DOE/EIA-0216(93)
Distribution Category UC-950

U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves

1993 Annual Report

Energy Information Administration
Office of Oil and Gas
U.S. Department of Energy
Washington, DC 20585

Diskette Information

Historical oil and gas reserves data are available on a 3.5 or 5.25 inch high-density diskette. These data cover the years 1977 through 1993, as published in the Energy Information Administration annual reports of *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*. Seventeen separate annual ASCII files are stored on a single diskette. Each of the annual files contains the following data tables:

- **Crude Oil Proved Reserves, Reserves Changes, and Production**
- **Total Dry Natural Gas Proved Reserves, Reserves Changes, and Production**
- **Natural Gas Proved Reserves, Reserves Changes, and Production, Wet After Lease Separation**
- **Nonassociated Natural Gas Proved Reserves, Reserves Changes, and Production, Wet After Lease Separation**
- **Associated-Dissolved Natural Gas Proved Reserves, Reserves Changes, and Production, Wet After Lease Separation**
- **Natural Gas Liquids Proved Reserves, Reserves Changes, and Production**
- **Natural Gas Plant Liquids Proved Reserves and Production**
- **Lease Condensate Proved Reserves and Production.**

This diskette, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1977-1993, is available from the Energy Information Administration. Please contact Bob King (202/586-4787 or Fax 202/586-1076).

Preface

The *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1993 Annual Report* is the 17th prepared by the Energy Information Administration (EIA) to fulfill its responsibility to gather and report proved reserves estimates. The EIA annual reserves report series is the only source of comprehensive, nationwide proved reserves estimates. This publication is used by the Congress, Federal and State agencies, industry, and other interested parties to obtain accurate, updated estimates of the Nation's proved reserves of crude oil, natural gas, and natural gas liquids. These data are essential to the development, implementation, and evaluation of energy policy and legislation.

This report presents estimates of proved reserves of crude oil, natural gas, and natural gas liquids as of December 31, 1993, as well as production volumes for the United States and selected States and State subdivisions for the year 1993. Estimates are presented for the following four categories of natural gas: total gas (wet after lease separation), its two major components (nonassociated and associated-dissolved gas), and total dry gas (wet gas adjusted for the removal of liquids at natural gas processing plants). In addition, two components of natural gas liquids, lease condensate and natural gas plant liquids, have their reserves and production data presented. The estimates are based upon data obtained from two annual EIA surveys: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves" and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production." Also included is information on indicated additional crude oil reserves and crude oil, natural gas, and lease condensate reserves in nonproducing reservoirs. A discussion of notable oil and gas exploration and development activities during 1993 is provided.

The appendices contain information on the top 100 oil and gas fields for 1992, report Table 1 converted to metric units, historical data series, a summary of survey operations, a discussion of statistical considerations, methods used to develop the estimates provided in this report, maps of selected State subdivisions, and examples of the survey forms. This year, a new appendix contains data by operator production size class for crude oil and natural gas reserves and production. A glossary of the terms used in this report and in survey Forms EIA-23 and EIA-64A is provided to assist readers in more fully understanding the data.

This annual reserves report was prepared by the Dallas Field Office staff of the Reserves and Production Branch, Reserves and Natural Gas Division, Office of Oil and Gas, Energy Information Administration. General information regarding preparation of the report may be obtained from Craig H. Cranston, Chief of the Reserves and Production Branch (202/586-6023). Specific information regarding the content of the report may be obtained from the authors: John H. Wood, Director of the Dallas Field Office (214/767-2200), Paul Chapman (214/767-0885), John R. Tower (214/767-2907), or Rhonda Green (214/767-0886).

Other recent reports published by the Energy Information Administration (EIA) offer additional information and analysis related to domestic oil and gas supply. They may be obtained from the Government Printing Office in the same manner as this oil and gas reserves report.

EIA Oil and Gas Publications Currently Available

***Natural Gas Productive Capacity for the Lower 48 States*, DOE/EIA-0542, July 1994**

This report describes an analysis of monthly natural gas wellhead productive capacity in the lower 48 States from 1980 through 1992, and projects this capacity from 1993 through 1995. The impacts of drilling, oil and gas price assumptions, and demand on gas productive capacity are integrated into the capacity projections as low, base, and high cases.

***Natural Gas Annual 1993*, DOE/EIA-0131(93), September 1994**

Comprehensive natural gas production, transmission, consumption, and price data are published by State and Census Division. Production statistics detail onshore and offshore gross withdrawals and number of producing wells. Consumption data are reported by sector and by firm or interruptible contract.

***Natural Gas 1994: Issues and Trends*, DOE/EIA-0560(94), July 1994**

This report addresses trends relating to natural gas supply, demand, prices, imports, contracting, transportation, storage, and Federal Energy Regulatory Commission (FERC) Order 636.

***Largest U.S. Oil and Gas Fields*, DOE/EIA-TR-0567, August 1993**

This report identifies the largest 1 percent of U.S. oil and gas fields and their general location, year of discovery, and approximate National rankings in several size categories including proved reserves and annual production. Nearly two-thirds of the remaining domestic crude oil proved reserves are found in the largest 100 oil reserves fields. U.S. natural gas proved reserves are not nearly so concentrated, as 45 percent are contained in the top 100 gas reserves fields.

***Geologic Distributions of U.S. Oil and Gas*, DOE/EIA-0557, July 1992**

Important properties of crude oil and nonassociated gas field size distributions, at the end of 1989, are discussed. These data are arranged by geologic provinces. Volumetric distributions of ultimate recovery estimates are discussed across the members of three macrogeologic variable suites: (1) principal lithology of the reservoir rock, (2) principal trapping condition, and (3) geologic age of the reservoir rock.

Contents

Tables

Page

Figures

Executive Summary

Although new discoveries were up substantially in 1993, U.S. proved reserves of crude oil, natural gas, and natural gas liquids all declined again. Increased gas prices and drilling helped to hold the natural gas reserves decline to 1.6 percent. Oil reserves declined by 3.3 percent.

As of December 31, 1993, proved reserves were:

- **Dry natural gas - 162,415 billion cubic feet** (excluding gas in underground storage)
- **Crude oil - 22,957 million barrels**
- **Natural gas liquids - 7,222 million barrels** (including lease condensate).

Proved reserves are those quantities that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Petroleum engineering and geological judgment is required in estimating reserves; therefore, the results are not precise measurements. This report of 1993 U.S. proved reserves of crude oil, natural gas, and natural gas liquids is the 17th in an annual series prepared by the Energy Information Administration (EIA).

Natural Gas

New discoveries were up substantially but lower *revisions and adjustments*, along with increased production, led to the 1993 reserves decline. Lower 48 gas reserves have been generally declining since the late 1960's. However, they have declined less than 1 percent per year since natural gas prices peaked in 1983. This is a low decline rate for a period in which rapid changes in price, demand, drilling, and industry regulatory environment occurred. These changes left gas prices and drilling levels much lower in 1993 than in 1983. While proved gas reserves declined in 1992 and 1993, production increased because there was sufficient gas productive capacity to meet increased demand. This caused the ratio of proved reserves to production (R/P ratio) to drop as the remaining reserve base was more intensively produced. The R/P ratio can drop still lower. But to sustain long-term increasing production, reserves will eventually have to increase. It will take a growing and successful drilling effort to reverse the decline of gas reserves.

All five leading gas producing areas, Texas, the Gulf of Mexico Federal Offshore, Oklahoma, Louisiana, and New Mexico had proved reserves declines that totaled 2,602 billion cubic feet. Partially offsetting these were substantial increases in coalbed methane reserves in Virginia and Colorado, where gas reserves increased by 942 billion cubic feet over 1992.

After several years of rapid growth, the rate of increase in coalbed methane reserves slowed in 1993 as Federal tax incentives for new coalbed methane wells expired. Also, estimates of proved coalbed methane reserves in Alabama were lowered. However, coalbed methane production grew by more than one third, to over 4 percent of U.S. dry gas production. Coalbed methane reserves accounted for over 6 percent of U.S. natural gas reserves in 1993.

U.S. *total discoveries* of dry gas reserves were 8,868 billion cubic feet in 1993, an increase of 26 percent over 1992. These *total discoveries* are equivalent to half the 1993 gas production. *Total discoveries* are those reserves attributable to field *extensions*, *new field discoveries*, and *new reservoir discoveries in old fields*; they result from drilling exploratory wells.

- *New field discoveries* were 899 billion cubic feet, up 39 percent.
- Field *extensions* were 6,103 billion cubic feet, up 31 percent.
- *New reservoir discoveries in old fields* were 1,866 billion cubic feet, up 8 percent, but still well below the prior 10-year average.
- *Total discoveries* per exploratory well continued the upward trend that began in the early 1980's.
- Texas and the Gulf of Mexico Federal Offshore accounted for almost two thirds of U.S. total discoveries of gas.

The net volume of *revisions and adjustments* to reserves plays a major role in sustaining U.S. natural gas proved reserves. This amounted to 6,321 billion cubic feet in 1993, a 24 percent decrease that negated the 26 percent increase from *total discoveries*.

Other natural gas highlights of 1993 were:

- Total gas well completions exceeded oil well completions for the first time.
- Total gas well completions increased 7 percent to 8,564.

- Contributing to the increase of gas well completions were wells completed in 1993 but started in 1992 to take advantage of expiring tax credits for new unconventional coalbed methane and tight-sand gas wells.
- Natural gas prices at the wellhead increased 16 percent to average $2.01 per thousand cubic feet.

Crude Oil

Proved reserves of crude oil have now declined for 6 consecutive years. Low oil prices and a continuing string of new lows for oil drilling are the major factors. A bright spot this year was *total discoveries*, especially *new field discoveries.*

Total discoveries of crude oil were up to 785 million barrels in 1993. Just two areas, the Gulf of Mexico Federal Offshore and Texas, accounted for three quarters of them.

New field discoveries were the highest in 23 years, 319 million barrels. This is 3 times the prior 10-year average for *new field discoveries*, and a tremendous turnaround from the exceptionally low 1992 level. Almost all of the *new field discoveries* were in the Gulf of Mexico Federal Offshore. Improved exploration and deepwater production technology enhanced the ability to discover and develop offshore fields. For example, Shell Oil Company installed platform Auger in 2,860 feet of water and announced plans to develop the Mars prospect in 2,933 feet of water. This will set a new U.S. depth record for a permanent platform.

Other crude oil highlights of 1993 were:

- Oil prices declined to $14.20 per barrel, the lowest annual average in constant dollars since the 1973 Arab oil embargo.
- The U.S. oil price dropped to $10.38 per barrel in December 1993 with Alaskan North Slope oil at $7.00 per barrel and the California price at $8.93 per barrel.
- Lower oil prices caused lower oil drilling. Oil well completions dropped to 8,070, yet another 20-year low.
- *Total discoveries* per exploratory well were up.
- *New reservoir discoveries in old fields* were 110 million barrels, up 29 percent.
- Field *extensions* were down to 356 million barrels, well below the prior 10-year average.
- *Revisions and adjustments* were down to 766 million barrels, less than half the prior 10-year average.

Indicated additional crude oil reserves were 3,453 million barrels, a 9-percent decrease from 1992. These reserves are crude oil volumes that may become economically recoverable from known reservoirs through the application of improved recovery techniques using current technology. The presence of large indicated additional reserves in the Alaskan North Slope, California, west Texas, and New Mexico implies that significant upward revisions to crude oil proved reserves could occur in the future.

Natural Gas Liquids

U.S. natural gas liquids proved reserves declined 3 percent to 7,222 million barrels in 1993. Natural gas liquids reserves are the sum of natural gas plant liquids and lease condensate reserves.

Total proved reserves of liquid hydrocarbons (crude oil plus natural gas liquids) were 30,179 million barrels in 1993, a decline of 1,017 million barrels from the 1992 level. Natural gas liquids were 24 percent of total liquid hydrocarbon proved reserves in 1993, the same percentage as for 1992.

Data

These estimates are based upon analysis of data from Form EIA-23, “Annual Survey of Domestic Oil and Gas Reserves,” filed by 3,824 operators of oil and gas wells, and Form EIA-64A, “Annual Report of the Origin of Natural Gas Liquids Production,” filed by operators of 848 active natural gas processing plants. The U.S. proved reserves estimates for crude oil and natural gas are associated with sampling errors of less than 1 percent at a 95 percent confidence level.

1. Introduction

Background

The primary focus of this report is to provide an accurate estimate of U.S. proved reserves of crude oil, natural gas, and natural gas liquids. These estimates are considered essential to the development, implementation, and evaluation of national energy policy and legislation. In the past, the Government and the public relied upon industry estimates of proved reserves. These estimates had been prepared jointly by the American Petroleum Institute and the American Gas Association and published in their annual report, *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada.* However, they ceased publication of reserves estimates after their 1979 report.

By the mid 1970's, various Federal agencies had separately established programs to collect data on, verify, or independently estimate domestic proved reserves of crude oil or natural gas. Each program was narrowly defined to meet the particular needs of the sponsoring agency. In response to a recognized need for unified, comprehensive proved reserves estimates, Congress, in 1977, required the Department of Energy to prepare such estimates. To meet this requirement, the Energy Information Administration (EIA) created a reserves program to establish a unified, verifiable, comprehensive, and continuing statistical series for proved reserves of crude oil and natural gas. The program was expanded to include proved reserves of natural gas liquids in the 1979 report.

Oil and Gas Resource Base

Our understanding of the earth, while extensive, is still uncertain when estimates of the current and potential resources and reserves are made. The terminology used in classifying petroleum resources and reserves continues to be the subject of much study and discussion in the oil and gas industry. Therefore, it is not surprising that some confusion still surrounds the use and understanding of the terminology developed to describe these quantities. A lack of understanding of the difference between reserves and the more generalized concept of resources causes confusion, as does the variety of definitions that describe various kinds of reserves.

The total resource base of oil and gas is the total volume formed and trapped in-place within the earth before production. A portion of this total resource base is nonrecoverable by current or foreseeable technology. A large part is found at very low concentrations throughout the earth's crust. It cannot be extracted short of mining the rock or the application of some other approach that would consume more energy than it produced. An additional portion of the total resource base cannot be recovered because current production techniques cannot extract all of the in-place oil and gas even when it is present in commercial concentrations. This inability to recover 100 percent of the in-place petroleum from a producible deposit occurs because of economics, intractable physical forces, or a combination of both. The concept of recoverable resources excludes these nonrecoverable fractions of the total resource base.

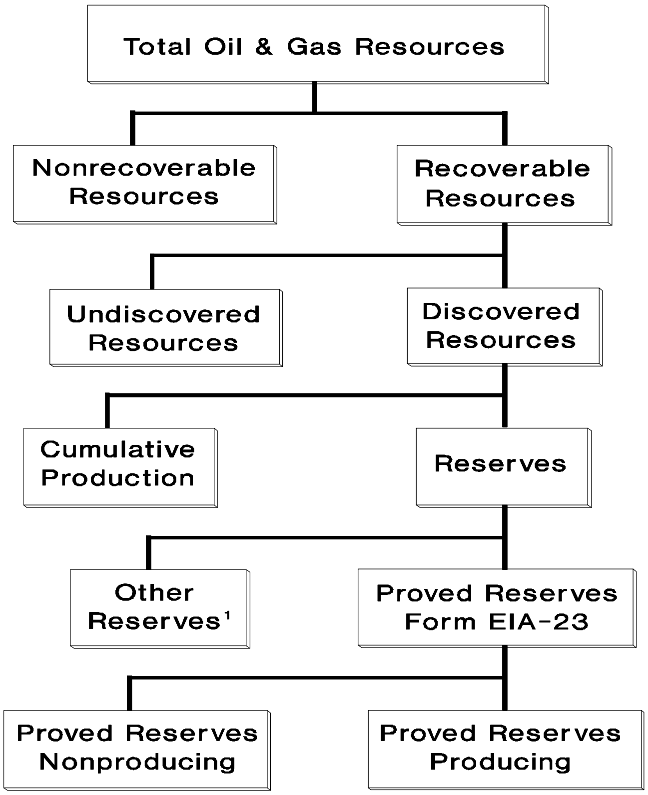
The entire structure presented in Figure 1 represents the total resource base. This total consists of recoverable and nonrecoverable portions discussed above. The next level divides recoverable resources into a discovered segment and an undiscovered segment. Discovered resources are then separated into cumulative production and reserves. Further, reserves are subdivided into other reserves and proved reserves. In addition, proved reserves may be in producing reservoirs or in nonproducing reservoirs. Although proved reserves are the focus of this report, the next several paragraphs discuss the spectrum of additional oil and gas estimated to reside in other portions of the recoverable resource base.

Recoverable Resources

Recoverable resources include both discovered and undiscovered resources. Discovered recoverable resources are defined here as those economically recoverable quantities of oil and gas, the locations of which are already known. The locations of undiscovered recoverable resources are not yet known with specificity, but they are thought to exist in geologically favorable settings.

While undiscovered recoverable resource estimates are outside the purview of this report, they merit a brief discussion to provide a sense of scale relative to proved reserves. The official sources of these domestic estimates of undiscovered recoverable

Figure 1. Relationship of Petroleum Resource and Reserve Terms



[1]Of the numerous other reserve classifications, only "Indicated Additional" reserves are in this report.

Source: Energy Information Administration, Office of Oil and Gas.

resources are the United States Geological Survey and the Minerals Management Service of the Department of the Interior (DOI).

DOI defines undiscovered recoverable conventional resources as accumulations of sufficient size and quality that they could be produced with conventional recovery technologies but without regard to economic viability. Therefore, only part of the undiscovered recoverable conventional resources is economically recoverable under conditions of current technology and imposed economic assumptions.{1}

For the 1989 national assessment, using data as of December 31, 1986, the United States Geological Survey estimated the undiscovered recoverable conventional crude oil, natural gas, and natural gas liquids resources of all onshore areas of the United States, as well as State offshore areas, while the Minerals Management Service was responsible for the Federal Offshore estimates. Both DOI groups general approach to resource estimation was a complex play analysis technique. A play is a related group of accumulations and/or prospects that have similar reservoir source and trap type. The 1989 DOI range of estimates for domestic undiscovered recoverable conventional resources was 33 to 70 billion barrels of crude oil with a mean estimate of 49 billion barrels; 307 to 507 trillion cubic feet of natural gas with a mean estimate of 399 trillion cubic feet; and 6 to 12 billion barrels of natural gas liquids with a mean estimate of 9 billion barrels.{1} These estimate ranges are stated at the 95 and 5 percent probability levels of occurrence, respectively. This means that there are 19 chances in 20 that more than the lower volume occurs and one chance in 20 that more than the higher volume occurs.

These DOI estimates for undiscovered resources were not intended to include (a) oil and gas extractable by enhanced methods, such as enhanced oil recovery and (b) so-called "unconventional" oil and gas resources, such as gas trapped in low-permeability (tight) formations. Other estimators use criteria that relax this restriction to one degree or another, in essence, speculating as to the effects of present or expected future advanced or enhanced recovery technology on the size of the recoverable resource base. Such estimates are usually made in association with different economic assumptions than those used by DOI, particularly as to future prices. For example, the American Association of Petroleum Geologists included 36 billion barrels of tertiary enhanced oil recovery in its estimate for resources recoverable with existing technology, in the price range of $25 to $50 per barrel.{2}

In 1992, DOE sponsored an assessment of the U.S. oil resource base, which among other categories, estimated from 99 to 130 billion barrels of oil recoverable with existing technology, at respective prices of $20 to $27 per barrel.{3} Also, the DOE Office of Policy, Planning, and Analysis sponsored a one-time assessment effort in May 1988, which among other gas categories, estimated 259 trillion cubic feet of unconventional gas.{4} These oil and gas amounts were considered recoverable with existing technologies in onshore areas of the lower 48 States as of December 31, 1986. Coalbed methane made up 48 trillion cubic feet of the 259 trillion cubic feet estimated in the 1988 DOE report. For comparison, the Potential Gas Committee identified 147 trillion cubic feet of coalbed methane as a recoverable resource (sum of probable, possible, and speculative mean values) in its report for data year 1992.{5} For still another comparison and among other natural gas categories, the National Petroleum Council (NPC), in December 1992, estimated 519 trillion cubic feet of unconventional gas as technically recoverable in the lower 48 States. Coalbed methane accounted for 98 trillion cubic feet of this NPC estimate, and natural gas from tight sands accounted for 349 of the 519 trillion cubic feet.{6} While the estimation of undiscovered resources is a relatively imprecise endeavor relative to estimation of proved reserves, and different assumptions as to economics and technology can yield very different results. It is clear that substantial volumes of technically recoverable resources remain to be found.

Discovered Resources

Besides cumulative production, discovered recoverable resources naturally include reserves. Cumulative production is the sum of the current year production and the production for all prior years. Reserves are volumes estimated to exist in known deposits and believed to be recoverable in the future through the application of present or anticipated technology.

Reserves

Reserves include both **proved reserves** and **other reserves**. There are many classifications of reserves used by different organizations, such as *measured*, *indicated*, *inferred*, *probable*, and *possible*. Different categorization systems are preferred by different workers. Consequently, definitions sometimes overlap. But other reserves, however they are categorized, labeled, and defined, are generally less well known and therefore less precisely quantifiable than proved reserves. Recovery of other reserves is also less assured than is that of proved reserves. Measured reserves are defined by DOI as that part of the identified economic resource that is estimated from geologic evidence supported directly by engineering data.{1} Measured reserves are demonstrated with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions and are generally equivalent to proved reserves (as defined by EIA). Indicated and inferred reserves, because of their uncertain economic or technical recoverability, remain in the other reserves category.

DOI defines inferred reserves as that part of the identified economic resources, over and above measured and indicated reserves, that will be added through extensions, revisions, and the addition of new pay zones in discovered fields.{1} Basically, inferred reserves are also considered probable reserves by many analysts, for example, those of the Potential Gas Committee.

Indicated additional reserves, a separate category, are defined by DOI and EIA as quantities of crude oil that may become economically recoverable in the future from existing productive reservoirs through the application of currently available but not installed recovery technology. When the techniques are successfully applied, the indicated additional reserves are reclassified to the proved category. Of the other reserves categories, only those classified as indicated additional reserves are estimated by EIA and included in this report.

DOI estimated the sum of indicated and inferred reserves to be 22 billion barrels of crude oil, 99 trillion cubic feet of natural gas, and 4 billion barrels of natural gas liquids.{1} In addition, another DOI report estimated 123 trillion cubic feet of unconventional gas resources in several basins thought to be recoverable using existing technology at wellhead prices of roughly $5 a thousand cubic feet.{7}

When estimates of proved reserves are added to amounts estimated for the many other oil and gas resource categories, large volumes result for potentially recoverable remaining resources. Under general conditions of historical prices and existing technology, remaining recoverable resources have been estimated to be as much as 140 billion barrels of crude oil{2} and 1,188 trillion cubic feet of natural gas.{4} Both of these estimated volumes include undiscovered and unconventional resources, and use data as of December 31, 1986. If advanced technology considerations are applied, even higher estimates would result. It should be borne in mind that such large resource estimates do not necessarily translate rapidly into large increases in proved reserves or production. That is, many decades will be required to bring these large potentially recoverable resources onstream, at great effort and cost.

Proved Reserves

EIA defines proved reserves, the major topic of this report, as those volumes of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. There are other categories of reserves, but by definition they are more speculative and less precise than proved reserves. These proved reserves are either proved producing or proved nonproducing (those reserves in reservoirs that did not produce during the report year). The proved nonproducing reserves are included in the proved reserves reported by EIA and may represent a substantial fraction of proved reserves each year. For example, 18 percent of the proved wet natural gas reserves were in nonproducing reservoirs in 1993. Others have issued similar, but not identical, proved reserves definitions. The Society of Petroleum Engineers, in concert with the Society of Petroleum Evaluation Engineers, has reserves definitions that cover proved reserves and subdivisions thereof, as well as several categories of other reserves. These societies' definitions explicitly restrict proved reserves to those that exist under current government regulations and have operational transportation facilities or a commitment or reasonable expectation that such facilities will be installed in the future. The Securities and Exchange Commission also publishes reserves definitions that are similar to those used by EIA, but the Securities and Exchange Commission definitions state the economic conditions and assumptions more explicitly. Prices and costs are as of the date the estimate is made. Future prices may include consideration of changes in existing prices provided by contractual arrangements, but not escalations based on assumptions about future conditions.

Reserves Changes

Estimates of the discovered volume of proved reserves can be made when an exploratory well penetrates an oil- or gas-bearing zone or reservoir. This estimate is based upon the initial flow data, thickness of the reservoir found, its apparent areal extent, and electrical and other measurements taken inside the hole that provide information about reservoir rock porosity (void space), permeability (ability to conduct fluid flow), fluid saturations, pressures, and temperatures. Initially, the estimate of proved reserves is based on a limited amount of data. These data are only available from exploratory drilling and interpretations of any seismic or other geophysical/geologic data. Therefore, this estimate is only a preliminary judgment regarding the amount of oil and gas in place and the amount that can be economically recovered.

As more wells are drilled and placed on production, reservoir performance data become available. These additional wells also provide more information on the thickness, extent, and other properties of the reservoir. Proved reserves estimates are then revised upward or downward, as appropriate, to reflect additional knowledge gained, as well as any improvements in technology, or changes in economic and operating conditions. As a reservoir is developed, upward revisions can occur because of additional wells from infill drilling that often add significant volumes of crude oil and/or natural gas reserves to known reservoirs, especially in tight formations.

The different physical properties of crude oil and natural gas have led to different trends in revisions. Primary recovery factors for crude oil are generally much lower than for natural gas. Therefore, improved recovery technology targeting the remaining oil in place results in relatively higher positive revisions for crude oil than for natural gas.

A field may contain a single reservoir or many reservoirs in its proved area. Changes to the originally estimated proved reserves of a field are usually made over time as revision increases, revision decreases, extensions to its proved area, or new reservoir discoveries occur. Thus, the estimate of proved reserves for any given field usually changes over time and is influenced directly by the amount, kind, and quality of data that become available concerning that field. The more data that are available and the longer the production history, the more accurate or closer to reality the proved reserve estimate becomes. (The exact amount of producible oil or gas is not known with certainty until the field is permanently abandoned and the recovered oil and gas have been recorded as cumulative production.)

Survey Overview

This report provides proved reserves estimates for the calendar year 1993. It is based on data filed by operators of oil and gas wells on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," and by operators of natural gas processing plants on Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production."

Form EIA-23

On Form EIA-23, an operator is defined as an organization or person responsible for the management and day-to-day operation of oil and/or gas wells. This definition eliminates responses from royalty owners, working interest owners (unless they are also operators), and others not directly responsible for oil and gas production operations. Each company and its parent company or subsidiaries are required to file, if they meet the survey's specifications.

Operator size categories are based upon their annual production as found in various Federal, State, and commercial records. Category I (large) operators are those that produced at least 1.5 million barrels of crude oil or 15 billion cubic feet of natural gas, or both, during the report year. Category II (intermediate) operators produced less than Category I operators, but more than 400,000 barrels of crude oil or 2 billion cubic feet of natural gas, or both. Category III (small) operators are those that produced less than did Category II operators. All data are reported on a total operated basis, encompassing all proved reserves and production associated with wells operated by an individual operator. This concept is also called the "gross operated" or "8/8ths" basis.

Large operators and most intermediate sized operators report reserves balance data on Form EIA-23 to show how reserve components changed during the year on a field-by-field basis. Small operators and intermediate sized operators who do not keep reserves data were not asked to provide estimates of reserves at the beginning of the year or annual changes to proved reserves by component of change; i.e., revisions, extensions, and new discoveries. When they did not, these volumes were estimated by applying an algebraic allocation scheme that preserved the relative relationships between these items within each State or State subdivision, as reported by large and intermediate operators.

The published reserve estimates include an additional term, adjustments, calculated by EIA, that preserves an exact annual reserves balance of the form:

Published Proved Reserves at End of Previous Report Year
+ Adjustments
+ Revision Increases
– Revision Decreases
+ Extensions
+ New Field Discoveries
+ New Reservoir Discoveries in Old Fields
– Report Year Production
= Published Proved Reserves at End of Report Year

Adjustments are the yearly changes in the published reserve estimates that cannot be attributed to the estimates for other reserve change categories because of the survey and statistical estimation methods employed. For example, variations caused by changes in the operator frame, different random samples, or imputations for missing or unreported reserve changes could contribute to adjustments.

While the primary topic of this report is proved reserves, information is also presented for crude oil on indicated additional reserves. Indicated additional crude oil reserves are not included in proved reserves because of their uncertain economic recoverability. When economic recoverability is demonstrated, these volumes will be reclassified and transferred to the proved reserves category as positive revisions.

Form EIA-64A

Form EIA-64A data were first collected for the 1979 survey year to develop estimates for total natural gas liquids reserves. Data on liquids recovered from natural gas, as reported by natural gas processing plant operators, are combined with lease condensate data collected on Form EIA-23 to provide the total natural gas liquids reserves estimates.

Data Collection Operations

An intensive effort is made each year to maintain an accurate frame of operators of oil and gas wells and of natural gas processing plants. The Form EIA-23 operator frame contained 23,576 probable active operators and the Form EIA-64A plant frame contained 843 probable active natural gas processing plants in the United States when the 1993 survey was initiated. There were additional operators added to the survey as it progressed and many operators in the sample frame were found to be inactive in 1993.

For the report year 1993, EIA mailed 4,074 EIA-23 forms to all known large and intermediate sized operators and to a sample of smaller operators that were expected to be active during 1993. Of these, 278 were nonoperators. Data were received from 3,824 operators, an overall response rate of 99.6 percent of the active operators in the Form EIA-23 survey. EIA mailed 885 EIA-64A forms to natural gas processing plant operators. More than one form is received for a plant that has more than one operator during the year. Forms were received from 100 percent of the operators of the 848 active plants in the Form EIA-64A survey.

National estimates of production volumes for crude oil, lease condensate, natural gas liquids, and dry natural gas based on Form EIA-23 and Form EIA-64A were compared with corresponding official production volumes published by EIA. For report year 1993, the Form EIA-23 national production estimates were 1.2 percent lower than the comparable *Petroleum Supply Annual 1993* volumes for crude oil and lease condensate combined, and were 2 percent lower than the comparable *Natural Gas Monthly August 1994* volume for 1993 dry natural gas. For report year 1993, the Form EIA-64A national estimates were 2.9 percent lower than the *Petroleum Supply Annual 1993* volume for natural gas plant liquids production.

Consistent data filings were fostered by the adoption of a set of specific definitions of proved reserves and related quantities to be followed by respondents in the reserve estimation and reporting process. The definitions were developed through extensive consultation with industry experts and other Government agencies. The definitions used in the Form EIA-23 and Form EIA-64A surveys and this report are presented in the Glossary. See Appendix E for a summary of data collection operations, detailed information on survey response, survey form content, frame maintenance, and data quality control procedures. See Appendix F for an explanation of the sampling and estimation methodologies used.

2. Overview

National Summary

New U.S. discoveries of crude oil and natural gas rose substantially in 1993, but not enough to prevent continuing declines in reserves. Increased gas prices and drilling helped to hold the natural gas reserves decline to 1.6 percent. Oil reserves declined by 3.3 percent.

As of December 31, 1993, proved reserves were 162,415 billion cubic feet of dry natural gas; 22,957 million barrels of crude oil; and 7,222 million barrels of natural gas liquids (including lease condensate). Statistical measures of sampling error of less than 1 percent at the 95 percent confidence level are associated with the crude oil and natural gas reserve estimates. The U.S. proved reserves balances are summarized for 1983 through 1993 in Table 1 and Figures 2 through 7.

Natural Gas Reserves

U.S. proved reserves of dry natural gas declined by 2,600 billion cubic feet. New discoveries were up substantially, but lower *revisions and adjustments*, along with increased production, led to the 1993 reserves decline. The five leading gas producing areas, Texas, the Gulf of Mexico Federal Offshore, Oklahoma, Louisiana, and New Mexico all had proved reserves declines that totaled 2,602 billion cubic feet. Partially offsetting these were substantial increases in coalbed methane reserves in Virginia and Colorado, where gas reserves increased by 942 billion cubic feet over 1992.

Of the several components of change in proved reserves, *total discoveries* are those new reserves attributable to *extensions*, *new field discoveries*, and *new reservoir discoveries in old fields*. They result from drilling exploratory wells. U.S. *total discoveries* of dry gas in 1993 were 8,868 billion cubic feet, an increase of 26 percent over 1992. However, this was still about 11 percent lower than the average during the prior 10 years. Almost two-thirds of *total discoveries* were in Texas and the Gulf of Mexico Federal Offshore.

New field discoveries of 899 billion cubic feet were up substantially from the 1992 level but 35 percent lower than the prior 10-year average of 1,389 billion cubic feet. *Extensions* (6,103 billion cubic feet) were also up, increasing 31 percent to approach the prior 10-year average. Gas reserve additions from new reservoirs increased to 1,866 billion cubic feet. This was higher than in 1992, but was much lower than the prior 10-year average.

The net volume of *revisions and adjustments* to reserves plays a major role in sustaining U.S. natural gas proved reserves. This amounted to 6,321 billion cubic feet in 1993, a 24 percent decrease that negated the 26-percent increase from *total discoveries.*

There are thousands of positive and negative revisions to proved reserves each year as infield wells are drilled, well performance is analyzed, new technology is used, or economic conditions change. In particular, *revisions and adjustments* for coalbed methane fields were down in 1993. However, the natural gas *revisions and adjustments* of 1993 and also those for 1989 through 1992 are still substantially larger than those of the 1983 through 1987 period (Figure 5).

The lower 48 States onshore reserves have been declining at a relatively low average rate of 0.6 percent per year for the last decade. The lower 48 States offshore gas reserves (20 percent of the U.S. total gas reserves) have been declining a little faster, 1.6 percent per year, for the last decade (Figure 4). Alaskan gas reserves have been generally increasing since the large 1988 downward revisions taken for economic reasons.

Crude Oil Reserves

During 1993, crude oil proved reserves decreased by 788 million barrels. With this 3.3-percent decline, reserves of crude oil have now declined for 6 consecutive years. Low oil prices and a continuing string of new lows for oil drilling are the major factors.

A bright spot for 1993 was *total discoveries*, especially *new field discoveries*. *Total discoveries* of crude oil were up to 785 million barrels in 1993. Just two areas, the Gulf of Mexico Federal Offshore and Texas, accounted for three quarters of the total.

New field discoveries were the highest in 23 years, 319 million barrels. This is 3 times the prior 10-year average for *new field discoveries* (Figure 3), and a tremendous turnaround from the exceptionally low 1992 level.

Table 1. Total U.S. Proved Reserves of Crude Oil, Dry Natural Gas, and Natural Gas Liquids, 1983 through 1993

Year	Adjustments (1)	Revision Increases (2)	Revision Decreases (3)	Revisions[a] and Adjustments (4)	Extensions (5)	New Field Discoveries (6)	New Reservoir Discoveries in Old Fields (7)	Total[b] Discoveries (8)	Production (9)	Proved[c] Reserves 12/31 (10)	Change from Prior Year (11)
	Crude Oil (million barrels of 42 U.S. gallons)										
1983	462	2,810	1,299	1,973	629	105	190	924	3,020	27,735	-123
1984	159	3,672	1,227	2,604	744	242	158	1,144	3,037	28,446	+711
1985	429	3,037	1,439	2,027	742	84	169	995	3,052	28,416	-30
1986	57	2,724	1,869	912	405	48	81	534	2,973	26,889	-1,527
1987	233	3,687	1,371	2,549	484	96	111	691	2,873	27,256	+367
1988	364	2,684	1,221	1,827	355	71	127	553	2,811	26,825	-431
1989	213	2,698	1,365	1,546	514	112	90	716	2,586	26,501	-324
1990	86	2,483	1,000	1,569	456	98	135	689	2,505	26,254	-247
1991	163	2,097	1,874	386	365	97	92	554	2,512	24,682	-1,572
1992	290	1,804	1,069	1,025	391	8	85	484	2,446	23,745	-937
1993	271	2,011	1,516	766	356	319	110	785	2,339	22,957	-788
	Dry Natural Gas (billion cubic feet, 14.73 psia, 60° Fahrenheit)										
1983	3,090	17,602	17,617	3,075	6,909	1,574	2,965	11,448	15,788	200,247	-1,265
1984	-2,241	17,841	14,712	888	8,299	2,536	2,686	13,521	17,193	197,463	-2,784
1985	-1,708	18,775	16,304	763	7,169	999	2,960	11,128	15,985	193,369	-4,094
1986	1,320	21,269	17,697	4,892	6,065	1,099	1,771	8,935	15,610	191,586	-1,783
1987	1,268	17,527	14,231	4,564	4,587	1,089	1,499	7,175	16,114	187,211	-4,375
1988	2,193	23,367	[d]38,427	-12,867	6,803	1,638	1,909	10,350	16,670	[d]168,024	-19,187
1989	3,013	26,673	23,643	6,043	6,339	1,450	2,243	10,032	16,983	167,116	-908
1990	1,557	18,981	13,443	7,095	7,952	2,004	2,412	12,368	17,233	169,346	+2,230
1991	2,960	19,890	15,474	7,376	5,090	848	1,604	7,542	17,202	167,062	-2,284
1992	2,235	18,055	11,962	8,328	4,675	649	1,724	7,048	17,423	165,015	-2,047
1993	972	17,597	12,248	6,321	6,103	899	1,866	8,868	17,789	162,415	-2,600
	Natural Gas Liquids (million barrels of 42 U.S. gallons)										
1983	849	847	781	915	321	70	99	490	725	7,901	+680
1984	-123	866	724	19	348	55	96	499	776	7,643	-258
1985	426	906	744	588	337	44	85	466	753	7,944	+301
1986	367	1,030	807	590	263	34	72	369	738	8,165	+221
1987	231	847	656	422	213	39	55	307	747	8,147	-18
1988	11	1,168	715	464	268	41	72	381	754	8,238	+91
1989	-277	1,143	1,020	-154	259	83	74	416	731	7,769	- 469
1990	-83	827	606	138	299	39	73	411	732	7,586	-183
1991	233	825	695	363	189	25	55	269	754	7,464	-122
1992	225	806	545	486	190	20	64	274	773	7,451	-13
1993	102	764	640	226	245	24	64	333	788	7,222	-229

[a]Revisions and adjustments = Col. 1 + Col. 2 - Col. 3.

[b]Total discoveries = Col. 5 + Col. 6 + Col. 7.

[c]Proved reserves = Col. 10 from prior year + Col. 4 + Col. 8 - Col. 9.

[d]An unusually large revision decrease to North Slope dry natural gas reserves was made in 1988. It recognizes some 24.6 trillion cubic feet of downward revisions reported during prior years by operators because of economic and market conditions. The Energy Information Administration (EIA) in previous years carried these reserves in the proved category.

Notes: *Old* means discovered in a prior year. *New* means discovered during the report year. The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves" and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production." They may differ from the official EIA production data for crude oil, natural gas, and natural gas liquids for 1993 contained in the *Petroleum Supply Annual 1993*, DOE/EIA-0340(93) and the *Natural Gas Annual 1993*, DOE/EIA-0131(93).

Sources: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, 1983 through 1992 annual reports, DOE/EIA-0216.{8-17}

Figure 2. U.S. Crude Oil Proved Reserves, 1983-1993

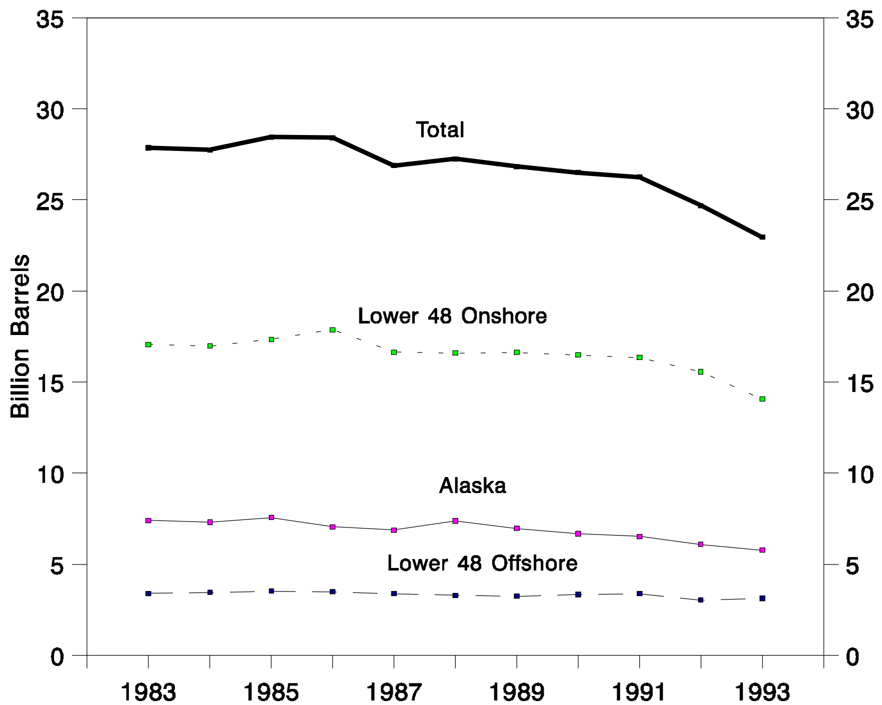
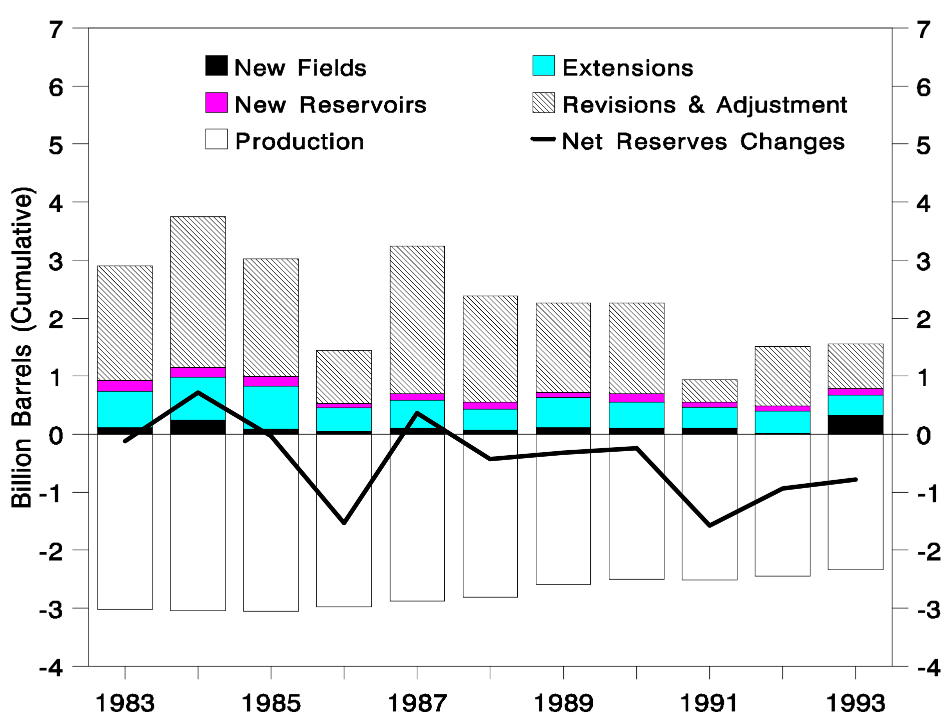


Figure 3. Components of Reserves Changes for Crude Oil, 1983-1993



Source: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1983 through 1992 annual reports, DOE/EIA-0216.{8-17}

Figure 4. U.S. Dry Natural Gas Proved Reserves, 1983-1993

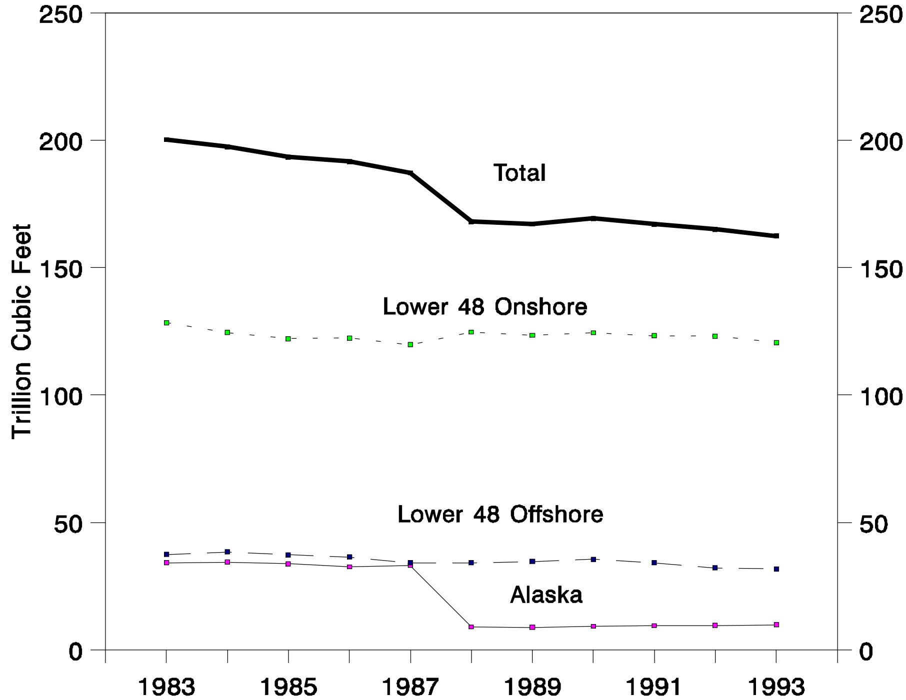
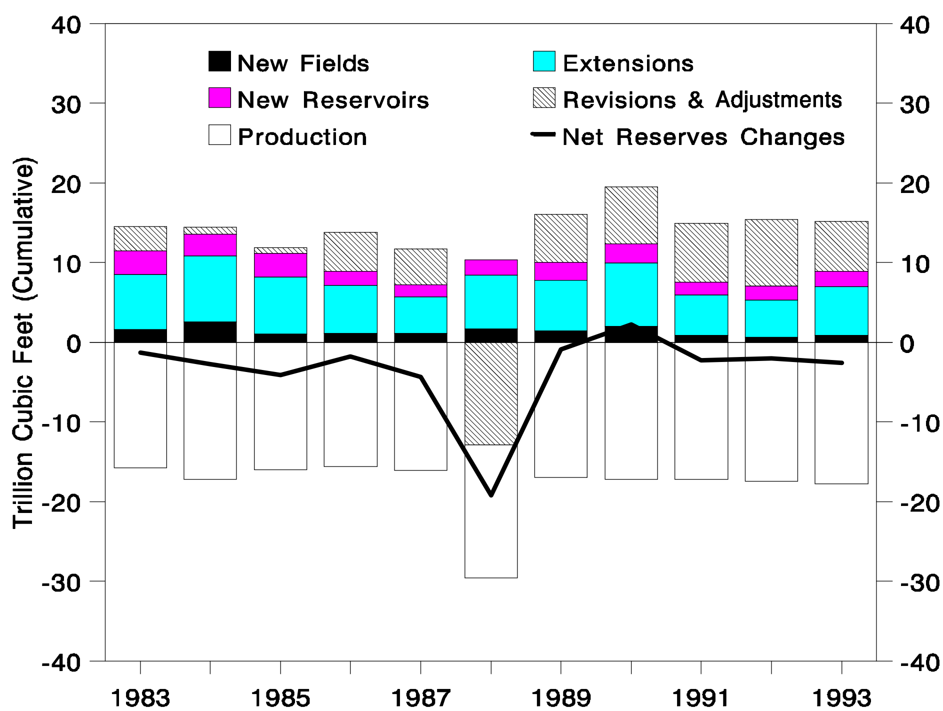


Figure 5. Components of Reserves Changes for Dry Natural Gas, 1983-1993



Source: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1983 through 1992 annual reports, DOE/EIA-0216.{8-17}

Figure 6. U.S. Natural Gas Liquids Proved Reserves, 1983-1993

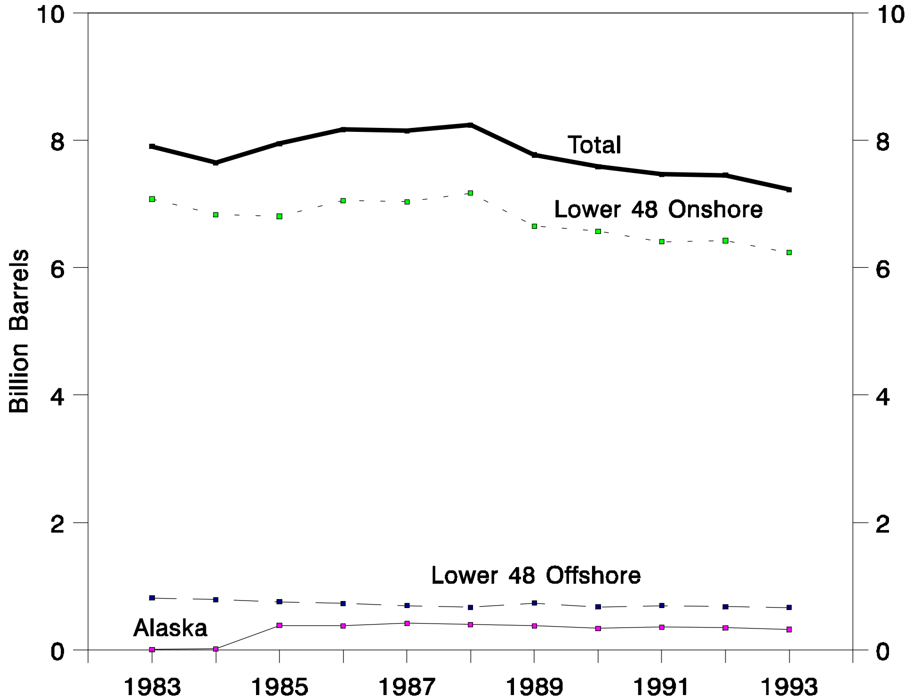
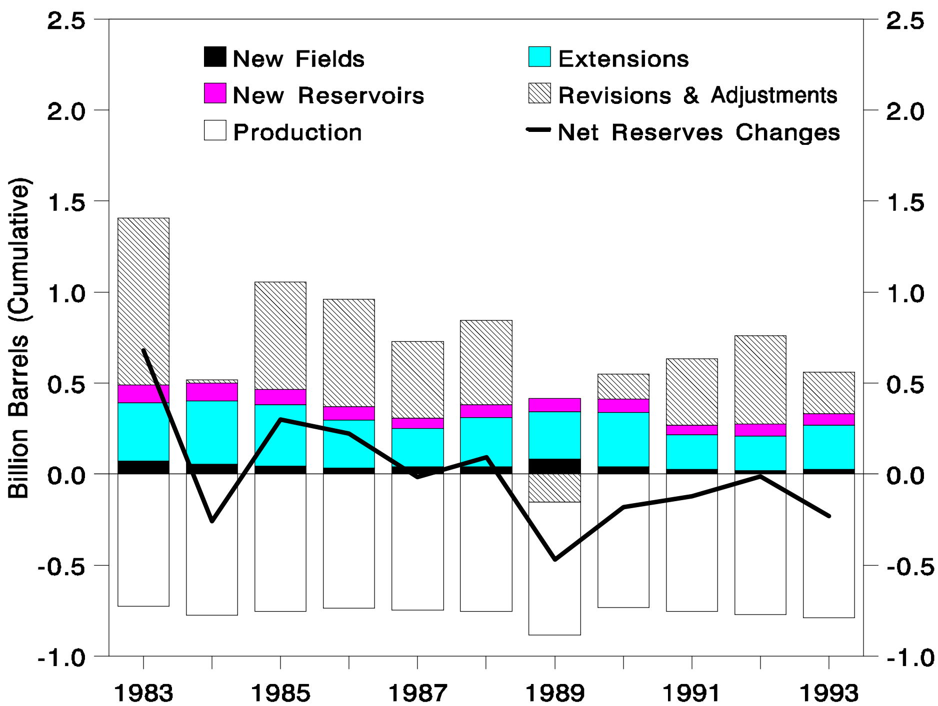


Figure 7. Components of Reserves Changes for Natural Gas Liquids, 1983-1993



Source: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1983 through 1992 annual reports, DOE/EIA-0216.{8-17}

Almost all of the *new field discoveries* were in the Gulf of Mexico Federal Offshore. Improved exploration and deepwater production technology has enhanced the ability to discover and develop offshore fields. For example, Shell Oil Company installed platform Auger in 2,860 feet of water and announced plans to develop the Mars prospect in 2,933 feet of water. This will set a new U.S. depth record for a permanent platform. Improved technology is also aiding exploration of major new subsalt plays in the Gulf of Mexico that should lead to future new field proved reserves.

Revisions and *adjustments* for crude oil in 1993 were only 766 million barrels. This component of reserves change is usually the largest and has consistently helped to sustain U.S. crude oil proved reserves. But in 1993, it was less than half the average of 1,642 million barrels for the prior 10 years. Three States had 86 percent of the positive net of *revisions* and *adjustments*: Alaska (318 million barrels), Texas (197 million barrels), and California (142 million barrels).

Even with the large *new field discoveries*, *total discoveries* were not particularly large. For the last 8 years, *total discoveries* have been relatively low, reflecting a similar trend in exploratory drilling that followed the crude oil price collapse of 1986. In 1981 there were more than 7 times as many successful exploratory oil wells drilled as in 1993. However, since 1981, *total discoveries* added per exploratory well has increased, moderating the impact of the drop in drilling. With the large 1993 *new field discoveries*, it was 4 times as high in 1993 as in 1981, but it may well drop from this high level.

Proved reserves added by *extensions* (356 million barrels) were down some from those in 1992 and substantially below the prior 10-year average of 509 million barrels.

Proved reserves of *new reservoir discoveries in old fields* (110 million barrels) were up 29 percent from 1992, but still below the 124 million barrel average for the prior 10 years.

There were proved reserves of 3,017 million barrels of crude oil located in nonproducing reservoirs. These are included in the total proved reserves and represent 13 percent of the total.

Indicated additional crude oil reserves were 3,453 million barrels, a 9-percent decrease from 1992. These reserves are crude oil volumes that may become economically recoverable from known reservoirs through the application of improved recovery techniques using current technology. The presence of large indicated additional reserves in the Alaskan North Slope, California, west Texas, and New Mexico imply that significant upward revisions to crude oil proved reserves could occur in the future.

Natural Gas Liquids Reserves

U.S. natural gas liquids proved reserves declined 3 percent to 7,222 million barrels in 1993. Natural gas liquids reserves are the sum of natural gas plant liquids and lease condensate reserves.

Total proved reserves of liquid hydrocarbons (crude oil plus natural gas liquids) were 30,179 million barrels in 1993, a decline of 1,017 million barrels from the 1992 level. Natural gas liquids were 24 percent of total liquid hydrocarbon proved reserves in 1993, the same percentage as in 1992.

Reserves by Operator Production Size Class

The oil and gas proved reserves estimates for 1993 are based on data collected from a sample of the 23,576 active operators of oil and gas wells. The 20 largest oil and gas producing operators in 1993 had 75 percent of U.S. proved reserves of crude oil. These operators concentrated their domestic operations on fewer fields and focused more of their resources on foreign operations during the last several years. Consequently, the top 20 producing operators had a 3.9-percent decline in their domestic proved reserves of crude oil during 1993, whereas the next 80 operators had a 1.3-percent increase.

All operators that reported production or reserves to EIA were ranked by production. Operator production was the sum of the barrel of oil equivalent of their crude oil production, lease condensate production, and wet gas production. The operators were placed in the following production size classes: 1-10, 11-20, 21-100, 101-500, 501-2,500, and “other.” The “other” class contains 21,076 small operators. Operators may change from one size class to another over time. For example, the top 10 class always contains the 10 highest producing operators each year, but it is not necessarily the same 10 operators each year. Tables of production and reserves by operator production size class for the years 1988 through 1993 are presented in Appendix A.

U.S. proved reserves are highly concentrated in the larger operator classes. In 1993, the top 20 operators had 59 percent of the reserves of wet natural gas or 100 trillion cubic feet (Figure 8). The 80 operators in the 21-100 class had 23 percent of the gas reserves. The smallest 21,076 operators had only 2 percent. Therefore, the average top 20 operator had 25,000 times as many gas reserves as the average operator in the "other" class.

While the top 20 had a 4-percent decline in their wet natural gas proved reserves from 1992 to 1993, the class 21-100 operators had a 2-percent increase (Figure 9). A substantial portion of this increase probably came from acquisitions of reserves from other companies.

Proved reserves of crude oil are more concentrated than those of natural gas. The top 20 had 75 percent of the U.S. oil reserves compared to 59 percent of the wet gas reserves in 1993 (Figure 10). The 80 operators in the 21-100 class had 10 percent of U.S. reserves of crude oil compared to 23 percent of the gas reserves. The 21,076 operators in the "other" class had only 4 percent of U.S. reserves of crude oil. The average top 20 operator had 22,000 times as many oil reserves as the average operator in the "other" class. While the oil and gas reserves are concentrated in the larger operators, the oil and gas industry is not nearly as concentrated as many major U.S. industries, for example, the automobile industry.

The top 20 operators had a 21-percent decline in their oil reserves from 1988 to 1993 (Figure 11), while total U.S. proved reserves of crude oil declined by 14 percent. Without the top 20, the rest of the U.S. operators had a 15-percent increase from 1988 to 1993. The large independents, the 80 operators in production size class 21-100, accounted for most of the increase. These operators had a 49-percent increase in their oil reserves during the 1988 through 1993 period. A substantial portion of this increase probably came from property acquisitions. The pattern of reserve changes continued during 1993 as the class 21-100 operators' oil reserves increased, while the top 20 operators' reserves declined.

Large operators produce oil and gas in a large number of fields. The average top 20 operator was active in 329 fields in 1993. In aggregate, they had an operator field count of 6,589 (Figure 12). The 400 operators in class 101-500 had an operator field count of 11,881. However, with roughly half the field count, the top 20 had 6 times the gas reserves and 12 times the oil reserves of class 101-500. Obviously, the top 20 have much larger fields.

Over the 1988-1993 period, the top 20 operators cut the number of fields they operated in by 38 percent as they concentrated their activities (Figure 13). The total number of active U.S. fields was relatively stable from 1988 through 1993.

Coalbed Methane

The rate of increase in coalbed methane reserves slowed in 1993 as Federal tax incentives for new coalbed methane wells expired (Figure 14). Also, estimates of proved coalbed methane reserves in Alabama were lowered. Coalbed methane reserves accounted for 6 percent of total U.S. gas reserves in 1993 at 10,184 billion cubic feet.

