.5
1982	.4	2.7	1.5	2.0	3.2	.6	6.2	.9	–	.9	.3	2.1	20.9
1983	.3	2.3	1.3	1.8	2.3	–	3.9	.5	–	.6	.4	2.8	16.1
1984	.2	1.9	1.1	1.5	1.7	–	2.9	.1	–	.4	.3	2.6	12.7
1985	.1	1.7	.9	1.2	1.1	–	1.2	–	–	.3	.3	2.9	9.9

Note: Totals may not agree due to rounding.

TABLE 575

GAS PLANT INVESTMENT—LOWER 48 STATES
(Millions of 1970 Dollars)

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	3.5	1.8	2.7	4.7	26.3	48.2	82.9	29.5	.2	5.5	.1	—	205.2
1972	2.5	1.4	2.4	4.3	23.8	46.1	76.7	24.1	.2	4.8	.1	—	186.5
1973	1.6	1.0	2.1	4.0	21.4	44.0	70.6	18.8	.1	4.1	.1	—	167.8
1974	1.3	2.7	2.0	4.1	18.0	36.7	68.7	14.3	.1	3.7	.1	—	151.6
1975	1.1	4.5	1.8	4.1	14.7	30.7	59.5	10.3	.1	3.3	.3	.1	130.5
1976	.8	5.9	1.6	4.0	11.6	25.4	48.2	7.3	.1	2.9	.4	.2	108.5
1977	1.0	5.6	1.6	4.3	14.1	24.5	40.7	6.7	.1	2.9	.4	.3	102.1
1978	.9	6.5	1.3	4.2	11.1	21.9	34.3	5.6	.1	2.4	.5	.4	89.2
1979	.8	6.3	1.1	3.9	8.3	19.2	27.5	4.3	.1	2.1	.4	.4	74.4
1980	.5	5.6	.9	3.4	5.9	13.7	20.3	3.5	.1	1.8	.6	.8	57.1
1981	.3	4.8	.7	3.0	4.3	9.0	14.8	2.8	.1	1.4	.5	1.6	43.3
1982	.3	4.2	.7	3.2	3.9	5.4	11.8	2.1	—	1.4	.4	3.0	36.4
1983	.2	3.5	.6	2.9	2.4	1.0	8.7	1.5	—	1.1	.6	3.7	26.2
1984	.1	3.0	.4	2.6	1.6	—	6.9	.9	—	.8	.5	3.6	20.5
1985	.1	2.6	.3	2.3	1.0	—	4.3	.5	—	.8	.6	4.0	16.3

Note: Totals may not agree due to rounding.

TABLE 576

GAS PLANT OPERATING COST—LOWER 48 STATES
(Millions of 1970 Dollars)

Case I

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	19.7	1.2	11.5	13.9	99.1	153.4	78.4	83.0	.3	7.6	.1	—	468.2
1972	19.0	1.2	11.6	13.4	94.9	153.0	81.1	81.5	.3	7.4	.1	—	463.5
1973	18.4	1.2	11.8	13.2	91.0	155.7	86.6	77.2	.3	7.6	.1	—	463.1
1974	17.3	1.5	12.0	13.2	87.8	156.3	92.7	74.1	.3	7.8	.1	—	463.0
1975	16.3	2.2	12.1	13.3	84.8	154.0	97.8	70.9	.3	8.0	.1	—	459.8
1976	15.4	3.2	12.1	13.4	81.8	150.9	102.4	67.3	.3	8.3	.2	.1	455.2
1977	14.6	4.3	11.4	13.5	79.7	149.5	107.0	63.7	.3	8.6	.2	.1	452.9
1978	13.8	5.8	10.8	13.7	77.7	148.3	112.2	60.2	.3	9.1	.3	.2	452.5
1979	13.2	7.3	10.3	14.1	75.9	147.1	117.6	56.9	.3	9.5	.4	.3	452.9
1980	12.5	8.8	10.1	14.7	74.4	146.3	123.4	54.1	.4	10.0	.6	.6	455.8
1981	11.9	10.3	9.8	15.4	73.4	144.0	128.2	52.1	.4	10.5	.7	1.1	457.8
1982	11.2	11.7	9.6	16.4	72.6	144.4	133.6	50.0	.4	11.0	.9	2.2	464.0
1983	10.5	13.1	9.5	17.4	71.7	144.8	138.5	47.9	.5	11.5	1.1	3.8	470.4
1984	9.9	14.5	9.4	18.5	70.5	143.6	141.5	45.8	.5	11.8	1.4	5.6	473.0
1985	9.2	15.8	9.4	19.7	69.2	141.5	142.9	44.1	.6	12.2	1.7	7.9	474.2

Note: Totals may not agree due to rounding.

TABLE 577

GAS PLANT OPERATING COST—LOWER 48 STATES
(Millions of 1970 Dollars)

Case IA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	19.7	1.2	11.5	13.9	99.1	153.4	78.4	83.0	.3	7.6	.1	—	468.2
1972	19.0	1.2	11.7	13.4	94.6	151.9	79.3	81.1	.3	7.4	.1	—	459.9
1973	18.4	1.2	11.9	13.1	89.8	152.5	81.4	76.1	.3	7.5	.1	—	452.3
1974	17.3	1.5	12.1	12.9	85.8	150.8	83.3	72.2	.3	7.6	.1	—	444.0
1975	16.4	2.1	12.3	12.8	82.1	146.0	84.3	68.3	.3	7.7	.1	—	432.2
1976	15.5	2.8	12.3	12.7	78.3	140.0	85.2	63.9	.3	7.8	.2	.1	419.1
1977	14.7	3.7	11.6	12.4	75.4	135.5	86.7	59.5	.3	8.0	.2	.1	408.2
1978	14.0	4.7	11.1	12.3	72.8	130.9	88.8	55.2	.3	8.3	.3	.2	398.8
1979	13.4	5.8	10.9	12.4	70.2	126.2	90.9	51.1	.3	8.5	.3	.3	390.2
1980	12.8	6.8	11.0	12.6	68.0	122.2	93.4	47.5	.3	8.8	.4	.5	384.3
1981	12.3	7.8	11.1	13.0	66.1	116.9	95.1	44.6	.4	9.2	.5	.8	377.6
1982	11.6	8.8	11.3	13.5	64.5	114.6	97.6	41.6	.4	9.5	.6	1.6	375.5
1983	11.0	9.9	11.5	14.2	62.8	112.6	100.2	38.5	.4	9.8	.8	2.8	374.4
1984	10.4	10.8	11.6	15.0	61.1	109.3	101.6	35.5	.4	10.1	.9	4.0	370.8
1985	9.8	11.8	11.9	15.9	59.3	105.5	102.4	32.9	.4	10.3	1.1	5.7	367.1

Note: Totals may not agree due to rounding.

TABLE 578

GAS PLANT OPERATING COST—LOWER 48 STATES
(Millions of 1970 Dollars)

Case II

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	19.7	1.2	11.5	13.9	99.1	153.4	78.4	83.0	.3	7.6	.1	—	468.2
1972	19.0	1.2	11.6	13.4	94.9	153.0	81.1	81.5	.3	7.4	.1	—	463.5
1973	18.4	1.2	11.8	13.2	90.9	155.6	86.4	77.2	.3	7.5	.1	—	462.6
1974	17.3	1.5	12.0	13.1	87.6	155.9	92.0	73.9	.3	7.7	.1	—	461.4
1975	16.3	2.1	12.1	13.2	84.4	153.1	96.3	70.6	.3	7.9	.1	—	456.4
1976	15.3	3.1	12.0	13.3	81.1	149.3	99.8	66.7	.3	8.1	.2	.1	449.2
1977	14.5	4.1	11.3	13.2	78.5	147.1	103.1	62.8	.3	8.4	.2	.1	443.5
1978	13.7	5.3	10.6	13.3	76.0	144.9	106.6	59.0	.3	8.7	.3	.2	438.9
1979	13.0	6.6	10.1	13.5	73.5	142.6	110.0	55.1	.3	8.9	.4	.3	434.4
1980	12.3	7.9	9.7	13.9	71.3	140.6	113.6	51.9	.3	9.3	.5	.5	431.8
1981	11.7	9.0	9.4	14.3	69.4	137.0	116.2	49.4	.3	9.6	.6	.9	427.8
1982	10.8	10.1	9.1	14.9	67.7	136.1	119.5	46.6	.4	9.9	.8	1.8	427.7
1983	10.1	11.2	8.9	15.5	65.9	135.4	122.6	43.9	.4	10.2	.9	3.0	428.1
1984	9.3	12.2	8.6	16.2	64.0	133.1	124.4	41.2	.4	10.4	1.1	4.3	425.4
1985	8.6	13.2	8.5	17.0	62.1	130.1	125.2	39.1	.4	10.5	1.3	5.9	422.1

Note: Totals may not agree due to rounding.

TABLE 579

GAS PLANT OPERATING COST—LOWER 48 STATES
(Millions of 1970 Dollars)

Case III

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	19.7	1.2	11.5	13.9	99.1	153.4	78.4	83.0	.3	7.6	.1	—	468.2
1972	19.0	1.2	11.7	13.4	94.6	151.9	79.3	81.1	.3	7.4	.1	—	459.9
1973	18.4	1.2	11.9	13.1	89.7	152.4	81.3	76.1	.3	7.4	.1	—	451.9
1974	17.3	1.5	12.1	12.9	85.7	150.6	82.9	72.1	.3	7.5	.1	—	442.9
1975	16.3	2.0	12.2	12.7	81.8	145.5	83.4	68.0	.3	7.6	.1	—	429.9
1976	15.4	2.7	12.2	12.6	77.8	139.2	83.5	63.5	.3	7.7	.1	.1	415.1
1977	14.6	3.5	11.5	12.2	74.6	134.2	84.1	58.9	.3	7.8	.2	.1	402.0
1978	13.9	4.4	10.9	12.0	71.4	129.2	85.1	54.4	.3	8.0	.2	.2	390.0
1979	13.2	5.3	10.6	11.9	68.4	124.1	85.9	50.0	.3	8.1	.3	.2	378.3
1980	12.5	6.1	10.5	12.0	65.6	119.5	87.1	46.3	.3	8.3	.4	.4	368.9
1981	11.9	6.9	10.4	12.1	63.2	113.7	87.3	43.1	.3	8.5	.5	.7	358.5
1982	11.1	7.7	10.5	12.4	60.9	110.8	88.4	39.8	.3	8.6	.5	1.3	352.2
1983	10.4	8.4	10.5	12.8	58.6	108.4	89.6	36.5	.3	8.8	.6	2.2	347.0
1984	9.7	9.2	10.5	13.2	56.2	104.7	89.9	33.2	.3	8.8	.8	3.1	339.5
1985	9.1	9.9	10.6	13.7	53.9	100.6	89.7	30.5	.4	8.9	.9	4.3	332.3

Note: Totals may not agree due to rounding.

TABLE 580

GAS PLANT OPERATING COST—LOWER 48 STATES
(Millions of 1970 Dollars)

Case IV

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	19.7	1.2	11.5	13.9	99.1	153.4	78.4	83.0	.3	7.6	.1	—	468.2
1972	19.0	1.2	11.7	13.4	94.5	151.9	79.3	81.1	.3	7.4	.1	—	459.8
1973	18.4	1.2	11.8	13.1	89.6	152.2	80.9	76.0	.3	7.4	.1	—	450.9
1974	17.3	1.4	12.0	12.8	85.3	149.9	81.6	71.7	.3	7.4	.1	—	439.9
1975	16.2	1.8	12.1	12.5	80.9	144.2	80.7	67.4	.3	7.4	.1	—	423.7
1976	15.3	2.3	12.0	12.2	76.4	137.1	79.1	62.5	.3	7.4	.1	—	404.7
1977	14.4	2.8	11.1	11.7	72.5	131.2	77.6	57.5	.3	7.4	.2	.1	386.8
1978	13.6	3.4	10.4	11.3	68.6	125.2	76.1	52.6	.3	7.3	.2	.1	369.0
1979	12.8	3.9	9.8	11.0	64.6	119.0	74.4	47.8	.3	7.2	.2	.2	351.0
1980	12.0	4.3	9.3	10.7	60.7	113.4	72.7	43.5	.3	7.1	.3	.2	334.5
1981	11.2	4.6	8.9	10.4	57.1	106.4	70.0	39.8	.3	7.1	.3	.4	316.5
1982	10.3	5.0	8.6	10.3	53.6	102.4	68.1	36.0	.2	6.9	.3	.7	302.4
1983	9.4	5.2	8.3	10.1	50.1	99.0	66.4	32.2	.2	6.7	.4	1.1	289.2
1984	8.5	5.4	8.0	10.0	46.6	94.3	64.0	28.6	.2	6.5	.4	1.5	274.0
1985	7.7	5.7	7.7	9.9	43.2	89.5	61.4	25.5	.2	6.2	.5	1.9	259.4

Note: Totals may not agree due to rounding.

TABLE 581

GAS PLANT OPERATING COST—LOWER 48 STATES
(Millions of 1970 Dollars)

Case IVA

	Region 2	Region 2A	Region 3	Region 4	Region 5	Region 6	Region 6A	Region 7	Region 8&9	Region 10	Region 11	Region 11A	Total Lower 48 States
1971	19.7	1.2	11.5	13.9	99.1	153.4	78.4	83.0	.3	7.6	.1	–	468.2
1972	19.0	1.2	11.6	13.4	94.9	152.9	81.1	81.5	.3	7.4	.1	–	463.4
1973	18.4	1.2	11.8	13.1	90.8	155.2	85.8	77.0	.3	7.5	.1	–	461.2
1974	17.3	1.5	12.0	13.0	87.1	154.8	90.0	73.4	.3	7.6	.1	–	456.9
1975	16.2	1.9	12.0	12.9	83.3	150.9	92.2	69.7	.3	7.7	.1	–	447.1
1976	15.2	2.6	11.8	12.8	79.3	145.4	93.0	65.2	.3	7.7	1.1	–	433.5
1977	14.3	3.2	11.0	12.4	75.8	141.3	93.5	60.6	.3	7.8	.2	.1	420.4
1978	13.5	3.9	10.2	12.2	72.3	136.9	93.5	56.0	.3	7.8	.2	.1	406.9
1979	12.7	4.6	9.6	12.0	68.5	132.1	93.0	51.4	.3	7.8	.3	.2	392.5
1980	11.8	5.3	9.0	11.9	64.9	127.7	92.2	47.3	.3	7.8	.4	.3	378.9
1981	11.1	5.8	8.5	11.8	61.4	121.7	90.1	43.8	.3	7.8	.4	.5	363.2
1982	10.1	6.3	8.1	11.8	58.0	118.3	88.7	40.1	.3	7.7	.5	1.0	350.9
1983	9.3	6.8	7.7	11.8	54.6	115.2	87.4	36.4	.3	7.6	.5	1.5	338.9
1984	8.4	7.1	7.2	11.7	51.1	110.8	85.2	32.7	.3	7.4	.6	2.0	324.5
1985	7.5	7.4	6.9	11.8	47.7	105.9	82.8	29.7	.2	7.2	.7	2.6	310.4

Note: Totals may not agree due to rounding.

TABLE 582

SUMMARY OF COSTS & INVESTMENTS—GAS
LOWER 48 STATES
(Millions of 1970 Constant Dollars)

Case I

	Dry Hole Costs	Successful Well Investment	Prod. Lease Operating Costs	Gas Plant Investment	Gas Plant Operating Cost
1971	447.9	587.6	543.0	210.4	469.3
1972	474.7	623.9	561.8	195.9	464.7
1973	506.2	667.2	581.4	181.3	464.2
1974	540.9	717.1	602.3	183.0	464.3
1975	581.6	773.8	624.5	180.3	461.2
1976	630.3	846.7	645.0	176.1	457.0
1977	685.6	923.2	664.2	182.3	455.0
1978	750.7	1020.1	685.7	186.1	455.1
1979	824.4	1139.8	710.6	183.4	456.1
1980	909.5	1258.7	738.7	179.3	459.8
1981	989.3	1387.1	765.9	171.3	462.5
1982	1053.5	1484.0	791.7	169.3	469.4
1983	1099.4	1552.2	818.9	157.6	476.6
1984	1124.5	1589.8	846.4	142.1	479.9
1985	1133.4	1603.4	873.5	126.9	481.9

TABLE 583

SUMMARY OF COSTS & INVESTMENTS—GAS
LOWER 48 STATES
(Millions of 1970 Constant Dollars)

Case IA

	Dry Hole Costs	Successful Well Investment	Prod. Lease Operating Costs	Gas Plant Investment	Gas Plant Operating Cost
1971	447.9	587.6	543.0	193.3	469.3
1972	474.7	623.9	561.8	161.6	461.1
1973	506.2	667.2	581.4	130.0	453.4
1974	540.9	717.1	602.3	123.2	445.2
1975	581.6	773.8	624.5	117.6	433.5
1976	630.3	846.7	645.0	113.6	420.6
1977	685.6	923.2	664.2	120.2	410.0
1978	750.7	1020.1	685.7	121.6	400.9
1979	824.4	1139.8	710.6	118.2	392.7
1980	909.5	1258.7	738.7	114.3	387.2
1981	989.3	1387.1	765.9	107.8	381.0
1982	1053.5	1484.0	791.7	107.6	379.2
1983	1099.4	1552.2	818.9	101.7	378.5
1984	1124.5	1589.8	846.4	92.0	375.2
1985	1133.4	1603.4	873.5	87.0	372.2

TABLE 584

SUMMARY OF COSTS & INVESTMENTS–GAS
LOWER 48 STATES
(Millions of 1970 Constant Dollars)

Case II

	Dry Hole Costs	Successful Well Investment	Prod. Lease Operating Costs	Gas Plant Investment	Gas Plant Operating Cost
1971	447.9	587.6	543.0	209.3	469.3
1972	461.1	606.0	561.5	193.6	464.7
1973	477.8	629.7	580.2	177.9	463.7
1974	496.1	657.7	599.4	175.1	462.7
1975	518.4	689.6	619.3	167.5	457.8
1976	546.0	733.5	636.8	157.2	450.9
1977	577.3	777.4	652.0	158.1	445.5
1978	614.6	835.2	668.4	156.3	441.3
1979	656.3	907.3	686.9	148.5	437.3
1980	704.1	974.4	707.2	139.9	435.4
1981	744.4	1043.7	725.2	128.9	432.1
1982	777.6	1095.3	740.7	125.0	432.6
1983	803.6	1134.6	756.9	115.0	433.7
1984	821.9	1162.0	773.2	103.4	431.6
1985	828.5	1172.0	789.2	93.8	429.0

TABLE 585

SUMMARY OF COSTS & INVESTMENTS–GAS
LOWER 48 STATES
(Millions of 1970 Constant Dollars)

Case III

	Dry Hole Costs	Successful Well Investment	Prod. Lease Operating Costs	Gas Plant Investment	Gas Plant Operating Cost
1971	447.9	587.6	543.0	192.5	469.3
1972	461.1	606.0	561.5	160.0	461.1
1973	477.8	629.7	580.2	127.6	453.1
1974	496.1	657.7	599.4	117.9	444.1
1975	518.4	689.6	619.3	109.2	431.3
1976	546.0	733.5	636.8	101.4	416.6
1977	577.3	777.4	652.0	104.6	403.8
1978	614.6	835.2	668.4	102.8	392.0
1979	656.3	907.3	686.9	96.1	380.6
1980	704.1	974.4	707.2	89.6	371.6
1981	744.4	1043.7	725.2	81.1	361.6
1982	777.6	1095.3	740.7	79.1	355.7
1983	803.6	1134.6	756.9	72.7	350.8
1984	821.9	1162.0	773.2	64.7	343.6
1985	828.4	1172.0	789.2	61.0	336.9

TABLE 586

SUMMARY OF COSTS & INVESTMENTS—GAS
LOWER 48 STATES
(Millions of 1970 Constant Dollars)

Case IV

	Dry Hole Costs	Successful Well Investment	Prod. Lease Operating Costs	Gas Plant Investment	Gas Plant Operating Cost
1971	441.7	579.5	542.9	190.3	469.3
1972	428.0	562.5	560.4	155.6	461.0
1973	415.3	547.4	577.1	120.8	452.1
1974	401.9	532.9	592.9	102.9	441.0
1975	389.6	518.3	608.0	86.0	425.0
1976	378.8	508.8	619.2	71.3	406.2
1977	367.9	495.4	626.6	69.8	388.4
1978	358.1	486.6	633.5	61.1	370.8
1979	347.9	481.1	640.1	50.6	352.9
1980	338.1	467.9	646.3	38.3	336.6
1981	330.0	462.6	648.6	27.6	318.9
1982	321.3	452.5	647.1	23.1	304.9
1983	312.5	441.2	645.2	18.5	291.9
1984	303.8	429.5	642.7	14.9	276.9
1985	293.9	415.8	639.8	12.8	262.6

TABLE 587

SUMMARY OF COSTS & INVESTMENTS—GAS
LOWER 48 STATES
(Millions of 1970 Constant Dollars)

Case IVA

	Dry Hole Costs	Successful Well Investment	Prod. Lease Operating Costs	Gas Plant Investment	Gas Plant Operating Cost
1971	441.7	579.5	542.9	206.1	469.3
1972	428.0	562.5	560.4	187.2	464.6
1973	415.3	547.4	577.1	168.3	462.3
1974	401.9	532.9	592.9	152.6	458.1
1975	389.6	518.3	608.0	131.9	448.4
1976	378.8	508.8	619.2	110.4	435.0
1977	367.9	495.4	626.6	104.4	422.1
1978	358.1	486.6	633.5	91.8	408.8
1979	347.9	481.1	640.1	77.1	394.7
1980	338.1	467.9	646.3	60.6	381.6
1981	330.0	462.6	648.6	46.6	366.2
1982	321.3	452.5	647.1	39.8	354.2
1983	312.5	441.2	645.2	30.1	342.6
1984	303.8	429.5	642.7	24.1	328.6
1985	293.9	415.8	639.8	21.2	315.0

TABLE 588

HISTORICAL
NET FIXED ASSETS
AT YEAR END—GAS OPERATIONS—
LOWER 48 STATES

	Billions of Constant 1970 Dollars
1956	3.9
1957	4.3
1958	4.7
1959	5.2
1960	5.7
1961	6.1
1962	6.8
1963	7.1
1964	7.4
1965	7.6
1966	7.6
1967	8.0
1968	8.5
1969	8.3
1970	8.7

TABLE 589

NET FIXED ASSETS AT END OF YEAR—GAS OPERATIONS—LOWER 48 STATES
(Millions of Constant 1970 Dollars)

	Case I	Case IA	Case II	Case III	Case IV	Case IVA
1971	9,169	9,138	9,168	9,137	9,118	9,148
1972	9,573	9,486	9,532	9,447	9,336	9,416
1973	9,985	9,828	9,865	9,712	9,432	9,575
1974	10,446	10,210	10,201	9,974	9,443	9,648
1975	10,986	10,670	10,570	10,270	9,405	9,663
1976	11,622	11,225	10,980	10,611	9,324	9,627
1977	12,379	11,904	11,455	11,021	9,223	9,561
1978	13,316	12,762	12,038	11,542	9,120	9,487
1979	14,494	13,862	12,771	12,219	9,036	9,424
1980	15,851	15,143	13,599	12,991	8,927	9,329
1981	17,363	16,584	14,495	13,838	8,810	9,220
1982	18,929	18,084	15,403	14,700	8,669	9,084
1983	20,448	19,545	16,278	15,530	8,498	8,916
1984	21,849	20,905	17,098	16,315	8,317	8,734
1985	23,069	22,109	17,819	17,015	8,122	8,538

TABLE 590

REQUIRED "PRICES" FOR GAS DISCOVERED AFTER 1970 WITH VARYING ASSUMPTIONS ON REVENUE RECEIVED FOR GAS DISCOVERED PRIOR TO 1971

(15-Percent Rate of Return)

Case I

	Marketed Gas Production from Pre-1971 Reserves (BCF)	Marketed Gas Production from Post-1970 Reserves (BCF)	Total Gas Revenue Required (MM Dollars)	Average Unit Revenue Required (¢/MCF)	Assumed Price for Production from Pre-1971 Reserves (¢/MCF)	Unit Revenue Required for Production from Post-1970 Reserves (¢/MCF)	Assumed "Price" for Production from Pre-1971 Reserves (¢/MCF)	Unit Revenue Required for Production from Post-1970 Reserves (¢/MCF)
1971	19,990	–	4,682.69	23.5	17.1	–	18.1	–
1972	19,587	786	4,951.76	24.3	17.1	203.9	19.1	154.0
1973	18,865	2,190	5,259.37	25.0	17.1	92.9	20.1	67.0
1974	18,027	3,562	5,550.34	25.7	17.1	69.3	21.1	49.0
1975	16,868	4,893	5,801.00	26.7	17.1	59.6	22.1	42.4
1976	15,566	6,181	6,120.85	28.1	17.1	56.0	23.1	40.9
1977	14,240	7,545	6,405.38	29.4	17.1	50.4	24.1	39.4
1978	12,950	8,959	6,641.90	30.3	17.1	49.4	25.1	37.9
1979	11,691	10,383	7,041.69	31.9	17.1	48.6	26.1	38.4
1980	10,634	11,769	7,552.72	33.7	17.1	48.7	27.1	39.7
1981	9,529	13,133	8,145.48	35.9	17.1	49.6	28.1	41.6
1982	8,687	14,506	8,789.38	37.9	17.1	50.4	29.1	43.2
1983	7,970	15,787	9,430.57	39.7	17.1	51.1	30.1	44.5
1984	7,137	16,940	10,047.94	41.7	17.1	52.1	31.1	46.2
1985	6,377	17,913	10,598.78	43.6	17.1	53.1	32.1	47.7

TABLE 591

REQUIRED "PRICES" FOR GAS DISCOVERED AFTER 1970 WITH VARYING ASSUMPTIONS ON REVENUE RECEIVED FOR GAS DISCOVERED PRIOR TO 1971

(15-Percent Rate of Return)

Case IA

	Marketed Gas Production From Pre-1971 Reserves (BCF)	Marketed Gas Production from Post-1970 Reserves (BCF)	Total Gas Revenue Required (MM Dollars)	Average Unit Revenue Required (¢/MCF)	Assumed Price for Production from Pre-1971 Reserves (¢/MCF)	Unit Revenue Required for Production from Post-1970 Reserves (¢/MCF)	Assumed "Price" for Production from Pre-1971 Reserves (¢/MCF)	Unit Revenue Required for Production from Post-1970 Reserves (¢/MCF)
1971	19,990	—	4,700.50	23.5	17.1	—	18.1	—
1972	19,587	598	4,973.28	24.6	17.1	271.6	19.1	206.0
1973	18,865	1,609	5,274.53	25.8	17.1	127.3	20.1	92.1
1974	18,027	2,558	5,553.38	27.0	17.1	96.6	21.1	68.4
1975	16,868	3,451	5,788.19	28.5	17.1	84.1	22.1	59.7
1976	15,566	4,293	6,092.28	30.7	17.1	79.9	23.1	58.2
1977	14,240	5,177	6,371.58	32.8	17.1	72.7	24.1	56.8
1978	12,950	6,081	6,618.63	34.8	17.1	72.4	25.1	55.4
1979	11,691	6,985	7,026.52	37.6	17.1	72.0	26.1	56.9
1980	10,634	7,855	7,554.15	40.9	17.1	73.0	27.1	59.5
1981	9,529	8,701	8,169.05	44.8	17.1	75.2	28.1	63.1
1982	8,687	9,553	8,846.73	48.5	17.1	77.1	29.1	66.1
1983	7,970	10,360	9,530.49	52.0	17.1	78.8	30.1	68.8
1984	7,137	11,107	10,182.80	55.8	17.1	80.7	31.1	71.7
1985	6,377	11,768	10,768.62	59.4	17.1	82.2	32.1	74.1

TABLE 592

REQUIRED "PRICES" FOR GAS DISCOVERED AFTER 1970 WITH VARYING ASSUMPTIONS ON REVENUE RECEIVED FOR GAS DISCOVERED PRIOR TO 1971 (15-Percent Rate of Return)

Case II

	Marketed Gas Production from Pre-1971 Reserves (BCF)	Marketed Gas Production from Post-1970 Reserves (BCF)	Total Gas Revenue Required (MM Dollars)	Average Unit Revenue Required (¢/MCF)	Assumed Price for Production from Pre-1971 Reserves (¢/MCF)	Unit Revenue Required for Production from Post-1970 Reserves (¢/MCF)	Assumed "Price" for Production from Pre-1971 Reserves (¢/MCF)	Unit Revenue Required for Production from Post-1970 Reserves (¢/MCF)
1971	19,990	–	4,682.68	23.5	17.1	–	18.1	–
1972	19,587	786	4,938.47	24.2	17.1	202.2	19.1	152.3
1973	18,865	2,168	5,216.13	24.8	17.1	91.8	20.1	65.7
1974	18,027	3,476	5,459.53	25.4	17.1	68.4	21.1	47.6
1975	16,868	4,703	5,642.74	26.2	17.1	58.7	22.1	40.7
1976	15,566	5,841	5,873.07	27.4	17.1	55.0	23.1	40.0
1977	14,240	7,015	6,044.49	28.4	17.1	49.0	24.1	37.2
1978	12,950	8,196	6,150.08	29.1	17.1	48.0	25.1	35.4
1979	11,691	9,346	6,382.44	30.3	17.1	46.9	26.1	35.6
1980	10,634	10,421	6,691.16	31.8	17.1	46.8	27.1	36.6
1981	9,529	11,440	7,046.53	33.6	17.1	47.4	28.1	38.2
1982	8,687	12,440	7,424.08	35.1	17.1	47.7	29.1	39.4
1983	7,970	13,354	7,794.48	36.6	17.1	47.4	30.1	40.4
1984	7,137	14,180	8,149.05	38.2	17.1	48.9	31.1	41.8
1985	6,377	14,892	8,466.47	39.8	17.1	49.5	32.1	43.1

TABLE 593

REQUIRED "PRICES" FOR GAS DISCOVERED AFTER 1970 WITH VARYING ASSUMPTIONS ON REVENUE RECEIVED FOR GAS DISCOVERED PRIOR TO 1971
(15-Percent Rate of Return)

Case III

	Marketed Gas Production from Pre-1971 Reserves (BCF)	Marketed Gas Production from Post-1970 Reserves (BCF)	Total Gas Revenue Required (MM Dollars)	Average Unit Revenue Required (¢/MCF)	Assumed Price for Production from Pre-1971 Reserves (¢/MCF)	Unit Revenue Required for Production from Post-1970 Reserves (¢/MCF)	Assumed "Price" for Production from Pre-1971 Reserves (¢/MCF)	Unit Revenue Required for Production from Post-1970 Reserves (¢/MCF)
1971	19,990	–	4,700.50	23.5	17.1	–	18.1	–
1972	19,587	598	4,959.09	24.6	17.1	269.2	19.1	203.7
1973	18,865	1,593	5,230.48	25.6	17.1	125.8	20.1	90.3
1974	18,027	2,500	5,459.78	26.6	17.1	95.1	21.1	66.2
1975	16,868	3,324	5,626.59	27.9	17.1	82.5	22.1	57.1
1976	15,566	4,070	5,839.88	29.7	17.1	78.1	23.1	55.1
1977	14,240	4,835	6,003.85	31.5	17.1	70.3	24.1	53.2
1978	12,950	5,595	6,116.90	33.0	17.1	69.7	25.1	51.2
1979	11,691	6,330	6,355.07	35.3	17.1	68.8	26.1	52.2
1980	10,634	7,009	6,674.54	37.8	17.1	69.3	27.1	54.1
1981	9,529	7,643	7,044.66	41.0	17.1	70.9	28.1	57.1
1982	8,687	8,261	7,448.20	44.0	17.1	72.2	29.1	59.6
1983	7,970	8,827	7,849.29	46.7	17.1	73.5	30.1	61.7
1984	7,137	9,345	8,231.40	49.9	17.1	75.0	31.1	64.3
1985	6,377	9,802	8,579.12	53.0	17.1	76.4	32.1	66.6

TABLE 594

REQUIRED "PRICES" FOR GAS DISCOVERED AFTER 1970 WITH VARYING ASSUMPTIONS ON REVENUE RECEIVED FOR GAS DISCOVERED PRIOR TO 1971

(15-Percent Rate of Return)

Case IV

	Marketed Gas Production from Pre-1971 Reserves (BCF)	Marketed Gas Production from Post-1970 Reserves (BCF)	Total Gas Revenue Required (MM Dollars)	Average Unit Revenue Required (¢/MCF)	Assumed Price for Production from Pre-1971 Reserves (¢/MCF)	Unit Revenue Required for Production from Post-1970 Reserves (¢/MCF)	Assumed "Price" for Production from Pre-1971 Reserves (¢/MCF)	Unit Revenue Required for Production from Post-1970 Reserves (¢/MCF)
1971	19,990	—	4,694.05	23.5	17.1	—	18.1	—
1972	19,587	592	4,918.42	24.4	17.1	265.0	19.1	198.9
1973	18,865	1,542	5,122.69	25.1	17.1	103.6	20.1	86.3
1974	18,027	2,347	5,253.54	25.8	17.1	92.5	21.1	61.8
1975	16,868	3,014	5,284.64	26.6	17.1	79.6	22.1	51.7
1976	15,566	3,555	5,320.50	27.8	17.1	74.8	23.1	48.5
1977	14,240	4,071	5,264.57	28.8	17.1	65.3	24.1	45.0
1978	12,950	4,533	5,130.43	29.3	17.1	64.3	25.1	41.5
1979	11,691	4,922	5,060.21	30.5	17.1	62.2	26.1	40.8
1980	10,634	5,211	5,011.14	31.6	17.1	61.3	27.1	40.9
1981	9,529	5,424	4,967.75	33.2	17.1	61.5	28.1	42.2
1982	8,687	5,592	4,922.22	34.5	17.1	61.5	29.1	42.8
1983	7,970	5,703	4,865.65	35.6	17.1	61.4	30.1	43.3
1984	7,137	5,774	4,795.53	37.1	17.1	61.9	31.1	44.6
1985	6,377	5,806	4,718.41	38.7	17.1	62.5	32.1	46.0

TABLE 595

REQUIRED "PRICES" FOR GAS DISCOVERED AFTER 1970 WITH VARYING ASSUMPTIONS ON REVENUE RECEIVED FOR GAS DISCOVERED PRIOR TO 1971
(15-Percent Rate of Return)

Case IVA

	Marketed Gas Production from Pre-1971 Reserves (BCF)	Marketed Gas Production from Post-1970 Reserves (BCF)	Total Gas Revenue Required (MM Dollars)	Average Unit Revenue Required (¢/MCF)	Assumed Price for Production from Pre-1971 Reserves (¢/MCF)	Unit Revenue Required for Production from Post-1970 Reserves (¢/MCF)	Assumed "Price" for Production from Pre-1971 Reserves (¢/MCF)	Unit Revenue Required for Production from Post-1970 Reserves (¢/MCF)
1971	19,990	–	4,676.46	23.4	17.1	–	18.1	–
1972	19,587	777	4,898.10	24.1	17.1	199.3	19.1	148.9
1973	18,865	2,095	5,112.04	24.4	17.1	90.0	20.1	63.0
1974	18,027	3,252	5,257.77	24.7	17.1	66.9	21.1	44.7
1975	16,868	4,239	5,306.10	25.1	17.1	57.1	22.1	37.2
1976	15,566	5,060	5,357.60	26.0	17.1	53.3	23.1	34.8
1977	14,240	5,842	5,308.40	26.4	17.1	46.3	24.1	32.1
1978	12,950	6,551	5,168.26	26.5	17.1	45.1	25.1	29.3
1979	11,691	7,159	5,097.07	27.0	17.1	43.3	26.1	28.6
1980	10.634	7,628	5,044.04	27.6	17.1	42.3	27.1	28.3
1981	9,529	7,978	4,995.93	28.5	17.1	42.2	28.1	29.1
1982	8,687	8,256	4,937.97	29.1	17.1	41.8	29.1	29.2
1983	7,970	8,448	4,867.48	29.6	17.1	41.5	30.1	29.2
1984	7,137	8,581	4,784.86	30.4	17.1	41.5	31.1	29.8
1985	6,377	8,651	4,695.20	31.2	17.1	41.7	32.1	30.6

TABLE 596

REQUIRED "PRICES" FOR MARKETED VOLUMES OF ALL NATURAL GAS IN LOWER 48 STATES TO ACHIEVE A 15-PERCENT RETURN ON NET FIXED ASSETS—HIGH FINDING 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	
	Average "Price" for Total Volume Marketed from All Reserves	"Price" for Volume Marketed from All Reserves Found Before 1971	"Price" for Volume Marketed from All Reserves Found After 1970	"Price" for Volume Marketed from All Reserves Found Before 1971	"Price" for Volume Marketed from All Reserves Found After 1970	"Price" for Volume Marketed from All Reserves Found Before 1971	"Price" for Volume Marketed from All Reserves Found After 1970
Case I							
1975	26.7	17.1	59.6	18.6	54.4	20.1	49.3
1980	33.7	17.1	48.7	21.1	45.1	25.1	41.5
1985	43.6	17.1	53.1	23.6	50.8	30.1	48.5
Case II							
1975	26.2	17.1	58.7	18.6	53.3	20.1	47.9
1980	31.8	17.1	46.8	21.1	42.7	25.1	38.6
1985	39.8	17.1	49.5	23.6	46.7	30.1	44.0
Case IVA							
1975	25.1	17.1	57.1	18.6	51.1	20.1	45.2
1980	27.6	17.1	42.3	21.1	36.7	25.1	31.1
1985	31.2	17.1	41.7	23.6	36.9	30.1	32.1

TABLE 597

REQUIRED "PRICES" FOR MARKETED VOLUMES OF ALL NATURAL GAS IN LOWER 48 STATES TO ACHIEVE
A 15-PERCENT RETURN ON NET FIXED ASSETS--LOW FINDING 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	
	Average "Price" for Total Volume Marketed from All Reserves	"Price" for Volume Marketed from All Reserves Found Before 1971	"Price" for Volume Marketed from All Reserves Found After 1970	"Price" for Volume Marketed from All Reserves Found Before 1971	"Price" for Volume Marketed from All Reserves Found After 1970	"Price" for Volume Marketed from All Reserves Found Before 1971	"Price" for Volume Marketed from All Reserves Found After 1970
Case IA							
1975	28.5	17.1	84.1	18.6	76.8	20.1	69.5
1980	40.9	17.1	73.0	21.1	67.6	25.1	62.2
1985	59.4	17.1	82.2	23.6	78.7	30.1	75.2
Case III							
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
Case IV							
1975	26.6	17.1	79.6	18.6	71.2	20.1	62.8
1980	31.6	17.1	61.3	21.1	53.1	25.1	44.9
1985	38.7	17.1	62.5	23.6	55.3	30.1	48.2

Chapter Seven—Section III

Economic Model Support and Results

TABLE 598

LEASE ACQUISITION COSTS—ONSHORE
(Million Dollars Per Year)*

	Onshore Lease Acquisitions†	Onshore Drilling Expenditures‡	Ratio
1959	311	2,469	0.126
1960	310	2,216	0.140
1961	305	2,167	0.140
1962	229	2,305	0.099
1963	338	2,012	0.168
1964	394	2,069	0.190
1965	339	1,974	0.172
1966	228	1,830	0.124
1967	202	1,685	0.120
1968	216	1,742	0.124
1969	215	1,945	0.110
Total	3,087	22,414	0.138
Projected			
1971-1985			0.138

* All values in current dollars.

