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U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2006 Annual Report

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Energy Information Administration

Preface

The *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2006 Annual Report* is the 30th 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, 2006, as well as production volumes for the United States and producing States and State subdivisions for the year 2006. 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 crude oil, natural gas, and lease condensate reserves in nonproducing reservoirs. A discussion of notable oil and gas exploration and development activities during 2006 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 2006; 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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COVER PHOTO:

Aerial View of Dallas/Fort Worth International Airport.

The DFW Airport Board has leased its 18,000 acres to Oklahoma City-based Chesapeake Energy Corporation to begin natural gas exploration in the Barnett Shale that lies below the Airport.

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Executive Summary

Proved reserves of natural gas increased by 3 percent in 2006, rising to over 211 trillion cubic feet, the highest level since 1976. Additions to reserves replaced 136 percent of the dry natural gas produced in 2006. This was the eighth year in a row that U.S. natural gas proved reserves have increased.

As of December 31, 2006 proved reserves were:

Crude Oil (million barrels)	
2005	21,757
2006	20,972
Decrease	-3.6%
Dry Natural Gas (billion cubic feet)	
2005	204,385
2006	211,085
Increase	+3.3%
Natural Gas Liquids (million barrels)	
2005	8,165
2006	8,472
Increase	+3.8%

U.S. crude oil proved reserves declined 4 percent in 2006. The Gulf of Mexico Federal Offshore and Alaska, two of the largest oil-producing areas, respectively reported 10 and 7 percent declines in crude oil proved reserves. This was due to downward revisions and fewer new discoveries.

Proved reserves are the estimated quantities which 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.

Natural Gas

Texas led the nation in natural gas reserves additions in 2006 with a 9 percent increase in dry gas proved reserves due to rapid development of Barnett Shale reservoirs in the Newark East Field. Advances in horizontal drilling and hydraulic fracturing technology and relatively high natural gas prices supported this development. Alaska and Utah were second and third for dry natural gas proved reserves additions in 2006.

Total U.S. natural gas production increased in 2006 due to production increases in Texas (Barnett Shale), Louisiana, and the Rocky Mountain states (Colorado, Wyoming, Utah, and Montana). Gulf of Mexico natural gas production declined the most with a 6 percent drop.

Total discoveries of dry natural gas reserves attributed to the drilling of exploratory wells, which include field extensions, new field discoveries, and new reservoir discoveries in old fields, were 23,342 billion cubic feet in 2006. This was 35 percent more than the prior 10-year average (17,255 billion cubic feet) and 1 percent more than in 2005.

The majority of natural gas total discoveries in 2006 were from extensions to existing gas fields. Field extensions were 21,778 billion cubic feet, 3 percent more than in 2005 and 61 percent more than the prior 10-year average (13,522 billion cubic feet).

New field discoveries were 409 billion cubic feet, 57 percent less than the volume discovered in 2005 and 75 percent less than the prior 10-year average (1,659 billion cubic feet).

New reservoir discoveries in old fields were 1,155 billion cubic feet, 4 percent less than 2005 and 44 percent less than the prior 10-year average (2,074 billion cubic feet).

Natural gas net revisions and adjustments were a net loss of 1,093 billion cubic feet in 2006. The prior occurrence of negative net revisions was in 1988. The net of sales and acquisitions of dry natural gas proved reserves was 2,996 billion cubic feet.

Coalbed natural gas reserves decreased 1 percent in 2006 and accounted for 9 percent of U.S. dry natural gas reserves. Coalbed natural gas production increased 2 percent in 2006 and accounted for 9 percent of U.S. dry natural gas production.

Other 2006 natural gas events of note:

- Natural gas prices at the wellhead declined 12 percent in 2006 to an average of $6.42 per thousand cubic feet, as compared to $7.33 per thousand cubic feet in 2005.

- Gas well completions (exploratory and development) were up 17 percent from 2005.

Crude Oil

U.S. crude oil proved reserves declined 4 percent in 2006. The Gulf of Mexico Federal Offshore and Alaska, two of the largest U.S. oil-producing areas, reported 10 and 7 percent declines in crude oil proved reserves. This was due to downward revisions and fewer new discoveries. Utah reported the largest increase in crude oil reserves, adding 78 million barrels (a 30 percent increase from 2005), followed by Colorado and New Mexico. Reserves additions of crude oil did not keep pace with production -- operators replaced only 52 percent of 2006 crude oil production with reserves additions.

U.S. crude oil production declined 5 percent in 2006 due mostly to lower Alaskan production. Part of the decline resulted from an August 2006 shut-in of producing wells in half of Prudhoe Bay Field for inspection and repair of corrosion in the gathering system. For the second year in a row Montana had the largest annual oil production increase of any State (6 million barrels; a 20 percent increase) owing to continued development of the Bakken Formation in the Elm Coulee Field. This relatively new and important oil field is difficult to produce and requires cutting-edge technology for economic production.

Total discoveries of crude oil were 577 million barrels in 2006, 49 percent less than the prior 10-year average and 45 percent less than 2005's discoveries of 1,051 million barrels.

The majority of crude oil total discoveries in 2006 came from extensions to fields in Texas, Alaska, the Gulf of Mexico Federal Offshore, Montana, California, New Mexico, and Louisiana.

Operators discovered 504 million barrels in extensions in 2006, 37 percent less than in 2005 and 10 percent less than the prior 10-year average (558 million barrels).

New field discoveries accounted for 30 million barrels of crude oil reserves additions. Seventy percent of these discoveries (21 of 30 million barrels) were in the Gulf of Mexico Federal Offshore. This was 85 percent less than the new field discoveries of 2005 and only 7 percent of the prior 10-year average (428 million barrels).

New reservoir discoveries in old fields were 43 million barrels, 5 percent more than 2005 and 71 percent less than the prior 10-year average (149 million barrels).

Reserves additions are the sum of total discoveries, revisions, adjustments, sales, and acquisitions. In 2006, reserves additions were 867 million barrels, 59 percent less than the volume of reserves additions in 2005 and 54 percent less than the prior 10-year average (1,876 million barrels).

Crude oil net revisions and adjustments were 96 million barrels, 88 percent less than the net revisions and adjustments of 2005 and only 13 percent of the prior 10-year average (759 million barrels). The net of sales and acquisitions of crude oil proved reserves was 194 million barrels.

Other 2006 crude oil events of note:

- The annual average domestic first purchase price for crude oil increased 19 percent from $50.28 per barrel in 2005 to $59.69 per barrel.
- Oil well completions (exploratory and development) were up 28 percent from 2005.

Natural Gas Liquids

Natural gas liquids reserves are the sum of lease condensate reserves and natural gas plant liquids reserves. Natural gas liquids proved reserves increased 4 percent in 2006. Operators replaced 138 percent of U.S. natural gas liquids production with reserves additions.

Total proved reserves of liquid hydrocarbons (crude oil plus natural gas liquids) were 29,444 million barrels in 2006, a 2 percent decrease from the 2005 level. Natural gas liquids represented 29 percent of total liquid hydrocarbon proved reserves in 2006.

Data

These estimates are based upon analysis of data from Form EIA-23, Annual Survey of Domestic Oil and Gas Reserves, filed by 1,501 operators of oil and gas wells, and Form EIA-64A, Annual Report of the Origin of Natural Gas Liquids Production, filed by operators of 496 active natural gas processing plants. The U.S. proved reserves estimates for crude oil and natural gas are associated with sampling errors of less than 1 percent.

1. Introduction

Background

The primary focus of EIA's reserves program is providing 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.

This report provides proved reserves estimates for calendar year 2006. It is based on data filed by large, intermediate, and a select group of small 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 natural 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 during the report year. 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 within a field. 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-23L 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 using statistical calculations that preserved the relative relationships between these items within each State or State subdivision, as reported by large and intermediate operators.

A sample selected from the large group of small (Category III) operators are requested to provide annual production and, if available, year ending reserves volumes on Form EIA-23S. 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
– Sales
+ Acquisitions
+ 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 estimates from 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, different timing of reporting, incorrectly reported data, or imputations for missing or unreported reserve changes can contribute to adjustments.

New Form EIA-23L Element: Type Code

For the 2006 survey, a new Form EIA-23L data element called *Type Code* replaced the underutilized *MMS Code*. The *Type Code* is used to categorize proved reserves and production from a field as either *Conventional* (C) or one of four types of *Unconventional* reservoirs: *Coal Bed* (CB); *Chalk* (CH); *Shale* (SH); or *other Low Permeability* (LP) reservoirs (permeability of 0.1 millidarcy or less).

Type Code was added because the importance of unconventional resources of natural gas and crude oil to domestic energy supply continues to increase.

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 13,820 probable active operators and the Form EIA-64A plant frame contained 491 probable active natural gas processing plants in the United States when the 2006 surveys were initiated.

For more details on the survey process, see Appendix E, Summary of Data Collection Operations.

The 2006 survey sample consisted of 1,355 operators. EIA sampled 872 operators with certainty; 173 Category I operators, 467 Category II operators, and 232 smaller operators that were selected with certainty because of their size in relation to the area or areas in which they operated. EIA also chose 483 Noncertainty operators as a systematic random sample of the remaining operators. There were 11 Successor operators in 2006. Fifty-eight (58) of the 1,355 ceased operating oil and/or gas properties (became non-operator) during the survey year. For more details on the survey response statistics, see Table E2 in Appendix E.

EIA mailed EIA-64A forms to all known natural gas processing plant operators as of February 1, 2006. Response rate was 100 percent from the operators surveyed (see Table E5 in Apppendix E).

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 2006, the Form EIA-23 National production estimates were 1.5 percent lower than the comparable *Petroleum Supply Annual (PSA) 2006* volumes for crude oil and lease condensate combined, and were less than 1 percent higher than the comparable *Natural Gas Monthly, October 2007* volume for 2006 dry natural gas.

Accuracy in reserves reporting is EIA's first and foremost goal for this report. Because of differences in timing and data availability, the estimates of oil and gas production presented in this report may differ from those presented in other EIA reports.

2. Overview

National Summary

The United States had the following proved reserves as of December 31, 2006:

- **Crude Oil — 20,972 million barrels**
- **Dry Natural Gas — 211,085 billion cubic feet**
- **Natural Gas Liquids — 8,472 million barrels.**

This Overview summarizes the 2006 proved reserves balances of crude oil, dry natural gas, and natural gas liquids on a National level and provides historical comparisons between 2006 and prior years. **Table 1** lists the estimated annual reserve balances since 1996 for crude oil, dry natural gas, and natural gas liquids.

Crude Oil

U.S. crude oil proved reserves declined 4 percent (785 million barrels) in 2006. **Figure 1** shows the crude oil proved reserves levels by major region and **Figure 2** shows the components of reserves changes from 1996 through 2006.

As indicated in **Figure 1**, U.S. crude oil proved reserves declined slightly (1 percent) onshore in the lower 48 States in 2006, but declined more in Alaska (7 percent) and the Gulf of Mexico Federal Offshore (10 percent).

The components of reserves changes for crude oil are shown in **Figure 2**. EIA tracks all components of reserves changes: adjustments, revision increases, revision decreases, sales, acquisitions, extensions, new field discoveries, new reservoir discoveries in old fields, and estimated production. These components are discussed below.

Total discoveries 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. Total discoveries of crude oil were 577 million barrels in 2006, 49 percent less than the prior 10-year average (1,135 million barrels) and 45 percent less than 2005's discoveries of 1,051 million barrels.

The majority of crude oil total discoveries in 2006 came from extensions to fields in Texas, Alaska, the Gulf of Mexico, and Montana.

Operators discovered 504 million barrels in extensions in 2006, 37 percent less than in 2005 and 10 percent less than the prior 10-year average (558 million barrels).

New field discoveries accounted for 30 million barrels of crude oil total discoveries. This was 85 percent less than the new field discoveries of 2005 (205 million barrels), and only 7 percent of the prior 10-year average (428 million barrels). Seventy percent of these discoveries (21 of 30 million) were in the Gulf of Mexico Federal Offshore.

New reservoir discoveries in old fields were 43 million barrels in 2006, 5 percent more than 2005 and 71 percent less than the prior 10-year average (149 million barrels).

Reserves additions are the sum of total discoveries, revisions, adjustments, sales, and acquisitions. In 2006, crude oil reserves additions were 867 million barrels, 59 percent less than in 2005 and 54 percent less than the prior 10-year average (1,876 million barrels).

Crude oil net revisions and adjustments were 96 million barrels, 88 percent less than the net revisions and adjustments of 2005 and 87 percent less than the prior 10-year average (759 million barrels). The net of sales and acquisitions of crude oil proved reserves was 194 million barrels.

U.S. crude oil production declined 5 percent in 2006 due mostly to lower Alaskan production. Part of the decline resulted from an August 2006 shut-in of producing wells in half of Prudhoe Bay Field for inspection and repair of corrosion in the gathering system. For the second year in a row Montana had the largest annual oil production increase of any State (6 million barrels; a 20 percent increase) owing to continued development of the Bakken Formation in the Elm Coulee Field. Reserves additions of crude oil replaced only 52 percent of 2006 crude oil production.

Dry Natural Gas

Natural gas proved reserves increased by 6,700 billion cubic feet in 2006. **Figure 3** shows the dry natural gas proved reserves levels by major region. It indicates that additions of gas reserves in the Lower 48 onshore are raising the National total despite declining Federal

Table 1. Total U.S. Proved Reserves of Crude Oil, Dry Natural Gas, and Natural Gas Liquids, 1996-2006

Year	Adjustments (1)	Net Revisions (2)	Revisions[a] and Adjustments (3)	Net of Sales[b] and Acquisitions (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)
					Crude Oil (million barrels of 42 U.S. gallons)						
1996	175	737	912	NA	543	243	141	927	2,173	22,017	-334
1997	520	914	1,434	NA	477	637	119	1,233	2,138	22,546	+529
1998	-638	518	-120	NA	327	152	120	599	1,991	21,034	-1,512
1999	139	1,819	1958	NA	259	321	145	725	1,952	21,765	+731
2000	143	746	889	-20	766	276	249	1,291	1,880	22,045	+280
2001	-4	-158	-162	-87	866	1,407	292	2,565	1,915	22,446	+401
2002	416	720	1,136	24	492	300	154	946	1,875	22,677	+231
2003	163	94	257	-398	426	705	101	1,232	1,877	21,891	-786
2004	74	420	494	23	617	33	132	782	1,819	21,371	-520
2005	221	569	790	278	805	205	41	1,051	1,733	21,757	+386
2006	94	2	96	194	504	30	43	577	1,652	20,972	-785
					Dry Natural Gas (billion cubic feet, 14.73 psia, 60° Fahrenheit)						
1996	3,785	4,086	7,871	NA	7,757	1,451	3,110	12,318	18,861	166,474	+1,328
1997	-590	4,902	4,312	NA	10,585	2,681	2,382	15,648	19,211	167,223	+749
1998	-1,635	5,740	4,105	NA	8,197	1,074	2,162	11,433	18,720	164,041	-3,182
1999	982	10,504	11,486	NA	7,043	1,568	2,196	10,807	18,928	167,406	+3,365
2000	-891	6,962	6,071	4,031	14,787	1,983	2,368	19,138	19,219	177,427	+10,021
2001	2,742	-2,318	424	2,630	16,380	3,578	2,800	22,758	19,779	183,460	+6,033
2002	3,727	937	4,664	380	14,769	1,332	1,694	17,795	19,353	186,946	+3,486
2003	2,841	-1,638	1,203	1,034	16,454	1,222	1,610	19,286	19,425	189,044	+2,098
2004	-114	744	630	1,844	18,198	759	1,206	20,163	19,168	192,513	+3,469
2005	1,887	2,699	4,586	2,544	21,050	942	1,208	23,200	18,458	204,385	+11,872
2006	743	-1,836	-1,093	2,996	21,778	409	1,155	23,342	18,545	211,085	+6,700
					Natural Gas Liquids (million barrels of 42 U.S. gallons)						
1996	474	175	649	NA	451	65	109	625	850	7,823	+424
1997	-15	289	274	NA	535	114	90	739	864	7,973	+150
1998	-361	208	-153	NA	383	66	88	537	833	7,524	-449
1999	99	727	826	NA	313	51	88	452	896	7,906	+382
2000	-83	459	376	145	645	92	102	839	921	8,345	+439
2001	-429	-132	-561	102	717	138	142	997	890	7,993	-352
2002	62	31	93	54	612	48	78	738	884	7,994	+1
2003	-338	-161	-499	30	629	35	72	736	802	7,459	-535
2004	273	97	370	112	734	26	54	814	827	7,928	+469
2005	-89	21	-68	156	863	32	42	937	788	8,165	+237
2006	173	-165	8	117	924	16	53	993	811	8,472	+307

[a]Revisions and adjustments = Col. 1 + Col. 2.
[b]Net of sales and acquisitions = acquisitions - sales.
[c]Total discoveries = Col. 5 + Col. 6 + Col. 7.
[d]Proved reserves = Col. 10 from prior year + Col. 3 + Col. 4 + Col. 8 - Col. 9.
NA=Not available.

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 2006 contained in the *Petroleum Supply Annual 2006*, DOE/EIA-0340(06) and the *Natural Gas Annual 2006, DOE/EIA-0131(06).*

Figure 1. U.S. Crude Oil Proved Reserves, 1996-2006

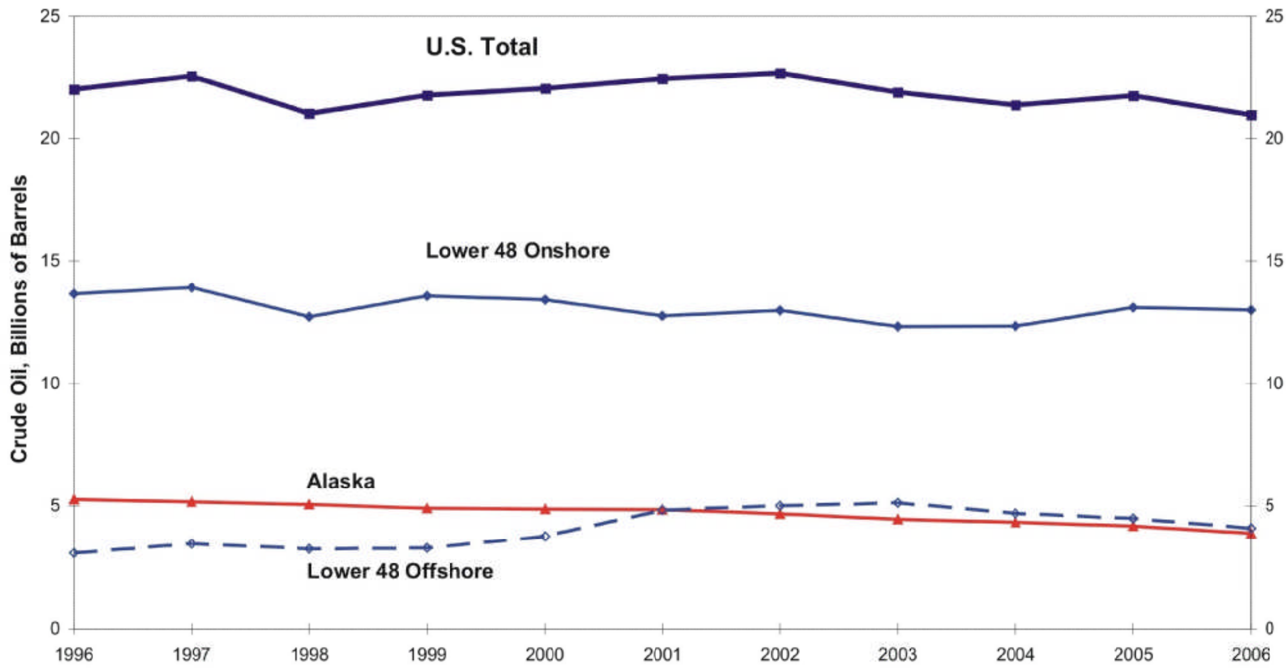
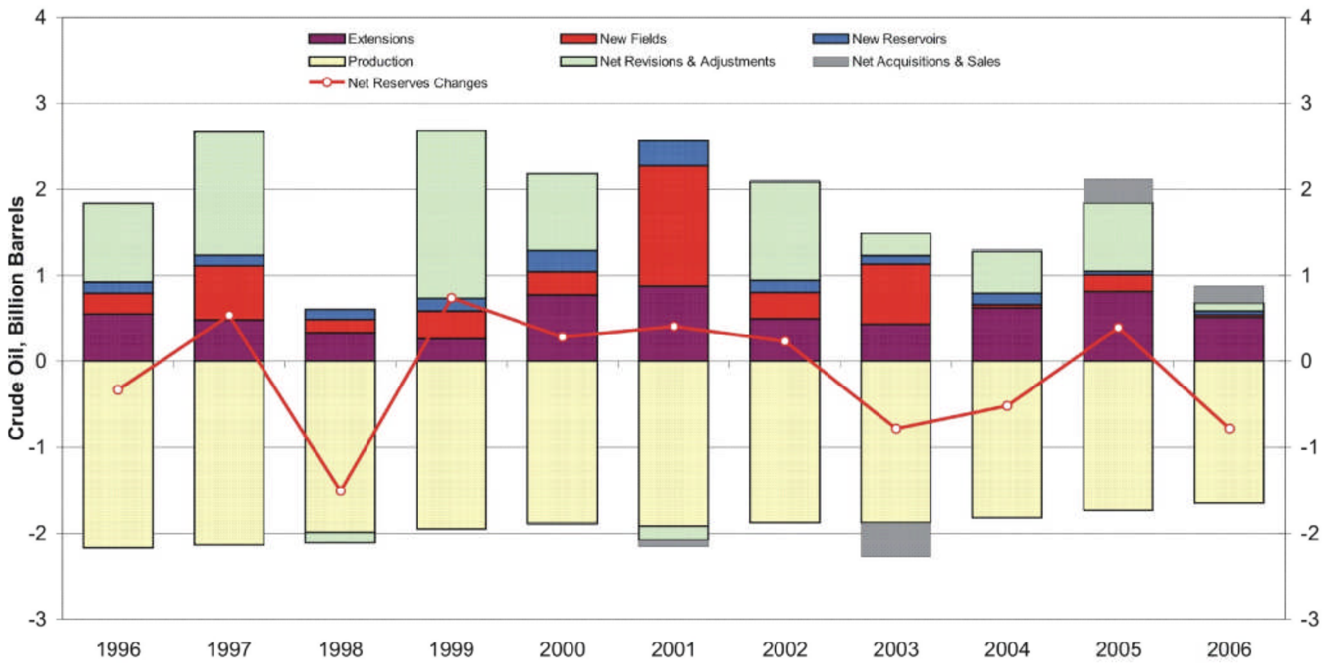


Figure 2. Components of Reserves Changes for Crude Oil, 1996-2006



Source: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1996-2005 annual reports, DOE/EIA-0216.{20-29}

Figure 3. U.S. Dry Natural Gas Proved Reserves, 1996-2006

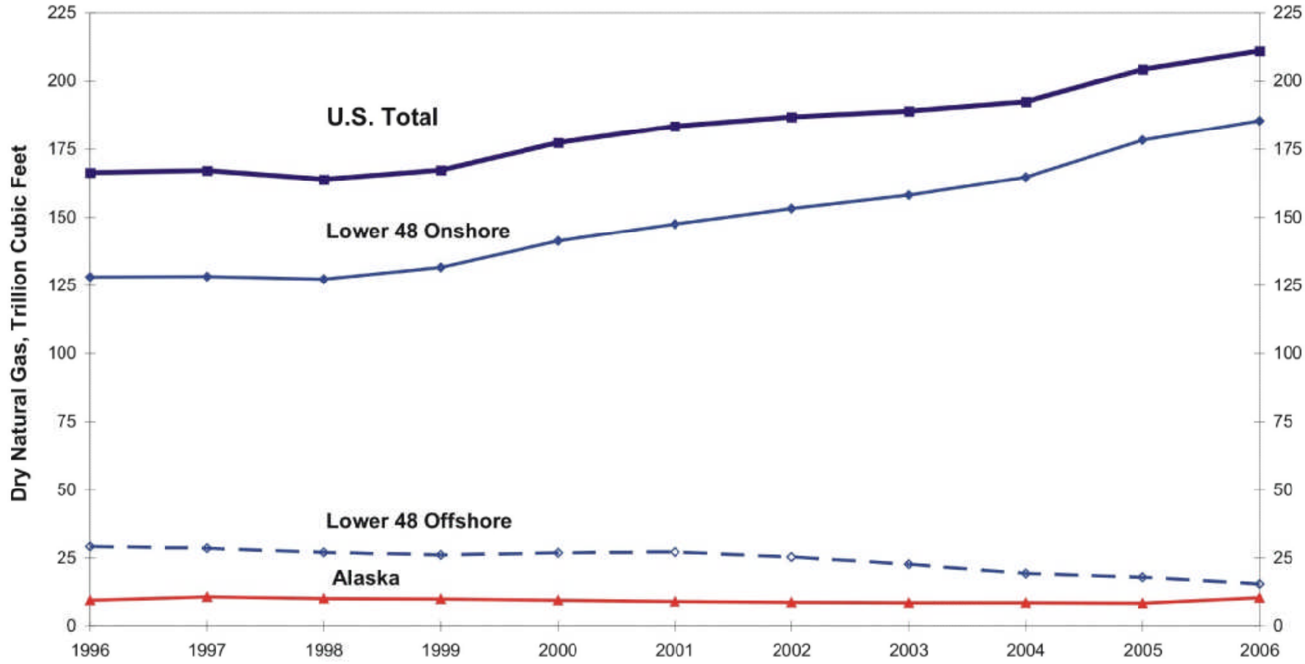
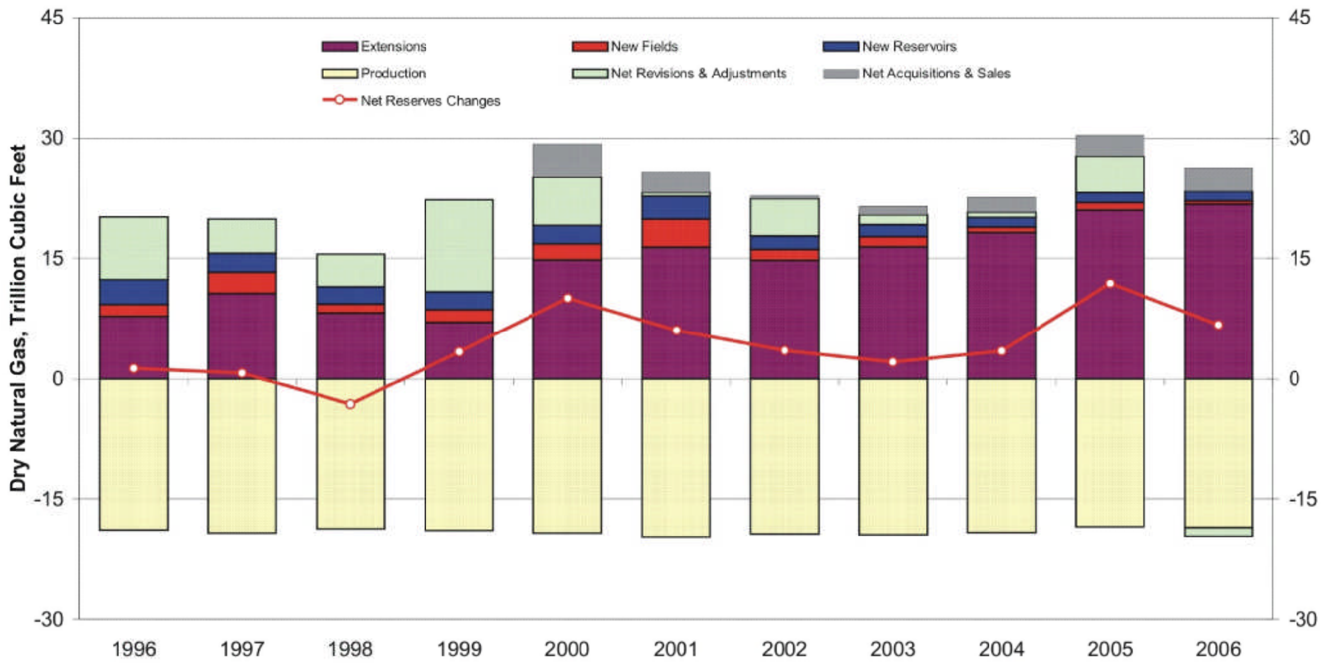


Figure 4. Components of Reserves Changes for Dry Natural Gas, 1996-2006



Source: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1996-2005 annual reports, DOE/EIA-0216.{20-29}

offshore gas reserves. **Figure 4** shows the components of reserves changes from 1996 through 2006.

Total discoveries of dry natural gas reserves, which is the sum of field extensions, new field discoveries, and new reservoir discoveries in old fields, were 23,342 billion cubic feet in 2006. This was 35 percent more than the prior 10-year average (17,255 billion cubic feet) and 1 percent more than in 2005.

The majority of natural gas total discoveries in 2006 were from extensions to existing fields. Field extensions were 21,778 billion cubic feet, 4 percent more than in 2005 and 61 percent more than the prior 10-year average (13,522 billion cubic feet).

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Natural gas net revisions and adjustments were a net loss of 1,093 billion cubic feet in 2006. The prior occurrence of negative net revisions was in 1988. The net of sales and acquisitions of dry natural gas proved reserves was 2,996 billion cubic feet.

Total U.S. natural gas production increased slightly in 2006 due to production increases in Texas (Barnett Shale), Louisiana, and the Rocky Mountain states (Colorado, Wyoming, Utah, and Montana). Gulf of Mexico natural gas production declined the most with a 6 percent drop.

Coalbed natural gas reserves decreased 1 percent in 2006 and accounted for 9 percent of U.S. dry natural gas reserves. Coalbed natural gas production increased 2 percent in 2006 and accounted for 9 percent of U.S. dry natural gas production.

Natural Gas Liquids

Natural gas liquids reserves are the sum of lease condensate reserves and natural gas plant liquids reserves. Natural gas liquids proved reserves increased 4 percent in 2006. Operators replaced 138 percent of U.S. natural gas liquids production with reserves additions.

Total proved reserves of liquid hydrocarbons (crude oil plus natural gas liquids) were 29,444 million barrels in 2006, a 2 percent decrease from the 2005 level. Natural gas liquids represented 29 percent of total liquid hydrocarbon proved reserves in 2006.

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 1977 through 2006. The table has 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 2006 proved reserves estimates as a means of gauging the past year against history.

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

- had average annual new reserves discoveries of 895 million barrels,
- had average annual proved reserves additions of 2,027 million barrels from total discoveries, net revisions and adjustments, and net sales and acquisitions, and
- had an average annual proved reserves decline of 418 million barrels Nationwide, because production exceeded reserve additions.

Since 1977, crude oil reserves have primarily been sustained by proved ultimate recovery appreciation in existing fields rather than by the discovery of new oil fields. Only 11 percent of reserves additions since 1977 were booked as new field discoveries. Proved ultimate recovery appreciation is the sum of net revisions, adjustments, net sales and acquisitions, extensions, and new reservoir discoveries in old fields (see the Proved Ultimate Recovery section later in this chapter.) Since 1977, the 26,837 million barrels of total discoveries accounted for 44 percent of reserves additions.

Compared to the averages of reserves changes since 1977, 2006 was a down year for crude oil discoveries. Total discoveries of crude oil (577 million barrels) in 2006 were 36 percent less than the post-1976 U.S. average (895 million barrels per year).

Looking at the components of total discoveries in 2006:

- Extensions in 2006 (504 million barrels) were slightly less than the post-1976 average (525 million barrels),

Figure 5. U.S. Natural Gas Liquids Proved Reserves, 1996-2006

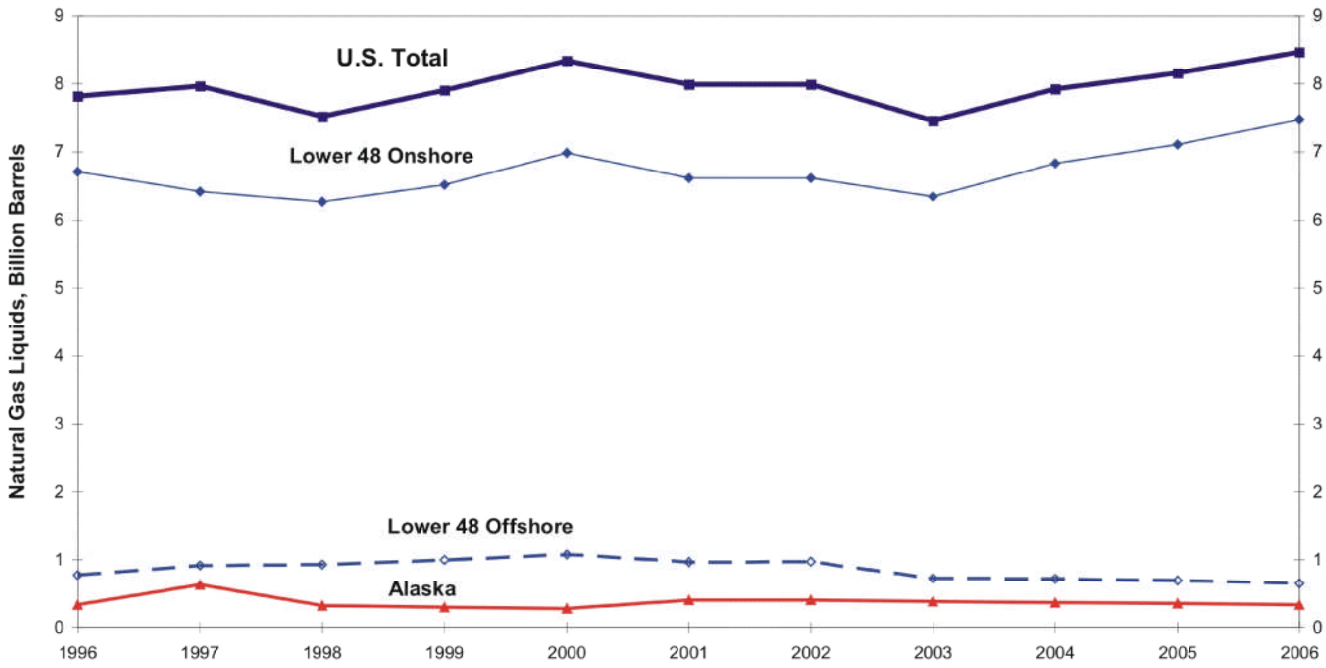
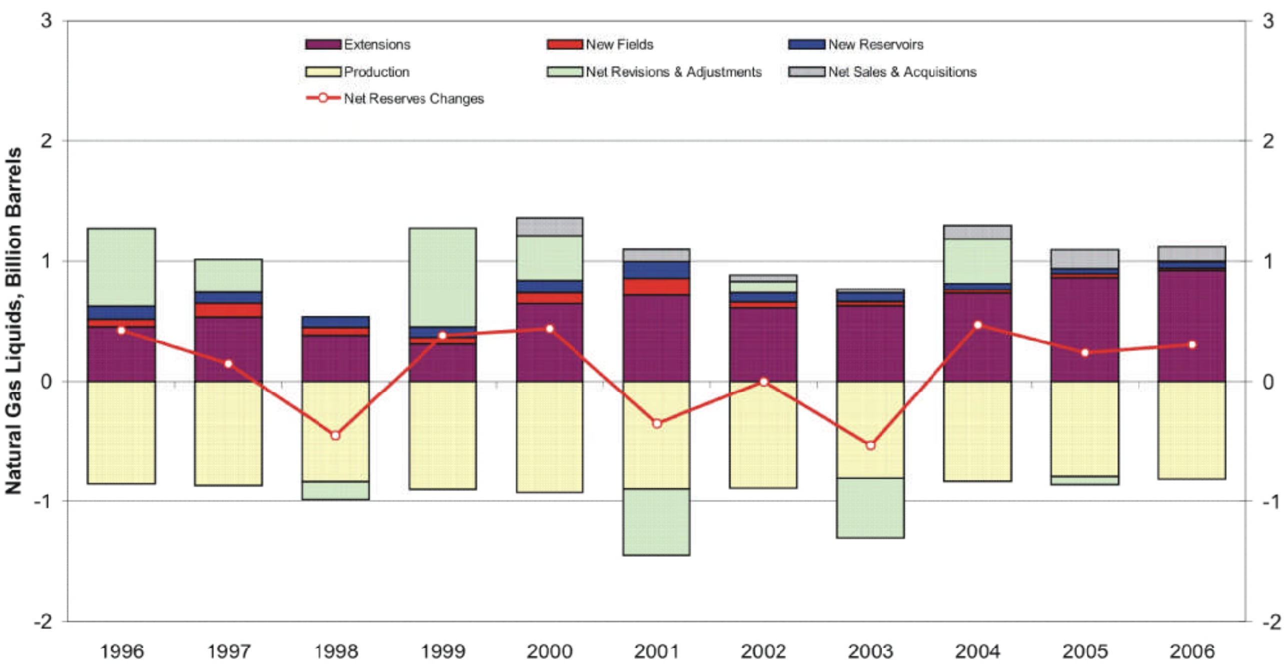


Figure 6. Components of Reserves Changes for Natural Gas Liquids, 1996-2006



Source: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1996-2005 annual reports, DOE/EIA-0216.{20-29}

Table 2. Reserves Changes, 1977-2006

Components of Change	Lower 48 States Volume	Lower 48 States Average per Year	Lower 48 States Percent of Reserves Additions	U.S. Total Volume	U.S. Total Average per Year	U.S. Total Percent of Reserves Additions
	Crude Oil (million barrels of 42 U.S. gallons)					
Proved Reserves as of 12/31/76	**24,928**	**—**	**—**	**33,502**	**—**	**—**
New Field Discoveries	5,960	199	11.9	6,911	230	11.4
New Reservoir Discoveries in Old Fields	3,998	133	8.0	4,186	140	6.9
Extensions	13,882	463	27.7	15,740	525	25.9
Total Discoveries	**23,840**	**795**	**47.6**	**26,837**	**895**	**44.1**
Revisions, Adjustments, Sales & Acquisitions[a]	26,295	877	52.4	33,972	1,132	55.9
Total Reserves Additions	**50,135**	**1,671**	**100.0**	**60,809**	**2,027**	**100.0**
Production	**57,906**	**1,930**	**115.5**	**73,339**	**2,445**	**120.6**
Net Reserves Change (since 1976)	**-7,771**	**-259**	**-15.5**	**-12,530**	**-418**	**-20.6**
	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	54,258	1,809	9.9	54,522	1,817	10.1
New Reservoir Discoveries in Old Fields	70,441	2,348	12.8	70,902	2,363	13.1
Extensions	292,309	9,744	53.1	295,631	9,854	54.8
Total Discoveries	**417,008**	**13,900**	**75.7**	**421,055**	**14,035**	**78.0**
Revisions, Adjustments, Sales & Acquisitions[a]	133,573	4,452	24.3	118,544	3,951	22.0
Total Reserves Additions	**550,581**	**18,353**	**100.0**	**539,599**	**17,987**	**100.0**
Production	**530,579**	**17,686**	**96.4**	**541,792**	**18,060**	**100.4**
Net Reserves Change (since 1976)	**20,002**	**667**	**3.6**	**-2,193**	**-73**	**-0.4**

[a] EIA did not separately collect data on sales and acquisitions of proved reserves until the year 2000.
Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves* 1977-2006 annual reports, DOE/EIA-0216.{1-29}

- 2006's new field discoveries (30 million barrels) were 87 percent less than the post-1976 average for crude oil (230 million barrels), and
- New reservoir discoveries in old fields (43 million barrels) in 2006 were 69 percent less than the post-1976 average (140 million barrels).

Revisions, Adjustments, Sales & Acquisitions were 290 million barrels in 2006. This was 74 percent less than the post-1976 average of 1,132 million barrels per year.

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

- had average annual new reserves discoveries of 14,035 billion cubic feet,
- had average annual proved reserves additions of 17,987 billion cubic feet from total discoveries, net revisions and adjustments, and net sales and acquisitions, and
- had an average annual production of 18,060 billion cubic feet, decreasing U.S. dry natural gas reserves by an average 73 billion cubic feet per year.

Like crude oil reserves, natural gas reserves have primarily been sustained by proved ultimate recovery appreciation since 1977. For gas, extensions rather than net revisions and adjustments are usually the largest component. Extensions accounted for 55 percent of all reserves additions since 1977 while net revisions, adjustments, sales, and acquisitions accounted for only 22 percent.

Compared to the averages of reserves changes since 1977, 2006 was an up year for dry natural gas total discoveries. Operators reported 23,342 billion cubic feet of total discoveries of dry natural gas proved reserves, 66 percent more than the post-1976 average (14,035 billion cubic feet).

The net of revisions, adjustments, sales, and acquisitions was 1,903 billion cubic feet in 2006, 52 percent lower than the post-1976 U.S. average (3,951 billion cubic feet per year).

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, 1977-2006

Year		Crude Oil		Natural Gas		
		Current	2006 Constant	Current	2006 Constant	
		(dollars per barrel)		(dollars per thousand cubic feet)		Number of Rigs
1977		8.57	22.22	0.79	2.05	2,001
1978		9.00	21.78	0.91	2.20	2,259
1979		12.64	28.24	1.18	2.64	2,177
1980		21.59	44.16	1.59	3.25	2,909
1981		31.77	59.45	1.98	3.70	3,970
1982		28.52	50.23	2.46	4.33	3,105
1983		26.19	44.38	2.59	4.39	2,232
1984		25.88	42.28	2.66	4.35	2,428
1985		24.09	38.15	2.51	3.97	1,980
1986		12.51	19.38	1.94	3.01	964
1987		15.40	23.17	1.67	2.51	936
1988		12.58	18.30	1.69	2.46	936
1989		15.86	22.23	1.69	2.37	869
1990		20.03	27.01	1.71	2.31	1,010
1991		16.54	21.53	1.64	2.13	860
1992		15.99	20.32	1.74	2.21	721
1993		14.25	17.68	2.04	2.53	754
1994		13.19	16.03	1.85	2.25	775
1995		14.62	17.39	1.55	1.84	723
1996		18.46	21.54	2.17	2.53	779
1997		17.23	19.72	2.32	2.66	943
1998		10.87	12.29	1.96	2.22	827
1999		15.56	17.35	2.19	2.44	625
2000		26.72	29.17	3.68	4.02	918
2001		21.84	23.29	4.00	4.27	1,156
2002		22.51	23.74	2.95	3.11	830
2003		27.56	28.60	4.88	5.06	1,032
2004		36.77	38.16	5.46	5.67	1,192
2005	January	40.18	41.23	5.80	5.95	1,255
	February	42.19	43.23	5.74	5.88	1,276
	March	47.56	48.67	5.95	6.09	1,306
	April	47.26	48.30	6.58	6.72	1,334
	May	44.03	44.94	6.24	6.37	1,320
	June	49.83	50.79	6.09	6.21	1,355
	July	53.35	54.32	6.71	6.83	1,398
	August	58.90	59.89	6.48	6.59	1,436
	September	59.64	60.56	8.96	9.10	1,452
	October	56.99	57.77	10.35	10.49	1,479
	November	53.20	53.84	9.91	10.03	1,486
	December	53.24	53.79	9.08	9.17	1,470
2005	**Average**	**50.28**	**51.15**	**7.33**	**7.46**	**1,381**
2006	January	57.85	58.32	8.66	8.73	1,473
	February	55.69	56.05	7.28	7.33	1,533
	March	55.64	55.92	6.52	6.55	1,551
	April	62.52	62.75	6.59	6.61	1,597
	May	64.40	64.55	6.19	6.20	1,635
	June	64.65	64.71	5.80	5.81	1,665
	July	67.71	67.69	5.82	5.82	1,681
	August	67.21	67.09	6.51	6.50	1,738
	September	59.37	59.17	5.51	5.49	1,739
	October	53.26	52.99	5.03	5.00	1,734
	November	52.42	52.06	6.43	6.39	1,706
	December	55.03	54.55	6.65	6.59	1,718
2006	**Average**	**59.69**	**59.69**	**6.42**	**6.42**	**1,649**

Sources: Crude oil first purchase prices, natural gas wellhead prices, and number of rigs: Tables 9.1, 9.11, and 5.1, *Monthly Energy Review October 2007*, DOE/EIA-0035(2007/10). 2006 constant dollars: U.S. Department of Commerce, Bureau of Economic Analysis, Gross Domestic Product Implicit Price Deflators, October 2007.

For the eighth year in a row (and 12 out of the last 13 years), the annual change to the National total of gas reserves has been positive, not negative.

Economics and Drilling

Economics: Table 3 lists the average annual domestic wellhead prices of crude oil and natural gas from 1977 to 2006.

In 2006, the U.S. crude oil first purchase price started at a monthly average of $57.85 per barrel in January, rose to a high of $67.71 in July, and ended the year at $55.03 per barrel in December. The average annual U.S. crude oil first purchase price increased from $50.28 in 2005 to $59.69 per barrel in 2006.

Oil prices vary by region. The average annual 2006 crude oil first purchase price ranged from $64.23 per barrel in Louisiana to $63.80 per barrel in Colorado, $61.31 per barrel in Texas, $57.34 per barrel in California, and a low of $51.85 per barrel in South Dakota. {30}

The average annual wellhead natural gas price decreased from $7.33 per thousand cubic feet in 2005 to $6.42 in 2006. Monthly average natural gas prices started at $8.66 per thousand cubic feet in January 2006, declined to $5.03 in October, and ended the year at $6.65 per thousand cubic feet in December 2006. {31}

Drilling: Also listed in **Table 3** is the average number of active rotary drilling rigs from 1977 to 2006. From 2005 to 2006, the annual average active rig count rose from 1,381 to 1,649, a 19 percent increase.

Looking first at exploratory wells, there were 4,005 exploratory wells drilled in 2006 (**Table 4**). Of these, 14 percent were completed as oil wells, 39 percent were completed as gas wells, and 47 percent were dry holes. Exploratory oil and gas completions (excluding dry holes) in 2006 were 8 percent more (**Figure 7**) than the revised 2005 total.

Figures 9 and 10 show the average volume of discoveries per exploratory well for dry natural gas and oil, respectively, since 1977. The 2006 average volume of oil discoveries per exploratory well decreased 57 percent compared to 2005. The 2006 average volume of gas discoveries per exploratory well decreased 1 percent compared to 2005.

The number of successful development wells increased by 28 percent for oil and by 18 percent for gas from their 2005 levels (**Figure 8**). Including dry holes, there were an estimated 49,507 exploratory and development wells drilled in 2006. This is 22 percent more than in 2005 and 73 percent more than the average number of wells drilled annually in the prior 10 years (28,630).