Coalbed methane production continued its rapid increase, growing by over one-third in 1993. Most of the 1993 production increases occurred in the San Juan Basin of Colorado and New Mexico. Over 4 percent of U.S. gas production came from coalbed methane in 1993, an increase of 800 percent in just 4 years.

Reserves Changes

Table 2 displays the reserves changes for crude oil and dry natural gas for the period 1977 through 1993. There have been 37,308 million barrels of reserves additions of crude oil since 1976. Reserves additions from exploratory drilling make up crude oil *total discoveries* of 13,380 million barrels, 36 percent of all reserves additions since 1976.

Crude oil reserves and production have been primarily sustained by continuing upward revisions to the reserves of older fields. The bulk of post-1976 crude oil reserves additions were the 23,928 million barrels of *revisions* and *adjustments* that accounted for 64 percent of all reserves additions. However, during the last 3 years these *revisions and adjustments* for crude oil have been much lower than average. Infill drilling, *extensions*, enhanced oil recovery projects, technological advances, better than expected reservoir performance, and improved economics are major factors in these revisions. However, economic factors do not always improve. Low oil and gas prices can lead to lower or even downward revisions of proved reserves.

The estimated ultimate recovery of fields (sum of cumulative production and proved reserves at a given point in time) generally increases over time. Newly discovered fields generally have large

Figure 8. Wet Natural Gas Proved Reserves by Operator Production Size Class in 1993

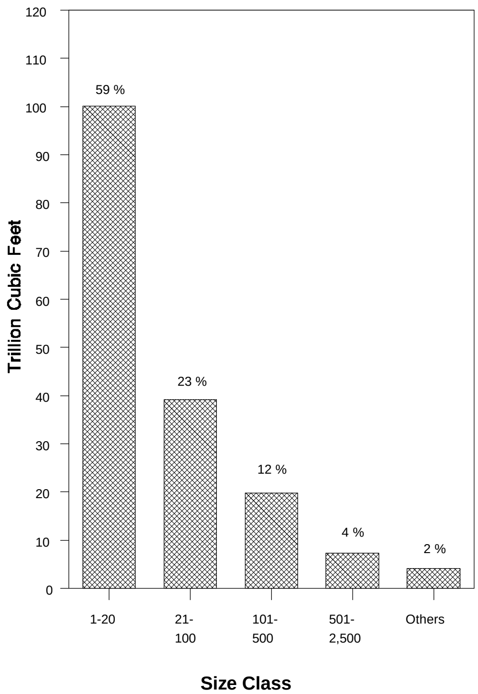


Figure 10. Crude Oil Proved Reserves by Operator Production Size Class in 1993

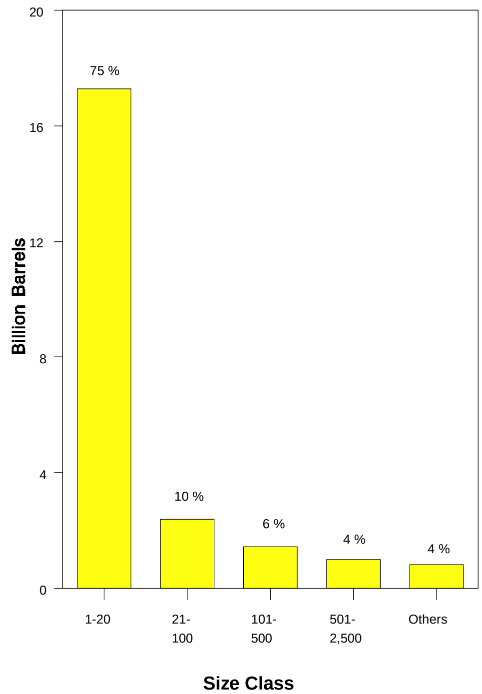


Figure 9. Percentage Change for Wet Natural Gas Proved Reserves by Operator Production Size Class, 1988-1993 and 1992-1993

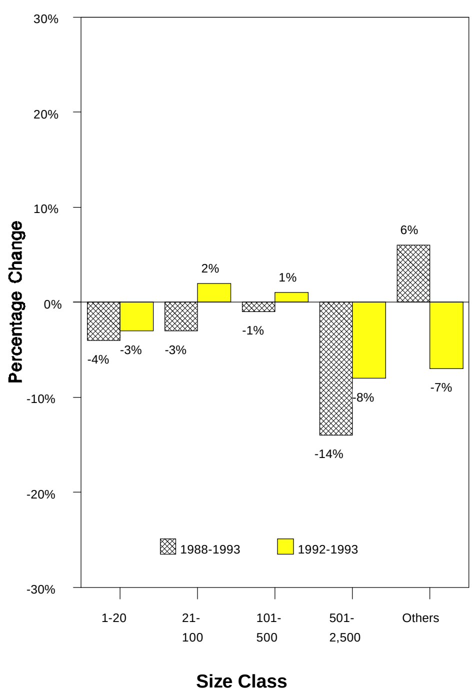
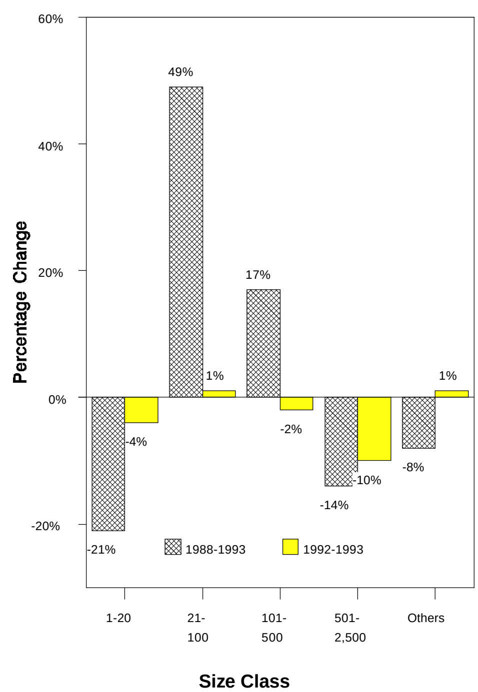
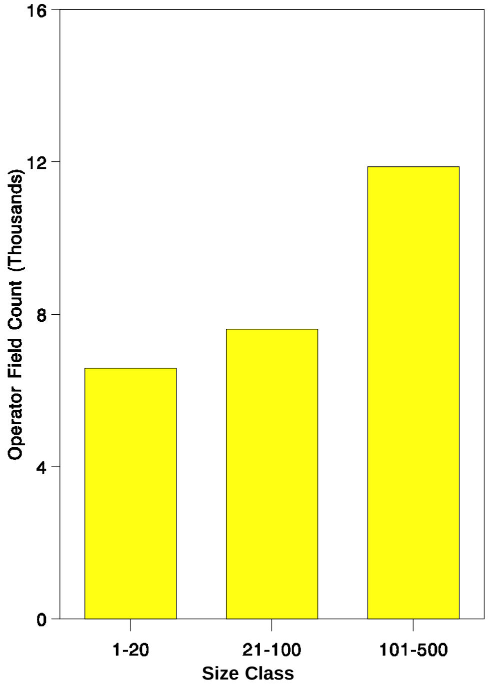


Figure 11. Percentage Change for Crude Oil Proved Reserves by Operator Production Size Class, 1988-1993 and 1992-1993



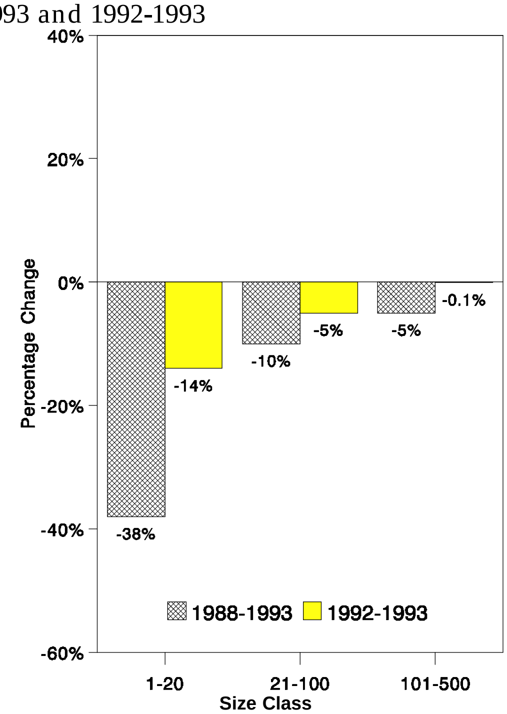
Source: Energy Information Administration, Office of Oil and Gas.

Figure 12. Operator Field Counts by Production Size Class in 1993



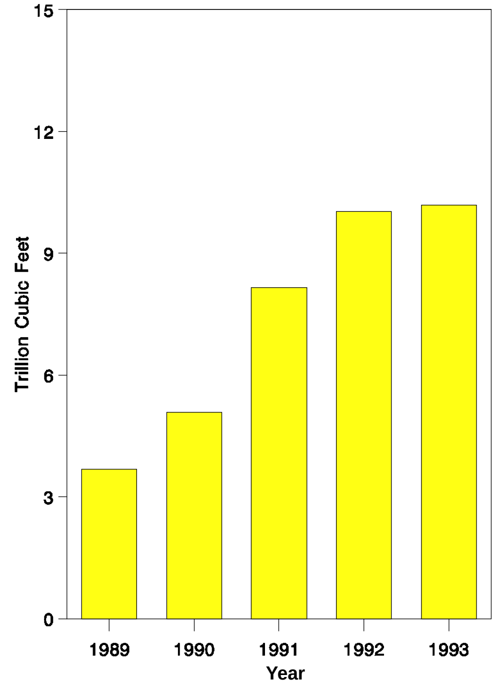
Source:Energy Information Administration, Office of Oil and Gas.

Figure 13.Percentage Change in Operator Field Counts by Production Size Class, 1988-1993 and 1992-1993



Source:Energy Information Administration, Office of Oil and Gas.

Figure 14. Coalbed Methane Proved Reserves, 1988-1993



Source:Energy Information Administration, Office of Oil and Gas.

increases in reserves during the first few years after they are first booked, because extensions, new reservoirs, and revisions add to the estimates of these new fields' ultimate recovery. However, most of the net of *revisions* and *adjustments*, most of the *new reservoir discoveries in old fields*, and substantial portions of the *extensions* booked since 1976 came from fields discovered before 1977. An EIA study described in the publication *U.S. Oil and Gas Reserves by Year of Field Discovery*{18} found that almost 87 percent of the crude oil and lease condensate reserves additions in 1978 through 1988 came from fields discovered before 1978. This means just 13 percent of the crude oil and lease condensate reserves were added in fields that had discovery wells completed during the 1978 through 1988 time period.

Due to the nature of the industry's proved reserves booking process, the year that proved reserves are first reported for a field is often later than the year of discovery, the year that the discovery well was completed. Therefore, it is probably true that a substantially higher proportion of the total reserve additions for the 1977 through 1993 period came from fields that were first reported as having booked proved reserves during that period than would be true for comparable year of discovery well data. A direct comparison of reserves changes by year of discovery and those in this report cannot currently be made, because it is often the case that fields are not booked as having proved reserves for several years after the discovery well is drilled. Delineation drilling and a commitment to develop the field are often required before a field's reserves are booked as proved and reported on Form EIA-23. This would be particularly true for fields found in frontier areas or the Federal Offshore. Decades can elapse between the discovery well and the year an offshore or frontier area field has its proved reserves booked, especially if economic and technical problems are compounded by regulatory problems or delays.

There has been a total of 244,974 billion cubic feet of reserves additions of dry natural gas since 1976 (Table 2). A markedly different pattern exists for the components of reserves additions for natural gas compared to crude oil. *Total discoveries* of dry natural gas make up 82 percent of all reserves additions compared to 36 percent for crude oil. *New reservoir discoveries in old fields* and *extensions* compose 83 percent of *total discoveries* of dry natural gas. As with crude oil, most *new reservoir discoveries in old fields* and *extensions* from 1976 through 1993 are probably associated with fields discovered before 1977. This is also true for the net of *revisions and adjustments* to natural gas reserves.

The percentages given for U.S. reserves additions of natural gas are somewhat distorted due to an unusually large revision decrease of some 24,613 billion cubic feet for Alaskan North Slope proved reserves that was made in 1988 for economic reasons. Without this large negative revision, total reserve additions would have been 269,587 billion cubic feet and the net of *revisions and adjustments* would have been 67,696 billion cubic feet, or 25 percent of the total. *Total discoveries* of dry natural gas would have been 75 percent of reserve additions, still well over twice as large a percentage of reserve additions as the equivalent *total discoveries* percentage for crude oil.

Table 2. Reserves Changes, 1977 through 1993

	Lower 48 States			U.S. Total		
Components of Change	**Volume**	**Average per Year**	**Percent of Reserve Additions**	**Volume**	**Average per Year**	**Percent of Reserve Additions**
	Crude Oil (million barrels of 42 U.S. gallons)					
Proved Reserves as of 12/31/76	**24,928**	**––**	**––**	**33,502**	**––**	**––**
New Field Discoveries	2,174	128	7.3	2,242	143	6.5
New Reservoir Discoveries in Old Fields	2,176	128	7.3	2,195	129	5.9
Extensions	7,981	469	26.6	8,761	515	23.5
Total Discoveries	**12,331**	**725**	**41.1**	**13,380**	**787**	**35.9**
Revisions and Adjustments	17,652	1,038	58.9	23,928	1,408	64.1
Total Reserve Additions	**29,983**	**1,764**	**100.0**	**37,308**	**2,195**	**100.0**
Production	**37,616**	**2,213**	**125.5**	**47,853**	**2,815**	**128.3**
Net Reserve Change	**–7,746**	**–456**	**–25.8**	**–10,545**	**–620**	**–28.3**
	Dry Natural Gas (billion cubic feet at 14.73 psia and 60° Fahrenheit)					
Proved Reserves as of 12/31/76	**180,838**	**––**	**––**	**213,278**	**––**	**––**
New Field Discoveries	33,936	1,996	12.9	33,963	1,998	13.9
New Reservoir Discoveries in Old Fields	42,714	2,513	16.3	43,079	2,534	17.6
Extensions	124,001	7,294	47.3	124,849	7,344	51.0
Total Discoveries	**200,651**	**11,803**	**76.5**	**201,891**	**11,876**	**82.4**
Revisions and Adjustments	61,615	3,624	23.5	43,083	2,534	17.6
Total Reserve Additions	**262,266**	**15,427**	**100.0**	**244,974**	**14,410**	**100.0**
Production	**290,596**	**17,094**	**110.8**	**295,837**	**17,402**	**120.8**
Net Reserve Change	**–28,330**	**–1,666**	**–10.8**	**–50,863**	**–2,992**	**–20.8**

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, 1977 through 1992 annual reports, DOE/EIA-0216.{8-17,79-84}

For the lower 48 States, proved reserves of dry natural gas have been relatively stable since 1976. The average decline has been under 1 percent per year (1,666 billion cubic feet). This is quite different from the decline from 1967 through 1977 for the lower 48 States, as estimated by the American Gas Association.{19} During that 10-year period, natural gas proved reserves for the lower 48 States dropped by an average of 11,252 billion cubic feet a year, or almost 5 percent annually. This excludes small changes for gas in underground storage that the American Gas Association included with its proved gas reserves. The relative stability of lower 48 States reserves after 1977 was caused by a higher price level for natural gas, substantially more drilling, and a lower demand for natural gas in the 1980's.

Positive revisions played a larger role in sustaining natural gas reserves in the lower 48 States during the last 8 years than in prior years. The 1986 through 1993 average of *revisions and adjustments* was 6,647 billion cubic feet per year while the 1977 through 1985 average was only 938 billion cubic feet per year. Infill drilling and a surge of recompletions contributed to this phenomenon.

Large *revisions and adjustments* have been the major factor sustaining oil reserves and keeping decline rates low for the lower 48 States during the last 14 years. Lower 48 States proved reserves of crude oil increased in 1980 responding to high oil prices and drilling. This ended a period of high oil decline rates. Led by large *revisions and adjustments*, lower-48 oil reserves increased three more times through 1985. From 1979 through 1990, the decline rate for these oil reserves was only half a percent per year. This is quite different from the decline from 1967 through 1977 estimated by the American Petroleum Institute.{19} During that 10-year period, crude oil proved reserves for the lower 48 States were declining by over 4 percent per year. The oil decline rate for lower 48 States proved reserves averaged 4.5 percent per year for the last 3 years, a return to high decline rates. It was **the absence** of large *revisions and adjustments* that caused most of the 6-percent decline in 1991 and 5-percent decline in 1992 for lower 48 States proved oil reserves. The decline was smaller at 3 percent in 1993 but only because of the exceptionally large *total discoveries*.

Rotary drilling rig activity during 1993 dropped below 1,000 rigs for the seventh time in the last 8 years. The 754 rig count in 1993 was a little higher than the record low of 1992 (Table 3). The 1993 rig activity represented an 81-percent drop from the 1981 historical peak.

Oil prices declined in 1993 to $14.20 per barrel, the lowest annual average in constant dollars since the 1973 Arab oil embargo. Inflation adjusted oil prices were $50 per barrel in 1993 dollars during 1981 (Table 3). In the early 1970's, before the Arab oil embargo, inflation adjusted oil prices were only about $11 per barrel, and some 1993 monthly oil prices dropped below that level. The U.S. oil price dropped to $10.38 per barrel in December 1993 with Alaskan North Slope oil at $7.00 per barrel and the California price at $8.93 per barrel.

The average gas price rose 16 percent to $2.01 per thousand cubic feet in 1993 following a small increase in 1992 (Table 3). Monthly gas prices varied from $1.74 in February to $2.20 per thousand cubic feet in December. There is still substantial month-to-month uncertainty about future natural gas prices, although higher average gas prices are expected. Increased gas drilling, caused by higher prices, is necessary to maintain the balance between wellhead gas productive capacity and increasing gas demand.{20}

Total gas well completions in 1993 exceeded oil well completions for the first time (Table 4). Total gas well completions increased 7 percent to 8,560. Contributing to the increase of gas well completions were wells completed in 1993 but started in 1992 to take advantage of expiring tax credits for new unconventional coalbed methane and tight-sand gas wells. Total exploratory and development well drilling was up slightly in 1993 due to increased gas well completions. Oil well completions were down, continuing the post-1981 trend. Low oil prices and uncertainty about future prices led to the low drilling. In 1981, total well completions were 90,030 or 4 times as many as in 1993. There were 7 times as many successful exploratory wells drilled in 1981 as there were in 1993. Of the wells drilled in 1993, 71 percent were successfully completed as oil or gas wells. Most development wells are successful, while most exploratory wells are not. Dry wells represented 21 percent of development wells but 76 percent of exploratory wells during 1993.

Figures 15 and 16 show exploratory gas well and oil well completions for the years 1977 through 1993. Exploratory oil well completions decreased in 1993 to 379. There were 7 times as many drilled in the peak year of 1981. However, crude oil *total discoveries* were up because there were large *new field discoveries* in the Federal Offshore Gulf of Mexico. Onshore *total discoveries* were low in 1993, reflecting the downward trend in exploratory drilling that followed the crude oil price collapse of 1986. Exploratory gas well completions increased 6 percent in 1993, but there

Table 3. U.S. Average Annual Domestic Wellhead Prices for Crude Oil and Natural Gas, and the Average Number of Active Rotary Drilling Rigs, 1970-1993

Year	Crude Oil		Natural Gas		
	Current	1993 Constant	Current	1993 Constant	
	(dollars per barrel)		(dollars per thousand cubic feet)		Number of Rigs
1970	3.18	11.25	0.17	0.60	1,028
1971	3.39	11.35	0.18	0.60	976
1972	3.39	10.85	0.19	0.61	1,107
1973	3.89	11.70	0.22	0.66	1,194
1974	6.87	19.00	0.30	0.83	1,472
1975	7.67	19.36	0.44	1.11	1,660
1976	8.19	19.45	0.58	1.38	1,658
1977	8.57	19.04	0.79	1.76	2,001
1978	9.00	18.54	0.91	1.87	2,259
1979	12.64	23.97	1.18	2.24	2,177
1980	21.59	37.40	1.59	2.75	2,909
1981	31.77	50.01	1.98	3.12	3,970
1982	28.52	42.27	2.46	3.65	3,105
1983	26.19	37.30	2.59	3.69	2,232
1984	25.88	35.32	2.66	3.63	2,428
1985	24.09	31.69	2.51	3.30	1,980
1986	12.51	16.03	1.94	2.49	964
1987	15.40	19.13	1.67	2.07	936
1988	12.58	15.04	1.69	2.02	936
1989	15.86	18.15	1.69	1.93	869
1990	20.03	21.96	1.71	1.87	1,010
1991	16.54	17.45	1.64	1.73	860
1992	R15.99	16.40	R1.74	1.78	721
1993	14.20	14.20	2.01	2.01	754

R=Revised data.

Sources: Current dollars and Number of rigs: *Annual Energy Review 1993*, DOE/EIA-0384(93). 1993 constant dollars: U.S. Department of Commerce, Bureau of Economic Anaylsis, Gross Domestic Product Implicit Price Deflators, January 1994.

were only 380 gas well completions. There were roughly 7 times as many drilled in the peak year of 1981. Peak and low years for *total discoveries* do not necessarily match peak and low years for exploratory drilling because the success of exploratory drilling can vary from year to year.

Figure 17 shows *total discoveries* of dry natural gas per exploratory gas well completion for the years 1977 through 1993. Similarly, Figure 18 shows *total discoveries* of crude oil per exploratory oil well completion. A striking feature is the decline of gas and oil discoveries per exploratory well as exploratory drilling increased rapidly in the late 1970's and early 1980's, followed by increasing discoveries per exploratory well as drilling and prices declined. Oil *total discoveries* per exploratory well were 4 times as large in 1993 as in the low year of 1982 and gas *total discoveries* per well were 3 times as large. Without these large increases in *total discoveries* per well to partially compensate for declining exploratory drilling in the late 1980's and early 1990's, *total discoveries* would have been much lower.

The 23.3 billion cubic feet of dry gas *total discoveries* per exploratory gas well in 1993 continued the trend toward higher discoveries per well. The 2.1 million barrels found per exploratory oil well reflects the exceptional *new field discoveries* booked as proved reserves in 1993. This very high level may fall next year.

There are several explanations for the improved reserve additions per exploratory well. With rapid price increases driving a drilling frenzy in the late 1970's and early 1980's, the industry was not as careful in picking exploratory targets and could afford to drill small prospects that would be

Table 4. U.S. Exploratory and Development Well Completions,[a] 1970 through 1993

	Exploratory				Total Exploratory and Development			
Year	Oil	Gas	Dry	Total	Oil	Gas	Dry	Total
1970	763	478	6,193	7,434	13,043	4,031	11,099	28,173
1971	664	472	5,995	7,131	11,903	3,983	10,382	26,268
1972	690	659	6,202	7,551	11,437	5,484	11,013	27,934
1973	654	1,079	6,038	7,771	10,251	6,975	10,466	27,692
1974	870	1,205	6,894	8,969	13,664	7,170	12,205	33,039
1975	991	1,263	7,207	9,461	16,979	8,170	13,736	38,885
1976	1,100	1,362	6,854	9,316	17,697	9,438	13,805	40,940
1977	1,183	1,562	7,402	10,147	18,700	12,119	15,036	45,855
1978	1,191	1,792	8,054	11,037	19,065	14,405	16,591	50,061
1979	1,335	1,920	7,478	10,733	20,703	15,170	16,038	51,911
1980	1,781	2,094	9,035	12,910	32,278	17,223	20,337	69,838
1981	2,667	2,533	12,297	17,497	42,843	19,907	27,284	90,034
1982	2,470	2,168	11,346	15,984	39,142	18,944	26,382	84,468
1983	2,113	1,660	10,271	14,044	37,199	14,556	24,336	76,091
1984	2,335	1,599	11,482	15,416	42,585	17,012	25,797	85,394
1985	1,879	1,282	9,445	12,606	35,021	14,252	21,208	70,481
1986	988	733	5,511	7,232	18,701	8,135	12,766	39,602
1987	859	673	5,179	6,711	16,186	7,757	11,481	35,424
1988	792	663	4,766	6,221	13,322	8,238	10,242	31,802
1989	580	654	4,001	R5,235	10,339	9,225	8,491	28,055
1990	617	R586	3,782	R4,985	12,150	10,440	R8,614	R31,204
1991	R545	R464	3,303	R4,312	R11,908	R9,166	7,830	R28,904
1992	446	R358	2,571	R3,375	R8,684	R7,975	R6,578	R23,237
1993	379	384	2,370	3,133	8,070	8,564	6,696	23,330

[a]Excludes service wells and stratigraphic and core testing.

R=Revised data.

Notes: Estimates are based on well completions taken from American Petroleum Institute data tapes through August 1994. Due to the method of estimation, data shown are frequently revised. Data are no longer rounded to nearest 10 wells.

Sources: Years 1970-1972: Energy Information Administration, Office of Oil and Gas. Years 1973-1993: *Monthly Energy Review*, DOE/EIA-0035(94/08), August 1994.

profitable at high prices. Lately, the industry has also tended to focus exploratory activity in areas where a higher payoff per well is expected, like the offshore areas, the Austin Chalk in Texas, and coalbed methane areas. There have also been improvements in exploration technology (such as 3-D seismic imaging) and drilling technology (such as horizontal drilling).

Reserves-to-Production Ratios

The relationship between reserves and production, expressed as the ratio of reserves to production (R/P ratio) is often used in analysis. For a mature producing area, the R/P ratio tends to be reasonably stable, so that the proved reserves at the end of a year serve as a rough guide to of the production level that can be maintained during the following year. Operators report data that yield R/P ratios that vary widely depending upon both the number and type of operators in a given area, the nature of the area, the number and size of new discoveries in the area, and the amount of drilling that has occurred in the area.

R/P ratios are an indication of the state of development in an area and, over time, the ratios change. For example, when the Alaskan North Slope reserves of oil were booked, the U.S. R/P ratio increased, because significant production from these reserves did not begin until 7 years after booking due to the need to first build the Trans-Alaska pipeline. The U.S. R/P ratio went from 11.1-to-1 to 9.4-to-1

Figure 15. U.S. Exploratory Gas Well Completions, 1977-1993

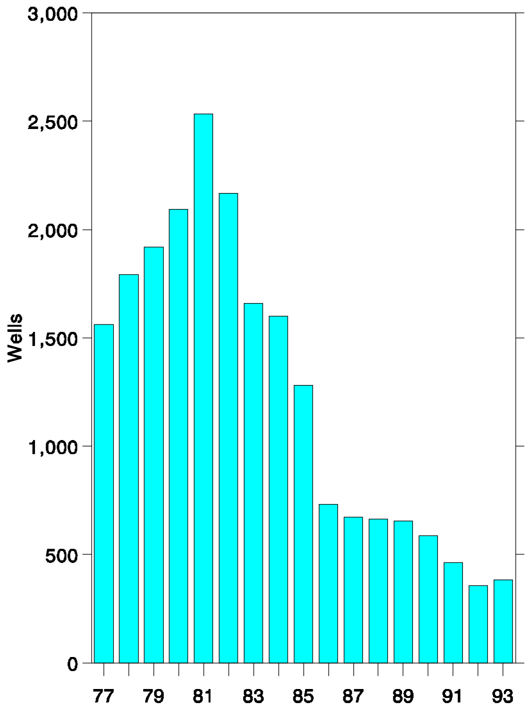
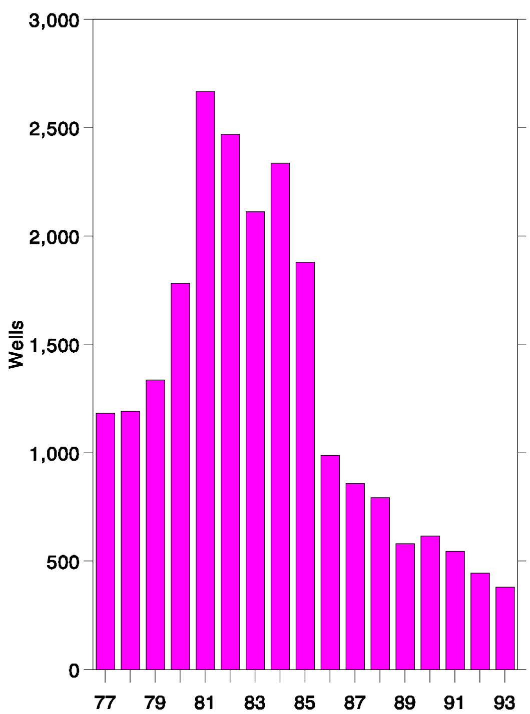


Figure 16. U.S. Exploratory Oil Well Completions, 1977-1993



Source: Energy Information Administration, Office of Oil and Gas.

Figure 17. U.S. Total Discoveries of Dry Natural Gas per Exploratory Gas Well Completion, 1977-1993

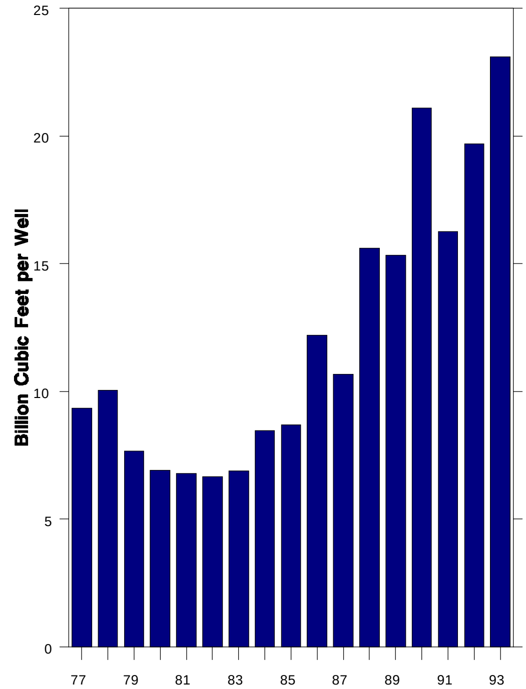
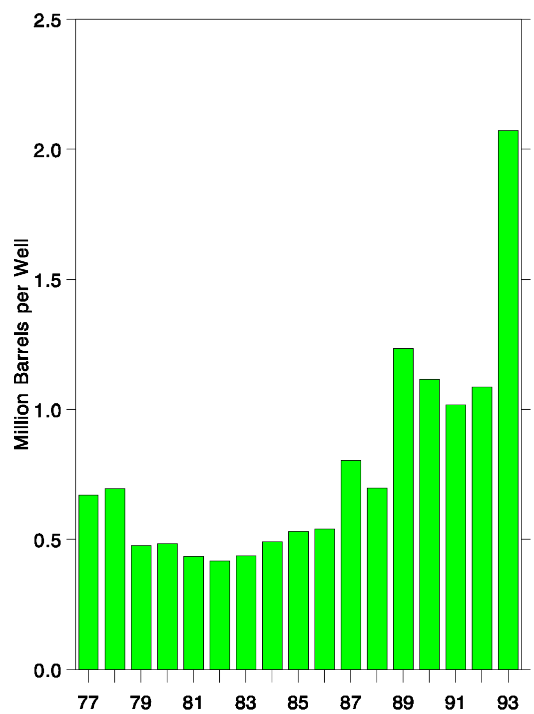


Figure 18. U.S. Total Discoveries of Crude Oil per Exploratory Oil Well Completion, 1977-1993



between 1977 and 1982, as Alaskan North Slope production reached high levels.

Less developed areas of the country, such as the Pacific offshore, have higher R/P ratios than the current National average of 9.8 to 1. Other areas with relatively high R/P ratios are the Permian Basin of Texas and New Mexico, and California, where enhanced recovery techniques such as CO_2 injection or steamflooding have enhanced recoverability in old, mature fields. Areas that have the lowest oil R/P ratios have many older fields, like the Mid-Continent area. There, even new technologies such as horizontal drilling, as practiced in Texas' Giddings oil field, could only add reserves equivalent to the annual production, keeping the regional reserves and R/P ratio for oil relatively stable.

Figure 19 shows the historical R/P ratio trend for crude oil for the period 1945 to 1993. After World War II, increased drilling and discoveries led to a greater ratio of reserves to production. Later, when drilling found fewer reserves than were produced, the ratio became smaller.

A much different picture emerges for wet natural gas R/P ratios shown in Figure 20. The different marketing and transportation settings of gas versus oil are more clearly seen when looking at regional average R/P ratios, compared to the current National average for natural gas of 9.1 to 1. The areas with the higher range of R/P ratios are the less developed areas of the country such as the Pacific offshore and the Rockies, but also include areas such as Alabama (18 to 1) and Colorado (17 to 1) where considerable booking of coalbed methane reserves has recently occurred. Several major gas producing areas have R/P ratios below the National average such as Texas (7.5 to 1), the Gulf of Mexico Federal Offshore (5.7 to 1), and Oklahoma (7.5 to 1). While proved gas reserves declined in 1992 and 1993, production increased because there was sufficient gas productive capacity to meet increased demand. This caused the ratio of proved reserves to production to drop as the remaining reserve base was more intensively produced. The R/P ratio can drop still lower. But to sustain long-term increasing production, reserves will eventually have to increase. It will take a growing and successful drilling effort to reverse the decline of gas reserves.

Figures 21 and 22 show the successive estimates of ultimate recovery, proved reserves, and cumulative production for oil and wet natural gas for 1977 through 1993. They illustrate the continued growth of estimated ultimate recovery over time. Ultimate recovery is defined as cumulative production plus proved reserves at a particular point in time. In 1976, U.S. proved oil reserves were 33,502 million barrels. Cumulative production for 1977 through 1993 of 47,853 million barrels substantially exceeded those proved reserves, and there were still 22,957 million barrels of proved oil reserves in 1993. Similarly, U.S. proved reserves of dry natural gas were 213,278 billion cubic feet in 1976, and 162,415 billion cubic feet remained in 1993. Cumulative dry gas production during this period exceeded the 1976 reserves by 82,559 billion cubic feet.

Top 100 Oil and Gas Fields for 1992

EIA generates tables of the largest oil fields and gas fields in Appendix B as a regular feature of this report. The tables contain estimates of the proved reserves, cumulative production, and ultimate recovery of the top 100 oil fields and the top 100 gas fields ranked by proved reserves for 1992. Also, the field name, location, year of discovery, and an estimate of 1992 annual production are provided. The oil field production and reserve data includes lease condensate.

There were more than 45,000 oil and gas fields with production, cumulative production, or reserves in the United States in 1992. Table B1 shows the top 100 oil fields as of December 31, 1992. These fields accounted for 66 percent of total proved reserves of oil and 54 percent of total oil production in 1992. Just the top 10 oil fields contained 38 percent of U.S. proved reserves of crude oil.

Gas proved reserves are not as concentrated in the top 100 gas fields (Table B2) as oil reserves are in the top 100 oil fields. They accounted for 47 percent of the total wet gas proved reserves and 29 percent of the total wet gas production. The top 10 gas fields contained 24 percent of U.S. proved reserves of wet gas in 1992. Some, but not all, of the same fields appear in both tables. As an example, the top gas field, Hugoton Gas Area, is not in the oil table. In contrast, the top oil field, Prudhoe Bay, is the number four field in the gas table.

Ten years of historical production for the top 100 oil and gas fields are shown in Tables B3 and B4. The top 100 gas fields accounted for 29 percent of U.S. gas production in 1992. This same group of fields accounted for 21 percent of the U.S. gas production in 1983. The 8-percent increase is attributable to the rise in the demand for natural gas. Major fields increased

Figure 19. Reserves-to-Production Ratios for Crude Oil, 1945-1993

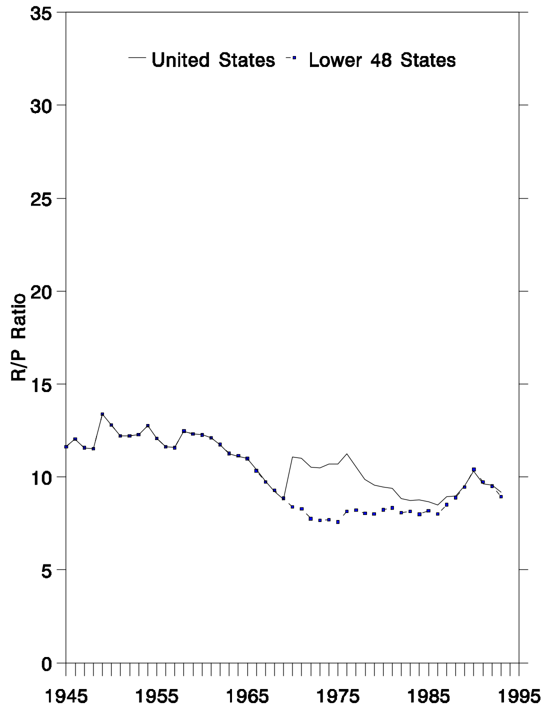


Figure 21. Components of Ultimate Recovery for Crude Oil and Lease Condensate, 1977-1993

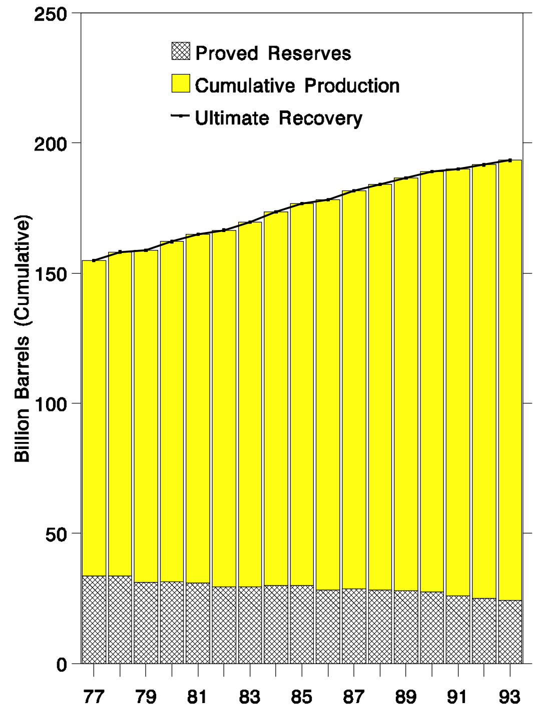


Figure 20. Reserves-to-Production Ratios for Wet Natural Gas, 1945-1993

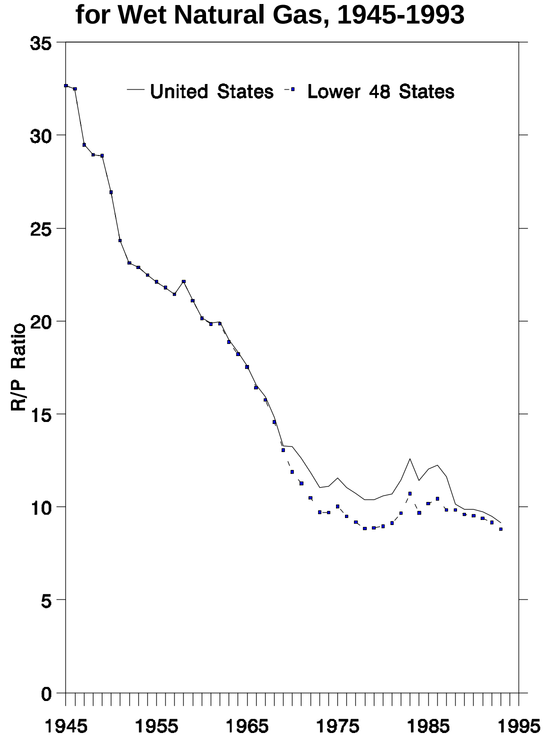
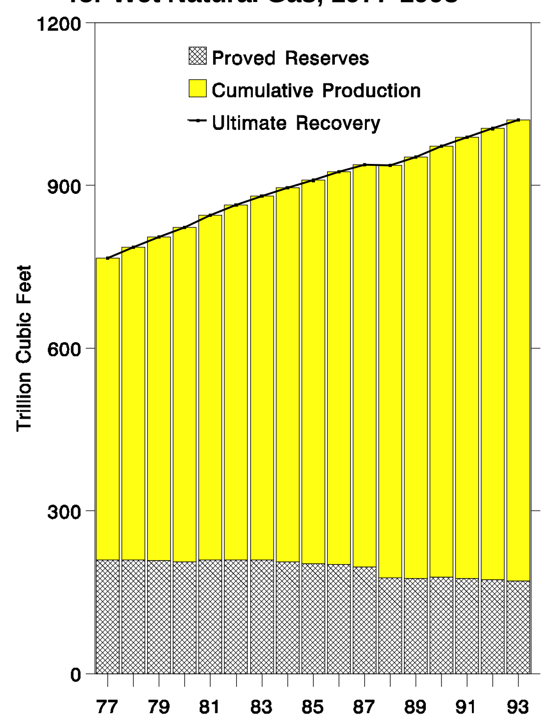


Figure 22. Components of Ultimate Recovery for Wet Natural Gas, 1977-1993



Sources: •Annual reserves and production - American Petroleum Institute and American Gas Association (1945–1976){19} and Energy Information Administration, Office of Oil and Gas (1977–1992){8-17,79-84}. •Cumulative production: *U.S. Oil and Gas Reserves by Year of Field Discovery* (1977–1988).{22} their production of both conventional and unconventional gas. The three largest gas fields, Hugoton Gas Area (discovered in 1922), Basin (discovered in 1947), and Blanco (discovered in 1927) produced twice as much gas in 1992 as they did in 1983.

An EIA report, *Largest U.S. Oil and Gas Fields*{21} was published in August 1993. It identifies the largest 1 percent of U.S. oil and gas fields and their general location, year of discovery, and approximate National rankings in several size categories including proved reserves and annual production. Also presented are the proportions of the National crude oil and natural gas proved reserves and production that are attributable to the largest fields. An earlier EIA report, *Geologic Distributions of U.S. Oil and Gas*{22}, was published in July 1992. It provides oil and gas field size distributions by geologic provinces, regions, and the Nation, as well as regional information on the distribution of oil and gas by trap type and the geologic age and lithology of the reservoir rock. The report covers the entire Nation with the exception of the Appalachian Basin. A major conclusion is that only in the Alaskan, Far West, and Gulf of Mexico regions can one expect to continue to locate very many new large fields, particularly where oil is concerned.

Conversion to the Metric System

Public Law 100-418, the Omnibus Trade and Competitiveness Act of 1988 established the policy that the metric system of measurement is the preferred system of weights and measures for United States trade and commerce.{23} The U.S. petroleum industry is slowly moving in the direction prescribed by this law. However, the estimates made by EIA for this report are based on data filed by operators on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves" and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production" using the units that are still common to the U.S. petroleum industry, namely barrels for crude oil and natural gas liquids, and cubic feet for natural gas. Standard metric conversion factors for barrels and cubic feet were used to convert National level volumes in Table 1 to their metric equivalents in Table C1. The metric U.S. proved reserves as of December 31, 1993 were 3,649.9 million cubic meters of crude oil, 4,599.08 billion cubic meters of dry natural gas, and 1,148.2 million cubic meters of natural gas liquids (including lease condensate).

International Perspective

The United States ranks eleventh in the world for proved reserves of crude oil and fifth for natural gas (Table 5). A comparison of EIA's U.S. proved reserve estimates with worldwide estimates obtained from other sources shows that the United States had 2 and 3 percent, respectively, of the world's total oil and natural gas proved reserves at the end of 1993. There are sometimes substantial differences between estimates from these sources. Condensate is often included in these oil reserve estimates. The EIA estimates domestic oil and gas reserves but does not systematically estimate worldwide reserves.

The *Oil & Gas Journal*{24} and *World Oil*{25} estimates of world oil reserves both rose slightly in 1993. For the United States, oil reserves estimates by *World Oil* were within 1 percent of EIA's estimates. The *Oil & Gas Journal* published EIA's 1992 U.S. oil proved reserves as its 1993 estimates.

Several foreign countries have oil reserves considerably larger than those of the United States. Saudi Arabian oil reserves are the largest in the world, dwarfing U.S. oil reserves. Iraqi oil reserves are over 4 times U.S. reserves, but exports of their oil production are currently prohibited under a United Nations embargo. Closer to home, Venezuela has 3 times and Mexico twice the United States' oil reserves.

Oil reserve estimates for the former Soviet Union (FSU) differ widely. *World Oil* reported oil reserves for the FSU of about 182 billion barrels. This was roughly 3 times their 1991 reported value and 3 times the *Oil & Gas Journal* 1992 estimate. But, *World Oil* has included more than proved reserves in its 1993 FSU estimate. This estimate uses the FSU reserves classification of $A+B+C_1$. EIA considers this classification group as roughly comparable to proved plus probable reserves classifications commonly used in the United States. The U.S. oil reserve estimates only include proved reserves.

For world natural gas reserves, the *Oil & Gas Journal* estimate was up 3 percent and the *World Oil* estimate was down 2 percent. For the United States, gas reserves estimates by *World Oil* were within 1 percent of EIA's estimates. The *Oil & Gas Journal* published EIA's 1992 U.S. gas proved reserves estimates as its 1993 estimates. Only two of the countries listed have gas reserves that are much larger than those of the United States. The FSU gas reserves, the worlds' largest, are roughly 12 times those of the United States and Iran's are over 4 times U.S. gas reserves.

Table 5. International Oil and Natural Gas Reserves as of December 31, 1993

Oil (million barrels)				Natural Gas (billion cubic feet)			
Rank[a]	Country	Oil & Gas Journal	World Oil	Rank[b]	Country	Oil & Gas Journal	World Oil
1	Saudi Arabia[c]	[d]261,203	[d]262,430	1	Former Soviet Union	1,997,000	1,877,041
2	Former Soviet Union	57,000	181,701	2	Iran[c]	730,000	612,000
3	Iraq[c]	100,000	99,628	3	Abu Dhabi[c]	188,400	188,000
4	Kuwait[c]	[d]96,500	[d]94,241	4	Saudi Arabia[c]	[d]185,860	[d]186,100
5	Abu Dhabi[c]	92,200	62,975	**5**	**United States**	**[e]165,015**	**163,199**
6	Iran[c]	92,860	59,964	6	Venezuela[c]	128,900	138,000
7	Venezuela[c]	63,330	64,447	7	Algeria[c]	128,000	130,663
8	Mexico	50,925	44,439	8	Nigeria[c]	120,000	121,870
9	Libya[c]	22,800	37,940	9	Iraq[c]	109,500	109,195
10	China	24,000	29,500	10	Canada	94,823	93,243
11	**United States**	**[e]23,745**	**22,819**	11	Norway	70,488	113,200
12	Nigeria[c]	17,900	17,466	12	Malaysia	76,700	80,800
13	Norway	9,284	18,860	13	Mexico	70,954	70,046
14	United Kingdom	4,554	16,911	14	Indonesia[c]	64,388	67,532
15	Algeria[c]	9,200	10,065	15	Kuwait[c]	[d]52,900	[d]51,362
16	Indonesia[c]	5,779	6,242	16	China	59,000	45,000
17	India	5,921	5,860	17	Libya[c]	45,800	45,520
18	Egypt	6,300	3,425	18	United Kingdom	21,542	54,740
19	Canada	5,096	4,622	19	Qatar	250,000	165,000
20	Oman	4,700	5,000	20	India	25,354	22,820
Top 20 Total for Oil		**929,551**	**1,048,534**	**Top 20 Total for Gas**		**4,584,624**	**4,335,331**
World Total for Oil		**999,124**	**1,093,115**	**World Total for Gas**		**5,016,213**	**4,712,609**

[a]Rank is based on an average of oil reserves reported by *Oil & Gas Journal* and *World Oil*.

[b]Rank is based on an average of natural gas reserves reported by *Oil & Gas Journal* and *World Oil*.

[c]Member of the Organization of Petroleum Exporting Countries.

[d]Includes one-half of the reserves in the Neutral Zone.

[e]Energy Information Administration proved reserves as of December 31, 1992 were published by the *Oil & Gas Journal* as its estimates as of December 31, 1993.

Note: The Energy Information Administration does not certify these international reserves data, but reproduces the information as a matter of convenience for the reader.

Sources: *Oil & Gas Journal*, December 27, 1993, pp. 44-45. *World Oil*, August, 1994, p. 28.

3. Crude Oil Statistics

Proved reserves of crude oil were 22,957 million barrels, 3.3 percent (788 million barrels) less than in 1992. This decline was more than twice the average annual decline of 1.5 percent experienced during the prior 10 years. Most of the substantial oil producing areas had proved reserve declines in 1993. U.S. crude oil production in 1993 declined 4.4 percent.

Proved Reserves

Table 6 presents the U.S. proved reserves of crude oil as of December 31, 1993, by selected States and State subdivisions. Five areas accounted for 80 percent of the total. Texas was the leader, followed closely by Alaska, with California third.

Area	Percent of U.S. Oil Reserves
Texas	27
Alaska	25
California	16
Gulf of Mexico Federal Offshore	9
New Mexico	3
Total	**80**

The Gulf of Mexico Federal Offshore had an oil reserve increase of 237 million barrels. Five other States/areas had minor gains or no change. The remainder had losses. Texas, Alaska and California accounted for 82 percent of the overall U.S. decline. Here's how the five largest oil reserve areas fared in 1993.

Area	Oil Reserves Change (million barrels)
Texas	-270
Alaska	-247
California	-129
Gulf of Mexico Federal Offshore	+237
New Mexico	-50
United States	-788

Low oil prices, along with local and State environmental concerns, contributed to the decline. In Texas, the largest losses in proved reserves were in Districts 1 in south Texas and 7C in west Texas. Even moderate percentage declines in States with large reserves cause substantial losses overall. Alaskan proved reserves declined 4 percent (247 million barrels), while Wyoming, with a 9-percent decline, lost 65 million barrels.

The net of *revisions* and *adjustments* for crude oil in 1993 was 766 million barrels. This was about half the average for the prior 10 years. This component of reserves change is usually the largest and has consistently helped to sustain U.S. crude oil proved reserves. Three areas had 86 percent of the positive net of *revisions* and *adjustments*, Alaska (318 million barrels), Texas (197 million barrels), and California (142 million barrels). Most of the Nation's thermally enhanced recovery of heavy oil takes place in California. Enhanced recovery from the existing resource base leads to positive reserves revisions. Twelve States and the Pacific Federal Offshore recorded combined negative *revisions* and *adjustments* of 96 million barrels.

Discoveries

In 1993, *total discoveries* of crude oil were 785 million barrels, up from 484 million barrels in 1992. Just two areas, the Gulf of Mexico Federal Offshore and Texas, accounted for 75 percent of the *total discoveries* for the year. For the previous 7 years, *total discoveries* had been relatively low, reflecting a similar trend in exploratory drilling that followed the crude oil price collapse of 1986.

New field discoveries were an exceptionally high 319 million barrels, the highest in 23 years. This is over 3 times the prior 10-year average for *new field discoveries.* Nearly all the increase came from the Gulf of Mexico Federal Offshore.

Proved reserves of *new reservoir discoveries in old fields* (110 million barrels) were up 29 percent from 1992 but still 11 percent below the 124 million barrel average for the prior 10 years. Of the 110 million barrels, 64 million were found in the Gulf of Mexico Federal Offshore and 30 million in Texas. Additions to proved reserves from *extensions* (356 million barrels) were 9 percent less than in 1992, and substantially below the prior 10-year average of 509 million barrels. Increased drilling was the major factor behind the 100 million barrels of *extensions* in the Gulf of Mexico Federal Offshore.

Table 6. Crude Oil Proved Reserves, Reserves Changes, and Production, 1993
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	Published Proved Reserves 12/31/92	Changes in Reserves During 1993: Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Production (-)	Proved Reserves 12/31/93
Alaska	6,022	21	299	2	13	0	1	579	5,775
Lower 48 States	**17,723**	**250**	**1,712**	**1,514**	**343**	**319**	**109**	**1,760**	**17,182**
Alabama	41	7	4	3	2	0	0	10	41
Arkansas	58	20	3	6	0	0	0	10	65
California	3,893	54	230	142	19	0	0	290	3,764
Coastal Region Onshore	522	7	29	9	1	0	0	22	528
Los Angeles Basin Onshore	236	8	17	6	4	0	0	21	238
San Joaquin Basin Onshore	2,898	30	182	124	12	0	0	226	2,772
State Offshore	237	9	2	3	2	0	0	21	226
Colorado	304	-6	26	35	23	1	1	30	284
Florida	36	4	5	0	1	0	0	6	40
Illinois	138	-10	5	2	0	0	0	15	116
Indiana	17	0	0	0	0	0	0	2	15
Kansas	310	-1	15	17	11	1	0	48	271
Kentucky	34	-3	0	2	0	0	0	3	26
Louisiana	668	29	104	76	12	1	7	106	639
North	125	-5	12	7	2	0	0	19	108
South Onshore	417	-1	66	55	10	1	6	62	382
State Offshore	126	35	26	14	0	0	1	25	149
Michigan	102	-2	10	9	1	0	0	12	90
Mississippi	165	-4	12	23	3	0	0	20	133
Montana	193	-7	8	12	4	0	1	16	171
Nebraska	26	-2	3	2	0	0	0	5	20
New Mexico	757	29	76	120	27	0	2	64	707
East	731	32	75	116	25	0	2	61	688
West	26	-3	1	4	2	0	0	3	19
North Dakota	237	3	21	19	12	0	2	30	226
Ohio	58	5	1	2	0	0	0	8	54
Oklahoma	698	6	88	46	19	0	1	86	680
Pennsylvania	16	0	0	1	0	0	0	1	14
Texas	6,441	130	479	412	79	3	30	579	6,171
RRC District 1	185	3	8	49	6	0	1	21	133
RRC District 2 Onshore	86	-2	11	6	1	0	0	13	77
RRC District 3 Onshore	304	45	54	48	18	0	23	69	327
RRC District 4 Onshore	50	9	10	6	2	1	2	9	59
RRC District 5	56	8	2	8	2	0	0	8	52
RRC District 6	442	-8	43	26	10	0	0	55	406
RRC District 7B	163	27	5	3	0	0	1	22	[a]171
RRC District 7C	255	-29	19	25	3	0	0	24	199
RRC District 8	2,031	52	195	85	24	0	1	161	2,057
RRC District 8A	2,599	20	101	137	9	2	2	161	2,435
RRC District 9	176	8	11	4	1	0	0	24	168
RRC District 10	89	-4	19	14	3	0	0	10	83
State Offshore	5	1	1	1	0	0	0	2	4
Utah	217	27	9	10	5	0	0	20	228
West Virginia	27	-1	4	6	2	0	0	2	24
Wyoming	689	0	48	43	7	0	1	78	624
Federal Offshore	2,569	-27	561	523	104	313	64	316	2,745
Pacific (California)	734	3	290	308	4	0	0	50	673
Gulf of Mexico (Louisiana)	1,643	-32	264	207	87	313	64	252	1,880
Gulf of Mexico (Texas)	192	2	7	8	13	0	0	14	192
Miscellaneous[b]	29	-1	0	3	12	0	0	3	34
U.S. Total	**23,745**	**271**	**2,011**	**1,516**	**356**	**319**	**110**	**2,339**	**22,957**

[a]Indicates the estimate is associated with a sampling error (95 percent confidence interval) that exceeds 20 percent of the estimated value.
[b]Includes Arizona, Missouri, Nevada, New York, South Dakota, Tennessee, and Virginia.

Note: The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves." They may differ from the official Energy Information Administration production data for crude oil for 1993 contained in the *Petroleum Supply Annual 1993*, DOE/EIA-0340(93).

Source: Energy Information Administration, Office of Oil and Gas.

Reserves in Nonproducing Reservoirs

Not all proved reserves of crude oil were contained in reservoirs that were producing. Operators reported 3,017 million barrels of proved reserves in nonproducing reservoirs. This is 14 percent greater than reported in 1992.

The reasons for the nonproducing status of these proved reserves are not collected by EIA. However, previous surveys showed that most of the wells or reservoirs were not producing for operational reasons. These included waiting for well workovers, drilling additional development or replacement wells, installing production or pipeline facilities, and awaiting depletion of other zones or reservoirs before recompletion in reservoirs not currently open to production.

Indicated Additional Reserves

In addition to proved reserves of crude oil, Category I and Category II operators estimate the quantities of crude oil, other than proved reserves, that may become economically recoverable from known reservoirs through the application of improved recovery techniques using current technology. The total 1993 volume, 3,453 million barrels, is about 9 percent less than was reported in 1992. Table 7 lists indicated additional reserves by selected States and State subdivisions. The presence of large indicated additional reserves for the Alaskan North Slope, California, and west Texas implies that significant upward revisions to proved crude oil reserves could occur in the future.

Areas of Note

The following State or area discussions summarize notable activities during the year concerning expected new field reserves, development plans, and possible production rates as reported by various trade publications. The citations do not necessarily reflect EIA's concurrence, but are considered important enough to be brought to the reader's attention.