† Chase Manhattan Bank Industry Cost Studies.

‡ *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 annually).

Historical and Projected Parameters Used In Economic Calculations

The following set of figures and tables show historical and projected parameters used in the economic calculations for oil and gas. Unless specified as applicable to oil operations or applicable to gas operations, the same values were used for both.

The parameters were developed with the specific intent of providing values for calculating various investments and expenses for a variety of industry drilling activities. Therefore, many of the parameters are a function of *drilling costs* (which include the cost of successful well and platforms, and dry holes). In general, the projected ratios are an extrapolation of historical trends; however, a few of the projections depart slightly from history where it was the judgment of the Task Groups that departure will occur.

One relationship which deserves special comment is the ratio of *geological and geophysical* expense to *drilling and producing costs.* Although geophysical expenses are more closely related to drilling activities, producing costs were included to recognize the substantial geological effort that is required in production operations, particularly for secondary and tertiary recovery.

For further information on how these projected parameters are applied, refer to pages on "Calculation Procedure—Expenses" or "Calculation Procedure—Investments" later in this section.

TABLE 599

LEASE ACQUISITION COSTS—OFFSHORE OUTER CONTINENTAL SHELF
OIL AND GAS LEASE SALES

Historical

Date of Sale	Location	Acres Leased (000)	Total Bonus ($000,000)	Avg. Bonus Per Acre ($)
10/54	Louisiana	394.7	116.38	295
11/54	Texas	67.1	23.36	348
7/55	Texas	149.8	8.44	56
7/55	Louisiana	252.8	100.09	396
5/59	Florida	132.5	1.71	13
8/59	Louisiana	38.8	88.04	2,269
Sub-Total		1,035.7	338.02	326
2/60	Texas	240.5	35.73	149
2/60	Louisiana	464.0	246.91	532
3/62	Louisiana	951.8	177.26	186
3/62	Texas	28.8	.56	19
3/62	Louisiana	927.7	267.78	289
10/62	Louisiana	16.2	43.89	2,709
5/63	California	312.9	12.81	41
4/64	Louisiana	32.7	60.34	1,845
10/64	Oregon	425.4	27.77	65
10/64	Washington	155.4	7.76	50
Sub-Total		3,555.4	880.81	248
3/66	Louisiana	35.1	88.85	2,531
10/66	Louisiana	104.7	99.16	947
12/66	California	2.0	21.19	10,595
6/67	Louisiana	744.5	510.08	685
2/68	California	363.2	602.72	1,659
5/68	Texas	541.3	593.90	1,097
11/68	Louisiana	29.7	149.87	5,046
1/69	Louisiana	48.5	44.04	908
12/69	Louisiana	60.2	66.91	1,111
7/70	Louisiana	44.6	97.77	2,192
12/70	Louisiana	543.9	845.83	1,555
Sub-Total		2,517.7	3,120.32	1,239
Grand Total		7,108.8	4,339.15	610

Projected	Avg. Bonus Per Acre ($)
1971	900.00
1972	937.50
1973	975.00
1974	1,012.00
1975	1,050.00
1976	1,087.50
1977	1,125.00
1978	1,162.50
1979	1,200.00
1980	1,237.50
1981-1985	1,237.50

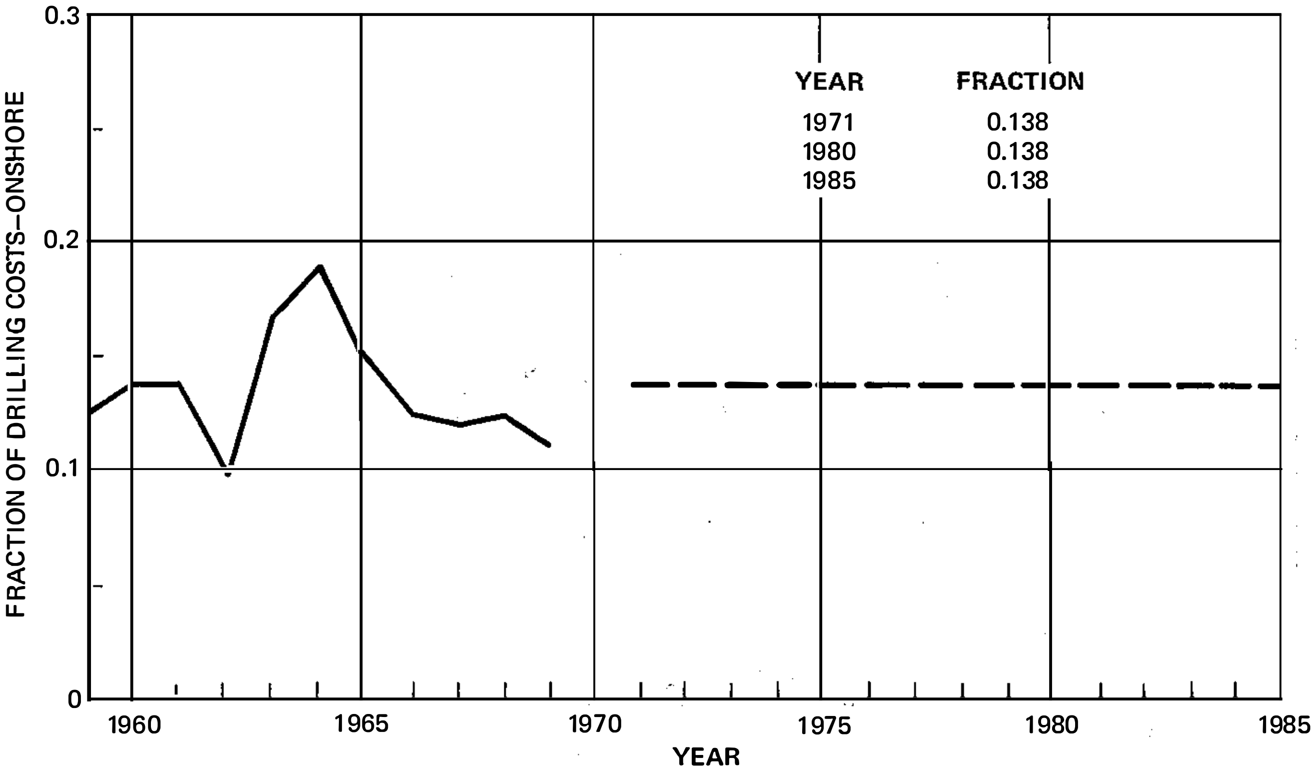


Figure 96. Onshore Lease Acquisition Costs.

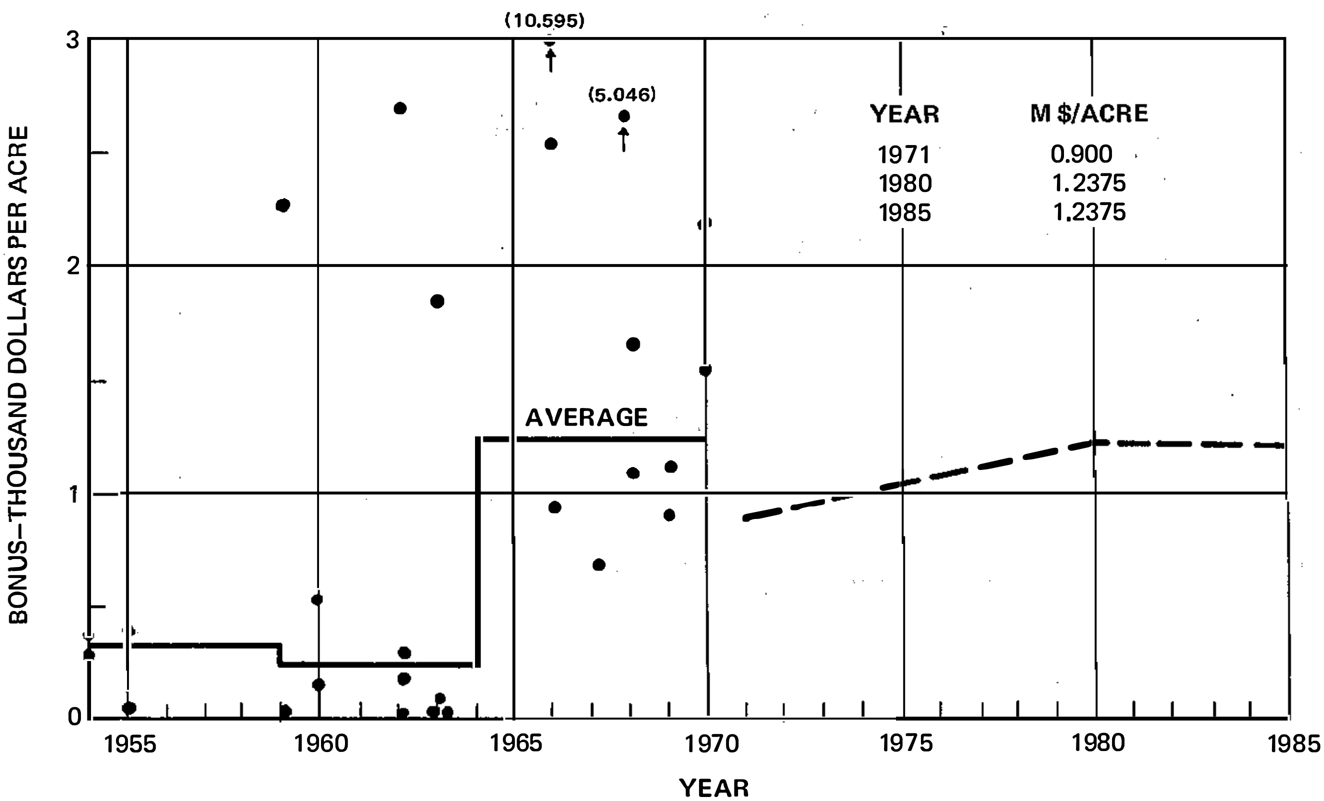


Figure 97. Offshore Lease Acquisition Costs.

TABLE 600

GEOLOGICAL AND GEOPHYSICAL COSTS
(Million Dollars Per Year)*

	Geological and Geophysical†			Drilling and Producing				
History	Geological and Geophysical	Land, Lease and Scouting	Total	Dry Holes	Drill & Equip Producing Wells	Producing Costs	Total	Ratio
1959	320	–	320	821	1,830	1,450	4,101	0.078
1960	277	104	381	774	1,651	1,390	3,815	0.100
1961	280	115	395	774	1,624	1,455	3,853	0.103
1962	299	108	407	847	1,729	1,535	4,111	0.099
1963	300	117	417	790	1,512	1,581	3,883	0.107
1964	336	100	436	854	1,574	1,613	4,041	0.108
1965	355	102	457	849	1,553	1,685	4,087	0.112
1966	378	70	448	832	1,528	1,895	4,255	0.105
1967	392	86	478	802	1,497	1,933	4,232	0.113
1968	373	82	455	826	1,583	2,094	4,503	0.101
1969	387	93	480	888	1,723	2,189	4,800	0.100
1970	349	98	447	873	1,706	2,379	4,958	0.090
Total			5,121				50,639	0.101
Projected								
1971-1985								0.105

* All values in current dollars.

† Including land, lease and scouting.

Source: Joint Association Survey.

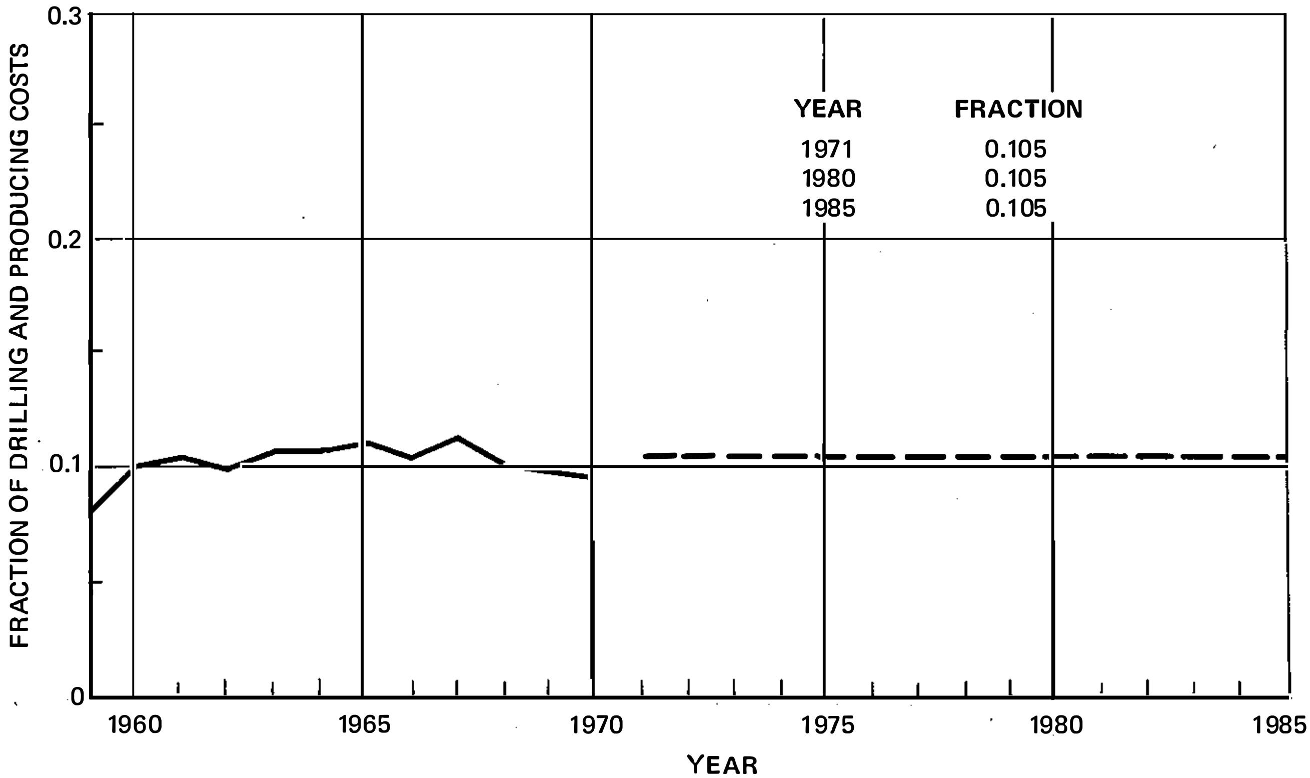


Figure 98. Geological and Geophysical Costs.

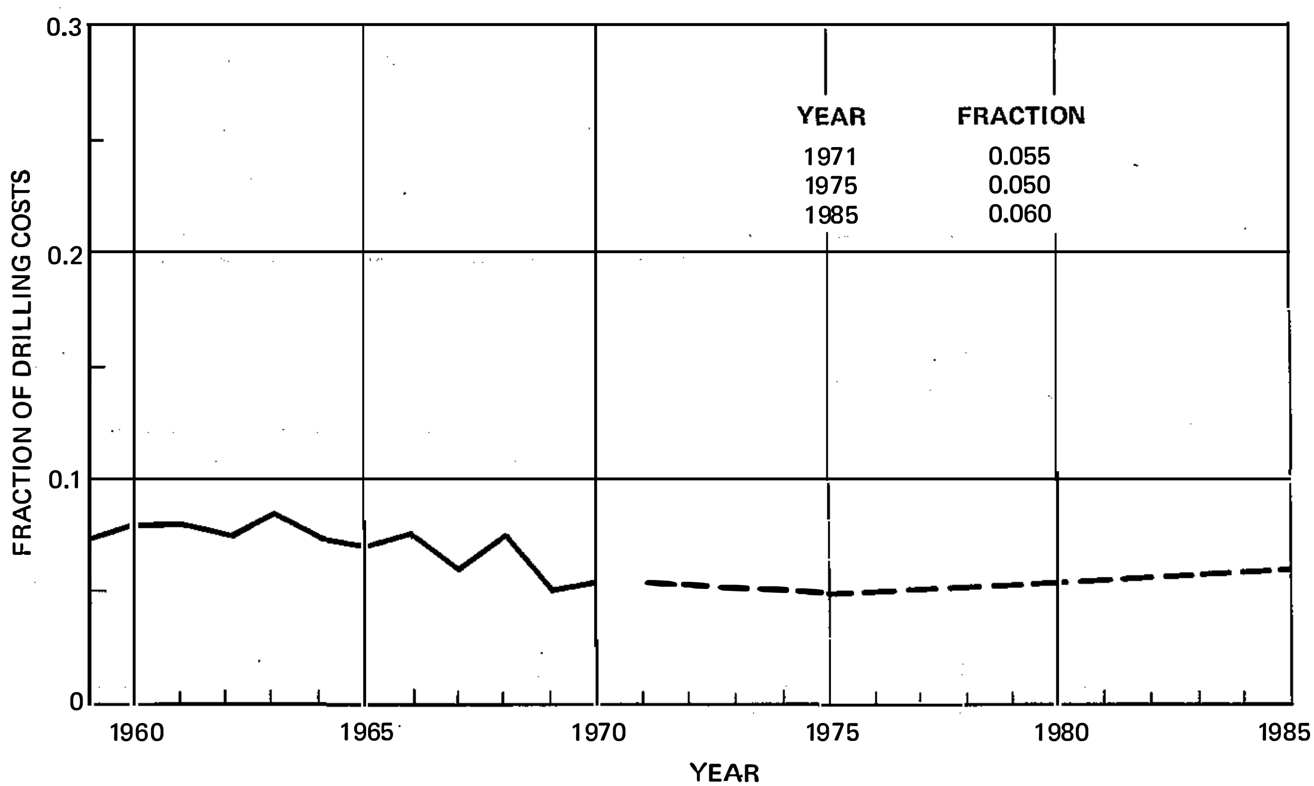


Figure 99. Lease Rental Costs.

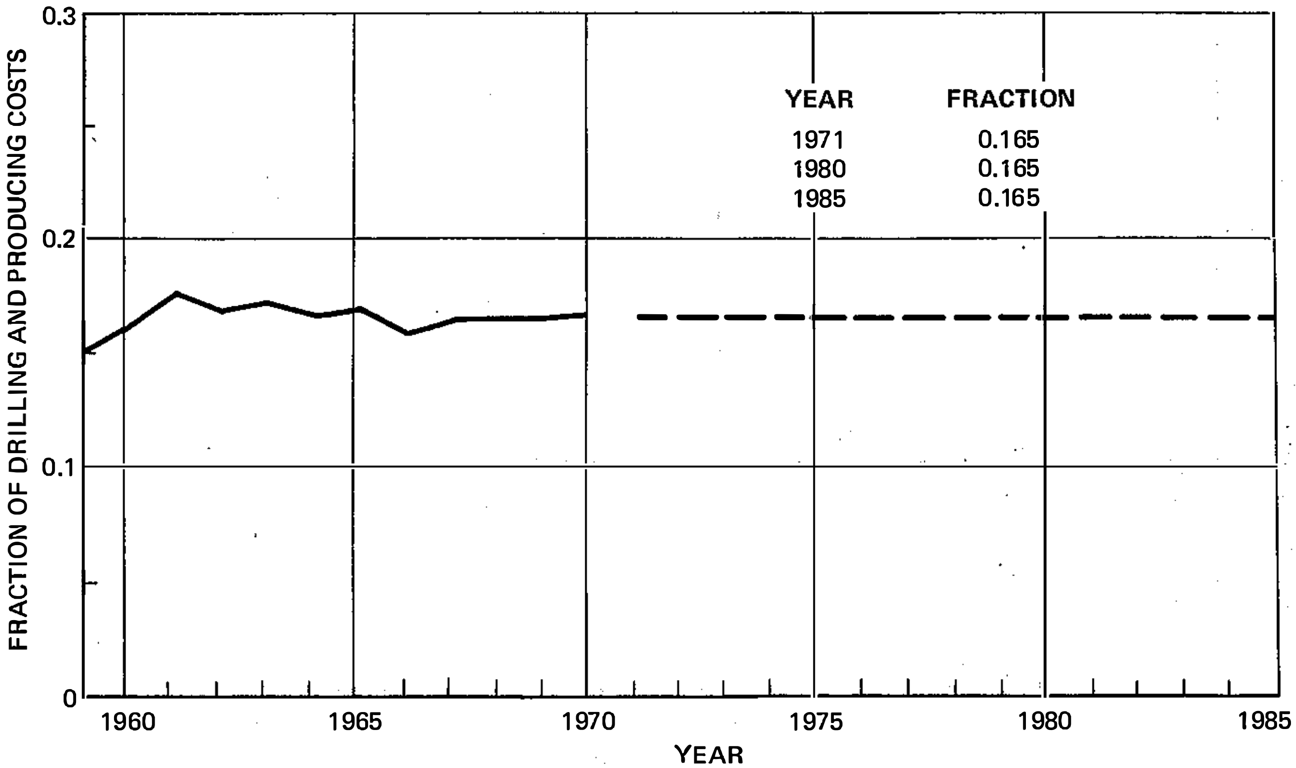


Figure 100. Exploration, Development, and Production Overhead.

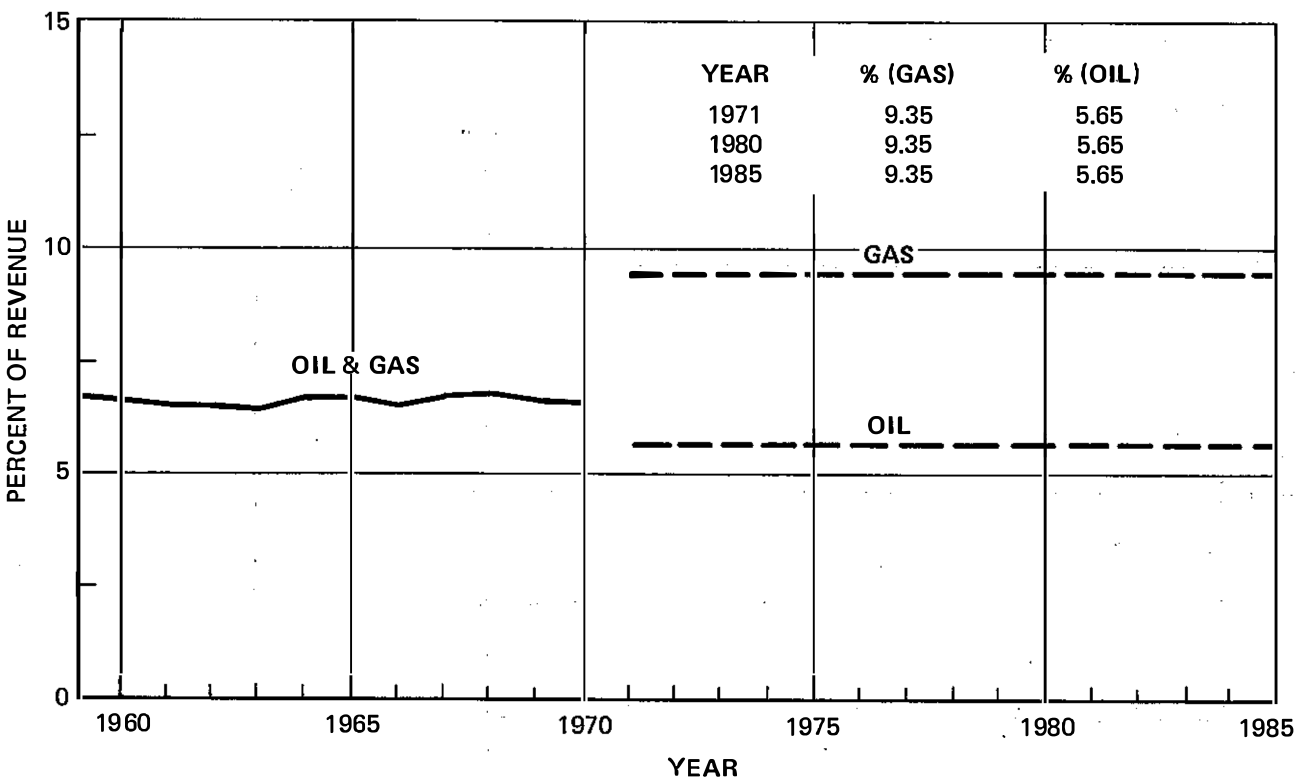


Figure 101. Ad Valorem and Production Taxes.

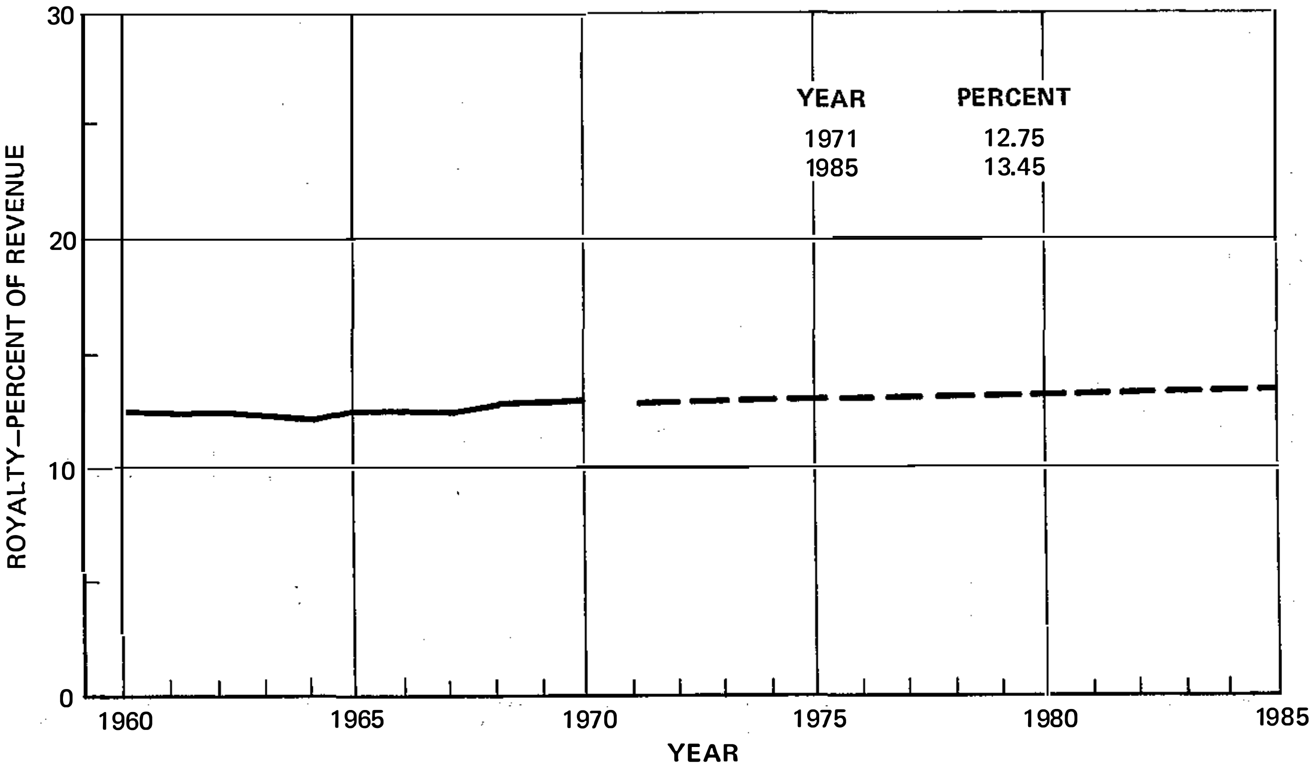


Figure 102. Royalty Rate.

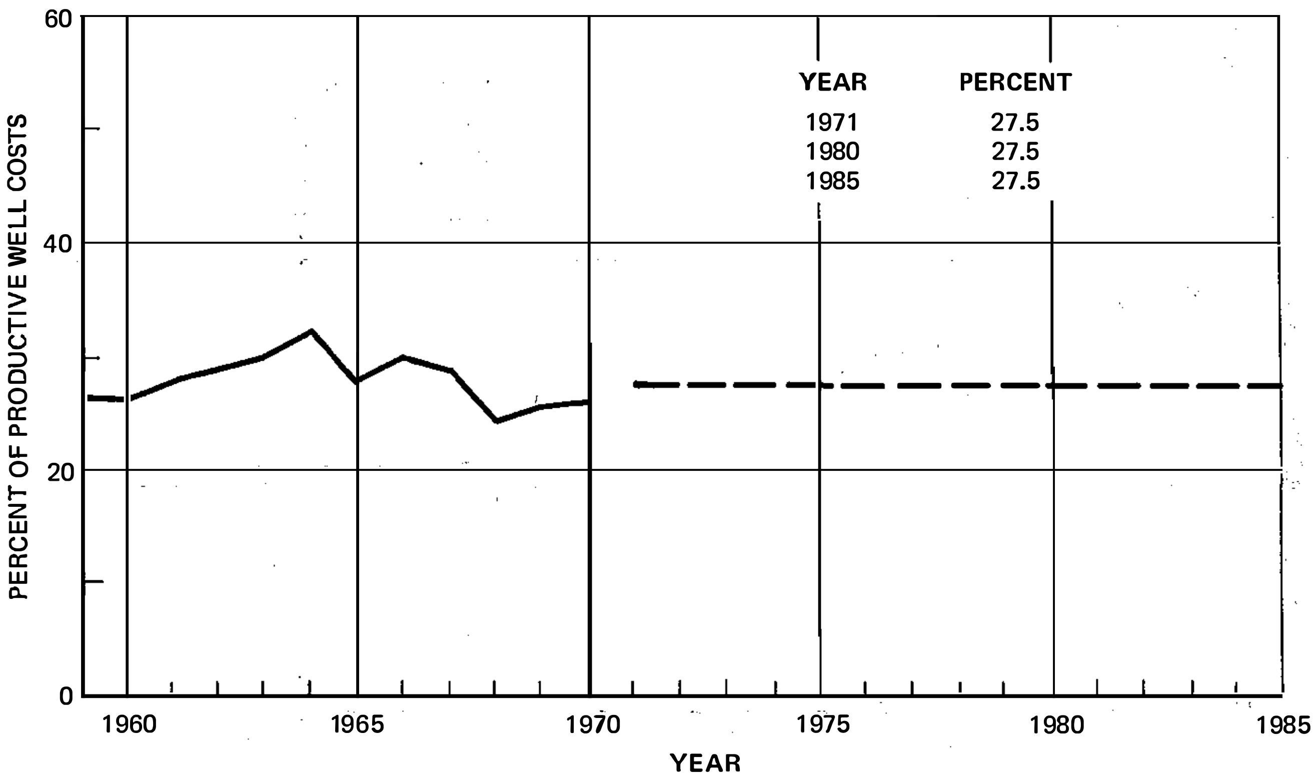


Figure 103. Lease Equipment Costs.

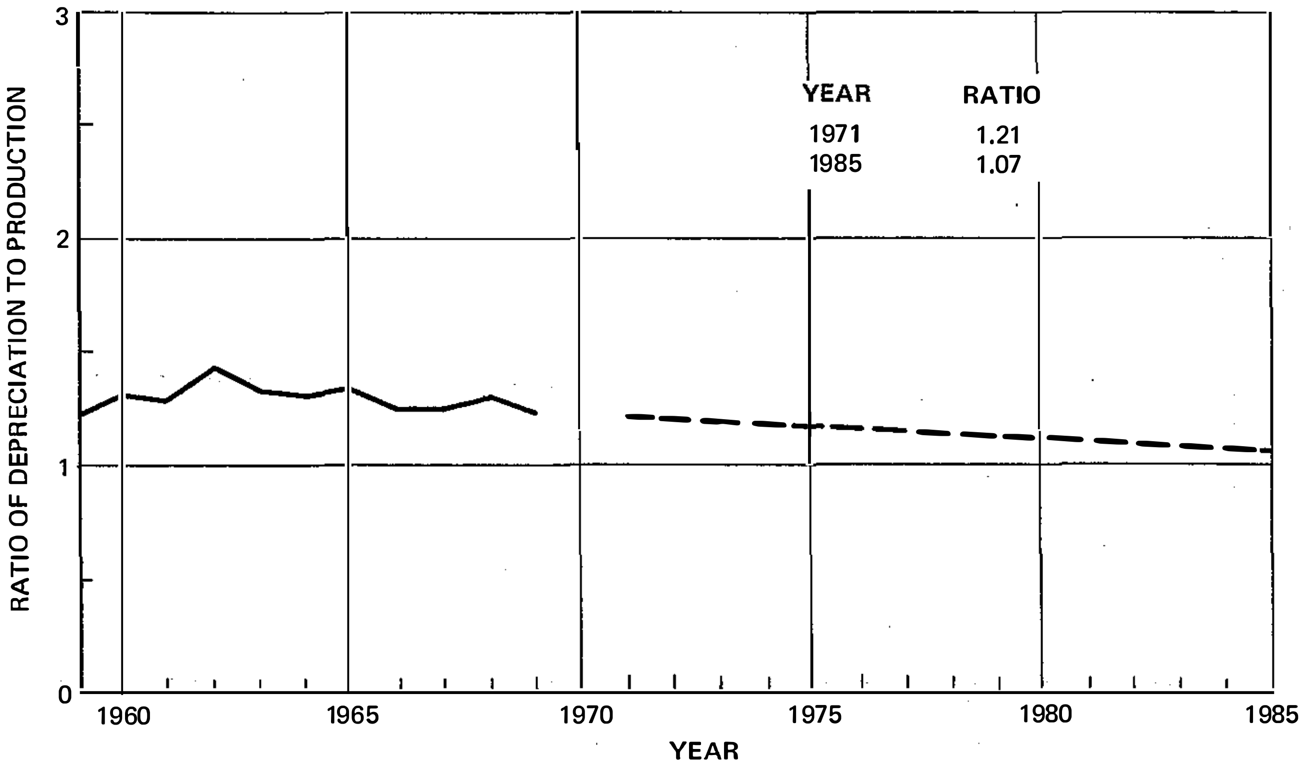
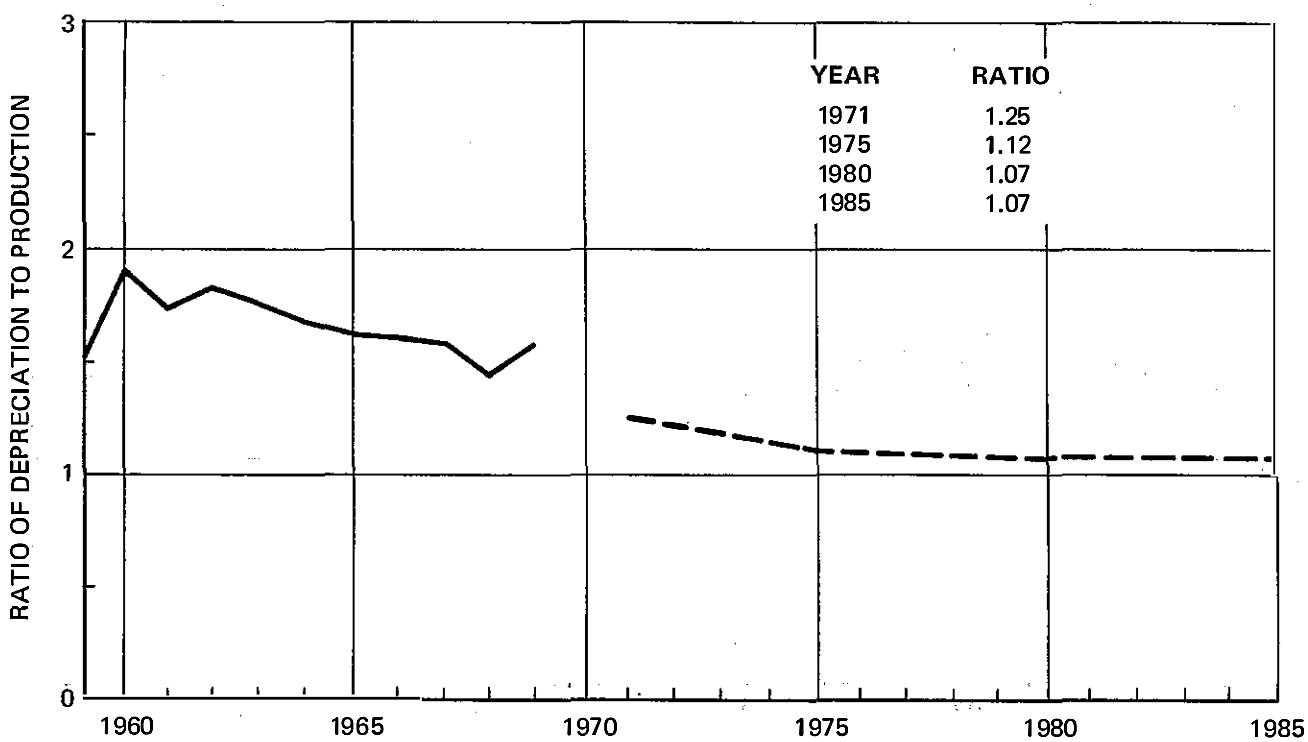


Figure 104. Rate of Depreciation—Oil.*



**Includes all book depreciation, amortization, and retirement per Chase Manhattan Bank analysis.*

Figure 105. Rate of Depreciation—Gas.*

TABLE 601

LEASE RENTAL COSTS
(Million Dollars Per Year)*

Historical	Lease Rentals	Drilling Costs	Ratio
1959	193	2,651	0.073
1960	193	2,425	0.080
1961	189	2,398	0.079
1962	197	2,576	0.076
1963	193	2,302	0.084
1964	177	2,428	0.073
1965	166	2,402	0.069
1966	180	2,360	0.076
1967	140	2,299	0.061
1968	179	2,409	0.074
1969	134	2,611	0.051
1970	138	2,548	0.054
Projected			
1971			0.0550
1972			0.0537
1973			0.0525
1974			0.0513
1975			0.0500
1976			0.0510
1977			0.0520
1978			0.0530
1979			0.0540
1980			0.0550
1981			0.0560
1982			0.0570
1983			0.0580
1984			0.0590
1985			0.0600

* All values in current dollars.

