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

1999 Annual Report

December 2000

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Preface

The *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1999 Annual Report* is the 23rd prepared by the Energy Information Administration (EIA) to fulfill its responsibility to gather and report annual proved reserves estimates. The EIA annual reserves report series is the only source of comprehensive domestic proved reserves estimates. This publication is used by the Congress, Federal and State agencies, industry, and other interested parties to obtain accurate 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, 1999, as well as production volumes for the United States and selected States and State subdivisions for the year 1999. Estimates are presented for the following four categories of natural gas: total gas (wet after lease separation), nonassociated gas and associated–dissolved gas (which are the two major types of wet natural gas), and total dry gas (wet gas adjusted for the removal of liquids at natural gas processing plants). In addition, reserve estimates for two types of natural gas liquids, lease condensate and natural gas plant liquids, are 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 1999 is provided.

The appendices contain data by operator production size class for crude oil and natural gas reserves and production; the top 100 U.S. fields ranked within an oil or gas proved reserves group for 1999; report Table 1 converted to metric units; historical State data; 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. 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 Reserves and Production Division (located in Dallas, Texas), Office of Oil and Gas, Energy Information Administration. General information regarding preparation of the report may be obtained from Kenneth A. Vagts, Director, Office of Oil and Gas and John H. Wood, Director, Reserves and Production Division (214·720·6160).

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EIA's CD-ROM, ***Energy InfoDisc***, contains most EIA publications and major energy database applications. The ***Energy InfoDisc***, produced quarterly, is available for a fee from STAT-USA, Department of Commerce, 1-800-STAT-USA.

Other EIA Oil and Gas Publications

Other 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.

Natural Gas Annual 1999, DOE/EIA–0131(99), October 2000
Petroleum Supply Annual 1999, DOE/EIA–0340(99), June 2000

These annual reports provide comprehensive statistics on supply, disposition, and prices of natural gas and petroleum in the United States.

Natural Gas 1998: Issues and Trends, DOE/EIA–0560(98), August 1999

Focuses on the increasing choices and challenges in the natural gas industry, as regulatory requirements are increasingly removed from the sale and transport of natural gas.

Petroleum: An Energy Profile, DOE/EIA–0545(99), July 1999

Explains in layman's terms the major components and operations of the U.S. Petroleum Industry.

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Executive Summary

U.S. proved reserves of crude oil rebounded from their unusually large 1998 decline, growing by about 3.5 percent in 1999 — the largest percentage increase in the 23-year EIA reserves program. Over 137 percent of 1999 oil production was replaced by proved reserve additions. This was not a result of increased drilling, more successful exploratory drilling, or dramatically improved technology. Crude oil prices began slowly increasing from the inflation-adjusted 53-year low of December 1998 and then accelerated during the year, reaching $22.55 per barrel in December 1999. The resurgent crude price generated the largest positive net revisions to proved reserves in over a decade.

U.S. dry natural gas reserves increased 2 percent in 1999, reversing the 2 percent decline of 1998. Natural gas reserve additions in 1999 replaced 118 percent of gas production.

As of December 31, 1999 proved reserves were:

Crude Oil (million barrels)	
1998	21,034
1999	21,765
Increase	3.5%
Dry Natural Gas (billion cubic feet)	
1998	164,041
1999	167,406
Increase	2.1%
Natural Gas Liquids (million barrels)	
1998	7,524
1999	7,906
Increase	5.1%

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 are required in estimating proved reserves, therefore the results are not precise measurements. This report of 1999 U.S. proved reserves of crude oil, natural gas, and natural gas liquids is the 23rd in the annual series prepared by the Energy Information Administration.

Crude Oil

Price matters. The 1999 rebound in crude oil reserves was fundamentally driven by price increases just as the unusually large oil reserve declines of 1998 had been fundamentally driven by very low oil prices. Changes in proved reserves are impacted by price in several ways.

The attainment of higher prices from an initially very low base level implies much better economics for oil producers. The December 1999 oil price used to evaluate oil field economics and estimate proved reserves was roughly three times the December 1998 price; many operators reported that the reason for their positive reserve revisions was the price increase.

Further, the December 1999 price ($22.55 per barrel) was relatively better for the smaller and marginal oil well operators because they are usually operating closer to their direct operating costs. Texas, like most of the lower-48 States, is basically a stripper well (less than 10 barrels per day per well) State. Texas' proved oil reserves fell 13 percent in 1998, which for the first time in a decade placed Texas second to Alaska in oil reserves. But in 1999, Texas oil reserves increased by over 8 percent while Alaskan reserves dropped, returning Texas to its number one position.

Reserve additions are the sum of total discoveries and revisions and adjustments. For crude oil, the net of revisions and adjustments was the highest in over a decade and replaced 100 percent of 1999 oil production. This price-induced rebound followed 1998's negative net revision and adjustment of 120 million barrels which marked the first time in 22 years that the net of revisions and adjustments had not made a positive contribution to oil reserve additions.

Total discoveries of crude oil were 725 million barrels in 1999, about the prior 10-year average and 21 percent more than those in 1998. The Gulf of Mexico Federal Offshore accounted for over half of them. Total discoveries, which equaled only 37 percent of 1999 oil production, are those reserves attributable to field extensions, new field discoveries, and new reservoir discoveries in old fields. They result from the drilling of exploratory wells. New field discoveries of 321 million barrels were twice those of 1998 and well above the prior 10-year average. Almost all of them were in the Gulf of Mexico Federal Offshore and Alaska. Well over half of the proved reserves of oil in the Gulf of Mexico are now located in deep water (water depths greater than 200 meters).

New reservoir discoveries in old fields were 145 million barrels, about the same as the prior 10-year average. Field extensions were down in 1999 to 60 percent of the prior 10-year average, but still added 259 million barrels of proved oil reserves.

Other 1999 crude oil events of note:

- The annual average domestic first purchase price for crude oil increased 43 percent from the 1998 level to $15.56 per barrel.
- Exploratory oil completions were down almost 50 percent at 148 and total oil well completions were down about 40 percent at 3,853. For both, the low drilling level reached in 1998 deepened in 1999 and did not begin to ameliorate until after mid-year inasmuch as oil prices did not reach $15 per barrel until July 1999.
- Total discoveries per exploratory oil well were much higher because most of the discoveries were in the less maturely explored Gulf of Mexico and Alaska and because the drilling level was also down. Nevertheless, as we predicted in the 1998 report, higher oil prices in December 1999 brought back some of the oil reserves that became uneconomic in1998.

Indicated additional reserves of crude oil decreased 9 percent to 2,865 million barrels in 1999. These 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 north Alaska, California, Texas, and Louisiana implies that significant upward revisions to crude oil proved reserves can occur in the future.

Natural Gas

With the 1999 increase, U.S. natural gas proved reserves have increased in 5 of the past 6 years. The combined 1999 reserve increases in Texas, Colorado, and Utah more than account for U.S. net proved reserve additions. Oklahoma and the Gulf of Mexico had significant gas reserve declines.

Proved reserves in the Gulf of Mexico Federal Offshore declined in both 1998 and 1999, even though deepwater Gulf of Mexico Federal Offshore reserves were up substantially in both 1998 and 1999, as was production. However, for those Gulf of Mexico fields located in water less than 200 meters deep, proved reserves declined by 5 percent and production declined by 9 percent in 1999.

The reserve additions of natural gas were higher in 1999 because the net of revisions and adjustments to reserves (11,486 billion cubic feet) was more than twice as high as in 1998 and 70 percent higher than the prior 10-year average. However, natural gas prices were only up 7 percent in 1999 to $2.08 per thousand cubic feet. The associated-dissolved gas revisions related to oil reserve revisions underwent larger percentage gains than did those for gas which is not associated with crude oil in the reservoir (nonassociated gas).

The other major component, total discoveries, declined in 1999 to 10,807 billion cubic feet. New field discoveries were 1,568 billion cubic feet, a little more than the prior 10-year average. Field extensions were 7,043 billion cubic feet, down from 1998 and almost exactly at the prior 10-year average. New reservoir discoveries in old fields were 2,196 billion cubic feet, about the same as in 1998 and 6 percent less than the prior 10-year average.

Coalbed methane reserves and production continued to grow faster in 1999 than did the reserves and production of conventional natural gas. Coalbed methane reserves increased to 8 percent of proved dry gas reserves and accounted for 7 percent of total dry gas production in 1999.

Other 1999 natural gas events of note:

- Exploratory gas well completions increased 13 percent in 1999 while development gas well completions declined 15 percent.
- Although the number of exploratory wells increased, the average of total discoveries per exploratory gas well was 16 percent less in 1999.
- U.S. gas production was slightly higher in 1999 according to the EIA reserves survey.

Natural Gas Liquids

U.S. natural gas liquids proved reserves increased 5 percent to 7,906 million barrels in 1999. 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 29,671 million barrels in 1999, a 4 percent increase from the 1998 level. Natural gas liquids represented 27 percent of total liquid hydrocarbon proved reserves in 1999.

Data

These estimates are based upon analysis of data from Form EIA-23, Annual Survey of Domestic Oil and Gas Reserves, filed by 1,897 operators of oil and gas wells, and Form EIA-64A, Annual Report of the Origin of Natural Gas Liquids Production, filed by operators of 608 active natural gas processing plants. By use of improved sampling and imputation procedures, the sample of oil and gas well operators was reduced by almost a third from that of the 1998 survey without sacrificing accuracy. The U.S. proved reserves estimates for crude oil and natural gas are associated with sampling errors of less than 1 percent.

1. Introduction

Background

The principal focus of this report is to provide accurate annual estimates of U.S. proved reserves of crude oil, natural gas, and natural gas liquids. These estimates are 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. However, the industry ceased publication of reserve estimates after its 1979 report.

In response to a recognized need for credible annual proved reserves estimates, Congress, in 1977, required the Department of Energy to prepare such estimates. To meet this requirement, the Energy Information Administration (EIA) developed a program that established a unified, verifiable, comprehensive, and continuing annual statistical series for proved reserves of crude oil and natural gas. It was expanded to include proved reserves of natural gas liquids for the 1979 and subsequent reports.

Survey Overview

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. Readers who are unfamiliar with the distinctions between types of reserves or with how reserves fit in the description of overall oil and gas resources should see Appendix G.

While the primary topic of this report is proved reserves, information is also presented on indicated additional crude oil 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.

This report provides proved reserves estimates for calendar year 1999. It is based on data filed by large operators of oil and gas wells on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," and by operators of all natural gas processing plants on Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production." The U.S. crude oil and natural gas proved reserves estimates are associated with sampling errors of less than 1 percent at a 95-percent confidence level.

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.

Operator size categories are based upon operator annual production as indicated in various Federal, State, and commercial records. 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. Intermediate operators produced less than large operators, but more than 400,000 barrels of crude oil or 2 billion cubic feet of natural gas, or both. Small operators are those that produced less than intermediate 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 (Category I) and most intermediate size operators (Category II) report reserves balance data on Form EIA-23 to show how and why reserves components changed during the year on a field-by-field basis. Intermediate size 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. 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.

A select group of small operators (Category III) are requested to provide annual production and year ending reserves volumes if available. Details on the selection of these operators and the determination of the reserves volumes is found in Appendix F.

The published reserve estimates include an additional term, adjustments, calculated by the 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 annual changes in the published reserve estimates that cannot be attributed to the estimates for other reserve change categories. They result from the survey and statistical estimation methods employed. For example, variations caused by changes in the operator frame, different random samples, changes in reserve estimates following ownership changes, incorrectly reported data, or imputations for missing or unreported reserve changes can contribute to adjustments.

Form EIA-64A

Form EIA-64A data were first collected for the 1979 survey year in order 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 and complete survey frame consisting of operators of oil and gas wells and of natural gas processing plants. The Form EIA-23 operator frame contained 22,125 probable active operators and the Form EIA-64A plant frame contained 589 probable active natural gas processing plants in the United States when the 1999 surveys were initiated. As usual, additional operators were added to the survey as it progressed, and many operators initially in the sample frame were found to be inactive in 1999.

For the report year 1999, EIA mailed 576 EIA-23 forms to all known large and intermediate size oil and gas well operators that were believed to be active during 1999. Of these, 33 were found to be nonoperators that did not have successor operator and 35 were new operators or operators that changed category. Data were received from 578 operators, an overall response rate of 100 percent of the active operators in the Form EIA-23 survey. EIA mailed 589 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 554 unique active natural gas processing plants in the Form EIA-64A survey.

National estimates of the 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, which are obtained from non-survey based State sources. For report year 1999, the Form EIA-23 National production estimates were 4 percent lower than the comparable *Petroleum Supply Annual (PSA) 1999* volumes for crude oil and lease condensate combined, and were 0.1 percent higher than the comparable *Natural Gas Annual 1999* volume for 1999 dry natural gas. For report year 1999, the Form EIA-64A National estimates were 6 percent lower than the *PSA 1999* volume for natural gas plant liquids production.

Accuracy in reserves reporting is EIA's first and foremost goal for this report. Estimates of production within this report may be lower than those made specifically to estimate oil or gas production like those in the *PSA*.

2. Overview

National Summary

The United States had the following proved reserves as of December 31, 1999:

- **Crude Oil — 21,765 million barrels**
- **Dry Natural Gas — 167,406 billion cubic feet**
- **Natural Gas Liquids — 7,906 million barrels.**

This Overview summarizes the 1999 proved reserves balances of crude oil, dry natural gas, and natural gas liquids on a National level and provides historical comparisons between 1999 and years past.

Table 1 lists the estimated annual reserve balances since 1989. From 1998 to 1999, proved reserves of crude oil increased by 3.5 percent—the largest percentage increase in the 23-year EIA reserves program. Proved reserves of dry natural gas increased by 2 percent. Natural gas liquids reserves increased 5 percent.

Crude Oil

Proved reserves of crude oil increased by 731 million barrels in 1999. **Figure 1** shows the crude oil proved reserves levels by major region and **Figure 2** shows the components of reserves changes from 1989 through 1999.

As shown in **Figure 2**, total reserve additions (the positive side of the scale) were up substantially in 1999, due primarily to the substantial difference in oil prices seen in December 1998 and December 1999. Operators replaced 137 percent of the 1999 oil production with reserve additions. Production of crude oil (the negative side of the scale of **Figure 2**) declined slightly for the eighth year in a row.

Total discoveries are those reserves attributable to field *extensions*, *new field discoveries*, and *new reservoir discoveries in old fields*. There were 725 million barrels of *total discoveries* of crude oil proved reserves in 1999. This is 21 percent more than what was discovered in 1998, but still 3 percent less than what was discovered on average in the prior 10 years.

Extensions added 259 million barrels of proved reserves. This is 21 percent less than in 1998 (327 million barrels) and 40 percent less than the average *extensions* in the prior 10 years (433 million barrels).

New field discoveries were 321 million barrels, more than double the 1998 level and 74 percent more than the average volume discovered in the prior 10 years (184 million barrels). New field discoveries in Alaska and the Gulf of Mexico Federal Offshore made up 99 percent of the 1999 volume of new field discoveries.

New reservoir discoveries in old fields added 145 million barrels of proved reserves. This is more than the 1998 level (120 million barrels) and the prior 10-year average for the United States (135 million barrels).

Net revisions and adjustments added 1,958 million barrels of proved reserves. This is substantially more than 1998's -120 million barrels, which was the first negative total for net revisions and adjustments for crude oil since EIA began collecting this data. In the past 10 years, *net revisions and adjustments* have added an average of 986 million barrels of crude oil proved reserves per year. Revisions include sales and acquisitions.

Production removed an estimated 1,952 million barrels of proved reserves from the National total. Production was down 2 percent from 1998's level (1,991 million barrels), and down 16 percent from the prior 10-year average (2,317 million barrels).

Natural Gas

U.S. proved reserves of dry natural gas increased 2 percent, resuming an increasing trend that began 5 years ago but was interrupted by a decline in 1998. Dry natural gas reserves increased by 3,558 billion cubic feet in the Lower 48 States, and in Alaska declined by 193 billion cubic feet. **Figure 3** shows the dry natural gas proved reserves levels by major region and **Figure 4** shows the components of reserves changes from 1989 through 1999. Dry natural gas production increased 1 percent from 1998 to 1999. Operators were able to replace 118 percent of 1999's dry gas production with new reserves.

For 1999, U.S. *total discoveries* of dry gas reserves were 10,807 billion cubic feet, down 5 percent from 1998, but almost equal the average annual volume discovered in the past 10 years. *Total discoveries* were 48 percent of all reserve additions in 1999.

Table 1. Total U.S. Proved Reserves of Crude Oil, Dry Natural Gas, and Natural Gas Liquids, 1989-1999

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)	Estimated Production (9)	Proved[c] Reserves 12/31 (10)	Change from Prior Year (11)
	Crude Oil (million barrels of 42 U.S. gallons)										
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
1994	189	2,364	1,357	1,196	397	64	111	572	2,268	22,457	-500
1995	122	1,823	795	1,150	500	114	343	957	2,213	22,351	-106
1996	175	1,723	986	912	543	243	141	927	2,173	22,017	-334
1997	520	1,998	1,084	1,434	477	637	119	1,233	2,138	22,546	+529
1998	-638	2,752	2,234	-120	327	152	120	599	1,991	21,034	-1,512
1999	139	6,284	4,465	1958	259	321	145	725	1,952	21,765	+731
	Dry Natural Gas (billion cubic feet, 14.73 psia, 60° Fahrenheit)										
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
1994	1,945	21,365	15,881	7,429	6,941	1,894	3,480	12,315	18,322	163,837	+1,422
1995	580	20,465	12,731	8,314	6,843	1,666	2,452	10,961	17,966	165,146	+1,309
1996	3,785	17,132	13,046	7,871	7,757	1,451	3,110	12,318	18,861	166,474	+1,328
1997	-590	21,658	16,756	4,312	10,585	2,681	2,382	15,648	19,211	167,223	+749
1998	-1,635	28,003	22,263	4,105	8,197	1,074	2,162	11,433	18,720	164,041	-3,182
1999	982	42,167	31,663	11,486	7,043	1,568	2,196	10,807	18,928	167,406	+3,365
	Natural Gas Liquids (million barrels of 42 U.S. gallons)										
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
1994	43	873	676	240	314	54	131	499	791	7,170	-52
1995	192	968	691	469	432	52	67	551	791	7,399	+229
1996	474	844	669	649	451	65	109	625	850	7,823	+424
1997	-15	1,199	910	274	535	114	90	739	864	7,973	+150
1998	-361	1,302	1,094	-153	383	66	88	537	833	7,524	-449
1999	99	2,048	1,321	826	313	51	88	452	896	7,906	+382

[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.

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 1999 contained in the *Petroleum Supply Annual 1999*, DOE/EIA-0340(99) and the *Natural Gas Annual 1999*, DOE/EIA-0131(99).

Sources: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, 1989 through 1999 annual reports, DOE/EIA-0216.

Figure 1. U.S. Crude Oil Proved Reserves, 1989-1999

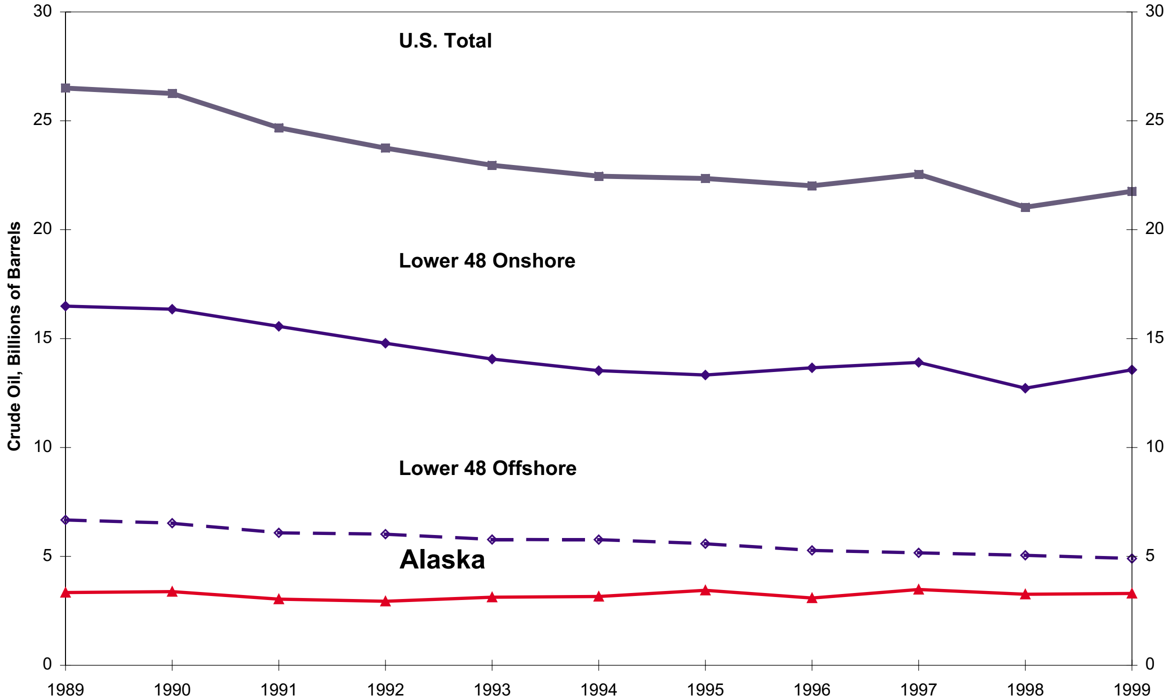
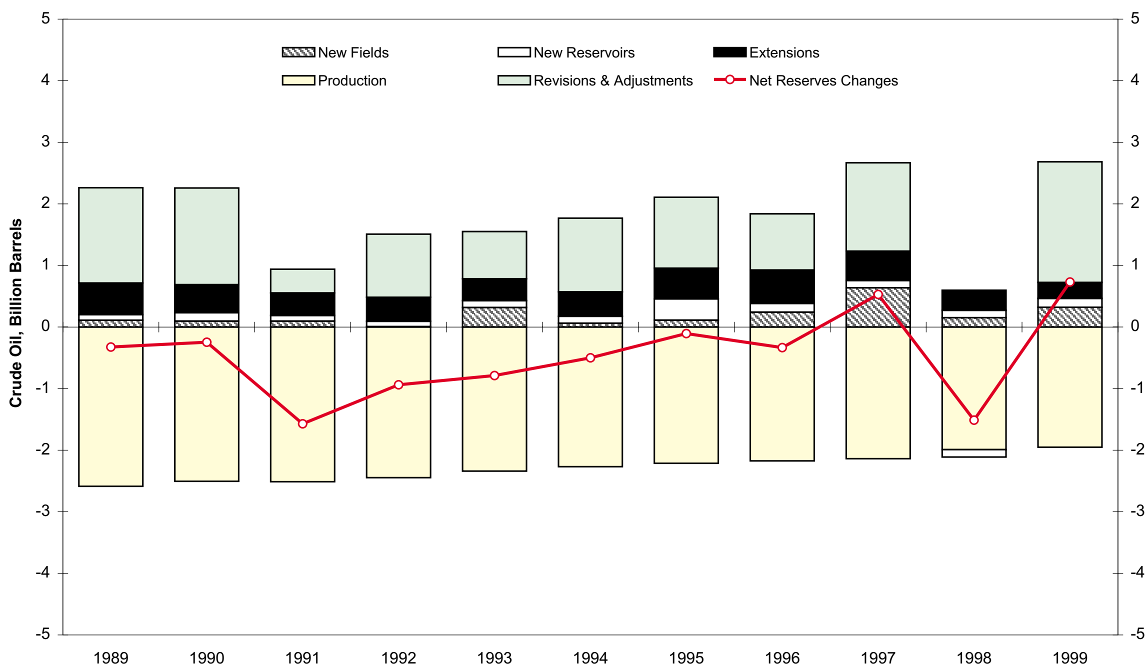


Figure 2. Components of Reserves Changes for Crude Oil, 1989-1999



Source: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1989-1999 annual reports, DOE/EIA-0216.{12-22}

Figure 3. U.S. Dry Natural Gas Proved Reserves, 1989-1999

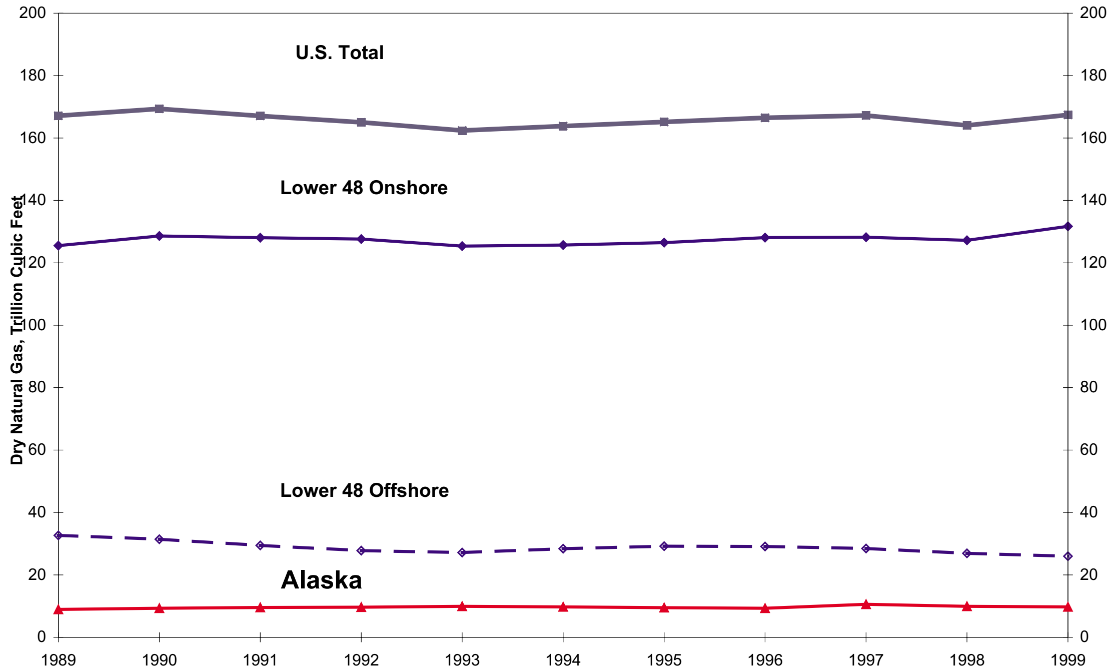
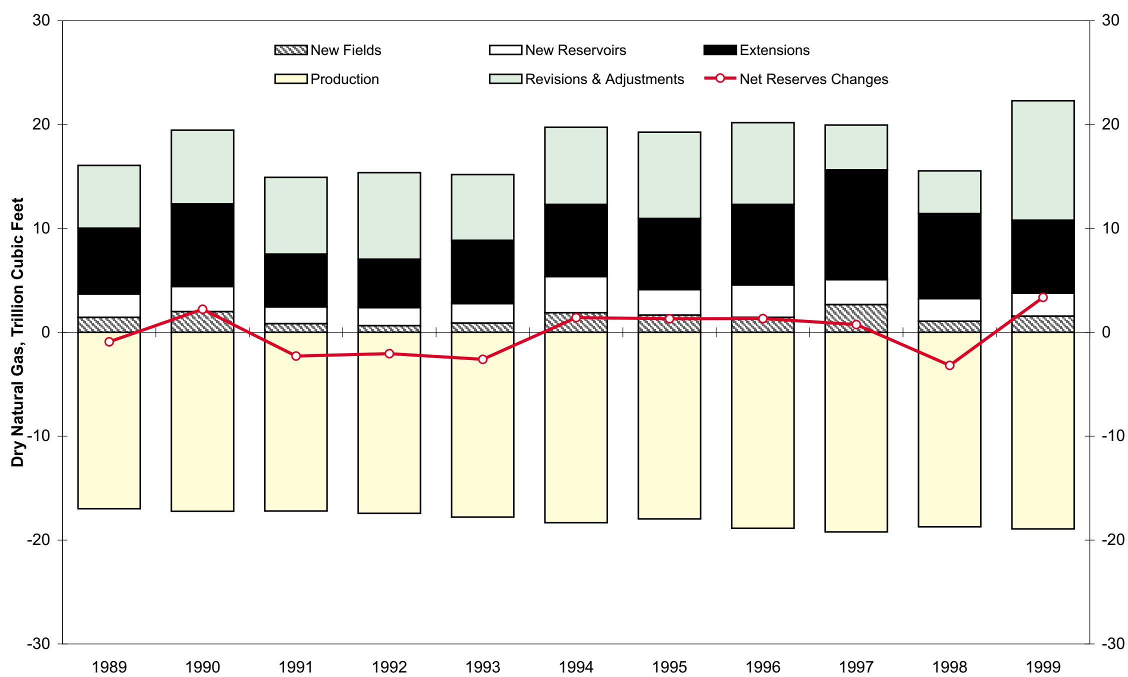


Figure 4. Components of Reserves Changes for Dry Natural Gas, 1989-1999



Source: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1989-1999 annual reports, DOE/EIA-0216.{12-22}

Extensions added 7,043 billion cubic feet of proved reserves. This is 14 percent less than 1998's *extensions* but is comparable to the average of *extensions* in the prior 10 years (7,048 billion cubic feet).

New field discoveries added 1,568 billion cubic feet of proved reserves. This is 46 percent higher than what was discovered in 1998 and 7 percent higher than the average volume discovered in the prior 10 years (1,462 billion cubic feet).

New reservoir discoveries in old fields added 2,196 billion cubic feet of proved reserves. This is 2 percent more than the volume discovered in 1998, and 6 percent lower than the prior 10-year average (2,344 billion cubic feet).

Net revisions and adjustments added 11,486 billion cubic feet of proved reserves. This is 180 percent more than 1998's revisions and adjustments and 71 percent more than the prior 10-year average (6,719 billion cubic feet). Revisions include sales and acquisitions.

Production removed an estimated 18,928 billion cubic feet of proved reserves from the National total. Dry gas production increased 1 percent compared to 1998.

Coalbed methane gas production and reserves are included in the 1999 totals. However, EIA separately tracks these reserves in order to record the development and performance of this gas source. Coalbed methane reserves increased in 1999 to a volume of 13,229 billion cubic feet. Coalbed methane accounted for 8 percent of 1999 U.S. dry natural gas reserves and 7 percent of 1999 U.S. dry gas production.

Natural Gas Liquids

Proved reserves of natural gas liquids increased 382 million barrels to 7,906 million barrels during 1999— a 5 percent increase from 1998 levels. **Figure 5** shows the natural gas liquids proved reserves levels by major region and **Figure 6** shows the components of reserves changes from 1989 through 1999.

Operators replaced 143 percent of their 1999 natural gas liquids production with reserve additions. *Total discoveries* added 452 million barrels, and net *revisions and adjustments* added 826 million barrels.

Total proved reserves of liquid hydrocarbons (crude oil plus natural gas liquids) were 29,671 million barrels in 1999—a 4 percent increase from the 1998 level. Natural gas liquids represented 27 percent of total liquid hydrocarbon proved reserves in 1999.

Reserves Changes Since 1977

EIA has collected oil and gas reserves estimates annually since 1977. **Table 2** lists the cumulative totals of the components of reserves changes for crude oil and dry natural gas from 1978 through 1999. **Table 2** contains two sections, one for the lower 48 States and another for the U.S. total (which includes Alaska's contribution). Annual averages for each component of reserves changes are also listed, along with the percentage of that particular component's impact on total U.S. proved reserves. In this section, we compare these averages to the 1999 proved reserves estimates as a means of gauging the past year against history.

Crude Oil: Since 1977 U.S. operators have:

- discovered an average of 800 million barrels per year of new reserves
- revised and adjusted their proved reserves upward by an average of 1,328 million barrels per year from *revisions and adjustments*
- ended each year with an average net reduction in U.S. proved reserves of 508 million barrels (the difference between post-1976 average annual production and post-1976 average annual reserve additions) because production has outpaced reserve additions.

Since 1977, crude oil reserves have been primarily sustained by the extension and development of existing fields (called field growth, reserves growth, or the EIA preferred term: proved ultimate recovery appreciation; see the Proved Ultimate Recovery section later in this chapter) rather than the discovery of new oil fields. Only 8 percent of reserves additions since 1976 were booked as *new field discoveries*. Proved ultimate recovery appreciation is the sum of net revisions and adjustments, extensions, and new reservoirs in old fields. Since 1977, the largest component of proved ultimate recovery appreciation for crude oil is upward *revisions and adjustments*, which accounted for 62 percent of all crude oil reserves additions. The 18,393 million barrels of *total discoveries* accounted for the remaining 38 percent of reserves additions.

Compared to the average reserves changes since 1977, 1999 was a down year for crude oil discoveries. *Total discoveries* of crude oil (725 million barrels) in 1999 were 9 percent less the post-1976 U.S. average. In 1999, *net*

Figure 5. U.S. Natural Gas Liquids Proved Reserves, 1989-1999

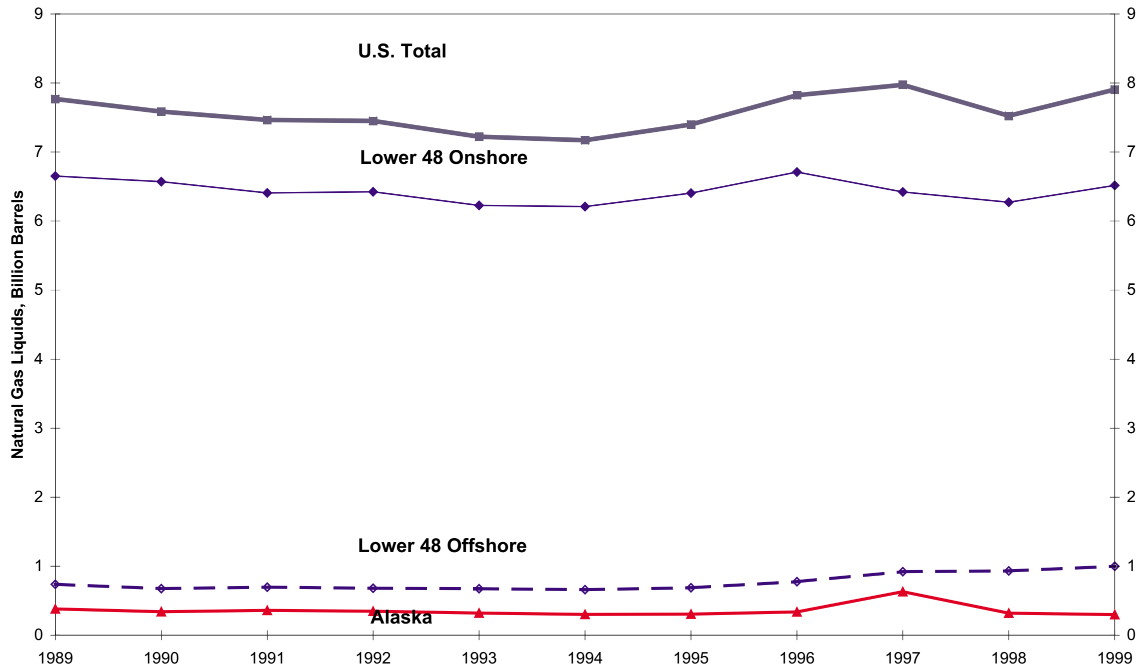
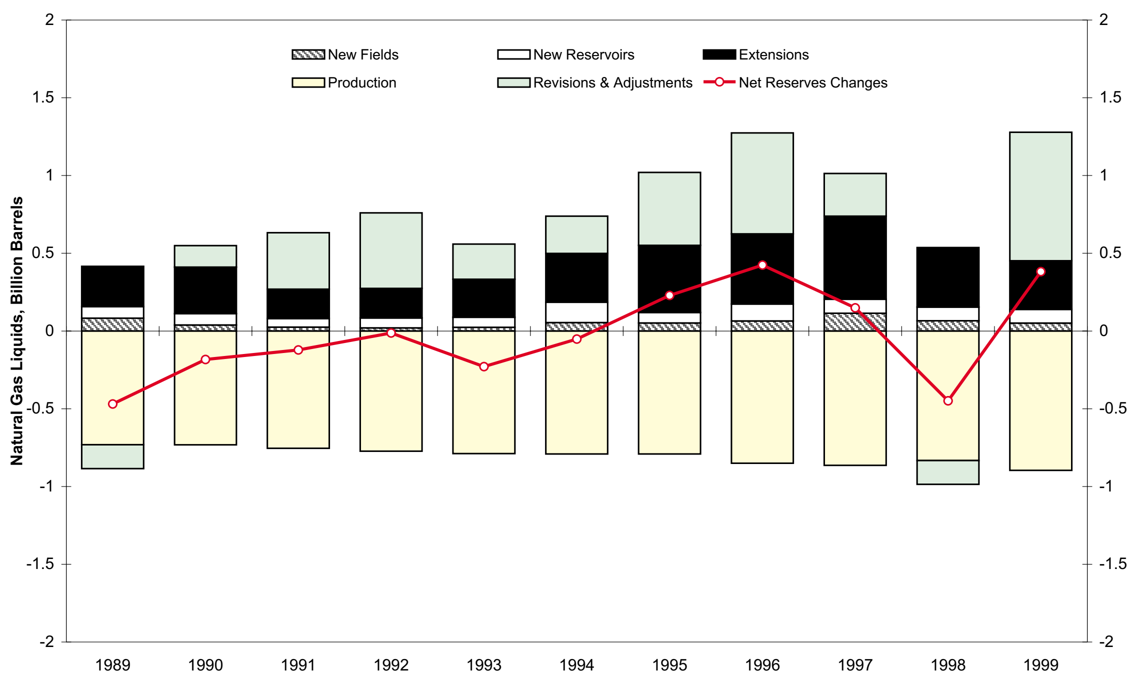


Figure 6. Components of Reserves Changes for Natural Gas Liquids, 1989-1999



Source: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1989-1999 annual reports, DOE/EIA-0216.{12-22}

Table 2. Reserves Changes, 1977-1999

Components of Change	Lower 48 States Volume	Lower 48 States Average per Year	Lower 48 States Percent of Reserve Additions	U.S. Total Volume	U.S. Total Average per Year	U.S. Total 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	3,285	143	8.3	3,955	172	8.1
New Reservoir Discoveries in Old Fields	3,144	137	8.0	3,174	138	6.5
Extensions	10,109	440	25.6	11,264	490	23.0
Total Discoveries	**16,538**	**719**	**41.9**	**18,393**	**800**	**37.6**
Revisions and Adjustments	22,907	996	58.1	30,534	1,328	62.4
Total Reserve Additions	**39,445**	**1,715**	**100.0**	**48,927**	**2,127**	**100.0**
Production	**47,444**	**2,063**	**120.3**	**60,600**	**2,635**	**123.9**
Net Reserve Change	**-7,999**	**-348**	**-20.3**	**-11,673**	**-508**	**-23.9**
	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	44,148	1,919	11.7	44,296	1,926	12.2
New Reservoir Discoveries in Old Fields	58,474	2,542	15.5	58,862	2,559	16.3
Extensions	171,290	7,447	45.5	172,209	7,487	47.6
Total Discoveries	**273,912**	**11,909**	**72.7**	**275,367**	**11,972**	**76.1**
Revisions and Adjustments	102,664	4,464	27.3	86,456	3,759	23.9
Total Reserve Additions	**376,576**	**16,373**	**100.0**	**361,823**	**15,731**	**100.0**
Production	**399,895**	**17,387**	**106.2**	**407,848**	**17,733**	**112.7**
Net Reserve Change	**-23,319**	**-1,014**	**-6.2**	**-46,025**	**-2,001**	**-12.7**

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves* 1977-1999 annual reports, DOE/EIA-0216.{1-22}

revisions and adjustments were 47 percent higher than the post-1976 U.S. Average.