Alaska

The big disappointment on the North Slope was the offshore Kuvlum prospect, thought in 1992 to be the next billion barrel field. Huge by lower 48 standards, Kuvlum was abandoned when delineation wells failed to prove up sufficient reserves to make this field economical in Alaska's North Slope high cost environment. Further proof came with the abandonment of the Arco/Phillips Wild Weasel prospect 6 miles south.{26}

The Cook Inlet produced a second disappointment. Results from the two exploratory wells drilled on the southern portion of the Sunfish prospect indicated the accumulation is much smaller than previously estimated. Delineation drilling is planned for 1994 on the northern portion, which remains commercially viable despite the dry holes to the south.{27}

Production of oil and condensate in Alaska declined 8 percent, from 627 million barrels in 1992 to 577 million barrels in 1993.{28}

Prudhoe Bay: After 16 years, production has peaked and is in decline. To mitigate the decline, the operators in September 1993 installed the first phase of a project which will raise overall gas-handling capacity to 7.5 billion cubic feet per day. The final units in the project are planned to be transported to Prudhoe Bay during the 1994 sealift. As a result gross production of liquids should increase by 120,000 barrels per day and reserves increase by 300 million barrels.{29}

Oil production at Prudhoe Bay declined 14 percent from 397 to 341 million barrels during 1993, while condensate production increased from 48 million barrels to 55 million barrels. During December 1993 oil and condensate production averaged 1.1 million barrels per day.{30}

The operators put in place a study aimed at taking a closer look at some of the lower zones in the Prudhoe Bay Field, passed up for the shallower, more accessible oil. All available well and production histories have been combined with a three-dimensional (3-D) seismic survey to assist in the study. These zones are believed to hold about 2 billion barrels.{31}

Point McIntyre: Discovered in 1988, Point McIntyre was one of the largest domestic oil discoveries of the last decade, with about 340 million barrels of recoverable oil.{29} Oil production began in October 1993. During December it averaged 103,000 barrels per day, 6,000 barrels per day greater than Endicott Field production.{30}

Niakuk: The Niakuk Field off Alaska's North Slope and north of Prudhoe Bay Field started producing in early 1994. Expensive offshore development of this field was avoided by using advanced directional

Table 7. Reported Indicated Additional Crude Oil Reserves,[a] 1993
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	Indicated Additional Reserves	State and Subdivision	Indicated Additional Reserves
Alaska	1,161	North Dakota	7
Lower 48 States	2,292	Ohio	0
Alabama	0	Oklahoma	40
Arkansas	0	Pennsylvania	0
California	965	Texas	581
Coastal Region Onshore	313	RRC District 1	0
Los Angeles Basin Onshore	4	RRC District 2 Onshore	0
San Joaquin Basin Onshore	648	RRC District 3 Onshore	31
State Offshore	0	RRC District 4 Onshore	<1
Colorado	22	RRC District 5	0
Florida	0	RRC District 6	<1
Illinois	0	RRC District 7B	7
Indiana	0	RRC District 7C	15
Kansas	0	RRC District 8	262
Kentucky	0	RRC District 8A	264
Louisiana	338	RRC District 9	2
North	0	RRC District 10	<1
South Onshore	329	State Offshore	0
State Offshore	9	Utah	54
Michigan	0	West Virginia	0
Mississippi	44	Wyoming	12
Montana	0	Federal Offshore	18
Nebraska	0	Pacific (California)	0
New Mexico	211	Gulf of Mexico (Louisiana)	18
East	211	Gulf of Mexico (Texas)	0
West	0	Miscellaneous[b]	0
		U.S. Total	**3,453**

[a]Includes only those operators who produced 400,000 barrels of crude oil or 2 billion cubic feet of natural gas, or both, during the report year (Category I or Category II operators).
[b]Includes Arizona, Missouri, Nevada, New York, South Dakota, Tennessee, and Virginia.
Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1993.

drilling technology from an onshore gravel pad. A total of 14 wells is planned. This field is reported by BP Exploration as containing 54 million barrels of recoverable oil. Nearby Lisburne facilities are being used to process this oil.{32}

Kuparuk River: The Kuparuk River Field (40 miles west of Prudhoe Bay), the second largest oil field in the United States, celebrated the production of its billionth barrel of oil during the year. Annual production of 115 million barrels was 2 percent less than 1992.{30,33}

Cascade: A BP Exploration (Alaska) discovery in early 1993, the Cascade find, off the southeastern edge of Milne Point Field, was found productive in the Kuparuk River formation. Other oil bearing zones have not been tested. It figures to contribute to North Slope production soon. Additional 3-D seismic has been done to delineate the discovery and assist in development. Oil will be processed through the Milne Point facilities.{34}

California

In 1993, California ranked third among the oil producing States. Operators concentrated on development work in proved fields. Limited exports of heavy crude oil continued to be shipped to the Pacific Rim.

California oil production declined 4 percent in 1993. Midway-Sunset Field, which produced 61 million barrels, continued to be the largest producing oil field in California and the lower 48 States.

San Joaquin Valley: Development drilling continued in California's "heavy" oil fields. Steam injection continued to play a major role in the production of oil. One out of every 2 barrels of oil produced in the State is incremental oil recovered using steam injection.

Kern County's top three fields—Midway-Sunset, Belridge South, and Kern River—retained a firm hold on the distinction of being the top three producing fields in the lower 48 States.

Elk Hills' 6-year old horizontal drilling program continues to be successful. Although the field has been actively produced since 1976, new horizontal wells consistently produce at rates of 1,000 barrels of oil per day.{35}

Offshore Region: A number of key operators have dropped or suspended State and Federal leases in the California offshore because of continuing impediments to oil development. Other companies have withdrawn or shelved possible development projects in the prolific Santa Barbara and Santa Maria basins.

Extended-reach drilling has increased reserves in the Dos Cuadras offshore field by enabling the operator to exploit oil reserves found in shallow zones which could not be economically recovered by vertical wells.{36}

In February of 1993, the California State Lands Commission, local agencies, and Mobil Exploration and Producing U.S. Inc. joined to consider the Clearview Oil and Gas development proposal. It would expand offshore oil and gas resource development under State waters near Ellwood using extended-reach drilling entirely from onshore drill sites. Drafts of a formal application were being prepared in early 1994.{37}

Federal Offshore

The U.S. Outer Continental Shelf (OCS), which is under the jurisdiction of the Federal Government, ranked fourth in crude oil reserves and third in crude oil production among the producing areas in 1993. Its crude oil reserves of 2,745 million barrels were 12 percent of U.S. total reserves, and its production of 316 million barrels was 14 percent of total U.S. crude oil production.

Pacific Federal Offshore

Point Arguello Field: 1992 was the first full year of production from the giant Point Arguello Field. Production from the field, which had been hindered by transportation problems, increased from an average of 47,000 barrels per day in 1992 to an average of 71,000 barrels per day in 1993.

Santa Ynez Unit: The $2.1 billion Santa Ynez Unit expansion in the Santa Barbara Channel started up, expanding from the existing Hondo platform to two new platforms. Total producible reserves, including those already produced from Hondo, are expected to be about 500 million barrels of oil and 1 trillion cubic feet of gas.{29}

First oil was received from Platform Harmony on December 4, 1993. Production is expected to quadruple to about 90,000 barrels as new wells are drilled. Following completion of the project, the offshore storage and treatment vessel, now being used to process oil from the Hondo platform, will be removed from service. All production from the unit will then be moved by pipeline to the Las Flores Canyon treatment plant.{29}

Gulf of Mexico Federal Offshore

Substantial hydrocarbon production potential is stirring up lots of excitement in the Gulf of Mexico.{38} Lease sale 142, conducted in March 1993, indicated greater interest in the OCS than those conducted during the prior 3 years. Sixty companies offered $86 million for 61 tracts. The mid-September western Gulf of Mexico lease sale 143 was the second successive sale that reversed the trend of declining interest over the last 3 years, as 48 companies offered 197 bids totaling $80 million for 157 tracts.{39}

During 1993 the Federal Offshore Gulf of Mexico saw increased activity as both major and independent operators drilled throughout the Gulf. Three areas were of major interest—the Norphlet gas play in the eastern Gulf, the deep water play (over 2,000 feet) in the Central Gulf, and last, topping all, the Phillips Mahogany discovery.

Breakthroughs in analysis of 3-D seismic surveys enabled Phillips, in a partnership with Anadarko and Amoco Production Co., to drill the first economically successful subsalt wildcat at the Mahogany prospect.{40} The discovery at 16,500 feet on the Mahogany prospect in 370 feet of water, which tested 7,256 barrels of oil per day, shows just what rewards may be reaped by using today's sophisticated 3-D seismic technology to identify and evaluate subsalt structures.{38} The No. 2 appraisal well tested at a flow rate of 4,366 barrels of oil per day. At the nearby Teak prospect, a discovery well flowed as much as 3,700 barrels of oil per day. Further evaluation is needed to determine if the Teak prospect is commercial.{41}

The subsalt trend now offers enormous promise for drilling in the Gulf. It covers more than 36,000 square miles in water depths ranging from 300 feet to 2,000 feet. Many observers predict significant increases in offshore drilling in the Gulf right away as new lease holders move quickly to see just how accurate their subsalt penetration technology can be.{40}

Somewhat obscured by the excitement over the subsalt play were announcements by Shell Oil Co. of development plans for two earlier giant deepwater discoveries. At Auger, Shell estimates gross ultimate recovery of 220 million barrels of oil equivalent and at its Mars project 700 million barrels of oil equivalent.{42,43}

The tension leg platform for Shell's Auger prospect in Garden Banks Block 426 was installed in early December in 2,860 feet of water, a record depth for the Gulf. Ten wells are to be predrilled and cased. Another 14 to 20 production wells are expected. The predrilled wells are expected to begin going on line in early 1994. This is the first of the fields in water deeper than 2,000 feet to begin producing. Production is expected to peak in 2001 at about 46,000 barrels per day with gas output of 125 million cubic feet per day.{42,44}

The development plans for the Mars project include a tension leg platform on Mississippi Canyon Block 807 in 2,933 feet of water some 130 miles south southeast of New Orleans. Ultimate recovery is estimated to be 700 million barrels of oil equivalent, about 85 percent of it oil. The first phase of the project is planned for completion with oil flowing in late 1996.{43}

In the eastern Gulf of Mexico discoveries in the Norphlet formation, found at depths of 22,000 to 25,000 feet, have added major gas reserves to the Alabama State and Federal offshore during the last few years. Most exploratory drilling has been in the Mobile Bay area but new exploration in the Destin Dome area off Florida may extend production further eastward.{45}

Three-dimensional seismic technology continues to be used extensively in the Gulf. Whereas in previous years it had been used mainly for development and exploitation work, now with better and better processing and improved detail, it is being used effectively in developing new exploratory targets. These improvements have been vital to the success of exploration for reserves to be found beneath the large salt masses found over a large area of the Gulf. A group of operators are participating in a 5-year 3-D seismic shoot on 600 blocks in the central Gulf.{46}

Texas

In 1993 Texas ranked second among the Nation's oil producing States. In 1993, the 63-year old East Texas Field, which produced 30.2 million barrels of oil, was supplanted by Giddings Field's 31.8 million barrels as the largest oil producer in the State.{47}

The main areas of oil exploration and development activity in 1993 were the Austin Chalk trend and the Permian basin. With a large number of properties changing hands, the new owners, mostly independents, focused their efforts on well workovers and the drilling of development wells rather than on exploration.

Operators are still actively drilling new wells along the Austin Chalk trend, with most of the work confined to development wells in the Giddings Field and further northeast in Brookeland Field near the eastern end of the trend. However, the reported number of producing oil wells in the Chalk declined from 4,300 to 4,200. Exploration along the trend has moved to central and western Louisiana.{48}

Production in the trend declined from 53.5 million barrels in 1992 to 46.5 million barrels. In the Pearsall Field, where horizontal wells were first used extensively, oil production peaked at 26 million barrels in 1991. Production fell to less than 9 million barrels in only 2 years.{47}

Three-dimensional seismic crews were active in east Texas, south Texas, along the Gulf coast, and in the Permian basin. Except for the Permian basin, the main thrust was in the discovery and exploitation of gas reserves. In west central Texas, 3-D seismic technology and the data processing power that modern computers bring to independents are fueling a search for Mississippian reef formations.

One operator's extensive 3-D seismic program in the Midland area found more than 150 drillable sites.{49} Major oil companies and independents were active installing carbon dioxide enhanced recovery projects in several fields.{50}

Other Areas

Alabama: Overall, Alabama was one of the few States with an increase in oil production during 1993. Activity continued in 1993 in Alabama's Frisco City North Field which has several oil wells that gauged some of the highest flowing capacities in U.S. onshore operations. The use of 3-D seismic technology has enabled the operator to more than double his drilling success rate. The field continued to make the headlines in 1993, producing 1.7 million barrels of oil, up from 53 thousand barrels of oil 2 years earlier.{51}

Colorado: The Wattenberg Field was probably the most active of any in the United States. Development drilling surged in 1993. Production increased from 3.5 million barrels of oil in 1992 to 5.8 million in 1993, from 5,800 producing wells.{47}

New Mexico: Development programs in the Delaware formation in the Sand Dunes West Field of southeastern New Mexico have been very successful. Oil production increased from 66 thousand barrels in 1992 to 1.8 million barrels in 1993. Overall, the Delaware trend produced winners for one operator in 55 out of 58 wells along the trend. Further development is planned for 1994.{52}

Oklahoma: Following an integrated geophysical, geological, and engineering study, oil production at Sho-Vel-Tum Field has turned around. The operator reports the results of the effort has added several million barrels of proved reserves.{53}

Wyoming: There were two fields in the State which had large increases in oil production in the last two years. Silo Field, in southeastern Wyoming, in the Denver basin, produced 1.5 million barrels of oil in 1993, double that in 1992. The other field was Sand Dunes, in the Powder River basin, which produced 202 thousand barrels in 1991 but jumped to 2.6 million barrels in both 1992 and 1993.{47}

At Silo Field the increase is due to the application of horizontal drilling in the Niobrara formation, a Cretaceous chalk similar to the Austin Chalk of south Texas. Like the Austin Chalk, the Silo Field area contains oil-filled vertical fractures which are the target of horizontal drilling.{54}

Incentives

Incentives to retain wells and increase overall oil and gas production and reserves have been put in place by several States, generally through various tax relief measures.

Testifying before the Subcommittee on Taxation of the U.S. Senate Finance Committee, Texas Railroad Commission Chairman Jim Nugent stated that “Tax incentives in Texas have added at least 945 million barrels of oil to our reserves.”{55}

In California, efforts are being made to reduce redundant permitting procedures. The Conservation Department is looking into methods which use bonding money as an incentive to keep wells active. “In Kern county there 18,000 stripper wells shutin, of which one-half could be back on production with sufficient incentives.”{56}

Montana approved a bill that lowers taxes on new secondary and tertiary recovery projects and extends an existing tax exemption for new horizontal wells.{57}

Oklahoma’s Governor Walters signed into law an oil and gas bill which offers incentives affecting inactive wells, enhanced oil recovery activity, 15,000 feet or deeper wells, and horizontally drilled wells.{58}

In Texas, a 10-year severance tax exemption has resulted in the reactivation of 1,690 wells in 1993, up from 368 in the previous year with no exemptions. Additional incentives are being designed.{59}

The Texas Railroad Commission has recently come up with 15 possible new incentives to encourage exploration and production activity by the State’s oil and gas producers.{60}

Other incentives to retain wells and increase overall oil and gas production and reserves have been put in place by Louisiana, Oklahoma, and Kansas. In fact, beyond State measures, two counties in Kansas approved ad valorem tax abatements to spur oil and gas operations.

3-D Seismic Activity

Three-dimensional seismic imaging has changed oil and gas exploration and development irrevocably. The technology is being called the greatest advance in the geophysical industry in decades. Recent advances have made this method such a reliable and cost-effective tool that producers are finding new oil and gas in fields once thought to be played out. Some producers consider that money spent on 3-D seismic surveys is money saved by not drilling dry holes.{61}

More efficient land surveys for collecting 3-D data and improved software have lowered costs so that even small companies can use this technology to reduce the cost of finding and developing petroleum reserves.{61}

It is being used in such diverse areas as the Appalachian and Illinois basins; the Permian and Michigan basins where it is an effective exploitation tool; in the south Texas Wilcox, Frio, and Lobo trends for exploration and development; in east Texas tight-sand areas; and in the Paradox basin of Utah, for appraisal and development.

The technology is playing a key role in reserve replacement in the Gulf of Mexico. Using the new technology enables operators to better define prospects and drill fewer dry holes. In both exploration and production phases, the use of 3-D seismology improves total hydrocarbon recovery. It is especially useful for development work around the many complex salt dome structures found both in the Gulf of Mexico and upper Gulf coast of Texas and Louisiana.

Horizontal Drilling

Historically, horizontal drilling has been centered in the United States, primarily in the naturally fractured reservoirs of the Austin Chalk of south Texas and the Bakken Shale formation of the Williston basin of North Dakota. Other notable horizontal drilling plays in the United States include the fractured Buda limestone in Texas and the Niobrara Chalk in the Rocky Mountains, especially in the Silo Field of southeast Wyoming. In these reservoirs, the advantage of horizontal wells lies in their ability to connect multiple fractures. Because of their longer length and increased contact with the reservoir, these wells can drain a large reservoir volume. Because of their high production rates, horizontal wells find excellent application in gas storage fields for meeting peak gas deliverability requirements.{62}

Otherwise the technique has been used sparingly in the United States for applications other than low porosity and low permeability, fractured reservoirs. Horizontal drilling as a percent of total U. S. drilling activity has remained fairly constant at 4 to 5 percent over the last 2 years. The costs must continue to come down for horizontal drilling to have the impact on improved oil recovery that many experts have predicted.{62}

Developments in technology have resulted in multiple completions where opposing laterals are drilled from a single bore in the up-dip and down-dip direction, the equivalent of two horizontal wells. This type of completion is becoming common in the Austin Chalk trend. One operator has reported a “quad-lateral well” completion with dual opposing laterals, one above the other up- and down-dip.{63}

Additional savings have been gained from horizontal re-entries. Drilled from existing vertical, plugged and abandoned wells, horizontal re-entry has become an important tool for field development and revitalizing old fields. Typically, re-entering an existing vertical well results in a 40-60 percent cost savings over drilling and completing a new horizontal well.{62}

Rigs drilling horizontal wells dropped again last year as oil and horizontal activity slowed. In south Texas, activity tapered off in the Pearsall Field and moved to other areas. However, it remained strong in the Giddings Field and further east along the Austin Chalk trend, extending into Louisiana.

4. Natural Gas Statistics

Dry Natural Gas

Proved Reserves

The Nation's proved reserves of dry natural gas were 162,415 billion cubic feet, 1.6 percent (2,600 billion cubic feet) less than in 1992 (Table 8). In the lower 48 States, they decreased by 1.9 percent (2,869 billion cubic feet). Five areas account for approximately 63 percent of the Nation's dry natural gas proved reserves.

Area	Percent of U.S. Gas Reserves
Texas	21
Gulf of Mexico Federal Offshore	16
New Mexico	11
Oklahoma	8
Wyoming	7
Total	**63**

Production

Dry natural gas production increased 2 percent to 17,789 billion cubic feet in 1993 (Table 8). The Gulf of Mexico Federal Offshore and the State of Texas, each with 26 percent of the U.S. total, were the leading producers of dry natural gas in 1993. Oklahoma (10 percent), Louisiana (8 percent), New Mexico (8 percent), and Wyoming (4 percent) contributed another 30 percent.

Discoveries

Total discoveries of dry natural gas reserves were 8,868 billion cubic feet, an increase of 26 percent (1,820 billion cubic feet) from that reported in 1992. These *total discoveries* are equivalent to half the level of 1993 gas production. *Total discoveries* are those reserves attributable to field *extensions*, *new field discoveries*, and *new reservoir discoveries in old fields*; they result from drilling exploratory wells. Areas with the largest *total discoveries* were the Gulf of Mexico Federal Offshore, Texas, Oklahoma, Wyoming, and Colorado. *New field discoveries* (899 billion cubic feet) were 39 percent higher than in 1992. Those areas with the largest *new field discoveries* were the Gulf of Mexico Federal Offshore (with over three-fourths of the total), Texas, and Oklahoma. *New reservoir discoveries in old fields* were 1,866 billion cubic feet, 8 percent higher than 1992. Among the areas with the largest *new reservoir discoveries in old fields* were the Gulf of Mexico Federal Offshore, Texas, Oklahoma, and Louisiana. The Louisiana portion of the Gulf of Mexico Federal Offshore accounted for over half of the *new reservoir discoveries in old fields. Extensions* were 6,103 billion cubic feet, 31 percent higher than in 1992. Among the areas with the largest *extensions* were Texas, the Gulf of Mexico Federal Offshore, Oklahoma, Wyoming, and Colorado. Texas accounted for 28 percent of the *extensions* in the United States; one-half of these were in far south Texas (Railroad Commission District 4).

Wet Natural Gas

Proved Reserves

U. S. proved reserves of wet natural gas, as of December 31, 1993, were 170,490 billion cubic feet, a decrease of 1.6 percent, or 2,819 billion cubic feet, from that reported in 1992 (Table 9). End of year 1993 proved wet natural gas reserves for the lower 48 States were lower by 2 percent (3,080 billion cubic feet) than in 1992, while those of Alaska increased by 261 billion cubic feet. The volumetric differences between the estimates reported in Table 8 (dry) and Table 9 (wet) results from the removal of natural gas liquids at natural gas processing plants. (All natural gas proved reserves data shown in this report exclude natural gas held in underground storage.)

Nonassociated Natural Gas

Proved Reserves

Proved reserves of nonassociated (NA) natural gas, wet after lease separation, in the United States decreased by 1,440 billion cubic feet (1 percent) in 1993 to 140,445 billion cubic feet (Table 10). This was the third straight year of decrease. The lower 48 States NA wet natural gas proved reserves decreased by 1,930 billion cubic feet, or 1 percent. Those areas with the largest increases in NA wet natural gas reserves were Texas, Alaska, Virginia, Wyoming, and Utah. There were large decreases in NA wet natural gas reserves in Oklahoma, Alabama, New Mexico, Louisiana, and Kansas.

Table 8. Total Dry Natural Gas Proved Reserves, Reserves Changes, and Production, 1993

(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State and Subdivision	Published Proved Reserves 12/31/92	Changes in Reserves During 1993: Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Production (-)	Proved Reserves 12/31/93
Alaska	9,638	57	679	109	27	0	8	393	9,907
Lower 48 States	**155,377**	**915**	**16,918**	**12,139**	**6,076**	**899**	**1,858**	**17,396**	**152,508**
Alabama	5,802	-644	44	159	378	0	0	281	5,140
Arkansas	1,750	-62	98	123	76	0	1	188	1,552
California	2,778	95	110	136	58	14	15	252	2,682
Coastal Region Onshore	203	-20	26	6	3	0	0	17	189
Los Angeles Basin Onshore	97	6	10	6	3	0	1	9	102
San Joaquin Basin Onshore	2,415	104	71	123	51	14	14	219	2,327
State Offshore	63	5	3	1	1	0	0	7	64
Colorado	6,198	-156	1,000	411	461	2	15	387	6,722
Florida	47	-4	11	0	2	0	0	[a]6	[a]50
Kansas	9,681	102	335	225	98	11	3	657	9,348
Kentucky	1,084	-34	34	31	8	0	8	66	1,003
Louisiana	9,780	579	1,419	1,527	284	5	91	1,457	9,174
North	2,311	85	395	264	122	0	3	327	2,325
South Onshore	6,693	265	913	1,159	122	5	86	993	5,932
State Offshore	776	229	111	104	40	0	2	137	917
Michigan	1,223	94	164	202	22	0	0	141	1,160
Mississippi	869	68	64	108	2	10	3	111	797
Montana	859	-154	29	11	0	0	0	50	673
New Mexico	18,998	-124	2,000	1,377	419	3	37	1,337	18,619
East	3,130	69	430	309	138	3	29	456	3,034
West	15,868	-193	1,570	1,068	281	0	8	881	15,585
New York	329	-51	12	9	5	0	0	[a]22	[a]264
North Dakota	496	49	37	27	21	0	1	52	525
Ohio	1,161	36	36	19	3	1	7	121	1,104
Oklahoma	13,926	-94	1,554	1,008	548	25	108	1,770	13,289
Pennsylvania	1,528	190	177	73	29	0	4	138	1,717
Texas	35,093	997	4,051	2,994	1,720	139	357	4,645	34,718
RRC District 1	933	-145	117	126	24	1	6	112	698
RRC District 2 Onshore	1,389	83	150	149	49	7	24	232	1,321
RRC District 3 Onshore	2,684	310	442	261	149	53	127	532	2,972
RRC District 4 Onshore	6,739	249	845	535	852	1	100	1,213	7,038
RRC District 5	1,747	159	130	99	49	56	0	175	1,867
RRC District 6	5,317	276	762	496	187	0	81	619	5,508
RRC District 7B	455	101	13	29	1	0	1	65	477
RRC District 7C	3,239	89	293	250	130	21	2	309	3,215
RRC District 8	5,924	125	591	572	96	0	12	660	5,516
RRC District 8A	1,239	-111	47	66	2	0	0	68	1,043
RRC District 9	670	23	66	43	76	0	0	104	688
RRC District 10	4,409	-159	500	333	89	0	4	470	4,040
State Offshore	348	-3	95	35	16	0	0	86	335
Utah	1,830	43	337	24	11	8	0	165	2,040
Virginia	904	348	125	21	1	0	1	36	1,322
West Virginia	2,356	62	212	60	27	0	11	169	2,439
Wyoming	10,826	-113	907	523	498	0	51	713	10,933
Federal Offshore[b]	27,767	-317	4,149	3,064	1,404	681	1,145	4,622	27,143
Pacific (California)	1,118	-4	435	410	5	0	0	45	1,099
Gulf of Mexico (Louisiana)[b]	19,653	-174	2,862	2,102	1,070	379	1,014	3,319	19,383
Gulf of Mexico (Texas)	6,996	-139	852	552	329	302	131	1,258	6,661
Miscellaneous[c]	92	5	13	7	1	0	0	10	94
U.S. Total	**165,015**	**972**	**17,597**	**12,248**	**6,103**	**899**	**1,866**	**17,789**	**162,415**

[a]Indicates the estimate is associated with a sampling error (95 percent confidence interval) that exceeds 20 percent of the estimated value.
[b]Includes Federal offshore Alabama.
[c]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada,Oregon, South Dakota, and Tennessee.

Note: The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production." They may differ from the official Energy Information Administration production data for natural gas for 1993 contained in the *Natural Gas Annual 1993*, DOE/EIA-0131(93).

Source: Energy Information Administration, Office of Oil and Gas.

Table 9. Total Natural Gas Proved Reserves, Reserves Changes, and Production, Wet After Lease Separation, 1993 (Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

		Changes in Reserves During 1993							Proved Reserves 12/31/93		
State and Subdivision	Published Proved Reserves 12/31/92	Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Production (-)	Total Gas	Non-associated Gas	Associated Dissolved Gas
Alaska	9,725	52	680	110	27	0	8	396	9,986	3,492	6,494
Lower 48 States	**163,584**	**996**	**17,714**	**12,743**	**6,349**	**927**	**1,922**	**18,245**	**160,504**	**136,953**	**23,551**
Alabama	5,870	-634	48	165	380	0	0	287	5,212	5,166	46
Arkansas	1,752	-62	98	123	77	0	1	188	1,555	1,462	93
California	2,892	104	116	142	61	15	15	262	2,799	817	1,982
Coastal Region Onshore	215	-20	28	7	3	0	0	18	201	66	135
Los Angeles Basin Onshore	103	5	11	6	3	0	1	9	108	0	108
San Joaquin Basin Onshore	2,511	113	74	128	54	15	14	228	2,425	749	1,676
State Offshore	63	6	3	1	1	0	0	7	65	2	63
Colorado	6,463	-177	1,027	430	483	3	16	406	6,979	5,817	1,162
Florida	55	-3	13	0	2	0	0	[a]8	[a]59	0	[a]59
Kansas	10,302	29	355	238	103	12	3	694	9,872	9,779	93
Kentucky	1,126	-42	35	32	9	0	8	68	1,036	1,030	6
Louisiana	10,227	551	1,477	1,593	294	5	96	1,516	9,541	8,615	926
North	2,363	86	404	270	124	0	3	334	2,376	2,256	120
South Onshore	7,019	273	958	1,215	128	5	91	1,040	6,219	5,570	649
State Offshore	845	192	115	108	42	0	2	142	946	789	157
Michigan	1,290	94	171	213	23	0	0	147	1,218	890	328
Mississippi	873	68	64	109	2	10	3	111	800	747	53
Montana	875	-159	29	11	0	0	0	50	684	631	53
New Mexico	20,399	-170	2,098	1,455	444	3	39	1,419	19,939	18,354	1,585
East	3,418	103	473	340	151	3	31	501	3,338	1,860	1,478
West	16,981	-273	1,625	1,115	293	0	8	918	16,601	16,494	107
New York	329	-51	12	9	5	0	0	[a]22	[a]264	[a]264	0
North Dakota	567	38	41	30	24	0	2	57	585	311	274
Ohio	1,161	37	36	19	3	2	7	121	1,106	763	343
Oklahoma	14,732	-56	1,649	1,069	581	27	114	1,879	14,099	12,549	1,550
Pennsylvania	1,533	191	177	73	29	0	4	139	1,722	1,714	8
Texas	38,141	1,239	4,374	3,252	1,841	150	384	5,030	37,847	29,967	7,880
RRC District 1	967	-144	123	131	25	1	7	117	731	540	191
RRC District 2 Onshore	1,484	103	162	161	54	7	26	250	1,425	1,137	288
RRC District 3 Onshore	2,929	344	484	285	164	58	139	582	3,251	2,092	1,159
RRC District 4 Onshore	7,041	258	882	558	889	1	105	1,267	7,351	7,136	215
RRC District 5	1,818	152	134	102	51	58	0	180	1,931	1,790	141
RRC District 6	5,593	272	800	520	196	0	85	649	5,777	5,170	607
RRC District 7B	550	126	16	35	1	1	1	80	580	393	187
RRC District 7C	3,621	82	325	278	146	24	2	344	3,578	2,945	633
RRC District 8	6,534	189	657	636	107	0	14	734	6,131	3,569	2,562
RRC District 8A	1,598	-13	64	92	3	0	0	97	1,463	12	1,451
RRC District 9	797	24	78	51	90	0	0	124	814	636	178
RRC District 10	4,859	-151	554	368	99	0	5	520	4,478	4,214	264
State Offshore	350	-3	95	35	16	0	0	86	337	333	4
Utah	2,018	0	364	26	12	8	0	178	2,198	1,909	289
Virginia	904	348	125	21	1	0	1	36	1,322	1,322	0
West Virginia	2,491	84	225	63	29	0	11	179	2,598	2,408	190
Wyoming	11,305	-148	945	544	518	0	53	742	11,387	10,885	502
Federal Offshore[b]	28,186	-291	4,222	3,119	1,427	692	1,165	4,696	27,586	21,466	6,120
Pacific (California)	1,136	2	444	419	5	0	0	45	1,123	147	976
Gulf of Mexico (Louisiana)[b]	20,006	-159	2,920	2,143	1,090	387	1,033	3,383	19,751	15,181	4,570
Gulf of Mexico (Texas)	7,044	-134	858	557	332	305	132	1,268	6,712	6,138	574
Miscellaneous[c]	93	6	13	7	1	0	0	10	96	87	9
U.S. Total	**173,309**	**1,048**	**18,394**	**12,853**	**6,376**	**927**	**1,930**	**18,641**	**170,490**	**140,445**	**30,045**

[a]Indicates the estimate is associated with a sampling error (95 percent confidence interval) that exceeds 20 percent of the estimated value.
[b]Includes Federal offshore Alabama.
[c]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee.

Note: The production estimates in this table are based on data reported on Form EIA-23. They may differ from the official Energy Information Administration production data for natural gas for 1993 contained in the *Natural Gas Annual 1993*, DOE/EIA-0131(93).

Source: Energy Information Administration, Office of Oil and Gas.

Table 10. Nonassociated Natural Gas Proved Reserves, Reserves Changes, and Production, Wet After Lease Separation, 1993
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State and Subdivision	Published Proved Reserves 12/31/92	Changes in Reserves During 1993 Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Production (-)	Proved Reserves 12/31/93
Alaska	3,002	81	609	43	19	0	8	184	3,492
Lower 48 States	**138,883**	**1,269**	**14,546**	**10,087**	**5,490**	**682**	**1,759**	**15,589**	**136,953**
Alabama	5,840	-639	29	164	376	0	0	276	5,166
Arkansas	1,619	-45	92	115	77	0	1	167	1,462
California	799	96	49	87	38	15	14	107	817
Coastal Region Onshore	19	39	11	1	2	0	0	4	66
Los Angeles Basin Onshore	3	0	0	3	0	0	0	0	0
San Joaquin Basin Onshore	773	59	37	83	36	15	14	102	749
State Offshore	4	-2	1	0	0	0	0	1	2
Colorado	5,701	-330	866	398	266	2	13	303	5,817
Florida	0	0	0	0	0	0	0	0	0
Kansas	10,208	42	330	221	81	11	3	675	9,779
Kentucky	1,118	-41	35	31	9	0	8	68	1,030
Louisiana	9,060	604	1,322	1,353	269	3	85	1,375	8,615
North	2,203	123	392	263	115	0	3	317	2,256
South Onshore	6,166	319	839	1,007	112	3	80	942	5,570
State Offshore	691	162	91	83	42	0	2	116	789
Michigan	938	100	135	190	18	0	0	111	890
Mississippi	788	81	57	99	2	10	3	95	747
Montana	814	-151	18	6	0	0	0	44	631
New Mexico	18,802	-234	1,824	1,239	374	2	37	1,212	18,354
East	1,948	31	214	147	89	2	29	306	1,860
West	16,854	-265	1,610	1,092	285	0	8	906	16,494
New York	329	-51	12	9	5	0	0	[a]22	[a]264
North Dakota	301	15	6	9	16	0	0	18	311
Ohio	780	26	29	8	0	0	3	67	763
Oklahoma	13,249	-116	1,363	932	515	27	106	1,663	12,549
Pennsylvania	1,523	192	177	73	29	0	4	138	1,714
Texas	29,474	1,386	3,649	2,498	1,627	150	340	4,161	29,967
RRC District 1	606	-59	113	60	23	1	7	91	540
RRC District 2 Onshore	1,176	101	136	138	50	7	25	220	1,137
RRC District 3 Onshore	1,723	296	356	166	133	58	104	412	2,092
RRC District 4 Onshore	6,813	276	832	542	885	1	101	1,230	7,136
RRC District 5	1,692	117	130	86	49	58	0	170	1,790
RRC District 6	4,987	257	762	487	153	0	83	585	5,170
RRC District 7B	380	91	10	32	0	1	1	58	393
RRC District 7C	2,873	131	260	212	131	24	2	264	2,945
RRC District 8	3,792	259	398	446	18	0	14	466	3,569
RRC District 8A	13	0	2	1	0	0	0	2	12
RRC District 9	613	27	50	35	77	0	0	96	636
RRC District 10	4,463	-107	506	259	92	0	3	484	4,214
State Offshore	343	-3	94	34	16	0	0	83	333
Utah	1,709	1	341	18	5	8	0	137	1,909
Virginia	904	348	125	21	1	0	1	36	1,322
West Virginia	2,293	72	221	58	29	0	10	159	2,408
Wyoming	10,681	2	832	517	517	0	53	683	10,885
Federal Offshore[b]	21,871	-94	3,022	2,036	1,235	454	1,078	4,064	21,466
Pacific (California)	149	0	10	1	0	0	0	11	147
Gulf of Mexico (Louisiana)[b]	15,369	43	2,174	1,534	909	149	946	2,875	15,181
Gulf of Mexico (Texas)	6,353	-137	838	501	326	305	132	1,178	6,138
Miscellaneous[c]	82	5	12	5	1	0	0	8	87
U.S. Total	**141,885**	**1,350**	**15,155**	**10,130**	**5,509**	**682**	**1,767**	**15,773**	**140,445**

[a]Indicates the estimate is associated with a sampling error (95 percent confidence interval) that exceeds 20 percent of the estimated value.
[b]Includes Federal offshore Alabama.
[c]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee.

Note: The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves." They may differ from the official Energy Information Administration production data for natural gas for 1993 contained in the *Natural Gas Annual 1993*, DOE/EIA-0131(93).

Source: Energy Information Administration, Office of Oil and Gas.

Production

U.S. production of NA wet natural gas increased by 4 percent (535 billion cubic feet) in 1993 (Table 10). While most areas showed some production increases, the areas that showed the largest increases were Texas, New Mexico, Kansas, Wyoming, and Utah. These accounted for 44 percent of total U.S. NA wet natural gas production.

Discoveries

NA wet natural gas *total discoveries* of 7,958 billion cubic feet increased 27 percent (1,687 billion cubic feet) in 1993. The Gulf of Mexico Federal Offshore, Texas, Oklahoma, Wyoming, and New Mexico accounted for 6,515 billion cubic feet or 82 percent of U.S. NA wet natural gas *total discoveries* in 1993.

Associated-Dissolved Natural Gas

Proved Reserves

Proved reserves of associated-dissolved (AD) natural gas, wet after lease separation, in the United States decreased by 4 percent to 30,045 billion cubic feet in 1993 (Table 11). Proved reserves of AD wet natural gas in the lower 48 States declined by 1,150 billion cubic feet to 23,551 billion cubic feet.

Production

U.S. production of AD wet natural gas decreased by 5 percent in 1993 (Table 11). Production of AD wet natural gas in the lower 48 States decreased by 6 percent to 2,656 billion cubic feet. The areas of the country with the largest AD wet natural gas reserves were Texas, Alaska, the Gulf of Mexico Federal Offshore, California, New Mexico, Oklahoma, and Louisiana. These areas correspond to the areas of the country with the largest volumes of crude oil reserves and production.

Coalbed Methane

Proved Reserves

Coalbed methane proved reserves are principally located in New Mexico, Colorado, and Alabama. After several years of rapid growth, the rate of growth in coalbed methane reserves slowed in 1993 as Federal tax incentives for new coalbed methane wells expired. Estimates of proved coalbed methane reserves in Alabama were lowered. Both Colorado and Virginia had substantial increases in 1993. Reserves in coalbed methane fields increased to 10,184 billion cubic feet, 1 percent more than in 1992. Coalbed methane reserves accounted for over 6 percent of U.S. natural gas reserves in 1993. The EIA estimates that the 1993 proved gas reserves of fields identified as having coalbed methane were twice the 5,087 billion cubic feet reported only 3 years ago (Table 12).

Production

Coalbed methane production grew by more than one-third in 1993. Most of the 193 billion cubic feet production increase occurred in the San Juan basin of Colorado and New Mexico. Coalbed methane production in 1993 represented 4 percent of the Nation's total dry gas production.

Reserves in Nonproducing Reservoirs

Proved natural gas reserves, wet after lease separation, of 30,850 billion cubic feet were reported in nonproducing reservoirs in 1993 (Table 13). This was 10 percent lower than in 1992. About 38 percent are located in the Gulf of Mexico Federal Offshore area. The most notable decrease occurred in Alabama, as natural gas fields in the shallow Miocene and deep Norphlet formations in Mobile Bay in the State and Federal offshore came on-stream and moved into the producing category of reserves.

Proved reserves in nonproducing reservoirs were reported by Category I and II operators, who collectively account for about 90 percent of the estimated total wet natural gas production in the United States. The reasons for the nonproducing status of these proved reserves are not collected by EIA. However, previous surveys showed that most of the wells or reservoirs were not producing for operational reasons. These included waiting for well workovers, drilling additional development or replacement wells, installing production or pipeline facilities, and awaiting depletion of other zones or reservoirs before recompletion in reservoirs not currently open to production.

Table 11. Associated-Dissolved Natural Gas Proved Reserves, Reserves Changes, and Production, Wet After Lease Separation, 1993

(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State and Subdivision	Published Proved Reserves 12/31/92	Changes in Reserves During 1993: Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Production (-)	Proved Reserves 12/31/93
Alaska	6,723	-29	71	67	8	0	0	212	6,494
Lower 48 States	**24,701**	**-273**	**3,168**	**2,656**	**859**	**245**	**163**	**2,656**	**23,551**
Alabama	30	5	19	1	4	0	0	11	46
Arkansas	133	-17	6	8	0	0	0	21	93
California	2,093	8	67	55	23	0	1	155	1,982
Coastal Region Onshore	196	-59	17	6	1	0	0	14	135
Los Angeles Basin Onshore	100	5	11	3	3	0	1	9	108
San Joaquin Basin Onshore	1,738	54	37	45	18	0	0	126	1,676
State Offshore	59	8	2	1	1	0	0	6	63
Colorado	762	153	161	32	217	1	3	103	1,162
Florida	55	-3	13	0	2	0	0	[a]8	[a]59
Kansas	94	-13	25	17	22	1	0	19	93
Kentucky	8	-1	0	1	0	0	0	0	6
Louisiana	1,167	-53	155	240	25	2	11	141	926
North	160	-37	12	7	9	0	0	17	120
South Onshore	853	-46	119	208	16	2	11	98	649
State Offshore	154	30	24	25	0	0	0	26	157
Michigan	352	-6	36	23	5	0	0	36	328
Mississippi	85	-13	7	10	0	0	0	16	53
Montana	61	-8	11	5	0	0	0	6	53
New Mexico	1,597	64	274	216	70	1	2	207	1,585
East	1,470	72	259	193	62	1	2	195	1,478
West	127	-8	15	23	8	0	0	12	107
New York	0	0	0	0	0	0	0	0	0
North Dakota	266	23	35	21	8	0	2	39	274
Ohio	381	11	7	11	3	2	4	54	343
Oklahoma	1,483	60	286	137	66	0	8	216	1,550
Pennsylvania	10	-1	0	0	0	0	0	1	8
Texas	8,667	-147	725	754	214	0	44	869	7,880
RRC District 1	361	-85	10	71	2	0	0	26	191
RRC District 2 Onshore	308	2	26	23	4	0	1	30	288
RRC District 3 Onshore	1,206	48	128	119	31	0	35	170	1,159
RRC District 4 Onshore	228	-18	50	16	4	0	4	37	215
RRC District 5	126	35	4	16	2	0	0	10	141
RRC District 6	606	15	38	33	43	0	2	64	607
RRC District 7B	170	35	6	3	1	0	0	22	187
RRC District 7C	748	-49	65	66	15	0	0	80	633
RRC District 8	2,742	-70	259	190	89	0	0	268	2,562
RRC District 8A	1,585	-13	62	91	3	0	0	95	1,451
RRC District 9	184	-3	28	16	13	0	0	28	178
RRC District 10	396	-44	48	109	7	0	2	36	264
State Offshore	7	0	1	1	0	0	0	3	4
Utah	309	-1	23	8	7	0	0	41	289
Virginia	0	0	0	0	0	0	0	0	0
West Virginia	198	12	4	5	0	0	1	20	190
Wyoming	624	-150	113	27	1	0	0	59	502
Federal Offshore[b]	6,315	-197	1,200	1,083	192	238	87	632	6,120
Pacific (California)	987	2	434	418	5	0	0	34	976
Gulf of Mexico (Louisiana)[b]	4,637	-202	746	609	181	238	87	508	4,570
Gulf of Mexico (Texas)	691	3	20	56	6	0	0	90	574
Miscellaneous[c]	11	1	1	2	0	0	0	2	9
U.S. Total	**31,424**	**-302**	**3,239**	**2,723**	**867**	**245**	**163**	**2,868**	**30,045**

[a]Indicates the estimate is associated with a sampling error (95 percent confidence interval) that exceeds 20 percent of the estimated value.
[b]Includes Federal offshore Alabama.
[c]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee.

Note: The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves." They may differ from the official Energy Information Administration production data for natural gas for 1993 contained in the *Natural Gas Annual 1993*, DOE/EIA-0131(93).

Table 12. U.S. Coalbed Methane Proved Reserves and Production, 1990 through 1993
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State	1990 Reserves	1990 Production	1991 Reserves	1991 Production	1992 Reserves	1992 Production	1993 Reserves	1993 Production
Alabama	1,224	36	1,714	68	1,968	89	1,237	103
Colorado.	1,320	26	2,076	48	2,716	82	3,107	125
New Mexico	2,510	133	4,206	229	4,724	358	4,775	486
Others[a]	33	1	167	3	626	10	1,065	18
Total	**5,087**	**196**	**8,163**	**348**	**10,034**	**539**	**10,184**	**732**

[a]Includes Kansas, Oklahoma, Pennsylvania, Utah, Virginia, and Wyoming.
Source: Energy Information Administration, Office of Oil and Gas.

Areas of Note

The following State or area discussions summarize notable activities during the year concerning expected new field reserves, development plans, and possible production rates as reported by various trade publications. The citations do not necessarily reflect EIA's concurrence, but are considered important enough to be brought to the reader's attention.

Gulf of Mexico

Deep Water: The deep water Gulf of Mexico continues to show significant potential for the development of natural gas. Many major projects are underway, or in advanced planning stages, to move out into the deep water off the continental shelf. Most companies plan to use state of the art subsea producing technology. Subsea technology allows the commercial development of deep water prospects that lack the size to support the cost of surface structures. Major announced projects in the deep water areas are: (1) Cooper, 2,375 feet, Garden Banks Block 387, (2) Lobster, 675 feet, Ewing Bank Block 873, (3) Popeye, 2,320 feet, Green Canyon Block 116, (4) Tahoe, 1,450 feet, Viosca Knoll Block 783, (5) Ram-Powell, 3,000 feet, Viosca Knoll Block 912, (6) Thor, 1,710 feet, Viosca Knoll Block 825, (7) Diana, 4,677 feet, East Breaks Block 945, (8) Mensa, 5,400 feet, Mississippi Canyon Block 731, (9) Mickey, 4,810 feet, Mississippi Canyon Block 211, (10) Lena, 1,000 feet, Mississippi Canyon Block 281, (11) Vancouver, 2,700 feet, Green Canyon Block 205.

New Production: An earlier natural gas discovery at the Zinc platform went onstream at a daily rate of 45 million cubic feet. This is one of the earliest deep water projects to come onstream and is expected to be followed by others shortly. Production began from a deepwater development template in Mississippi Canyon Block 441. Three wells began producing in April, and three more wells were planned, which should boost production to 70 million cubic feet per day of gas and 600 barrels per day of condensate.{64} Mississippi Canyon Block 400 unit began production through the West Delta 152 platform. Three wells are expected to produce a combined 40 million cubic feet per day of gas.{65} A well in Mississippi Canyon Block 445 has set the deep water world record for a subsea completed gas well. In 2,088 feet of water, the well is also the deepest subsea producing gas well in the Gulf of Mexico. The 7 mile flexible gas flow line which serves the well is also a worldwide first. Nearby, a well in Mississippi Canyon Block 401, in 1,696 feet of water, is the Gulf's second deepest subsea producing gas well. These fields are about 30 miles off the Louisiana coast.{65} Production also began from the Seattle Slew Field through Ewing Bank Block 826 production facilities.{66} Fourth quarter production also began from a three-platform development in the Alabama Outer Continental Shelf. Production from Mobile Block 904 was expected to stabilize at 20-25 million cubic feet per day.{67}

Independents: Independents are increasing their presence in the Gulf of Mexico. The statistics on leasing, rig contracting, and field acquisitions tell a story of the changing profile of the offshore industry. In 1993, independents offered 83 percent of the bonuses in federal lease sales, compared to less than 47 percent in 1986. Further, independents won 76 percent of the acreage offered for federal tracts in 1992, compared to only 45 percent in 1988. Since the first quarter of 1991, 70 percent of all the rigs operating in the Gulf have been employed by independents.{68}

Texas

The Val Verde basin of west Texas has become the site of an aggressive campaign to develop Permian basin gas. Several areas in Texas are sources of

Table 13. Reported Reserves of Natural Gas, Wet After Lease Separation, in Nonproducing Reservoirs, 1993[a]
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State and Subdivision	Nonassociated Gas	Associated-Dissolved Gas	Total
Alaska	55	144	199
Lower 48 States	**26,132**	**4,519**	**30,651**
Alabama	360	0	360
Arkansas	161	6	167
California	110	54	164
Coastal Region Onshore	19	33	52
Los Angeles Basin Onshore	<1	13	13
San Joaquin Basin Onshore	91	4	95
State Offshore	0	4	4
Colorado	695	443	1,138
Florida	0	0	0
Kansas	354	20	374
Kentucky	89	0	89
Louisiana	2,663	243	2,906
North	552	5	557
South Onshore	1,835	202	2,037
South State Offshore	276	36	312
Michigan	122	14	136
Mississippi	62	5	67
Montana	8	1	9
New Mexico	2,710	105	2,815
East	168	92	260
West	2,542	13	2,555
New York	5	0	5
North Dakota	167	15	182
Ohio	64	2	66
Oklahoma	914	158	1,072
Pennsylvania	54	1	55
Texas	6,032	861	6,893
District 1	54	44	98
District 2 Onshore	197	76	273
District 3 Onshore	380	78	458
District 4 Onshore	2,399	72	2,471
District 5	743	20	763
District 6	1,277	121	1,398
District 7B	2	3	5
District 7C	432	30	462
District 8	227	276	503
District 8A	2	108	110
District 9	9	2	11
District 10	213	31	244
State Offshore	97	<1	97
Utah	152	74	226
Virginia	3	0	3
West Virginia	143	4	147
Wyoming	1,796	25	1,821
Federal Offshore[b]	9,464	2,488	11,952
Pacific (California)	62	156	218
Gulf of Mexico (Texas)	2,380	412	2,792
Gulf of Mexico (Louisiana)[b]	7,022	1,920	8,942
Miscellaneous[c]	4	0	4
U.S Total	**26,187**	**4,663**	**30,850**

[a]Includes only those operators who produced 400,000 barrels of crude oil or 2 billion cubic feet of natural gas, or both, during the report year (Category I or Category II operators).

[b]Includes Federal Offshore Alabama.

[c]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee.

Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1993.

tight-formation gas: the Anadarko basin, East Texas basin, Permian basin, Strawn basin, and the Texas Gulf Coast basin. The Carthage Field, in east Texas, remained as the top natural gas producing field in Texas, superseding the 1991 leader, Panhandle West Field.

South Texas: Throughout 1993, discoveries were made across south Texas while targeting the Wilcox formational group. The Bob West Field, a 1990 discovery in Starr county, Texas Railroad Commission District 4, has shown a significant increase in production over the last 3 years. Operators, both majors and independents, are using improved seismic technology with more sophisticated drilling and completion techniques to increase tight-sands gas production in far south Texas. Advanced seismic technology, two-dimensional as well three-dimensional, is helping producers overcome the geological obstacles. This is especially true in the Lobo trend around Laredo in Webb and Zapata counties. Production has increased sixfold from 30 million cubic feet per day 5 years ago to 180 million cubic feet per day in 1993. Much drilling is necessary to maintain deliverability from the Lobo formation as well declines in the first year are between 40 and 50 percent. However, Lobo wells start production at very high rates, so payback is rapid. The geology in the area is very complex. Structures are extremely faulted into small deposits requiring a high well density to develop the formation.{69}

Rockies

The Rocky Mountain region continues to be an active area, contributing more than 27 percent of the Nation's new gas well completions in 1993.

Colorado: More than 850 wells completed in the giant Wattenberg Field made it the most active area in the country in 1993, topping Kern County, California. Low-risk development is shown with a success rate of just one dry hole per 100 drilled. Much of the drilling activity involves short-term, streamlined recovery to maximize economics, then repetition of the procedure in another area. This may lead to a reduced overall field life. Wattenberg was discovered in 1970.{70}

New State intervention on surface rights bonds could result in pullouts and set an unwelcome precedent for producers in Wattenberg. A 1993 government mandate requires mineral rights owners/petroleum producers in the Wattenburg Field to post bonds to surface rights owners before beginning to drill. Experts predict that this could reduce new drilling in this field and across the State. Farmers' claims of property destruction, including irrigation and soil damage and lost crop revenue, seem to have spurred the government's decision. This decision marks a break from past private rights ownership and dispute arbitration procedures for the industry.{71}

Coalbed methane development in Colorado continued at full pace, despite the removal of federal tax credits. New development projects and drilling programs were slated by several companies, to drill up to 175 wells in the Raton basin.{72}

New Mexico: Coalbed methane activity continued throughout 1993 in New Mexico's San Juan basin, which has experienced increased production since 1989. Northeast NM suffered considerably with the discontinuation of tax credits for coalbed methane, and although some finds were made in Pictured Cliffs deposits in Rio Arriba and Sandoval counties, activity within the Fruitland formation play was considerably less than in previous years.{73}

Wyoming: In January 1993, Moxa Arch gas was second only to Appalachian gas in value, and production has room to grow. With much unexplored land in the Moxa Arch area of southwestern Wyoming, the surrounding Green River basin still holds hope for even bigger gas plays.{74} Because land acquisition is an important indicator of future drilling activity, recent lease sales indicate that Wyoming should experience a higher level of drilling activity in the next few years. The Wyoming Geological Survey forecasts annual gas production to increase to over 1 trillion cubic feet by the end of 1996. In 1993, there were 636 total well completions of which 345 were gas well completions. This compares with 434 and 157 in 1992, respectively.{75}

Michigan

The Antrim Shale areas of Michigan have been active in 1993 as drillers responded to tax credits. Even with the loss of tight-formation tax credits, Antrim shale drilling continued in several areas across the northern portion of the Lower Michigan Peninsula during 1993. Most of the drilling has been by independents. In terms of the number of wells drilled, this has been the Michigan basin's dominant hydrocarbon play for several years. Production is generally found at depths of 1,200 to 1,800 feet, but ranges from 600 to 2,200 feet deep across the basin. Gas production from about 3,500 Antrim completions, which now yield 350 million cubic feet per day (more than 60 percent of

Michigan's gas production), could increase to about 500 to 600 million cubic feet per day in the next 2 to 3 years. Petroleum Information Corporation reported 3 Antrim fields were among the top 12 U.S. fields in 1993 well completions with 225, 132, and 122 completions.{76}

Gulf Coast

Eastern Gulf of Mexico discoveries have added major gas reserves to the Alabama offshore. The Norphlet formation, found at depths of 22,000 to 25,000 feet, has added trillions of cubic feet of gas reserves over the last few years. Most exploratory drilling has been in the Mobile Bay area, but new exploration in the Destin Dome area off Florida may extend production further eastward.

Alabama: Nearly a quarter of a century after Alabama issued its first offshore State lease, the enormous Norphlet gas fields in Mobile Bay are beginning to produce. The cost and the complexity of producing and processing sour gas had precluded more rapid development of the large fields of Mobile Bay. The completion of essential infrastructure, pipelines and processing systems, and the interconnection of other State and Federal offshore fields, is making the Mobile Bay area one of the primary natural gas supply sources in the United States.{67} Gas supplies from the Mobile Bay region are expected to burgeon over the next few years as several huge processing plants come on-line, and new and expanded pipelines are constructed. The region can produce and process an estimated 1 billion cubic feet per day. Producer and pipeline companies are positioning themselves to bring to market even more gas from the Mobile Bay reserves.{77}

Coalbed methane fields continued producing in the Black Warrior basin, but without federal tax incentives, most operators limited new drilling. Permits for coalbed methane were dropped drastically in 1993—from about 13 per month in 1992 to about 6 per month in 1993. Production should hold up for the time being as newer wells go through a 12 to 18 month dewatering stage before peak production.{78}

Appalachia

The Appalachian basin continues to be an important resource close to major gas-using markets. Non-conventional gas from Devonian Shale is produced in areas in eastern Kentucky, southeastern Ohio, West Virginia, and a small area of Virginia. The National Petroleum Council, in December 1992, estimated that these are areas of high potential for future gas production and contain about 27 trillion cubic feet of resources that could be recovered using current technology.

Virginia: Developments in 1993 were highlighted by coalbed methane development in the Nora and Oakwood fields. Virginia production doubled as coalbed methane production exceeded conventional production for the first time.

Ohio: Activity in Ohio has centered on exploration for gas in the shallow Rose Run formation.

West Virginia: Operators have been active drilling for shallow gas reserves in West Virginia.

5. Natural Gas Liquids Statistics

Natural Gas Liquids

Proved Reserves

Natural gas liquids proved reserves decreased in 1993 by 3 percent to 7,222 million barrels (Table 14). This was the lowest level since 1982. The 229 million barrel decrease was predominantly in the lower 48 States as it declined to 6,901 million barrels in 1993. This was the lowest level for the lower 48 States since 1980. The reserves in five areas account for about three-fourths of the Nation's natural gas liquids proved reserves. Of these, Texas had 34 percent, New Mexico had 14 percent, Oklahoma had 9 percent, and the Gulf of Mexico Federal Offshore and Utah-Wyoming had 8 percent each. (The volumes of NGL proved reserves and production shown in Table 14 are the sums of the natural gas plant liquid volumes listed in Table 15 and the lease condensate volumes listed in Table 16.)

Production

Natural gas liquids production increased 2 percent to 788 million barrels in 1993. Five areas accounted for about 80 percent of the Nation's natural gas liquids production. Of these, Texas had 40 percent, the Gulf of Mexico Federal Offshore had 12 percent, Oklahoma had 11 percent, Louisiana had 9 percent, and New Mexico had 8 percent.

Discoveries

Total discoveries of natural gas liquids reserves increased by 22 percent to 333 million barrels in 1993. Areas with the largest *total discoveries* were Texas, the Gulf of Mexico Federal Offshore, Oklahoma, New Mexico, and Utah-Wyoming. *New field discoveries*, at 24 million barrels, were 20 percent greater than in 1992. Areas with the largest amount of *new field discoveries* were the Gulf of Mexico Federal Offshore and Texas, with 88 percent of the total. *New reservoir discoveries in old fields*, at 64 million barrels, were the same as in 1992. Areas with the largest amounts of *new reservoir discoveries in old fields* were the Gulf of Mexico Federal Offshore and Texas. *Extensions* were 245 million barrels, an increase of 29 percent in 1993. Areas with the largest *extensions* were Texas, the Gulf of Mexico Federal Offshore, Oklahoma, New Mexico, and Utah-Wyoming.

Natural Gas Plant Liquids

Proved Reserves

Natural gas plant liquids proved reserves decreased in 1993 by 3 percent to 6,030 million barrels (Table 15). Five areas accounted for approximately 75 percent of the Nation's natural gas plant liquids proved reserves: Texas (37 percent), New Mexico (15 percent), Oklahoma (10 percent), Utah-Wyoming (8 percent), and Kansas (6 percent).

Production

Natural gas plant liquids production increased 1 percent to 635 million barrels in 1993 (Table 15). Five areas accounted for approximately 79 percent of the Nation's natural gas plant liquids production: Texas (43 percent), Oklahoma (12 percent), New Mexico (9 percent), the Gulf of Mexico Federal Offshore (8 percent), and Louisiana (7 percent). The production of gas plant liquids increased in 1993 as did U.S. natural gas production. Natural gas processing plants are usually located in the same general area where the natural gas is produced. Of the 16.4 trillion cubic feet of natural gas processed in plants, about 15.8 trillion cubic feet are both produced and processed in the same State (Table E4, Appendix E).

Lease Condensate

Proved Reserves

Proved reserves of lease condensate for the United States were 1,192 million barrels (Table 16). This was 34 million barrels or 3 percent lower than reported in 1992.

Production

Production of lease condensate was 153 million barrels, an increase of 6 million barrels, or 4 percent, in 1993. Almost all of the lease condensate production is in the Gulf of Mexico Federal Offshore, Texas, and Louisiana.