Source: Joint Association Survey.

Note: The annual expenditure for lease rentals was assumed to continue the declining trend of the recent past which probably reflects the industry's effort to reduce non-producing lease inventories. By 1976 it is assumed that inventories will be as low as practical and competition for acreage will increase total lease rental expenses.

TABLE 602

EXPLORATION AND PRODUCTION OVERHEAD
(Million Dollars Per Year)*

Historical	Overhead	Drilling and Producing Costs	Ratio
1959	625	4,101	0.152
1960	621	3,815	0.163
1961	676	3,853	0.175
1962	691	4,111	0.168
1963	670	3,883	0.173
1964	676	4,041	0.167
1965	694	4,087	0.170
1966	673	4,255	0.158
1967	701	4,232	0.166
1968	743	4,503	0.165
1969	786	4,800	0.164
1970	825	4,927	0.167
Projected			
1971-1985			0.165

* All values in current dollars.

Source: Joint Association Survey.

TABLE 603

AD VALOREM AND PRODUCTION TAXES
(Million Dollars)*

History	Ad Valorem and Production Taxes	Net Revenue	Royalty Payments Received	Total† Receipts	Tax Rate (Percent)
1959	508	7,676	—	7,676	6.62
1960	538	7,829	233	8,062	6.67
1961	541	8,128	244	8,372	6.46
1962	556	8,431	254	8,685	6.40
1963	571	8,750	279	9,029	6.32
1964	597	8,844	292	9,136	6.53
1965	612	9,055	272	9,327	6.56
1966	642	9,715	284	9,999	6,42
1967	712	10,433	310	10,743	6.63
1968	758	11,019	309	11,328	6.69
1969	796	11,800	329	12,129	6.56
1970	857	12,681	324	13,005	6.59
Projected					
Gas					
1971-1985					9.35
Oil					
1971-1985					5.65

* All values in current dollars.

† Excludes income from other than oil and gas.

Source: Joint Association Survey.

Note: The projected tax rates are based on a composite representative sample of several important states, including Texas, Louisiana and Oklahoma.

TABLE 604

ROYALTY RATE*

Historical	Net Revenue	Gross† Revenue	Total‡ Receipts	Royalty Rate (%)
1959	7,676	9,031	—	—
1960	7,829	9,211	8,062	12.47
1961	8,128	9,562	8,372	12.45
1962	8,431	9,919	8,685	12.44
1963	8,750	10,294	9,029	12.29
1964	8,844	10,405	9,136	12.20
1965	9,055	10,653	9,327	12.45
1966	9,715	11,429	9,999	12.51
1967	10,433	12,274	10,743	12.47
1968	11,019	12,964	11,328	12.62
1969	11,800	13,882	12,129	12.63
1970	12,681	14,919	13,005	12.83
Projected				
1971				12.75
1972				12.80
1973				12.85
1974				12.90
1975				12.95
1976				13.00
1977				13.05
1978				13.10
1979				13.15
1980				13.20
1981				13.25
1982				13.30
1983				13.35
1984				13.40
1985				13.45

* Royalty that goes outside the industry.

† Calculated from net revenue assuming 15 percent royalty per Joint Association Survey.

‡ Reported by Joint Association Survey as net revenue plus revenue from royalties.

Source: Joint Association Survey.

TABLE 605

LEASE EQUIPMENT COSTS
(Million Dollars)*

Historical	Total Lease Equipment Expenditure†	Improved Recovery Equipment Expenditure ‡	Primary Lease Equipment Expenditure	Drilling and Equipment Producing Wells Expenditures	Ratio of Primary Lease Equipment to Productive Well Costs Percent
1959	483	–	483	1,830	26.4
1960	431	–	431	1,651	26.1
1961	446	–	446	1,624	27.5
1962	537	40	497	1,729	28.7
1963	527	80	447	1,512	29.6
1964	619	115	504	1,574	32.0
1965	580	150	430	1,553	27.7
1966	646	187	459	1,528	30.0
1967	675	247	428	1,497	28.6
1968	606	222	384	1,583	24.3
1969	745	303	442	1,723	25.7
1970	728	285	443	1,705	26.0
Projected					
1971-1985					27.5

* All values in current dollars.

† Reported by Joint Association Survey as "Equipping Leases" through 1965; for 1966 and future years, equal to the sum of lease equipment and improved recovery equipment.

‡ As reported by Joint Association Survey in 1966 and future years. Prior to 1966, values attained by back extrapolation of 1966-70 data.

Source: Joint Association Survey.

Note: The lease equipment costs as a fraction of productive well cost were very nearly (± 1%) the same for both oil wells and gas wells. In this study the same fraction was used for both.

TABLE 606

FACTORS FOR ACCELERATING DEPRECIATION
(Ratio of Depreciation Rate to Production Rate)*

Historical	For Oil	For Gas
1959	1.210	1.437
1960	1.327	1.847
1961	1.298	1.729
1962	1.423	1.824
1963	1.326	1.758
1964	1.302	1.675
1965	1.338	1.627
1966	1.251	1.612
1967	1.245	1.594
1968	1.303	1.450
1969	1.236	1.572
Projected		
1971	1.2100	1.2500
1972	1.2000	1.2175
1973	1.1900	1.1850
1974	1.1800	1.1525
1975	1.1700	1.1200
1976	1.1600	1.1100
1977	1.1500	1.1000
1978	1.1400	1.0900
1979	1.1300	1.0800
1980	1.1200	1.0700
1981	1.1100	1.0700
1982	1.1000	1.0700
1983	1.0900	1.0700
1984	1.0800	1.0700
1985	1.0700	1.0700

* The Depreciation Rate is defined as the ratio of annual Depreciation, Amortization, and Retirement to beginning of year Net Fixed Assets. The production Rate is defined as the ratio of annual production to the reserves at the beginning of the year.

Sources: Chase Manhattan Bank Industry-Cost Studies.
Reserves of Crude Oil Natural Gas, Liquids and Natural Gas in the United States and Canada and United States Productive Capacity, a joint report of the American Gas Association, American Petroleum Institute and Canadian Petroleum Association (published annually).

Note: The declining trend in the ratio of depreciation rate to production rate is extrapolated to a minimum of 1.07. The limit of 1.07 rather than 1.00 is due to nonproducing leases being written off faster than the depletion of normal producing leases.

TABLE 607

OTHER ECONOMIC PARAMETERS APPLIED IN BASE CASES

Projected (1971-1985)	
Intangible Drilling Cost—Oil (Fraction of Successful Well Cost)	0.70
Intangible Drilling Cost—Gas (Fraction of Successful Well Cost)	0.73
Effective Depletion Rate (Fraction of Net Revenue)	0.18*
Depreciation for Tax—Oil (Fraction of Book Depreciation, Amortization and Retirement)	0.50
Depreciation for Tax—Gas (Fraction of Book Depreciation Amortization and Retirement)	0.60
Federal Income Tax Rate—Percent (Including 2 Percent State Income Tax)	50
Investment Tax Credit—Percent	7
Preference Tax Rate	0*

* The effective depletion rate includes the effects of a 22-percent statutory depletion rate, cost depletion and a 10-percent preference tax rate.

Calculation Procedure — Expenses

- *Geological and Geophysical:* Equal to a fraction times the annual investment for producing wells and platforms, dry hole expenses and producing expenses (Fractional values as a function of time are read from data cards.)
- *Lease Rental:* Equal to a fraction times the annual investment for producing wells and platforms, and dry hole expenses (Fractional values as a function of time are read from data cards.)
- *Dry Holes:* Computed in the Oil and Gas Supply Program
- *Producing Lease and Well Expense:* This expense covers the cost of operating productive leases, wells and production facilities, includ-

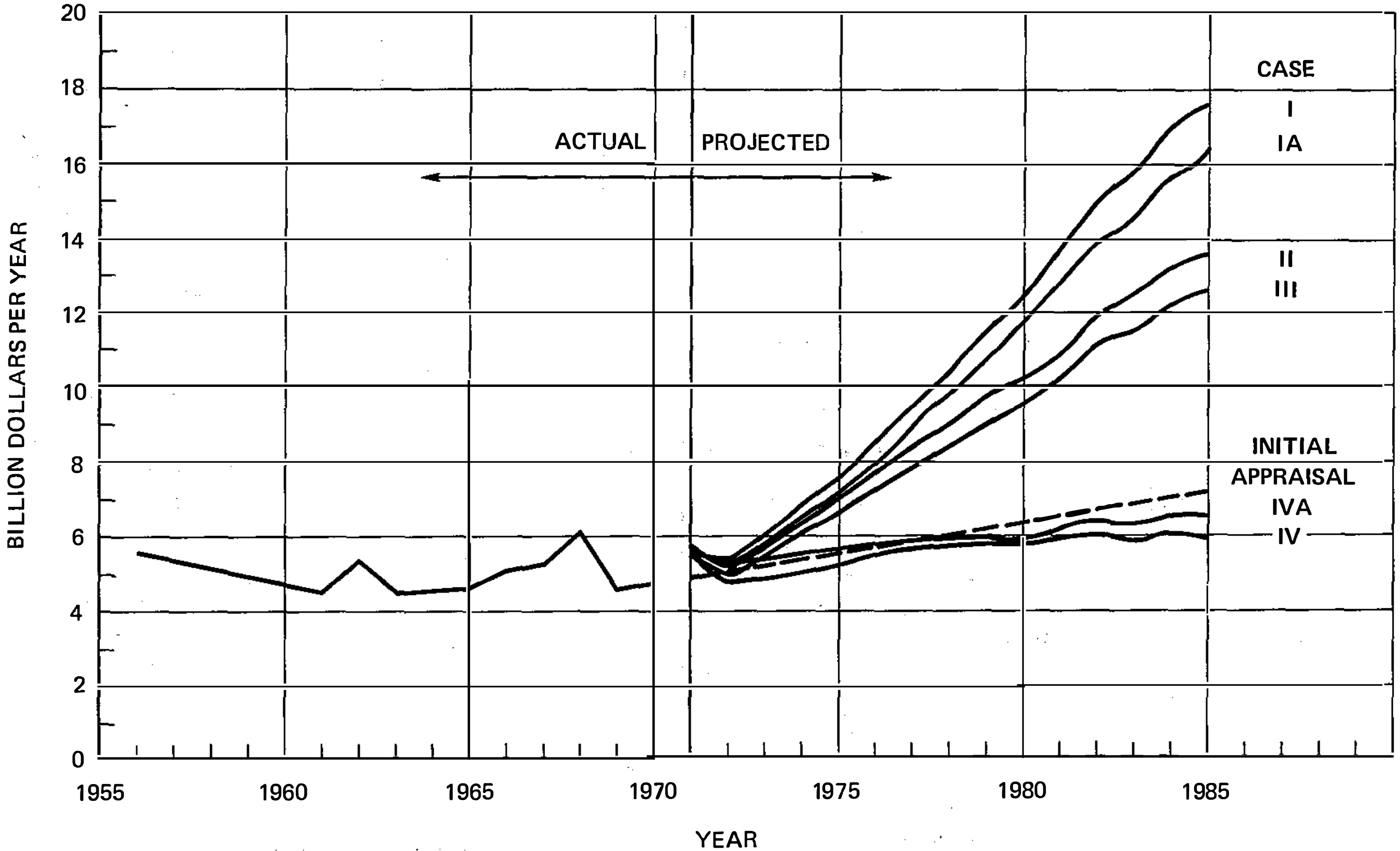
ing additional recovery projects (These values are computed by the oil and sub-model and gas sub-model.)

- *Gas Plant Expenses:* Computed in the Gas Supply Program
- *Miscellaneous Expenses:* Computed in the Oil and Gas Supply Program (These expenses are primarily environmental and safety expenses in excess of the historical rates.)
- *Ad Valorem, Production and Other Taxes:* Equal to a fraction of net revenue which is total revenue less royalty (Separate tax rates are specified for crude oil and natural gas with both tax rates being a function of time as read from data cards.)
- *Depreciation, Depletion, Amortization and Retirement:* Same as value in Net Investment table
- *(Overhead) Indirect Expense:* Equal to a fraction times the sum of annual investment for producing wells and platforms plus producing lease and well expense plus dry hole expense (Fractional values as a function of time are read from data cards.)
- *Total Expense (Before Federal Income Tax):* Summation of above items.

Calculation Procedures for Net Investment In Property, Plant, and Equipment

- *Beginning of Year Net Fixed Assets:* Equal to end-of-year net fixed assets from prior year (Values for first year for each region are read from data cards.)
- *Lease Acquisition Expenditures:* Onshore—equal to a fraction of the drilling cost of both productive wells and dry holes (Fractional values as a function of time are read from data cards.)

  Offshore—equal to the average lease bonus per acre times 2,000 acres per exploratory well times the number of exploratory wells drilled (Average lease bonus per acre as a function of time is read from data cards.)
- *Producing Wells and Platforms Investment:* Computed in the Oil and Gas Supply Programs (based upon average well depth and average cost per foot by region)
- *Lease Equipment Investment:* Equal to the investment for additional recovery equipment plus a fraction times the investment for producing wells and platforms
- *Miscellaneous Tangible Investments:* Computed in the Oil and Gas Supply Programs (These values are primarily environmental and safety investments in excess of the historical rates.)
- *Gas Plant Investment:* Computed in the Gas Supply Programs (based upon the incremental increase in gas production over the prior year within a region and the average cost per unit of capacity)
- *Depreciation, Depletion, Amortization and Retirement:* Computed by region as the product of the beginning-of-the-year net fixed assets times the ratio of annual production to beginning-of-year reserves times a depreciation factor which adjusts the depreciation rate to historical rates (The depreciation factor varies with time but ranges from approximately 1.25 to 1.07 to account for write-offs of some items at a rate faster than the ratio of production to reserves.)
- *End of Year Net Fixed Assets:* Equals the sum of beginning-of-year net fixed assets plus the above capital expenditures less the depreciation, depletion, amortization and retirement.



Excluding North Slope oil and Alaskan gas operations.

Figure 106. Exploration and Development Costs—Oil and Gas.

TABLE 608

CASE II OIL OPERATIONS—1985
(15-Percent Rate of Return)

Example—Profit and Loss Statement in Millions of Dollars

Total Revenue		**24,034**
Royalty (Outside the Industry)		3,232
Operating Revenue		20,802
Operating Expenses		
G & G	673	
Lease Rental	212	
Dry Hole	855	
Lease and Well	2,870	
Gas Plant	—	
Miscellaneous	84	
Ad Valorem and Prod. Tax	1,209	
Overhead	1,058	
Total Operating Expenses	**6,961**	
Book DDA & R	5,133	
Total Book Expenses (BFIT)		**12,094**
Book Net Income (BFIT)		8,708
Expenses for Tax		
Operating Expenses	6,961	
Depr., Amort., and Retir.*	2,566	
Depletion (@ 22%)†	3,744	
Intangible Devel. Cost‡	1,881	
Total Expense for Tax	**15,152**	
Taxable Income	5,650	
FIT (@ 50%)	2,825	
Investment Tax Credit (@ 7%) §	281	
Regular Federal Income Tax		2,544
Book Net Income (AFIT)		6,164

* 50% of Book DDA & R for oil, 60% for gas.

† 18% of operating revenue excluding non-depletable gas plant products.

‡ 70% of successful well and platform costs for oil; 73% for gas.

§ 7% of tangible investments.

TABLE 609

CASE II OIL OPERATIONS—1985
(15-Percent Rate of Return)

Example—Asset Accounting in Millions of Dollars

Beginning of Year Net Fixed Assets		39,608
Annual Capital Expenditures		
Lease Acquisitions	2,125	
Producing Wells and Platforms	2,687	
Lease Equipment	3,028	
Misc. Tangible Investments	175	
Gas Plants	—	
Total Annual Capital Expenditures		8,015
Less Book Depr., Depl., Amort., and Retir.		5,133
End of Year Net Fixed Assets		42,490
Average Annual Net Fixed Assets		41,049
Book Net Income (AFIT)	6,164	
Book DDA & R	5,133	
Net Cash Income	11,297	
Percent of Cash Income Reinvested (8,015/11,297)		71
Rate of Return on Net Fixed Assets % (6,164/41,049)		15

TABLE 610

CASE II OIL AND GAS OPERATIONS—1985
(15-Percent Rate of Return)

Example—Profit and Loss Statement in Millions of Dollars

Total Revenue		34,467
Royalty (Outside the Industry)		4,467
Operating Revenue		30,000
Operating Expenses		
G & G	966	
Lease Rental	333	
Dry Hole	1,683	
Lease and Well	3,659	
Gas Plant	429	
Miscellaneous	107	
Ad Valorem and Prod. Tax	1,893	
Overhead	1,518	
Total Operating Expenses	10,588	
Book DDA & R	7,084	
Total Book Expenses (BFIT)		17,672
Book Net Income (BFIT)		12,328
Expenses for Tax		
Operating Expenses	10,588	
Depr., Amort., and Retir.*	3,737	
Depletion (@ 22%)†	5,175	
Intangible Drilling Cost‡	2,736	
Total Expense for Tax	22,236	
Taxable Income	7,764	
FIT (@ 50%)	3,882	
Investment Tax Credit (@ 7%)§	335	
Regular Federal Income Tax		3,547
Book Net Income (AFIT)		8,781

* 50% of Book DDA & R for oil, 60% for gas.

† 18% of operating revenue excluding non-depletable gas plant products.

‡ 70% of successful well and platform costs for oil; 73% for gas.

§ 7% of tangible investments.

TABLE 611

CASE II OIL AND GAS OPERATIONS—1985
(15-Percent Rate of Return)

Example—Asset Accounting in Millions of Dollars

Beginning of Year Net Fixed Assets		56,707
Annual Capital Expenditures		
Lease Acquisitions	3,166	
Producing Wells and Platforms	3,859	
Lease Equipment	3,350	
Misc. Tangible Investments	217	
Gas Plants	94	
Total Annual Capital Expenditures		10,686
Less Book Depr., Depl, Amort., and Retir.		7,084
End of Year Net Fixed Assets		60,309
Average Annual Net Fixed Assets		58,508
Book Net Income (AFIT)	8,781	
Book DDA & R	7,084	
Net Cash Income	15,865	
Percent of Cash Income Reinvested		67
Rate of Return on Net Fixed Assets %		15

TABLE 612

EXPLORATION AND DEVELOPMENT COSTS OIL AND GAS*
(Million Dollars Per Year—Constant 1970 Dollars)

	Case IA	Case IVA
1971	5,479	5,523
1972	5,152	4,936
1973	5,729	5,224
1974	6,387	5,421
1975	7,106	5,525
1976	8,025	5,908
1977	8,890	5,989
1978	9,596	5,999
1979	10,649	6,109
1980	11,426	6,005
1981	12,662	6,368
1982	13,811	6,449
1983	14,493	6,363
1984	15,660	6,493
1985	16,225	6,428

* Excluding North Slope oil and Alaskan gas operations.

TABLE 613

EXPLORATION AND DEVELOPMENT EXPENDITURES—TOTAL UNITED STATES
(Billion 1970 Dollars)

	1971	1975	1980	1985	15-Year Total	1971	1975	1980	1985	15-Year Total
	Case I					Case III				
Oil	3.6	5.4	8.6	12.5	113.1	3.5	4.5	6.6	8.8	88.8
Gas	2.1	2.7	4.6	5.8	58.7	2.1	2.4	3.6	4.3	46.3
Total	5.7	8.1	13.2	18.3	171.8	5.6	6.9	10.2	13.1	135.1
	Case IA					Case IV				
Oil	3.5	5.0	7.7	11.1	102.4	3.5	3.5	4.1	5.0	61.5
Gas	2.1	2.7	4.6	5.8	57.5	2.0	1.8	1.7	1.5	26.5
Total	5.6	7.7	12.3	16.9	159.9	5.5	5.3	5.8	6.5	88.0
	Case II					Case IVA				
Oil	3.6	4.9	7.3	9.9	97.7	3.6	3.7	4.5	5.4	66.0
Gas	2.1	2.4	3.6	4.3	47.1	2.0	1.9	1.7	1.5	26.9
Total	5.7	7.3	10.9	14.2	144.8	5.6	5.6	6.2	6.9	92.9

TABLE 614

CASE I EXPENDITURES FOR EXPLORATION, DEVELOPMENT AND PRODUCTION OF OIL AND GAS—1971 TO 1985*
(Million 1970 Dollars)

	1971	1975	1980	1985	15-Year Total
			Exploration		
Dry Holes	838	1,135	1,726	2,295	22,607
Lease Acquisitions	817	1,552	2,998	4,316	36,534
Lease Rentals	140	177	298	447	3,927
Geological & Geophysical	530	643	897	1,205	12,193
Total	2,325	3,507	5,919	8,263	75,261
			Development		
Drilling & Equipping Producing Wells	1,916	2,512	3,869	5,452	50,839
Equipping Leases	1,103	1,378	2,456	3,762	34,120
Gas Plant Development	210	180	179	127	2,625
Total	3,229	4,070	6,504	9,341	87,584
			Total Exploration & Development		
	5,644	7,577	12,423	17,604	162,845
			Production		
Producing Costs	2,533	2,621	3,209	4,151	46,185
Production & Ad Valorem Taxes	958	1,081	1,525	2,269	21,425
Total	3,491	3,702	4,734	6,420	67,610
			Gas Plant Expenses		
	459	461	460	482	6,977
			Overhead Expenses		
	832	1,010	1,410	1,894	19,160

* Excludes North Slope oil and all Alaskan gas.

TABLE 615

CASE IA EXPENDITURES FOR EXPLORATION, DEVELOPMENT AND PRODUCTION OF OIL AND GAS—1971 TO 1985*
(Million 1970 Dollars)

	1971	1975	1980	1985	15-Year Total
			Exploration		
Dry Holes	830	1,081	1,643	2,215	21,659
Lease Acquisitions	815	1,524	2,953	4,275	36,031
Lease Rentals	138	154	265	402	3,559
Geological & Geophysical	525	511	820	1,089	11,303
Total	2,309	3,380	5,682	7,981	72,552
			Development		
Drilling & Equipping Producing Wells	1,883	2,292	3,342	4,729	44,921
Equipping Leases	1,094	1,316	2,288	3,428	32,006
Gas Plant Development	193	118	114	87	1,810
Total	3,170	3,726	5,744	8,244	78,737
			Total Exploration & Development		
	5,479	7,106	11,426	16,225	151,289
			Production		
Producing Costs	2,533	2,686	3,048	3,791	44,214
Production & Ad Valorem Taxes	960	1,061	1,451	2,122	20,581
Total	3,493	3,647	4,499	5,913	64,775
			Gas Plant Expenses		
	469	434	387	372	6,160
			Overhead Expenses		
	826	960	1,288	1,712	17,762

* Excludes North Slope oil and all Alaskan gas.

TABLE 616

CASE II EXPENDITURES FOR EXPLORATION, DEVELOPMENT AND PRODUCTION OF OIL ANDGAS—1971 TO 1985*
(Million 1970 Dollars)

	1971	1975	1980	1985	15-Year Total
			Exploration		
Dry Holes	839	1,033	1,354	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
GasPlant Development	209	167	140	94	2,250
Total	3,228	3,804	5,491	7,520	75,943
			Total Exploration & 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.

TABLE 617

CASE III EXPENDITURES FOR EXPLORATION, DEVELOPMENT AND PRODUCTION OF OIL AND GAS—1971 TO 1985*
(Million 1970 Dollars)

	1971	1975	1980	1985	15-Year Total
			Exploration		
Dry Holes	838	983	1,296	1,613	17,734
Lease Acquisitions	815	1,395	2,347	3,131	28,940
Lease Rentals	138	150	212	295	2,920
Geological & Geophysical	526	581	708	871	9,970
Total	2,317	3,109	4,563	5,910	59,564
			Development		
Drilling & Equipping Producing Wells	1,882	2,109	2,783	3,490	37,217
Equipping Leases	1,094	1,267	2,110	3,076	29,871
Gas Plant Development	193	109	90	61	1,560
Total	3,169	3,485	4,983	6,627	68,648
			Total Exploration & Development		
	5,486	6,594	9,546	12,537	128,212
			Production		
Producing Costs	2,533	2,673	2,942	3,468	42,745
Production & Ad Valorem Taxes	960	1,042	1,323	1,771	18,865
Total	3,493	3,615	4,265	5,239	61,610
			Gas Plant Expenses		
	469	431	372	337	5,972
			Overhead Expenses		
	828	912	1,112	1,368	15,668

* Excludes North Slope oil and all Alaskan gas.

TABLE 618

CASE IV EXPENDITURES FOR EXPLORATION, DEVELOPMENT AND PRODUCTION OF OIL AND GAS—1971 TO 1985*
(Million 1970 Dollars)

	1971	1975	1980	1985	15-Year Total
			Exploration		
Dry Holes	824	737	645	568	10,209
Lease Acquisitions	810	1,041	1,182	1,108	13,792
Lease Rentals	137	113	110	107	11,694
Geological & Geophysical	524	499	486	476	7,350
Total	2,295	2,390	2,423	2,259	35,045
			Development		
Drilling & Equipping Producing Wells	1,875	1,597	1,419	1,291	22,132
Equipping Leases	1,091	1,132	1,754	2,421	25,597
Gas Plant Development	190	86	38	13	1,044
Total	3,156	2,815	3,211	3,725	48,773
			Total Exploration & Development		
	5,451	5,205	5,634	5,984	82,818
			Production		
Producing Costs	2,533	2,532	2,680	2,806	39,477
Production & Ad Valorem Taxes	959	990	1,048	1,119	15,458
Total	3,492	3,522	3,728	3,925	54,935
			Gas Plant Expenses		
	469	425	337	263	55,558
			Overhead Expenses		
	824	785	763	749	11,550

* Excludes North Slope oil and Alaskan gas.

TABLE 619

CASE IVA EXPENDITURES FOR EXPLORATION, DEVELOPMENT AND PRODUCTION OF OIL AND GAS—1971 TO 1985*
(Million 1970 Dollars)

	1971	1975	1980	1985	15-Year Total
			Exploration		
Dry Holes	832	773	681	598	10,677
Lease Acquisitions	811	1,058	1,203	1,123	15,833
Lease Rentals	139	122	121	121	1,844
Geological & Geophysical	528	521	517	517	7,741
Total	2,310	2,474	2,522	2,359	36,095
			Development		
Drilling & Equipping Producing Wells	1,907	1,746	1,601	1,504	24,481
Equipping Leases	1,100	1,173	1,821	2,544	26,523
Gas Plant Development	206	132	81	21	1,442
Total	3,213	3,051	3,483	4,069	52,446
			Total Exploration & Development		
	5,523	5,525	6,005	6,428	88,541
			Production		
Producing Costs	2,533	2,561	2,773	2,963	40,518
Production & Ad Valorem Taxes	958	1,007	1,091	1,180	15,922
Total	3,491	3,568	3,864	4,143	56,440
			Gas Plant Expenses		
	469	448	382	315	6,052
			Overhead Expenses		
	830	819	813	812	12,165

* Excludes North Slope oil and all Alaskan gas.

TABLE 620

OIL OPERATIONS*
UNITED STATES NET INVESTMENT IN PROPERTY, PLANT, AND EQUIPMENT
(Million 1970 Dollars)

CASE I

YEAR	BEGINNING YEAR NET FIXED ASSETS	LEASE ACQUISITIONS	PRODUCING WELLS AND PLATFORMS	LEASE EQUIPMENT	MISC. TANGIBLE INVESTMENT	GAS PLANT INVESTMENT	LESS DEPRECIATION DEPLETION AMORTIZATION, RETIREMENT	END OF YEAR NET FIXED ASSETS	AVERAGE NET FIXED ASSETS
1971	17074.00	431.73	1120.81	941.06	148.23	.00	2532.14	17183.69	17128.85
1972	17183.69	396.54	1018.09	933.34	40.09	.00	2533.95	17037.79	17110.74
1973	17037.79	575.98	1237.28	1014.55	55.50	.00	2456.61	17464.49	17251.14
1974	17464.49	772.45	1446.64	1092.90	69.89	.00	2468.64	18377.73	17921.11
1975	18377.73	985.08	1632.67	1165.25	84.07	.00	2550.88	19693.92	19035.83
1976	19693.92	1090.18	1685.30	1707.22	82.98	.00	2693.85	21565.74	20629.83
1977	21565.74	1339.77	1899.61	1806.20	98.67	.00	2895.60	23814.40	22690.07
1978	23814.40	1477.45	2048.04	1898.38	107.58	.00	3171.81	26174.05	24994.22
1979	26174.05	1704.05	2296.83	2019.02	128.06	.00	3437.50	28884.50	27529.27
1980	28884.50	1865.87	2431.40	2110.01	136.56	.00	3800.64	31627.70	30256.10
1981	31627.70	1988.27	2571.33	2677.12	145.22	.00	4156.74	34852.90	33240.30
1982	34852.90	2314.70	2852.13	2831.62	171.35	.00	4541.52	38481.18	36667.04
1983	38481.18	2443.10	2998.39	2966.54	181.89	.00	5033.45	42037.65	40259.41
1984	42037.65	2754.19	3394.51	3186.96	219.96	.00	5443.77	46149.49	44093.57
1985	46149.49	2892.00	3556.71	3321.44	233.63	.00	5999.48	50153.80	48151.64

*EXCLUDING NORTH SLOPE.

TABLE 621

OIL OPERATIONS*
UNITED STATES NET INVESTMENT IN PROPERTY, PLANT, AND EQUIPMENT
(Million 1970 Dollars)

CASE IA

YEAR	BEGINNING YEAR NET FIXED ASSETS	LEASE ACQUISITIONS	PRODUCING WELLS AND PLATFORMS	LEASE EQUIPMENT	MISC. TANGIBLE INVESTMENT	GAS PLANT INVESTMENT	LESS DEPRECIATION DEPLETION AMORTIZATION, RETIREMENT	END OF YEAR NET FIXED ASSETS	AVERAGE NET FIXED ASSETS
1971	17074.00	430.11	1090.44	932.10	146.17	.00	2540.07	17132.76	17103.38
1972	17132.76	391.46	947.24	912.26	36.08	.00	2549.21	16870.58	17001.67
1973	16870.58	562.34	1095.82	973.42	49.48	.00	2467.62	17084.02	16977.30
1974	17084.02	749.67	1253.34	1037.32	64.05	.00	2458.57	17729.82	17406.92
1975	17729.82	957.11	1417.81	1103.49	79.11	.00	2510.31	18777.03	18253.42
1976	18777.03	1055.75	1438.75	1633.10	78.68	.00	2618.81	20364.50	19570.76
1977	20364.50	1299.53	1601.08	1714.04	92.60	.00	2790.53	22281.23	21322.86
1978	22281.23	1434.26	1683.50	1782.80	96.72	.00	3024.93	24253.58	23267.41
1979	24253.58	1659.59	1858.97	1876.99	110.71	.00	3240.18	26519.66	25386.62
1980	26519.66	1820.33	1927.79	1941.55	113.42	.00	3539.35	28783.39	27651.53
1981	28783.39	1941.58	2019.35	2479.35	118.09	.00	3825.13	31516.63	30150.01
1982	31516.63	2268.54	2242.90	2597.14	138.34	.00	4138.64	34624.95	33070.79
1983	34624.95	2397.38	2367.88	2705.32	146.75	.00	4536.01	37706.26	36165.60
1984	37706.26	2710.58	2713.56	2881.95	178.70	.00	4874.76	41316.30	39511.28
1985	41316.30	2850.85	2876.50	2987.29	191.10	.00	5358.05	44863.97	43090.13

*EXCLUDING NORTH SLOPE.

TABLE 622

OIL OPERATIONS*
UNITED STATES NET INVESTMENT IN PROPERTY, PLANT, AND EQUIPMENT
(Million 1970 Dollars)

CASE II

YEAR	BEGINNING YEAR NET FIXED ASSETS	LEASE ACQUISITIONS	PRODUCING WELLS AND PLATFORMS	LEASE EQUIPMENT	MISC. TANGIBLE INVESTMENT	GAS PLANT INVESTMENT	LESS DEPRECIATION DEPLETION AMORTIZATION, RETIREMENT	END OF YEAR NET FIXED ASSETS	AVERAGE NET FIXED ASSETS
1971	17074.00	431.73	1120.81	941.06	148.23	.00	2532.14	17183.69	17128.85
1972	17183.69	387.77	995.98	927.10	39.24	.00	2536.24	16997.53	17090.61
1973	16997.53	558.08	1200.06	1004.09	53.89	.00	2454.20	17359.45	17178.49
1974	17359.45	738.20	1385.67	1075.82	67.07	.00	2459.26	18166.95	17763.20
1975	18166.95	915.23	1524.16	1134.88	78.85	.00	2532.30	19287.77	18727.36
1976	19287.77	984.41	1530.17	1663.60	75.97	.00	2652.79	20889.12	20088.44
1977	20889.12	1182.37	1684.17	1744.40	87.82	.00	2823.71	22764.17	21826.65
1978	22764.17	1262.63	1759.25	1815.10	92.38	.00	3054.03	24639.51	23701.84
1979	24639.51	1416.28	1923.81	1910.65	107.23	.00	3258.79	26738.69	25689.10
1980	26738.69	1508.19	1986.63	1977.80	111.65	.00	3535.75	28787.21	27762.95
1981	28787.21	1563.21	2051.30	2519.01	116.07	.00	3791.55	31245.25	30016.23
1982	31245.25	1786.65	2240.72	2640.76	134.68	.00	4070.49	33977.57	32611.41
1983	33977.57	1852.08	2322.21	2749.73	140.80	.00	4430.67	36611.73	35294.65
1984	36611.73	2050.61	2585.17	2922.41	166.63	.00	4727.73	39608.81	38110.27
1985	39608.81	2125.28	2686.61	3027.55	175.08	.00	5133.20	42490.13	41049.47

*EXCLUDING NORTH SLOPE.