For the thirteenth 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

The following large mergers and acquisitions were announced in 2006 and are expected to have an impact on the energy industry in the future:

On December 13, 2005, ConocoPhillips Company (ConocoPhillips) announced that it had agreed to acquire Burlington Resources Incorporated for about $35.6 billion of cash and stock. Additionally, ConocoPhillips would assume approximately $1,078 million of Burlington Resources debt. Burlington's natural gas assets in North America would balance political risks in [ConocoPhillips'] Venezuelan and Russian ventures. {32}

On June 23, 2006, Anadarko Petroleum Corporation agreed to acquire Kerr-McGee Corporation and Western Gas Resources Incorporated for $21.1 billion plus the assumption of about $2.2 billion of debt. The resulting company would have industry-leading positions in the deepwater Gulf of Mexico and the Rockies. {33}

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.

Table 4. U.S. Exploratory and Development Well Completions,[a] 1973-2006

Year	Exploratory				Total Exploratory and Development			
	Oil	Gas	Dry	Total	Oil	Gas	Dry	Total
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	1,777	2,099	9,081	12,957	32,959	17,461	20,785	71,205
1981	2,651	2,522	12,400	17,573	43,887	20,250	27,953	92,090
1982	2,437	2,133	11,307	15,877	39,459	19,076	26,379	84,914
1983	2,030	1,605	10,206	13,841	37,366	14,684	24,355	76,405
1984	2,209	1,528	11,321	15,058	42,906	17,338	25,884	86,128
1985	1,680	1,200	8,954	11,834	35,261	14,324	21,211	70,796
1986	1,084	797	5,567	7,448	19,213	8,599	12,799	40,611
1987	926	756	5,052	6,734	16,210	8,096	11,167	35,473
1988	855	747	4,711	6,313	13,646	8,578	10,119	32,343
1989	607	706	3,934	5,247	10,230	9,522	8,236	27,988
1990	664	693	3,793	5,150	12,445	11,126	8,496	32,067
1991	601	544	3,390	4,535	12,035	9,611	7,882	29,528
1992	498	427	2,550	3,475	9,019	8,305	6,284	23,608
1993	509	541	2,509	3,559	8,764	10,174	6,513	25,451
1994	579	740	2,465	3,784	7,001	9,739	5,515	22,255
1995	549	583	2,279	3,411	7,827	8,454	5,319	21,600
1996	496	591	2,246	3,333	8,760	9,539	5,587	23,886
1997	434	543	2,178	3,155	10,445	11,186	5,955	27,586
1998	286	510	1,649	2,445	6,979	11,127	4,805	22,911
1999	156	519	1,167	1,842	4,314	11,121	3,504	18,939
2000	267	615	1,349	2,231	7,585	16,242	4,046	27,873
2001	330	972	1,716	3,018	8,186	21,403	4,432	34,021
2002	239	701	1,283	2,223	6,226	16,728	3,610	26,564
2003	326	892	1,266	2,484	7,465	19,522	3,688	30,675
2004 R	368	1,323	1,200	2,891	7,806	21,816	3,474	33,096
2005 R	448	1,532	1,358	3,338	9,668	27,014	4,063	40,745
2006	576	1,559	1,870	4,005	12,339	31,587	5,581	49,507

[a]Excludes service wells and stratigraphic and core testing.
R = Revised Data.

Notes: Estimates include only the original drilling of a hole intended to discover of further develop already discovered oil or gas resources. Other drilling activities, such as drilling an old well deeper, drilling of laterals from the original well, drilling of service and injection wells, and drilling for resources other than oil and gas are excluded.
Source: Table 5.2, EIA *Monthly Energy Review October 2007*, DOE/EIA-0035(2007/10).

Figure 7. U.S. Exploratory Well Completions, 1996-2006

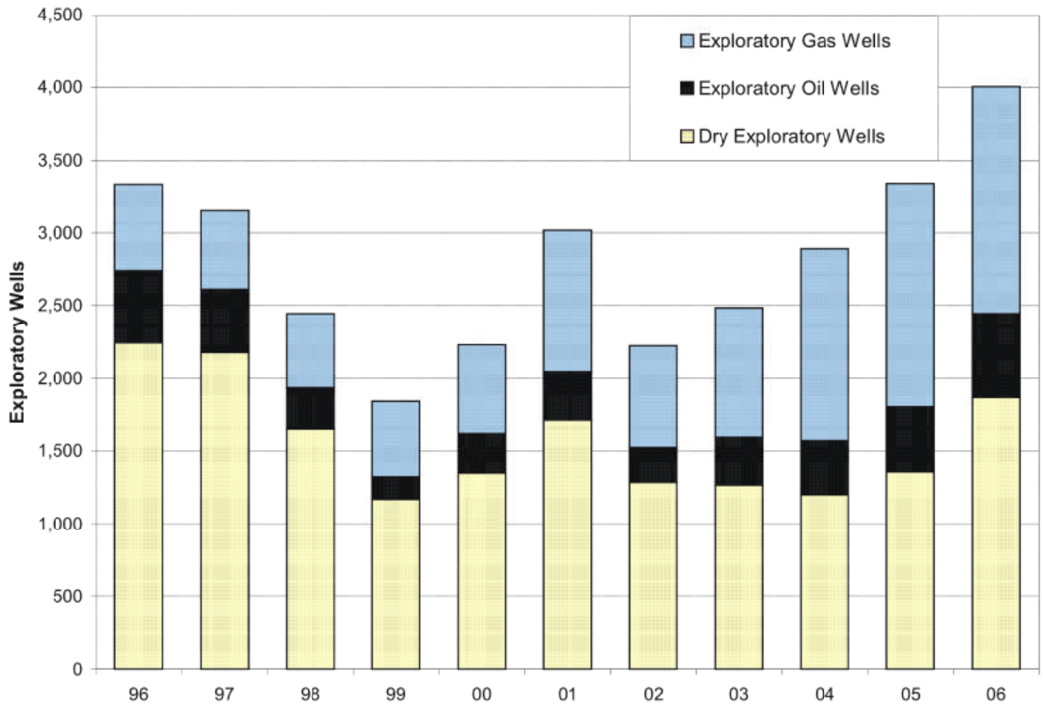
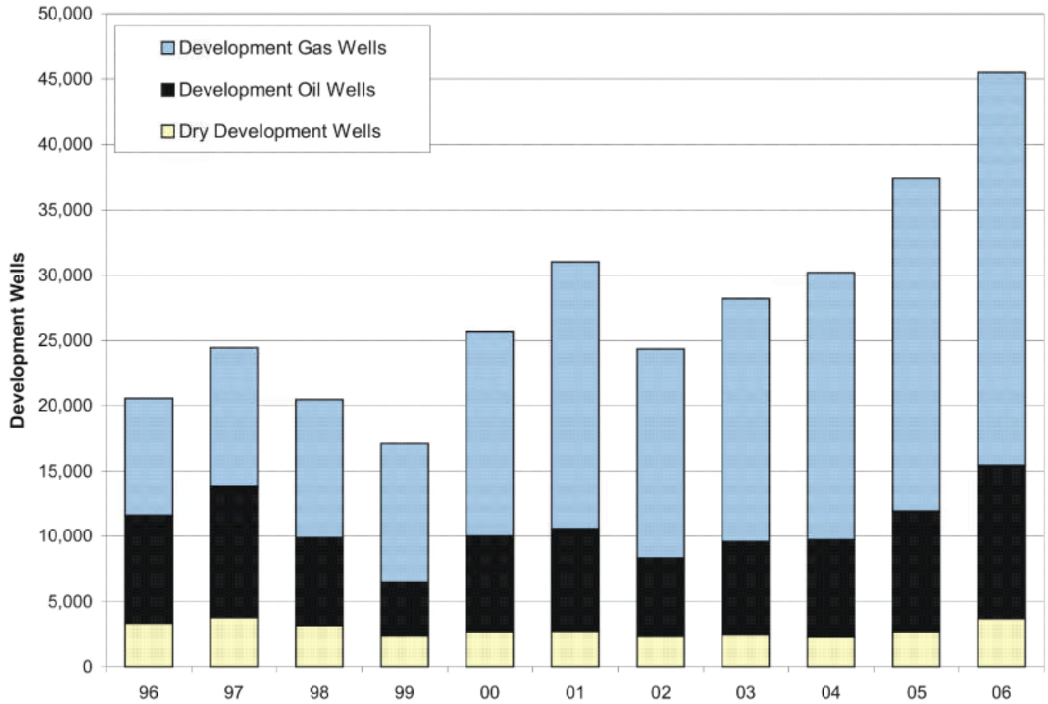


Figure 8. U.S. Development Well Completions, 1996-2006



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

Figure 9. U.S. Total Discoveries of Dry Natural Gas per Exploratory Gas Well Completion, 1977-2006

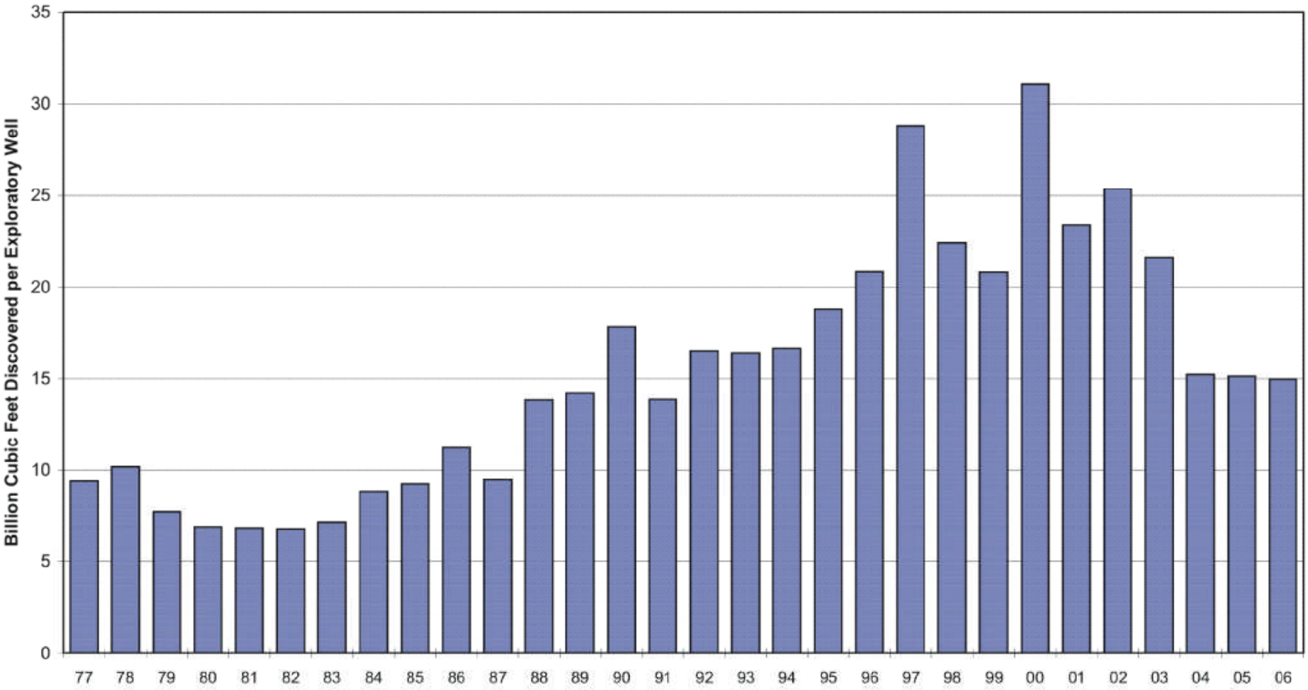
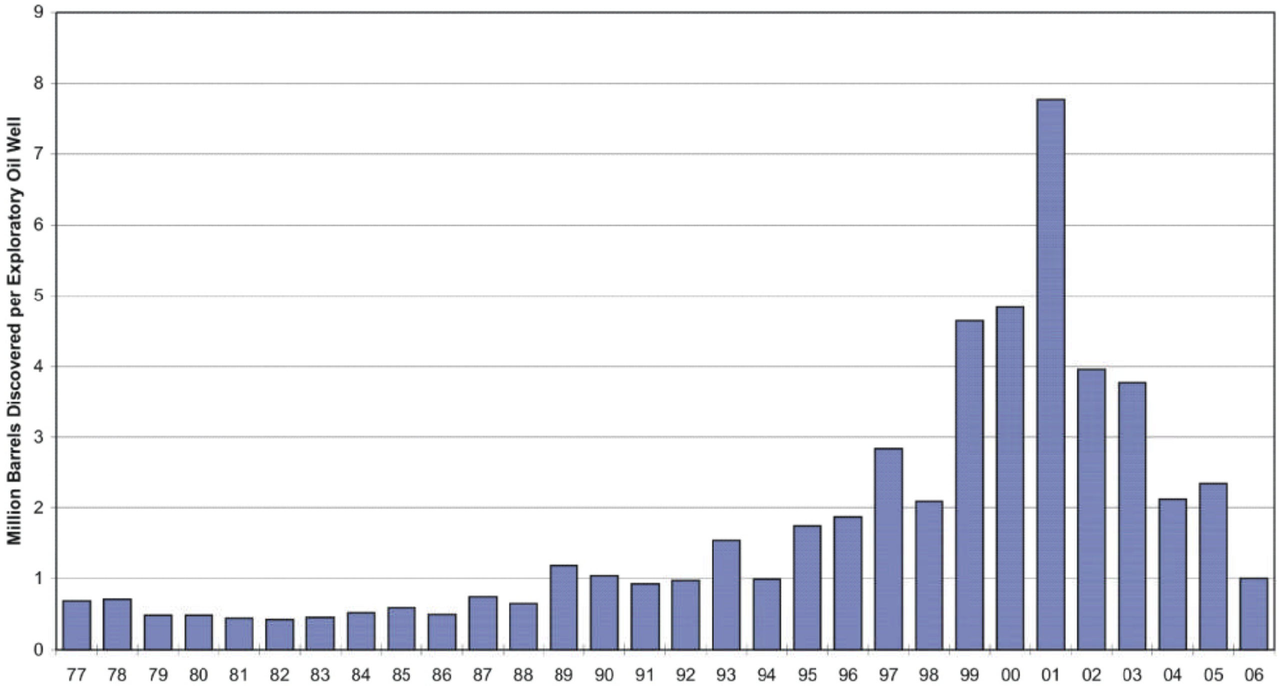


Figure 10. U.S. Total Discoveries of Crude Oil per Exploratory Oil Well Completion, 1977-2006



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

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 and reserves development reached high levels.

In 2006, U.S. crude oil proved reserves decreased and oil production decreased, increasing the National average R/P ratio from 12.6 to 12.7.

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, because of differences in development history and reservoir conditions. The 2006 National average R/P ratio for crude oil was 12.7-to-1. 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 the 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 to 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 natural gas grew rapidly after World War II, lowering the R/P ratio. From 2005 to 2006 the U.S. average R/P ratio for natural gas increased from 11.1 to 11.4 since proved reserves increased more than production increased.

Different marketing, transportation, and production characteristics for gas are seen when looking at regional average R/P ratios as compared to the 2006 U.S. average R/P ratio of about 11.4-to-1. Areas with a higher range of R/P ratios than the National average were the Pacific offshore and the Rockies. Several major gas producing areas have R/P ratios below the National average, particularly Texas, the Gulf of Mexico Federal Offshore, and Oklahoma.

Proved Ultimate Recovery

Proved Ultimate Recovery is the sum of proved reserves and cumulative production at a specified point in time. It measures the maximum recoverable volume *known* at that time and is a dynamic quantity that is expected to change over time for any field, group of fields, State, or Country. In most instances, therefore, an estimate of Proved Ultimate Recovery does not represent the all-time maximum recoverable volume of resources for a given field or area. In fact, the proved ultimate recovery of a field, a group of fields, a State, a region, or a country grows (appreciates) over time in most instances.

Figures 13 and 14 show successive estimates of proved ultimate recovery for the United States. The figures show proved reserves and cumulative production for *crude oil plus lease condensate* and *wet natural gas*, over the period 1977 through 2006. They illustrate the continued appreciation (growth) of proved ultimate recovery over time.

In 1977, U.S. *crude oil plus lease condensate* proved reserves were 33,615 million barrels. Cumulative production of *crude oil plus lease condensate* for 1977 through 2006 was 75,474 million barrels. This substantially exceeds the 1977 proved reserves, but at the end of 2006 there were still 22,312 million barrels of *crude oil plus 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* phenomenon that typically accompanies the continued development of old fields. In fact, only 11 percent of proved reserves additions of crude oil were booked as *new field discoveries* from 1976 through 2006. The other 89 percent came from the proved reserves categories related to the proved ultimate recovery appreciation process.

Similarly, the 1977 *wet natural gas* proved reserves were 209,490 billion cubic feet, but 551 trillion cubic feet of gas was produced from 1977 through 2006 and there are still 220,416 billion cubic feet of *wet natural gas* proved reserves in 2006. Only 10 percent of proved

Figure 11. Reserves-to-Production Ratios for Crude Oil, 1945-2006

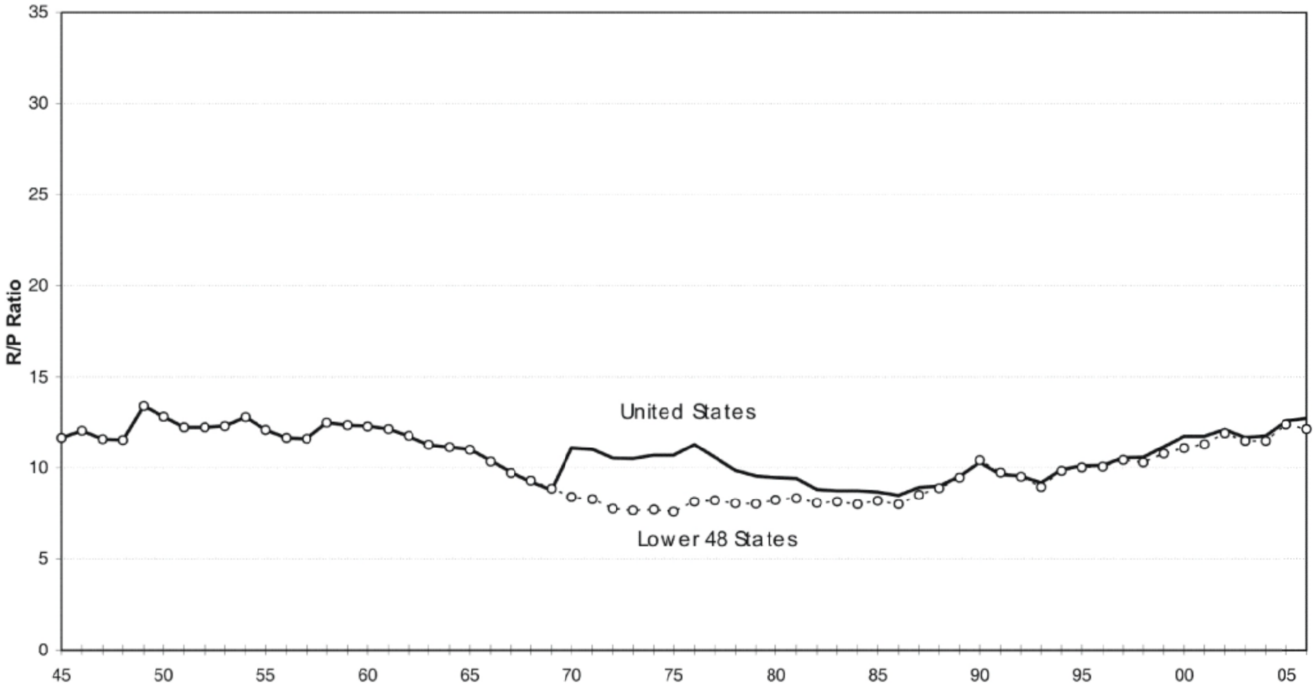
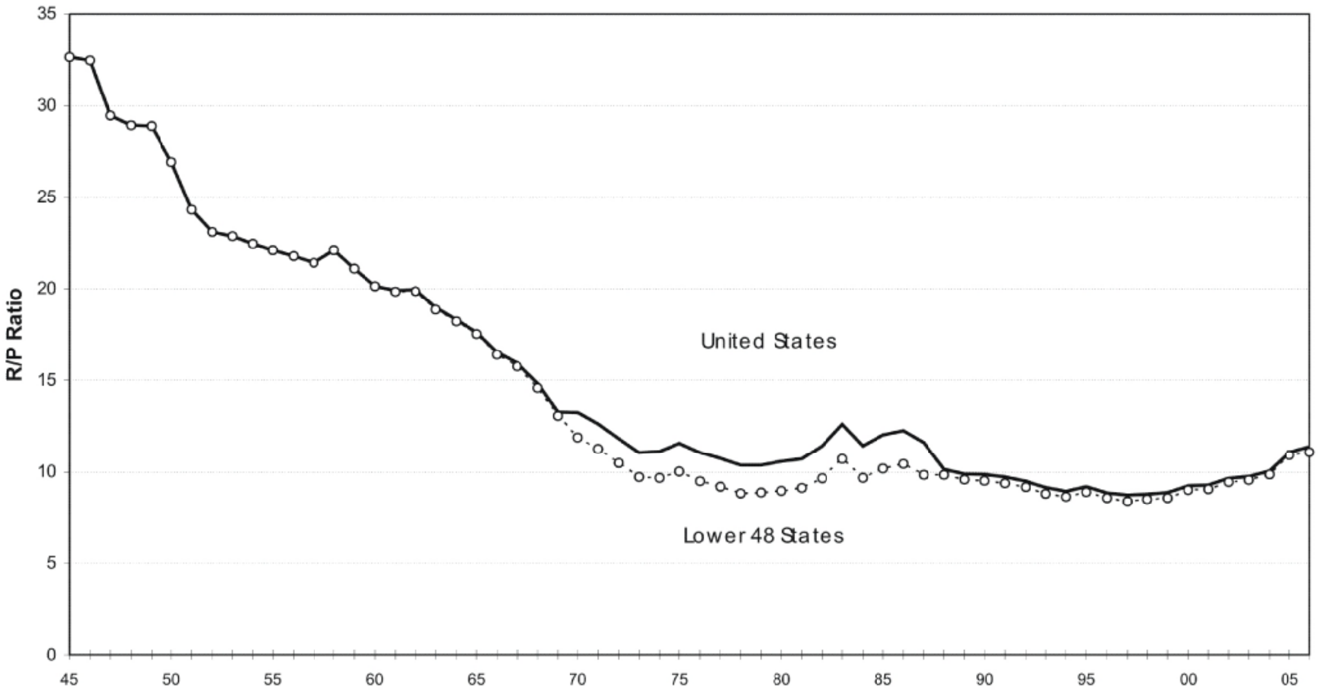


Figure 12. Reserves-to-Production Ratios for Wet Natural Gas, 1945-2006



Sources: Annual reserves and production - American Petroleum Institute and American Gas Association (1945–1976) {34} and Energy Information Administration, Office of Oil and Gas (1977–2005){1-29}. Cumulative production: *U.S. Oil and Gas Reserves by Year of Field Discovery* (1977-1988).{35}

Figure 13. Components of Proved Ultimate Recovery for Crude Oil and Lease Condensate, 1977-2006

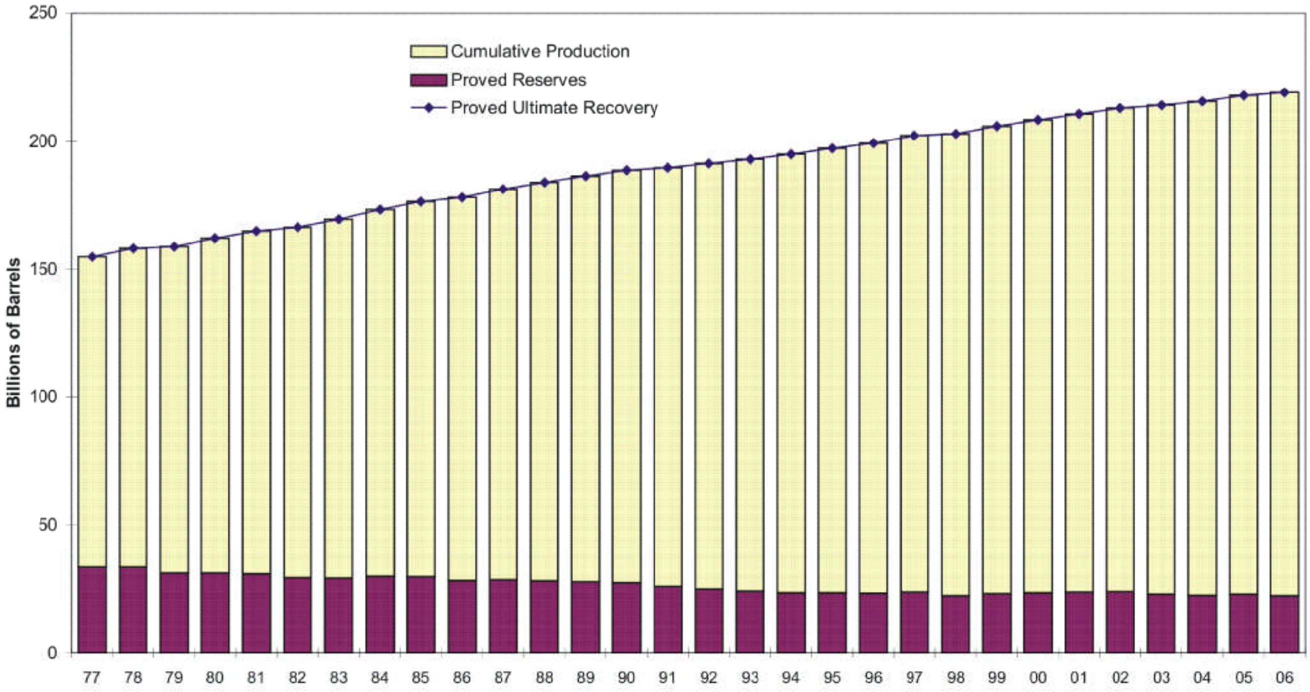
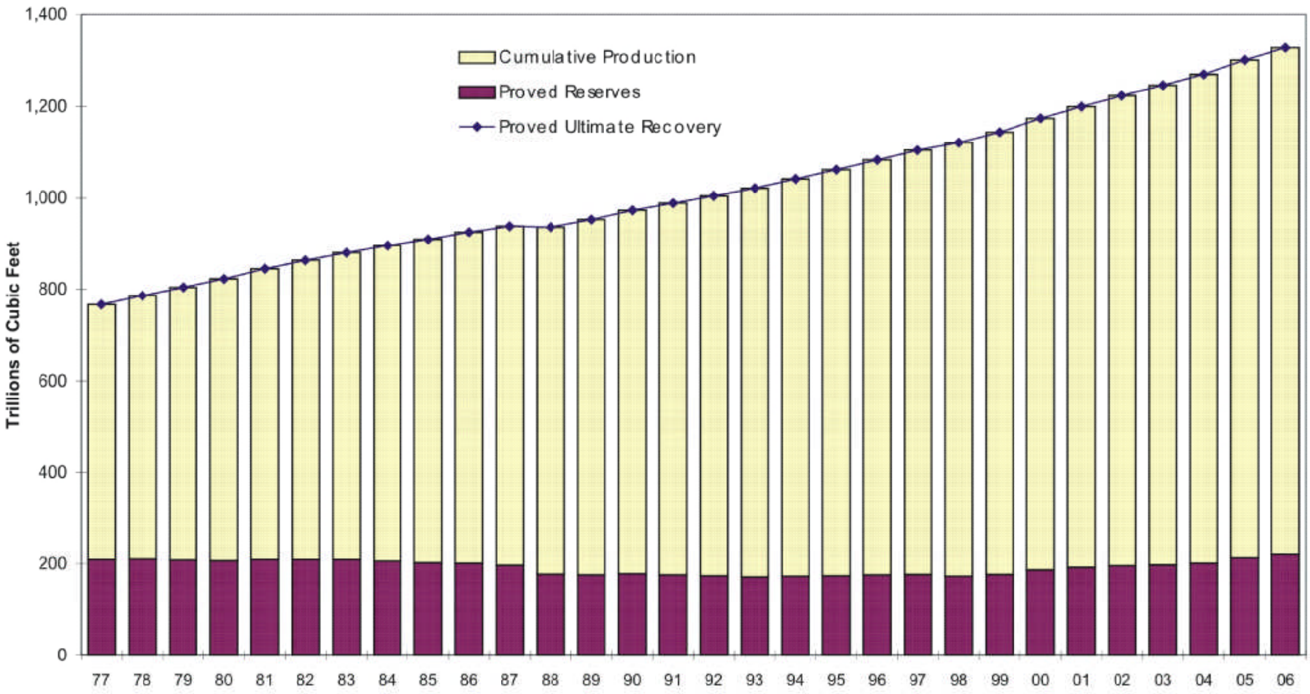


Figure 14. Components of Proved Ultimate Recovery for Wet Natural Gas, 1977-2006



Sources: Annual reserves and production - American Petroleum Institute and American Gas Association (1945–1976) {34} and Energy Information Administration, Office of Oil and Gas (1977–2005){1-29}. Cumulative production: *U.S. Oil and Gas Reserves by Year of Field Discovery* (1977-1988).{35}

Table 5. International Oil and Natural Gas Reserves as of December 31, 2006

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	Saudia Arabia[c]	[d]262,300	[d]262,275	1	Russia	1,680,000	1,688,755
2	Iran[c]	136,270	133,000	2	Iran[c]	974,000	971,154
3	Iraq[c]	115,000	125,100	3	Qatar[c]	910,500	906,000
4	Canada[e]	179,210	25,591	4	Saudia Arabia[c]	[d]240,000	[d]240,000
5	Kuwait[c]	[d]101,500	[d]100,110	5	United States	211,085	211,085
6	United Arab Emirates[c]	97,800	70,560	6	United Arab Emirates[c]	214,400	205,550
7	Russia	60,000	74,435	7	Nigeria[c]	181,900	182,000
8	Venezuela[c]	80,012	52,945	8	Algeria[c]	161,740	160,682
9	Libya[c]	41,464	34,970	9	Venezuela[c]	152,380	150,890
10	Nigeria[c]	36,220	37,200	10	Iraq[c]	112,000	88,000
Top 10 Total		**1,109,776**	**916,186**	**Top 10 Total**		**4,838,005**	**4,804,116**
11	Kazakhstan	30,000	-	11	Turkmenistan	100,000	-
12	United States	20,972	20,972	12	Kazakhstan	100,000	-
13	Qatar[c]	15,207	20,400	13	Indonesia[c]	97,780	91,800
14	China	16,000	16,256	14	Australia	30,370	152,359
15	Algeria[c]	12,270	11,921	15	Norway	82,320	83,272
16	Brazil	11,773	12,267	16	China	80,000	55,606
17	Mexico	12,352	11,656	17	Malaysia	75,000	58,000
18	Angola	8,000	9,330	18	Uzbekistan	65,000	-
19	Norway	7,849	7,070	19	Egypt	58,500	66,364
20	Azerbaijan	6,999	-	20	Canada	57,946	57,946
21	Sudan	5,000	6,615	21	Kuwait[c]	[d]55,000	[d]53,500
22	Oman	5,500	4,655	22	Libya[c]	52,650	51,500
23	Ecuador	4,517	4,933	23	Netherlands	50,000	50,500
24	India	5,625	3,812	24	Ukraine	39,000	-
25	Indonesia[c]	4,300	4,840	25	India	37,960	27,259
Top 25 Total		**1,276,140**	**1,050,913**	**Top 25 Total**		**5,819,531**	**5,552,222**
OPEC Total		**902,343**	**853,321**	**OPEC Total**		**3,152,350**	**3,101,076**
World Total		**1,317,447**	**1,144,358**	**World Total**		**6,182,692**	**6,332,193**

[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]*Oil and Gas Journal* Canadian oil reserves include heavy (low gravity) oil.

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*, Vol. 104, No.47 (December 18, 2006). Gulf Publishing Company, *World Oil*, Vol.228, No. 9 (September, 2007).

reserve additions of natural gas were booked as *new field discoveries* from 1976 through 2006. The other 90 percent came from proved ultimate recovery appreciation.

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 1.2 trillion barrels of oil and 6.3 quadrillion cubic feet of gas.

The United States ranked 12th in the world for proved reserves of crude oil and 5th for natural gas in 2006. A comparison of EIA's U.S. proved reserves estimates with worldwide estimates obtained from other sources shows that the United States had 2 percent of the world's total crude oil proved reserves and 3 percent of the world's total natural gas proved reserves at the end of 2006. There are sometimes substantial differences between the estimates from these sources. The *Oil & Gas Journal* reported oil reserves for Canada at about 179 billion barrels. This is much higher than the *World Oil* estimate of 26 billion. The *Oil and Gas Journal* estimate includes a larger contribution of heavy oil from Canadian tar sands. Another reason (among many) for these differences is that condensate is often included in foreign oil reserve estimates.

The *Oil & Gas Journal* {35} estimate for world oil reserves increased 2 percent in 2006 owing to an increase in its estimate of Kazakstan and Iranian reserves. The *World Oil* {36} estimate increased 3 percent in 2006 due to its larger estimate of Canadian and Iranian reserves. For world gas reserves, the *Oil & Gas Journal* reported a 1 percent increase, while *World Oil* reported an 2 percent increase in 2006.

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, Canada has almost 5 times U.S. 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*.{38} In 2006:

- The U.S. consumed 99,873,000,000,000,000 Btu of energy (99.9 quadrillion Btu). This was a decrease of 0.82 quadrillion Btu from the 2005 level of consumption.
- 62 percent of U.S. energy consumption was provided by petroleum and natural gas—crude oil and natural gas liquids combined (40 percent), and natural gas (22 percent).
- U.S. petroleum consumption was about 21 million barrels of oil and natural gas liquids and 60 billion cubic feet of gas per day.

Dependence on Imports

The United States remains dependent on imported oil and gas. In 2006, crude oil imports made up 66 percent of the U.S. crude oil supply. Canada, Mexico, Saudi Arabia, Venezuela, Nigeria, and Iraq were the primary foreign suppliers of petroleum to the United States.{39}

Net gas imports decreased from the 2005 total of 4.33 trillion cubic feet to 4.14 trillion cubic feet in 2006. Imports satisfied approximately 19 percent of consumption. Almost all of this gas was pipelined from Canada. Some liquefied natural gas was imported from Trinidad and Tobago, Nigeria, and Algeria.

List of Appendices

Appendix A: Operator Level Data - How much of the National total of proved reserves are 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. Table A6 lists the top U.S. operators by reported 2006 production.

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.

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 National level. Readers interested in a historical look at one specific State or region can review these tables in an electronic data archive on the EIA website. Table D9 contains the production and proved reserves for 1996-2006 for the Gulf of Mexico Federal Offshore region by water depths greater than 200 meters, and less than 200 meters. Table D10 contains Nonproducing Reserves.

Appendix E: Summary of Data Collection Operations - This report is based on two annual EIA surveys. Proved reserves data is collected 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 all of the technical terms used in this report.

3. Crude Oil Statistics

The United States had 20,972 million barrels of crude oil proved reserves as of December 31, 2006. This is 4 percent (-785 million barrels) less than in 2005. The principal factors contributing to the decline were lower than average net revisions and adjustments and fewer total discoveries.

The Gulf of Mexico Federal Offshore and Alaska, two of the largest U.S. oil-producing areas, reported 10 and 7 percent declines in crude oil proved reserves. Downward revisions exceeded revision increases in these two areas in 2006.

Reserves additions of crude oil in the U.S. did not keep pace with production. Operators replaced only 52 percent of 2006 crude oil production with reserves additions (**Figure 15**).

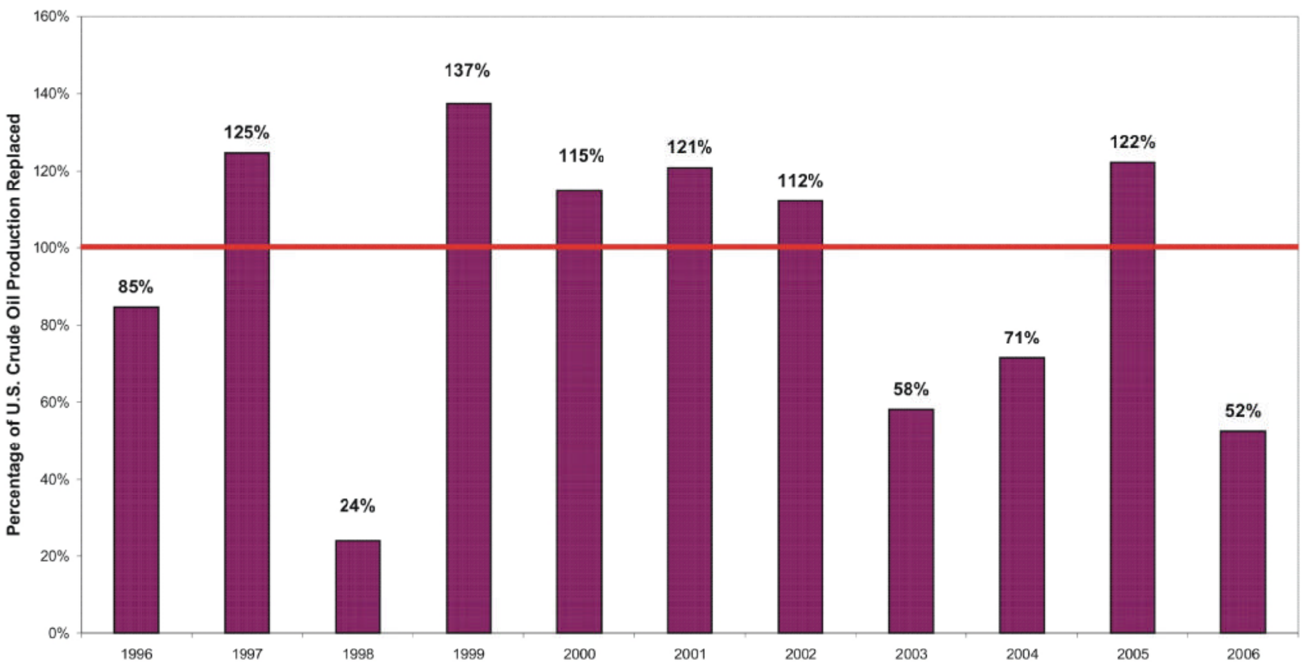
Proved Reserves

Table 6 presents the U.S. proved reserves of crude oil as of December 31, 2006, by selected States and State subdivisions.

Figure 16 maps 2006 crude oil proved reserves by area. The following four areas account for 74 percent of U.S. crude oil proved reserves:

Area	Percent of U.S. Oil Reserves
Texas	23
Alaska	18
Gulf of Mexico Federal Offshore	17
California	16
Area Total	**74**

Figure 15. Replacement of U.S. Crude Oil Production by Reserves Additions, 1996-2006.



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

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Table 6. Crude Oil Proved Reserves, Reserves Changes, and Production, 2006
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	Published Proved Reserves 12/31/05	Changes in Reserves During 2006: Adjustments (+,–)	Revision Increases (+)	Revision Decreases (–)	Sales (–)	Acquisitions (+)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Estimated Production (–)	Proved Reserves 12/31/06
Alaska	4,171	1	84	235	0	0	100	0	0	242	3,879
Lower 48 States	**17,586**	**93**	**1,506**	**1,353**	**982**	**1,176**	**404**	**30**	**43**	**1,410**	**17,093**
Alabama	55	2	2	4	19	14	0	0	0	5	45
Arkansas	40	5	3	5	0	0	0	0	0	6	37
California	3,435	13	243	125	120	130	27	0	8	222	3,389
Coastal Region Onshore	374	1	22	10	46	47	0	0	2	15	375
Los Angeles Basin Onshore	300	6	83	23	47	49	6	0	6	16	364
San Joaquin Basin Onshore	2,556	6	115	76	27	34	16	0	0	176	2,448
State Offshore	205	0	23	16	0	0	5	0	0	15	202
Colorado	250	4	30	7	72	68	19	0	0	18	274
Florida	59	1	0	20	0	0	0	0	0	2	38
Illinois	95	2	6	6	0	1	0	0	1	10	89
Indiana	16	-5	1	2	0	3	0	0	0	1	12
Kansas	281	9	23	20	1	1	3	1	1	35	263
Kentucky	23	3	1	0	0	0	0	0	0	2	25
Louisiana	432	13	47	31	44	39	23	0	2	53	428
North	68	8	5	8	2	2	3	0	0	8	68
South Onshore	299	16	37	16	36	34	15	0	2	39	312
State Offshore	65	-11	5	7	6	3	5	0	0	6	48
Michigan	62	5	5	6	1	2	0	1	0	5	63
Mississippi	189	5	7	11	6	7	8	0	2	15	186
Montana	427	1	29	35	53	50	36	0	0	36	419
Nebraska	16	0	1	1	0	0	0	0	0	2	14
New Mexico	690	-2	66	45	64	90	26	0	0	56	705
East	682	-5	65	43	64	90	26	0	0	55	696
West	8	3	1	2	0	0	0	0	0	1	9
North Dakota	418	8	36	30	142	140	15	2	3	38	412
Ohio	46	1	5	1	0	1	1	0	0	4	49
Oklahoma	630	-21	51	68	29	45	10	0	0	49	569
Pennsylvania	14	5	3	2	0	0	2	0	0	2	20
Texas	4,919	50	340	312	100	198	128	1	2	355	4,871
RRC District 1	65	5	7	3	20	24	8	0	0	10	76
RRC District 2 Onshore	62	12	7	9	2	2	1	0	0	8	65
RRC District 3 Onshore	179	11	21	20	7	10	9	1	1	25	180
RRC District 4 Onshore	40	7	2	15	1	0	1	0	0	4	30
RRC District 5	24	1	4	1	0	0	0	0	0	4	24
RRC District 6	168	8	8	36	0	18	6	0	0	15	157
RRC District 7B	80	-5	25	4	1	3	1	0	0	10	89
RRC District 7C	245	3	15	16	4	40	25	0	0	20	288
RRC District 8	1,731	2	119	102	42	75	44	0	1	111	1,717
RRC District 8A	2,164	2	107	88	18	25	30	0	0	129	2,093
RRC District 9	103	6	8	5	4	1	0	0	0	13	96
RRC District 10	53	-2	17	11	1	0	3	0	0	6	53
State Offshore	5	0	0	2	0	0	0	0	0	0	3
Utah	256	0	55	12	42	76	16	2	0	17	334
West Virginia	21	2	6	4	0	0	0	0	0	2	23
Wyoming	704	-2	72	51	32	37	19	2	0	43	706
Federal Offshore	4,483	-3	471	555	257	272	71	21	24	431	4,096
Pacific (California)	441	0	29	6	0	0	2	0	1	26	441
Gulf of Mexico (Louisiana)	3,852	-2	397	520	202	215	68	21	18	347	3,500
Gulf of Mexico (Texas)	190	-1	45	29	55	57	1	0	5	58	155
Miscellaneous[a]	25	-3	3	0	0	2	0	0	0	1	26
U.S. Total	**21,757**	**94**	**1,590**	**1,588**	**982**	**1,176**	**504**	**30**	**43**	**1,652**	**20,972**

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

Note: The production estimates in this table are based on data reported on Form EIA-23, “Annual Survey of Domestic Oil and Gas Reserves.” They may differ from the official Energy Information Administration production data for crude oil for 2006 contained in the *Petroleum Supply Annual 2006*, DOE/EIA-0340(06).