Table 14. Natural Gas Liquids Proved Reserves, Reserves Changes, and Production, 1993
(Million Barrels of 42 U.S. Gallons)

		Changes in Reserves During 1993							
State and Subdivision	**Published Proved Reserves 12/31/92**	**Adjustments (+,-)**	**Revision Increases (+)**	**Revision Decreases (-)**	**Extensions (+)**	**New Field Discoveries (+)**	**New Reservoir Discoveries in Old Fields (+)**	**Production (-)**	**Proved Reserves 12/31/93**
Alaska	347	1	9	9	0	0	0	27	321
Lower 48 States	**7,104**	**101**	**755**	**631**	**245**	**24**	**64**	**761**	**6,901**
Alabama	171	5	7	16	3	0	0	12	158
Arkansas	4	0	0	0	0	0	0	0	4
California	99	10	5	4	2	1	0	9	104
Coastal Region Onshore	10	1	2	0	0	0	0	1	12
Los Angeles Basin Onshore	5	0	1	0	0	0	0	0	6
San Joaquin Basin Onshore	83	9	2	4	2	1	0	8	85
State Offshore	1	0	0	0	0	0	0	0	1
Colorado	226	-12	25	28	18	0	1	16	214
Florida	8	0	2	0	0	0	0	1	9
Kansas	444	-46	15	10	4	0	0	27	380
Kentucky	32	-4	1	1	0	0	0	2	26
Louisiana	495	-10	64	82	16	0	6	68	421
North	60	-2	12	8	3	0	0	8	57
South Onshore	380	16	48	71	11	0	6	56	334
State Offshore	55	-24	4	3	2	0	0	4	30
Michigan	68	-4	13	15	1	0	0	6	57
Mississippi	9	-1	4	1	0	1	0	1	11
Montana	12	-3	0	0	0	0	0	1	8
New Mexico	1,066	-48	77	60	21	0	2	62	996
East	223	23	33	25	11	0	2	34	233
West	843	-71	44	35	10	0	0	28	763
North Dakota	64	-7	3	2	2	0	0	5	55
Oklahoma	629	39	80	56	29	1	6	85	643
Texas	2,402	198	275	218	94	10	23	315	2,469
RRC District 1	27	2	5	4	1	0	0	5	26
RRC District 2 Onshore	80	15	10	10	4	0	3	16	86
RRC District 3 Onshore	211	37	45	23	13	6	12	48	253
RRC District 4 Onshore	272	8	38	25	30	0	4	49	278
RRC District 5	71	-1	4	6	2	1	0	7	64
RRC District 6	251	7	33	26	8	0	3	28	248
RRC District 7B	68	23	2	4	0	0	0	10	79
RRC District 7C	289	-9	26	20	10	3	0	26	273
RRC District 8	444	38	47	46	7	0	1	52	439
RRC District 8A	257	66	13	19	1	0	0	20	298
RRC District 9	92	1	9	6	10	0	0	14	92
RRC District 10	336	11	42	29	8	0	0	39	329
State Offshore	4	0	1	0	0	0	0	1	4
Utah and Wyoming	660	-57	70	50	21	0	2	46	600
West Virginia	97	11	9	3	1	0	0	7	108
Federal Offshore[a]	610	30	105	85	33	11	24	98	630
Pacific (California)	20	5	9	8	0	0	0	1	25
Gulf of Mexico (Louisiana)[a]	472	25	83	69	27	9	23	80	490
Gulf of Mexico (Texas)	118	0	13	8	6	2	1	17	115
Miscellaneous[b]	8	0	0	0	0	0	0	0	8
U.S. Total	**7,451**	**102**	**764**	**640**	**245**	**24**	**64**	**788**	**7,222**

[a]Includes Federal offshore Alabama.

[b]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, New York, Ohio, Oregon, Pennsylvania, South Dakota, Tennessee, and Virginia.

Note: The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production." They may differ from the official Energy Information Administration production data for natural gas and natural gas liquids for 1993 contained in the publications *Petroleum Supply Annual 1993*, DOE/EIA-0340(93) and *Natural Gas Annual 19923* DOE/EIA-0131(93).

Source: Energy Information Administration, Office of Oil and Gas.

Table 15. Natural Gas Plant Liquids Proved Reserves and Production, 1993
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	1993 Reserves	1993 Production	State and Subdivision	1993 Reserves	1993 Production
Alaska	321	27	North Dakota	46	5
Lower 48 States	**5,709**	**608**	Oklahoma	575	77
Alabama	55	4	Texas	2,211	272
Arkansas	2	0	RRC District 1	23	4
California	98	9	RRC District 2 Onshore	72	13
Coastal Region Onshore	10	1	RRC District 3 Onshore	196	35
Los Angeles Basin Onshore	6	0	RRC District 4 Onshore	213	37
San Joaquin Basin Onshore	81	8	RRC District 5	50	5
State Offshore	1	0	RRC District 6	202	23
Colorado	190	14	RRC District 7B	73	10
Florida	9	1	RRC District 7C	250	24
Kansas	378	27	RRC District 8	430	51
Kentucky	25	2	RRC District 8A	297	20
Louisiana	260	42	RRC District 9	88	13
North	38	5	RRC District 10	316	37
South Onshore	201	34	State Offshore	1	0
State Offshore	21	3	Utah and Wyoming	458	32
Michigan	44	5	West Virginia	107	7
Mississippi	3	0	Federal Offshore[a]	309	52
Montana	8	1	Pacific (California)	20	1
New Mexico	925	58	Gulf of Mexico (Louisiana)[a]	255	45
East	215	32	Gulf of Mexico (Texas)	34	6
West	710	26	Miscellaneous[b]	6	0
			U.S. Total	**6,030**	**635**

[a]Includes Federal Offshore Alabama.
[b]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, New York, Ohio, Oregon, Pennsylvania, South Dakota, Tennessee, and Virginia.

Note: The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production." They may differ from the official Energy Information Administration production data for natural gas plant liquids for 1993 contained in the publications *Petroleum Supply Annual 1993,* DOE/EIA-0340(93) and *Natural Gas Annual 1993*, DOE/EIA-0131(93).

Source: Energy Information Administration, Office of Oil and Gas.

Reserves in Nonproducing Reservoirs

Like crude oil and natural gas, not all lease condensate proved reserves were contained in reservoirs that were producing during 1993. Proved reserves of 392 million barrels of lease condensate, an increase of 10-percent, were reported in nonproducing reservoirs in 1993. These reserves were reported by Category I and Category II operators, who collectively accounted for more than 96 percent of total lease condensate production. About 46 percent of the nonproducing lease condensate reserves were located in the Gulf of Mexico Federal Offshore.

Table 16. Lease Condensate Proved Reserves and Production, 1993
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	1993 Reserves	1993 Production
Alaska	0	0
Lower 48 States	**1,192**	**153**
Alabama	103	8
Arkansas	2	0
California	6	0
Coastal Region Onshore	2	0
Los Angeles Basin Onshore	0	0
San Joaquin Basin Onshore	4	0
State Offshore	0	0
Colorado	24	2
Florida	0	0
Kansas	2	0
Kentucky	1	0
Louisiana	161	26
North	19	3
South Onshore	133	22
State Offshore	9	1
Michigan	13	1
Mississippi	8	1
Montana	0	0
New Mexico	71	4
East	18	2
West	53	2
North Dakota	9	0
Oklahoma	68	8
Texas	258	43
RRC District 1	3	1
RRC District 2 Onshore	14	3
RRC District 3 Onshore	57	13
RRC District 4 Onshore	65	12
RRC District 5	14	2
RRC District 6	46	5
RRC District 7B	6	0
RRC District 7C	23	2
RRC District 8	9	1
RRC District 8A	1	0
RRC District 9	4	1
RRC District 10	13	2
State Offshore	3	1
Utah and Wyoming	142	14
West Virginia	1	0
Federal Offshore[a]	321	46
Pacific (California)	5	0
Gulf of Mexico (Louisiana)[a]	235	35
Gulf of Mexico (Texas)	81	11
Miscellaneous[b]	2	0
U.S. Total	**1,192**	**153**

[a]Includes Federal Offshore Alabama.
[b]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, New York, Ohio, Oregon, Pennsylvania, South Dakota, Tennessee, and Virginia.

Note: The estimates in this table are based on data reported on Form EIA-23, “Annual Survey of Domestic Oil and Gas Reserves” 1993.
Source: Energy Information Administration, Office of Oil and Gas.

References

1. Mast, R.F., Martin, P.E., et. al. 1989. *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States – A Part of the Nation's Energy Endowment.* U.S. Department of the Interior, U.S. Geological Survey and Minerals Management Service, Washington, DC.

2. American Association of Petroleum Geologists. April 1989. "Data Support Need for Exploration", AAPG Position Paper, Committee on the Resource Base, *AAPG Explorer*. Vol. 10, No. 4, pp. 42, 43.

3. U.S. Department of Energy, Fossil Energy, Bartlesville Project Office, October 1992. *An Assessment of the Oil Resource Base of the United States, Oil Resources Panel.* DOE/BC—93/1/SP. Bartlesville, OK, p. 1.

4. U.S. Department of Energy, Office of Policy, Planning & Analysis, May 1988. *An Assessment of the Natural Gas Resource Base of the United States.* DOE/W/31109-H1. Washington, DC, p. 2.

5. Potential Gas Committee. May 1993. *Potential Supply of Natural Gas in the United States.* December 31, 1992. Potential Gas Agency, Colorado School of Mines, Golden, CO, p. 135.

6. National Petroleum Council. December 1992. *The Potential for Natural Gas in the United State.* Vol. I. Washington, DC, p. 5.

7. U.S. Department of the Interior. 1988. *National Assessment of Undiscovered Conventional Oil and Gas Resources.* USGS-MMS Working Paper, Open File Report 88-373, U.S. Geological Survey and Minerals Management Service, Reston, VA.

8. Energy Information Administration. October 1984. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1983 Annual Report.* DOE/EIA-0216(83). Washington, DC.

9. Energy Information Administration. September 1985. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1984 Annual Report.* DOE/EIA-0216(84). Washington, DC.

10. Energy Information Administration. October 1986. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1985 Annual Report.* DOE/EIA-0216(85). Washington, DC.

11. Energy Information Administration. October 1987. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1986 Annual Report.* DOE/EIA-0216(86). Washington, DC.

12. Energy Information Administration. October 1988. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1987 Annual Report.* DOE/EIA-0216(87). Washington, DC.

13. Energy Information Administration. September 1989. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1988 Annual Report.* DOE/EIA-0216(88). Washington, DC.

14. Energy Information Administration. October 1990. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1989 Annual Report.* DOE/EIA-0216(89). Washington, DC.

15. Energy Information Administration. September 1991. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1990 Annual Report.* DOE/EIA-0216(90). Washington, DC.

16. Energy Information Administration. November 1992. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1991 Annual Report.* DOE/EIA-0216(91). Washington, DC.

17. Energy Information Administration. October 1993. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1992 Annual Report.* DOE/EIA-0216(92). Washington, DC.

18. Energy Information Administration, August 1990. *U.S. Oil and Gas Reserves by Year of Field Discovery*. DOE/EIA-0534. Washington, DC.

19. American Petroleum Institute, American Gas Association, and Canadian Petroleum Association. *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1979.* Vol. 34. June 1980. Washington, DC.

20. Energy Information Administration, July 1994. *Natural Gas Productive Capacity for the Lower 48 States 1980 Through 1995.* DOE/EIA-0542(95). Washington, DC.

21. Energy Information Administration, August 1993. *Largest U.S. Oil and Gas Fields.* DOE/EIA-TR-0567. Washington, DC.

22. Energy Information Administration, July 1992. *Geologic Distributions of U.S. Oil and Gas*. DOE/EIA-0557. Washington, DC.

23. U.S. Department of Energy. *DOE This Month*. Vol. 15, No. 8. Washington, DC, August 1992. p. 13.

24. *Oil and Gas Journal*. December 27, 1993. "Worldwide Look at Reserves and Production". Vol. 91, No. 52. Tulsa, OK, pp. 44-45.

25. *World Oil*. August 1994. "World Trends". Houston, TX, p. 30.

26. *World Oil*. January 1994. "Weasel Fizzles". Houston, TX, p. 29.

27. *Hart's Oil and Gas World*. February 1994. "Pacific-Activities Highlights". Denver, CO, p. 73.

28. Energy Information Administration, June 1994. *Petroleum Supply Annual. Vol 1.* DOE/EIA-0340(93)/1. Washington, DC.

29. Exxon Corporation, December 1993. "Perspectives". Irving, TX, p. 2.

30. Bulletin. State of Alaska, Alaska Oil and Gas Conservation Commission. February 1994.

31. *Oil & Gas Journal*. June 6, 1994. "Razor Project". Tulsa, OK, p. 24.

32. *Oil & Gas Journal*. June 6, 1994. "Niakuk Development". Tulsa, OK, p. 28.

33. *Improved Recovery Week*. July 19, 1993. "Kuparuk Field Flows Billionth Barrel". Arlington, VA, p. 2.

34. *Oil & Gas Journal*. June 13, 1994. "BP Cascade Discovery". Tulsa, OK, p. 44.

35. *Improved Recovery Week*. May 23, 1994. "Elk Hills Horizontals a Success". Arlington, VA, p. 2.

36. *Pacific Oil and Gas World*. July/August 1993. "Unocal Wins Best New Technology Award". Denver, CO, p. 21.

37. U.S. Department of the Interior, Minerals Management Service. Pacific Update: December 1989-January 1994. "Development in State Waters". Herndon, VA, 1994.

38. *Hart's Oil and Gas World*. February 1994. "Sophisticated Geophysics Influence Successful Subsalt Exploration Play". Denver, CO, p. 36.

39. *Oil & Gas Journal*. September 20, 1993. "Gas Prices Buoy Gulf of Mexico Leasing Recovery". Tulsa, OK, p. 44.

40. *AAPG Explorer*. May 1994. "Subsalt Spices Gulf Lease Sale". American Association of Petroleum Geologists, Tulsa, OK, p. 6.

41. Phillips Petroleum Company. "Second Quarter Report to Stockholders". August 1994. Bartlesville, OK, p. 2.

42. *Oil & Gas Journal*. December 6, 1993. "Shell's Big Auger TLP Project Progressing". Tulsa, OK, pp. 25-26.

43. *Oil & Gas Journal*. October 11, 1993. "Shell-BP Plans TLP to Develop Giant Mars Field in Gulf of Mexico". Tulsa, OK, p. 28.

44. *World Oil*. January 1994. "Auger Moves Offshore". Houston, TX, p. 29.

45. *World Oil*. May 1994. "A New Look at the Eastern Gulf". Houston, TX, p. 23.

46. *Oil & Gas Journal*. September 27, 1993. "Independents Spark Behind Gulf of Mexico Resurgence - Front Line Technology". Tulsa, OK, p. 20-26.

47. Petroleum Data System, Release 2.4. Dwights EnergyData. August 1994. Dallas, TX.

48. *AAPG Explorer*. August 1993. "Chalk Chase in the Bayou". American Association of Petroleum Geologists, Tulsa, OK, pp. 1-8.

49. *Petroleum Engineer International*. June 1944. "Santa Fe Resources Found More Than 150 Drillable Permian Basin Sites". Houston Tx, p. 3.

50. *Hart's Oil and Gas World*. May 1994. "Independents Keep Pace With Majors on Permian CO_2 Flood Technology". Denver, CO, pp. 48-49.

51. *The American Oil & Gas Reporter*. April 1994. "Independents Find 3-D Seismic Improves Gulf Coast Odds". Derby, KS, p. 70.

52. *Hart's Oil and Gas World*. February 1994. "Permian Basin Newsline". Denver, CO, p. 48.

53. *Midcontinent Oil and Gas World*. July/August 1993. "Mobil Steals Top Honors in Advanced Recovery". Vol. 9, No.4, Denver, CO, p. 27.

54. *The American Oil & Gas Reporter*. July 1993. "Correct Application Spells Horizontal Success". Derby, KS, pp. 69-77.

55. *Petroleum Engineer International.* May 1994. “Texas Tax Incentives for Upstream Operations Also Can Work Nationally”. Houston Tx, p. 3.

56. *Improved Recovery Week.* February 28, 1994. “California Regulators Search for Incentives”. Arlington, VA, p. 4.

57. *Improved Recovery Week.* March 28, 1994. “Montana OKs Tax Incentives”. Arlington, VA, p. 3.

58. *Improved Recovery Week.* June 20, 1994. “Oklahoma Governor Signs Incentive Bill”. Arlington, VA, p. 2.

59. *Improved Recovery Week.* May 23, 1994. “Texas to Air New Incentives”. Arlington, VA, p. 2.

60. *Improved Recovery Week.* July 4, 1994. “Plan Sees Texas as High-tech Petroleum R&D Center”. Arlington, VA, p. 1.

61. Brochure for Meeting February 23-24, 1994. “3D Seismic Another Dimension”. Sponsored by Improved Recovery Week, Houston, TX. p. 2.

62. *The American Oil & Gas Reporter.* July 1993. “Correct Application Spells Horizontal Success”. Derby, KS, pp. 69-77.

63. *Petroleum Engineer International.* September 1993. “UPRC Completes First Quad-Lateral Well”. Houston Tx, pp. 44-48.

64. *Oil & Gas Journal.* April 26, 1993. “Enserch Starts Gulf Gas/Condensate Flow.” Vol 91, No. 17. Tulsa, OK, p. 95.

65. *Oil & Gas Journal.* November 22, 1993. “Oryx Taps Deepwater Gulf Gas.” Vol 91, No. 47. Tulsa, OK, p. 33.

66. *Oil and Gas Investor.* October 1993. “Exploration Highlights.” Denver, CO, p. 73.

67. *Oil & Gas Journal.* January 10, 1994. “Mobile Bay Gas Flow Rising in Response to E&D Campaigns.” Vol 92, No. 2. Tulsa, OK, pp. 21-24.

68. *Oil and Gas Investor.* November 1993. “Exploration Highlights.” Denver, CO, p. 61.

69. *Improved Recovery Week.* August 22, 1994. “New Seismic, Drilling/Completion Dope Spurs S. Texas Boom.” Vol 3, No. 32. Arlington, VA, p. 1.

70. *Oil and Gas Investor.* February 1994, “Wattenburg.” Denver, CO p. 26ff.

71. *Oil & Gas Journal.* October 25, 1993. “Mineral, Surface Rights at Issue in Colorado.” Vol 91, No. 43. Tulsa, OK, p. 30.

72. *Oil & Gas Journal.* August 23, 1993. “Exploration.” Vol 91, No. 34. Tulsa, OK, p. 57.

73. *Oil and Gas Investor.* October 1993, “Exploration Highlights.” Denver, CO, p. 79.

74. *Oil and Gas Investor.* May 1993, “Moxa Arch.” Denver, CO, p. 30.

75. Glass, Gary B. “Overview.” *Wyoming Geo-notes* Number 42, Wyoming State Geological Survey. Laramie, WY. May 1994. p. 1.

76. *Oil & Gas Journal.* May 30, 1994 “Antrim Gas Play, Production Expanding in Michigan.” Vol 92, No. 22. Tulsa, OK, p. 97.

77. *Gas Daily*. Conference Bulletin, “Southeast-Mobile Bay Gas: New Projects to Serve Growing Demand, New Orleans, March 8-9, 1994.” Houston, TX.

78. *Hart’s Oil and Gas World.* December, 1993. “Exploration Highlights.” Denver, CO.

79. Energy Information Administration. February 1980. *U.S. Crude Oil and Natural Gas Reserves 1977 Annual Report.* DOE/EIA-0216(77). Washington, DC.

80. Energy Information Administration. September 1980. *U.S. Crude Oil and Natural Gas Reserves 1978 Annual Report.* DOE/EIA-0216(78). Washington, DC.

81. Energy Information Administration. August 1981. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1979 Annual Report.* DOE/EIA-0216(79). Washington, DC.

82. Energy Information Administration. October 1981. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1980 Annual Report.* DOE/EIA-0216(80). Washington, DC.

83. Energy Information Administration. August 1982. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1981 Annual Report.* DOE/EIA-0216(81). Washington, DC.

84. Energy Information Administration. August 1983. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1982 Annual Report.* DOE/EIA-0216(82). Washington, DC.

Operator Data by Size Class

Appendix A contains tables of the proved reserves and production of the top 2,500 oil and gas operators by production size class for the years 1988 through 1993. Because of the changing nature of the industry, it is important to document changes in industry structure. The tables show the volumetric change and percent change from the previous year and from 1988, and also the 1993 average per operator in each class. All companies operating in the United States that reported production or reserves to EIA were ranked by production size for each year of the six years. Company production size classes were computed as the sum of the barrel oil equivalent of the crude oil production, lease condensate production, and wet gas production for each operator. The companies were then placed in the following production size classes: 1-10, 11-20, 21-100, 101-500, 501-2,500, and all “other” oil and gas operators. The “other” category contains 21,076 small operators. Production and reserves of this category of operator are estimated each year from a sample of about 8 percent of these operators.

The class 1-10 category contains the 10 highest producing companies each year on a barrel oil equivalent basis. These companies are not necessarily the same 10 companies each year, for example in 1993 an operator moved from the 11-20 production size class to the 1-10 class, displacing an operator from the group who had been there since 1991. Most of the apparent changes in these two size classes resulted from the operator movement between the size classes.

Natural Gas

Proved Reserves

The natural gas proved reserves reported by operator production size class for 1988 through 1993 has decreased from 177 trillion cubic feet to 170.5 trillion cubic feet (Table A1). These proved reserves are highly concentrated in the larger companies. In 1993, the top 20 producing companies had 59 percent of the proved reserves of natural gas or 100 trillion cubic feet of the total. The next two size classes contain 80 companies and 400 companies, and account for 23 and 12 percent of the U.S. natural gas proved reserves, respectively. On average, a company in the top 20 production size class has more than 25,000 times the natural gas reserves as the average operator in the “other” category of small operators. The top 20 operators had a decline of 4 percent in their natural gas proved reserves from 1988 to 1993. The rest of the 23,576 U.S. operators had a decline of 3 percent. For the period from 1992 to 1993 the top 20 operators natural gas reserves decreased 3 percent. The rest of the operators had a much smaller decrease of less than 0.1 percent.

Production

The natural gas production reported by operator production size class for 1988 through 1993 has increased from 17.5 trillion cubic feet to 18.6 trillion cubic feet (Table A2). In 1993, the top 20 producing companies had 52 percent of the production of natural gas or 9.7 trillion cubic feet, while having 59 percent of the proved reserves. The next two size classes contain 80 companies and 400 companies, and have 26 and 14 percent of the gas production, respectively. The average top 20 company has more than 17,000 times the gas production as the average operator in the “other” category of small operators. Total U.S. natural gas production increased 7 percent from 1988 to 1993. The top 20 operators had an increase of 2 percent in their natural gas production from 1988 to 1993. The rest of the U.S. operators in the had an increase of 12 percent from 1988 to 1993. The top 20 operators natural gas production remained the same from 1992 to 1993, while the rest of the U.S. operators had an increase of 4 percent, from 1992 to 1993.

Crude Oil

Proved Reserves

Proved reserves of crude oil are more highly concentrated than those of natural gas. Crude oil proved reserves for 1988 through 1993 decreased 14 percent (Table A3). The 20 largest oil and gas producing companies in 1993 had 75 percent of U.S. proved reserves of crude oil, as opposed to natural gas where only 59 percent of the total proved reserves was operated by these same companies. These companies have tended to concentrate their operations in fewer fields in the United States and focus more of their resources on their foreign operations in the past few years. U.S. proved reserves of crude oil declined 3 percent from 1992 to 1993. The top 20 producing companies had a decline of 4 percent in their domestic proved reserves of crude oil during 1993. The companies in the 21-100 category had 10 percent of U.S. proved reserves of crude oil. The average top 20 company had about 22,000 times the oil reserves as the average operator in the "other" category. The top 20 class had a decline of 21 percent in their crude oil proved reserves from 1988 to 1993. Without the top 20, the rest of the U.S. operators had a 15 percent increase from 1988 to 1993. The large independents, the 80 companies in production size category 21-100, accounted for most of the increase in crude oil proved reserves. These companies had a 49 percent increase in their oil reserves during the 1988 through 1993 period. A substantial portion of this increase came from property acquisitions. During the 1988 through 1993 period, many operators bought, sold, and restructured their property positions.

Production

The crude oil production reported by operator production size class for 1988 through 1993 has decreased from 2.8 billion barrels to 2.3 billion barrels (Table A4). The 20 largest oil and gas producing companies in 1993 had 68 percent of U.S. production of crude oil, as opposed to natural gas where only 52 percent of the total is operated by these same companies. Production of crude oil is more concentrated than production of natural gas. The top 20 operators had 68 percent of the U.S. production, or 1.6 billion barrels, in 1993, while in 1988 they accounted for 74 percent of production. The top 20 operators had a decline of 6 percent in their domestic production of crude oil during 1993. In contrast, the rest of the producers had no aggregate decline during 1993. The average top 20 company has about 13,000 times the oil production as the average operator in the "other" category. U.S. production of crude oil declined by 17 percent from 1988 to 1993. The top 20 operators had a decline of 24 percent in their oil production during the same period. U.S. production of crude oil declined by declined 4 percent from 1992 to 1993, while the top 20 operators production declined 6 percent. The large independents, the 80 companies in production size category 21-100, had a 23-percent increase in their oil production during the 1988 through 1993 period. A substantial portion of this increase came because of property acquisitions.

Fields

The number of fields that large operators were active in dropped significantly during the 1988-1993 period. The large operators report field-level information on Form EIA-23 if their production of crude oil exceeds 400,000 per year, or natural gas production exceeds 2 billion cubic feet per year, or both. From 1988 through 1993, fields that these large operators were active in dropped by 4,952 or 15 percent. The trend continued in 1993 with a 5-percent decline. Most of the changes in operator field counts resulted from the top 20 operators concentrating their effort in a smaller number of fields. From 1988 through 1993, the number of fields the top 20 operators were active in dropped by 4,002 or 38 percent, while from 1992 to 1993 the number dropped 14 percent.

Table A1. Natural Gas Proved Reserves, Wet After Lease Separation, by Operator Production Size Class, 1988-1993
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

Size Class	1988	1989	1990	1991	1992	1993	1992-1993 Volume and Percent Change	1988-1993 Volume and Percent Change	1993 Average Reserves per Operator
Class 1-10	84,140	80,608	R82,356	R79,028	74,350	77,552	3,202	-6,588	7,755.161
Percent of Total	47.5%	45.9%	R46.4%	R45.1%	42.9%	45.5%	4.3%	-7.8%	
Class 11-20	20,045	23,883	R24,765	R25,763	28,442	22,467	-5,975	2,422	2,246.660
Percent of Total	11.3%	13.6%	R13.9%	R14.7%	16.4%	13.2%	-21.0%	12.1%	
Class 21-100	40,368	R37,809	R36,696	R38,362	R38,388	39,135	747	-1,233	489.184
Percent of Total	22.8%	R21.6%	R20.7%	21.9%	22.2%	23.0%	1.9%	-3.1%	
Class 101-500	R20,010	R20,784	R20,995	R19,330	R19,728	19,870	142	-140	49.675
Percent of Total	R11.3%	R11.8%	R11.8%	11.0%	R11.4%	11.7%	0.7%	-0.7%	
Class 501-2,500	R8,479	R8,085	R8,328	R8,414	R7,922	7,278	-644	-1,201	3.639
Percent of Total	R4.8%	R4.6%	R4.7%	R4.8%	R4.6%	4.3%	-8.1%	-14.2%	
Class Other	R3,957	R4,260	R4,436	R4,428	R4,479	4,188	-291	231	0.199
Percent of Total	R2.2%	R2.4%	R2.5%	R2.5%	R2.6%	2.5%	-6.5%	5.8%	
Category I	R146,407	R145,458	R145,483	R145,595	R144,351	142,892	-1,459	-3,515	959.010
Percent of Total	82.7%	82.9%	R81.9%	R83.0%	83.3%	83.8%	-1.0%	-2.4%	
Category II	R18,126	R17,307	R19,684	R17,604	R17,682	17,305	-377	-821	36.432
Percent of Total	R10.2%	R9.9%	R11.1%	R10.0%	R10.2%	10.2%	-2.1%	-4.5%	
Category III	R12,465	R12,663	R12,409	R12,126	R11,276	10,292	-984	-2,173	0.448
Percent of Total	R7.0%	R7.2%	R7.0%	R6.9%	R6.5%	6.0%	-8.7%	-17.4%	
Total Published	**176,999**	**175,428**	**177,576**	**175,325**	**173,309**	**170,490**	**-2,819**	**-6,509**	**7.232**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**-1.6%**	**-3.7%**	

R=Revised data.

Note: There were 23,576 operators in 1993 including 149 Category I , 475 Category II, and 22,952 Category III. The “other” size class had 21,076 operators in 1993.

Source: Energy Information Administration, Office of Oil and Gas.

Table A2. Natural Gas Production, Wet After Lease Separation, by Operator Production Size Class, 1988-1993
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

Size Class	1988	1989	1990	1991	1992	1993	1992-1993 Volume and Percent Change	1988-1993 Volume and Percent Change	1993 Average Production per Operator
Class 1-10	7,131	7,030	R6,955	R6,857	R6,625	6,801	176	-330	680.144
Percent of Total	40.8%	39.6%	R38.6%	R38.1%	R36.3%	36.5%	2.7%	-4.6%	
Class 11-20	2,344	2,545	R2,723	R2,864	R3,036	2,861	-175	517	286.090
Percent of Total	13.4%	14.3%	R15.1%	R15.9%	R16.6%	15.3%	-5.8%	22.1%	
Class 21-100	4,104	4,287	R4,366	R4,367	R4,592	4,894	302	790	61.175
Percent of Total	23.5%	24.1%	24.3%	R24.2%	25.1%	26.3%	6.6%	19.2%	
Class 101-500	2,357	2,369	R2,421	R2,348	R2,411	2,597	186	240	6.493
Percent of Total	13.5%	13.3%	R13.4%	R13.0%	13.2%	13.9%	7.7%	10.2%	
Class 501-2,500	1,022	971	R916	R956	R974	904	-70	-118	0.452
Percent of Total	5.9%	5.5%	5.1%	5.3%	5.3%	4.8%	-7.2%	-11.5%	
Class Other	508	550	R622	R620	R631	584	-47	76	0.028
Percent of Total	2.9%	3.1%	R3.5%	R3.4%	R3.5%	3.1%	-7.4%	15.0%	
Category I	13,714	14,084	R14,235	R14,464	R14,767	15,122	355	1,408	101.491
Percent of Total	78.5%	79.3%	R79.1%	R80.3%	80.8%	81.1%	2.4%	10.3%	
Category II	2,264	2,081	R2,226	R2,086	R2,036	2,159	123	-105	4.546
Percent of Total	13.0%	11.7%	R12.4%	R11.6%	11.1%	11.6%	6.0%	-4.6%	
Category III	1,487	1,587	R1,541	R1,462	R1,467	1,360	-107	-127	0.059
Percent of Total	8.5%	8.9%	R8.6%	R8.1%	R8.0%	7.3%	-7.3%	-8.5%	
Total Published	**17,466**	**17,752**	**18,003**	**18,012**	**R18,269**	**18,641**	**372**	**1,175**	**0.791**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**2.0%**	**6.7%**	

R=Revised data.

Note: There were 23,576 operators in 1993 including 149 Category I , 475 Category II, and 22,952 Category III. The “other” size class had 21,076 operators in 1993.

Source: Energy Information Administration, Office of Oil and Gas.

Table A3. Crude Oil Proved Reserves by Operator Production Size Class, 1988-1993
(Million Barrels of 42 U.S. Gallons)

Size Class	1988	1989	1990	1991	1992	1993	1992-1993 Volume and Percent Change	1988-1993 Volume and Percent Change	1993 Average Reserves per Operator
Class 1-10	19,466	19,085	18,639	16,825	15,733	14,894	-839	-4,572	1,489.371
Percent of Total	72.6%	72.0%	71.0%	68.2%	66.3%	64.9%	-5.3%	-23.5%	
Class 11-20	2,438	2,398	1,892	2,247	2,250	2,389	139	-49	238.920
Percent of Total	9.1%	9.0%	7.2%	9.1%	9.5%	10.4%	6.2%	-2.0%	
Class 21-100	1,615	1,735	R2,310	R2,270	2,370	2,401	31	786	30.012
Percent of Total	6.0%	6.5%	R8.8%	9.2%	10.0%	10.5%	1.3%	48.7%	
Class 101-500	1,236	1,295	R1,410	R1,415	R1,463	1,440	-23	204	3.600
Percent of Total	4.6%	4.9%	R5.4%	R5.7%	6.2%	6.3%	-1.6%	16.5%	
Class 501-2,500	1,168	1,096	R1,214	R1,121	R1,107	1,000	-107	-168	0.500
Percent of Total	4.4%	4.1%	4.6%	R4.5%	4.7%	4.4%	-9.7%	-14.4%	
Class Other	902	893	R790	R805	R822	833	11	-69	0.040
Percent of Total	3.4%	3.4%	3.0%	R3.3%	R3.5%	3.6%	1.3%	-7.6%	
Category I	23,797	23,365	23,209	21,714	20,767	20,090	-677	-3,707	134.831
Percent of Total	88.7%	88.2%	88.4%	88.0%	87.5%	87.5%	-3.3%	-15.6%	
Category II	1,057	1,056	R1,066	R1,088	R1,150	1,131	-19	74	2.380
Percent of Total	3.9%	4.0%	R4.1%	R4.4%	4.8%	4.9%	-1.7%	7.0%	
Category III	1,971	2,079	R1,979	R1,880	R1,828	1,737	-91	-234	0.076
Percent of Total	7.3%	7.8%	R7.5%	7.6%	7.7%	7.6%	-5.0%	-11.9%	
Total Published	**26,825**	**26,501**	**26,254**	**24,682**	**23,745**	**22,957**	**-788**	**-3,868**	**0.974**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**-3.3%**	**-14.4%**	

R=Revised data.

Note: There were 23,576 operators in 1993 including 149 Category I , 475 Category II, and 22,952 Category III. The “other” size class had 21,076 operators in 1993.

Source: Energy Information Administration, Office of Oil and Gas.

Table A4. Crude Oil Production by Operator Production Size Class, 1988-1993
(Million Barrels of 42 U.S. Gallons)

Size Class	1988	1989	1990	1991	1992	1993	1992-1993 Volume and Percent Change	1988-1993 Volume and Percent Change	1993 Average Production per Operator
Class 1-10	1,833	1,683	1,574	1,544	1,458	1,346	-112	-487	134.588
Percent of Total	65.2%	65.1%	62.8%	61.5%	59.6%	57.5%	-7.7%	-26.6%	
Class 11-20	255	235	215	218	231	236	5	-19	23.644
Percent of Total	9.1%	9.1%	8.6%	8.7%	9.4%	10.1%	2.2%	-7.5%	
Class 21-100	224	227	R241	R259	272	276	4	52	3.450
Percent of Total	8.0%	8.8%	R9.6%	R10.3%	11.1%	11.8%	1.5%	23.2%	
Class 101-500	183	175	R193	R208	R213	202	-11	19	0.505
Percent of Total	6.5%	6.8%	R7.7%	R8.3%	8.7%	8.6%	-5.2%	10.4%	
Class 501-2,500	173	159	165	R167	153	148	-5	-25	0.074
Percent of Total	6.2%	6.1%	6.6%	R6.6%	6.3%	6.3%	-3.3%	-14.5%	
Class Other	142	107	R117	R115	R118	131	13	-11	0.006
Percent of Total	5.1%	4.1%	R4.7%	R4.6%	4.8%	5.6%	11.0%	-7.7%	
Category I	2,346	2,159	2,075	2,068	2,022	1,922	-100	-424	12.898
Percent of Total	83.5%	83.5%	82.8%	82.3%	82.7%	82.2%	-4.9%	-18.1%	
Category II	164	150	R147	167	R163	153	-10	-11	0.321
Percent of Total	5.8%	5.8%	R5.9%	R6.6%	R6.7%	6.5%	-6.1%	-6.7%	
Category III	301	277	R283	277	R261	264	3	-37	0.012
Percent of Total	10.7%	10.7%	R11.3%	R11.0%	10.7%	11.3%	1.1%	-12.3%	
Total Published	**2,811**	**2,586**	**2,505**	**2,512**	**2,446**	**2,339**	**-107**	**-472**	**0.099**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**-4.4%**	**-16.8%**	

R=Revised data.

Note: There were 23,576 operators in 1993 including 149 Category I , 475 Category II, and 22,952 Category III. The “other” size class had 21,076 operators in 1993.

Source: Energy Information Administration, Office of Oil and Gas.

Table A5. Operator Field Count by Operator Production Size Class, 1988-1993

Size Class	1988	1989	1990	1991	1992	1993	1992-1993 Number and Percent Change	1988-1993 Number and Percent Change	1993 Average Number of Fields per Operator
Class 1-10	7,198	6,661	R6,045	R4,947	R4,189	3,591	-598	-3,607	359
Percent of Total	22.4%	21.4%	R20.0%	R16.7%	R14.7%	13.2%	-14.3%	-50.1%	
Class 11-20	3,393	3,194	R3,282	R3,466	R3,432	2,998	-434	-395	300
Percent of Total	10.6%	10.3%	10.8%	R11.7%	R12.1%	11.1%	-12.6%	-11.6%	
Class 21-100	8,463	8,736	R7,907	R8,156	R8,003	7,600	-403	-863	95
Percent of Total	26.4%	28.1%	R26.1%	R27.6%	R28.2%	28.0%	-5.0%	-10.2%	
Class 101-500	12,447	12,345	R12,620	R11,824	R11,896	11,881	-15	-566	30
Percent of Total	38.8%	39.7%	R41.7%	R40.0%	R41.9%	43.8%	-0.1%	-4.5%	
Rest	1,833	1,314	R1,660	R1,760	R2,059	1,715	-344	-118	14
Percent of Total	5.7%	4.2%	R5.5%	R6.0%	R7.2%	6.3%	-16.7%	-6.4%	
Category I	19,690	19,493	R18,806	R18,189	R17,620	16,603	-1,017	-3,087	111
Percent of Total	61.4%	62.7%	R62.1%	R61.5%	R62.0%	61.2%	-5.8%	-15.7%	
Category II	12,381	11,583	R11,478	R11,370	R10,799	10,516	-283	-1,865	22
Percent of Total	38.6%	37.3%	R37.9%	R38.5%	R38.0%	38.8%	-2.6%	-15.1%	
Total Published	**32,071**	**31,076**	**R30,284**	**R29,559**	**R28,419**	**27,119**	**-1,300**	**-4,952**	**43**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**-4.6%**	**-15.4%**	

R=Revised data.

Note: Includes only data from Category 1 and Category II operators. In 1993, there were 149 Category I operators and 475 Category II operators. The “rest” size class had 124 operators in 1993.

Source: Energy Information Administration, Office of Oil and Gas.

Top 100 Oil and Gas Fields for 1992

For several years before 1980, the American Petroleum Institute published lists of the largest oil fields in its annual report.{19} Until 1991, the Energy Information Administration (EIA) has not produced a similar listing for either oil or gas fields. Such lists now appear as Tables B1 and B2 of this Appendix, which contain estimates of the proved reserves, cumulative production, and ultimate recovery of the top 100 oil and gas fields. Both Table B3, Historical Production for the Top 100 Largest Oil Fields 1983-1992, and Table B4, Historical Production for the Top 100 Largest Natural Gas Fields 1983-1992 are also in this appendix. They reflect the production for the last 10 years for the same groups of fields shown in Tables B1 and B2. The oil field production and reserves data include both crude oil and lease condensate. The gas field production and reserves data are wet gas, after lease separation.

The top 100 oil fields in the United States as of December 31, 1992, had 16,364.9 million barrels of proved reserves or 66 percent of the total (Table B1). Although there is considerable grouping of field-level statistics within the tables, rough magnitudes can be estimated for the proved reserves, cumulative production, and ultimate recovery of most fields. Because many fields in the top 100 group are operated by only one or two operators, totals for proved reserves are grouped as top 10, top 20, top 50, and top 100 to avoid revealing company proprietary data. While the top 100 oil fields accounted for 66 percent of total proved oil reserves, they accounted for 54 percent of total oil production in the United States in 1992.

The top 100 gas fields in the United States as of December 31, 1992, had 80,852.4 billion cubic feet of proved reserves or 47 percent of the total (Table B2). The top 100 gas fields show less concentration than the top 100 oil fields. Many, but not all, of the same fields are in both tables. As an example, the top gas field, Hugoton Gas Area, is not in the oil table. While the top 100 gas fields accounted for 47 percent of total proved gas reserves, they only accounted for 29 percent of total gas production in the United States in 1992.

These are the 100 largest oil and gas fields in terms of proved reserves, however, the corresponding production does not represent the top 100 fields in terms of production. The top 100 oil fields accounted for 54 percent of total oil production in the United States in 1992 (Table B3). However, the same group of fields accounted for 47 percent of the total oil production in 1983. The top 100 gas fields accounted for 29 percent of total gas production in the United States in 1992 (Table B4). However, the same group of fields only accounted for 21 percent of the total gas production in 1983. The bulk of the 8-percent difference is from older fields that were able to produce more gas in 1992 than they produced in 1983. These fields had extensive infield drilling and/or in drilling for coalbed methane since 1983. In Tables B3 and B4 there are 6 oil and 4 gas fields that had no production in 1992.

The field name, location, year of discovery, and an estimate of 1992 annual production are also a part of the information found in the tables. Where two or more States are listed, the name of the field shown is that name recognized by the State listed first. This field also contains the largest part of the total hydrocarbons. The additional States listed may recognize an alternative field name. A list of all U.S. oil and gas fields that cross State boundaries is included in the annual EIA report *Oil and Gas Field Code Master List*, published each year.

The top 100 field lists lag one year behind the report data on which this publication focuses. This lag reflects the analysis needed to estimate field totals beyond that associated with preparation of the annual reserves report.

There were two difficulties encountered in constructing the lists. The first was that Form EIA-23 survey data, from which the national and State estimates are derived, do not always provide field totals, nor do they show the degree of field coverage attained by the survey. The second is that there is a significantly greater chance of releasing proprietary data when presenting field-by-field statistics, as compared to State and State Subdivision statistics.

The coverage problem was solved by using an EIA data base system, the Oil and Gas Integrated Field File (OGIFF) System. It matches fields reported in Form EIA-23 with two oil and gas data bases gotten from Dwight's Energydata, Inc., of Richardson, Texas. The measure of Form EIA-23 coverage for a given field is determined by comparing the volumes of oil and gas annual production available from each source. One of several methods of imputing the reserves associated with production missed by Form EIA-23 is carried out when necessary. The resultant total field reserves estimates are then subjected to small adjustments to force the field totals within a State to sum to those reported by EIA.

The OGIFF data base system contained information on more than 45,000 fields in 1992. It is also being used in preparation of a series of special reports illustrating selected oil and gas distributions not found in the annual oil and gas reserve's report. Three reports have already been published: *U.S. Oil and Gas Reserves by Year of Discovery*{18}, *Geologic Distributions of U.S. Oil and Gas*{22}, and *Largest U.S. Oil and Gas Fields.*{21} The latter publication is the newest in the series and was released in July 1992. This report identifies the largest one percent of U.S. oil and gas fields and their general location, year of discovery, and approximate national rankings in several size categories including proved reserves and annual production. The report also presents the proportions of the national crude oil and natural gas proved reserves and production that are attributable to the largest fields.

Table B1. Top 100 U.S. Oil[a] Fields as Ranked by Production within Proved Reserves Group, 1992
(Million Barrels of 42 U.S. Gallons)

Field Name	Location	Discovery Year	Proved Reserves 12/31/92 Rank Group	Annual Production Rank	Annual Production Volume	Cumulative Production Rank	Ultimate Recovery Rank Group
Prudhoe Bay	AK	1967	1-10	1	445.1	1	1-10
Kuparuk River	AK	1969	1-10	2	118.5	14	1-10
Midway-Sunset	CA	1901	1-10	3	61.1	4	1-10
Belridge South	CA	1911	1-10	4	50.2	17	11-20
Kern River	CA	1899	1-10	5	44.9	7	1-10
Endicott	AK	1978	1-10	6	41.6	137	21-50
Wasson	TX	1937	1-10	9	25.7	5	1-10
Elk Hills	CA	1919	1-10	10	24.7	13	11-20
Yates	TX	1926	1-10	14	18.1	10	1-10
Point McIntyre	AK	1988	1-10	-	0.0	-	51-100
Top 10 Volume Subtotal			**9,370.6**		**830.0**	**17,547.3**	**26,917.9**
Top 10 Percentage of U.S. Total			**37.5%**		**31.6%**	**10.6%**	**14.1%**
East Texas	TX	1930	11-20	8	32.9	2	1-10
Wilmington	CA	1932	11-20	11	23.2	3	1-10
Spraberry Trend Area	TX	1950	11-20	12	19.0	25	11-20
Slaughter	TX	1937	11-20	16	16.8	11	11-20
Levelland	TX	1945	11-20	19	15.5	37	21-50
Cowden North	TX	1930	11-20	20	13.4	41	21-50
Rangely	CO	1902	11-20	24	11.8	21	11-20
Hondo	PF	1969	11-20	32	8.2	225	51-100
San Ardo	CA	1947	11-20	65	4.3	52	21-50
Pescado	PF	1970	11-20	-	0.0	-	101-200
Top 20 Volume Subtotal			**11,536.5**		**975.0**	**29,403.0**	**40,939.5**
Top 20 Percentage of U.S. Total			**46.2%**		**37.1%**	**17.8%**	**21.5%**
Giddings	TX	1960	21-50	7	34.0	87	51-100
Point Arguello	PF	1981	21-50	15	17.1	958	101-200
Sho-Vel-Tum	OK	1905	21-50	17	15.8	8	1-10
Seminole	TX	1936	21-50	18	15.6	43	21-50
Pearsall	TX	1924	21-50	21	13.3	208	101-200
Bay Marchand Blk 2	GF & LA	1949	21-50	22	13.0	22	21-50
Main Pass SA Blk 299	GF	1967	21-50	23	12.4	371	201-300
Coalinga	CA	1887	21-50	25	11.5	20	11-20
Cymric	CA	1916	21-50	26	10.7	109	51-100
Lost Hills	CA	1910	21-50	27	8.9	134	51-100
McElroy	TX	1926	21-50	28	8.8	33	21-50
South Pass SA Blk 89	GF	1969	21-50	29	8.5	226	101-200
Salt Creek	TX	1942	21-50	30	8.4	83	51-100
Mississippi Canyon Blk 194	GF	1975	21-50	31	8.2	209	101-200
Vacuum	NM	1929	21-50	33	7.9	48	21-50
Fullerton	TX	1942	21-50	36	7.2	67	51-100
Milne Point	AK	1982	21-50	38	7.0	778	201-300
Ventura	CA	1916	21-50	45	5.8	16	11-20
Robertson North	TX	1956	21-50	48	5.5	294	101-200
Greater Aneth	UT	1956	21-50	55	5.0	66	51-100
Beta	PF	1976	21-50	64	4.4	452	201-300
Wattenberg	CO	1970	21-50	73	3.9	826	301-400
Wasson 72	TX	1940	21-50	76	3.8	254	101-200
Huntington Beach	CA	1920	21-50	77	3.7	12	11-20
Elk Basin	WY & MT	1915	21-50	102	2.9	44	21-50
Eunice Monument	NM	1929	21-50	136	2.3	65	51-100
Arroyo Grande	CA	1906	21-50	477	0.6	> 1,000	301-400
Justis	NM	1944	21-50	682	0.4	423	201-300
Viosca Knoll Blk 990	GF	1981	21-50	-	0.0	-	201-300
Garden Banks Blk 426	GF	1987	21-50	-	0.0	-	201-300
Top 50 Volume Subtotal			**14,377.3**		**1,221.7**	**39,468.6**	**53,845.9**
Top 50 Percentage of U.S. Total			**57.6%**		**46.5%**	**23.9%**	**28.3%**

Table B1. Top 100 U.S. Oil[a] Fields as Ranked by Production within Proved Reserves Group, 1992 (Continued) (Million Barrels of 42 U.S. Gallons)

Field Name	Location	Discovery Year	Proved Reserves 12/31/92 Rank Group	Annual Production Rank	Annual Production Volume	Cumulative Production Rank	Ultimate Recovery Rank Group
Green Canyon Blk 65	GF	1983	51-100	13	18.8	751	301-400
McArthur River	AK	1965	51-100	35	7.4	40	21-50
Eugene Island SA Blk 330	GF	1971	51-100	37	7.0	78	51-100
Kelly-Snyder	TX	1948	51-100	39	6.4	9	11-20
Panhandle	TX	1910	51-100	40	6.1	6	1-10
Oregon Basin	WY	1912	51-100	41	6.1	54	51-100
West Delta Blk 73	GF	1962	51-100	42	6.1	131	101-200
West Delta Blk 30	GF	1949	51-100	43	6.0	47	21-50
Dagger Draw North	NM	1964	51-100	44	5.9	> 1,000	601-700
Means	TX	1934	51-100	49	5.5	111	101-200
Hobbs	NM	1928	51-100	50	5.2	74	51-100
Hawkins	TX	1940	51-100	51	5.2	19	21-50
Howard-Glasscock	TX	1925	51-100	52	5.2	53	51-100
Anschutz Ranch East	UT & WY	1979	51-100	54	5.0	266	101-200
Goldsmith	TX	1935	51-100	56	4.9	27	21-50
Prentice	TX	1950	51-100	57	4.9	159	101-200
Tom OConnor	TX	1934	51-100	59	4.8	23	21-50
Stephens County Regular	TX	1915	51-100	62	4.6	101	51-100
Point Pedernales	PF	1983	51-100	63	4.5	740	401-500
Hatters Pond	AL	1974	51-100	70	4.0	532	301-400
Mississippi Canyon Blk 109	GF	1984	51-100	71	3.9	> 1,000	701-800
Hartzog Draw	WY	1976	51-100	82	3.5	341	201-300
Dollarhide	TX & NM	1945	51-100	86	3.4	112	51-100
Salt Creek	WY	1889	51-100	87	3.3	30	21-50
South Pass EA Blk 62	GF	1965	51-100	89	3.3	221	201-300
Bluebell	UT	1949	51-100	90	3.3	224	101-200
South Pass Blk 61	GF & LA	1955	51-100	97	3.0	140	101-200
Foster	TX	1932	51-100	104	2.8	93	51-100
South Pass Blk 27	GF & LA	1954	51-100	107	2.8	68	51-100
Pennel	MT	1955	51-100	111	2.7	344	201-300
Welch	TX	1942	51-100	112	2.7	188	101-200
Kern Front	CA	1925	51-100	115	2.6	157	101-200
Altamont	UT	1952	51-100	116	2.5	282	201-300
Granite Point	AK	1965	51-100	118	2.5	234	201-300
Belridge North	CA	1912	51-100	121	2.5	299	201-300
Middle Ground Shoal	AK	1962	51-100	125	2.4	171	101-200
Chunchula	AL	1974	51-100	139	2.2	513	301-400
Fitts	OK	1933	51-100	141	2.2	138	101-200
Mabee	TX	1944	51-100	151	2.1	297	201-300
Sharon Ridge	TX	1923	51-100	165	1.9	305	201-300
Brea-Olinda	CA	1897	51-100	193	1.7	57	51-100
T X L	TX	1944	51-100	209	1.6	94	51-100
Maljamar	NM	1926	51-100	214	1.5	115	101-200
McKittrick	CA	1887	51-100	258	1.2	90	51-100
Pegasus	TX	1949	51-100	273	1.1	191	101-200
Placerita	CA	1920	51-100	274	1.1	534	301-400
Cat Canyon	CA	1909	51-100	296	1.1	82	51-100
Monument	NM	1935	51-100	> 1,000	0.2	130	101-200
Ewing Bank Blk 873	GF	1991	51-100	-	0.0	-	501-600
Niakuk	AK	1984	51-100	-	0.0	-	501-600
Top 100 Volume Subtotal			**16,364.9**		**1,410.3**	**53,361.4**	**69,726.4**
Top 100 Percentage of U.S. Total			**65.5%**		**53.7%**	**32.3%**	**36.6%**

[a]Includes lease condensate.

– = Not Applicable.

Note: Fields are grouped in "proved reserves rank groups" and then listed within that group in descending order by National 1992 annual production rank. The U.S. total production estimate, 2,627.654 million barrels, used to calculate the percentages in this table, is from the official Energy Information Administration production data for crude oil and lease condensate for 1992 contained in the *Petroleum Supply Annual 1993*, DOE/EIA-0340(93), pp.168-169. They differ from the U.S. total data reported in this publication. Column totals may not add due to independent rounding.

Source: Energy Information Administration, Office of Oil and Gas.

Table B2. Top 100 U.S. Gas[a] Fields as Ranked by Production within Proved Reserves Group, 1992
(Billion Cubic Feet)

Field Name	Location	Discovery Year	Proved Reserves 12/31/92 Rank Group	Annual Production Rank	Annual Production Volume	Cumulative Production Rank	Ultimate Recovery Rank Group
Hugoton Gas Area	KS & OK & TX	1922	1-10	1	515.9	1	1-10
Basin	NM	1947	1-10	2	462.4	8	1-10
Blanco	NM & CO	1927	1-10	3	310.9	4	1-10
Prudhoe Bay	AK	1967	1-10	4	213.8	62	1-10
Panhandle West	TX	1918	1-10	5	166.4	2	1-10
Carthage	TX	1936	1-10	6	149.2	5	1-10
Panoma Gas Area	KS	1956	1-10	10	104.9	50	11-20
Wattenberg	CO	1970	1-10	11	96.0	147	21-50
Red Oak-Norris	OK	1910	1-10	19	69.7	88	21-50
Elk Hills	CA	1919	1-10	57	37.6	103	51-100
Top 10 Volume Subtotal			**41,269.7**		**2,126.9**	**90,261.0**	**131,530.6**
Top 10 Percentage of U.S. Total			**23.8%**		**11.3%**	**10.8%**	**13.1%**
Mocane-Laverne Gas Area	OK & KS & TX	1946	11-20	8	124.3	7	1-10
Gomez	TX	1963	11-20	15	85.0	10	1-10
McArthur River	AK	1965	11-20	18	70.1	249	101-200
Northwest Gulf	AL & GF	1984	11-20	37	49.5	> 1,000	101-200
Big Sandy	KY	1881	11-20	58	37.5	67	21-50
Beluga River	AK	1962	11-20	60	36.5	326	51-100
Fogarty Creek	WY	1975	11-20	91	27.5	170	51-100
Madden	WY	1968	11-20	117	23.1	384	101-200
Lake Ridge	WY	1981	11-20	229	14.3	> 1,000	101-200
North Central Gulf	AL & GF	1985	11-20	-	0.0	-	201-300
Top 20 Volume Subtotal			**49,658.6**		**2,594.6**	**104,402.2**	**154,060.7**
Top 20 Percentage of U.S. Total			**28.7%**		**13.7%**	**12.5%**	**15.3%**
Watonga-Chickasha Trend	OK	1948	21-50	9	113.6	13	11-20
Whitney Canyon-Carter Creek	WY	1978	21-50	12	95.0	139	51-100
McAllen Ranch	TX	1960	21-50	13	93.1	100	51-100
Wilburton	OK	1941	21-50	14	88.1	78	51-100
Lake Arthur South	LA	1955	21-50	16	84.2	236	101-200
Kinta	OK	1914	21-50	17	82.2	37	21-50
Headlee	TX	1953	21-50	20	66.9	51	21-50
Spraberry Trend Area	TX	1950	21-50	22	62.5	66	51-100
Matagorda Island Blk 623	GF	1980	21-50	23	61.7	470	201-300
Fairway	AL	1986	21-50	28	57.4	> 1,000	201-300
Strong City District	OK	1966	21-50	29	57.3	314	101-200
Vermilion Blk 14	GF & LA	1956	21-50	34	50.6	16	11-20
Oak Hill	TX	1958	21-50	35	50.5	255	101-200
Bruff	WY	1974	21-50	42	47.1	666	101-200
Cook Inlet North	AK	1962	21-50	43	44.4	116	51-100
Sawyer	TX	1960	21-50	51	41.1	169	51-100
Natural Buttes	UT	1940	21-50	63	35.1	404	101-200
Ozona	TX	1953	21-50	67	34.2	190	101-200
Lower Mobile Bay-Mary Ann	AL	1979	21-50	83	29.6	> 1,000	201-300
Wasson	TX	1937	21-50	111	23.6	92	51-100
Anschutz Ranch East	UT & WY	1979	21-50	128	21.7	> 1,000	201-300
Lisbon	UT	1960	21-50	132	21.1	305	101-200
Painter Reservoir East	WY	1979	21-50	143	19.9	977	201-300
Tip Top	WY	1928	21-50	169	17.3	464	101-200
South Pass SA Blk 89	GF	1969	21-50	173	16.8	672	201-300
Hondo	PF	1969	21-50	308	11.7	> 1,000	201-300
Oakwood	VA	1990	21-50	809	4.6	> 1,000	201-300
Green Canyon Blk 116	GF	1983	21-50	-	0.0	-	301-400
Bon Secour Bay	AL	1983	21-50	-	0.0	-	201-300
Garden Banks Blk 426	GF	1987	21-50	-	0.0	-	301-400
Top 50 Volume Subtotal			**66,326.3**		**3,925.8**	**128,691.2**	**195,017.5**
Top 50 Percentage of U.S. Total			**38.3%**		**20.8%**	**15.4%**	**19.4%**

Table B2. Top 100 U.S. Gas[a] Fields as Ranked by Production within Proved Reserves Group, 1992 (Continued)
(Billion Cubic Feet)

Field Name	Location	Discovery Year	Proved Reserves 12/31/92 Rank Group	Annual Production Rank	Annual Production Volume	Cumulative Production Rank	Ultimate Recovery Rank Group
Giddings	TX	1960	51-100	7	148.9	76	51-100
Golden Trend	OK	1945	51-100	24	60.5	9	11-20
Coyanosa	TX	1959	51-100	25	60.4	48	21-50
South Timbalier Blk 172	GF	1965	51-100	26	58.8	71	51-100
Sooner Trend	OK	1938	51-100	30	55.2	12	11-20
Boonsville	TX	1945	51-100	31	54.2	28	21-50
Chalkley	LA	1938	51-100	32	53.9	296	101-200
Matagorda Island Blk 668	GF	1981	51-100	38	49.5	226	101-200
Elk City	OK	1947	51-100	40	48.2	93	51-100
Indian Basin	NM	1963	51-100	44	44.3	79	51-100
Eakly-Weatherford Trend	OK	1953	51-100	47	43.4	173	101-200
Brown-Bassett	TX	1953	51-100	48	43.0	55	51-100
Puckett	TX	1952	51-100	49	41.6	14	11-20
High Island SA Blk A573	GF	1973	51-100	50	41.3	321	201-300
Main Pass Blk 41	GF	1956	51-100	55	38.3	114	101-200
Panola South	OK	1990	51-100	56	37.9	> 1,000	501-600
Eumont	NM	1929	51-100	59	37.1	45	21-50
Sho-Vel-Tum	OK	1905	51-100	70	33.4	29	21-50
Waskom	TX & LA	1924	51-100	75	32.5	64	51-100
Conger	TX	1973	51-100	76	31.9	323	201-300
Panhandle	TX	1910	51-100	80	30.3	49	21-50
Carpenter	OK	1951	51-100	85	29.1	402	301-400
Eugene Island SA Blk 330	GF	1971	51-100	86	29.0	70	51-100
Reydon	OK	1962	51-100	87	28.8	206	101-200
Cheyenne West	OK	1971	51-100	88	28.1	264	201-300
Garden Banks Blk 236	GF	1977	51-100	95	26.6	> 1,000	401-500
Kuparuk River	AK	1969	51-100	98	26.2	623	201-300
Sugg Ranch	TX	1985	51-100	104	24.5	> 1,000	401-500
Cecil	AR	1950	51-100	114	23.3	267	201-300
Mississippi Canyon Blk 194	GF	1975	51-100	134	20.8	471	201-300
Cedar Cove Coal Degas	AL	1983	51-100	137	20.4	> 1,000	401-500
Opelika	TX	1937	51-100	138	20.3	96	51-100
Willow Springs	TX	1938	51-100	155	18.8	161	101-200
Big Piney	WY	1964	51-100	165	17.7	703	301-400
Nora	VA	1949	51-100	197	15.8	> 1,000	401-500
Oak Grove Coal Degas	AL	1980	51-100	201	15.6	> 1,000	601-700
Blanco South	NM	1951	51-100	209	15.4	111	51-100
Echo Springs	WY	1976	51-100	231	14.3	716	401-500
Sonora	TX	1954	51-100	232	14.2	647	301-400
Endicott	AK	1978	51-100	272	12.7	> 1,000	601-700
Keystone	TX	1935	51-100	321	10.9	165	101-200
Hogsback	WY	1955	51-100	329	10.6	428	301-400
Lake Pagie	LA	1958	51-100	340	10.4	97	51-100
Hawkins	TX	1940	51-100	487	7.8	257	201-300
Mississippi Canyon Blk 397	GF	1984	51-100	556	6.9	> 1,000	601-700
Whelan	TX	1937	51-100	590	6.5	491	301-400
Pegasus	TX	1949	51-100	617	6.1	389	201-300
Anahuac	TX	1935	51-100	702	5.4	194	101-200
Robinsons Bend Coal Degas	AL	1985	51-100	847	4.4	> 1,000	401-500
Bowdoin	MT	1917	51-100	> 1,000	3.2	> 1,000	401-500
Top 100 Volume Subtotal			**80,852.4**		**5,444.4**	**177,931.8**	**258,784.2**
Top 100 Percentage of U.S. Total			**46.7%**		**28.8%**	**21.4%**	**25.7%**

[a]Wet after lease separation.

