Statistical Considerations

Survey Methodology

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

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

Sampling Strategy

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

The total volume of production varies among the State/subdivisions. To meet the survey objectives while controlling total respondent burden, EIA selected the following target sampling error for the 1999 survey for each product class.

- 1.0 percent for National estimates.
- 1.0 percent for each of the 5 States having subdivisions: Alaska, California, Louisiana, New Mexico, and Texas. For selected subdivisions within these States, targets of 1.0 percent or 1.5 percent as required to meet the State target.
- 2.5 percent for each State/subdivision having 1 percent or more of estimated U.S. reserves or production in 1998 (lower 48 States) for any product class.
- 4 percent for each State/subdivision having less than 1 percent of estimated U.S. reserves or production in 1998 (lower 48 States) for all 3 product classes.
- 8 percent for States not published separately. The combined production from these States was less than 0.2 percent of the U.S. total in 1998 for crude oil and for natural gas.

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

- **Category I -** *Large Operators:* Operators who produced a total of 1.5 million barrels or more of crude, or 15 billion cubic feet or more of natural gas, or both in 1999.
- **Category II -** *Intermediate Operators:* Operators who produced a total of at least 400,000 barrels of crude oil or 2 billion cubic feet of natural gas, or both, but less than Category I operators in 1999.
- **Category III -** *Small Operators:* Operators who produced less than the Category II operators in 1999, but which were selected with certainty. Category III operators were subdivided into operators sampled with certainty (**Certainty**) and operators that were randomly sampled (**Noncertainty**).
  - **Certainty -** A small operators who satisfied any of the following criteria based upon their production shown in the operator frame:
    - Operators with annual crude oil production of 200 thousand barrels or more, or reserves of 4 million barrels or more; or annual natural gas production of 1 billion cubic feet or more, or reserves of 20 billion cubic feet or more.

Table F1. 1999 EIA–23 Survey Initial Sample Criteria

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

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

[b]Nonduplicative count of operators by States.

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

— = Not applicable.

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

- All other operators with production or reserves in a State/subdivision that exceed selected cutoff levels for that State/subdivision.
- The largest operator in each State/subdivision regardless of level of production or reserves.
- Operators with production or reserves of oil or gas for six or more State/subdivisions.

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

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

In each State/subdivision the balance between the number of small certainty operators and the sample size was determined in an iterative procedure designed to minimize the number of total respondents. The iteration for each State/subdivision began with only the Category I and Category II operators in the certainty stratum. The size of the sample of small operators required to meet the target variance was calculated based on the variance of the volumes of those operators. For a number of State/subdivisions with high correlations between frame values across pairs of consecutive years, an adjusted target variance was calculated that utilized the information about the correlations. This allowed the selection of a smaller sample that still met the target sampling error criteria. At each iteration a small operator, beginning with the largest of the Category III operators, was added to the certainty group and the required sample size was again calculated. The procedure of adding one operator at a time stopped when the proportion of operators to be sampled at random dropped below 8 percent. Independent samples of single location operators (operators who, according to the sampling frame, operate in only one State/subdivision) were selected from each State/subdivision using random sampling proportional to size.

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

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

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

Total U.S. Reserve Estimates

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

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

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

where

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

V_{SC} = total volume in the State/subdivision reported by Certainty operators

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

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

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

where

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

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

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

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

where

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

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

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

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

The weight used for the estimation is the reciprocal of the probability of selection for the stratum from which the sample operator was selected. In making estimates for a State/subdivision, separate weights are applied as appropriate for noncertainty operators shown in the frame as having had production in only the State/subdivision, for those shown as having had production in that State/subdivision and up to four other State/subdivisions, and for operators with no previous record of production in the State/subdivision. National totals were then obtained by summation of the component totals.

Imputation for Operator Nonresponse

The response rate for Noncertainty operators for the 1999 survey was 99.4 percent, therefore an imputation was made for the production and reserves of the 8 nonresponding operators.