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

Figure 16. Crude Oil Proved Reserves by Area, 2006

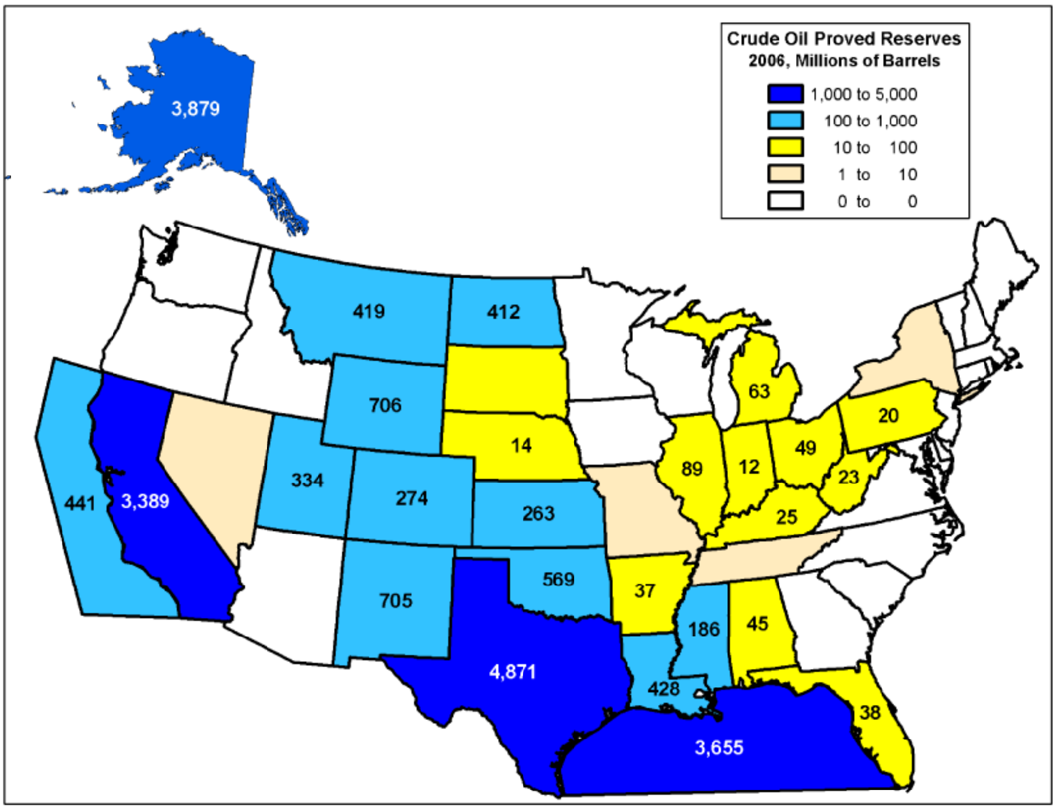
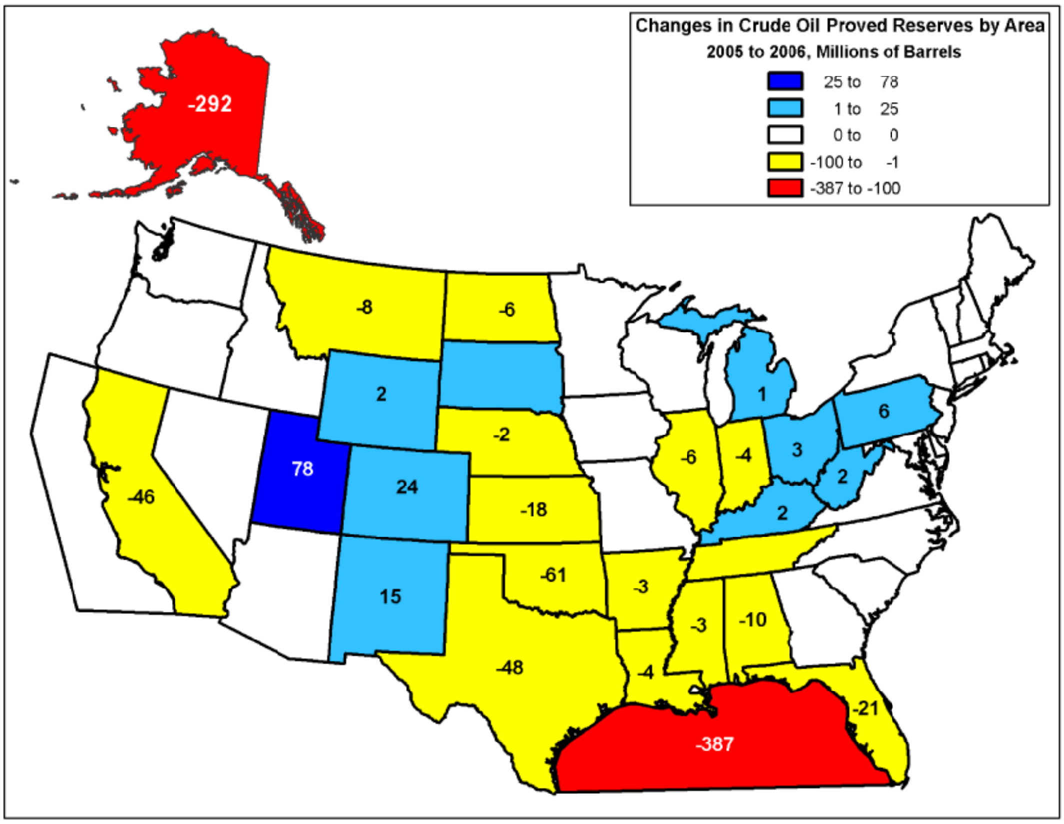


Figure 17. Changes in Crude Oil Proved Reserves by Area, 2005 to 2006



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

Discussion of Reserves Changes

Figure 17 maps the change in crude oil proved reserves from 2005 to 2006 by area. Here's how the top four areas fared compared to the total United States:

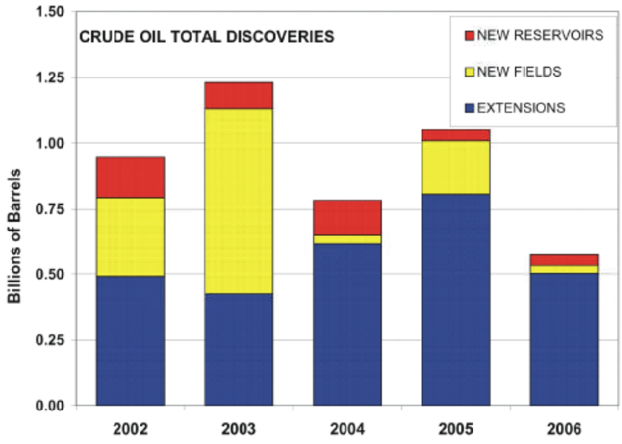
Area	Change in U.S. Oil Reserves (million barrels)
Texas	-48
Alaska	-292
Gulf of Mexico Federal Offshore	-387
California	-46
Area Total	**-773**
U.S. Total	**-785**

The Gulf of Mexico had a 10 percent decrease in crude oil proved reserves in 2006. Alaska declined 7 percent, and Texas and California each declined 1 percent.

Figure 2 in Chapter 2 shows the components of the changes in crude oil proved reserves for 2006 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 (see graph below). They result from the drilling of exploratory wells.



Total discoveries of crude oil were 577 million barrels in 2006, 45 percent less than those of 2005 (1,051 million barrels).

Only five areas had total discoveries of 35 million barrels or more in 2006:

Area	Percent of U.S. Oil Total Discoveries
Texas	23
Federal Offshore Gulf of Mexico	20
Alaska	17
Montana	6
California	6
Area Total	**72**

The United States discovered an average of 1,135 million barrels of new crude oil proved reserves per year in the prior 10 years. Total discoveries in 2006 were 49 percent lower than that average.

Extensions

Operators reported 504 million barrels of extensions in 2006, 37 percent less than in 2005. The highest volume of extensions was reported in Texas (128 million barrels). The second highest volume of 2006 extensions was 100 million barrels in Alaska, followed by 69 million barrels in the Gulf of Mexico Federal Offshore and 36 million barrels in Montana.

In the prior 10 years, U.S. operators reported an average of 558 million barrels of extensions per year. The 2006 extensions were 10 percent less than that average.

New Field Discoveries

New field discoveries accounted for 30 million barrels of crude oil reserves additions. This was 85 percent less than the new field discoveries of 2005. Seventy percent of these discoveries (21 of 30 million barrels) were in the Gulf of Mexico Federal Offshore.

In the prior 10 years, U.S. operators reported an annual average of 428 million barrels of reserves from new field discoveries. Reserves from new field discoveries in 2006 were only 7 percent of that average.

New Reservoir Discoveries in Old Fields

Operators reported 43 million barrels of crude oil reserves from new reservoir discoveries in old fields in 2006. This is 5 percent more than in 2005. The majority of the new reservoir discoveries in old fields (23 of 43 million barrels) came from the Gulf of Mexico Federal Offshore.

In the prior 10 years, U.S. operators reported an annual average of 149 million barrels of reserves from new reservoir discoveries in old fields. Reserves from new reservoir discoveries in old fields in 2006 were 71 percent less than that average.

Revisions and Adjustments

Operators report thousands of positive and negative revisions to proved reserves each year as development 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 1,590 million barrels of revision increases, 1,588 million barrels of revision decreases, and 94 million barrels of adjustments in 2006. Combined, there were 96 million barrels of net revisions and adjustments for crude oil in 2006.

In the prior 10 years, net revisions and adjustments added an annual average of 759 million barrels. The 2006 net revisions and adjustments were 87 percent less than that average.

Sales and Acquisitions

In the context of this report, *Sales* represents the volume of crude oil proved reserves deducted from an operator's total reserves by sale or transfer of operations of existing oil fields or properties to another operator, instead of a volume of production "sold" at the wellhead. Similarly, *Acquisitions* are that volume of proved reserves added to an operator's total reserves through purchase or operations transfer of an existing oil field or properties.

There are several reasons why sales and acquisitions volumes are not equal for a given year. Since operators have different engineering staffs and resources, or different development plans or schedules, the estimate of proved reserves for a field can change upon a change in operatorship. Timing of the transfer of operations can also impact these values.

In 2006, there were 982 million barrels of sales transactions between operators and 1,176 million barrels of acquisitions yielding a net difference of +194 million barrels.

Production

U.S. production of crude oil in 2006 was an estimated 1,652 million barrels. This volume, which does not include lease condensate, was 5 percent lower than 2005's production of 1,733 million barrels.

Part of the decline resulted from an August 2006 shut-in of producing wells in half of Alaska's Prudhoe Bay Field (still the largest producing U.S. oil field) for inspection and repair of corrosion in the gathering system.

In 2006, the Gulf of Mexico Federal Offshore remained the largest oil producing area in the United States with 25 percent of the national total (405 million barrels of production). Texas and Alaska were second and third, with 21 and 15 percent of the national production total, respectively. California was fourth with 13 percent.

For the second year in a row Montana had the largest annual oil production increase of any State (6 million barrels; a 20 percent increase) owing to continued development of the Bakken Formation in the Elm Coulee Field. This relatively new and important oil field is difficult to produce and requires cutting-edge technology for economic production.

The 2006 Form EIA-23 national production estimates (1,652 million barrels of crude oil and 182 million barrels of lease condensate) are 1.5 percent lower than the comparable Petroleum Supply Annual (PSA) 2006 volumes for crude oil and lease condensate production combined (1,862 million barrels).

Areas of Note: Large Discoveries and Reserves Additions

The following State and area discussions summarize notable activities during 2006 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 were the major success stories for crude oil reserves and production for 2006.

Utah

Utah reported the largest increase (78 million barrels) of proved oil reserves in 2006. The majority of these reserves additions were reported as acquisitions. Utah's production increased by 13 percent from 15 to 17 million barrels in 2006.

- **Greater Aneth Field**: On April 26, 2006, Resolute Natural Resources Company and Navajo Nation Oil and Gas Company announced they had completed the purchase of ExxonMobil's assets in Greater Aneth Field in southeast Utah. Their combined assets now include 359 active producing wells and 289 active [CO_2] injection wells in the Aneth, McElmo Creek, and Ratherford Units. {40}

Colorado

Colorado reported a net increase of 24 million barrels of crude oil proved reserves in 2006, primarily from revision increases and extensions. Colorado's production decreased from 19 million barrels in 2005 to 18 million barrels in 2006.

- **Wattenberg Field**: Anadarko Petroleum Corporation accelerated its infill drilling program at its Wattenberg Field in northeast Colorado in 2006 following the approval of down-spacing which created a significant increase in drill sites. {41} Although Wattenberg Field is primarily a tight nonassociated natural gas field (the 8th largest gas field in the U.S. in 2006, ranked by proved reserves), it produces significant crude oil -- Wattenberg Field was the 16th largest oil field in the U.S. in 2006, ranked by proved reserves. For a listing of the Top 100 U.S. oil and gas fields, see Appendix B.

New Mexico

New Mexico reported a net increase of 15 million barrels of crude oil proved reserves in 2006. Extensions and the net of sales and acquisitions provided the majority of reserves additions. New Mexico's production declined from 58 million barrels in 2005 to 56 million barrels in 2006.

- **Monument Field:** On January 17, 2006 Apache Corporation completed its purchase of Amerada-Hess Corporation's interest in eight fields in the Permian Basin of west Texas and New Mexico. Apache estimated the acquired interests had proved reserves of 27 million barrels of liquid hydrocarbons and 27 billion cubic feet of natural gas equivalent at year-end 2005. {42}

Other Gain Areas

Pennsylvania: Pennsylvania reported a net increase of 6 million barrels of crude oil proved reserves in 2006.

Ohio: Ohio reported a net increase of 3 million barrels of crude oil proved reserves in 2006.

Areas of Note: Large Reserves Declines

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

Gulf of Mexico Federal Offshore

The Gulf of Mexico Federal Offshore crude oil proved reserves declined 10 percent (-387 million barrels) in 2006. Crude oil production declined 1 percent from 409 million barrels in 2005 to 405 million barrels in 2006.

Alaska

Alaskan crude oil proved reserves declined 7 percent (-292 million barrels) in 2006. Despite 100 million barrels of extensions, net downward revisions exceeded reserves additions. Alaska's estimated 2006 production of 242 million barrels decreased 22 percent from the 2005 level (312 million barrels). Part of the decline resulted from an August 2006 shut-in of producing wells in half of Alaska's Prudhoe Bay Field (still the largest producing U.S. oil field) for inspection and repair of corrosion in the gathering system.

Oklahoma

There was a 10 percent decline (-61 million barrels) in the crude oil proved reserves of Oklahoma in 2006. Crude oil production from this area declined 4 percent from its 2005 level.

Other Decline Areas

Discovery and development of new or existing oil fields was also outpaced by crude oil production in the following areas of the United States:

Texas: Proved oil reserves decreased by 1 percent (-48 million barrels).

California: Proved oil reserves decreased by 1 percent (-46 million barrels).

Table 7. Reported Reserves in Nonproducing Status for Crude Oil, 2006[a]

(Million Barrels of 42 U.S. Gallons)

State and Subdivision	Nonproducing Crude Oil Reserves
Alaska	442
Lower 48 States	**4,732**
Alabama	0
Arkansas	1
California	496
Coastal Region Onshore	85
Los Angeles Basin Onshore	149
San Joaquin Basin Onshore	228
State Offshore	34
Colorado	102
Florida	1
Kansas	17
Kentucky	0
Louisiana	198
North	14
South Onshore	162
State Offshore	22
Michigan	15
Mississippi	79
Montana	91
New Mexico	159
East	159
West	0
New York	0
North Dakota	53
Ohio	8
Oklahoma	90
Pennsylvania	0
Texas	1,077
RRC District 1	26
RRC District 2 Onshore	16
RRC District 3 Onshore	18
RRC District 4 Onshore	4
RRC District 5	1
RRC District 6	17
RRC District 7B	5
RRC District 7C	120
RRC District 8	466
RRC District 8A	386
RRC District 9	9
RRC District 10	9
State Offshore	0
Utah	164
Virginia	0
West Virginia	0
Wyoming	258
Federal Offshore	1,921
Pacific (California)	37
Gulf of Mexico (Louisiana)[c]	1,816
Gulf of Mexico (Texas)	68
Miscellaneous[b]	2
U.S. Total	**5,174**

[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, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee.

[c] Includes Federal Offshore Alabama.

Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 2006.

Reserves in Nonproducing Status

Not all proved reserves of crude oil reported in 2006 were producing. Operators reported 5,174 million barrels of proved reserves in nonproducing status in 2006, 9 percent less than in 2005 (5,691 million barrels). Nonproducing crude oil reserves (not including lease condensate) are listed in **Table 7**.

Nonproducing reserves are those awaiting well workovers, the drilling of extensions or additional development wells, installation of production or pipeline facilities, and depletion of other zones or reservoirs before recompletion in reservoirs not currently open to production.

4. Natural Gas Statistics

Dry Natural Gas

Proved Reserves

The United States had 211,085 billion cubic feet of dry natural gas proved reserves as of December 31, 2006 (**Table 8**), the highest level since 1976. Proved reserves of natural gas increased by 3 percent from 2005 to 2006. All natural gas proved reserves data shown in this report exclude natural gas held in underground storage.

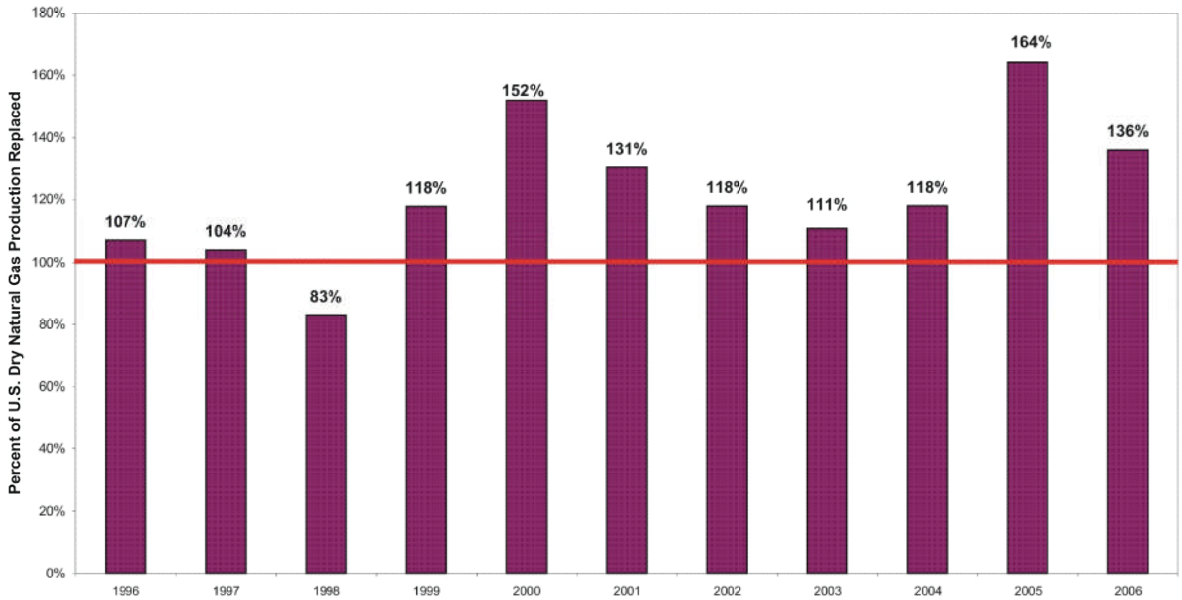
Texas led the nation in natural gas reserves additions in 2006 with a 9 percent increase in dry gas proved reserves due to rapid development of Barnett Shale reservoirs in the Newark East Field. Advances in horizontal drilling and hydraulic fracturing technology and relatively high natural gas prices supported this development. Alaska and Utah were second and third for dry natural gas proved reserves additions in 2006. Total U.S. reserves additions replaced 136 percent of 2006 dry gas production **(Figure 18)**.

The proved reserves by State are shown on the map in **Figure 19**. Eight areas accounted for 81 percent of the Nation's dry natural gas proved reserves:

Area	Percent of U.S. Gas Reserves
Texas	29
Wyoming	11
New Mexico	8
Oklahoma	8
Colorado	8
Gulf of Mexico Federal Offshore	7
Louisiana	5
Alaska	5
Area Total	**81**

Total U.S. natural gas production increased in 2006 due to production increases in Texas (Barnett Shale), Louisiana, and the Rocky Mountain states (Colorado, Wyoming, Utah, and Montana). Texas had the largest increase in production in 2006 (3 percent; 184 billion cubic feet), while the Gulf of Mexico Federal Offshore declined the most (6 percent; -168 billion cubic feet).

Figure 18. Replacement of U.S. Dry Natural Gas Production by Reserves Additions, 1996-2006.



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

Table 8. Dry Natural Gas Proved Reserves, Reserves Changes, and Production, 2006
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State and Subdivision	Published Proved Reserves 12/31/05	Changes in Reserves During 2006: Adjustments (+,–)	Revision Increases (+)	Revision Decreases (–)	Sales (–)	Acquisitions (+)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Estimated Production (–)	Proved Reserves 12/31/06
Alaska	8,171	-46	2,853	376	0	0	49	0	2	408	10,245
Lower 48 States	**196,214**	**789**	**17,980**	**22,293**	**22,850**	**25,846**	**21,729**	**409**	**1,153**	**18,137**	**200,840**
Alabama	3,965	-11	234	208	188	253	146	0	7	287	3,911
Arkansas	1,964	-26	101	113	4	5	491	7	32	188	2,269
California	3,228	-74	156	419	274	252	176	0	4	255	2,794
Coastal Region Onshore	268	-62	28	12	70	58	5	0	0	9	206
Los Angeles Basin Onshore	176	0	7	29	35	38	4	0	0	8	153
San Joaquin Basin Onshore	2,694	-12	112	371	169	156	166	0	1	232	2,345
State Offshore	90	0	9	7	0	0	1	0	3	6	90
Colorado	16,596	52	1,178	1,524	1,539	1,540	1,980	14	26	1,174	17,149
Florida	77	2	0	32	0	0	0	0	0	2	45
Kansas	4,314	89	807	1,020	18	13	93	0	3	350	3,931
Kentucky	2,151	-22	56	21	432	534	23	0	4	66	2,227
Louisiana	10,447	86	1,191	1,417	500	738	1,026	27	185	1,309	10,474
North	6,695	-27	603	759	57	189	619	0	4	552	6,715
South Onshore	3,334	135	526	607	388	523	328	10	148	674	3,335
State Offshore	418	-22	62	51	55	26	79	17	33	83	424
Michigan	2,910	112	460	291	48	27	86	1	5	197	3,065
Mississippi	755	-26	96	40	44	30	119	0	6	83	813
Montana	986	13	65	78	20	17	144	19	28	117	1,057
New Mexico	18,201	91	1,273	1,203	6,248	6,278	793	35	140	1,426	17,934
East	3,791	56	607	495	297	327	370	35	0	480	3,914
West	14,410	35	666	708	5,951	5,951	423	0	140	946	14,020
New York	349	33	22	38	55	52	5	45	0	50	363
North Dakota	453	18	70	31	53	40	30	1	3	52	479
Ohio	898	129	49	112	11	83	17	0	0	78	975
Oklahoma	17,123	-149	1,515	1,868	821	1,202	2,051	0	12	1,601	17,464
Pennsylvania	2,782	-117	185	224	6	234	359	13	0	176	3,050
Texas	56,507	835	6,392	7,853	4,603	6,366	9,467	80	253	5,608	61,836
RRC District 1	1,161	77	36	182	0	4	74	2	0	109	1,063
RRC District 2 Onshore	2,073	207	209	511	138	195	321	9	18	323	2,060
RRC District 3 Onshore	3,192	-5	411	472	407	389	384	20	70	532	3,050
RRC District 4 Onshore	8,761	250	844	1,857	1,156	1,184	1,138	23	86	1,157	8,116
RRC District 5	9,557	84	2,318	683	661	804	1,953	4	0	783	12,593
RRC District 6	8,976	69	854	1,741	511	856	1,357	1	0	774	9,087
RRC District 7B	802	-61	197	67	48	57	681	0	0	90	1,471
RRC District 7C	5,123	25	170	634	111	231	691	0	0	369	5,126
RRC District 8	5,993	43	511	714	845	1,065	488	2	7	480	6,070
RRC District 8A	1,366	34	114	135	11	5	19	0	0	102	1,290
RRC District 9	4,328	4	139	183	516	1,318	1,535	0	0	407	6,218
RRC District 10	4,910	95	573	639	128	198	826	2	0	450	5,387
State Offshore	265	13	16	35	71	60	0	17	72	32	305
Utah	4,295	-11	218	502	1,147	1,189	1,408	45	0	349	5,146
Virginia	2,018	25	234	14	133	154	114	6	0	102	2,302
West Virginia	4,459	-251	298	188	745	886	229	3	5	187	4,509
Wyoming	23,774	36	1,339	2,281	3,239	3,372	2,211	2	30	1,695	23,549
Federal Offshore[a]	17,831	-39	2,030	2,798	2,718	2,575	733	111	410	2,775	15,360
Pacific (California)	824	2	43	22	0	0	0	0	1	37	811
Gulf of Mexico (Louisiana)[a]	13,665	-37	1,606	2,201	1,532	1,341	530	82	343	1,973	11,824
Gulf of Mexico (Texas)	3,342	-4	381	575	1,186	1,234	203	29	66	765	2,725
Miscellaneous[b]	131	-6	11	18	4	6	28	0	0	10	138
U.S. Total	**204,385**	**743**	**20,833**	**22,669**	**22,850**	**25,846**	**21,778**	**409**	**1,155**	**18,545**	**211,085**

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

Note: The production estimates in this table are based on data reported on Form EIA-23, “Annual Survey of Domestic Oil and Gas Reserves,” and Form EIA-64A, “Annual Report of the Origin of Natural Gas Liquids Production.” They may differ from the official Energy Information Administration production data for natural gas for 2006 contained in the *Natural Gas Annual 2006*, DOE/EIA-0131(06).

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

Figure 19. Dry Natural Gas Proved Reserves by Area, 2006

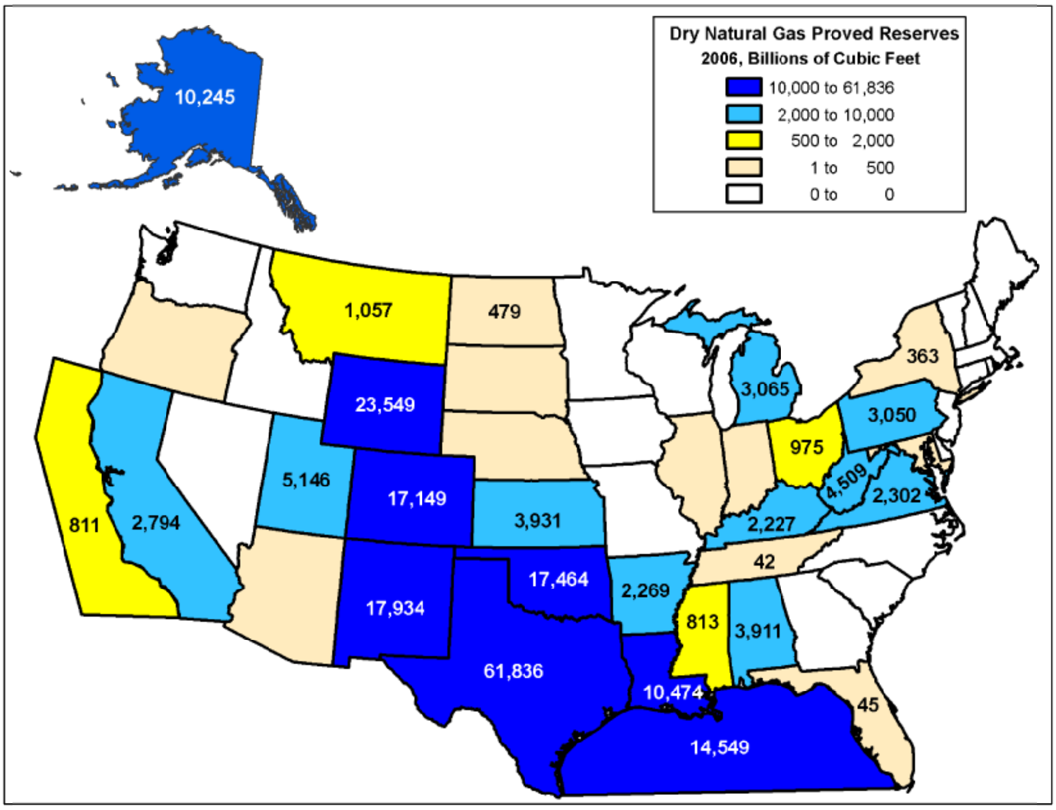
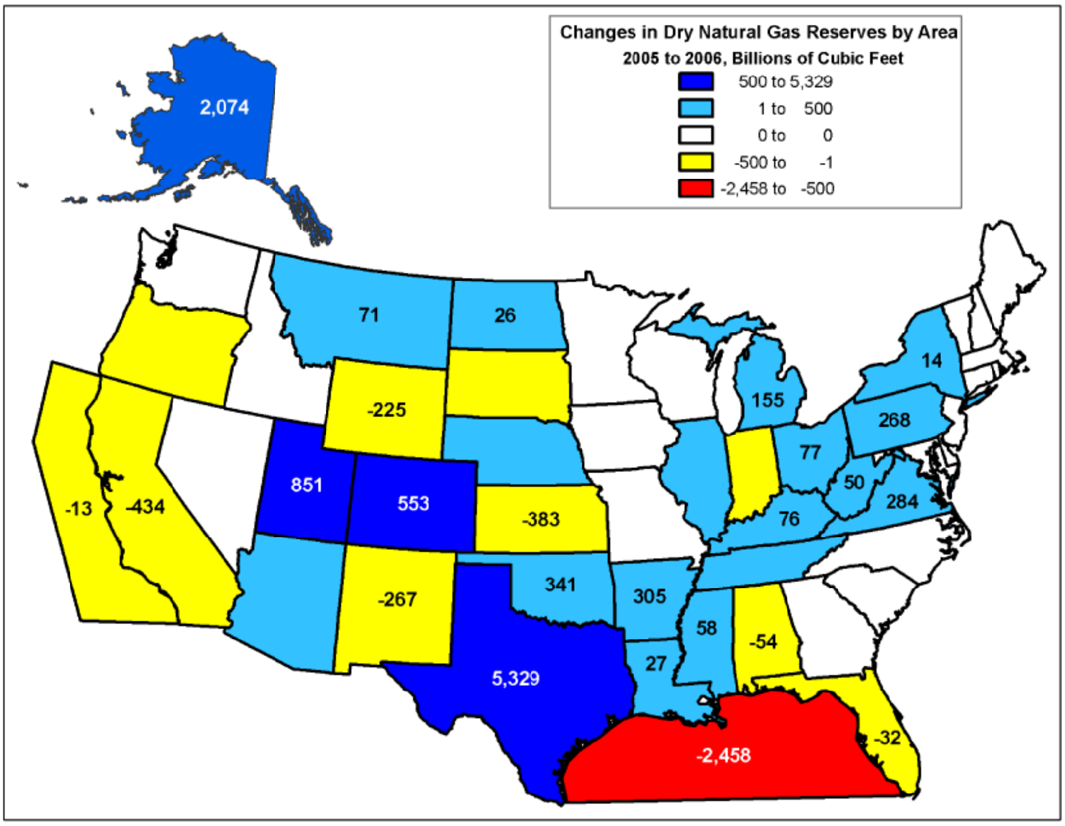


Figure 20. Changes in Dry Natural Gas Proved Reserves by Area, 2005 to 2006



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

Discussion of Reserves Changes

Figure 20 maps the change in dry gas proved reserves from 2005 to 2006 by area. Here's how the top eight areas fared, compared to the total United States:

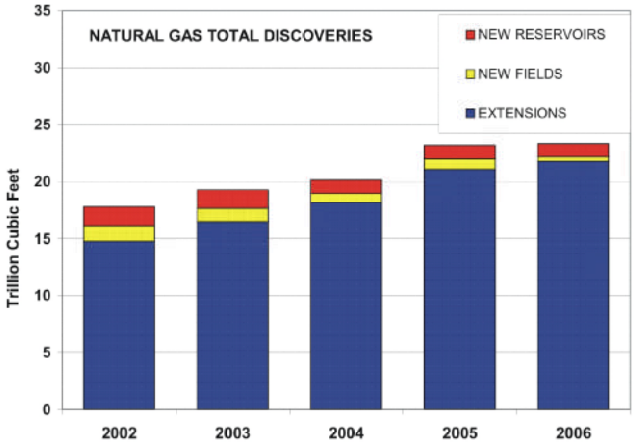
Area	Change in U.S. Gas Reserves (billion cubic feet)
Texas	+5,329
Wyoming	-225
New Mexico	-267
Oklahoma	+341
Colorado	+553
Gulf of Mexico Federal Offshore	-2,458
Louisiana	+27
Alaska	+2,074
Area Total	**+5,374**
U.S. Total	**+6,700**

Figure 4 in Chapter 2 shows the components of change in dry natural gas proved reserves for 2006 and the preceding 10 years.

Total 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 (see graph below).

Total discoveries of dry natural gas reserves were 23,342 billion cubic feet in 2006, a 1 percent increase from the level reported in 2005.



Seven areas reported total discoveries of dry natural gas exceeding 1 trillion cubic feet in 2006:

Area	2006 Total Discoveries (Billion cubic feet)
Texas	9,800
Wyoming	2,243
Oklahoma	2,063
Colorado	2,020
Utah	1,453
Gulf of Mexico Federal Offshore	1,253
Louisiana	1,238
Area Total	**20,070**
U.S. Total	**23,342**

Extensions

The largest component of total discoveries in 2006 was extensions of existing gas fields. Extensions were 21,778 billion cubic feet, 3 percent more than 2005 and 61 percent more than the prior 10-year average (13,522 billion cubic feet). Areas with the largest extensions and their percentage of total extensions were:

Area	Percent of 2006 Extensions
Texas	43
Wyoming	10
Oklahoma	9
Colorado	9
Utah	6
Louisiana	5
New Mexico	4
Area Total	**86**

New Field Discoveries

New field discoveries were 409 billion cubic feet in 2006, 57 percent less than in 2005. The areas with the largest new field discoveries were the Gulf of Mexico Federal Offshore (111 billion cubic feet; 27 percent of the total), Texas (80 billion cubic feet; 20 percent), Utah (45 billion cubic feet; 11 percent) and New York (45 billion cubic feet; 11 percent). In the prior 10 years, U.S. operators had reported an annual average of 1,659 billion cubic feet of reserves from new field discoveries. Reserves from new field discoveries in 2006 were 75 percent less than the prior 10 year average.

New Reservoir Discoveries in Old Fields

New reservoir discoveries in old fields were 1,155 billion cubic feet, 4 percent less than 2005 (1,208 billion cubic feet). The areas with the largest new reservoir

Table 9. Natural Gas Proved Reserves, Reserves Changes, and Production, Wet After Lease Separation, 2005 (Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State and Subdivision	Published Proved Reserves 12/31/05	Changes in Reserves During 2006: Adjustments (+,–)	Revision Increases (+)	Revision Decreases (–)	Sales (–)	Acquisitions (+)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Estimated Production (–)	Proved Reserves 12/31/06
Alaska	8,237	-50	2,882	378	0	0	50	0	2	410	10,333
Lower 48 States	**205,071**	**996**	**18,758**	**23,361**	**23,904**	**27,082**	**22,784**	**425**	**1,195**	**18,963**	**210,083**
Alabama	4,006	-2	238	213	192	259	150	0	7	290	3,963
Arkansas	1,967	-28	101	114	4	5	492	7	33	188	2,271
California	3,384	-73	163	440	287	266	186	0	4	268	2,935
Coastal Region Onshore	277	-64	29	12	72	60	5	0	0	9	214
Los Angeles Basin Onshore	186	-1	7	31	37	41	4	0	0	8	161
San Joaquin Basin Onshore	2,831	-9	118	390	178	165	176	0	1	244	2,470
State Offshore	90	1	9	7	0	0	1	0	3	7	90
Colorado	17,122	42	1,215	1,571	1,587	1,588	2,042	15	27	1,211	17,682
Florida	87	1	0	35	0	0	0	0	0	3	50
Kansas	4,598	103	862	1,090	19	14	100	0	3	374	4,197
Kentucky	2,240	23	60	22	459	568	24	0	5	70	2,369
Louisiana	10,679	95	1,222	1,453	519	762	1,049	29	192	1,346	10,710
North	6,768	-20	610	768	57	191	626	0	4	559	6,795
South Onshore	3,478	134	548	632	404	544	341	11	154	701	3,473
State Offshore	433	-19	64	53	58	27	82	18	34	86	442
Michigan	2,961	112	467	295	48	27	88	1	5	201	3,117
Mississippi	758	-23	95	40	44	29	119	0	6	84	816
Montana	998	13	66	79	20	17	145	20	28	119	1,069
New Mexico	19,344	138	1,369	1,292	6,612	6,645	851	39	147	1,525	19,104
East	4,132	89	666	543	326	359	405	39	0	526	4,295
West	15,212	49	703	749	6,286	6,286	446	0	147	999	14,809
New York	349	32	22	38	55	52	5	45	0	49	363
North Dakota	508	20	79	34	60	45	34	1	4	58	539
Ohio	898	128	49	112	11	83	18	0	0	78	975
Oklahoma	18,146	-131	1,608	1,983	871	1,275	2,177	0	13	1,699	18,535
Pennsylvania	2,793	-117	186	225	6	235	361	14	0	177	3,064
Texas	60,178	891	6,708	8,348	4,906	6,807	10,090	84	265	5,964	65,805
RRC District 1	1,205	87	38	190	0	4	77	2	0	114	1,109
RRC District 2 Onshore	2,175	222	220	537	146	206	337	10	19	340	2,166
RRC District 3 Onshore	3,406	18	442	506	437	417	413	22	75	572	3,278
RRC District 4 Onshore	9,104	304	881	1,939	1,207	1,236	1,188	24	91	1,208	8,474
RRC District 5	9,611	72	2,328	686	664	807	1,962	4	0	786	12,648
RRC District 6	9,343	94	890	1,816	533	894	1,416	1	0	808	9,481
RRC District 7B	932	-95	222	76	54	65	770	0	0	101	1,663
RRC District 7C	5,702	49	190	708	124	258	772	0	0	412	5,727
RRC District 8	6,800	17	577	807	955	1,203	552	2	8	542	6,855
RRC District 8A	1,471	32	122	144	12	5	20	0	0	110	1,384
RRC District 9	4,734	-20	151	199	562	1,434	1,670	0	0	443	6,765
RRC District 10	5,430	98	632	705	141	218	913	2	0	497	5,950
State Offshore	265	13	15	35	71	60	0	17	72	31	305
Utah	4,359	-21	220	509	1,161	1,204	1,426	46	0	353	5,211
Virginia	2,018	25	234	14	133	154	114	6	0	102	2,302
West Virginia	4,572	-227	308	195	769	914	236	3	5	193	4,654
Wyoming	24,722	14	1,391	2,370	3,365	3,503	2,297	1	31	1,761	24,463
Federal Offshore[a]	18,252	-11	2,084	2,871	2,772	2,624	751	114	420	2,841	15,750
Pacific (California)	825	1	43	22	0	0	0	0	1	37	811
Gulf of Mexico (Louisiana)[a]	14,073	-10	1,658	2,272	1,581	1,384	547	85	353	2,036	12,201
Gulf of Mexico (Texas)	3,354	-2	383	577	1,191	1,240	204	29	66	768	2,738
Miscellaneous[b]	132	-8	11	18	4	6	29	0	0	9	139
U.S. Total	**213,308**	**946**	**21,640**	**23,739**	**23,904**	**27,082**	**22,834**	**425**	**1,197**	**19,373**	**220,416**

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

Note: The prouction 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 2006 contained in the *Natural Gas Annual 2006,* DOE/EIA-0131(06).

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

Table 10. Nonassociated Natural Gas Proved Reserves, Reserves Changes, and Production, Wet After Lease Separation, 2006 (Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State and Subdivision	Published Proved Reserves 12/31/05	Changes in Reserves During 2006									Proved Reserves 12/31/06
		Adjustments (+,–)	Revision Increases (+)	Revision Decreases (–)	Sales (–)	Acquisitions (+)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Estimated Production (–)	
Alaska	1,875	-49	32	267	0	0	46	0	2	192	1,447
Lower 48 States	**183,197**	**1,049**	**16,236**	**20,690**	**22,178**	**25,122**	**21,978**	**385**	**1,130**	**16,900**	**189,329**
Alabama	3,977	-3	234	205	188	259	150	0	7	286	3,945
Arkansas	1,921	-31	99	112	4	5	492	7	33	183	2,227
California	799	-11	67	49	154	47	165	0	4	88	780
Coastal Region Onshore	8	0	0	0	2	0	0	0	0	0	6
Los Angeles Basin Onshore	0	0	0	0	0	0	0	0	0	0	0
San Joaquin Basin Onshore	790	-11	65	49	152	47	165	0	1	87	769
State Offshore	1	0	2	0	0	0	0	0	3	1	5
Colorado	15,796	44	981	1,536	1,009	1,009	1,929	15	27	1,115	16,141
Florida	0	0	0	0	0	0	0	0	0	0	0
Kansas	4,515	100	839	1,071	19	14	99	0	3	365	4,115
Kentucky	2,210	24	53	22	459	568	24	0	5	70	2,333
Louisiana	10,091	98	1,129	1,391	449	713	1,022	29	189	1,282	10,149
North	6,670	-18	597	757	57	190	626	0	4	550	6,705
South Onshore	3,051	127	476	586	338	498	321	11	151	653	3,058
State Offshore	370	-11	56	48	54	25	75	18	34	79	386
Michigan	2,808	112	406	290	45	24	88	0	5	183	2,925
Mississippi	738	-23	94	39	39	29	112	0	4	81	795
Montana	837	12	15	60	1	0	123	20	28	100	874
New Mexico	17,683	159	1,023	1,136	6,399	6,390	758	39	147	1,332	17,332
East	2,569	110	332	408	121	112	312	39	0	340	2,605
West	15,114	49	691	728	6,278	6,278	446	0	147	992	14,727
New York	346	33	22	38	55	52	5	45	0	49	361
North Dakota	165	18	12	10	1	0	16	0	0	18	182
Ohio	714	110	32	81	11	83	17	0	0	63	801
Oklahoma	17,337	-97	1,435	1,881	858	1,254	2,136	0	13	1,604	17,735
Pennsylvania	2,659	-129	183	214	6	235	337	14	0	166	2,913
Texas	53,175	875	5,953	7,636	4,751	6,401	9,768	80	241	5,370	58,736
RRC District 1	1,148	83	32	186	0	4	72	2	0	107	1,048
RRC District 2 Onshore	2,066	224	212	530	132	192	313	10	19	326	2,048
RRC District 3 Onshore	2,961	28	401	454	412	307	391	20	52	505	2,789
RRC District 4 Onshore	8,956	302	860	1,900	1,198	1,235	1,188	24	90	1,193	8,364
RRC District 5	9,560	72	2,316	685	664	807	1,961	4	0	780	12,591
RRC District 6	8,999	88	825	1,703	532	889	1,395	1	0	757	9,205
RRC District 7B	859	-94	212	72	53	62	765	0	0	90	1,589
RRC District 7C	4,665	42	110	653	108	138	673	0	0	336	4,531
RRC District 8	3,829	16	277	537	887	1,055	465	2	8	337	3,891
RRC District 8A	85	34	5	38	0	3	5	0	0	12	82
RRC District 9	4,608	-14	140	188	560	1,433	1,669	0	0	428	6,660
RRC District 10	5,177	81	548	655	136	216	871	0	0	468	5,634
State Offshore	262	13	15	35	69	60	0	17	72	31	304
Utah	4,051	-22	184	472	1,145	1,199	1,382	40	0	323	4,894
Virginia	2,018	25	234	14	133	154	114	6	0	102	2,302
West Virginia	4,553	-227	308	193	769	914	236	3	5	192	4,638
Wyoming	24,338	5	1,365	2,335	3,362	3,502	2,286	0	31	1,714	24,116
Federal Offshore[a]	12,348	-11	1,559	1,887	2,317	2,264	690	87	388	2,206	10,915
Pacific (California)	49	0	8	0	0	0	0	0	0	2	55
Gulf of Mexico (Louisiana)[a]	9,492	-10	1,274	1,445	1,261	1,150	487	58	329	1,574	8,500
Gulf of Mexico (Texas)	2,807	-1	277	442	1,056	1,114	203	29	59	630	2,360
Miscellaneous[b]	118	-12	9	18	4	6	29	0	0	8	120
U.S. Total	**185,072**	**1,000**	**16,268**	**20,957**	**22,178**	**25,122**	**22,024**	**385**	**1,132**	**17,092**	**190,776**

[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 2006 contained in the *Natural Gas Annual 2006,* DOE/EIA-0131(06).

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, 2006 (Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

State and Subdivision	Published Proved Reserves 12/31/05	Changes in Reserves During 2006: Adjustments (+,–)	Revision Increases (+)	Revision Decreases (–)	Sales (–)	Acquisitions (+)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Estimated Production (–)	Proved Reserves 12/31/06
Alaska	6,362	-1	2,850	111	0	0	4	0	0	218	8,886
Lower 48 States	**21,874**	**-53**	**2,522**	**2,671**	**1,726**	**1,960**	**806**	**40**	**65**	**2,063**	**20,754**
Alabama	29	1	4	8	4	0	0	0	0	4	18
Arkansas	46	3	2	2	0	0	0	0	0	5	44
California	2,585	-62	96	391	133	219	21	0	0	180	2,155
Coastal Region Onshore	269	-64	29	12	70	60	5	0	0	9	208
Los Angeles Basin Onshore	186	-1	7	31	37	41	4	0	0	8	161
San Joaquin Basin Onshore	2,041	2	53	341	26	118	11	0	0	157	1,701
State Offshore	89	1	7	7	0	0	1	0	0	6	85
Colorado	1,326	-2	234	35	578	579	113	0	0	96	1,541
Florida	87	1	0	35	0	0	0	0	0	3	50
Kansas	83	3	23	19	0	0	1	0	0	9	82
Kentucky	30	-1	7	0	0	0	0	0	0	0	36
Louisiana	588	-3	93	62	70	49	27	0	3	64	561
North	98	-2	13	11	0	1	0	0	0	9	90
South Onshore	427	7	72	46	66	46	20	0	3	48	415
State Offshore	63	-8	8	5	4	2	7	0	0	7	56
Michigan	153	0	61	5	3	3	0	1	0	18	192
Mississippi	20	0	1	1	5	0	7	0	2	3	21
Montana	161	1	51	19	19	17	22	0	0	19	195
New Mexico	1,661	-21	346	156	213	255	93	0	0	193	1,772
East	1,563	-21	334	135	205	247	93	0	0	186	1,690
West	98	0	12	21	8	8	0	0	0	7	82
New York	3	-1	0	0	0	0	0	0	0	0	2
North Dakota	343	2	67	24	59	45	18	1	4	40	357
Ohio	184	18	17	31	0	0	1	0	0	15	174
Oklahoma	809	-34	173	102	13	21	41	0	0	95	800
Pennsylvania	134	12	3	11	0	0	24	0	0	11	151
Texas	7,003	16	755	712	155	406	322	4	24	594	7,069
RRC District 1	57	4	6	4	0	0	5	0	0	7	61
RRC District 2 Onshore	109	-2	8	7	14	14	24	0	0	14	118
RRC District 3 Onshore	445	-10	41	52	25	110	22	2	23	67	489
RRC District 4 Onshore	148	2	21	39	9	1	0	0	1	15	110
RRC District 5	51	0	12	1	0	0	1	0	0	6	57
RRC District 6	344	6	65	113	1	5	21	0	0	51	276
RRC District 7B	73	-1	10	4	1	3	5	0	0	11	74
RRC District 7C	1,037	7	80	55	16	120	99	0	0	76	1,196
RRC District 8	2,971	1	300	270	68	148	87	0	0	205	2,964
RRC District 8A	1,386	-2	117	106	12	2	15	0	0	98	1,302
RRC District 9	126	-6	11	11	2	1	1	0	0	15	105
RRC District 10	253	17	84	50	5	2	42	2	0	29	316
State Offshore	3	0	0	0	2	0	0	0	0	0	1
Utah	308	1	36	37	16	5	44	6	0	30	317
Virginia	0	0	0	0	0	0	0	0	0	0	0
West Virginia	19	0	0	2	0	0	0	0	0	1	16
Wyoming	384	9	26	35	3	1	11	1	0	47	347
Federal Offshore[a]	5,904	0	525	984	455	360	61	27	32	635	4,835
Pacific (California)	776	1	35	22	0	0	0	0	1	35	756
Gulf of Mexico (Louisiana)[a]	4,581	0	384	827	320	234	60	27	24	462	3,701
Gulf of Mexico (Texas)	547	-1	106	135	135	126	1	0	7	138	378
Miscellaneous[b]	14	4	2	0	0	0	0	0	0	1	19
U.S. Total	**28,236**	**-54**	**5,372**	**2,782**	**1,726**	**1,960**	**810**	**40**	**65**	**2,281**	**29,640**

[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 2006 contained in the *Natural Gas Annual 2006*, DOE/EIA-0131(06).

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

discoveries in old fields and their percentage of the total were the Gulf of Mexico Federal Offshore (409 billion cubic feet; 35 percent of the total), Texas (253 billion cubic feet; 22 percent of the total), Louisiana (185 billion cubic feet; 16 percent of the total), and New Mexico (140 billion cubic feet; 12 percent of the total).