TABLE 623

OIL OPERATIONS*
UNITED STATES NET INVESTMENT IN PROPERTY, PLANT, AND EQUIPMENT
(Million 1970 Dollars)

CASE III

YEAR	BEGINNING YEAR NET FIXED ASSETS	LEASE ACQUISITIONS	PRODUCING WELLS AND PLATFORMS	LEASE EQUIPMENT	MISC. TANGIBLE INVESTMENT	GAS PLANT INVESTMENT	LESS DEPRECIATION DEPLETION AMORTIZATION, RETIREMENT	END OF YEAR NET FIXED ASSETS	AVERAGE NET FIXED ASSETS
1971	17074.00	430.11	1090.44	932.10	146.17	.00	2540.07	17132.76	17103.38
1972	17132.76	382.83	926.98	906.58	35.33	.00	2550.93	16833.55	16983.15
1973	16833.55	544.97	1063.42	964.37	48.05	.00	2464.40	16989.96	16911.75
1974	16989.96	716.61	1201.09	1022.75	61.39	.00	2448.56	17543.24	17266.60
1975	17543.24	889.65	1325.68	1077.84	74.11	.00	2491.23	18419.30	17981.27
1976	18419.30	954.16	1311.77	1597.63	72.01	.00	2578.87	19776.00	19097.65
1977	19776.00	1147.17	1426.59	1664.14	82.86	.00	2723.45	21373.30	20574.65
1978	21373.30	1225.17	1455.01	1717.10	84.13	.00	2917.60	22937.12	22155.21
1979	22937.12	1378.53	1574.81	1794.65	94.72	.00	3081.27	24698.56	23817.84
1980	24698.56	1470.44	1590.98	1842.05	94.58	.00	3308.85	26387.76	25543.16
1981	26387.76	1525.29	1622.07	2360.17	95.84	.00	3510.84	28480.28	27434.02
1982	28480.28	1749.10	1765.89	2451.21	109.76	.00	3742.44	30813.80	29647.04
1983	30813.80	1814.76	1825.38	2536.96	113.68	.00	4035.66	33068.92	31941.36
1984	33068.92	2014.25	2043.77	2673.34	134.60	.00	4269.85	35665.03	34366.97
1985	35665.03	2089.78	2134.16	2753.44	141.59	.00	4609.23	38174.76	36919.89

*EXCLUDING NORTH SLOPE.

TABLE 624

OIL OPERATIONS*
UNITED STATES NET INVESTMENT IN PROPERTY, PLANT, AND EQUIPMENT
(Million 1970 Dollars)

CASE IV

YEAR	BEGINNING YEAR NET FIXED ASSETS	LEASE ACQUISITIONS	PRODUCING WELLS AND PLATFORMS	LEASE EQUIPMENT	MISC. TANGIBLE INVESTMENT	GAS PLANT INVESTMENT	LESS DEPRECIATION DEPLETION AMORTIZATION, RETIREMENT	END OF YEAR NET FIXED ASSETS	AVERAGE NET FIXED ASSETS
1971	17074.00	430.11	1090.44	932.10	146.17	.00	2540.07	17132.76	17103.38
1972	17132.76	359.70	872.55	891.30	33.32	.00	2555.57	16734.05	16933.40
1973	16734.05	476.24	933.20	927.98	42.23	.00	2459.39	16654.30	16694.17
1974	16654.30	576.37	975.11	959.76	49.90	.00	2416.09	16799.36	16726.83
1975	16799.36	661.05	1007.91	989.37	56.65	.00	2408.05	17106.29	16952.82
1976	17106.29	661.21	945.88	1495.40	52.84	.00	2417.16	17844.46	17475.37
1977	17844.46	732.78	948.79	1527.55	56.02	.00	2487.88	18621.72	18233.09
1978	18621.72	749.79	920.04	1560.04	53.89	.00	2566.09	19339.40	18980.56
1979	19339.40	775.86	933.00	1602.26	57.52	.00	2625.45	20082.59	19710.99
1980	20082.59	760.82	880.97	1625.11	54.15	.00	2710.30	20693.34	20387.97
1981	20693.34	725.65	832.37	2116.23	50.98	.00	2758.76	21659.82	21176.58
1982	21659.82	768.70	838.68	2157.26	53.70	.00	2845.71	22632.47	22146.15
1983	22632.47	734.05	794.78	2203.75	50.80	.00	2947.61	23468.24	23050.36
1984	23468.24	761.36	829.03	2271.80	55.65	.00	3008.46	24377.61	23922.93
1985	24377.61	738.53	806.12	2306.85	54.29	.00	3110.26	25173.14	24775.37

*EXCLUDING NORTH SLOPE.

TABLE 625

OIL OPERATIONS*
UNITED STATES NET INVESTMENT IN PROPERTY, PLANT, AND EQUIPMENT
(Million 1970 Dollars)

CASE IVA

YEAR	BEGINNING YEAR NET FIXED ASSETS	LEASE ACQUISITIONS	PRODUCING WELLS AND PLATFORMS	LEASE EQUIPMENT	MISC. TANGIBLE INVESTMENT	GAS PLANT INVESTMENT	LESS DEPRECIATION DEPLETION AMORTIZATION, RETIREMENT	END OF YEAR NET FIXED ASSETS	AVERAGE NET FIXED ASSETS
1971	17074.00	431.73	1120.81	941.06	148.23	.00	2532.14	17183.69	17128.85
1972	17183.69	364.27	936.63	910.35	36.96	.00	2542.40	16889.50	17036.60
1973	16889.50	486.95	1048.90	961.62	47.40	.00	2452.79	16981.58	16935.54
1974	16981.58	592.70	1120.14	1001.46	54.73	.00	2430.12	17320.48	17151.03
1975	17320.48	678.97	1152.36	1030.86	60.50	.00	2448.53	17794.64	17557.56
1976	17794.64	680.24	1093.25	1540.70	56.33	.00	2482.75	18682.40	18238.52
1977	18682.40	752.77	1095.73	1575.60	58.91	.00	2572.00	19593.42	19137.91
1978	19593.42	771.44	1079.94	1615.35	57.09	.00	2668.67	20448.57	20021.00
1979	20448.57	797.85	1103.26	1663.81	61.55	.00	2746.55	21328.48	20888.52
1980	21328.48	781.86	1058.11	1691.83	59.42	.00	2851.93	22067.78	21698.13
1981	22067.78	745.35	1012.84	2192.39	57.37	.00	2920.97	23154.76	22611.27
1982	23154.76	787.02	1027.22	2246.61	61.70	.00	3022.76	24254.54	23704.65
1983	24254.54	751.20	986.66	2304.90	59.80	.00	3146.04	25211.06	24732.80
1984	25211.06	777.63	1030.68	2386.76	66.13	.00	3224.64	26247.63	25729.34
1985	26247.63	754.08	1007.59	2429.38	65.16	.00	3347.10	27156.75	26702.19

*EXCLUDING NORTH SLOPE.

TABLE 626

GAS OPERATIONS*
UNITED STATES NET INVESTMENT IN PROPERTY, PLANT, AND EQUIPMENT
(Million 1970 Dollars)

CASE I

YEAR	BEGINNING YEAR NET FIXED ASSETS	LEASE ACQUISITIONS	PRODUCING WELLS AND PLATFORMS	LEASE EQUIPMENT	MISC. TANGIBLE INVESTMENT	GAS PLANT INVESTMENT	LESS DEPRECIATION DEPLETION AMORTIZATION, RETIREMENT	END OF YEAR NET FIXED ASSETS	AVERAGE NET FIXED ASSETS
1971	8730.40	385.09	587.60	161.59	59.22	210.45	965.24	9169.11	8949.75
1972	9169.11	419.31	623.87	171.56	16.87	195.89	1024.01	9572.59	9370.85
1973	9572.59	461.56	667.24	183.49	18.29	181.34	1099.67	9984.84	9778.72
1974	9984.84	511.02	717.10	197.20	19.93	183.05	1167.44	10445.70	10215.27
1975	10445.70	566.63	773.77	212.79	21.80	180.30	1214.61	10986.38	10716.04
1976	10986.38	631.47	846.71	232.84	24.66	176.07	1275.95	11622.18	11304.28
1977	11622.18	713.04	923.19	253.88	27.45	182.34	1342.77	12379.31	12000.75
1978	12379.31	834.80	1020.12	280.53	31.75	186.06	1416.53	13316.05	12847.68
1979	13316.05	1003.52	1139.77	313.44	37.71	183.43	1500.36	14493.57	13904.81
1980	14493.57	1132.33	1258.69	346.14	42.08	179.29	1601.05	15851.04	15172.31
1981	15851.04	1248.00	1387.08	381.45	48.18	171.28	1724.36	17362.67	16606.86
1982	17362.67	1340.70	1483.96	408.09	52.48	169.25	1888.63	18928.51	18145.59
1983	18928.51	1402.10	1552.23	426.86	55.63	157.61	2074.93	20448.03	19688.27
1984	20448.03	1428.17	1589.77	437.19	57.41	142.05	2253.86	21848.75	21148.39
1985	21848.75	1424.47	1603.44	440.94	57.92	126.88	2433.82	23068.58	22458.67

*EXCLUDING ALASKA.

TABLE 627

GAS OPERATIONS*
UNITED STATES NET INVESTMENT IN PROPERTY, PLANT, AND EQUIPMENT
(Million 1970 Dollars)

CASE IA

YEAR	BEGINNING YEAR NET FIXED ASSETS	LEASE ACQUISITIONS	PRODUCING WELLS AND PLATFORMS	LEASE EQUIPMENT	MISC. TANGIBLE INVESTMENT	GAS PLANT INVESTMENT	LESS DEPRECIATION DEPLETION AMORTIZATION, RETIREMENT	END OF YEAR NET FIXED ASSETS	AVERAGE NET FIXED ASSETS
1971	8730.40	385.09	587.60	161.59	59.22	193.32	979.24	9137.98	8934.19
1972	9137.98	419.31	623.87	171.56	16.87	161.64	1045.01	9486.21	9312.10
1973	9486.21	461.56	667.24	183.49	18.29	129.96	1118.74	9828.01	9657.11
1974	9828.01	511.02	717.10	197.20	19.93	123.17	1186.49	10209.95	10018.98
1975	10209.95	566.63	773.77	212.79	21.80	117.56	1232.81	10669.68	10439.82
1976	10669.68	631.47	846.71	232.84	24.66	113.64	1293.76	11225.25	10947.47
1977	11225.25	713.04	923.19	253.88	27.45	120.23	1359.51	11903.52	11564.39
1978	11903.52	834.80	1020.12	280.53	31.75	121.64	1430.84	12761.53	12332.53
1979	12761.53	1003.52	1139.77	313.44	37.71	118.17	1512.06	13862.10	13311.82
1980	13862.10	1132.33	1258.69	346.14	42.08	114.33	1612.75	15142.90	14502.50
1981	15142.90	1248.00	1387.08	381.45	48.18	107.77	1731.50	16583.88	15863.39
1982	16583.88	1340.70	1483.96	408.09	52.48	107.59	1893.18	18083.51	17333.70
1983	18083.51	1402.10	1552.23	426.86	55.63	101.67	2077.06	19544.95	18814.23
1984	19544.95	1428.17	1589.77	437.19	57.41	91.97	2244.56	20904.90	20224.93
1985	20904.90	1424.47	1603.44	440.94	57.92	87.04	2409.43	22109.28	21507.09

*EXCLUDING ALASKA.

TABLE 628

GAS OPERATIONS*
UNITED STATES NET INVESTMENT IN PROPERTY, PLANT, AND EQUIPMENT
(Million 1970 Dollars)

CASE II

YEAR	BEGINNING YEAR NET FIXED ASSETS	LEASE ACQUISITIONS	PRODUCING WELLS AND PLATFORMS	LEASE EQUIPMENT	MISC. TANGIBLE INVESTMENT	GAS PLANT INVESTMENT	LESS DEPRECIATION DEPLETION AMORTIZATION, RETIREMENT	END OF YEAR NET FIXED ASSETS	AVERAGE NET FIXED ASSETS
1971	8730.40	385.09	587.60	161.59	59.22	209.30	965.24	9167.96	8949.18
1972	9167.96	407.33	606.04	166.66	16.39	193.60	1025.99	9531.99	9349.97
1973	9531.99	435.63	629.74	173.18	17.26	177.89	1101.05	9864.64	9698.31
1974	9864.64	468.65	657.65	180.85	18.28	175.08	1164.24	10200.91	10032.77
1975	10200.91	505.02	689.63	189.65	19.43	167.49	1202.52	10569.60	10385.26
1976	10569.60	547.03	733.48	201.71	21.36	157.17	1250.34	10980.01	10774.80
1977	10980.01	600.44	777.42	213.79	23.12	158.14	1298.25	11454.67	11217.34
1978	11454.67	683.45	835.18	229.67	26.00	156.27	1347.66	12037.58	11746.13
1979	12037.58	798.87	907.34	249.52	30.02	148.49	1400.56	12771.26	12404.42
1980	12771.26	876.60	974.43	267.97	32.57	139.93	1463.82	13598.93	13185.10
1981	13598.93	939.06	1043.71	287.02	36.26	128.91	1539.39	14494.50	14046.72
1982	14494.50	989.60	1095.34	301.22	38.73	125.00	1641.07	15403.32	14948.91
1983	15403.32	1024.87	1134.61	312.02	40.66	115.02	1752.82	16277.68	15840.50
1984	16277.68	1043.93	1162.05	319.56	41.96	103.44	1850.85	17097.77	16687.72
1985	17097.77	1041.22	1172.04	322.31	42.33	93.81	1950.79	17818.68	17458.23

*EXCLUDING ALASKA.

TABLE 629

GAS OPERATIONS*
UNITED STATES NET INVESTMENT IN PROPERTY, PLANT, AND EQUIPMENT
(Million 1970 Dollars)

CASE III

YEAR	BEGINNING YEAR NET FIXED ASSETS	LEASE ACQUISITIONS	PRODUCING WELLS AND PLATFORMS	LEASE EQUIPMENT	MISC. TANGIBLE INVESTMENT	GAS PLANT INVESTMENT	LESS DEPRECIATION DEPLETION AMORTIZATION, RETIREMENT	END OF YEAR NET FIXED ASSETS	AVERAGE NET FIXED ASSETS
1971	8730.40	385.09	587.60	161.59	59.22	192.52	979.24	9137.17	8933.79
1972	9137.17	407.33	606.04	166.66	16.39	160.04	1046.59	9447.04	9292.11
1973	9447.04	435.63	629.74	173.18	17.26	127.55	1118.89	9711.52	9579.28
1974	9711.52	468.65	657.65	180.85	18.28	117.87	1180.93	9973.89	9842.70
1975	9973.89	505.02	689.63	189.65	19.43	109.18	1217.26	10269.54	10121.71
1976	10269.54	547.03	733.48	201.71	21.36	101.35	1263.64	10610.83	10440.18
1977	10610.83	600.44	777.42	213.79	23.12	104.64	1309.60	11020.63	10815.73
1978	11020.63	683.45	835.18	229.67	26.00	102.85	1355.74	11542.04	11281.34
1979	11542.04	798.87	907.34	249.52	30.02	96.15	1405.38	12218.55	11880.29
1980	12218.55	876.60	974.43	267.97	32.57	89.58	1468.41	12991.28	12604.92
1981	12991.28	939.06	1043.71	287.02	36.26	81.08	1540.63	13837.78	13414.53
1982	13837.78	989.60	1095.34	301.22	38.73	79.14	1641.93	14699.88	14268.83
1983	14699.88	1024.87	1134.61	312.02	40.66	72.70	1754.71	15530.04	15114.96
1984	15530.04	1043.93	1162.05	319.56	41.96	64.69	1847.28	16314.95	15922.49
1985	16314.95	1041.22	1172.04	322.31	42.33	61.05	1939.36	17014.54	16664.74

*EXCLUDING ALASKA.

TABLE 630

GAS OPERATIONS*
UNITED STATES NET INVESTMENT IN PROPERTY, PLANT, AND EQUIPMENT
(Million 1970 Dollars)

CASE IV

YEAR	BEGINNING YEAR NET FIXED ASSETS	LEASE ACQUISITIONS	PRODUCING WELLS AND PLATFORMS	LEASE EQUIPMENT	MISC. TANGIBLE INVESTMENT	GAS PLANT INVESTMENT	LESS DEPRECIATION DEPLETION AMORTIZATION, RETIREMENT	END OF YEAR NET FIXED ASSETS	AVERAGE NET FIXED ASSETS
1971	8730.40	379.77	579.49	159.36	59.00	190.28	979.93	9118.36	8924.38
1972	9118.36	378.07	562.51	154.69	15.21	155.56	1048.90	9335.51	9226.94
1973	9335.51	378.70	547.44	150.55	15.01	120.84	1116.35	9431.69	9383.60
1974	9431.69	379.72	532.85	146.53	14.81	102.91	1165.08	9443.44	9437.57
1975	9443.44	379.53	518.28	142.53	14.60	86.02	1179.50	9404.89	9424.16
1976	9404.89	379.48	508.82	139.93	14.82	71.28	1194.94	9324.28	9364.59
1977	9324.28	382.66	495.44	136.25	14.73	69.84	1200.16	9223.03	9273.66
1978	9223.03	398.22	486.63	133.82	15.15	61.14	1198.03	9119.95	9171.49
1979	9119.95	423.56	481.07	132.29	15.92	50.60	1187.71	9035.67	9077.81
1980	9035.67	420.92	467.90	128.67	15.64	38.35	1180.09	8927.06	8981.37
1981	8927.06	416.23	462.61	127.22	16.07	27.64	1166.57	8810.27	8868.66
1982	8810.27	408.82	452.51	124.44	16.00	23.12	1165.81	8669.34	8739.80
1983	8669.34	398.49	441.16	121.32	15.81	18.46	1166.31	8498.27	8583.80
1984	8498.27	385.80	429.46	118.10	15.51	14.86	1145.39	8316.60	8407.43
1985	8316.60	369.41	415.82	114.35	15.02	12.85	1122.42	8121.63	8219.11

*EXCLUDING ALASKA.

TABLE 631

GAS OPERATIONS*
UNITED STATES NET INVESTMENT IN PROPERTY, PLANT, AND EQUIPMENT
(Million 1970 Dollars)

CASE IVA

YEAR	BEGINNING YEAR NET FIXED ASSETS	LEASE ACQUISITIONS	PRODUCING WELLS AND PLATFORMS	LEASE EQUIPMENT	MISC. TANGIBLE INVESTMENT	GAS PLANT INVESTMENT	LESS DEPRECIATION DEPLETION AMORTIZATION, RETIREMENT	END OF YEAR NET FIXED ASSETS	AVERAGE NET FIXED ASSETS
1971	8730.40	379.77	579.49	159.36	59.00	206.10	966.10	9148.01	8939.21
1972	9148.01	378.07	562.51	154.69	15.21	187.20	1029.38	9416.32	9282.16
1973	9416.32	378.70	547.44	150.55	15.01	168.30	1101.26	9575.05	9495.69
1974	9575.05	379.72	532.85	146.53	14.81	152.58	1153.29	9648.25	9611.65
1975	9648.25	379.53	518.28	142.53	14.60	131.92	1171.62	9663.49	9655.87
1976	9663.49	379.48	508.82	139.93	14.82	110.38	1190.18	9626.74	9645.11
1977	9626.74	382.66	495.44	136.25	14.73	104.41	1198.74	9561.49	9594.12
1978	9561.49	398.22	486.63	133.82	15.15	91.78	1199.90	9487.19	9524.34
1979	9487.19	423.56	481.07	132.29	15.92	77.12	1193.57	9423.57	9455.38
1980	9423.57	420.92	467.90	128.67	15.64	60.63	1188.45	9328.89	9376.23
1981	9328.89	416.23	462.61	127.22	16.07	46.59	1178.06	9219.56	9274.22
1982	9219.56	408.82	452.51	124.44	16.00	39.77	1176.98	9084.12	9151.84
1983	9084.12	398.49	441.16	121.32	15.81	30.10	1175.09	8915.89	9000.00
1984	8915.89	385.80	429.46	118.10	15.51	24.06	1154.49	8734.32	8825.10
1985	8734.32	369.41	415.82	114.35	15.02	21.20	1132.44	8537.68	8636.00

*EXCLUDING ALASKA.

TABLE 632

OIL AND GAS OPERATIONS*
UNITED STATES NET INVESTMENT IN PROPERTY, PLANT, AND EQUIPMENT
(Million 1970 Dollars)

CASE I

YEAR	BEGINNING YEAR NET FIXED ASSETS	LEASE ACQUISITIONS	PRODUCING WELLS AND PLATFORMS	LEASE EQUIPMENT	MISC. TANGIBLE INVESTMENT	GAS PLANT INVESTMENT	LESS DEPRECIATION DEPLETION AMORTIZATION, RETIREMENT	END OF YEAR NET FIXED ASSETS	AVERAGE NET FIXED ASSETS
1971	25804.40	816.82	1708.41	1102.65	207.45	210.45	3497.37	26352.80	26078.60
1972	26352.80	815.85	1641.96	1104.90	56.96	195.89	3557.97	26610.38	26481.59
1973	26610.38	1037.54	1904.52	1198.04	73.79	181.34	3556.28	27449.34	27029.86
1974	27449.34	1283.47	2163.74	1290.11	89.82	183.05	3636.08	28823.44	28136.39
1975	28823.44	1551.71	2406.44	1378.04	105.86	180.30	3765.50	30680.30	29751.87
1976	30680.30	1721.65	2532.01	1940.07	107.64	176.07	3969.80	33187.93	31934.11
1977	33187.93	2052.81	2822.80	2060.08	126.12	182.34	4238.36	36193.71	34690.82
1978	36193.71	2312.25	3068.17	2178.92	139.33	186.06	4588.34	39490.09	37841.90
1979	39490.09	2707.57	3436.60	2332.46	165.77	183.43	4937.86	43378.07	41434.08
1980	43378.07	2998.19	3690.09	2456.15	178.63	179.29	5401.69	47478.75	45428.41
1981	47478.75	3236.27	3958.41	3058.56	193.41	171.28	5881.10	52215.57	49847.16
1982	52215.57	3655.40	4336.09	3239.71	223.82	169.25	6430.15	57409.69	54812.63
1983	57409.69	3845.21	4550.62	3393.40	237.52	157.61	7108.38	62485.67	59947.68
1984	62485.67	4182.36	4984.28	3624.14	277.37	142.05	7697.63	67998.25	65241.96
1985	67998.25	4316.47	5160.15	3762.39	291.54	126.88	8433.30	73222.37	70610.31

*EXCLUDING NORTH SLOPE OIL AND ALASKAN GAS.

TABLE 633

OIL AND GAS OPERATIONS*
UNITED STATES NET INVESTMENT IN PROPERTY, PLANT, AND EQUIPMENT
(Million 1970 Dollars)

CASE IA

YEAR	BEGINNING YEAR NET FIXED ASSETS	LEASE ACQUISITIONS	PRODUCING WELLS AND PLATFORMS	LEASE EQUIPMENT	MISC. TANGIBLE INVESTMENT	GAS PLANT INVESTMENT	LESS DEPRECIATION DEPLETION AMORTIZATION, RETIREMENT	END OF YEAR NET FIXED ASSETS	AVERAGE NET FIXED ASSETS
1971	25804.40	815.20	1678.04	1093.69	205.39	193.32	3519.31	26270.73	26037.56
1972	26270.73	810.77	1571.10	1083.83	52.95	161.64	3594.23	26356.79	26313.76
1973	26356.79	1023.90	1763.05	1156.91	67.78	129.96	3586.37	26912.03	26634.41
1974	26912.03	1260.69	1970.44	1234.52	83.97	123.17	3645.06	27939.77	27425.90
1975	27939.77	1523.75	2191.58	1316.28	100.90	117.56	3743.13	29446.71	28693.24
1976	29446.71	1687.22	2285.46	1865.95	103.34	113.64	3912.57	31589.75	30518.23
1977	31589.75	2012.57	2524.27	1967.92	120.05	120.23	4150.04	34184.75	32887.25
1978	34184.75	2269.06	2703.62	2063.34	128.47	121.64	4455.77	37015.11	35599.94
1979	37015.11	2663.11	2998.74	2190.42	148.43	118.17	4752.23	40381.75	38698.43
1980	40381.75	2952.66	3186.49	2287.69	155.49	114.33	5152.11	43926.30	42154.03
1981	43926.30	3189.59	3406.43	2860.79	166.27	107.77	5556.63	48100.51	46013.41
1982	48100.51	3609.27	3726.86	3005.23	190.82	107.59	6031.82	52708.46	50404.49
1983	52708.46	3799.48	3920.11	3132.18	202.38	101.67	6613.07	57251.21	54979.83
1984	57251.21	4138.75	4303.33	3319.14	236.11	91.97	7119.31	62221.20	59736.20
1985	62221.20	4275.32	4479.93	3428.23	249.01	87.04	7767.48	66973.25	64597.22

*EXCLUDING NORTH SLOPE OIL AND ALASKAN GAS.

TABLE 634

OIL AND GAS OPERATIONS*
UNITED STATES NET INVESTMENT IN PROPERTY, PLANT, AND EQUIPMENT
(Million 1970 Dollars)

CASE II

YEAR	BEGINNING YEAR NET FIXED ASSETS	LEASE ACQUISITIONS	PRODUCING WELLS AND PLATFORMS	LEASE EQUIPMENT	MISC. TANGIBLE INVESTMENT	GAS PLANT INVESTMENT	LESS DEPRECIATION DEPLETION AMORTIZATION, RETIREMENT	END OF YEAR NET FIXED ASSETS	AVERAGE NET FIXED ASSETS
1971	25804.40	816.82	1708.41	1102.65	207.45	209.30	3497.37	26351.65	26078.03
1972	26351.65	795.10	1602.02	1093.76	55.63	193.60	3562.23	26529.52	26440.59
1973	26529.52	993.71	1829.80	1177.26	71.16	177.89	3555.26	27224.09	26876.80
1974	27224.09	1206.85	2043.32	1256.67	85.34	175.08	3623.50	28367.86	27795.97
1975	28367.86	1420.25	2213.79	1324.53	98.27	167.49	3734.82	29857.37	29112.61
1976	29857.37	1531.44	2263.64	1865.31	97.33	157.17	3903.13	31869.13	30863.25
1977	31869.13	1782.81	2461.59	1958.19	110.93	158.14	4121.95	34218.84	33043.99
1978	34218.84	1946.08	2594.43	2044.78	118.38	156.27	4401.69	36677.09	35447.97
1979	36677.09	2215.15	2831.15	2160.17	137.25	148.49	4659.35	39509.95	38093.52
1980	39509.95	2384.79	2961.06	2245.77	144.23	139.93	4999.58	42386.15	40948.05
1981	42386.15	2502.27	3095.00	2806.03	152.33	128.91	5330.94	45739.75	44062.95
1982	45739.75	2776.24	3336.07	2941.98	173.41	125.00	5711.56	49380.89	47560.32
1983	49380.89	2876.95	3456.82	3061.75	181.47	115.02	6183.49	52889.41	51135.15
1984	52889.41	3094.53	3747.22	3241.97	208.59	103.44	6578.58	56706.58	54797.99
1985	56706.58	3166.50	3858.65	3349.86	217.41	93.81	7083.99	60308.82	58507.70

*EXCLUDING NORTH SLOPE OIL AND ALASKAN GAS.

TABLE 635

OIL AND GAS OPERATIONS*
UNITED STATES NET INVESTMENT IN PROPERTY, PLANT, AND EQUIPMENT
(Million 1970 Dollars)

CASE III

YEAR	BEGINNING YEAR NET FIXED ASSETS	LEASE ACQUISITIONS	PRODUCING WELLS AND PLATFORMS	LEASE EQUIPMENT	MISC. TANGIBLE INVESTMENT	GAS PLANT INVESTMENT	LESS DEPRECIATION DEPLETION AMORTIZATION, RETIREMENT	END OF YEAR NET FIXED ASSETS	AVERAGE NET FIXED ASSETS
1971	25804.40	815.20	1678.04	1093.69	205.39	192.52	3519.31	26269.93	26037.16
1972	26269.93	790.16	1533.02	1073.24	51.72	160.04	3597.52	26280.59	26275.26
1973	26280.59	980.59	1693.16	1137.55	65.31	127.55	3583.28	26701.48	26491.03
1974	26701.48	1185.27	1858.74	1203.60	79.67	117.87	3629.49	27517.13	27109.30
1975	27517.13	1394.67	2015.32	1267.49	93.54	109.18	3708.49	28688.84	28102.98
1976	28688.84	1501.19	2045.24	1799.34	93.37	101.35	3842.51	30386.82	29537.83
1977	30386.82	1747.62	2204.00	1877.93	105.97	104.64	4033.06	32393.94	31390.38
1978	32393.94	1908.62	2290.18	1946.78	110.13	102.85	4273.34	34479.15	33436.54
1979	34479.15	2177.41	2482.15	2044.17	124.75	96.15	4486.66	36917.11	35698.13
1980	36917.11	2347.04	2565.40	2110.02	127.15	89.58	4777.27	39379.04	38148.08
1981	39379.04	2464.35	2665.78	2647.19	132.10	81.08	5051.47	42318.06	40848.55
1982	42318.06	2738.70	2861.23	2752.43	148.49	79.14	5384.37	45513.69	43915.87
1983	45513.69	2839.63	2959.99	2848.98	154.34	72.70	5790.37	48598.95	47056.32
1984	48598.95	3058.18	3205.82	2992.91	176.56	64.69	6117.13	51979.98	50289.46
1985	51979.98	3131.00	3306.20	3075.75	183.92	61.05	6548.59	55189.30	53584.64

*EXCLUDING NORTH SLOPE OIL AND ALASKAN GAS.

TABLE 636

OIL AND GAS OPERATIONS*
UNITED STATES NET INVESTMENT IN PROPERTY, PLANT, AND EQUIPMENT
(Million 1970 Dollars)

CASE IV

YEAR	BEGINNING YEAR NET FIXED ASSETS	LEASE ACQUISITIONS	PRODUCING WELLS AND PLATFORMS	LEASE EQUIPMENT	MISC. TANGIBLE INVESTMENT	GAS PLANT INVESTMENT	LESS DEPRECIATION DEPLETION AMORTIZATION, RETIREMENT	END OF YEAR NET FIXED ASSETS	AVERAGE NET FIXED ASSETS
1971	25804.40	809.88	1669.93	1091.46	205.17	190.28	3519.99	26251.12	26027.76
1972	26251.12	737.78	1435.06	1045.99	48.53	155.56	3604.47	26069.56	26160.34
1973	26069.56	854.94	1480.65	1078.52	57.23	120.84	3575.75	26085.99	26077.78
1974	26085.99	956.09	1507.96	1106.29	64.71	102.91	3581.17	26242.80	26164.39
1975	26242.80	1040.58	1526.18	1131.90	71.25	86.02	3587.55	26511.18	26376.99
1976	26511.18	1040.69	1454.71	1635.33	67.66	71.28	3612.10	27168.74	26839.96
1977	27168.74	1115.44	1444.23	1663.80	70.75	69.84	3688.04	27844.75	27506.74
1978	27844.75	1148.01	1406.67	1693.86	69.04	61.14	3764.12	28459.35	28152.05
1979	28459.35	1199.42	1414.07	1734.56	73.43	50.60	3813.16	29118.26	28788.81
1980	29118.26	1181.74	1348.87	1753.79	69.79	38.35	3890.39	29620.40	29369.33
1981	29620.40	1141.88	1294.98	2243.45	67.05	27.64	3925.32	30470.09	30045.25
1982	30470.09	1177.52	1291.18	2281.70	69.71	23.12	4011.52	31301.81	30885.95
1983	31301.81	1132.54	1235.93	2325.07	66.61	18.46	4113.92	31966.51	31634.16
1984	31966.51	1147.16	1258.49	2389.90	71.15	14.86	4153.85	32694.21	32330.36
1985	32694.21	1107.94	1221.94	2421.20	69.31	12.85	4232.69	33294.76	32994.49

*EXCLUDING NORTH SLOPE OIL AND ALASKAN GAS.

TABLE 637

OIL AND GAS OPERATIONS*
UNITED STATES NET INVESTMENT IN PROPERTY, PLANT, AND EQUIPMENT
(Million 1970 Dollars)

CASE IVA

YEAR	BEGINNING YEAR NET FIXED ASSETS	LEASE ACQUISITIONS	PRODUCING WELLS AND PLATFORMS	LEASE EQUIPMENT	MISC. TANGIBLE INVESTMENT	GAS PLANT INVESTMENT	LESS DEPRECIATION DEPLETION AMORTIZATION, RETIREMENT	END OF YEAR NET FIXED ASSETS	AVERAGE NET FIXED ASSETS
1971	25804.40	811.50	1700.30	1100.42	207.23	206.10	3498.24	26331.71	26068.05
1972	26331.71	742.34	1499.15	1065.04	52.17	187.20	3571.78	26305.82	26318.76
1973	26305.82	865.65	1596.35	1112.17	62.41	168.30	3554.05	26556.63	26431.23
1974	26556.63	972.42	1652.99	1147.99	69.54	152.58	3583.42	26968.73	26762.68
1975	26968.73	1058.50	1670.64	1173.39	75.10	131.92	3620.15	27458.13	27213.43
1976	27458.13	1059.72	1602.07	1680.62	71.15	110.38	3672.93	28309.15	27883.64
1977	28309.15	1135.43	1591.17	1711.85	73.65	104.41	3770.74	29154.91	28732.03
1978	29154.91	1169.66	1566.57	1749.17	72.24	91.78	3868.57	29935.76	29545.33
1979	29935.76	1221.41	1584.32	1796.10	77.47	77.12	3940.13	30752.05	30343.90
1980	30752.05	1202.78	1526.01	1820.51	75.07	60.63	4040.37	31396.67	31074.36
1981	31396.67	1161.59	1475.46	2319.61	73.44	46.59	4099.03	32374.32	31885.50
1982	32374.32	1195.84	1479.73	2371.04	77.70	39.77	4199.75	33338.66	32856.49
1983	33338.66	1149.69	1427.82	2426.21	75.61	30.10	4321.13	34126.95	33732.80
1984	34126.95	1163.43	1460.14	2504.86	81.64	24.06	4379.13	34981.95	34554.45
1985	34981.95	1123.49	1423.41	2543.73	80.18	21.20	4479.54	35694.43	35338.19

*EXCLUDING NORTH SLOPE OIL AND ALASKAN GAS.

TABLE 638

OIL OPERATIONS*
UNITED STATES EXPENSES
(Million 1970 Dollars)

U.S. RATE OF RETURN = 15.0 PERCENT

CASE I

YEAR	GEOLOGICAL AND GEOPHYSICAL	LEASE RENTAL	DRY HOLE	PRODUCING LEASE AND WELL	GAS PLANT	MISC.	AD VALOREM PROD. AND OTHER TAX	DEPREC. DEPLETION · AMORTIZ. RETIREMENTS	(OVERHEAD) INDIRECT EXPENSE	TOTAL EXPENSE (BFIT)
1971	363.91	83.10	390.11	1954.93	.00	23.53	601.10	2532.14	571.86	6520.68
1972	348.53	74.65	370.67	1930.56	.00	23.46	600.63	2533.95	547.69	6430.13
1973	376.45	87.76	434.36	1913.62	.00	24.36	593.99	2456.61	591.57	6478.71
1974	405.71	99.55	495.72	1921.55	.00	26.29	604.08	2468.64	637.55	6659.08
1975	434.62	109.31	553.59	1952.97	.00	29.50	628.51	2550.88	682.97	6942.36
1976	449.21	115.88	586.86	2006.04	.00	33.34	665.07	2693.85	705.90	7256.17
1977	485.78	132.64	651.20	2075.63	.00	38.57	715.89	2895.60	763.36	7758.67
1978	515.95	145.61	699.23	2166.55	.00	44.38	777.62	3171.81	810.78	8331.93
1979	560.34	165.51	768.17	2271.59	.00	50.92	842.75	3437.50	880.54	8977.32
1980	592.25	178.61	816.10	2392.97	.00	57.77	920.76	3800.64	930.68	9689.79
1981	626.15	192.56	867.33	2524.65	.00	65.01	999.94	4156.74	983.95	10416.33
1982	678.54	216.80	951.44	2658.67	.00	73.05	1089.92	4541.52	1066.27	11276.22
1983	715.06	232.09	1003.09	2808.63	.00	81.39	1192.39	5033.45	1123.67	12189.77
1984	784.16	265.50	1105.44	2968.24	.00	90.85	1290.43	5443.77	1232.25	13180.63
1985	826.07	283.11	1161.77	3148.82	.00	100.62	1406.44	5999.48	1298.11	14224.41

*EXCLUDING NORTH SLOPE.

TABLE 639

OIL OPERATIONS*
UNITED STATES EXPENSES
(Million 1970 Dollars)

U.S. RATE OF RETURN = 15.0 PERCENT

CASE IA

YEAR	GEOLOGICAL AND GEOPHYSICAL	LEASE RENTAL	DRY HOLE	PRODUCING LEASE AND WELL	GAS PLANT	MISC.	AD VALOREM PROD. AND OTHER TAX	DEPREC. DEPLETION AMORTIZ. RETIREMENTS	(OVERHEAD) INDIRECT EXPENSE	TOTAL EXPENSE (BFIT)
1971	359.92	81.01	382.47	1954.93	.00	23.36	601.62	2540.07	565.59	6508.98
1972	339.09	69.94	353.89	1928.28	.00	22.96	600.82	2549.21	532.85	6397.05
1973	357.19	78.54	400.13	1905.84	.00	23.41	591.63	2467.62	561.29	6385.65
1974	378.40	87.17	447.58	1902.93	.00	24.89	596.15	2458.57	594.63	6490.32
1975	402.89	95.87	499.59	1919.63	.00	27.56	613.40	2510.31	633.11	6702.37
1976	411.82	100.27	527.35	1955.97	.00	30.68	642.49	2618.81	647.14	6934.54
1977	439.95	113.60	583.56	2005.36	.00	34.88	686.02	2790.53	691.35	7345.26
1978	459.96	122.36	625.18	2071.89	.00	39.46	739.16	3024.93	722.79	7805.73
1979	493.14	137.58	688.77	2148.88	.00	44.56	794.07	3240.18	774.94	8322.12
1980	514.51	146.36	733.21	2239.05	.00	49.78	860.01	3539.35	808.51	8890.78
1981	539.48	156.88	782.06	2336.51	.00	55.23	925.94	3825.13	847.76	9468.98
1982	581.85	177.11	864.26	2434.24	.00	61.34	1002.53	4138.64	914.33	10174.28
1983	612.28	190.54	917.35	2545.99	.00	67.70	1089.02	4536.01	962.15	10921.05
1984	672.10	220.30	1020.39	2666.98	.00	75.06	1173.72	4874.76	1056.15	11759.47
1985	710.37	237.49	1081.71	2807.20	.00	82.75	1275.69	5358.05	1116.29	12669.54

*EXCLUDING NORTH SLOPE.