Looking at the components of *total discoveries* in 1999:

- both *new field discoveries* and *new reservoir discoveries in old fields* exceeded the post-1976 averages for crude oil, and
- 1999's extensions fell far short of the post-1976 average -- enough to result in the 9 percent decline in *total discoveries*.

Dry Natural Gas: Since 1977, U.S. operators:

- discovered an average of 11,972 billion cubic feet per year of new reserves
- revised and adjusted their proved reserves upward by an average 3,759 billion cubic feet per year
- had an average net reduction in U.S. reserves of 2,001 billion cubic feet per year.

Like crude oil reserves, natural gas reserves have been sustained primarily by proved ultimate recovery appreciation since 1977. Usually *extensions* rather than *net revisions and adjustments* are the largest component. *Extensions* account for 48 percent while *net revisions and adjustments* account for only 24 percent of all reserve additions since 1977. In 1999, *net revisions and adjustments* were 52 percent of all reserves additions. In 1999, *extensions* were 32 percent of all reserves additions.

Compared to the average reserves changes since 1977, 1999 was a below average year for natural gas reserve additions from *total discoveries*. U.S. total dry natural gas reserves increased 2 percent, resuming an increasing trend. Operators reported 10,807 billion cubic feet of *total discoveries* of dry natural gas proved reserves—10 percent less than the post-1976 average (11,972 billion cubic feet). However, *net revisions and adjustments* were substantially more in 1999 (11,486 billion cubic feet) compared to the post-1976 U.S. Average (3,759 billion cubic feet).

Table 3. U.S. Average Annual Domestic First Purchase Prices for Crude Oil, Wellhead Prices for Natural Gas, and the Average Number of Active Rotary Drilling Rigs, 1977-1999

Year		Crude Oil Current	Crude Oil 1999 Constant	Natural Gas Current	Natural Gas 1999 Constant	Number of Rigs
		(dollars per barrel)		(dollars per thousand cubic feet)		
1977		8.57	20.38	0.79	1.88	2,001
1978		9.00	19.89	0.91	2.01	2,259
1979		12.64	25.76	1.18	2.40	2,177
1980		21.59	40.28	1.59	2.97	2,909
1981		31.77	54.33	1.98	3.39	3,970
1982		28.52	45.85	2.46	3.95	3,105
1983		26.19	40.38	2.59	3.99	2,232
1984		25.88	38.43	2.66	3.95	2,428
1985		24.09	34.54	2.51	3.60	1,980
1986		12.51	17.49	1.94	2.71	964
1987		15.40	20.89	1.67	2.26	936
1988		12.58	16.47	1.69	2.21	936
1989		15.86	19.93	1.69	2.12	869
1990		20.03	24.12	1.71	2.06	1,010
1991		16.54	19.16	1.64	1.90	860
1992		15.99	18.02	1.74	1.96	721
1993		14.25	15.65	2.04	2.24	754
1994		13.19	14.14	1.85	1.98	775
1995		14.62	15.33	1.55	1.62	723
1996		18.46	19.00	2.17	2.23	779
1997		17.23	17.40	2.32	2.34	943
1998	January	13.45	13.72	1.95	1.99	993
	February	12.17	12.41	1.95	1.99	974
	March	11.15	11.36	2.05	2.09	932
	April	11.28	11.48	2.15	2.19	886
	May	11.13	11.31	2.04	2.07	855
	June	10.00	10.15	1.90	1.93	854
	July	10.44	10.58	2.08	2.11	816
	August	10.20	10.33	1.81	1.83	792
	September	11.29	11.42	1.69	1.71	774
	October	11.32	11.45	1.85	1.87	734
	November	9.64	9.74	1.93	1.95	688
	December	8.03	8.10	1.94	1.96	647
1998		**10.87**	**11.03**	**1.94**	**1.97**	**827**
1999	January	8.59	8.64	1.80	1.81	587
	February	8.58	8.62	1.73	1.74	542
	March	10.75	10.78	1.70	1.71	526
	April	12.84	12.87	1.93	1.93	496
	May	13.84	13.85	2.10	2.10	516
	June	14.34	14.34	2.09	2.09	558
	July	16.13	16.14	2.07	2.07	588
	August	17.58	17.60	2.34	2.34	639
	September	20.10	20.12	2.42	2.42	696
	October	19.21	19.73	2.31	2.31	741
	November	21.35	21.39	2.44	2.44	782
	December	22.55	22.60	2.03	2.03	798
1999		**15.56**	**15.56**	**2.08**	**2.08**	**625**

=Revised data.

Sources: Current dollars and number of rigs: *Monthly Energy Review August 2000*, DOE/EIA-0035(00/08). 1999 constant dollars: U.S. Department of Commerce, Bureau of Economic Analysis, Gross Domestic Product Implicit Price Deflators, August 2000.

Economics and Drilling

Economics: Price matters. In 1999, resurgent crude oil prices generated the largest positive net revisions to proved reserves in over a decade. This section describes the price behavior in 1999 and the following section addresses drilling.

Table 3 lists the average annual domestic wellhead prices of crude oil and natural gas, as well as the average number of active rotary drilling rigs, from 1970 to 1999.

The U.S. crude oil first purchase price started at an average of $8.03 per barrel in December 1998 (an inflation-adjusted 53-year low), then accelerated during the year, reaching $22.55 per barrel in December 1999. The average U.S. crude oil first purchase price increased from an average $10.87 in 1998 to $15.56 per barrel in 1999. The price increases continue in the year 2000.

Oil prices vary by region. In Texas the average 1999 crude oil first purchase price was $17.29 per barrel, while in California it was $14.08 per barrel, and only $12.46 per barrel on the Alaskan North Slope. The lowest average crude oil first purchase price in 1999 was for Federal Offshore California oil—$11.78 per barrel.{23}

The average annual wellhead natural gas price increased from $1.94 in 1998 to $2.08 per thousand cubic feet in 1999. Natural gas prices started at $1.80 per thousand cubic feet in January 1999 and rose to $2.44 per thousand cubic feet by November 1999 (the highest average price of the year). The price increases continue in 2000, passing $3.00 per thousand cubic feet in June 2000. {24}

Drilling: From 1998 to 1999, the annual average active rig count decreased from 827 to 625 (**Table 3**), a 24 percent decline in active rigs. The rig count remains well below the peak activity level of the early 80's. Operators are now using significantly improved drilling and seismic exploration technology to dramatically increase their drilling success rate.

Looking first at exploratory wells, there were 2,123 exploratory wells drilled in 1999 (**Table 4**). Of these, 7 percent were oil wells, 27 percent were gas wells, and 66 percent were dry holes. The total (which includes dry holes) was 21 percent less than in 1998.

There were 1 percent more exploratory gas wells (**Figure 7**) and 50 percent fewer exploratory oil wells (**Figure 8**) than in 1998. The number of successful development wells decreased 42 percent for oil and decreased 14 percent for gas from 1998.

Figures 9 and 10 show the average volume of discoveries per exploratory well for dry natural gas and oil, respectively, since 1977. The average volume of gas discoveries per exploratory well decreased slightly, while the average volume of oil discoveries per exploratory well in 1999 increased. Altogether there were an estimated 18,180 exploratory and development wells drilled in 1999, 25 percent less than in 1998 and 28 percent less than the average number of wells drilled annually in the prior 10 years (25,328).

For the seventh year in a row, the number of gas well completions exceeded the number of oil well completions in both the exploratory and development categories.

Mergers and Acquisitions

Not all the notable activity in 1999 occurred in frontier drilling areas. Some occurred around the boardroom tables of major oil and gas corporations. The following large mergers were announced in 1999, and are expected to have a major impact on the energy industry in the future:

On November 30, 1999, Exxon Corporation and Mobil Corporation confirmed that the U.S. Federal Trade Commission (FTC) completed its review of the proposed merger and has approved a consent order for the merger of the two companies. Exxon and Mobil have accepted terms and conditions specified by the FTC and will comply with them fully and in a timely manner. The merged ExxonMobil Corporation expects that the scale of the worldwide near-term cost savings and the long-term strategic benefits will likely exceed those announced last year. The FTC's review was one of the most thorough and exhaustive ever undertaken, lasting some 11 months. Exxon and Mobil worked closely with the FTC to provide appropriate information on a timely basis to facilitate regulatory review of the merger. {25}

On August 17, 1999 Devon Energy Corporation and PennzEnergy Company announced that their merger had been completed. The merger was announced on May 20, 1999. Shareholders of both companies approved the merger at special meetings of shareholders on August 17, 1999. PennzEnergy shareholders will own approximately 31 percent of the

Table 4. U.S. Exploratory and Development Well Completions,[a] 1970-1999

Year	Exploratory[b]				Total Exploratory and Development[b]			
	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	642	1,067	5,952	7,661	10,167	6,933	10,320	27,420
1974	859	1,190	6,833	8,882	13,647	7,138	12,116	32,901
1975	982	1,248	7,129	9,359	16,948	8,127	13,646	38,721
1976	1,086	1,346	6,772	9,204	17,688	9,409	13,758	40,855
1977	1,164	1,548	7,283	9,995	18,745	12,122	14,985	45,852
1978	1,171	1,771	7,965	10,907	19,181	14,413	16,551	50,145
1979	1,321	1,907	7,437	10,665	20,851	15,254	16,099	52,204
1980	1,764	2,081	9,039	12,884	32,639	17,333	20,638	70,610
1981	2,636	2,514	12,349	17,499	43,598	20,166	27,789	91,553
1982	2,431	2,125	11,247	15,803	39,199	18,979	26,219	84,397
1983	2,023	1,593	10,148	13,764	37,120	14,564	24,153	75,837
1984	2,198	1,521	11,278	14,997	42,605	17,127	25,681	85,413
1985	1,679	1,190	8,924	11,793	35,118	14,168	21,056	70,342
1986	1,084	793	5,549	7,426	19,097	8,516	12,678	40,291
1987	925	754	5,049	6,728	16,164	8,055	11,112	35,331
1988	855	732	4,693	6,280	13,636	8,555	10,041	32,232
1989	607	705	3,924	5,236	10,204	9,539	8,188	27,931
1990	654	689	3,715	5,058	12,198	11,044	8,313	31,555
1991	592	534	3,314	4,440	11,770	9,526	7,596	28,892
1992	493	423	2,513	3,429	8,757	8,209	6,118	23,084
1993	502	548	2,469	3,519	8,407	10,017	6,328	24,752
1994	570	726	2,405	3,701	6,721	9,538	5,307	21,566
1995	542	570	2,198	3,310	7,627	8,354	5,075	21,056
1996	483	570	2,136	3,189	8,314	9,302	5,282	22,898
1997	428	536	2,110	3,074	10,436	11,327	5,702	27,465
1998	303	579	1,816	2,698	7,064	12,106	4,913	24,083
1999	151	583	1,389	2,123	4,087	10,513	3,580	18,180

[a]Excludes service wells and stratigraphic and core testing.
[b]All drilling counts for the years 1973-1998 have been revised.
Notes: Estimates are based on well completions taken from American Petroleum Institute data tapes through August 2000. 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 1973-1999: *Monthly Energy Review August 2000*, DOE/EIA-0035(00/08).

combined company and Devon shareholders will own approximately 69 percent. The new Devon Energy Corporation now ranks in the top 10 of all U.S.-based independent oil and gas producers in terms of market capitalization, total proved reserves and annual production. Devon Energy Corporation operates one of the world's largest coal bed methane fields in the San Juan Basin, plus has significant exposure to the developing Powder River Basin and Raton Basin coal seam plays. Devon also is one of the largest producers in the Gulf of Mexico with operations on 75 blocks and interests in an additional 98 undeveloped blocks. {26}

On October 25, 1999, El Paso Energy Corporation and Sonat Incorporated completed their $6 billion merger. The transaction creates a natural gas transmission system comprising over 40,000 miles, the largest natural gas transmission system in North America,

Figure 7. U.S. Exploratory Gas Well Completions, 1977-1999

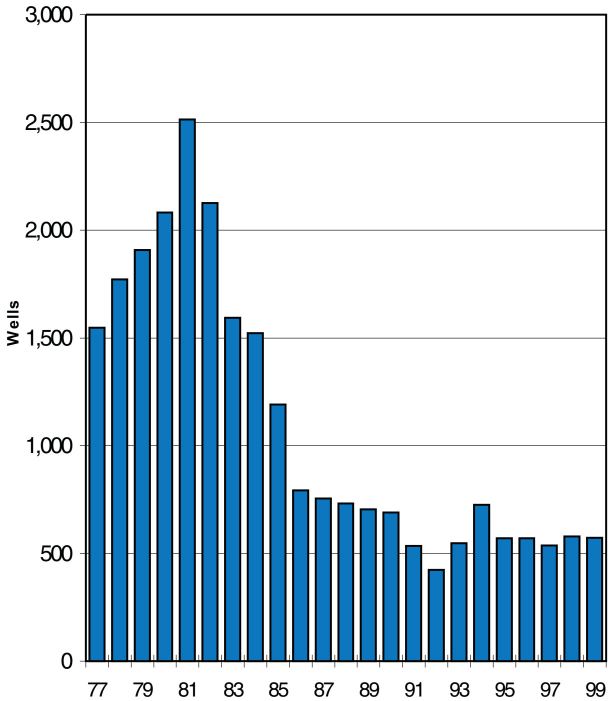


Figure 9. U.S. Total Discoveries of Dry Natural Gas per Exploratory Gas Well Completion, 1977-1999

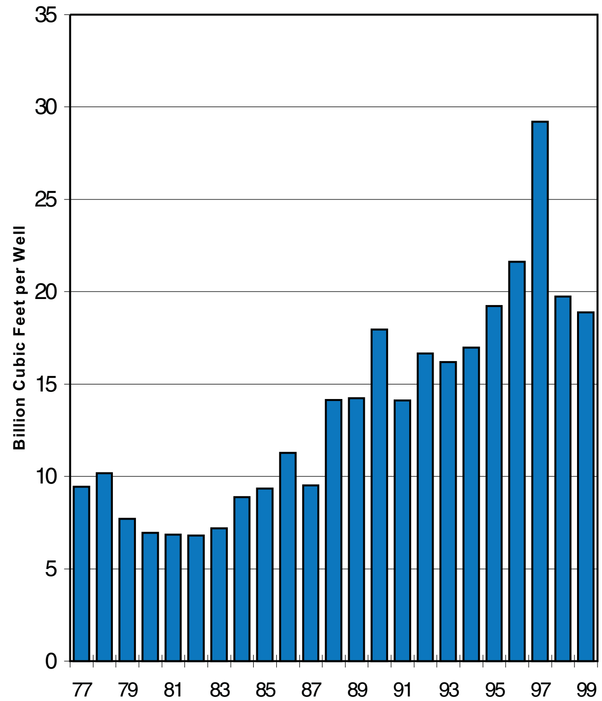


Figure 8. U.S. Exploratory Oil Well Completions, 1977-1999

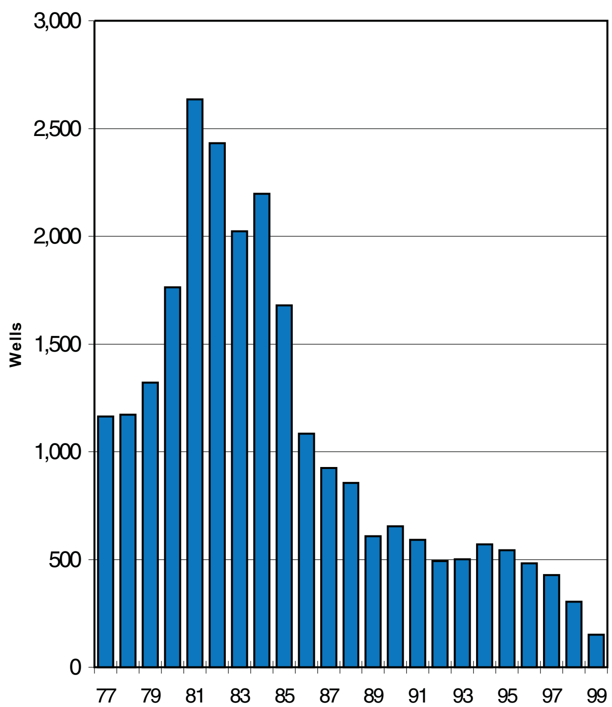
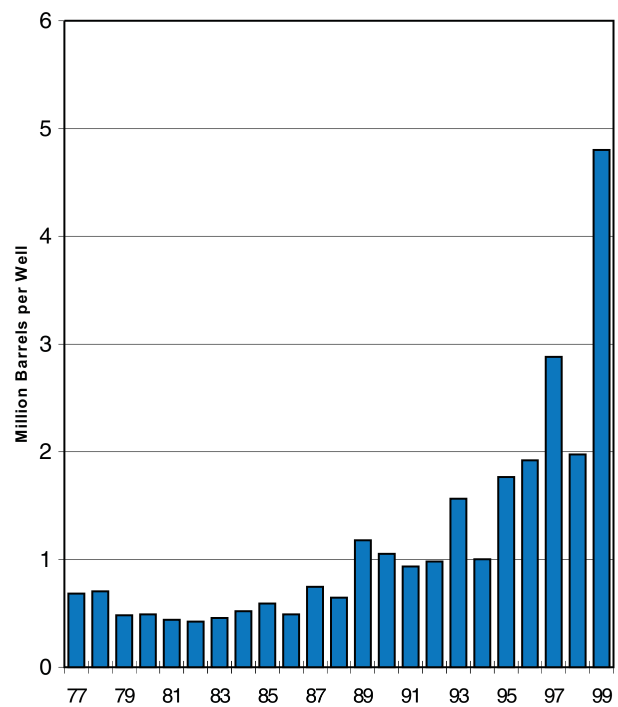


Figure 10. U.S. Total Discoveries of Crude Oil per Exploratory Oil Well Completion, 1977-1999



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

both in terms of throughput and miles of pipeline. El Paso Energy's pipeline systems will transport 12.4 billion cubic feet of natural gas—fully one quarter of the natural gas volumes transported in the United States each day. El Paso Energy has agreed to divest its 100-percent ownership in East Tennessee Natural Gas Company, Sonat's 100-percent ownership of Sea Robin Pipeline Company, and Sonat's one-third interest in Destin Pipeline Company, L.L.C. following the merger. {27}

Reserve-to-Production Ratio and Ultimate Recovery

R/P Ratios

The relationship between proved reserves and production levels, expressed as the ratio of reserves to production (R/P ratio) is often used in analyses. 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 the production level that can be maintained during the following year. Operators report data which yield R/P ratios that vary widely by area depending upon:

- category of operator
- geology and economics
- number and size of new discoveries
- amount of drilling that has occurred.

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 oil reserves were booked, the U.S. R/P ratio for crude oil 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 for crude oil decreased from 11.1-to-1 to 9.4-to-1 between 1977 and 1982, as Alaskan North Slope oil production reached high levels.

In 1999, U.S. crude oil proved reserves increased, while oil production decreased—resulting in an upward shift in the National average R/P ratio (11.1).

Figure 11 shows the U.S. R/P ratio trend for crude oil since 1945. After World War II, increased drilling and discoveries led to a greater R/P ratio. Later, when drilling found fewer reserves than were produced, the ratio became smaller. R/P ratios also vary geographically. Less developed areas of the country, such as the Pacific offshore, have higher R/P ratios for crude oil than the 1999 National average of 11.1-to-1. Other areas with relatively high R/P ratios are the Permian Basin of Texas and New Mexico, and California, where enhanced oil recovery techniques such as carbon dioxide (CO_2) injection or steamflooding have improved recoverability of oil in old, mature fields. Areas that have the lowest R/P ratios, like the Mid-Continent region, usually have many older fields. There, new technologies such as horizontal drilling have helped add reserves equivalent to the annual production, keeping the regional reserves and R/P ratio for oil relatively stable.

Figure 12 shows the historical R/P ratio for wet natural gas since 1945. Prior to 1945, R/P ratios were very high since the interstate pipeline infrastructure was not well developed. The market for and production of natural gas grew rapidly after World War II, lowering the R/P ratio. The U.S. average R/P ratio for natural gas increased in 1999, as reserves increased 2 percent Nationally while production had a slight increase.

Different marketing, transportation, and production characteristics for gas are seen when looking at regional average R/P ratios, compared to the 1999 U.S. average R/P ratio of about 8.9-to-1. The areas with the higher range of R/P ratios are the less developed or less productive areas of the country, such as the Pacific offshore and the Rockies, and also include areas such as Alabama and Colorado where considerable booking of coalbed methane reserves has recently occurred. Several major gas producing areas have R/P ratios below the National average, particularly Texas, the Gulf of Mexico Federal Offshore, and Oklahoma. The R/P ratio of these three areas combined increased from 6.9-to-1 in 1998 to 7.1-to-1 in 1999, and is below the National 1999 average.

Proved Ultimate Recovery

EIA has in past reports defined Ultimate Recovery as the sum of proved reserves and cumulative production. However, despite EIA's clear definition, the volume presented by EIA has often been misused or misinterpreted as the maximum recoverable volume of resources for an area. This neglects the addition of proved reserves over time through ultimate recovery appreciation (a.k.a. reserves growth or field growth) and has led some to make overly-pessimistic resource assessments for the United States. EIA is therefore introducing a new term, *Proved Ultimate Recovery*:

> **Proved Ultimate Recovery** is the sum of proved reserves and cumulative production. It is

Figure 11. Reserves-to-Production Ratios for Crude Oil, 1945-1999

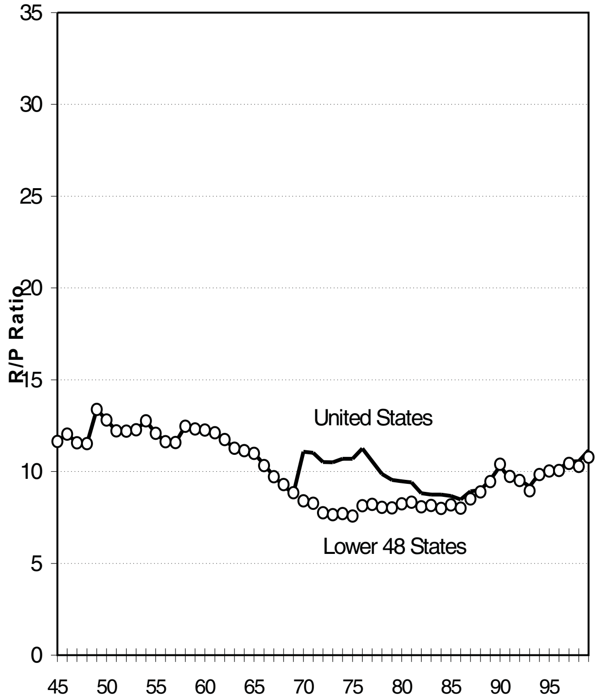


Figure 12. Reserves-to-Production Ratios for Wet Natural Gas, 1945-1999

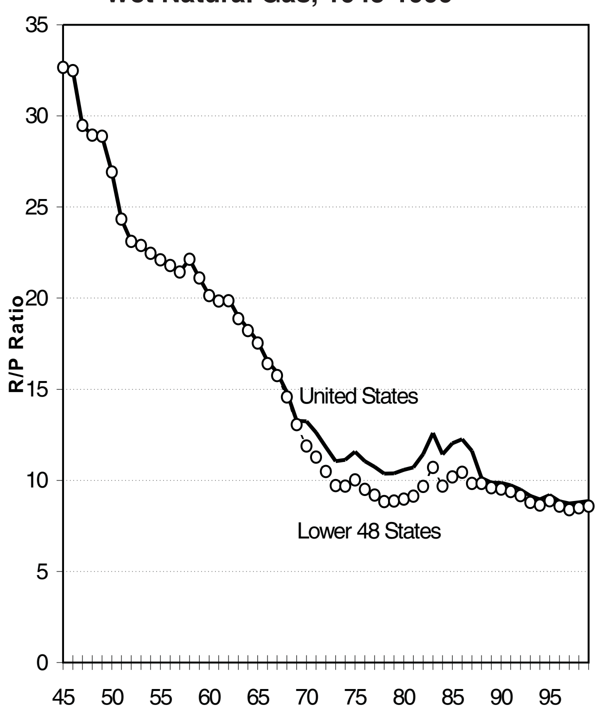


Figure 13. Components of Proved Ultimate Recovery for Crude Oil and Lease Condensate, 1977-1999

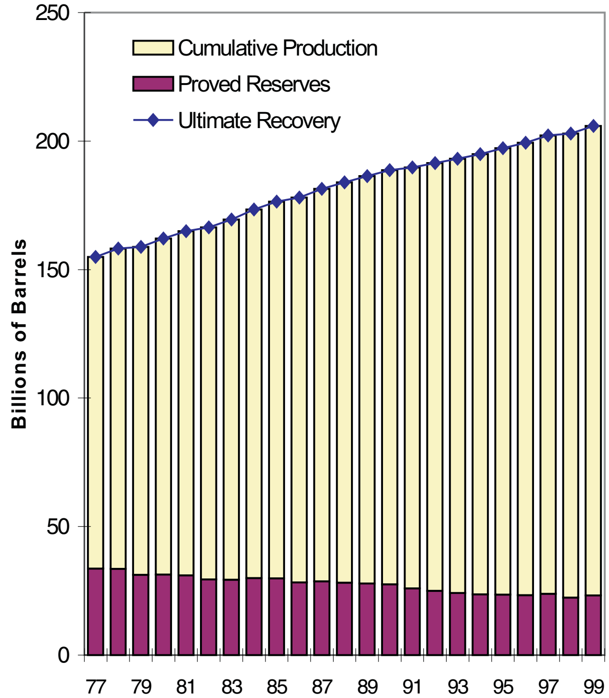
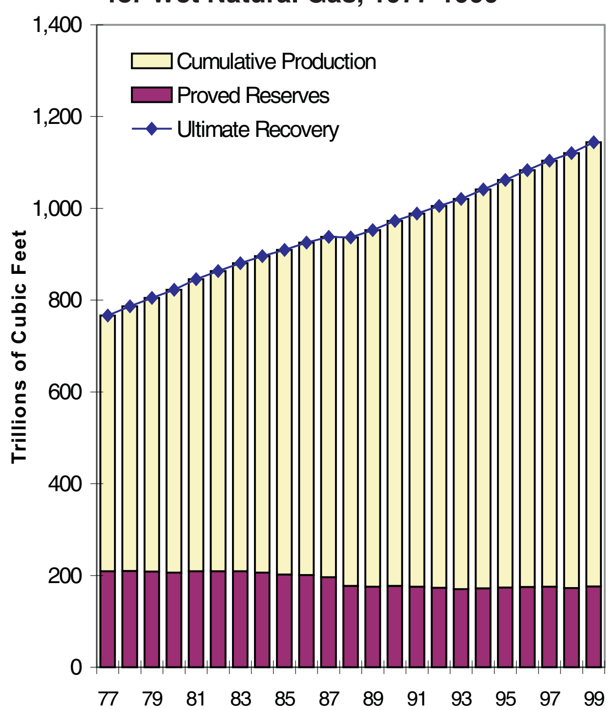


Figure 14. Components of Proved Ultimate Recovery for Wet Natural Gas, 1977-1999



Sources: Annual reserves and production - American Petroleum Institute and American Gas Association (1945–1976){28} and Energy Information Administration, Office of Oil and Gas (1977–1999){1-22}. Cumulative production: *U.S. Oil and Gas Reserves by Year of Field Discovery* (1977-1988).{29}

Table 5. International Oil and Natural Gas Reserves as of December 31, 1999

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]263,500	[d]261,425	1	Former U.S.S.R.	1,979,330	1,935,731
2	Iraq[c]	112,500	100,000	2	Iran[c]	812,300	789,990
3	Kuwait[c]	[d]96,500	[d]94,725	3	Qatar[c]	300,000	394,000
4	Iran[c]	89,700	93,100	4	Saudi Arabia[c]	[d]204,500	[d]208,000
5	United Arab Emirates[c]	96,200	63,460	5	United Arab Emirates[c]	200,200	202,550
6	Former U.S.S.R.	57,252	63,016	**6**	**United States**	**[e]164,041**	**160,920**
7	Venezuela[c]	72,600	47,058	7	Algeria[c]	159,700	159,700
8	Libya[c]	29,500	29,500	8	Venezuela[c]	142,500	145,763
9	China	24,000	34,100	9	Nigeria[c]	124,000	126,000
10	Mexico	28,399	28,259	10	Iraq[c]	109,800	112,600
Top 10 Total		**870,151**	**814,643**	**Top 10 Total**		**4,196,371**	**4,235,254**
11	Nigeria[c]	22,500	24,500	11	Malaysia	81,700	85,200
12	**United States**	**[e]21,034**	**19,625**	12	Indonesia[c]	72,268	80,832
13	Algeria[c]	9,200	13,000	13	Canada	63,874	63,515
14	Norway	10,787	10,026	14	Netherlands	62,542	59,763
15	Brazil	7,357	8,150	15	Kuwait[c]	[d]52,700	[d]57,350
16	Angola	5,412	8,475	16	Libya[c]	46,400	46,400
17	Indonesia[c]	4,980	8,380	17	China	48,300	41,300
18	Oman	5,283	5,700	18	Australia	44,638	44,600
19	Canada	4,931	5,578	19	Norway	41,389	42,854
20	United Kingdom	5,153	5,003	20	Egypt	35,180	42,500
21	Qatar[c]	3,700	5,437	21	Mexico	30,064	30,393
22	Malaysia	3,900	4,557	22	Oman	28,416	29,300
23	India	4,838	3,390	23	United Kingdom	26,663	26,828
24	Egypt	2,948	3,767	24	Argentina	24,247	24,300
25	Yemen	4,000	2,100	25	Pakistan	21,600	22,900
Top 25 Total		**986,174**	**942,331**	**Top 25 Total**		**4,876,352**	**4,933,289**
OPEC Total		**800,880**	**740,585**	**OPEC Total**		**2,224,368**	**2,323,185**
World Total		**1,016,041**	**978,868**	**World Total**		**5,146,207**	**5,197,863**

[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 (OPEC).
[d]Includes one-half of the reserves in the Neutral Zone.
[e]Energy Information Administration proved reserves as of December 31, 1998 were published by the *Oil & Gas Journal* as its estimates as of December 31, 1999.

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: PennWell Publishing Company, *Oil and Gas Journal*, December 20, 1999, pp. 91-93. Gulf Publishing Company, *World Oil*, August, 2000, pp. 31-35.

expected to change over time for any field, group of fields, State, or Country. Proved Ultimate Recovery does not represent the maximum recoverable volume of resources for an area. It is instead a gauge of how much has already been produced plus proved reserves. Proved reserves of crude oil or natural gas are the estimated quantities of petroleum which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. When deterministic proved reserves estimation methods are used, the term reasonable certainty is intended to express a high degree of confidence that the estimated quantities will be recovered. When probabilistic methods are used there should be at least a 90 percent probability that the actual quantities recovered will exceed the estimate.

Figures 13 and 14 show successive estimates of proved ultimate recovery and its components, proved reserves and cumulative production, for crude oil plus lease condensate, and wet natural gas, from 1977 through 1999. They illustrate the continued appreciation (growth) of proved ultimate recovery over time.

In 1977, U.S. crude oil and lease condensate proved reserves were 33,615 million barrels. Cumulative production of crude oil and lease condensate for 1977 through 1999 was 61,356 million barrels. This substantially exceeds the 1977 proved reserves, but at the end of 1999 there were still 23,168 million barrels of crude oil and lease condensate proved reserves. Therefore, the Nation's estimated proved ultimate recovery of crude oil was fundamentally increased during this period owing to the *proved ultimate recovery appreciation* process (continued development of old fields). In fact, only 8 percent of proved reserves additions of crude oil were booked as *new field discoveries* from 1976 through 1999. The rest was from proved reserves categories included in the proved ultimate recovery appreciation process (*new reservoir discoveries in old fields, extensions*, and *revisions and adjustments*.) A significant part of the total proved ultimate recovery appreciation came from the proved ultimate recovery appreciation of those new fields discovered between 1976 and 1999.

Similarly, the 1977 wet natural gas proved reserves were 209,490 billion cubic feet, and cumulative dry gas production from 1977 through 1999 was 410,846 billion cubic feet. Cumulative wet gas production exceeded the 1977 reserves, but at the end of 1999 there were still 176,159 billion cubic feet of wet natural gas proved reserves, for the same reasons. Only 12 percent of proved reserve additions of natural gas were booked as *new field discoveries* from 1976 through 1999.

International Perspective

International Reserves

The EIA estimates domestic oil and gas reserves but does not systematically estimate worldwide reserves. As shown in **Table 5**, international reserves estimates are presented in two widely circulated trade publications. The world's total reserves are estimated to be roughly 1 trillion barrels of oil and 5 quadrillion cubic feet of gas.

The United States ranked 12th in the world for proved reserves of crude oil and 6th for natural gas in 1999. A comparison of EIA's U.S. proved reserves estimates with worldwide estimates obtained from other sources shows that the United States had about 2 percent of the world's total crude oil proved reserves and over 3 percent of the world's total natural gas proved reserves at the end of 1999. There are sometimes substantial differences between the estimates from these sources. The *Oil & Gas Journal* reported oil reserves for the United Arab Emirates at about 96 billion barrels. This is about 50 percent higher than the *World Oil* estimate of 63 billion. One reason (among many) for these differences is that condensate is often included in foreign oil reserve estimates.

The *Oil & Gas Journal*{30} estimate for world oil reserves decreased 2 percent in 1999, while the *World Oil*{31} estimate increased 1 percent. For world gas reserves, the *Oil & Gas Journal* reported no change, while *World Oil* reported a 1 percent increase.

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 almost 5 times U.S. reserves. Closer to home, Venezuela has almost triple and Mexico has around 30 percent more than the United States' oil reserves. (Based on averages of the World Oil and Oil & Gas Journal estimates).

Petroleum Consumption

The United States is the world's largest energy consumer. The EIA estimates energy consumption and publishes it in its *Annual Energy Review*.{32} In 1999:

- The U.S. consumed 96,596,000,000,000,000 Btu of energy (96.6 quadrillion Btu).
- 62 percent of U.S. energy consumption was provided by petroleum and natural gas—crude oil and natural gas liquids combined (39 percent), and natural gas (23 percent).
- U.S. petroleum consumption was about 19.4 million barrels of oil and natural gas liquids and 58.7 billion cubic feet of dry gas per day.

Dependence on Imports

The United States remains heavily dependent on imported oil and gas to satisfy its ever-increasing appetite for energy. In 1999, crude oil imports made up 59 percent of the U.S. crude oil supply.

Net gas imports increased slightly in 1999 to 3.56 trillion cubic feet, which is approximately 17 percent of consumption. Almost all of this gas was pipelined from Canada, some came from Mexico, though Mexico remains a net importer of natural gas from the U.S., and liquefied natural gas was imported from Algeria and Australia.

Canada, Saudi Arabia, Venezuela, and Mexico were the primary foreign suppliers of petroleum to the United States.{33}

List Of Appendices

Appendix A: Reserves by Operator Production Size Class - How much of the National total of proved reserves are owned and operated by the large oil and gas corporations? Appendix A separates the large operators from the small and presents reserves data according to operator production size classes.

Appendix B: Top 100 Oil and Gas Fields - What fields have the most reserves and production in the United States? The top 100 fields for oil and natural gas out of the inventory of more than 45,000 oil and gas fields are listed in Appendix B. These fields hold two-thirds of U.S. crude oil proved reserves. Table B3 in Appendix B lists the top U.S. operators by reported 1999 production and indicates pending mergers announced in 1999 with linked arrows.

Appendix C: Conversion to the Metric System - To simplify international comparisons, a summary of U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves expressed in metric units is included as Appendix C.

Appendix D: Historical Reserves Statistics - Appendix D contains selected historical reserves data presented at the State and National level. Readers interested in a historical look at one specific State or region can review these tables. We have again included Table D9, Deepwater Production and Proved Reserves of the Gulf of Mexico Federal Offshore 1992-1999, due to expressed interest from the industry regarding this area. Table D9 contains the production and proved reserves for 1992-1999 for the Gulf of Mexico Federal Offshore region by water depths greater than 200 meters, and less than 200 meters.

Appendix E: Summary of Data Collection Operations - This report is based on two EIA surveys. Proved reserves data is collected annually from U.S. oil and gas field operators on Form EIA-23. Natural gas liquids production data is collected annually from U.S. natural gas plant operators on Form EIA-64A. Appendix E describes survey designs, response statistics, reporting requirements, and sampling frame maintenance.

Appendix F: Statistical Considerations - The EIA strives to maintain or improve the accuracy of its reports. Since complete coverage of all oil and gas operators is impractical, the EIA has adopted sound statistical methods to impute data for those operators not sampled and for those data elements that smaller operators are not required to file. These methods are described in Appendix F.

Appendix G: Estimation of Reserves and Resources - Reserves are not measured directly. Reserves are estimated on the basis of the best geological, engineering, and economic data available to the estimator. Appendix G describes reserve estimation techniques commonly used by oil and gas field operators and EIA personnel when in the field performing quality assurance checks. A discussion of the relationship of reserves to overall U.S. oil and gas resources is also included.

Appendix H: Maps of Selected State Subdivisions - Certain large producing States have been subdivided into smaller regions to allow more specific reporting of reserves data. Maps of these States identifying the smaller regions are provided in Appendix H.

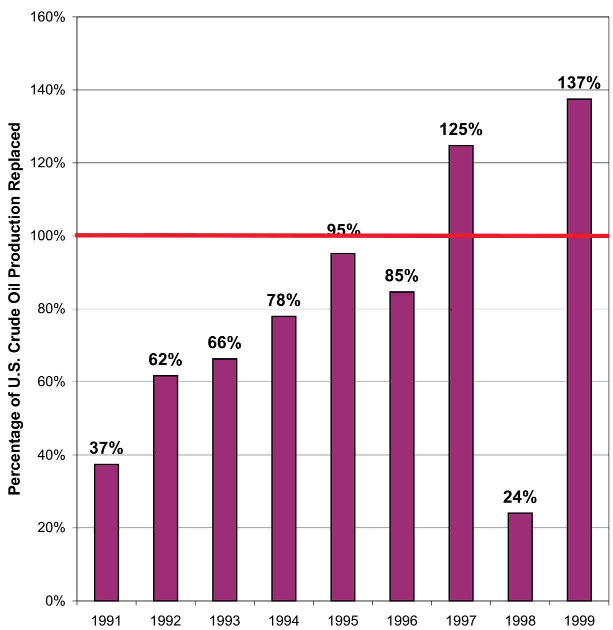
Appendix I: Annual Survey Forms of Domestic Oil and Gas Reserves - Samples of Form EIA-23 and Form EIA-64A are presented in Appendix I.

Glossary - Contains definitions of many of the technical terms used in this report.