In the prior 10 years, U.S. operators had reported an annual average of 2,074 billion cubic feet of reserves from new reservoirs discovered in old fields. Reserves from new reservoirs discovered in old fields in 2006 were 44 percent less than that average.

Revisions and Adjustments

There were 20,833 billion cubic feet of revision increases, 22,669 billion cubic feet of revision decreases, and 743 billion cubic feet of adjustments in 2006. Net revisions and adjustments were therefore a net loss of 1,093 billion cubic feet in 2006. The previous occurrence of negative net revisions was in 1988. In the prior 10 years, operators reported net revisions and adjustments of 4,535 billion cubic feet.

Sales and Acquisitions

Sales represents that volume of dry natural gas proved reserves deducted from an operator's total reserves through sale or transfer of operations of an existing gas field or property to another operator (not a volume of production "sold" at the wellhead). Similarly, acquisitions are that volume of proved reserves added to an operator's total reserves by purchase or transfer of operations of an existing gas field or property.

There are several reasons why sales and acquisitions volumes are not equal. Since operators have different engineering staffs and resources, or different development plans or schedules, the estimate of proved reserves for a field can change with a change in operatorship. Timing of the transfer of operations can also impact these values.

There were 22,850 billion cubic feet of sales transactions between operators in 2006, and 25,846 billion cubic feet of acquisitions. The net difference of 2,996 billion cubic feet was added to the national total of dry natural gas proved reserves in 2006.

Production

The estimated 2006 U.S. dry natural gas production was 18,545 billion cubic feet (**Table 8**), a slight increase from 2005 (18,458 billion cubic feet). Areas with the largest production and their percentage of total production were:

Area	Percent of 2006 U.S. Dry Gas Production
Texas	30
Gulf of Mexico Federal Offshore	15
Wyoming	9
Oklahoma	9
New Mexico	8
Louisiana	7
Colorado	6
Area Total	**84**

Wet Natural Gas

U. S. proved reserves of wet natural gas as of December 31, 2006 were 220,416 billion cubic feet, a 3 percent increase over the volume reported in 2005 (**Table 9**). At year-end 2006, proved wet natural gas reserves for the lower 48 States had increased by 2 percent compared to 2005, while those of Alaska had increased by 25 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. See Appendix F for a discussion of the methodology used to generate the wet and dry natural gas reserves estimates tabulated in this report.

Nonassociated Natural Gas

Proved Reserves

Proved reserves of nonassociated (NA) natural gas, wet after lease separation, in the United States increased by 3 percent (5,704 billion cubic feet) in 2006 to 190,776 billion cubic feet (**Table 10**). The lower 48 States' NA wet natural gas proved reserves increased 3 percent to a level of 189,329 billion cubic feet, while Alaska had a 23 percent decline to a level of 1,447 billion cubic feet.

Seven areas accounted for 81 percent of U.S. NA natural gas proved reserves in 2006:

Area	Percent of 2006 U.S. NA Gas Reserves
Texas	31
Wyoming	13
Oklahoma	9
New Mexico	9
Colorado	8
Gulf of Mexico Federal Offshore	6
Louisiana	5
Area Total	**81**

Total Discoveries

NA wet natural gas *total discoveries* of 23,541 billion cubic feet in 2006 were 2 percent more than the 2005 total of 23,055 billion cubic feet. Areas with the most *total discoveries* of nonassociated natural gas in 2006 were Texas (10,089 billion cubic feet), Wyoming (2,317 billion cubic feet), Oklahoma (2,149 billion cubic feet), Colorado (1,971 billion cubic feet), Utah (1,422 billion cubic feet), Louisiana (1,240 billion cubic feet), and the Gulf of Mexico Federal Offshore (1,165 billion cubic feet).

Production

U.S. production of NA wet natural gas increased 2 percent from an estimated 16,827 billion cubic feet in 2005 to 17,092 billion cubic feet in 2006. The leading producing areas were Texas (31 percent of the national total), the Gulf of Mexico Federal Offshore (13 percent), Wyoming (10 percent), Oklahoma (9 percent), New Mexico (8 percent), Louisiana (8 percent), and Colorado (7 percent).

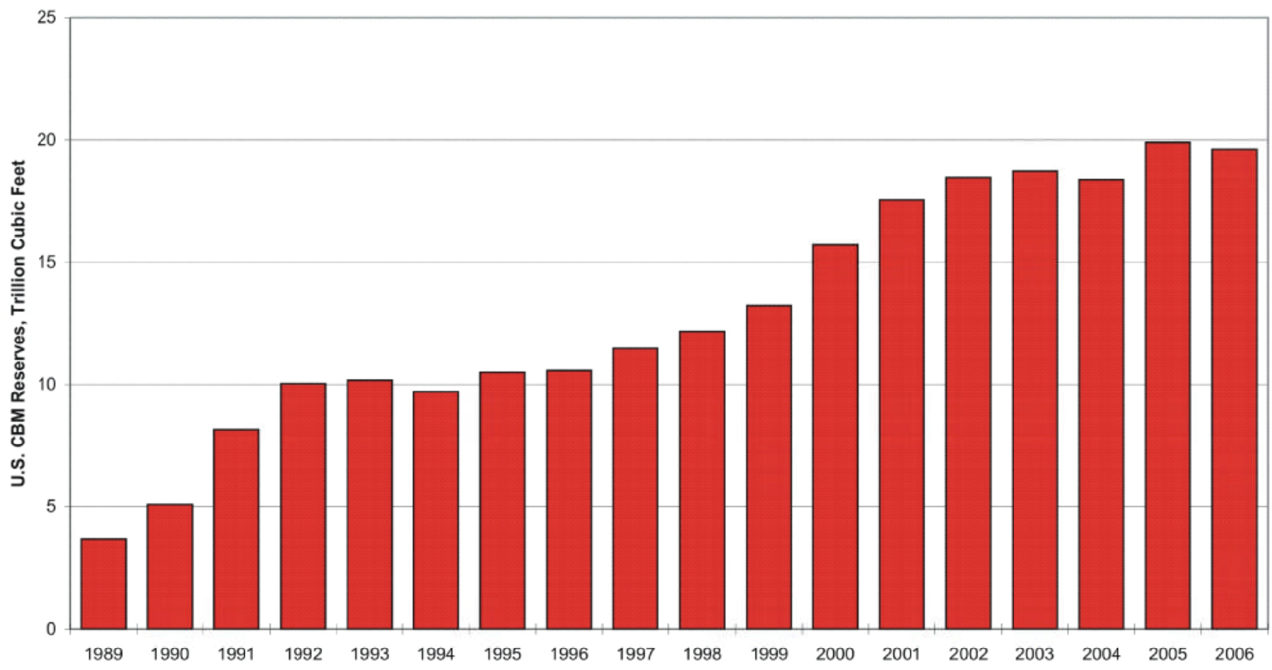
Associated-Dissolved Natural Gas

Proved Reserves

Proved reserves of associated-dissolved (AD) natural gas, wet after lease separation, in the United States increased 5 percent to 29,640 billion cubic feet in 2006 (**Table 11**). Proved reserves of AD wet natural gas in Alaska increased 40 percent to 8,886 billion cubic feet, and decreased in the lower 48 States by 5 percent to 20,754 billion cubic feet.

The areas of the country with the largest AD wet natural gas reserves and their percentage of the total were:

Figure 21. Coalbed Natural Gas Proved Reserves, 1989-2006



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

Area	Percent of 2006 U.S. AD Gas Reserves
Alaska	30
Texas	24
Gulf of Mexico Federal Offshore	14
California	7
New Mexico	6
Area Total	**81**

These areas logically correspond to the areas of the country with the largest volumes of crude oil reserves. For the first time Alaska's AD gas proved reserves surpass those of Texas.

Production

U.S. production of AD wet natural gas decreased 6 percent from an estimated 2,432 billion cubic feet in 2005 to 2,281 billion cubic feet in 2006 (**Table 11**). Production of AD wet natural gas in the lower 48 States decreased from 2,174 billion cubic feet in 2005 to 2,063 billion cubic feet in 2006, a decline of 5 percent. Although Alaska's AD gas reserves were revised significantly upward, its production declined 16 percent from 258 billion cubic feet in 2005 to 218 billion cubic feet in 2006. The areas of the country with the largest AD wet natural gas production and their percentage of the total were:

Area	Percent of 2006 U.S. AD Gas Production
Gulf of Mexico Federal Offshore	26
Texas	26
Alaska	10
New Mexico	8
California	8
Area Total	**78**

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

Coalbed Natural Gas

Proved Reserves

Proved reserves of coalbed natural gas decreased from 19,892 billion cubic feet in 2005 to 19,620 billion cubic feet in 2006, a 1 percent decline (**Figure 21**). Coalbed natural gas accounted for 9 percent of all 2006 dry natural gas reserves (**Table 12**). Six States (Alabama, Colorado, New Mexico, Utah, Virginia, and Wyoming) currently have the vast majority (93 percent) of U.S. coalbed natural gas proved reserves. Three of them (Colorado, New Mexico, and Utah) reported declines in their proved coalbed natural gas reserves in 2006.

Production

U.S. coalbed natural gas production increased 2 percent in 2006 to 1,758 billion cubic feet. It accounted for 9 percent of U.S. dry natural gas production.

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 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.

Texas

Texas had a 9 percent increase in dry natural gas proved reserves in 2006 (5,329 billion cubic feet), the largest of any State. Production also increased 3 percent. This resulted primarily from extensions in the Newark East Field in north central Texas and natural gas fields in the Permian Basin of west Texas.

- **Newark East Field**: On May 2, 2006 Devon Energy Corporation announced Devon's outlook for the Barnett Shale has been greatly enhanced by the results of its successful 20-acre infill well pilot program. The company increased its estimated recoveries for 20-acre infill horizontal wells from 1.8 Bcfe per well to 2.0 Bcfe per well. The increase is based upon the results to date of 29 horizontal infill wells drilled on its core acreage. Ultimately, Devon expects to drill infill wells on both its core and non-core acreage. {43}

Alaska

Alaska's dry natural gas reserves increased by 25 percent (2,074 billion cubic feet) in 2006. This resulted primarily from revision increases of associated dissolved natural gas.

Table 12. Coalbed Natural Gas Proved Reserves and Production for 1989–2006
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

Year	Alabama	Colorado	New Mexico	Utah	Wyoming	Virginia	Eastern States[a]	Western States[b]	Others[c]	United States
					Reserves					
1989	537	1,117	2,022	NA	NA	NA	NA	NA	0	3,676
1990	1,224	1,320	2,510	NA	NA	NA	NA	NA	33	5,087
1991	1,714	2,076	4,206	NA	NA	NA	NA	NA	167	8,163
1992	1,968	2,716	4,724	NA	NA	NA	NA	NA	626	10,034
1993	1,237	3,107	4,775	NA	NA	NA	NA	NA	1,065	10,184
1994	976	2,913	4,137	NA	NA	NA	NA	NA	1,686	9,712
1995	972	3,461	4,299	NA	NA	NA	NA	NA	1,767	10,499
1996	823	3,711	4,180	NA	NA	NA	NA	NA	1,852	10,566
1997	1,077	3,890	4,351	NA	NA	NA	NA	NA	2,144	11,462
1998	1,029	4,211	4,232	NA	NA	NA	NA	NA	2,707	12,179
1999	1,060	4,826	4,080	NA	NA	NA	NA	NA	3,263	13,229
2000	1,241	5,617	4,278	1,592	1,540	NA	1,399	41	--	15,708
2001	1,162	6,252	4,324	1,685	2,297	NA	1,453	358	--	17,531
2002	1,283	6,691	4,380	1,725	2,371	NA	1,488	553	--	18,491
2003	1,665	6,473	4,396	1,224	2,759	NA	1,528	698	--	18,743
2004	1,900	5,787	5,166	934	2,085	NA	1,620	898	--	18,390
2005	1,773	6,772	5,249	902	2,446	NA	1,822	928	--	19,892
2006	2,068	6,344	4,894	750	2,448	1,813	273	1,030	--	19,620
					Production					
1989	23	12	56	NA	NA	NA	NA	NA	0	91
1990	36	26	133	NA	NA	NA	NA	NA	1	196
1991	68	48	229	NA	NA	NA	NA	NA	3	348
1992	89	82	358	NA	NA	NA	NA	NA	10	539
1993	103	125	486	NA	NA	NA	NA	NA	18	752
1994	108	179	530	NA	NA	NA	NA	NA	34	851
1995	109	226	574	NA	NA	NA	NA	NA	47	956
1996	98	274	575	NA	NA	NA	NA	NA	56	1,003
1997	111	312	597	NA	NA	NA	NA	NA	70	1,090
1998	123	401	571	NA	NA	NA	NA	NA	99	1,194
1999	108	432	582	NA	NA	NA	NA	NA	130	1,252
2000	109	451	550	74	133	NA	58	NA	--	1,379
2001	111	490	517	83	278	NA	69	NA	--	1,562
2002	117	520	471	103	302	NA	68	NA	--	1,614
2003	98	488	451	97	344	NA	71	NA	--	1,600
2004	121	520	528	82	320	NA	72	NA	--	1,720
2005	113	515	514	75	336	NA	90	NA	--	1,732
2006	114	477	510	66	378	81	24	108	--	1,758

[a]Includes Illinois, Indiana, Ohio, Pennsylvania, Virginia, and West Virginia. In 2006, Virginia is individually listed.
[b]Includes Arkansas, Kansas, Louisiana, Montana, and Oklahoma.
[c]Includes Oklahoma, Pennsylvania, Utah, Virginia, West Virginia, and Wyoming. These states are individually listed or grouped in Eastern States and Western States for 2000-2006.
NA -- Not applicable.
Source: Energy Information Administration, Office of Oil and Gas.

Utah

Utah's dry natural gas reserves increased by 20 percent (851 billion cubic feet) in 2006. This was the result of development of the Greater Natural Buttes Field, a tight natural gas play.

- **Greater Natural Buttes Field**: Kerr-McGee Oil & Gas Onshore LP (KMG) a wholly-owned subsidiary of Anadarko Petroleum Corporation proposed to conduct infill drilling to develop the hydrocarbon resources from oil and gas leases within the Greater Natural Buttes Project Area in Uintah County, Utah. KMG's plan is to drill 3,496 additional wells over a period of 10 years on 40-acre and 20-acre surface spacing throughout the project area. {44}

Areas of Note: Large Reserves Declines

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

Gulf of Mexico Federal Offshore

The Gulf of Mexico Federal Offshore continues to physically recover from the storm damage of Hurricanes Katrina and Rita. However, proved dry natural gas reserves in the Gulf of Mexico Federal Offshore decreased by 14 percent (-2,458 billion cubic feet) in 2006. Downward revisions of the reserves of existing gas fields exceeded upward revisions by 778 billion cubic feet. Production also decreased by 6 percent from 2,906 billion cubic feet in 2005 to 2,738 billion cubic feet in 2006.

For a more complete assessment of the 2005 hurricane damage effects, readers should consult the joint report prepared by the Energy Information Administration, Office of Oil and Gas and the U.S. Department of Energy, Office of Fossil Energy entitled *"Impact of the 2005 Hurricanes on the Natural Gas Industry in the Gulf of Mexico Region."*which was published in July 2006.

California

California's proved dry natural gas reserves decreased by 7 percent (-434 billion cubic feet) in 2006. Production in California decreased 5 percent (-13 billion cubic feet) in 2006.

Kansas

Kansas' proved dry natural gas reserves decreased by 9 percent (-383 billion cubic feet) in 2006. Production in Kansas decreased 8 percent (-30 billion cubic feet) in 2006.

Reserves in Nonproducing Status

Nonproducing proved natural gas reserves (wet after lease separation) of 66,714 billion cubic feet were reported in 2006, 12 percent more than the 59,658 billion cubic feet reported in 2005 (**Appendix D, Table D10**). About 35 percent of the reserves in nonproducing status are located in Texas. Another 12 percent are in the Gulf of Mexico Federal Offshore, as most new deepwater reserves are in the nonproducing category. Wells or reservoirs are nonproducing due to any of several operational reasons. These include awaiting well workovers, the drilling of extensions or additional development wells, installation of production or pipeline facilities, and 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 4 percent to 8,472 million barrels in 2006 (**Table 13**). Reserves additions replaced 138 percent of 2006 natural gas liquids production.

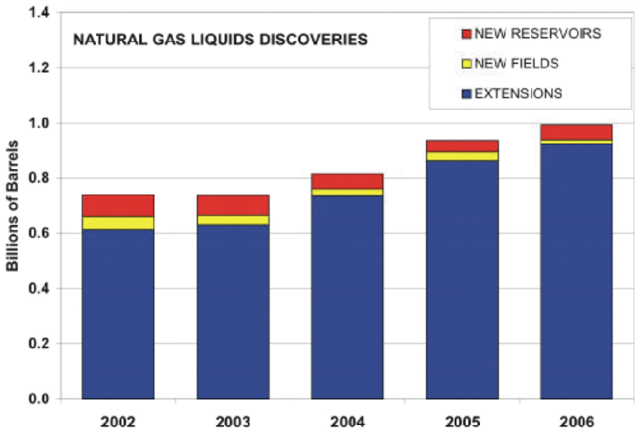
The reserves of seven areas accounted for 88 percent of the Nation's natural gas liquids proved reserves.

Area	Percent of U.S. NGL Reserves
Texas	39
Oklahoma	11
Utah and Wyoming	10
New Mexico	10
Gulf of Mexico Federal Offshore	8
Colorado	6
Alaska	4
Area Total	**88**

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.**

Total Discoveries

Total discoveries of natural gas liquids reserves were 993 million barrels in 2006, an increase of 6 percent from 2005 (937 million barrels) (see graph below).



Areas with the largest total discoveries were:

Area	Percent of U.S. NGL Total Discoveries
Texas	53
Utah and Wyoming	12
Oklahoma	11
Gulf of Mexico Federal Offshore	6
Colorado	6
New Mexico	5
Louisiana	5
Area Total	**98**

Extensions

Extensions were 924 million barrels in 2006, 7 percent more than the 2005 volume of 863 million barrels. Areas with the largest extensions were Texas (55 percent of the National total), Utah and Wyoming (13 percent), Oklahoma (11 percent), and Colorado (6 percent).

New Field Discoveries

New field discoveries in 2006 (16 million barrels) were 50 percent lower than in 2005 (32 million barrels). Areas with the largest new field discoveries were the Gulf of Mexico Federal Offshore (38 percent) and Texas (31 percent).

New Reservoir Discoveries in Old Fields

New reservoir discoveries in old fields in 2006 (53 million barrels) were 26 percent higher than they were in 2005 (42 million barrels). Areas with the largest new reservoir discoveries in old fields were the Gulf of Mexico Federal Offshore (36 percent of the National total), Louisiana (26 percent), and Texas (23 percent).

Revisions and Adjustments

In 2006, there were 845 million barrels of revision increases, 1,010 million barrels of revision decreases, and 173 million barrels of adjustments. The net of revisions and adjustments was 8 million barrels.

Table 13. Natural Gas Liquids Proved Reserves, Reserves Changes, and Production, 2006[a]
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	Published Proved Reserves 12/31/05	Adjustments (+,–)	Revision Increases (+)	Revision Decreases (–)	Sales (–)	Acquisitions (+)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries in Old Fields (+)	Estimated Production (–)	Proved Reserves 12/31/06
		Changes in Reserves During 2006									
Alaska	352	0	0	0	0	0	0	0	0	14	338
Lower 48 States	**7,813**	**173**	**845**	**1,010**	**931**	**1,048**	**924**	**16**	**53**	**797**	**8,134**
Alabama	61	9	5	5	17	5	3	0	0	5	56
Arkansas	3	2	0	1	0	0	0	0	0	0	4
California	137	8	8	19	17	18	8	0	0	11	132
Coastal Region Onshore	16	5	3	1	7	6	1	0	0	1	22
Los Angeles Basin Onshore	9	0	0	2	2	5	0	0	0	0	10
San Joaquin Basin Onshore	112	3	5	16	8	7	7	0	0	10	100
State Offshore	0	0	0	0	0	0	0	0	0	0	0
Colorado	484	-14	34	41	70	62	54	0	1	32	478
Florida	7	-2	0	2	0	0	0	0	0	0	3
Kansas	224	8	44	54	1	1	6	0	0	19	209
Kentucky	70	30	3	1	21	26	1	0	0	3	105
Louisiana	292	-14	46	51	24	30	36	1	14	50	280
North	83	2	10	11	2	4	11	0	0	8	89
South Onshore	168	-5	32	36	18	25	18	0	11	36	159
State Offshore	41	-11	4	4	4	1	7	1	3	6	32
Michigan	39	-1	10	3	1	0	1	0	0	3	42
Mississippi	7	0	1	0	0	0	1	0	0	1	8
Montana	9	1	1	1	0	0	1	0	0	1	10
New Mexico	840	35	81	67	265	264	44	2	5	78	861
East	271	23	47	38	27	26	28	2	0	37	295
West	569	12	34	29	238	238	16	0	5	41	566
North Dakota	49	6	8	3	6	4	3	0	0	6	55
Oklahoma	839	13	88	96	38	61	105	0	1	81	892
Texas	3,080	53	331	441	243	346	505	5	12	313	3,335
RRC District 1	36	8	4	6	0	0	3	1	0	4	42
RRC District 2 Onshore	91	12	12	24	6	7	13	0	1	16	90
RRC District 3 Onshore	226	20	33	41	31	25	37	2	6	43	234
RRC District 4 Onshore	309	41	55	77	44	47	46	1	4	49	333
RRC District 5	48	-8	10	3	5	8	7	0	0	4	53
RRC District 6	333	16	37	72	20	37	57	0	0	31	357
RRC District 7B	90	-24	18	6	4	5	62	0	0	8	133
RRC District 7C	411	16	25	53	9	19	61	0	0	31	439
RRC District 8	575	-15	52	67	77	97	45	0	1	45	566
RRC District 8A	250	3	20	24	2	1	3	0	0	18	233
RRC District 9	285	-16	11	12	35	83	95	0	0	26	385
RRC District 10	423	1	53	56	10	17	76	0	0	38	466
State Offshore	3	-1	1	0	0	0	0	1	0	0	4
Utah and Wyoming	879	-28	58	87	106	112	118	2	1	62	887
West Virginia	85	19	7	5	18	21	6	0	0	5	110
Federal Offshore[b]	696	47	118	132	104	97	31	6	19	125	653
Pacific (California)	8	1	0	5	0	0	0	0	0	0	4
Gulf of Mexico (Louisiana)[b]	603	44	99	107	84	72	26	6	18	102	575
Gulf of Mexico (Texas)	85	2	19	20	20	25	5	0	1	23	74
Miscellaneous[c]	12	1	2	1	0	1	1	0	0	2	14
U.S. Total	**8,165**	**173**	**845**	**1,010**	**931**	**1,048**	**924**	**16**	**53**	**811**	**8,472**

[a]This table is natural gas plant liquids (Table 14) plus lease condensate (Table 15).
[b]Includes Federal offshore Alabama.
[c]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 2005 contained in the publications *Petroleum Supply Annual 2005*, DOE/EIA-0340(05) and *Natural Gas Annual 2005* DOE/EIA-0131(05).

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

Table 14. Natural Gas Plant Liquids Proved Reserves and Production, 2006
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	2006 Reserves	2006 Production
Alaska	338	14
Lower 48 States	**6,795**	**615**
Alabama	41	3
Arkansas	2	0
California	130	11
Coastal Region Onshore	22	1
Los Angeles Basin Onshore	8	0
San Joaquin Basin Onshore	100	10
State Offshore	0	0
Colorado	382	26
Florida	3	0
Kansas	204	18
Kentucky	104	3
Louisiana	176	28
North	60	5
South Onshore	94	19
State Offshore	22	4
Michigan	36	2
Mississippi	2	0
Montana	10	1
New Mexico	804	68
East	264	32
West	540	36
North Dakota	51	6
Oklahoma	732	67
Texas	2,913	260
RRC District 1	32	3
RRC District 2 Onshore	74	12
RRC District 3 Onshore	159	28
RRC District 4 Onshore	246	35
RRC District 5	42	3
RRC District 6	279	24
RRC District 7B	131	8
RRC District 7C	404	29
RRC District 8	547	43
RRC District 8A	231	18
RRC District 9	372	24
RRC District 10	396	33
State Offshore	0	0
Utah and Wyoming	686	49
West Virginia	109	5
Federal Offshore[a]	399	67
Pacific (California)	0	0
Gulf of Mexico (Louisiana)[a]	390	65
Gulf of Mexico (Texas)	9	2
Miscellaneous[b]	11	1
U.S. Total	**7,133**	**629**

[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 2006 contained in the publications *Petroleum Supply Annual 2006, DOE/EIA-0340(2006) and Natural Gas Annual 2006*, DOE/EIA-0131(2006).

Table 15. Lease Condensate Proved Reserves and Production, 2006
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	2006 Reserves	2006 Production
Alaska	0	0
Lower 48 States	**1,339**	**182**
Alabama	15	2
Arkansas	2	0
California	2	0
Coastal Region Onshore	0	0
Los Angeles Basin Onshore	2	0
San Joaquin Basin Onshore	0	0
State Offshore	0	0
Colorado	96	6
Florida	0	0
Kansas	5	1
Kentucky	1	0
Louisiana	104	22
North	29	3
South Onshore	65	17
State Offshore	10	2
Michigan	6	1
Mississippi	6	1
Montana	0	0
New Mexico	57	10
East	31	5
West	26	5
North Dakota	4	0
Oklahoma	160	14
Texas	422	53
RRC District 1	10	1
RRC District 2 Onshore	16	4
RRC District 3 Onshore	75	15
RRC District 4 Onshore	87	14
RRC District 5	11	1
RRC District 6	78	7
RRC District 7B	2	0
RRC District 7C	35	2
RRC District 8	19	2
RRC District 8A	2	0
RRC District 9	13	2
RRC District 10	70	5
State Offshore	4	0
Utah and Wyoming	201	13
West Virginia	1	0
Federal Offshore[a]	254	58
Pacific (California)	4	0
Gulf of Mexico (Louisiana)[a]	185	37
Gulf of Mexico (Texas)	65	21
Miscellaneous[b]	3	1
U.S. Total	**1,339**	**182**

[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" 2006.
Source: Energy Information Administration, Office of Oil and Gas.

Sales and Acquisitions

There were 1,048 million barrels of acquisitions and 931 million barrels of sales in 2006. The net of these transactions added 117 million barrels of natural gas liquids proved reserves.

Production

Natural gas liquids production was an estimated 811 million barrels in 2006, an increase of 3 percent from 2005's production (788 million barrels).

Six areas accounted for about 88 percent of the Nation's natural gas liquids production.

Area	Percent of U.S. NGL Production
Texas	39
Gulf of Mexico Federal Offshore	15
Oklahoma	10
New Mexico	10
Utah and Wyoming	8
Louisiana	6
Area Total	**88**

Natural Gas Plant Liquids

Proved Reserves

Natural gas plant liquids proved reserves increased in 2006 to 7,133 million barrels, a 3 percent increase from the 2005 level (6,903 million barrels) (**Table 14**). Six areas accounted for about 83 percent of the Nation's natural gas plant liquids proved reserves:

Area	Percent of U.S. Gas Plant Liquids
Texas	41
New Mexico	11
Oklahoma	10
Utah and Wyoming	10
Gulf of Mexico Federal Offshore	6
Colorado	5
Area Total	**83**

Production

Natural gas plant liquids production increased 2 percent in 2006—from 614 million barrels in 2005 to 629 million barrels of production (**Table 14**).

At the time of the Form EIA-64A survey mailout, the number of unique active U.S. natural gas processing plants had increased from 489 in 2005 to 491 in 2006.

The top six areas for proved reserves of natural gas plant liquids accounted for about 86 percent of the Nation's natural gas plant liquids production:

Area	Percent of U.S. Gas Plant Liquids Production
Texas	41
New Mexico	11
Oklahoma	11
Gulf of Mexico Federal Offshore	11
Utah and Wyoming	8
Colorado	4
Area Total	**86**

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 1,339 million barrels in 2006 (**Table 15**). This was 6 percent higher than the volume reported in 2005 (1,262 million barrels). The reserves of five areas accounted for about 86 percent of the Nation's lease condensate proved reserves.

Area	Percent of U.S. Condensate Reserves
Texas	32
Gulf of Mexico Federal Offshore	19
Utah and Wyoming	15
Oklahoma	12
Louisiana	8
Area Total	**86**

Production

Production of lease condensate was 182 million barrels in 2006, an increase of 5 percent from 2005's production (174 million barrels). The production of five areas accounted for about 88 percent of the Nation's lease condensate production.

Area	Percent of U.S. Condensate Production
Gulf of Mexico Federal Offshore	32
Texas	29
Louisiana	12
Oklahoma	8
Utah and Wyoming	7
Area Total	**88**

Reserves in Nonproducing Status

Like crude oil and natural gas, not all lease condensate proved reserves were producing during 2006. Proved reserves of 504 million barrels of lease condensate, an increase of 17 percent from 2005's level (430 million barrels), were reported in nonproducing status in 2006 (**Appendix D, Table D10**). About 27 percent of the nonproducing lease condensate reserves were located in Texas and 26 percent were in the Gulf of Mexico Federal Offshore.

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Appendix A

Operator Level Data

Appendix A

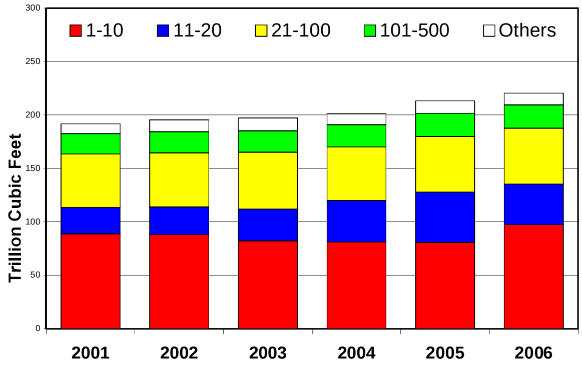
Operator Level Data

This appendix provides a series of tables of the proved reserves and production by production size class for the years 2001 through 2006 for crude oil and natural gas well operators. The tables show the volumetric change and percent change from the previous year and from 2000. In addition they show the 2006 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 14,658 small operators. We estimated production and reserves for small operators for 2006 from a sample of approximately 3 percent.

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.

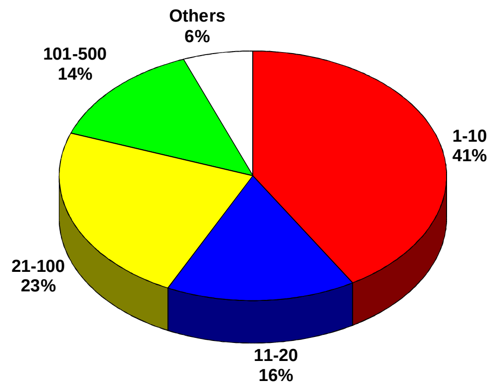
Natural Gas Proved Reserves

The wet natural gas proved reserves reported for 2001 through 2006 have changed from 191,743 billion cubic feet to 220,416 billion cubic feet (**Table A1**). These proved reserves are concentrated in the larger companies. In 2006, the top 20 operators (Class 1-10 and Class 11-20) producing companies had 61 percent of the proved reserves of natural gas. The next two size classes contain 80 and 400 companies and account for 24 and 10 percent of the U.S. natural gas proved reserves, respectively. The top 20 operators had an increase of 19 percent in their natural gas proved reserves from 2001 to 2006. The rest of the operators in (Class 21-100, Class 101-500, and Class Other) had an increase of 7 percent in their reserves in the same time period. In 2006, the top 20 operators' natural gas reserves had an increase of 6 percent from 2005.



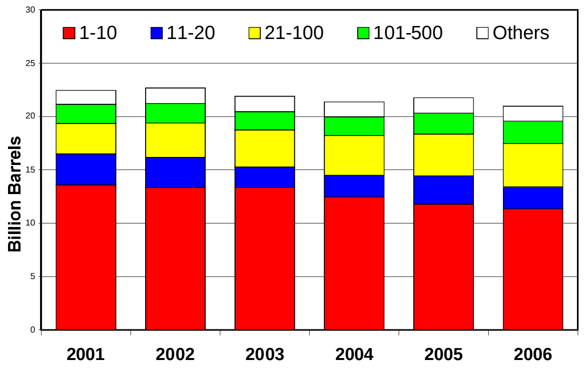
Natural Gas Production

Wet natural gas production has increased from 19,259 billion cubic feet in 2005 to 19,373 billion cubic feet in 2006 (**Table A2**). In 2006, the top 20 producing companies had 57 percent of the production of wet natural gas. The next two size classes have 23 and 13 percent of the wet natural gas production, respectively. The top 20 operators had a decrease of 9 percent in wet natural gas production from 2001 to 2006. The rest of the operators had a decrease of 3 percent from 2001 to 2006.



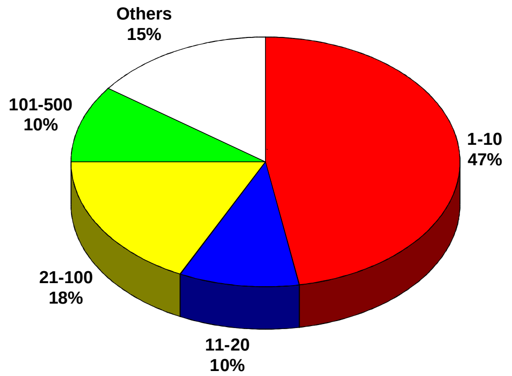
Crude Oil Proved Reserves

The 10 largest producing companies in 2006 had 54 percent of U.S. proved reserves of crude oil. The 20 largest oil and gas producing companies in 2006 had 64 percent of proved reserves of crude oil (**Table A3**), Proved reserves of crude oil decreased 4 percent in 2006 from 2005.



Crude Oil Production

Crude oil production reported for 2005 to 2006 has decreased from 1,733 million barrels to 1,652 million barrels (**Table A4**). The 20 largest oil and gas producing companies had 60 percent of U.S. production of crude oil in 2006. In 2005 they accounted for 63 percent of production.



Crude Oil and Natural Gas Fields

The number of fields in which Category I and Category II operators were active increased during the 2001-2006 period (**Table A5**). From 2001-2006, the number of fields in which the top 20 operators were active increased by 1,174 fields (20 percent) while in 2006 the number increased by 954 fields from 2005.

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.

Ranked Crude Oil and Natural Gas Production

Table A6 lists the top U.S. Oil and gas operators ranked by reported 2006 operated production data.

Table A1. Natural Gas Proved Reserves, Wet After Lease Separation, by Operator Production Size Class, 2001–2006

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

Size Class	2001	2002	2003	2004	2005	2006	2005–2006 Volume and Percent Change	2001–2006 Volume and Percent Change	2006 Average Reserves per Operator
Class 1-10	88,936	88,100	82,222	81,325	80,785	97,372	16,587	8,436	9,737.237
Percent of Total	46.4%	45.0%	41.7%	40.4%	37.9%	44.2%	20.5%	9.5%	
Class 11-20	24,588	25,938	29,890	38,643	47,078	38,134	-8,944	13,546	3,813.421
Percent of Total	12.8%	13.3%	15.2%	19.2%	22.1%	17.3%	-19.0%	55.1%	
Class 21-100	50,055	50,633	53,098	50,149	52,061	52,064	3	2,009	650.802
Percent of Total	26.1%	25.9%	26.9%	24.9%	24.4%	23.6%	0.0%	4.0%	
Class 101-500	19,046	19,723	20,030	20,912	21,737	21,877	141	2,831	54.693
Percent of Total	9.9%	10.1%	10.2%	10.4%	10.2%	9.9%	0.6%	14.9%	
Class Other (13,320)	9,118	11,167	11,905	10,170	11,647	10,968	-678	1,850	0.823
Percent of Total	4.8%	5.7%	6.0%	5.1%	5.5%	5.0%	-5.8%	20.3%	
Category I (173)	162,144	169,056	173,325	173,225	178,269	189,644	11,375	27,500	1,102.582
Percent of Total	88.2%	88.6%	87.9%	88.6%	88.9%	82.6%	-4.0%	7.7%	
Category II (467)	13,346	11,051	11,983	12,494	11,838	27,294	15,456	13,948	58.446
Percent of Total	7.0%	5.7%	6.1%	6.2%	5.5%	12.4%	130.6%	104.5%	
Category III (13,180)	9,342	11,184	11,937	10,437	11,826	10,989	-837	1,647	0.834
Percent of Total	4.9%	5.7%	6.1%	5.2%	5.5%	5.0%	-7.1%	17.6%	
Total Published	**191,743**	**195,561**	**197,145**	**201,200**	**213,308**	**220,416**	**7,108**	**28,673**	**15.949**

Note: There were 13,180 active Category III operators in the 2006 sample frame. The reserves and production of Category III operators were estimated from an adjusted sample of 700 Category III operators (Table E2). The "other" size class represents 13,320 operators in the 2006 frame (13,820 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, 2001–2006

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

Size Class	2001	2002	2003	2004	2005	2006	2005–2006 Volume and Percent Change	2001–2006 Volume and Percent Change	2006 Average Production per Operator
Class 1-10	9,019	8,996	8,220	7,617	7,068	7,956	888	-1,063	795.593
Percent of Total	43.7%	44.4%	40.6%	38.1%	36.7%	41.1%	12.6%	-11.8%	
Class 11-20	3,064	2,854	3,136	3,647	3,534	3,078	-456	14	307.847
Percent of Total	14.8%	14.1%	15.5%	18.2%	18.4%	15.9%	-12.9%	0.5%	
Class 21-100	4,949	4,763	5,275	4,982	4,832	4,492	-340	-457	56.154
Percent of Total	24.0%	23.5%	26.1%	24.9%	25.1%	23.2%	-7.0%	-9.2%	
Class 101-500	2,609	2,475	2,386	2,559	2,506	2,605	99	-4	6.513
Percent of Total	12.6%	12.2%	11.8%	12.8%	13.0%	13.4%	4.0%	-0.1%	
Class Other (13,320)	1,000	1,161	1,215	1,213	1,318	1,241	-77	241	0.093
Percent of Total	4.8%	5.7%	6.0%	6.1%	6.8%	6.4%	-5.8%	24.1%	
Category I (173)	17,672	17,335	17,347	17,036	16,311	15,092	-1,219	-2,579	87.238
Percent of Total	85.6%	85.6%	85.7%	85.1%	84.7%	77.9%	-7.5%	-14.6%	
Category II (467)	1,932	1,738	1,648	1,718	1,605	3,026	1,421	1,094	6.480
Percent of Total	9.4%	8.6%	8.1%	8.6%	8.3%	15.6%	88.5%	56.6%	
Category III (13,180)	1,038	1,176	1,236	1,263	1,342	1,255	-88	216	0.095
Percent of Total	5.0%	5.8%	6.1%	6.3%	7.0%	6.5%	-6.5%	20.8%	
Total Published	**20,642**	**20,248**	**20,231**	**20,017**	**19,259**	**19,373**	**114**	**-1,269**	**1.402**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**0.6%**	**-6.1%**	

Note: There were 13,180 active Category III operators in the 2006 sample frame. The reserves and production of Category III operators were estimated from an adjusted sample of 700 Category III operators (Table E2). The "other" size class represents 13,320 operators in the 2006 frame (13,820 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, 2001–2006
(Million Barrels of 42 U.S. Gallons)

Size Class	2001	2002	2003	2004	2005	2006	2005–2006 Volume and Percent Change	2001–2006 Volume and Percent Change	2006 Average Reserves per Operator
Class 1-10	13,590	13,346	13,355	12,454	11,775	11,352	-424	-2,239	1,135.171
Percent of Total	60.5%	58.9%	61.0%	58.3%	54.1%	54.1%	-3.6%	-16.5%	
Class 11-20	2,901	2,817	1,907	2,053	2,659	2,048	-612	-854	204.758
Percent of Total	12.9%	12.4%	8.7%	9.6%	12.2%	9.8%	-23.0%	-29.4%	
Class 21-100	2,856	3,230	3,483	3,711	3,915	4,066	151	1,210	50.827
Percent of Total	12.7%	14.2%	15.9%	17.4%	18.0%	19.4%	3.9%	42.4%	
Class 101-500	1,794	1,817	1,705	1,761	1,969	2,111	142	317	5.278
Percent of Total	8.0%	8.0%	7.8%	8.2%	9.1%	10.1%	7.2%	17.7%	
Class Other (13,320)	1,305	1,468	1,440	1,393	1,439	1,395	-43	91	0.105
Percent of Total	5.8%	6.5%	6.6%	6.5%	6.6%	6.7%	-3.0%	6.9%	
Category I (173)	20,325	20,213	19,499	19,055	19,348	17,927	-1,420	-2,398	103.626
Percent of Total	90.6%	89.1%	89.1%	89.2%	88.9%	85.5%	-7.3%	-11.8%	
Category II (467)	794	992	937	906	954	1,642	689	848	3.517
Percent of Total	3.5%	4.4%	4.3%	4.2%	4.4%	7.8%	72.2%	106.7%	
Category III (13,180)	1,326	1,472	1,456	1,410	1,456	1,403	-53	76	0.106
Percent of Total	5.9%	6.5%	6.6%	6.6%	6.7%	6.7%	-3.7%	5.8%	
Total Published	**22,446**	**22,677**	**21,891**	**21,371**	**21,757**	**20,972**	**-785**	**-1,474**	**1.518**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**-3.6%**	**-6.6%**	

Note: There were 13,180 active Category III operators in the 2006 sample frame. The reserves and production of Category III operators were estimated from an adjusted sample of 700 Category III operators (Table E2). The "other" size class represents 13,320 operators in the 2006 frame (13,820 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, 2001–2006
(Million Barrels of 42 U.S. Gallons)

Size Class	2001	2002	2003	2004	2005	2006	2005–2006 Volume and Percent Change	2001–2006 Volume and Percent Change	2006 Average Production per Operator
Class 1-10	1,061	1,037	1,047	986	912	820	-91	-240	82.042
Percent of Total	55.4%	55.3%	55.8%	54.2%	52.6%	49.7%	-10.0%	-22.6%	
Class 11-20	240	233	205	180	178	170	-7	-70	17.022
Percent of Total	12.5%	12.4%	10.9%	9.9%	10.3%	10.3%	-4.2%	-29.2%	
Class 21-100	233	240	272	303	293	309	16	76	3.866
Percent of Total	12.2%	12.8%	14.5%	16.6%	16.9%	18.7%	5.6%	32.8%	
Class 101-500	195	181	178	172	178	173	-5	-22	0.433
Percent of Total	10.2%	9.7%	9.5%	9.5%	10.3%	10.5%	-2.7%	-11.4%	
Class Other (13,320)	186	184	175	178	173	179	6	-7	0.013
Percent of Total	9.7%	9.8%	9.3%	9.8%	10.0%	10.8%	3.6%	-3.7%	
Category I (173)	1,612	1,573	1,574	1,534	1,451	1,314	-138	-299	7.593
Percent of Total	84.2%	83.9%	83.9%	84.3%	83.7%	79.5%	-9.5%	-18.5%	
Category II (467)	112	115	124	105	105	157	52	45	0.336
Percent of Total	5.8%	6.1%	6.6%	5.8%	6.1%	9.5%	49.2%	40.5%	
Category III (13,180)	191	187	179	180	176	181	5	-10	0.014
Percent of Total	10.0%	10.0%	9.5%	9.9%	10.2%	11.0%	2.8%	-5.0%	
Total Published	**1,915**	**1,875**	**1,877**	**1,819**	**1,733**	**1,652**	**-81**	**-263**	**0.120**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**-4.7%**	**-13.7%**	

Note: There were 13,180 active Category III operators in the 2006 sample frame. The reserves and production of Category III operators were estimated from an adjusted sample of 700 Category III operators (Table E2). The "other" size class represents 13,320 operators in the 2006 frame (13,820 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, 2001–2006

Size Class	2001	2002	2003	2004	2005	2006	2005–2006 Number and Percent Change	2001–2006 Number and Percent Change	2006 Average Number of Fields per Operator
Class 1-10	3,794	3,596	3,689	3,409	3,738	4,667	929	873	466.700
Percent of Total	14.0%	12.9%	13.2%	12.4%	13.2%	16.4%	24.9%	23.0%	
Class 11-20	2,212	2,392	2,492	3,352	2,488	2,513	25	301	251.300
Percent of Total	8.2%	8.6%	8.9%	12.2%	8.8%	8.8%	1.0%	13.6%	
Class 21-100	7,195	7,947	8,168	8,071	9,196	8,433	-763	1,238	105.413
Percent of Total	26.5%	28.4%	29.3%	29.4%	32.6%	29.6%	-8.3%	17.2%	
Class 101-500	12,435	12,661	11,859	10,698	10,845	11,219	374	-1,216	28.048
Percent of Total	45.9%	45.3%	42.5%	39.0%	38.4%	39.4%	3.4%	-9.8%	
Rest	1,480	1,349	1,709	1,929	1,952	1,662	-290	182	11.871
Percent of Total	5.5%	4.8%	6.1%	7.0%	6.9%	5.8%	-14.9%	12.3%	
Category I	16,196	17,049	16,760	17,368	17,858	16,953	-905	757	97.994
Percent of Total	59.7%	61.0%	60.0%	63.3%	63.3%	59.5%	-5.1%	4.7%	
Category II	10,764	10,473	10,688	9,486	9,738	11,161	1,423	397	23.899
Percent of Total	39.7%	37.5%	38.3%	34.5%	34.5%	39.2%	14.6%	3.7%	
Total	**27,116**	**27,945**	**27,917**	**27,459**	**28,219**	**28,494**	**275**	**1,378**	**44.522**
Percent of Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**1.0%**	**5.1%**	

Note: Includes only data from Category I and Category II operators. In 2006 there were 173 Category I operators and 467 Category II operators. The "rest" size class had 140 operators in 2006.