– = Not Applicable.

Note: Fields are grouped in “proved reserves rank groups” and then listed within that group in descending order by National 1992 annual production rank. The U.S. total production estimate, 18,879.327 billion cubic feet, used to calculate the percentages in this table, is from the official Energy Information Administration production data for natural gas for 1992 contained in the *Natural Gas Annual 1992*, DOE/EIA-0131(92). They differ from the U.S. total data reported in this publication.Column totals may not add due to independent rounding.

Source: Energy Information Administration, Office of Oil and Gas.

Table B3. Annual Production, 1983-1992, for the Top 100 U.S. Oil[a] Fields in 1992
(Million Barrels of 42 U.S. Gallons)

State	Field Name	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
AK	Prudhoe Bay	560.9	563.1	571.7	566.2	588.2	574.5	519.0	484.6	478.7	445.1
AK	Kuparuk River	39.9	46.2	79.2	93.9	102.4	110.9	110.1	107.2	113.4	118.5
CA	Midway-Sunset	47.5	50.8	55.1	56.8	57.8	57.9	56.6	59.1	61.3	61.1
CA	Belridge South	38.4	46.7	55.2	61.3	63.6	60.3	56.8	54.7	55.1	50.2
CA	Kern River	48.3	49.3	51.7	47.8	45.7	47.3	45.2	44.1	44.7	44.9
AK	Endicott	- -	- -	- -	0.0	8.8	37.4	36.1	37.7	41.3	41.6
TX	Wasson	41.3	35.5	30.8	29.0	28.4	27.8	27.1	25.6	24.6	25.7
CA	Elk Hills	55.2	49.3	46.6	39.8	40.3	38.1	34.0	28.7	26.3	24.7
TX	Yates	45.5	45.9	44.6	41.4	35.8	32.7	27.3	21.9	20.0	18.1
AK	Point McIntyre	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
Top 10 Volume Subtotal		**877.0**	**886.8**	**934.8**	**936.1**	**971.0**	**986.9**	**912.2**	**863.6**	**865.3**	**830.0**
Top 10 Percentage of U.S. Total		**27.3%**	**26.9%**	**28.7%**	**29.5%**	**32.0%**	**33.1%**	**33.0%**	**32.1%**	**32.0%**	**31.6%**
TX	East Texas	51.0	49.1	46.9	44.4	41.7	39.5	37.2	35.6	33.5	32.9
CA	Wilmington	38.5	40.6	41.2	36.6	32.1	29.3	27.3	25.9	24.8	23.2
TX	Spraberry Trend Area	17.6	19.9	21.4	21.5	20.3	20.4	19.1	18.7	19.6	19.0
TX	Slaughter	25.0	24.6	22.8	20.8	20.1	19.9	18.8	17.7	17.3	16.8
TX	Levelland	18.9	19.0	18.6	18.1	17.3	17.0	16.7	16.8	16.3	15.5
TX	Cowden North	13.9	13.8	13.9	13.7	14.1	14.7	14.5	13.7	13.8	13.4
CO	Rangely	13.9	13.4	12.2	11.4	12.1	12.4	12.0	12.5	12.8	11.8
PF	Hondo	13.2	11.1	12.0	11.1	9.6	9.9	8.7	8.2	7.7	8.2
CA	San Ardo	8.1	7.7	8.1	6.9	4.9	4.7	3.8	4.1	3.7	4.3
PF	Pescado	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
Top 20 Volume Subtotal		**1,077.1**	**1,086.0**	**1,131.9**	**1,120.6**	**1,143.3**	**1,154.7**	**1,070.2**	**1,016.8**	**1,014.8**	**975.0**
Top 20 Percentage of U.S. Total		**33.5%**	**32.9%**	**34.7%**	**35.3%**	**37.7%**	**38.7%**	**38.7%**	**37.8%**	**37.5%**	**37.1%**
TX	Giddings	23.6	21.2	18.8	13.9	10.3	9.3	8.9	10.5	20.9	34.0
PF	Point Arguello	0.0	- -	- -	- -	0.1	- -	- -	- -	5.5	17.1
OK	Sho-Vel-Tum	20.5	19.8	19.5	18.6	17.9	18.5	17.4	16.9	16.3	15.8
TX	Seminole	14.6	12.6	12.9	13.8	14.5	15.2	15.9	16.4	16.3	15.6
TX	Pearsall	2.8	2.4	2.2	2.2	1.8	1.6	2.5	22.7	26.4	13.3
GF & LA	Bay Marchand Blk 2	10.7	9.1	9.1	9.6	9.3	9.8	8.8	13.1	13.8	13.0
GF	Main Pass SA Blk 299	1.9	1.7	1.5	1.4	2.0	2.1	2.3	2.6	2.8	12.4
CA	Coalinga	9.6	10.1	11.4	11.4	10.4	10.0	10.7	11.6	12.4	11.5
CA	Cymric	5.1	5.7	6.3	7.0	7.0	8.8	8.9	9.0	10.4	10.7
CA	Lost Hills	5.7	5.2	5.0	4.7	5.3	5.6	6.0	6.6	8.0	8.9
TX	McElroy	9.6	9.4	9.2	8.5	7.9	7.7	7.5	8.0	8.4	8.8
GF	South Pass SA Blk 89	5.9	10.1	13.5	17.8	13.8	16.6	11.2	9.3	8.2	8.5
TX	Salt Creek	7.4	7.1	6.9	7.3	9.1	10.7	10.5	10.0	9.5	8.4
GF	Mississippi Canyon Blk 194	26.1	20.0	18.2	12.9	8.5	4.9	2.4	- -	6.3	8.2
NM	Vacuum	16.2	15.4	13.9	11.5	10.6	10.2	9.4	9.1	8.7	7.9
TX	Fullerton	6.6	6.8	7.7	7.9	7.1	7.6	7.8	7.9	7.5	7.2
AK	Milne Point	- -	- -	0.7	4.7	0.0	- -	3.7	6.6	7.5	7.0
CA	Ventura	7.3	7.4	7.4	7.4	7.3	7.0	6.5	6.5	6.2	5.8
TX	Robertson North	4.7	4.7	4.4	4.1	4.1	4.7	5.3	5.6	5.7	5.5
UT	Greater Aneth	5.9	5.6	6.0	5.4	5.1	5.2	5.3	5.7	5.5	5.0
PF	Beta	3.9	5.2	6.2	7.0	6.6	6.0	5.6	5.3	4.2	4.4
CO	Wattenberg	0.7	1.3	2.1	2.7	2.8	2.7	2.5	2.7	3.3	3.9
TX	Wasson 72	1.6	2.3	3.3	4.1	4.0	4.1	3.9	3.9	3.9	3.8
CA	Huntington Beach	9.0	8.7	8.1	7.1	6.1	5.5	4.8	3.8	3.8	3.7
WY & MT	Elk Basin	4.2	3.9	3.9	3.7	3.5	3.4	3.4	3.2	3.1	2.9
NM	Eunice Monument	2.9	3.0	2.8	2.7	2.4	2.3	2.3	2.3	2.2	2.3
CA	Arroyo Grande	0.3	0.3	0.3	0.2	0.2	0.3	0.4	0.5	0.6	0.6
NM	Justis	0.7	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.4
GF	Viosca Knoll Blk 990	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
GF	Garden Banks Blk 426	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
Top 50 Volume Subtotal		**1,284.5**	**1,285.4**	**1,333.6**	**1,318.9**	**1,321.3**	**1,335.2**	**1,244.7**	**1,217.1**	**1,242.8**	**1,221.7**
Top 50 Percentage of U.S. Total		**40.0%**	**39.0%**	**40.9%**	**41.5%**	**43.6%**	**44.8%**	**45.0%**	**45.3%**	**45.9%**	**46.5%**

Table B3. Annual Production, 1983-1992, for the Top 100 U.S. Oil[a] Fields in 1992 (Continued)
(Million Barrels of 42 U.S. Gallons)

State	Field Name	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
GF	Green Canyon Blk 65	- -	- -	- -	- -	- -	- -	0.9	4.7	8.2	18.8
AK	Mcarthur River	13.6	11.8	7.5	8.0	7.4	7.1	7.0	4.3	7.4	7.4
GF	Eugene Island SA Blk 330	10.5	11.3	10.7	10.5	9.1	8.0	7.5	6.1	6.0	7.0
TX	Kelly-Snyder	22.1	19.8	17.7	14.6	12.0	10.8	9.7	8.6	7.5	6.4
TX	Panhandle	9.4	10.4	9.9	8.7	8.0	7.7	7.2	6.9	6.6	6.1
WY	Oregon Basin	9.7	9.2	9.6	10.0	9.1	8.5	7.9	7.2	6.8	6.1
GF	West Delta Blk 73	3.4	2.7	2.5	3.7	4.6	4.6	3.5	2.7	6.6	6.1
GF	West Delta Blk 30	8.1	10.3	9.6	8.4	7.1	6.6	5.6	5.7	6.0	6.0
NM	Dagger Draw North	0.1	0.2	0.3	0.2	0.5	0.7	0.9	2.0	4.6	5.9
TX	Means	3.8	4.8	6.3	6.4	6.5	6.4	6.0	6.1	5.8	5.5
NM	Hobbs	4.8	6.0	6.6	7.0	7.9	7.9	7.3	6.4	5.6	5.2
TX	Hawkins	10.7	11.1	11.4	11.0	9.5	8.0	6.8	6.3	5.7	5.2
TX	Howard-Glasscock	6.0	5.9	5.7	5.9	5.9	5.7	5.6	6.0	5.8	5.2
UT & WY	Anschutz Ranch East	8.6	13.3	14.5	15.8	14.5	12.1	9.1	7.7	5.9	5.0
TX	Goldsmith	7.8	7.9	7.4	6.8	6.3	6.0	5.7	5.5	5.4	4.9
TX	Prentice	3.6	4.0	4.5	5.0	5.6	5.7	5.3	4.9	5.3	4.9
TX	Tom OConnor	17.2	16.7	15.6	13.4	9.2	7.3	6.6	5.8	5.3	4.8
TX	Stephens County Regular	4.8	5.5	6.3	6.5	6.1	5.9	5.4	5.3	5.0	4.6
PF	Point Pedernales	- -	- -	- -	0.0	4.7	6.2	7.3	5.5	5.0	4.5
AL	Hatters Pond	2.9	3.5	3.4	3.2	3.4	4.0	3.5	3.9	4.1	4.0
GF	Mississippi Canyon Blk 109	- -	- -	- -	- -	- -	- -	- -	- -	0.1	3.9
WY	Hartzog Draw	2.7	3.5	5.2	6.5	6.8	6.3	5.6	4.7	4.1	3.5
TX & NM	Dollarhide	2.5	2.6	2.6	2.6	2.7	3.4	3.2	3.2	3.4	3.4
WY	Salt Creek	6.0	5.7	6.1	5.9	5.0	5.1	4.5	4.3	3.8	3.3
GF	South Pass EA Blk 62	3.6	3.0	3.0	2.4	3.3	3.2	3.9	4.0	3.3	3.3
UT	Bluebell	5.0	6.2	5.7	4.8	4.5	4.0	3.6	3.9	3.6	3.3
GF & LA	South Pass Blk 61	10.6	11.9	12.0	12.8	9.3	8.5	4.9	5.2	7.5	3.0
TX	Foster	5.5	5.0	4.6	4.3	4.0	3.9	3.6	3.4	3.1	2.8
GF & LA	South Pass Blk 27	5.1	5.1	4.6	4.8	4.3	3.6	3.8	3.1	3.1	2.8
MT	Pennel	3.1	3.4	3.6	3.2	3.0	3.0	2.9	2.8	2.9	2.7
TX	Welch	3.2	3.4	3.4	3.2	3.0	3.0	3.0	3.0	2.9	2.7
CA	Kern Front	2.5	2.8	2.8	2.2	1.7	1.5	1.7	2.3	2.7	2.6
UT	Altamont	3.6	3.8	5.1	4.1	3.1	2.9	2.6	3.2	3.1	2.5
AK	Granite Point	3.6	3.3	3.1	3.2	2.8	2.7	2.3	1.5	2.1	2.5
CA	Belridge North	1.0	1.1	1.3	1.8	2.4	3.6	2.6	2.8	2.7	2.5
AK	Middle Ground Shoal	3.4	3.2	3.1	3.2	2.9	2.8	2.8	2.7	2.7	2.4
AL	Chunchula	3.9	3.6	3.9	3.8	3.6	3.2	2.9	2.6	2.5	2.2
OK	Fitts	3.3	3.3	3.3	3.2	3.0	2.8	2.5	2.6	2.3	2.2
TX	Mabee	3.2	2.7	2.6	2.5	2.3	2.5	2.7	2.8	2.3	2.1
TX	Sharon Ridge	2.7	2.7	2.7	2.4	2.3	2.3	2.2	2.1	2.0	1.9
CA	Brea-Olinda	2.6	2.6	2.5	2.4	2.3	2.1	1.9	1.9	1.7	1.7
TX	T X L	1.5	1.4	1.7	2.0	1.7	1.9	1.6	1.5	1.4	1.6
NM	Maljamar	2.4	2.2	2.0	1.9	1.8	1.9	1.8	1.7	1.6	1.5
CA	McKittrick	4.5	4.2	4.1	3.6	2.9	2.5	1.9	1.6	1.5	1.2
TX	Pegasus	1.6	1.5	1.3	1.5	1.5	1.3	1.2	1.1	1.2	1.1
CA	Placerita	0.5	0.5	0.5	0.4	0.5	0.6	0.6	0.7	0.8	1.1
CA	Cat Canyon	5.0	5.0	4.7	3.5	2.9	2.4	1.5	1.3	1.2	1.1
NM	Monument	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
GF	Ewing Bank Blk 873	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
AK	Niakuk	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
Top 100 Volume Subtotal		**1,524.5**	**1,534.1**	**1,578.8**	**1,556.2**	**1,542.5**	**1,545.7**	**1,435.5**	**1,398.2**	**1,431.0**	**1,410.3**
Top 100 Percentage of U.S. Total		**47.4%**	**46.5%**	**48.5%**	**49.0%**	**50.8%**	**51.8%**	**51.9%**	**52.0%**	**52.9%**	**53.7%**

[a]Includes lease condensate.

– = Not Applicable.

Note: Fields are grouped in "proved reserves rank groups" and then listed within that group in descending order by National 1992 annual production rank. The U.S. total production estimates in this table for 1983 through 1992 are from the official Energy Information Administration production data for crude oil and lease condensate for 1983 through 1993 contained in the *Petroleum Supply Annual*, DOE/EIA-0340. They differ from the U.S. total data reported in this publication. Column totals may not add due to independent rounding.

Source: Energy Information Administration, Office of Oil and Gas.

Table B4. Annual Production, 1983-1992, for the Top 100 U.S. Natural Gas[a] Fields in 1992
(Billion Cubic Feet)

State	Field Name	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
KS/OK/TX	Hugoton Gas Area	341.1	408.0	424.0	394.4	367.7	466.7	481.1	459.6	513.9	515.9
NM	Basin	75.3	135.9	134.5	88.5	116.6	108.1	102.4	229.7	305.6	462.4
NM & CO	Blanco	201.3	225.9	219.9	174.9	225.4	204.1	216.1	240.4	239.5	310.9
AK	Prudhoe Bay	65.1	78.1	91.7	53.3	131.9	166.6	171.4	174.6	206.4	213.8
TX	Panhandle West	211.6	207.7	170.2	132.4	128.0	146.2	157.3	158.4	164.5	166.4
TX	Carthage	74.5	99.5	98.1	95.8	93.0	83.8	118.0	163.9	171.3	149.2
KS	Panoma Gas Area	59.1	68.5	83.4	84.9	68.1	84.0	95.8	91.4	107.7	104.9
CO	Wattenberg	25.2	37.3	44.7	47.3	53.5	62.8	62.8	74.4	88.4	96.0
OK	Red Oak-Norris	21.4	28.0	20.5	18.5	46.5	74.2	64.6	64.7	65.7	69.7
CA	Elk Hills	67.9	68.7	73.4	63.3	63.5	60.5	61.4	49.1	43.7	37.6
Top 10 Volume Subtotal		**1,142.5**	**1,357.7**	**1,360.4**	**1,153.4**	**1,294.1**	**1,457.0**	**1,530.8**	**1,706.2**	**1,906.7**	**2,126.9**
Top 10 Percentage of U.S. Total		**6.8%**	**7.4%**	**7.8%**	**6.8%**	**7.4%**	**8.0%**	**8.3%**	**9.1%**	**10.2%**	**11.3%**
OK/KS/TX	Mocane-Laverne Gas Area	101.5	112.4	108.1	83.6	97.1	120.0	127.8	137.3	134.5	124.3
TX	Gomez	85.7	83.7	70.7	69.2	71.7	98.6	93.3	93.7	86.3	85.0
AK	McArthur River	14.4	15.1	10.7	13.6	13.3	16.7	31.0	51.5	61.2	70.1
AL & GF	Northwest Gulf	- -	- -	- -	- -	- -	- -	- -	- -	2.7	49.5
KY	Big Sandy	27.7	31.2	31.6	32.6	35.4	32.4	34.9	37.4	39.3	37.5
AK	Beluga River	18.1	19.8	22.6	25.4	24.0	25.6	30.1	39.5	38.5	36.5
WY	Fogarty Creek	0.3	0.2	0.1	6.6	24.9	23.1	28.7	30.3	30.7	27.5
WY	Madden	12.7	14.1	11.3	11.7	21.5	15.1	19.0	21.8	21.4	23.1
WY	Lake Ridge	- -	- -	- -	0.6	10.0	9.3	9.3	9.1	11.6	14.3
AL & GF	North Central Gulf	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
Top 20 Volume Subtotal		**1,402.9**	**1,634.2**	**1,615.5**	**1,396.7**	**1,591.9**	**1,797.9**	**1,905.0**	**2,126.6**	**2,332.9**	**2,594.6**
Top 20 Percentage of U.S. Total		**8.4%**	**9.0%**	**9.3%**	**8.2%**	**9.1%**	**9.8%**	**10.4%**	**11.3%**	**12.4%**	**13.7%**
OK	Watonga-Chickasha Trend	162.0	166.0	155.9	162.9	159.0	151.4	152.0	138.1	127.8	113.6
WY	Whitney Canyon-Carter Creek	97.7	67.7	112.7	89.8	99.8	100.1	112.4	58.4	100.9	95.0
TX	McAllen Ranch	22.2	18.9	36.5	46.9	66.9	71.8	58.4	63.6	82.4	93.1
OK	Wilburton	22.8	22.1	21.5	23.2	37.1	69.4	114.2	129.5	106.2	88.1
LA	Lake Arthur South	3.3	5.3	7.3	9.1	30.3	72.9	88.2	82.9	80.1	84.2
OK	Kinta	38.4	48.5	43.1	44.1	62.4	72.1	80.4	88.3	95.4	82.2
TX	Headlee	67.7	66.9	66.9	69.4	68.7	69.8	69.6	69.0	67.3	66.9
TX	Spraberry Trend Area	52.8	57.4	62.7	65.3	65.9	64.1	61.5	60.7	61.9	62.5
GF	Matagorda Island Blk 623	- -	15.2	25.8	28.2	32.9	42.1	31.2	25.9	38.9	61.7
AL	Fairway	- -	- -	- -	- -	- -	- -	- -	- -	3.4	57.4
OK	Strong City District	27.0	34.2	34.7	32.6	36.3	41.0	48.4	51.9	50.4	57.3
GF & LA	Vermilion Blk 14	108.3	93.6	95.7	71.9	72.2	66.1	55.1	57.8	57.2	50.6
TX	Oak Hill	39.2	39.4	29.9	38.2	36.3	43.7	39.1	46.6	49.0	50.5
WY	Bruff	12.0	10.5	11.4	10.3	9.5	8.3	8.8	15.4	33.4	47.1
AK	Cook Inlet North	47.9	47.0	45.8	43.8	42.9	45.0	45.3	45.0	44.7	44.4
TX	Sawyer	30.1	31.9	40.1	33.6	33.3	34.8	36.5	39.7	45.3	41.1
UT	Natural Buttes	20.4	27.3	21.8	20.9	17.8	17.6	19.1	22.8	23.5	35.1
TX	Ozona	21.3	20.0	24.0	20.7	24.1	30.1	31.3	35.9	35.9	34.2
AL	Lower Mobile Bay-Mary Ann	- -	- -	- -	- -	- -	9.3	14.1	21.3	29.2	29.6
TX	Wasson	26.9	24.4	24.5	21.9	21.0	19.7	27.9	19.2	19.9	23.6
UT & WY	Anschutz Ranch East	5.7	10.1	11.7	14.7	8.3	0.1	6.3	5.7	8.3	21.7
UT	Lisbon	20.2	1.4	1.5	1.4	0.7	1.6	1.9	21.6	20.4	21.1
WY	Painter Reservoir East	6.6	8.5	7.9	11.9	10.5	14.0	17.0	29.0	14.5	19.9
WY	Tip Top	6.5	6.7	3.8	8.5	6.1	9.2	11.1	10.6	14.2	17.3
GF	South Pass SA Blk 89	6.8	12.7	19.6	24.5	16.9	32.7	37.6	21.0	26.5	16.8
PF	Hondo	0.8	5.5	9.6	14.8	11.2	11.0	10.7	9.6	16.7	11.7
VA	Oakwood	- -	- -	- -	- -	- -	- -	- -	- -	- -	4.6
AL	Green Canyon Blk 116	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
GF	Bon Secour Bay	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
AL	Garden Banks Blk 426	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
Top 50 Volume Subtotal		**2,249.5**	**2,475.5**	**2,530.0**	**2,305.4**	**2,561.8**	**2,895.9**	**3,083.2**	**3,296.3**	**3,586.2**	**3,925.8**
Top 50 Percentage of U.S. Total		**13.5%**	**13.6%**	**14.5%**	**13.6%**	**14.6%**	**15.8%**	**16.8%**	**17.5%**	**19.1%**	**20.8%**

Table B4. Annual Production, 1983-1992, for the Top 100 U.S. Natural Gas[a] Fields in 1992 (Continued)
(Billion Cubic Feet)

State	Field Name	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
TX	Giddings	130.5	120.7	133.6	115.1	84.7	70.8	62.4	61.7	92.3	148.9
OK	Golden Trend	20.6	23.2	35.1	47.1	52.4	56.2	62.5	64.0	67.2	60.5
TX	Coyanosa	42.2	9.0	7.0	9.2	10.0	8.2	4.4	25.6	79.0	60.4
GF	South Timbalier Blk 172	47.8	82.0	50.9	55.2	48.5	65.1	78.8	69.0	56.3	58.8
OK	Sooner Trend	89.1	89.6	88.2	80.4	78.4	72.2	73.2	62.9	60.7	55.2
TX	Boonsville	72.8	76.0	79.6	75.0	58.6	66.9	61.1	61.2	58.1	54.2
LA	Chalkley	2.8	2.6	3.6	5.1	3.0	2.5	2.5	12.2	39.4	53.9
GF	Matagorda Island Blk 668	- -	- -	8.1	62.1	89.1	118.3	140.3	89.8	55.4	49.5
OK	Elk City	46.6	52.3	64.2	73.2	62.1	49.0	60.1	58.4	51.9	48.2
NM	Indian Basin	31.7	41.6	35.4	24.2	27.1	34.4	35.9	37.7	35.8	44.3
OK	Eakly-Weatherford Trend	47.3	71.2	84.2	101.1	96.9	81.3	67.2	52.8	49.0	43.4
TX	Brown-Bassett	30.5	35.1	31.1	8.7	18.3	24.8	34.0	36.1	43.5	43.0
TX	Puckett	38.7	29.7	40.9	33.5	35.5	42.7	40.0	44.3	43.6	41.6
GF	High Island SA Blk A573	25.7	30.0	21.9	22.0	18.9	37.3	41.7	31.7	46.3	41.3
GF	Main Pass Blk 41	44.3	54.5	43.1	46.7	36.1	32.6	32.3	32.0	25.5	38.3
NM	Panola South	- -	- -	- -	- -	- -	- -	- -	1.1	39.0	37.9
OK	Eumont	26.7	26.4	25.8	19.8	24.6	22.9	25.9	30.2	35.5	37.1
TX & LA	Sho-Vel-Tum	30.2	26.6	43.5	42.4	40.2	20.9	32.9	36.6	37.0	33.4
TX	Waskom	12.0	13.3	15.6	19.7	27.8	34.9	34.2	32.5	33.1	32.5
TX	Conger	27.4	31.3	32.2	24.5	28.4	27.5	27.3	30.5	31.0	31.9
OK	Panhandle	92.8	107.4	89.7	68.4	60.8	56.7	47.4	36.8	31.7	30.3
GF	Carpenter	20.7	22.4	19.4	21.3	18.8	25.8	36.6	34.7	33.1	29.1
OK	Eugene Island SA Blk 330	58.9	67.6	59.1	48.1	47.4	50.3	46.6	33.2	31.4	29.0
OK	Reydon	50.1	56.4	40.8	39.0	35.8	29.1	28.1	28.6	31.4	28.8
GF	Cheyenne West	18.5	20.7	18.0	26.3	35.6	32.0	36.3	38.5	34.7	28.1
AK	Garden Banks Blk 236	- -	- -	- -	- -	- -	6.9	28.6	35.7	28.3	26.6
TX	Kuparuk River	6.1	9.5	18.5	24.5	35.9	32.0	24.2	25.3	27.2	26.2
AR	Sugg Ranch	- -	- -	- -	0.0	0.3	5.7	10.2	12.5	15.3	24.5
GF	Cecil	9.0	8.2	10.2	13.1	16.9	15.3	17.9	19.5	18.4	23.3
AL	Mississippi Canyon Blk 194	40.8	32.1	30.6	34.2	35.0	21.1	8.8	0.0	12.3	20.8
TX	Cedar Cove Coal Degas	- -	0.1	0.5	0.8	0.7	0.8	0.9	4.7	15.6	20.4
TX	Opelika	19.8	27.9	30.1	32.8	42.2	33.2	29.0	26.9	22.3	20.3
WY	Willow Springs	8.0	7.3	8.2	4.7	5.6	8.9	11.1	12.9	14.6	18.8
VA	Big Piney	0.2	0.4	0.1	0.1	0.1	2.7	3.3	3.1	15.0	17.7
AL	Nora	2.8	3.1	3.8	4.3	7.5	9.3	8.3	8.0	8.3	15.8
NM	Oak Grove Coal Degas	0.8	0.7	0.7	1.2	3.4	5.4	8.0	10.9	14.2	15.6
WY	Blanco South	18.0	18.4	18.7	7.9	9.4	14.7	15.4	14.5	12.2	15.4
TX	Echo Springs	11.7	17.2	18.3	14.3	15.7	14.2	14.3	15.0	14.2	14.3
AK	Sonora	4.7	5.3	5.9	2.6	3.2	8.0	7.2	14.3	17.5	14.2
TX	Endicott	- -	- -	- -	0.2	2.6	6.8	8.4	8.4	11.5	12.7
WY	Keystone	16.0	24.5	12.7	10.7	6.9	9.3	12.3	10.6	8.9	10.9
LA	Hogsback	5.0	5.9	3.1	6.4	3.2	6.6	7.5	7.7	8.5	10.6
TX	Lake Pagie	8.7	7.5	5.7	8.1	7.1	8.6	9.4	9.9	9.6	10.4
GF	Hawkins	12.5	11.8	11.1	12.7	12.1	14.7	13.8	11.4	19.8	7.8
TX	Mississippi Canyon Blk 397	- -	- -	- -	- -	- -	- -	- -	- -	- -	6.9
TX	Whelan	6.5	6.1	4.6	4.6	9.3	9.2	7.5	6.0	5.8	6.5
TX	Pegasus	4.3	5.3	5.9	10.0	8.1	3.0	9.1	4.0	4.4	6.1
AL	Anahuac	8.5	4.7	6.3	5.5	4.6	4.3	2.0	1.6	8.5	5.4
MT	Robinsons Bend Coal Degas	- -	- -	0.0	0.3	0.1	0.2	0.1	0.1	1.1	4.4
GF	Bowdoin	0.8	0.7	0.9	0.9	0.7	1.7	1.9	2.0	4.0	3.2
Top 100 Volume Subtotal		**3,441.6**	**3,761.9**	**3,797.0**	**3,573.5**	**3,831.7**	**4,201.0**	**4,454.3**	**4,603.7**	**5,045.5**	**5,444.4**
Top 100 Percentage of U.S. Total		**20.6%**	**20.6%**	**21.8%**	**21.0%**	**21.8%**	**22.9%**	**24.3%**	**24.4%**	**26.9%**	**28.8%**

[a]Wet after lease separation.

- - = Not Applicable.

Note: Fields are grouped in "proved reserves rank groups" and then listed within that group in descending order by National 1992 annual production rank. The U.S. total production estimates in this table for 1983 through 1992 are from the official Energy Information Administration production data for natural gas for 1983 through 1992 contained in the *Natural Gas Annual*, DOE/EIA-0131. They differ from the U.S. total data reported in this publication. Column totals may not add due to independent rounding.

Source: Energy Information Administration, Office of Oil and Gas.

Appendix C

Conversion to the Metric System

Public Law 100-418, the Omnibus Trade and Competitiveness Act of 1988, states: "It is the declared policy of the United States—

> (1) to designate the metric system of measurement as the preferred system of weights and measures for United States trade and commerce. . . .
>
> (2) to require that each Federal agency, by the end of Fiscal Year 1992, use the metric system of measurement in its procurements, grants, and other business-related activities."{23}

It is in keeping with the spirit of this law that Table C1 has been created. The petroleum industry in the United States is slowly moving in the direction of this law; however, the data collected by EIA in these surveys were in the units that are still common to the U.S. petroleum industry, namely barrels and cubic feet. Standard metric conversion factors for barrels and cubic feet were used to convert National level volumes in Table 1 to the metric equivalents for Table C1. Barrels were multiplied by 0.1589873 to convert to cubic meters and cubic feet were multiplied by 0.02831685 to convert to cubic meters.

Table C1. Total U.S. Proved Reserves of Crude Oil, Dry Natural Gas, and Natural Gas Liquids, in Metric Units, 1983 through 1993

Year	Adjustments[a] (1)	Revision Increases (2)	Revision Decreases (3)	Revisions[b] and Adjustments (4)	Extensions (5)	New Field Discoveries (6)	New Reservoir Discoveries in Old Fields (7)	Total[c] Discoveries (8)	Production (9)	Proved[d] Reserves 12/31 (10)	Change from Prior Year (11)
					Crude Oil (million cubic meters)						
1983	73.3	446.8	206.5	313.6	100.0	16.7	30.2	146.9	480.1	4,409.5	-19.6
1984	25.3	583.8	195.1	414.0	118.3	38.5	25.1	181.9	482.8	4,522.6	+113.1
1985	68.1	482.8	228.8	322.1	118.0	13.4	26.9	158.3	485.2	4,517.8	-4.8
1986	9.0	433.1	297.1	145.0	64.4	7.6	12.9	84.9	472.7	4,275.0	-242.8
1987	37.2	586.2	218.0	405.4	76.9	15.3	17.6	109.8	456.8	4,333.4	+58.4
1988	57.8	426.7	194.1	290.4	56.4	11.3	20.2	87.9	446.9	4,264.8	-68.6
1989	33.9	428.9	217.0	245.8	81.7	17.8	14.3	113.8	411.1	4,213.3	-51.5
1990	13.7	394.8	159.0	249.5	72.5	15.6	21.5	109.6	398.3	4,174.1	-39.2
1991	25.9	333.4	297.9	61.4	58.0	15.4	14.6	88.0	399.4	3,924.1	-250.0
1992	R46.2	286.8	170.0	R163.0	62.2	1.3	13.5	77.0	388.9	3,775.2	-148.9
1993	43.1	319.7	241.0	121.8	56.6	50.7	17.5	124.8	371.9	3,649.9	-125.3
					Dry Natural Gas (billion cubic meters)						
1983	87.50	498.43	498.86	87.07	195.64	44.57	83.96	324.17	447.07	5,670.36	-35.83
1984	-63.45	505.20	416.60	25.15	235.00	71.81	76.06	382.87	486.85	5,591.53	-78.83
1985	-48.37	531.65	461.68	21.60	203.00	28.29	83.82	315.11	452.64	5,475.60	-115.93
1986	37.38	602.27	501.12	138.53	171.74	31.12	50.15	253.01	442.03	5,425.11	-50.49
1987	35.91	496.31	402.98	129.24	129.89	30.84	42.45	203.18	456.30	5,301.23	-123.88
1988	62.09	661.68	[e]1,088.13	-364.36	192.64	46.38	54.06	293.08	472.04	[e]4,757.91	-543.32
1989	85.33	755.30	669.50	171.13	179.50	41.06	63.51	284.07	480.91	4,732.20	-25.71
1990	44.08	537.48	380.66	200.90	225.18	56.75	68.30	350.23	487.98	4,795.35	+63.15
1991	83.82	563.22	438.17	208.87	144.13	24.01	45.42	213.56	487.11	4,730.67	-64.68
1992	63.29	511.26	338.73	235.82	132.38	18.38	48.82	199.58	493.36	4,672.71	-57.96
1993	27.51	498.29	346.82	178.98	172.82	25.46	52.84	251.12	503.73	4,599.08	-73.63
					Natural Gas Liquids (million cubic meters)						
1983	135.2	134.7	124.2	145.7	51.0	11.1	15.7	77.8	115.3	1,256.2	+108.2
1984	-19.6	137.7	115.1	3.0	55.3	8.7	15.3	79.3	123.4	1,215.1	-41.1
1985	67.8	144.0	118.3	93.5	53.6	7.0	13.5	74.1	119.7	1,263.0	+47.9
1986	58.3	163.8	128.3	93.8	41.8	5.4	11.4	58.6	117.3	1,298.1	+35.1
1987	36.8	134.7	104.3	67.2	33.9	6.2	8.7	48.8	118.8	1,295.3	-2.8
1988	1.8	185.7	113.7	73.8	42.6	6.5	11.4	60.5	119.9	1,309.7	+14.4
1989	-44.0	181.7	162.2	-24.5	41.2	13.2	11.8	66.2	116.2	1,235.2	-74.5
1990	-13.2	131.5	96.3	22.0	47.5	6.2	11.6	65.3	116.4	1,206.1	-29.1
1991	37.1	131.2	110.5	57.8	30.0	4.0	8.7	42.7	119.9	1,186.7	-19.4
1992	R35.7	128.1	86.6	R77.2	30.2	3.2	10.2	43.6	122.9	1,184.6	-2.1
1993	16.2	121.5	101.8	35.9	39.0	3.8	10.2	53.0	125.3	1,148.2	-36.4

[a]Includes operator reported corrections for year 1981. After 1981, operators included corrections with revisions. Adjustments included any necessary changes to maintain an exact line balance for each year.

[b]Revisions and adjustments = Col. 1 + Col. 2 - Col. 3.

[c]Total discoveries = Col. 5 + Col. 6 + Col. 7.

[d]Proved reserves = Col. 10 from prior year + Col. 4 + Col. 8 - Col. 9.

[e]An unusually large revision decrease to North Slope dry natural gas reserves was made in 1988. It recognizes some 696.59 billion cubic meters of downward revisions reported during prior years by operators because of economic and market conditions. EIA in previous years carried these reserves in the proved category.

R=Revised data.

Notes: Old means discovered in a prior year. New means discovered during the report year. The production estimates in this table are based on data reported on Form EIA-23, “Annual Survey of Domestic Oil and Gas Reserves” and Form EIA-64A, “Annual Report of the Origin of Natural Gas Liquids Production.” They may differ from the official Energy Information Administration production data for crude oil, natural gas, and natural gas liquids for 1993 contained in the publications *Petroleum Supply Annual 1993,* DOE/EIA-0340(93) and *Natural Gas Annual 1993*, DOE/EIA-0131(93). The following conversion factors were used to convert data in Columns 2, 3, 5, 6, 7, 9, and 10: barrels = 0.1589873 per cublic meter, cubic feet = 0.02831685 per cublc meter. Number of decimal digits varies in order to accurately reproduce corresponding equivalents shown on Table 1.

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, 1983 through 1992 annual reports, DOE/EIA-0216.{8-17}

Historical Reserves Statistics

These are selected historical data presented at the State and National level. All historical statistics included have previously been published in the annual reports of 1977 through 1992 of the EIA publication *U.S Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE EIA-0216,{8-17,79-84}

Liquid volumes are in million barrels of 42 U.S. gallons. Gas volumes are in billion cubic feet (Bcf), at 14.73 psia and 60° Fahrenheit. NA appears in this appendix wherever data are not available or are withheld to avoid disclosure of data which may be proprietary. An asterisk (*) marks those estimates associated with sampling errors (95 percent confidence interval) greater than 20 percent of the value estimated.

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Alabama				
1977	85	0	530	NA
1978	*74	0	514	NA
1979	45	NA	652	213
1980	54	NA	636	226
1981	55	NA	648	192
1982	54	NA	[a]648	193
1983	51	NA	[a]785	216
1984	*68	NA	[a]961	200
1985	69	NA	[a]821	182
1986	55	20	[b]951	177
1987	55	20	[b]842	166
1988	54	20	[b]809	166
1989	43	20	[b]819	168
1990	44	<1	[c]4,125	170
1991	43	<1	[c]5,414	145
1992	41	0	[c]5,802	171
1993	41	0	[c]5,140	158

[a]Onshore only; offshore included in Louisiana.
[b]Onshore only; offshore included in Federal Offshore - Gulf of Mexico (Louisiana).
[c]Includes State Offshore: 2,519 Bcf in 1990; 3,191 Bcf in 1991; 3,233 Bcf in 1992; 3,364 Bcf in 1993.

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Alaska				
1977	8,413	846	32,243	NA
1978	9,384	398	32,045	NA
1979	8,875	398	32,259	23
1980	8,751	0	33,382	11
1981	8,283	0	33,037	10
1982	7,406	60	34,990	9
1983	7,307	576	34,283	8
1984	7,563	369	34,476	19
1985	7,056	379	33,847	383
1986	6,875	902	32,664	381
1987	7,378	566	33,225	418
1988	6,959	431	9,078	401
1989	6,674	750	8,939	380
1990	6,524	969	9,300	340
1991	6,083	1,456	9,553	360
1992	6,022	1,331	9,638	347
1993	5,775	1,161	9,907	321

Note: See 1988 Chapter 4 discussion “Alaskan North Slope Natural Gas Reserves.”

Arkansas

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	116	17	1,660	NA
1978	111	8	1,681	NA
1979	107	8	1,703	17
1980	107	11	1,774	16
1981	113	11	1,801	16
1982	107	4	1,958	15
1983	120	4	2,069	11
1984	114	6	2,227	12
1985	97	11	2,019	11
1986	88	9	1,992	16
1987	82	0	1,997	16
1988	77	<1	1,986	13
1989	66	1	1,772	9
1990	60	1	1,731	9
1991	*70	0	1,669	5
1992	58	<1	1,750	4
1993	65	0	1552	4

California - Coastal Region Onshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	679	NA	334	NA
1978	602	NA	350	NA
1979	578	NA	365	22
1980	652	NA	299	23
1981	621	NA	306	14
1982	580	NA	362	16
1983	559	NA	381	17
1984	628	140	265	15
1985	631	152	256	16
1986	592	164	255	15
1987	625	298	238	13
1988	576	299	215	13
1989	731	361	224	11
1990	588	310	217	12
1991	554	327	216	12
1992	522	317	203	10
1993	528	313	189	12

California - Total

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	5,005	1,047	4,737	NA
1978	4,974	968	4,947	NA
1979	5,265	960	5,022	111
1980	5,470	891	5,414	120
1981	5,441	660	5,617	82
1982	5,405	616	5,552	154
1983	5,348	576	5,781	151
1984	5,707	674	5,554	141
1985	[d]4,810	590	[d]4,325	[d]146
1986	[d]4,734	[d]616	[d]3,928	[d]134
1987	[d]4,709	[d]1,493	[d]3,740	[d]130
1988	[d]4,879	[d]1,440	[d]3,519	[d]123
1989	[d]4,816	[d]1,608	[d]3,374	[d]113
1990	[d]4,658	[d]1,425	[d]3,185	[d]105
1991	[d]4,217	[d]1,471	[d]3,004	[d]92
1992	[d]3,893	[d]1,299	[d]2,778	[d]99
1993	[d]3,764	[d]965	[d]2,682	[d]104

[d]Excludes Federal offshore; now included in Federal Offshore-Pacific (California).

California - Los Angeles Basin Onshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	910	NA	255	NA
1978	493	NA	178	NA
1979	513	NA	163	10
1980	454	NA	193	15
1981	412	NA	154	6
1982	370	NA	96	6
1983	343	NA	107	6
1984	373	126	156	5
1985	420	86	181	6
1986	330	66	142	8
1987	361	105	148	8
1988	391	106	151	7
1989	342	32	137	4
1990	316	3	106	5
1991	272	4	115	4
1992	236	4	97	5
1993	238	4	102	6

California - San Joaquin Basin Onshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	2,965	NA	3,784	NA
1978	3,099	NA	3,960	NA
1979	3,294	NA	3,941	77
1980	3,360	NA	4,344	81
1981	3,225	NA	4,163	57
1982	3,081	NA	3,901	124
1983	3,032	NA	3,819	117
1984	3,197	384	3,685	105
1985	3,258	350	3,574	120
1986	3,270	368	3,277	109
1987	3,208	1,070	3,102	107
1988	3,439	1,029	2,912	101
1989	3,301	1,210	2,782	95
1990	3,334	1,109	2,670	86
1991	3,126	1,139	2,614	75
1992	2,898	977	2,415	83
1993	2,772	648	2,327	85

California - State Offshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	181	NA	114	NA
1978	519	NA	213	NA
1979	632	NA	231	2
1980	604	NA	164	1
1981	NA	NA	NA	NA
1982	NA	NA	NA	NA
1983	NA	NA	NA	NA
1984	NA	25	NA	NA
1985	501	0	314	4
1986	542	18	254	2
1987	515	18	252	2
1988	473	6	241	2
1989	442	5	231	3
1990	420	3	192	2
1991	265	1	59	1
1992	237	1	63	1
1993	226	0	64	1

California-State and Federal Offshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	451	NA	364	NA
1978	780	NA	457	NA
1979	880	NA	553	2
1980	1,004	NA	578	1
1981	1,183	NA	994	5
1982	1,374	NA	1,193	8
1983	1,414	NA	1,474	11
1984	1,509	25	1,448	16
1985	1,492	2	1,433	16
1986	1,516	19	1,579	17
1987	1,552	20	1,704	19
1988	1,497	6	1,793	23
1989	1,429	5	1,727	28
1990	1,382	3	1,646	20
1991	1,050	1	1,221	19
1992	971	1	1,181	21
1993	899	0	1,163	26

California - Federal Offshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	270	NA	250	NA
1978	261	NA	246	NA
1979	248	NA	322	0
1980	400	NA	414	0
1981	NA	NA	NA	NA
1982	NA	NA	NA	NA
1983	NA	NA	NA	NA
1984	NA	0	NA	NA
1985	991	2	1,119	12
1986	974	1	1,325	15
1987	1,037	2	1,452	17
1988	1,024	0	1,552	21
1989	987	0	1,496	25
1990	962	0	1,454	18
1991	785	0	1,162	18
1992	734	<1	1,118	20
1993	673	0	1,099	25

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Colorado				
1977	230	73	2,512	NA
1978	194	75	2,765	NA
1979	159	43	2,608	177
1980	*183	46	2,922	194
1981	147	47	2,961	204
1982	169	100	3,314	186
1983	186	113	3,148	183
1984	198	119	*2,943	155
1985	198	119	2,881	173
1986	207	95	3,027	148
1987	272	67	2,942	166
1988	257	67	3,535	181
1989	359	8	4,274	209
1990	305	8	4,555	169
1991	329	33	5,767	197
1992	304	34	6,198	226
1993	284	22	6,722	214

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Illinois				
1977	*150	1	NA	NA
1978	*158	1	NA	NA
1979	*136	1	NA	NA
1980	113	2	NA	NA
1981	129	1	NA	NA
1982	150	1	NA	NA
1983	135	1	NA	NA
1984	153	1	NA	NA
1985	136	1	NA	NA
1986	135	1	NA	NA
1987	153	5	NA	NA
1988	143	<1	NA	NA
1989	123	<1	NA	NA
1990	131	0	NA	NA
1991	128	52	NA	NA
1992	138	0	NA	NA
1993	116	0	NA	NA

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Florida				
1977	213	1	151	NA
1978	168	1	119	NA
1979	128	1	77	21
1980	134	1	84	27
1981	109	1	69	NA
1982	97	1	64	17
1983	78	4	49	11
1984	82	2	65	17
1985	77	2	55	17
1986	67	2	49	14
1987	61	0	49	9
1988	59	0	51	16
1989	50	0	46	10
1990	42	0	45	8
1991	37	0	38	7
1992	36	0	47	8
1993	40	0	50	9

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Indiana				
1977	*20	0	NA	NA
1978	*29	0	NA	NA
1979	*40	0	NA	NA
1980	23	0	NA	NA
1981	23	0	NA	NA
1982	28	1	NA	NA
1983	34	3	NA	NA
1984	*33	2	NA	NA
1985	*35	2	NA	NA
1986	*32	2	NA	NA
1987	23	2	NA	NA
1988	*22	0	NA	NA
1989	*16	0	NA	NA
1990	12	0	NA	NA
1991	*16	0	NA	NA
1992	17	0	NA	NA
1993	15	0	NA	NA

Kansas

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	*349	3	11,457	NA
1978	303	3	10,992	NA
1979	*377	3	10,243	402
1980	310	2	9,508	389
1981	371	2	9,860	409
1982	378	13	9,724	302
1983	344	13	9,553	443
1984	377	2	9,387	424
1985	423	<1	9,337	373
1986	312	<1	10,509	440
1987	357	<1	10,494	462
1988	327	<1	10,104	345
1989	338	3	10,091	329
1990	321	<1	9,614	313
1991	300	<1	9,358	428
1992	310	0	9,681	444
1993	271	0	9,348	380

Louisiana - Total

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	3,600	139	57,010	NA
1978	3,448	143	55,725	NA
1979	2,780	76	50,042	1,424
1980	2,751	62	47,325	1,346
1981	2,985	50	47,377	1,327
1982	2,728	49	[e]44,916	1,295
1983	2,707	45	[e]42,561	1,332
1984	2,661	55	[e]41,399	1,188
1985	[f]883	35	[f]14,038	[f]546
1986	[f]826	[f]47	[f]12,930	[f]524
1987	[f]807	[f]56	[f]12,430	[f]525
1988	[f]800	[f]69	[f]12,224	[f]517
1989	[f]745	[f]63	[f]12,516	[f]522
1990	[f]705	[f]22	[f]11,728	[f]538
1991	[f]679	[f]44	[f]10,912	[f]526
1992	[f]668	[f]35	[f]9,780	[f]495
1993	[f]639	[f]338	[f]9174	[f]421

[e]Includes State and Federal offshore Alabama.
[f]Excludes Federal offshore; now included in Federal Offshore-Gulf of Mexico (Louisiana).

Kentucky

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	30	0	451	NA
1978	*40	0	545	NA
1979	25	0	468	26
1980	*35	12	508	25
1981	29	13	530	25
1982	*36	13	551	35
1983	35	12	554	31
1984	*41	0	613	24
1985	*42	0	766	27
1986	*31	0	841	29
1987	25	0	909	23
1988	*34	0	923	24
1989	33	0	992	16
1990	33	0	1,016	25
1991	*31	0	1,155	24
1992	34	0	1,084	32
1993	26	0	1.003	26

Louisiana - North

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	244	78	3,135	NA
1978	255	78	3,203	NA
1979	216	NA	2,798	96
1980	248	NA	3,076	95
1981	* 317	NA	3,270	99
1982	* 240	NA	2,912	85
1983	223	NA	2,939	74
1984	165	9	2,494	57
1985	196	5	2,587	65
1986	160	7	2,515	57
1987	175	3	2,306	50
1988	154	23	2,398	56
1989	123	22	2,652	60
1990	120	<1	2,588	58
1991	127	<1	2,384	59
1992	125	<1	2,311	60
1993	108	0	2,325	57

Louisiana - South Onshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	1,382	46	18,580	NA
1978	1,242	38	17,755	NA
1979	682	NA	13,994	676
1980	682	NA	13,026	540
1981	642	NA	12,645	544
1982	611	NA	11,801	501
1983	569	NA	11,142	527
1984	585	20	10,331	454
1985	565	16	9,808	442
1986	547	30	9,103	428
1987	505	22	8,693	429
1988	511	35	8,654	421
1989	479	30	8,645	411
1990	435	11	8,171	431
1991	408	33	7,504	417
1992	417	26	6,693	380
1993	382	329	5,932	334

Michigan

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	*233	0	*1,386	NA
1978	*220	9	*1,422	NA
1979	159	23	1,204	112
1980	*205	14	*1,406	112
1981	*240	17	1,118	102
1982	184	34	1,084	97
1983	209	48	1,219	105
1984	180	46	1,112	84
1985	191	37	985	67
1986	146	34	1,139	88
1987	151	27	1,451	111
1988	132	27	1,323	99
1989	128	8	1,342	97
1990	124	3	1,243	81
1991	119	0	1,334	72
1992	102	0	1,223	68
1993	90	0	1,160	57

Louisiana - State Offshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	1,974	15	35,295	NA
1978	1,951	27	34,767	NA
1979	1,882	14	33,250	652
1980	1,821	13	31,223	711
1981	2,026	16	31,462	684
1982	1,877	21	[e]30,203	709
1983	1,915	15	[e]28,480	731
1984	1,911	27	[e]28,574	677
1985	[f]122	2	[f]1,643	[f]39
1986	[f]119	[f]10	[f]1,312	[f]39
1987	[f]127	[f]22	[f]1,431	[f]46
1988	[f]135	[f]11	[f]1,172	[f]40
1989	[f]143	[f]11	[f]1,219	[f]51
1990	[f]150	[f]11	[f]969	[f]49
1991	[f]144	[f]11	[f]1,024	[f]50
1992	[f]126	[f]9	[f]776	[f]55
1993	[f]149	[f]9	[f]917	[f]30

[e]Includes State and Federal offshore Alabama.
[f]Excludes Federal offshore; now included in Federal Offshore-Gulf of Mexico (Louisiana).

Mississippi

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	241	9	1,437	NA
1978	*250	27	1,635	NA
1979	238	24	1,504	16
1980	202	36	1,769	20
1981	209	93	2,035	18
1982	223	85	1,796	18
1983	205	77	1,596	19
1984	201	50	1,491	15
1985	184	53	1,360	12
1986	199	16	1,300	11
1987	202	12	1,220	11
1988	221	10	1,143	12
1989	218	6	1,104	12
1990	227	8	1,126	11
1991	194	8	1,057	10
1992	165	7	869	9
1993	133	44	797	11

Montana

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	175	27	*887	NA
1978	158	27	926	NA
1979	152	38	825	10
1980	179	13	*1,287	16
1981	186	11	*1,321	11
1982	216	6	847	18
1983	234	8	896	19
1984	224	4	802	18
1985	232	3	857	21
1986	248	27	803	16
1987	246	<1	780	16
1988	241	0	819	11
1989	225	<1	867	16
1990	221	0	899	15
1991	201	0	831	14
1992	193	0	859	12
1993	171	0	673	8

Nebraska

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	22	0	NA	NA
1978	30	1	NA	NA
1979	25	0	NA	NA
1980	*46	0	NA	NA
1981	41	0	NA	NA
1982	*32	0	NA	NA
1983	44	0	NA	NA
1984	*46	0	NA	NA
1985	42	0	NA	NA
1986	*45	7	NA	NA
1987	33	0	NA	NA
1988	42	0	NA	NA
1989	32	0	NA	NA
1990	26	0	NA	NA
1991	26	0	NA	NA
1992	26	0	NA	NA
1993	20	0	NA	NA

New Mexico - Total

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	605	97	12,000	NA
1978	579	90	12,688	NA
1979	563	77	13,724	530
1980	547	58	13,287	541
1981	555	93	13,870	560
1982	563	76	12,418	531
1983	576	75	11,676	551
1984	660	87	11,364	511
1985	688	99	10,900	445
1986	644	225	11,808	577
1987	654	235	11,620	771
1988	661	241	17,166	1,023
1989	665	256	15,434	933
1990	687	256	17,260	990
1991	721	275	18,539	908
1992	757	293	18,998	1,066
1993	707	211	18,619	996

New Mexico - East

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	576	95	3,848	NA
1978	554	88	3,889	NA
1979	542	77	4,031	209
1980	518	58	3,530	209
1981	522	93	3,598	214
1982	537	76	3,432	209
1983	542	75	3,230	232
1984	625	87	3,197	221
1985	643	98	3,034	209
1986	593	225	2,694	217
1987	608	230	2,881	192
1988	621	235	2,945	208
1989	619	252	3,075	196
1990	633	253	3,256	222
1991	694	275	3,206	205
1992	731	293	3,130	223
1993	688	211	3,034	233

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
New Mexico - West				
1977	*29	2	8,152	NA
1978	*25	2	8,799	NA
1979	21	0	9,693	321
1980	*29	0	9,757	332
1981	*33	0	10,272	346
1982	26	0	8,986	322
1983	34	0	8,446	319
1984	35	0	8,167	290
1985	45	1	7,866	236
1986	51	0	9,114	360
1987	46	5	8,739	579
1988	40	6	14,221	815
1989	46	4	12,359	737
1990	54	3	14,004	768
1991	27	0	15,333	703
1992	26	0	15,868	843
1993	19	0	15,585	763
New York				
1977	NA	NA	165	NA
1978	NA	NA	193	NA
1979	NA	NA	211	0
1980	NA	NA	208	0
1981	NA	NA	*264	0
1982	NA	NA	229	NA
1983	NA	NA	295	NA
1984	NA	NA	389	NA
1985	NA	NA	*369	NA
1986	NA	NA	*457	NA
1987	NA	NA	410	NA
1988	NA	NA	351	NA
1989	NA	NA	368	NA
1990	NA	NA	354	NA
1991	NA	NA	331	NA
1992	NA	NA	329	NA
1993	NA	NA	*264	NA

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
North Dakota				
1977	155	10	361	NA
1978	162	4	374	NA
1979	211	6	439	47
1980	214	6	537	61
1981	223	8	581	68
1982	237	8	629	71
1983	258	53	600	69
1984	260	54	566	73
1985	255	34	569	74
1986	218	35	541	69
1987	215	33	508	67
1988	216	39	541	52
1989	246	31	561	59
1990	285	0	586	60
1991	232	4	472	56
1992	237	3	496	64
1993	226	7	525	55
Ohio				
1977	*74	0	495	NA
1978	69	0	684	NA
1979	*82	0	*1,479	0
1980	*116	0	*1,699	0
1981	*112	0	965	0
1982	111	0	1,141	NA
1983	130	0	2,030	NA
1984	*116	0	1,541	NA
1985	79	0	1,331	NA
1986	72	0	1,420	NA
1987	66	0	1,069	NA
1988	64	0	1,229	NA
1989	56	0	1,275	NA
1990	65	0	1,214	NA
1991	66	0	1,181	NA
1992	58	0	1,161	NA
1993	54	0	1,104	NA

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Oklahoma				
1977	1,109	69	13,889	NA
1978	979	33	14,417	NA
1979	1,014	35	13,816	583
1980	930	27	13,138	604
1981	950	43	14,699	631
1982	971	25	16,207	745
1983	931	27	16,211	829
1984	940	40	16,126	769
1985	935	37	16,040	826
1986	874	35	16,685	857
1987	788	56	16,711	781
1988	796	79	16,495	765
1989	789	63	15,916	654
1990	734	37	16,151	657
1991	700	54	14,725	628
1992	698	54	13,926	629
1993	680	40	13,289	643

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Texas - Total				
1977	9,751	637	56,422	NA
1978	8,911	533	55,583	NA
1979	8,284	471	53,021	2,482
1980	8,206	384	50,287	2,452
1981	8,093	459	50,469	2,646
1982	7,616	377	49,757	2,771
1983	7,539	421	50,052	3,038
1984	7,557	735	49,883	3,048
1985	[g]7,782	609	[g]41,775	[g]2,981
1986	[g]7,152	1,270	[g]40,574	[g]2,964
1987	[g]7,112	1,028	[g]38,711	[g]2,822
1988	[g]7,043	1,099	[g]38,167	[g]2,617
1989	[g]6,966	805	[g]38,381	[g]2,563
1990	[g]7,106	618	[g]38,192	[g]2,575
1991	[g]6,797	756	[g]36,174	[g]2,493
1992	[g]6,441	[g]612	[g]35,093	[g]2,402
1993	[g]6,171	[g]581	[g]34,718	[g]2,469

[g]Excludes Federal Offshore; now included in Federal Offshore-Gulf of Mexico (Texas).