TABLE 640

OIL OPERATIONS*
UNITED STATES EXPENSES
(Million 1970 Dollars)

U.S. RATE OF RETURN = 15.0 PERCENT

CASE II

YEAR	GEOLOGICAL AND GEOPHYSICAL	LEASE RENTAL	DRY HOLE	PRODUCING LEASE AND WELL	GAS PLANT	MISC.	AD VALOREM PROD. AND OTHER TAX	DEPREC. DEPLETION AMORTIZ. RETIREMENTS	(OVERHEAD) INDIRECT EXPENSE	TOTAL EXPENSE (BFIT)
1971	363.91	83.10	390.11	1954.93	.00	23.53	601.10	2532.14	571.86	6520.68
1972	345.35	73.02	362.54	1930.56	.00	23.40	600.37	2536.24	542.70	6414.19
1973	370.98	85.11	421.00	1912.12	.00	24.22	592.39	2454.20	582.98	6443.01
1974	396.61	95.31	474.01	1917.55	.00	25.98	600.23	2459.26	623.24	6592.19
1975	418.31	101.96	514.95	1944.83	.00	28.83	621.17	2532.30	657.35	6819.69
1976	425.37	105.10	530.66	1990.30	.00	32.14	651.60	2652.79	668.44	7056.40
1977	452.33	117.48	575.09	2048.69	.00	36.59	694.26	2823.71	710.81	7458.96
1978	470.54	124.92	597.66	2124.40	.00	41.40	744.60	3054.03	739.42	7896.95
1979	501.10	138.39	638.90	2209.67	.00	46.68	795.11	3258.79	787.44	8376.08
1980	520.10	145.58	660.31	2306.35	.00	52.07	854.42	3535.75	817.29	8891.87
1981	540.02	153.11	682.87	2408.91	.00	57.65	912.00	3791.55	848.61	9394.74
1982	576.01	169.66	735.79	2509.30	.00	63.76	978.76	4070.49	905.16	10008.94
1983	599.06	178.90	762.27	2620.88	.00	69.98	1054.03	4430.67	941.38	10657.17
1984	645.46	201.12	823.67	2738.37	.00	76.87	1125.16	4727.73	1014.29	11352.67
1985	673.17	212.47	854.63	2869.92	.00	83.90	1209.12	5133.20	1057.84	12094.25

*EXCLUDING NORTH SLOPE.

TABLE 641

OIL OPERATIONS*
UNITED STATES EXPENSES
(Million 1970 Dollars)

CASE III

U.S. RATE OF RETURN = 15.0 PERCENT

YEAR	GEOLOGICAL AND GEOPHYSICAL	LEASE RENTAL	DRY HOLE	PRODUCING LEASE AND WELL	GAS PLANT	MISC.	AD VALOREM PROD. AND OTHER TAX	DEPREC. DEPLETION AMORTIZ. RETIREMENTS	(OVERHEAD) INDIRECT EXPENSE	TOTAL EXPENSE (BFIT)
1971	359.92	81.01	382.47	1954.93	.00	23.36	601.62	2540.07	565.59	6508.98
1972	336.15	68.43	346.20	1928.28	.00	22.92	600.52	2550.93	528.24	6381.68
1973	352.37	76.20	387.95	1904.49	.00	23.29	589.99	2464.40	553.72	6352.38
1974	370.50	83.49	428.04	1899.44	.00	24.61	592.47	2448.56	582.21	6429.32
1975	388.85	89.53	464.92	1912.69	.00	26.97	606.48	2491.23	611.04	6591.70
1976	391.86	91.25	477.42	1942.79	.00	29.66	629.98	2578.87	615.78	6757.60
1977	412.18	100.99	515.56	1983.37	.00	33.23	666.27	2723.45	647.71	7082.76
1978	422.81	105.41	533.89	2037.88	.00	37.01	709.09	2917.60	664.42	7428.10
1979	445.88	115.94	572.31	2099.33	.00	41.14	751.17	3081.27	700.66	7807.71
1980	457.14	120.07	592.14	2170.56	.00	45.28	801.11	3308.85	718.36	8213.51
1981	470.57	125.21	613.74	2245.83	.00	49.50	848.79	3510.84	739.47	8603.96
1982	498.57	138.55	664.75	2317.69	.00	54.12	905.71	3742.44	783.47	9105.30
1983	516.18	145.98	691.44	2399.16	.00	58.82	969.35	4035.66	811.14	9627.71
1984	554.55	164.92	751.54	2486.12	.00	64.08	1029.46	4269.85	871.44	10191.97
1985	577.94	175.11	784.36	2585.69	.00	69.47	1101.27	4609.23	908.20	10811.28

*EXCLUDING NORTH SLOPE.

TABLE 642

OIL OPERATIONS*
UNITED STATES EXPENSES
(Million 1970 Dollars)

CASE IV

U.S. RATE OF RETURN = 15.0 PERCENT

YEAR	GEOLOGICAL AND GEOPHYSICAL	LEASE RENTAL	DRY HOLE	PRODUCING LEASE AND WELL	GAS PLANT	MISC.	AD VALOREM PROD. AND OTHER TAX	DEPREC. DEPLETION AMORTIZ. RETIREMENTS	(OVERHEAD) INDIRECT EXPENSE	TOTAL EXPENSE (BFIT)
1971	359.92	81.01	382.47	1954.93	.00	23.36	601.58	2540.07	565.59	6508.93
1972	328.27	64.40	325.54	1928.28	.00	22.80	599.74	2555.57	515.85	6340.44
1973	333.22	66.81	339.46	1900.87	.00	22.84	585.33	2459.39	523.63	6231.56
1974	336.76	67.65	344.83	1887.27	.00	23.52	579.78	2416.09	529.19	6185.09
1975	340.26	67.75	347.02	1885.60	.00	24.84	580.84	2408.05	534.69	6189.03
1976	333.25	65.25	333.59	1894.34	.00	26.27	586.63	2417.16	523.68	6180.17
1977	334.95	66.58	331.60	1909.62	.00	28.08	603.71	2487.88	526.35	6288.78
1978	333.71	66.10	327.08	1931.10	.00	29.96	621.79	2566.09	524.41	6400.24
1979	337.22	67.80	322.48	1956.13	.00	31.92	637.90	2625.45	529.92	6508.82
1980	333.15	65.34	306.94	1984.95	.00	33.73	656.20	2710.30	523.52	6614.13
1981	329.53	62.98	292.32	2013.70	.00	35.48	670.29	2758.76	517.84	6680.90
1982	332.35	64.45	292.02	2034.53	.00	37.25	692.42	2845.71	522.26	6820.99
1983	328.79	62.25	278.58	2057.93	.00	38.84	714.91	2947.61	516.66	6945.57
1984	335.18	65.55	282.07	2081.13	.00	40.50	733.23	3008.46	526.72	7072.85
1985	334.70	64.80	273.81	2107.66	.00	41.98	755.20	3110.26	525.95	7214.36

*EXCLUDING NORTH SLOPE.

TABLE 643

OIL OPERATIONS*
UNITED STATES EXPENSES
(Million 1970 Dollars)

CASE IVA

U.S. RATE OF RETURN = 15.0 PERCENT

YEAR	GEOLOGICAL AND GEOPHYSICAL	LEASE RENTAL	DRY HOLE	PRODUCING LEASE AND WELL	GAS PLANT	MISC.	AD VALOREM PROD. AND OTHER TAX	DEPREC. DEPLETION AMORTIZ. RETIREMENTS	(OVERHEAD) INDIRECT EXPENSE	TOTAL EXPENSE (BFIT)
1971	363.91	83.10	390.11	1954.93	.00	23.53	601.05	2532.14	571.86	6520.64
1972	336.83	68.66	340.72	1930.56	.00	23.26	599.78	2542.40	529.31	6371.52
1973	349.06	74.36	367.40	1908.12	.00	23.70	587.74	2452.79	548.53	6311.71
1974	357.47	76.93	380.98	1903.36	.00	24.73	586.91	2430.12	561.74	6322.25
1975	362.12	76.81	383.79	1912.62	.00	26.38	593.43	2448.53	569.05	6372.72
1976	356.51	74.62	369.88	1932.24	.00	28.21	604.16	2482.75	560.24	6408.62
1977	359.36	76.09	367.63	1959.14	.00	30.51	625.46	2572.00	564.71	6554.92
1978	360.85	76.53	364.07	1992.63	.00	32.94	646.82	2668.67	567.05	6709.56
1979	366.87	79.02	360.03	2030.73	.00	35.47	667.37	2746.55	576.51	6862.56
1980	364.81	77.08	343.35	2072.90	.00	37.84	689.62	2851.93	573.27	7010.79
1981	362.73	75.03	326.96	2114.81	.00	40.12	707.65	2920.97	570.01	7118.28
1982	367.61	77.10	325.49	2148.34	.00	42.42	733.01	3022.76	577.67	7294.41
1983	365.54	75.24	310.50	2184.19	.00	44.54	759.31	3146.04	574.42	7459.79
1984	374.19	79.31	313.56	2219.48	.00	46.73	781.10	3224.64	588.01	7627.02
1985	374.83	78.71	304.19	2258.05	.00	48.73	806.98	3347.10	589.02	7807.62

*EXCLUDING NORTH SLOPE.

TABLE 644

GAS OPERATIONS*
UNITED STATES EXPENSES
(Million 1970 Dollars)

CASE I U.S. RATE OF RETURN = 15.0 PERCENT

YEAR	GEOLOGICAL AND GEOPHYSICAL	LEASE RENTAL	DRY HOLE	PRODUCING LEASE AND WELL	GAS PLANT	MISC.	AD VALOREM PROD. AND OTHER TAX	DEPREC. DEPLETION AMORTIZ. RETIREMENTS	(OVERHEAD) INDIRECT EXPENSE	TOTAL EXPENSE (BFIT)
1971	165.75	56.95	447.92	543.03	469.31	11.47	357.09	965.24	260.46	3277.22
1972	174.33	59.05	474.65	561.76	464.68	12.12	379.95	1024.01	273.95	3424.49
1973	184.26	61.61	506.20	581.43	464.21	12.82	406.04	1099.67	289.55	3605.77
1974	195.33	64.47	540.90	602.26	464.25	13.57	430.57	1167.44	306.94	3785.75
1975	207.89	67.77	581.64	624.46	461.24	14.39	452.14	1214.61	326.68	3950.81
1976	222.81	75.33	630.31	645.03	456.96	15.15	477.37	1275.95	350.14	4149.05
1977	238.66	83.65	685.55	664.20	455.03	16.00	502.14	1342.77	375.04	4363.04
1978	257.94	93.85	750.72	685.74	455.09	17.05	526.85	1416.53	405.34	4609.11
1979	280.84	106.06	824.37	710.55	456.07	18.38	561.01	1500.36	441.32	4898.97
1980	305.22	119.25	909.49	738.69	459.77	19.85	603.79	1601.05	479.63	5236.74
1981	329.94	133.08	989.34	765.90	462.52	21.30	652.34	1724.36	518.48	5597.26
1982	349.56	144.64	1053.55	791.67	469.43	22.87	706.65	1888.63	549.31	5976.31
1983	364.40	153.80	1099.42	818.86	476.61	24.49	762.14	2074.93	572.63	6347.29
1984	373.87	160.14	1124.47	846.43	479.87	26.11	814.67	2253.86	587.51	6666.95
1985	379.08	164.21	1133.38	873.46	481.87	27.67	862.32	2433.82	595.70	6951.51

*EXCLUDING ALASKA.

TABLE 645

GAS OPERATIONS*
UNITED STATES EXPENSES
(Million 1970 Dollars)

CASE IA

U.S. RATE OF RETURN = 15.0 PERCENT

YEAR	GEOLOGICAL AND GEOPHYSICAL	LEASE RENTAL	DRY HOLE	PRODUCING LEASE AND WELL	GAS PLANT	MISC.	AD VALOREM PROD. AND OTHER TAX	DEPREC. DEPLETION AMORTIZ. RETIREMENTS	(OVERHEAD) INDIRECT EXPENSE	TOTAL EXPENSE (BFIT)
1971	165.75	56.95	447.92	543.03	469.31	11.47	358.34	979.24	260.46	3292.48
1972	174.33	59.05	474.65	561.76	461.07	12.12	380.96	1045.01	273.95	3442.89
1973	184.26	61.61	506.20	581.43	453.41	12.82	405.46	1118.74	289.55	3613.47
1974	195.33	64.47	540.90	602.26	445.20	13.57	428.29	1186.49	306.94	3783.46
1975	207.89	67.77	581.64	624.46	433.54	14.39	447.85	1232.81	326.68	3937.03
1976	222.81	75.33	630.31	645.03	420.64	15.15	471.03	1293.76	350.14	4124.19
1977	238.66	83.65	685.55	664.20	409.99	16.00	493.88	1359.51	375.04	4326.49
1978	257.94	93.85	750.72	685.74	400.93	17.05	517.23	1430.84	405.34	4559.64
1979	280.84	106.06	824.37	710.55	392.67	18.38	549.76	1512.06	441.32	4836.01
1980	305.22	119.25	909.49	738.69	387.21	19.85	591.41	1612.75	479.63	5163.51
1981	329.94	133.08	989.34	765.90	381.00	21.30	638.70	1731.50	518.48	5509.24
1982	349.56	144.64	1053.55	791.67	379.19	22.87	692.31	1893.18	549.31	5876.28
1983	364.40	153.80	1099.42	818.86	378.50	24.49	747.67	2077.06	572.63	6236.84
1984	373.87	160.14	1124.47	846.43	375.24	26.11	799.38	2244.56	587.51	6537.73
1985	379.08	164.21	1133.38	873.46	372.20	27.67	846.45	2409.43	595.70	6801.58

*EXCLUDING ALASKA.

TABLE 646

GAS OPERATIONS*
UNITED STATES EXPENSES
(Million 1970 Dollars)

CASE II U.S. RATE OF RETURN = 15.0 PERCENT

YEAR	GEOLOGICAL AND GEOPHYSICAL	LEASE RENTAL	DRY HOLE	PRODUCING LEASE AND WELL	GAS PLANT	MISC.	AD VALOREM PROD. AND OTHER TAX	DEPREC. DEPLETION AMORTIZ. RETIREMENTS	(OVERHEAD) INDIRECT EXPENSE	TOTAL EXPENSE (BFIT)
1971	165.75	56.95	447.92	543.03	469.31	11.47	357.09	965.24	260.46	3277.22
1972	171.00	57.36	461.09	561.46	464.68	12.10	379.01	1025.99	268.72	3401.40
1973	177.21	58.14	477.75	580.20	463.74	12.75	402.88	1101.05	278.47	3552.20
1974	184.08	59.13	496.06	599.44	462.65	13.43	423.72	1164.24	289.27	3692.02
1975	191.87	60.40	518.39	619.31	457.81	14.15	439.92	1202.52	301.51	3805.88
1976	201.21	65.25	546.02	636.76	450.86	14.77	458.04	1250.34	316.18	3939.44
1977	210.70	70.45	577.30	651.95	445.50	15.45	473.69	1298.25	331.10	4074.40
1978	222.41	76.84	614.62	668.44	441.35	16.26	487.50	1347.66	349.51	4224.59
1979	236.30	84.43	656.25	686.87	437.33	17.26	507.88	1400.56	371.33	4398.21
1980	250.50	92.32	704.09	707.15	435.40	18.34	533.91	1463.82	393.64	4599.17
1981	263.90	100.14	744.43	725.20	432.08	19.33	562.70	1539.39	414.70	4801.88
1982	274.44	106.76	777.64	740.70	432.61	20.38	594.56	1641.07	431.26	5019.42
1983	282.98	112.42	803.63	756.85	433.66	21.46	626.75	1752.82	444.69	5235.25
1984	289.50	117.06	821.94	773.20	431.56	22.54	656.59	1850.85	454.94	5418.17
1985	292.92	120.03	828.45	789.24	429.02	23.57	683.95	1950.79	460.30	5578.27

*EXCLUDING ALASKA.

TABLE 647

GAS OPERATIONS*
UNITED STATES EXPENSES
(Million 1970 Dollars)

CASE III U.S. RATE OF RETURN = 15.0 PERCENT

YEAR	GEOLOGICAL AND GEOPHYSICAL	LEASE RENTAL	DRY HOLE	PRODUCING LEASE AND WELL	GAS PLANT	MISC.	AD VALOREM PROD. AND OTHER TAX	DEPREC. DEPLETION AMORTIZ. RETIREMENTS	(OVERHEAD) INDIRECT EXPENSE	TOTAL EXPENSE (BFIT)
1971	165.75	56.95	447.92	543.03	469.31	11.47	358.34	979.24	260.46	3292.48
1972	171.00	57.36	461.09	561.46	461.07	12.10	379.96	1046.59	268.72	3419.34
1973	177.21	58.14	477.75	580.20	453.08	12.75	402.26	1118.89	278.47	3558.75
1974	184.08	59.13	496.06	599.44	444.12	13.43	421.32	1180.93	289.27	3687.78
1975	191.87	60.40	518.39	619.31	431.26	14.15	435.60	1217.26	301.51	3789.75
1976	201.21	65.25	546.02	636.76	416.62	14.77	451.73	1263.64	316.18	3912.19
1977	210.70	70.45	577.30	651.95	403.76	15.45	465.62	1309.60	331.10	4035.93
1978	222.41	76.84	614.62	668.44	392.02	16.26	478.21	1355.74	349.51	4174.05
1979	236.30	84.43	656.25	686.87	380.60	17.26	497.25	1405.38	371.33	4335.68
1980	250.50	92.32	704.09	707.15	371.61	18.34	522.35	1468.41	393.64	4528.42
1981	263.90	100.14	744.43	725.20	361.58	19.33	550.08	1540.63	414.70	4719.99
1982	274.44	106.76	777.64	740.70	355.66	20.38	581.58	1641.93	431.26	4930.35
1983	282.98	112.42	803.63	756.85	350.79	21.46	613.76	1754.71	444.69	5141.29
1984	289.50	117.06	821.94	773.20	343.58	22.54	643.09	1847.28	454.94	5313.12
1985	292.92	120.03	828.45	789.24	336.86	23.57	670.21	1939.36	460.30	5460.94

*EXCLUDING ALASKA.

TABLE 648

GAS OPERATIONS*
UNITED STATES EXPENSES
(Million 1970 Dollars)

CASE IV

U.S. RATE OF RETURN = 15.0 PERCENT

YEAR	GEOLOGICAL AND GEOPHYSICAL	LEASE RENTAL	DRY HOLE	PRODUCING LEASE AND WELL	GAS PLANT	MISC.	AD VALOREM PROD. AND OTHER TAX	DEPREC. DEPLETION AMORTIZ. RETIREMENTS	(OVERHEAD) INDIRECT EXPENSE	TOTAL EXPENSE (BFIT)
1971	164.23	56.17	441.73	542.90	469.31	11.46	357.89	979.93	258.08	3281.69
1972	162.85	53.24	427.97	560.45	460.98	12.04	377.06	1048.90	255.90	3359.39
1973	161.68	50.54	415.32	577.10	452.07	12.58	394.33	1116.35	254.08	3434.06
1974	160.41	47.91	401.93	592.93	441.04	13.12	405.77	1165.08	252.07	3480.25
1975	159.16	45.39	389.58	607.98	425.00	13.63	409.46	1179.50	250.11	3479.83
1976	158.21	45.27	378.78	619.20	406.16	13.98	411.81	1194.94	248.62	3476.98
1977	156.45	44.89	367.91	626.62	388.37	14.32	408.59	1200.16	245.84	3453.15
1978	155.22	44.77	358.12	633.50	370.75	14.69	401.38	1198.03	243.91	3420.36
1979	154.26	44.77	347.94	640.11	352.86	15.10	396.06	1187.71	242.41	3381.21
1980	152.49	44.33	338.09	646.29	336.60	15.48	392.04	1180.09	239.62	3345.03
1981	151.32	44.38	329.96	648.58	318.87	15.70	387.18	1166.57	237.79	3300.34
1982	149.19	44.10	321.26	647.10	304.93	15.90	382.99	1165.81	234.44	3265.73
1983	146.87	43.71	312.46	645.16	291.94	16.08	378.37	1166.31	230.80	3231.71
1984	144.48	43.26	303.76	642.75	276.90	16.23	371.35	1145.39	227.03	3171.16
1985	141.70	42.58	293.92	639.82	262.61	16.35	363.83	1122.42	222.68	3105.92

*EXCLUDING ALASKA.

TABLE 649

GAS OPERATIONS*
UNITED STATES EXPENSES
(Million 1970 Dollars)

CASE IVA

U.S. RATE OF RETURN = 15.0 PERCENT

YEAR	GEOLOGICAL AND GEOPHYSICAL	LEASE RENTAL	DRY HOLE	PRODUCING LEASE AND WELL	GAS PLANT	MISC.	AD VALOREM PROD. AND OTHER TAX	DEPREC. DEPLETION AMORTIZ. RETIREMENTS	(OVERHEAD) INDIRECT EXPENSE	TOTAL EXPENSE (BFIT)
1971	164.23	56.17	441.73	542.90	469.31	11.46	356.66	966.10	258.08	3266.63
1972	162.85	53.24	427.97	560.45	464.56	12.04	376.11	1029.38	255.90	3342.50
1973	161.68	50.54	415.32	577.10	462.30	12.58	395.17	1101.26	254.08	3430.03
1974	160.41	47.91	401.93	592.93	458.13	13.12	408.34	1153.29	252.07	3488.12
1975	159.16	45.39	389.58	607.98	448.41	13.63	413.87	1171.62	250.11	3499.75
1976	158.21	45.27	378.78	619.20	435.02	13.98	417.88	1190.18	248.62	3507.14
1977	156.45	44.89	367.91	626.62	422.12	14.32	415.96	1198.74	245.84	3492.84
1978	155.22	44.77	358.12	633.50	408.84	14.69	409.59	1199.90	243.91	3468.53
1979	154.26	44.77	347.94	640.11	394.71	15.10	405.06	1193.57	242.41	3437.93
1980	152.49	44.33	338.09	646.29	381.56	15.48	401.55	1188.45	239.62	3407.85
1981	151.32	44.38	329.96	648.58	366.22	15.70	397.18	1178.06	237.79	3369.19
1982	149.19	44.10	321.26	647.10	354.17	15.90	392.85	1176.98	234.44	3335.99
1983	146.87	43.71	312.46	645.16	342.59	16.08	387.88	1175.09	230.80	3300.64
1984	144.48	43.26	303.76	642.75	328.58	16.23	380.73	1154.49	227.03	3241.33
1985	141.70	42.58	293.92	639.82	315.03	16.35	373.03	1132.44	222.68	3177.56

*EXCLUDING ALASKA.

TABLE 650

OIL AND GAS OPERATIONS*
UNITED STATES EXPENSES
(Million 1970 Dollars)

CASE I

U.S. RATE OF RETURN = 15.0 PERCENT

YEAR	GEOLOGICAL AND GEOPHYSICAL	LEASE RENTAL	DRY HOLE	PRODUCING LEASE AND WELL	GAS PLANT	MISC.	AD VALOREM PROD. AND OTHER TAX	DEPREC. DEPLETION AMORTIZ. RETIREMENTS	(OVERHEAD) INDIRECT EXPENSE	TOTAL EXPENSE (BFIT)
1971	529.66	140.05	838.02	2497.96	469.31	35.00	958.18	3497.37	832.33	9797.90
1972	522.86	133.69	845.32	2492.32	464.68	35.58	980.57	3557.97	821.63	9854.62
1973	560.71	149.37	940.55	2495.04	464.21	37.18	1000.02	3556.28	881.12	10084.48
1974	601.04	164.02	1036.63	2523.81	464.25	39.86	1034.65	3636.08	944.49	10444.83
1975	642.51	177.08	1135.23	2577.43	461.24	43.89	1080.65	3765.50	1009.65	10893.18
1976	672.03	191.21	1217.18	2651.07	456.96	48.49	1142.44	3969.80	1056.04	11405.22
1977	724.44	216.30	1336.76	2739.83	455.03	54.57	1218.02	4238.36	1138.40	12121.71
1978	773.89	239.46	1449.95	2852.29	455.09	61.43	1304.47	4588.34	1216.12	12941.03
1979	841.19	271.57	1592.54	2982.14	456.07	69.29	1403.76	4937.86	1321.86	13876.29
1980	897.47	297.86	1725.60	3131.66	459.77	77.62	1524.55	5401.69	1410.31	14926.53
1981	956.09	325.64	1856.67	3290.55	462.52	86.31	1652.28	5881.10	1502.43	16013.59
1982	1028.10	361.44	2004.99	3450.34	469.43	95.92	1796.57	6430.15	1615.58	17252.53
1983	1079.47	385.88	2102.51	3627.49	476.61	105.89	1954.53	7108.38	1696.30	18537.06
1984	1158.03	425.64	2229.91	3814.67	479.87	116.96	2105.10	7697.63	1819.76	19847.58
1985	1205.15	447.32	2295.15	4022.29	481.87	128.29	2268.76	8433.30	1893.80	21175.92

*EXCLUDING NORTH SLOPE OIL AND ALASKAN GAS.

TABLE 651

OIL AND GAS OPERATIONS*
UNITED STATES EXPENSES
(Million 1970 Dollars)

CASE IA

U.S. RATE OF RETURN = 15.0 PERCENT

YEAR	GEOLOGICAL AND GEOPHYSICAL	LEASE RENTAL	DRY HOLE	PRODUCING LEASE AND WELL	GAS PLANT	MISC.	AD VALOREM PROD. AND OTHER TAX	DEPREC. DEPLETION AMORTIZ. RETIREMENTS	(OVERHEAD) INDIRECT EXPENSE	TOTAL EXPENSE (BFIT)
1971	525.67	137.96	830.38	2497.96	469.31	34.83	959.96	3519.31	826.05	9801.45
1972	513.42	128.98	828.54	2490.03	461.07	35.08	981.78	3594.23	806.80	9839.93
1973	541.45	140.14	906.32	2487.26	453.41	36.22	997.09	3586.37	850.85	9999.12
1974	573.73	151.64	988.48	2505.19	445.20	38.46	1024.44	3645.06	901.58	10273.78
1975	610.78	163.64	1081.23	2544.09	433.54	41.95	1061.25	3743.13	959.79	10639.41
1976	634.63	175.60	1157.67	2600.99	420.64	45.83	1113.52	3912.57	997.28	11058.73
1977	678.61	197.26	1269.11	2669.56	409.99	50.89	1179.91	4150.04	1066.39	11671.75
1978	717.90	216.21	1375.90	2757.63	400.93	56.51	1256.39	4455.77	1128.13	12365.38
1979	773.99	243.64	1513.14	2859.43	392.67	62.93	1343.83	4752.23	1216.27	13158.13
1980	819.73	265.61	1642.71	2977.73	387.21	69.63	1451.43	5152.11	1288.14	14054.29
1981	869.42	289.96	1771.40	3102.40	381.00	76.53	1564.64	5556.63	1366.24	14978.22
1982	931.41	321.75	1917.80	3225.91	379.19	84.20	1694.84	6031.82	1463.65	16050.56
1983	976.68	344.34	2016.77	3364.85	378.50	92.19	1836.69	6613.07	1534.79	17157.89
1984	1045.97	380.44	2144.87	3513.42	375.24	101.17	1973.10	7119.31	1643.67	18297.19
1985	1089.45	401.70	2215.08	3680.66	372.20	110.42	2122.14	7767.48	1711.99	19471.12

*EXCLUDING NORTH SLOPE OIL AND ALASKAN GAS.

TABLE 652

OIL AND GAS OPERATIONS*
UNITED STATES EXPENSES
(Million 1970 Dollars)

CASE II

U.S. RATE OF RETURN = 15.0 PERCENT

YEAR	GEOLOGICAL AND GEOPHYSICAL	LEASE RENTAL	DRY HOLE	PRODUCING LEASE AND WELL	GAS PLANT	MISC.	AD VALOREM PROD. AND OTHER TAX	DEPREC. DEPLETION AMORTIZ. RETIREMENTS	(OVERHEAD) INDIRECT EXPENSE	TOTAL EXPENSE (BFIT)
1971	529.66	140.05	838.02	2497.96	469.31	35.00	958.18	3497.37	832.33	9797.90
1972	516.35	130.38	823.63	2492.02	464.68	35.50	979.38	3562.23	811.41	9815.58
1973	548.19	143.25	898.75	2492.33	463.74	36.97	995.28	3555.26	861.45	9995.21
1974	580.69	154.44	970.07	2516.99	462.65	39.41	1023.95	3623.50	912.51	10284.21
1975	610.18	162.36	1033.34	2564.13	457.81	42.98	1061.09	3734.82	958.86	10625.57
1976	626.58	170.36	1076.68	2627.06	450.86	46.91	1109.65	3903.13	984.62	10995.84
1977	663.03	187.93	1152.39	2700.64	445.50	52.04	1167.96	4121.95	1041.91	11533.36
1978	692.95	201.76	1212.28	2792.84	441.35	57.66	1232.10	4401.69	1088.92	12121.53
1979	737.40	222.82	1295.16	2896.54	437.33	63.94	1302.99	4659.35	1158.77	12774.29
1980	770.59	237.90	1364.40	3013.50	435.40	70.41	1388.33	4999.58	1210.93	13491.05
1981	803.92	253.25	1427.30	3134.12	432.08	76.98	1474.71	5330.94	1263.31	14196.62
1982	850.45	276.42	1513.43	3250.01	432.61	84.14	1573.32	5711.56	1336.42	15028.36
1983	882.05	291.32	1565.90	3377.73	433.66	91.44	1680.77	6183.49	1386.07	15892.43
1984	934.96	318.18	1645.61	3511.57	431.56	99.41	1781.75	6578.58	1469.23	16770.85
1985	966.09	332.50	1683.07	3659.15	429.02	107.47	1893.07	7083.99	1518.14	17672.52

*EXCLUDING NORTH SLOPE OIL AND ALASKAN GAS.

TABLE 653

OIL AND GAS OPERATIONS*
UNITED STATES EXPENSES
(Million 1970 Dollars)

CASE III

U.S. RATE OF RETURN = 15.0 PERCENT

YEAR	GEOLOGICAL AND GEOPHYSICAL	LEASE RENTAL	DRY HOLE	PRODUCING LEASE AND WELL	GAS PLANT	MISC.	AD VALOREM PROD. AND OTHER TAX	DEPREC. DEPLETION AMORTIZ. RETIREMENTS	(OVERHEAD) INDIRECT EXPENSE	TOTAL EXPENSE (BFIT)
1971	525.67	137.96	830.38	2497.96	469.31	34.83	959.96	3519.31	826.05	9801.45
1972	507.15	125.79	807.29	2489.73	461.07	35.02	980.48	3597.52	796.96	9801.02
1973	529.57	134.34	865.70	2484.70	453.08	36.03	992.25	3583.28	832.19	9911.13
1974	554.58	142.62	924.10	2498.89	444.12	38.04	1013.79	3629.49	871.48	10117.10
1975	580.72	149.93	983.31	2531.99	431.26	41.12	1042.08	3708.49	912.55	10381.45
1976	593.07	156.50	1023.45	2579.55	416.62	44.43	1081.71	3842.51	931.96	10669.79
1977	622.88	171.44	1092.86	2635.33	403.76	48.68	1131.89	4033.06	978.81	11118.70
1978	645.23	182.25	1148.50	2706.32	392.02	53.26	1187.30	4273.34	1013.93	11602.15
1979	682.18	200.38	1228.56	2786.20	380.60	58.41	1248.42	4486.66	1071.99	12143.39
1980	707.63	212.39	1296.23	2877.71	371.61	63.62	1323.46	4777.27	1111.99	12741.93
1981	734.47	225.34	1358.17	2971.04	361.58	68.83	1398.87	5051.47	1154.17	13323.95
1982	773.01	245.31	1442.40	3058.39	355.66	74.50	1487.29	5384.37	1214.73	14035.65
1983	799.16	258.39	1495.07	3156.01	350.79	80.28	1583.11	5790.37	1255.83	14769.01
1984	844.05	281.98	1573.48	3259.32	343.58	86.62	1672.55	6117.13	1326.37	15505.09
1985	870.86	295.14	1612.81	3374.93	336.86	93.04	1771.48	6548.59	1368.50	16272.22

*EXCLUDING NORTH SLOPE OIL AND ALASKAN GAS.

TABLE 654

OIL AND GAS OPERATIONS*
UNITED STATES EXPENSES
(Million 1970 Dollars)

CASE IV

U.S. RATE OF RETURN = 15.0 PERCENT

YEAR	GEOLOGICAL AND GEOPHYSICAL	LEASE RENTAL	DRY HOLE	PRODUCING LEASE AND WELL	GAS PLANT	MISC.	AD VALOREM PROD. AND OTHER TAX	DEPREC. DEPLETION AMORTIZ. RETIREMENTS	(OVERHEAD) INDIRECT EXPENSE	TOTAL EXPENSE (BFIT)
1971	524.15	137.18	824.20	2497.83	469.31	34.82	959.47	3519.99	823.67	9790.63
1972	491.12	117.64	753.52	2488.72	460.98	34.83	976.80	3604.47	771.75	9699.83
1973	494.91	117.36	754.77	2477.97	452.07	35.43	979.66	3575.75	777.71	9665.62
1974	497.17	115.55	746.76	2480.20	441.04	36.64	985.55	3581.17	781.26	9665.33
1975	499.42	113.14	736.60	2493.58	425.00	38.46	990.30	3587.55	784.80	9668.86
1976	491.47	110.52	712.37	2513.54	406.16	40.25	998.44	3612.10	772.30	9657.15
1977	491.40	111.47	699.50	2536.24	388.37	42.40	1012.30	3688.04	772.20	9741.93
1978	488.93	110.87	685.20	2564.60	370.75	44.64	1023.17	3764.12	768.32	9820.60
1979	491.48	112.56	670.43	2596.25	352.86	47.02	1033.96	3813.16	772.32	9890.03
1980	485.64	109.66	645.03	2631.24	336.60	49.21	1048.24	3890.39	763.15	9959.17
1981	480.85	107.37	622.29	2662.28	318.87	51.18	1057.46	3925.32	755.63	9981.24
1982	481.54	108.55	613.28	2681.63	304.93	53.14	1075.42	4011.52	756.71	10086.72
1983	475.66	105.96	591.05	2703.09	291.94	54.92	1093.29	4113.92	747.46	10177.28
1984	479.66	108.81	585.83	2723.88	276.90	56.73	1104.58	4153.85	753.75	10244.00
1985	476.40	107.38	567.73	2747.48	262.61	58.33	1119.03	4232.69	748.63	10320.28

*EXCLUDING NORTH SLOPE OIL AND ALASKAN GAS.

TABLE 655

OIL AND GAS OPERATIONS*
UNITED STATES EXPENSES
(Million 1970 Dollars)

CASE IVA

U.S. RATE OF RETURN = 15.0 PERCENT

YEAR	GEOLOGICAL AND GEOPHYSICAL	LEASE RENTAL	DRY HOLE	PRODUCING LEASE AND WELL	GAS PLANT	MISC.	AD VALOREM PROD. AND OTHER TAX	DEPREC. DEPLETION AMORTIZ. RETIREMENTS	(OVERHEAD) INDIRECT EXPENSE	TOTAL EXPENSE (BFIT)
1971	528.15	139.27	831.83	2497.83	469.31	34.99	957.71	3498.24	829.94	9787.27
1972	499.68	121.90	768.69	2491.01	464.56	35.30	975.90	3571.78	785.21	9714.01
1973	510.75	124.90	782.72	2485.21	462.30	36.29	982.91	3554.05	802.61	9741.74
1974	517.88	124.84	782.91	2496.29	458.13	37.85	995.25	3583.42	813.81	9810.37
1975	521.28	122.20	773.37	2520.60	448.41	40.00	1007.29	3620.15	819.16	9872.48
1976	514.73	119.89	748.66	2551.45	435.02	42.19	1022.04	3672.93	808.86	9915.76
1977	515.81	120.99	735.53	2585.76	422.12	44.84	1041.42	3770.74	810.56	10047.76
1978	516.06	121.30	722.19	2626.13	408.84	47.62	1056.41	3868.57	810.96	10178.09
1979	521.13	123.78	707.97	2670.84	394.71	50.57	1072.44	3940.13	818.92	10300.49
1980	517.30	121.41	681.44	2719.19	381.56	53.32	1091.17	4040.37	812.89	10418.64
1981	514.06	119.41	656.92	2763.38	366.22	55.82	1104.83	4099.03	807.80	10487.47
1982	516.80	121.21	646.75	2795.44	354.17	58.32	1125.86	4199.75	812.12	10630.40
1983	512.41	118.95	622.97	2829.36	342.59	60.62	1147.19	4321.13	805.22	10760.43
1984	518.67	122.57	617.32	2862.22	328.58	62.96	1161.83	4379.13	815.05	10868.35
1985	516.54	121.29	598.11	2897.88	315.03	65.08	1180.00	4479.54	811.70	10985.17

*EXCLUDING NORTH SLOPE OIL AND ALASKAN GAS.