3. Crude Oil Statistics

The United States had 21,765 million barrels of crude oil proved reserves as of December 31, 1999. This is 3.5 percent (731 million barrels) more than in 1998, and is the largest percentage increase in oil reserves in the 23-year EIA reserves program.

Figure 15. Reserve Additions Replace 137 Percent of U.S. Oil Production in 1999



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

Operators replaced 137 percent of 1999 oil production with proved reserves additions (**Figure 15**). This was not a result of increased drilling, more successful exploratory drilling, or dramatically improved technology. Crude oil prices began slowly increasing from the inflation-adjusted 53-year low of December 1998 and then accelerated during the year, reaching $22.55 per barrel in December 1999. Price was the most significant factor in the largest positive net revisions to proved reserves in over a decade.

Over the past decade, U.S. crude oil proved reserves had been declining (**Figure 1**) an average of 2 percent per year. The decline was much more severe in 1998. In 1999, oil reserve levels appear to have recovered from the 1998 decline.

Proved Reserves

Table 6 presents the U.S. proved reserves of crude oil as of December 31, 1999, by selected States and State subdivisions.

Figure 16 maps 1999 crude oil proved reserves by area. The following four areas account for 79 percent of U.S. crude oil proved reserves:

Area	Percent of U.S. Oil Reserves
Texas	25
Alaska	23
California	18
Gulf of Mexico Federal Offshore	13
Area Total	**79**

Of these four areas, Texas and California increased their reserves in 1999, while Alaska and the Gulf of Mexico had decreases in crude oil proved reserves.

Discussion of Reserves Changes

Figure 17 maps the change in crude oil proved reserves from 1997 to 1998 by area. Here's how the top four areas fared compared to the total United States:

Area	Change in U.S. Oil Reserves (million barrels)
Texas	+412
Alaska	-152
California	+91
Gulf of Mexico Federal Offshore	-49
Area Total	**+302**
U.S. Total	**+731**

Figure 2 in Chapter 2 shows the components of the changes in crude oil proved reserves for 1999 and the preceding 10 years.

Total Discoveries

Total discoveries are those new reserves attributable to *extensions* of existing fields, *new field discoveries*, and *new reservoir discoveries in old fields*. They result from the drilling of exploratory wells.

Table 6. Crude Oil Proved Reserves, Reserves Changes, and Production, 1999
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	Published Proved Reserves 12/31/98	Changes in Reserves During 1999: Adjustments (+,-)	Revision Increases (+)	Revision Decreases (--)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Estimated Production (-)	Proved Reserves 12/31/99
Alaska	5,052	1	2,351	2,201	6	79	0	388	4,900
Lower 48 States	**15,982**	**138**	**3,933**	**2,264**	**253**	**242**	**145**	**1,564**	**16,865**
Alabama	39	-1	29	13	0	0	0	5	49
Arkansas	47	-7	23	10	0	0	0	5	48
California	3,843	72	575	337	60	0	0	279	3,934
Coastal Region Onshore	354	2	150	31	33	0	0	17	491
Los Angeles Basin Onshore	207	40	98	42	13	0	0	19	297
San Joaquin Basin Onshore	3,127	19	275	264	14	0	0	222	2,949
State Offshore	155	11	52	0	0	0	0	21	197
Colorado	212	-9	25	9	0	0	0	16	203
Florida	71	1	18	0	0	0	0	5	85
Illinois	81	5	24	1	0	0	0	9	100
Indiana	13	-4	3	1	0	0	0	1	10
Kansas	246	-97	60	17	4	0	2	23	175
Kentucky	23	0	3	0	0	0	0	2	24[b]
Louisiana	551	10	184	90	20	2	10	87	600
North	101	-6	33	15	12	0	0	17	108
South Onshore	353	3	126	63	8	2	8	53	384
State Offshore	97	13	25	12	0	0	2	17	108
Michigan	44	3	26	14	0	0	0	7	52
Mississippi	141	-16	62	12	2	0	1	15	163
Montana	167	-5	136	94	15	0	0	12	207
Nebraska	18	-3	7	3	0	0	0	2	17
New Mexico	620	54	149	55	11	0	0	61	718
East	610	51	147	54	11	0	0	60	705
West	10	3	2	1	0	0	0	1	13
North Dakota	245	21	55	31	3	0	0	31	262
Ohio	40	-21	28	2	0	0	10	4[b]	51
Oklahoma	599	5	148	81	6	0	0	56	621
Pennsylvania	15	0	3	2	1	0	0	1	16
Texas	4,927	127	1,239	601	59	1	3	416	5,339
RRC District 1	61	-17	31	1	0	0	0	8	66
RRC District 2 Onshore	45	8	15	6	0	0	0	9	53
RRC District 3 Onshore	211	15	62	44	10	0	0	33	221
RRC District 4 Onshore	40	-1	14	7	2	0	0	6	42
RRC District 5	40	-2	6	2	1	0	0	6	37
RRC District 6	308	6	126	167	3	0	0	31	245
RRC District 7B	115	20	9	7	0	0	0	14	123
RRC District 7C	173	21	60	31	3	0	1	18	209
RRC District 8	1,865	31	406	123	18	0	2	132	2,067
RRC District 8A	1,895	22	444	159	21	1	0	135	2,089
RRC District 9	111	16	52	41	1	0	0	16	123
RRC District 10	62	4	11	9	0	0	0	7	61
State Offshore	1	4	3	4	0	0	0	1	3
Utah	201	4	112	35	0	0	0	14	268
West Virginia	17	5	2	2	0	0	0	1	21
Wyoming	547	-6	141	45	4	1	0	52	590
Federal Offshore	3,261	1	876	808	68	238	119	458	3,297
Pacific (California)	468	-1	147	26	2	0	0	37	553
Gulf of Mexico (Louisiana)	2,483	2	693	730	55	238	77	376	2,442
Gulf of Mexico (Texas)	310	0	36	52	11	0	42	45	302
Miscellaneous[a]	14	-1	5	1	0	0	0	2	15
U.S. Total	**21,034**	**139**	**6,284**	**4,465**	**259**	**321**	**145**	**1,952**	**21,765**

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

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 1999 contained in the *Petroleum Supply Annual 1999*, DOE/EIA-0340(99).

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

Figure 16. 1999 Crude Oil Proved Reserves by Area

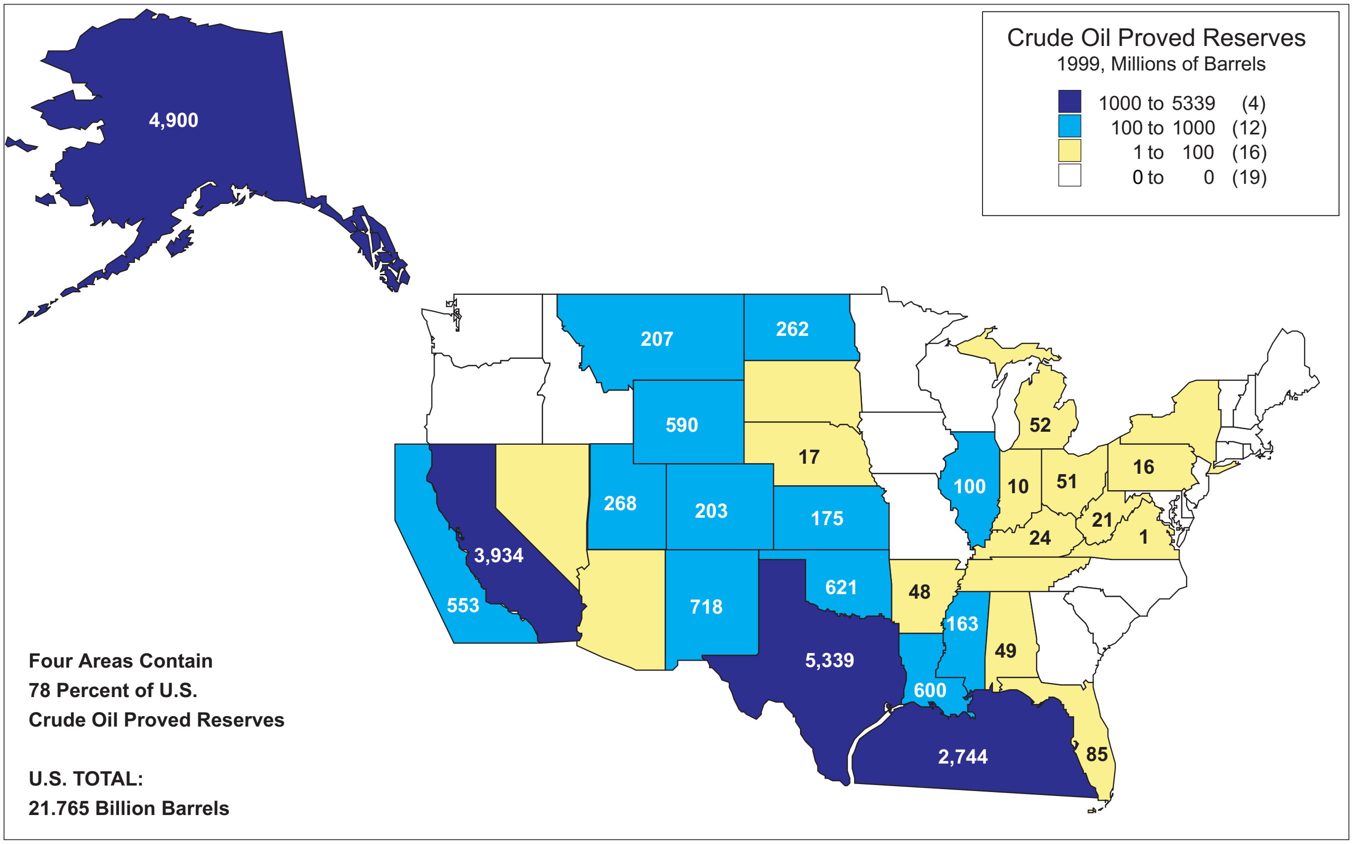
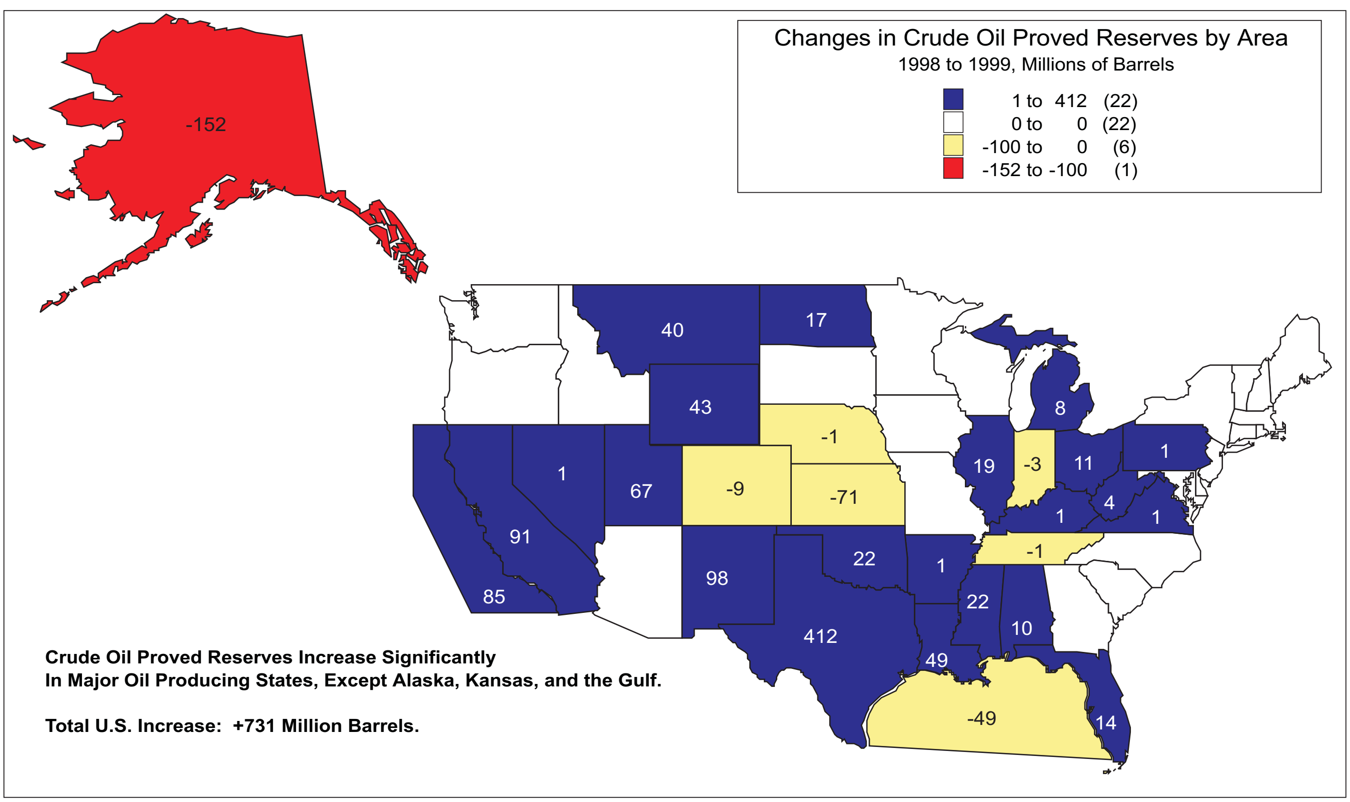


Figure 17. Changes in Crude Oil Proved Reserves by Area, 1998 to 1999



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

Total discoveries of crude oil were 725 million barrels in 1999, 21 percent more than those of 1998. Only five areas had *total discoveries* exceeding 30 million barrels:

- The Gulf of Mexico Federal Offshore had 423 million barrels of *total discoveries*, 58 percent of the National total.
- Alaska had 85 million barrels of *total discoveries,* 12 percent of the National total.
- Texas had 63 million barrels of *total discoveries,* 9 percent of the National total.
- California had 60 million barrels of *total discoveries,* 8 percent of the National total.
- Louisiana had 32 million barrels of *total discoveries,* 4 percent of the National total.

The United States discovered an average of 752 million barrels of new crude oil proved reserves per year in the prior 10 years (1989 through 1998). *Total discoveries* in 1999 were 4 percent less than that average.

Extensions

Operators reported 259 million barrels of *extensions* in 1999. The highest volume of *extensions* was reported in the Gulf of Mexico Federal Offshore (66 million barrels of *extensions.*) Operators in California reported 60 million barrels of *extensions*. Texas was third with 59 million barrels, followed by Louisiana with 20 million barrels.

In the prior 10 years, U.S. operators reported an average of 433 million barrels of *extensions* per year. The 1999 *extensions* were 40 percent less than that average.

New Field Discoveries

There were 321 million barrels of *new field discoveries* reported in 1998. Only five areas in the United States reported any *new field discoveries,* and only two contributed more than 1 percent to the total:

- Gulf of Mexico Federal Offshore (74 percent; 238 million barrels)
- Alaska (25 percent; 79 million barrels).

In the prior 10 years, U.S. operators reported an average of 184 million barrels of reserves from *new field discoveries* per year. Reserves from *new field discoveries* in 1999 were 74 percent more than that average volume.

New Reservoir Discoveries in Old Fields

Operators in the United States reported 145 million barrels of crude oil reserves from *new reservoir discoveries in old fields* in 1999. As with *new field discoveries*, the most significant portion of the *new reservoir discoveries in old fields* came from the Gulf of Mexico Federal Offshore—119 million barrels or 82 percent of the total. Louisiana and Ohio each had 10 million barrels (7 percent each). In the prior 10 years, U.S. operators reported an average of 135 million barrels of reserves from *new reservoir discoveries in old fields* per year. Reserves from *new reservoir discoveries in old fields* in 1999 were 7 percent more than that average.

Revisions and Adjustments

Thousands of positive and negative *revisions* to proved reserves occur each year as infill wells are drilled, well performance is analyzed, new technology is applied, or economic conditions change. *Adjustments* are the annual changes in the published reserve estimates that cannot be directly attributed to the estimates for other reserve change categories because of the survey and statistical estimation methods employed.

There were 1,958 million barrels of net *revisions and adjustments* for crude oil in 1999. This is the largest contribution in the 23-year history of the EIA reserves program. Average *revisions and adjustments* for the prior 10 years were 986 million barrels.

Production

U.S. *production* of crude oil in 1999 was 1,952 million barrels. This was 2 percent lower than 1998's production of 1,991 million barrels. U.S. crude oil *production* has declined eight years in a row. The Gulf of Mexico Federal Offshore leapt from third place to the largest producing area in the United States in 1999 with 22 percent of the National total of oil production. Texas and Alaska are now second and third with 21 percent and 20 percent of the total, respectively. California is fourth with 14 percent.

In 1999, the Form EIA-23 National production estimates were within two tenths of 1 percent of the comparable *Petroleum Supply Annual (PSA) 1999* volumes for crude oil and lease condensate production combined (2,147 million barrels).

Areas of Note: Large Discoveries and Reserves Additions

The following State and area discussions summarize notable activities during 1999 concerning expected new field reserves, development plans, and possible production rates as reported in 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.

The following areas are the major success stories for crude oil reserves and production for 1999.

Texas

Texas, the state with the largest proved reserves of crude oil, also reported the largest increase in proved reserves in 1999. Texas proved oil reserves increased by 412 million barrels in 1999. The largest increase component was revisions and adjustments in the Permian Basin area (Texas Subdivisions 8 and 8A). These 2 state subdivisions accounted for 396 million barrels of the crude oil proved reserves increase.

New Mexico

New Mexico had the second highest net increase in crude oil proved reserves in 1999, an increase of 98 million barrels. Operators in New Mexico, as they did in Texas, revised their crude oil proved reserves upward in 1999. New Mexico had a 16 percent increase in proved crude oil reserves, and a production increase of 3 percent from 1998 (59 million barrels production) to 1999.

Gulf of Mexico Federal Offshore

Despite the net loss of reserves in 1999, the Gulf of Mexico still holds much promise for future development and reserves additions, especially in deep water. In 1999, this area had the most *total discoveries* of crude oil proved reserves – 423 million barrels of *total discoveries*, which is 58 percent of the National total.

- **The British (Petroleum) Invasion:** BP Amoco announced four major discoveries in the deepwater Gulf in 1999. These include Crazy Horse, Mad Dog, Atlantis, and Holstein. All four of these fields are operated by BP Amoco. Crazy Horse, the largest deepwater discovery to date, is anticipated to have reserves of at least one billion barrels of oil equivalent. It is owned 75% by the BP Amoco group, and 25% by Exxon Mobil. Mad Dog is 63.56% group-owned by BP Amoco, with partners Unocal and BHP. Atlantis is owned 56% by the BP Amoco group and 44% by BHP, and Holstein is an equal partnership between BP Amoco and Shell. The latter three discoveries are anticipated to add another 600 million barrels of oil equivalent in net additional reserves.{34}
- **Brutus**: Shell Exploration and Production Company announced in April 1999 its plans to develop Brutus using a tension leg platform to be installed on Green Canyon Block 158 in 2,985 feet of water. Estimated ultimate gross recovery from the development is greater than 200 million barrels of oil equivalent, with a 70:30 oil/gas ratio. The Brutus TLP facilities are designed to accommodate 100,000 barrels of oil and 300 million cubic feet of gas per day. The TLP will be utilized as a hub for surrounding developments.{35}
- **Oregano**: On April 22, 1999, Shell Exploration and Production Company announced its third oil and gas discovery in the deepwater Auger basin of the Gulf of Mexico. The Oregano prospect, located at Garden Banks Block 559 in a water depth of 3,393 feet, was drilled to a measured depth of 19,500 feet and encountered commercial quantities of hydrocarbons.{36}
- **Hoover and Diana:** In 1999, Exxon Mobil Corporation installed the largest deep draft caisson vessel in the Gulf of Mexico to develop the Hoover and Diana fields, located in the Gulf of Mexico 320 kilometers (200 miles) from Houston. These fields hold the equivalent of 400 million barrels of oil. ExxonMobil is also the primary leaseholder on several good prospects and discoveries nearby, such as the Marshall and Madison fields, which will be tied into the Hoover hub in 2002. Exxon Mobil set another record while developing these fields – the deepest water-depth for horizontal wells and gravel packs: 760 meters (2,500 feet) of horizontal section in 1,425 meters (4,700 feet) of water, Diana field, Gulf of Mexico.{37}

California

California's crude oil proved reserves increased 2 percent (91 million barrels) in 1999. Operators in

California revised their 1998 reserves upward, plus added reserves through extensions.

Other Gain Areas

Pacific Federal Offshore: Proved oil reserves in the Pacific Federal Offshore increased by 18 percent (85 million barrels) in 1999. The increase was from upward revisions of reserves.

Utah: Utah's proved oil reserves increased by 33 percent (67 million barrels) in 1999 compared to 1998. The increase was from upward revisions of reserves.

Areas of Note: Large Reserves Declines

The following areas had large declines in crude oil proved reserves due to downward revisions or unreplaced production.

Alaska

Alaska's crude oil proved reserves declined 152 million barrels in 1999, 39 percent more than the decline reported in 1998 (109 million barrels). Alaska had the second highest volume of *new field discoveries* (79 million barrels) of any area in 1999, but this did not offset Alaska's oil production—an estimated 388 million barrels in 1999. Alaska's production declined 11 percent from its 1998 level (437 million barrels production).

Kansas

Kansas' crude oil proved reserves declined 29 percent (71 million barrels) in 1999. Operators also reported a production decline of 32 percent (11 million barrels) from 1998 (34 million barrels production) to 1999.

Gulf of Mexico Federal Offshore

There was a net decline of 49 million barrels of crude oil proved reserves in the Gulf of Mexico Federal Offshore in 1999. It is expected that development and exploration in the Gulf of Mexico Federal Offshore will continue to add future reserves.

The Gulf of Mexico produced about 421 million barrels of crude oil in 1999, an increase of 13 percent over 1998's production (372 million barrels). However, there were only 372 million barrels of total reserves additions (which includes adjustments, net revisions, and total discoveries) in this area, which replaced just 88 percent of production from this area.

Other Decline Areas

In the following areas of the United States, development of existing or new oil fields was outpaced by crude oil production.

Colorado: Proved oil reserves decreased by 4 percent (9 million barrels).

Indiana: Proved oil reserves decreased by 23 percent (3 million barrels).

Reserves in Nonproducing Reservoirs

Not all proved reserves of crude oil were contained in reservoirs that were producing. Operators reported 4,206 million barrels of proved reserves in nonproducing reservoirs, 1 percent more than reported in 1998 (4,147 million barrels).

Nonproducing reserves are those 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 currently available technology. The 1999 volume, 2,865 million barrels, is about 9 percent less than what was reported in 1998 (3,160 million barrels).

Table 7 lists the indicated additional reserves by selected States and State subdivisions. The presence of large indicated additional reserves in Alaska, California, south Louisiana and west Texas implies that significant upward revisions to proved crude oil reserves could occur in the future.

Table 7. Reported Indicated Additional Crude Oil Reserves,[a] 1999
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	Indicated Additional Reserves
Alaska	464
Lower 48 States	2,400
Alabama	0
Arkansas	0
California	1,400
Coastal Region Onshore	30
Los Angeles Basin Onshore	0
San Joaquin Basin Onshore	1,330
State Offshore	30
Colorado	21
Florida	0
Illinois	0
Indiana	0
Kansas	0
Kentucky	0
Louisiana	278
North	0
South Onshore	278
State Offshore	0
Michigan	0
Mississippi	0
Montana	0
Nebraska	0
New Mexico	165
East	165
West	0
North Dakota	1
Ohio	0
Oklahoma	58
Pennsylvania	0
Texas	426
RRC District 1	0
RRC District 2 Onshore	0
RRC District 3 Onshore	25
RRC District 4 Onshore	0
RRC District 5	0
RRC District 6	4
RRC District 7B	0
RRC District 7C	3
RRC District 8	279
RRC District 8A	115
RRC District 9	0
RRC District 10	0
State Offshore	0
Utah	42
West Virginia	0
Wyoming	5
Federal Offshore	5
Pacific (California)	0
Gulf of Mexico (Louisiana)	5
Gulf of Mexico (Texas)	0
Miscellaneous[b]	0
U.S. Total	**2,865**

[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," 1999.

4. Natural Gas Statistics

Dry Natural Gas

Proved Reserves

As of December 31, 1999, U.S. operators had 167,406 billion cubic feet of dry natural gas proved reserves, 2 percent more than in 1998 (**Table 8**).

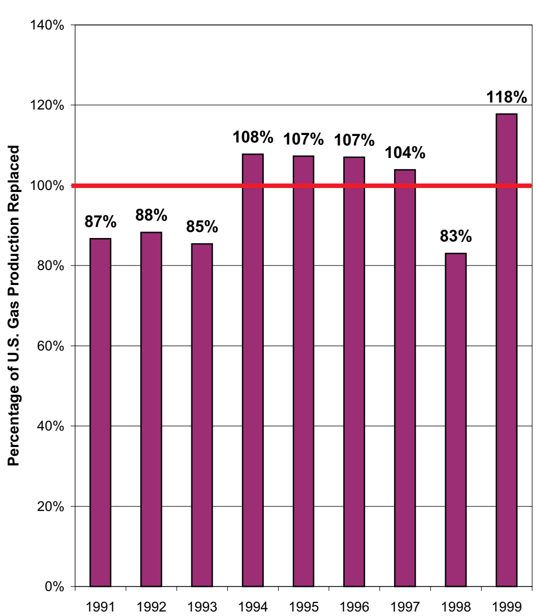
Additions to dry gas reserves in 1999 were 22,293 billion cubic feet, up 43 percent compared to 1998. Operators replaced 118 percent of dry gas production (**Figure 18**). U.S. *total discoveries* of dry natural gas reserves were 10,807 billion cubic feet in 1998, down 5 percent from 1998 (11,433 billion cubic feet).

Proved reserves by State are shown on the map in **Figure 19**. Seven areas account for 75 percent of the Nation's dry natural gas proved reserves:

Area	Percent of U.S. Gas Reserves
Texas	24
Gulf of Mexico Federal Offshore	15
New Mexico	9
Wyoming	8
Oklahoma	7
Alaska	6
Louisiana	6
Area Total	**75**

Of these seven areas, Texas, New Mexico, Wyoming, and Louisiana had increased reserves in 1999, while Alaska, the Gulf of Mexico Federal Offshore, and Oklahoma had decreases in dry natural gas proved reserves.

Figure 18. Reserve Additions Replace 118% of 1999 U.S. Dry Natural Gas Production.



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

Discussion of Reserves Changes

Figure 20 maps the change in dry gas proved reserves from 1998 to 1999 by area. Here's how the top seven areas fared, compared to the total United States:

Area	Change in U.S. Gas Reserves (billion cubic feet)
Texas	+2,573
Gulf of Mexico Federal Offshore	-971
New Mexico	+462
Wyoming	+576
Oklahoma	-1,102
Alaska	-193
Louisiana	+95
Area Total	**+1,440**
U.S. Total	**+3,365**

Figure 4 in Chapter 2 shows the components of the changes in dry natural gas proved reserves for 1999 and the preceding 10 years.

Revisions and Adjustments

Net revisions and adjustments increased to 11,486 billion cubic feet in 1999, almost triple 1998's level (4,105 billion cubic feet). Texas had the largest increase in *net revisions and adjustments* (4,456 billion cubic feet). New Mexico had the second largest with 1,412 billion cubic feet of *net revisions and adjustments*.

Table 8. Dry Natural Gas Proved Reserves, Reserves Changes, and Production, 1999
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State and Subdivision	Published Proved Reserves 12/31/98	Changes in Reserves During 1999: Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Estimated Production (-)	Proved Reserves 12/31/99
Alaska	9,927	133	3,577	3,525	2	56	23	459	9,734
Lower 48 States	**154,114**	**849**	**38,590**	**28,138**	**7,041**	**1,512**	**2,173**	**18,469**	**157,672**
Alabama	4,604	-17	215	140	1	0	0	376	4,287
Arkansas	1,328	-48	761	376	27	1	12	163	1,542
California	2,244	111	553	316	58	0	3	266	2,387
Coastal Region Onshore	106	-11	69	10	46	0	0	8	192
Los Angeles Basin Onshore	149	-1	40	15	4	0	0	9	168
San Joaquin Basin Onshore	1,945	125	398	291	8	0	3	237	1,951
State Offshore	44	-2	46	0	0	0	0	12	76
Colorado	7,881	82	2,788	1,607	430	123	9	719	8,987
Florida	88	1	0	0	0	0	0	5	84
Kansas	6,402	-152	437	479	24	6	1	486	5,753
Kentucky	1,222	34	230	41	30	0	19	59	1,435
Louisiana	9,147	509	2,571	2,297	316	44	373	1,421	9,242
North	2,898	222	1,024	842	149	0	5	377	3,079
South Onshore	5,698	104	1,412	1,238	144	23	319	927	5,535
State Offshore	551	183	135	217	23	21	49	117	628
Michigan	2,328	12	624	478	2	0	1	234	2,255
Mississippi	658	34	165	120	11	0	8	79	677
Montana	782	42	98	55	15	0	0	41	841
New Mexico	14,987	394	1,882	864	560	2	27	1,539	15,449
East	2,693	187	938	411	113	2	6	491	3,037
West	12,294	207	944	453	447	0	21	1,048	12,412
New York	218	-78	89	44	0	42	10	16	221
North Dakota	447	-13	50	31	1	0	1	39	416
Ohio	890	-75	401	113	8	0	162	94	1,179
Oklahoma	13,645	-1,233	3,029	2,251	624	0	37	1,308	12,543
Pennsylvania	1,840	-9	642	595	23	0	1	130	1,772
Texas	37,584	1,379	11,392	8,315	2,690	92	232	4,897	40,157
RRC District 1	1,104	-163	287	137	19	1	4	107	1,008
RRC District 2 Onshore	1,614	203	556	339	108	20	25	306	1,881
RRC District 3 Onshore	3,961	220	932	890	429	39	35	813	3,913
RRC District 4 Onshore	8,429	94	3,442	2,777	803	10	150	1,236	8,915
RRC District 5	1,953	52	334	203	398	3	1	219	2,319
RRC District 6	5,949	163	1,557	1,581	353	5	2	591	5,857
RRC District 7B	442	55	153	171	0	0	1	64	416
RRC District 7C	3,113	192	659	542	64	11	8	327	3,178
RRC District 8	4,857	145	1,281	514	218	2	4	559	5,434
RRC District 8A	807	121	479	96	45	1	0	100	1,257
RRC District 9	734	-16	584	64	3	0	0	104	1,137
RRC District 10	4,273	279	958	888	208	0	2	408	4,424
State Offshore	348	34	170	113	42	0	0	63	418
Utah	2,388	-56	801	322	618	4	0	220	3,213
Virginia	1,973	-12	198	81	2	0	3	66	2,017
West Virginia	2,868	28	360	260	60	0	53	173	2,936
Wyoming	13,650	171	3,857	2,910	603	18	50	1,213	14,226
Federal Offshore[a]	26,902	-283	7,406	6,405	938	1,180	1,171	4,922	25,987
Pacific (California)	480	9	107	23	0	0	0	37	536
Gulf of Mexico (Louisiana)[a]	20,774	-202	5,752	5,480	493	1,077	905	3,721	19,598
Gulf of Mexico (Texas)	5,648	-90	1,547	902	445	103	266	1,164	5,853
Miscellaneous[b]	38	28	41	38	0	0	0	3[c]	66
U.S. Total	**164,041**	**982**	**42,167**	**31,663**	**7,043**	**1,568**	**2,196**	**18,928**	**167,406**

[a]Includes Federal offshore Alabama.

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

[c]Indicates the estimate is associated with a sampling error (95 percent confidence interval) that exceeds 20 percent of the estimated value.

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 1999 contained in the *Natural Gas Annual 1999*, DOE/EIA-0131(99).

Figure 19. 1999 Dry Natural Gas Proved Reserves by Area

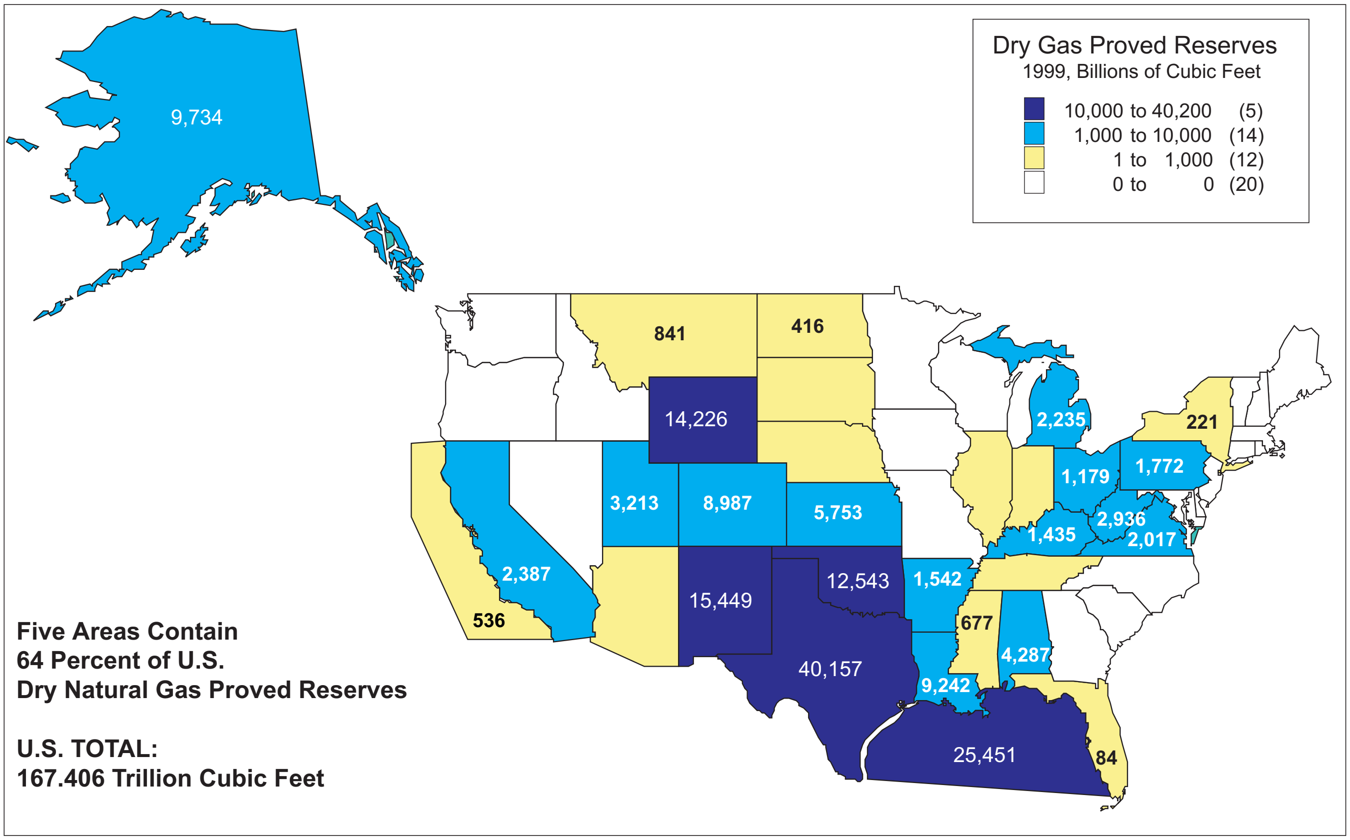
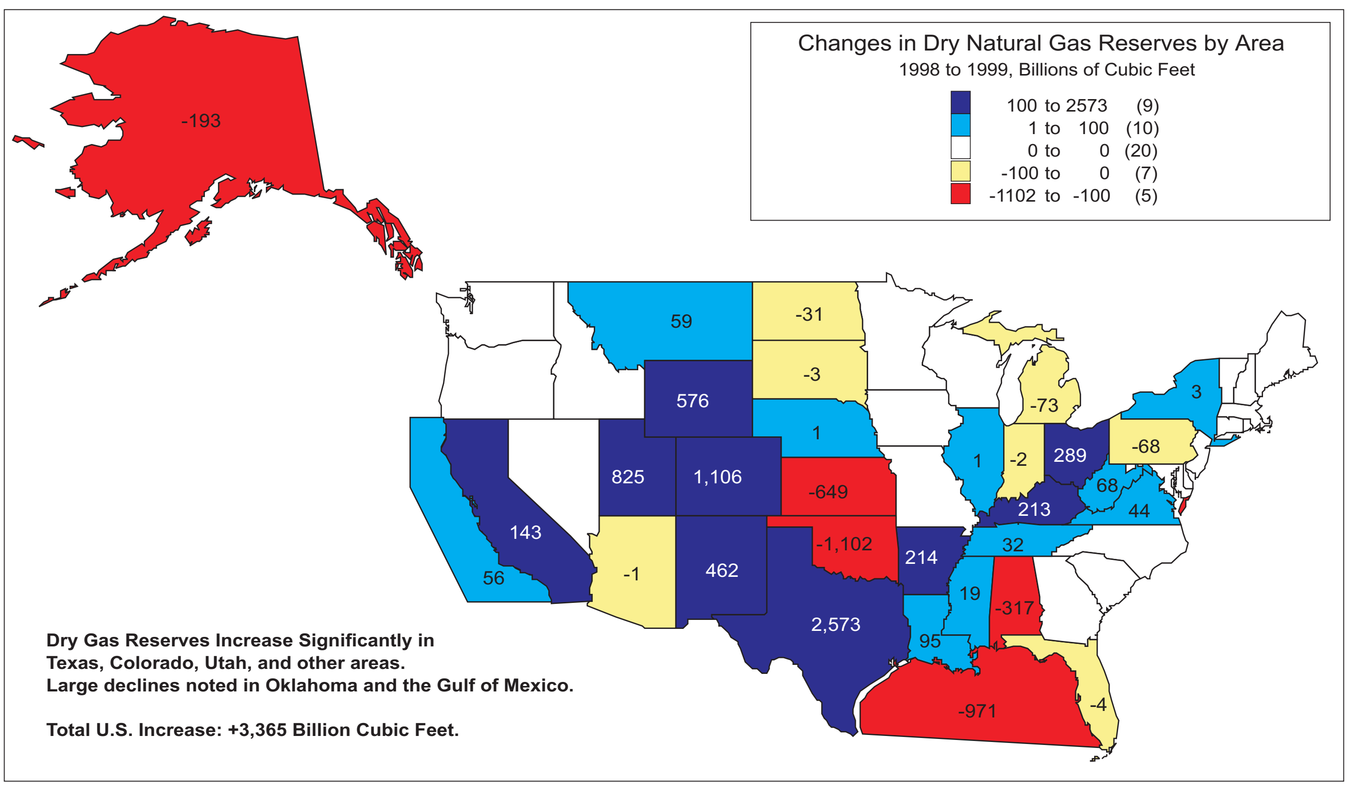


Figure 20. Changes in Dry Natural Gas Proved Reserves by Area, 1998 to 1999



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

Discoveries

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. *Total discoveries* of dry natural gas reserves were 10,807 billion cubic feet in 1999, a 5 percent decrease from the level reported in 1998 and equivalent to 57 percent of 1999 dry gas production. About 30 percent of the *total discoveries* were in the Gulf of Mexico Federal Offshore, and 28 percent were in Texas.