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Pennsylvania				
1977	*57	0	769	NA
1978	27	0	899	NA
1979	33	0	*1,515	1
1980	35	0	951	0
1981	32	0	*1,264	0
1982	37	0	1,429	NA
1983	41	0	1,882	NA
1984	*40	0	1,575	NA
1985	*38	0	*1,617	NA
1986	*26	0	*1,560	1
1987	26	0	1,647	NA
1988	*27	0	2,072	NA
1989	26	0	1,642	NA
1990	22	0	1,720	NA
1991	15	0	1,629	NA
1992	16	0	1,528	NA
1993	14	0	1,717	NA

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Texas - RRC District 1				
1977	*174	0	1,319	NA
1978	111	2	986	NA
1979	110	0	919	23
1980	*150	0	829	24
1981	127	5	*1,022	26
1982	129	6	892	29
1983	165	6	1,087	43
1984	173	4	838	39
1985	177	8	967	40
1986	144	1	913	35
1987	143	1	812	27
1988	136	1	1,173	30
1989	139	1	1,267	25
1990	252	0	1,048	26
1991	227	0	1,030	28
1992	185	0	933	27
1993	133	0	698	26

Texas - RRC District 2 Onshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	395	80	3,162	NA
1978	334	1	2,976	NA
1979	292	1	2,974	64
1980	252	1	2,502	64
1981	229	1	2,629	88
1982	206	0	2,493	75
1983	192	0	2,534	99
1984	192	<1	2,512	103
1985	168	0	2,358	100
1986	148	<1	2,180	89
1987	137	0	2,273	102
1988	117	0	2,037	92
1989	107	0	1,770	72
1990	91	0	1,737	80
1991	90	0	1,393	75
1992	86	0	1,389	80
1993	77	0	1,321	86

Texas - RRC District 3 Onshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	937	33	7,518	NA
1978	794	22	7,186	NA
1979	630	32	6,315	231
1980	581	11	5,531	216
1981	552	11	5,292	230
1982	509	22	4,756	265
1983	517	27	4,680	285
1984	522	25	4,708	270
1985	471	6	4,180	260
1986	420	3	3,753	237
1987	386	4	3,632	241
1988	360	16	3,422	208
1989	307	11	3,233	213
1990	275	13	2,894	181
1991	300	28	2,885	208
1992	304	27	2,684	211
1993	327	31	2,972	253

Texas - RRC District 4 Onshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	145	7	9,621	NA
1978	123	3	9,031	NA
1979	113	4	8,326	248
1980	96	3	8,130	252
1981	97	6	8,004	260
1982	87	7	8,410	289
1983	96	3	8,316	292
1984	99	3	8,525	295
1985	98	2	8,250	269
1986	87	2	8,274	281
1987	80	2	7,490	277
1988	65	1	7,029	260
1989	77	<1	7,111	260
1990	67	<1	7,475	279
1991	52	<1	7,048	273
1992	50	<1	6,739	272
1993	59	<1	7,038	278

Texas - RRC District 5

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	68	0	931	NA
1978	*68	0	*1,298	NA
1979	55	1	1,155	34
1980	52	0	1,147	44
1981	49	0	1,250	49
1982	45	0	1,308	53
1983	42	0	1,448	73
1984	36	<1	1,874	74
1985	*59	1	2,058	77
1986	*53	1	2,141	86
1987	54	0	2,119	88
1988	48	0	1,996	81
1989	46	0	1,845	80
1990	47	0	1,875	81
1991	46	0	1,863	71
1992	56	0	1,747	71
1993	52	0	1,867	64

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Texas - RRC District 6				
1977	1,568	12	3,214	NA
1978	1,444	3	3,240	NA
1979	1,177	6	3,258	272
1980	1,115	6	4,230	321
1981	1,040	7	4,177	308
1982	947	6	4,326	278
1983	918	5	4,857	342
1984	889	5	4,703	298
1985	851	4	4,822	293
1986	750	2	4,854	277
1987	733	3	4,682	264
1988	685	5	4,961	263
1989	631	4	5,614	266
1990	605	6	5,753	247
1991	504	7	5,233	243
1992	442	7	5,317	251
1993	406	<1	5,508	248

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Texas - RRC District 7B				
1977	250	NA	699	NA
1978	190	NA	743	NA
1979	208	NA	*751	64
1980	196	NA	*745	85
1981	254	NA	804	102
1982	199	NA	805	105
1983	217	NA	1,027	133
1984	218	62	794	106
1985	239	63	708	104
1986	193	64	684	109
1987	200	46	697	92
1988	205	42	704	98
1989	204	11	459	73
1990	198	8	522	76
1991	184	8	423	82
1992	163	11	455	68
1993	*171	7	477	79

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Texas - RRC District 7C				
1977	191	NA	2,831	NA
1978	202	NA	2,821	NA
1979	206	NA	2,842	182
1980	207	NA	2,378	135
1981	230	NA	2,503	186
1982	229	NA	2,659	199
1983	228	NA	2,568	219
1984	240	24	2,866	233
1985	243	21	2,914	256
1986	213	22	2,721	246
1987	220	25	2,708	243
1988	212	31	2,781	238
1989	247	16	3,180	238
1990	274	8	3,514	256
1991	253	9	3,291	241
1992	255	33	3,239	289
1993	199	15	3,215	273

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Texas - RRC District 8				
1977	2,915	127	11,728	NA
1978	2,795	102	11,093	NA
1979	2,686	88	10,077	505
1980	2,597	86	9,144	498
1981	2,503	105	8,546	537
1982	2,312	75	8,196	588
1983	2,350	99	8,156	681
1984	2,342	363	7,343	691
1985	2,333	325	7,330	665
1986	2,183	592	7,333	717
1987	2,108	399	6,999	640
1988	2,107	412	7,058	547
1989	2,151	366	6,753	554
1990	2,152	282	6,614	558
1991	2,114	328	6,133	477
1992	2,013	260	5,924	444
1993	2,057	262	5,516	439

Texas - RRC District 8A

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	2,626	291	1,630	NA
1978	2,439	330	1,473	NA
1979	2,371	270	1,055	351
1980	2,504	196	1,057	290
1981	2,538	247	1,071	335
1982	2,481	200	1,041	296
1983	2,366	203	966	262
1984	2,413	217	907	282
1985	2,711	147	958	283
1986	2,618	559	845	331
1987	2,735	525	876	307
1988	2,800	569	832	326
1989	2,754	377	1,074	332
1990	2,847	285	1,036	354
1991	2,763	363	1,073	333
1992	2,599	273	1,239	257
1993	2,435	264	1,043	298

Texas - RRC District 9

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	260	28	724	NA
1978	190	27	*908	NA
1979	200	30	*700	79
1980	218	37	649	92
1981	225	34	953	86
1982	219	17	*1,103	119
1983	220	18	932	121
1984	214	25	900	119
1985	285	27	892	111
1986	237	19	868	119
1987	206	21	834	115
1988	202	18	783	106
1989	200	16	703	94
1990	193	12	776	104
1991	162	11	738	101
1992	176	1	670	92
1993	168	2	688	92

Texas - RRC District 10

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	*120	4	7,744	NA
1978	90	0	7,406	NA
1979	97	2	6,784	375
1980	89	2	6,435	369
1981	107	2	6,229	364
1982	112	2	6,210	391
1983	105	6	5,919	413
1984	108	6	5,461	440
1985	*140	5	5,469	433
1986	*104	5	5,276	428
1987	102	2	4,962	417
1988	99	4	4,830	363
1989	97	3	4,767	342
1990	99	3	4,490	328
1991	95	2	4,589	356
1992	89	<1	4,409	336
1993	83	<1	4,040	329

Texas - State and Federal Offshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	102	0	5,301	NA
1978	131	1	6,422	NA
1979	139	0	7,865	54
1980	149	0	7,510	62
1981	142	0	7,989	75
1982	141	0	7,558	84
1983	123	0	7,562	75
1984	111	0	8,452	98
1985	119	0	8,129	90
1986	103	0	8,176	109
1987	96	0	7,846	98
1988	85	0	7,802	94
1989	75	0	7,573	84
1990	77	0	7,758	87
1991	67	0	7,150	84
1992	197	0	7,344	122
1993	196	0	6,996	119

Texas - State Offshore

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	NA	NA	NA	NA
1978	NA	NA	NA	NA
1979	NA	NA	NA	NA
1980	NA	NA	NA	12
1981	NA	NA	NA	13
1982	NA	NA	NA	18
1983	NA	NA	NA	11
1984	NA	NA	NA	10
1985	7	0	869	10
1986	2	0	732	9
1987	8	0	627	9
1988	7	0	561	5
1989	6	0	605	6
1990	6	0	458	5
1991	7	0	475	5
1992	5	0	348	4
1993	4	0	335	4

Virginia

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	NA	NA	NA	NA
1978	NA	NA	NA	NA
1979	NA	NA	NA	NA
1980	NA	NA	NA	NA
1981	NA	NA	118	NA
1982	NA	NA	122	NA
1983	NA	NA	175	NA
1984	NA	NA	216	NA
1985	NA	NA	235	NA
1986	NA	NA	253	NA
1987	NA	NA	248	NA
1988	NA	NA	230	NA
1989	NA	NA	217	NA
1990	NA	NA	138	NA
1991	NA	NA	225	NA
1992	NA	NA	904	NA
1993	NA	NA	1,322	NA

Utah

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	252	6	877	NA
1978	188	7	925	NA
1979	201	NA	948	59
1980	198	NA	1,201	127
1981	190	NA	1,912	277
1982	173	NA	2,161	(h)
1983	187	NA	2,333	(h)
1984	172	8	2,080	(h)
1985	276	13	1,999	(h)
1986	269	14	1,895	(h)
1987	284	22	1,947	(h)
1988	260	21	1,298	(h)
1989	246	50	1,507	(h)
1990	249	44	1,510	(h)
1991	233	66	1,702	(h)
1992	217	65	1,830	(h)
1993	228	54	2,040	(h)

[h]Included with Wyoming.

West Virginia

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	21	0	1,567	NA
1978	*30	0	1,634	NA
1979	*48	0	1,558	74
1980	30	8	*2,422	97
1981	30	8	1,834	85
1982	48	8	2,148	79
1983	49	0	2,194	91
1984	*76	0	2,136	80
1985	40	0	2,058	85
1986	37	0	2,148	87
1987	34	0	2,242	87
1988	33	0	2,306	92
1989	30	0	2,201	100
1990	*31	0	2,207	86
1991	26	0	2,528	103
1992	27	0	2,356	97
1993	24	0	2,439	108

Wyoming

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	851	31	6,305	NA
1978	845	36	7,211	NA
1979	841	40	7,526	285
1980	928	28	9,100	341
1981	840	53	9,307	384
1982	856	58	9,758	[i]681
1983	957	61	10,227	[i]789
1984	954	71	10,482	[i]860
1985	951	18	10,617	[i]949
1986	849	126	9,756	[i]950
1987	854	27	10,023	[i]924
1988	815	35	10,308	[i]1,154
1989	825	46	10,744	[i]896
1990	794	42	9,944	[i]812
1991	757	24	9,941	[i]748
1992	689	18	10,826	[i]660
1993	624	12	10,933	[i]600

[i]Utah and Wyoming are combined.

Miscellaneous

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1977	23	0	102	NA
1978	24	0	109	NA
1979	22	1	*153	2
1980	*38	0	176	3
1981	40	7	191	21
1982	33	0	69	4
1983	30	8	78	5
1984	23	0	75	5
1985	35	0	76	3
1986	33	0	133	2
1987	30	0	65	4
1988	34	0	83	5
1989	39	0	83	5
1990	43	1	*70	3
1991	42	5	75	8
1992	29	0	92	8
1993	34	0	94	8

Note: States included may vary for different report years and hydrocarbon types.

Federal Offshore - Total

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1985	2,862	11	[j]34,492	702
1986	2,715	16	[j]34,223	681
1987	2,639	21	[j]31,931	638
1988	2,629	21	[j]32,264	622
1989	2,747	32	[j]32,651	678
1990	2,805	49	31,433	619
1991	2,620	18	29,448	642
1992	2,569	31	27,767	610
1993	2,745	18	27,143	630

[j]Includes State offshore Alabama.
Note: Data not tabulated for years 1977 through 1984.

Federal Offshore - Gulf of Mexico (Louisiana)

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1985	1,759	11	[f]26,113	610
1986	1,640	14	[f]25,454	566
1987	1,514	19	[f]23,260	532
1988	1,527	21	[f]23,471	512
1989	1,691	32	[f]24,187	575
1990	1,772	49	[k]22,679	[k]519
1991	1,775	18	[k]21,611	[k]545
1992	1,643	31	[k]19,653	[k]472
1993	1,880	18	[k]19,383	[k]490

[f]Includes State and Federal offshore Alabama.
[k]Includes Federal offshore Alabama.
Note: Data not tabulated for years 1977 through 1984.

Federal Offshore - Pacific (California)

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1985	991	NA	1,119	12
1986	974	2	1,325	15
1987	1,037	2	1,452	17
1988	1,024	0	1,552	21
1989	987	0	1,496	25
1990	962	0	1,454	18
1991	785	0	1,162	18
1992	734	0	1,118	20
1993	673	0	1,099	25

Note: Data not tabulated for years 1977 through 1984.

Federal Offshore - Gulf of Mexico (Texas)

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
1985	112	0	7,260	80
1986	101	0	7,444	100
1987	88	0	7,219	89
1988	78	0	7,241	89
1989	69	0	6,968	78
1990	71	0	7,300	82
1991	60	0	6,675	79
1992	192	0	6,996	118
1993	192	0	6,661	115

Note: Data not tabulated for years 1977 through 1984.

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Lower 48 States				
1977	23,367	2,168	175,170	NA
1978	21,971	1,964	175,988	NA
1979	20,935	1,878	168,738	6,592
1980	21,054	1,622	165,639	6,717
1981	21,143	1,594	168,693	7,058
1982	20,452	1,478	166,522	7,212
1983	20,428	1,548	165,964	7,893
1984	20,883	1,956	162,987	7,624
1985	21,360	1,662	159,522	7,561
1986	20,014	2,597	158,922	7,784
1987	19,878	3,084	153,986	7,729
1988	19,866	3,169	158,946	7,837
1989	19,827	2,999	158,177	7,389
1990	19,730	2,514	160,046	7,246
1991	18,599	2,810	157,509	7,106
1992	17,723	2,451	155,377	7,104
1993	17,182	2,292	152,508	6,901

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
U.S. Total				
1977	31,780	3,014	207,413	NA
1978	31,355	2,362	208,033	NA
1979	29,810	2,276	200,997	6,615
1980	29,805	1,622	199,021	6,728
1981	29,426	1,594	201,730	7,068
1982	27,858	1,478	201,512	7,221
1983	27,735	2,124	200,247	7,901
1984	28,446	2,325	197,463	7,643
1985	28,416	2,041	193,369	7,944
1986	26,889	3,499	191,586	8,165
1987	27,256	3,649	187,211	8,147
1988	26,825	3,600	168,024	8,238
1989	26,501	3,749	167,116	7,769
1990	26,254	3,483	169,346	7,586
1991	24,682	4,266	167,062	7,466
1992	23,745	3,782	165,015	7,451
1993	22,957	3,453	162,415	7,222

Table D1. Total U.S. Proved Reserves of Crude Oil, 1976 through 1993
(Million Barrels of 42 U.S. Gallons)

Year	Adjustments[a] (1)	Revision Increases (2)	Revision Decreases (3)	Revisions[b] and Adjustments (4)	Extensions (5)	New Field Discoveries (6)	New Reservoir Discoveries in Old Fields (7)	Total[c] Discoveries (8)	Production (9)	Proved[d] Reserves 12/31 (10)	Change from Prior Year (11)
						U.S. Total					
1976	–	–	–	–	–	–	–	–	–	[e]33,502	–
1977	[f]-40	1,503	1,117	346	496	168	130	794	2,862	31,780	-1,722
1978	366	2,799	1,409	1,756	444	267	116	827	3,008	31,355	-425
1979	337	2,438	2,001	774	424	108	104	636	2,955	29,810	-1,545
1980	219	2,883	994	2,108	572	143	147	862	2,975	29,805	-5
1981	138	2,151	880	1,409	750	254	157	1,161	2,949	29,426	-379
1982	-83	2,245	1,811	351	634	204	193	1,031	2,950	27,858	-1,568
1983	462	2,810	1,299	1,973	629	105	190	924	3,020	27,735	-123
1984	159	3,672	1,227	2,604	744	242	158	1,144	3,037	28,446	+711
1985	429	3,037	1,439	2,027	742	84	169	995	3,052	28,416	-30
1986	57	2,724	1,869	912	405	48	81	534	2,973	26,889	-1,527
1987	233	3,687	1,371	2,549	484	96	111	691	2,873	27,256	+367
1988	364	2,684	1,221	1,827	355	71	127	553	2,811	26,825	-431
1989	213	2,698	1,365	1,546	514	112	90	716	2,586	26,501	-324
1990	86	2,483	1,000	1,569	456	98	135	689	2,505	26,254	-247
1991	163	2,097	1,874	386	365	97	92	554	2,512	24,682	-1,572
1992	290	1,804	1,069	1,025	391	8	85	484	2,446	23,745	-937
1993	271	2,011	1,516	766	356	319	110	785	2,339	22,957	-788
						Lower 48 States					
1976	–	–	–	–	–	–	–	–	–	[e]24,928	–
1977	[f]-40	1,499	1,116	343	496	168	130	794	2,698	23,367	-1,561
1978	-48	1,909	1,400	461	444	142	116	702	2,559	21,971	-1,396
1979	342	2,404	1,975	771	424	108	104	636	2,443	20,935	-1,036
1980	210	2,505	981	1,734	479	143	147	769	2,384	21,054	+119
1981	276	1,887	878	1,285	750	254	157	1,161	2,357	21,143	+89
1982	-82	2,146	1,462	602	633	204	193	1,030	2,323	20,452	-691
1983	462	2,247	1,298	1,411	625	105	190	920	2,355	20,428	-24
1984	160	2,801	1,214	1,747	742	207	158	1,107	2,399	20,883	+455
1985	361	2,864	1,197	2,028	581	84	169	834	2,385	21,360	+477
1986	70	2,001	1,642	429	399	48	81	528	2,303	20,014	-1,346
1987	233	2,566	1,213	1,586	294	38	101	433	2,155	19,878	-136
1988	359	2,399	1,218	1,540	340	43	127	510	2,062	19,866	-12
1989	214	2,438	1,325	1,327	342	108	87	537	1,903	19,827	-39
1990	151	1,997	996	1,152	371	98	135	604	1,853	19,730	-97
1991	164	1,898	1,848	214	327	97	87	511	1,856	18,599	-1,131
1992	297	1,343	1,066	574	279	8	84	371	1,821	17,723	-876
1993	250	1,712	1,514	448	343	319	109	771	1,760	17,182	-541

[a]Includes operator reported corrections for the years 1978 through 1981. After 1981 operators included corrections with revisions.

[b]Revisions and adjustments = Col. 1 + Col. 2 - Col. 3.

[c]Total discoveries = Col. 5 + Col. 6 + Col. 7.

[d]Proved reserves = Col. 10 from prior year + Col. 4 + Col. 8 - Col. 9.

[e]Based on following year data only.

[f]Consists only of operator reported corrections and no other adjustments.

– = Not applicable.

Notes: Old means discovered in a prior year. New means discovered during the report year. The production estimates in this table are based on data reported on Form EIA-23, “Annual Survey of Domestic Oil and Gas Reserves,”. They may differ from the official Energy Information Administration production data for crude oil for 1993 contained in the *Petroleum Supply Annual 1993 , DOE/EIA-0340(93).*

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1977 through 1992 annual reports, DOE/EIA-0216.{8-17,79-84}

Table D2. Total U.S. Proved Reserves of Dry Natural Gas, 1976 through 1993

(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

Year	Adjustments[a] (1)	Revision Increases (2)	Revision Decreases (3)	Revisions[b] and Adjustments (4)	Extensions (5)	New Field Discoveries (6)	New Reservoir Discoveries in Old Fields (7)	Total[c] Discoveries (8)	Production (9)	Proved[d] Reserves 12/31 (10)	Change from Prior Year (11)
						U.S. Total					
1976	–	–	–	–	–	–	–	–	–	[e]213,278	–
1977	[f]-20	13,691	15,296	-1,625	8,129	3,173	3,301	14,603	18,843	207,413	-5,865
1978	2,429	14,969	15,994	1,404	9,582	3,860	4,579	18,021	18,805	208,033	+620
1979	-2,264	16,410	16,629	-2,483	8,950	3,188	2,566	14,704	19,257	200,997	-7,036
1980	1,201	16,972	15,923	2,250	9,357	2,539	2,577	14,473	18,699	199,021	-1,976
1981	1,627	16,412	13,813	4,226	10,491	3,731	2,998	17,220	18,737	201,730	+2,709
1982	2,378	19,795	19,340	2,833	8,349	2,687	3,419	14,455	17,506	201,512	-218
1983	3,090	17,602	17,617	3,075	6,909	1,574	2,965	11,448	15,788	200,247	-1,265
1984	-2,241	17,841	14,712	888	8,299	2,536	2,686	13,521	17,193	197,463	-2,784
1985	-1,708	18,775	16,304	763	7,169	999	2,960	11,128	15,985	193,369	-4,094
1986	1,320	21,269	17,697	4,892	6,065	1,099	1,771	8,935	15,610	191,586	-1,783
1987	1,268	17,527	14,231	4,564	4,587	1,089	1,499	7,175	16,114	187,211	-4,375
1988	2,193	23,367	38,427	-12,867	6,803	1,638	1,909	10,350	16,670	[g]168,024	-19,187
1989	3,013	26,673	23,643	6,043	6,339	1,450	2,243	10,032	16,983	167,116	-908
1990	1,557	18,981	13,443	7,095	7,952	2,004	2,412	12,368	17,233	169,346	+2,230
1991	2,960	19,890	15,474	7,376	5,090	848	1,604	7,542	17,202	167,062	-2,284
1992	2,235	18,055	11,962	8,328	4,675	649	1,724	7,048	17,423	165,015	-2,047
1993	972	17,597	12,248	6,321	6,103	899	1,866	8,868	17,789	162,415	-2,600
						Lower 48 States					
1976	–	–	–	–	–	–	–	–	–	[e]180,838	–
1977	[f]-21	13,689	15,229	-1,561	8,056	3,173	3,301	14,530	18,637	175,170	-5,668
1978	2,446	13,912	14,670	1,688	9,582	3,860	4,277	17,719	18,589	175,988	818
1979	-2,202	15,691	16,398	-2,909	8,949	3,173	2,566	14,688	19,029	168,738	-7,250
1980	1,163	15,881	15,819	1,225	9,046	2,539	2,577	14,162	18,486	165,639	-3,099
1981	1,840	16,258	13,752	4,346	10,485	3,731	2,994	17,210	18,502	168,693	3,054
1982	2,367	17,570	19,318	619	8,349	2,687	3,419	14,455	17,245	166,522	-2,171
1983	3,089	17,296	16,875	3,510	6,908	1,574	2,965	11,447	15,515	165,964	-558
1984	-2,245	16,934	14,317	372	8,298	2,536	2,686	13,520	16,869	162,987	-2,977
1985	-1,349	18,252	15,752	1,151	7,098	999	2,960	11,057	15,673	159,522	-3,465
1986	1,618	21,084	16,940	5,762	6,064	1,099	1,761	8,924	15,286	158,922	-600
1987	1,066	16,809	14,164	3,711	4,542	1,077	1,499	7,118	15,765	153,986	-4,936
1988	2,017	22,571	13,676	10,912	6,771	1,638	1,909	10,318	16,270	158,946	4,960
1989	2,997	26,446	23,507	5,936	6,184	1,450	2,243	9,877	16,582	158,177	-769
1990	1,877	17,916	13,344	6,449	7,898	2,004	2,412	12,314	16,894	160,046	+1,869
1991	2,967	19,095	15,235	6,827	5,074	848	1,563	7,485	16,849	157,509	-2,537
1992	1,946	17,878	11,941	7,883	4,621	649	1,724	6,994	17,009	155,377	-2,132
1993	915	16,918	12,139	5,694	6,076	899	1,858	8,833	17,396	152,508	-2,869

[a]Includes operator reported corrections for the years 1978 through 1981. After 1981 operators included corrections with revisions.

[b]Revisions and adjustments = Col. 1 + Col. 2 - Col. 3.

[c]Total discoveries = Col. 5 + Col. 6 + Col. 7.

[d]Proved reserves = Col. 10 from prior year + Col. 4 + Col. 8 - Col. 9.

[e]Based on following year data only.

[f]Consists only of operator reported corrections and no other adjustments.

[g]An unusually large revision decrease to North Slope dry natural gas reserves was made in 1988. It recognizes some 24.6 trillion cubic feet of downward revisions reported during the last few years by operators because of economic and market conditions. EIA in previous years carried these reserves in the proved category.

– = Not applicable.

Notes: Old means discovered in a prior year. New means discovered during the report year. The production estimates in this table are based on data reported on Form EIA-23, “Annual Survey of Domestic Oil and Gas Reserves,” and Form EIA-64A, “Annual Report of the Origin of Natural Gas Liquids Production,”. They may differ from the official Energy Information Administration production data for crude oil, natural gas, and natural gas liquids for 1993 contained in the *Petroleum Supply Annual 1993,* DOE/EIA-0340(93) and the *Natural Gas Annual 1993,* DOE/EIA-0131(93).

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1977 through 1992 annual reports, DOE/EIA-0216.{8-17,79-84}

Table D3. Total U.S. Proved Reserves of Wet Natural Gas, After Lease Separation, 1978 through 1993

(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

Year	Adjustments[a] (1)	Revision Increases (2)	Revision Decreases (3)	Revisions[b] and Adjustments (4)	Extensions (5)	New Field Discoveries (6)	New Reservoir Discoveries in Old Fields (7)	Total[c] Discoveries (8)	Production (9)	Proved[d] Reserves 12/31 (10)	Change from Prior Year (11)
						U.S. Total					
1978	–	–	–	–	–	–	–	–	–	[e]208,033	–
1979	5,356	17,077	17,300	5,133	9,332	3,279	2,637	15,248	20,079	208,335	+302
1980	1,253	17,668	16,531	2,390	9,757	2,629	2,648	15,034	19,500	206,259	-2,076
1981	2,057	17,156	14,413	4,800	10,979	3,870	3,080	17,929	19,554	209,434	+3,175
1982	2,598	20,596	20,141	3,053	8,754	2,785	3,520	15,059	18,292	209,254	-180
1983	4,363	18,442	18,385	4,420	7,263	1,628	3,071	11,962	16,590	209,046	-208
1984	-2,413	18,751	15,418	920	8,688	2,584	2,778	14,050	18,032	205,984	-3,062
1985	-1,299	19,732	17,045	1,388	7,535	1,040	3,053	11,628	16,798	202,202	-3,782
1986	2,137	22,392	18,557	5,972	6,359	1,122	1,855	9,336	16,401	201,109	-1,093
1987	1,199	18,455	14,933	4,721	4,818	1,128	1,556	7,502	16,904	196,428	-4,681
1988	2,180	24,638	[f]39,569	-12,751	7,132	1,677	1,979	10,788	17,466	[f]176,999	-19,429
1989	2,537	27,844	24,624	5,757	6,623	1,488	2,313	10,424	17,752	175,428	-1,571
1990	1,494	19,861	14,024	7,331	8,287	2,041	2,492	12,820	18,003	177,576	+2,148
1991	3,368	20,758	16,189	7,937	5,298	871	1,655	7,824	18,012	175,325	-2,251
1992	2,543	18,906	12,532	8,917	4,895	668	1,773	7,336	18,269	173,309	-2,016
1993	1,048	18,394	12,853	6,589	6,376	927	1,930	9,233	18,641	170,490	-2,819
						Lower 48 States					
1978	–	–	–	–	–	–	–	–	–	[e]175,988	–
1979	5,402	16,358	17,069	4,691	9,331	3,264	2,637	15,232	19,851	176,060	+72
1980	1,218	16,577	16,427	1,368	9,446	2,629	2,648	14,723	19,287	172,864	-3,196
1981	2,270	17,002	14,352	4,920	10,973	3,870	3,076	17,919	19,318	176,385	+3,521
1982	2,586	18,371	20,119	838	8,754	2,785	3,520	15,059	18,030	174,252	-2,133
1983	4,366	18,136	17,643	4,859	7,262	1,628	3,071	11,961	16,317	174,755	+503
1984	-2,409	17,844	15,023	412	8,687	2,584	2,778	14,049	17,708	171,508	-3,247
1985	-1,313	19,203	16,490	1,400	7,463	1,040	3,053	11,556	16,485	167,979	-3,529
1986	2,114	22,207	17,797	6,524	6,357	1,122	1,845	9,324	16,073	167,754	-225
1987	1,200	17,733	14,865	4,068	4,772	1,116	1,556	7,444	16,553	162,713	-5,041
1988	2,025	23,829	[f]14,439	11,415	7,099	1,677	1,979	10,755	17,063	167,820	+5,107
1989	2,545	27,616	24,488	5,673	6,467	1,485	2,313	10,265	17,349	166,409	-1,411
1990	1,811	18,784	13,925	6,670	8,232	2,041	2,492	12,765	17,661	168,183	+1,774
1991	3,367	19,961	15,948	7,380	5,281	871	1,614	7,766	17,657	165,672	-2,511
1992	2,265	18,728	12,511	8,482	4,840	668	1,773	7,281	17,851	163,584	-2,088
1993	996	17,714	12,743	5,967	6,349	927	1,922	9,198	18,245	160,504	-3,080

[a]Includes operator reported corrections for the years 1978 through 1981. After 1981 operators included corrections with revisions.

[b]Revisions and adjustments = Col. 1 + Col. 2 - Col. 3.

[c]Total discoveries = Col. 5 + Col. 6 + Col. 7.

[d]Proved reserves = Col. 10 from prior year + Col. 4 + Col. 8 - Col. 9.

[e]Based on following year data only.

[f]An unusually large revision decrease to North Slope wet natural gas reserves was made in 1988. It recognizes some 25 trillion cubic feet of downward revisions reported during the last few years by operators because of economic and market conditions. EIA in previous years carried these reserves in the proved category.

– = Not applicable.

Notes: Old means discovered in a prior year. New means discovered during the report year. The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production,". They may differ from the official Energy Information Administration production data for crude oil, natural gas, and natural gas liquids for 1993 contained in the *Petroleum Supply Annual 1993,* DOE/EIA-0340(93) and the *Natural Gas Annual 1993,* DOE/EIA-0131(93).

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1977 through 1992 annual reports, DOE/EIA-0216.{8-17,81-84}

Table D4. Total U.S. Proved Reserves of Natural Gas Liquids, 1978 through 1993
(Million Barrels of 42 U.S. Gallons)

Year	Adjustments[a] (1)	Revision Increases (2)	Revision Decreases (3)	Revisions[b] and Adjustments (4)	Extensions (5)	New Field Discoveries (6)	New Reservoir Discoveries in Old Fields (7)	Total[c] Discoveries (8)	Production (9)	Proved[d] Reserves 12/31 (10)	Change from Prior Year (11)
					U.S. Total						
1978	–	–	–	–	–	–	–	–	–	[e]6,772	–
1979	[f]64	677	726	15	364	94	97	555	727	6,615	-157
1980	153	743	639	257	418	90	79	587	731	6,728	+113
1981	231	729	643	317	542	131	91	764	741	7,068	+340
1982	299	811	832	278	375	112	109	596	721	7,221	+153
1983	849	847	781	915	321	70	99	490	725	7,901	+680
1984	-123	866	724	19	348	55	96	499	776	7,643	-258
1985	426	906	744	588	337	44	85	466	753	7,944	+301
1986	367	1,030	807	590	263	34	72	369	738	8,165	+221
1987	231	847	656	422	213	39	55	307	747	8,147	-18
1988	11	1,168	715	464	268	41	72	381	754	8,238	+91
1989	-277	1,143	1,020	-154	259	83	74	416	731	7,769	-469
1990	-83	827	606	138	299	39	73	411	732	7,586	-183
1991	233	825	695	363	189	25	55	269	754	7,464	-122
1992	225	806	545	486	190	20	64	274	773	7,451	-13
1993	102	764	640	226	245	24	64	333	788	7,222	-229
					Lower 48 States						
1978	–	–	–	–	–	–	–	–	–	[e]6,749	–
1979	[f]63	677	726	14	364	94	97	555	726	6,592	-157
1980	165	743	639	269	418	90	79	587	731	6,717	+125
1981	233	728	643	318	542	131	91	764	741	7,058	+341
1982	300	811	832	279	375	112	109	596	721	7,212	+154
1983	850	847	781	916	321	70	99	490	725	7,893	+681
1984	-115	847	724	8	348	55	96	499	776	7,624	-269
1985	70	883	731	222	334	44	85	463	748	7,561	-63
1986	363	1,030	804	589	263	34	72	369	735	7,784	+223
1987	179	846	655	370	212	39	55	306	731	7,729	-55
1988	10	1,167	715	462	267	41	72	380	734	7,837	+108
1989	-273	1,141	1,018	-150	259	83	74	416	714	7,389	-448
1990	-60	827	606	161	298	39	73	410	714	7,246	-143
1991	183	815	677	321	187	25	55	267	730	7,104	-142
1992	225	796	542	479	183	20	64	267	746	7,104	0
1993	101	755	631	225	245	24	64	333	761	6,901	-203

[a]Includes operator reported corrections for the years 1978 through 1981. After 1981 operators included corrections with revisions.
[b]Revisions and adjustments = Col. 1 + Col. 2 - Col. 3.
[c]Total discoveries = Col. 5 + Col. 6 + Col. 7.
[d]Proved reserves = Col. 10 from prior year + Col. 4 + Col. 8 - Col. 9.
[e]Based on following year data only.
[f]Consists only of operator reported corrections and no other adjustments.
– = Not applicable.

Notes: Old means discovered in a prior year. New means discovered during the report year. The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production,". They may differ from the official Energy Information Administration production data for crude oil, natural gas, and natural gas liquids for 1993 contained in the *Petroleum Supply Annual 1993,* DOE/EIA-0340(93) and the *Natural Gas Annual 1993,* DOE/EIA-0131(93).

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1979 through 1992 annual reports, DOE/EIA-0216.{8-17,81-84}

Summary of Data Collection Operations

Form EIA-23 Survey Design

The data collected on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," were used to produce this report. This section provides information concerning the survey design, response statistics, reporting requirements, and frame maintenance.

Form EIA-23 is mailed annually to all known large and intermediate sized operators, and a scientifically selected sample of small operators. Operator size categories were based upon their annual production as indicated in various Federal, State, and commercial records. The term **State/subdivision** refers to an individual subdivision within a State or an individual State that is not subdivided. Operators were divided into the three size categories shown below.

- **Category I - *Large Operators***: Operators who produced 1.5 million barrels or more of crude oil, or 15 billion cubic feet or more of natural gas, or both.

- **Category II - *Intermediate Operators***: Operators who produced at least 400,000 barrels of crude oil or 2 billion cubic feet of natural gas, or both, but less than Category I operators.

- **Category III - *Small Operators:*** Operators who produced less than the Category II operators.

Category III operators were further subdivided into operators sampled with certainty (certainties) and operators that were randomly sampled (noncertainty).

- **Certainties -** Small operators who produced less than the Category II operators but satisfied any of the following criteria based upon their production as shown in the operator frame master file:

  - Operators with annual crude oil production of 200 thousand barrels or more, or reserves of 4 million barrels or more; or annual natural gas production of 1 billion cubic feet or more, or reserves of 20 billion cubic feet or more.

  - All other operators with production or reserves in a State/subdivision that exceed selected cutoff levels for that State/subdivision.

  - The largest operator in each State/subdivision regardless of level of production or reserves.

  - Operators with production or reserves of oil or gas shown for six or more State/subdivisions.

- **Noncertainties -** Small operators not in the certainty stratum were classified in a noncertainty stratum sampled at an overall rate of 8 percent.

Data were filed for calendar year 1993 by crude oil or natural gas well operators who were active as of December 31, 1993. EIA defines an operator as an organization or person responsible for the management and day-to-day operation of crude oil or natural gas wells. The purpose of this definition is to eliminate responses from royalty owners, working interest owners (unless they are also operators), and others not directly responsible for operations. An operator need not be a separately incorporated entity. To minimize reporting burden, corporations are permitted to report on the basis of operating units of the company convenient for them. A large corporation may be represented by a single form or by several forms.

Table E1 shows a comparison of the EIA-23 sample and sampling frame between 1986 and 1993, and depicts the number of active operators, 1989 showing the largest in the series. The 1993 sampling frame of 4,074 operators consisted of 160 Category I, 500 Category II, 1,723 Category III certainties, and 21,193 operators in the noncertainty stratum for a total of 23,106 active operators. The survey sample consisted of 2,383 operators selected with certainty that included all of the Category I and II certainty operators, the 1,723 smaller operators that were selected with certainty because of their size in relation to the area or areas in which they operated, and 1,691 noncertainty operators selected as random samples from the remaining operators.

Table E1. Comparison of the EIA-23 Sample and Sampling Frame, 1986 through 1993

Operator Category	Number of Operators 1986	1987	1988	1989	1990	1991	1992	1993
Certainty								
Category I	155	152	149	134	144	144	157	160
Category II	548	541	500	500	468	484	480	500
Category III	2,451	3,116	3,289	2,936	2,316	2,074	1,896	1,723
Total in Frame	3,154	3,809	3,938	3,570	2,929	2,702	2,533	2,383
Sampled	3,154	3,809	3,938	3,570	2,929	2,702	2,533	2,383
Percent Sampled	100	100	100	100	100	100	100	100
Noncertainty								
Total in Frame	23,019	23,570	22,797	24,062	24,628	21,972	21,573	21,193
Sampled	1,423	1,265	1,282	1,325	1,431	1,760	1,724	1,691
Percent Sampled	8	6	5	6	6	8	8	8
Total								
Active Operators	26,173	27,379	26,735	27,632	27,556	24,674	24,106	23,576
Not Sampled	21,596	22,305	21,515	22,737	23,196	20,212	19,849	19,502
Sampled	4,577	5,074	5,220	4,895	4,360	4,462	4,257	4,074
Percent Sampled	17	19	20	18	16	18	18	17

Source: Energy Information Administration, Office of Oil and Gas.

Table E2. Form EIA-23 Survey Response Statistics, 1993

Operator Category	Sample Selected	Successor[a] Operators	Net[b] Category Changes	Non-[c] operators	Total Operators	Responding Operators Number	Responding Operators Percent	Nonresponding Operators Number	Nonresponding Operators Percent
Certainty									
Category I	160	1	-5	-7	149	149	100.0	0	0.0
Category II	500	1	-3	-23	475	475	100.0	0	0.0
Category III	1,723	23	8	-57	1,697	1,697	100.0	0	0.0
Subtotal	2,38	25	0	-87	2,321	2,321	100.0	0	0.0
Noncertainty	1,691	20	0	-191	1,520	1,503	98.9	17	1.1
Total	4,074	45	0	-278	3,841	3,824	99.6	17	0.4

[a]Successor operators are those, not initially sampled, that have taken over the production of a sampled operator.
[b]Net of recategorized operators in the sample (excluding nonoperators).
[c]Includes former operators reporting that they were not operators during the report year and operators that could not be located who are treated as nonoperators.
Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves" 1993.

Form EIA-23 Response Statistics

Each company and its parent company or subsidiaries were required to file Form EIA-23 if they met the survey specifications. Response to the 1993 survey is summarized in Table E2. EIA makes a considerable effort to gain responses from all operators. About 7 percent of those selected turned out to be nonoperators (those that reported being nonoperators during the report year and operators that could not be located). Of the 278 nonoperators, 45 had successor operators that had taken over the production of the nonoperator. These successor operators were subsequently sampled. The overall response rate for the 1993 survey was 99.6 percent. This compares with a 99.1 percent overall response rate for all operators in 1992. The response rates for Certainty operators in 1993 was 100 percent.

Form EIA-23 Reporting Requirements

The collection format for Form EIA-23 actually consists of two forms. The form that the respondent is required to file is dependent upon the annual production levels of crude oil, natural gas, and lease condensate. Category I and Category II operators file a more detailed field level data form. Category III operators file a summary report which is aggregated at a State/subdivision level.

The cover page required of all respondents identifies each operator by name and address (Figure I1, Appendix I). The oil and gas producing industry includes a large number of small enterprises. To minimize reporting burden, only a sample of small operators were required to file a summary report of Form EIA-23 (Figures I2 and I3, Appendix I). Report year production data were required by State/subdivision areas for crude oil, natural gas, and lease condensate. Proved reserves data for operators were required only for those properties where estimates existed in the respondent's records.

All Category I and Category II operators were required to file field level data on Schedule A, "Operated Proved Reserves, Production, and Related Data by Field," for each oil and/or gas field in which the respondent operated properties (Figure I4, Appendix I). All Category I and those Category II operators who had reserve estimates were required to file on a total operated basis for crude oil, nonassociated natural gas, associated-dissolved natural gas, and lease condensate. The following data items were required to be filed: proved reserves at the beginning and the end of the report year, revision increases and revision decreases, extensions, new field discoveries, new reservoirs in old fields, production, indicated additional reserves of crude oil, nonproducing reserves, field discovery year, water depth, and field location information.

Category II operators who did not have reserves estimates were required to file the field location information and report year production for the four hydrocarbon types from properties where reserves were not estimated. These respondents used Schedule B, "Footnotes," to provide clarification of reported data items when required in the instructions, or electively to provide narrative or detail to explain any data item filed(Figure I5, Appendix I).

Crude oil and lease condensate volumes were reported rounded to thousands of barrels of 42 U.S. gallons at 60° Fahrenheit, and natural gas volumes were reported rounded to millions of cubic feet. All natural gas volumes were requested to be reported at 60° Fahrenheit and a pressure base of 14.73 pounds per square inch absolute. Other minor report preparation standards were specified to assure that the filed data could be readily processed.

Oil and Gas Field Coding

A major effort to create standardized codes for all identified oil or gas fields throughout the United States was implemented during the 1982 survey year. Information from previous lists was reviewed and reconciled with State lists and a consolidated list was created. The publication of the *Oil and Gas Field Code Master List 1993*, in December of 1993, was the 12th annual report and reflected data collected through October 1993. This publication was mailed to operators to assist in identifying the field code data necessary for the preparation of Form EIA-23. A copy of this publication may be purchased from the National Energy Information Center. A machine-readable tape version of the publication is available from the National Technical Information Service.

Form EIA-23 Comparison with Other Data Series

Estimated crude oil, lease condensate, and natural gas production volumes from Form EIA-23 were compared with official EIA production data supplied by Federal and State oil and natural gas regulatory agencies and published in EIA's monthly and annual reports. Reports published by the Federal and State oil and natural gas regulatory agencies were used to compare specific operator production responses to these agencies with Form EIA-23 responses. When significant differences were found, responses were researched to detect and reconcile possible reporting errors.

For 1993, Form EIA-23 national estimates of production were 2,492 million barrels for crude oil and lease condensate or 7 million barrels (0.3 percent) lower than that reported in the *Petroleum Supply Annual 1993* for crude oil and lease condensate. Form EIA-23 national estimates of production for dry natural gas were 17,789 billion cubic feet or 562 billion cubic feet (3.1 percent) lower than the *Natural Gas Monthly August 1994* for 1993 dry natural gas production.

Form EIA-23 Frame Maintenance

Operator frame maintenance is a major data quality control effort. It is necessary to update and maintain the frame regularly in order to ensure an accurate basis for each annual survey. Extensive effort is expended to keep the frame as current as possible. The Form EIA-23 frame contains a listing of all crude oil and natural gas well operators in the United States and must be maintained and updated regularly in order to ensure an accurate frame from which to draw the sample for the annual crude oil and natural gas reserves survey. The original frame, created in 1977, has been revised annually. In addition, outside sources, such as State publications and computer tapes, and commercial information data bases such as Dwight's Energydata and Petroleum Information, are used to obtain information on operator status and to update addresses for the frame each year.

A maintenance procedure is utilized, using a postcard form with prepaid return postage, to contact possible active crude oil and natural gas well operators presently listed on EIA's master frame, but for whom the listing had not been updated for 2 years. This procedure identifies active operators and nonoperators which improves the frame for future sample selections for the survey. Table E3 provides a summary of changes made to the Form EIA-23 frame of crude oil and natural gas well operators for the 1993 survey mailing. These changes resulted from all frame maintenance activities.

Table E3. Summary of the 1993 Operator Frame Activity, Form EIA-23

Total 1992 Operator Frame	59,355
Changes to 1992 Operator Status	
From Operator to Nonoperator	2,564
From Nonoperator to Operator	530
Subtotal	3,094
No Changes to 1992 Operator Status	
Operators	21,515
Nonoperators	34,746
Subtotal	56,261
Additions to Operator Frame	
Operator	1,513
Nonoperator	24
Subtotal	1,537
Total 1993 Operator Frame	**60,892**

Note: Includes operator frame activity through December 14, 1993.
Source: Energy Information Administration, Office of Oil and Gas.

The Form EIA-23 operator frame contained a total of 59,355 entries as of December 14, 1993. Of these, 23,558 were confirmed operators. These are operators who have filed in the past or for whom the EIA has recent production data from an outside source. The remaining operators (including both definite and probable nonoperators) exist as a pool of names and addresses that may be added to the active list if review indicates activity.

Form EIA-64A Survey Design

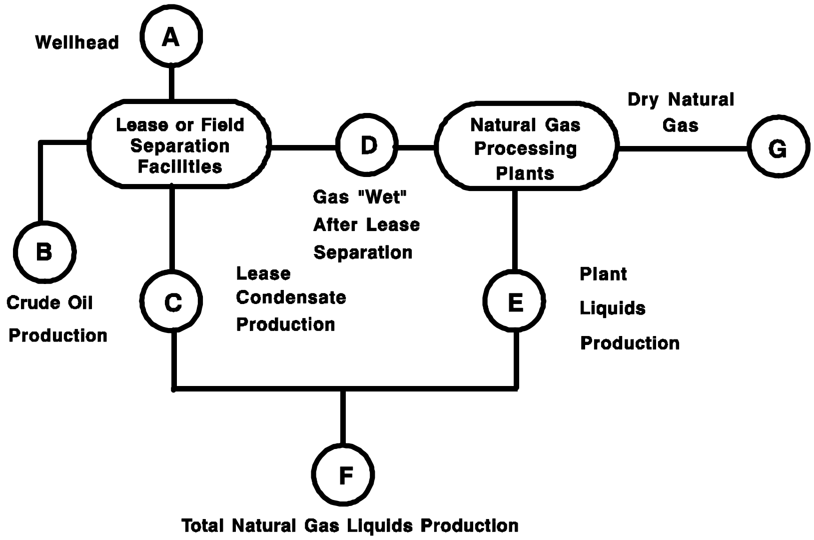
The data for this report are also collected on Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production." This section provides information concerning the survey design, response statistics, reporting requirements, and frame maintenance for Form EIA-64A.

Form EIA-23 for report years 1977 and 1978 required natural gas well operators to report their natural gas data on a fully dry basis. It was discovered in the course of those surveys that many operators had little or no knowledge of the extraction of liquids from their produced natural gas streams once custody transfer had taken place. Therefore, these operators reverted to reporting the only natural gas volume data they had in their possession. These volume data were for dryer natural gas than that which had passed through the wellhead, but wetter than fully dry natural gas. With reference to Figure E1, they reported their volumes either at point A, the wellhead, or point C, after removal of lease condensate in their lease or field separation facilities.

Some of the larger operators, however, also owned or operated natural gas processing plants. They reported their volumes at point E, after removal of both lease condensate and plant liquids, as required by Form EIA-23. The aggregate volumes resulting from the 1977 and 1978 surveys, therefore, were neither fully dry (as was intended) nor fully wet. They do appear to have been more dry than wet simply because the operators who reported fully dry volumes also operated properties that contained the bulk of proved natural gas reserves.

The EIA recognized that its estimates of proved reserves of natural gas liquids (NGL) had to reflect not only those volumes extractable in the future under current economic and operating conditions at the lease or field (lease condensate), but also volumes (plant liquids) extractable downstream at existing natural gas processing plants. Form EIA-64, which already canvassed these processing plants, did not request that the plants' production volumes be attributed to source areas. Beginning with the 1979 survey, a new form to collect plant liquids production according to the area or areas where their input natural gas stream had been produced was mailed to all of the operating plants. The instructions for filing the Form EIA-23 were altered to collect data from natural gas well operators that reflected those volumes of natural gas dried only through the lease or field separation facilities. The reporting basis of

Figure E1. Natural Gas Liquids Extraction Flows



Source: Energy Information Administration, Office of Oil and Gas.

these volumes are referred to as "wet after lease separation." The methodology used to estimate NGL reserves by State and State subdivision is provided in Appendix F.

Form EIA-64A Response Statistics

EIA mailed EIA-64A forms to all known natural gas processing plant operators as of December 31, 1993. In addition, plant operators whose plants were shut down or dismantled during 1993 were required to complete forms for the portion of 1993 when the plants were in operation.

Natural gas processing plant operators were requested to file a Form EIA-64A for each of their plants. A total of 319 operators of 848 plants were sent forms. This number included 9 new plants and 21 successor plants identified after the initial 1993 survey mailing. A total of 56 plants were reported as nonoperating according to the Form EIA-64A definition. The response rate was again 100 percent.

Form EIA-64A respondents were requested to report natural gas liquids production data by area of origin. Table E4 summarizes the responses by plant operators of the volume and origin of natural gas delivered to the processing plants and the volume of the natural gas liquids extracted by the plants by State. The majority of the plant operators reported only one area of origin for the natural gas that was processed by a plant. The State or area of origin reported is generally also the plant's location.

Form EIA-64A Reporting Requirements

Form EIA-64A consisted of the reporting schedule shown in Figure I6, Appendix I. The form identifies the plant, its geographic location, the plant operator's name and address, and the parent company name. The certification was signed by a responsible official of the operating entity. The form pertains to the volume of natural gas received and of natural gas liquids produced at the plant, allocated to each area of origin. Operators also filed the data pertaining to the amount of natural gas shrinkage that resulted from extraction of natural gas liquids at the plant, and the amount of fuel used in processing.

Natural gas liquids volumes were reported rounded to thousands of barrels of 42 U.S. gallons at 60° Fahrenheit, and natural gas volumes were reported rounded to millions of cubic feet. All natural gas volumes were requested to be reported at 60° Fahrenheit and a pressure base of 14.73 pounds per square inch absolute. Other minor report preparation standards were specified to assure that the filed data could be readily processed.

Table E4. Processed Natural Gas and Liquids Extracted at Natural Gas Processing Plants, 1993

Plant Location	Volume of Natural Gas Delivered to Processing Plants (million cubic feet)			Total Liquids Extracted (thousand barrels)
	State Production	Out of State Production	Natural Gas Processed	
Alaska	2,295,499	0	2,295,499	27,020
Lower 48 States	**13,484,798**	**616,679**	**14,101,477**	**607,461**
Alabama	130,632	1,590	132,222	4,200
Arkansas	195,683	2,391	198,074	417
California	246,283	0	246,283	9,944
Colorado	306,967	283	307,250	13,749
Florida	7,829	200,146	207,975	2,372
Kansas	819,888	141,630	961,518	31,691
Kentucky	44,391	1,391	45,782	1,703
Louisiana	4,120,748	194,564	4,315,312	90,899
Michigan	201,985	0	201,985	5,366
Mississippi	4,892	0	4,892	305
Montana	10,973	37	11,010	572
North Dakota	51,713	0	51,713	4,563
New Mexico	798,935	5,601	804,536	58,516
Oklahoma	1,068,753	13,699	1,082,452	72,301
Texas	4,264,094	37,410	4,301,504	271,351
Utah and Wyoming	1,083,635	15,228	1,098,863	31,670
West Virginia	115,963	0	115,963	7,288
Miscellaneous[a]	11,434	2,709	14,143	554
Total	**15,780,297**	**616,679**	**16,396,976**	**634,481**

[a]Includes Illinois, Nebraska, Ohio, Pennsylvania, and Tennessee.
Source: Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production," 1993.

Form EIA-64A Comparison with Other Data Series

Form EIA-64A plant liquids production data were compared with data collected on Form EIA-816, "Monthly Natural Gas Liquids Report." Aggregated production from Form EIA-816 represents the net volume of natural gas processing plant liquid output less input for the report year. These data are published in EIA's *Petroleum Supply Annual* reports. The Form EIA-64A annual responses reflect all corrections and revisions to EIA's monthly estimates. Differences, when found, were reconciled in both sources. For 1993, the Form EIA-64A national estimates were 2.9 percent (19 million barrels) lower than the *Petroleum Supply Annual 1993* volume for natural gas plant liquids production.

Form EIA-64A Frame Maintenance

The Form EIA-64A plant frame contains data on all known active and inactive natural gas processing plants in the United States. The 1993 plant frame was compared to listings of natural gas processing plants from Form EIA-816, "Monthly Natural Gas Liquids Report"; the *LPG Almanac*; and the *Oil and Gas Journal*. A list of possible additions to the plant frame was compiled. Table E5 summarizes the Form EIA-64A plant frame changes made as a result of the comparisons as of December 31, 1993.

Table E5. Summary of the 1992 Plant Frame Activity, Form EIA-64A

Frame as of 1992 survey mailing	868
Additions	165
Deletions	–178
Frame as of 1993 survey mailing	855

Note: Includes operator frame activity through December 31,1993.
Source: Energy Information Administration, Office of Oil and Gas.

Appendix F

Statistical Considerations

Survey Methodology

The Form EIA-23 survey is designed to provide reliable estimates for reserves and production of crude oil, natural gas, and lease condensate for the United States. Operators of crude oil and natural gas wells were selected as the appropriate respondent population because they have access to the most current and detailed information, and therefore, presumably have better reserve estimates than do other possible classes of respondents, such as working interest or royalty owners.

While large operators are quite well known, they comprise only a small portion of all operators. The small operators are not well known and are difficult to identify because they go into and out of business, alter their corporate identities, and change addresses frequently. As a result, EIA conducts extensive frame maintenance activities each year to identify all current operators of crude oil and natural gas wells in the country.

Sampling Strategy

EIA publishes data on reserves and production for crude oil, natural gas, and lease condensate by State for most States, and by State subdivision for the States of California, Louisiana, New Mexico, and Texas. To meet the survey objectives, while minimizing respondent burden, a random sampling strategy has been used since 1977. Each operator reporting on the survey is asked to report production for crude oil, natural gas, and lease condensate for each State/subdivision in which he operates. The term **State/subdivision** refers to an individual subdivision within a State or an individual State that is not subdivided.

The total volume of production varies among the State/subdivisions. To meet the survey objectives while controlling total respondent burden, EIA selected the following target sampling error for the 1993 survey for each product class.

- 1.0 percent for National estimates.

- 1.0 percent for each of the 5 States having subdivisions: Alaska, California, Louisiana, New Mexico, and Texas. For selected subdivisions within these States, targets of 1.0 percent or 1.5 percent as required to meet the State target.

- 2.5 percent for each State/subdivision having 1 percent or more of estimated U.S. reserves or production in 1992 (lower 48 States) for any product class.

- 4 percent for each State/subdivision having less than 1 percent of estimated U.S. reserves or production in 1992 (lower 48 States) for all 3 product classes.

- 8 percent for States not published separately. The combined production from these States was less than 0.2 percent of the U.S. total in 1992 for crude oil and for natural gas.

The volume of production defining the certainty stratum, referred to as the **cutoff**, varies by product or State/subdivision. The cutoff criteria and sampling rates are shown in Table F1. The certainty stratum, therefore, has three components.

- **Category I** - *Large Operators:* Operators who produced a total of 1.5 million barrels or more of crude, or 15 billion cubic feet or more of natural gas, or both in 1992.

- **Category II** - *Intermediate Operators:* Operators who produced a total of at least 400,000 barrels of crude oil or 2 billion cubic feet of natural gas, or both, but less than Category I operators in 1992.

- **Category III** - *Small Operators:* Operators who produced less than the Category II operators in 1992, but which were selected with certainty because they operate in six or more States/subdivisions, or because their production volumes exceeded the State/subdivision cutoff.