TABLE 656

HISTORICAL AVERAGE U.S. CRUDE OIL PRICE
(Dollars Per Barrel)

	Current Dollars*	Constant 1970 Dollars†
1956	2.79	3.38
1957	3.09	3.64
1958	3.01	3.54
1959	2.90	3.35
1960	2.88	3.33
1961	2.89	3.35
1962	2.90	3.36
1963	2.89	3.36
1964	2.88	3.33
1965	2.86	3.26
1966	2.88	3.22
1967	2.92	3.21
1968	2.94	3.15
1969	3.09	3.21
1970	3.18	3.18

* Bureau of Mines.

† Adjusted by Wholesale Price Index for Industrial Commodities.

TABLE 657

WHOLESALE PRICE INDEX INDUSTRIAL COMMODITIES
(1970 = 100)

	Index
1956	82.5
1957	84.8
1958	85.1
1959	86.6
1960	86.6
1961	86.2
1962	86.2
1963	86.1
1964	86.5
1965	87.6
1966	89.5
1967	90.9
1968	93.2
1969	96.4
1970	100.0

TABLE 658

AVERAGE UNIT REVENUE REQUIRED PER BARREL OF CRUDE OIL*
(Dollars Per Barrel)†

Case I

	10% Rate of Return	12.5% Rate of Return	15% Rate of Return	17.5% Rate of Return	20% Rate of Return‡
†1971	2.739	2.981	3.223	3.465	3.706
1972	2.819	3.066	3.315	3.563	3.812
1973	2.855	3.112	3.370	3.628	3.886
1974	2.941	3.214	3.486	3.759	4.031
1975	3.068	3.359	3.650	3.941	4.232
1976	3.216	3.530	3.844	4.158	4.472
1977	3.398	3.738	4.078	4.418	4.758
1978	3.612	3.978	4.344	4.711	5.077
1979	3.815	4.208	4.601	4.995	5.389
1980	4.056	4.476	4.896	5.317	5.737
1981	4.288	4.738	5.188	5.639	6.087
1982	4.553	5.037	5.520	6.004	6.487
1983	4.864	5.381	5.899	6.417	6.935
1984	5.151	5.707	6.262	6.818	7.374
1985	5.500	6.093	6.687	7.280	7.873

* Based on economics for lower 48 states and South Alaska.

† Constant 1970 dollars.

‡ All rates of return are annual book return on average net fixed assets.

TABLE 659

AVERAGE UNIT REVENUE REQUIRED PER BARREL OF CRUDE OIL*
(Dollars Per Barrel)†

Case IA

	10% Rate of Return	12.5% Rate of Return	15% Rate of Return	17.5% Rate of Return	20% Rate of Return‡
1971	2.741	2.983	3.224	3.466	3.707
1972	2.831	3.079	3.327	3.574	3.822
1973	2.879	3.136	3.392	3.649	3.906
1974	2.975	3.246	3.518	3.789	4.060
1975	3.116	3.406	3.697	3.986	4.277
1976	3.288	3.603	3.919	4.234	4.549
1977	3.502	3.845	4.189	4.533	4.877
1978	3.756	4.130	4.504	4.876	5.250
1979	3.999	4.403	4.808	5.212	5.616
1980	4.285	4.719	5.155	5.590	6.024
1981	4.553	5.023	5.493	5.961	6.431
1982	4,859	5.367	5.875	6.384	6.891
1983	5.208	5.757	6.304	6.852	7.401
1984	5.536	6.128	6.719	7.310	7.902
1985	5.934	6.570	7.206	7.841	8.477

* Based on economics for lower 48 states and South Alaska.

† Constant 1970 dollars.

‡ All rates of return are annual book return on average next fixed assets.

TABLE 660

AVERAGE UNIT REVENUE REQUIRED PER BARREL OF CRUDE OIL*
(Dollars Per Barrel)†

Case II

	10% Rate of Return	12.5% Rate of Return	15% Rate of Return	17.5% Rate of Return	20% Rate of Return‡
1971	2.739	2.981	3.223	3.465	3.706
1972	2.819	3.066	3.314	3.563	3.811
1973	2.852	3.109	3.366	3.623	3.880
1974	2.934	3.205	3.476	3.747	4.018
1975	3.053	3.341	3.629	3.917	4.205
1976	3.189	3.497	3.806	4.115	4.424
1977	3.354	3.686	4.018	4.350	4.682
1978	3.545	3.900	4.255	4.611	4.965
1979	3.719	4.097	4.476	4.855	5.234
1980	3.922	4.323	4.725	5.126	5.526
1981	4.109	4.535	4.961	5.387	5.813
1982	4.325	4.779	5.234	5.688	6.142
1983	4.576	5.058	5.541	6.023	6.507
1984	4.805	5.319	5.832	6.345	6.858
1985	5.088	5.631	6.175	6.719	7.262

* Based on economics for lower 48 states and South Alaska.

† Constant 1970 dollars.

‡ All rates of return are annual book return on average net fixed assets.

TABLE 661

AVERAGE UNIT REVENUE REQUIRED PER BARREL OF CRUDE OIL*
(Dollars Per Barrel)†

Case III

	10% Rate of Return	12.5% Rate of Return	15% Rate of Return	17.5% Rate of Return	20% Rate of Return‡
1971	2.741	2.983	3.225	3.466	3.707
1972	2.832	3.079	3.326	3.574	3.821
1973	2.876	3.132	3.387	3.643	3.899
1974	2.967	3.236	3.506	3.776	4.045
1975	3.099	3.386	3.673	3.960	4.248
1976	3.254	3.565	3.874	4.184	4.494
1977	3.448	3.783	4.119	4.454	4.789
1978	3.674	4.035	4.396	4.758	5.119
1979	3.879	4.267	4.655	5.043	5.431
1980	4.119	4.533	4.947	5.361	5.775
1981	4.335	4.777	5.220	5.663	6.104
1982	4.584	5.059	5.533	6.008	6.483
1983	4.867	5.375	5.883	6.391	6.897
1984	5.126	5.669	6.212	6.753	7.296
1985	5.439	6.017	6.595	7.173	7.751

* Based on economics for lower 48 states and South Alaska.

† Constant 1970 dollars.

‡ All rates of return are annual book return on average net fixed assets.

TABLE 662

AVERAGE UNIT REVENUE REQUIRED PER BARREL OF CRUDE OIL*
(Dollars Per Barrel)†

Case IV

	10% Rate of Return	12.5% Rate of Return	15% Rate of Return	17.5% Rate of Return	20% Rate of Return‡
1971	2.742	2.983	3.225	3.466	3.708
1972	2.832	3.078	3.325	3.572	3.819
1973	2.865	3.119	3.372	3.625	3.878
1974	2.932	3.194	3.457	3.720	3.982
1975	3.021	3.295	3.570	3.844	4.118
1976	3.116	3.406	3.696	3.987	4.277
1977	3.252	3.560	3.868	4.176	4.484
1978	3.401	3.726	4.051	4.376	4.702
1979	3.528	3.870	4.212	4.554	4.897
1980	3.671	4.029	4.387	4.745	5.103
1981	3.784	4.160	4.535	4.912	5.288
1982	3.932	4.329	4.725	5.121	5.518
1983	4.088	4.505	4.921	5.336	5.752
1984	4.219	4.654	5.089	5.524	5.959
1985	4.372	4.825	5.279	5.732	6.185

* Based on economics for lower 48 states and South Alaska.

† Constant 1970 dollars.

‡ All rates of return are annual book return on average net fixed assets.

TABLE 663

AVERAGE UNIT REVENUE REQUIRED PER BARREL OF CRUDE OIL*
(Dollars Per Barrel)†

Case IVA

	10% Rate of Return	12.5% Rate of Return	15% Rate of Return	17.5% Rate of Return	20% Rate of Return‡
1971	2.739	2.981	3.223	3.465	3.707
1972	2.819	3.067	3.314	3.561	3.808
1973	2.844	3.098	3.353	3.607	3.861
1974	2.904	3.168	3.431	3.696	3.958
1975	2.986	3.261	3.536	3.811	4.086
1976	3.070	3.360	3.649	3.939	4.229
1977	3.191	3.497	3.803	4.109	4.414
1978	3.320	3.641	3.962	4.282	4.603
1979	3.432	3.769	4.106	4.442	4.779
1980	3.557	3.908	4.258	4.608	4.958
1981	3.657	4.023	4.390	4.756	5.122
1982	3.789	4.174	4.559	4.943	5.328
1983	3.931	4.333	4.736	5.136	5.538
1984	4.050	4.470	4.890	5.309	5.729
1985	4.191	4.627	5.063	5.499	5.935

* Based on economics for lower 48 states and South Alaska.

† Constant 1970 dollars.

‡ All rates of return are annual book return on average net fixed assets.

TABLE 664

HISTORICAL
BUREAU OF MINES WELLHEAD "VALUE"–GAS
LOWER 48 STATES
(Constant 1970 Dollars)

	Cent/MCF
1956	13.1
1957	13.3
1958	14.0
1959	14.9
1960	16.2
1961	17.5
1962	18.0
1963	18.4
1964	17.8
1965	17.8
1966	17.5
1967	17.6
1968	17.6
1969	17.3
1970	17.1

TABLE 665

UNIT REVENUE REQUIRED–GAS OPERATIONS
LOWER 48 STATES
(Cent/MCF)*

Case I

	10% Rate of Return	12.5% Rate of Return	15% Rate of Return	17.5% Rate of Return	20% Rate of Return
1971	19.6	21.5	23.5	25.4	27.4
1972	20.3	22.3	24.3	26.3	28.4
1973	20.9	22.9	25.0	27.0	29.1
1974	21.5	23.6	25.7	27.8	29.9
1975	22.3	24.5	26.7	28.9	31.0
1976	23.5	25.8	28.1	30.5	32.8
1977	24.5	27.0	29.4	31.8	34.3
1978	25.2	27.8	30.3	32.9	35.4
1979	26.5	29.2	31.9	34.6	37.3
1980	27.9	30.8	33.7	36.6	39.5
1981	29.6	32.8	35.9	39.1	42.3
1982	31.2	34.5	37.9	41.3	44.6
1983	32.6	36.1	39.7	43.2	46.8
1984	34.2	38.0	41.7	45.5	49.2
1985	35.8	39.7	43.6	47.6	51.5

* Constant 1970 dollars.

TABLE 666

UNIT REVENUE REQUIRED—GAS OPERATIONS
LOWER 48 STATES
(Cent/MCF)*

Case IA

	10% Rate of Return	12.5% Rate of Return	15% Rate of Return	17.5% Rate of Return	20% Rate of Return
1971	19.6	21.6	23.5	25.5	27.4
1972	20.6	22.6	24.6	26.7	28.7
1973	21.6	23.7	25.8	27.9	30.0
1974	22.6	24.8	27.0	29.2	31.3
1975	23.9	26.2	28.5	30.8	33.1
1976	25.7	28.2	30.7	33.2	35.7
1977	27.5	30.1	32.8	35.5	38.2
1978	29.0	31.9	34.8	37.6	40.5
1979	31.3	34.5	37.6	40.8	43.9
1980	33.9	37.4	40.9	44.3	47.8
1981	37.1	40.9	44.8	48.7	52.6
1982	40.0	44.3	48.5	52.7	57.0
1983	42.8	47.4	52.0	56.6	61.2
1984	45.9	50.9	55.8	60.8	65.7
1985	48.8	54.1	59.4	64.7	70.0

* Constant 1970 dollars.

TABLE 667

UNIT REVENUE REQUIRED—GAS OPERATIONS
LOWER 48 STATES
(Cent/MCF)*

Case II

	10% Rate of Return	12.5% Rate of Return	15% Rate of Return	17.5% Rate of Return	20% Rate of Return
1971	19.6	21.5	23.5	25.4	27.4
1972	20.2	22.2	24.2	26.3	28.3
1973	20.7	22.8	24.8	26.8	28.9
1974	21.2	23.3	25.4	27.5	29.5
1975	21.9	24.0	26.2	28.3	30.4
1976	22.9	25.2	27.4	29.7	31.9
1977	23.8	26.1	28.4	30.8	33.1
1978	24.3	26.7	29.1	31.5	33.9
1979	25.3	27.8	30.3	32.9	35.4
1980	26.4	29.1	31.8	34.5	37.2
1981	27.9	30.7	33.6	36.5	39.4
1982	29.1	32.1	35.1	38.2	41.2
1983	30.2	33.4	36.6	39.7	42.9
1984	31.6	34.9	38.2	41.6	44.9
1985	32.8	36.3	39.8	43.3	46.8

* Constant 1970 dollars.

TABLE 668

UNIT REVENUE REQUIRED—GAS OPERATIONS
LOWER 48 STATES
(Cent/MCF)*

Case III

	10% Rate of Return	12.5% Rate of Return	15% Rate of Return	17.5% Rate of Return	20% Rate of Return
1971	19.6	21.6	23.5	25.5	27.4
1972	20.5	22.5	24.6	26.6	28.6
1973	21.4	23.5	25.6	27.6	29.7
1974	22.3	24.5	26.6	28.7	30.9
1975	23.4	25.6	27.9	30.1	32.4
1976	25.0	27.3	29.7	32.1	34.5
1977	26.4	28.9	31.5	34.0	36.6
1978	27.6	30.3	33.0	35.7	38.3
1979	29.5	32.4	35.3	38.2	41.1
1980	31.6	34.7	37.8	41.0	44.1
1981	34.1	37.6	41.0	44.5	47.9
1982	36.5	40.2	44.0	47.7	51.4
1983	38.8	42.7	46.7	50.7	54.7
1984	41.4	45.7	49.9	54.2	58.5
1985	43.8	48.4	53.0	57.6	62.2

* Constant 1970 dollars.

TABLE 669

UNIT REVENUE REQUIRED—GAS OPERATIONS
LOWER 48 STATES
(Cent/MCF)*

Case IV

	10% Rate of Return	12.5% Rate of Return	15% Rate of Return	17.5% Rate of Return	20% Rate of Return
1971	19.6	21.6	23.5	25.5	27.4
1972	20.4	22.4	24.4	26.4	28.4
1973	21.0	23.1	25.1	27.1	29.2
1974	21.6	23.7	25.8	27.9	29.9
1975	22.3	24.5	26.6	28.7	30.8
1976	23.4	25.6	27.8	30.0	32.2
1977	24.2	26.5	28.8	31.0	33.3
1978	24.8	27.1	29.3	31.6	33.9
1979	25.7	28.1	30.5	32.8	35.2
1980	26.7	29.2	31.6	34.1	36.5
1981	28.1	30.7	33.2	35.8	38.4
1982	29.2	31.8	34.5	37.1	39.8
1983	30.2	32.9	35.6	38.3	41.0
1984	31.5	34.3	37.1	40.0	42.8
1985	32.9	35.8	38.7	41.7	44.6

* Constant 1970 dollars.

TABLE 670

UNIT REVENUE REQUIRED—GAS OPERATIONS
LOWER 48 STATES
(Cent/MCF)*

Case IVA

	10% Rate of Return	12.5% Rate of Return	15% Rate of Return	17.5% Rate of Return	20% Rate of Return
1971	19.5	21.5	23.4	25.4	27.3
1972	20.1	22.0	24.1	26.1	28.1
1973	20.4	22.4	24.4	26.4	28.4
1974	20.7	22.7	24.7	26.7	28.7
1975	21.1	23.1	25.1	27.2	29.2
1976	21.8	23.9	26.0	28.1	30.1
1977	22.2	24.3	26.4	28.5	30.6
1978	22.3	24.4	26.5	28.6	30.7
1979	22.8	24.9	27.0	29.2	31.3
1980	23.3	25.5	27.6	29.8	32.0
1981	24.1	26.3	28.5	30.8	33.0
1982	24.6	26.9	29.1	31.4	33.7
1983	25.1	27.4	29.6	31.9	34.2
1984	25.8	28.1	30.4	32.8	35.1
1985	26.5	28.9	31.2	33.6	36.0

* Constant 1970 dollars.

Chapter Eight

Parametric Studies

TABLE 671

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

"Prices" at 10% Return

	$/Bbl		¢/MCF	
	Case II Oil	Change to Case III	Case II Gas	Change to Case III
1971	2.74	–	19.6	–
1975	3.05	+0.05	21.9	+1.5
1980	3.92	+0.20	26.4	+5.2
1985	5.09	+0.35	32.8	+11.0

"Prices" at 12.50% Return

	S/Bbl		¢/MCF	
	Case II Oil	Change to Case III	Case II Gas	Change to Case III
1971	2.98	–	21.5	+0.1
1975	3.34	+0.05	24.0	+1.6
1980	4.32	+0.21	29.1	+5.6
1985	5.63	+0.39	36.3	+12.1

"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

"Prices" at 17.50% Return

	S/Bbl		¢/MCF	
	Case II Oil	Change to Case III	Case II Gas	Change to Case III
1971	3.47	–	25.4	+0.1
1975	3.92	+0.04	28.3	+1.8
1980	5.13	+0.23	34.5	+6.5
1985	6.72	+0.45	43.3	+14.3

"Prices" at 20% Return

	$/Bbl		¢/MCF	
	Case II Oil	Change to Case III	Case II Gas	Change to Case III
1971	3.71	–	27.4	–
1975	4.21	+0.04	30.4	+2.4
1980	5.53	+0.25	37.2	+6.9
1985	7.26	+0.49	46.8	+15.4

TABLE 672

INCREASE OF OIL FINDINGS RATES BY 10 PERCENT

"Prices" at 10% Return ($/Bbl)

	Case II		Case III	
	Base	Change	Base	Change
1971	2.74	–	2.74	–
1975	3.05	–0.04	3.10	–0.04
1980	3.92	–0.12	4.12	–0.10
1985	5.09	–0.21	5.44	–0.17

"Prices" at 12.5% Return ($/Bbl)

	Case II		Case III	
	Base	Change	Base	Change
1971	2.98	–	2.98	–
1975	3.34	–0.05	3.39	–0.04
1980	4.32	–0.13	4.53	–0.10
1985	5.63	–0.23	6.02	–0.19

"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

"Prices" at 17.50% Return ($/Bbl)

	Case II		Case III	
	Base	Change	Base	Change
1971	3.47	–	3.47	–0.01
1975	3.92	–0.06	3.96	–0.04
1980	5.13	–0.16	5.36	–0.12
1985	6.72	–0.27	7.17	–0.22

"Prices" at 20% Return ($/Bbl)

	Case II		Case III	
	Base	Change	Base	Change
1971	3.71	–0.01	3.71	–0.01
1975	4.21	–0.06	4.25	–0.05
1980	5.53	–0.17	57.8	–0.14
1985	7.26	–0.29	7.75	–0.24

TABLE 673

INCREASE OF 10 PERCENT IN DRILLING COSTS

	Gas "Prices" at 10% Return (¢/MCF)					Oil "Prices" at 10% Return ($/Bbl)			
	Case II	Change	Case III	Change		Case II	Change	Case III	Change
1971	19.6	–	19.6	+0.1	1971	2.74	–0.01	2.74	–0.01
1975	21.9	+0.4	23.4	+0.4	1975	3.05	+0.04	3.10	+0.03
1980	26.4	+0.8	31.6	+0.9	1980	3.92	+0.08	4.12	+0.08
1985	32.8	+1.1	43.8	+1.6	1985	5.09	+0.11	5.44	+0.11

	Gas "Prices" at 12.50% Return (¢/MCF)					Oil "Prices" at 12.50% Return ($/Bbl)			
	Case II	Change	Case III	Change		Case II	Change	Case III	Change
1971	21.5	+0.1	21.6	+0.1	1971	2.98	–0.01	2.98	–
1975	24.0	+0.5	25.6	+0.5	1975	3.34	+0.05	3.39	+0.04
1980	29.1	+0.8	34.7	+1.0	1980	4.32	+0.10	4.53	+0.09
1985	36.3	+1.3	48.4	+1.6	1985	5.63	+0.13	6.02	+0.12

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

	Gas "Prices" at 17.50% Return (¢/MCF)					Oil "Prices" at 17.50% Return ($/Bbl)			
	Case II	Change	Case III	Change		Case II	Change	Case III	Change
1971	25.4	+0.1	25.5	+0.1	1971	3.47	–0.01	3.47	–0.01
1975	28.3	+0.5	30.1	+0.6	1975	3.92	+0.05	3.96	+0.05
1980	34.5	+1.0	41.0	+1.2	1980	5.13	+0.11	5.36	+0.11
1985	43.3	+1.5	57.6	+2.1	1985	6.72	+0.16	7.17	+0.16

	Gas "Prices" at 20% Return (¢/MCF)					Oil "Prices" at 20% Return (S/Bbl)			
	Case II	Change	Case III	Change		Case II	Change	Case III	Change
1971	27.4	+0.1	27.4	+0.1	1971	3.71	–0.01	3.71	–0.01
1975	30.4	+0.6	32.4	+0.6	1975	4.21	+0.06	4.25	+0.06
1980	37.2	+1.1	44.1	+1.4	1980	5.53	+0.13	5.78	+0.12
1985	46.8	+1.6	62.2	+2.3	1985	7.26	+0.18	7.75	+0.17

TABLE 674

INCREASE OF 10 PERCENT IN OPERATING COSTS

	Oil "Prices" at 10% Return ($/Bbl)			
	Case II	Change	Case III	Change
1971	2.74	+0.07	2.74	+0.07
1975	3.05	+0.08	3.10	+0.07
1980	3.92	+0.08	4.12	+0.08
1985	5.09	+0.09	5.44	+0.10

	Gas "Prices" at 10% Return (¢/MCF)			
	Case II	Change	Case III	Change
1971	19.6	+0.2	19.6	+0.3
1975	21.9	+0.2	23.4	+0.2
1980	26.4	+0.3	31.6	+0.3
1985	32.8	+0.3	43.8	+0.5

	Oil "Prices" at 12.50% Return ($/Bbl)			
	Case II	Change	Case III	Change
1971	2.98	+0.07	2.98	+0.07
1975	3.34	+0.07	3.39	+0.07
1980	4.32	+0.08	4.53	+0.09
1985	5.63	+0.09	6.02	+0.09

	Gas "Prices" at 12.50% Return (¢/MCF)			
	Case II	Change	Case III	Change
1971	21.5	+0.2	21.6	+0.2
1975	24.0	+0.3	25.6	+0.3
1980	29.1	+0.3	34.7	+0.4
1985	36.3	+0.3	48.4	+0.5

	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

	Oil "Prices" at 17.50% Return ($/Bbl)			
	Case II	Change	Case III	Change
1971	3.47	+0.06	3.47	+0.06
1975	3.92	+0.07	3.96	+0.07
1980	5.13	+0.08	5.36	+0.08
1985	6.72	+0.09	7.17	+0.10

	Gas "Prices" at 17.50% Return (¢/MCF)			
	Case II	Change	Case III	Change
1971	25.4	+0.2	25.5	+0.2
1975	28.3	+0.3	30.1	+0.3
1980	34.5	+0.3	41.0	+0.3
1985	43.3	+0.3	57.6	+0.5

	Oil "Prices" at 20% Return ($/Bbl)			
	Case II	Change	Case III	Change
1971	3.71	+0.06	3.71	+0.06
1975	4.21	+0.07	4.25	+0.07
1980	5.53	+0.08	5.78	+0.08
1985	7.26	+0.09	7.75	+0.10

	Gas "Prices" at 20% Return (¢/MCF)			
	Case II	Change	Case III	Change
1971	27.4	+0.2	27.4	+0.2
1975	30.4	+0.3	32.4	+0.2
1980	37.2	+0.2	44.1	+0.4
1985	46.8	+0.3	62.2	+0.5

TABLE 675

INCREASE OF 10 PERCENT IN
ADDITIONAL OIL RECOVERY INVESTMENTS

	Oil "Prices" at 10% Return ($/Bbl)			
	Case II	Change	Case III	Change
1971	2.74	–	2.74	–
1972	3.05	+0.03	3.10	+0.03
1980	3.92	+0.07	4.12	+0.07
1985	5.09	+0.11	5.44	+0.13

	Oil "Prices" at 12.50% Return ($/Bbl)			
	Case II	Change	Case III	Change
1971	2.98	–	2.98	–
1975	3.34	+0.03	3.39	+0.03
1980	4.22	+0.08	4.53	+0.09
1985	5.63	+0.13	6.02	+0.14

	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

	Oil "Prices" at 17.50% Return ($/Bbl)			
	Case II	Change	Case III	Change
1971	3.47	–	3.47	–
1975	3.92	+0.04	3.96	+0.04
1980	5.13	+0.09	5.36	+0.11
1985	6.72	+0.16	7.17	+0.19

	Oil "Prices" at 20% Return ($/Bbl)			
	Case II	Change	Case III	Change
1971	3.71	–	3.71	–
1975	4.21	+0.04	4.25	+0.04
1980	5.53	+0.10	5.78	+0.11
1985	7.26	+0.18	7.75	+0.20

TABLE 676

ELIMINATION OF BONUS PAYMENTS OFFSHORE

Oil "Prices" at 10% Return ($/Bbl)	Case II	Change	Case III	Change
1971	2.74	–0.01	2.74	–0.01
1975	3.05	–0.18	3.10	–0.19
1980	3.92	–0.55	4.12	–0.63
1985	5.09	–0.91	5.44	–1.06

Gas "Prices" at 10% Return (¢/MCF)	Case II	Change	Case III	Change
1971	19.6	–0.2	19.6	–0.1
1975	21.9	–1.8	23.4	–1.9
1980	26.4	–4.0	31.6	–4.9
1985	32.8	–7.1	43.8	–9.5

Oil "Prices" at 12.50% Return ($/Bbl)	Case II	Change	Case III	Change
1971	2.98	–0.01	2.98	–0.01
1975	3.34	–0.21	3.39	–0.22
1980	4.32	–0.62	4.53	–0.71
1985	5.63	–1.02	6.02	–1.19

Gas "Prices" at 12.50% Return (¢/MCF)	Case II	Change	Case III	Change
1971	21.5	–0.2	21.6	–0.2
1975	24.0	–2.0	25.6	–2.2
1980	29.1	–4.6	34.7	–5.5
1985	36.3	–8.1	48.4	–10.9

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

Oil "Prices" at 17.50% Return ($/Bbl)	Case II	Change	Case III	Change
1971	3.47	–0.02	3.47	–0.02
1975	3.92	–0.26	3.96	–0.27
1980	5.13	–0.77	5.36	–0.88
1985	6.72	–1.25	7.17	–1.46

Gas "Prices" at 17.50% Return (¢/MCF)	Case II	Change	Case III	Change
1971	25.4	–0.2	25.5	–0.2
1975	28.3	–2.5	30.1	–2.7
1980	34.5	–5.8	41.0	–7.0
1985	43.3	–10.3	57.6	–13.7

Oil "Prices" at 20% Return ($/Bbl)	Case II	Change	Case III	Change
1971	3.71	–0.02	3.71	–0.02
1972	4.21	–0.29	4.25	–0.30
1980	5.53	–0.84	5.78	–0.97
1985	7.26	–1.37	7.75	–1.60

Gas "Prices" at 20% Return (¢/MCF)	Case II	Change	Case III	Change
1971	27.4	–0.3	27.4	–0.2
1975	30.4	–2.7	32.4	–3.0
1980	37.2	–6.5	44.1	–7.6
1985	46.8	–11.4	62.2	–15.1

TABLE 677

REPLACEMENT OF CASH BONUS PAYMENTS WITH WORK PROGRAM

	Oil "Prices" at 10% Return ($/Bbl)			
	Case II	Change	Case III	Change
1971	2.74	–0.01	2.74	–0.01
1975	3.05	–0.18	3.10	–0.19
1980	3.92	–0.52	4.12	–0.58
1985	5.09	–0.74	5.44	–0.91

	Gas "Prices" at 10% Return (¢/MCF)			
	Case II	Change	Case III	Change
1971	19.6	–0.2	19.6	–0.1
1975	21.9	–1.7	23.4	–1.8
1980	26.4	–3.8	31.6	–4.5

	Oil "Prices" at 12.50% Return ($/Bbl)			
	Case II	Change	Case III	Change
1971	2.98	–0.01	2.98	–0.01
1975	3.34	–0.20	3.39	–0.12
1980	4.32	–0.58	4.53	–0.65
1985	5.63	–0.84	6.02	–1.03

	Gas "Prices" at 12.50% Return (¢/MCF)			
	Case II	Change	Case III	Change
1971	21.5	–0.2	21.6	–0.2
1975	24.0	–1.9	25.6	–2.1
1980	29.1	–4.4	34.7	–5.1
1985	36.3	–7.7	48.4	–1.0

	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	–0.65	4.95	–0.72
1985	6.18	–0.93	6.60	–1.14

	Gas "Prices" at 15% Return (¢/MCF)			
	Case II	Change	Case III	Change
1971	23.5	–0.2	23.5	–0.2
1975	26.2	–2.2	27.9	–2.4
1980	31.8	–5.0	37.8	–5.8
1985	39.8	–8.7	53.0	–11.3

	Oil "Prices" at 17.50% Return ($/Bbl)			
	Case II	Change	Case III	Change
1971	3.47	–0.02	3.47	–0.02
1975	3.92	–0.28	3.96	–0.26
1980	5.13	–0.72	5.36	–0.80
1985	6.72	–1.03	7.17	–1.26

	Gas "Prices" at 17.50% Return (¢/MCF)			
	Case II	Change	Case III	Change
1971	25.4	–0.2	25.5	–0.2
1975	28.3	–2.4	30.1	–2.6
1980	34.5	–5.6	41.0	–6.5

	Oil "Prices" at 20% Return ($/Bbl)			
	Case II	Change	Case III	Change
1971	3.71	–0.02	3.71	–0.02
1975	4.21	–0.28	4.25	–0.29
1980	5.53	–0.78	5.78	–0.88
1985	7.26	–1.12	7.75	–1.38

	Gas "Prices" at 20% Return (¢/MCF)			
	Case II	Change	Case III	Change
1971	27.4	–0.3	27.4	–0.2
1975	30.4	–2.7	32.4	–2.9
1980	37.2	–6.2	44.1	–7.1
1985	46.8	–10.7	62.2	–13.9

TABLE 678

CHANGE OF STATUTORY DEPLETION RATES
WITH 50-PERCENT TAX RATE

	Case II	Change to 35% Depletion	Case III	Change to 35% Depletion
	Oil "Prices" at 10% Return ($/Bbl)			
1971	2.74	–0.22	2.74	–0.22
1975	3.05	–0.24	3.10	–0.24
1980	3.92	–0.31	4.12	–0.32
1985	5.09	–0.40	5.44	–0.43
	Oil "Prices" at 12.50% Return ($/Bbl)			
1971	2.98	–0.23	2.98	–0.23
1975	3.34	–0.26	3.39	–0.29
1980	4.32	–0.34	4.53	–0.35
1985	5.63	–0.44	6.02	–0.47
	Oil "Prices" at 15% Return ($/Bbl)			
1971	3.22	–0.26	3.23	–0.26
1975	3.63	–0.29	3.67	–0.29
1980	4.73	–0.37	4.95	–0.39
1985	6.18	–0.48	6.60	–0.52
	Oil "Prices" at 17.50% Return ($/Bbl)			
1971	3.47	–0.28	3.47	–0.28
1975	3.92	–0.31	3.96	–0.31
1980	5.13	–0.41	5.36	–0.42
1985	6.72	–0.53	7.17	–0.56
	Oil "Prices" at 20% Return ($/Bbl)			
1971	3.71	–0.30	3.71	–0.30
1975	4.21	–0.34	4.25	–0.34
1980	5.53	–0.44	5.78	–0.46
1985	7.26	–0.57	7.75	–0.61

	Case II	Change to 35% Depletion	Case III	Change to 35% Depletion
	Gas "Prices" at 10% Return (¢/MCF)			
1971	19.6	–1.3	19.6	–1.2
1975	21.9	–1.5	23.4	–1.6
1980	26.4	–1.8	31.6	–2.2
1985	32.8	–2.2	43.8	–3.0
	Gas "Prices" at 12.50% Return (¢/MCF)			
1971	21.5	–1.4	21.6	–1.4
1975	24.0	–1.6	25.6	–1.7
1980	29.1	–2.0	34.7	–2.4
1985	36.3	–2.5	48.4	–3.3
	Gas "Prices" at 15% Return (¢/MCF)			
1971	23.5	–1.6	23.5	–1.5
1975	26.2	–1.8	27.9	–1.9
1980	31.8	–2.2	37.8	–2.6
1985	39.8	–2.7	53.0	–3.7
	Gas "Prices" at 17.50% Return (¢/MCF)			
1971	25.4	–1.6	25.5	–1.7
1975	28.3	–1.9	30.1	–2.1
1980	34.5	–2.4	41.0	–2.8
1985	43.3	–3.0	57.6	–4.0
	Gas "Prices" at 20% Return (¢/MCF)			
1971	27.4	–1.8	27.4	–1.7
1975	30.4	–2.1	32.4	–2.3
1980	37.2	–2.6	44.1	–3.0
1985	46.8	–3.2	62.2	–4.3

	Case II	Change to 27.5% Depletion	Case III	Change to 27.5% Depletion
	Oil "Prices" at 10% Return ($/Bbl)			
1971	2.74	–0.07	2.74	–0.07
1975	3.05	–0.08	3.10	–0.08
1980	3.92	–0.10	4.12	–0.11
1985	5.09	–0.14	5.44	–0.14
	Oil "Prices" at 12.50% Return ($/Bbl)			
1971	2.98	–0.08	2.98	–0.08
1975	3.34	–0.09	3.39	–0.09
1980	4.32	–0.11	4.53	–0.12
1985	5.63	–0.16	6.02	–0.16
	Oil "Prices" at 15% Return ($/Bbl)			
1971	3.22	–0.09	3.23	–0.09
1975	3.63	–0.10	3.67	–0.10
1980	4.73	–0.13	4.95	–0.13
1985	6.18	–0.16	6.60	–0.17
	Oil "Prices" at 17.50% Return ($/Bbl)			
1971	3.47	–0.10	3.47	–0.10
1975	3.92	–0.11	3.96	–0.10
1980	5.13	–0.14	5.36	–0.14
1985	6.72	–0.18	7.17	–0.18
	Oil "Prices" at 20% Return ($/Bbl)			
1971	3.71	–0.10	3.71	–0.10
1975	4.21	–0.11	4.25	–0.11
1980	5.53	–0.15	5.78	–0.16
1985	7.26	–0.19	7.75	–0.20

TABLE 678 (CONT'D)

CHANGE OF STATUTORY DEPLETION RATES WITH 50-PERCENT TAX RATE

	Case II	Change to 27.5% Depletion	Case III	Change to 27.5% Depletion
	Gas "Prices" at 10% Return (¢/MCF)			
1971	19.6	–0.5	19.6	–0.4
1975	21.9	–0.5	23.4	–0.6
1980	26.4	–0.6	31.6	–0.8
1985	32.8	–0.7	43.8	–1.0
	Gas "Prices" at 12.50% Return (¢/MCF)			
1971	21.5	–0.5	21.6	–0.5
1975	24.0	–0.5	25.6	–0.6
1980	29.1	–0.7	34.7	–0.8
1985	36.3	–0.8	48.4	–1.1
	Gas "Prices" at 15% Return (¢/MCF)			
1971	23.5	–0.5	23.5	–0.5
1975	26.2	–0.6	27.9	–0.7
1980	31.8	–0.7	37.8	–0.8
1985	39.8	–0.9	53.0	–1.2
	Gas "Prices" at 17.50% Return (¢/MCF)			
1971	25.4	–0.5	25.5	–0.6
1975	28.3	–0.6	30.1	–0.7
1980	34.5	–0.8	41.0	–1.0
1985	43.3	–1.0	57.6	–1.3
	Gas "Prices" at 20% Return (¢/MCF)			
1971	27.4	–0.6	27.4	–0.6
1975	30.4	–0.7	32.4	–0.8
1980	37.2	–0.9	44.1	–1.0
1985	46.8	–1.1	62.2	–1.4

	Case II	Change to 0% Depletion	Case III	Change to 0% Depletion
	Oil "Prices" at 10% Return ($/Bbl)			
1971	2.74	+0.41	2.74	+0.42
1975	3.05	+0.46	3.10	+0.46
1980	3.92	+0.59	4.12	+0.62
1985	5.09	+0.76	5.44	+0.81
	Oil "Prices" at 12.50% Return ($/Bbl)			
1971	2.98	+0.45	2.98	+0.45
1975	3.34	+0.50	3.39	+0.50
1980	4.32	+0.65	4.53	+0.68
1985	5.63	+0.84	6.02	+0.90
	Oil "Prices" at 15% Return ($/Bbl)			
1971	3.22	+0.49	3.23	+0.49
1975	3.63	+0.55	3.67	+0.55
1980	4.73	+0.71	4.95	+0.74
1985	6.18	+0.92	6.60	+0.99
	Oil "Prices" at 17.50% Return ($/Bbl)			
1971	3.47	+0.52	3.47	+0.52
1975	3.92	+0.59	3.96	+0.60
1980	5.13	+0.76	5.36	+0.80
1985	6.72	+1.00	7.17	+1.08
	Oil "Prices" at 20% Return ($/Bbl)			
1971	3.71	+0.55	3.71	+0.56
1975	4.21	+0.63	4.25	+0.64
1980	5.53	+0.82	5.78	+0.86
1985	7.26	+1.09	7.75	+1.16