Extensions were 7,043 billion cubic feet, 14 percent lower than in 1998. Areas with the largest *extensions* and their percentage of total *extensions* were:

- Texas (38 percent)
- Gulf of Mexico Federal Offshore (13 percent)
- Oklahoma (9 percent)
- Utah (9 percent)
- Wyoming (9 percent)
- New Mexico (8 percent).

In the prior 10 years, U.S. operators reported an average of 7,048 billion cubic feet of dry gas reserves from *extensions* per year. Reserves from *extensions* in 1999 were almost an exact match of this average volume.

New field discoveries were 1,568 billion cubic feet in 1999—46 percent more than in 1998. Those areas with the largest *new field discoveries* were the Gulf of Mexico Federal Offshore (with 75 percent of the total), Colorado (8 percent), and Texas (6 percent). In the prior 10 years, U.S. operators reported an average of 1,462 billion cubic feet of reserves from *new field discoveries* per year. Reserves from *new field discoveries* in 1999 were 7 percent higher than that average.

New reservoir discoveries in old fields were 2,196 billion cubic feet, 2 percent higher than 1998. Among the areas with the largest *new reservoir discoveries in old fields* and their percentage of the total were:

- Gulf of Mexico Federal Offshore (53 percent)
- Louisiana (17 percent)
- Texas (11 percent).

In the prior 10 years, U.S. operators reported an average of 2,344 billion cubic feet of reserves from *new reservoirs discovered in old fields* per year. Reserves from *new reservoirs discovered in old fields* in 1999 were 6 percent lower than that average volume.

Production

The estimated 1999 U.S. dry natural gas production was 18,928 billion cubic feet, an increase of 1 percent from 1998 (**Table 8**). As in 1998, the Gulf of Mexico Federal Offshore and the State of Texas were the leading producers of dry natural gas in 1999, each with over one-fourth of the U.S. total. The next three States combined, New Mexico (8 percent), Louisiana (8 percent), and Oklahoma (7 percent) added almost another one-fourth of the 1999 dry gas production.

Wet Natural Gas

U. S. proved reserves of wet natural gas as of December 31, 1999 were 176,159 billion cubic feet, a 2 percent increase from the volume reported in 1998 (**Table 9**). At year-end 1999, proved wet natural gas reserves for the lower 48 States had increased by 2 percent compared to 1998, while those of Alaska had decreased by 2 percent.

The volumetric differences between the estimates reported in **Table 8** (dry) and **Table 9** (wet) result from the removal of natural gas liquids at natural gas processing plants. A discussion of the methodology used to generate wet and dry natural gas reserves tables in this report is found in Appendix F. 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 increased by 2 percent (2,961 billion cubic feet) in 1999 to 144,744 billion cubic feet (**Table 10**). The lower 48 States' NA wet natural gas proved reserves increased 2 percent to a level of 142,098 billion cubic feet, while Alaska declined 4 percent to a level of 2,646 billion cubic feet of NA wet natural gas proved reserves in 1999. Those States with the largest increases in NA wet natural gas reserves were Texas, Colorado, Utah, Wyoming, and New Mexico. There were large decreases in NA wet natural gas reserves in Oklahoma, Kansas, and the Gulf of Mexico Federal Offshore.

Discoveries

NA wet natural gas *total discoveries* of 9,884 billion cubic feet in 1999 decreased 10 percent (1,050 billion cubic

Table 9. Natural Gas Proved Reserves, Reserves Changes, and Production, Wet After Lease Separation, 1999 (Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

		Changes in Reserves During 1999							Proved Reserves 12/31/99		
State and Subdivision	Published Proved Reserves 12/31/98	Adjustments (+,–)	Revision Increases (+)	Revision Decreases (–)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Estimated Production (–)	Total Gas	Non-associated Gas	Associated Dissolved Gas
Alaska	10,043	144	3,627	3,575	2	56	23	465	9,855	2,646	7,209
Lower 48 States	**162,400**	**958**	**40,606**	**29,476**	**7,399**	**1,566**	**2,242**	**19,391**	**166,304**	**142,098**	**24,206**
Alabama	4,643	31	219	142	1	0	0	387	4,365	4,338	27
Arkansas	1,332	-48	763	377	27	1	12	164	1,546	1,505	41
California	2,332	125	583	329	68	0	3	277	2,505	355	2,150
Coastal Region Onshore	118	-3	84	12	56	0	0	10	233	0	233
Los Angeles Basin Onshore	154	0	41	16	4	0	0	9	174	0	174
San Joaquin Basin Onshore	2,016	129	412	301	8	0	3	246	2,021	336	1,685
State Offshore	44	-1	46	0	0	0	0	12	77	19	58
Colorado	8,208	105	2,875	1,660	443	135	10	744	9,372	8,591	781
Florida	106	0	0	0	0	0	0	6	100	0	100
Kansas	6,862	-73	475	521	26	6	1	528	6,248	6,196	52
Kentucky	1,295	44	245	43	31	0	20	62	1,530	1,501	29
Louisiana	9,480	597	2,678	2,393	329	47	394	1,486	9,646	8,667	979
North	2,943	224	1,041	855	152	0	5	383	3,127	2,867	260
South Onshore	5,966	173	1,495	1,310	152	25	337	980	5,858	5,259	599
State Offshore	571	200	142	228	25	22	52	123	661	541	120
Michigan	2,386	16	639	491	2	0	1	240	2,313	2,086	227
Mississippi	662	34	166	120	11	0	8	80	681	650	31
Montana	789	46	98	56	15	0	0	41	851	784	67
New Mexico	16,259	392	2,044	942	611	2	30	1,646	16,750	15,172	1,578
East	3,039	153	1,040	456	125	2	7	544	3,366	1,880	1,486
West	13,220	239	1,004	486	486	0	23	1,102	13,384	13,292	92
New York	218	-78	89	44	0	42	10	16	221	212	9
North Dakota	501	-4	57	36	1	0	1	45	475	225	250
Ohio	890	-75	401	113	8	0	162	94	1,179	777	402
Oklahoma	14,517	-1,169	3,258	2,422	672	0	39	1,405	13,490	12,252	1,238
Pennsylvania	1,848	-9	645	598	23	0	1	130	1,780	1,684	96
Texas	40,793	1,165	12,327	8,858	2,841	97	245	5,260	43,350	35,470	7,880
RRC District 1	1,152	-2	351	167	23	1	5	131	1,232	1,165	67
RRC District 2 Onshore	1,720	188	583	355	113	20	26	321	1,974	1,772	202
RRC District 3 Onshore	4,205	210	984	940	453	40	38	858	4,132	3,218	914
RRC District 4 Onshore	8,824	115	3,611	2,912	842	11	157	1,297	9,351	9,169	182
RRC District 5	1,995	35	339	205	404	3	1	222	2,350	2,301	49
RRC District 6	6,271	102	1,623	1,648	368	5	2	616	6,107	5,562	545
RRC District 7B	510	44	170	190	0	0	1	70	465	275	190
RRC District 7C	3,496	241	746	613	72	13	9	371	3,593	2,977	616
RRC District 8	5,547	89	1,443	579	245	3	4	630	6,122	2,947	3,175
RRC District 8A	1,115	35	592	118	56	1	0	124	1,557	44	1,513
RRC District 9	864	-5	699	76	3	0	0	125	1,360	1,180	180
RRC District 10	4,744	81	1,015	942	220	0	2	432	4,688	4,447	241
State Offshore	350	32	171	113	42	0	0	63	419	413	6
Utah	2,502	-52	838	343	653	5	0	232	3,371	3,050	321
Virginia	1,973	-12	198	81	2	0	3	66	2,017	2,017	0
West Virginia	2,968	32	372	270	62	0	55	179	3,040	2,952	88
Wyoming	14,371	26	4,014	3,027	618	19	51	1,263	14,809	14,096	713
Federal Offshore[a]	27,426	-163	7,581	6,572	955	1,212	1,196	5,037	26,598	19,505	7,093
Pacific (California)	489	0	107	23	0	0	0	37	536	48	488
Gulf of Mexico (Louisiana)[a]	21,261	-79	5,917	5,642	507	1,108	929	3,829	20,172	14,950	5,222
Gulf of Mexico (Texas)	5,676	-84	1,557	907	448	104	267	1,171	5,890	4,507	1,383
Miscellaneous[b]	39	28	41	38	0	0	0	3[c]	67	13	54
U.S. Total	**172,443**	**1,102**	**44,233**	**33,051**	**7,401**	**1,622**	**2,265**	**19,856**	**176,159**	**144,744**	**31,415**

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

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 1999 contained in the *Natural Gas Annual 1999,* DOE/EIA-0131(99).

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

Table 10. Nonassociated Natural Gas Proved Reserves, Reserves Changes, and Production, Wet After Lease Separation, 1999

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

State and Subdivision	Published Proved Reserves 12/31/98	Changes in Reserves During 1999							Proved Reserves 12/31/99
		Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Estimated Production (-)	
Alaska	2,768	-1	50	45	0	53	23	202	2,646
Lower 48 States	**139,015**	**960**	**32,957**	**24,301**	**6,815**	**1,175**	**1,818**	**16,341**	**142,098**
Alabama	4,615	31	210	139	1	0	0	380	4,338
Arkansas	1,294	-47	734	357	27	1	12	159	1,505
California	453	27	92	176	3	0	3	47	355
Coastal Region Onshore	2	0	0	2	0	0	0	0	0
Los Angeles Basin Onshore	1	-1	0	0	0	0	0	0	0
San Joaquin Basin Onshore	445	28	72	174	3	0	3	41	336
State Offshore	5	0	20	0	0	0	0	6	19
Colorado	7,436	92	2,727	1,565	443	135	10	687	8,591
Florida	0	0	0	0	0	0	0	0	0
Kansas	6,802	-66	453	503	24	6	0	520	6,196
Kentucky	1,275	43	231	39	31	0	20	60	1,501
Louisiana	8,569	556	2,298	2,108	264	46	365	1,323	8,667
North	2,760	184	930	793	109	0	5	328	2,867
South Onshore	5,336	191	1,271	1,108	130	24	309	894	5,259
State Offshore	473	181	97	207	25	22	51	101	541
Michigan	2,158	44	532	441	1	0	0	208	2,086
Mississippi	615	40	156	106	11	0	8	74	650
Montana	737	42	56	28	12	0	0	35	784
New Mexico	14,816	357	1,544	734	580	2	28	1,421	15,172
East	1,694	104	558	251	94	2	6	327	1,880
West	13,122	253	986	483	486	0	22	1,094	13,292
New York	217	-84	86	44	0	42	10	15	212
North Dakota	240	-3	7	6	0	0	1	14	225
Ohio	548	-36	343	88	8	0	54	52	777
Oklahoma	13,321	-1,064	2,703	2,103	634	0	39	1,278	12,252
Pennsylvania	1,769	-5	616	589	15	0	0	122	1,684
Texas	33,429	1,179	9,927	7,525	2,582	81	235	4,438	35,470
RRC District 1	1,101	0	318	159	23	1	5	124	1,165
RRC District 2 Onshore	1,516	181	561	337	113	12	26	300	1,772
RRC District 3 Onshore	3,275	185	679	684	321	34	35	627	3,218
RRC District 4 Onshore	8,430	129	3,555	2,673	838	11	156	1,277	9,169
RRC District 5	1,906	34	336	172	404	2	1	210	2,301
RRC District 6	5,691	126	1,338	1,374	360	5	2	586	5,562
RRC District 7B	306	35	154	165	0	0	0	55	275
RRC District 7C	2,939	243	563	542	60	13	7	306	2,977
RRC District 8	2,727	103	632	344	200	3	1	375	2,947
RRC District 8A	18	35	8	9	0	0	0	8	44
RRC District 9	665	0	676	63	3	0	0	101	1,180
RRC District 10	4,510	76	946	895	218	0	2	410	4,447
State Offshore	345	32	161	108	42	0	0	59	413
Utah	2,293	-52	623	264	653	5	0	208	3,050
Virginia	1,973	-12	198	81	2	0	3	66	2,017
West Virginia	2,925	32	311	259	61	0	55	173	2,952
Wyoming	13,577	27	3,883	2,879	598	19	44	1,173	14,096
Federal Offshore[a]	19,931	-164	5,227	4,236	865	838	931	3,887	19,505
Pacific (California)	52	0	0	4	0	0	0	0	48
Gulf of Mexico (Louisiana)[a]	15,427	-80	4,054	3,434	443	734	729	2,923	14,950
Gulf of Mexico (Texas)	4,452	-84	1,173	798	422	104	202	964	4,507
Miscellaneous[b]	22	23	0	31	0	0	0	1	13
U.S. Total	**141,783**	**959**	**33,007**	**24,346**	**6,815**	**1,228**	**1,841**	**16,543**	**144,744**

[a]Includes Federal offshore Alabama.

[b]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 1999 contained in the *Natural Gas Annual 1999*, DOE/EIA-0131(99).

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

Table 11. Associated-Dissolved Natural Gas Proved Reserves, Reserves Changes, and Production, Wet After Lease Separation, 1999
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State and Subdivision	Published Proved Reserves 12/31/98	Changes in Reserves During 1999							Proved Reserves 12/31/99
		Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Estimated Production (-)	
Alaska	7,275	145	3,577	3,530	2	3	0	263	7,209
Lower 48 States	**23,385**	**-2**	**7,649**	**5,175**	**584**	**391**	**424**	**3,050**	**24,206**
Alabama	28	0	9	3	0	0	0	7	27
Arkansas	38	-1	29	20	0	0	0	5	41
California	1,879	98	491	153	65	0	0	230	2,150
Coastal Region Onshore	116	-3	84	10	56	0	0	10	233
Los Angeles Basin Onshore	153	1	41	16	4	0	0	9	174
San Joaquin Basin Onshore	1,571	101	340	127	5	0	0	205	1,685
State Offshore	39	-1	26	0	0	0	0	6	58
Colorado	772	13	148	95	0	0	0	57	781
Florida	106	0	0	0	0	0	0	6	100
Kansas	60	-7	22	18	2	0	1	8	52
Kentucky	20	1	14	4	0	0	0	2	29
Louisiana	911	41	380	285	65	1	29	163	979
North	183	40	111	62	43	0	0	55	260
South Onshore	630	-18	224	202	22	1	28	86	599
State Offshore	98	19	45	21	0	0	1	22	120
Michigan	228	-28	107	50	1	0	1	32	227
Mississippi	47	-6	10	14	0	0	0	6	31
Montana	52	4	42	28	3	0	0	6	67
New Mexico	1,443	35	500	208	31	0	2	225	1,578
East	1,345	49	482	205	31	0	1	217	1,486
West	98	-14	18	3	0	0	1	8	92
New York	1	6	3	0	0	0	0	1	9
North Dakota	261	-1	50	30	1	0	0	31	250
Ohio	342	-39	58	25	0	0	108	42	402
Oklahoma	1,196	-105	555	319	38	0	0	127	1,238
Pennsylvania	79	-4	29	9	8	0	1	8	96
Texas	7,364	-14	2,400	1,333	259	16	10	822	7,880
RRC District 1	51	-2	33	8	0	0	0	7	67
RRC District 2 Onshore	204	7	22	18	0	8	0	21	202
RRC District 3 Onshore	930	25	305	256	132	6	3	231	914
RRC District 4 Onshore	394	-14	56	239	4	0	1	20	182
RRC District 5	89	1	3	33	0	1	0	12	49
RRC District 6	580	-24	285	274	8	0	0	30	545
RRC District 7B	204	9	16	25	0	0	1	15	190
RRC District 7C	557	-2	183	71	12	0	2	65	616
RRC District 8	2,820	-14	811	235	45	0	3	255	3,175
RRC District 8A	1,097	0	584	109	56	1	0	116	1,513
RRC District 9	199	-5	23	13	0	0	0	24	180
RRC District 10	234	5	69	47	2	0	0	22	241
State Offshore	5	0	10	5	0	0	0	4	6
Utah	209	0	215	79	0	0	0	24	321
Virginia	0	0	0	0	0	0	0	0	0
West Virginia	43	0	61	11	1	0	0	6	88
Wyoming	794	-1	131	148	20	0	7	90	713
Federal Offshore[a]	7,495	1	2,354	2,336	90	374	265	1,150	7,093
Pacific (California)	437	0	107	19	0	0	0	37	488
Gulf of Mexico (Louisiana)[a]	5,834	1	1,863	2,208	64	374	200	906	5,222
Gulf of Mexico (Texas)	1,224	0	384	109	26	0	65	207	1,383
Miscellaneous[b]	17	5	41	7	0	0	0	2	54
U.S. Total	**30,660**	**143**	**11,226**	**8,705**	**586**	**394**	**424**	**3,313**	**31,415**

[a]Includes Federal offshore Alabama.
[b]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 1999 contained in the *Natural Gas Annual 1999*, DOE/EIA-0131(99).
Source: Energy Information Administration, Office of Oil and Gas.

feet) compared to 1998. Areas with the most *total discoveries* in 1999 were Texas, the Gulf of Mexico Federal Offshore, Louisiana, Oklahoma, and Wyoming.

Production

U.S. production of NA wet natural gas increased by 57 billion cubic feet from 1998 to 1999 (**Table 10**). The five leading producing areas were: Texas (27 percent), the Gulf of Mexico Federal Offshore (23 percent), New Mexico (9 percent), Louisiana (8 percent) and Oklahoma (8 percent).

Associated-Dissolved Natural Gas

Proved Reserves

Proved reserves of associated-dissolved (AD) natural gas, wet after lease separation, in the United States increased 2 percent (755 billion cubic feet) to 31,415 billion cubic feet in 1999 (**Table 11**). Proved reserves of AD wet natural gas in the lower 48 States increased by 4 percent (821 billion cubic feet) to 24,206 billion cubic feet, and Alaska declined 1 percent to 7,209 billion cubic feet in 1999. Those areas of the country with the largest AD wet natural gas reserves and their percentage of the total were:

- Texas (25 percent)
- Alaska (23 percent)
- Gulf of Mexico Federal Offshore (21 percent)
- California (7 percent)
- New Mexico (5 percent).

These areas logically correspond to the areas of the country with the largest volumes of crude oil reserves.

Production

U.S. production of AD wet natural gas increased by 6 percent in 1999 (**Table 11**), and production of AD wet natural gas in the lower 48 States increased by 8 percent (228 billion cubic feet). Those areas of the country with the largest AD wet natural gas production and their percentage of the total were:

- Gulf of Mexico Federal Offshore (34 percent)
- Texas (25 percent)
- Alaska (8 percent)
- California (7 percent)
- New Mexico (7 percent).

Again, these areas logically correspond to the areas of the country with the largest volumes of crude oil production.

Coalbed Methane

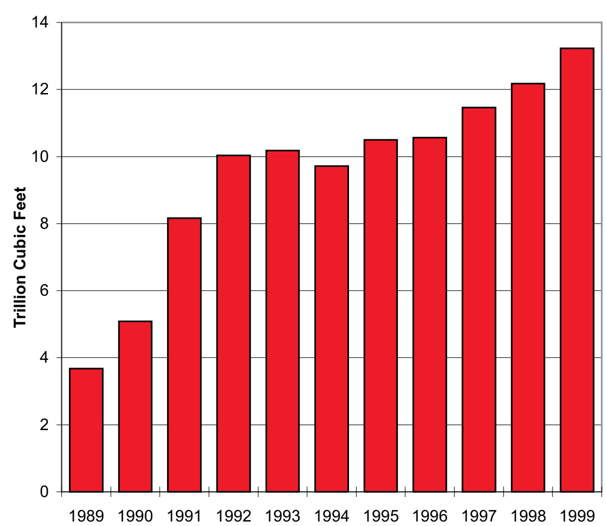
Proved Reserves

In 1999, reserves of coalbed methane increased 9 percent to 13,229 billion cubic feet from 1998's level (12,179 billion cubic feet), and now account for 8 percent of all 1999 dry natural gas reserves (**Table 12**). EIA estimates that the 1999 proved gas reserves of fields identified as having coalbed methane are now more than triple the volume reported in 1989 (**Figure 21**). Three States (New Mexico, Colorado, and Alabama) currently have the majority (75 percent) of U.S. Coalbed methane proved reserves. Estimates of proved coalbed methane reserves increased in Colorado and Alabama, but decreased slightly in New Mexico in 1999.

Production

Coalbed methane production grew by about 5 percent in 1999 to 1,252 billion cubic feet—about 7 percent of U.S. dry gas production.

Figure 21. Coalbed Methane Proved Reserves 1989-1999



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

Table 12. U.S. Coalbed Methane Proved Reserves and Production, 1989-1999
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

Year	Alabama Reserves	Alabama Production	Colorado Reserves	Colorado Production	New Mexico Reserves	New Mexico Production	Others[a] Reserves	Others[a] Production	Total Reserves	Total Production
1989	537	23	1,117	12	2,022	56	0	0	**3,676**	**91**
1990	1,224	36	1,320	26	2,510	133	33	1	**5,087**	**196**
1991	1,714	68	2,076	48	4,206	229	167	3	**8,163**	**348**
1992	1,968	89	2,716	82	4,724	358	626	10	**10,034**	**539**
1993	1,237	103	3,107	125	4,775	486	1,065	18	**10,184**	**752**
1994	976	108	2,913	179	4,137	530	1,686	34	**9,712**	**851**
1995	972	109	3,461	226	4,299	574	1,767	47	**10,499**	**956**
1996	823	98	3,711	274	4,180	575	1,852	56	**10,566**	**1,003**
1997	1,077	111	3,890	312	4,351	597	2,144	70	**11,462**	**1,090**
1998	1,029	123	4,211	401	4,232	571	2,707	99	**12,179**	**1,194**
1999	**1,060**	**108**	**4,826**	**432**	**4,080**	**582**	**3,263**	**130**	**13,229**	**1,252**

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

Areas of Note: Large Discoveries and Reserves Additions

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

Texas

The State of Texas had the largest increase in dry natural gas proved reserves of any State in 1999. Texas' dry natural gas reserves increased by 2,573 billion cubic feet.

South Texas: As in 1998, operators remain active in the Lobo Trend in the lower Rio Grande Valley of south Texas (RRC District 4). The trend occurs primarily in Webb and Zapata counties and contains four producing horizons: Wilcox, Expanded Wilcox, Frio, and Lobo. Unlike some other parts of the country, one or two fields do not dominate the area. RRC District 4 increased its dry natural gas reserves by 486 billion cubic feet in 1999. This district accounts for 22 percent of all of the reserves of dry natural gas in the State and leads the State in gas production (26 percent of the State total). RRC District 4's dry gas production decreased 7 percent from 1998 to 1999.

West Texas: In 1999, operators in the Permian Basin in west Texas (RRC District 8, 8A) reported an increase in dry gas reserves of 1,027 billion cubic feet.

Colorado

Colorado had a net increase of 1,106 billion cubic feet of dry natural gas proved reserves in 1999. Development of coalbed methane fields in the San Juan Basin and other existing conventional gas fields boosted the reserves additions for this State.

Utah

Utah had a net increase of 825 billion cubic feet of dry natural gas proved reserves in 1999. This was the result of development of large existing coalbed methane fields and gas fields within the Uinta Basin.

Areas of Note: Large Reserves Declines

The following areas had large declines in dry natural gas proved reserves due to downward revisions or unreplaced production.

Oklahoma

This State's proved dry natural gas reserves decreased by 8 percent (1,102 billion cubic feet) in 1999. Dry gas production in Oklahoma declined by 15 percent (236 billion cubic feet) from 1998 to 1999.

Gulf of Mexico Federal Offshore

This area's proved dry natural gas reserves decreased by 4 percent (971 billion cubic feet) in 1999. Production from this area in 1999 remained essentially the same as in 1998 (a decline of only 13 billion cubic feet).

Kansas

This State's proved dry natural gas reserves decreased by 10 percent (649 billion cubic feet) in 1999. Production in Kansas in 1999 decreased 11 percent (62 billion cubic feet) from 1998.

Reserves in Nonproducing Reservoirs

Nonproducing proved natural gas reserves (wet after lease separation) of 36,873 billion cubic feet were reported in 1999 (**Appendix D, Table D10**). This was 2 percent more gas than in 1998 (36,047 billion cubic feet). About 30 percent of the reserves in nonproducing reservoirs are located in the Gulf of Mexico Federal Offshore area. Much of the new deepwater reserves are in the nonproducing category. Wells or reservoirs are nonproducing due to any of several operational reasons. These include:

- waiting for well workovers
- waiting for additional development or replacement wells to be drilled
- production or pipeline facilities not yet installed
- awaiting depletion of other zones or reservoirs before recompletion in reservoirs not currently open to production (called "behind pipe" reserves).

5. Natural Gas Liquids Statistics

Natural Gas Liquids

Proved Reserves

U.S. natural gas liquids proved reserves increased 5 percent to 7,906 million barrels in 1999 (**Table 13**). Reserve additions replaced 143 percent of 1999 natural gas liquids production.

The reserves of six areas account for 81 percent of the Nation's natural gas liquids proved reserves.

Area	Percent of U.S. NGL Reserves
Texas	33
Gulf of Mexico Federal Offshore	13
New Mexico	12
Oklahoma	9
Utah-Wyoming	8
Louisiana	6
Area Total	**81**

The volumes of natural gas liquids proved reserves and production shown in **Table 13** are the sum of the natural gas plant liquid volumes listed in **Table 14** and the lease condensate volumes listed in **Table 15**.

Discoveries

Total discoveries of natural gas liquids reserves were 452 million barrels in 1999, a decrease of 16 percent from 1998. Areas with the largest *total discoveries* were:

- Texas (31 percent)
- Gulf of Mexico Federal Offshore (23 percent)
- Louisiana (9 percent)
- Oklahoma (9 percent)
- Utah and Wyoming (9 percent)
- New Mexico (9 percent).

New field discoveries in 1999 (51 million barrels) were 23 percent lower than in 1998. Areas with the largest *new field discoveries* were the Gulf of Mexico Federal Offshore (67 percent of 1999 new field discoveries) and Colorado (16 percent).

New reservoir discoveries in old fields (88 million barrels) were the same as they were in 1998. Areas with the largest *new reservoir discoveries in old fields* were the Gulf of Mexico Federal Offshore (49 percent of 1999 new reservoir discoveries in old fields), Louisiana (25 percent), and Texas (14 percent).

Extensions were 313 million barrels, a decrease of 18 percent from 1998 to 1999. Areas with the largest *extensions* were Texas (40 percent of 1999 extensions), Oklahoma (13 percent), and New Mexico (12 percent).

Production

Natural gas liquids production was an estimated 896 million barrels in 1999. Alaska production decreased 13 percent to 21 million barrels in 1999, while lower 48 States production increased 5 percent to 848 million barrels in 1999.

Six areas accounted for about 86 percent of the Nation's natural gas liquids production.

- Texas (33 percent)
- Gulf of Mexico Federal Offshore (19 percent)
- New Mexico (9 percent)
- Oklahoma (9 percent)
- Louisiana (9 percent)
- Utah-Wyoming (7 percent).

Natural Gas Plant Liquids

Proved Reserves

Natural gas plant liquids proved reserves increased 5 percent in 1999 to 6,503 million barrels (**Table 14**). Six areas accounted for about 79 percent of the Nation's natural gas plant liquids proved reserves:

Area	Percent of U.S. Gas Plant Liquids
Texas	35
New Mexico	14
Oklahoma	10
Utah-Wyoming	8
Gulf of Mexico Federal Offshore	7
Kansas	5
Area Total	**79**

Table 13. Natural Gas Liquids Proved Reserves, Reserves Changes, and Production, 1999
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	Published Proved Reserves 12/31/98	Changes in Reserves During 1999: Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Estimated Production (-)	Proved Reserves 12/31/99
Alaska	320	0	0	0	0	0	0	21	299
Lower 48 States	**7,204**	**102**	**1,902**	**1,285**	**304**	**50**	**86**	**848**	**7,515**
Alabama	81	31	9	2	0	0	0	12	107
Arkansas	5	-2	3	1	0	0	0	0	5
California	72	14	25	12	7	0	0	8	98
Coastal Region Onshore	9	7	11	2	7	0	0	1	31
Los Angeles Basin Onshore	5	1	2	1	0	0	0	0	7
San Joaquin Basin Onshore	58	6	12	9	0	0	0	7	60
State Offshore	0	0	0	0	0	0	0	0	0
Colorado	260	18	71	43	10	8	1	22	303
Florida	18	-1	0	0	0	0	0	1	16
Kansas	334	55	28	30	1	0	0	30	358
Kentucky	54	8	11	3	1	0	1	3	69
Louisiana	411	83	134	135	17	3	22	78	457
North	57	5	24	21	5	0	0	9	61
South Onshore	325	53	103	87	11	2	20	63	364
State Offshore	29	25	7	27	1	1	2	6	32
Michigan	51	-2	14	11	0	0	0	4	48
Mississippi	8	-1	4	1	1	0	0	1	10
Montana	5	3	1	1	0	0	0	0	8
New Mexico	929	-1	129	62	37	0	3	81	954
East	262	-26	85	35	10	0	0	41	255
West	667	25	44	27	27	0	3	40	699
North Dakota	48	7	6	4	0	0	0	4	53
Oklahoma	698	44	186	142	40	0	2	79	749
Texas	2,544	-137	794	464	126	4	12	295	2,584
RRC District 1	38	120	46	23	3	0	1	18	167
RRC District 2 Onshore	85	-13	24	15	5	1	1	12	76
RRC District 3 Onshore	246	-5	53	49	22	2	2	45	226
RRC District 4 Onshore	363	21	178	125	32	0	7	54	422
RRC District 5	35	-9	8	3	4	0	0	3	32
RRC District 6	276	-46	62	60	14	0	0	23	223
RRC District 7B	51	-7	15	17	0	0	0	6	36
RRC District 7C	282	37	63	54	7	1	1	32	305
RRC District 8	491	-38	119	47	21	0	0	51	495
RRC District 8A	226	-60	84	17	8	0	0	18	223
RRC District 9	93	8	81	10	0	0	0	14	158
RRC District 10	354	-146	61	43	10	0	0	19	217
State Offshore	4	1	0	1	0	0	0	0	4
Utah and Wyoming	675	-101	172	112	38	1	1	59	615
West Virginia	72	0	9	6	1	0	1	4	73
Federal Offshore[a]	931	82	304	254	25	34	43	167	998
Pacific (California)	12	-8	0	0	0	0	0	0	4
Gulf of Mexico (Louisiana)[a]	776	87	253	234	17	34	36	136	833
Gulf of Mexico (Texas)	143	3	51	20	8	0	7	31	161
Miscellaneous[b]	8	2	2	2	0	0	0	0	10
U.S. Total	**7,524**	**99**	**2,048**	**1,321**	**313**	**51**	**88**	**896**	**7,906**

[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 1999 contained in the publications *Petroleum Supply Annual 1999*, DOE/EIA-0340(99) and *Natural Gas Annual 1999* DOE/EIA-0131(99).

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

Table 14. Natural Gas Plant Liquids Proved Reserves and Production, 1999
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	1999 Reserves	1999 Production
Alaska	299	21
Lower 48 States	**6,112**	**649**
Alabama	57	8
Arkansas	3	0
California	97	8
Coastal Region Onshore	31	1
Los Angeles Basin Onshore	7	0
San Joaquin Basin Onshore	59	7
State Offshore	0	0
Colorado	277	19
Florida	16	1
Kansas	355	30
Kentucky	69	3
Louisiana	281	45
North	36	4
South Onshore	222	37
State Offshore	23	4
Michigan	42	4
Mississippi	3	0
Montana	8	0
New Mexico	896	74
East	230	37
West	666	37
North Dakota	46	4
Oklahoma	667	70
Texas	2,257	254
RRC District 1	161	17
RRC District 2 Onshore	64	10
RRC District 3 Onshore	152	31
RRC District 4 Onshore	300	42
RRC District 5	24	2
RRC District 6	182	18
RRC District 7B	34	5
RRC District 7C	291	30
RRC District 8	479	49
RRC District 8A	222	18
RRC District 9	156	14
RRC District 10	191	18
State Offshore	1	0
Utah and Wyoming	531	45
West Virginia	72	4
Federal Offshore[a]	427	80
Pacific (California)	0	0
Gulf of Mexico (Louisiana)[a]	403	75
Gulf of Mexico (Texas)	24	5
Miscellaneous[b]	8	0
U.S. Total	**6,503**	**697**

[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 1999 contained in the publications *Petroleum Supply Annual 1999,* DOE/EIA-0340(99) and *Natural Gas Annual 1999*, DOE/EIA-0131(99).

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

Table 15. Lease Condensate Proved Reserves and Production, 1999
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	1999 Reserves	1999 Production
Alaska	0	0
Lower 48 States	**1,403**	**199**
Alabama	50	4
Arkansas	2	0
California	1	0
Coastal Region Onshore	0	0
Los Angeles Basin Onshore	0	0
San Joaquin Basin Onshore	1	0
State Offshore	0	0
Colorado	26	3
Florida	0	0
Kansas	3	0
Kentucky	0	0
Louisiana	176	33
North	25	5
South Onshore	142	26
State Offshore	9	2
Michigan	6	0
Mississippi	7	1
Montana	0	0
New Mexico	58	7
East	25	4
West	33	3
North Dakota	7	0
Oklahoma	82	9
Texas	327	41
RRC District 1	6	1
RRC District 2 Onshore	12	2
RRC District 3 Onshore	74	14
RRC District 4 Onshore	122	12
RRC District 5	8	1
RRC District 6	41	5
RRC District 7B	2	1
RRC District 7C	14	2
RRC District 8	16	2
RRC District 8A	1	0
RRC District 9	2	0
RRC District 10	26	1
State Offshore	3	0
Utah and Wyoming	84	14
West Virginia	1	0
Federal Offshore[a]	571	87
Pacific (California)	4	0
Gulf of Mexico (Louisiana)[a]	430	61
Gulf of Mexico (Texas)	137	26
Miscellaneous[b]	2	0
U.S. Total	**1,403**	**199**

[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” 1999.
Source: Energy Information Administration, Office of Oil and Gas.

Production

Natural gas plant liquids production increased 6 percent in 1999—from 655 million barrels in 1998 to 697 million barrels of production (**Table 14**). The top six areas for proved reserves of natural gas plant liquids accounted for about 80 percent of the Nation's natural gas plant liquids production:

- Texas (36 percent)
- New Mexico (11 percent)
- Gulf of Mexico Federal Offshore (11 percent)
- Oklahoma (10 percent)
- Utah and Wyoming (6 percent)
- Louisiana (6 percent).

Natural gas processing plants are usually located in the same general area where the natural gas is produced. Table E4 in Appendix E lists the volumes of natural gas produced and processed in the same State, and the volumes of liquids extracted.

Lease Condensate

Proved Reserves

Proved reserves of lease condensate in the United States were 1,403 million barrels in 1999 (**Table 15**). This was 5 percent more than the volume reported in 1998. The reserves of five areas account for about 88 percent of the Nation's lease condensate proved reserves.

Area	Percent of U.S. Condensate Reserves
Gulf of Mexico Federal Offshore	40
Texas	23
Louisiana	13
Oklahoma	6
Utah-Wyoming	6
Area Total	**88**

Production

Production of lease condensate was 199 million barrels, an increase of 12 percent in 1999. The production of five areas account for about 93 percent of the Nation's lease condensate production.

- Gulf of Mexico Federal Offshore (44 percent)
- Texas (21 percent)
- Louisiana (17 percent)
- Utah-Wyoming (7 percent)
- Oklahoma (5 percent).

Reserves in Nonproducing Reservoirs

Like crude oil and natural gas, not all lease condensate proved reserves were contained in reservoirs that were producing during 1999. Proved reserves of 418 million barrels of lease condensate, a decrease of 21 percent from 1998, were reported in nonproducing reservoirs in 1999 (**Appendix D, Table D10**). About 55 percent of the nonproducing lease condensate reserves were located in the Gulf of Mexico Federal Offshore.

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Appendix A

Operator Data by Size Class

Appendix A

Operator Data by Size Class

To remain competitive in the domestic oil and gas industry, companies have to reduce costs and look for areas of profitable growth. Over the past few years, we have seen companies restructure to focus on their core areas of profit. This restructuring has taken many forms, for example, mega-mergers, laying off employees, early retirements and buyouts, flattening management structure, selective sales of marginally profitable properties, and acquisitions. Documenting some of these changes is important.

Appendix A is a series of tables of the proved reserves and production by production size class for the years 1994 through 1999 for oil and gas well operators. The tables show the volumetric change and percent change from the previous year and from 1994. In addition they show the 1999 average per operator in each class. All companies that reported to EIA were ranked by production size for each of the 6 years. We computed company production size classes 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, and all "other" oil and gas operators. The "other" category contains 22,127 small operators. We estimate production and reserves for small operators each year from a sample of approximately 8 percent or less of these operators.

Class 1–10 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.

We also include statistics for operator Category sizes at the bottom portion of tables in this appendix. These are the categories used by EIA in processing and assessing reserves surveys and are presented here as additional perspective. For further explanation of categories sizes see definitions and descriptions in Appendix E.

Natural Gas

Proved Reserves

The wet natural gas proved reserves reported for 1994 through 1999 have changed from 171,939 billion cubic feet to 176,159 billion cubic feet (Table A1). These proved reserves are highly concentrated in the larger companies. In 1999, the top 20 operators (Class 1–10 and Class 11–20) producing companies had 51 percent of the proved reserves of natural gas. The next two size classes contain 80 and 400 companies and account for 30 and 15 percent of the U.S. natural gas proved reserves, respectively. The top 20 operators had a decline of 10 percent in their natural gas proved reserves from 1994 to 1999. While the rest of the operators in (Class 21–100, Class 101–500, and Class Other) had an increase of 20 percent in their reserves. In 1999, the top 20 operators' natural gas reserves decreased by 4 percent from 1998.

Production

Wet natural gas production has increased from 19,622 billion cubic feet in 1998 to 19,856 billion cubic feet in 1999 (Table A2). In 1999, the top 20 producing companies had 53 percent of the production of wet natural gas, while having 51 percent of the proved reserves. The next two size classes have 28 and 14 percent of the wet natural gas production, respectively. The top 20 operators had an increase of 1 percent in their wet natural gas production from 1994 to 1999. The rest of the operators had an increase of 6 percent from 1994 to 1999. The top 20 operators' wet natural gas production had a increase of 2 percent in 1999 from 1998, while the rest of the operators had a increase of 0.1 percent.

Crude Oil

Proved Reserves

Proved reserves of crude oil are more highly concentrated in a few companies than those of natural gas. The 20 largest oil and gas producing companies in 1999 had 63 percent of U.S. proved reserves of crude oil (Table A3), in contrast to wet natural gas where these same companies operated only 51 percent of the total proved reserves. These companies have tended in the past few years to concentrate their domestic operations in fewer fields and focus more of their resources on their foreign operations.

U.S. proved reserves of crude oil increased 3.5 percent in 1999. The top 20 producing companies proved reserves of crude oil during 1999 decreased 5 percent. The top 20 class had a decline of 18 percent in their crude oil proved reserves from 1994 to 1999. The class "other" had a 22 percent decrease from 1994 to 1999. During the 1994–1999 period, many operators were continuing to actively buy, sell, and restructure their oil property positions.