Imputation and Estimation for Reserves Data

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

The data reported by operator category by Form EIA-23 respondents for the report year 1999 are summarized in **Tables F2, F3, F4, and F5**. The reported data in **Table F2** shows that those responding operators accounted for 97.9 percent of the published production for natural gas shown in **Table 9** and 93.9 percent of the reserves. Data shown in **Table F3** indicate that those responding operators accounted for 95.3 percent of the nonassociated natural gas production and 92.7 percent of the reserves published in **Table 10**. The reported data shown in **Table F4** indicate that those responding operators accounted for 96.7 percent of published crude oil production and 94.7 percent of the reserves shown in **Table 6**. Additionally, **Table F5** indicates that those responding operators accounted for 100 percent of the published production and 96 percent of the published proved reserves for lease condensate shown in **Table 16**.

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

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

– = Not applicable.

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

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

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

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

– = Not applicable.
Notes: Table 10 totals include imputed and estimated nonassociated wet natural gas proved reserves rounded at the State/subdivision level. Field level data are reported volumes and may not balance due to submission of incomplete reserve component records.
Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1999.

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

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

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

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

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

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

Imputation of Year-End Proved Reserves

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

R/P Function

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

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

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

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

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

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

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

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

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

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

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

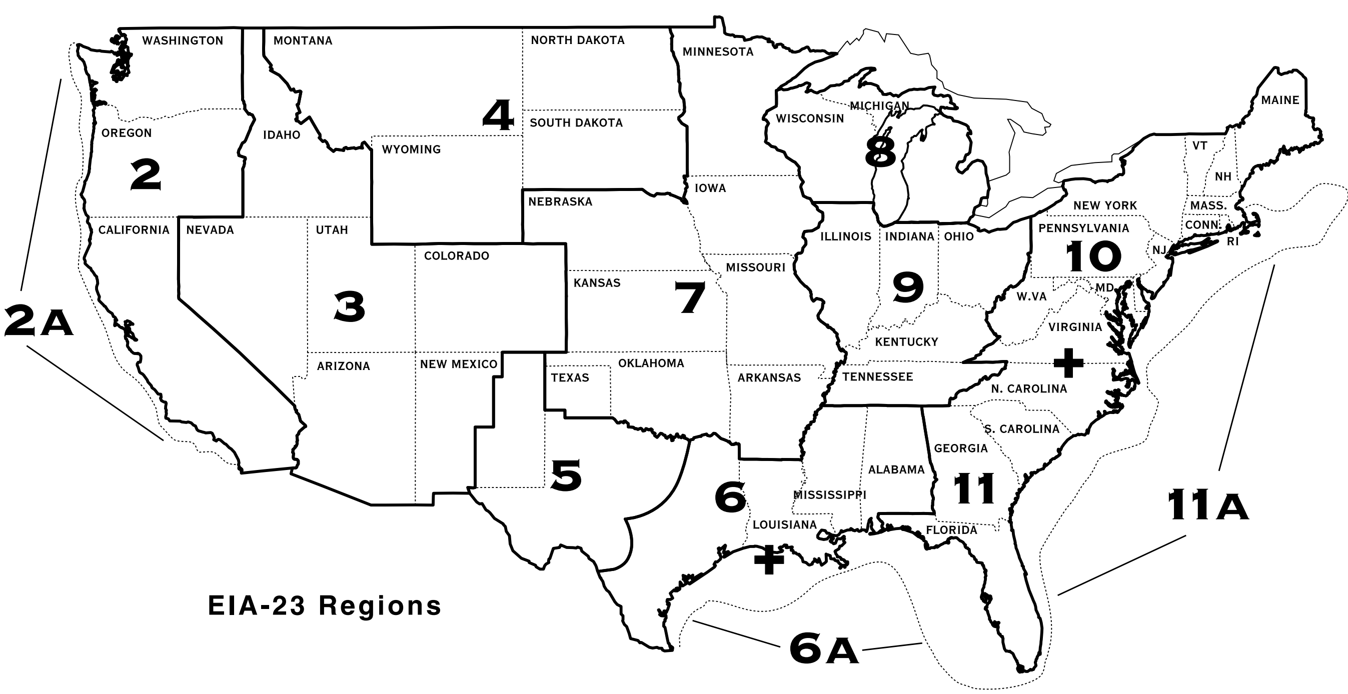
Imputation of Annual Changes to Proved Reserves by Component of Change

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

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

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

Figure F1. Form EIA-23 Regional Boundaries



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

Imputation of Natural Gas Type Volumes

Operators in the State/subdivision certainty and noncertainty strata were not asked to segregate their natural gas volumes by type of natural gas, i.e., nonassociated natural gas (NA) and associated-dissolved natural gas (AD). The total estimated year-end proved reserves of natural gas and the total annual production of natural gas reported by, or imputed to, operators in the State/subdivision certainty and noncertainty strata were, therefore, subdivided into the NA and AD categories, by State/subdivision, in the same proportion as was reported by Category I and Category II operators in the same area.