	Case II	Change to 0% Depletion	Case III	Change to 0% Depletion
	Gas "Prices" at 10% Return (¢/MCF)			
1971	19.6	+2.3	19.6	+2.4
1975	21.9	+2.8	23.4	+2.9
1980	26.4	+3.3	31.6	+4.0
1985	32.8	+4.2	43.8	+5.7
	Gas "Prices" at 12.50% Return (¢/MCF)			
1971	21.5	+2.5	21.6	+2.5
1975	24.0	+3.1	25.6	+3.3
1980	29.1	+3.7	34.7	+4.4
1985	36.3	+4.6	48.4	+6.3
	Gas "Prices" at 15% Return (¢/MCF)			
1971	23.5	+2.7	23.5	+2.8
1975	26.2	+3.3	27.9	+3.5
1980	31.8	+4.0	37.8	+6.8
1985	39.8	+5.1	53.0	+6.8
	Gas "Prices" at 17.50% Return (¢/MCF)			
1971	25.4	+3.0	25.5	+3.0
1975	28.3	+3.6	30.1	+3.8
1980	34.5	+4.3	41.0	+5.2
1985	43.3	+5.5	57.6	+7.4
	Gas "Prices" at 20% Return (¢/MCF)			
1971	27.4	+3.2	27.4	+3.3
1975	30.4	+3.9	32.4	+4.1
1980	37.2	+4.6	44.1	+5.6
1985	46.8	+5.9	62.2	+8.0

TABLE 679

CHANGE OF 22-PERCENT STATUTORY DEPLETION RATE AT 70-PERCENT INCOME TAX RATE

	70% Income Tax Rate				70% Income Tax Rate		
		Change 22% Depl. Rate to				Change 22% Depl. Rate to	
	Case III	35%	0%		Case III	35%	0%
	Oil "Prices" at 10% Return ($/Bbl)				Gas "Prices" at 10% Return (¢/MCF)		
1971	2.92	−0.41	+0.98	1971	20.4	−2.4	+5.5
1975	3.26	−0.46	+1.09	1975	24.3	−3.1	+6.9
1980	4.45	−0.63	+1.48	1980	32.3	−4.1	+9.2
1985	5.96	−0.84	+1.98	1985	45.9	−5.8	+13.2
	Oil "Prices" at 12.50% Return ($/Bbl)				Gas "Prices" at 12.50% Return (¢/MCF)		
1971	3.25	−0.46	+1.09	1971	23.2	−2.8	+6.2
1975	3.65	−0.51	+1.23	1975	27.5	−3.5	+7.8
1980	5.02	−0.71	+1.67	1980	36.7	−4.6	+1.04
1985	6.75	−0.95	+2.25	1985	52.4	−6.7	+1.50
	Oil "Prices" at 15% Return ($/Bbl)				Gas "Prices" at 15% Return (¢/MCF)		
1971	3.59	−0.51	+1.20	1971	25.9	−3.1	+7.0
1975	4.05	−0.57	+1.35	1975	30.6	−3.9	+8.7
1980	5.58	−0.79	+1.86	1980	41.1	−5.2	+11.7
1985	7.54	−1.06	+2.51	1985	58.8	−7.5	+16.9
	Oil "Prices" at 17.50% Return ($/Bbl)				Gas "Prices" at 17.50% Return (¢/MCF)		
1971	3.92	−0.56	+1.31	1971	28.7	−3.5	+7.6
1975	4.44	−0.63	+1.48	1975	33.8	−4.3	+9.6
1980	6.15	−0.87	+2.05	1980	45.6	−5.8	+12.9
1985	8.33	−1.17	+2.78	1985	65.2	−8.3	+18.8
	Oil "Prices" at 20% Return ($/Bbl)				Gas "Prices" at 20% Return (¢/MCF)		
1971	4.25	−0.61	+1.42	1971	31.4	−3.8	+8.4
1975	4.83	−0.68	+1.62	1975	36.9	−4.7	+10.6
1980	6.72	−0.95	+2.24	1980	50.0	−6.4	+14.1
1985	9.12	−1.28	+3.04	1985	71.7	−9.2	+20.6

TABLE 680

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		Case II	Change Due to Removing 7% Job Development Credits	Change Due to Implementing 12.5% Exploration and Additional Recovery Credits
	Oil "Prices" at 10% Return ($/Bbl)				Gas "Prices" at 10% Return (¢/MCF)		
1971	2.74	+0.06	–0.17	1971	19.6	+0.3	–1.4
1975	3.05	+0.08	–0.23	1975	21.9	+0.3	–1.5
1980	3.92	+0.11	–0.30	1980	26.4	+0.3	–2.2
1985	5.09	+0.15	–0.38	1985	32.8	+0.3	–2.6
	Oil "Prices" at 12.50% Return ($B/				Gas "Prices" at 12.50% Return (¢/MCF)		
1971	2.98	+0.06	–0.17	1971	21.5	+0.3	–1.4
1975	3.34	+0.08	–0.24	1975	24.0	+0.3	–1.5
1980	4.32	+0.12	–0.30	1980	29.1	+0.3	–2.2
1985	5.63	+0.15	–0.38	1985	36.3	+0.3	–2.6
	Oil "Prices" at 15% Return ($/Bbl)				Gas "Prices" at 15% Return (¢/MCF)		
1971	3.22	+0.06	–0.17	1971	23.5	+0.3	–1.4
1975	3.63	+0.08	–0.24	1975	26.2	+0.2	–1.5
1980	4.73	+0.11	–0.30	1980	31.8	+0.3	–2.2
1985	6.18	+0.15	–0.38	1985	39.8	+0.3	–2.6
	Oil "Prices" at 17.50% Return ($/Bbl)				Gas "Prices" at 17.50% Return (¢/MCF)		
1971	3.47	+0.05	–0.17	1971	25.4	+0.3	–1.4
1975	3.92	+0.07	–0.24	1975	28.3	+0.3	–1.5
1980	5.13	+0.11	–0.30	1980	34.5	+0.3	–2.2
1985	6.72	+0.15	–0.38	1985	43.3	+0.3	–2.6
	Oil "Prices" at 20% Return ($/Bbl)				Gas "Prices" at 20% Return (¢/MCF)		
1971	3.71	+0.05	–0.17	1971	27.4	+0.3	–1.4
1975	4.21	+0.07	–0.23	1975	30.4	+0.3	–1.5
1980	5.53	+0.11	–0.30	1980	37.2	+0.3	–2.2
1985	7.26	+0.16	–0.38	1985	46.8	+0.3	–2.6

TABLE 681

CAPITALIZATION OF INTANGIBLE DRILLING COSTS

(Million Dollars Per Year of Increased Revenue Requirements)*

	Case II			Case III		
10%	Oil	Gas	Total	Oil	Gas	Total
1971	633	351	984	616	352	968
1975	622	280	902	530	280	810
1980	452	237	689	318	237	555
1985	332	92	424	230	94	324
12.5%						
1971	633	352	984	616	352	968
1975	622	280	902	532	280	812
1980	451	236	687	318	237	555
1985	332	92	424	227	92	319
15%						
1971	633	352	984	616	351	968
1975	620	279	900	530	280	809
1980	451	236	687	318	238	555
1985	332	92	424	227	92	319
17.5%						
1971	632	352	984	616	352	968
1975	621	279	900	530	280	810
1980	452	236	688	318	237	555
1985	332	94	426	227	92	319
20%						
1971	632	352	984	616	352	968
1975	621	280	901	530	279	809
1980	452	235	687	319	237	556
1985	332	93	425	227	94	320

* Constant 1970 dollars.

Chapter Nine

Foreign Oil and Gas Availability

Free Foreign Energy and Oil Demand

Energy and oil requirements and supplies outside the United States must be considered if U.S. needs are to be put into proper prospective. Accordingly, a projection of Free Foreign energy and oil consumption was made for the period 1970 to 1985 inclusive. These projections are summarized in the tabulation below:

Free Foreign Population and Energy and Oil Consumption

	1970	1975	1980	1985	Percent Annual Growth 1985 vs. 1970
Population (Millions)	2,266	2,517	2,827	3,179	2.3
Energy (Oil Equivalent- MMB/D)	42.5	58.0	78.7-80.4	106.0-111.2	6.3-6.6
Oil (MMB/D)	25.4	37.3-38.3	49.7-53.1	64.2- 74.2	6.4-7.4
Percent Oil to Total Energy	59.8	64.3-66.0	63.2-66.0	60.6- 66.7	(.1)-.9
Per Capita Consumption					
Energy (Barrels/Capita/Year)	6.8	8.4	10.2-10.4	12.2- 12.7	4.0-4.4
Oil (Barrels/Capita/Year)	4.1	5.4- 5.6	6.4- 6.9	7.4- 8.5	4.0-5.0

A range for estimated Free Foreign energy and oil consumption was used to show the difference in individual Task Group members' inputs. It is significant that only a minor difference developed within the Task Group relative to the Free Foreign energy outlook. A substantial difference exists, however, as to the outlook for oil. In essence, the range differential shown reflects two fundamentally different outlooks which developed from the inputs of individual Task Group members. One group sees oil's role in the energy mix declining in the Free 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 Free Foreign energy fuels market, particularly after 1975. The other group is quite pessimistic about prospects for nuclear (higher cost, construction and environmental road blocks), low sulfur coal (higher delivered cost) and coal gasification (commercially feasible processes unlikely until after 1980), with the result that much higher requirements for oil are projected—largely on the basis that oil is the only available energy fuel with sufficient supply flexibility to meet the expected energy demand of the Free Foreign area. The differences between the two groups as to the projected energy mix were fundamental and irreconcilable. Thus, the Task Group, deemed it appropriate to show the two positions as a projected possible range. It should be noted that there is a range of views among Task Group members as to the potential availability of various fuels on a worldwide basis, including oil.

Based on the above projection, the Free Foreign area will consume between 257 to 277 billion barrels of crude oil during the period 1970 to 1985 inclusive. The United States will consume about 121 billion barrels during the same period. Thus, total Free World oil consumption will range between about 380 to 400 billion barrels, with the United States accounting for between 30 to 32 percent of the total.

Free 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 and will continue to undergird the dynamics of international energy and oil supply. Historically, and into the foreseeable future, international oil supply patterns are influenced by (1) the geographical distribution of oil reserves, (2) political and economic factors, (3) reserve additions and particularly the annual rate thereof, (4) price competition, (5) quality and relative refining value of alternative crude supplies, (6) security considerations, (7) need for diversified energy and crude sources, (8) changes in demand patterns such as shifts in the geography of demand and the product mix and (9) environmental considerations.

Taking the above factors into account it is our overall assessment that:

1. The Free World resource base remaining to be discovered and developed is large. Sufficient discoverable oil potential probably exists to meet Free World oil requirements beyond 1985.
2. Assuming that political and economic conditions throughout the Free World will continue to provide rewarding investment opportunities, we believe it is probably 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 Free World crude oil reserves during the 15-year period through 1985. Any events or conditions that adversely affect the political or economic climate will have a negative impact on future oil finding and development.
3. To find and develop this range of gross additions to proved Free World crude oil reserves in the period through 1985 will, to a large extent, depend on the oil industry's ability to continue to attract large amounts of capital while confronted with a variety of domestic and foreign government based uncertainties including increased taxation, nationalistic foreign government policies and actions including current demands for participation in oil operations by foreign producing country governments. Also, restraints on capital recovery and possible future currency exchange adjustments may add to the already large risks and affect long-term profitability and thereby ultimately the oil industry's ability to provide the required supplies during this period.
4. Free World oil supplies will gradually tighten during the period 1970 to 1985 as the ready availability of low-cost oil declines. This conclusion takes into account and is based on (1) the *Oil & Gas Journal*'s December 27, 1971, estimate of Free World proved crude oil reserves which the Oil Supply Task Group adjusted downward from 533.4 to 463.4 billion barrels as of January 1, 1972, (2) the estimated range of gross additions to proved Free World crude oil reserves in item 2 above and (3) the Free World oil demand projection set forth at the outset of this section of the report. Together, these factors combine to show a decline in the Free World Reserve/Production ratio from 27 years remaining life based on 1972 production to between 14 to 19 years remaining life based on estimated 1985 production.
5. The cost of finding, developing and supplying the volume of oil required through 1985 will likely increase sharply over the next 15 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 increasingly more costly as we expect much of the new producing capacity will 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 at the same time meeting environmental standards. As costs increase, so must—and will—the price of crude oil and products processed therefrom.
6. Absent substantive changes in current 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 or 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 (see Table 682).

A particularly significant implication of the projected Western Hemisphere liquid hydrocarbon balance is that it is an extremely doubtful posture—if not a wholly unrealistic one—to place too much long-term reliance on Canadian or Latin American crude resources to meet the projected increasing U.S. oil deficit. The Canadian and Venezuelan governments will likely not permit dedication of their reserves to U.S. markets on a long-term basis, or at least too far in advance of an ability to reliably predict the consequences of such actions on their respective economies or before detailed assessments of long-term domestic requirements and supply capabilities are completed and approved by the Canadian and Venezuelan governments.

TABLE 682

WESTERN HEMISPHERE LIQUID HYDROCARBON SUPPLY—OIL CONSUMPTION BALANCE (1960-1985)
(Thousand Barrels Per Day)

	1960	1965	1970	1975	1980	1985	
						Low	High
Domestic Oil Consumption (Ex. Exports)							
United States	9,807	11,523	14,709	18,111	22,109	25,767	
Canada	854	1,448	1,504	1,900	2,300	2,700	3,000
North American Atlantic Islands	1	2	3	4	5	6	6
Latin America	1,708	2,068	2,775	3,900	5,100	6,500	7,000
Total Western Hemisphere	**12,370**	**14,741**	**18,991**	**23,915**	**29,514**	**34,973**	**35,773**
Conventional Liquid Hydrocarbon Productic							
United States - Lower 48 and South Alasl	7,965	9,014	11,297	9,750	9,610	9,830	
- North Slope	—	—	—	—	2,000	2,000	
Subtotal	**7,965**	**9,014**	**11,297**	**9,750**	**11,610**	**11,830**	
Canada - Western Canada	544	923	1,477	2,230	2,250	2,185	
- New Frontier Areas	—	—	—	50	750	1,500	
Subtotal	**544**	**923**	**1,477**	**2,280**	**3,000**	**3,685**	
Latin America	3,789	4,711	5,308	5,800	6,700	7,000	
Total Western Hemisphere	**12,298**	**14,648**	**18,082**	**17,830**	**21,310**	**22,515**	
Conventional Liquid Hydrocarbon Production Available for Export or (Imports Required)							
United States	(1,842)	(2,509)	(3,412)	(8,361)	(10,499)	(13,937)	(13,937)
Canada	(310)	(225)	(27)	380	700	985	685
North American Atlantic Islands	(1)	(2)	(3)	(4)	(5)	(6)	(6)
Latin America	2,081	2,643	2,533	1,900	1,600	500	—
Total Western Hemisphere	**(72)**	**(93)**	**(909)**	**(6,085)**	**(8,204)**	**(12,458)**	**(13,258)**
Less: Synthetic Liquid Production							
United States - Oil Shale	—	—	—	—	100	400	
- Coal Liquefaction	—	—	—	—	—	80	
Subtotal	—	—	—	—	**100**	**480**	
Canada - Tar Sands	—	—	33	65	375	1,000	
Latin America - Synthetic	—	—	—	—	250	750	
Total Western Hemisphere	—	—	**33**	**65**	**725**	**2,230**	
Total Liquid Hydrocarbon Production (Conventional Plus Synthetic) Available For Export of (Imports Required)							
United States	(1,842)	(2,509)	(3,412)	(8,361)	(10,399)	(13,457)	(13,457)
Canada	(310)	(225)	6	445	1,075	1,985	1,685
North American Atlantic Islands	(1)	(2)	(3)	(4)	(5)	(6)	(6)
Latin America	2,081	2,643	2,533	1,900	1,850	1,250	750
Total Western Hemisphere	**(72)**	**(93)**	**(876)**	**(6,020)**	**(7,479)**	**(10,228)**	**(11,028)**

Note: Based on NPC Case III supply.

7. Other Factors Considered:

- *Projected Import of USSR and Eastern Europe Oil Imports/Exports on Free World Oil Supplies:* Total USSR oil exports to the Free World could increase to 1.6 million barrels per day (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 Free World—mostly Western Europe—will likely remain at about the current level of 1.1 million b/d until 1976, at which time they may decline slightly to about 900 thousand barrels per day (MB/D) and remain at around 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. Oil imports from Free World sources are expected to remain relatively small throughout the period. However, historically there has been a tendency to over estimate both the USSR's ultimate resource potential and the rate of development of its oil and gas reserves. In the event this tendency persists into the future, oil imports from Free World sources may have to increase sharply to meet growing Soviet demand as well as its export commitments to Eastern Europe countries.

  Eastern Europe's limited oil exports to the Free World, which consist mainly of products from Roumania, are expected to decline from the current 120 MB/D level to between 70 to 80 MB/D by 1985. Meanwhile, oil imports from the Free World 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 Free World 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 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 total. In 1971, locally produced coal supplied about 90 percent of total energy requirements. Hydro 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 USSR and 20 MB/D from Free World sources. Estimated energy consumption for the years 1975, 1980 and 1985 is summarized in the following tabulation:

Thousand Barrels **Daily Oil Equivalent**

	1975	1980	1985
Oil—Domestic	550	700	700
—Imports			
(USSR)	40	50	50
(Free 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

  Conjecturally, the potential for oil imports, based on need, is very large. By 1980, this potential could exceed 1 million b/d and by 1985, 1.5 MMB/D. The realization of this potential, however, will depend upon the amount of international purchasing power China is able to develop in world markets. New political arrangements are required to make such a level of trading possible.

- *Contracted Increases in Organization of Petroleum Exporting Countries (OPEC) Tax Take:* We believe that the contract increases in OPEC country tax take through 1975 will not have a substantial effect on consumer demand in the market place in the short to intermediate term. First, the price of OPEC oil to the consumer, taken over a number of years, has not increased out of proportion with general world-wide price trends. Second, because of the interchangeability of different forms of energy supplies, it is likely that energy demand will respond more to overall energy price trends, rather than the price trend in any one energy fuel supply segment.

  The effect of the OPEC tax increases in the long term will probably be seen largely in terms of its competitive position *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. Still, the OPEC tax take increases have reduced the competitiveness of OPEC oil in a number of markets—for example, versus nuclear world-wide and coal for power generation in the United States. Ultimately, we anticipate that the OPEC producing countries will seek prices that are within a competitive range with alternate sources of oil and other forms of energy. This circumstance should provide the impetus to intensify the development of alternate energy fuels world-wide.

- *Current Participation Demands:* The four partners in Aramco (Standard Oil of California, Texaco, Exxon and Mobil), early in March 1972 agreed in principle to the Saudi Arabian Government's request for 20 percent participation in Aramco operations. This principle has since been adopted by other companies operating in the Arabian Gulf area.

  The concept of "participation" is not unique. 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, the primary goal of participation is not to acquire a larger share of profits, but rather to enable the producing countries to assume a greater role in development of their own natural resources. If this proves to be the case, government ownership or participation in foreign oil operations could work to strengthen existing relationships between oil companies and foreign governments and thereby contribute needed stability to these operations as well as moderate widely different current political attitudes.

  The major issues of 1971 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 their share of the oil operations, and 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 ultimate participation percentage and timing thereof or foreign producing governments' participation in downsteam operations, can be considered—far less agreed to.

  In 1971 there were differences on the above major issues as between the negotiating parties, and it would be premature to speculate too much 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 cost of oil from the OPEC countries rises due to increased government *take*, the greater the incentive will become to explore for and develop crude oil reserves or synthetic oil from shale in the United States and tar sands in Canada.

- Table 683 shows a consensus estimate of Free World crude oil producing capacity for the years 1975, 1980 and 1985.

Eastern Europe and USSR

All of the new five-year (1971-1975) economic plans of the Comecon* countries provide for continued large scale industrial expansion. The expansion will be supported by a sizable rise in the supply of both oil and natural gas, largely within the USSR, where major new reserves are being rapidly developed in Western Siberia and in other outlying regions. However, full development of these reserves, as in Alaska, will be difficult, costly and time consuming.

Production from these new reserves probably cannot be increased rapidly enough to permit a substantial expansion of oil exports to the Free World, since rapidly rising petroleum requirements within the USSR and Eastern Europe must first be met. Exceptions would be the expansion of crude oil exports to Japan (up to 1 MMB/D) through the proposed 3,400 mile pipeline system, and sizable exports of gas to Western Europe by 1980.

The Economies

In 1971 economic growth in Eastern Europe and the USSR proceeded at a vigorous pace, probably

* Communist Economic Alliance (Eastern Bloc Economic Community, which includes Roumania, Bulgaria, Czechoslovakia and East Germany).

TABLE 683

POTENTIAL DEVELOPABLE U.S. AND NON-COMMUNIST FOREIGN LIQUID HYDROCARBON PRODUCING CAPACITY*
(Million Barrels Per Day)

	Actual	Estimated		
	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	0.5	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**	**80.4**	**98.3**
Total Non-Communist World Demand	**40.0**	**55.56**	**72.75**	**87.93**

* Including Synthetics from Coal and Shale in United States and from Tar Sands in Canada.

slightly exceeding 7 percent, up from 6.7 percent in 1970, but below the 7.7 percent per year of the past five years. In the USSR the rate of industrial expansion approached 7 percent, compared with 6.3 percent in 1970. Future growth for the combined area is expected to average 7 percent per year to 1980. These growth rates are based on industrial production. With services, transportation, etc., scheduled to increase more rapidly in the future, the historical relation of energy consumption and industrial growth will be altered.

Energy Consumption

Energy consumption in the combined area — USSR plus Eastern Europe — increased by 4.9 percent in 1971, with total energy consumption reaching 22.6 MMB/D oil equivalent. By 1980 energy consumption will increase 13.8 MMB/D to a total of 36.4 MMB/D. This represents an average annual gain of 5.4 percent compared with 4.9 percent average for the last five years (USSR 5.7 percent and Eastern Europe 4.2 percent).

Oil and gas will supply 72 percent of the increase. Most of the remainder will be furnished by coal, the most costly fuel increment not only in Russia but also in Eastern Europe.

Oil will be supplying 32 percent of the area's energy in 1980, compared with 30 percent in 1971. Natural gas will grow very rapidly, climbing from 19 percent of the total in 1971 to 26 percent in 1980. Although coal production will increase, its share of the market will decline from 48 percent in 1971 to 38 percent in 1980. Hydropower will continue to supply slightly more than 2 percent of total energy in 1980. Nuclear electricity will remain relatively insignificant, supplying just under 2 percent of total energy.

In Eastern Europe the worldwide trend toward greater reliance on oil and gas is substantially less advanced than in the USSR. Coal still supplied 70 percent of Eastern Europe's energy in 1971, compared with 39 percent in the USSR.

However, the shift to oil and natural gas in Eastern Europe is now well under way. Their combined share of total energy consumption will rise to about 40 percent in 1980, compared with 28 percent in 1971. Oil's growth rate is expected to average about 8.8 percent per year, gas 6.8 percent.

In Russia the 5.3 percent annual growth in oil and 9.5 percent increase in natural gas use to 1980 will raise these fuels' combined share of energy used to about 64 percent up from 58 per-percent in 1971. Coal's share will decline from 39 percent in 1971 to about 32 percent in 1980, but will still increase in amount at the rate of about 3.5 percent annually — even if the USSR succeeds in meeting the goals established for the rapid expansion of its large oil and gas reserves in Western Siberia and other outlaying areas.

Electricity consumption is growing rapidly in Communist Europe, with thermal plants accounting for approximately 78 percent of the expansion, nuclear 15 percent and hydro 7 percent.

Energy Supply — Eastern Europe

Eastern Europe's indigenous energy resources (mostly coal) are becoming increasingly limited in relation to requirements. Essentially self-sufficient in energy until about 1964, Eastern Europe now finds itself dependent upon imported energy (mostly oil) for nearly 20 percent of its total energy consumption.

Although Eastern Europe's potential for further substantial increases in energy production is generally limited, there are certain exceptions. Poland's coal reserves are being expanded for use at home and for export. In Eastern Germany there will be further, although somewhat limited, development of lignite production for electric power generation. Overall, however, further substantial increases in coal production will be restricted by quality and quantity of reserves—and cost. Expansion at the rate of 1.5 percent annually is expected to 1980.

Natural gas production in Eastern Europe totaled about 600 MB/D oil equivalent in 1971, representing approximately 10 percent of total energy. Further development is expected to increase gas production to 800 MB/D by 1980.

Natural gas imports, all from Russia, will rise to 340 MB/D by 1980, up from 40 MB/D in 1971.

Crude oil production, mostly in Rumania, reached 362 MB/D in 1971. Output is expected to increase slightly through 1976 then decline to 346 MB/D by 1980.

In total, increases in domestic energy production will be substantially less than the growth in consumption. As a result, 1980 energy imports, expected to exceed 2.8 MMB/D, will be two and one half times those of 1971. Oil and natural gas will supply nearly all of the imports, with coal and electricity furnishing only about 200 MB/D.

Eastern Europe has doubled its oil imports over the last 5 years to supply its growing energy needs. Imports climbed from 565 MB/D in 1966 to more than 1 MMB/D in 1971. By 1980 imports will jump to 2.3 MMB/D. This will amount to 25 percent of the area's total energy consumption, up from 15.8 percent in 1971 and 10.7 percent in 1966.

Because of logistical, economic and political necessity, a major portion of these imports will continue to come from the USSR. The Comecon pipeline is being doubled in capacity and tied into the Western Siberia's large new oil reserves.* Nevertheless, the future potential for oil imports from Russia is not unlimited. The cost and time involved in developing new productive capacity and new pipeline networks will continue to constrain the growth rate of USSR export capacity. With this limitation in mind, we expect Eastern European imports from the USSR to reach 1.2 MMB/D by 1976 and 1.5 MMB/D by 1980, up from 874 MB/D in 1971.

Meanwhile, imports from the Free World will rise from 158 MB/D in 1971 to 300 MB/D in 1976 and about 800 MB/D in 1980. Most of the imports from the Free World to 1976 appear to be covered by arrangements already made with host governments of the Middle East and North Africa. British Petroleum, however, will supply 60 MB/D of crude oil to Poland beginning in 1975 according to recent announcements.

Arrangements with host governments include the Iraqi National Oil Company (INOC) barter oil from Iraq's North Rumalia field, which is being

* The Comecon pipeline is the Soviet's main supply line to the Eastern European countries (Comecon countries).

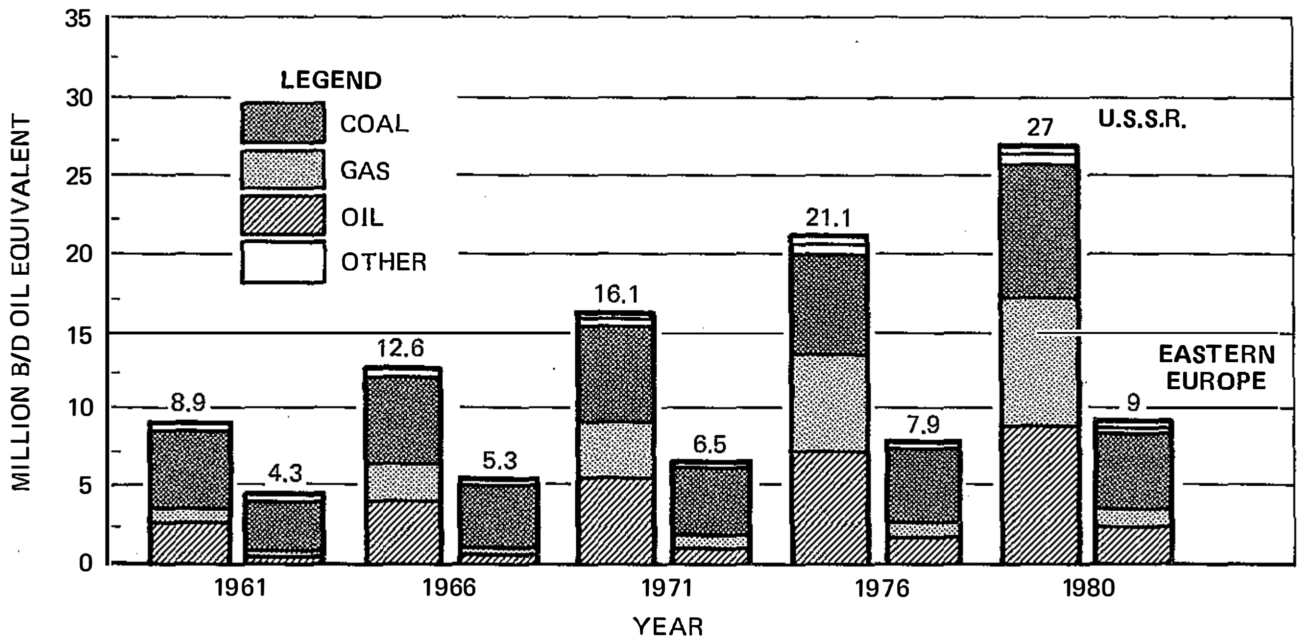


Figure 107. USSR and Eastern Europe Energy Consumption.

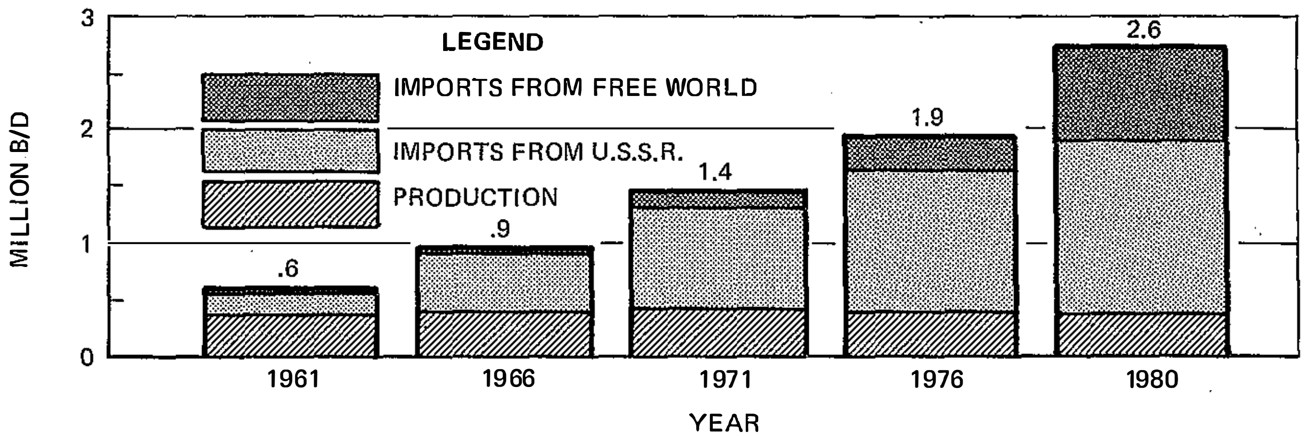


Figure 108. Eastern Europe Oil Supply.

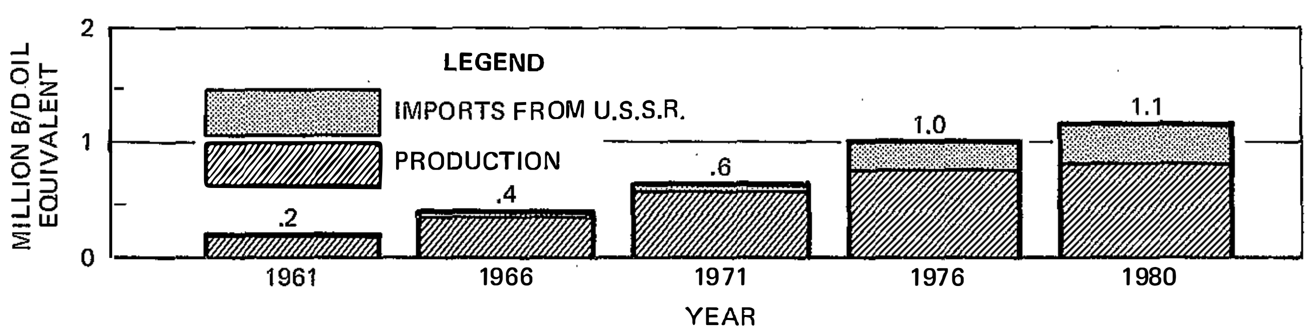


Figure 109. Eastern Europe Gas Supply.

developed with Soviet assistance. Production is scheduled to commence in early 1972 at 100 MB/D.

It is also possible that the oft-proposed pipeline from the Adriatic port of Rijeka, through Yugoslavia to Czechoslovakia and Hungary, could provide an outlet for up to 200 MB/D of additional Free World oil to Eastern Europe, probably after mid-decade.

Energy Supply — USSR

In contrast to Eastern Europe, the USSR is a substantial net exporter of energy. Priorities placed on attaining energy-production objectives have expanded supply since the mid 1950's at a faster rate than consumption growth. By 1971 total energy production of 18.3 MMB/D oil equivalent (approximately 60 percent of total U.S. energy production) was enough to satisfy not only the USSR's own requirements, but also nearly all of Eastern Europe's import needs as well. Continued large oil exports to the Free World also brought in substantial amounts of hard currency.

Russia's very large undeveloped and future potential hydrocarbon reserves give it the potential for sizeable future energy production.

For example, Russia's proved natural gas reserves, as of January 1, 1971, were reported by the Russian Oil Ministry to be 556 trillion cubic feet, more than twice those of the United States. By contrast, Russia's 1970 natural gas production was less than a third of the total produced in the United States.

Potential discoverable gas reserves in Russia are estimated by the USSR Minister of the Gas Industry to be five times or more greater than proved reserves, 60 percent of which are in Western Siberia.

Although the USSR does not publish oil reserve figures, considerable information on potential future oil production is available. For example, the major new oil province of Western Siberia, now being rapidly developed by the Russians, is indicated to have a future oil production potential comparable to the 14 MMB/D produced in the Middle East in 1970. (In that year Western Siberia's oil production was only 628 MB/D, accounting for only 9 percent of the total oil produced in the USSR.)

With large oil and gas reserves being found and delineated in outlying regions, Russia's future production, particularly up to 1980, appears to be limited only by its ability to complete long distance pipelines to move this oil and gas to market.

Coal reserves also are sizeable, but expansion of production is substantially more costly than for oil or natural gas. Therefore, output increases are expected to be limited to quantities necessary to supply marginal energy needs beyond supplies made available by continuing intensive development of oil and gas.

Nuclear plant construction is on a relatively small scale. By 1980 this source will be generating about 500 MB/D of oil equivalent, less than 2 percent of the total energy expected to be consumed at that time.

Crude and natural gas liquids production is expected to increase about 5.5 percent annually, reaching 12.5 MMB/D by 1980, up from 7.6 MMB/D in 1971.

About 20 percent of this expansion hinges upon construction of the proposed oil pipeline which will supply Japan up to 1 MMB/D through the Far East port of Nakhodka on the Sea of Japan.

Natural gas production will expand rapidly, rising from 3.65 MMB/D oil equivalent in 1971 to 9 MMB/D in 1980. Although this represents an average gain of 10.5 percent annually, the total is still less than the published 1980 production objective of 9.5 MMB/D to 10.4 MMB/D.

In 1971, USSR also imported natural gas from Afghanistan and Iran (the latter starting during the fourth quarter of 1970) totaling about 150 MB/D oil equivalent. These imports are expected to increase to about 240 MB/D in 1976, and to remain at that level to 1980. A second gas pipeline from Iran, if constructed, would increase future imports appreciably.

Increased quantities of coal also will be needed, even with the expected rapid growth of oil and gas production. In 1971 coal production equaled about 6.5 MMB/D of oil equivalent, approximately 35 percent of the USSR's total energy production. Coal output is expected to increase about 3.5 percent annually, reaching 8.8 MMB/D oil equivalent in 1980—approximately 27 percent of total energy production at that time.