Production

Crude oil production reported for 1994 to 1999 has decreased from 2.3 billion barrels to 1.9 billion barrels (Table A4). The 20 largest oil and gas producing companies had 62 percent of U.S. production of crude oil in 1999, while in 1994 they accounted for 68 percent of production. This is in contrast to wet natural gas where these same companies produced only 51 percent of the total. U.S. production of crude oil declined by 14 percent from 1994 to 1999. The top 20 operators had a decline of 21 percent in their oil production during the same period. U.S. production of crude oil declined by 2 percent from 1998 to 1999, while the top 20 operators production decreased by 5 percent. The next two size classes account for 18 and 11 percent of the U.S. crude oil production, respectively.

Fields

The number of fields in which Category I and Category II operators were active dropped significantly during the 1994–1999 period (Table A5). From 1994 through 1999, the number of fields in which the top 20 operators were active in dropped by 1,980 (33 percent), while in 1999 the number dropped 224 (5 percent) from 1998.

Table A1. Natural Gas Proved Reserves, Wet After Lease Separation, by Operator Production Size Class, 1994–1999
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

Size Class	1994	1995	1996	1997	1998	1999	1998–1999 Volume and Percent Change	1994–1999 Volume and Percent Change	1999 Average Reserves per Operator
Class 1–10	76,665	75,856	72,606	68,876	64,336	64,320	-16	-12,235	6,431.995
Percent of Total	44.6%	43.7%	41.5%	39.2%	37.3%	36.5%	0.0%	-16.1%	
Class 11–20	22,691	24,648	25,416	27,705	28,338	24,925	-3,413	2,234	2,492.482
Percent of Total	13.2%	14.2%	14.5%	15.8%	16.4%	14.1%	-12.0%	9.8%	
Class 21–100	40,566	42,604	43,300	45,593	47,009	52,160	1,151	11,594	652.006
Percent of Total	23.6%	24.6%	24.7%	25.9%	27.3%	29.6%	11.0%	28.6%	
Class 101–500	20,608	20,150	22,483	23,338	24,471	25,967	1,496	5,359	64.918
Percent of Total	12.0%	11.6%	12.8%	13.3%	14.2%	14.7%	6.1%	26.0%	
Class Other (23,120)	11,409	10,218	11,342	10,209	8,289	8,787	498	-2,622	0.408
Percent of Total	6.6%	5.9%	6.5%	5.8%	4.8%	5.0%	6.0%	-23.0%	
Category I (170)	143,703	148,233	146,601	147,491	146,458	145,922	-536	2,219	824.420
Percent of Total	83.6%	85.4%	83.7%	83.9%	84.9%	82.8%	-0.4%	1.5%	
Category II (418)	18,158	15,828	18,382	17,764	18,033	21,979	3,946	3,821	55.086
Percent of Total	10.6%	9.1%	10.5%	10.1%	10.5%	12.5%	21.9%	21.0%	
Category III (23,032)	10,078	9,416	10,164	10,466	7,952	8,257	305	-1,821	0.384
Percent of Total	5.9%	5.4%	5.8%	6.0%	4.6%	4.7%	3.8%	-18.1%	
Total Published	**171,939**	**173,476**	**175,147**	**175,721**	**172,443**	**176,159**	**3,716**	**4,220**	**7.975**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.00%**	**100.00%**	**2.2%**	**2.5%**	

Note: There were 21,513 active Category III operators in the 1999 sample frame. The reserves and production of Category III operators were estimated from an adjusted sample of 1,953 Category III operators (Table E2). The “other” size class represents 21,589 operators in the 1999 frame (22,089 active operators minus the 500 largest operators).
Source: Energy Information Administration, Office of Oil and Gas.

Table A2. Natural Gas Production, Wet After Lease Separation, by Operator Production Size Class, 1994–1999

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

Size Class	1994	1995	1996	1997	1998	1999	1998–1999 Volume and Percent Change	1994–1999 Volume and Percent Change	1999 Average Production per Operator
Class 1–10	7,216	7,174	7,448	7,178	6,954	6,881	-73	-335	688.074
Percent of Total	37.6%	38.0%	37.5%	35.7%	35.4%	34.7%	-1.0%	-4.6%	
Class 11–20	3,083	3,101	3,002	3,286	3,317	3,560	243	477	356.000
Percent of Total	16.0%	16.4%	15.1%	16.3%	16.9%	17.9%	7.3%	15.5%	
Class 21–100	4,878	4,871	5,316	5,729	5,595	5,523	-72	645	69.044
Percent of Total	25.4%	25.8%	26.7%	28.4%	28.5%	27.8%	-1.3%	13.2%	
Class 101–500	2,552	2,477	2,623	2,665	2,721	2,793	72	241	6.983
Percent of Total	13.3%	13.1%	13.2%	13.2%	13.9%	14.1%	2.6%	9.4%	
Class Other (23,120)	1,481	1,251	1,484	1,276	1,035	1,099	64	-382	0.051
Percent of Total	7.7%	6.6%	7.5%	6.3%	5.3%	5.5%	6.2%	-25.8%	
Category I (170)	15,656	15,800	16,381	16,897	16,619	16,248	-371	592	91.799
Percent of Total	81.5%	83.7%	82.4%	83.9%	84.7%	81.8%	-2.2%	3.8%	
Category II (418)	2,221	1,923	2,128	1,979	2,019	2,556	537	335	6.406
Percent of Total	11.6%	10.2%	10.7%	9.8%	10.3%	12.9%	26.6%	15.1%	
Category III (23,032)	1,333	1,151	1,364	1,258	984	1,052	68	-281	0.049
Percent of Total	6.9%	6.1%	6.9%	6.2%	5.0%	5.3%	6.9%	-21.1%	
Total Published	**19,210**	**18,874**	**19,873**	**20,134**	**19,622**	**19,856**	**234**	**646**	**0.899**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**1.2%**	**3.4%**	

Note: There were 21,513 active Category III operators in the 1999 sample frame. The reserves and production of Category III operators were estimated from an adjusted sample of 1,953 Category III operators (Table E2). The "other" size class represents 23,589 operators in the 1999 frame (22,089 active operators minus the 500 largest operators).

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

Table A3. Crude Oil Proved Reserves by Operator Production Size Class, 1994–1999
(Million Barrels of 42 U.S. Gallons)

Size Class	1994	1995	1996	1997	1998	1999	1998–1999 Volume and Percent Change	1994–1999 Volume and Percent Change	1999 Average Reserves per Operator
Class 1–10	14,351	13,891	13,362	11,434	11,501	11,121	-380	-3,230	1,112.080
Percent of Total	63.9%	62.1%	60.7%	50.7%	54.7%	51.1%	-3.3%	-22.5%	
Class 11–20	2,276	2,422	2,013	2,977	2,894	2,585	-309	309	258.454
Percent of Total	10.1%	10.8%	9.1%	13.2%	13.8%	11.9%	-10.7%	13.6%	
Class 21–100	2,607	2,623	3,155	4,384	3,677	4,338	661	1,731	54.224
Percent of Total	11.6%	11.7%	14.3%	19.4%	17.50%	19.9%	18.0%	66.4%	
Class 101–500	1,512	1,793	1,838	2,111	1,754	2,379	625	867	5.949
Percent of Total	6.7%	8.0%	8.3%	9.4%	8.3%	10.9%	35.6%	57.3%	
Class Other (23,120)	1,711	1,622	1,649	1,640	1,208	1,342	134	-369	0.062
Percent of Total	7.6%	7.3%	7.5%	7.3%	5.7%	6.2%	11.1%	-21.6%	
Category I (170)	19,648	19,647	19,312	19,461	18,819	18,952	133	-696	107.073
Percent of Total	87.5%	87.9%	87.7%	86.3	89.5%	87.1%	-3.3%	-3.5%	
Category II (418)	1,142	1,103	1,117	1,400	1,018	1,521	503	379	3.811
Percent of Total	5.1%	4.9%	5.1%	6.2	4.8%	7.0%	49.4%	33.2%	
Category III (23,032)	1,668	1,600	1,588	1,685	1,197	1,293	96	-375	0.060
Percent of Total	7.4%	7.2%	7.2%	7.5	5.7%	5.9%	-29.0%	-22.5%	
Total Published	**22,457**	**22,351**	**22,017**	**22,546**	**21,034**	**21,765**	**731**	**-692**	**0.985**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**3.5%**	**-3.1%**	

Note: There were 21,513 active Category III operators in the 1999 sample frame. The reserves and production of Category III operators were estimated from an adjusted sample of 1,953 Category III operators (Table E2). The “other” size class represents 21,589 operators in the 1999 frame (22,089 active operators minus the 500 largest operators).
Source: Energy Information Administration, Office of Oil and Gas.

Table A4. Crude Oil Production by Operator Production Size Class, 1994–1999
(Million Barrels of 42 U.S. Gallons)

Size Class	1994	1995	1996	1997	1998	1999	1998–1999 Volume and Percent Change	1994–1999 Volume and Percent Change	1999 Average Production per Operator
Class 1–10	1,310	1,270	1,220	1,047	1,025	974	-51	-336	97.397
Percent of Total	57.8%	57.4%	56.1%	49.0%	51.5%	49.9%	-2.1%	-25.6%	
Class 11–20	224	221	185	262	255	241	-14	17	24.138
Percent of Total	9.9%	10.0%	8.5%	12.3%	12.8%	12.3%	-2.7%	7.6%	
Class 21–100	287	276	307	373	342	350	8	63	4.378
Percent of Total	12.7%	12.5%	14.1%	17.4%	17.2%	17.9%	-8.3%	22.0%	
Class 101–500	200	214	213	237	206	208	2	8	0.520
Percent of Total	8.8%	9.7%	9.8%	11.1%	10.3%	10.7%	-13.1%	4.0%	
Class Other (23,120)	247	232	248	219	163	179	16	-68	0.008
Percent of Total%	10.9%	10.5%	11.4%	10.2%	8.2%	9.2%	-25.6%	-27.5%	
Category I (170)	1,879	1,844	1,791	1,760	1,714	1,617	-97	-262	9.135
Percent of Total	82.8%	83.3%	82.4%	82.3%	86.1%	82.8%	-2.6%	-13.9%	
Category II (418)	150	139	143	157	118	160	42	10	0.401
Percent of Total	6.6%	6.3%	6.6%	7.3%	5.9%	8.2%	-24.8%	6.7%	
Category III (23,032)	239	230	239	221	159	175	16	-64	0.008
Percent of Total	10.5%	10.4%	11.0%	10.3%	8.0%	9.0%	-28.1%	-26.8%	
Total Published	**2,268**	**2,213**	**2,173**	**2,138**	**1,991**	**1,952**	**-39**	**-316**	**0.088**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**-2.0%**	**-13.9%**	

Note: There were 21,513 active Category III operators in the 1999 sample frame. The reserves and production of Category III operators were estimated from an adjusted sample of 1,953 Category III operators (Table E2). The “other” size class represents 21,589 operators in the 1999 frame (22,089 active operators minus the 500 largest operators).

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

Table A5. Operator Field Count by Operator Production Size Class, 1994–1999

Size Class	1994	1995	1996	1997	1998	1999	1998–1999 Number and Percent Change	1994–1999 Number and Percent Change	1999 Average Number of Fields per Operator
Class 1–10	3,258	3,113	2,800	2,566	2,475	2,559	84	-699	255.900
Percent of Total	12.2%	11.9%	10.7%	10.4%	9.5%	10.0%	3.4%	-21.5%	
Class 11–20	2,795	2,772	2,441	2,257	1,822	1,514	-308	-1,281	151.400
Percent of Total	10.5%	10.6%	9.3%	9.1%	7.0%	5.9%	-16.9%	-45.8%	
Class 21–100	7,752	7,569	7,526	7,159	7,526	8,180	654	177	102.250
Percent of Total	29.1%	28.9%	28.7%	28.9%	29.0%	32.0%	8.7%	2.2%	
Class 101–500	11,878	11,886	12,492	12,878	12,817	12,344	473	466	30.860
Percent of Total	44.6%	45.4%	47.7%	52.0%	49.4%	48.2%	-3.7%	3.9%	
Rest	1,897	1,601	[a]952	1,332	1,524	1,287	-237	-359	1.778
Percent of Total	7.1%	6.1%	[a]3.6%	5.4%	5.9%	5.0%	-15.6%	-21.8%	
Category I	16,161	16,256	15,635	15,232	15,666	15,120	-546	-1,041	85.424
Percent of Total	60.7%	62.1%	59.7%	58.2%	60.4%	59.1%	-3.5%	-6.4%	
Category II	10,452	9,939	10,576	R9,530	10,271	10,467	196	15	26.233
Percent of Total	39.3%	37.9%	40.3%	41.8%	39.6%	40.9%	1.9%	0.1%	
Total Reported	**26,613**	**26,195**	**26,211**	**R24,762**	**25,937**	**25,587**	**-350**	**-1,026**	**44.422**
Percent Change	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.00%**	**-1.3%**	**-3.9%**	

[a]The reduced 1996 survey had fewer operators and fields in the “rest” class.

R = Revised

Note: Includes only data from Category I and Category II operators. In 1999, there were 177 Category I operators and 399 Category II operators. The “rest” size class had 76 operators in 1999.

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

Appendix B

Top 100 Oil and Gas Fields for 1999

Top 100 Oil and Gas Fields for 1999

This appendix presents estimates of the proved reserves and production of the top 100 oil and gas fields. The oil field production and reserve data include both crude oil and lease condensate. The gas field production and reserve data is total wet natural gas (associated-dissolved natural gas and nonassociated natural gas, wet after lease separation).

Table B1. Top 100 Oil Fields for 1998

The top 100 oil fields in the United States as of December 31, 1999, had 14,681 million barrels of proved reserves accounting for 63 percent of the total United States (**Table 6 and Table 16**). Although there is considerable grouping of field–level statistics within the tables, rough orders of magnitude can be estimated for the proved reserves and production of most fields. Many of the fields in the top 100 group are operated by only one or two operators, therefore, the totals for proved reserves are grouped as top 10, top 20, top 50, and top 100 to avoid revealing company proprietary data.

In the top 20 oil fields for 1999 there are two fields, Mississippi Canyon Block 807 (Mars) and Mississippi Canyon Block 810 (Ursa) which are in the deep water of the Gulf of Mexico Federal Offshore.

The top 100 oil fields in the United States as of December 31, 1999, had 1,120 million barrels of production, or 52 percent of the total (**Table 6 and Table 15**). Many of the oil fields in the top 100 are very old, 49 of the oil fields in Table B1 were discovered prior to 1950. The oldest, Coalinga in California, was discovered in 1887. The newest, Mississippi Canyon Block 127, in the Gulf of Mexico Federal Offshore was reported to EIA in 1999.

The oil fields with newer discovery dates are typically located in the Gulf of Mexico Offshore and Alaska. Of the top 100 oil fields; 25 percent are in Texas, 24 percent are in the Gulf of Mexico Federal Offshore, 20 percent are in California, and11 percent are in Alaska. There were 17 different fields in this year's tabulation than in last years.

Table B2. Top 100 Gas Fields for 1998

The top 100 gas fields in the United States as of December 31, 1999, had 81,759 billion cubic feet of wet natural gas proved reserves, or 47 percent of the total (**Table 9**).

The top 100 gas fields in the United States as of December 31, 1999, had 6,700 billion cubic feet of production, or 34 percent of the total (**Table 9**). Fewer of the gas fields in the top 100 are as old as the top100 oil fields. There were 20 gas fields in Table B2 that were discovered prior to 1950. Gas fields in the top 100 are newer than the oil fields, 51 gas fields were discovered after 1967. The oldest, Big Sandy in Kentucky, was discovered in 1881. The newest, Mississippi Canyon Block 810, in the Gulf of Mexico Federal Offshore was only reported to EIA in 1996.

The gas fields with newer discovery dates are located in the Gulf of Mexico Offshore, south Texas and Virginia. Several of the same fields are in both tables. Of the top 100 gas fields 26 percent are in Texas, 14 percent in the Gulf of Mexico Offshore, an additional 24 percent are in Oklahoma and Wyoming. There were 11 different fields in this year's tabulation than in last year's table.

Table B3. Top 100 Gas Fields for 1998

Table B3 lists the top U.S. operators ranked by reported 1999 operated production data. Pending mergers and acquisitions announced in 1999 between these top operators are indicated in the left margin with linked arrows.

Table B1. Top 100 U.S. Fields Ranked by Oil[a] Proved Reserves, from Reported 1999 Field Level Data
(Million Barrels of 42 U.S. Gallons)

Field Name	Location	Discovery Year	Proved Reserves Rank Group	Reported Production Rank Group
Prudhoe Bay	AK	1967	1-10	193.2
Kuparuk River	AK	1969	1-10	81.9
Midway-Sunset	CA	1901	1-10	56.9
Belridge South	CA	1911	1-10	42.3
Wasson	TX	1937	1-10	24.9
Yates	TX	1926	1-10	14.3
Kern River	CA	1899	1-10	48.1
Elk Hills	CA	1920	1-10	23.6
Mississippi Canyon Blk 807	GF	1989	1-10	51.5
Slaughter	TX	1937	1-10	14.5
Top 10 Volume Subtotal			**7,686.4**	**551.2**
Top 10 Percentage of U.S. Total			**33.2%**	**25.6%**
Milne Point	AK	1982	11-20	19.6
Spraberry Trend Area	TX	1951	11-20	17.7
Hondo	CA	1969	11-20	12.1
Levelland	TX	1945	11-20	9.6
Alpine	AK	1994	11-20	0.0
Point McIntyre	AK	1988	11-20	33.7
Endicott	AK	1978	11-20	13.7
Cymric	CA	1916	11-20	17.8
Mississippi Canyon Blk 810	GF	1996	11-20	8.5
San Ardo	CA	1947	11-20	4.2
Top 20 Volume Subtotal			**9,821.0**	**688.1**
Top 20 Percentage of U.S. Total			**42.4%**	**32.0%**
Wilmington	CA	1932	21-50	16.3
Sho-Vel-Tum	OK	1905	21-50	8.7
Cowden North	TX	1930	21-50	8.2
Lost Hills	CA	1910	21-50	10.9
Ventura	CA	1916	21-50	4.8
Green Canyon Blk 244	GF	1994	21-50	35.0
Pescado	CA	1970	21-50	9.2
Vacuum	NM	1929	21-50	7.7
Alaminos Canyon Blk 25	GF	1997	21-50	0.0
Greater Aneth	UT	1956	21-50	6.1
Rangely	CO	1902	21-50	6.0
Fullerton	TX	1942	21-50	5.7
Hawkins	TX	1940	21-50	3.4
Mississippi Canyon Blk 127	GF	1999	21-50	0.0
Green Canyon Blk 205	GF	1988	21-50	10.8
Coalinga	CA	1887	21-50	8.1
Seminole	TX	1936	21-50	10.8
McElroy	TX	1926	21-50	6.3
Wattenberg	CO	1970	21-50	5.1
Goldsmith	TX	1935	21-50	4.2
Howard-Glasscock	TX	1925	21-50	3.1
Salt Creek	TX	1950	21-50	7.1
Monument Butte	UT	1964	21-50	1.6
Garden Banks Blk 426	GF	1992	21-50	21.4
Mississippi Canyon Blk 935	GF	1994	21-50	0.0
Robertson North	TX	1956	21-50	3.0
Jay	FL & AL	1970	21-50	4.2
Green Canyon Blk 158	GF	1992	21-50	0.0
Arroyo Grande	CA	1906	21-50	0.6
Wasson 72	TX	1940	21-50	2.2
Top 50 Volume Subtotal			**12,531.7**	**898.8**
Top 50 Percentage of U.S. Total			**54.1%**	**41.8%**

Table B1. Top 100 U.S. Fields Ranked by Oil[a] Proved Reserves, from Reported 1999 Field Level Data (Continued)
(Million Barrels of 42 U.S. Gallons)

Field Name	Location	Discovery Year	Proved Reserves Rank Group	Reported Production Rank Group
Hobbs	NM	1928	51-100	2.7
Monument	NM & UT	1935	51-100	2.8
Niakuk	AK	1984	51-100	16.0
Viosca Knoll Blk 990	GF	1981	51-100	15.1
West Delta Blk 30	GF	1949	51-100	7.7
Giddings	TX	1960	51-100	11.7
East Texas	TX	1930	51-100	12.9
Pennel	MT	1955	51-100	1.7
Tarn	AK	1991	51-100	9.5
Sacate	CA	1970	51-100	0.2
West Sak	AK	1969	51-100	1.2
Inglewood	CA	1924	51-100	2.5
Mississippi Canyon Blk 84	GF	1993	51-100	0.0
Garden Banks Blk 260	GF	1995	51-100	22.6
Jo-Mill	TX	1954	51-100	2.3
Ewing Bank Blk 873	GF	1991	51-100	18.0
Viosca Knoll Blk 956	GF	1985	51-100	16.9
Cedar Lake	TX	1939	51-100	2.5
Fiord	AK	1992	51-100	0.0
Fitts	OK	1934	51-100	1.3
Foster	TX	1932	51-100	2.7
Bay Marchand Blk 2	GF & LA	1949	51-100	5.4
Beverly Hills	CA	1900	51-100	1.5
Eugene Island SA Blk 330	GF	1971	51-100	8.5
Lisburne	AK	1967	51-100	2.0
Elk Basin	WY	1915	51-100	2.2
Eunice Monument	NM	1929	51-100	1.4
T X L	TX	1944	51-100	1.9
Dollarhide	TX & NM	1945	51-100	3.2
Lookout Butte East	MT	1986	51-100	1.3
Bluebell	UT	1949	51-100	2.0
Viosca Knoll Blk 915	GF	1993	51-100	0.0
Cogdell	TX	1949	51-100	0.7
Garden Banks Blk 171	GF	1988	51-100	0.9
Mississippi Canyon Blk 755	GF	1986	51-100	0.0
Dos Cuadras	CA	1968	51-100	2.3
Brea-Olinda	CA	1897	51-100	0.8
Means	TX	1934	51-100	3.9
Huntington Beach	CA	1920	51-100	3.6
Kern Front	CA	1925	51-100	1.5
Westbrook	TX	1920	51-100	0.9
Grayburg-Jackson	NM	1929	51-100	3.3
Viosca Knoll Blk 786	GF	1996	51-100	0.0
South Pass EA Blk 62	GF	1967	51-100	3.4
Main Pass SA Blk 299	GF	1967	51-100	4.6
Cedar Hills	ND	1995	51-100	3.8
Mississippi Canyon Blk 899	GF	1998	51-100	0.0
Hartzog Draw	WY	1976	51-100	2.3
Hamilton Dome	WY	1918	51-100	1.7
Pecan Lake	LA	1982	51-100	7.7
Top 100 Volume Subtotal			**14,681.0**	**1,120.0**

[a]Includes lease condensate.

Notes: The U.S. total production estimate of 2,169 million barrels and the U.S. total reserves estimate of 22,370 million barrels, used to calculate the percentages in this table, are from the combined totals of Table 6 and Table 15 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. Fields Ranked by Gas[a] Proved Reserves, from Reported 1999 Field Level Data
(Billion Cubic Feet)

Field Name	Location	Discovery Year	Proved Reserves Rank Group	Reported Production Rank Group
Blanco / Ignacio-Blanco	NM & CO	1927	1-10	713.6
Basin	NM	1947	1-10	673.7
Prudhoe Bay	AK	1967	1-10	198.3
Hugoton Gas Area	KS & OK & TX	1922	1-10	442.5
Madden	WY	1968	1-10	71.3
Carthage	TX	1944	1-10	203.9
Mobile Bay	AL	1979	1-10	150.0
Wattenberg	CO	1970	1-10	125.9
Natural Buttes	UT	1952	1-10	63.4
Oakwood	VA	1990	1-10	36.8
Top 10 Volume Subtotal			**38,938.5**	**2,679.3**
Top 10 Percentage of U.S. Total			**22.1%**	**13.5%**
Fogarty Creek	WY	1975	11-20	31.1
Antrim	MI	1965	11-20	126.1
Panhandle West	TX	1918	11-20	109.8
Big Sandy	KY & WV	1881	11-20	48.5
Jonah	WY	1977	11-20	79.2
Spraberry Trend Area	TX	1951	11-20	64.9
Raton	CO	1994	11-20	27.7
Panoma Gas Area	KS	1956	11-20	83.7
Red Oak-Norris	OK	1910	11-20	54.2
Lake Ridge	WY	1981	11-20	15.8
Top 20 Volume Subtotal			**49,617.4**	**3,320.3**
Top 20 Percentage of U.S. Total			**28.2%**	**16.7%**
Giddings	TX	1960	21-50	240.3
Elk Hills	CA	1920	21-50	133.3
Cook Inlet North	AK	1962	21-50	51.3
Beluga River	AK	1962	21-50	34.9
Wasson	TX	1937	21-50	20.2
Gomez	TX	1977	21-50	62.4
Mocane-Laverne Gas Area	KS & OK & TX	1979	21-50	69.5
Whitney Canyon-Carter Crk	WY	1978	21-50	74.7
Viosca Knoll Blk 956	GF	1985	21-50	103.3
Newark East	TX	1981	21-50	36.6
East Breaks Blk 945	GF	1994	21-50	0.0
Strong City District	OK	1966	21-50	67.1
Sawyer	TX	1975	21-50	44.4
Oak Hill	TX	1958	21-50	62.1
Knox	OK	1916	21-50	62.4
Drunkards Wash	UT	1989	21-50	47.7
Mobile Blk 823	GF	1983	21-50	66.7
Lower Mobile Bay-Mary Ann	AL	1979	21-50	28.7
Mississippi Canyon Blk 810	GF	1996	21-50	14.5
Nora	VA	1949	21-50	23.4
Golden Trend	OK	1945	21-50	38.9
Mississippi Canyon Blk 731	GF	1987	21-50	92.0
Watonga-Chickasha Trend	OK	1962	21-50	61.6
Bruff	WY	1969	21-50	42.0
Bob West	TX	1990	21-50	52.2
Wilburton	OK	1941	21-50	47.7
Indian Basin	NM	1971	21-50	90.3
Kinta	OK	1914	21-50	37.2
Elk City	OK	1947	21-50	47.2
Agua Dulce	TX	1928	21-50	8.1
Top 50 Volume Subtotal			**67,829.4**	**5,081.3**
Top 50 Percentage of U.S. Total			**38.5%**	**25.6%**

Table B2. Top 100 U.S. Fields Ranked by Gas[a] Proved Reserves, from Reported 1999 Field Level Data (Continued)
(Billion Cubic Feet)

Field Name	Location	Discovery Year	Proved Reserves Rank Group	Reported Production Rank Group
Garden Banks Blk 426	GF	1992	51-100	89.6
Judge Digby	LA	1977	51-100	42.8
La Perla	TX	1958	51-100	58.0
Vaquillas Ranch	TX	1978	51-100	78.5
Viosca Knoll Blk 915	GF	1993	51-100	0.1
McArthur River	AK	1965	51-100	70.0
Wamsutter	WY	1958	51-100	28.6
Ozona	TX	1962	51-100	33.6
Mississippi Canyon Blk 807	GF	1989	51-100	55.0
Belridge South	CA	1911	51-100	18.5
Dew	TX	1982	51-100	20.7
McAllen Ranch	TX	1986	51-100	61.0
Kuparuk River	AK	1969	51-100	28.9
Fairway	AL	1986	51-100	28.6
Elm Grove	LA	1958	51-100	13.1
Verden	OK	1948	51-100	36.6
Standard Draw	WY	1979	51-100	21.6
Garden Banks Blk 171	GF	1988	51-100	16.5
Rulison	CO	1956	51-100	12.8
Anschutz Ranch East	UT & WY	1980	51-100	58.0
A W P	TX	1981	51-100	19.1
Mimms Creek	TX	1978	51-100	14.6
Painter Reservoir East	WY	1979	51-100	35.3
Matagorda Island Blk 623	GF	1980	51-100	97.9
Grand Valley	CO	1985	51-100	7.9
Table Rock	WY	1946	51-100	12.4
Double A Wells	TX	1980	51-100	33.0
South Pass SA Blk 89	GF	1969	51-100	35.4
Pegasus	TX	1949	51-100	23.7
Willow Springs	TX	1954	51-100	26.8
Hondo	CA	1969	51-100	22.6
Cedar Cove Coal Degas	AL	1983	51-100	20.2
Lake Arthur South	LA	1955	51-100	20.2
Blanco South	NM	1952	51-100	17.4
Waltman	WY	1959	51-100	41.2
Moorewood NE	OK	1979	51-100	29.4
Wild Rose	WY	1975	51-100	18.2
Tip Top	WY	1928	51-100	18.5
Mississippi Canyon Blk 354	GF	1977	51-100	36.9
Monte Christo	TX	1982	51-100	16.2
Cement	OK	1917	51-100	24.0
Boonsville	TX	1950	51-100	29.9
Kenai	AK	1959	51-100	10.1
Sugg Ranch	TX	1985	51-100	7.8
Bryceland West	LA	1952	51-100	29.9
Sarita East	TX	1967	51-100	31.8
Endicott	AK	1978	51-100	10.1
Jeffress NE	TX	1975	51-100	27.6
Green Canyon Blk 244	GF	1994	51-100	68.3
Viosca Knoll Blk 783	GF	1985	51-100	59.5
Top 100 Volume Subtotal			**82,759.0**	**6,699.8**
Top 100 Percentage of U.S. Total			**47.0%**	**33.7%**

[a]Total wet gas after lease separation.

Note: The U.S. total production estimate of 19,622 billion cubic feet and the U.S. total reserves estimate of 172,443 billion cubic feet, used to calculate the percentages in this table, are from Table 9 in this publication. Column totals may not add due to independent rounding.

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

Table B3. Top U.S. Operators Ranked by Reported 1999 Operated Production Data

Rank	Company Name	Crude Oil Production (thousand barrels/day)	Rank	Company Name	Total Natural Gas Production (billion cubic feet/day)
1	Arco Exploration & Production	682	1	Exxon Mobil Production Co	3,611
2	BP Amoco	581	2	BP Amoco	3,540
3	Shell Oil Co	359	3	Shell Oil Co	2,699
4	Chevron U S A Production Co.	346	4	Burlington Resources Oil & Gas	2,302
5	Texaco Inc	310	5	Chevron U S A Production Co.	2,116
6	Exxon Mobil Production Co	310	6	Texaco Inc	1,715
7	Aera Energy LLC	260	7	Unocal Corp	1,333
8	Altura Energy Ltd	170	8	Santa Fe Snyder Corp.	1,306
9	Marathon Oil Co	165	9	Union Pacific Resources	1,275
10	Amerada Hess Corp	117	10	Vastar Resources Inc	1,191
	Top 10 Volume Subtotal	***3,298***		***Top 10 Volume Subtotal***	***21,088***
	Top 10 Percentage of U.S. Total	***56%***		***Top 10 Percentage of U.S. Total***	***39%***
11	Oxy USA Inc	99	11	Devon Energy Corp	1,157
12	Unocal Corp	74	12	Conoco Inc	1,125
13	Kerr McGee O&G Corp	74	13	Phillips Petroleum Co	1,123
14	Apache Corp	72	14	Coastal Oil & Gas Corp	1,042
15	Devon Energy Corp	67	15	Marathon Oil Co	862
16	Union Pacific Resources	54	16	EOG Resources Inc	855
17	Ocean Energy Inc	46	17	Oxy USA Inc.	847
18	Burlington Resources Oil & Gas	46	18	Apache Corp	742
19	Vastar Resources Inc	41	19	Arco Exploration & Production	673
20	City Of Long Beach	38	20	El Paso Production Co	635
	Top 20 Volume Subtotal	***3,910***		***Top 20 Volume Subtotal***	***30,149***
	Top 20 Percentage of U.S. Total	***66%***		***Top 20 Percentage of U.S. Total***	***55%***
21	Conoco Inc	37	21	Amerada Hess Corp.	600
22	Nuevo Energy Co	36	22	Kerr McGee O&G Corp	561
23	Phillips Petroleum Co	36	23	Cross Timbers Operating Co	490
24	Pioneer Natural Resources USA	35	24	Anadarko Petroleum Corp	466
25	Santa Fe Snyder Corp.	32	25	Newfield Exploration Co	454
26	Plains Resources Inc	29	26	Ocean Energy Inc	439
27	Merit Energy Co	24	27	Chesapeake Operating Inc.	429
28	British Borneo USA Inc	24	28	Pioneer Natural Resources USA	416
29	Anadarko Petroleum Corp	23	29	Questar Exploration & Production	387
30	Goodrich Petroleum Co	22	30	C N G Producing Co	378
31	Citation Oil & Gas Corp	22	31	Samedan Oil Corp	368
32	Samedan Oil Corp.	22	32	Louis Dreyfus Natural Gas Corp	352
33	Newfield Exploration Co	22	33	Mitchell Energy Corp	320
34	Hunt Oil Co	21	34	Samson Resources Co	317
35	EOG Resources Inc	21	35	Houston Exploration Co The	257
36	Vintage Petroleum Inc	21	36	Walter Oil & Gas Corp	251
37	Coastal Oil & Gas Corp	17	37	Cabot Oil & Gas Corp	239
38	Meridian Resource Corp	16	38	Murphy Exploration & Production	230
39	Duncan Oil Inc.	16	39	Barrett Resources Corp	206
40	Berry Petroleum Co	16	40	Equitable Production Co.	196
41	Denbury Resources Inc.	15	41	Tom Brown Inc	190
42	Swift Energy Co	15	42	River Gas Corp	182
43	Cross Timbers Operating Co.	15	43	Helmerich & Payne Inc	180
44	El Paso Production Co	15	44	Fina Oil & Chemical Co	177
45	C N G Producing Co	14	45	Hunt Oil Co.	177
46	Seneca Resources Corp	14	46	Kaiser - Francis Oil Co	172
47	Prize Energy Corp	13	47	Altura Energy Ltd	172
48	Continental Resources Inc	13	48	Yates Petroleum Corp	164
49	Murphy Exploration & Production	13	49	Koch Exploration Co.	164
50	Howell Petroleum Corp	13	50	Forest Oil Corp	161
	Top 50 Volume Subtotal	***4,542***		***Top 50 Volume Subtotal***	***39,244***
	Top 50 Percentage of U.S. Total	***77%***		***Top 50 Percentage of U.S. Total***	***72%***

Note: Arrows indicate mergers, acquisitions in 2000, and announced plans.
[a]Crude oil production includes production of lease condensate. Total natural gas is wet after lease separation.

Appendix C

Conversion to the Metric System

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."{38}

Table C1 is in keeping with the spirit of this law. The petroleum industry in the United States is slowly moving in the direction prescribed by this law and the data collected by EIA are collected in the units that are still common to the U.S. petroleum industry, namely barrels and cubic feet. Standard metric conversion factors were used to convert the National level volumes in **Table 1** to the metric equivalents in **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. U.S. Proved Reserves of Crude Oil, Dry Natural Gas, and Natural Gas Liquids, in Metric Units, 1989 – 1999

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 cubic meters)										
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	46.2	286.8	170.0	163.0	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
1994	30.1	375.8	215.7	190.2	63.1	10.2	17.6	90.9	360.6	3,570.4	–79.5
1995	19.4	289.8	126.4	182.8	79.5	18.1	54.5	152.1	351.8	3,553.5	–16.9
1996	28.0	273.9	156.8	145.1	86.3	38.6	22.4	147.3	345.5	3,500.4	–53.1
1997	82.7	317.7	172.3	228.0	75.8	101.3	18.9	196.0	339.9	3,584.2	83.8
1998	–101.5	437.5	355.2	–19.2	52.0	24.2	19.1	95.3	316.5	3,344.1	–240.4
1999	22.1	999.1	709.9	311.3	41.2	51.0	23.1	115.3	310.3	3,460.4	116.3
	Dry Natural Gas (billion cubic meters)										
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
1994	55.08	604.99	449.70	210.37	196.55	53.63	98.54	348.72	518.82	4,639.35	40.27
1995	16.42	579.50	360.50	235.42	193.77	47.18	69.43	310.38	508.74	4,676.41	37.06
1996	107.18	485.12	369.42	222.88	219.65	41.09	88.07	348.81	534.08	4,714.02	37.61
1997	–16.70	613.28	474.47	122.10	299.73	75.92	67.45	443.10	544.00	4,735.22	21.22
1998	–46.30	792.96	630.42	116.24	232.11	30.41	61.22	323.74	530.09	4,645.12	–90.11
1999	27.81	1,194.04	896.60	325.25	199.44	44.40	62.18	306.02	535.98	4,740.41	95.29
	Natural Gas Liquids (million cubic meters)										
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	35.7	128.1	86.6	77.2	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
1994	6.9	138.8	107.5	38.2	49.9	8.6	20.8	79.3	125.8	1,139.9	–8.3
1995	30.5	153.9	109.9	74.5	68.7	8.3	10.7	87.7	125.8	1,176.3	36.4
1996	75.5	134.2	106.4	103.3	71.7	10.3	17.3	99.3	135.1	1,243.8	67.5
1997	–2.4	190.6	144.7	43.6	85.1	18.1	14.3	117.5	137.4	1,267.6	23.8
1998	–57.4	207.0	173.9	-24.3	60.9	10.5	14.0	85.4	132.4	1,196.2	–71.4
1999	15.8	325.6	210.0	131.4	49.8	8.1	14.0	71.9	142.5	1,257.0	60.8

[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.

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.” 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 in Chapter 2.

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, 1989–1999 annual reports, DOE/EIA–0216.{12–21}

Appendix D

Historical Reserves Statistics

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 1999 of the EIA publication *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE EIA-0216.{1-22}

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.

Alabama

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1994	44	0	[c]4,830	142
1995	43	0	[c]4,868	120
1996	45	0	[c]5,033	119
1997	47	0	[c]4,968	93
1998	39	0	[c]4,604	81
1999	49	0	[c]4,287	107

[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; 3,297 Bcf in 1994; 3,432 Bcf in 1995; 3,509 Bcf in 1996; 3,422 Bcf in 1997; 3,144 Bcf in 1998; 2,853 Bcf in 1999.