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

Table A6. Top 50 U.S. Operators Ranked by Reported 2006 Operated Production Data

Rank	Company Name	Crude Oil Production (thousand barrels/day)	Rank	Company Name	Total Natural Gas Production (milion cubic feet/day)
1	BP PLC	586	1	CONOCOPHILLIPS CO.	4,033
2	CHEVRON CORP.	450	2	ANADARKO PETROLEUM CORP	2,896
3	CONOCOPHILLIPS CO	401	3	BP PLC	2,739
4	SHELL OIL CO	305	4	CHEVRON CORP	2,142
5	OCCIDENTAL PETROLEUM CORP	285	5	DEVON ENERGY CORP.	2,059
6	AERA ENERGY LLC	188	6	CHESAPEAKE ENERGY CORP	1,999
7	ANADARKO PETROLEUM CORP	183	7	EXXONMOBIL CORP	1,903
8	EXXONMOBIL CORP	131	8	SHELL OIL CO	1,619
9	APACHE CORP	81	9	ENCANA OIL & GAS INC	1,540
10	PLAINS EXPLORATION & PRODUCTION CO	59	10	XTO ENERGY INC	1,360
Top 10 Volume Subtotal		***2,669***	***Top 10 Volume Subtotal***		***22,290***
Top 10 Percentage of U.S. Total		***53%***	***Top 10 Percentage of U.S. Total***		***42%***
11	KINDER MORGAN ENERGY PARTNERS	57	11	DOMINION RESOURCES INC	1,202
12	AMERADA HESS CORP	57	12	EOG RESOURCES INC	1,049
13	DOMINION RESOURCES INC.	54	13	APACHE CORP.	1,031
14	NOBLE ENERGY INC	52	14	WILLIAMS ENERGY INC	949
15	MARATHON OIL CO	47	15	OCCIDENTAL PETROLEUM CORP	866
16	MERIT ENERGY CO	46	16	EL PASO ENERGY	823
17	MURPHY OIL CORP	43	17	NEWFIELD EXPLORATION CO	715
18	XTO ENERGY INC	40	18	SAMSON RESOURCES CO	678
19	DEVON ENERGY CORP	38	19	MARATHON OIL CO	670
20	EOG RESOURCES INC	37	20	QUESTAR CORP	654
Top 20 Volume Subtotal		***3,140***	***Top 20 Volume Subtotal***		***30,927***
Top 20 Percentage of U.S. Total		***62%***	***Top 20 Percentage of U.S. Total***		***58%***
21	PIONEER NATURAL RESOURCES USA INC.	31	21	NOBLE ENERGY INC	569
22	CITY OF LONG BEACH	31	22	PIONEER NATURAL RESOURCES USA INC.	528
23	CHESAPEAKE ENERGY CORP	30	23	CIMAREX ENERGY CO	432
24	CITATION OIL & GAS CORP	30	24	MERIT ENERGY CO	379
25	CONTINENTAL RESOURCES INC	27	25	ENERGEN RESOURCES CORP	291
26	HILCORP ENERGY CO	26	26	ULTRA PETROLEUM INC	288
27	ALLIANT ENERGY CORP	26	27	EQUITABLE RESOURCES INC.	262
28	ENCORE OPERATING LP	26	28	YATES PETROLEUM CORP	258
29	ST MARY LAND & EXPLORATION CO	25	29	HILCORP ENERGY CO	257
30	DENBURY RESOURCES INC	24	30	HUNT OIL CO.	252
31	ENI PETROLEUM CO INC	24	31	FOREST OIL CORP	251
32	FOREST OIL CORP	24	32	POGO PRODUCING CO	225
33	ENERGEN RESOURCES CORP	23	33	SANDRIDGE ENERGY INC	222
34	SWIFT ENERGY CO	23	34	CABOT OIL & GAS CORP	217
35	BERRY PETROLEUM CO	21	35	THE HOUSTON EXPLORATION CO	210
36	CIMAREX ENERGY CO	21	36	AMERADA HESS CORP	207
37	POGO PRODUCING CO	20	37	MARINER ENERGY INC	204
38	EL PASO ENERGY	20	38	J - W OPERATING CO	196
39	STONE ENERGY CORP	18	39	UNIT CORP	192
40	HENRY PETROLEUM LP	16	40	HUNT PETROLEUM CORPORATION	188
41	W & T OFFSHORE INC	15	41	BILL BARRETT CORP	184
42	ENERPLUS RESOURCES USA CORP	14	42	KCS ENERGY INC	183
43	NEWFIELD EXPLORATION CO	13	43	ENERGY PARTNERS LTD	181
44	ENCANA OIL & GAS INC	13	44	C N X GAS CO LLC	177
45	HEADINGTON RESOURCES INC	12	45	FIDELITY EXPLORATION & PROD CO	171
46	LLOG EXPLORATION CO	12	46	KAISER - FRANCIS OIL CO.	171
47	ENDEAVOR ENERGY RESOURCES LP	12	47	W & T OFFSHORE INC	171
48	WALTER OIL & GAS CORP	12	48	WALTER OIL & GAS CORP	160
49	SANDRIDGE ENERGY INC	12	49	ST MARY LAND & EXPLORATION CO	159
50	MARINER ENERGY INC	11	50	RANGE RESOURCES CORP	149
Top 50 Volume Subtotal		***3,752***	***Top 50 Volume Subtotal***		***38,261***
Top 50 Percentage of U.S. Total		***75%***	***Top 50 Percentage of U.S. Total***		***72%***

Note: Crude oil production includes production of lease condensate. Total natural gas production is wet after lease separation.

Appendix B

Top 100 Oil and Gas Fields

Appendix B

Top 100 Oil and Gas Fields

This appendix presents estimates of the proved reserves and production of the top 100 liquids or gas fields by reserves or by production. The liquids production and reserve data include both crude oil and lease condensate, and are labeled as liquids. The total gas production and reserve data is wet after lease separation. Although there is considerable grouping of field-level statistics within the tables, rough orders of magnitude may be estimated for the proved reserves and production of most fields. They rank the top 100 fields by production (**Table B3 and Table B4**) rather than by reserves (**Table B1 and Table B**2).

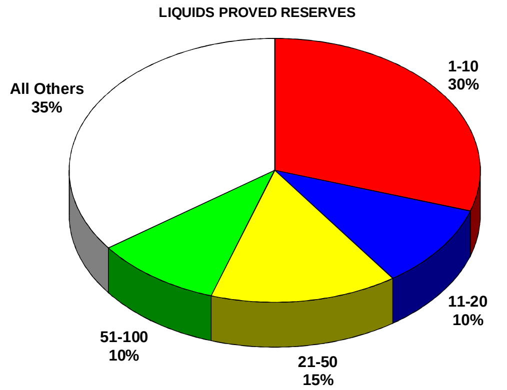
Many of the fields in the top 100 group are operated by only one or two operators, therefore, the totals for proved reserves are grouped as top 10, top 20, top 50, and top 100 to avoid revealing company proprietary data. Many of the same fields are in each of the tables **B1, B2, B3, and B4**. The liquids fields with the more recent discovery dates are typically located in the Gulf of Mexico Offshore and Alaska. The gas fields with the more recent discovery dates are located in the Gulf of Mexico Offshore, New Mexico, Colorado, and Wyoming.

Summary for the Top 100 Fields for 2006 Liquids and Gas

Rank Group	12/31/2006 Proved Reserves	Percent	12/31/2006 Nonproducing Reserves	Percent	Estimated 2006 Production	Percent
Table B1. Top 100 U.S. Fields as Ranked by Liquids Proved Reserves (Million Barrels)						
Top 10	6,666.1	29.9%	1,002.6	17.7%	374.6	20.4%
Top 20	8,966.2	40.2%	2,031.0	35.8%	507.5	27.7%
Top 50	12,247.5	54.9%	2,825.9	49.8%	760.8	41.5%
Top 100	14,523.3	65.1%	3,712.2	65.4%	945.4	51.6%
Others	7,787.7	34.9%	1,965.8	34.6%	888.6	48.4%
Total	22,311.0	100.0%	5,678.0	100.0%	1,834.0	100.0%
Table B2. Top 100 U.S. Fields as Ranked by Gas Proved Reserves (Billion Cubic Feet)						
Top 10	62,526.4	28.4%	18,026.6	27.0%	3,739.2	19.3%
Top 20	82,049.8	37.2%	22,117.5	33.2%	5,141.9	26.5%
Top 50	107,692.0	48.9%	32,368.7	48.5%	7,218.2	37.3%
Top 100	127,076.2	57.7%	37,133.6	55.7%	8,728.6	45.1%
Others	93,339.8	42.3%	29,580.4	44.3%	10,644.4	54.9%
Total	220,416.0	100.0%	66,714.0	100.0%	19,373.0	100.0%
Table B3. Top 100 U.S. Fields as Ranked by Liquids Production (Million Barrels)						
Top 10	n/a	n/a	n/a	n/a	428.9	23.4%
Top 20	n/a	n/a	n/a	n/a	600.3	32.7%
Top 50	n/a	n/a	n/a	n/a	848.2	46.2%
Top 100	n/a	n/a	n/a	n/a	1,022.6	55.8%
Others	n/a	n/a	n/a	n/a	811.4	44.2%
Total	n/a	n/a	n/a	n/a	1,834.0	100.0%
Table B4. Top 100 U.S. Fields as Ranked by Gas Production (Billion Cubic Feet)						
Top 10	n/a	n/a	n/a	n/a	4,074.3	21.0%
Top 20	n/a	n/a	n/a	n/a	5,333.8	27.5%
Top 50	n/a	n/a	n/a	n/a	7,421.9	38.3%
Top 100	n/a	n/a	n/a	n/a	9,141.7	47.2%
Others	n/a	n/a	n/a	n/a	10,231.3	52.8%
Total	n/a	n/a	n/a	n/a	19,373.0	100.0%

Table B1. Top 100 Liquids Fields Ranked by Reserves

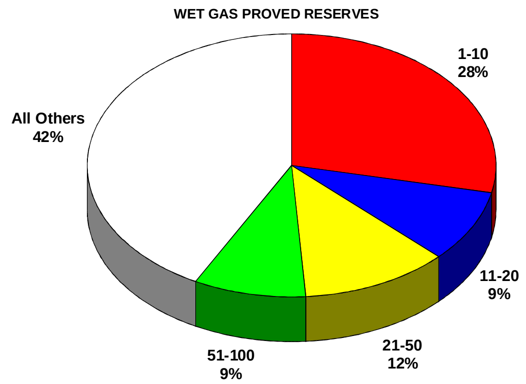
The top 100 liquids fields by reserves had 15,722 million barrels of **proved reserves** accounting for 68 percent of the total United States as of December 31, 2005, (**Table 6 and Table 14**) and 70 percent of the reported nonproducing reserves. In the top 20 liquids fields for 2005 there are five fields, which are in the deep water of the Gulf of Mexico Federal Offshore and two are currently nonproducing.



The top 100 liquids fields by reserves had 945 million barrels of production, or 52 percent of the 2006 U.S.total (Table 6 and Table 14).

Table B2. Top 100 Gas Fields Ranked by Reserves

The top 100 gas fields by reserves had 127,076 billion cubic feet of wet natural gas proved reserves or 58 percent of the total, as of December 31, 2006 (**Table 9**) and 56 percent of the reported nonproducing reserves. The Newark East (Barnett Shale) field in Texas became the second largest in the country.



The top 100 gas fields by reserves had 8,614 billion cubic feet of **production**, or 45 percent of the 2005 U.S. total (**Table 9**).

Table B3. Top 100 Liquids Fields Ranked by Production

The top 100 liquids fields by production had 1,023 million barrels of **production**, or 56 percent of the 2006 U.S. total (**Table 6 and Table 14**).

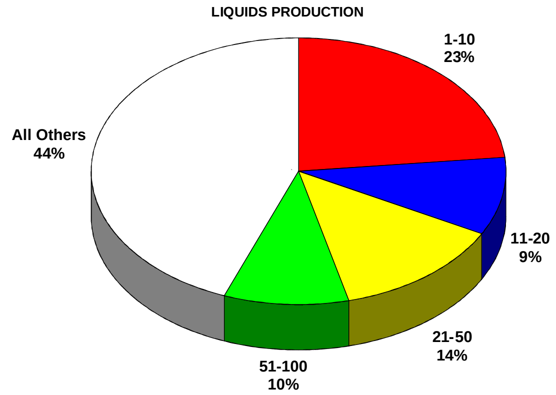


Table B4. Top 100 Gas Fields Ranked by Production

The top 100 gas fields had 9,142 billion cubic feet of **production**, or 47 percent of the 2006 U.S. total (**Table 9**).

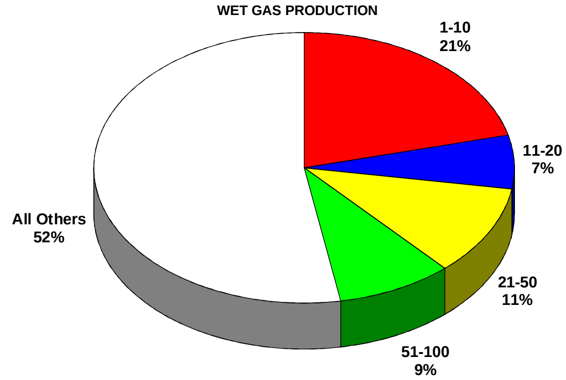


Table B1. Top 100 U.S. Fields Ranked by Liquids Proved Reserves from Estimated 2006 Field Level Data[a]
(Million Barrels of 42 U.S. Gallons)

Num	Field Name	Location	2006 Estimated Production Volume	Rank Group: Proved Reserves	Rank Group: Nonproducing Reserves	Discovery Year
1	PRUDHOE BAY	AK	92.1			1967
2	WASSON	TX	24.7			1937
3	BELRIDGE SOUTH	CA	38.9			1911
4	MISSISSIPPI CANYON BLK 807 (MARS-URSA)	FG	61.6			1989
5	SPRABERRY TREND AREA	TX	24.2	(1-10)		1949
6	KUPARUK RIVER	AK	45.5			1969
7	MISSISSIPPI CANYON BLK 778 (THUNDER HORSE)	FG	0.0			1999
8	MIDWAY-SUNSET	CA	39.6			1901
9	ELK HILLS	CA	17.2			1919
10	KERN RIVER	CA	30.8			1899
Top 10 Volume Subtotal			**374.6**	**6,666.1**	**1,002.6**	
Top 10 Percentage of U.S. Total			**20.4%**	**29.9%**	**17.7%**	
11	GREEN CANYON BLK 743 (ATLANTIS)	FG	0.0			1998
12	SLAUGHTER	TX	11.6			1937
13	WILMINGTON	CA	14.8			1932
14	ALPINE	AK	41.7			1994
15	MILNE POINT	AK	13.3	(11-20)		1982
16	WATTENBERG	CO	11.1			1970
17	SALT CREEK	WY	2.6			1889
18	GREEN CANYON BLK 826 (MAD DOG)	FG	11.1			1998
19	LEVELLAND	TX	8.2			1945
20	CYMRIC	CA	18.5			1916
Top 20 Volume Subtotal			**507.5**	**8,966.2**	**2,031.0**	
Top 20 Percentage of U.S. Total			**27.7%**	**40.2%**	**35.8%**	
21	CEDAR HILLS	ND & MT & SD	15.6			1951
22	LOST HILLS	CA	11.9			1910
23	GREEN CANYON BLK 644 (HOLSTEIN)	FG	11.4			1999
24	GREEN CANYON BLK 640 (TAHITI)	FG	0.0			2002
25	ELM COULEE	MT	19.0			2000
26	GREATER ANETH	UT	3.5			1956
27	HONDO	FP	5.6			1969
28	PESCADO	FP	5.1			1970
29	YATES	TX	9.5			1926
30	SHO-VEL-TUM	OK	8.8			1905
31	HOBBS	NM	4.7			1928
32	MISSISSIPPI CANYON BLK 84 (KING/HORN MT)	FG	22.5			1993
33	ORION	AK	2.5			2002
34	COWDEN NORTH	TX	5.4			1930
35	GOLDSMITH	TX	5.6	(21-50)		1935
36	NORTHSTAR	AK	18.9			1984
37	INGLEWOOD	CA	3.3			1924
38	POINT MCINTYRE	AK	7.7			1988
39	ENDICOTT	AK	5.2			1978
40	SACATE	FP	4.1			1970
41	VENTURA	CA	4.2			1916
42	SAN ARDO	CA	3.2			1947
43	WEST SAK	AK	6.6			1969
44	SEMINOLE	TX	7.8			1936
45	MONUMENT BUTTE	UT	3.5			1964
46	KELLY-SNYDER	TX	11.3			1948
47	BOREALIS	AK	5.7			2001
48	WARD-ESTES NORTH	TX	2.2			1927
49	GREEN CANYON BLK 562 (K2)	FG	8.7			1999
50	MISSISSIPPI CANYON BLK 383 (KEPLER)	FG	29.7			1987
Top 50 Volume Subtotal			**760.8**	**12,247.5**	**2,825.9**	
Top 50 Percentage of U.S. Total			**41.5%**	**54.9%**	**49.8%**	

Table B1. Top 100 U.S. Fields Ranked by Liquids Proved Reserves from Estimated 2006 Field Level Data[a] (Continued)
(Million Barrels of 42 U.S. Gallons)

Num	Field Name	Location	2006 Estimated Production Volume	Rank Group Proved Reserves	Rank Group Nonproducing Reserves	Discovery Year
51	VACUUM	NM	5.8			1929
52	ROBERTSON NORTH	TX	4.2			1956
53	MCELROY	TX	5.0			1926
54	FULLERTON	TX	4.3			1942
55	PENNEL	MT	2.3			1955
56	SALT CREEK	TX	4.5			1942
57	LAKE WASHINGTON	LA	8.4			1931
58	COALINGA	CA	5.7			1887
59	GREEN CANYON BLK 339 (FRONT RUNNER)	FG	5.6			2001
60	FUHRMAN-MASCHO	TX	2.9			1930
61	RANGELY	CO	5.2			1902
62	WESTBROOK	TX	1.8			1920
63	ARROYO GRANDE	CA	0.6			1906
64	MISSISSIPPI CANYON BLK 696 (BLIND FAITH)	FG	0.0			2005
65	MISSISSIPPI CANYON BLK 773 (DEVILS TOWER)	FG	14.7			1999
66	LISBURNE	AK	3.2			1967
67	ATWATER VALLEY BLK 575 (NEPTUNE (AT))	FG	0.0			1995
68	GIDDINGS	TX	7.1			1960
69	GREEN CANYON BLK 652	FG	0.0			1999
70	ANTON-IRISH	TX	3.2			1944
71	NATURAL BUTTES	UT	1.5			1940
72	FITTS	OK	1.8			1933
73	EAST TEXAS	TX	4.3			1930
74	CEDAR LAKE	TX	2.0			1939
75	AURORA	AK	3.8	(51-100)		1969
76	HAWKINS	TX	2.6			1940
77	HOWARD-GLASSCOCK	TX	2.7			1925
78	POSTLE	OK	1.7			1958
79	GARDEN BANKS BLK 388 (COOPER)	FG	11.1			1989
80	MEANS	TX	3.3			1934
81	PINEDALE	WY	1.8			1955
82	TARN	AK	7.6			1991
83	POLARIS	AK	0.8			2000
84	KERN FRONT	CA	1.6			1925
85	GREEN CANYON BLK 654	FG	0.0			2003
86	MISSISSIPPI CANYON BLK 20	FG	0.9			1982
87	GRAND ISLE BLK 43	FG	0.5			1956
88	MISSISSIPPI CANYON BLK 429 (ARIEL)	FG	9.4			1995
89	GREEN CANYON BLK 680 (CONSTITUTION)	FG	3.8			2001
90	ALTAMONT-BLUEBELL	UT	2.7			1949
91	EUNICE MONUMENT	NM	1.8			1929
92	BREA-OLINDA	CA	1.2			1897
93	FULLER	TX	0.6			1951
94	EAST BREAKS BLK 602 (NANSEN)	FG	7.6			1999
95	GOLDEN TREND	OK	2.0			1945
96	WELCH	TX	1.6			1942
97	VIOSCA KNOLL BLK 786 (PETRONIUS)	FG	17.0			1995
98	CARTHAGE	TX	2.3			1936
99	SOUTH PASS BLK 62	FG	0.2			1965
100	JAY	AL & FL	1.7			1951
Top 100 Volume Subtotal			**945.4**	**14,523.3**	**3,712.2**	
Top 100 Percentage of U.S. Total			**51.6%**	**65.1%**	**65.4%**	

[a]Includes lease condensate.

Notes: The U.S. total production estimate of 1,907 million barrels and the U.S. total reserves estimate of 23,019 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.

FP = Federal Offshore Pacific.

FG = Federal Offshore Gulf of Mexico.

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

Table B2. Top 100 U.S. Fields Ranked by Gas Proved Reserves from Estimated 2006 Field Level Data[a]
(Billion Cubic Feet)

Num	Field Name	Location	2006 Estimated Production Volume	Rank Group Proved Reserves	Rank Group Nonproducing Reserves	Discovery Year
1	SAN JUAN BASIN GAS AREA	CO & NM	1380.8			1927
2	NEWARK EAST	TX	716.7			1981
3	PRUDHOE BAY	AK	160.9			1967
4	PINEDALE	WY	236.7			1955
5	HUGOTON GAS AREA	KS & OK & TX	342.0	(1-10)		1922
6	JONAH	WY	292.5			1977
7	NATURAL BUTTES	UT	166.0			1940
8	WATTENBERG	CO	176.0			1970
9	RATON BASIN GAS AREA	CO & NM	109.6			1998
10	MADDEN	WY	157.9			1968
Top 10 Volume Subtotal			**3,739.2**	**62,526.4**	**18,026.6**	
Top 10 Percentage of U.S. Total			**19.3%**	**28.4%**	**27.0%**	
11	PRB COALBED	WY	377.0			1992
12	CARTHAGE	TX	224.8			1936
13	ANTRIM	MI	140.0			1965
14	NORTHSTAR	AK	0.0			1984
15	SPRABERRY TREND AREA	TX	81.5	(11-20)		1949
16	FOGARTY CREEK	WY	161.7			1975
17	SAWYER	TX	82.8			1960
18	LOWER MOBILE BAY AREA	AL & FG	143.5			1979
19	FREESTONE	TX	90.3			1949
20	VERNON	LA	100.9			1967
Top 20 Volume Subtotal			**5,141.9**	**82,049.8**	**22,117.5**	
Top 20 Percentage of U.S. Total			**26.5%**	**37.2%**	**33.2%**	
21	ELM GROVE	LA	113.0			1916
22	GRAND VALLEY	CO	88.3			1985
23	OAKWOOD	VA	63.0			1990
24	ELK HILLS	CA	143.8			1919
25	PARACHUTE	CO	81.8			1985
26	OAK HILL	TX	94.6			1958
27	MAMM CREEK	CO	95.1			1959
28	RULISON	CO	65.4			1958
29	STRONG CITY DISTRICT	OK	84.6			1966
30	PINON	TX	40.8			1982
31	MISSISSIPPI CANYON BLK 807 (MARS-URSA)	FG	83.9			1989
32	BALD PRAIRIE	TX	57.0			1976
33	FARRAR	TX	55.4			1963
34	STILES RANCH	TX	44.0			1978
35	LAKE RIDGE	WY	75.7	(21-50)		1981
36	HALEY	TX	70.8			1983
37	RED OAK-NORRIS	OK	55.8			1910
38	MESA UNIT	WY	37.2			1981
39	PANOMA GAS AREA	KS	49.7			1956
40	MOCANE-LAVERNE GAS AREA	KS & OK & TX	63.8			1946
41	GOLDEN TREND	OK	38.9			1945
42	DRUNKARDS WASH	UT	57.2			1989
43	TEAGUE	TX	62.2			1945
44	MAYFIELD NE	OK	90.8			1951
45	BUFFALO WALLOW	TX	63.3			1969
46	WATONGA-CHICKASHA TREND	OK	39.6			1948
47	BEAR GRASS	TX	38.6			1977
48	SAVELL	TX	72.0			1997
49	BELUGA RIVER	AK	55.4			1962
50	GIDDINGS	TX	94.6			1960
Top 50 Volume Subtotal			**7,218.2**	**107,692.0**	**32,368.7**	
Top 50 Percentage of U.S. Total			**37.3%**	**48.9%**	**48.5%**	

Table B2. Top 100 U.S. Fields Ranked by Gas Proved Reserves from Estimated 2006 Field Level Data[a] (Continued)
(Billion Cubic Feet)

Num	Field Name	Location	2006 Estimated Production Volume	Rank Group: Proved Reserves	Rank Group: Nonproducing Reserves	Discovery Year
51	OVERTON	TX	54.6			1973
52	PICEANCE CREEK	CO	17.1			1930
53	NORA	VA	25.8			1949
54	HONDO	FP	20.3			1969
55	SHO-VEL-TUM	OK	28.5			1905
56	CASPIANA	LA	27.8			1925
57	WASSON	TX	43.0			1937
58	WAMSUTTER	WY	26.2			1958
59	CEDARDALE NE	OK	28.9			1957
60	WILD ROSE	WY	30.1			1975
61	MINDEN	TX	37.7			1954
62	KINTA	OK	61.6			1914
63	GOMEZ	TX	38.1			1963
64	VERDEN	OK	30.0			1948
65	DEW	TX	32.6			1982
66	GURNEE COAL DEGAS	AL	2.8			1990
67	B-43	AR	19.4			2005
68	ELK CITY	OK	45.3			1947
69	ECHO SPRINGS	WY	31.0			1976
70	DOWDY RANCH	TX	33.6			1999
71	SLIGO	LA	43.7			1922
72	BRUFF	WY	34.5			1969
73	MISSISSIPPI CANYON BLK 731 (MENSA)	FG	60.5			1986
74	EAST BREAKS BLK 602 (NANSEN)	FG	61.6			1999
75	STANDARD DRAW	WY	21.6	(51-100)		1979
76	MISSISSIPPI CANYON BLK 778 (THUNDER HORSE)	FG	0.0			1999
77	NACONICHE CREEK	TX	11.8			1978
78	OZONA NE	TX	26.0			1966
79	BETHANY	TX	26.0			1921
80	WAYNOKA NE	OK	20.4			1956
81	CHEYENNE WEST	OK	39.1			1971
82	WILBURTON	OK	29.5			1941
83	EXSUN	TX	46.7			1974
84	PINE HOLLOW SOUTH	OK	18.1			1959
85	KUPARUK RIVER	AK	20.9			1969
86	MISSISSIPPI CANYON BLK 383 (KEPLER)	FG	77.9			1987
87	BOONSVILLE	TX	28.8			1945
88	OZONA	TX	22.4			1953
89	TIP TOP	WY	18.9			1928
90	OKEENE NW	OK	15.2			1956
91	CEMENT	OK	35.2			1916
92	HEMPHILL	TX	23.7			1961
93	CHARCO	TX	21.4			1948
94	MOBILE BLK 823	FG	25.0			1983
95	CLEBURNE WEST	TX	19.6			1992
96	COOK INLET NORTH	AK	38.2			1962
97	CARTHAGE NORTH	TX	16.6			1966
98	SOONER TREND	OK	25.2			1938
99	EAKLY-WEATHERFORD TREND	OK	20.4			1953
100	BROWN-BASSETT	TX	27.3			1953
Top 100 Volume Subtotal			**8,728.6**	**127,076.2**	**37,133.6**	
Top 100 Percentage of U.S. Total			**45.1%**	**57.7%**	**55.7%**	

[a]Total wet gas after lease separation.

Note: The U.S. total production estimate of 19,259 billion cubic feet and the U.S. total reserves estimate of 213,308 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.

FP = Federal Offshore Pacific.

FG = Federal Offshore Gulf of Mexico.

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

Table B3. Top 100 U.S. Fields Ranked by Liquids Production from Estimated 2006 Field Level Data[a]
(Million Barrels of 42 U.S. Gallons)

Num	Field Name	Location	2006 Estimated Production Volume	Discovery Year
1	PRUDHOE BAY	AK	92.1	1967
2	MISSISSIPPI CANYON BLK 807 (MARS-URSA)	FG	61.6	1989
3	KUPARUK RIVER	AK	45.5	1969
4	ALPINE	AK	41.7	1994
5	MIDWAY-SUNSET	CA	39.6	1901
6	BELRIDGE SOUTH	CA	38.9	1911
7	KERN RIVER	CA	30.8	1899
8	MISSISSIPPI CANYON BLK 383 (KEPLER)	FG	29.7	1987
9	WASSON	TX	24.7	1937
10	SPRABERRY TREND AREA	TX	24.2	1949
Top 10 Volume Subtotal			**428.9**	
Top 10 Percentage of U.S. Total			**23.4%**	
11	MISSISSIPPI CANYON BLK 84 (KING/HORN MT)	FG	22.5	1993
12	ELM COULEE	MT	19.0	2000
13	NORTHSTAR	AK	18.9	1984
14	CYMRIC	CA	18.5	1916
15	ELK HILLS	CA	17.2	1919
16	VIOSCA KNOLL BLK 786 (PETRONIUS)	FG	17.0	1995
17	CEDAR HILLS	ND & MT & SD	15.6	1951
18	WILMINGTON	CA	14.8	1932
19	MISSISSIPPI CANYON BLK 773 (DEVILS TOWER)	FG	14.7	1999
20	MILNE POINT	AK	13.3	1982
Top 20 Volume Subtotal			**600.3**	
Top 20 Percentage of U.S. Total			**32.7%**	
21	LOST HILLS	CA	11.9	1910
22	SLAUGHTER	TX	11.6	1937
23	GREEN CANYON BLK 644 (HOLSTEIN)	FG	11.4	1999
24	KELLY-SNYDER	TX	11.3	1948
25	GREEN CANYON BLK 826 (MAD DOG)	FG	11.1	1998
26	WATTENBERG	CO	11.1	1970
27	GARDEN BANKS BLK 388 (COOPER)	FG	11.1	1989
28	MISSISSIPPI CANYON BLK 582 (MEDUSA)	FG	10.0	1998
29	YATES	TX	9.5	1926
30	MISSISSIPPI CANYON BLK 429 (ARIEL)	FG	9.4	1995
31	SHO-VEL-TUM	OK	8.8	1905
32	GREEN CANYON BLK 562 (K2)	FG	8.7	1999
33	LAKE WASHINGTON	LA	8.4	1931
34	LEVELLAND	TX	8.2	1945
35	GREEN CANYON BLK 65 (BULLWINKLE)	FG	7.9	1983
36	SEMINOLE	TX	7.8	1936
37	POINT MCINTYRE	AK	7.7	1988
38	EAST BREAKS BLK 602 (NANSEN)	FG	7.6	1999
39	TARN	AK	7.6	1991
40	EWING BANK BLK 873 (N/A)	FG	7.3	1985
41	GIDDINGS	TX	7.1	1960
42	WEST SAK	AK	6.6	1969
43	GARDEN BANKS BLK 171 (SALSA)	FG	6.0	1988
44	VACUUM	NM	5.8	1929
45	COALINGA	CA	5.7	1887
46	BOREALIS	AK	5.7	2001
47	HONDO	FP	5.6	1969
48	GREEN CANYON BLK 339 (FRONT RUNNER)	FG	5.6	2001
49	MISSISSIPPI CANYON BLK 755 (GOMEZ)	FG	5.6	1986
50	GOLDSMITH	TX	5.6	1935
Top 50 Volume Subtotal			**848.2**	
Top 50 Percentage of U.S. Total			**46.2%**	

Table B3. Top 100 U.S. Fields Ranked by Liquids Production from Estimated 2006 Field Level Data[a] (Continued)
(Million Barrels of 42 U.S. Gallons)

Num	Field Name	Location	2006 Estimated Production Volume	Discovery Year
51	COWDEN NORTH	TX	5.4	1930
52	MISSISSIPPI CANYON BLK 522 (LEO)	FG	5.2	1989
53	RANGELY	CO	5.2	1902
54	ENDICOTT	AK	5.2	1978
55	PESCADO	FP	5.1	1970
56	MCELROY	TX	5.0	1926
57	GREEN CANYON BLK 768 (TICONDEROGA)	FG	5.0	2004
58	HOBBS	NM	4.7	1928
59	SALT CREEK	TX	4.5	1942
60	SAN JUAN BASIN GAS AREA	CO & NM	4.4	1927
61	EAST TEXAS	TX	4.3	1930
62	FULLERTON	TX	4.3	1942
63	VENTURA	CA	4.2	1916
64	ROBERTSON NORTH	TX	4.2	1956
65	SACATE	FP	4.1	1970
66	ALAMINOS CANYON BLK 25 (HOOVER)	FG	4.1	1997
67	WEST DELTA BLK 30	FG	3.9	1949
68	AURORA	AK	3.8	1969
69	GREEN CANYON BLK 680 (CONSTITUTION)	FG	3.8	2001
70	VIOSCA KNOLL BLK 990 (POMPANO)	FG	3.7	1981
71	GREATER ANETH	UT	3.5	1956
72	MONUMENT BUTTE	UT	3.5	1964
73	MAIN PASS BLK 61	FG	3.4	2001
74	BROOKELAND	TX	3.4	1962
75	INGLEWOOD	CA	3.3	1924
76	MEANS	TX	3.3	1934
77	ANTON-IRISH	TX	3.2	1944
78	LISBURNE	AK	3.2	1967
79	SAN ARDO	CA	3.2	1947
80	POINT PEDERNALES	FP	3.0	1983
81	FUHRMAN-MASCHO	TX	2.9	1930
82	MCKITTRICK	CA	2.8	1887
83	JONAH	WY	2.8	1977
84	ALTAMONT-BLUEBELL	UT	2.7	1949
85	LOST SOLDIER	WY	2.7	1916
86	DOLLARHIDE	NM & TX	2.7	1945
87	HOWARD-GLASSCOCK	TX	2.7	1925
88	MAIN PASS SA BLK 299	FG	2.7	1967
89	HAWKINS	TX	2.6	1940
90	SALT CREEK	WY	2.6	1889
91	OREGON BASIN	WY	2.5	1912
92	GRAYBURG-JACKSON	NM	2.5	1929
93	LOOKOUT BUTTE EAST	MT	2.5	1986
94	MCARTHUR RIVER	AK	2.5	1965
95	ORION	AK	2.5	2002
96	NIAKUK	AK	2.4	1984
97	JO-MILL	TX	2.4	1953
98	MALLALIEU WEST	MS	2.4	1946
99	PENNEL	MT	2.3	1955
100	ELK BASIN	MT & WY	2.3	1915
Top 100 Volume Subtotal			**1,022.6**	
Top 100 Percentage of U.S. Total			**55.8%**	

[a]Includes lease condensate.

Notes: The U.S. total production estimate of 1,907 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.

FP = Federal Offshore Pacific.

FG = Federal Offshore Gulf of Mexico.

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

Table B4. Top 100 U.S. Fields Ranked by Gas Production from Estimated 2006 Field Level Data[a]
(Billion Cubic Feet)

Num	Field Name	Location	2006 Estimated Production Volume	Discovery Year
1	SAN JUAN BASIN GAS AREA	CO & NM	1380.8	1927
2	NEWARK EAST	TX	716.7	1981
3	PRB COALBED	WY	377.0	1992
4	HUGOTON GAS AREA	KS & OK & TX	342.0	1922
5	JONAH	WY	292.5	1977
6	PINEDALE	WY	236.7	1955
7	CARTHAGE	TX	224.8	1936
8	WATTENBERG	CO	176.0	1970
9	NATURAL BUTTES	UT	166.0	1940
10	FOGARTY CREEK	WY	161.7	1975
Top 10 Volume Subtotal			**4,074.3**	
Top 10 Percentage of U.S. Total			**21.0%**	
11	PRUDHOE BAY	AK	160.9	1967
12	MADDEN	WY	157.9	1968
13	ELK HILLS	CA	143.8	1919
14	LOWER MOBILE BAY AREA	AL & FG	143.5	1979
15	ANTRIM	MI	140.0	1965
16	ELM GROVE	LA	113.0	1916
17	RATON BASIN GAS AREA	CO & NM	109.6	1998
18	VERNON	LA	100.9	1967
19	MAMM CREEK	CO	95.1	1959
20	GIDDINGS	TX	94.6	1960
Top 20 Volume Subtotal			**5,333.8**	
Top 20 Percentage of U.S. Total			**27.5%**	
21	OAK HILL	TX	94.6	1958
22	MAYFIELD NE	OK	90.8	1951
23	FREESTONE	TX	90.3	1949
24	GRAND VALLEY	CO	88.3	1985
25	STRONG CITY DISTRICT	OK	84.6	1966
26	MISSISSIPPI CANYON BLK 807 (MARS-URSA)	FG	83.9	1989
27	SAWYER	TX	82.8	1960
28	PARACHUTE	CO	81.8	1985
29	SPRABERRY TREND AREA	TX	81.5	1949
30	MISSISSIPPI CANYON BLK 383 (KEPLER)	FG	77.9	1987
31	LAKE RIDGE	WY	75.7	1981
32	SAVELL	TX	72.0	1997
33	HALEY	TX	70.8	1983
34	RULISON	CO	65.4	1958
35	MOCANE-LAVERNE GAS AREA	KS & OK & TX	63.8	1946
36	BUFFALO WALLOW	TX	63.3	1969
37	OAKWOOD	VA	63.0	1990
38	TEAGUE	TX	62.2	1945
39	EAST BREAKS BLK 602 (NANSEN)	FG	61.6	1999
40	KINTA	OK	61.6	1914
41	VIOSCA KNOLL BLK 956 (RAM-POWELL)	FG	61.0	1985
42	MISSISSIPPI CANYON BLK 731 (MENSA)	FG	60.5	1986
43	YATES	TX	59.2	1926
44	DRUNKARDS WASH	UT	57.2	1989
45	BALD PRAIRIE	TX	57.0	1976
46	PANOLA	OK	56.2	1964
47	RED OAK-NORRIS	OK	55.8	1910
48	FARRAR	TX	55.4	1963
49	BELUGA RIVER	AK	55.4	1962
50	OVERTON	TX	54.6	1973
Top 50 Volume Subtotal			**7,421.9**	

Table B4. Top 100 U.S. Fields Ranked by Gas Production from Estimated 2006 Field Level Data[a] (Continued)
(Billion Cubic Feet)

Num	Field Name	Location	2006 Estimated Production Volume	Discovery Year
Top 50 Percentage of U.S. Total			**38.3%**	
51	MCALLEN RANCH	TX	54.2	1960
52	PANOMA GAS AREA	KS	49.7	1956
53	EXSUN	TX	46.7	1974
54	JUDGE DIGBY	LA	45.8	1977
55	ELK CITY	OK	45.3	1947
56	STILES RANCH	TX	44.0	1978
57	SLIGO	LA	43.7	1922
58	GARDEN BANKS BLK 668 (GUNNISON)	FG	43.1	2000
59	WASSON	TX	43.0	1937
60	PINON	TX	40.8	1982
61	HAYNES	TX	40.8	1954
62	LA PERLA	TX	40.5	1958
63	WATONGA-CHICKASHA TREND	OK	39.6	1948
64	CHEYENNE WEST	OK	39.1	1971
65	VAQUILLAS RANCH	TX	39.0	1978
66	GOLDEN TREND	OK	38.9	1945
67	BEAR GRASS	TX	38.6	1977
68	COOK INLET NORTH	AK	38.2	1962
69	GOMEZ	TX	38.1	1963
70	MINDEN	TX	37.7	1954
71	MESA UNIT	WY	37.2	1981
72	CEMENT	OK	35.2	1916
73	BRUFF	WY	34.5	1969
74	DOWDY RANCH	TX	33.6	1999
75	DEW	TX	32.6	1982
76	LAKE PASTURE	TX	31.9	1939
77	BROOKELAND	TX	31.6	1962
78	ECHO SPRINGS	WY	31.0	1976
79	WILD ROSE	WY	30.1	1975
80	VERDEN	OK	30.0	1948
81	WILBURTON	OK	29.5	1941
82	NAN-SU-GAIL	TX	29.0	1957
83	CEDARDALE NE	OK	28.9	1957
84	BOONSVILLE	TX	28.8	1945
85	GARDEN BANKS BLK 877 (RED HAWK)	FG	28.5	2001
86	SHO-VEL-TUM	OK	28.5	1905
87	JAVELINA	TX	28.1	1947
88	HOBBS	NM	28.1	1928
89	CASPIANA	LA	27.8	1925
90	ADA	LA	27.5	1944
91	BROWN-BASSETT	TX	27.3	1953
92	ROLETA	TX	26.7	1955
93	CEDAR CREEK	ND	26.4	1929
94	WAMSUTTER	WY	26.2	1958
95	WILLOW SPRINGS	TX	26.1	1938
96	OZONA NE	TX	26.0	1966
97	BETHANY	TX	26.0	1921
98	NORA	VA	25.8	1949
99	SOONER TREND	OK	25.2	1938
100	MOBILE BLK 823	FG	25.0	1983

[a]Total wet gas after lease separation.

Note: The U.S. total production estimate of 19,259 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.

FP = Federal Offshore Pacific.

FG = Federal Offshore Gulf of Mexico.

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

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."{45}

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, 1996 – 2006

Year	Adjustments (1)	Net Revisions (2)	Revisions[a] and Adjustments (3)	Net of Sales and Acquisitions (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 cubic meters)					
1996	28.0	117.1	145.1	NA	86.3	38.6	22.4	147.3	345.5	3,500.4	-53.1
1997	82.6	145.4	228.0	NA	75.8	101.3	18.9	196.0	339.9	3,584.5	84.1
1998	-101.5	82.3	-19.2	NA	52.0	24.2	19.1	95.3	316.5	3,344.1	-240.4
1999	22.1	289.2	311.3	NA	41.2	51.0	23.1	115.3	310.3	3,460.4	116.3
2000	22.7	118.6	141.3	-3.2	121.8	43.9	39.6	205.3	298.9	3,504.9	44.5
2001	-0.6	-25.1	-25.8	-13.8	137.7	223.7	46.4	407.8	304.5	3,568.6	63.7
2002	66.1	114.5	180.6	3.8	78.2	47.7	24.5	150.4	298.1	3,605.4	36.8
2003	25.9	14.9	40.9	-63.3	67.7	112.1	16.1	195.9	298.4	3,480.4	-125.0
2004	11.8	66.8	78.5	3.7	98.1	5.2	21.0	124.3	289.2	3,397.7	-82.7
2005	35.1	90.5	125.6	44.2	128.0	32.6	6.5	167.1	275.5	3,459.1	61.4
2006	14.9	0.3	15.3	30.8	80.1	4.8	6.8	91.7	262.6	3,334.3	-124.8
						Dry Natural Gas (billion cubic meters)					
1996	107.18	115.70	222.88	NA	219.65	41.09	88.07	348.81	534.08	4,714.02	37.61
1997	-16.70	138.81	122.11	NA	299.73	75.92	67.45	443.10	544.00	4,735.23	21.21
1998	-46.30	162.54	116.24	NA	232.11	30.41	61.22	323.74	530.09	4,645.12	-90.11
1999	27.81	297.44	325.25	NA	199.44	44.40	62.18	306.02	535.98	4,740.41	95.29
2000	-25.23	197.14	171.91	114.15	418.72	56.15	67.05	541.93	544.22	5,024.17	283.76
2001	77.64	-65.64	12.01	74.47	463.83	101.32	79.29	644.44	560.08	5,195.01	170.84
2002	105.54	26.53	132.07	10.76	418.21	37.72	47.97	503.90	548.02	5,293.72	98.71
2003	80.45	-46.38	34.07	29.28	465.93	34.60	45.59	546.12	550.05	5,353.10	59.38
2004	-3.23	21.07	17.84	52.22	515.31	21.49	34.15	570.95	542.78	5,451.36	98.23
2005	53.43	76.43	129.86	72.04	596.07	26.67	34.21	656.95	522.67	5,787.54	336.18
2006	21.04	-51.99	-30.95	84.84	616.68	11.58	32.71	660.97	525.14	5,977.26	189.72
						Natural Gas Liquids (million cubic meters)					
1996	75.4	27.8	103.2	NA	71.7	10.3	17.3	99.4	135.1	1,243.8	67.4
1997	-2.2	45.9	43.7	NA	85.1	18.1	14.3	117.5	137.4	1,267.6	23.8
1998	-57.4	33.1	-24.3	NA	60.9	10.5	14.0	85.4	132.4	1,196.2	-71.4
1999	15.8	115.6	131.4	NA	49.8	8.1	14.0	71.9	142.5	1,257.0	60.8
2000	-13.2	73.0	59.8	23.1	102.5	14.6	16.2	133.4	146.4	1,326.7	69.7
2001	-68.2	-21.0	-89.2	16.2	114.0	21.9	22.6	158.5	141.5	1,270.8	-55.9
2002	9.9	4.9	14.8	8.6	97.3	7.6	12.4	117.3	140.5	1,270.9	0.1
2003	-53.7	-25.6	-79.3	4.8	100.0	5.6	11.4	117.0	127.5	1,185.9	-85.0
2004	43.4	15.4	58.8	17.8	116.7	4.1	8.6	129.4	131.5	1,260.5	74.6
2005	-14.1	3.3	-10.8	24.8	137.2	5.1	6.7	149.0	125.3	1,298.1	37.7
2006	27.5	-26.2	1.3	18.6	146.9	2.5	8.4	157.9	128.9	1,346.9	48.8

[a]Revisions and adjustments = Col. 1 + Col. 2.
[b]Total discoveries = Col. 5 + Col. 6 + Col. 7.
[c]Proved reserves = Col. 10 from prior year + Col. 3 + 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: barrels = 0.1589873 per cubic meter and cubic feet = 0.02831685 per cubic 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*, 1996–2006 annual reports, DOE/EIA–0216.{19–29}

Appendix D

Historical Reserves Statistics

Appendix D

Historical Reserves Statistics

EIA maintains a data archive of all published proved reserves volumes at the State and National level. Appendix D provides a series of tables of the proved reserves and production of crude oil, natural gas, and natural gas liquids for the U.S. and the lower 48 States for the years 1977 through 2006.

All historical statistics included have previously been published in the annual reports of 1977 through 2005 of the EIA publication *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves Annual Report*, DOE EIA-0216.{1-29}

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.

An electronic version of the Data Archive (in Microsoft Excel™) format is available for downloading at the following link:
http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/cr.html

The Data Archive is listed in the "Special Files" section of the destination site.