In each State/subdivision the balance between the number of small certainty operators and the sample size was determined in an iterative procedure designed to minimize the number of total respondents. The iteration for each State/subdivision began with only the Category I and Category II operators in the certainty stratum. The size of the sample of small operators required to meet the target variance was calculated based on the variance of the volumes of those operators. For a number of State/subdivisions with high correlations between frame values across pairs of consecutive years, an adjusted target variance was calculated, that utilized

Table F1. 1993 EIA-23 Survey Initial Sample Criteria

State and Subdivision	Production Cutoffs Crude Oil (mbbls)	Production Cutoffs Cutoff (mmcf)	Certainty Sample Number	Noncertainty Sample Single State Operator Number	Noncertainty Sample Multi-State Operator Number
Alabama Onshore	200	1,000	59	1	2
Alaska	0	0	10	0	0
Arkansas	30	1,000	146	19	4
California Unspecified	2	597	1	5	0
California-Coastal Region Onshore	200	597	29	8	1
California-Los Angeles Basin Onshore	200	21	45	12	1
California-San Joaquin Basin Onshore	200	646	67	27	0
Colorado	200	1,000	177	30	12
Florida Onshore	0	0	9	0	0
Illinois	38	29	139	36	6
Indiana	5	11	110	9	4
Kansas	70	877	314	181	22
Kentucky	8	295	124	14	3
Louisiana Unspecified	2	49	9	8	0
Louisiana North	17	720	231	46	9
Louisiana South Onshore	96	1,000	247	16	6
Michigan	79	1,000	62	10	1
Mississippi Onshore	200	1,000	129	8	4
Montana	200	506	103	10	1
Nebraska	29	1,000	65	5	5
New Mexico Unspecified	3	1,000	1	2	0
New Mexico East	200	1,000	205	17	15
New Mexico West	32	1,000	78	6	3
New York	5	115	59	51	2
North Dakota	200	1,000	129	6	3
Ohio	9	249	340	127	1
Oklahoma	140	1,000	449	260	45
Pennsylvania	6	656	100	26	1
Texas Unspecified	33	1,000	10	52	1
Texas-RRC District 1	81	1,000	215	64	26
Texas-RRC District 2 Onshore	200	1,000	201	13	21
Texas-RRC District 3 Onshore	200	1,000	303	38	22
Texas-RRC District 4 Onshore	200	1,000	229	13	21
Texas-RRC District 5	200	1,000	116	12	6
Texas-RRC District 6	200	1,000	231	26	10
Texas-RRC District 7B	50	134	308	83	49
Texas-RRC District 7C	200	1,000	249	26	21
Texas-RRC District 8	200	1,000	288	38	28
Texas-RRC District 8A	200	1,000	249	20	16
Texas-RRC District 9	60	1,000	244	88	32
Texas-RRC District 10	69	923	216	37	11
Utah	200	1,000	69	6	2
Virginia	0	0	28	0	0
West Virginia	7	287	136	43	1
Wyoming	200	1,000	192	10	1
Offshore Areas	0	0	291	0	0
Other States[a]	200	95	46	12	1
Total	**--**	**--**	**[b]2,285**	**1,521**	**[b]176**

[a]Includes Arizona, Connecticut, Delaware, Georgia, Idaho, Iowa, Massachusetts, Maryland, Minnesota, Missouri, North Carolina, New Hampshire, Nevada, New Jersey, Oregon, Rhode Island, South Carolina, South Dakota, Tennessee, Washington, and Wisconsin.

[b]Non-duplicative count of operators by States.

Note: Sampling rate was 8 percent except in Alaska, Florida Onshore, Virginia, and Offshore areas where sampling rate was 100 percent.

-- = Not applicable.

Source: Energy Information Administration, Office of Oil and Gas.

the information about the correlations. This allowed the selection of a smaller sample that still met the target sampling error criteria. At each iteration a small operator, beginning with the largest of the Category III operators, was added to the certainty group and the required sample size was again calculated. The procedure of adding one operator at a time stopped when the proportion of operators to be sampled at random dropped below 8 percent. Independent samples of single location operators (operators who, according to the sampling frame, operate in only one State/subdivision, were selected from each State/subdivision using simple random sampling.

An additional complexity is introduced by the fact that some small operators selected for the sample in another region or regions, sometimes report production volumes in a region in which EIA has no previous record of production.

State/subdivision volume estimates are calculated as the sum of the certainty strata and all of the estimates for the sampling strata in that region. The sampling variance of the estimated total is the sum of the sampling variances for the sampling strata. There is no sampling error associated with the certainty stratum. The square root of the sampling variance is the standard error. It can be used to provide confidence intervals for the State/subdivision totals.

For the States in which subdivision volume estimates are published, the State total is the sum of the individual volume estimates for the subdivisions. The U.S. total is the sum of the State estimates. A sampling variance is calculated for each State subdivision, State, and for the U.S. total.

Total U.S. Reserve Estimates

Conceptually, the estimates of U.S. reserves and production can be thought of as the sum of the estimates for the individual States. Correspondingly, the estimates for the four States for which estimates are published separately by subdivision (California, Louisiana, New Mexico, and Texas) can be thought of as the sum of the estimates by subdivision. The remaining States are not subdivided and may be considered as a single subdivision.

The estimates of year-end proved reserves and annual production for any State/subdivision is the sum of the volumes in the State/subdivision reported by the certainty stratum operators and an estimate of the total volume in the State/subdivision by the noncertainty stratum operators. Mathematically, this may be stated as the following sum:

$$\hat{V}_s = V_{sc} + \hat{V}_{sr}$$

where

$\hat{V}_s$ = estimated total volume in the State/subdivision

V_{sc} = total volume in the State/subdivision reported by certainty operators

$\hat{V}_{sr}$ = estimated total volume in the State/subdivision of noncertainty operators.

The total volume of certainty operators in the State/subdivision is simply the sum of individual operator's volumes:

$$V_{sc} = \sum_{m=1}^{n_{sc}} V_{scm}$$

where

n_{sc} = number of certainty operators reporting production in the State/subdivision

V_{scm} = volume reported by the *m*-th certainty stratum operator in the State/subdivision.

The estimated total volume of noncertainty operators in the State/subdivision is the weighted sum of the reports of the noncertainty sample operators:

$$\hat{V}_{sr} = \sum_{m=1}^{n_{sr}} W_{srm} V_{srm}$$

where

n_{sr} = number of noncertainty operators reporting production in the State/subdivision

V_{srm} = volume reported by the *m*-th noncertainty sample operator in the State/subdivision

W_{srm} = weight for the report by the *m*-th noncertainty sample operator in the State/subdivision.

In many State/subdivisions, the accuracy of the oil and gas estimates was improved by using a difference estimator for many of the noncertainty operator reports. This difference estimator took advantage of the stability of production reports from year-to-year in those State/subdivisions. The difference estimator was only applied to operators who had known production greater than one in the previous year. For those State/subdivisions and operators the above formula was modified with V_{srm} replaced by V'_{srm}:

$$V'_{srm} = V_{srm} + k\,(\overline{X}_{sr} - X_{srm})$$

where

k = 1 when estimating production volumes

k = regional R/P ratio (Table F6) when estimating reserve volumes

$\overline{X}_{sr}$ = average production volume reported in the State/subdivision for the preceding year by all noncertainty operators who reported greater than 1 in that preceding year

X_{srm} = production volume reported by the *m*-th noncertainty sample operator in the State/subdivision.

In selecting the noncertainty sample, the number of sample operators with production in a given State/subdivision is not controlled to the number expected based on the sampling rate, but is subject to some variation. The weight used is the reciprocal of the actual sampling rate that resulted for the stratum from which the sample operator was selected, rather than the reciprocal of the expected sampling rate. The sample estimate with either set of weights is an unbiased estimator of the noncertainty stratum total. However, use of the actual sampling rates is expected to lead to smaller sampling errors for the estimates. In making estimates for a State/subdivision, separate weights are applied as appropriate for noncertainty operators shown in the frame as having had production in only the State/subdivision, for those shown as having had production in that State/subdivision and up to four other States/subdivisions, and for operators with no previous record of production in the State/subdivision. National totals were then obtained by summation of the component totals.

Imputation for Operator Nonresponse

The response rate for Certainty operators for the 1993 survey was 100 percent. The nonresponse rate among noncertainty operators has been relatively low in past surveys and was 1.1 percent in 1993. Due to the 100 percent response rate of Certainly operators, imputing for the nonresponding Certainty operators was not necessary.

Estimation and Imputation for Reserves Data

In order to estimate reserve balances for National and State/subdivision levels, a series of estimation and imputation steps at the operator level must be carried out. Year-end reserves for operators who provided production data only were imputed on the basis of their production volumes. Imputation was also applied to the small and intermediate operators as necessary to provide data on each of the reserve balance categories (i.e., revisions, extensions, or new discoveries). Finally, an imputation was required for the natural gas data of the small operators to estimate their volumes of associated-dissolved and nonassociated natural gas. The final manipulation of the data accounts for the differences caused by different sample frames from year to year. Each of these imputations generated only a small percentage of the total estimates. The methods used are discussed in the following paragraphs.

The actual data reported on an operated basis by Form EIA-23 respondents for the report year 1993 are summarized in Tables F2, F3, F4, and F5. The differences between these sums and the total estimates shown in Tables 6, 9, 10, and 16 in the main text represent the aggregate result of statistical estimation and imputation performed by EIA. The reported data in Table F2 shows that those responding operators accounted for 93.5 percent of the published production for natural gas shown in Table 9 and 93.3 percent of the reserves. Data shown in Table F3 indicate that those responding operators accounted for 93.3 percent of the nonassociated natural gas production and 91.9 percent of the reserves published in Table 10. The reported data shown in Table F4 indicate that those responding operators accounted for 94.5 percent of published crude oil production and 93.8 percent of the reserves shown in Table 6. Additionally, Table F5 indicates that those responding operators accounted for 100 percent of the published production and published proved reserves for lease condensate shown in Table 16.

Imputation of Year-End Proved Reserves

Category I operators were required to submit year-end estimates of proved reserves. Category II and Category III operators were required to provide year-end estimates of proved reserves only if such estimates existed in their records. Some of these respondents provided estimates for all of their operated properties, others provided estimates for only a portion of their properties, and still others provided no estimates for any of their properties. All respondents did, however, provide annual production data. The production reported by noncertainty sample operators and the corresponding reserves imputed were weighted to estimate the full noncertainty stratum when calculating reserves and production as described in the section "Total U.S. Reserves Estimates."

A year-end proved reserves estimate was imputed in each case where an estimate was not provided by the respondent. Reserves were imputed from reported production data for all random operators. The reported annual production was multiplied by a reserves-to-production (R/P) ratio (Table F6) characteristic of operators of similar size in the region where the properties were located. The regional R/P ratios in this report are averages calculated by dividing the mean of reported reserves by the mean of reported production for selected respondents of similar size who did report estimated reserves. Operators that had R/P ratios that exceeded 25 to 1 and Category I operators were excluded from the respondents selected to calculate the characteristic regional R/P ratio. All other respondents who reported both production and reserves were used to calculate the regional R/P ratio characteristic.

The R/P ratio varied significantly from region to region. This variation was presumably in response to variation in geologic conditions and the degree of development of crude oil and natural gas resources in each area. The average R/P ratio was computed for regional areas similar to the National Petroleum Council regional units (Figure F1). These units generally follow the boundaries of geologic provinces wherein the stage of resource development tends to be similar. Table F6 lists the R/P ratio calculated for each region that required such imputations and the number of observations on which it was based.

The regional R/P ratio is determined primarily to provide a factor that can be applied to the production reported by operators without reserve estimates to provide an estimate of the reserves of these operators when aggregated to the regional level. The average R/P ratio, when multiplied by each individual production in the distribution of R,P pairs used to calculate it, will exactly reproduce the sum of the reported reserves in the distribution.

Imputation of Annual Changes to Proved Reserves by Component of Change

Category II and Category III operators that do not keep reserves data were not asked to provide estimates of beginning-of-year reserves or annual changes to proved reserves by component of change, i.e., revisions, extensions, and discoveries. When they did not provide estimates, these volumes were estimated by applying an algebraic allocation scheme which preserved the relative relationships between these items within each State/subdivision, as reported by Category I and Category II operators, and also preserved an exact annual reserves balance of the following form:

Published Proved Reserves at End of Previous Report Year
- \+ Adjustments
- \+ Revision Increases
- – Revision Decreases
- \+ Extensions
- \+ New Field Discoveries
- \+ New Reservoir Discoveries in Old Fields
- – Report Year Production
- = Published Proved Reserves at End of Report Year

A ratio was calculated as the sum of the annual production and year-end proved reserves of those respondents who did not provide the reserves balance components, divided by the sum of year-end proved reserves and annual production of those respondents who did provide these quantities. This ratio was then multiplied by each of the reserves balance components reported by Category I and some Category II operators, to obtain imputed volumes for the reserves balances of the other Category II operators and certainty and noncertainty operators. These were then added to the State/subdivision totals.

Imputation of Natural Gas Type Volumes

Operators in the State/subdivision certainty and noncertainty strata were not asked to segregate their natural gas volumes by type of natural gas, i.e., nonassociated natural gas (NA) and associated-dissolved natural gas (AD). The total estimated year-end proved reserves of natural gas

Table F2. Summary of Reported Total Natural Gas, Wet After Lease Separation, Data Used in Estimation Process, Form EIA-23

(Million Cubic Feet at 14.73 psia and 60° Fahrenheit)

Level of Reporting	Operator Category				
	I	II	Noncertainty[a] III	Certainty III	Total
Field Level Detail Report					
Proved Reserves as of 12/31/92	145,676,101	13,538,095	—	574,682	159,788,878
(+) Revisions Increases	15,363,662	1,628,024	—	32,413	16,727,420
(-) Revisions Decreases	10,703,055	1,130,678	—	11,809	12,142,221
(+) Extensions	5,071,774	754,603	—	75,933	5,902,310
(+) New Field Discoveries	813,126	76,539	—	3,250	892,915
(+) New Reservoirs in Old Fields	1,683,076	142,077	—	9,692	1,834,845
(-) Production in 1993	15,106,973	1,581,957	—	80,348	16,769,278
Proved Reserves as of 12/31/93	142,799,936	13,426,622	—	603,811	156,830,369
State Level Summary Report					
Production in 1993	0	27,593	14,295	221,332	263,220
Proved Reserves as of 12/31/93	0	143,574	145,514	2,201,725	2,490,813
Production Without Proved Reserves Reported in 1993	15,234	549,620	40,500	424,407	1,029,761
Total Production in 1993	**15,122,207**	**2,159,170**	**54,795**	**726,087**	**18,062,259**
Total Proved Reserves as of 12/31/93	**142,799,936**	**13,570,196**	**145,514**	**2,805,536**	**159,321,182**

[a]Unweighted reported data.
— = Not applicable.
Note: Field level data are reported volumes and may not balance due to submission of incomplete records.
Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1993.

Table F3. Summary of Reported Nonassociated Natural Gas, Wet After Lease Separation, Data Used in Estimation Process, Form EIA-23

(Million Cubic Feet at 14.73 psia and 60° Fahrenheit)

Level of Reporting	Operator Category				
	I	II	Noncertainty[a] III	Certainty III	Total
Field Level Detail Report					
Proved Reserves as of 12/31/92	119,763,299	11,152,945	—	506,446	131,422,690
(+) Revisions Increases	12,788,523	1,230,379	—	31,416	14,050,318
(-) Revisions Decreases	8,452,643	864,890	—	7,765	9,325,298
(+) Extensions	4,529,796	518,517	—	75,933	5,124,246
(+) New Field Discoveries	571,777	73,762	—	3,250	648,789
(+) New Reservoirs in Old Fields	1,548,423	123,114	—	9,692	1,681,229
(-) Production in 1993	12,898,895	1,280,444	—	71,928	14,251,267
Proved Reserves as of 12/31/93	117,852,177	10,953,322	—	547,044	129,352,543
State Level Summary Report					
Production in 1993	NA	NA	NA	NA	NA
Proved Reserves as of 12/31/93	NA	NA	NA	NA	NA
Production Without Proved Reserves Reported in 1993	7,048	413,085	NA	65,304	485,437
Total Production in 1993	**12,905,943**	**1,693,529**	**NA**	**137,232**	**14,736,704**
Total Proved Reserves as of 12/31/93	**117,852,177**	**10,953,322**	**NA**	**547,044**	**129,352,543**

[a]Unweighted reported data.
— = Not applicable.
Note: Field level data are reported volumes and may not balance due to submission of incomplete records.
Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1993.

Table F4. Summary of Reported Crude Oil Used in Estimation Process, Form EIA-23
(Thousand Barrels of 42 U.S. Gallons)

Level of Reporting	Operator Category I	II	Noncertainty[a] III	Certainty III	Total
Field Level Detail Report					
Proved Reserves as of 12/31/92	20,842,690	925,747	—	72,611	21,841,048
(+) Revisions Increases	1,719,166	143,047	—	3,894	1,866,107
(-) Revisions Decreases	1,264,792	114,078	—	3,383	1,382,253
(+) Extensions	284,030	32,921	—	200	317,151
(+) New Field Discoveries	316,866	1,847	—	0	318,713
(+) New Reservoirs in Old Fields	94,178	8,099	—	100	102,377
(-) Production in 1993	1,919,080	113,522	—	6,917	2,039,519
Proved Reserves as of 12/31/93	20,073,358	884,056	—	66,505	21,023,919
State Level Summary Report					
Production in 1993	0	3,886	2,802	40,751	47,439
Proved Reserves as of 12/31/93	0	25,751	83,723	402,120	511,594
Production Without Proved Reserves Reported in 1993	2,772	35,258	8,902	75,695	122,627
Total Production in 1993	**1,921,852**	**152,666**	**11,704**	**123,363**	**2,209,585**
Total Proved Reserves as of 12/31/93	**20,073,358**	**909,807**	**83,723**	**468,625**	**21,535,513**

[a]Unweighted reported data.
— = Not applicable.
Note: Field level data are reported volumes and may not balance due to submission of incomplete records.
Source: Form EIA-23, “Annual Survey of Domestic Oil and Gas Reserves,” 1993.

Table F5. Summary of Reported Lease Condensate Data Used in Estimation Process, Form EIA-23
(Thousand Barrels of 42 U.S. Gallons)

Level of Reporting	Operator Category I	II	Noncertainty[a] III	Certainty III	Total
Field Level Detail Report					
Proved Reserves as of 12/31/92	1,102,676	90,127	—	4,146	1,196,949
(+) Revisions Increases	154,993	19,470	—	166	174,629
(-) Revisions Decreases	165,057	23,306	—	124	188,487
(+) Extensions	42,863	4,703	—	0	47,566
(+) New Field Discoveries	6,758	1,757	—	0	8,515
(+) New Reservoirs in Old Fields	19,104	2,594	—	2	21,700
(-) Production in 1993	131,900	12,240	—	545	144,685
Proved Reserves as of 12/31/93	1,029,432	83,095	—	3,646	1,116,173
State Level Summary Report					
Production in 1993	0	92	45	1,186	1,323
Proved Reserves as of 12/31/93	0	1,731	10,502	41,798	54,031
Production Without Proved Reserves Reported in 1993	417	3,815	45	2,915	7,342
Total Production in 1993	**132,317**	**16,147**	**90**	**4,646**	**153,350**
Total Proved Reserves as of 12/31/93	**1,029,432**	**84,826**	**10,502**	**45,444**	**1,170,204**

[a]Unweighted reported data.
— = Not applicable.
NA = Not available.
Note: Field level data are reported volumes and may not balance due to submission of incomplete records.
Source: Form EIA-23, “Annual Survey of Domestic Oil and Gas Reserves,” 1993.

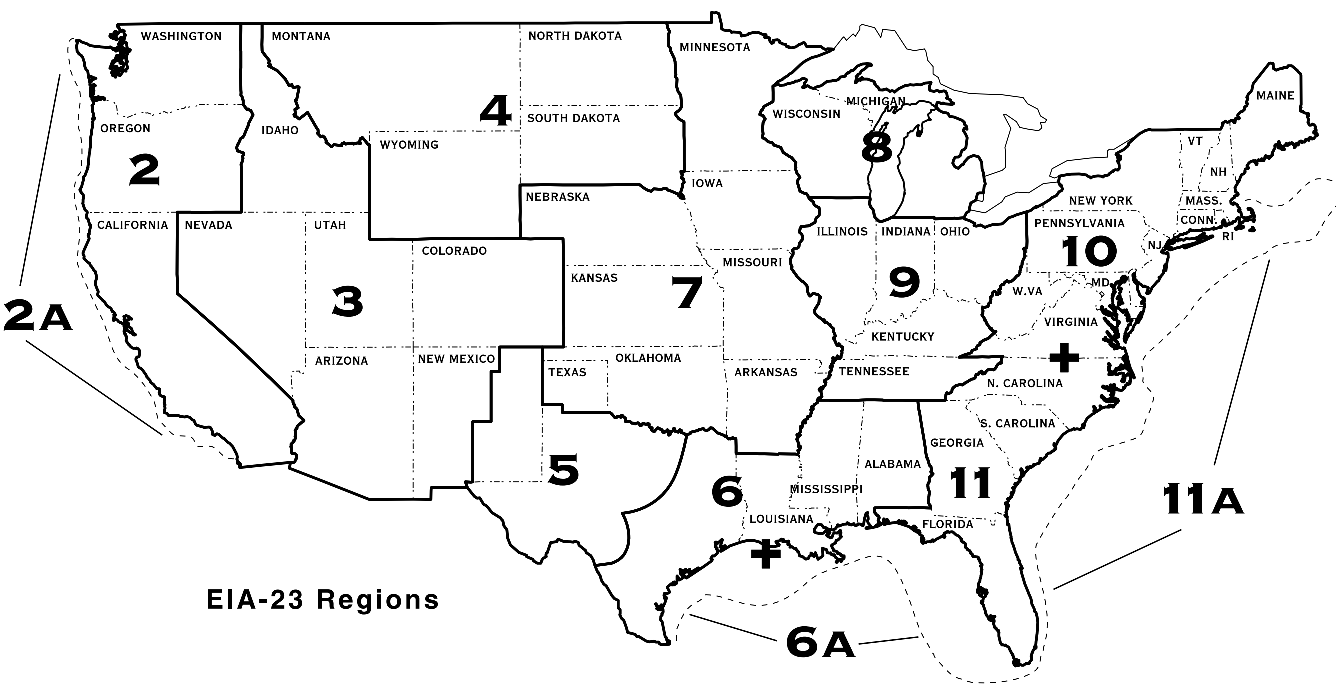
Table F6. Statistical Parameters of Reserve Estimation Equation by Region for 1993

Region Number	Region	Number of Nonzero R/P Pairs: Oil	Gas	Lease Condensate	Characteristic Multipliers: Oil	Gas	Lease Condensate
2	Pacific Coastal States	35	26	3	8.5	[a]7.3	[a]6.0
3	Western Rocky Mountains	72	78	19	6.1	8.6	[a]6.0
4	Northern Rocky Mountains	82	79	10	7.6	7.8	[a]6.0
5	West Texas and East New Mexico	212	202	51	6.7	7.5	6.4
6 + 6A	Western Gulf Basin and Gulf of Mexico	242	266	178	5.9	5.9	5.7
7	Mid-Continent	259	226	96	5.7	6.6	6.3
8 + 9	Michigan Basin and Eastern Interior	95	71	11	6.4	7.9	[a]6.0
10 + 11	Appalachians	29	53	2	7.3	11.9	[a]6.0
	United States	1,026	1,001	370	6.3	7.3	6.0

[a]Multiplier of the U.S. national average is assumed. Effect of multiplier on related natural gas or lease condensate reserves estimate negligible in these regions.

Source: Estimated based on data filed on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves, 1993.

Figure F1. Form EIA-23 Regional Boundaries



Source: Energy Information Administration, Office of Oil and Gas.

Source: Energy Information Administration, Office of Oil and Gas.

and the total annual production of natural gas reported by, or imputed to, operators in the State/subdivision certainty and noncertainty strata were, therefore, subdivided into the NA and AD categories, by State/subdivision, in the same proportion as was reported by Category I and Category II operators in the same area.

Adjustments

The instructions for Schedule A of Form EIA-23 specify that, when reporting reserves balance data, the following arithmetic equation must hold:

Proved Reserves at End of Previous Year
+ Revision Increases
– Revision Decreases
+ Extensions
+ New Field Discoveries
+ New Reservoir Discoveries in Old Fields
– Report Year Production
= Proved Reserves at End of Report Year

Any remaining difference in the State/subdivision annual reserves balance between the published previous year-end proved reserves and current year-end proved reserves not accounted for by the imputed reserves changes was included in the adjustments for the area. One of the primary reasons that adjustments are necessary is that very few of the same random operators are sampled each year. Less than 8 percent of the random stratum operators sampled in 1992 were sampled again in 1993, and there is no guarantee that in the smaller producing States/subdivision the same number of small operators will be selected each year, or that the operators selected will be of comparable sizes when paired with operators selected in a prior year. Thus, some instability of this stratum from year to year is unavoidable, resulting in minor adjustments.

Some of the adjustments are, however, more substantial, and could be required for any one or more of the following reasons:

- The frame coverage may or may not have improved between survey years, such that more or fewer certainty operators were included in 1993 than in 1992.
- The random sample for either year may have been an unusual one loaded by chance with either larger or smaller random operators.
- One or more operators may have reported data incorrectly on Schedule A in 1992 or 1993, but not both, and the error was not detected by edit processing.
- Operation of properties was transferred during 1993 from operators not in the frame or random operators not selected for the sample to certainty operators or random operators selected for the sample.
- Operations of properties was transferred during 1993 to an operator with a different evaluation of the proved reserves associated with the properties than that of the 1992 operator.
- Respondent changed classification of natural gas from NA to AD or vice versa.
- The trend in reserve changes imputed for the small operators, that was based on the trend reported by the large operators, did not reflect the actual trend for the small operators.
- Random operators, who have grown substantially in size since they were added to the frame, occasionally cause a larger standard error than expected.

The causes of adjustments are known for some but not all areas. The only problems whose effects cannot be expected to balance over a period of several years are those associated with an inadequate frame or those associated with any actual trend in reserve changes for small operators not being the same as those for large operators. EIA continues to attempt to improve sources of operator data to resolve problems in frame completeness.

Sampling Reliability of the Estimates

The sample of noncertainty operators selected is only one of the large number of possible samples that could have been selected and each would have resulted in different estimates. The standard error or sampling error of the estimates provides a measure of this variability. When probability sampling methods are used, as in the EIA-23 survey, the sampling error of estimates can also be estimated from the survey data.

The estimated sampling error can be used to compute a confidence interval around the survey estimate, with a prescribed degree of confidence that the interval covers the value that would have been obtained if all operators in the frame had been surveyed. If the estimated volume is denoted by $\hat{V}_S$ and its sampling error by S.E. ($\hat{V}_S$), the confidence interval can be expressed as:

$$\hat{V}_s \pm k\,S.E.(\hat{V}_s)$$

where k is a multiple selected to provide the desired level of confidence. For this survey, k was taken equal to 2. Then there is approximately 95 percent confidence that the interval:

$$\hat{V}_s \pm 2S.E.(\hat{V}_s)$$

includes the universe value, for both the estimates of reserves and production volumes. Correspondingly, for approximately 95 percent of the estimates in this report, the difference between the published estimate and the value that would be found from a complete survey of all operators is expected to be less than twice the sampling error of the estimate. Tables F7, F8, F9, and F10 provide estimates for 2S.E.($\hat{V}_S$) by product. These estimates are directly applicable for constructing approximate 95 percent confidence intervals. EIA estimates should be viewed as the value of the estimate plus or minus twice the associated sampling error. The sampling error of $\hat{V}_S$ is equal to the sampling error of the noncertainty estimate $\hat{V}_{sr}$, because the certainty total is not subject to sampling error. The estimated sampling error of a noncertainty estimate is the square root of its estimated sampling variance.

The noncertainty estimate for a given State/subdivision had two separately weighted components based on reports of:

- **Type 1 Operators** shown in the frame as having had crude oil or natural gas production in the State/subdivision.
- **Type 2 Operators** shown in the frame as having had no crude oil or natural gas production in the State/subdivision.

Correspondingly, the sampling variance had two components associated with the estimated production from each component:

$$Var(\hat{V}_{sr}) = Var(\hat{V}_{sr1}) + Var(\hat{V}_{sr2})$$

The $Var(V_{sr})$ was estimated as the sum of the estimated variances of the two component estimates. The variance for any component, say component j, was estimated from the formula:

$$Var(\hat{V}_{srj}) = n_{srj}\left(\frac{W_{srj}-1}{W_{srj}}\right)S^2_{srj}$$

In general, $\hat{V}_{srj}$ denotes the production estimate from component j for each of the two types of operator, and $Var(\hat{V}_{srj})$ denotes its variance where

n_{srj} = number of operators in sample in component j

w_{srj} = weight for operator reports in component j

S^2_{srj} = variance between operator reports in component j.

If the subscripts sr are dropped, S^2_{srj} can be expressed as:

$$S^2_j = \frac{\sum_i^{n_j} V'^2_{ji} - \left(\sum_i^{n_j} V'_{ji}\right)^2 / n_j}{n_j - 1}$$

where

V'_{ji} = weighted production or reserves volume for the i-th sample operator in the component j.

The variance of the estimated total volume for a State having subdivisions is the sum of corresponding Type 1 and Type 2 components where the classification of operators by type is with regard to the State as a whole; e.g., Type 2 operators at the State level are those that were not shown in the sample frame as having production anywhere in the State.

Since there are no operators in the frame who would be classified as Type 2 at the U.S. level, there would be no Type 2 components at the U.S. level. Therefore, at the U.S. level there was only one sample variance component calculated, for Type 1 operators.

Discussion of Nonsampling Errors

Several sources of possible error, apart from sampling error, are associated with the Form EIA-23 survey. These include bias due to nonresponse of operators in the sample, proved reserve estimation errors, and reporting errors on the part of the respondents to the survey. On the part of EIA, possible errors include inadequate frame coverage, data processing error, and errors associated with statistical estimates. Each

Table F7. Factors for Confidence Intervals (2S.E.) for Dry Natural Gas Proved Reserves and Production, 1993 (Billion Cubic Feet at 14.73 psia and 60 Degrees Fahrenheit)

State and Subdivision	1993 Reserves	1993 Production
United States	578	79
Alabama	34	6
Alaska	0	0
Arkansas	20	3
California	35	5
Coastal Region Onshore	8	2
Los Angeles Basin Onshore	1	0
San Joaquin Basin Onshore	30	4
State Offshore	0	0
Colorado	145	13
Florida	20	3
Kansas	91	16
Kentucky	56	7
Louisiana	151	25
North	34	6
South Onshore	154	25
State Offshore	0	0
Michigan	72	7
Mississippi	69	8
Montana	19	2
New Mexico	102	15
East	38	6
West	89	14
New York	79	7
North Dakota	39	5
Ohio	27	3
Oklahoma	235	51
Pennsylvania	97	8
Texas	314	39
RRC District 1	15	3
RRC District 2 Onshore	52	7
RRC District 3 Onshore	96	17
RRC District 4 Onshore	149	13
RRC District 5	26	5
RRC District 6	98	17
RRC District 7B	50	5
RRC District 7C	65	9
RRC District 8	88	11
RRC District 8A	10	1
RRC District 9	38	5
RRC District 10	38	6
State Offshore	0	0
Utah	26	2
Virginia	0	0
West Virginia	119	10
Wyoming	37	6
Federal Offshore[a]	0	0
Pacific (California)	0	0
Gulf of Mexico (Louisiana)[a]	0	0
Gulf of Mexico (Texas)	0	0
Miscellaneous[b]	5	0

[a]Includes Federal offshore Alabama.

[b]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee.

Note: Factors for confidence intervals for each State subdivision, State, and the United States are independently estimated and do not add.

Source: Factor estimates based on data filed on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1993 and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production," 1993.

Table F8. Factors for Confidence Intervals (2S.E.) for Natural Gas Proved Reserves and Production, Wet After Lease Separation, 1993 (Billion Cubic Feet at 14.73 psia and 60 Degrees Fahrenheit)

State and Subdivision	1993 Reserves	1993 Production
United States	611	84
Alabama	38	6
Alaska	0	0
Arkansas	20	3
California	37	5
Coastal Region Onshore	9	2
Los Angeles Basin Onshore	1	0
San Joaquin Basin Onshore	31	5
State Offshore	0	0
Colorado	156	14
Florida	22	4
Kansas	96	17
Kentucky	58	7
Louisiana	158	26
North	35	6
South Onshore	161	26
State Offshore	0	0
Michigan	76	7
Mississippi	69	8
Montana	19	2
New Mexico	106	16
East	42	7
West	98	15
New York	79	7
North Dakota	44	6
Ohio	27	3
Oklahoma	249	54
Pennsylvania	97	8
Texas	338	42
RRC District 1	16	3
RRC District 2 Onshore	56	8
RRC District 3 Onshore	105	18
RRC District 4 Onshore	156	13
RRC District 5	27	5
RRC District 6	103	17
RRC District 7B	61	6
RRC District 7C	73	10
RRC District 8	97	12
RRC District 8A	14	2
RRC District 9	44	6
RRC District 10	42	6
State Offshore	0	0
Utah	28	3
Virginia	0	0
West Virginia	127	11
Wyoming	38	6
Federal Offshore[a]	0	0
Pacific (California)	0	0
Gulf of Mexico (Louisiana)[a]	0	0
Gulf of Mexico (Texas)	0	0
Miscellaneous[b]	5	0

[a]Includes Federal offshore Alabama.

[b]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee.

Note: Factors for confidence intervals for each State subdivision, State, and the United States are independently estimated and do not add.

Source: Factor estimates based on data filed on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1993

Table F9. Factors for Confidence Intervals (2S.E.) for Crude Oil Proved Reserves and Production, 1993
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	1993 Reserves	1993 Production	State and Subdivision	1993 Reserves	1993 Production
United States	98	13	North Dakota	14	2
Alabama	1	0	Ohio	5	1
Alaska	0	0	Oklahoma	38	6
Arkansas	11	2	Pennsylvania	0	0
California	35	2	Texas	67	9
Coastal Region Onshore	31	1	RRC District 1	13	2
Los Angeles Basin Onshore	3	0	RRC District 2 Onshore	5	1
San Joaquin Basin Onshore	11	2	RRC District 3 Onshore	21	3
State Offshore	0	0	RRC District 4 Onshore	6	1
Colorado	8	1	RRC District 5	7	1
Florida	1	0	RRC District 6	10	2
Illinois	8	1	RRC District 7B	39	1
IndianaT 0	0		RRC District 7C	10	1
Kansas	17	2	RRC District 8	29	4
Kentucky	2	0	RRC District 8A	14	2
Louisiana	10	2	RRC District 9	10	1
North	3	0	RRC District 10	5	1
South Onshore	8	1	State Offshore	0	0
State Offshore	0	0	Utah	15	3
Michigan	8	2	West Virginia	1	0
Mississippi	7	1	Wyoming	8	1
Montana	6	1	Federal Offshore	0	0
Nebraska	1	0	Pacific (California)	0	0
New Mexico	13	2	Gulf of Mexico (Louisiana)	0	0
East	11	2	Gulf of Mexico (Texas)	0	0
West	5	1	Miscellaneous[a]	2	0

[a]Includes Arizona, Missouri, Nevada, New York, South Dakota, Tennessee, and Virginia.

Note: Factors for confidence intervals for each State subdivision, State, and the United States are independently estimated and do not add.

Source: Factor estimates based on data filed on Form EI-23, “Annual Survey of Domestic Oil and Gas Reserves,” 1993.

Table F10. Factors for Confidence Intervals (2S.E.) for Lease Condensate Proved Reserves and Production, 1993 (Million Barrels of 42 U.S. Gallons)

State and Subdivision	1993 Reserves	1993 Production	State and Subdivision	1993 Reserves	1993 Production
United States	8	1	North Dakota	0	0
Alabama	0	0	Oklahoma	2	0
Alaska	0	0	Texas	7	1
Arkansas	0	0	RRC District 1	0	0
California	0	0	RRC District 2 Onshore	1	0
Coastal Region Onshore	0	0	RRC District 3 Onshore	1	0
Los Angeles Basin Onshore	0	0	RRC District 4 Onshore	1	0
San Joaquin Basin Onshore	0	0	RRC District 5	0	0
State Offshore	0	0	RRC District 6	3	0
Colorado	1	0	RRC District 7B	0	0
Florida	0	0	RRC District 7C	1	0
Kansas	0	0	RRC District 8	0	0
Kentucky	0	0	RRC District 8A	2	0
Louisiana	1	0	RRC District 9	6	1
North	0	0	RRC District 10	0	0
South Onshore	1	0	State Offshore	0	0
State Offshore	0	0	Utah and Wyoming	0	0
Michigan	0	0	West Virginia	0	0
Mississippi	0	0	Federal Offshore[a]	0	0
Montana	0	0	Pacific (California)	0	0
New Mexico	1	0	Gulf of Mexico (Louisiana)[a]	0	0
East	0	0	Gulf of Mexico (Texas)	0	0
West	1	0	Miscellaneous[b]	0	0

[a]Includes Federal offshore Alabama.

[b]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, New York, Ohio, Oregon, Pennsylvania, South Dakota, Tennessee, and Virginia.

Note: Factors for confidence intervals for each State subdivision, State, and the United States are independently estimated and do not add.

Source: Factor estimates based on data filed on Form EIA-23, “Annual Survey of Domestic Oil and Gas Reserves,” 1993.

of these sources is discussed below. An estimate of the bias from nonresponse is presented in the section on adjustment for operator nonresponse.

Assessing the Accuracy of the Reserve Data

The EIA maintains an evaluation program to assess the accuracy and quality of proved reserve estimates gathered on Form EIA-23. Field teams consisting of petroleum engineers from EIA's Dallas Field Office conduct technical reviews of reserve estimates and independently estimate the proved reserves of a statistically selected sample of operator properties. The results of these reviews are used to evaluate the accuracy of reported reserve estimates. Operators are apprised of the team's findings to assist them in completing future filings. The magnitude of errors due to differences between reserve volumes submitted by operators on the Form EIA-23 and those estimated by EIA petroleum engineers on their field trips were generally within accepted professional engineering standards.

Respondent Estimation Errors

The principal data elements of the Form EIA-23 survey consist of respondent estimates of proved reserves of crude oil, natural gas, and lease condensate. Unavoidably, the respondents are bound to make some estimation errors, i.e., until a particular reservoir has been fully produced to its economic limit and abandoned, its reserves are not subject to direct measurement but must be inferred from limited, imperfect, or indirect evidence. A more complete discussion of the several techniques of estimating proved reserves, and the many problems inherent in the task, appears in Appendix G.

Reporting Errors and Data Processing Errors

Reporting errors on the part of respondents are of definite concern in a survey of the magnitude and complexity of the Form EIA-23 program. Several steps were taken by EIA to minimize and detect such problems. The survey instrument itself was carefully developed, and included a detailed set of instructions for filing data, subject to a common set of definitions similar to those already used by the industry. Editing software is continually developed to detect different kinds of probable reporting errors and flag them for resolution by analysts, either through confirmation of the data by the respondent or through submission of amendments to the filed data. Data processing errors, consisting primarily of random keypunch errors, are detected by the same software.

Imputation Errors

Some error, generally expected to be small, is an inevitable result of the various estimations outlined. These imputation errors have not yet been completely addressed by EIA and it is possible that estimation methods may be altered in future surveys. Nationally, about 6.2 percent of the crude oil proved reserve estimates, 6.7 percent of the natural gas proved reserve estimates, and 2.8 percent of the lease condensate proved reserve estimates resulted from the imputation and estimation of reserves for those certainty and noncertainty operators who did not provide estimates for all of their properties, in combination with the expansion of the sample of noncertainty operators to the full population. Errors for the latter were quantitatively calculated, as discussed in the previous section. Standard errors, for the former, would tend to cancel each other from operator to operator, and are, therefore, expected to be negligible, especially at the National level of aggregation. In States where a large share of total reserves is accounted for by Category III and smaller Category II operators, the errors are expected to be somewhat larger than in States where a large share of total reserves is accounted for by Category I and larger Category II operators.

Frame Coverage Errors

Of all the sources of controllable error connected with the Form EIA-23 survey, errors in the operator frame were expected to be the most important. If the frame does not list all operators in a given State, the sample selected from the frame for the State will not represent the entire operator population, a condition called undercoverage. Undercoverage is a problem with certain States, but it does not appear to be a problem with respect to the National proved reserve estimates for either crude oil or natural gas. While it is relatively straightforward to use existing sources to identify large operators and find addresses for them, such is not the case for small operators. A frame such as that used in the 1993 survey is particularly likely to be deficient in States where a large portion of total reserves and production is accounted for by small operators. These States are not likely to allocate sufficient resources to keep track of all operators on a current basis. Some undercoverage of this type seems to exist, particularly, with reference to natural gas operators. EIA is continuing to work to remedy the undercoverage problem in those States where it occurred.

Calculation of Reserves of Natural Gas Liquids and Dry Natural Gas

Natural Gas Liquids Reserve Balance

The published reserves, production, and reserves change statistics for crude oil, lease condensate, and natural gas, wet after lease separation, were derived from the data reported on Form EIA-23 and the application of the imputation methods discussed previously. The information collected on Form EIA-64A was then utilized in converting the estimates of the wet natural gas reserves into two components: plant liquids reserve data and dry natural gas reserve data. The total natural gas liquids reserve estimates presented in Table 14 were computed as the sum of plant liquids estimates (Table 15) and lease condensate (Table 16) estimates.

To generate estimates for each element in the reserves balance for plant liquids in a given producing area, the first step was to group all natural gas processing plants that reported this area as an area-of-origin on their Form EIA-64A, and then sum the liquids production attributed to this area over all respondents. Next, the ratio of the liquids production to the total wet natural gas production for the area was determined. This ratio represented the percentage of the wet natural gas that was recovered as natural gas liquids. Finally, it was assumed that this ratio was applicable to the reserves and each component of reserve changes (except adjustments), as well as production. Therefore, each element in the wet natural gas reserves balance was multiplied by this recovery factor to yield the corresponding estimate for plant liquids. Adjustments of natural gas liquids were set equal to the difference between the end of previous year reserve estimates, based upon the current report year Form EIA-23 and Form EIA-64A surveys, and the end of current year reserve estimates published in the preceding year's annual reserves report.

Natural Gas Reserve Balance

This procedure involved downward adjustments of the natural gas data, wet after lease separation, in estimating the volumes of natural gas on a fully dry basis. These reductions were based on estimates of the gaseous equivalents of the liquids removed (in the case of production), or expected to be removed (in the case of reserves), from the natural gas stream at natural gas processing plants. Form EIA-64A collected the volumetric reduction, or **shrinkage**, of the input natural gas stream that resulted from the removal of the NGL at each natural gas processing plant.

The shrinkage volume was then allocated to the plant's reported area or areas of origin. Because shrinkage is, by definition, roughly in proportion to the NGL recovered, i.e. the NGL produced, the allocation was in proportion to the reported NGL volumes for each area of origin. However, these derived shrinkage volumes were rejected if the ratio between the shrinkage and the NGL production (gas equivalents ratio) fell outside certain limits of physical accuracy. The ratio was expected to range between 1,558 cubic feet per barrel (where NGL consists primarily of ethane) and 900 cubic feet per barrel (where NGL consists primarily of natural gasolines). When the computed gas equivalents ratio fell outside these limits, an imputed ratio was utilized to estimate the plant's natural gas shrinkage allocation to each reported area of origin.

This imputed ratio was that calculated for the aggregate of all other plants reporting production and shrinkage, and having a gas equivalent ratio within the aforesaid limits, from the area in question. The imputed area ratio was applied only if there were at least five plants to base its computation on. If there were less than five plants, the imputed ratio was calculated based on all plants in the survey whose individual gas equivalents ratio was within the acceptable limits. Less than one percent of the liquids production was associated with shrinkage volumes imputed in this manner. Based on the 1993 Form EIA-64A survey, the national weighted average gas equivalents ratio was computed to be 1,397 cubic feet of natural gas shrinkage per barrel of NGL recovered. This is 5 cubic feet per barrel more than in the 1992 survey. The total shrinkage volume (reported plus imputed) for all plants reporting a given area of origin was then subtracted from the estimated value of natural gas production, wet after lease separation, yielding dry natural gas production for the area. The amount of the reduction in the wet natural gas production was then expressed as a percentage of the wet natural gas production. Dry natural gas reserves and reserve changes were determined by reducing the wet natural gas reserves and reserve changes by the same percentage reduction factor.

A further refinement of the estimation process was added this year. This refinement was a change in methodology to generate an estimate of the natural gas liquid reserves in those States with large amounts of coalbed methane. The first step in the process was to identify all Form EIA-23 reported coalbed methane fields. The second step was to estimate the amount of the undercoverage in the nonreported coalbed methane fields on Form EIA-23. Production of coalbed methane in reported fields was compared to the State reported production of coalbed methane, to calculate a factor to increase reported coalbed methane production to the reported State production of coalbed methane. This factor was applied to each reported element in the reserve balance for a State. The assumption was made that coalbed methane fields contained little or no extractable natural gas liquids. Therefore, when the normal shrinkage procedure was applied to the wet gas volume elements, the estimate of State coalbed methane volumes were excluded and were not reduced for liquid extraction. Following the computation for shrinkage, each coalbed field gas volume was added back to each of the dry gas volume elements in a State. The effect of this is that the large increases in reserves in some States from coalbed methane fields did not cause corresponding increases in the State natural gas liquids proved reserves. The States where this procedure was applied were Alabama, Colorado, and New Mexico.

Adjustments of dry natural gas were set equal to the difference between the end of previous year reserves estimates, based upon the current report year Form EIA-23 and Form EIA-64A surveys, and the end of current year reserve estimates published in the preceding year's annual reserves report.

Each estimate of end of year reserves and report year production has associated with it an estimated sampling error. The standard errors for dry natural gas were computed by multiplying the wet natural gas standard errors by these same percentage reduction factors. Table F7 provides estimates for 2 times the $S.E.(\hat{V}_S)$ for dry natural gas.

Appendix G

Reserve Estimation Methodologies

The adoption of a standard definition of proved reserves for each type of hydrocarbon surveyed by the Form EIA-23 program provided a far more consistent response from operators than if each operator had used his own definition. Such standards, however, do not guarantee that the resulting estimates themselves are determinate. Regardless of the definition selected, proved reserves cannot be measured directly. They are estimated quantities that are inferred on the basis of the best geological, engineering, and economic data available to the estimator, who generally uses considerable judgment in the analysis and interpretation of the data. Consequently, the accuracy of a given estimate varies with and depends on the quality and quantity of raw data available, the estimation method used, and the training and experience of the estimator. The element of judgment commonly accounts for the differences among independent estimates for the same reservoir or field.

Data Used in Making Reserve Estimates

The raw data used in estimating proved reserves include data on engineering and geological properties of the reservoir rock and its hydrocarbon fluids. These data are obtained from direct measurements. The data available for a given reservoir vary in kind, quality, and quantity. When a reservoir is first discovered only data from a single well are available, and prior to flow testing or actual production, proved reserves can only be inferred. As development of the reservoir proceeds, and flow tests are made or actual production commences, more and more data become available, enabling proved reserves estimates to become more accurate.

Many different kinds of data are useful in making reserves estimates. They may include: data on porosity, permeability, and fluid saturations of the reservoir rocks (obtained directly from core analysis or from various types of electrical measurements taken in a well or several wells); data on the production of fluids from a well or several wells; geologic maps of the areal extent, thickness, and continuity of the reservoir rocks (inferred from well logs, geophysical, and geological data); and reservoir pressure and temperature data. Also involved are economic data including the current price of crude oil and natural gas, and various developmental and operating costs.

Reserve Estimation Techniques

Depending on the kinds and amounts of data available, and a judgment on the reliability of those data, the estimator will select one of several methods of making a proved reserves estimate. Methods based on production performance data are generally more accurate than those based strictly on inference from geological and engineering data. Such methods include the *Production Decline* method (for crude oil or natural gas reservoirs), the *Material Balance* method (for crude oil reservoirs), the *Pressure Decline* method (which is actually a material balance, for natural gas reservoirs), and *Reservoir Simulation* method (for crude oil or natural gas reservoirs). The reservoir type and production mechanisms and the types and amounts of reliable data available determine which of these methods is more appropriate for a given reservoir. These methods are of comparable accuracy.

Methods not based upon production data include the *Volumetric* method (for crude oil or natural gas reservoirs) and the *Nominal* method. Of these, the *Volumetric* method is the more accurate. Both methods, however, are less accurate than those based on production data. Table G1 summarizes the various methods.

Judgmental Factors in Reserve Estimation

The determination of rock and hydrocarbon fluid properties involves judgment and is subject to some uncertainty; however, the construction of the geologic maps and cross sections and the determination of the size of the reservoir are the major judgmental steps in the *Volumetric* method, and are subject to the greatest uncertainty. Estimates made using the *Material Balance* method, the *Reservoir Simulation* method, or the *Pressure Decline* method are based on the

Table G1. Reserve Estimation Techniques

Method	Comments
Volumetric	Applies to crude oil and natural gas reservoirs. Based on raw engineering and geologic data.
Material Balance	Applies to crude oil and natural gas reservoirs. Is used in estimating reserves. Usually of more value in predicting reserves, and reservoir performance.
Pressure Decline	Applies to nonassociated and associated gas reservoirs. The method is a special case of material balance equation in the absence of water influx.
Production Decline	Applies to crude oil and natural gas reservoirs during production decline (usually in the later stages of reservoir life).
Reservoir Simulation	Applies to crude oil and natural gas reservoirs. Is used in estimating reserves. Usually of more value in predicting reservoir performance. Accuracy increases when matched with past pressure and production data.
Nominal	Applied to crude oil and natural gas reservoirs. Based on rule of thumb or analogy with another reservoir or reservoirs believed to be similar; least accurate of methods used.

Source: Energy Information Administration, Office of Oil and Gas.

estimator's judgment that the type of reservoir drive mechanism has been identified and on the specification of abandonment conditions. Estimates based on the *Production Decline* method are subject to judgment in constructing the trend line, and are based on the estimator's assumption of reservoir performance through abandonment.

Contributing to the degree of uncertainty inherent in the above methods for estimating reserves are other factors associated with economic considerations and the perceived reservoir limits, which together influence the final reserves estimate. A brief discussion of these other factors follows.

Economic Considerations. There has been continuing debate about the effects of prices on proved reserves. Although no all-inclusive statement can be made on the impact of price, the points at issue can be discussed and some general remarks can be made about some circumstances where price may be a factor.

Developed gas fields. In a gas reservoir, price affects the economic limit (i.e., the production rate required to meet operating costs) and, therefore, the abandonment pressure. Thus, price change has some effect on the conversion of noneconomic hydrocarbon resources to the category of proved reserves. In both nearly depleted reservoirs and newly developed reservoirs, the actual increase in the quantity of proved reserves resulting from price rises is generally limited in terms of national volumes (even though the percentage increase for a given reservoir may be great).

- ***Developed oil fields.*** In developed crude oil reservoirs many of the same comments apply; however, there is an additional consideration. If the price is raised to a level sufficient to justify initiation of an improved recovery project, and if the improved recovery technique is effective, then the addition to ultimate recovery from the reservoir can be significant. Because of the speculative nature of predicting prices and costs many years into the future, proved reserves are estimated on the basis of current prices, costs, and operating practices in effect as of the date the estimation was made.

- ***Successful exploration efforts.*** Price can have a major impact on whether a new discovery is produced or abandoned. For example, the decision to set casing in a new onshore discovery, or to install a platform as the result of an offshore discovery, are both price-sensitive. If the decision is made to set pipe or to install a platform, the discoveries in both cases will add to the proved reserves total. If such projects are abandoned, they will make no contribution to the proved reserves total.

Effect of operating conditions. Operating conditions are subject to change caused by changes in economic conditions, unforeseen production problems, new production practices or methods, and the operator's financial position. As with economic conditions, operating conditions to be expected at the time of abandonment are speculative. Thus, current operating conditions are used in estimating proved reserves. In considering the effect of operating conditions, a distinction must be made between processes and techniques that would normally be applied by a prudent operator in producing his oil and gas, and initiation of changes in operating conditions that would require substantial new investment.

- **Compression.** Compression facilities are normally installed when the productive capacity or deliverability of a natural gas reservoir or its individual wells declines. In other cases compression is used in producing shallow, low-pressure reservoirs or reservoirs in which the pressure has declined to a level too low for the gas to flow into a higher pressure pipeline. The application of compression increases the pressure and, when economical, is used to make production into the higher pressure pipeline possible. Compression facilities normally require a significant investment and result in a change in operating conditions. It increases the proved reserves of a reservoir, and reasonably accurate estimates of the increase can be made.

- **Well stimulation.** Procedures that increase productive capacity (workovers, such as acidizing or fracturing, and other types of production practices) are routine field operations. The procedures accelerate the rate of production from the reservoir, or extend its life, and they have only small effect on proved reserves. Reasonable estimates of their effectiveness can be made.

- **Improved recovery techniques.** These techniques involve the injection of a fluid or fluids into a reservoir to augment natural reservoir energy. Because the response of a given reservoir to the application of an improved recovery technique cannot be accurately predicted, crude oil production that may ultimately result from the application of these techniques is classified as "indicated additional reserves of crude oil" rather than as proved reserves until response of the reservoir to the technique has been demonstrated. In addition, improved recovery methods are not applicable to all crude oil reservoirs. Initiation of improved recovery techniques may require significant investment.

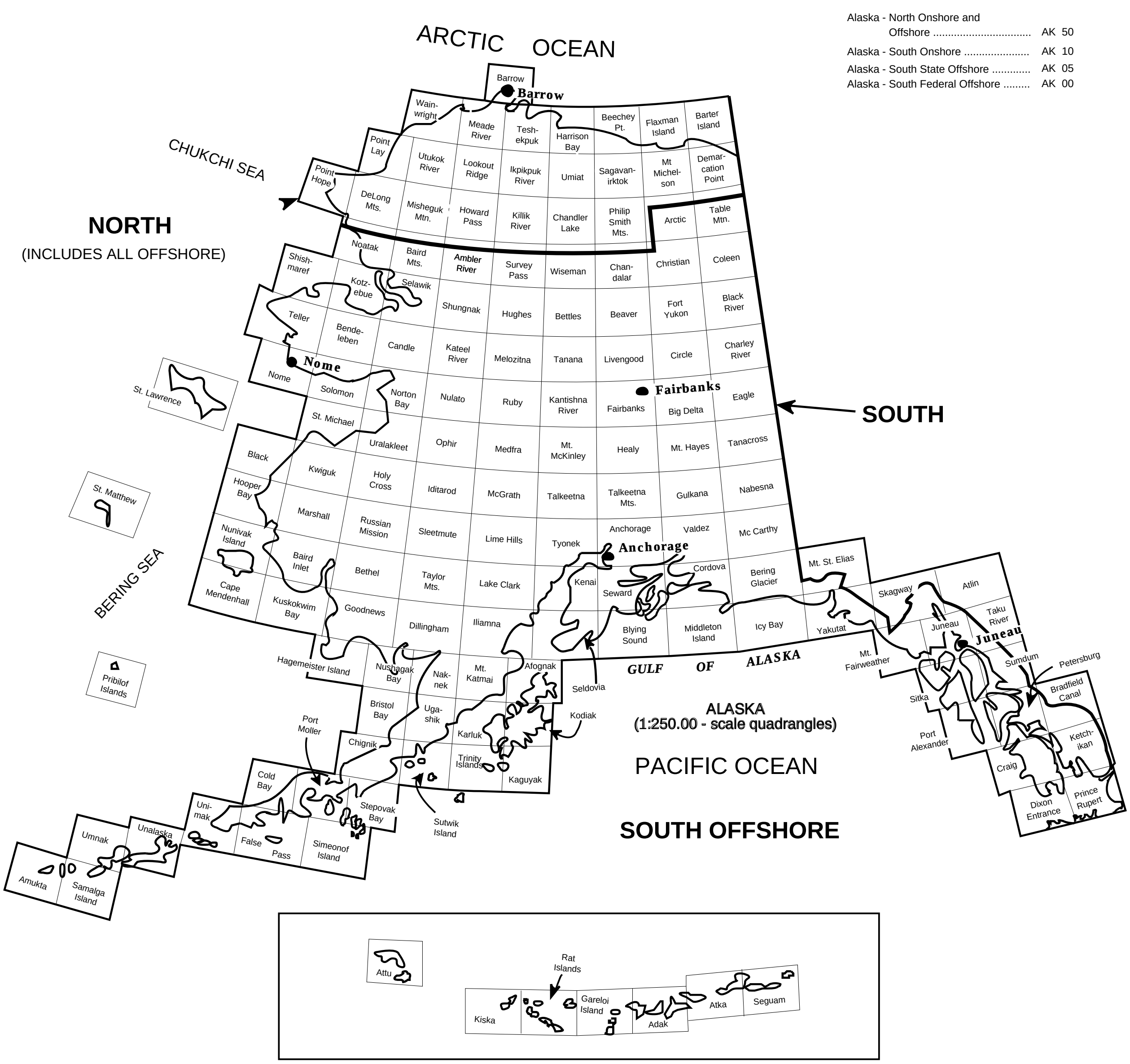
- **Infill drilling.** Infill drilling (drilling of additional wells within a field/reservoir) may result in a higher recovery factor, and, therefore, be economically justified. Predictions of whether infill drilling will be justified under current economic conditions are generally based on the expected production behavior of the infill wells.

Reservoir Limits. The initial proved reserves estimate made from the discovery well is subject to significant uncertainty because one well provides little information on the size of the reservoir. The area proved by a discovery well is frequently estimated on the basis of experience in a given producing region. Where there is continuity of the producing formation over wide geographic areas, a relatively large proved area may be assigned. In some cases where reliable geophysical and geological data are available, a reasonable estimate of the extent of the reservoir can be made by drilling a relatively small number of delineation wells. Conversely, a relatively small proved area may be assigned when the producing formation is of limited continuity, owing to either structural or lithological factors.

Additional wells provide more information and reduce the uncertainty of the reserves estimate. As additional wells are drilled, the geometry of the reservoir and, consequently, its bulk volume, become more clearly defined. This process accounts for the large extensions to proved reserves typical of the early stages of most reservoir development.