Alaska

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1994	5,767	1,022	9,733	301
1995	5,580	582	9,497	306
1996	5,274	952	9,294	337
1997	5,161	832	10,562	631
1998	5,052	832	9,927	320
1999	4,900	464	9,734	299

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	1,552	4
1994	51	0	1,607	6
1995	48	0	1,563	6
1996	58	0	1,470	4
1997	45	0	1,475	7
1998	47	0	1,328	5
1999	48	0	1,542	5

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
1994	[d]3,573	[d]835	[d]2,402	[d]92
1995	[d]3,462	[d]823	[d]2,243	[d]92
1996	[d]3,437	[d]905	[d]2,082	[d]92
1997	[d]3,750	[d]1,264	[d]2,273	[d]95
1998	[d]3,843	[d]1,297	[d]2,244	[d]72
1999	[d]3,934	[d]1,400	[d]2,387	[d]98

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

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
1994	480	238	194	11
1995	456	234	153	8
1996	425	261	156	9
1997	430	43	164	9
1998	354	40	106	9
1999	491	40	192	31

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
1994	221	4	103	5
1995	227	4	111	4
1996	234	0	109	3
1997	268	0	141	4
1998	207	0	149	5
1999	297	0	168	7

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
1994	2,647	593	2,044	75
1995	2,577	585	1,920	80
1996	2,597	644	1,768	80
1997	2,871	1,221	1,912	82
1998	3,127	1,257	1,945	58
1999	2,949	1,330	1,951	60

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
1994	878	0	1,231	22
1995	773	0	1,324	25
1996	699	0	1,293	23
1997	709	0	600	14
1998	623	0	524	12
1999	750	30	612	4

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
1994	225	0	61	1
1995	202	0	59	0
1996	181	0	49	0
1997	181	0	56	0
1998	155	0	44	0
1999	197	30	76	0

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
1994	653	0	1,170	21
1995	571	0	1,265	25
1996	518	0	1,244	23
1997	528	0	544	14
1998	468	0	480	12
1999	553	0	536	4

Colorado

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1994	271	22	6,753	248
1995	252	24	7,256	273
1996	231	22	7,710	287
1997	198	22	6,828	264
1998	212	21	7,881	260
1999	203	21	8,987	303

Florida

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1994	71	0	98	18
1995	71	0	92	17
1996	97	0	96	22
1997	91	0	96	17
1998	71	0	88	18
1999	85	0	84	16

Illinois

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1994	117	0	NA	NA
1995	119	0	NA	NA
1996	94	0	NA	NA
1997	92	0	NA	NA
1998	81	0	NA	NA
1999	100	0	NA	NA

Indiana

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1994	15	0	NA	NA
1995	13	0	NA	NA
1996	11	0	NA	NA
1997	*10	0	NA	NA
1998	13	0	NA	NA
1999	10	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
1994	260	0	9,156	398
1995	275	<1	8,571	369
1996	266	<1	7,694	338
1997	238	0	6,989	271
1998	246	0	6,402	334
1999	175	0	5,753	358

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
1994	26	0	969	39
1995	24	0	1,044	43
1996	21	0	983	46
1997	*20	0	1,364	48
1998	23	0	1,222	54
1999	24	0	1,435	69

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]9,174	[f]421
1994	[f]649	[f]340	[f]9,748	[f]434
1995	[f]637	[f]475	[f]9,274	[f]601
1996	[f]658	[f]331	[f]9,543	[f]543
1997	[f]714	[f]313	[f]9,673	[f]437
1998	[f]551	[f]316	[f]9,147	[f]411
1999	[f]600	[f]278	[f]9,242	[f]457

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

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
1994	108	0	2,537	69
1995	108	0	2,788	79
1996	128	0	3,105	85
1997	136	<1	3,093	80
1998	101	0	2,898	57
1999	108	0	3,079	61

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
1994	391	331	6,251	337
1995	387	324	5,648	495
1996	382	322	5,704	411
1997	427	309	5,855	333
1998	353	307	5,698	325
1999	384	278	5,535	364

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
1994	[f]150	[f]9	[f]960	[f]28
1995	[f]142	[f]151	[f]838	[f]27
1996	[f]148	[f]9	[f]734	[f]47
1997	[f]151	[f]4	[f]725	[f]24
1998	[f]97	[f]2	[f]551	[f]29
1999	[f]108	[f]0	[f]628	[f]32

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

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
1994	91	1	1,323	54
1995	76	1	1,294	45
1996	74	0	2,061	53
1997	68	2	2,195	50
1998	44	0	2,328	51
1999	52	0	2,255	48

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
1994	151	40	650	9
1995	140	6	663	8
1996	164	6	631	7
1997	183	0	582	6
1998	141	0	658	8
1999	163	0	677	10

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
		Montana		
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
1994	175	0	717	8
1995	178	0	782	8
1996	168	0	796	7
1997	159	1	762	5
1998	167	0	782	5
1999	207	0	841	8
		Nebraska		
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
1994	22	0	NA	NA
1995	25	0	NA	NA
1996	28	0	NA	NA
1997	*21	0	NA	NA
1998	18	0	NA	NA
1999	17	0	NA	NA

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
		New Mexico - Total		
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
1994	718	215	17,228	1,011
1995	732	185	17,491	943
1996	744	148	16,485	1,059
1997	735	146	15,514	869
1998	620	168	14,987	929
1999	718	165	15,449	954
		New Mexico - East		
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
1994	702	215	3,021	234
1995	713	185	2,867	247
1996	731	148	2,790	299
1997	719	146	2,642	273
1998	610	168	2,693	262
1999	705	165	3,037	255

New Mexico - West

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1994	16	0	14,207	777
1995	19	0	14,624	696
1996	13	0	13,695	760
1997	16	0	12,872	596
1998	10	0	12,294	667
1999	13	0	12,412	699

New York

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1994	NA	NA	242	NA
1995	NA	NA	197	NA
1996	NA	NA	232	NA
1997	NA	NA	*224	NA
1998	NA	NA	218	NA
1999	NA	NA	221	NA

North Dakota

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1994	226	2	507	55
1995	233	6	463	53
1996	248	6	462	48
1997	279	6	479	47
1998	245	1	447	48
1999	262	1	416	53

Ohio

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1994	58	0	1,094	NA
1995	53	0	1,054	NA
1996	53	0	1,113	NA
1997	*43	0	985	NA
1998	40	0	890	NA
1999	51	0	1,179	NA

Oklahoma

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1994	689	47	13,487	652
1995	676	48	13,438	674
1996	632	43	13,074	684
1997	605	20	13,439	685
1998	599	59	13,645	698
1999	621	58	12,543	749

Pennsylvania

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1994	15	0	1,800	NA
1995	11	0	1,482	NA
1996	10	0	1,696	NA
1997	17	0	1,852	NA
1998	15	0	1,840	NA
1999	16	0	1,772	NA

Texas - Total

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1994	[g]5,847	[g]491	[g]35,974	[g]2,414
1995	[g]5,743	[g]395	[g]36,542	[g]2,524
1996	[g]5,736	[g]358	[g]38,270	[g]2,606
1997	[g]5,687	[g]479	[g]37,761	[g]2,687
1998	[g]4,927	[g]400	[g]37,584	[g]2,544
1999	[g]5,339	[g]426	[g]40,157	[g]2,584

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

Texas - RRC District 1

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
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
1994	100	1	703	26
1995	90	6	712	26
1996	86	1	906	46
1997	83	<1	953	54
1998	61	0	1,104	38
1999	66	0	1,008	167

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
1994	74	0	1,360	86
1995	61	0	1,251	93
1996	63	<1	1,322	93
1997	66	0	1,634	87
1998	45	<1	1,614	85
1999	53	0	1,881	76

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
1994	330	61	3,366	254
1995	267	27	3,866	272
1996	281	27	4,349	289
1997	259	28	4,172	286
1998	211	28	3,961	246
1999	221	25	3,913	226

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
1994	41	<1	7,547	290
1995	50	<1	7,709	287
1996	51	0	7,769	323
1997	70	<1	8,099	347
1998	40	0	8,429	363
1999	42	0	8,915	422

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
1994	49	0	2,011	59
1995	34	0	1,862	54
1996	29	0	2,079	54
1997	54	0	1,710	35
1998	40	0	1,953	35
1999	37	0	2,319	32

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
1994	424	<1	5,381	265
1995	409	1	5,726	271
1996	359	1	5,899	290
1997	348	1	5,887	260
1998	308	0	5,949	276
1999	245	4	5,857	223
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
1994	145	5	425	62
1995	126	4	440	70
1996	136	4	520	65
1997	155	3	478	59
1998	115	0	442	51
1999	123	0	416	36

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
1994	221	14	3,316	265
1995	204	8	3,107	274
1996	219	5	3,655	303
1997	227	4	3,407	327
1998	173	1	3,113	282
1999	209	3	3,178	305
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
1994	2,002	256	5,442	414
1995	2,032	187	5,441	444
1996	2,079	217	5,452	429
1997	2,100	308	5,397	459
1998	1,865	272	4,857	491
1999	2,067	279	5,434	495

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Texas - RRC District 8A				
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
1994	2,223	154	1,219	267
1995	2,233	156	941	284
1996	2,207	99	931	262
1997	2,098	131	847	290
1998	1,895	99	807	226
1999	2,089	115	1,257	223
Texas - RRC District 9				
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
1994	159	<1	728	98
1995	149	<1	738	94
1996	144	0	705	119
1997	144	0	794	98
1998	111	0	734	93
1999	123	0	1,137	158

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Texas - RRC District 10				
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
1994	75	<1	4,246	326
1995	80	6	4,436	353
1996	74	4	4,391	332
1997	79	4	4,094	382
1998	62	0	4,273	354
1999	61	0	4,424	217
Texas - State and Federal Offshore				
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
1994	209	10	6,613	105
1995	257	16	6,838	136
1996	218	5	6,288	133
1997	366	5	6,277	124
1998	311	0	5,996	147
1999	305	0	6,271	165

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
1994	4	0	230	2
1995	8	0	313	2
1996	8	0	292	1
1997	4	0	289	3
1998	1	0	348	4
1999	3	0	418	4

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)
1994	231	70	1,789	(h)
1995	216	50	1,580	(h)
1996	237	46	1,633	(h)
1997	234	70	1,839	(h)
1998	201	56	2,388	(h)
1999	268	42	3,213	(h)

[h]Included with Wyoming.

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
1994	NA	NA	1,833	NA
1995	NA	NA	1,836	NA
1996	NA	NA	1,930	NA
1997	NA	NA	2,446	NA
1998	NA	NA	1,973	NA
1999	NA	NA	2,017	NA

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
1994	25	0	2,565	93
1995	28	0	2,499	62
1996	25	0	2,703	61
1997	26	0	2,846	71
1998	17	0	2,868	72
1999	21	0	2,936	73

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
1994	565	13	10,879	[i]564
1995	605	12	12,166	[i]593
1996	603	14	12,320	[i]727
1997	627	11	13,562	[i]761
1998	547	10	13,650	[i]675
1999	590	5	14,226	[i]615

[i]Utah and Wyoming are combined.

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	16
1992	734	0	1,118	20
1993	673	0	1,099	25
1994	653	0	1,170	21
1995	571	0	1,265	25
1996	518	0	1,244	23
1997	528	0	544	14
1998	468	0	480	12
1999	553	0	536	4

Note: Data not tabulated for years 1977-1984.

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	640
1992	2,569	31	27,767	610
1993	2,745	18	27,143	630
1994	2,780	53	28,388	624
1995	3,089	62	29,182	655
1996	3,085	45	29,096	776
1997	3,477	41	28,466	920
1998	3,261	7	26,902	931
1999	3,297	5	25,987	998

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

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
1994	1,922	43	[k]20,835	[k]500
1995	2,269	46	[k]21,392	[k]496
1996	2,357	40	[k]21,856	[k]621
1997	2,587	36	[k]21,934	[k]785
1998	2,483	7	[k]20,774	[k]776
1999	2,442	5	[k]19,598	[k]833

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

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Federal Offshore - Gulf of Mexico (Texas)				
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
1994	205	10	6,383	103
1995	249	16	6,525	134
1996	210	5	5,996	132
1997	362	5	5,988	121
1998	310	0	5,648	143
1999	302	0	5,853	161

Note: Data not tabulated for years 1977-1984.

Year	Crude Oil Proved Reserves	Crude Oil Indicated Additional Reserves	Dry Natural Gas Proved Reserves	Natural Gas Liquids Proved Reserves
Miscellaneous				
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
1994	20	0	65	8
1995	*22	0	*69	7
1996	18	0	67	7
1997	19	0	*43	9
1998	14	0	38	8
1999	15	0	66	10

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

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	7,104
1992	17,723	2,451	155,377	7,104
1993	17,182	2,292	152,508	6,901
1994	16,690	2,129	154,104	6,869
1995	16,771	2,087	155,649	7,093
1996	16,743	1,924	157,180	7,486
1997	17,385	2,375	156,661	7,342
1998	15,982	2,328	154,114	7,204
1999	16,865	2,400	157,672	7,515

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	7,464
1992	23,745	3,782	165,015	7,451
1993	22,957	3,453	162,415	7,222
1994	22,457	3,151	163,837	7,170
1995	22,351	2,669	165,146	7,399
1996	22,017	2,876	166,474	7,823
1997	22,546	3,207	167,223	7,973
1998	21,034	3,160	164,041	7,524
1999	21,765	2,865	167,406	7,906

Table D1. U.S. Proved Reserves of Crude Oil, 1976–1999

(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)	Estimated Production (9)	Proved[d] Reserves 12/31 (10)	Change from Prior Year (11)
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
1994	189	2,364	1,357	1,196	397	64	111	572	2,268	22,457	–500
1995	122	1,823	795	1,150	500	114	343	957	2,213	22,351	–106
1996	175	1,723	986	912	543	243	141	927	2,173	22,017	–334
1997	520	1,998	1,084	1,434	477	637	119	1,233	2,138	22,546	+529
1998	–638	2,752	2,234	–120	327	152	120	599	1,991	21,034	–1,512
1999	139	6,284	4,465	1,958	259	321	145	725	1,952	21,765	+731

[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 contained in the *Petroleum Supply Annual*, DOE/EIA-0340.

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, 1977 through 1999 annual reports, DOE/EIA-0216.{1-22}

Table D2. U.S. Lower 48 Proved Reserves of Crude Oil, 1976–1999
(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)	Estimated Production (9)	Proved[d] Reserves 12/31 (10)	Change from Prior Year (11)
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
1994	187	1,873	1,346	714	316	64	111	491	1,697	16,690	–492
1995	117	1,521	765	873	434	114	333	881	1,673	16,771	+81
1996	172	1,654	926	900	479	115	141	735	1,663	16,743	–28
1997	514	1,724	1,029	1,209	459	520	119	1,098	1,665	17,385	+642
1998	–639	2,485	2,170	–324	299	56	120	475	1,554	15,982	–1,403
1999	138	3,933	2,264	1,807	253	242	145	640	1,564	16,865	+883

[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 contained in the *Petroleum Supply Annual*, DOE/EIA-0340.

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1977 through 1999 annual reports, DOE/EIA-0216.{1-22}

Table D3. U.S. Proved Reserves of Dry Natural Gas, 1976–1999
(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)	Estimated Production (9)	Proved[d] Reserves 12/31 (10)	Change from Prior Year (11)
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
1994	1,945	21,365	15,881	7,429	6,941	1,894	3,480	12,315	18,322	163,837	+1,422
1995	580	20,465	12,731	8,314	6,843	1,666	2,452	10,961	17,966	165,146	+1,309
1996	3,785	17,132	13,046	7,871	7,757	1,451	3,110	12,318	18,861	166,474	+1,328
1997	–590	21,658	16,756	4,312	10,585	2,681	2,382	15,648	19,211	167,223	+749
1998	–1,635	28,003	22,263	4,105	8,197	1,074	2,162	11,433	18,720	164,041	–3,182
1999	982	42,167	31,663	11,486	7,043	1,568	2,196	10,807	18,928	167,406	+3,365

[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 natural gas contained in the *Natural Gas Annual,* DOE/EIA-0131.

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1977 through 1999 annual reports, DOE/EIA-0216.{1-22}

Table D4. U.S. Lower 48 Proved Reserves of Dry Natural Gas, 1976–1999
(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)	Estimated Production (9)	Proved[d] Reserves 12/31 (10)	Change from Prior Year (11)
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
1994	1,896	21,121	15,832	7,185	6,936	1,894	3,480	12,310	17,899	154,104	+1596
1995	973	19,903	12,680	8,196	6,801	1,666	2,452	10,919	17,570	155,649	+1,545
1996	3,640	16,930	12,875	7,695	7,751	1,390	3,110	12,251	18,415	157,180	+1,531
1997	–609	19,849	16,657	2,583	10,571	2,681	2,382	15,634	18,734	156,661	–519
1998	–1,463	27,834	22,138	4,233	8,195	1,070	2,162	11,427	18,207	154,114	–2,547
1999	849	38,590	28,138	11,301	7,041	1,512	2,173	10,726	18,469	157,672	+3,558

[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 natural gas contained in the *Natural Gas Annual,* DOE/EIA-0131.

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1977 through 1999 annual reports, DOE/EIA-0216.{1-22}

Table D5. U.S. Proved Reserves of Wet Natural Gas, After Lease Separation, 1978–1999
(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)	Estimated Production (9)	Proved[d] Reserves 12/31 (10)	Change from Prior Year (11)
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
1994	1,977	22,345	16,509	7,813	7,299	1,941	3,606	12,846	19,210	171,939	+1,449
1995	889	21,548	13,457	8,980	7,204	1,709	2,518	11,431	18,874	173,476	+1,537
1996	4,288	18,034	13,757	8,565	8,189	1,491	3,209	12,889	19,783	175,147	+1,671
1997	–730	22,712	17,655	4,327	11,179	2,747	2,455	16,381	20,134	175,721	+574
1998	–1,624	29,401	23,419	4,385	8,630	1,116	2,240	11,986	19,622	172,433	-3,288
1999	1,102	44,233	33,051	12,284	7,401	1,622	2,265	11,288	19,856	176,159	+3,726

[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”. They may differ from the official Energy Information Administration production data for natural gas contained in the *Natural Gas Annual,* DOE/EIA-013.

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1979 through 1999 annual reports, DOE/EIA-0216.{2-22}

Table D6. U.S. Lower 48 Proved Reserves of Wet Natural Gas, After Lease Separation, 1978–1999
(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)	Estimated Production (9)	Proved[d] Reserves 12/31 (10)	Change from Prior Year (11)
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	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
1994	1,924	22,071	16,458	7,537	7,294	1,941	3,606	12,841	18,756	162,126	+1,622
1995	1,304	20,928	13,403	8,829	7,162	1,709	2,518	11,389	18,443	163,901	+1,775
1996	4,219	17,832	13,586	8,465	8,183	1,430	3,209	12,822	19,337	165,851	+1,950
1997	–835	20,878	17,556	2,497	11,165	2,747	2,455	16,367	19,657	165,048	–803
1998	–1,461	29,231	23,294	4,476	8,628	1,112	2,240	11,980	19,104	162,400	–2,648
1999	958	40,606	29,476	12,088	7,399	1,566	2,242	11,207	19,391	166,304	+3,904

[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.
– = 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 natural gas contained in the *Natural Gas Annual,* DOE/EIA-0131.

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1979 through 1999 annual reports, DOE/EIA-0216.{2-22}

Table D7. U.S. Proved Reserves of Natural Gas Liquids, 1978–1999
(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)	Estimated Production (9)	Proved[d] Reserves 12/31 (10)	Change from Prior Year (11)
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
1994	43	873	676	240	314	54	131	499	791	7,170	–52
1995	192	968	691	469	432	52	67	551	791	7,399	+229
1996	474	844	669	649	451	65	109	625	850	7,823	+424
1997	–14	1,199	910	275	535	114	90	739	864	7,973	+150
1998	–361	1,302	1,094	–153	383	66	88	537	833	7,524	–449
1999	99	2,048	1,321	826	313	51	88	452	896	7,906	+382

[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 natural gas liquids contained in the *Natural Gas Annual,* DOE/EIA-0131.

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1979 through 1999 annual reports, DOE/EIA-0216.{2-22}

Table D8. U.S. Lower 48 Proved Reserves of Natural Gas Liquids, 1978–1999
(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)	Estimated Production (9)	Proved[d] Reserves 12/31 (10)	Change from Prior Year (11)
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
1994	38	872	676	234	314	54	131	499	765	6,869	–32
1995	204	918	688	434	432	52	67	551	761	7,093	+224
1996	417	832	654	595	450	56	109	615	817	7,486	+393
1997	–107	965	910	–52	533	114	90	737	829	7,342	–144
1998	–74	1,301	1,093	134	383	66	88	537	809	7,204	–138
1999	102	1,902	1,285	719	304	50	86	440	848	7,515	+311

[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 natural gas liquids contained in the *Natural Gas Annual,* DOE/EIA-0131.

Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, 1979 through 1999 annual reports, DOE/EIA-0216.{2-22}

Table D9. Deepwater Production and Proved Reserves of the Gulf of Mexico Federal Offshore, 1992-1999

Year	Gulf of Mexico Total	Gulf of Mexico Louisiana[a]	Gulf of Mexico Texas	Depth Greater than 200 meters	Depth Less than 200 meters	Deepwater Percentage
	Crude Oil (million barrels of 42 U.S. gallons)					
Production						
1992	267	253	14	46	221	17.2
1993	266	252	14	46	220	17.3
1994	265	245	20	53	212	20.1
1995	292	262	30	77	215	26.4
1996	303	265	38	90	213	29.7
1997	342	298	44	123	219	36.0
1998	372	336	36	171	201	46.0
1999	421	376	45	228	193	54.2
Reserves						
1992	1,835	1,643	192	557	1,278	30.4
1993	2,072	1,880	192	824	1,248	39.8
1994	2,127	1,922	205	877	1,250	41.2
1995	2,518	2,269	249	1,241	1,277	49.3
1996	2,567	2,357	210	1,311	1,256	51.1
1997	2,949	2,587	362	1,682	1,267	57.0
1998	2,793	2,483	310	1,611	1,182	57.8
1999	2,744	2,442	302	1,626	1,118	59.3
	Natural Gas, Wet After Lease Separation (billion cubic feet at 14.73 psia and 60° Fahrenheit)					
Production						
1992	4,576	3,292	1,284	166	4,410	3.6
1993	4,651	3,383	1,268	229	4,422	4.9
1994	4,797	3,505	1,292	294	4,503	6.1
1995	4,679	3,421	1,258	354	4,315	7.8
1996	5,045	3,752	1,293	549	4,496	10.9
1997	5,230	3,984	1,246	577	4,653	11.0
1998	4,967	3,817	1,150	724	4,243	14.6
1999	5,000	3,829	1,171	1,124	3,876	22.5
Reserves						
1992	27,050	20,006	7,044	3,273	23,777	12.1
1993	26,463	19,751	6,712	3,495	22,968	13.2
1994	27,626	21,208	6,418	4,772	22,854	17.3
1995	28,229	21,664	6,565	5,811	22,418	20.6
1996	28,153	22,119	6,034	6,389	21,764	22.7
1997	28,455	22,428	6,027	7,491	20,964	26.3
1998	26,937	21,261	5,676	7,575	19,362	28.1
1999	26,062	20,172	5,890	7,726	18,336	29.6
	Natural Gas Liquids (million barrels of 42 U.S. gallons)					
Production						
1992	91	76	15	4	87	4.4
1993	97	80	17	6	91	6.2
1994	98	83	15	6	92	6.1
1995	85	71	14	12	73	14.1
1996	101	84	17	13	88	12.9
1997	140	123	17	17	123	12.1
1998	139	120	19	26	113	18.7
1999	167	136	31	51	116	30.5
Reserves						
1992	590	472	118	91	499	15.4
1993	605	490	115	97	508	16.0
1994	603	500	103	110	493	18.2
1995	630	496	134	294	336	46.7
1996	753	621	132	300	456	39.8
1997	906	785	121	349	557	38.5
1998	919	776	143	387	532	42.1
1999	994	833	161	411	583	41.3

[a]Includes Federal Offshore Alabama.
[b]Revisions result from reclassing all field depths to match Minerals Management Service assignments.
Source: Based on data reported on Form EIA-23, “Annual Survey of Domestic Oil and Gas Reserves.”

Table D10. 1999 Reported Reserves in Nonproducing Reservoirs for Crude Oil, Lease Condensate, and Natural Gas[a]

State and Subdivision	Crude Oil (mbbls)	Lease Condensate (mbbls)	Nonassociated Gas (bcf)	Associated Dissolved Gas (bcf)	Total Gas (bcf)
Alaska	932	-	696	97	793
Lower 48 States	**3,274**	**418**	**30,539**	**5,542**	**36,080**
Alabama	2	5	172	1	173
Arkansas	5	-	186	9	195
California	511	-	73	215	288
Coastal Region Onshore	134	-	0	63	63
Los Angeles Basin Onshore	56	-	0	43	43
San Joaquin Basin Onshore	321	-	73	108	181
State Offshore	0	-	0	0	0
Colorado	30	8	1,689	296	1,985
Florida	12	-	-	-	-
Illinois	11	-	-	2	2
Indiana	-	-	-	-	-
Kansas	12	-	92	7	99
Kentucky	-	-	226	-	226
Louisiana	226	58	2,970	456	3,426
North	42	5	936	123	1,059
South Onshore	146	50	1,796	289	2,085
State Offshore	38	3	238	44	282
Michigan	1	1	52	1	53
Mississippi	68	2	152	4	156
Montana	83	-	89	20	110
Nebraska	-	-	-	-	-
New Mexico	157	8	2,423	122	2,545
East	156	4	286	118	404
West	0	4	2,137	4	2,141
New York	-	-	32	-	32
North Dakota	22	3	67	15	81
Ohio	17	-	142	69	211
Oklahoma	80	18	1,559	181	1,741
Pennsylvania	5	-	190	26	216
Texas	565	71	7,642	860	8,502
RRC District 1	13	2	309	5	314
RRC District 2 Onshore	7	3	380	73	453
RRC District 3 Onshore	26	18	769	141	910
RRC District 4 Onshore	9	25	2,395	79	2,474
RRC District 5	5	2	857	4	860
RRC District 6	10	10	1,146	45	1,191
RRC District 7B	6	-	7	2	8
RRC District 7C	33	1	332	54	386
RRC District 8	234	1	430	364	794
RRC District 8A	212	-	3	55	58
RRC District 9	4	-	489	2	491
RRC District 10	5	6	471	33	505
State Offshore	-	2	54	3	57
Utah	58	1	1,177	101	1,278
Virginia	-	-	165	-	165
West Virginia	3	-	427	1	428
Wyoming	52	9	3,075	60	3,136
Federal Offshore[b]	1,355	234	7,941	3,093	11,034
Pacific (California)	15	4	48	20	68
Gulf of Mexico (Louisiana)[b]	1,133	180	6,267	2,099	8,366
Gulf of Mexico (Texas)	207	50	1,625	975	2,600
Miscellaneous[c]	1	-	-	1	1
Total	**4,206**	**418**	**31,235**	**5,639**	**36,873**

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

[b]Includes Federal offshore Alabama.

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

Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1999.

Appendix E

Summary of Data Collection Operations

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 size 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 (**Certainty**) and operators that were randomly sampled (**Noncertainty**).

Data were filed for calendar year 1999 by crude oil or natural gas well operators who were active as of December 31, 1999. 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 1992 and 1999, and depicts the number of active operators, 1994 showing the largest in the series. The 1999 sampling frame consisted of 177 Category I, 399 Category II, 648 Category III Certainty, and 20,865 Category III Noncertainty operators, for a total of 22,089 active operators. The survey sample consisted of 1,224 operators selected with certainty that included all of the Category I and II Certainty operators, the 648 smaller operators that were selected with certainty because of their size in relation to the area or areas in which they operated, and 1,305 Noncertainty operators selected as a systematic random sample of the remaining operators.

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 1999 survey is summarized in **Table E2**. EIA makes a considerable effort to gain responses from all operators. About 3 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 88 nonoperators, 20 had successor operators that had taken over the production of the nonoperator. These successor operators were subsequently sampled. The overall response rate for the 1999 survey was 94.1 percent. For the 146 operators that did not respond, production data was obtained from State or other sources.

Form EIA-23 Reporting Requirements

The collection format for Form EIA-23 actually consists of two forms. The form 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

Table E1. Comparison of the EIA-23 Sample and Sampling Frame, 1992-1999

Operator Category	Number of Operators							
	1992	1993	1994	1995	1996	1997	1998	1999
Certainty								
Category I	157	160	161	161	176	180	178	177
Category II	480	500	482	476	486	461	420	399
Category III	1,896	1,723	1,694	1,596	3	1,194	862	648
Sampled	2,533	2,383	2,337	2,233	665	1,835	1,460	1,224
Percent Sampled	100	100	100	100	100	100	100	100
Noncertainty								
Sampled	1,724	1,691	1,737	1,632	0	1,645	1,459	1,305
Percent Sampled	8	8	8	8	0	8	7	6
Total								
Active Operators	R24,173	R23,656	R24,222	22,766	23,410	22,678	23,620	22,089
Not Sampled	19,916	19,791	20,148	18,901	22,745	19,198	20,701	19,560
Sampled	4,257	4,074	4,074	3,865	665	3,480	2,919	1,868
Percent Sampled	18	17	17	17	3	15	12	8

R=Revised data.
Note: Active operators in 1998 include 10 operators added after December 29, 1998 and not included in Table E3.
Source: Energy Information Administration, Office of Oil and Gas.

Table E2. Form EIA-23 Survey Response Statistics, 1999

Operator Category	Original Sample Selected	Successor[a] Operators	Net[b] Category Changes	Non-[c] operators	Adjusted[d] Sample	Responding Operators		Nonresponding Operators	
						Number	Percent	Number	Percent
Certainty									
Category I	177	3	10	-16	174	174	100.0	0	0.0
Category II	399	17	-33	-17	366	366	100.0	0	0.0
Category III	648	0	23	-21	650	591	90.9	59[e]	9.1
Subtotal	1,224	20	0	-54	1,190	1,131	95.0	59[e]	5.0
Noncertainty	1,305	1	0	-34	1,272	1,185	93.2	87[e]	6.8
Total	2,529	1	0	-88	2,462	2,316	94.1	146[e]	5.9

[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.
[d]Adjusted sample equals original sample plus successor operators plus net category changes minus nonoperators.
[e]For the 146 operators (59 CategoryIII operators and 87 Noncertainty operators) that did not respond, production data was obtained from State or other sources.
Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves" 1999.

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 1998*, in January of 1999, was the 17th annual report and reflected data collected through October 1998. 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 (see inside cover page).

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 1999, Form EIA-23 National estimates of production were 2,151 million barrels for crude oil and lease condensate or 4 million barrels (0.1 percent) higher than that reported in the *Petroleum Supply Annual 1999* for crude oil and lease condensate. Form EIA-23 National estimates of production for dry natural gas were 18,928 billion cubic feet – 231 billion cubic feet (1 percent) higher than the *Natural Gas Annual 1999* for 1999 dry natural gas production.

Form EIA-23 Frame Maintenance

Operator frame maintenance is a major data quality control effort. 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, is revised annually. In addition, outside sources, such as State publications and electronic data, and commercial information data bases such as IHS Energy Group, 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 1999 survey mailing. These changes resulted from all frame maintenance activities.

The Form EIA-23 operator frame contained a total of 68,501 entries as of December 29, 1999. Of these, 22,127 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.

Table E3. Summary of the 1999 Operator Frame Activity, Form EIA-23

Total 1998 Operator Frame	68,468
Operators	23,392
Nonoperators	45,076
Changes to 1998 Operator Status	1,642
From Nonoperator to Operator	54
From Operator to Nonoperator	1,588
No Changes to 1998 Operator Status	66,826
Operators	22,040
Nonoperators	44,786
Additions to 1998 Operator Frame	33
Operator	33
Nonoperator	0
Total 1999 Operator Frame	**68,501**
Operators	22,127
Nonoperators	46,374

Note: Includes operator frame activity through December 29, 1999.
Source: Energy Information Administration, Office of Oil and Gas.

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 the wellhead or 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 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 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.

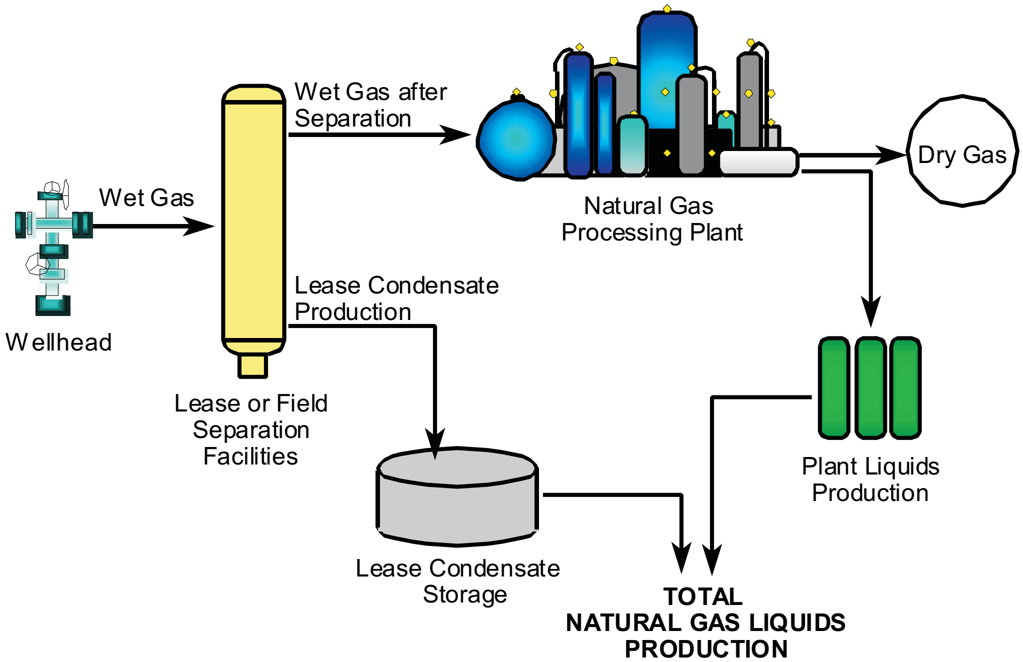
Form EIA-64A Response Statistics

EIA mailed EIA-64A forms to all known natural gas processing plant operators as of February 1, 2000. In addition, plant operators whose plants were shut down or dismantled during 1999 were required to complete forms for the portion of 1999 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 254 operators of 554 plants were sent forms. This number included 3 new plant, 2 reactivated plants, and 14 successor plants identified after the initial 1999 survey mailing. A total of 35 plants were reported as nonoperating according to the Form EIA-64A definition. For the twelfth consecutive year the response rate was 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

Figure E1. Natural Gas Liquids Extraction Flows



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

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.

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 1999, the Form EIA-64A National estimates were 21 percent (157 million barrels) higher than the *Petroleum Supply Annual 1999* volume for natural gas plant liquids production.

Table E4. Natural Gas Processed and Liquids Extracted at Natural Gas Processing Plants, 1999

Plant Location	Volume of Natural Gas Delivered to Processing Plants (million cubic feet) State Production	Out of State Production	Natural Gas Processed	Total Liquids Extracted (thousand barrels)
Alaska	2,950,502	0	2,950,502	32,297
Alabama	308,008	1,484	309,492	12,586
Arkansas	179,524	0	179,524	355
California	259,518	0	259,518	8,848
Colorado	444,894	84	444,978	19,047
Florida	4,937	3,502	8,439	1,594
Illinois	358	0	358	43
Kansas	532,139	121,376	653,515	34,455
Kentucky	44,064	0	44,064	1,691
Louisiana	4,526,840	160,421	4,687,261	114,826
Michigan	67,514	0	67,514	4,315
Mississippi	3,661	132,112	135,773	4,149
Montana	5,211	0	5,211	337
North Dakota	52,191	0	52,191	4,462
New Mexico	872,842	959	873,801	74,570
Ohio	2,933	0	2,933	61
Oklahoma	883,517	8,879	892,396	65,212
Pennsylvania	6,773	4,488	11,261	674
Texas	3,875,214	28,137	3,903,351	257,661
Utah	205,709	5,805	211,514	7,974
West Virginia	66,249	139	66,388	5,112
Wyoming	902,365	524	902,889	36,593
Total	**16,194,963**	**467,910**	**16,662,873**	**686,862**

[a]Includes Illinois, Nebraska, Ohio, Pennsylvania, and Tennessee.
Source: Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production," 1999.

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 1999 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 28, 1999.

Table E5. Form EIA-64A 1999 Plant Frame Activity

Frame as of 1998 survey mailing	621
Additions	159
Deletions	–191
Frame as of 1999 survey mailing	589

Note: Includes operator frame activity through December 28, 1999.
Source: Energy Information Administration, Office of Oil and Gas.

Appendix F

Statistical Considerations

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 1999 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 1998 (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 1998 (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 1998 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 1999.
- **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 1999.
- **Category III -** *Small Operators:* Operators who produced less than the Category II operators in 1999, but which were selected with certainty. Category III operators were subdivided into operators sampled with certainty (**Certainty**) and operators that were randomly sampled (**Noncertainty**).
  - **Certainty -** A small operators who satisfied any of the following criteria based upon their production shown in the operator frame:
    - 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.

Table F1. 1999 EIA–23 Survey Initial Sample Criteria

State and Subdivision	Production Cutoffs: Crude Oil (mbbls)	Production Cutoffs: Gas (mmcf)	Certainty Operators	Noncertainty Sample Number of Single State Operators	Noncertainty Sample Number of Multi–State Operators
Alabama Onshore	107	1,000	61	2	0
Alaska	0	0	11	0	0
Arkansas	21	1,000	140	18	4
California Unspecified	17	88	38	34	1
California Coastal Region Onshore	200	1,000	20	0	1
California Los Angeles Basin Onshore	200	25	27	1	0
California San Joaquin Basin Onshore	200	1,000	46	2	1
Colorado	200	1,000	151	24	6
Florida Onshore	200	1,000	2	2	0
Illinois	200	27	43	71	5
Indiana	12	1	54	22	4
Kansas	85	1,000	199	147	15
Kentucky	37	1,000	34	42	5
Louisiana Unspecified	73	183	14	50	3
Louisiana North	13	633	207	9	1
Louisiana South Onshore	70	1,000	218	4	2
Michigan	200	1,000	53	9	0
Mississippi Onshore	200	1,000	115	9	2
Montana	200	1,000	82	11	2
Nebraska	13	2	56	5	1
New Mexico Unspecified	10	13	137	11	0
New Mexico East	200	1,000	187	0	0
New Mexico West	21	1,000	64	1	0
New York	3	1,000	28	51	0
North Dakota	200	1,000	88	4	2
Ohio	92	1,000	48	180	2
Oklahoma	143	1,000	355	263	25
Pennsylvania	4	1,000	65	61	0
Texas Unspecified	7	118	10	99	0
Texas-RRC District 1	23	800	173	36	18
Texas-RRC District 2 Onshore	200	1,000	205	10	14
Texas-RRC District 3 Onshore	200	1,000	281	20	22
Texas-RRC District 4 Onshore	91	1,000	202	7	15
Texas-RRC District 5	38	630	119	7	8
Texas-RRC District 6	200	1,000	199	19	8
Texas-RRC District 7B	34	82	290	55	29
Texas-RRC District 7C	200	1,000	216	15	24
Texas-RRC District 8	200	1,000	272	25	21
Texas-RRC District 8A	200	1,000	238	11	14
Texas-RRC District 9	52	1,000	216	65	19
Texas-RRC District 10	200	1,000	188	31	7
Utah	200	1,000	65	6	1
Virginia	200	1,000	12	1	1
West Virginia	5	1,000	76	34	1
Wyoming	200	1,000	161	16	6
Offshore Areas	0	0	286	0	0
Other States[a]	125	49	32	19	1
Total			**[b]1,724**	**1,509**	**[b]121**

[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]Nonduplicative 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.

- 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 for six or more State/subdivisions.

▪ **Noncertainties -** Small operators not in the certainty stratum were classified in a noncertainty stratum.

- In most areas, data from the noncertainty operators were sampled at a rate of 8 percent.
- In four States (Texas, California, Louisiana, and New Mexico) EIA did not survey the noncertainty operators in 1999. Instead, a new imputation function was applied to estimate reserves volumes. The function used EIA historic production and reserves data, State and commercially available production data, and the size classifications of reporting operators.