Table D1. U.S. Proved Reserves of Crude Oil, 1976–2006
(Million Barrels of 42 U.S. Gallons)

Year	Adjustments[a] (1)	Net Revisions (2)	Revisions[b] and Adjustments (3)	Net of Sales and Acquisitions (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	386	346	NA	496	168	130	794	2,862	31,780	-1,722
1978	366	1,390	1,756	NA	444	267	116	827	3,008	31,355	-425
1979	337	437	774	NA	424	108	104	636	2,955	29,810	-1,545
1980	219	1,889	2,108	NA	572	143	147	862	2,975	29,805	-5
1981	138	1,271	1,409	NA	750	254	157	1,161	2,949	29,426	-379
1982	-83	434	351	NA	634	204	193	1,031	2,950	27,858	-1,568
1983	462	1,511	1,973	NA	629	105	190	924	3,020	27,735	-123
1984	159	2,445	2,604	NA	744	242	158	1,144	3,037	28,446	711
1985	429	1,598	2,027	NA	742	84	169	995	3,052	28,416	-30
1986	57	855	912	NA	405	48	81	534	2,973	26,889	-1,527
1987	233	2,316	2,549	NA	484	96	111	691	2,873	27,256	367
1988	364	1,463	1,827	NA	355	71	127	553	2,811	26,825	-431
1989	213	1,333	1,546	NA	514	112	90	716	2,586	26,501	-324
1990	86	1,483	1,569	NA	456	98	135	689	2,505	26,254	-247
1991	163	223	386	NA	365	97	92	554	2,512	24,682	-1,572
1992	290	735	1,025	NA	391	8	85	484	2,446	23,745	-937
1993	271	495	766	NA	356	319	110	785	2,339	22,957	-788
1994	189	1,007	1,196	NA	397	64	111	572	2,268	22,457	-500
1995	122	1,028	1,150	NA	500	114	343	957	2,213	22,351	-106
1996	175	737	912	NA	543	243	141	927	2,173	22,017	-334
1997	520	914	1,434	NA	477	637	119	1,233	2,138	22,546	529
1998	-638	518	-120	NA	327	152	120	599	1,991	21,034	-1,512
1999	139	1,819	1,958	NA	259	321	145	725	1,952	21,765	731
2000	143	746	889	-20	766	276	249	1,291	1,880	22,045	280
2001	-4	-158	-162	-87	866	1,407	292	2,565	1,915	22,446	401
2002	416	720	1,136	24	492	300	154	946	1,875	22,677	231
2003	163	94	257	-398	426	705	101	1,232	1,877	21,891	-786
2004	74	420	494	23	617	33	132	782	1,819	21,371	-520
2005	221	569	790	278	805	205	41	1,051	1,733	21,757	386
2006	94	2	96	194	504	30	43	577	1,652	20,972	-785

[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.
[c]Total discoveries = Col. 5 + Col. 6 + Col. 7.
[d]Proved reserves = Col. 10 from prior year + Col. 3 + 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 2006 annual reports, DOE/EIA-0216.{1-29}

Table D2. U.S. Lower 48 Proved Reserves of Crude Oil, 1976–2006
(Million Barrels of 42 U.S. Gallons)

Year	Adjustments[a] (1)	Net Revisions (2)	Revisions[b] and Adjustments (3)	Net of Sales and Acquisitions (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	383	343	NA	496	168	130	794	2,698	23,367	-1,561
1978	-48	509	461	NA	444	142	116	702	2,559	21,971	-1,396
1979	342	429	771	NA	424	108	104	636	2,443	20,935	-1,036
1980	210	1,524	1,734	NA	479	143	147	769	2,384	21,054	119
1981	276	1,009	1,285	NA	750	254	157	1,161	2,357	21,143	89
1982	-82	684	602	NA	633	204	193	1,030	2,323	20,452	-691
1983	462	949	1,411	NA	625	105	190	920	2,355	20,428	-24
1984	160	1,587	1,747	NA	742	207	158	1,107	2,399	20,883	455
1985	361	1,667	2,028	NA	581	84	169	834	2,385	21,360	477
1986	70	359	429	NA	399	48	81	528	2,303	20,014	-1,346
1987	233	1,353	1,586	NA	294	38	101	433	2,155	19,878	-136
1988	359	1,181	1,540	NA	340	43	127	510	2,062	19,866	-12
1989	214	1,113	1,327	NA	342	108	87	537	1,903	19,827	-39
1990	151	1,001	1,152	NA	371	98	135	604	1,853	19,730	-97
1991	164	50	214	NA	327	97	87	511	1,856	18,599	-1,131
1992	297	277	574	NA	279	8	84	371	1,821	17,723	-876
1993	250	198	448	NA	343	319	109	771	1,760	17,182	-541
1994	187	527	714	NA	316	64	111	491	1,697	16,690	-492
1995	117	756	873	NA	434	114	333	881	1,673	16,771	81
1996	172	728	900	NA	479	115	141	735	1,663	16,743	-28
1997	514	695	1,209	NA	459	520	119	1,098	1,665	17,385	642
1998	-639	315	-324	NA	299	56	120	475	1,554	15,982	-1,403
1999	138	1,669	1,807	NA	253	242	145	640	1,564	16,865	883
2000	144	622	766	132	540	276	157	973	1,552	17,184	319
2001	-5	-71	-76	-87	716	1,126	292	2,134	1,560	17,595	411
2002	414	567	981	24	467	300	146	913	1,514	17,999	404
2003	162	5	167	-398	391	705	101	1,197	1,520	17,445	-554
2004	75	373	448	23	506	33	74	613	1,485	17,044	-401
2005	223	467	690	278	749	205	41	995	1,421	17,586	542
2006	93	153	246	194	404	30	43	477	1,410	17,093	-493

[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.
[c]Total discoveries = Col. 5 + Col. 6 + Col. 7.
[d]Proved reserves = Col. 10 from prior year + Col. 3 + 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 2006 annual reports, DOE/EIA-0216.{1-29}

Table D3. U.S. Proved Reserves of Dry Natural Gas, 1976–2006
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

Year	Adjustments[a] (1)	Net Revisions (2)	Revisions[b] and Adjustments (3)	Net of Sales and Acquisitions (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	-1,605	-1,625	NA	8,129	3,173	3,301	14,603	18,843	207,413	-5,865
1978	2,429	-1,025	1,404	NA	9,582	3,860	4,579	18,021	18,805	208,033	620
1979	-2,264	-219	-2,483	NA	8,950	3,188	2,566	14,704	19,257	200,997	-7,036
1980	1,201	1,049	2,250	NA	9,357	2,539	2,577	14,473	18,699	199,021	-1,976
1981	1,627	2,599	4,226	NA	10,491	3,731	2,998	17,220	18,737	201,730	2,709
1982	2,378	455	2,833	NA	8,349	2,687	3,419	14,455	17,506	201,512	-218
1983	3,090	-15	3,075	NA	6,909	1,574	2,965	11,448	15,788	200,247	-1,265
1984	-2,241	3,129	888	NA	8,299	2,536	2,686	13,521	17,193	197,463	-2,784
1985	-1,708	2,471	763	NA	7,169	999	2,960	11,128	15,985	193,369	-4,094
1986	1,320	3,572	4,892	NA	6,065	1,099	1,771	8,935	15,610	191,586	-1,783
1987	1,268	3,296	4,564	NA	4,587	1,089	1,499	7,175	16,114	187,211	-4,375
1988	2,193	-15,060	-12,867	NA	6,803	1,638	1,909	10,350	16,670	168,024	-19,187
1989	3,013	3,030	6,043	NA	6,339	1,450	2,243	10,032	16,983	167,116	-908
1990	1,557	5,538	7,095	NA	7,952	2,004	2,412	12,368	17,233	169,346	2,230
1991	2,960	4,416	7,376	NA	5,090	848	1,604	7,542	17,202	167,062	-2,284
1992	2,235	6,093	8,328	NA	4,675	649	1,724	7,048	17,423	165,015	-2,047
1993	972	5,349	6,321	NA	6,103	899	1,866	8,868	17,789	162,415	-2,600
1994	1,945	5,484	7,429	NA	6,941	1,894	3,480	12,315	18,322	163,837	1,422
1995	580	7,734	8,314	NA	6,843	1,666	2,452	10,961	17,966	165,146	1,309
1996	3,785	4,086	7,871	NA	7,757	1,451	3,110	12,318	18,861	166,474	1,328
1997	-590	4,902	4,312	NA	10,585	2,681	2,382	15,648	19,211	167,223	749
1998	-1,635	5,740	4,105	NA	8,197	1,074	2,162	11,433	18,720	164,041	-3,182
1999	982	10,504	11,486	NA	7,043	1,568	2,196	10,807	18,928	167,406	3,365
2000	-891	6,962	6,071	4,031	14,787	1,983	2,368	19,138	19,219	177,427	10,021
2001	2,742	-2,318	424	2,630	16,380	3,578	2,800	22,758	19,779	183,460	6,033
2002	3,727	937	4,664	380	14,769	1,332	1,694	17,795	19,353	186,946	3,486
2003	2,841	-1,638	1,203	-10,092	16,454	1,222	1,610	19,286	19,425	189,044	2,098
2004	-114	744	630	1,844	18,198	759	1,206	20,163	19,168	192,513	3,469
2005	1,887	2,699	4,856	2,544	21,050	942	1,208	23,200	18,458	204,385	11,872
2006	743	-1,836	-1,093	2,996	21,778	409	1,155	23,342	18,545	211,085	6,700

[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.
[c]Total discoveries = Col. 5 + Col. 6 + Col. 7.
[d]Proved reserves = Col. 10 from prior year + Col. 3 + 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 2006 annual reports, DOE/EIA-0216.{1-29}

Table D4. U.S. Lower 48 Proved Reserves of Dry Natural Gas, 1976–2006
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

Year	Adjustments[a] (1)	Net Revisions (2)	Revisions[b] and Adjustments (3)	Net of Sales and Acquisitions (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	-1,540	-1,561	NA	8,056	3,173	3,301	14,530	18,637	175,170	-5,668
1978	2,446	-758	1,688	NA	9,582	3,860	4,277	17,719	18,589	175,988	818
1979	-2,202	-707	-2,909	NA	8,949	3,173	2,566	14,688	19,029	168,738	-7,250
1980	1,163	62	1,225	NA	9,046	2,539	2,577	14,162	18,486	165,639	-3,099
1981	1,840	2,506	4,346	NA	10,485	3,731	2,994	17,210	18,502	168,693	3,054
1982	2,367	-1,748	619	NA	8,349	2,687	3,419	14,455	17,245	166,522	-2,171
1983	3,089	421	3,510	NA	6,908	1,574	2,965	11,447	15,515	165,964	-558
1984	-2,245	2,617	372	NA	8,298	2,536	2,686	13,520	16,869	162,987	-2,977
1985	-1,349	2,500	1,151	NA	7,098	999	2,960	11,057	15,673	159,522	-3,465
1986	1,618	4,144	5,762	NA	6,064	1,099	1,761	8,924	15,286	158,922	-600
1987	1,066	2,645	3,711	NA	4,542	1,077	1,499	7,118	15,765	153,986	-4,936
1988	2,017	8,895	10,912	NA	6,771	1,638	1,909	10,318	16,270	158,946	4,960
1989	2,997	2,939	5,936	NA	6,184	1,450	2,243	9,877	16,582	158,177	-769
1990	1,877	4,572	6,449	NA	7,898	2,004	2,412	12,314	16,894	160,046	1,869
1991	2,967	3,860	6,827	NA	5,074	848	1,563	7,485	16,849	157,509	-2,537
1992	1,946	5,937	7,883	NA	4,621	649	1,724	6,994	17,009	155,377	-2,132
1993	915	4,779	5,694	NA	6,076	899	1,858	8,833	17,396	152,508	-2,869
1994	1,896	5,289	7,185	NA	6,936	1,894	3,480	12,310	17,899	154,104	1,596
1995	973	7,223	8,196	NA	6,801	1,666	2,452	10,919	17,570	155,649	1,545
1996	3,640	4,055	7,695	NA	7,751	1,390	3,110	12,251	18,415	157,180	1,531
1997	-609	3,192	2,583	NA	10,571	2,681	2,382	15,634	18,736	156,661	-519
1998	-1,463	5,696	4,233	NA	8,195	1,070	2,162	11,427	18,207	154,114	-2,547
1999	849	10,452	11,301	NA	7,041	1,512	2,173	10,726	18,469	157,672	3,558
2000	-914	8,755	7,841	4,214	12,838	1,983	2,355	17,176	18,713	168,190	10,518
2001	2,753	-2,216	537	2,630	16,321	3,504	2,796	21,621	19,318	174,660	6,470
2002	3,692	914	4,606	380	14,707	1,332	1,686	17,725	18,893	178,478	3,818
2003	2,840	-1,830	1,010	1,034	16,373	1,202	1,609	19,184	18,947	180,759	2,281
2004	-113	319	206	1,844	18,057	759	1,171	19,987	18,690	184,106	3,347
2005	1,889	2,560	4,449	2,542	20,988	920	1,198	23,106	17,989	196,214	12,108
2006	789	-4,313	-3,524	2,996	21,729	409	1,153	23,291	18,137	200,840	4,626

[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.
[c]Total discoveries = Col. 5 + Col. 6 + Col. 7.
[d]Proved reserves = Col. 10 from prior year + Col. 3 + 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 2006 annual reports, DOE/EIA-0216.{1-29}

Table D5. U.S. Proved Reserves of Wet Natural Gas, After Lease Separation, 1978–2006
(Billion Cubic Feet at 14.73 psia and 60° Fahrenheit)

Year	Adjustments[a] (1)	Net Revisions (2)	Revisions[b] and Adjustments (3)	Net of Sales and Acquisitions (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	-223	5,133	NA	9,332	3,279	2,637	15,248	20,079	208,335	302
1980	1,253	1,137	2,390	NA	9,757	2,629	2,648	15,034	19,500	206,259	-2,076
1981	2,057	2,743	4,800	NA	10,979	3,870	3,080	17,929	19,554	209,434	3,175
1982	2,598	455	3,053	NA	8,754	2,785	3,520	15,059	18,292	209,254	-180
1983	4,363	57	4,420	NA	7,263	1,628	3,071	11,962	16,590	209,046	-208
1984	-2,413	3,333	920	NA	8,688	2,584	2,778	14,050	18,032	205,984	-3,062
1985	-1,299	2,687	1,388	NA	7,535	1,040	3,053	11,628	16,798	202,202	-3,782
1986	2,137	3,835	5,972	NA	6,359	1,122	1,855	9,336	16,401	201,109	-1,093
1987	1,199	3,522	4,721	NA	4,818	1,128	1,556	7,502	16,904	196,428	-4,681
1988	2,180	-14,931	[f]-12,751	NA	7,132	1,677	1,979	10,788	17,466	[f]176,999	–19,429
1989	2,537	3,220	5,757	NA	6,623	1,488	2,313	10,424	17,752	175,428	-1,571
1990	1,494	5,837	7,331	NA	8,287	2,041	2,492	12,820	18,003	177,576	2,148
1991	3,368	4,569	7,937	NA	5,298	871	1,655	7,824	18,012	175,325	-2,251
1992	2,543	6,374	8,917	NA	4,895	668	1,773	7,336	18,269	173,309	-2,016
1993	1,048	5,541	6,589	NA	6,376	927	1,930	9,233	18,641	170,490	-2,819
1994	1,977	5,836	7,813	NA	7,299	1,941	3,606	12,846	19,210	171,939	1,449
1995	889	8,091	8,980	NA	7,204	1,709	2,518	11,431	18,874	173,476	1,537
1996	4,288	4,277	8,565	NA	8,189	1,491	3,209	12,889	19,783	175,147	1,671
1997	-730	5,057	4,327	NA	11,179	2,747	2,455	16,381	20,134	175,721	574
1998	-1,624	5,982	4,358	NA	8,630	1,116	2,240	11,986	19,622	172,433	-3,288
1999	1,102	11,182	12,284	NA	7,401	1,622	2,265	11,288	19,856	176,159	3,726
2000	-1,295	7,456	6,161	4,286	15,550	2,055	2,463	20,068	20,164	186,510	10,351
2001	1,849	-2,438	-589	2,715	17,183	3,668	2,898	23,749	20,642	191,743	5,233
2002	4,004	1,038	5,042	428	15,468	1,374	1,752	18,594	20,248	195,561	3,816
2003	2,323	-1,715	608	1,107	17,195	1,252	1,653	20,100	20,231	197,145	1,584
2004	170	825	995	1,975	19,068	790	1,244	21,102	20,017	201,200	4,055
2005	1,693	2,715	4,408	2,674	22,069	973	1,243	24,285	19,259	213,308	12,108
2006	946	-2,099	-1,153	3,178	22,834	425	1,197	24,456	19,373	220,416	7,108

[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.
[c]Total discoveries = Col. 5 + Col. 6 + Col. 7.
[d]Proved reserves = Col. 10 from prior year + Col. 3 + 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 2006 annual reports, DOE/EIA-0216.{3-29}

Table D6. U.S. Lower 48 Proved Reserves of Wet Natural Gas, After Lease Separation, 1978–2006

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

Year	Adjustments[a] (1)	Net Revisions (2)	Revisions[b] and Adjustments (3)	Net of Sales and Acquisitions (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	-711	4,691	NA	9,331	3,264	2,637	15,232	19,851	176,060	72
1980	1,218	150	1,368	NA	9,446	2,629	2,648	14,723	19,287	172,864	-3,196
1981	2,270	2,650	4,920	NA	10,973	3,870	3,076	17,919	19,318	176,385	3,521
1982	2,586	-1,748	838	NA	8,754	2,785	3,520	15,059	18,030	174,252	-2,133
1983	4,366	493	4,859	NA	7,262	1,628	3,071	11,961	16,317	174,755	503
1984	-2,409	2,821	412	NA	8,687	2,584	2,778	14,049	17,708	171,508	-3,247
1985	-1,313	2,713	1,400	NA	7,463	1,040	3,053	11,556	16,485	167,979	-3,529
1986	2,114	4,410	6,524	NA	6,357	1,122	1,845	9,324	16,073	167,754	-225
1987	1,200	2,868	4,068	NA	4,772	1,116	1,556	7,444	16,553	162,713	-5,041
1988	2,025	9,390	11,415	NA	7,099	1,677	1,979	10,755	17,063	167,820	5,107
1989	2,545	3,128	5,673	NA	6,467	1,485	2,313	10,265	17,349	166,409	-1,411
1990	1,811	4,859	6,670	NA	8,232	2,041	2,492	12,765	17,661	168,183	1,774
1991	3,367	4,013	7,380	NA	5,281	871	1,614	7,766	17,657	165,672	-2,511
1992	2,265	6,217	8,482	NA	4,840	668	1,773	7,281	17,851	163,584	-2,088
1993	996	4,971	5,967	NA	6,349	927	1,922	9,198	18,245	160,504	-3,080
1994	1,924	5,613	7,537	NA	7,294	1,941	3,606	12,841	18,756	162,126	1,622
1995	1,304	7,525	8,829	NA	7,162	1,709	2,518	11,389	18,443	163,901	1,775
1996	4,219	4,246	8,465	NA	8,183	1,430	3,209	12,822	19,337	165,851	1,950
1997	-835	3,322	2,487	NA	11,165	2,747	2,455	16,367	19,657	165,048	-803
1998	-1,461	5,937	4,476	NA	8,628	1,112	2,240	11,980	19,104	162,400	-2,648
1999	958	11,130	12,088	NA	7,399	1,566	2,242	11,207	19,391	166,304	3,904
2000	-1,294	9,273	7,979	4,471	13,574	2,055	2,450	18,079	19,654	177,179	10,875
2001	1,849	-2,336	-487	2,715	17,123	3,593	2,894	23,610	20,175	182,842	5,663
2002	4,004	1,038	5,042	428	15,468	1,374	1,752	18,594	20,248	19,5561	3,816
2003	2,324	-1,909	415	1,107	17,114	1,232	1,652	19,998	19,751	188,797	1,769
2004	170	395	565	1,975	18,927	790	1,209	20,926	19,536	192,727	3,930
2005	1,694	2,575	4,269	2,672	22,007	951	1,233	24,191	18,788	205,071	12,344
2006	996	-4,603	-3,607	3,178	22,784	425	1,195	24,404	18,963	210,083	5,012

[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.
[c]Total discoveries = Col. 5 + Col. 6 + Col. 7.
[d]Proved reserves = Col. 10 from prior year + Col. 3 + 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 2006 annual reports, DOE/EIA-0216.{3-29}

Table D7. U.S. Proved Reserves of Natural Gas Liquids, 1978–2006
(Million Barrels of 42 U.S. Gallons)

Year	Adjustments[a] (1)	Net Revisions (2)	Revisions[b] and Adjustments (3)	Net of Sales and Acquisitions (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	-49	15	NA	364	94	97	555	727	6,615	-157
1980	153	104	257	NA	418	90	79	587	731	6,728	113
1981	231	86	317	NA	542	131	91	764	741	7,068	340
1982	299	-21	278	NA	375	112	109	596	721	7,221	153
1983	849	66	915	NA	321	70	99	490	725	7,901	680
1984	-123	142	19	NA	348	55	96	499	776	7,643	-258
1985	426	162	588	NA	337	44	85	466	753	7,944	301
1986	367	223	590	NA	263	34	72	369	738	8,165	221
1987	231	191	422	NA	213	39	55	307	747	8,147	-18
1988	11	453	464	NA	268	41	72	381	754	8,238	91
1989	-277	123	-154	NA	259	83	74	416	731	7,769	-469
1990	-83	221	138	NA	299	39	73	411	732	7,586	-183
1991	233	130	363	NA	189	25	55	269	754	7,464	-122
1992	225	261	486	NA	190	20	64	274	773	7,451	-13
1993	102	124	226	NA	245	24	64	333	788	7,222	-229
1994	43	197	240	NA	314	54	131	499	791	7,170	-52
1995	192	277	469	NA	432	52	67	551	791	7,399	229
1996	474	175	649	NA	451	65	109	625	850	7,823	424
1997	-14	289	275	NA	535	114	90	739	864	7,973	150
1998	-361	208	-153	NA	383	66	88	537	833	7,524	-449
1999	99	727	826	NA	313	51	88	452	896	7,906	382
2000	-83	459	376	145	645	92	102	839	921	8,345	439
2001	-429	-132	-561	102	717	138	142	997	890	7,993	-352
2002	62	31	93	54	612	48	78	738	884	7,994	1
2003	-338	-161	-499	30	629	35	72	736	802	7,459	-535
2004	273	97	370	112	734	26	54	814	827	7,928	469
2005	-89	21	-68	156	863	32	42	937	788	8,165	237
2006	173	-165	8	117	924	16	53	993	811	8,472	307

[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.
[c]Total discoveries = Col. 5 + Col. 6 + Col. 7.
[d]Proved reserves = Col. 10 from prior year + Col. 3 + 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 2006 annual reports, DOE/EIA-0216.{3-29}

Table D8. U.S. Lower 48 Proved Reserves of Natural Gas Liquids, 1978–2006
(Million Barrels of 42 U.S. Gallons)

Year	Adjustments[a] (1)	Net Revisions (2)	Revisions[b] and Adjustments (3)	Net of Sales and Acquisitions (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	-49	14	NA	364	94	97	555	726	6,592	-157
1980	165	104	269	NA	418	90	79	587	731	6,717	125
1981	233	85	318	NA	542	131	91	764	741	7,058	341
1982	300	-21	279	NA	375	112	109	596	721	7,212	154
1983	850	66	916	NA	321	70	99	490	725	7,893	681
1984	-115	123	8	NA	348	55	96	499	776	7,624	-269
1985	70	152	222	NA	334	44	85	463	748	7,561	-63
1986	363	226	589	NA	263	34	72	369	735	7,784	223
1987	179	191	370	NA	212	39	55	306	731	7,729	-55
1988	10	452	462	NA	267	41	72	380	734	7,837	108
1989	-273	123	-150	NA	259	83	74	416	714	7,389	-448
1990	-60	221	161	NA	298	39	73	410	714	7,246	-143
1991	183	138	321	NA	187	25	55	267	730	7,104	-142
1992	225	254	479	NA	183	20	64	267	746	7,104	0
1993	101	124	225	NA	245	24	64	333	761	6,901	-203
1994	38	196	234	NA	314	54	131	499	765	6,869	-32
1995	204	230	434	NA	432	52	67	551	761	7,093	224
1996	417	178	595	NA	450	56	109	615	817	7,486	393
1997	-107	55	-52	NA	533	114	90	737	829	7,342	-144
1998	-74	208	134	NA	383	66	88	537	809	7,204	-138
1999	102	617	719	NA	304	50	86	440	848	7,515	311
2000	9	459	468	145	645	92	102	839	899	8,068	553
2001	-429	-280	-709	-102	717	138	142	997	870	7,588	-480
2002	42	31	73	54	612	48	78	738	864	7,589	1
2003	-338	-161	-499	30	629	35	72	736	784	7,072	-517
2004	273	97	370	112	734	26	54	814	809	7,559	487
2005	-89	21	-68	156	863	32	42	937	771	7,813	254
2006	173	-165	8	117	924	16	53	993	797	8,134	321

[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.
[c]Total discoveries = Col. 5 + Col. 6 + Col. 7.
[d]Proved reserves = Col. 10 from prior year + Col. 3 + 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 2006 annual reports, DOE/EIA-0216.{3-29}

Table D9. Deepwater Production and Proved Reserves of the Gulf of Mexico Federal Offshore, 1992-2006

Year	Gulf of Mexico			Depth		Deepwater Percentage
	Total	Louisiana[a]	Texas	Greater than 200 meters	Less than 200 meters	
	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
2000	419	381	38	234	185	55.8
2001	459	417	42	286	173	62.2
2002	451	395	57	288	163	63.9
2003	485	426	59	336	149	69.3
2004	467	404	63	310	157	66.4
2005	409	342	67	305	104	75.0
2006	406	348	58	318	87	78.5
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
2000	3,174	2,751	423	2,021	1,153	63.7
2001	4,288	3,877	411	3,208	1,080	74.8
2002	4,444	4,088	356	3,372	1,072	75.9
2003	4,554	4,251	303	3,627	927	79.6
2004	4,144	3,919	225	3,280	864	79.2
2005	4,042	3,851	191	3,272	770	81.0
2006	3,655	3,500	155	2,983	672	81.6

Table D9. Deepwater Production and Proved Reserves of the Gulf of Mexico Federal Offshore, 1992-2006 (continued)

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
	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
2000	4,901	3,747	1,154	1,196	3,705	24.4
2001	5,027	3,843	1,184	1,367	3,660	27.2
2002	4,544	3,541	1,003	1,365	3,180	30.0
2003	4,397	3,330	1,067	1,545	2,852	35.1
2004	3,967	2,890	1,077	1,251	2,716	31.5
2005	2,968	2,056	912	1,070	1,898	36.1
2006	2,805	2,036	769	1,112	1,692	39.6
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
2000	26,891	20,466	6,425	8,731	18,160	32.5
2001	27,100	20,290	6,810	11,229	15,871	41.4
2002	25,347	19,113	6,234	10,540	14,807	41.6
2003	22,522	17,168	5,354	10,041	12,481	44.6
2004	19,288	15,144	4,144	8,591	10,698	44.5
2005	17,427	14,073	3,354	8,042	9,385	46.1
2006	14,938	12,201	2,737	6,690	8,248	44.8

Table D9. Deepwater Production and Proved Reserves of the Gulf of Mexico Federal Offshore, 1992-2006 (continued)

Year	Gulf of Mexico			Depth		Deepwater Percentage
	Total	Louisiana[a]	Texas	Greater than 200 meters	Less than 200 meters	
	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
2000	199	164	35	84	115	42.2
2001	192	147	45	96	96	50.0
2002	184	149	35	66	118	36.0
2003	148	120	28	55	93	37.2
2004	155	127	28	51	104	32.9
2005	123	98	25	44	79	35.8
2006	125	102	23	50	75	39.6
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
2000	1,074	921	153	468	606	43.6
2001	967	785	182	443	524	45.8
2002	965	783	182	407	558	42.2
2003	717	598	119	262	455	36.5
2004	713	615	98	292	421	32.9
2005	688	603	85	248	440	36.0
2006	649	575	74	291	358	44.8

Table D9. Deepwater Production and Proved Reserves of the Gulf of Mexico Federal Offshore, 1992-2006 (continued)

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
	Dry Natural Gas (billion cubic feet at 14.73 psia and 60° Fahrenheit)					
Production						
1992	4,508	3,233	1,275	162	4,346	3.6
1993	4,577	3,319	1,258	224	4,353	4.9
1994	4,725	3,440	1,285	288	4,437	6.1
1995	4,627	3,376	1,251	361	4,266	7.8
1996	4,991	3,706	1,285	544	4,447	10.9
1997	5,133	3,895	1,238	565	4,568	11.0
1998	4,872	3,728	1,144	711	4,161	14.6
1999	4,885	3,721	1,164	1,099	3,786	22.5
2000	4,773	3,626	1,147	1,165	3,608	24.4
2001	4,913	3,735	1,178	1,334	3,578	27.4
2002	4,423	3,427	996	1,328	3,095	30.0
2003	4,306	3,244	1,062	1,513	2,793	35.1
2004	3,874	2,802	1,072	1,222	2,652	31.5
2005	2,906	1,997	909	1,069	1,837	36.8
2006	2,738	1,973	765	1,086	1,652	39.6
Reserves						
1992	26,649	19,653	6,996	3,225	23,424	12.1
1993	26,044	19,383	6,661	3,438	22,606	13.2
1994	27,218	20,835	6,383	4,709	22,509	17.3
1995	27,917	21,392	6,525	5,751	22,166	20.6
1996	27,852	21,856	5,996	6,322	21,530	22.7
1997	27,922	21,934	5,988	7,343	20,579	26.3
1998	26,422	20,774	5,648	7,425	18,997	28.1
1999	25,451	19,598	5,853	7,533	17,918	29.6
2000	26,172	19,788	6,384	8,506	17,666	32.5
2001	26,456	19,721	6,735	10,943	15,513	41.4
2002	24,689	18,500	6,189	10,266	14,423	41.6
2003	22,059	16,728	5,331	9,835	12,224	44.6
2004	18,812	14,685	4,127	8,379	10,433	44.5
2005	17,007	13,665	3,342	8,043	8,964	47.3
2006	14,549	11,824	2,725	6,516	8,033	44.8

Table D9. Deepwater Production and Proved Reserves of the Gulf of Mexico Federal Offshore, 1992-2006 (continued)

Year	Gulf of Mexico Total	Louisiana[a]	Texas	Depth Greater than 200 meters	Depth Less than 200 meters	Deepwater Percentage
	Lease Condensate (million barrels of 42 U.S. gallons)					
Production						
1992	44	35	9	2	42	4.4
1993	46	35	11	3	43	6.2
1994	47	37	10	3	44	6.1
1995	49	40	9	7	42	14.1
1996	60	49	11	8	52	12.9
1997	70	59	11	8	62	12.1
1998	72	57	15	13	59	18.7
1999	87	61	26	27	60	30.5
2000	106	76	30	45	61	42.2
2001	101	60	41	51	50	50.2
2002	90	60	30	38	52	42.2
2003	78	53	25	30	48	38.5
2004	74	49	25	27	47	36.2
2005	62	39	23	26	36	41.9
2006	58	37	21	23	35	40.1
Reserves						
1992	310	226	84	48	262	15.4
1993	316	235	81	51	265	16.0
1994	311	233	78	57	254	18.2
1995	412	305	107	192	220	46.7
1996	527	422	105	210	317	39.8
1997	527	433	94	203	324	38.5
1998	557	435	122	234	323	42.1
1999	567	430	137	234	333	41.3
2000	560	433	127	244	316	43.6
2001	482	325	157	221	261	45.8
2002	454	300	154	195	259	43.0
2003	353	251	102	135	218	38.2
2004	290	205	85	103	187	35.6
2005	272	196	76	104	168	38.2
2006	249	185	64	90	159	36.2

[a]Includes Federal Offshore Alabama.

Table D10. 2006 Reported Proved Nonproducing Reserves of Crude Oil, Lease Condensate, and Wet Natural Gas, After Lease Separation[a]

State and Subdivision	Crude Oil (million bbls)	Lease Condensate (million bbls)	Nonassociated Gas (bcf)	Associated Dissolved Gas (bcf)	Total Gas (bcf)
Alaska	442	0	339	7	346
Lower 48 States	**4,732**	**504**	**60,330**	**6,038**	**66,368**
Alabama	0	0	244	1	245
Arkansas	1	0	615	8	623
California	496	0	282	488	770
Coastal Region Onshore	85	0	6	52	58
Los Angeles Basin Onshore	149	0	0	63	63
San Joaquin Basin Onshore	228	0	274	350	624
State Offshore	34	0	2	23	25
Colorado	102	40	5,828	857	6,685
Florida	1	0	0	0	0
Kansas	17	0	144	2	146
Kentucky	0	0	286	0	286
Louisiana	198	40	4,038	316	4,354
North	14	10	2,363	38	2,401
South Onshore	162	27	1,473	252	1,725
State Offshore	22	3	202	26	228
Michigan	15	1	436	24	460
Mississippi	79	0	143	6	149
Montana	91	0	152	24	176
New Mexico	159	12	3,814	322	4,136
East	159	10	668	318	986
West	0	2	3,146	4	3,150
New York	0	0	38	0	38
North Dakota	53	1	17	29	46
Ohio	8	0	115	8	123
Oklahoma	90	55	4,838	110	4,948
Pennsylvania	0	0	603	36	639
Texas	1,077	136	21,461	1,726	23,187
RRC District 1	26	5	319	19	338
RRC District 2 Onshore	16	2	573	46	619
RRC District 3 Onshore	18	24	826	68	894
RRC District 4 Onshore	4	39	3,083	24	3,107
RRC District 5	1	1	6,211	21	6,232
RRC District 6	17	23	3,101	27	3,128
RRC District 7B	5	0	830	4	834
RRC District 7C	120	10	1,156	415	1,571
RRC District 8	466	3	1,439	687	2,126
RRC District 8A	386	1	3	353	356
RRC District 9	9	3	2,257	13	2,270
RRC District 10	9	23	1,544	49	1,593
State Offshore	0	2	119	0	119
Utah	164	32	1,978	140	2,118
Virginia	0	0	868	0	868
West Virginia	0	0	923	0	923
Wyoming	258	52	7,359	28	7,387
Federal Offshore[b]	1,921	135	6,121	1,911	8,032
Pacific (California)	37	4	47	99	146
Gulf of Mexico (Louisiana)[b]	1,816	101	4,877	1,688	6,565
Gulf of Mexico (Texas)	68	30	1,197	124	1,321
Miscellaneous[c]	2	0	27	2	29
U.S. Total	**5,174**	**504**	**60,669**	**6,045**	**66,714**

[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," 2006.

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 2006 by crude oil or natural gas well operators who were active as of December 31, 2006. 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 1999 and 2006, and depicts the number of active operators, with 2002 showing the largest in the series. The 2006 sampling frame consisted of 173 Category I, 467 Category II, 232 Category III Certainty, and 12,948 Category III Noncertainty operators, for a total of 13,820 active operators. The survey sample consisted of 872 operators selected with certainty that included all of the Category I and II Certainty operators, the 232 smaller operators that were selected with certainty because of their size in relation to the area or areas in which they operated, and 483 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 2006 survey is summarized in **Table E2**. EIA makes a considerable effort to gain responses from all operators. About 5.3 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 58 nonoperators, 11 had successor operators that had taken over the production of the nonoperator. These successor operators were subsequently sampled. The overall response rate for the 2006 survey was 95 percent. For the 69 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, 1999-2006

Operator Category	Number of Operators							
	1999	2000	2001	2002	2003	2004	2005	2006
Certainty								
Category I	177	175	179	176	164	164	172	173
Category II	399	436	485	480	512	532	522	467
Category III	648	854	559	388	399	275	195	232
Sampled	1,224	1,465	1,223	1,044	1,075	971	889	872
Percent Sampled	100	100	100	100	100	100	100	100
Noncertainty								
Sampled	1,305	1,311	644	533	479	370	505	483
Percent Sampled	7	7	3	3	3	2	4	4
Total								
Active Operators	22,089	22,102	22,519	22,823	20,923	20,670	15,158	13,820
Not Sampled	19,560	19,326	20,652	21,246	19,369	19,329	13,764	12,465
Sampled	R2,529	2,776	1,867	1,577	1,554	1,341	1,394	1,355
Percent Sampled	R11	13	8	7	7	7	9	10

R=Revised data.
Source: Energy Information Administration, Office of Oil and Gas.

Table E2. Form EIA-23 Survey Response Statistics, 2006

Operator Category	Original Sample Selected	Successor[a] Operators	Net[b] Category Changes	Non-[c] operators	Adjusted[d] Sample	Responding Operators		Nonresponding[e] Operators	
						Number	Percent	Number	Percent
Certainty									
Category I	173	0	1	-6	168	168	100.0	0	0.0
Category II	467	3	-19	-11	440	427	97.0	13	3.0
Category III	232	8	24	-17	247	224	90.7	23	9.3
Subtotal	872	11	6	-34	855	819	95.8	36	4.2
Noncertainty	483	0	-6	-24	453	420	92.7	33	7.3
Total	1,355	11	0	-58	1,308	1,239	94.7	69	5.3

[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 69 operators (13 Category II operators, 23 Category III operators, and 33 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" 2006.

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, sales and acquisitions, 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 2006*, in January 2007, was the 25th annual report and reflected data collected through December 2006. This list was made available to operators to assist in identifying the field code data necessary for the preparation of Form EIA-23.

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 2006, Form EIA-23 National estimates of production were 1,834 million barrels for crude oil and lease condensate or 28 million barrels (1.5 percent) lower than that reported in the *Petroleum Supply Annual 2006* for crude oil and lease condensate (1,862 million barrels). Form EIA-23 National estimates of production for dry natural gas were 18,545 billion cubic feet, 14 billion cubic feet (less than 1 percent) higher than the *Natural Gas Monthly, October 2007* for 2006 dry natural gas production (18,531 billion cubic feet).

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 HPDI, LLC., are used to obtain information on operator status and to update addresses for the frame each year.

A maintenance procedure is utilized in conjunction with State production records and commercial information data bases to update possible crude oil and natural gas well operators presently listed on EIA's master frame and add new operators to the master frame. This procedure identifies active operators and nonoperators which improves the frame for future sample selections for the annual 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 2006 survey mailing. These changes resulted from all frame maintenance activities.

The Form EIA-23 operator frame contained a total of 68,616 entries as of December 31, 2006. Of these, 15,158 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

Table E3. Summary of the 2006 Operator Frame Activity, Form EIA-23

Total 2005 Operator Frame	68,616
Operators	15,158
Nonoperators	53,458
Changes to 2005 Operator Status	2,574
From Nonoperator to Operator[a]	1,761
From Operator to Nonoperator	813
New Operators	811
No Changes to 2005 Operator Status	66,042
Operators	13,007
Nonoperators	53,035
Additions to 2005 Operator Frame	0
Operator	0
Nonoperator	0
Total 2006 Operator Frame	**68,616**
Operators	16,106
Nonoperators	52,510

[a]Includes operator frame activity through December 31, 2006.
[B]No additions were made since EIA ID numbers are now being recycled when no useable data is available with a specific EIA ID number. This procedure will increase the number of Nonoperator to Operator changes more than usual.

that may be added to the active list if review indicates activity.

Form EIA-64A Survey Design

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

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

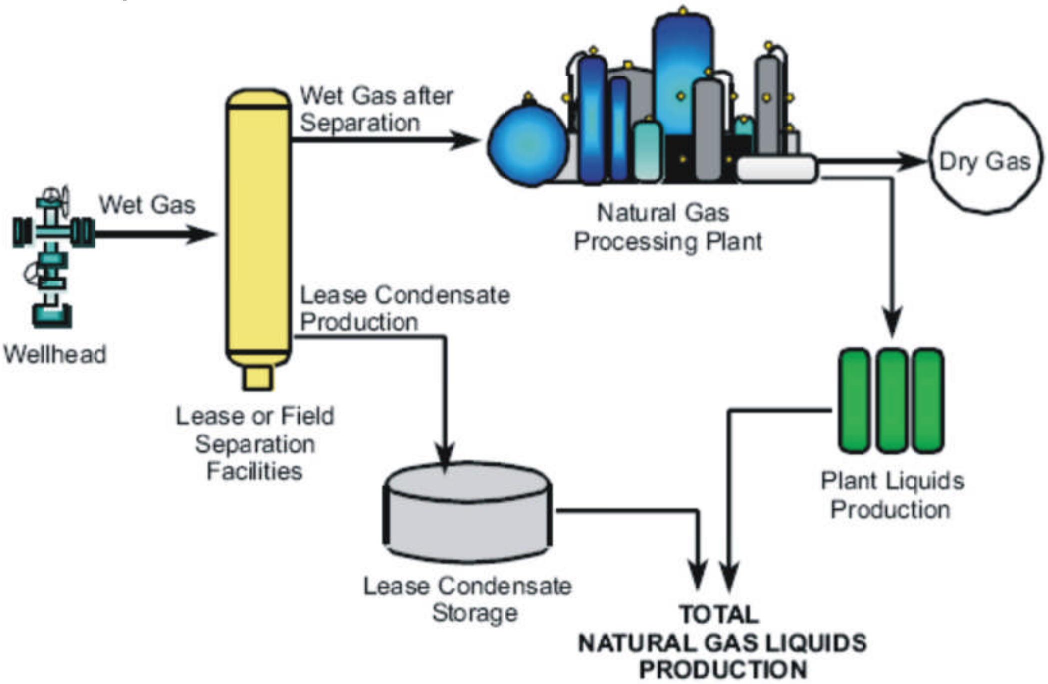
The EIA recognized that its estimates of proved reserves of natural gas liquids (NGL) had to reflect not only those volumes extractable in the future under current economic and operating conditions at the lease or field (lease condensate), but also volumes (plant liquids) extractable downstream at existing 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, 2006. In addition, plant operators whose plants were shut down or dismantled during 2006 were required to complete forms for the portion of 2006 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 221 operators of 491 plants were sent forms. This number included 6 new plants, 2 reactivated plants, and 1 successor plants, all identified after the initial 2006 survey mailing. A total of 5 plants were reported as nonoperating according to the Form EIA-64A

Figure E1. Natural Gas Liquids Extraction Flows



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

definition. For the 19th 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 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

Table E4. Natural Gas Processed and Liquids Extracted at Natural Gas Processing Plants, 2006

Plant Location	Volume of Natural Gas Delivered to Processing Plants: State Production	Federal Production	Out of State Production	Natural Gas Processed	Total Liquids Extracted
	(million cubic feet)				(thousand barrels)
Alaska	2,665,742	0	0	2,665,742	20,993
Alabama	33,239	252,889	1,150	287,278	14,736
Arkansas	13,702	0	0	13,702	166
California	223,029	551	0	223,580	11,267
Colorado	750,835	0	201	751,036	26,111
Florida	1,973	0	1,999	3,972	357
Kansas	323,765	0	129,346	453,111	21,509
Kentucky	39,559	0	0	39,559	1,666
Louisiana	904,476	1,607,326	0	2,511,802	73,551
Michigan	33,213	0	0	33,213	2,335
Mississippi	6,019	272,417	0	278,436	9,666
Montana	12,685	0	0	12,685	1,043
North Dakota	65,575	0	0	65,575	5,560
New Mexico	817,261	0	0	817,261	68,755
Oklahoma	899,826	0	8,229	908,055	62,992
Texas	3,953,075	0	37,787	3,990,862	261,087
Utah	190,119	0	3,717	193,836	2,418
West Virginia	98,521	0	30,813	129,334	5,939
Wyoming	1,272,661	0	15,463	1,288,124	46,847
Miscellanous[a]	15,025	0	0	15,025	637
Total	**12,320,300**	**2,133,183**	**228,705**	**14,682,188**	**637,635**

[a]Includes Illinois, Ohio, and Pennsylvania.
Source: Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production," 2006

revisions to EIA's monthly estimates. Differences, when found, were reconciled in both sources. For 2006, the Form EIA-64A National estimates (**Table E4**) were 1 percent (6,819 thousand barrels) lower than the *Petroleum Supply Annual 2006* volume of 626,703 thousand barrels for natural gas plant liquids production.

Table E5. Form EIA-64A 2006 Plant Frame Activity

Frame as of 2005 survey mailing	489
Additions	58
Deletions	–56
Frame as of 2006 survey mailing	491

Note: Includes operator frame activity through March 1, 2007.
Source: Energy Information Administration, Office of Oil and Gas.

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 2006 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 March 1, 2007.

Appendix F

Statistical Considerations

Appendix F

Statistical Considerations

Sampling Plan

The goal was a sample that would provide estimates of reserves and production of crude oil, natural gas, and lease condensate for the United States. A stratified sample using a single stage and systematic selection with probability proportional to size was designed. The measure of size was the volume of production for crude oil, natural gas, and lease condensate by State by company in 2005. There were two strata: companies selected with certainty and companies selected under the systematic probability proportional to size design.

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. EIA conducts extensive frame maintenance activities each year to identify all current operators of crude oil and natural gas wells in the country. 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.

Sample Design

To meet survey objectives, while minimizing respondent burden, a sampling strategy has been used since 1977. EIA publishes data on reserves and production for crude oil, natural gas, and lease condensate by State for most States, and by subdivision for the States of California, Louisiana, New Mexico, and Texas.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 2004 survey for each product class.

Each operator is asked to report production and reserves 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.

EIA selected the following target sampling error for the 2006 survey for each product class.

- 1.0 percent for National estimates and for each of the States having subdivisions: Alaska, California, Louisiana, New Mexico, and Texas.
- 2.5 percent for each State having 1 percent or more of estimated lower 48 States reserves or production in 2005 for any product class.
- 4 percent for each State/subdivision having less than 1 percent of estimated U.S. reserves or production in 2005 (lower 48 States) for all 3 product class.
- 8 percent for States not published separately.

Certainty Stratum

There are three components to the certainty stratum Category I, Category II, and certain Category III Small Operators.

- **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 2005.
- **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 2005, and additionally, all coalbed methane and Federal Offshore operators.
- **Category III** - *Small Operators:* Operators who produced less than the Category II operators in 2005.