The USSR's expected total energy production of 31.5 MMB/D oil equivalent in 1980 will permit exports of about 4.6 MMB/D, compared with 2.5 MMB/D in 1971. About 1.8 MMB/D oil and gas,

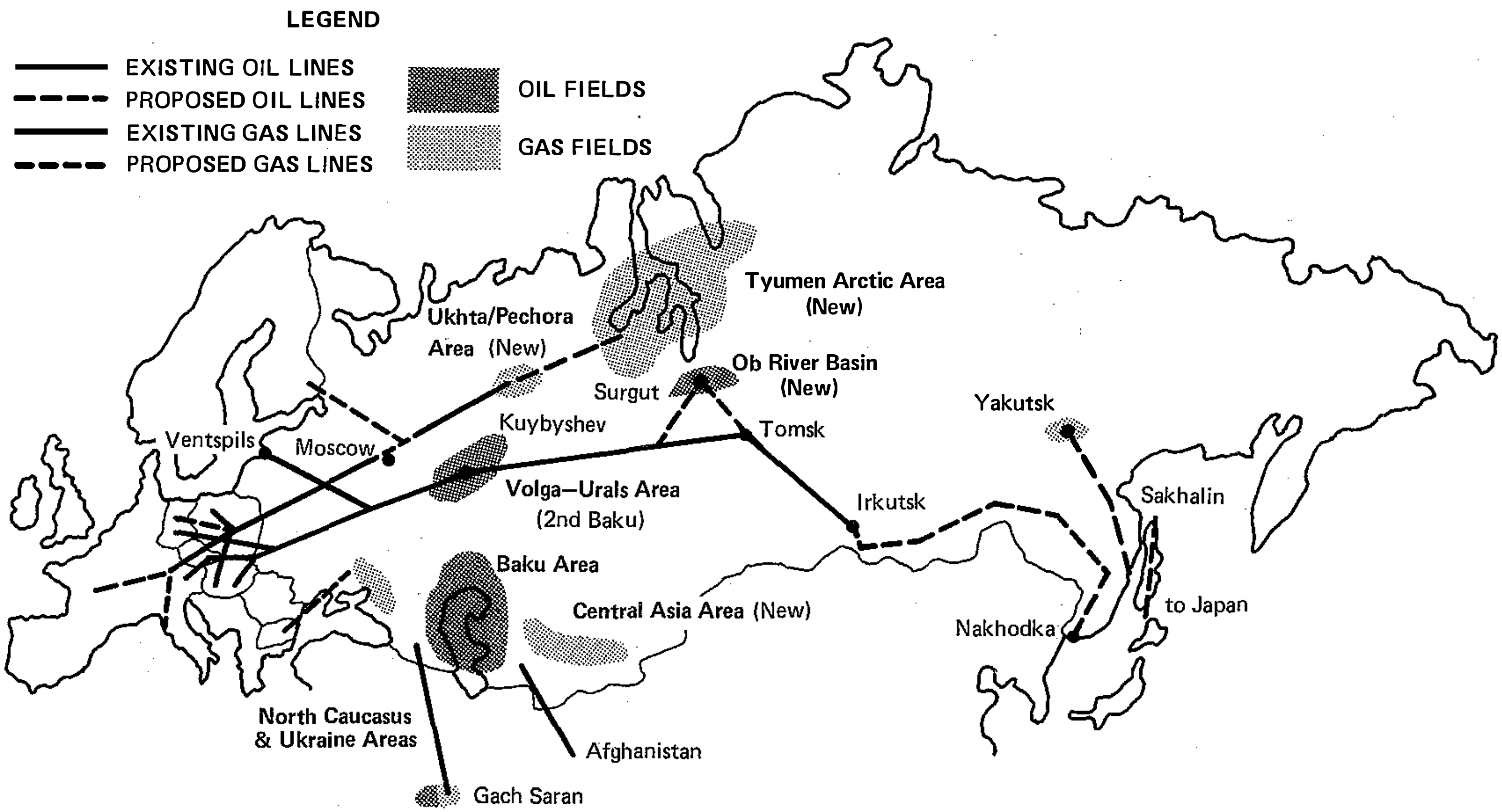


Figure 110. USSR Major Oil and Gas Pipeline Grid.

40 percent of the total, will go to Eastern Europe and 50 MB/D to Communist Asia, while the Free World will receive the balance. Oil and gas exports will total 4.3 MMB/D, and coal and electricity expects about 350 MB/D oil equivalent.

Oil Exports

USSR oil exports to Eastern Europe were 874 MB/D in 1971. By 1980, with the approximate doubling of the Comecon oil pipeline's capacity, these exports are expected to rise to at least 1.5 MMB/D.

Assuming the proposed pipeline system to Japan is in operation by mid-1976, total USSR oil exports to the Free World likely would increase to 1.6 MMB/D in 1976, and to 1.9 MMB/D by 1980. Excluding these shipments to Japan, Russian oil exports to the Free World, mostly Western Europe, are expected to remain, for the near future, near the current level of 1.1 MMB/D—a level which has remained substantially unchanged over the last four years. By 1980, these exports may decline slightly to about 900 MB/D.

Thus, the outlook to 1980 is for little, if any, additional competitive impact from Russian supplies—except for the expansion of exports to Japan.

Eastern Europe's limited oil exports to the Free World, consisting mainly of products from Roumania, are expected to decline. Estimated at about 120 MB/D in 1971 (approximate level of 5 years ago), they are expected to drop to about 80 MB/D by 1980.

Natural Gas Exports

In 1971 the USSR's exports of natural gas were still relatively small, totaling 60 MB/D oil equivalent. This gas was received in about equal quantities by Czechoslovakia, Poland and Austria.

Firm arrangements have been made, and pipeline systems are being built or planned, to extend USSR gas supply potential into five of the seven Eastern European countries (Roumania and Albania excluded) and into the Western European countries of Austria, West Germany, Italy, France and Finland. Small quantities of gas are also scheduled to go to Japan.

Future possibilities include extensions into Switzerland and Sweden by 1980, and, probably after 1980, large exports of Far Eastern Siberian gas to Japan.

Communist Asia

Total energy consumption of Communist Asia (Communist China, North Korea, North Vietnam and Mongolia) is substantial amounting to about 6.2 MMB/D oil equivalent in 1971—nearly half again as large as Latin America's consumption, and roughly 6 percent of the world total.

The economics of these countries are currently based almost entirely on local coal as a source of energy. Energy imports consist almost entirely of a small quantity of oil which is supplied predominantly from Russia.

In 1971, locally produced coal supplied about 90 percent of total energy requirements. Hydro furnished 3 percent. The remaining 7 percent was supplied by about 400 MB/D of local oil production, augmented by approximately 50 MB/D of oil imports—30 MB/D from USSR and 20 MB/D from Free World sources. The areas potential future energy requirements are huge. An annual average increase of 4 percent to 1980 would result in energy requirements of about 9 MMB/D, and to 1985 about 10.25 MMB/D oil equivalent.

With indigenous oil and natural gas reserves apparently limited, the estimate for 1980 assumes that most of the additional 2.8 MMB/D of required energy will be supplied by increased domestic coal production. This allows for a substantial increase in oil output to 700 MB/D, some increase in hydro power, and expansion of nuclear electricity to 200 MB/D oil equivalent—about 2 percent of total energy consumption.

Energy imports to 1980 will consist of about 50 MB/D of oil from Russia and a nominal 100 MB/D from Free World sources. Conjecturally, the potential for oil imports, based on need, is very large. On an order of magnitude basis this exceeds 1 MMB/D by 1980, then rises rapidly thereafter for an extended period. The realization of this potential, however, will depend upon the amount of international purchasing power China is able to develop in world markets, along with new political arrangements which would make such trading possible.

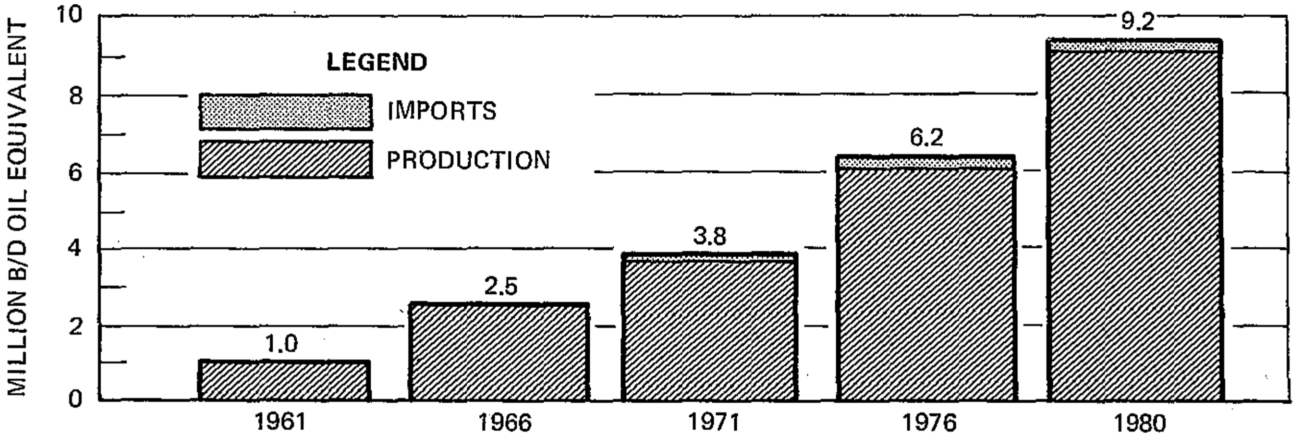


Figure 111. USSR Gas Supply.

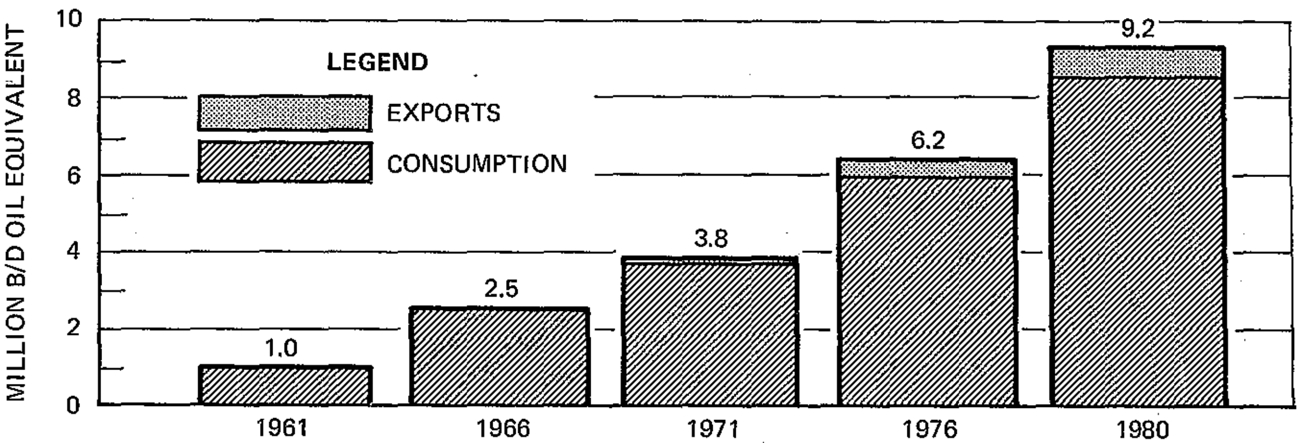


Figure 112. USSR Gas Demand.

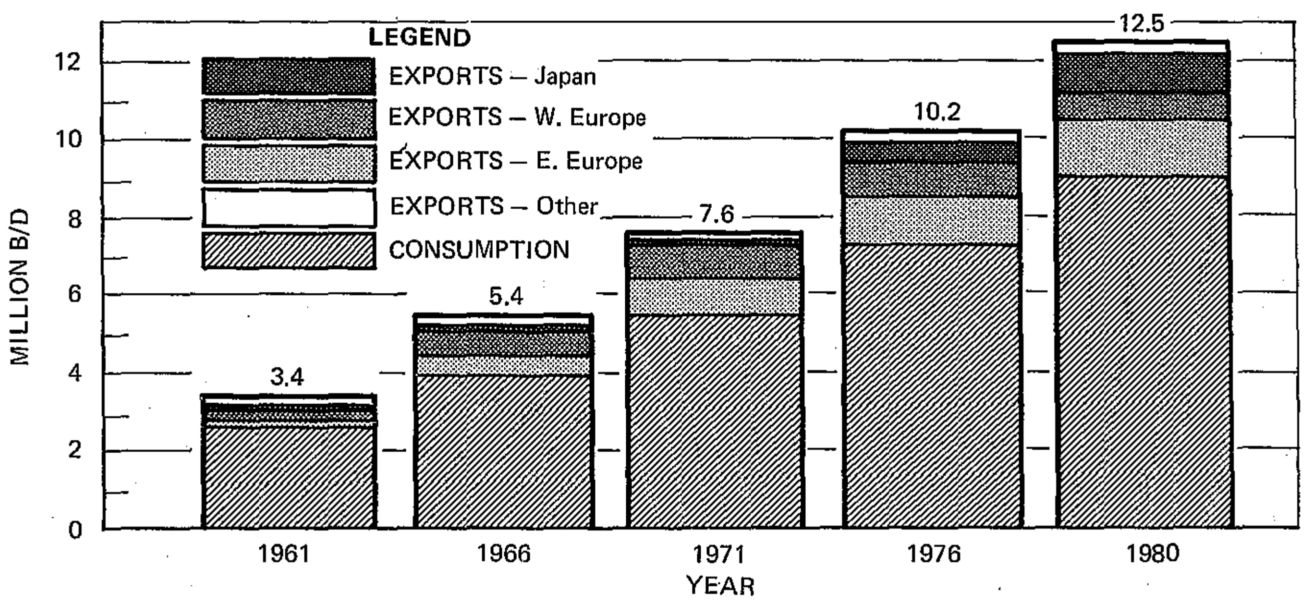


Figure 113. USSR Oil Demand.

Estimated Energy Consumption—Communist Asia
(Thousand Barrels Daily Oil Equivalent)

	1971	1975	1980	1985
Oil—Domestic	400	550	700	700
—Imported, USSR	30	40	50	50
—Free World	20	60	100	150
Total	450	650	850	900
Natural Gas	—	—	100	200
Coal	5,550	6,400	7,550	8,550
Hydro and Nuclear	200	250	500	600
Total	6,200	7,300	9,000	10,250

Peoples Republic of China

Summary

The Peoples Republic of China has a large potential for petroleum consumption in the coming years. Political and economic steps now being initiated, especially with the United States, should help to determine the extent of participation by Free World suppliers to satisfy this latent demand. In the long term, such participation will probably be limited to mitigating imbalances in this oil demand through purchases of deficit products. Joint ventures with the government on marine exploration and production are possible. In the short term, the government may also purchase crude oil while pipelines to bring their western production into the eastern consuming centers are being built.

Background Information

The Peoples Republic of China is the most populated country in the world (about 800 million) but are about the lowest unit consumption of petroleum products per capita—less than India's 10 gallons per capita annually. Oil demand has been at a low level because of a stagnating economy, particularly in the last decade. The economy is likely to improve with a lessening of internal political turmoil and increasing commercial contacts with the Free World.

This economic growth will give rise to greater and more efficient use of the natural and human resources of China. The ability of the Chinese to produce and sustain viable economics is evident from the examples of Hong Kong, Singapore and Taiwan. These countries have sustained unusually high real growth rates of GNP in the past decade, averaging roughly 10 percent per year.

With the expected surge in economic growth, the Peoples Republic of China can be expected to sustain a parallel surge in petroleum consumption which is now met from indigenous crude oil production. With improved living standards the more efficient commercial fuels such as oil will increasingly replace human energy and such non-commercial fuels as bagasse and other agricultural and animal refuse in the domestic and agricultural sectors of the economy. Oil will to some extent replace coal in the transportation and industrial sectors for special end-uses—for example in steam locomotives, where oil is more efficient.

The country's consumption of oil products will be constrained, however, because of the availability of coal from large, well-distributed fields. The country is the world's third largest producer and consumer of coal. In the coming years, it could well surpass the USSR and then the United States in coal consumption. About 90 percent of the country's commercial energy consumption is coal, and the outlook is that coal will continue to be by far the major source of energy for the large energy consuming industries such as steel and electric power.

Oil demand will also be constrained because the petroleum industry is more capital intensive than coal. In addition, the oil fields of the country are in good part located in the more remote areas of the west, over 1,500 miles from the large refining and oil consuming centers of the east and generally not as well distributed as the coal fields. As a result, additional capital outlays are required especially for pipelines to realize fully and efficiently the country's crude oil production, currently at about 400 MB/D.

In spite of these constraints on oil demand, the expected rise in economic growth will result in sharp increases in oil demand especially for selected products which are not competitive with coal. These products are likely to be kerosine, diesel and lube oils. Motor gasoline demand might increase significantly, especially if the new auto plants now being mooted are built and the road network is greatly expanded. Demand for residual fuel oil should not increase much because of competition with coal in most end-uses.

TABLE 684

ENERGY PROFILE — PEOPLES REPUBLIC OF CHINA

Petroleum and Shale Oil			
Petroleum:	Production	1970	400 Thousand Barrels per Day
		1960-1970 Growth	20% per year
		1968-1970 Growth	26% per year
	Proved Reserves		6 Billion Barrels
	Proved + Probable + Potential Reserves		20 Billion Barrels
Shale Oil:	Production	1970	80 Thousand Barrels per Day
		1960-1970 Growth	10% per year
		1968-1970 Growth	30% per year
	Proved Reserved		5 Billion Barrels
Oil Refining Capacity — 1970			400 Thousand Barrels per Day
Oil Product Consumption — 1970			400 Thousand Barrels per Day
		per capita	8 U.S. Gallons
		1960-1970 Growth	10% per year
		1968-1970 Growth	28% per year
Coal and Lignite			
Production — 1970			360 Million Metric Tons
	1960-1970 Growth		Nil
	1968-1970 Growth		10% per year
Reserves			1 Trillion Tons
Consumption — 1970			360 Million Metric Tons
	per capita		450 Kilograms
Natural Gas			
Production and Consumption — 1970			100 Million cubic feet per day
Reserves — Proved + Probable			20 Trillion cubic feet
Electric Power			
Production and Consumption — 1970			55 Billion Kilowatt Hours
Total Primary Energy			
Consumption — 1970			400 Million Metric Tons Coal Equiv.
	per capita		500 Kilograms
	% Breakdown		90% coal 7% oil 3% other
Industrial Production Index			
1960-1970 Growth			6% per year
1968-1970 Growth			20% per year

It is entirely possible that the Peoples Republic of China could increase its real GNP per capita in the next decade by at least 50 percent, based on the experience of Taiwan at the same level of GNP per capita as an example. If so, petroleum demand could well exceed 1 MB/D by 1980. It probably could not be met by refining indigenous crude oil, which could be produced in sufficient volume from the known reserves of the country, because of untenable surpluses of residual fuel oil when meeting the indicated relatively large demand for middle distillates.

TABLE 685

ENERGY AND ECONOMIC DATA—PEOPLES REPUBLIC OF CHINA VS. OTHER ASIA

All Figures Per Capita (Except Population)	1950	1955	1960	1965	1970
Petroleum Consumption			U.S. Gallons		
China	1	1	4	4	8
India	3	4	5	8	10
Indonesia	5	10	13	15	14
South Korea	2	4	9	15	86
Taiwan	4	10	20	38	95
Japan	8	32	94	258	563
Total Commercial Energy			Kilograms of Coal Equivalent		
China	90	101	687	460	505
India	100	114	140	171	187
Indonesia	60	116	134	113	110
South Korea	60	138	261	447	634
Taiwan	250	383	513	652	884
Japan	780	740	1163	1782	2828
Electric Power			Kilowatt Hours		
China	16	20	47	53	72
India	14	28	40	71	100
Indonesia	5	17	19	19	19
South Korea	22	41	69	124	287
Taiwan	136	221	342	535	944
Japan	541	733	1196	1875	3404
GNP			In 1964 U.S. $		
China	48	73	79	82	80
India	69	75	83	84	90
Indonesia	76	90	89	91	95
South Korea	78	98	104	123	180
Taiwan	95	127	147	201	257
Japan	251	338	515	780	1218
Population			Millions		
China	560	600	650	720	800
India	360	390	430	490	550
Indonesia	76	84	94	105	121
South Korea	19	21	25	28	32
Taiwan	8	9	11	12	14
Japan	83	89	93	98	103

TABLE 686

JAPANESE PRODUCTION, IMPORTS AND CONSUMPTION OF COAL
(Millions of Metric Tons)

	Actual		MITI Forecast	
	1969	1970	1975	1985
Production	45	40	38	37
Imports				
U.S.A.	19	25	–	–
Australia	16	17	–	–
U.S.S.R.	3	3	–	–
Canada	1	3	–	–
Poland	1	1	–	–
Mainland China	0.2	0.2	–	–
Other	0.8	0.8	–	–
Total	41	50	81	188
Total Production and Imports	86	90	119	225
Consumption of indigenous coal by industry:				
Electric power stations	25	21	19	19
Iron and steel plants	8	7	9	8
Coke and gas plants	5	5	6	6
Briquet plants	2	2	1	1
Other	2	3	3	3
Subtotal	42	38	38	37
Indigenous imported coal by industry:				
Iron and steel plants	38	46	78	180
Coke and gas plants	2	2	2	3
Other	2	1	1	5
Subtotal Imports	42	49	81	188
Total Indigenous + Imports	84	87	119	225

As a result, the country is expected to be short of middle distillate products in the long term with concomitant surpluses of residual fuel oils. The government would look to external purchases of these deficit products on the best possible terms. Lube oils could well constitute a sizable part of the deficits on a value basis, since the government may not be in a position to build the relatively expensive lube oil capacity needed. The country may also have some difficulty in supplying sufficient crude oil to its refineries in the short term because of transport bottlenecks. Until the required pipelines are built to the west, the country may be periodically short of crude oil and would look to imports from foreign sources if politically expedient and economically attractive.

This outlook on the oil demand of the country could be altered markedly if the government finds it expedient to export relatively large quantities of coal and residual fuel oil to Japan in exchange for needed capital and technology. This possibility exists because, on the one hand, the country's coal and crude oil reserves are large enough to support such volume exports to Japan, and on the other hand, Japan is actively seeking to increase trade with the country and to diversify its raw-material imports, especially in naphtha, low sulfur residual fuels and crude oils and coking coal for its steel industry.

It is possible that these Japanese goals would be satisfied by imports of these materials from mainland China under deals similar to the Japanese building of the Dumai refinery for Pertamina with payment in MWR product. Crude oil from the country's largest reserves at Taching is heavy and waxy and could well be low sulfur, ideally suited to Japan's needs.

If such trade with Japan transpires, then the projected surplus of residual fuel oil of the country would no longer be a problem limiting the production of desired middle distillates. Volume exports of coal to Japan could also make attractive the utilization of residual fuel oil in place of coal for electric power generation, further minimizing the surplus fuel problem of the country. It would then process additional crude oil to make up the indicated deficits of middle distillates, thereby reducing imports of these products.

The end result of such a trade deal between the Peoples Republic of China and Japan would be to essentially rule out any significant participation by other foreign oil companies. In such circumstances, the government of China would likely not permit foreign companies participation in producing, refining, distribution and marketing activities on the Chinese mainland. The following section provides the basis of the foregoing discussion and includes energy data on the Peoples Republic of China.

Market Profile

Foreign Trade

- *Imports*—1970, $2.1 billion; 1969, $1.8 billion. Principal suppliers, 1969: Japan (19 percent), West Germany (7 percent), United Kingdom (6 percent), Australia (6 percent) and Canada (5 percent). Principal imports, 1969: food-

TABLE 687

COMMUNICATIONS FACILITIES
PEOPLES REPUBLIC OF CHINA VERSUS OTHER ASIA

Country	Railways (Kilometers)	Roads & Motor Vehicles	Inland Waterways	Number of Ships	Gross Registered Tonnage (GRT)
China (PRC)	35,000	300,000 Kilometers* 409,000 Trucks 60,000 Cars 30,000 Buses	40,000 KM	237	868,000 (Tanker GRT–117,000)
India	36,900	317,800 Kilometers† 429,000 Trucks & Buses 483,000 Cars	–	254	2,402,000 (Tanker GRT–288,000)
Indonesia	7,282	51,702 Kilometers‡ 113,027 Trucks & Buses 201,743 Cars	–	–	643,000 (Tanker GRT–88,000)

* "Predominantly all-weather" and 500,000 KM "secondary" (1969).

† 317,800 "metalled" roads and 623,300 KM "other."

‡ Paved and gravelled or stabilized (51,702 KM) and 32,566 "other."

Note: Above data relate to the years 1969 and 1970; source material does not indicate if vehicles include military uses.

TABLE 688

APPROXIMATE SPECTRUM OF CONSUMPTION PEOPLES REPUBLIC OF CHINA

(Thousand Barrels Per Day)

	1969*
Production:	
Crude Oil	54
Shale Oil	21
Subtotal	75
Crude Oil Imports	
USSR	13
Other	18
Subtotal	31
Total Crude Production + Imports	106
†Products from Total Crude	
Mogas + Avgas	21
Kerosine	11
Diesel Oil	26
Fuel Oil + Lubes	43
Subtotal	101
Product Imports from USSR	
Mogas	30
Kerosine	9
Diesel Oil	12
Fuel Oil	—
Lubes	4
Subtotal	55
‡Apparent Product Consumption	
Mogas + Avgas	51
Kerosine	20
Diesel Oil	38
Fuel Oil + Domestic Lubes	43
Imported Lubes	4
Total	156
Product Spectrum as Percentage	
Mogas + Avgas	33
Kerosine	13
Diesel Oil	24
Fuel Oil + Domestic Lubes	27
Imported Lubes	3
Total	100

* Latest year available.

† Assumed refinery production: 20% Mogas, 10% Kerosine, 25% Diesel and 40% Fuel Oil.

‡ . Products from Total Crude + Product Imports.

stuffs (mainly wheat), industrial raw materials (mainly steel and nonferrous metals), textiles, machinery and equipment, and chemical fertilizers.

- *Exports*—1970, $2.1 billion; 1969, $1.8 billion. Principal buyers: Hong Kong (15 percent), Japan (11 percent), Singapore (6 percent), United Kingdom (4 percent), and West Germany (4 percent). Principal exports, 1969: foodstuffs (mainly fruits and vegetables, hogs, meat, rice and fish), textiles, clothing, crude materials (mainly silk and soybeans) and consumer goods (such as footwear, toys, glassware and pottery).
- *Trade Policy*—Foreign trade is a state monopoly conducted through seven foreign trade corporations. Dominant policy one of economic autarky. Predisposed toward bilateral trade with some flexibility relative to individual countries. Seeks to avoid dependence on any one nation as a source of supply. Mainly interested in acquiring industrial raw materials and advanced technology from West. Demand for imports tempered by policy of purchasing on a pay-as-you-go basis.
- *Trade Prospects*—Potential for U.S. exports highly speculative. Apparent best prospect categories: agricultural machinery, complete plants (especially for producing chemicals), machinery and equipment for the steel, mining, transport, construction, and petroleum industries, and industrial raw materials.

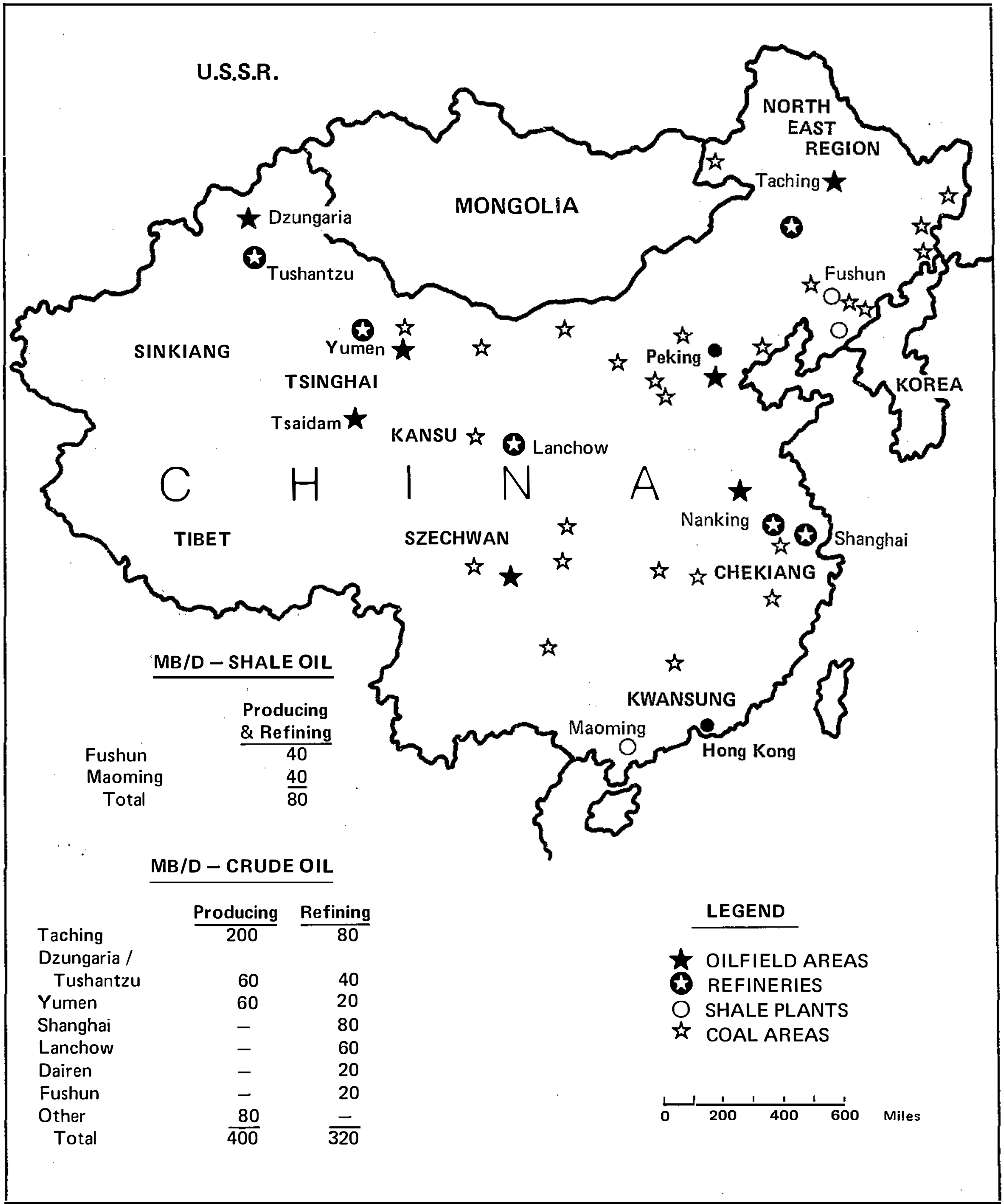
Foreign Investment

Direct investment in the People's Republic of China is not permitted. There is no indication of a change, over the short term, in this policy.

- *Currency*—Currency is called renminbi (RMB, the People's currency); the basic unit is the yuan (2.46 Yuan = $1). Renminbi is highly stable; not internationally convertible.
- *Banking*—Centrally controlled government monopoly.
- *Balance of Payments*—Believed to have accumulated a relatively significant amount of foreign exchange reserves.

Economy

Predominantly agricultural; characterized by



MB/D – SHALE OIL

	Producing & Refining
Fushun	40
Maoming	40
Total	80

MB/D – CRUDE OIL

	Producing	Refining
Taching	200	80
Dzungaria / Tushantzu	60	40
Yumen	60	20
Shanghai	–	80
Lanchow	–	60
Dairen	–	20
Fushun	–	20
Other	80	–
Total	400	320

Figure 114. Map of Crude Oil and Shale Oil Producing and Refining Centers in China.

centralized planning, administration and control.

- *GNP*—Estimated at $80 to $110 billion in 1970 in current prices; estimated annual rate of growth 4 percent. Agriculture chief source of income.
- *Agriculture*—Characterized by intensive farming and high yields; irrigation is common, crop rotation practiced; fruits grown in great variety. Principal crops: rice, wheat, potatoes, soybeans, cotton, tea, silk and tobacco. Present emphasis on increasing productivity.
- *Industry*—Principal industries: iron and steel, coal, textiles, food processing and machine building. Average annual rate of industrial growth estimated at 7 to 10 percent in recent years.
- *Commerce*—Virtually all items available to consumers are domestically produced. Adequate supplies of essential items, such as food and clothing.
- *Tourism*—Tourism as a commercial enterprise is very small.
- *Development Program*—Strategy for industrialization emphasizes modernizing agriculture and those manufacturing industries most directly related to processing agricultural raw materials. Investment is otherwise directed mainly toward consolidating and strengthening its present industrial position and developing its scientific and technical resources.

Basic Economic Facilities

All major transportation facilities are state-owned. There are over 23,000 miles of railways, over 300,000 miles of highways, and about 100,000 miles of inland waterways, 25 percent of which are navigable.

- *Communications* — Well-developed telegraph service; nationwide radio network; limited telephone and television systems.

Natural Resources

- *Land*—3.7 million square miles, mostly mountainous or hilly, little over 10 percent cultivated, 8 percent forested.
- *Climate*—Varies considerably by locale; generally temperate in north and subtropical in south. Annual rainfall increases from north to south (25 inches in Peking, 75 inches in Canton).
- *Minerals*—Coal, iron ore, oil, tin, antimony, tungsten, mercury, molybdenum, silver, lead, copper, zinc and bauxite.

Population

- *Size*—Estimated at 750 to 850 million in 1970; 85 percent rural; capital and most important commercial center is Peking, over 6 million; other principal cities: Shanghai, Tientsin, Tsingtao, Darien, Swatow and Canton.
- *Language*—National language is Mandarin.
- *Education*—Formal schooling, through university level, undergoing considerable transformation from traditional system; about 25 percent literacy.
- *Labor*—Labor force estimated at 380 to 430 million, of which some 220 to 300 million are in agriculture; shortage of scientific and technical people.

Appendices

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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.
Washington, D.C. 20006

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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.

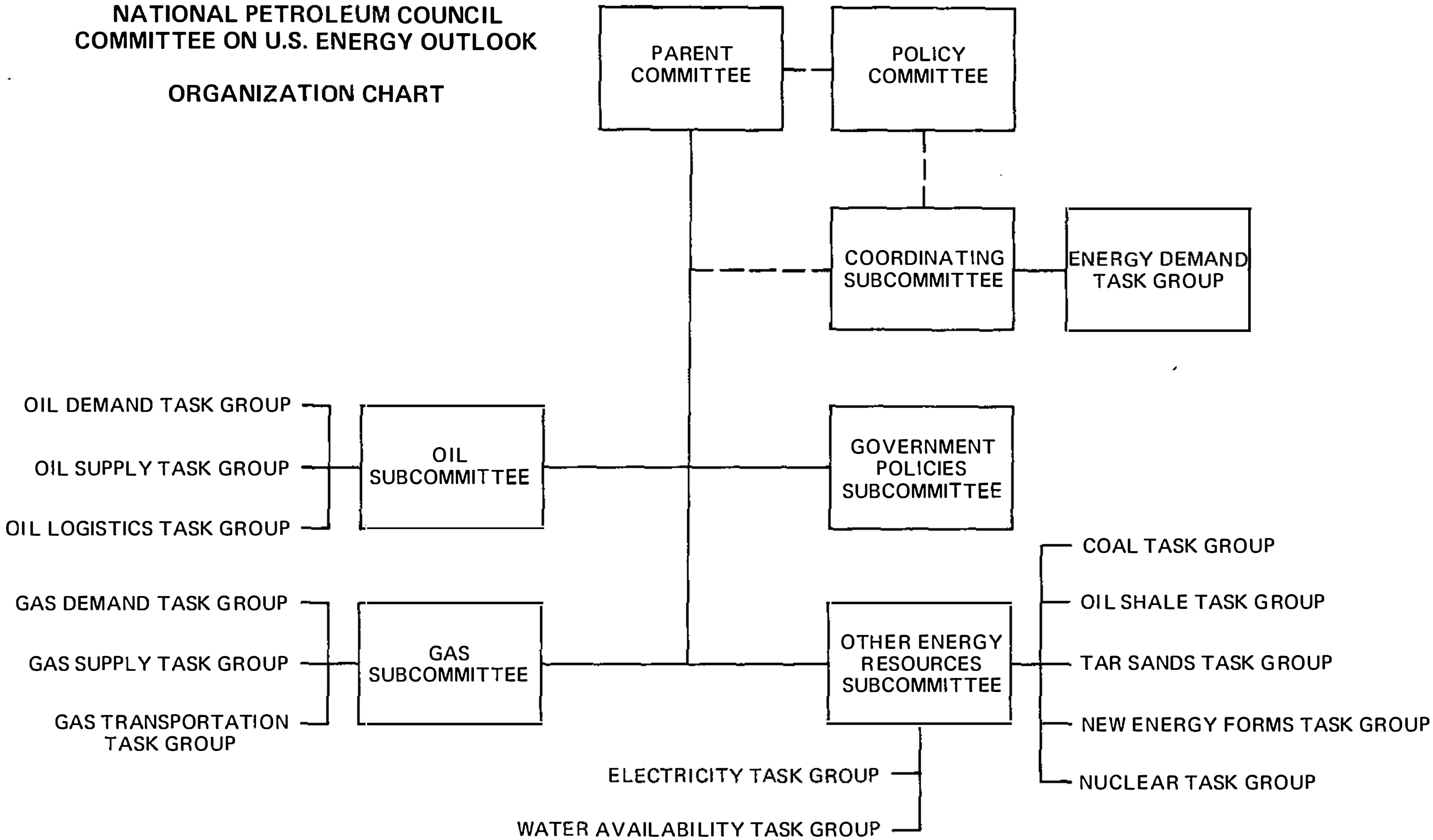
Sincerely yours,

/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

NATIONAL PETROLEUM COUNCIL
COMMITTEE ON U.S. ENERGY OUTLOOK

ORGANIZATION CHART



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W. J. Beirne, Jr. Production Department Exxon Company, U.S.A.	Petroleum
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* Served until December 15, 1972; replaced by Duke R. Ligon.
† Replaced Henry C. Rubin—June 1972.

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Trends Beyond 1985 and Balance of Trade

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* Replaced S. R. Slovenko—September 1971.
† Replaced James S. Fujioka—March 1972.

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