Adjustments

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

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

Any remaining difference in the State/subdivision annual reserves balance between the published previous year-end proved reserves and current year-end proved reserves not accounted for by the imputed reserves changes is included in the adjustments for the area. One of the primary reasons that adjustments are necessary is instability of the Noncertainty operators sampled each year. About 24 percent of the Noncertainty stratum operators sampled in 1998 were sampled again in 1999. There is no guarantee that in the smaller States/subdivisions the same number of small operators will be selected each year, or that the operators selected will be of comparable sizes when paired with operators selected in a prior year. Thus, some instability of this stratum from year to year is unavoidable, resulting in minor adjustments.

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

- The frame coverage may or may not have improved between survey years, such that more or fewer Certainty operators were included in 1999 than in 1998.
- One or more operators may have reported data incorrectly on Schedule A in 1998 or 1999, but not both, and the error was not detected by edit processing.
- Operation of properties was transferred during 1999 from operators not in the frame or Noncertainty operators not selected for the sample to Certainty operators or Noncertainty operators selected for the sample.
- Operations of properties was transferred during 1999 to an operator with a different evaluation of the proved reserves associated with the properties than that of the 1998 operator.
- Respondent changed classification of natural gas from NA to AD or vice versa.
- The trend in reserve changes imputed for the small operators, that was based on the trend reported by the large operators, did not reflect the actual trend for the small operators.
- Noncertainty operators, who have grown substantially in size since they were added to the frame, occasionally cause a larger standard error than expected.
- The Noncertainty sample for either year in a state may have been an unusual one.

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

Sampling Reliability of the Estimates

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

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

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

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

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

includes the universe value, for both the estimates of reserves and production volumes. Correspondingly, for approximately 95 percent of the estimates in this report, the difference between the published estimate and the value that would be found from a complete survey of all operators is expected to be less than twice the sampling error of the estimate. **Tables F7, F8, F9, and F10** provide estimates for 2S.E. ($\hat{V}_s$) by product. These estimates are directly applicable for constructing approximate 95 percent confidence intervals. For example, the 95 percent confidence interval for dry natural gas proved reserves is 164,041 ± 1,003 billion cubic feet. The sampling error of $\hat{V}_s$ is equal to the sampling error of the noncertainty estimate $\hat{V}_{sr}$, because the certainty total is not subject to sampling error. The estimated sampling error of a noncertainty estimate is the square root of its estimated sampling variance.

Nonsampling Errors

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

Assessing the Accuracy of the Reserve Data

The EIA maintains an evaluation program to assess the accuracy and quality of proved reserve estimates gathered on Form EIA-23. Field teams consisting of petroleum engineers from EIA's Dallas Field Office conduct technical reviews of reserve estimates and independently estimate the proved reserves of a statistically selected sample of operator properties. The results of these reviews are used to evaluate the accuracy of reported reserve estimates. Operators are apprised of the team's findings to assist them in completing future filings. The magnitude of errors due to differences between reserve volumes submitted by operators on the Form EIA-23 and those estimated by EIA petroleum engineers on their field trips were generally within accepted professional engineering standards.

Respondent Estimation Errors

The principal data elements of the Form EIA-23 survey consist of respondent estimates of proved reserves of crude oil, natural gas, and lease condensate. Unavoidably, the respondents are bound to make some estimation errors, i.e., until a particular reservoir has been fully produced to its economic limit and abandoned, its reserves are not subject to direct measurement but must be inferred from limited, imperfect, or indirect evidence. A more complete discussion of the several techniques of estimating proved reserves, and the many problems inherent in the task, appears in Appendix G.