Small operators were further subdivided into certainty and noncertainty strata. Small operators who satisfied any of the following criteria based upon their production shown in the operator frame are certainty operators:

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

Table F1. 2006 EIA–23 Initial Number of Operators in Survey Sample

State and Subdivision	Number of Certainty Operators	Number of Multi–State Operators	Number of Noncertainty Operators	Target Error	
				Oil	Gas
Alabama Onshore	42	1	5	0.040	0.025
Alaska	7	0	0		
Arkansas	64	10	9	0.040	0.025
California - Coastal Region Onshore	14	1	1	0.080	0.080
California - Los Angeles Basin Onshore	13	2	2	0.010	0.010
California - San Joaquin Basin Onshore	42	4	4	0.025	0.040
Colorado	121	2	18	0.025	0.010
Florida	4	0	0	0.025	0.025
Illinois	28	45	34	0.040	0.040
Indiana	23	7	33	0.040	0.080
Kansas	165	53	52	0.040	0.080
Kentucky	32	23	18	0.025	0.010
Louisiana-North	124	19	22	0.040	0.040
Louisiana-South Onshore	182	9	25	0.010	0.010
Michigan	33	6	3	0.010	0.010
Mississippi - Onshore	79	2	11	0.040	0.040
Montana	67	1	4	0.040	0.040
Nebraska	24	1	11	0.040	0.040
New Mexico - East	157	0	27	0.040	0.080
New Mexico - West	47	3	1	0.025	0.025
New York	15	2	7	0.025	0.010
North Dakota	65	0	6	0.080	0.040
Ohio	25	33	14	0.040	0.040
Oklahoma	268	131	79	0.040	0.040
Pennsylvania	46	18	12	0.025	0.025
Texas - RRC District 1	142	30	39	0.040	0.040
Texas - RRC District 2 Onshore	188	2	37	0.025	0.025
Texas - RRC District 3 Onshore	276	25	61	0.040	0.025
Texas - RRC District 4 Onshore	212	13	34	0.025	0.025
Texas - RRC District 5	107	3	20	0.040	0.010
Texas - RRC District 6	178	7	40	0.040	0.010
Texas - RRC District 7B	169	38	98	0.025	0.010
Texas - RRC District 7C	159	1	55	0.025	0.025
Texas - RRC District 8	189	1	46	0.040	0.025
Texas - RRC District 8A	174	9	54	0.010	0.010
Texas - RRC District 9	164	44	83	0.010	0.040
Texas - RRC District 10	141	15	31	0.025	0.025
Utah	56	3	2	0.040	0.010
Virginia	22	0	0	0.040	0.025
West Virginia	38	25	10	0.080	0.040
Wyoming	151	0	10	0.040	0.025
Offshore Areas	322	0	0	0.025	0.025
Other States[a]	46	3	3	0.080	0.080
Total	**[b]1022**	**592**	**[b]383**	**0.010**	**0.010**

[a]Includes Arizona, Idaho, Iowa, Maryland, Missouri, Nevada, Oregon, South Dakota, Tennessee, and Washington.

[b]Nonduplicative count of operators by States.

Note: Sampling rate was 10 percent except in Alaska, Florida Onshore, Virginia, and Offshore areas where sampling rate was 100 percent.

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

Noncertainty Stratum

Small operators not in the certainty stratum were classified in the noncertainty stratum. They were systematically sampled with probability proportional to size. Only the operators in the following 10 states were included in the noncertainty sample: Illinois, Indiana, Kentucky, Maryland, New York, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. All other States were treated as certainty stratum.

In each State/subdivision the balance between the number of 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. 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 systematic random sampling.

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 and for the U.S. Total. **Table F1** shows sampling rates.

Total U.S. Reserve Estimates

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

The estimates of year-end proved reserves and annual production for any State/subdivision is the sum of the volumes in the State/subdivision reported by the certainty stratum operators and an estimate of the total volume in the State/subdivision by the noncertainty stratum operators. The total volume of certainty operators in the State/subdivision is simply the sum of individual operator's volumes. The estimated total volume of noncertainty operators in the State/subdivision is the weighted sum of the reports of the noncertainty sample operators.

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

There were 453 operators sampled proportional to size (Table E2) that responded as Category III noncertainty operators. Only 194 of these, located in 10 states, had their data weighted and used to estimate the production and reserves of the operators that were not sampled in those states. The remaining 259 noncertainty sampled operators were treated as certainty sampled operators with a weight of 1 and were used in states where the bulk of the operator production data was obtained from auxiliary State data (**Table F2-F5**).

The data reported by operator category on Form EIA-23 and data imputed and estimated for report year 2006 are summarized in **Tables F2, F3, F4, and F5**. The reported data in **Table F2** shows that those responding operators accounted for 90.4 percent of the published production for wet natural gas and 94.5 percent of the reserves shown in **Table 9**. Data shown in **Table F3** indicate that those responding operators accounted for 90.4 percent of the nonassociated natural gas production and 94.3 percent of the reserves published in **Table 10**. The reported data shown in **Table F4** indicate that those responding operators accounted for 88.1 percent of published crude oil production and 93.9 percent of the reserves shown in **Table 6**. Additionally, **Table F5** indicates that those responding operators accounted for 91.8 percent of the published production and 94.5 percent of the published proved reserves for lease condensate shown in **Table 15**.

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).
- Imputation was required for the natural gas data of the small operators to estimate their volumes of associated-dissolved and nonassociated natural gas.
- Adjustments to maintain reserves balance.

Methods used are discussed in the following sections.

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.

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 P/[P+R] = Beta * EXP(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 2005 production.

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 production plus end of year reserves equal to zero were excluded from the respondents selected to calculate the R/P coefficients.

In 2005, rather than rely on a weighted sample, the R/P function was used to estimate the proved reserves of all noncertainty operators in these States: Texas, California, Colorado, Louisiana, Montana, New Mexico, South Dakota, Utah, and Wyoming. These States were chosen for this new procedure because of the many years of historical production and reserves data within EIA and availability of reliable State government and commercial production data 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.

Imputation of 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 either:

- 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, or
- applying a modified version of the R/P function to each separate component of change, calculated with its own set of geographically dependent coefficients. This method was used in all four states where the R/P Function was applied to calculate end of year reserves.

Table F2. Summary of Form EIA-23 Reported, Imputed, and Estimated Natural Gas Data for 2006, Wet after Lease Separation (Million Cubic Feet at 14.73 psia and 60 Degrees Fahrenheit)

Level of Reporting	I	II	Certainty III	Noncertainty III	Auxillary State Data	Total
			Reported			
Number of Operators	168	427	224	420	9,485	10,724
Proved Reserves as of 12/31/05	168,423,878	33,397,261	71,754	0	0	201,892,893
(+) Revision Increases	17,306,398	3,274,953	4,124	0	0	20,585,475
(-) Revision Decreases	17,759,712	4,661,005	32,328	0	0	22,453,045
(-) Sales	20,900,422	3,012,204	45	0	0	23,912,671
(+) Acquisitions	22,445,453	4,625,322	0	0	0	27,070,775
(+) Extensions	15,437,038	5,671,753	876	0	0	21,109,667
(+) New Field Discoveries	216,759	169,793	500	0	0	387,052
(+) New Reservoirs in Old Fields	753,295	373,524	45	0	0	1,126,864
(-) Production With Proved Reserves Reported	14,416,133	3,059,545	11,996	0	0	17,487,674
(-) Production Without Proved Reserves Reported	7,162	16,018	0	0	0	23,180
Proved Reserves as of 12/31/06	171,509,399	36,823,576	64,038	0	0	208,397,013
			Imputed and Estimated			
Number of Operators	-	-	-	3,096	-	3,096
Proved Reserves as of 12/31/05	-	-	-	-	-	-
(+) Revision Increases	0	0	0	1,627,948	1	1,627,949
(-) Revision Decreases	0	0	0	126,374	10	126,384
(-) Sales	0	0	0	151,668	0	151,668
(+) Acquisitions	0	0	0	274	53	327
(+) Extensions	0	0	0	4,616	373	4,989
(+) New Field Discoveries	0	0	0	617,444	0	617,444
(+) New Reservoirs in Old Fields	0	0	0	11,116	7	11,123
(-) Production With Proved Reserves Reported	0	0	0	20,108	17	20,125
(-) Production Without Proved Reserves Reported	15,013	32,045	298,476	345,534	1,152,454	1,843,522
Proved Reserves as of 12/31/06	151,038	380,871	2,542,797	3,074,706	5,868,964	12,018,376
			Total			
Number of Operators	168	427	224	3,516	9,485	13,820
Proved Reserves as of 12/31/05	168,423,878	33,397,261	71,754	0	0	203,520,841
(+) Revision Increases	17,306,398	3,274,953	4,124	1,627,948	1	22,213,424
(-) Revision Decreases	17,759,712	4,661,005	32,328	126,374	10	22,579,429
(-) Sales	20,900,422	3,012,204	45	151,668	0	24,064,339
(+) Acquisitions	22,445,453	4,625,322	0	274	53	27,071,102
(+) Extensions	15,437,038	5,671,753	876	4,616	373	21,114,656
(+) New Field Discoveries	216,759	169,793	500	617,444	0	1,004,496
(+) New Reservoirs in Old Fields	753,295	373,524	45	11,116	7	1,137,987
(-) Production With Proved Reserves Reported	14,416,133	3,059,545	11,996	20,108	17	17,507,799
(-) Production Without Proved Reserves Reported	22,175	48,063	298,476	345,534	1,152,454	1,866,702
Proved Reserves as of 12/31/06	171,660,437	37,204,447	2,606,835	3,074,706	5,868,964	220,415,389
			Summary			
Total Number of Operators	**168**	**427**	**224**	**3,516**	**9,485**	**13,820**
Percent of Total	**1.2%**	**3.1%**	**1.6%**	**25.4%**	**68.6%**	**100.0%**
Total Production in 2006	**14,438,308**	**3,107,608**	**310,472**	**365,642**	**1,152,471**	**19,374,501**
Percent of Total	**74.5%**	**16.0%**	**1.6%**	**1.9%**	**5.9%**	**100.0%**
Total Proved Reserves 12/31/06	**171,660,437**	**37,204,447**	**2,606,835**	**3,074,706**	**5,868,964**	**220,415,389**
Percent of Total	**77.9%**	**16.9%**	**1.2%**	**1.4%**	**2.7%**	**100.0%**

[a]There were 453 noncertainty responses, 194 were used with their sample weights and 259 were treated as Certainty III operators.
– = 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," 2006.

Table F3. Summary of Form EIA-23 Reported, Imputed, and Estimated Nonassociated Natural Gas Data for 2006, Wet after Lease Separation (Million Cubic Feet at 14.73 psia and 60 Degrees Fahrenheit)

Level of Reporting	Operator Category I	II	Certainty III	Noncertainty III	Auxillary State Data	Total
Reported						
Number of Operators	168	427	224	420	9,485	10,724
Proved Reserves as of 12/31/05	143,717,198	31,216,588	58,006	0	0	174,991,792
(+) Revision Increases	12,441,499	2,935,760	2,497	0	0	15,379,756
(-) Revision Decreases	15,358,820	4,418,535	26,425	0	0	19,803,780
(-) Sales	19,466,118	2,719,100	45	0	0	22,185,263
(+) Acquisitions	20,659,612	4,447,704	0	0	0	25,107,316
(+) Extensions	14,858,938	5,497,594	876	0	0	20,357,408
(+) New Field Discoveries	182,556	165,085	0	0	0	347,641
(+) New Reservoirs in Old Fields	715,711	349,685	0	0	0	1,065,396
(-) Production With Proved Reserves Reported	12,557,479	2,858,572	10,440	0	0	15,426,491
(-) Production Without Proved Reserves Reported	6,747	17,023	0	0	0	23,770
Proved Reserves as of 12/31/06	145,195,200	34,657,843	53,505	0	0	179,906,548
Imputed and Estimated						
Number of Operators	-	-	-	3,096	-	3,096
Proved Reserves as of 12/31/05	-	-	-	-	-	-
(+) Revision Increases	0	0	0	1,587,065	1	1,587,066
(-) Revision Decreases	0	0	0	110,025	11	110,036
(-) Sales	0	0	0	147,410	0	147,410
(+) Acquisitions	0	0	0	274	53	327
(+) Extensions	0	0	0	4,616	360	4,976
(+) New Field Discoveries	0	0	0	610,908	0	610,908
(+) New Reservoirs in Old Fields	0	0	0	11,116	6	11,122
(-) Production With Proved Reserves Reported	0	0	0	20,108	17	20,125
(-) Production Without Proved Reserves Reported	13,938	30,073	288,687	332,698	956,918	1,622,314
Proved Reserves as of 12/31/06	141,076	361,290	2,450,640	2,953,006	4,964,260	10,870,272
Total						
Number of Operators	168	427	224	3,516	9,485	13,820
Proved Reserves as of 12/31/05	143,717,198	31,216,588	58,006	0	0	176,578,857
(+) Revision Increases	12,441,499	2,935,760	2,497	1,587,065	1	16,966,822
(-) Revision Decreases	15,358,820	4,418,535	26,425	110,025	11	19,913,816
(-) Sales	19,466,118	2,719,100	45	147,410	0	22,332,673
(+) Acquisitions	20,659,612	4,447,704	0	274	53	25,107,643
(+) Extensions	14,858,938	5,497,594	876	4,616	360	20,362,384
(+) New Field Discoveries	182,556	165,085	0	610,908	0	958,549
(+) New Reservoirs in Old Fields	715,711	349,685	0	11,116	6	1,076,518
(-) Production With Proved Reserves Reported	12,557,479	2,858,572	10,440	20,108	17	15,446,616
(-) Production Without Proved Reserves Reported	20,685	47,096	288,687	332,698	956,918	1,646,084
Proved Reserves as of 12/31/06	145,336,276	35,019,133	2,504,145	2,953,006	4,964,260	190,776,820
Summary						
Total Number of Operators	**168**	**427**	**224**	**3,516**	**9,485**	**13,820**
Percent of Total	**1.2%**	**3.1%**	**1.6%**	**25.4%**	**68.6%**	**100.0%**
Total Production in 2006	**12,578,164**	**2,905,668**	**299,127**	**352,806**	**956,935**	**17,092,700**
Percent of Total	**73.6%**	**17.0%**	**1.8%**	**2.1%**	**5.6%**	**100.0%**
Total Proved Reserves 12/31/06	**145,336,276**	**35,019,133**	**2,504,145**	**2,953,006**	**4,964,260**	**190,776,820**
Percent of Total	**76.2%**	**18.4%**	**1.3%**	**1.5%**	**2.6%**	**100.0%**

[a]There were 453 noncertainty responses, 194 were used with their sample weights and 259 were treated as Certainty III operators.
– = 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," 2006.

Table F4. Summary of Form EIA-23 Reported, Imputed, and Estimated Crude Oil Data for 2006,
(Thousand Barrels of 42 U.S. Gallons)

Level of Reporting	I	II	Certainty III	Noncertainty III	Auxillary State Data	Total
			Reported			
Number of Operators	168	427	224	420	9,485	10,724
Proved Reserves as of 12/31/05	18,910,624	1,497,104	14,348	0	0	20,422,076
(+) Revision Increases	1,128,749	354,685	763	0	0	1,484,197
(-) Revision Decreases	1,363,587	140,374	3,200	0	0	1,507,161
(-) Sales	817,259	166,859	0	0	0	984,118
(+) Acquisitions	957,488	217,684	48	0	0	1,175,220
(+) Extensions	420,329	62,395	146	0	0	482,870
(+) New Field Discoveries	22,780	4,892	901	0	0	28,573
(+) New Reservoirs in Old Fields	25,315	14,750	17	0	0	40,082
(-) Production With Proved Reserves Reported	1,316,485	136,772	2,354	0	0	1,455,611
(-) Production Without Proved Reserves Reported	0	609	0	0	0	609
Proved Reserves as of 12/31/06	17,968,311	1,707,959	14,762	0	0	19,691,032
			Imputed and Estimated			
Number of Operators	-	-	-	3,096	-	3,096
Proved Reserves as of 12/31/05	-	-	-	-	-	-
(+) Revision Increases	0	0	0	20,747	5	20,752
(-) Revision Decreases	0	0	0	1,483	56	1,539
(-) Sales	0	0	0	2,858	0	2,858
(+) Acquisitions	0	0	0	0	32	32
(+) Extensions	0	0	0	0	20,084	20,084
(+) New Field Discoveries	0	0	0	528	4	532
(+) New Reservoirs in Old Fields	0	0	0	0	2,456	2,456
(-) Production With Proved Reserves Reported	0	0	0	0	19,787	19,787
(-) Production Without Proved Reserves Reported	1,398	6,311	12,331	20,040	137,036	177,116
Proved Reserves as of 12/31/06	23,611	66,330	123,372	213,313	857,835	1,284,461
			Total			
Number of Operators	168	427	224	3,516	9,485	13,820
Proved Reserves as of 12/31/05	18,910,624	1,497,104	14,348	0	0	20,442,823
(+) Revision Increases	1,128,749	354,685	763	20,747	5	1,504,949
(-) Revision Decreases	1,363,587	140,374	3,200	1,483	56	1,508,700
(-) Sales	817,259	166,859	0	2,858	0	986,976
(+) Acquisitions	957,488	217,684	48	0	32	1,175,252
(+) Extensions	420,329	62,395	146	0	20,084	502,954
(+) New Field Discoveries	22,780	4,892	901	528	4	29,105
(+) New Reservoirs in Old Fields	25,315	14,750	17	0	2,456	42,538
(-) Production With Proved Reserves Reported	1,316,485	136,772	2,354	0	19,787	1,475,398
(-) Production Without Proved Reserves Reported	1,398	6,920	12,331	20,040	137,036	177,725
Proved Reserves as of 12/31/06	17,991,922	1,774,289	138,134	213,313	857,835	20,975,493
			Summary			
Total Number of Operators	**168**	**427**	**224**	**3,516**	**9,485**	**13,820**
Percent of Total	**1.2%**	**3.1%**	**1.6%**	**25.4%**	**68.6%**	**100.0%**
Total Production in 2006	**1,317,883**	**143,692**	**14,685**	**20,040**	**156,823**	**1,653,123**
Percent of Total	**79.7%**	**8.7%**	**0.9%**	**1.2%**	**9.5%**	**100.0%**
Total Proved Reserves 12/31/06	**17,991,922**	**1,774,289**	**138,134**	**213,313**	**857,835**	**20,975,493**
Percent of Total	**85.8%**	**8.5%**	**0.7%**	**1.0%**	**4.1%**	**100.0%**

[a]There were 453 noncertainty responses, 194 were used with their sample weights and 259 were treated as Certainty III operators.
– = 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," 2006.

Table F5. Summary of Form EIA-23 Reported, Imputed, and Estimated Lease Condensate Data for 2006,
(Thousand Barrels of 42 U.S. Gallons)

Level of Reporting	I	II	Certainty III	Noncertainty III	Auxillary State Data	Total
			Reported			
Number of Operators	168	427	224	420	9,485	10,724
Proved Reserves as of 12/31/05	965,527	231,313	193	0	0	1,197,033
(+) Revision Increases	183,570	63,391	47	0	0	247,008
(-) Revision Decreases	149,518	55,065	31	0	0	204,614
(-) Sales	152,665	17,784	0	0	0	170,449
(+) Acquisitions	132,420	33,364	0	0	0	165,784
(+) Extensions	128,187	43,584	0	0	0	171,771
(+) New Field Discoveries	3,496	3,815	0	0	0	7,311
(+) New Reservoirs in Old Fields	10,875	8,570	0	0	0	19,445
(-) Production With Proved Reserves Reported	134,695	31,231	88	0	0	166,014
(-) Production Without Proved Reserves Reported	30	673	0	0	0	703
Proved Reserves as of 12/31/06	987,311	280,052	190	0	0	1,267,553
			Imputed and Estimated			
Number of Operators	-	-	-	3,096	-	3,096
Proved Reserves as of 12/31/05	-	-	-	-	-	-
(+) Revision Increases	0	0	0	16,382	1	16,383
(-) Revision Decreases	0	0	0	2,740	5	2,745
(-) Sales	0	0	0	3,102	0	3,102
(+) Acquisitions	0	0	0	3	13	16
(+) Extensions	0	0	0	0	10,753	10,753
(+) New Field Discoveries	0	0	0	2,075	0	2,075
(+) New Reservoirs in Old Fields	0	0	0	145	7	152
(-) Production With Proved Reserves Reported	0	0	0	275	10	285
(-) Production Without Proved Reserves Reported	68	156	2,537	2,761	9,566	15,088
Proved Reserves as of 12/31/06	652	898	17,237	18,787	33,564	71,138
			Total			
Number of Operators	168	427	224	3,516	9,485	13,820
Proved Reserves as of 12/31/05	965,527	231,313	193	0	0	1,213,415
(+) Revision Increases	183,570	63,391	47	16,382	1	263,391
(-) Revision Decreases	149,518	55,065	31	2,740	5	207,359
(-) Sales	152,665	17,784	0	3,102	0	173,551
(+) Acquisitions	132,420	33,364	0	3	13	165,800
(+) Extensions	128,187	43,584	0	0	10,753	182,524
(+) New Field Discoveries	3,496	3,815	0	2,075	0	9,386
(+) New Reservoirs in Old Fields	10,875	8,570	0	145	7	19,597
(-) Production With Proved Reserves Reported	134,695	31,231	88	275	10	166,299
(-) Production Without Proved Reserves Reported	98	829	2,537	2,761	9,566	15,791
Proved Reserves as of 12/31/06	987,963	280,950	17,427	18,787	33,564	1,338,691
			Summary			
Total Number of Operators	**168**	**427**	**224**	**3,516**	**9,485**	**13,820**
Percent of Total	**1.2%**	**3.1%**	**1.6%**	**25.4%**	**68.6%**	**100.0%**
Total Production in 2006	**134,793**	**32,060**	**2,625**	**3,036**	**9,576**	**182,090**
Percent of Total	**74.0%**	**17.6%**	**1.4%**	**1.7%**	**5.3%**	**100.0%**
Total Proved Reserves 12/31/06	**987,963**	**280,950**	**17,427**	**18,787**	**33,564**	**1,338,691**
Percent of Total	**73.8%**	**21.0%**	**1.3%**	**1.4%**	**2.5%**	**100.0%**

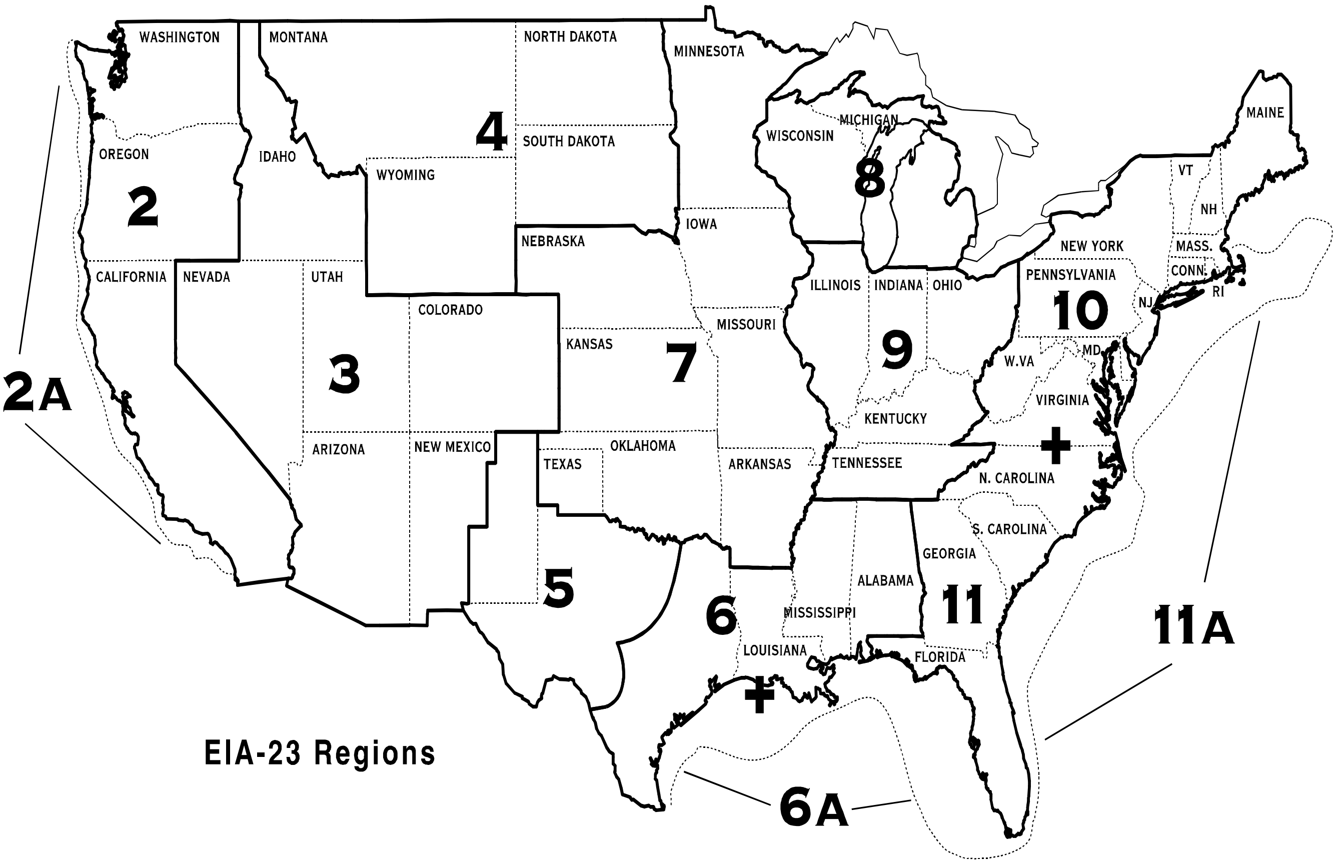
[a]There were 453 noncertainty responses, 194 were used with their sample weights and 259 were treated as Certainty III operators.
– = Not applicable.
Notes: Table 15 totals include imputed and estimated lease condensate proved reserves rounded at the State/subdivision level. Field level data are reported 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," 2006.

Table F6. Statistical Parameters of Reserves Estimation Equation by Region for 2006

Region Number	Region	Number of Nonzero R/P Pairs Oil	Number of Nonzero R/P Pairs Gas	Number of Nonzero R/P Pairs LC	Equation Coefficients Oil Alpha	Equation Coefficients Oil Beta	Equation Coefficients Gas Alpha	Equation Coefficients Gas Beta	Equation Coefficients LC Alpha	Equation Coefficients LC Beta
1	Alaska.	6	10	-	-0.1373	0.3427	-0.1486	0.2435	0.0000	0.0000
2	Pacific Coast States	46	57	7	-0.1373	0.2897	-0.1486	0.4199	-0.1224	0.1432
2A	Federal Offshore Pacific	7	7	-	-0.1373	0.2451	-0.1486	0.2284	0.0000	0.0000
3	Western Rocky Mountains	78	136	62	-0.1373	0.2014	-0.1486	0.3279	-0.1224	0.3288
4	Northern Rocky Mountains	163	170	52	-0.1373	0.2619	-0.1486	0.3508	-0.1224	0.2658
5	West Texas and East New Mexico	484	482	171	-0.1373	0.2612	-0.1486	0.3643	-0.1224	0.4047
6	Western Gulf Basin.	508	839	561	-0.1373	0.3344	-0.1486	0.4438	-0.1224	0.4958
6A	Gulf of Mexico	73	130	101	-0.1373	0.4985	-0.1486	0.8075	-0.1224	0.7175
7	Mid-Continent	293	378	141	-0.1373	0.2783	-0.1486	0.3686	-0.1224	0.2943
8 + 9	Michigan Basin and Eastern Interior	78	64	16	-0.1373	0.2028	-0.1486	0.1849	-0.1224	0.4602
10 + 11	Appalachians	26	80	13	-0.1373	0.1988	-0.1486	0.1785	-0.1224	0.2935
	United States	1,762	2,353	1,124	-0.1373	0.3292	-0.1486	0.3940	-0.1224	0.4567

Source: Based on data filed on Form EIA-23,"Annual Survey of Domestic Oil and Gas Reserves, 2006".

Figure F1. Form EIA-23 Regional Boundaries



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

Both methods preserved an exact annual reserves balance of the following form:

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

The algebraic allocation method used for all but six states in the 2006 survey worked as follows: 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.

Imputation of Natural Gas Volumes

Small operators in the 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 large and intermediate 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
– Sales
+ Acquisitions
+ Extensions
+ New Field Discoveries
+ New Reservoir Discoveries in Old Fields
– Report Year Production
= Proved Reserves at End of Report Year

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

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

- The frame coverage may or may not have improved between survey years, such that more or fewer certainty operators were included in 2006 than in 2005.
- One or more operators may have reported data incorrectly on Schedule A in 2006 or 2005, but not both, and the error was not detected by edit processing.
- Operation of properties was transferred during 2006 from operators not in the frame or noncertainty operators not selected for the sample to certainty operators or noncertainty operators selected for the sample.
- Respondent changed classification of natural gas from NA to AD or vice versa.
- The trend in reserve changes imputed for the small operators, which 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 whose effects cannot be expected to balance over a period of several years are those associated with an inadequate frame or those associated with any actual trend in reserves changes for small operators not being the same as those for large operators. EIA continues to attempt to improve sources of operator data to resolve problems in frame completeness.

Sampling Reliability of the Estimates

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

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

$$V_s \pm k\ S.E.(V_s)$$

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:

$$V_s \pm 2\ S.E.(V_s)$$

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 and F8** provide estimates for $2S.E.(V_s)$ 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 211,085 ± 59 billion cubic feet. The sampling error of V_s is equal to the sampling error of the noncertainty estimate 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.

Sources of Errors

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 Reserves and Production Division conduct technical reviews of reserve estimates and independently estimate the proved reserves of a selected sample of operator properties. The results of these reviews are used to evaluate the accuracy of reported reserve estimates. Operators are apprized 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. Several sources of possible error, apart from sampling error, are associated with the Form EIA-23 survey:

- Operator nonresponse
- Respondent estimation errors
- Reporting errors and data processing errors
- Inadequate frame coverage
- Errors associated with statistical estimates.

Imputation for Operator Nonresponse

The nonresponse rate for certainty operators for the 2006 survey was 4.2 percent and for the noncertainty operators 7.3 percent. An imputation was made for the production and reserves for the 33 nonresponding operators.

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 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.

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 under coverage. Under coverage 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 2006 survey is particularly likely to be deficient in States where a large portion of total reserves and production is accounted for by small operators. EIA is continuing to work to remedy the under coverage problem in those States where it occurred.

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, 6.1 percent of the crude oil proved reserve estimates, 5.5 percent of the wet natural gas proved reserve estimates, and 5.5 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.

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

Table F7. Factors for Confidence Intervals (2S.E.) for Crude Oil Proved Reserves and Production, 2006
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	2006 Reserves	2006 Production	State and Subdivision	2006 Reserves	2006 Production
United States	5	1	Montana[b]	0	0
Alabama[b]	0	0	Nebraska	0	0
Alaska[a]	0	0	New Mexico[b]	0	0
Arkansas[b]	0	0	North Dakota[b]	0	0
California[b]	0	0	Ohio[b]	0	0
Colorado[b]	0	0	Oklahoma[b]	0	0
Florida[a]	0	0	Pennsylvania	0	0
Illinois	0	0	Texas[b]	0	0
Indiana	0	0	Utah[b]	0	0
Kansas[b]	0	0	Virginia[a]	0	0
Kentucky	0	0	West Virginia	0	0
Louisiana[b]	0	0	Wyoming[b]	0	0
Michigan[b]	0	0	Federal Offshore[a]	0	0
Mississippi[b]	0	0	Miscellaneous[c]	2	0

[a]Sampling rate was 100 percent in Alaska, Florida Onshore, Virginia, and Offshore areas.
[b]Sampling was not used. Estimates for each operator were made using an imputation function.
[c]Includes Arizona, Missouri, Nevada, South Dakota, Tennessee, and Virginia.
Notes: Confidence intervals are associated with Table 6 reserves and production data.
Factors for confidence intervals for each 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," 2006.

Table F8. Factors for Confidence Intervals (2S.E.) for Natural Gas Proved Reserves and Production, Wet After Lease Separation, 2006 (Billion Cubic Feet at 14.73 psia and 60 Degrees Fahrenheit)

State and Subdivision	2006 Reserves	2006 Production	State and Subdivision	2006 Reserves	2006 Production
United States	59	5	New Mexico[b]	0	0
Alabama[b]	0	0	New York[b]	0	0
Alaska[a]	0	0	North Dakota[b]	0	0
Arkansas[b]	0	0	Ohio[b]	0	0
California[b]	0	0	Oklahoma[b]	0	0
Colorado[b]	0	0	Pennsylvania	7	1
Florida[a]	0	0	Texas[b]	0	0
Kansas[b]	0	0	Utah[b]	0	0
Kentucky	0	0	Virginia[a]	0	0
Louisiana[b]	0	0	West Virginia	10	1
Michigan[b]	0	0	Wyoming[b]	0	0
Mississippi[b]	0	0	Federal Offshore[a c]	0	0
Montana[b]	0	0	Miscellaneous[d]	4	0

[a]Sampling rate was 100 percent in Alaska, Florida Onshore, Virginia, and Offshore areas.
[b]Sampling was not used. Estimates for each operator were made using an imputation function.
[c]Includes Federal offshore Alabama.
[d]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 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," 2006

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 MMCF per thousand barrels (where NGL consists primarily of ethane) and 0.940 MMCF per thousand barrels (where NGL consists primarily of natural gasolines). When the computed gas equivalents ratio fell outside these limits, an imputed ratio was utilized to estimate the plant's natural gas shrinkage allocation to each reported area of origin.

This imputed ratio was that calculated for the aggregate of all other plants reporting production and shrinkage, and having a gas equivalent ratio within the aforesaid limits, from the area in question. The imputed area ratio was applied only if there were at least five plants to base its computation on. If there were less than five plants, the imputed ratio was calculated based on all plants in the survey whose individual gas equivalents ratio was within the acceptable limits. Less than one percent of the liquids production was associated with shrinkage volumes imputed in this manner. Based on the 2006 Form EIA-64A survey, the national weighted average gas equivalents ratio was computed to be 1,421 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. Coalbed methane fields contain 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.

Appendix G

Estimation of Reserves and Resources

Appendix G

Estimation of Reserves and Resources

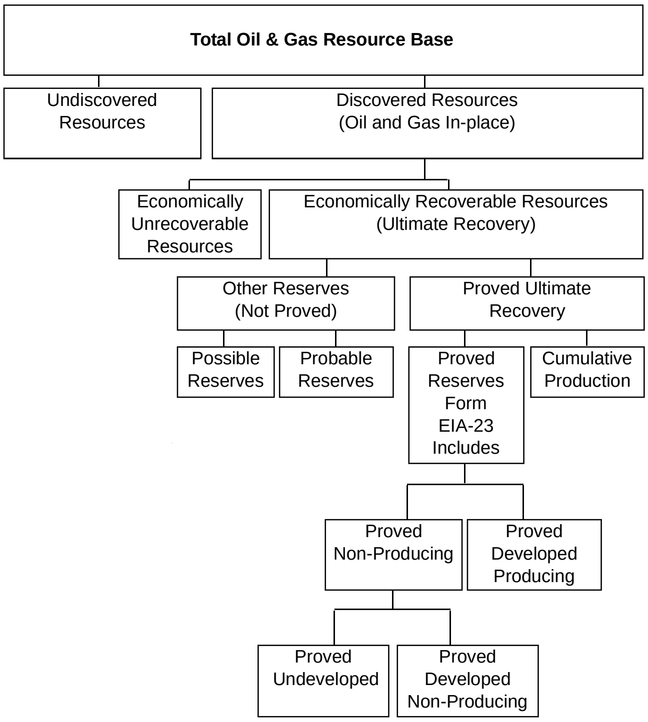
Oil and Gas Resource Base

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 commercially viable 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 tree diagram presented in **Figure G1** outlines a simplified version of the total resource base and its components in two dimensions. 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

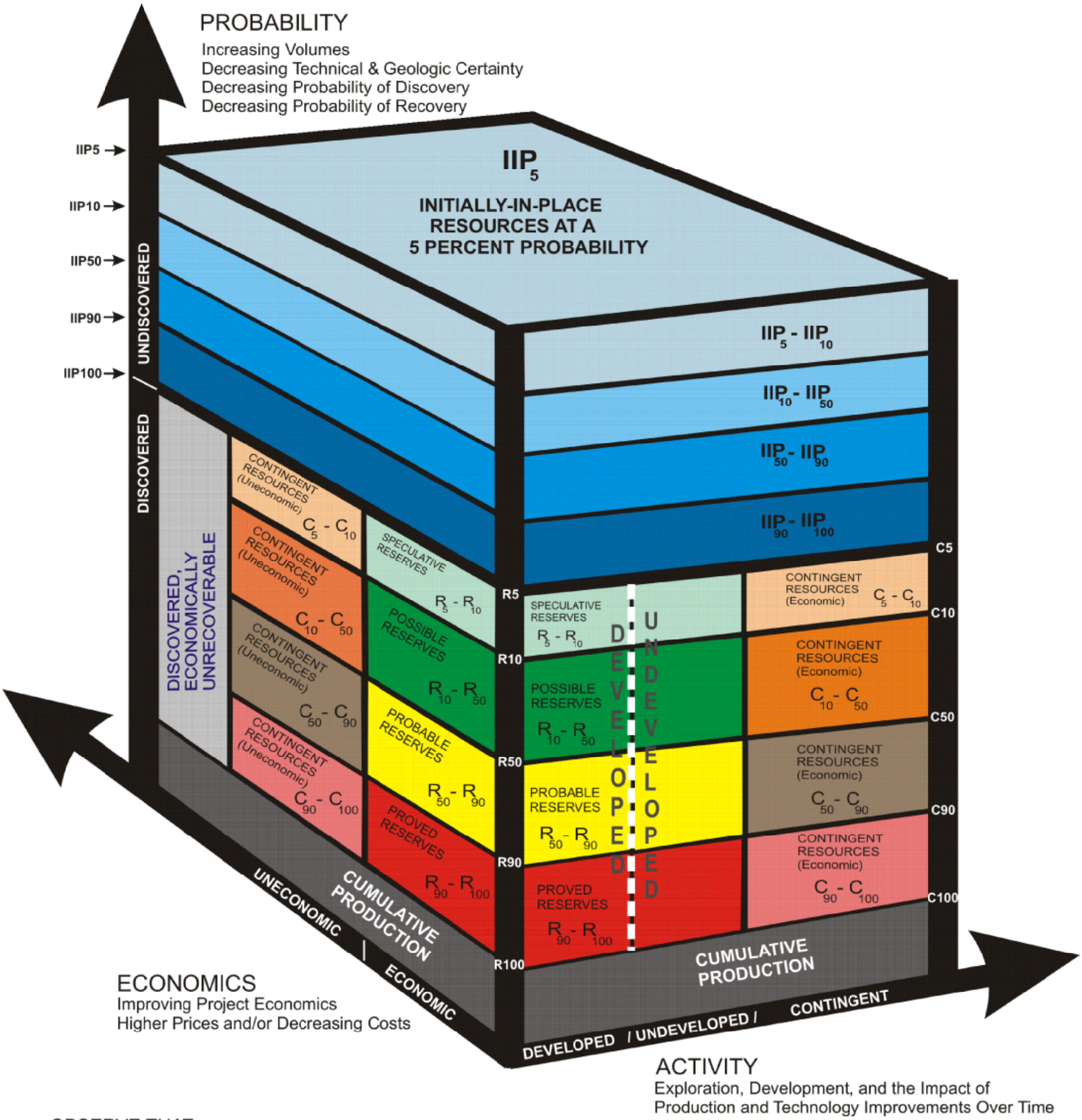


Source: Energy Information Administration, Office of Oil and Gas.

A three-dimensional diagram of the Total In-Place Resource base is presented in **Figure G2**. This diagram represents the total in-place resource base as mapped over three axes: Probability, Activity, and Economics.

Included are definitions of proved, probable, possible, and speculative reserves, developed or undeveloped reserves, contingent resources (economic and uneconomic), nonlinear probability distributions for reserves, contingent resources, and undiscovered initially-in-place resources.

Figure G2. Resource Base



OBSERVE THAT:

- Proved Reserves are a small subset of the Initially-In-Place Resource Base.
- A substantial portion of the Initially-In-Place Resource Base remains to be discovered.
- It is quite possible that future discoveries may exceed current cumulative production.
- The figure implies that only one time in twenty will the IIP5 volume be exceeded as the discovery process unfolds.

Notes: Numeric subscripts (e.g. R_{50}, IIP_{90}) indicate the probability that the associated volume exists.
Drawing is not scaled to any volumetric estimates. Probability distributions in this diagram are nonlinear.

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

The terms in **Figure G2** are consistent with the resource definitions adopted by the Society of Petroleum Engineers (SPE) as set forth in their 2007 document, *Petroleum Resources Management System*, prepared by its Oil and Gas Reserves Committee; reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE). {46}

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 a compilation of USGS and MMS estimates.

Technically recoverable resources of dry natural gas (discovered, unproved, and undiscovered) are estimated at 1,533 trillion cubic feet (**Table G1**). Adding the 2006 U.S. proved reserves of 211 trillion cubic feet yields a technically recoverable resource target of 1,744 trillion cubic feet. This is about 94 times the 2006 dry 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 2006 the PGC mean estimate of potential gas resources was 1,321 trillion cubic feet, about 211 trillion cubic feet less than the estimates in **Table G1**. The differences among these estimates are usually due to the availability of newer data, differences in coverage or resource category definitions, and legitimate but differing data interpretations.

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 unproven technically recoverable oil resources to 2006 oil production (**Table G1**) was about 107 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 economically 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

Table G1. Mean Estimates of Technically Recoverable Oil and Gas Resources by Deposit Type and Location

Area	Crude Oil (billion barrels)	Natural Gas (Dry) (trillion cubic feet)	Natural Gas Liquids (billion barrels)
Undiscovered Conventionally Reservoired Fields			
Alaska Onshore + State Offshore	26.04	126.75	2.23
Alaska Federal Offshore	26.61[a]	132.06	0.00[a]
Lower 48 States Onshore + State Offshore	18.24	178.21	5.56
Lower 48 States Federal Offshore	59.27[a]	287.82	0.00[a]
Alaska Subtotal	52.65	258.81	2.23
Lower 48 States Subtotal	77.51	466.03	5.56
Technically Recoverable Resources in U.S. Undiscovered Conventionally Reservoired Fields	**130.16**	**724.84**	**7.79**
Ultimate Recovery Appreciation			
Alaska Onshore + State Offshore	6.96	12.30	0.41
Lower 48 States Onshore + State Offshore	31.70	442.50	17.85
U.S. Federal Offshore	6.88[a]	30.91	0.00[a]
Technically Recoverable Resources in U.S. from Ultimate Recovery Appreciation in Discovered Conventionally Reservoired Fields	**45.54**	**485.71**	**18.26**
Continuous Type Deposits			
Alaska Non-coal bed	0.00	0.00	0.00
Lower 48 States Non-coal bed	2.13	236.89	3.80
Alaska Coal bed	0.00	18.06	0.00
Lower 48 States Coal bed	0.00	67.32	0.00
Non-coal bed Subtotal	2.13	236.89	3.80
Coal bed Subtotal	0.00	85.38	0.00
Technically Recoverable Resources in U.S. from Continuous Type Deposits	**2.13**	**322.27**	**3.80**
U.S. Totals All Sources			
U.S. Onshore + State Offshore	85.07	1,082.03	29.85
Federal Offshore	92.76[a]	450.79	0.00[a]
U.S. Technically Recoverable Resources	**177.83**	**1,532.82**	**29.85**

[a] The MMS jointly reports natural gas liquids with crude oil for the Federal Offshore.

Additional Notes: Proved Reserves are excluded from these estimates as are undiscovered oil resources in tar deposits and oil shales, and undiscovered gas resources in geopressured brines and gas hydrates.

Zero (0) indicates either that none exists in this area or that no estimate of this resource has been made for this area, or in the instance of Federal offshore natural gas liquids resources that they are jointly reported with crude oil.

Federal Onshore excludes Indian and Native lands even when Federally managed in trust.

Federal Offshore indicates MMS estimates for Federal Offshore jurisdictions (Outer Continental Shelf and deeper water areas seaward of State Offshore).

Data Sources: National Oil and Gas Resource Assessment Team, 2007 Assessment Updates, United States Geological Survey, Washington DC, December 2007 at <http://energy.cr.usgs.gov/oilgas/noga/ass_updates.html>

Resource Evaluation Division, Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, 2006, MMS Fact Sheet RED-2006-01b, Minerals Management Service, Washington, DC, February 2006 at <http://www.mms.gov/revaldiv/PDFs/2006NationalAssessmentBrochure.pdf>.

The ultimate recovery appreciation estimates for Alaska and the Lower 48 States Onshore Plus State Waters were developed by the Reserves and Production Division, Office of Oil and Gas, Energy Information Administration, based on data available as of year-end 2006.

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.

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.{47} They are similarly defined by the MMS, although its system also subdivides them by degree of development and producing status.{48} 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.{45} Inferred reserves are considered equivalent to "probable reserves" by many analysts, for example, those of the PGC.

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.

Unconventional Production and Proved Reserves

For the 2006 survey, a new Form EIA-23L data element called *Type Code* replaced the underutilized *MMS Code*. The *Type Code* is used to categorize proved reserves and production from a field as either *Conventional* (C) or one of four types of *Unconventional* reservoirs: *Coal Bed* (CB); *Chalk* (CH); *Shale* (SH); or *other Low Permeability* (LP) reservoirs (permeability of 0.1 millidarcy or less). *Type Code* was added because the importance of unconventional resources of natural gas and crude oil to domestic energy supply continues to increase.

2006 was the first year the *Type Code* classification was introduced, therefore, the results of the reported data were considered incomplete for all sources of unconventional proved reserves and production except coalbed natural gas at the time of publication for this report. EIA has reported coalbed natural gas proved reserves and production separately since 1989 (see Table 12, Chapter 4).