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 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 random sampling proportional to size.

An additional complexity is introduced because 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 consisting of 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 reporting production in the State/subdivision.

In many State/ subdivisions, the accuracy of the oil and gas estimates was improved by using the probability proportional to size sampling procedure. This procedure took advantage of the correlation between year-to-year production reports. The weights used for estimating the oil production for a State/subdivision were different from the weights used for estimating the gas production.

The weight used for the estimation is the reciprocal of the probability of selection for the stratum from which the sample operator was selected. 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 State/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 Noncertainty operators for the 1999 survey was 99.4 percent, therefore an imputation was made for the production and reserves of the 8 nonresponding operators.

Imputation and Estimation for Reserves Data

In order to estimate reserve balances for National and State/subdivision levels, a series of imputation and estimation 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. A 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 sections.

The data reported by operator category by Form EIA-23 respondents for the report year 1999 are summarized in **Tables F2, F3, F4, and F5**. The reported data in **Table F2** shows that those responding operators accounted for 97.9 percent of the published production for natural gas shown in **Table 9** and 93.9 percent of the reserves. Data shown in **Table F3** indicate that those responding operators accounted for 95.3 percent of the nonassociated natural gas production and 92.7 percent of the reserves published in **Table 10**. The reported data shown in **Table F4** indicate that those responding operators accounted for 96.7 percent of published crude oil production and 94.7 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 96 percent of the published proved reserves for lease condensate shown in **Table 16**.

Table F2. Summary of Total Natural Gas, Wet After Lease Separation, Used in Estimation Process, Form EIA-23 (Million Cubic Feet at 14.73 psia and 60 Degrees Fahrenheit)

Level of Reporting	Operator Category I	II	Certainty III	Non-certainty III	Total
Field Level Reported and Imputed Data					
Proved Reserves as of 12/31/98	148,732,495	11,704,959	54,744	8,705	160,500,903
(+) Revision Increases	32,573,449	9,208,444	100,511	56,489	41,938,893
(–) Revision Decreases	28,575,341	2,996,869	7,071	1,709	31,580,990
(+) Extensions	6,271,113	813,319	0	0	7,084,432
(+) New Field Discoveries	1,253,294	326,453	0	0	1,579,747
(+) New Reservoirs in Old Fields	1,680,270	454,447	0	0	2,134,717
(–) Production With Reserves in 1999	16,218,949	2,013,038	17,183	4,390	18,253,560
Proved Reserves Reported as of 12/31/99	145,716,341	17,497,716	131,001	59,095	163,404,153
Production Without Proved Reserves	29,444	510,699	4,382	0	544,525
Reserves Imputed for Production Without Proved Reserves	205,356	4,134,411	35,348	0	4,375,115
Subtotal Production	**16,248,393**	**2,523,737**	**21,565**	**4,390**	**18,798,085**
Subtotal Proved Reserves 1999	**145,921,697**	**21,632,127**	**166,349**	**59,095**	**167,779,268**
State Level Reported and Imputed Data					
Production With Proved Reserves	0	0	112,958	48,281	161,239
Production Without Proved Reserves	93	32,080	120,620	99,838	252,631
Production Estimated from Auxiliary Data	0	0	576,759	0	576,759
Subtotal Production	93	32,080	810,133	148,119	990,425
Weighted Subtotal Production	**93**	**32,080**	**810,133**	**201,420**	**1,043,726**
Proved Reserves Reported	0	0	1,163,024	445,339	1,608,363
Reserves Imputed for Reported Production Without Proved Reserves	679	347,293	4,559,148	1,497,537	6,404,657
Reserves Estimated from Auxiliary Data	0	0	3,735,072	0	3,735,072
Subtotal Proved Reserves	679	347,293	5,722,172	1,942,876	8,013,020
Weighted Subtotal Proved Reserves	**679**	**347,293**	**5,722,172**	**1,942,876**	**8,013,020**
Total Production in 1999	**16,248,486**	**2,555,817**	**831,698**	**219,999**	**19,856,000**
Total Proved Reserves as of 12/31/99	**145,922,376**	**21,979,420**	**5,888,521**	**2,368,683**	**176,159,000**

– = Not applicable.

Notes: Table 9 totals include imputed and estimated wet natural gas proved reserves rounded at the State/subdivision level. Field level data are reported volumes and may not balance due to submission of incomplete reserve component records.

Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1999.

Table F3. Summary of Nonassociated Natural Gas, Wet After Lease Separation, Used in Estimation Process, Form EIA-23 (Million Cubic Feet at 14.73 psia and 60 Degrees Fahrenheit)

	Operator Category				
Level of Reporting	I	II	Certainty III	Non-certainty III	Total
Field Level Detail Report					
Proved Reserves as of 12/31/98	121,614,116	10,129,399	50,538	6,188	131,800,241
(+) Revision Increases	23,517,230	7,552,399	81,650	51,456	31,202,735
(–) Revision Decreases	20,577,502	2,500,921	7,044	958	23,086,425
(+) Extensions	5,741,639	791,613	0	0	6,533,252
(+) New Field Discoveries	980,988	207,124	0	0	1,188,112
(+) New Reservoirs in Old Fields	1,501,800	257,025	0	0	1,758,825
(–) Production With Reserves in 1999	13,540,667	1,645,093	15,729	3,774	15,205,263
Proved Reserves Reported as of 12/31/99	119,237,615	14,791,547	109,415	52,912	134,191,489
Production Without Proved Reserves	27,987	441,491	3,718	0	473,196
Reserves Imputed for Production Without Proved Reserves	195,254	3,579,110	0	29,459	3,803,823
Subtotal Production	**13,568,654**	**2,086,584**	**19,447**	**3,774**	**15,678,459**
Subtotal Proved Reserves 1999	**119,432,869**	**18,370,657**	**109,415**	**52,912**	**137,965,853**
State Level Reported and Imputed Data					
Production With Proved Reserves	—	—	—	—	—
Production Without Proved Reserves	—	—	—	—	—
Production Estimated from Auxiliary Data	—	—	864,541	—	—
Subtotal Production	—	—	864,541	—	—
Weighted Subtotal Production	—	—	864,541	—	—
Proved Reserves Reported	—	—	—	—	—
Reserves Imputed for Reported Production Without Proved Reserves	—	—	—	—	—
Reserves Estimated from Auxiliary Data	—	—	6,778,147		
Subtotal Proved Reserves	—	—	6,778,147	—	—
Weighted Subtotal Proved Reserves	**—**	**—**	**6,778,147**	**—**	**—**
Total Production in 1999	**13,568,654**	**2,086,584**	**883,988**	**3,774**	**16,543,000**
Total Proved Reserves as of 12/31/99	**119,432,869**	**18,370,657**	**6,887,562**	**52,912**	**144,744,000**

– = Not applicable.

Notes: Table 10 totals include imputed and estimated nonassociated wet natural gas proved reserves rounded at the State/subdivision level. Field level data are reported volumes and may not balance due to submission of incomplete reserve component records.

Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1999.

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

Level of Reporting	Operator Category I	II	Certainty III	Non-certainty III	Total
Field Level Detail Report					
Proved Reserves as of 12/31/98	18,860,026	741,381	2,054	1,537	19,604,998
(+) Revision Increases	5,299,692	596,144	5,294	2,604	5,903,734
(–) Revision Decreases	4,157,555	126,081	75	210	4,283,921
(+) Extensions	230,211	8,206	0	0	238,417
New Field Discoveries	206,812	114,514	0	0	321,326
(+) New Reservoirs in Old Fields	122,952	15,871	60	0	138,883
(–) Production With Reserves in 1999	1,616,216	126,524	809	387	1,743,936
Proved Reserves Reported as of 12/31/99	18,945,924	1,223,512	6,524	3,544	20,179,504
Production Without Proved Reserves	743	28,579	698	0	30,020
Reserves Imputed for Production Without Proved Reserves	5,975	235,271	5,598	0	246,844
Subtotal Production	**1,616,959**	**155,103**	**1,507**	**387**	**1,773,956**
Subtotal Proved Reserves 1999	**18,951,899**	**1,458,783**	**12,122**	**3,544**	**20,426,348**
State Level Reported and Imputed Data					
Production With Proved Reserves	0	0	22,406	5,555	27,961
Production Without Proved Reserves	0	5,094	28,810	16,356	50,260
Production Estimated from Auxiliary Data	0	0	83,639	0	83,639
Subtotal Production	0	5,094	134,702	21,911	161,707
Weighted Subtotal Production	**0**	**5,094**	**134,702**	**39,281**	**179,077**
Proved Reserves Reported	0	0	246,391	79,963	326,354
Reserves Imputed for Reported Production Without Proved Reserves	0	61,768	714,585	218,753	995,106
Reserves Estimated from Auxiliary Data	0	0	559,169	0	559,169
Subtotal Proved Reserves	0	61,768	960,976	298,716	1,321,460
Weighted Subtotal Proved Reserves	**0**	**61,768**	**960,976**	**298,716**	**1,321,460**
Total Production in 1999	**1,616,959**	**160,197**	**136,209**	**38,635**	**1,952,000**
Total Proved Reserves as of 12/31/99	**18,951,899**	**1,520,551**	**973,098**	**319,452**	**21,765,000**

– = Not applicable.
Notes: Table 6 totals include imputed and estimated crude oil proved reserves rounded at the State/subdivision level. Field level data are reported volumes and may not balance due to submission of incomplete reserve component records.
Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1999.

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

Level of Reporting	Operator Category I	II	Certainty III	Non-certainty III	Total
Field Level Detail Report					
Proved Reserves as of 12/31/98	1,191,176	89,125	791	21	1,281,113
(+) Revision Increases	372,808	85,654	367	5	458,834
(–) Revision Decreases	279,078	37,219	6	2	316,305
(+) Extensions	44,694	4,125	0	0	48,819
(+) New Field Discoveries	14,148	1,763	0	0	15,911
(+) New Reservoirs in Old Fields	32,083	3,163	0	0	35,246
(–) Production With Reserves in 1999	168,321	20,016	121	10	188,468
Proved Reserves Reported as of 12/31/99	1,207,508	126,595	1,031	14	1,335,148
Production Without Proved Reserves	691	3,224	5	0	3,920
Reserves Imputed for Production Without Proved Reserves	3,959	17,430	35	0	21,424
Subtotal Production	**169,012**	**23,240**	**126**	**10**	**192,388**
Subtotal Proved Reserves 1999	**1,211,467**	**144,025**	**1,066**	**14**	**1,356,572**
State Level Reported and Imputed Data					
Production With Proved Reserves	0	0	690	209	899
Production Without Proved Reserves	0	301	797	246	1,344
Production Estimated from Auxiliary Data	0	0	6,192	0	6,192
Subtotal Production	0	301	7,475	455	8,231
Weighted Subtotal Production	**0**	**301**	**7,475**	**455**	**8,231**
Proved Reserves Reported	0	0	15,574	2,391	17,965
Reserves Imputed for Reported Production Without Proved Reserves	0	2,473	25,883	0	28,356
Reserves Estimated from Auxiliary Data	0	0	29,894	0	29,894
Subtotal Proved Reserves	0	2,473	41,457	0	43,930
Weighted Subtotal Proved Reserves	**0**	**2,473**	**41,457**	**2,498**	**46,428**
Total Production in 1999	**169,012**	**23,541**	**7,601**	**465**	**200,619**
Total Proved Reserves as of 12/31/99	**1,211,467**	**146,498**	**42,523**	**2,512**	**1,403,000**

– = Not applicable.
Notes: Table 15 totals include imputed and estimated lease condensate proved reserves rounded at the State/subdivision level. Field level data are reported volumes and may not balance due to submission of incomplete reserve component records.
Source: Form EIA-23, “Annual Survey of Domestic Oil and Gas Reserves,” 1999.

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 imputed reserves were weighted to estimate the full noncertainty stratum when calculating reserves and production as previously described in the section "Total U.S. Reserves Estimates" in this appendix.

R/P Function

A year-end proved reserves estimate was imputed from reported production data in each case where an estimate was not provided by the respondent. A R/P function was derived and used to calculate a reserves-to-production (R/P) ratio, based on operator size and the geographic region where the operator's properties were located. The R/P function has the following functional form for each geographic region:

Calculated R/P = Beta (Alpha + ln (1 + MOS))

- *Alpha, Beta* = Regional Coefficients (calculated).
- *MOS = Measure of size* for a respondent, which is equal to the barrel oil equivalent volume of a respondent's 1999 oil, gas, and condensate production (in units of thousand barrels per year).

Table F6 lists the coefficients used for each region and the number of observations on which it was based. The regional areas used are similar to the National Petroleum Council Regions (**Figure F1**). These regions generally follow the boundaries of geologic provinces wherein the stage of resource development tends to be somewhat similar.

Once the R/P ratio was obtained for an operator, it could be multiplied by the reported or estimated production to give a proved reserves estimate. Operators that had R/P ratios equal to zero or that exceeded 25 to 1 were excluded from the respondents selected to calculate the R/P coefficients.

In 1999, the R/P function was used to estimate the proved reserves of all noncertainty operators in four States -- Texas, California, Louisiana, and New Mexico, rather than rely on a sample. These four States were chosen for this new procedure because EIA has many years of production and reserves data for them, and reliable State government and commercial production data are available for these States. This technique improved the correlation of EIA data with State and commercial production data, and reduced the burden of reporting and analysis on both EIA and the noncertainty operators in these States.

In Region 5 (West Texas and East New Mexico) in 1999, the average MOS of all noncertainty respondents was 149 thousand barrels of oil equivalent per year. Using the coefficients in **Table F6**, the regional R/P for noncertainty operators in Region 5 of average MOS size was 7.9 for oil, 6.9 for natural gas, and 4.3 for lease condensate. In 1998, the characteristic multipliers in

Table F6. Statistical Parameters of Reserve Estimation Equation by Region for 1999

Region Number	Region	Number of Nonzero R/P Pairs			Equation Coefficients					
					Oil		Gas		LC	
		Oil	Gas	LC	Alpha	Beta	Alpha	Beta	Alpha	Beta
2	Pacific Coast States	40	47	4	2.89	0.95	17.08	0.29	11.00	0.40
3	Western Rocky Mountains	98	150	50	2.89	0.96	17.08	0.41	11.00	0.44
4	Northern Rocky Mountains	193	153	42	2.89	0.84	17.08	0.41	11.00	0.26
5	West Texas and East New Mexico	575	556	160	2.89	1.01	17.08	0.31	11.00	0.27
6 + 6A	Western Gulf Basin and Gulf of Mexico	630	882	532	2.89	0.62	17.08	0.26	11.00	0.29
7	Mid-Continent	394	475	174	2.89	0.85	17.08	0.38	11.00	0.40
8 + 9	Michigan Basin and Eastern Interior	89	60	12	2.89	0.93	17.08	0.41	11.00	0.41
10 + 11	Appalachians	31	80	6	2.89	1.11	17.08	0.59	11.00	0.63
	United States	2,050	2,403	980	2.89	0.89	17.08	0.33	11.00	0.31

Source: Based on data filed on Form EIA-23,"Annual Survey of Domestic Oil and Gas Reserves, 1999".

Region 5 were 7.0 for oil, 7.1 for natural gas, and 6.5 for lease condensate.

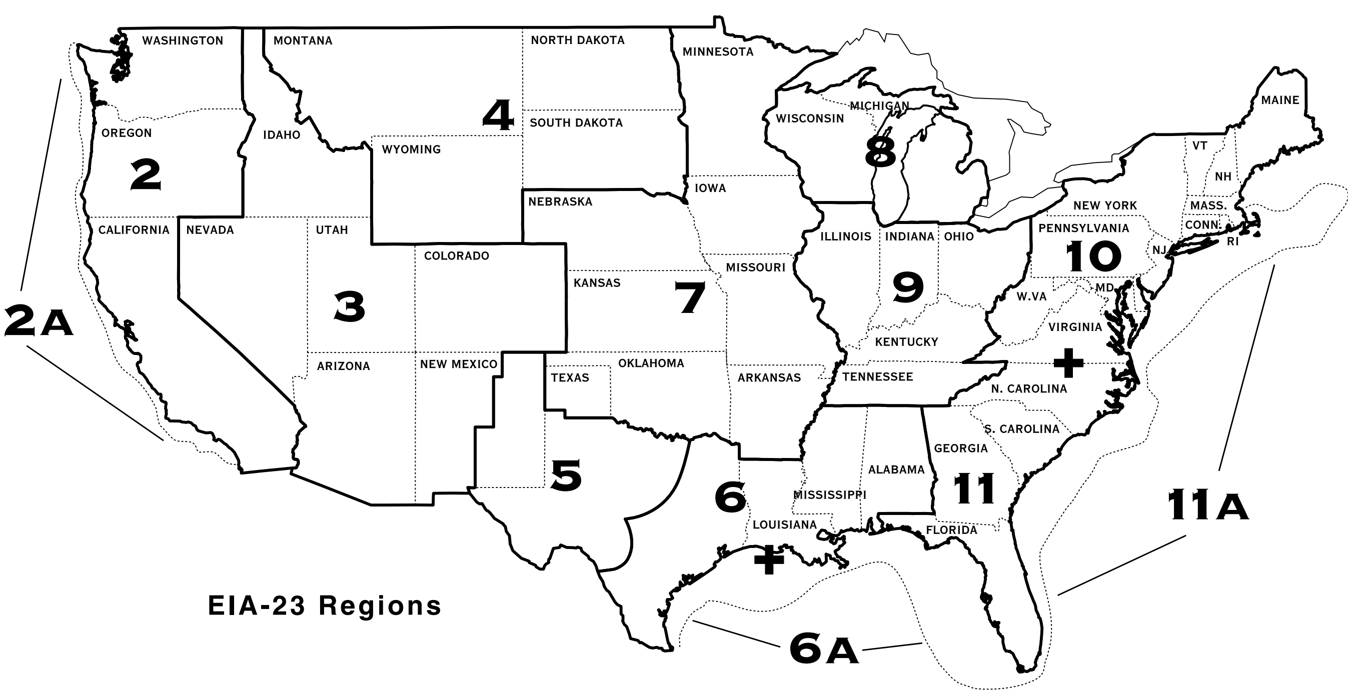
Imputation of Annual Changes to Proved Reserves by Component of Change

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 of similar size 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.

Figure F1. Form EIA-23 Regional Boundaries



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

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 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 is included in the adjustments for the area. One of the primary reasons that adjustments are necessary is instability of the Noncertainty operators sampled each year. About 24 percent of the Noncertainty stratum operators sampled in 1998 were sampled again in 1999. There is no guarantee that in the smaller States/subdivisions 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 1999 than in 1998.
- One or more operators may have reported data incorrectly on Schedule A in 1998 or 1999, but not both, and the error was not detected by edit processing.
- Operation of properties was transferred during 1999 from operators not in the frame or Noncertainty operators not selected for the sample to Certainty operators or Noncertainty operators selected for the sample.
- Operations of properties was transferred during 1999 to an operator with a different evaluation of the proved reserves associated with the properties than that of the 1998 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.
- Noncertainty operators, who have grown substantially in size since they were added to the frame, occasionally cause a larger standard error than expected.
- The Noncertainty sample for either year in a state may have been an unusual one.

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

Sampling Reliability of the Estimates

The sample of Noncertainty operators selected is only one of a large number of possible samples that could have been selected; each would have resulted in slightly 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. For example, the 95 percent confidence interval for dry natural gas proved reserves is 164,041 ± 1,003 billion cubic feet. 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.

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 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.

Table F7. Factors for Confidence Intervals (2S.E.) for Dry Natural Gas Proved Reserves and Production, 1999 (Billion Cubic Feet at 14.73 psia and 60 Degrees Fahrenheit)

State and Subdivision	1999 Reserves	1999 Production
United States	142	13
Alabama	45	10
Alaska	0	0
Arkansas	31	4
California	0	0
Coastal Region Onshore	0	0
Los Angeles Basin Onshore	0	0
San Joaquin Basin Onshore	0	0
State Offshore	0	0
Colorado	58	5
Florida	0	0
Kansas	5	1
Kentucky	0	0
Louisiana	0	0
North	0	0
South Onshore	0	0
State Offshore	0	0
Michigan	0	0
Mississippi	10	2
Montana	7	1
New Mexico	0	0
East	0	0
West	0	0
New York	12	1
North Dakota	0	0
Ohio	62	5
Oklahoma	34	3
Pennsylvania	0	0
Texas	0	0
RRC District 1	0	0
RRC District 2 Onshore	0	0
RRC District 3 Onshore	0	0
RRC District 4 Onshore	0	0
RRC District 5	0	0
RRC District 6	0	0
RRC District 7B	0	0
RRC District 7C	0	0
RRC District 8	0	0
RRC District 8A	0	0
RRC District 9	0	0
RRC District 10	0	0
State Offshore	0	0
Utah	0	0
Virginia	0	0
West Virginia	80	4
Wyoming	0	0
Federal Offshore[a]	0	0
Pacific (California)	0	0
Gulf of Mexico (Louisiana)[a]	0	0
Gulf of Mexico (Texas)	0	0
Miscellaneous[b]	0	0

[a]Includes Federal offshore Alabama.

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

Notes: Confidence intervals are associated with Table 8 reserves and production data. 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," 1999 and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production," 1999.

Table F8. Factors for Confidence Intervals (2S.E.) for Natural Gas Proved Reserves and Production, Wet After Lease Separation, 1999 (Billion Cubic Feet at 14.73 psia and 60 Degrees Fahrenheit)

State and Subdivision	1999 Reserves	1999 Production
United States	147	14
Alabama	55	13
Alaska	0	0
Arkansas	31	4
California	0	0
Coastal Region Onshore	0	0
Los Angeles Basin Onshore	0	0
San Joaquin Basin Onshore	0	0
State Offshore	0	0
Colorado	63	6
Florida	0	0
Kansas	6	1
Kentucky	0	0
Louisiana	0	0
North	0	0
South Onshore	0	0
State Offshore	0	0
Michigan	0	0
Mississippi	10	2
Montana	7	1
New Mexico	0	0
East	0	0
West	0	0
New York	12	1
North Dakota	2	0
Ohio	63	5
Oklahoma	36	3
Pennsylvania	0	0
Texas	0	0
RRC District 1	0	0
RRC District 2 Onshore	0	0
RRC District 3 Onshore	0	0
RRC District 4 Onshore	0	0
RRC District 5	0	0
RRC District 6	0	0
RRC District 7B	0	0
RRC District 7C	0	0
RRC District 8	0	0
RRC District 8A	0	0
RRC District 9	0	0
RRC District 10	0	0
State Offshore	0	0
Utah	3	1
Virginia	0	0
West Virginia	82	4
Wyoming	0	0
Federal Offshore[a]	0	0
Pacific (California)	0	0
Gulf of Mexico (Louisiana)[a]	0	0
Gulf of Mexico (Texas)	0	0
Miscellaneous[b]	0	0

[a]Includes Federal offshore Alabama.

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

Notes: Confidence intervals are associated with Table 9 reserves and production data. 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," 1999.

Table F9. Factors for Confidence Intervals (2S.E.) for Crude Oil Proved Reserves and Production, 1999
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	1999 Reserves	1999 Production
United States	24	2
Alabama	0	0
Alaska	0	0
Arkansas	2	0
California	0	0
Coastal Region Onshore	0	0
Los Angeles Basin Onshore	0	0
San Joaquin Basin Onshore	0	0
State Offshore	0	0
Colorado	4	0
Florida	0	0
Illinois	5	0
Indiana	1	0
Kansas	5	1
Kentucky	10	0
Louisiana	0	0
North	0	0
South Onshore	0	0
State Offshore	0	0
Michigan	1	0
Mississippi	2	0
Montana	4	0
Nebraska	1	0
New Mexico	0	0
East	0	0
West	0	0
North Dakota	8	1
Ohio	4	1
Oklahoma	15	1
Pennsylvania	1	0
Texas	10	2
RRC District 1	14	1
RRC District 2 Onshore	0	0
RRC District 3 Onshore	4	1
RRC District 4 Onshore	1	0
RRC District 5	1	0
RRC District 6	4	1
RRC District 7B	4	1
RRC District 7C	3	0
RRC District 8	50	1
RRC District 8A	22	2
RRC District 9	10	1
RRC District 10	13	2
State Offshore	0	0
Utah	5	1
West Virginia	6	0
Wyoming	0	0
Federal Offshore	0	0
Pacific (California)	0	0
Gulf of Mexico (Louisiana)	0	0
Gulf of Mexico (Texas)	0	0
Miscellaneous[a]	0	0

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

Notes: Confidence intervals are associated with Table 6 reserves and production data. 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," 1999.

Table F10. Factors for Confidence Intervals (2S.E.) for Lease Condensate Proved Reserves and Production, 1999 (Million Barrels of 42 U.S. Gallons)

State and Subdivision	1999 Reserves	1999 Production
United States	1	0
Alabama	0	0
Alaska	0	0
Arkansas	0	0
California	0	0
Coastal Region Onshore	0	0
Los Angeles Basin Onshore	0	0
San Joaquin Basin Onshore	0	0
State Offshore	0	0
Colorado	0	0
Florida	0	0
Kansas	0	0
Kentucky	0	0
Louisiana	0	0
North	0	0
South Onshore	0	0
State Offshore	0	0
Michigan	0	0
Mississippi	0	0
Montana	0	0
New Mexico	0	0
East	0	0
West	0	0
North Dakota	0	0
Oklahoma	1	0
Texas	0	0
RRC District 1	0	0
RRC District 2 Onshore	0	0
RRC District 3 Onshore	0	0
RRC District 4 Onshore	0	0
RRC District 5	0	0
RRC District 6	0	0
RRC District 7B	0	0
RRC District 7C	0	0
RRC District 8	0	0
RRC District 8A	0	0
RRC District 9	0	0
RRC District 10	0	0
State Offshore	0	0
Utah and Wyoming	0	0
West Virginia	0	0
Federal Offshore[a]	0	0
Pacific (California)	0	0
Gulf of Mexico (Louisiana)[a]	0	0
Gulf of Mexico (Texas)	0	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.

Notes: Confidence intervals are associated with Table 15 reserves and production data. 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," 1999.

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, 8.3 percent of the crude oil proved reserve estimates, 8.2 percent of the natural gas proved reserve estimates, and 5.7 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 1999 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. The 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 1999 Form EIA-64A survey, the national weighted average gas equivalents ratio was computed to be 1,406 cubic feet of natural gas shrinkage per barrel of NGL recovered. 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 used to generate an estimate of the natural gas liquids reserves in those States with coalbed methane fields. The States where this procedure was applied were Alabama, Colorado, Kansas, New Mexico, Oklahoma, Pennsylvania, Utah, Virginia, West Virginia, and Wyoming. The first step in the process was to identify all Form EIA-23 reported coalbed methane fields. 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 reserve components, 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 reserve components was added back to each of the dry gas volume reserve components 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.

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

Estimation of Reserves and Resources

Estimation of Reserves and Resources

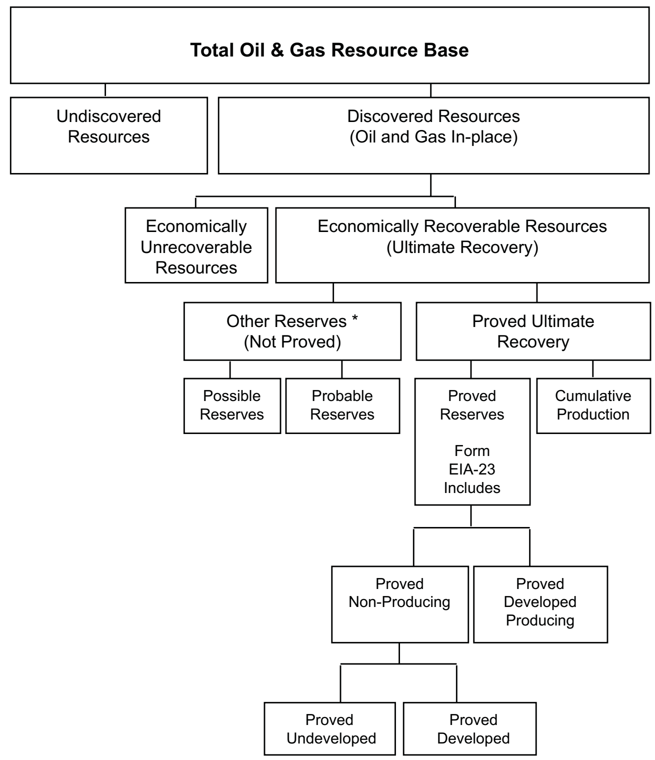
Oil and Gas Resource Base

Universally accepted definitions have not been developed for the many terms used by geologists, engineers, accountants and others to denote various components of overall oil and gas resources. In part, this is because most of these terms describe estimated and therefore uncertain, rather than measured, quantities. The lack of standardized terminology sometimes leads to inaccurate understanding of the meaning and/or import of estimates. Particularly common is an apparently widespread lack of understanding of the substantial difference between the terms "reserves" and "resources", as indicated by the frequent misuse of either term in place of the other.

The total resource base of oil and gas is the entire volume formed and trapped in–place within the Earth before any production. The largest portion of this total resource base is nonrecoverable by current or foreseeable technology. Most of the nonrecoverable volume occurs at very low concentrations throughout the earth's crust and 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 currently available production techniques cannot extract all of the in–place oil and gas even when present in commercial concentrations. The inability to recover all of the in–place oil and gas from a producible deposit occurs because of unfavorable economics, intractable physical forces, or a combination of both. Recoverable resources, the subset of the total resource base that is of societal and economic interest, are defined so as to exclude these nonrecoverable portions of the total resource base.

The structure presented in **Figure G1** outlines the total resource base and its components. The total resource base first consists of the recoverable and nonrecoverable portions discussed above. The next level down divides recoverable resources into discovered and undiscovered segments. Discovered resources are further separated into cumulative (i.e., all past) production, and reserves. Reserves are additionally subdivided into proved reserves and "other reserves".

Figure G1. Components of the Oil and Gas Resource Base



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

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

Recoverable Resources

Discovered recoverable resources are those economically recoverable quantities of oil and gas for which specific locations are known. While the specific locations of estimated undiscovered recoverable resources are not yet known, they are believed to exist in geologically favorable settings.

Current estimates of undiscovered recoverable resources merit discussion in order to provide a useful sense of scale relative to proved reserves. The sources of official estimates of domestic undiscovered recoverable resources are two agencies of the Department of the Interior (DOI), the United States Geological Survey (USGS) for onshore areas and those offshore waters subject to State jurisdiction, and the Minerals Management Service (MMS) for those offshore waters under Federal jurisdiction.

The USGS defines undiscovered recoverable conventional resources as those expected to be resident in accumulations of sufficient size and quality that they could be produced using conventional recovery technologies, without regard to present economic viability. Therefore, only part of the USGS undiscovered recoverable conventional resource is economically recoverable now. The USGS also defines a class of resources that occur in "continuous–type" accumulations. Unlike conventional oil and gas accumulations, continuous–type accumulations do not occur in discrete reservoirs of limited areal extent. They include accumulations in low–permeability (tight) sandstones, shales, and chalks, and those in coal beds. Again, only part of the continuous–type technically recoverable resource is economically recoverable now. In fact, only a small portion of the in–place continuous–type resource accumulations are estimated to be technically recoverable now. **Table G1** presents the latest available USGS and MMS estimates, along with the EIA 1997 proved reserves estimates.

Technically recoverable resources of wet natural gas (discovered, both proved and unproved, and undiscovered) are estimated at 1,341 trillion cubic feet (**Table G1**). Subtracting U.S. proved reserves of 175 trillion cubic feet yields an unproven technically recoverable resource target of 1,166 trillion cubic feet. This is about 61 times the 1997 gas production level.

Other organizations have also estimated unproven technically recoverable gas resources. For example, the Potential Gas Committee (PGC), an industry sponsored group, provides detailed geology–based gas resource estimates every 2 years. In 1996 the PGC mean estimate of potential gas resources was 1,067 trillion cubic feet, about 99 trillion cubic feet less than the DOI estimates in **Table G1**. Another recent estimate was made by the National Petroleum Council (NPC), an industry–based group that serves in an advisory capacity to the U.S. Secretary of Energy. The NPC's estimate, based on data available at year–end 1990, was 1,135 trillion cubic feet, 111 trillion cubic feet less than the DOI estimates summarized in **Table G1**. The differences among these estimates are usually due to the availability of newer data, the differences in coverage or resource category definitions, and to legitimate but differing data interpretations. The USGS estimates of reserve growth in known fields are much larger than previous estimates due to the utilization of newer EIA reserves growth data.

While the estimation of undiscovered resources is certainly a more imprecise endeavor than is the estimation of proved reserves, it is clear that substantial volumes of technically recoverable oil and gas resources remain to be found and produced domestically. Current estimates indicate that as much domestic gas remains to be found and then produced as has been to date. Of course, much effort, investment and time will be required to bring this gas to market.

There is a perception that the oil resource base has been more intensively developed than the gas resource base. And in fact, more oil has been produced in the United States than is estimated as remaining recoverable. Nevertheless, the ratio of 1996 unproven technically recoverable oil resources to oil production (**Table G1**) was about 62 to 1, higher than the comparable gas ratio.

Discovered Resources

In addition to cumulative production, which is the sum of current year production and the production in all prior years, estimates of discovered recoverable resources include estimates of reserves. Broadly, reserves are those volumes that are believed to be recoverable in the future from known deposits through the eventual application of present or anticipated technology.

Reserves

Reserves include both **proved reserves** and **other reserves**. Several different reserve classification systems are in use by different organizations, as preferred for operational reasons. These systems utilize and incorporate various definitions of terms such as *measured reserves*, *indicated reserves*, *inferred reserves*, *probable reserves*, and *possible reserves*. As used by the different organizations, the definitions that attach to these terms sometimes overlap, or the terms may require a slightly different interpretation from one organization to the next. Nevertheless, all kinds of "other reserves" are generally less well known and therefore less precisely quantifiable than proved reserves, and their eventual recovery is less assured.

Table G1. Estimated Oil and Gas Reserves and Mean Estimates of Technically Recoverable Oil and Gas Resources

Categories	Crude Oil[a] (million barrels)	Natural Gas (Dry) (billion cubic feet)	Natural Gas Liquids (million barrels)
Lower 48 States			
Discovered			
Proved Reserves (EIA, 1999)	16,865	[b]157,672	7,515
Reserve Growth - conventional, onshore[c] (USGS, 1991)	[d]47,000	290,000	12,900
Reserve Growth - conventional, Federal Offshore (MMS, 1995)	[e]2,238	[e]32,719	NE
Unproved Reserves, Federal Offshore (MMS, 1996)	1,643	4,436	NE
Undiscovered, Technically Recoverable			
Conventional, onshore[c] (USGS, 1993)	21,810	190,280	6,080
Continuous-type - sandstone, shale, chalk; onshore[c] (USGS, 1993)	2,066	308,080	2,119
Continuous-type - coalbeds, onshore[c] (USGS, 1993)	NA	49,910	NA
Federal Offshore - conventional (MMS, 1994)	21,300	142,100	[f]<1,800
Subtotal	**112,922**	**1,175,197**	**NA**
Alaska			
Discovered			
Proved Reserves (EIA, 1999)	8,900	9,734	299
Reserve Growth - conventional, onshore[c] (USGS, 1991)	[g]13,000	32,000	500
Reserve Growth conventional, Federal Offshore (MMS, 1994)	0	0	NE
Unproved Reserves, Federal Offshore (MMS, 1994)	400	700	NE
Undiscovered, Technically Recoverable			
Conventional onshore[c] (USGS, 1993)	8,440	68,410	1,120
Continuous-type - sandstone, shale, chalk; onshore[c] (USGS, 1993)	NE	NE	NE
Continuous-type - coalbeds, onshore[c] (USGS, 1993)	NA	NE	NA
Federal Offshore - conventional (MMS, 1994)	24,300	125,900	[f]<1,800
Subtotal	**51,040**	**236,744**	**NA**
Total Lower 48 States and Alaska	**163,962**	**1,411,941**	**32,333**
Deductions for Production and Proved Reserves Changes, 1991-1999	**-13,461**	**-133,119**	**-6,684**
U.S. Total, 1999	**150,501**	**1,278,822**	**25,649**

[a] Condensate is included with crude oil for MMS estimates in Federal Offshore regions.
[b] Includes 13,229 billion cubic feet of coalbed methane (EIA, 1999).
[c] Includes USGS estimates for all onshore plus State Offshore (near-shore and shallow-water areas under State jurisdiction).
[d] Using USGS definition, 1,924 million barrels of indicated additional oil reserves in the lower 48 States were included (EIA, 1996).
[e] Reserve growth in the Pacific Federal offshore is not included and was not estimated by the MMS. This volume is not dry gas, but wet, after lease separation.
[f] Total undiscovered natural gas liquids for Federal offshore are 1,800 million barrels; MMS source did not separate lower 48 and Alaska estimates of undiscovered natural gas liquids (1986).
[g] Using USGS definition, 952 million barrels of indicated additional oil reserves in Alaska were included (EIA, 1996).
NE = not estimated.
NA = not applicable.

Notes: Federal Offshore indicates MMS estimates for Federal Offshore jurisdictions (Outer Continental Shelf and deeper water areas seaward of State Offshore). Energy Information Administration (EIA), onshore and offshore estimated reserves. U.S. Geological Survey (USGS): 1995 National Assessment mean estimates as of the end of 1993 (onshore and State Offshore). Minerals Management Service (MMS): 1996 National Assessment mean estimates as of the end of 1994. The MMS also has end-1994 estimates for economically recoverable resources. Probable and Possible reserves are considered by USGS definition to be part of USGS Reserve Growth, but are separately considered by the MMS as its Unproved Reserves term. The USGS did not set a time limit for the duration of Reserve Growth; the MMS set the year 2020 as the time limit in its estimates of Reserve Growth in existing fields of the Gulf of Mexico. Excluded from the estimates are undiscovered oil resources in tar deposits and oil shales, and undiscovered gas resources in geopressured brines and gas hydrates.

Sources: Energy Information Administration, Office of Oil and Gas; USGS and MMS - *Estimates of Undiscovered Conventional Oil and Gas Resources in the United States—A Part of the Nation's Energy Endowment* (1989), U.S. Department of the Interior; *1995 National Assessment of United States Oil and Gas Resources*, USGS Circular 1118, U.S. Department of the Interior; and *An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf* (1996), U.S. Department of the Interior.

Measured reserves are defined by the USGS as that part of the identified (i.e., discovered) economically recoverable resource that is estimated from geologic evidence and supported directly by engineering data.{39} They are similarly defined by the MMS, although its system also subdivides them by degree of development and producing status.{40} Measured reserves are demonstrated with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, and are essentially equivalent to proved reserves as defined by the EIA. Effectively, estimates of proved reserves may be thought of as reasonable estimates (as opposed to exact measures) of "on–the–shelf inventory".

Inferred reserves and indicated reserves, due to their more uncertain economic or technical recoverability, are included in the "other reserves" category. The USGS defines inferred reserves as that part of the identified economically recoverable resource, over and above both measured and indicated (see below) reserves, that will be added to proved reserves in the future through extensions, revisions, and the discovery of new pay zones in already discovered fields.{41} Inferred reserves are considered equivalent to "probable reserves" by many analysts, for example, those of the PGC.