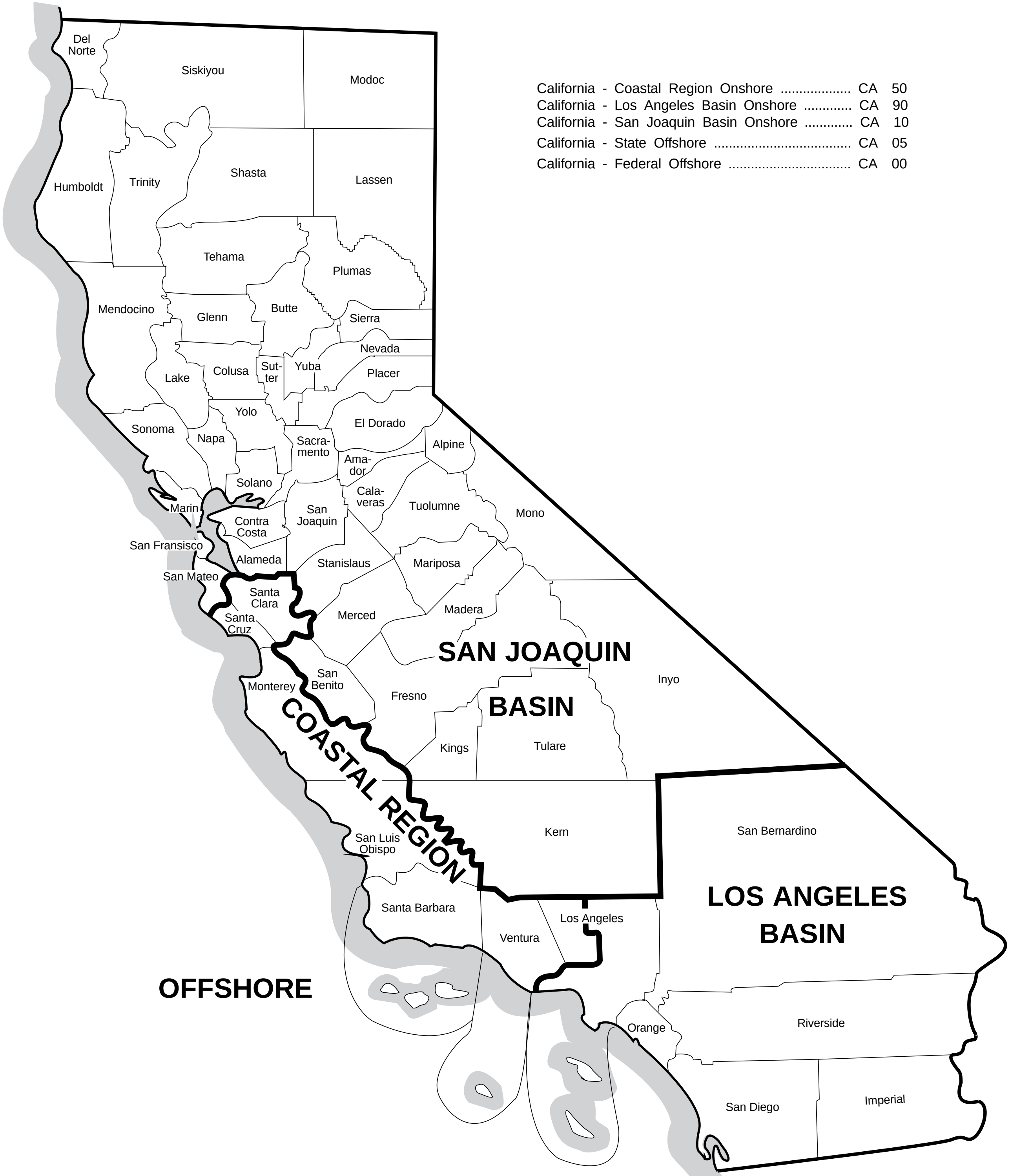
Maps of Selected State Subdivisions

Figure H1. Subdivisions of Alaska



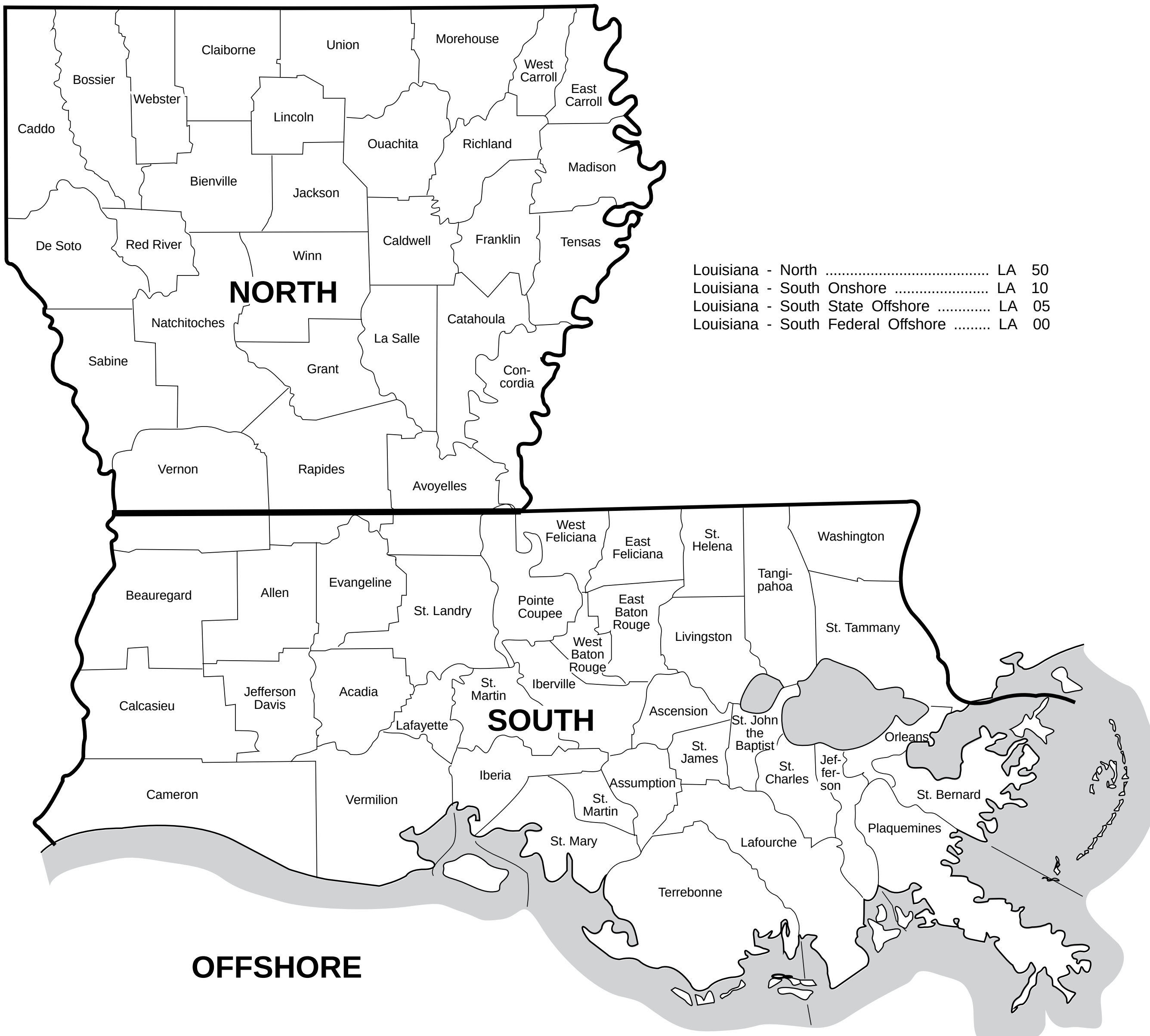
Source: After U.S. Geological Survey

Figure H2. Subdivisions of California



Source: Energy Information Administration, Office of Oil and Gas.

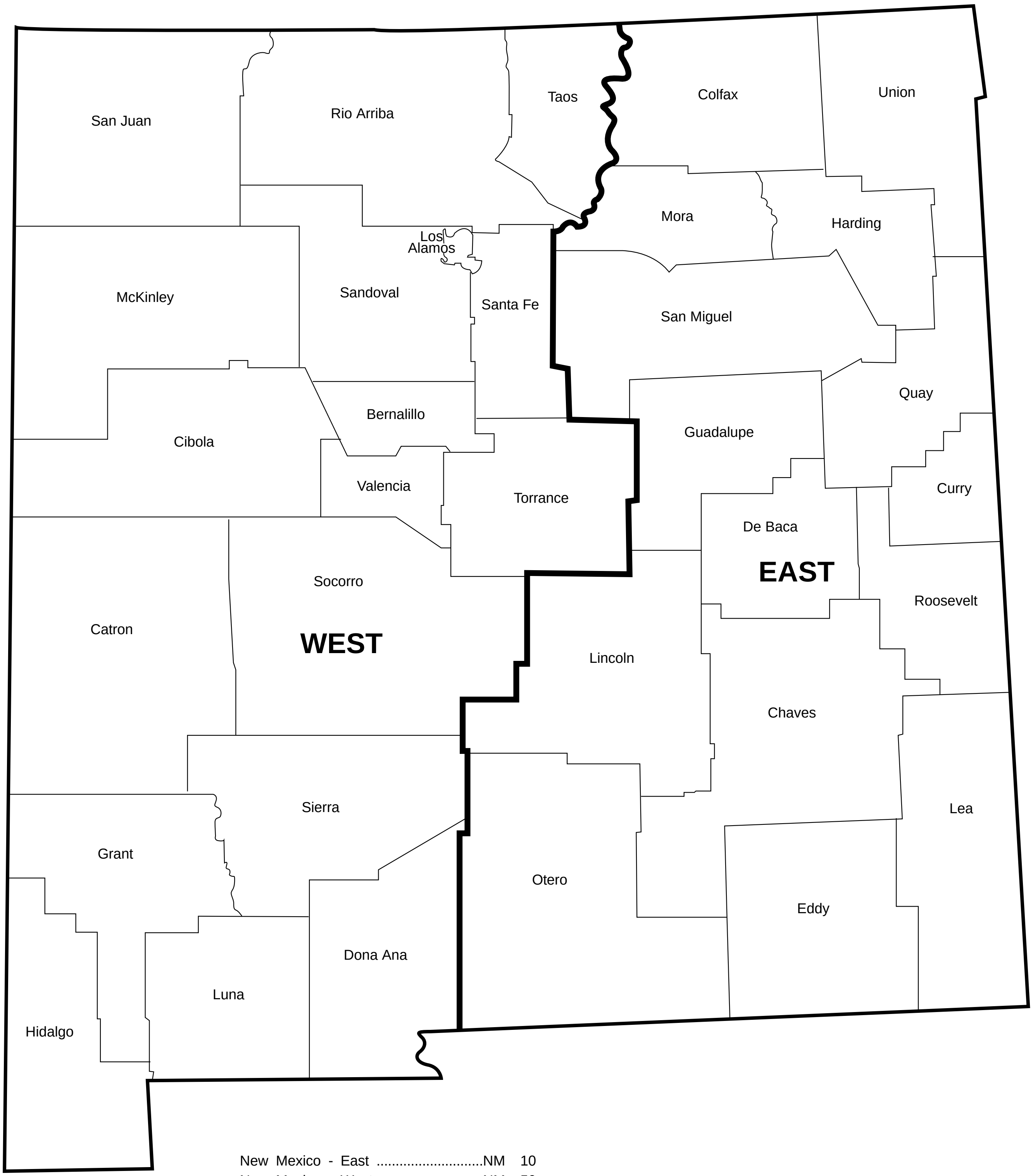
Figure H3. Subdivisions of Louisiana



Louisiana - North .... LA 50
Louisiana - South Onshore .... LA 10
Louisiana - South State Offshore .... LA 05
Louisiana - South Federal Offshore .... LA 00

Source: Energy Information Administration, Office of Oil and Gas.

Figure H4. Subdivisions of New Mexico

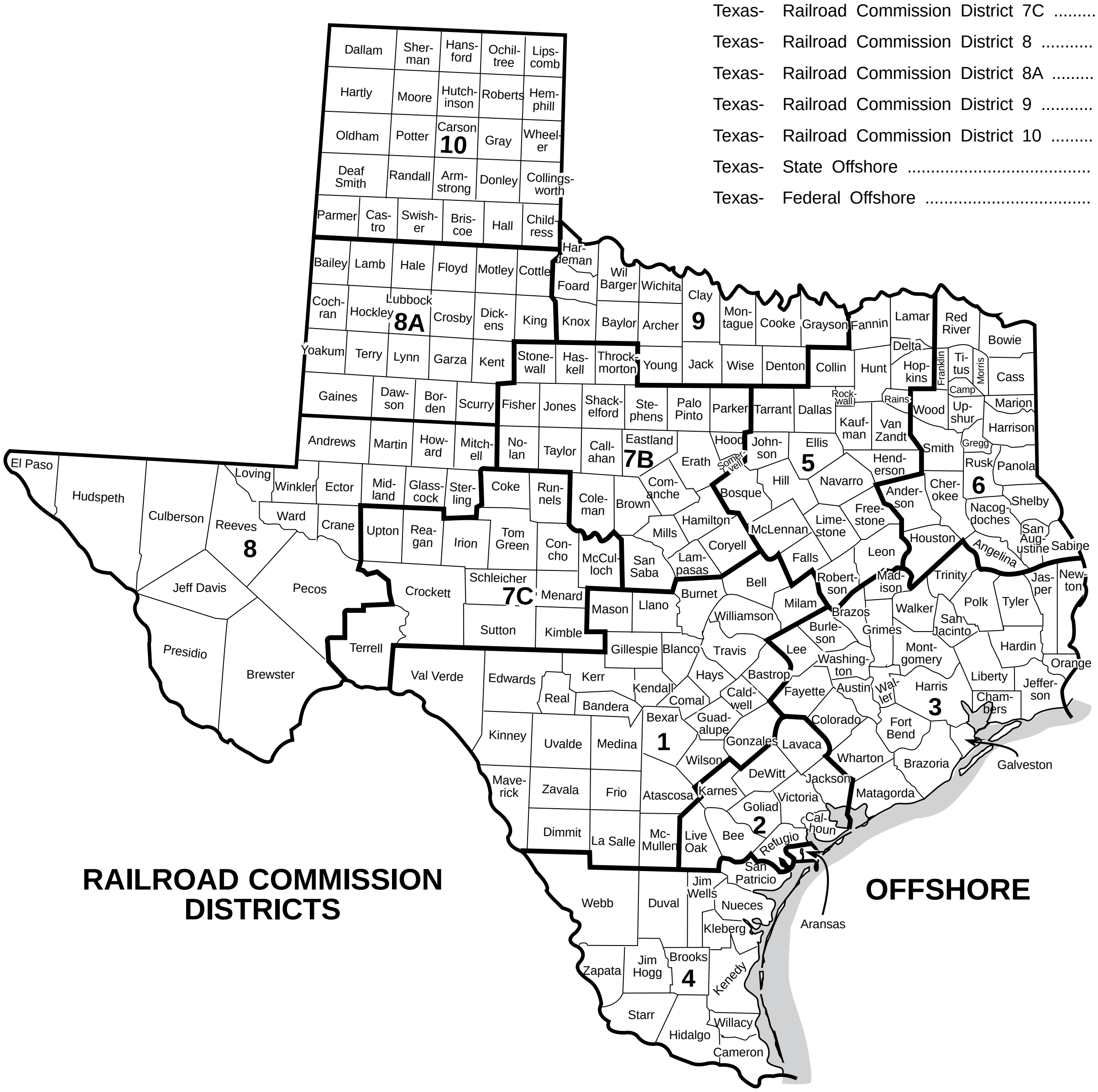


New Mexico - East ....NM 10
New Mexico - West ....NM 50

Source: Energy Information Administration, Office of Oil and Gas.

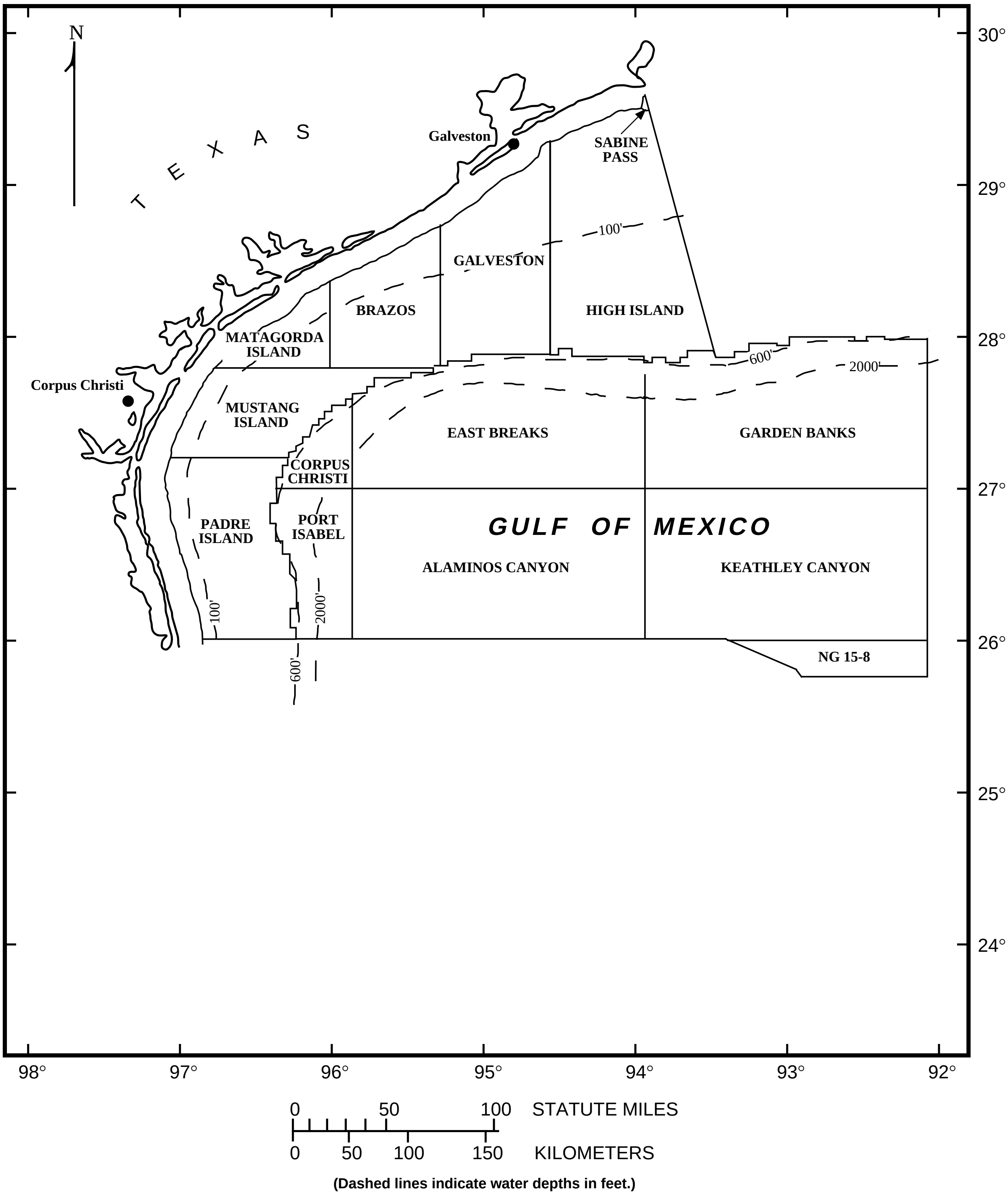
Figure H5. Subdivisions of Texas

Texas-	Railroad Commission District 1	TX 10
Texas-	Railroad Commission District 2 Onshore	TX 20
Texas-	Railroad Commission District 3 Onshore	TX 30
Texas-	Railroad Commission District 4 Onshore	TX 40
Texas-	Railroad Commission District 5	TX 50
Texas-	Railroad Commission District 6	TX 60
Texas-	Railroad Commission District 7B	TX 70
Texas-	Railroad Commission District 7C	TX 75
Texas-	Railroad Commission District 8	TX 80
Texas-	Railroad Commission District 8A	TX 85
Texas-	Railroad Commission District 9	TX 90
Texas-	Railroad Commission District 10	TX 95
Texas-	State Offshore	TX 05
Texas-	Federal Offshore	TX 00



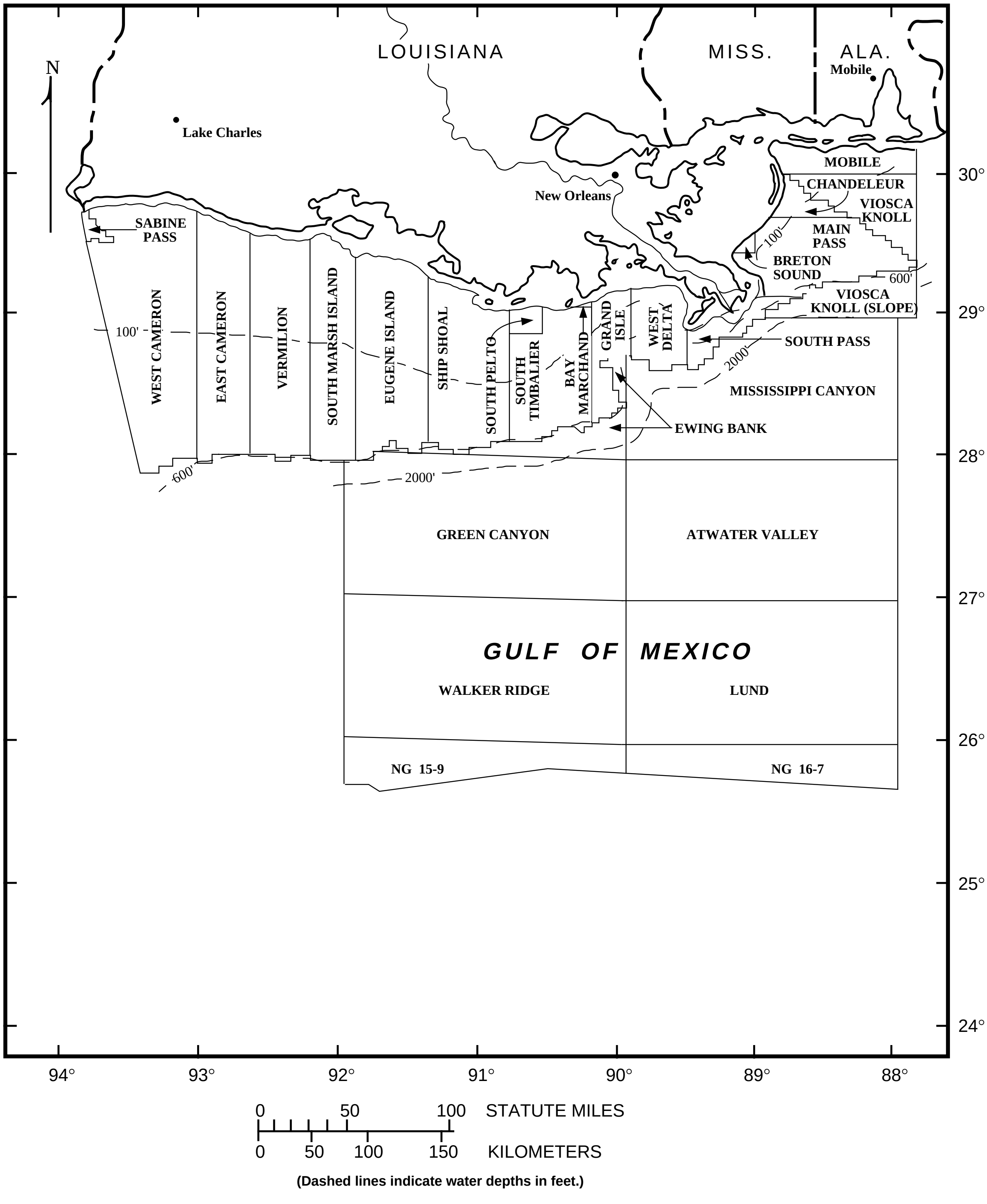
Source: Energy Information Administration, Office of Oil and Gas.

Figure H6. Western Planning Area, Gulf of Mexico Outer Continental Shelf Region



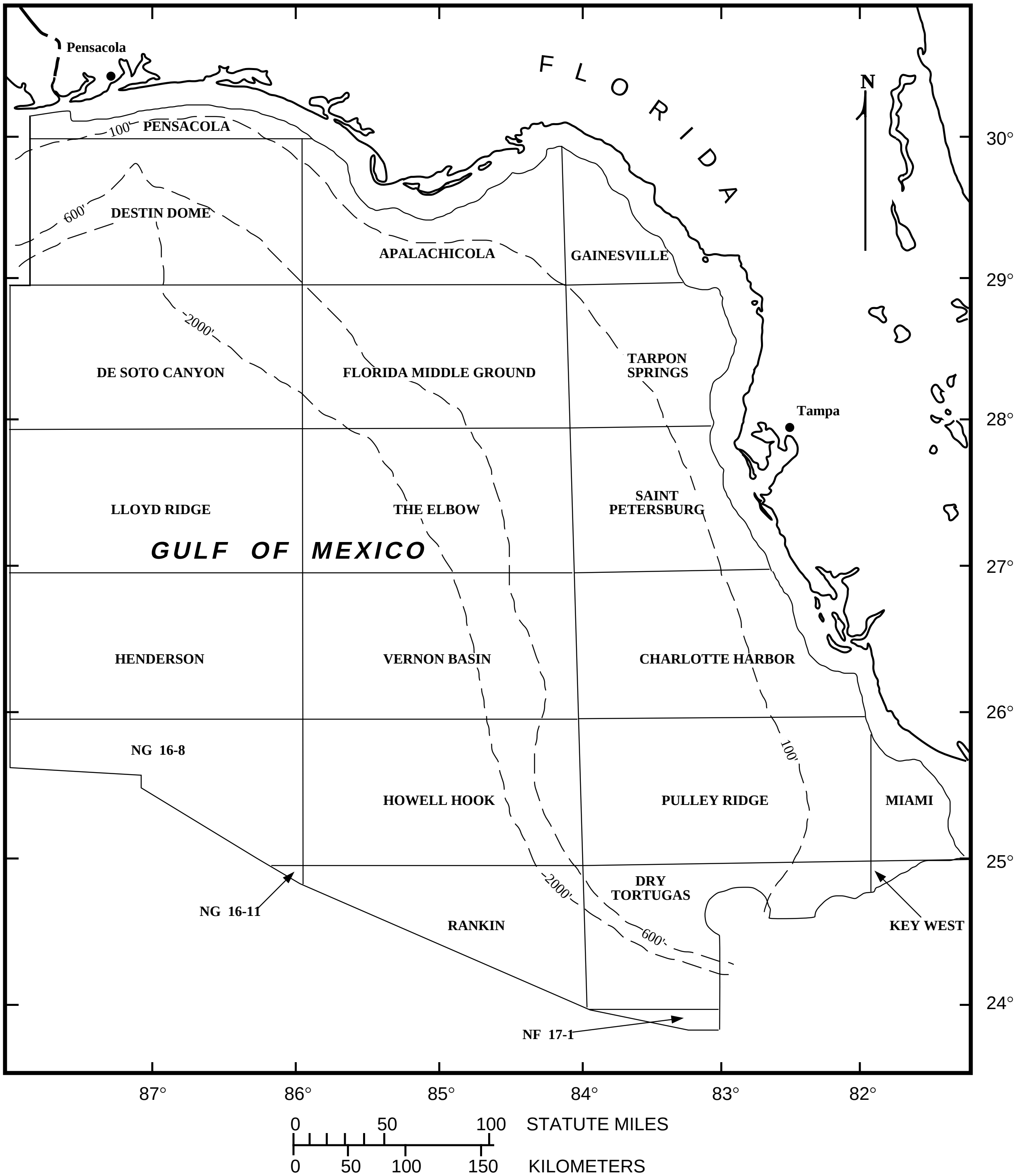
Source: Energy Information Administration, Office of Oil and Gas.

Figure H7. Central Planning Area, Gulf of Mexico Outer Continental Shelf Region



Source: Energy Information Administration, Office of Oil and Gas.

Figure H8. Eastern Planning Area, Gulf of Mexico Outer Continental Shelf Region



(Dashed lines indicate water depths in feet.)

Source: Energy Information Administration, Office of Oil and Gas.

OFFICIAL USE ONLY

1992

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES
U.S. DEPARTMENT OF ENERGY
CALENDAR YEAR 1992

Form Approved
OMB No. 1905-0057
Expires 12/94

This report is mandatory under Public Law 93-275. Failure to comply may result in criminal fines, civil penalties and other sanctions as provided by law. For the sanctions and the provisions concerning the confidentiality of information submitted on this form, see page 2 of the Instructions. Public reporting burden for this collection of information is estimated to average from 62 to 333 hours per response, including the time of reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to the Energy Information Administration, Office of Statistical Standards EI-73, Washington, DC 20585; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503.

COVER PAGE

IDENTIFICATION

1. Were you an operator *(see definition of an operator, p.1)* **of one or more oil or gas wells on December 31, 1992?**

(1) ☐ No... *Complete only items 3 through 22 below and return this page with a letter stating when operations ceased and what became of the wells you operated to* **P.O. Box 1470 Rockville, MD 20849-1470**

(2) ☐ Yes... *Complete the attached forms and return them to* **P.O. Box 1470 Rockville, MD 20849-1470**

2. I.D. Code FOR DOE USE ONLY

						0	0	0	0

If information to the left is incorrect or is missing, enter correct information below.

3. Name

4. Address

5. City

6. State

7. Zip Code

8. EIN

Check if Attestor's Social Security Number ☐

9. Name of Contact Person

10. Telephone Number of Contact Person Area Code ( ) ______- ___________

PARENT COMPANY IDENTIFICATION

11. Is there a parent company which exercises ultimate control over your company?

(1) ☐ No... Answer 18 thru 22

(2) ☐ Yes... Answer 12 thru 22

12. Name

13. Address

14. City

15. State

16. Zip Code

17. Parent Company EIN

18. What is the total number of pages (including this page) submitted in this filing?

ATTESTATION

(This report must be attested to by a responsible official of the company.)
I hereby swear or affirm that I have read the report and am familiar with its contents, and that to the best of my knowledge, information, and belief, the information provided and appended is true and complete.

19. Name of Attestor *(Please print)*

21. Signature

20. Title

22. Date

Title 18 USC 1001 makes it a criminal offense for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction

FOR ASSISTANCE CALL 1-800-879-1470

OFFICIAL USE ONLY

1993

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES

SUMMARY REPORT
PAGE 1 OF 2

Form Approved
OMB No. 1905-0057
Expires 12/94

(Report All Volumes of Crude Oil and Lease Condensate in Thousands of Barrels [Mbbl]:
Report All Volumes of Natural Gas in Millions of Cubic Feet [MMcf] at 14.73 psia and 60°F)

1.0 OPERATOR AND REPORT IDENTIFICATION DATA

1.1 OPERATOR I.D. CODE	1.2 OPERATOR NAME	REPORT DATE	1.3 ORIGINAL	1.4 AMENDED
		12 31 93		

2.0 PRODUCTION AND RESERVES DATA

STATE OR GEOGRAPHIC SUBDIVISION		CRUDE OIL RESERVES	CRUDE OIL 1993 PRODUCTION		NATURAL GAS RESERVES	NATURAL GAS 1993 PRODUCTION		LEASE CONDENSATE RESERVES	LEASE CONDENSATE 1993 PRODUCTION	
		Proved Reserves Dec. 31, 1993 (Mbbl) (A)	(From properties for which reserves were Estimated) (Mbbl) (B)	(From properties for which reserves were Not Estimated) (Mbbl) (C)	Proved Reserves Dec. 31, 1993 (MMcf) (D)	(From properties for which reserves were Estimated) (MMcf) (E)	(From properties for which reserves were Not Estimated (MMcf) (F)	Proved Reserves Dec. 31, 1993 (Mbbl) (G)	(From properties for which reserves were Estimated) (Mbbl) (H)	(From properties for which reserves were Not Estimated) (Mbbl) (I)
ALABAMA-ONSHORE	AL									
ALABAMA-STATE OFFSHORE	AL05									
ALASKA-NORTH ONSHORE AND OFFSHORE	AK50									
ALASKA-SOUTH ONSHORE	AK10									
ALASKA-SOUTH STATE OFFSHORE	AK05									
ARIZONA	AZ									
ARKANSAS	AR									
CALIFORNIA-COASTAL REGION ONSHORE	CA50									
CALIFORNIA-LOS ANGELES BASIN ONSHORE	CA90									
CALIFORNIA-SAN JOAQUIN BASIN ONSHORE	CA10									
CALIFORNIA-STATE OFFSHORE	CA05									
COLORADO	CO									
FLORIDA-ONSHORE	FL									
FLORIDA-STATE OFFSHORE	FL05									
ILLINOIS	IL									
INDIANA	IN									
KANSAS	KS									
KENTUCKY	KY									
LOUISIANA-NORTH	LA50									
LOUISIANA-SOUTH ONSHORE	LA10									
LOUISIANA-SOUTH STATE ONSHORE	LA05									
MARYLAND	MD									
MICHIGAN	MI									
MISSISSIPPI-ONSHORE	MS									
MISSISSIPPI-STATE OFFSHORE	MS05									
MISSOURI	MO									
MONTANA	MT									
NEBRASKA	NE									
NEVADA	NV									
NEW MEXICO-EAST	NM10									
NEW MEXICO-WEST	NM50									
NEW YORK	NY									
NORTH DAKOTA	ND									
OHIO	OH									

OFFICIAL USE ONLY

1993

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES

Form Approved
OMB No. 1905-0057
Expires 12/94

SUMMARY REPORT
PAGE 2 OF 2

(Report All Volumes of Crude Oil and Lease Condensate in Thousands of Barrels [Mbbl]:
Report All Volumes of Natural Gas in Millions of Cubic Feet [MMcf] at 14.73 psia and 60°F)

1.0 OPERATOR AND REPORT IDENTIFICATION DATA

1.1 OPERATOR I.D. CODE	1.2 OPERATOR NAME	REPORT DATE	1.3 ORIGINAL	1.4 AMENDED
		12 31 93		

2.0 PRODUCTION AND RESERVES DATA

STATE OR GEOGRAPHIC SUBDIVISION		CRUDE OIL			NATURAL GAS			LEASE CONDENSATE		
		RESERVES	1993 PRODUCTION		RESERVES	1993 PRODUCTION		RESERVES	1993 PRODUCTION	
		Proved Reserves Dec. 31, 1993 (Mbbl) (A)	(From properties for which reserves were Estimated) (Mbbl) (B)	(From properties for which reserves were Not Estimated) (Mbbl) (C)	Proved Reserves Dec. 31, 1993 (MMcf) (D)	(From properties for which reserves were Estimated) (MMcf) (E)	(From properties for which reserves were Not Estimated) (MMcf) (F)	Proved Reserves Dec. 31, 1993 (Mbbl) (G)	(From properties for which reserves were Estimated) (Mbbl) (H)	(From properties for which reserves were Not Estimated) (Mbbl) (I)
OKLAHOMA	OK									
PENNSYLVANIA	PA									
SOUTH DAKOTA	SD									
TENNESSEE	TN									
TEXAS-RRC DISTRICT 1	TX10									
TEXAS-RRC DISTRICT 2 ONSHORE	TX20									
TEXAS-RRC DISTRICT 3 ONSHORE	TX30									
TEXAS-RRC DISTRICT 4 ONSHORE	TX40									
TEXAS-RRC DISTRICT 5	TX50									
TEXAS-RRC DISTRICT 6	TX60									
TEXAS-RRC DISTRICT 7B	TX70									
TEXAS-RRC DISTRICT 7C	TX75									
TEXAS-RRC DISTRICT 8	TX80									
TEXAS-RRC DISTRICT 8A	TX85									
TEXAS-RRC DISTRICT 9	TX90									
TEXAS-RRC DISTRICT 10	TX95									
TEXAS-STATE OFFSHORE	TX05									
UTAH	UT									
VIRGINIA	VA									
WEST VIRGINIA	WV									
WYOMING	WY									
FEDERAL OFFSHORE-GULF OF MEXICO (ALABAMA)	AL00									
FEDERAL OFFSHORE-GULF OF MEXICO (FLORIDA)	FL00									
FEDERAL OFFSHORE-GULF OF MEXICO (LOUISIANA)	LA00									
FEDERAL OFFSHORE-GULF OF MEXICO (MISSISSIPPI)	MS00									
FEDERAL OFFSHORE-GULF OF MEXICO (TEXAS)	TX00									
FEDERAL OFFSHORE-PACIFIC (ALASKA)	AK00									
FEDERAL OFFSHORE-PACIFIC (CALIFORNIA)	CA00									
FEDERAL OFFSHORE-PACIFIC (OREGON)	OR00									
OTHER STATE (SPECIFY)										
TOTAL (SUM EACH COLUMN)	US									

OFFICIAL USE ONLY

1993

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES

Form Approved
OMB No. 1905-0057
Expires 12/94

SCHEDULE A - OPERATED PROVED RESERVES, PRODUCTION, AND RELATED DATA BY FIELD

(Report All Liquid Volumes in Thousands of Barrels [Mbbl] at 60°F;
Report All Volumes of Natural Gas in Millions of Cubic Feet [MMcf] at 60 °F and 14.73 psia)

1.0 OPERATOR AND REPORT IDENTIFICATION DATA

1.1 OPERATOR I.D. CODE	1.2 OPERATOR NAME	REPORT DATE			1.3 ORIGINAL	1.4 AMENDED	1.5 PAGE	FOR DOE USE ONLY
		12	31	93				

2.0 FIELD DATA (OPERATED BASIS)

2.1

1. STATE ABBR.	2. SUBDIV. CODE	3. COUNTY CODE	4. FIELD CODE	5. OCS BLOCK NUMBER	6. FIELD NAME	7. Calendar Year PRODUCTION From Properties For which RESERVES Were NOT ESTIMATED (a) CRUDE OIL (Mbbl)	(b) ASSOC-DISSOLVED GAS (MMcf)	(c) NONASSOCIATED GAS (MMcf)	(d) LEASE CONDENSATE (Mbbl)	8. FOOTNOTE

9. WATER DEPTH | 10. FIELD DISCOVERY YEAR | 11. INDICATED ADDITIONAL RESERVES OF CRUDE OIL (Mbbl)

TYPE HYDROCARBON	RESERVES (a) DECEMBER 31, 1992	REVISION (b) INCREASES	REVISION (c) DECREASES	EXTENSIONS (d)	NEW FIELD (e) DISCOVERIES	NEW RESERVOIRS (f) IN OLD FIELDS	CALENDAR YEAR (g) PRODUCTION	RESERVES (h) DECEMBER 31, 1993	NONPRODUCING (i) RESERVES
12. CRUDE OIL (Mbbl)									
13. ASSOCIATED-DISSOLVED GAS(MMcf)									
14. NONASSOCIATED GAS (MMcf)									
15. LEASE CONDENSATE (Mbbl)									

2.2

1. STATE ABBR.	2. SUBDIV. CODE	3. COUNTY CODE	4. FIELD CODE	5. OCS BLOCK NUMBER	6. FIELD NAME	7. Calendar Year PRODUCTION From Properties For which RESERVES Were NOT ESTIMATED (a) CRUDE OIL (Mbbl)	(b) ASSOC-DISSOLVED GAS (MMcf)	(c) NONASSOCIATED GAS (MMcf)	(d) LEASE CONDENSATE (Mbbl)	8. FOOTNOTE

9. WATER DEPTH | 10. FIELD DISCOVERY YEAR | 11. INDICATED ADDITIONAL RESERVES OF CRUDE OIL (Mbbl)

TYPE HYDROCARBON	RESERVES (a) DECEMBER 31, 1992	REVISION (b) INCREASES	REVISION (c) DECREASES	EXTENSIONS (d)	NEW FIELD (e) DISCOVERIES	NEW RESERVOIRS (f) IN OLD FIELDS	CALENDAR YEAR (g) PRODUCTION	RESERVES (h) DECEMBER 31, 1993	NONPRODUCING (i) RESERVES
12. CRUDE OIL (Mbbl)									
13. ASSOCIATED-DISSOLVED GAS(MMcf)									
14. NONASSOCIATED GAS (MMcf)									
15. LEASE CONDENSATE (Mbbl)									

2.3

1. STATE ABBR.	2. SUBDIV. CODE	3. COUNTY CODE	4. FIELD CODE	5. OCS BLOCK NUMBER	6. FIELD NAME	7. Calendar Year PRODUCTION From Properties For which RESERVES Were NOT ESTIMATED (a) CRUDE OIL (Mbbl)	(b) ASSOC-DISSOLVED GAS (MMcf)	(c) NONASSOCIATED GAS (MMcf)	(d) LEASE CONDENSATE (Mbbl)	8. FOOTNOTE

9. WATER DEPTH | 10. FIELD DISCOVERY YEAR | 11. INDICATED ADDITIONAL RESERVES OF CRUDE OIL (Mbbl)

TYPE HYDROCARBON	RESERVES (a) DECEMBER 31, 1992	REVISION (b) INCREASES	REVISION (c) DECREASES	EXTENSIONS (d)	NEW FIELD (e) DISCOVERIES	NEW RESERVOIRS (f) IN OLD FIELDS	CALENDAR YEAR (g) PRODUCTION	RESERVES (h) DECEMBER 31, 1993	NONPRODUCING (i) RESERVES
12. CRUDE OIL (Mbbl)									
13. ASSOCIATED-DISSOLVED GAS(MMcf)									
14. NONASSOCIATED GAS (MMcf)									
15. LEASE CONDENSATE (Mbbl)									

2.4

1. STATE ABBR.	2. SUBDIV. CODE	3. COUNTY CODE	4. FIELD CODE	5. OCS BLOCK NUMBER	6. FIELD NAME	7. Calendar Year PRODUCTION From Properties For which RESERVES Were NOT ESTIMATED (a) CRUDE OIL (Mbbl)	(b) ASSOC-DISSOLVED GAS (MMcf)	(c) NONASSOCIATED GAS (MMcf)	(d) LEASE CONDENSATE (Mbbl)	8. FOOTNOTE

9. WATER DEPTH | 10. FIELD DISCOVERY YEAR | 11. INDICATED ADDITIONAL RESERVES OF CRUDE OIL (Mbbl)

TYPE HYDROCARBON	RESERVES (a) DECEMBER 31, 1992	REVISION (b) INCREASES	REVISION (c) DECREASES	EXTENSIONS (d)	NEW FIELD (e) DISCOVERIES	NEW RESERVOIRS (f) IN OLD FIELDS	CALENDAR YEAR (g) PRODUCTION	RESERVES (h) DECEMBER 31, 1993	NONPRODUCING (i) RESERVES
12. CRUDE OIL (Mbbl)									
13. ASSOCIATED-DISSOLVED GAS(MMcf)									
14. NONASSOCIATED GAS (MMcf)									
15. LEASE CONDENSATE (Mbbl)									

OFFICIAL USE ONLY

1993

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES
SCHEDULE B - FOOTNOTES

Form Approved
OMB No. 1905-0057
Expires 12/94

1.0 OPERATOR AND REPORT IDENTIFICATION DATA

1.1 OPERATOR I.D. CODE	1.2 OPERATOR NAME	REPORT DATE			1.3 ORIGINAL	1.4 AMENDED	1.5 PAGE	FOR DOE USE ONLY
		12	31	93				

2.0 FOOTNOTE DATA

Page Number (a)	Item Number (b)	Subitem Number (c)	Column Desig-nation (d)	Sequence Number (e)	Notation (f)	FOR DOE USE ONLY

Figure I6. Form EIA-64A

EIA-64A (Revised 9/91)

N:9530\953075\64A-FRM.WFW - 9/13/94 - 5:41 PM - sl (HP LaserJet IIISi - postscrp)

OFFICIAL USE ONLY **1993**

Energy Information Administration
U.S. DEPARTMENT OF ENERGY
Calendar Year 1993

Form Approved
OMB No. 1905-0057
Expires 12/94

ANNUAL REPORT OF THE ORIGIN OF NATURAL GAS LIQUIDS PRODUCTION FORM EIA-64A

This report is mandatory under Public Law 93-275. Failure to comply may result in criminal fines, civil penalties and other sanctions as provided by law. For the sanctions and the provisions concerning the confidentiality of information submitted on this form, see Page 2 of the Instructions. Public reporting burden for this collection of information is estimated to average 5.9 hours per respondent, including the time of reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to the Energy Information Administration, Office of Statistical Standards EI-73, Washington, DC 20585; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503.

PLEASE COMPLETE THIS FORM AND RETURN TO

DOMESTIC OIL AND GAS RESERVES PROGRAM
PO BOX 1470
ROCKVILLE, MD 20849-1470

PLANT AND PRODUCTION REPORT IDENTIFICATION

1.0 Does this report reflect active natural gas processing at the facility for the entire year? ☐ Yes ☐ No

Months covered by this report___________ through ___________ (Include Explanatory Notes in Section **8.0**)

2.0 *If label is incorrect or information is missing or no label is given, enter correct information to the right*

2.1 Plant Operator's Name

2.2 Contact Person's Name

2.3 Plant Name

2.4 Geographic Location (Use Area of Origin Codes, Page 6) ☐☐☐☐

2.5 Mailing Address

2.6 City State Zip Code

2.7 Telephone Number ( )

3.0 Parent Company's Name

4.0 Submission Status ☐ Original ☐ Amended

5.0 Origin of Natural Gas Received and Natural Gas Liquids Produced

Line	Area of Origin Code (A)	Natural Gas Received (MMcf) (B)	Natural Gas Liquids Production (Mbbl) (C)
5.1			
5.2			
5.3			
5.4			
5.5			
5.6			
5.7			
5.8			
5.9			
5.10			
5.11			
5.12			
5.13			
5.14			
5.15			
5.16	**TOTAL**		

6.0 Gas Shrinkage Resulting from Natural Gas Liquids Extracted (MMcf)

7.0 Natural Gas Used as Fuel in Processing (MMcf)

8.0 Explanatory Notes

9.0 Certification: I certify that the information provided herein and appended hereto is true and accurate to the best of my knowledge.

Name (Please Print) Date

Signature Title

Title 18 USC 1001 makes it a criminal offense for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious, or fraudulent statements as to any matter within its jurisdiction.

FOR ASSISTANCE CALL 1-800-879-1470

Source: Energy Information Administration, Offfice of Oil and Gas.

Glossary

This glossary contains definitions of the technical terms used in this report and employed by respondents in completing Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," or Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production," for the report year 1993.

Adjustments: The quantity which preserves an exact annual reserves balance within each State or State subdivision of the following form:

Published Proved Reserves at End of Previous Report Year
+ Adjustments
+ Revision Increases
− Revision Decreases
+ Extensions
+ New Field Discoveries
+ New Reservoir Discoveries in Old Fields
+ Report Year Production
= Published Proved Reserves at End of Report Year

These adjustments are the yearly changes in the published reserve estimates that cannot be attributed to the estimates for other reserve change categories because of the survey and statistical estimation methods employed. For example, variations as a result of changes in the operator frame, different random samples or imputations for missing or unreported reserve changes, could contribute to adjustments.

Affiliated (**Associated**) **Company:** An "affiliate" of, or a person "affiliated" with, a specific person is a person that directly, or indirectly through one or more intermediaries: controls; or is controlled by; or is under common control with, the person specified. (See **Person and Control**)

Control: The term "control" (including the terms "controlling," "controlled by," and "under common control with") means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a person, whether through the ownership of voting shares, by contract, or otherwise. (See **Person**)

Corrections: (See **Revisions**)

Crude Oil: A mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Crude oil may also include:

1. Small amounts of hydrocarbons that exist in the gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well (casinghead) gas in lease separators, and that subsequently are comingled with the crude stream without being separately measured
2. Small amounts of nonhydrocarbons produced with the oil.

When a State regulatory agency specifies a definition of crude oil which differs from that set forth above, the State definition is to be followed and its use footnoted on Schedule B of Form EIA-23.

Extensions: The reserves credited to a reservoir because of enlargement of its proved area. Normally the ultimate size of newly discovered fields, or newly discovered reservoirs in old fields, is determined by wells drilled in years subsequent to discovery. When such wells add to the proved area of a previously discovered reservoir, the increase in proved reserves is classified as an extension.

Field: An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both.

Field Area: A geographic area encompassing two or more pools that have a common gathering and metering system, the reserves of which are reported as a single unit. This concept applies primiaily to the Appalachian region. (See **Pool**)

Field Discovery Year: The calendar year in which a field was first recognized as containing economically recoverable accumulations of oil and/or gas.

Field Separation Facility: A surface installation designed to recover lease condensate from a produced natural gas stream frequently originating from more than one lease, and managed by the operator of one or more of these leases. (See **Lease Condensate**)

Gross Working Interest Ownership Basis: Gross working interest ownership is the respondent's working interest in a given property plus the proportionate share of any royalty interest, including overriding royalty interest, associated with the working interest. (See **Working Interest** and **Royalty** (including **Overriding Royalty**) **Interest**)

Indicated Additional Reserves of Crude Oil: Quantities of crude oil (other than proved reserves) which may become economically recoverable from existing productive reservoirs through the application of improved recovery techniques using current technology. These recovery techniques may:

1. Already be installed in the reservoir, but their effects are not yet known to the degree necessary to classify the additional reserves as proved
2. Be installed in another similar reservoir, where the results of that installation can be used to estimate the indicated additional reserves.

Indicated additional reserves are not included in proved reserves due to their uncertain economic recoverability. When economic recoverability is demonstrated, the indicated additional reserves must be transferred to proved reserves as positive revisions.

Lease Condensate: A mixture consisting primarily of pentanes and heavier hydrocarbons which is recovered as a liquid from natural gas in lease or field separation facilities, exclusive of products recovered at natural gas processing plants or facilities.

Lease Separator: A lease separator is a facility installed at the surface for the purpose of (a) separating gases from produced crude oil and water at the temperature and pressure conditions of the separator, and/or (b) separating gases from that portion of the produced natural gas stream which liquefies at the temperature and pressure conditions of the separator.

Natural Gas: A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in natural underground reservoirs at reservoir conditions. The principal hydrocarbons normally contained in the mixture are methane, ethane, propane, butane, and pentanes. Typical nonhydrocarbon gases which may be present in reservoir natural gas are water vapor, carbon dioxide, helium, hydrogen sulfide, and nitrogen. Under reservoir conditions, natural gas and the liquefiable portions occur either in a single gaseous phase in the reservoir or in solution with crude oil, and are not distinguishable at the time as separate substances. (See **Natural Gas, Associated-Dissolved** and **Natural Gas, Nonassociated**)

Natural Gas, Associated-Dissolved: The combined volume of natural gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).

Natural Gas, "Dry": The actual or calculated volumes of natural gas which remain after:

1. The liquefiable hydrocarbon portion has been removed from the gas stream (i.e., gas after lease, field, and/or plant separation)
2. Any volumes of nonhydrocarbon gases have been removed where they occur in sufficient quantity to render the gas unmarketable.

Natural Gas, Nonassociated: Natural gas not in contact with significant quantities of crude oil in a reservoir.

Natural Gas Liquids: Those hydrocarbons in natural gas which are separated from the gas through the processes of absorption, condensation, adsorption, or other methods in gas processing or cycling plants. Generally such liquids consist of propane and heavier hydrocarbons and are commonly referred to as condensate, natural gasoline, or liquefied petroleum gases. Where hydrocarbon components lighter than propane are recovered as liquids, these components are included with natural gas liquids.

Natural Gas Processing Plant: A facility designed to recover natural gas liquids from a stream of natural gas which may or may not have passed through lease separators and/or field separation facilities. Another function of the facility is to control the quality of the processed natural gas stream. Cycling plants are considered natural gas processing plants.

Natural Gas, Wet After Lease Separation: The volume of natural gas remaining after removal of lease condensate in lease and/or field separation facilities, if any, and after exclusion of nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. Natural gas liquids may be recovered from volumes of natural gas, wet after lease separation, at natural gas processing plants. (See **Lease Condensate, Lease Separator,** and **Field Separation Facility**)

Net Revisions: (See **Revisions**)

New Field: A field discovered during the report year.

New Field Discoveries: The volumes of proved reserves of crude oil, natural gas and/or natural gas liquids discovered in new fields during the report year.

New Reservoir: A reservoir discovered during the report year.

New Reservoir Discoveries in Old Fields: The volumes of proved reserves of crude oil, natural gas, and/or natural gas liquids discovered during the report year in new reservoir(s) located in old fields.

Nonproducing Reservoirs: Reservoirs in which proved liquid or gaseous hydrocarbon reserves have been identified, but which did not produce during the last calandar year regardless of the availability and/or operation of production, gathering, or transportation facilities.

Old Field: A field discovered prior to the report year.

Old Reservoir: A reservoir discovered prior to the report year.

Operator, Gas Plant: The person responsible for the management and day-to-day operation of one or more natural gas processing plants as of December 31 of the report year. The operator is generally a working interest owner or a company under contract to the working interest owner(s). Plants shut down during the report year are also to be considered "operated" as of December 31. (See **Person**)

Operator, Oil and/or Gas Well: The person responsible for the management and day-to-day operation of one or more crude oil and/or natural gas wells as of December 31 of the report year. The operator is generally a working interest owner or a company under contract to the working interest owner(s). Wells included are those which have proved reserves of crude oil, natural gas, and/or lease condensate in the reservoirs associated with them, whether or not they are producing. Wells abandoned during the report year are also to be considered "operated" as of December 31. (See **Person**, **Proved Reserves of Crude Oil**, **Proved Reserves of Natural Gas**, **Proved Reserves of Lease Condensate**, **Report Year**, and **Reservoir**)

Ownership: (See **Gross Working Interest Ownership Basis**)

Parent Company: The parent company of a business entity is an affiliated company which exercises ultimate control over that entity, either directly or indirectly through one or more intermediaries. (See **Affiliated** (**Associated**) **Company and Control**)

Person: An individual, a corporation, a partnership, an association, a joint-stock company, a business trust, or an unincorporated organization.

Pool: In geenral, a reservoir. In certain situations a pool may consist of more than one reservoir. (See **Field Area**)

Plant Liquids: Those volumes of natural gas liquids recovered in natural gas processing plants.

Production, Crude Oil: The volumes of crude oil which are extracted from oil reservoirs during the report year. These volumes are determined through measurement of the volumes delivered from lease storage tanks, (i.e., at the point of custody transfer) with adjustment for (1) net differences between opening and closing lease inventories, and for (2) basic sediment and water. Oil used on the lease is considered production.

Production, Lease Condensate: The volume of lease condensate produced during the report year. Lease condensate volumes include only those volumes recovered from lease or field separation facilities. (See **Lease Condensate**)

Production, Natural Gas, Dry: The volume of natural gas withdrawn from reservoirs during the report year less (1) the volume returned to such reservoirs in cycling, repressuring of oil reservoirs and conservation operations; less (2) shrinkage resulting from the removal of lease condensate and plant liquids; and less (3) nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. Volumes of gas withdrawn from gas storage reservoirs and native gas, which has been transferred to the storage category, are not considered production. This is not the same as marketed production, since the latter also excludes vented and flared gas, but contains plant liquids.

Production, Natural Gas, Wet after Lease Separation: The volume of natural gas withdrawn from reservoirs during the report year less (1) the volume returned to such reservoirs in cycling, repressuring of oil reservoirs and conservation operations; less (2) shrinkage resulting from the removal of lease condensate; and less (3) nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. Volumes of gas withdrawn from gas storage reservoirs and native gas, which has been transferred to the storage category, are not considered production. This is not the same as marketed production, since the latter excludes vented and flared gas.

Production, Natural Gas Liquids: The volume of natural gas liquids removed from natural gas in lease separators, field facilities, gas processing plants or cycling plants during the report year.

Production, Plant Liquids: The volume of liquids removed from natural gas in natural gas processing plants or cycling plants during the report year.

Proved Reserves of Crude Oil: Proved reserves of crude oil as of December 31 of the report year are the estimated quantities of all liquids defined as crude oil, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Reservoirs are considered proved if economic producibility is supported by actual production or conclusive formation test (drill stem or wire line), or if economic producibility is supported by core analyses and/or electric or other log interpretations. The area of an oil reservoir considered proved includes (1) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (2) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons is considered to be the lower proved limit of the reservoir.

Volumes of crude oil placed in underground storage are not to be considered proved reserves.

Reserves of crude oil which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of proved crude oil reserves do not include the following: (1) oil that may become available from known reservoirs but is reported separately as "indicated additional reserves"; (2) natural gas liquids (including lease condensate); (3) oil, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (4) oil that may occur in undrilled prospects; and (5) oil that may be recovered from oil shales, coal, gilsonite, and other such sources. It is not necessary that production, gathering or transportation facilities be installed or operative for a reservoir to be considered proved.

Proved Reserves of Lease Condensate: Proved reserves of lease condensate as of December 31 of the report year are the volumes of lease condensate expected to be recovered in future years in conjunction with the production of proved reserves of natural gas as of December 31 of the report year, based on the recovery efficiency of lease and/or field separation facilities installed as of December 31 of the report year. (See **Lease Condensate** and **Proved Reserves of Natural Gas**)

Proved Reserves of Natural Gas: Proved reserves of natural gas as of December 31 of the report year are the estimated quantities which analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Reservoirs are considered proved if economic producibility is supported by actual production or conclusive formation test (drill stem or wire line), or if economic producibility is supported by core analyses and/or electric or other log interpretations.

The area of a gas reservoir considered proved includes: (1) that portion delineated by drilling and defined by gas-oil and/or gas-water contacts, if any; and (2) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons is considered to be the lower proved limit of the reservoir.

Volumes of natural gas placed in underground storage are not to be considered proved reserves.

For natural gas, wet after lease separation, an appropriate reduction in the reservoir gas volume has been made to cover the removal of the liquefiable portions of the gas in lease and/or field separation facilities and the exclusion of nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable.

For dry natural gas, an appropriate reduction in the gas volume has been made to cover the removal of the liquefiable portions of the gas in lease and/or field separation facilities, and in natural gas processing plants, and the exclusion of nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable.

It is not necessary that production, gathering, or transportation facilities be installed or operative for a reservoir to be considered proved. It is to be assumed that compression will be initiated if and when economically justified.

Proved Reserves of Natural Gas Liquids: Proved reserves of natural gas liquids as of December 31 of the report year are those volumes of natural gas liquids (including lease condensate) demonstrated with reasonable certainty to be separable in the future from proved natural gas reserves, under existing economic and operating conditions.

Report Year: The calendar year to which data reported in this publication pertain.

Reserves: (See **Proved Reserves**)

Reserve Additions: Consist of adjustments, net revisions, extensions to old reservoirs, new reservoir discoveries in old fields, and new field discoveries.

Reserves Changes: Positive and negative revisions, extensions, new reservoir discoveries in old fields, and new field discoveries, which occurred during the report year.

Reservoir: A porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (oil and/or gas) which is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.

Revisions: Changes to prior year-end proved reserves estimates, either positive or negative, resulting from new information other than an increase in proved acreage (extension). Revisions include increases of proved reserves associated with the installation of improved recovery techniques or equipment. They also include correction of prior report year arithmetical or clerical errors and adjustments to prior year-end production volumes to the extent that these alter reported prior year reserves estimates.

Royalty (Including Overriding Royalty) Interests: These interests entitle their owner(s) to a share of the mineral production from a property or to a share of the proceeds therefrom. They do not contain the rights and obligations of operating the property, and normally do not bear any of the costs of exploration, development, and operation of the property.

Subdivision: A prescribed portion of a given State or other geographical region defined in this publication for statistical reporting purposes.

Subsidiary Company: A company which is controlled through the ownership of voting stock, or a corporate joint venture in which a corporation is owned by a small group of businesses as a separate and specific business or project for the mutual benefit of the members of the group. (See **Control**)

Total Discoveries: The sum of extensions, new reservoir discoveries in old fields, and new field discoveries, which occurred during the report year.

Total Liquid Hydrocarbon Reserves: The sum of crude oil and natural gas liquids reserves volumes.

Total Operated Basis: The total reserves or production associated with the wells operated by an individual operator. This is also commonly known as the “gross operated” or “8/8ths” basis.

Working Interest: A working interest permits the owner(s) to explore, develop and operate a property. The working interest owner(s) bear(s) the costs of exploration, development and operation of the property, and in return is (are) entitled to a share of the mineral production from the property or to a share of the proceeds therefrom.