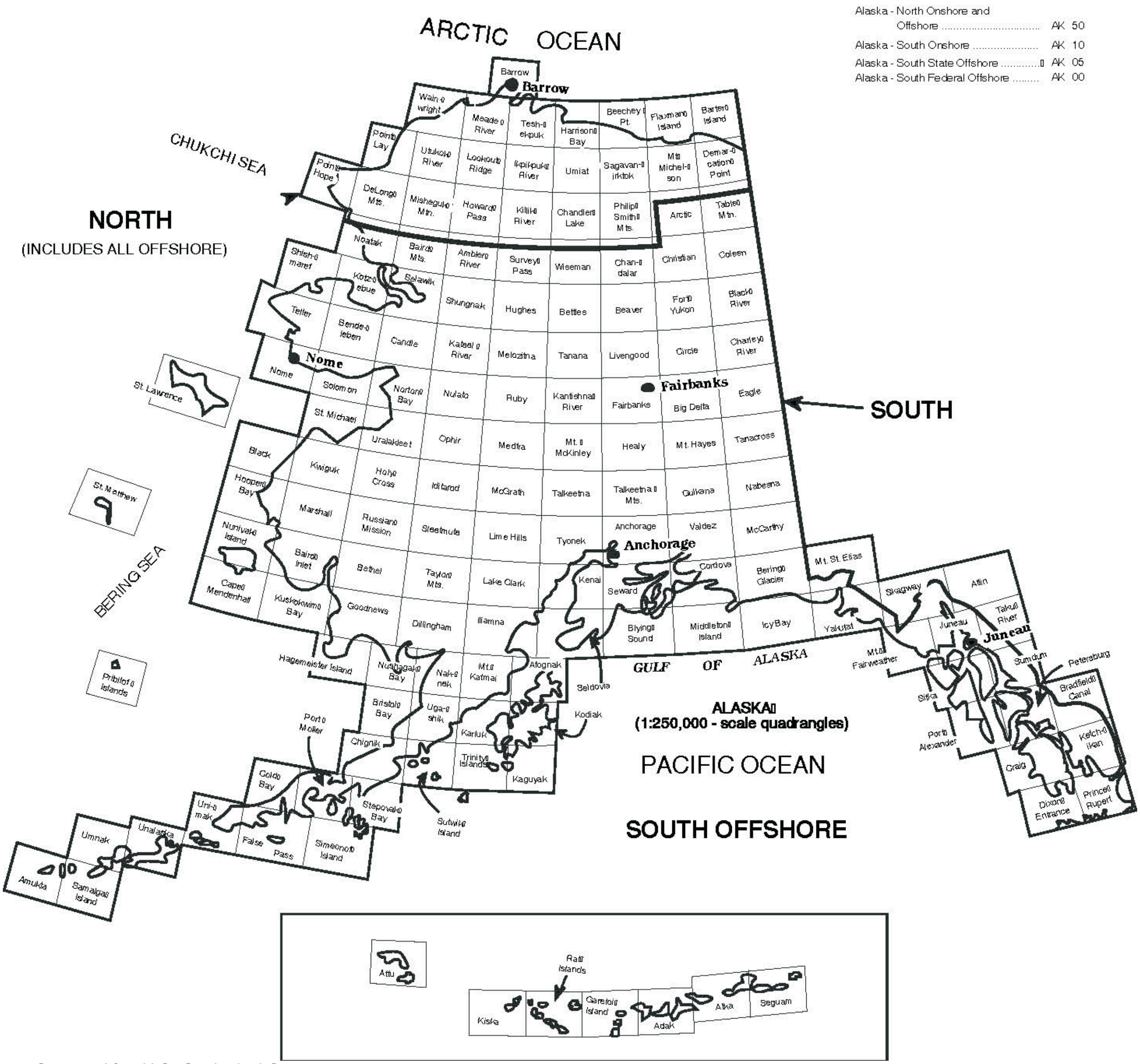
In future reports, as operators familiarize themselves with the *Type Code*, we expect increased coverage and reliability from the reported volumes.

Appendix H

Maps of Selected State Subdivisions

Maps of Selected State Subdivisions

Figure H1. Subdivisions of Alaska

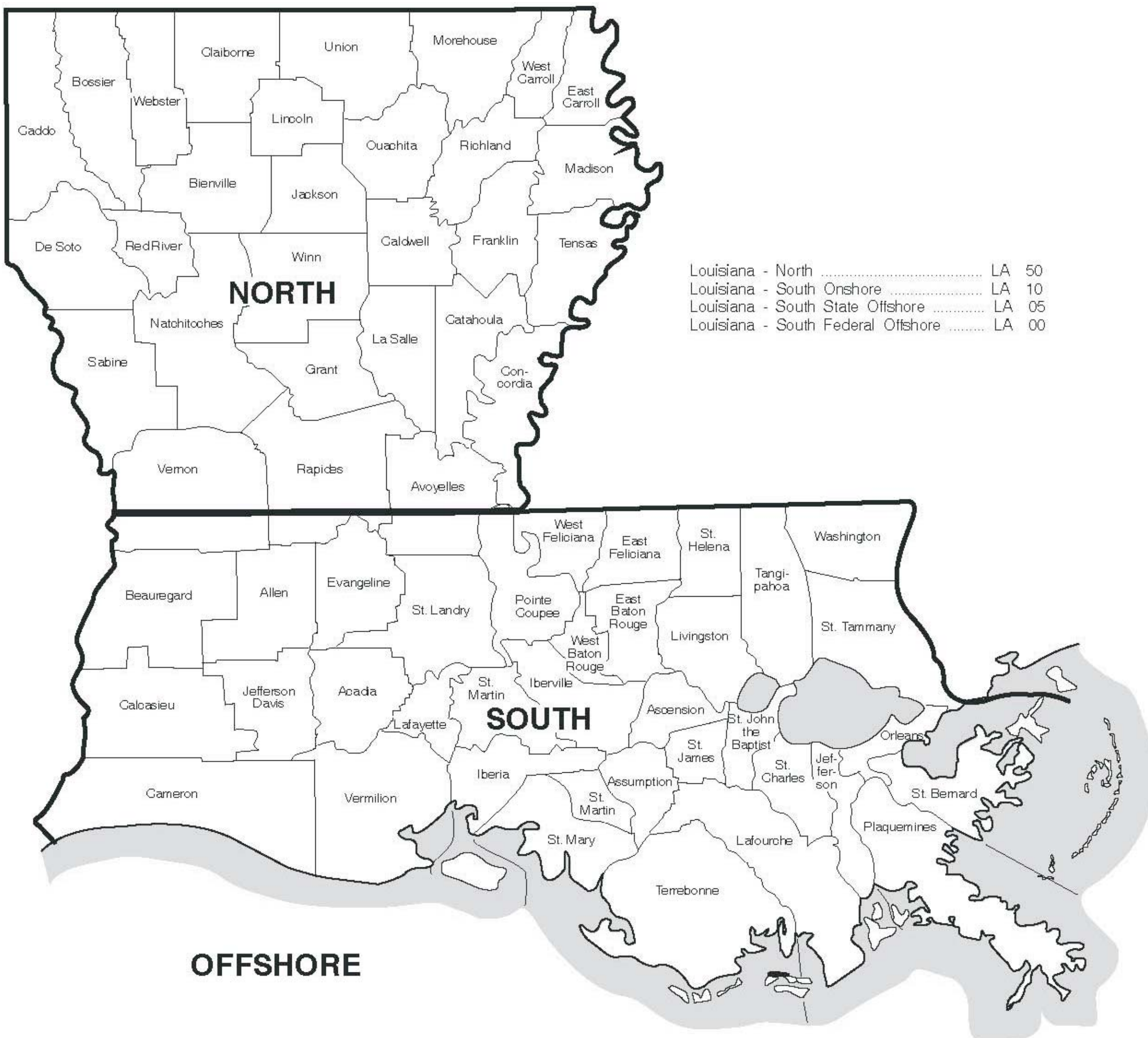


Source: After U.S. Geological Survey.

Figure H2. Subdivisions of California

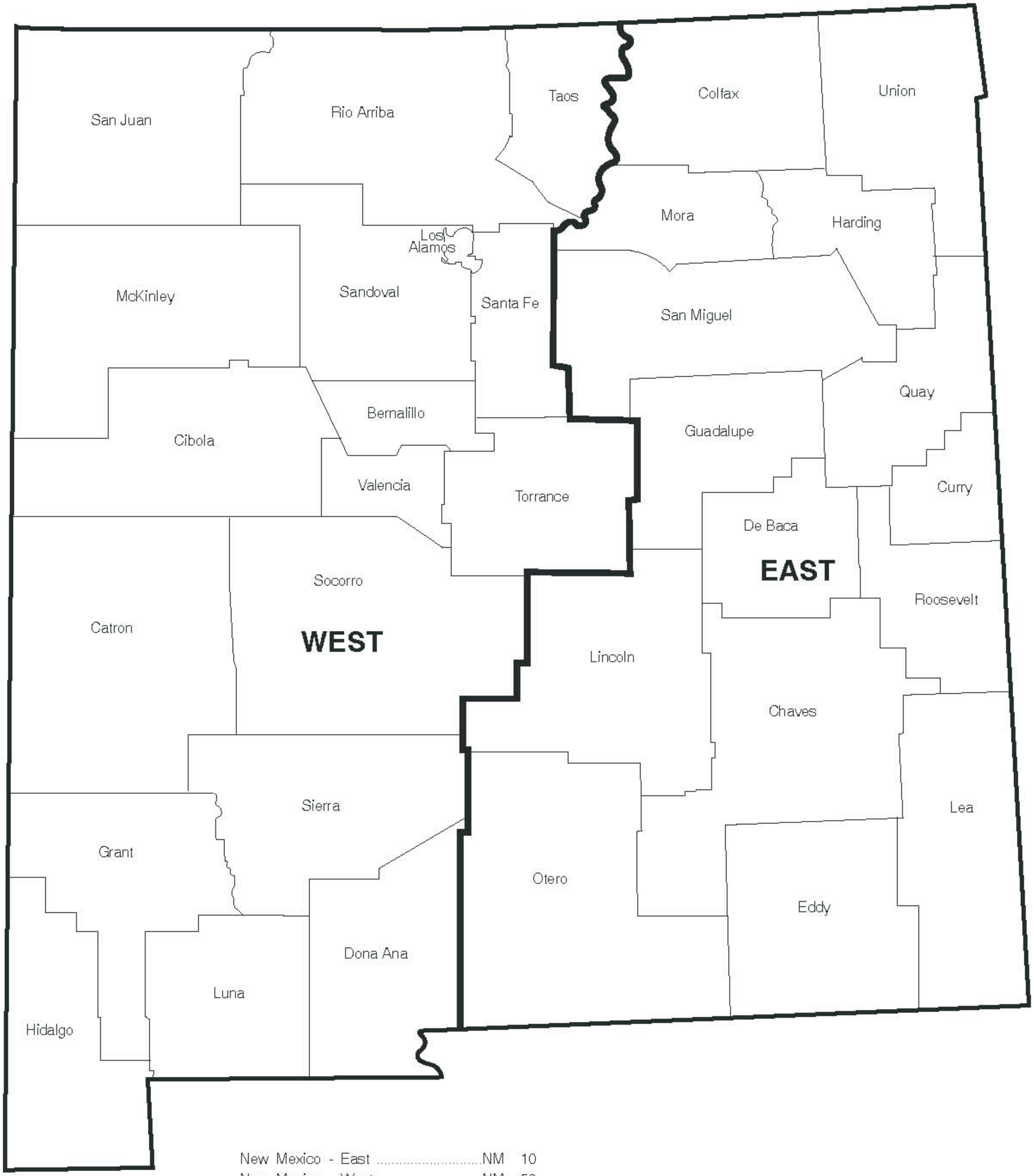
Source: Energy Information Administration, Office of Oil and Gas.

Figure H3. Subdivisions of Louisiana



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

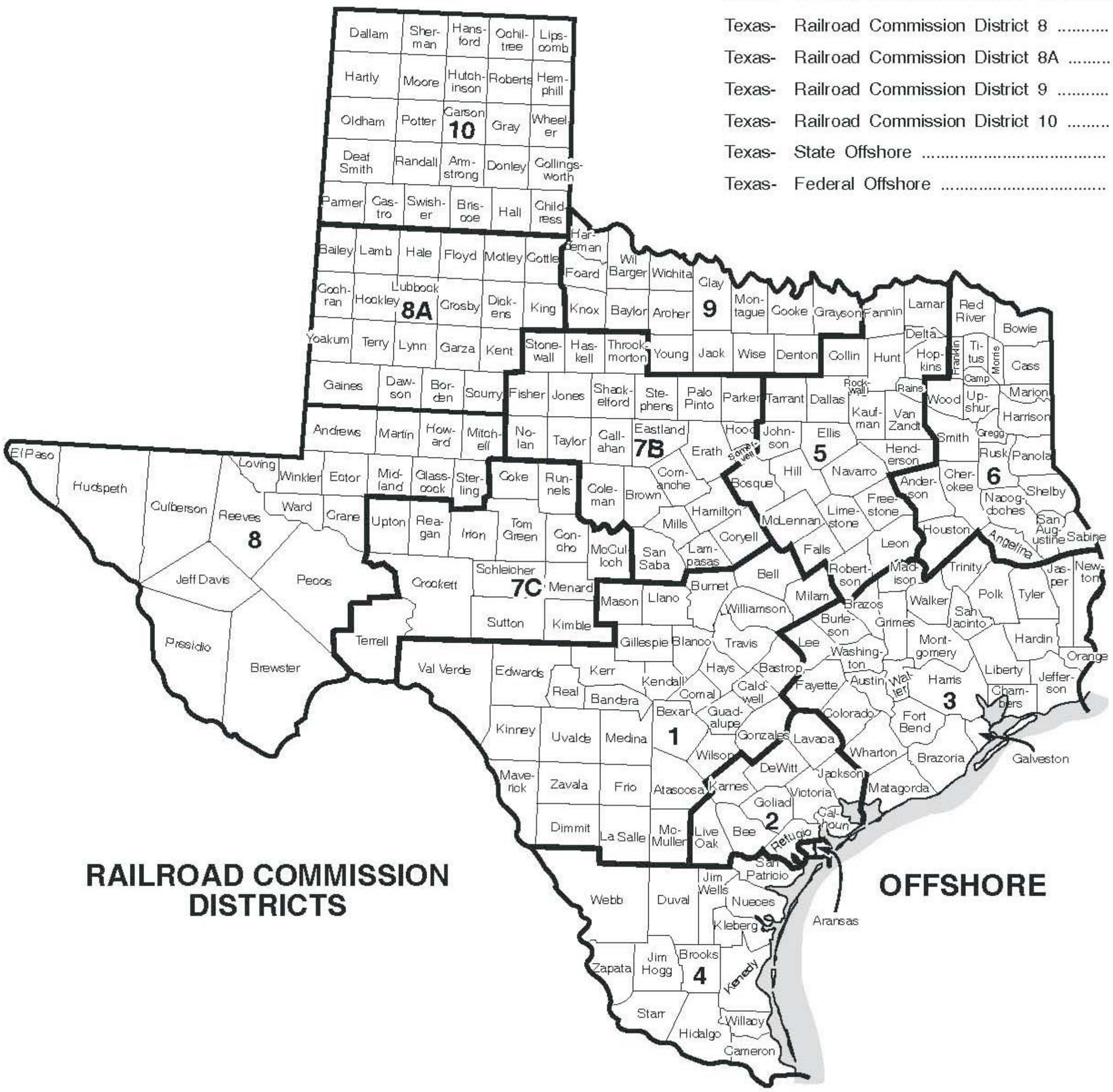
Figure H4. Subdivisions of New Mexico



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

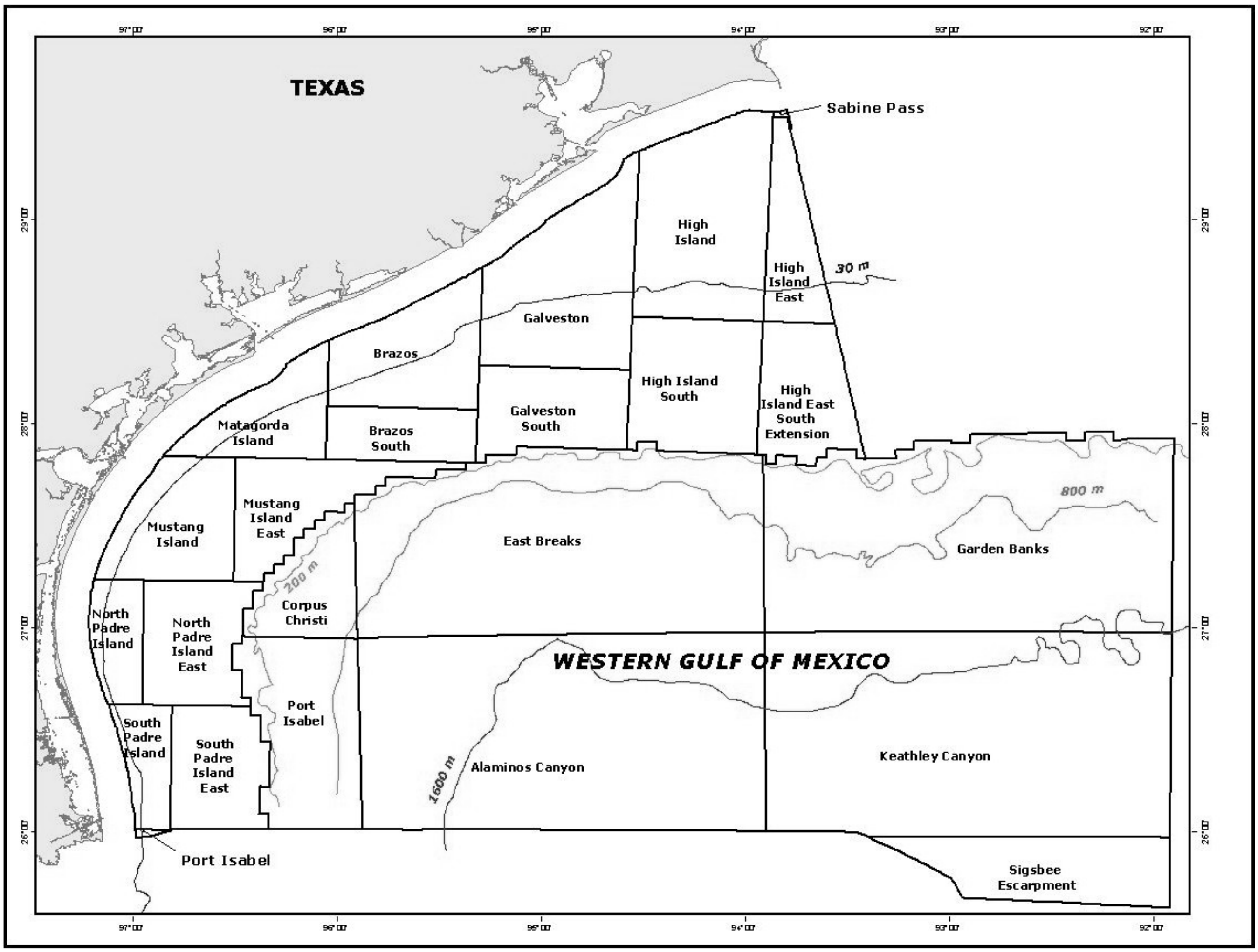
Figure H5. Subdivisions of Texas

Texas-	Railroad Commission District 1	TX 10
Texas-	Railroad Commission District 2 Onshore	TX 20
Texas-	Railroad Commission District 3 Onshore	TX 30
Texas-	Railroad Commission District 4 Onshore	TX 40
Texas-	Railroad Commission District 5	TX 50
Texas-	Railroad Commission District 6	TX 60
Texas-	Railroad Commission District 7B	TX 70
Texas-	Railroad Commission District 7C	TX 75
Texas-	Railroad Commission District 8	TX 80
Texas-	Railroad Commission District 8A	TX 85
Texas-	Railroad Commission District 9	TX 90
Texas-	Railroad Commission District 10	TX 95
Texas-	State Offshore	TX 05
Texas-	Federal Offshore	TX 00



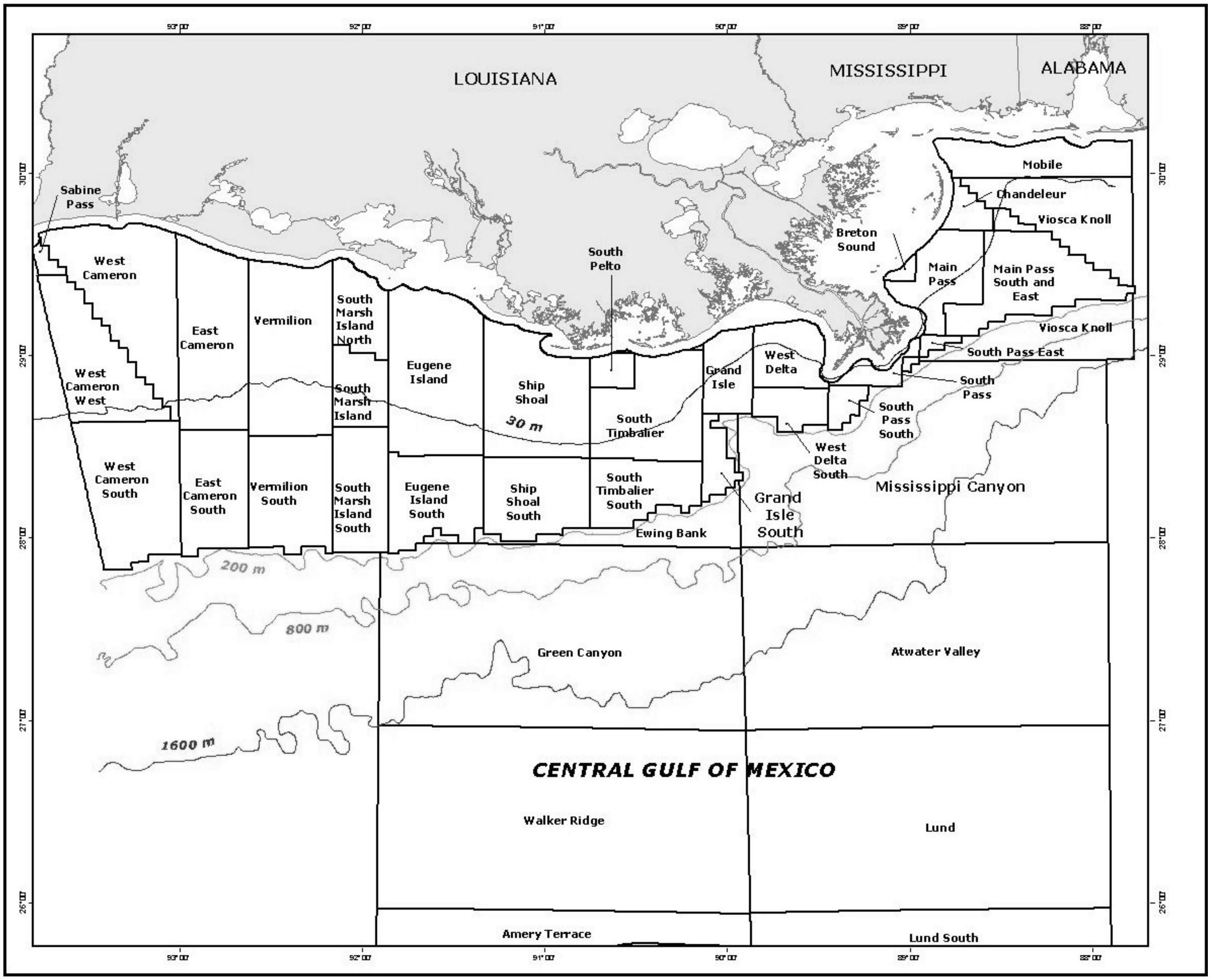
Source: Energy Information Administration, Office of Oil and Gas.

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



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

Figure H7. Central Planning Area, Gulf of Mexico Outer Continental Shelf Region



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

Figure H8. Eastern Planning Area, Gulf of Mexico Outer Continental Shelf Region

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

www.eia.doe.gov
eia Energy Information Administration

U.S. DEPARTMENT OF ENERGY
ENERGY INFORMATION ADMINISTRATION
Washington, DC 20585

Form Approved
OMB No. 1905-0057
Expiration Date: 2/28/2010
(Revised 2007)

FORM EIA-23S
ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES
REPORT YEAR 2 0 0 6

This report is mandatory under the Federal Energy Administration Act of 1974 (Public Law 93-275). For the provisions concerning the confidentiality of information and sanction statements, see Section VII and VIII of the instructions.

Resubmission?

PART I. IDENTIFICATION

Complete and return by April 15, 2007 to:

Energy Information Administration
U.S. Department of Energy
P O Box 8279
Silver Spring, MD 20907-8279
Attn: Form EIA-23
OR
Fax to: (202) 586-1076/ATTN: FORM EIA-23

Questions? Call 1-800-879-1470

Enter mailing address and EIA ID number, if not shown

EIA Identification Number: 0 0 0 0

Company Name:

Street or P.O Box:

City, State, Zip Code:

1. Contact Information ***(person most knowledgeable about the reported data)***

Contact Person:

Phone Number: ( ) - Ext.

Fax Number: ( ) -

E-mail Address:

2. Was your company an oil and gas field operator at any time during calendar year 2006? ***(See definition of an operator, page 1)***

(1) ☐ No... *Complete only items 3 through14 below and return this page.*

(2) ☐ Yes... *Complete rest of form.*

3. Company Status, Name, and/or Address Change or Correction. (Check appropriate box.)

☐ Name and address on mailing label are correct.

☐ Change company name, contact person, and/or mailing address,as indicated below.

☐ Company was sold to or merged with company entered below.

☐ Company went out of business. Operations transferred to company entered below.

4. Change Company Name, Address, and/or Contact Information to:

Company Name:

Street or P. O. Box:

City, State, Zip Code:

Contact Person (*Please Print*):

Phone Number: ( ) - Ext. Fax number: ( ) - E-Mail Address:

Comments:

SAMPLE

PART II. PARENT COMPANY IDENTIFICATION

5. Is there a parent company which exercises ultimate control over your company?

(1) ☐ No... Answer 11 through 14.

(2) ☐ Yes... Answer 6 through 14.

6. Parent Company Name

7. Street or P.O. Box

8. City **9.** State **10.** Zip Code

PART III. APPROVAL

11. Reviewed and approved by: (*Please Print*) **12.** Title

13. Signature **14.** 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.

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

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

OFFICIAL USE ONLY

2006 **FORM EIA-23S**

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES

SUMMARY REPORT

PAGE 1 OF 2

Form Approved
OMB No. 1905-0057
Expiration Date: 2/28/2010
(Revised 2007)

Report All Volumes of Crude Oil and Lease Condensate in Thousands of Barrels [MBbls] at 60°F
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 EIA ID CODE	1.2 OPERATOR NAME	REPORT DATE			1.3 ORIGINAL	1.4 RESUBMISSION
		12	31	06		

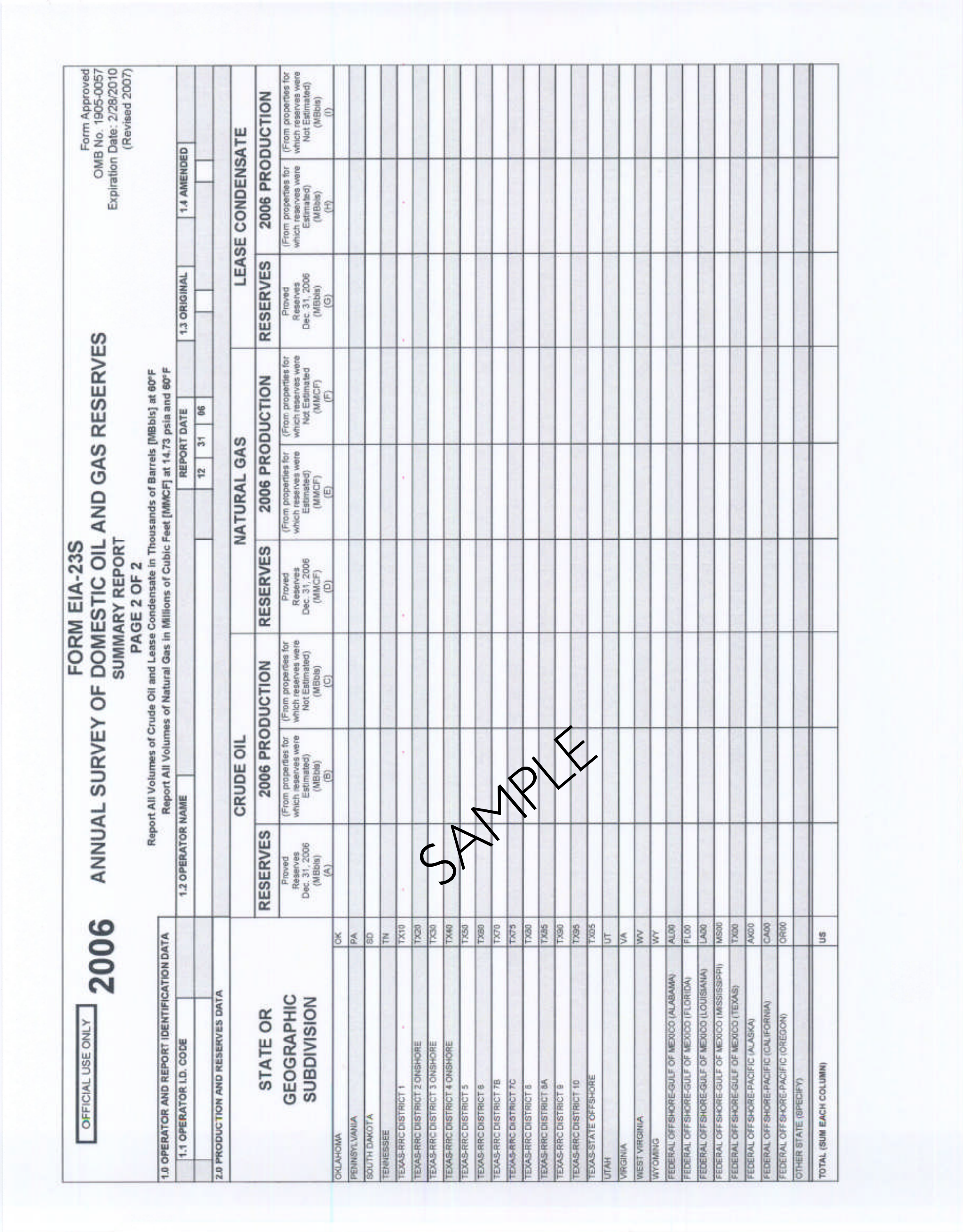
2.0 PRODUCTION AND RESERVES DATA

SAMPLE

STATE OR GEOGRAPHIC SUBDIVISION		CRUDE OIL			NATURAL GAS			LEASE CONDENSATE		
		RESERVES	2006 PRODUCTION		RESERVES	2006 PRODUCTION		RESERVES	2006 PRODUCTION	
		Proved Reserves Dec. 31, 2006 (MBbls) (A)	(From properties for which reserves were Estimated) (MBbls) (B)	(From properties for which reserves were Not Estimated) (MBbls) (C)	Proved Reserves Dec. 31, 2006 (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, 2006 (MBbls) (G)	(From properties for which reserves were Estimated) (MBbls) (H)	(From properties for which reserves were Not Estimated) (MBbls) (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-STATE OFFSHORE	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									

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

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



OFFICIAL USE ONLY

2006

FORM EIA-23S
ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES
SUMMARY REPORT
PAGE 2 OF 2

Form Approved
OMB No. 1905-0057
Expiration Date: 2/28/2010
(Revised 2007)

Report All Volumes of Crude Oil and Lease Condensate in Thousands of Barrels [MBbls] at 60°F
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 06		

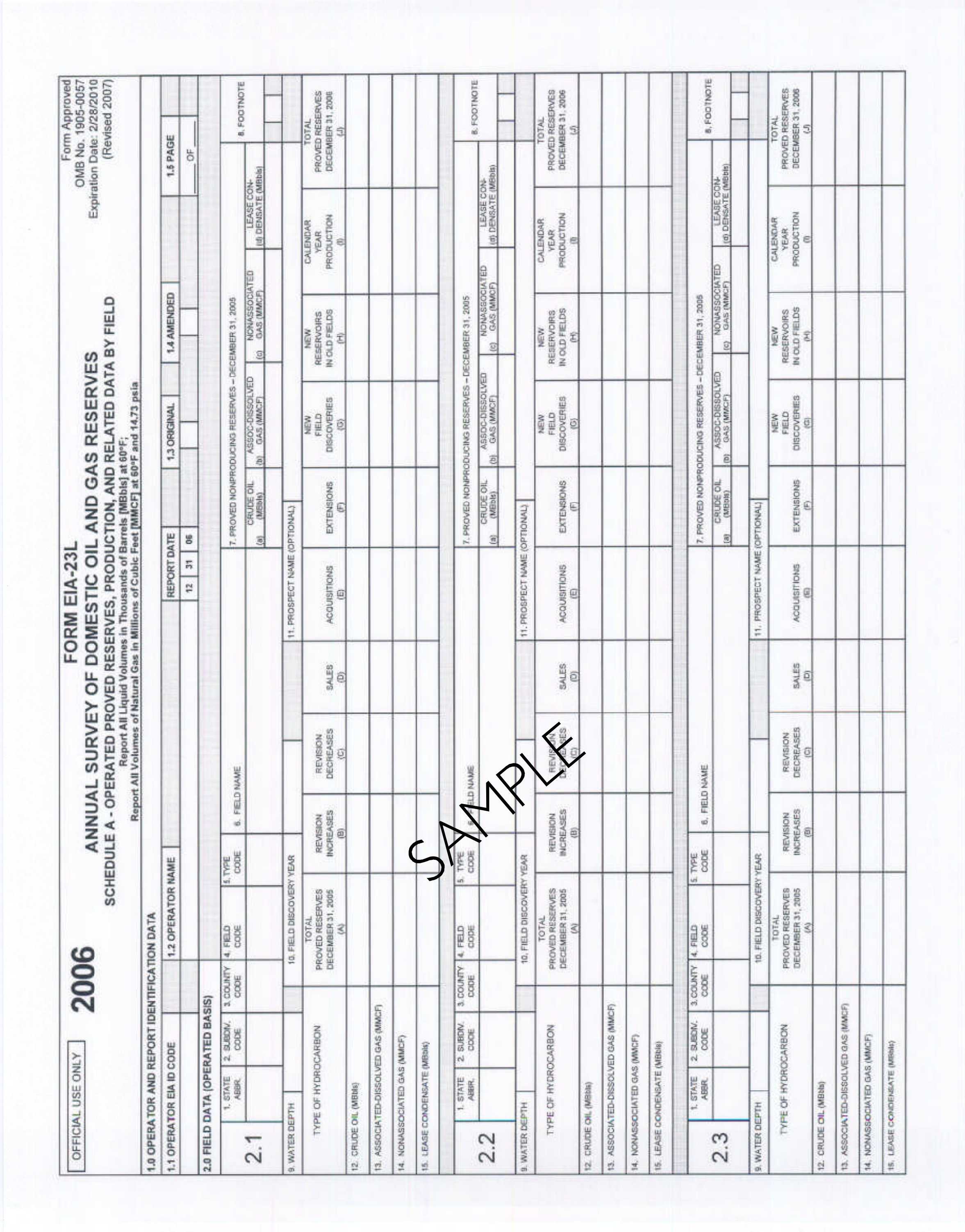
2.0 PRODUCTION AND RESERVES DATA

STATE OR GEOGRAPHIC SUBDIVISION		CRUDE OIL			NATURAL GAS			LEASE CONDENSATE		
		RESERVES	2006 PRODUCTION		RESERVES	2006 PRODUCTION		RESERVES	2006 PRODUCTION	
		Proved Reserves Dec. 31, 2006 (MBbls) (A)	(From properties for which reserves were Estimated) (MBbls) (B)	(From properties for which reserves were Not Estimated) (MBbls) (C)	Proved Reserves Dec. 31, 2006 (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, 2006 (MBbls) (G)	(From properties for which reserves were Estimated) (MBbls) (H)	(From properties for which reserves were Not Estimated) (MBbls) (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

2006

FORM EIA-23L

ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES

SCHEDULE A - OPERATED PROVED RESERVES, PRODUCTION, AND RELATED DATA BY FIELD

Report All Liquid Volumes in Thousands of Barrels [MBbls] at 60°F;
Report All Volumes of Natural Gas in Millions of Cubic Feet [MMCF] at 60°F and 14.73 psia

Form Approved
OMB No. 1905-0057
Expiration Date: 2/28/2010
(Revised 2007)

1.0 OPERATOR AND REPORT IDENTIFICATION DATA

1.1 OPERATOR EIA ID CODE	1.2 OPERATOR NAME	REPORT DATE	1.3 ORIGINAL	1.4 AMENDED	1.5 PAGE
		12 31 06			___ OF ___

2.0 FIELD DATA (OPERATED BASIS)

2.1

1. STATE ABBR.	2. SUBDIV. CODE	3. COUNTY CODE	4. FIELD CODE	5. TYPE CODE	6. FIELD NAME	7. PROVED NONPRODUCING RESERVES – DECEMBER 31, 2005: (a) CRUDE OIL (MBbls)	(b) ASSOC-DISSOLVED GAS (MMCF)	(c) NONASSOCIATED GAS (MMCF)	(d) LEASE CONDENSATE (MBbls)	8. FOOTNOTE

9. WATER DEPTH | 10. FIELD DISCOVERY YEAR | 11. PROSPECT NAME (OPTIONAL)

TYPE OF HYDROCARBON	TOTAL PROVED RESERVES DECEMBER 31, 2005 (A)	REVISION INCREASES (B)	REVISION DECREASES (C)	SALES (D)	ACQUISITIONS (E)	EXTENSIONS (F)	NEW FIELD DISCOVERIES (G)	NEW RESERVOIRS IN OLD FIELDS (H)	CALENDAR YEAR PRODUCTION (I)	TOTAL PROVED RESERVES DECEMBER 31, 2006 (J)
12. CRUDE OIL (MBbls)										
13. ASSOCIATED-DISSOLVED GAS (MMCF)										
14. NONASSOCIATED GAS (MMCF)										
15. LEASE CONDENSATE (MBbls)										

2.2

1. STATE ABBR.	2. SUBDIV. CODE	3. COUNTY CODE	4. FIELD CODE	5. TYPE CODE	6. FIELD NAME	7. PROVED NONPRODUCING RESERVES – DECEMBER 31, 2005: (a) CRUDE OIL (MBbls)	(b) ASSOC-DISSOLVED GAS (MMCF)	(c) NONASSOCIATED GAS (MMCF)	(d) LEASE CONDENSATE (MBbls)	8. FOOTNOTE

9. WATER DEPTH | 10. FIELD DISCOVERY YEAR | 11. PROSPECT NAME (OPTIONAL)

TYPE OF HYDROCARBON	TOTAL PROVED RESERVES DECEMBER 31, 2005 (A)	REVISION INCREASES (B)	REVISION DECREASES (C)	SALES (D)	ACQUISITIONS (E)	EXTENSIONS (F)	NEW FIELD DISCOVERIES (G)	NEW RESERVOIRS IN OLD FIELDS (H)	CALENDAR YEAR PRODUCTION (I)	TOTAL PROVED RESERVES DECEMBER 31, 2006 (J)
12. CRUDE OIL (MBbls)										
13. ASSOCIATED-DISSOLVED GAS (MMCF)										
14. NONASSOCIATED GAS (MMCF)										
15. LEASE CONDENSATE (MBbls)										

2.3

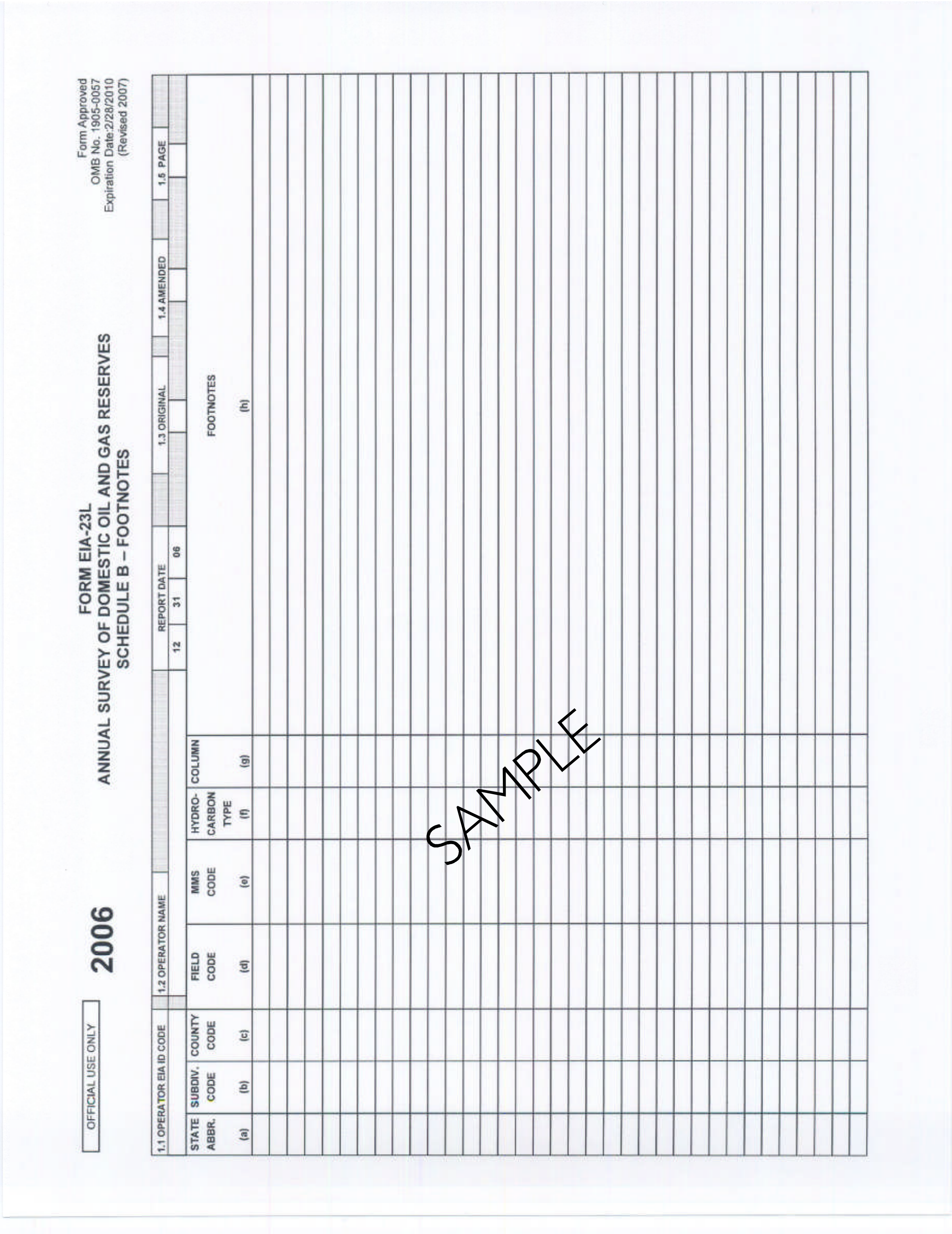
1. STATE ABBR.	2. SUBDIV. CODE	3. COUNTY CODE	4. FIELD CODE	5. TYPE CODE	6. FIELD NAME	7. PROVED NONPRODUCING RESERVES – DECEMBER 31, 2005: (a) CRUDE OIL (MBbls)	(b) ASSOC-DISSOLVED GAS (MMCF)	(c) NONASSOCIATED GAS (MMCF)	(d) LEASE CONDENSATE (MBbls)	8. FOOTNOTE

9. WATER DEPTH | 10. FIELD DISCOVERY YEAR | 11. PROSPECT NAME (OPTIONAL)

TYPE OF HYDROCARBON	TOTAL PROVED RESERVES DECEMBER 31, 2005 (A)	REVISION INCREASES (B)	REVISION DECREASES (C)	SALES (D)	ACQUISITIONS (E)	EXTENSIONS (F)	NEW FIELD DISCOVERIES (G)	NEW RESERVOIRS IN OLD FIELDS (H)	CALENDAR YEAR PRODUCTION (I)	TOTAL PROVED RESERVES DECEMBER 31, 2006 (J)
12. CRUDE OIL (MBbls)										
13. ASSOCIATED-DISSOLVED GAS (MMCF)										
14. NONASSOCIATED GAS (MMCF)										
15. LEASE CONDENSATE (MBbls)										

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

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



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2006

FORM EIA-23L
ANNUAL SURVEY OF DOMESTIC OIL AND GAS RESERVES
SCHEDULE B – FOOTNOTES

Form Approved
OMB No. 1905-0057
Expiration Date:2/28/2010
(Revised 2007)

1.1 OPERATOR EIA ID CODE	1.2 OPERATOR NAME	REPORT DATE 12 31 06	1.3 ORIGINAL	1.4 AMENDED	1.5 PAGE

STATE ABBR. (a)	SUBDIV. CODE (b)	COUNTY CODE (c)	FIELD CODE (d)	MMS CODE (e)	HYDRO-CARBON TYPE (f)	COLUMN (g)	FOOTNOTES (h)

SAMPLE

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

Figure I6. Form EIA-64A

www.eia.doe.gov
eia Energy Information Administration

U.S. DEPARTMENT OF ENERGY
ENERGY INFORMATION ADMINISTRATION
Washington, DC 20585

Form Approved
OMB No. 1905-0057
Expiration Date: 2/28/2010

ANNUAL REPORT OF THE ORIGIN OF NATURAL GAS LIQUIDS PRODUCTION
FORM EIA-64A
CALENDAR YEAR 2006

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.

Complete and return by April 1, 2007 to:

Energy Information Administration
P O Box 8279
Silver Spring, MD 20907-8279
Attn: EIA-64A
OR
Fax to (202) 586-1076 (Attn: EIA-64A)

Questions?: Call 1-800-879-1470

Affix Mailing Label

PART I. PLANT AND PRODUCTION REPORT IDENTIFICATION

1.0 Does this report reflect active natural gas processing at the facility for the entire year? ☐ Yes ☐ No (indicate number of months below)

Months covered by this report __________ through __________, 2006 (Include Explanatory Notes in Section 7.0)

2.0 Submission Status ☐ Original ☐ Amended

3.0 Label Information **(If label is incorrect or information is missing or no label is given, enter correct information below).**

3.1 Parent Company's Name

3.2 Operator's Name

3.3 Plant Name

3.4 Geographic Location (Use Area of Origin Codes, Page 6) ☐☐☐☐

3.5 Operator's Address – Street Address/PO Box:

City State Zip Code

3.6 Contact Name E-mail Address

Telephone Number ( ) Ext Fax Number 3.7 Date

PART II. ORIGIN OF NATURAL GAS RECEIVED AND NATURAL GAS LIQUIDS PRODUCED

SAMPLE

Line	Area of Origin Code (A)	Natural Gas Received Report in millions of cubic feet (MMCF) (B)	Natural Gas Liquids Production Report in thousands of barrels (MBbl) (C)
4.1			
4.2			
4.3			
4.4			
4.5			
4.6			
4.7			
4.8	TOTAL		

5.0 Gas Shrinkage Resulting from Natural Gas Liquids Extracted (MMCF):

6.0 Natural Gas Used as Fuel in Processing (MMCF):

7.0 Explanatory Notes:

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 2001.

Acquisitions: The volume of proved reserves gained by the purchase of an existing fields or properties, from the date of purchase or transfer.

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
− Sales
+ Acquisitions
+ 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**)

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 Reserves: Quantities of proved liquid or gaseous hydrocarbon reserves that 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. This includes both proved undeveloped and proved developed non-producing reserves.

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 at a specified point in time. It measures the maximum recoverable volume *known* at that time and is a dynamic quantity that is expected to change over time for any field, group of fields, State, or Country. In most instances, therefore, an estimate of Proved Ultimate Recovery does not represent the all-time maximum recoverable volume of resources for a given field or area.

Also, the proved ultimate recovery of a field, a group of fields, a State, or a Country grows (appreciates) over time in most instances.

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.

Sales: The volume of proved reserves deducted from an operator's total reserves when selling an existing field or property, during the calendar year.

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.