Reporting Errors and Data Processing Errors

Reporting errors on the part of respondents are of definite concern in a survey of the magnitude and complexity of the Form EIA-23 program. Several steps were taken by EIA to minimize and detect such problems. The survey instrument itself was carefully developed, and included a detailed set of instructions for filing data, subject to a common set of definitions similar to those already used by the industry. Editing software is continually developed to detect different kinds of probable reporting errors and flag them for resolution by analysts, either through confirmation of the data by the respondent or through submission of amendments to the filed data. Data processing errors, consisting primarily of random keypunch errors, are detected by the same software.

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

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

[a]Includes Federal offshore Alabama.
[b]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee.
Notes: Confidence intervals are associated with Table 8 reserves and production data. Factors for confidence intervals for each State subdivision, State, and the United States are independently estimated and do not add.
Source: Factor estimates based on data filed on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1999 and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production," 1999.

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

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

[a]Includes Federal offshore Alabama.
[b]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee.
Notes: Confidence intervals are associated with Table 9 reserves and production data. Factors for confidence intervals for each State subdivision, State, and the United States are independently estimated and do not add.
Source: Factor estimates based on data filed on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 1999.

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

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

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

Notes: Confidence intervals are associated with Table 6 reserves and production data. Factors for confidence intervals for each State subdivision, State, and the United States are independently estimated and do not add.

Source: Factor estimates based on data filed on Form EI-23, "Annual Survey of Domestic Oil and Gas Reserves," 1999.

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

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

[a]Includes Federal offshore Alabama.

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

Notes: Confidence intervals are associated with Table 15 reserves and production data. Factors for confidence intervals for each State subdivision, State, and the United States are independently estimated and do not add.

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

Imputation Errors

Some error, generally expected to be small, is an inevitable result of the various estimations outlined. These imputation errors have not yet been completely addressed by EIA and it is possible that estimation methods may be altered in future surveys. Nationally, 8.3 percent of the crude oil proved reserve estimates, 8.2 percent of the natural gas proved reserve estimates, and 5.7 percent of the lease condensate proved reserve estimates resulted from the imputation and estimation of reserves for those Certainty and Noncertainty operators who did not provide estimates for all of their properties, in combination with the expansion of the sample of Noncertainty operators to the full population. Errors for the latter were quantitatively calculated, as discussed in the previous section. Standard errors, for the former, would tend to cancel each other from operator to operator, and are, therefore, expected to be negligible, especially at the National level of aggregation. In States where a large share of total reserves is accounted for by Category III and smaller Category II operators, the errors are expected to be somewhat larger than in States where a large share of total reserves is accounted for by Category I and larger Category II operators.

Frame Coverage Errors

Of all the sources of controllable error connected with the Form EIA-23 survey, errors in the operator frame were expected to be the most important. If the frame does not list all operators in a given State, the sample selected from the frame for the State will not represent the entire operator population, a condition called undercoverage. Undercoverage is a problem with certain States, but it does not appear to be a problem with respect to the National proved reserve estimates for either crude oil or natural gas. While it is relatively straightforward to use existing sources to identify large operators and find addresses for them, such is not the case for small operators. A frame such as that used in the 1999 survey is particularly likely to be deficient in States where a large portion of total reserves and production is accounted for by small operators. These States are not likely to allocate sufficient resources to keep track of all operators on a current basis. Some undercoverage of this type seems to exist, particularly, with reference to natural gas operators. EIA is continuing to work to remedy the undercoverage problem in those States where it occurred.

Calculation of Reserves of Natural Gas Liquids and Dry Natural Gas

Natural Gas Liquids Reserve Balance

The published reserves, production, and reserves change statistics for crude oil, lease condensate, and natural gas, wet after lease separation, were derived from the data reported on Form EIA-23 and the application of the imputation methods discussed previously. The information collected on Form EIA-64A was then utilized in converting the estimates of the wet natural gas reserves into two components: plant liquids reserve data and dry natural gas reserve data. The total natural gas liquids reserve estimates presented in **Table 14** were computed as the sum of plant liquids estimates (**Table 15**) and lease condensate (**Table 16**) estimates.