Indicated additional reserves, a separate category, are defined by both the DOI and the 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 as–yet uninstalled recovery technology. At such time as the technology is successfully applied, indicated additional reserves are reclassified to the proved reserves category. Of all the various "other reserves" categories, only indicated additional reserves are estimated by the EIA and reported herein.

Proved Reserves

The EIA defines proved reserves 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.

When deterministic proved reserves estimation methods are used, the term reasonable certainty is intended to express a high degree of confidence that the estimated quantities will be recovered. When probabilistic methods are used there should be at least a 90 percent probability that the actual quantities recovered will exceed the estimate.

Proved reserves are either proved producing or proved nonproducing (i.e., resident in reservoirs that did not produce during the report year). The latter may represent a substantial fraction of total proved reserves.

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 their 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 the engineering and geological data for reservoir rock and its fluid content. These data are obtained from direct and indirect 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 the *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 G2** summarizes the various methods.

Table G2. 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.

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 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.

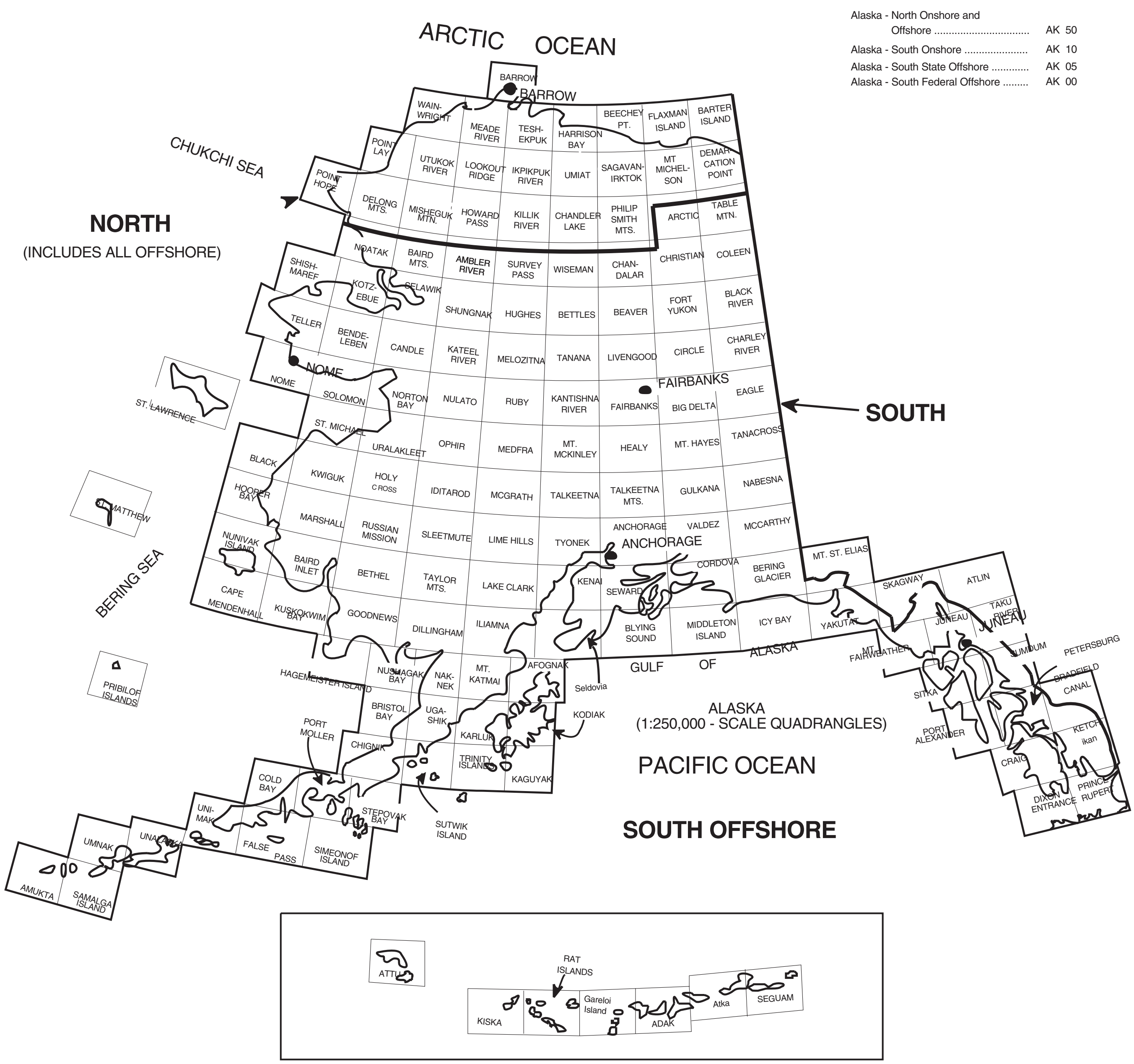
Appendix H

Maps of Selected State Subdivisions

Appendix H

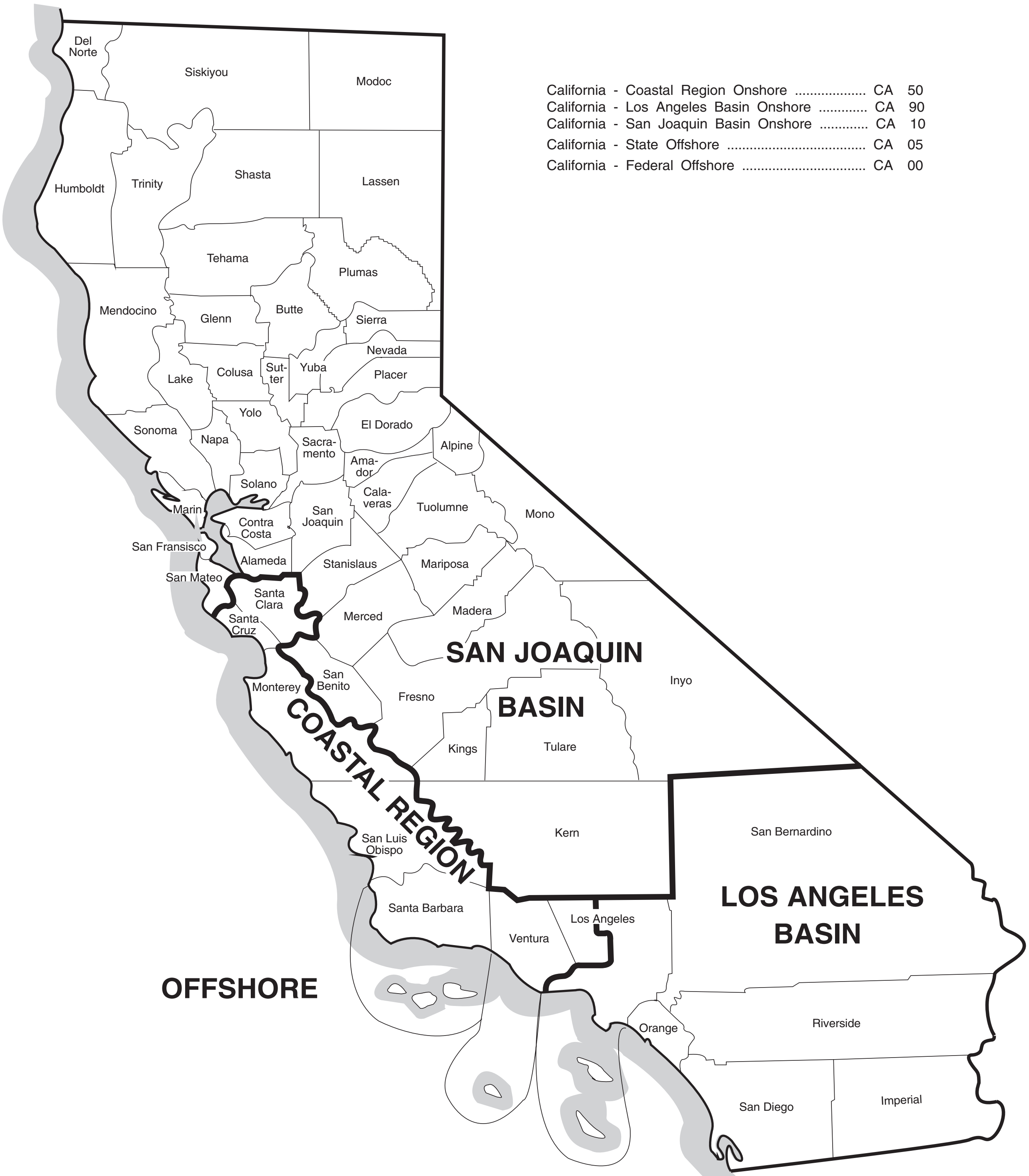
Maps of Selected State Subdivisions

Figure H1. Subdivisions of Alaska



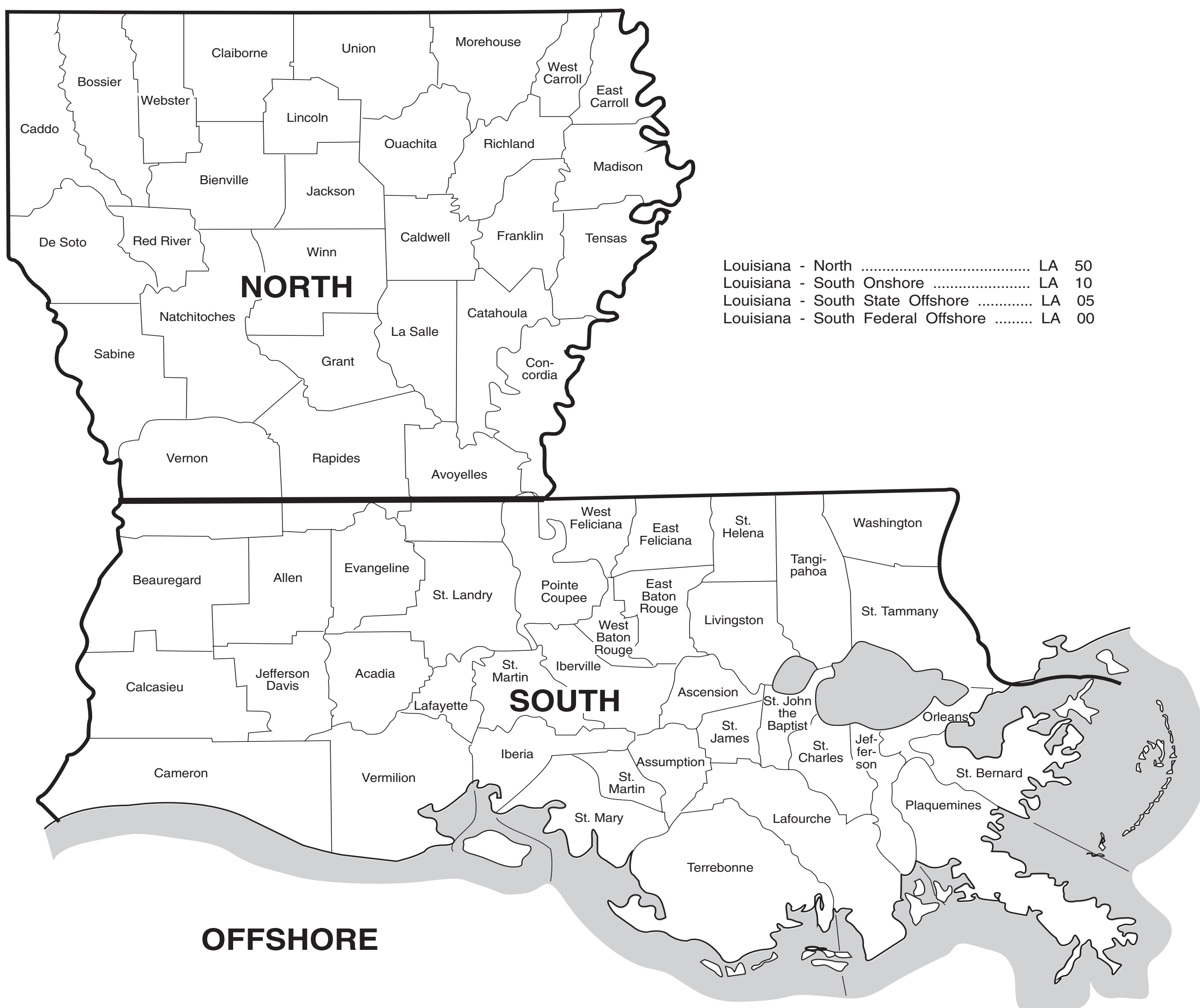
Source: After U.S. Geological Survey.

Figure H2. Subdivisions of California



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

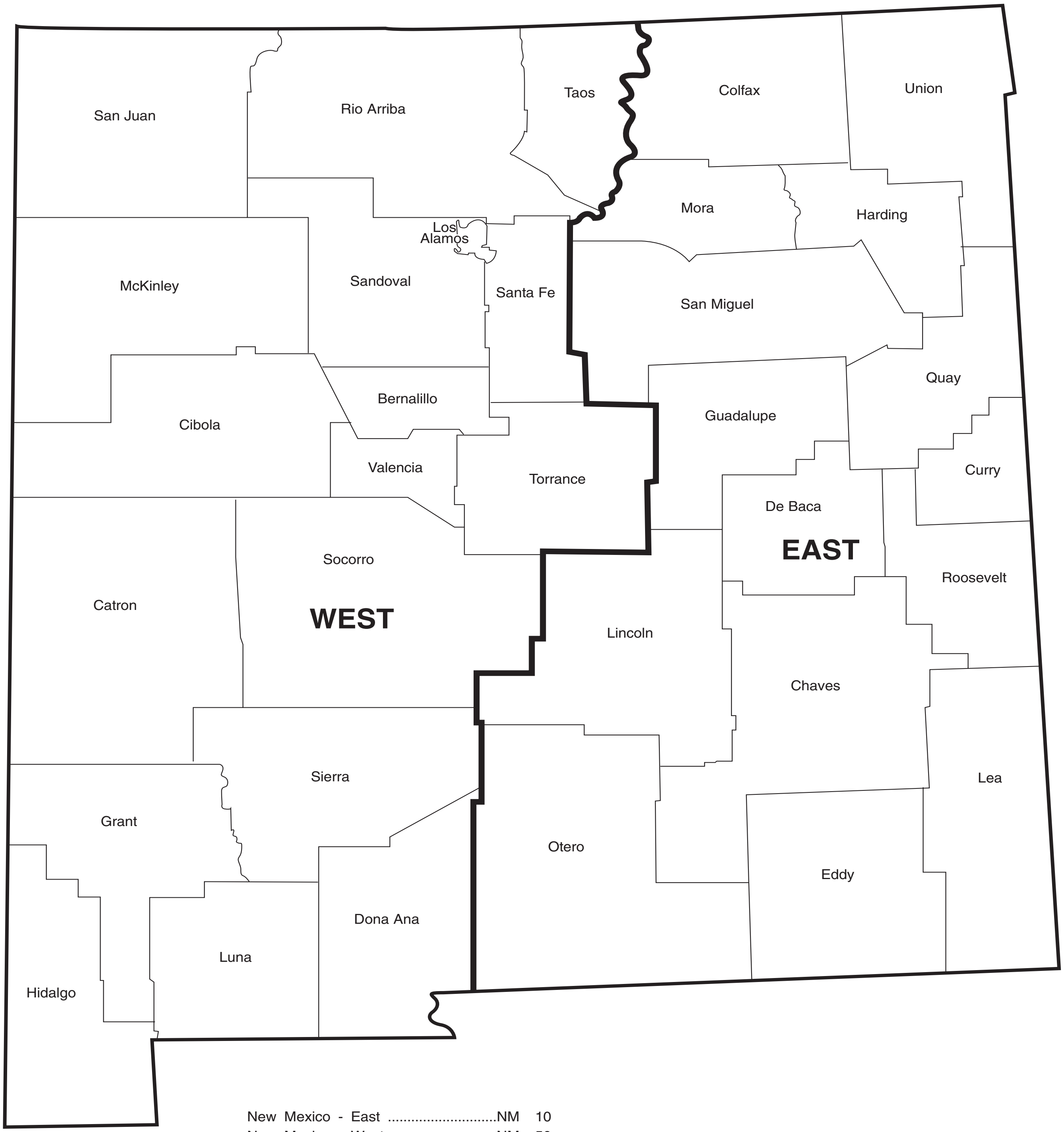
Figure H3. Subdivisions of Louisiana



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

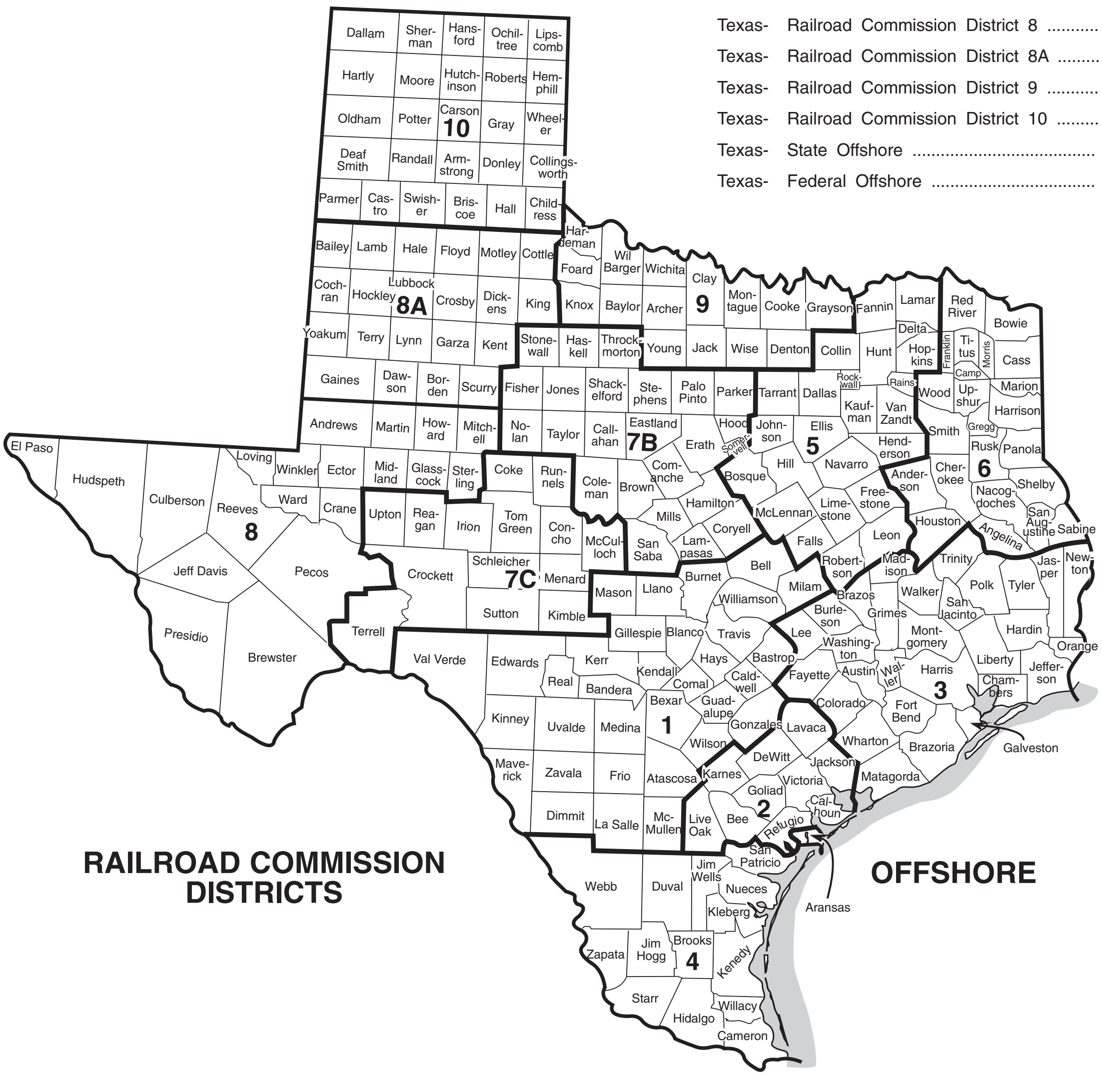


New Mexico - East ....NM 10
New Mexico - West ....NM 50

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

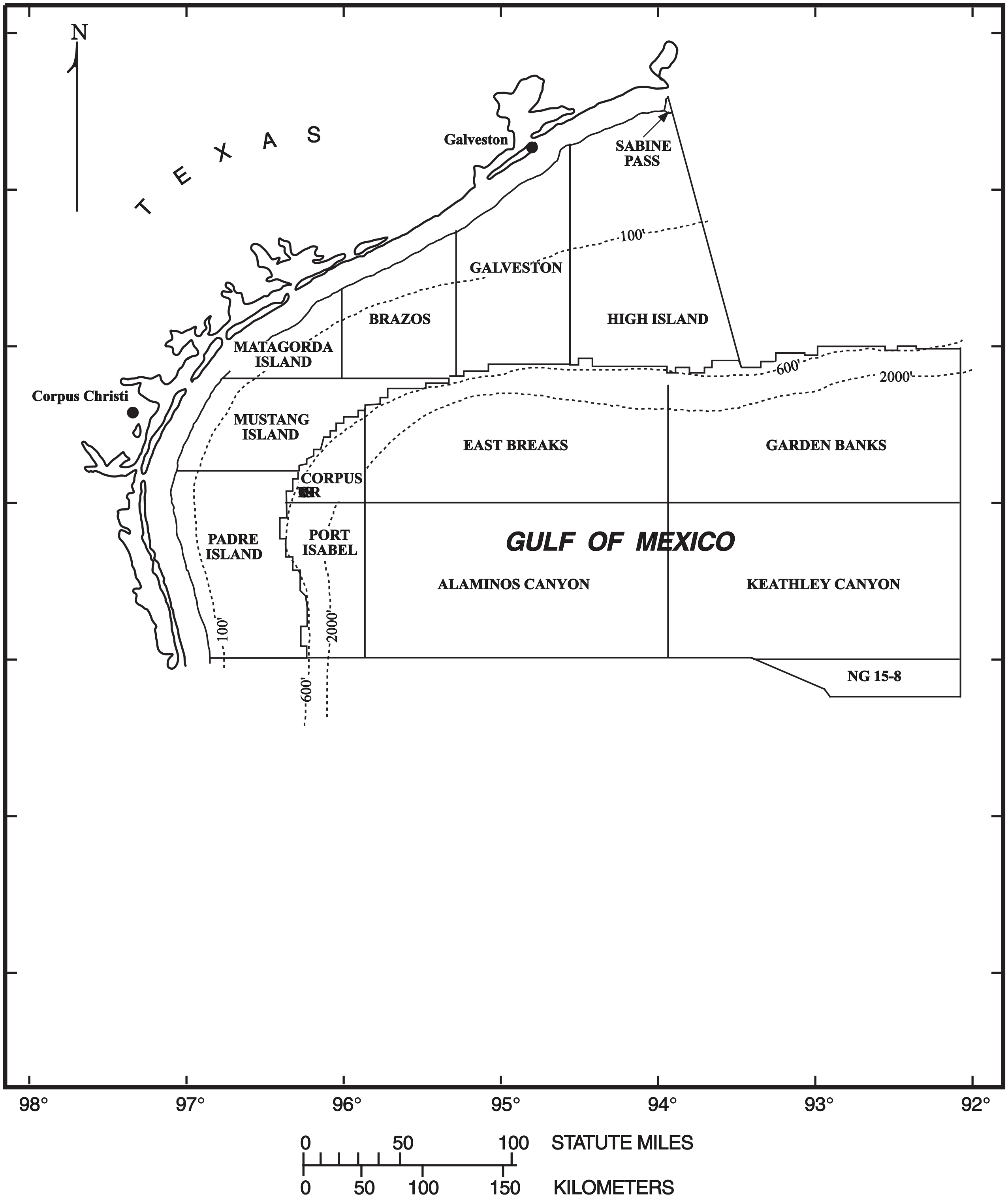
Figure H5. Subdivisions of Texas

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.

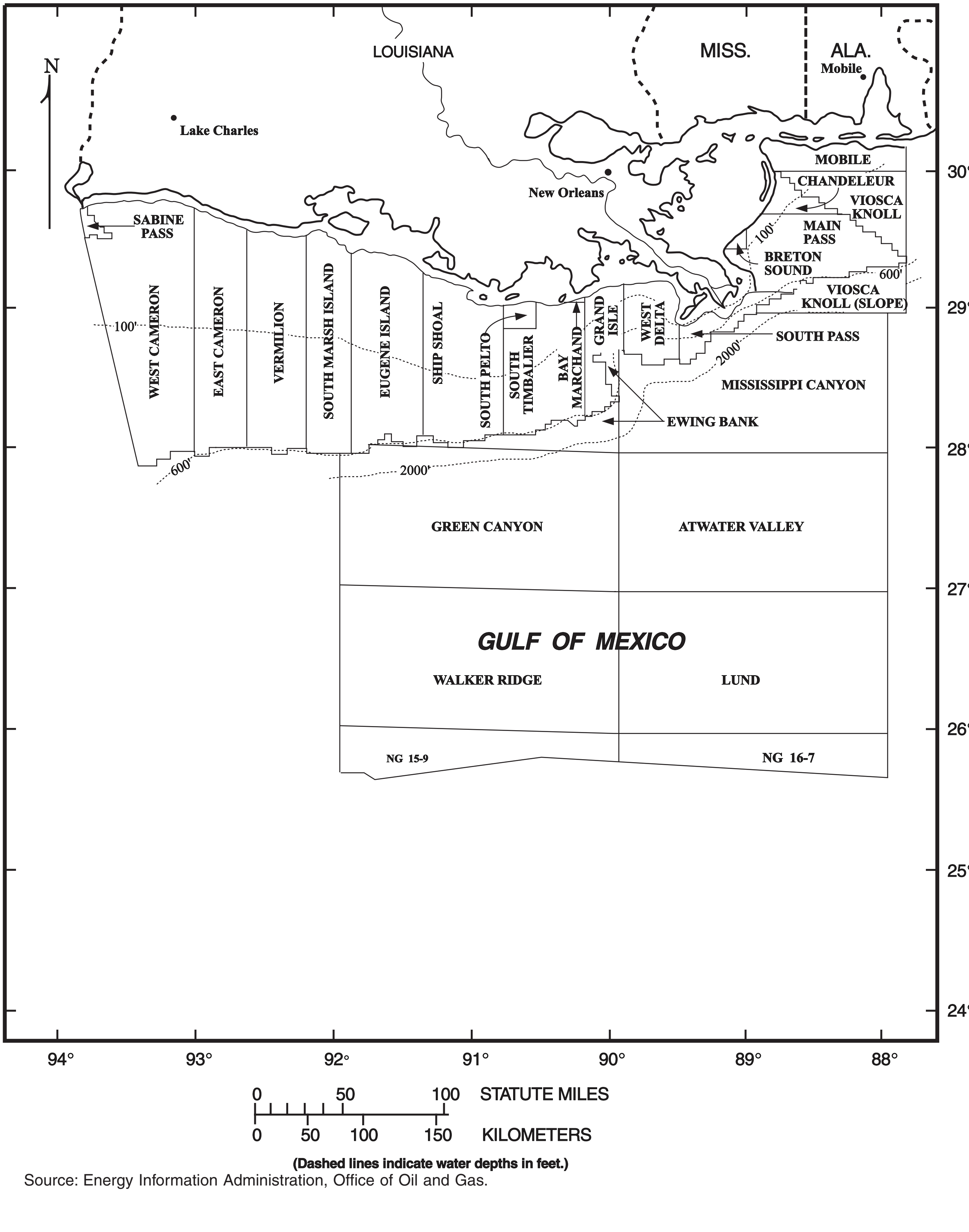
Figure H6. Western Planning Area, Gulf of Mexico Outer Continental Shelf Region



(Dashed lines indicate water depths in feet.)

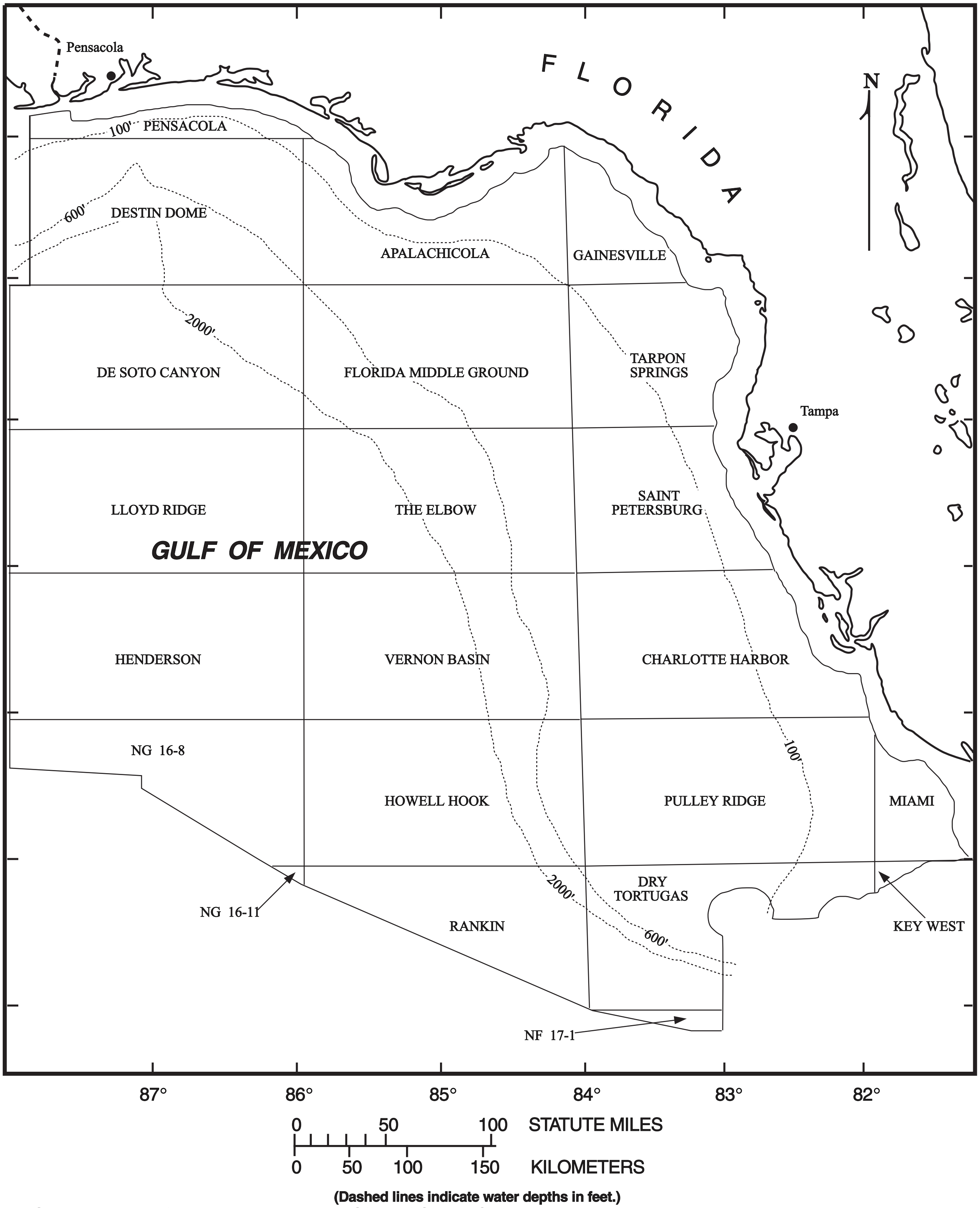
Source: Energy Information Administration, Office of Oil and Gas.

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



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

Appendix I

Annual Survey Forms for Domestic Oil and Gas Reserves

Figure I1. Form EIA-23, Cover Page

OFFICIAL USE ONLY

1999

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES
U.S. DEPARTMENT OF ENERGY
CALENDAR YEAR 1999

Form Approved
OMB No. 1905-0057
Expires 12/31/2000

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, Statistical Methods Group EI-70, 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, 1999?**
   (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* **U. S. Department of Energy Washington, DC 20585**
   (2) ☐ Yes... *Complete the attached forms and return them to* **U. S. Department of Energy Washington, DC 20585**

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 ( ) ______-__________

SAMPLE

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

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

Figure I2. Form EIA-23, Summary Report – Page 1

OFFICIAL USE ONLY

1999

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES
SUMMARY REPORT
PAGE 1 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 60oF)

Form Approved
OMB No. 1905-0057
Expires 12/2000

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 / 99		

2.0 PRODUCTION AND RESERVES DATA

STATE OR GEOGRAPHIC SUBDIVISION		CRUDE OIL			NATURAL GAS			LEASE CONDENSATE		
		RESERVES	1999 PRODUCTION		RESERVES	1999 PRODUCTION		RESERVES	1999 PRODUCTION	
		Proved Reserves Dec. 31, 1999 (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, 1999 (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, 1999 (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									

SAMPLE

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

Figure I3. Form EIA-23, Summary Report – Page 2

OFFICIAL USE ONLY

1999

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES

Form Approved
OMB No. 1905-0057
Expires 12/2000

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 99		

2.0 PRODUCTION AND RESERVES DATA

STATE OR GEOGRAPHIC SUBDIVISION		CRUDE OIL RESERVES	CRUDE OIL 1999 PRODUCTION		NATURAL GAS RESERVES	NATURAL GAS 1999 PRODUCTION		LEASE CONDENSATE RESERVES	LEASE CONDENSATE 1999 PRODUCTION	
		Proved Reserves Dec. 31, 1999 (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, 1999 (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, 1999 (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									

SAMPLE

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

Figure I4. Form EIA-23, Detail Report – Schedule A

OFFICIAL USE ONLY

1999

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES

Form Approved
OMB No. 1905-0057
Expires 12/2000

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 99				

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				8. FOOTNOTE
						(a) CRUDE OIL (Mbbl)	(b) ASSOC-DISSOLVED GAS (MMcf)	(c) NONASSOCIATED GAS (MMcf)	(d) LEASE CONDENSATE (Mbbl)	

9. WATER DEPTH | 10. FIELD DISCOVERY YEAR | 11. INDICATED ADDITIONAL RESERVES OF CRUDE OIL (Mbbl)

TYPE HYDROCARBON	RESERVES (a) DECEMBER 31, 1998	REVISION (b) INCREASES	REVISION (c) DECREASES	(d) EXTENSIONS	NEW FIELD (e) DISCOVERIES	NEW RESERVOIRS (f) IN OLD FIELDS	CALENDAR YEAR (g) PRODUCTION	RESERVES (h) DECEMBER 31, 1999	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				8. FOOTNOTE
						(a) CRUDE OIL (Mbbl)	(b) ASSOC-DISSOLVED GAS (MMcf)	(c) NONASSOCIATED GAS (MMcf)	(d) LEASE CONDENSATE (Mbbl)	

9. WATER DEPTH | 10. FIELD DISCOVERY YEAR | 11. INDICATED ADDITIONAL RESERVES OF CRUDE OIL (Mbbl)

TYPE HYDROCARBON	RESERVES (a) DECEMBER 31, 1998	REVISION (b) INCREASES	REVISION (c) DECREASES	(d) EXTENSIONS	NEW FIELD (e) DISCOVERIES	NEW RESERVOIRS (f) IN OLD FIELDS	CALENDAR YEAR (g) PRODUCTION	RESERVES (h) DECEMBER 31, 1999	NONPRODUCING (i) RESERVES
12. CRUDE OIL (Mbbl)									
13. ASSOCIATED-DISSOLVED GAS(MMcf)									
14. NONASSOCIATED GAS (MMcf)									
15. LEASE CONDENSATE (Mbbl)									

SAMPLE

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				8. FOOTNOTE
						(a) CRUDE OIL (Mbbl)	(b) ASSOC-DISSOLVED GAS (MMcf)	(c) NONASSOCIATED GAS (MMcf)	(d) LEASE CONDENSATE (Mbbl)	

9. WATER DEPTH | 10. FIELD DISCOVERY YEAR | 11. INDICATED ADDITIONAL RESERVES OF CRUDE OIL (Mbbl)

TYPE HYDROCARBON	RESERVES (a) DECEMBER 31, 1998	REVISION (b) INCREASES	REVISION (c) DECREASES	(d) EXTENSIONS	NEW FIELD (e) DISCOVERIES	NEW RESERVOIRS (f) IN OLD FIELDS	CALENDAR YEAR (g) PRODUCTION	RESERVES (h) DECEMBER 31, 1999	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				8. FOOTNOTE
						(a) CRUDE OIL (Mbbl)	(b) ASSOC-DISSOLVED GAS (MMcf)	(c) NONASSOCIATED GAS (MMcf)	(d) LEASE CONDENSATE (Mbbl)	

9. WATER DEPTH | 10. FIELD DISCOVERY YEAR | 11. INDICATED ADDITIONAL RESERVES OF CRUDE OIL (Mbbl)

TYPE HYDROCARBON	RESERVES (a) DECEMBER 31, 1998	REVISION (b) INCREASES	REVISION (c) DECREASES	(d) EXTENSIONS	NEW FIELD (e) DISCOVERIES	NEW RESERVOIRS (f) IN OLD FIELDS	CALENDAR YEAR (g) PRODUCTION	RESERVES (h) DECEMBER 31, 1999	NONPRODUCING (i) RESERVES
12. CRUDE OIL (Mbbl)									
13. ASSOCIATED-DISSOLVED GAS(MMcf)									
14. NONASSOCIATED GAS (MMcf)									
15. LEASE CONDENSATE (Mbbl)									

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

Figure I5. Form EIA-23, Detail Report – Schedule B

OFFICIAL USE ONLY **1999**

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES
SCHEDULE B - FOOTNOTES

Form Approved
OMB No. 1905-0057
Expires 12/2000

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 99				

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

SAMPLE

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

Figure I6. Form EIA-64A

U.S. DEPARTMENT OF ENERGY
ENERGY INFORMATION ADMINISTRATION
Washington, D.C. 20585

Form Approved
OMB No. 1905-0057
Expiration Date: 12/31/00

ANNUAL REPORT OF THE ORIGIN OF NATURAL GAS LIQUIDS PRODUCTION
FORM EIA-64A
CALENDAR YEAR 1999

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, Statistics and Methods Group EI-70, 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

ENERGY INFORMATION ADMINISTRATION, EI-45
1000 INDEPENDENCE AVE., SW MAIL STATION: 2G-024
WASHINGTON, DC 20585

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		

SAMPLE

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**

Fax Number: ( ) - **E-mail address:**

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.

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

Glossary

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 1998.

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 primarily 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 calendar 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 Ownershi p 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 general, 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.

Proved Ultimate Recovery: The sum of proved reserves and cumulative production. It is expected to change over time for any field, group of fields, State, or Country. Proved Ultimate Recovery does not represent the maximum recoverable volume of resources for an area. It is instead a gauge of how much has already been produced plus proved reserves. Proved reserves of crude oil or natural gas are the estimated quantities of petroleum which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. When deterministic proved reserves estimation methods are used, the term reasonable certainty is intended to express a high degree of confidence that the estimated quantities will be recovered. When probabilistic methods are used there should be at least a 90 percent probability that the actual quantities recovered will exceed the estimate.

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.