To generate estimates for each element in the reserves balance for plant liquids in a given producing area, the first step was to group all natural gas processing plants that reported this area as an area-of-origin on their Form EIA-64A, and then sum the liquids production attributed to this area over all respondents. Next, the ratio of the liquids production to the total wet natural gas production for the area was determined. This ratio represented the percentage of the wet natural gas that was recovered as natural gas liquids. Finally, it was assumed that this ratio was applicable to the reserves and each component of reserve changes (except adjustments), as well as production. Therefore, each element in the wet natural gas reserves balance was multiplied by this recovery factor to yield the corresponding estimate for plant liquids. Adjustments of natural gas liquids were set equal to the difference between the end of previous year reserve estimates, based upon the current report year Form EIA-23 and Form EIA-64A surveys, and the end of current year reserve estimates published in the preceding year's annual reserves report.

Natural Gas Reserve Balance

This procedure involved downward adjustments of the natural gas data, wet after lease separation, in estimating the volumes of natural gas on a fully dry basis. These reductions were based on estimates of the gaseous equivalents of the liquids removed (in the case of production), or expected to be removed (in the case of reserves), from the natural gas stream at natural gas processing plants. Form EIA-64A collected the volumetric reduction, or **shrinkage**, of the input natural gas stream that resulted from the removal of the NGL at each natural gas processing plant.

The shrinkage volume was then allocated to the plant's reported area or areas of origin. Because shrinkage is, by definition, roughly in proportion to the NGL recovered, i.e. the NGL produced, the allocation was in proportion to the reported NGL volumes for each area of origin. However, these derived shrinkage volumes were rejected if the ratio between the shrinkage and the NGL production (gas equivalents ratio) fell outside certain limits of physical accuracy. The ratio was expected to range between 1,558 cubic feet per barrel (where NGL consists primarily of ethane) and 900 cubic feet per barrel (where NGL consists primarily of natural gasolines).

When the computed gas equivalents ratio fell outside these limits, an imputed ratio was utilized to estimate the plant's natural gas shrinkage allocation to each reported area of origin. The imputed ratio was that calculated for the aggregate of all other plants reporting production and shrinkage, and having a gas equivalent ratio within the aforesaid limits, from the area in question. The imputed area ratio was applied only if there were at least five plants to base its computation on. If there were less than five plants, the imputed ratio was calculated based on all plants in the survey whose individual gas equivalents ratio was within the acceptable limits. Less than one percent of the liquids production was associated with shrinkage volumes imputed in this manner. Based on the 1999 Form EIA-64A survey, the national weighted average gas equivalents ratio was computed to be 1,406 cubic feet of natural gas shrinkage per barrel of NGL recovered. The total shrinkage volume (reported plus imputed) for all plants reporting a given area of origin was then subtracted from the estimated value of natural gas production, wet after lease separation, yielding dry natural gas production for the area. The amount of the reduction in the wet natural gas production was then expressed as a percentage of the wet natural gas production. Dry natural gas reserves and reserve changes were determined by reducing the wet natural gas reserves and reserve changes by the same percentage reduction factor.

A further refinement of the estimation process was used to generate an estimate of the natural gas liquids reserves in those States with coalbed methane fields. The States where this procedure was applied were Alabama, Colorado, Kansas, New Mexico, Oklahoma, Pennsylvania, Utah, Virginia, West Virginia, and Wyoming. The first step in the process was to identify all Form EIA-23 reported coalbed methane fields. The assumption was made that coalbed methane fields contained little or no extractable natural gas liquids. Therefore, when the normal shrinkage procedure was applied to the wet gas volume reserve components, the estimate of State coalbed methane volumes were excluded and were not reduced for liquid extraction. Following the computation for shrinkage, each coalbed field gas volume reserve components was added back to each of the dry gas volume reserve components in a State. The effect of this is that the large increases in reserves in some States from coalbed methane fields did not cause corresponding increases in the State natural gas liquids proved reserves.

Adjustments of dry natural gas were set equal to the difference between the end of previous year reserves estimates, based upon the current report year Form EIA-23 and Form EIA-64A surveys, and the end of current year reserve estimates published in the preceding year's annual reserves report.

Each estimate of end of year reserves and report year production has associated with it an estimated sampling error. The standard errors for dry natural gas were computed by multiplying the wet natural gas standard errors by these same percentage reduction factors. **Table F7** provides estimates for 2 times the $S.E.(\hat{V}_s)$ for dry natural gas.