Economics and the 1995 National Assessment of United States Oil and Gas Resources

By Emil D. Attanasi

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Economics and the 1995 National Assessment of United States Oil and Gas Resources

By Emil D. Attanasi

SUMMARY

This report summarizes the economic component of the U.S. Geological Survey's 1995 National Assessment of Oil and Gas Resources for U.S. onshore areas and State waters. This area accounts for 80 percent of U.S. hydrocarbon production and 85 percent of U.S. proved reserves. The Minerals Management Service (1996) has released a parallel study for Federal offshore areas. Estimates are as of January 1994. The economic evaluation uses mean values of the technically recoverable resources assessed by geologists.

Figures 1*A* and 1*B* summarize for all U.S. onshore and State offshore areas *aggregate* incremental costs of finding, developing, and producing oil and non-associated gas from *undiscovered conventional* oil and gas fields and from selected *unconventional* sources. In the figures, unconventional economic resources are depicted as the difference between the conventional undiscovered curve and the curve designated as total. At $18 per barrel and $2 per thousand cubic feet (mcf), 9.2 billion barrels oil (BBO), 15.8 trillion cubic feet associated gas, and 1.1 billion barrels (BBL) natural gas liquids (NGL) from *undiscovered conventional* oil fields, and 61.7 trillion cubic feet of gas (TCFG) and 2.0 BBL NGL from *undiscovered conventional* gas fields can be found, developed, and produced. At $30 per barrel and $3.34 per mcf, estimates of economic oil increase by 85 percent and total conventional economic gas increases by 57 percent. In both cases, associated gas accounts for about one-fifth of total economic undiscovered conventional gas. Similarly, NGL from associated and non-associated gas accounts for 20 to 25 percent of total liquid hydrocarbons (crude oil plus NGL). Regionally, Alaska and the Gulf Coast account for 40 percent of the economic oil in future discoveries, and the Gulf Coast accounts for 60 percent of the economic gas in future gas discoveries.

Crude oil in unconventional (continuous-type) accumulations add less than 6 percent to economic crude oil, even at $30 per barrel. Unconventional gas accumulations add 35.6 TCFG to economic gas resources at $2 per mcf, and, at $3.34 per mcf, 72.1 TCFG is added. Total economic gas resources (undiscovered conventional and unconventional) available at $2 per mcf are 113.4 TCFG and at $3.34 are 196.3 TCFG. Provinces of the Colorado Plateau Region and the Eastern Region have the highest concentrations of economic unconventional gas and are in strategic locations to supply West Coast markets and the industrial Northeast.

Figures 2*A* and 2*B* show sources and amounts of oil and non-associated gas *that could be available* for production during the next 2 decades through 2015. Figure 2*A* represents 69 BBO, and figure 2*B* represents 381 TCFG. Amounts include economic quantities of undiscovered conventional and unconventional oil and non-associated gas evaluated at $30 per barrel and $3.34 per mcf, proved reserves as of January 1994, and projections of field growth (inferred reserves) from 1994 through 2015 for pre-1992 discoveries. In figure 2*A*, projected quantities of oil from field growth account for 44 percent, proved reserves 29 percent, and undiscovered conventional and unconventional oil account for 27 percent. For non-associated gas (figure 2*B*), field growth accounts for 26 percent, proved reserves 30 percent, undiscovered conventional gas 25 percent, and unconventional gas accumulations (continuous-type and coal-bed gas) 19 percent. Even with these projected amounts from inferred reserves and real price increases to $30 per barrel ($3.34 per mcf) that yield additional oil and gas from undiscovered conventional and unconventional accumulations, it will be possible but very difficult to sustain production at levels comparable to the 1994 level over this period without improvements in exploration and production technology.

INTRODUCTION

The 1995 National Assessment of United States Oil and Gas Resources by the U.S. Geological Survey (USGS) (U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995) posits a set of scientifically based estimates of recoverable quantities of oil and gas that could be added to the measured (proved) reserves of the United States. The geologic component of the 1995 National Assessment (U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995) developed estimates of hydrocarbons that are producible using current technology but without reference to economic profitability, whereas the economic component (this report) presents costs of finding, developing, and producing the assessed resources. In particular, this report presents estimates of costs of transforming technically recoverable resources assessed in undiscovered conventional fields and unconventional oil and gas accumulations into producible proved reserves. The *incremental cost functions* show costs as a function of the cumulative quantity of resources transformed. Costs include finding, development, production, and also a return on investment. The computation of the incremental cost functions requires that the "full cost" of the marginal unit of resources added to producible reserves equal well-head price.[1]

Incremental cost functions show the quantity of resources that the industry is capable of adding to *proved reserves or cumulative production* rather than predicting what the industry will actually supply. Actual additions and market supply are the outcome of optimizations of numerous supplier decisions over geographically diverse regions and hydrocarbon sources that assure market supply at lowest costs. This report provides a base line to compare costs when examining alternative supply regions, alternative sources for oil and gas, and alternative technologies. Coal-bed gas and conventional gas, for example, have different production technologies that characterize discovery, development, and production costs. These differences are taken into account when economic quantities of the resources are put on a common basis by incremental cost functions.

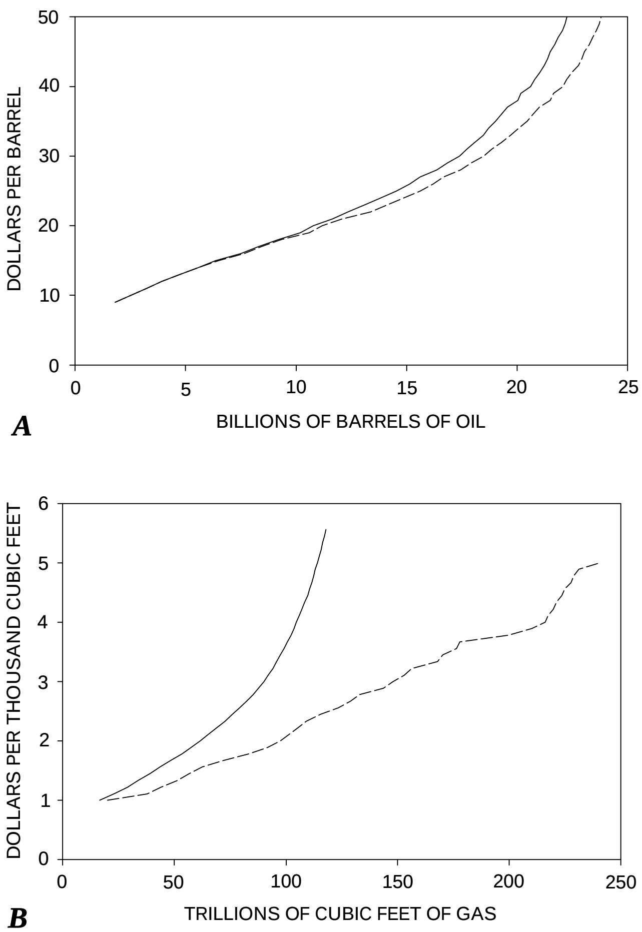


Figure 1. *A*, Incremental costs, in dollars per barrel, of finding, developing, and producing crude oil from undiscovered conventional oil fields and continuous-type oil accumulations in onshore and State offshore areas of the United States. Solid line represents undiscovered conventional oil, and dashed line represents total of undiscovered conventional oil and oil in continuous-type accumulations. *B*, Incremental costs, in dollars per thousand cubic feet, of finding, developing, and producing undiscovered conventional non-associated gas in gas fields and unconventional non-associated gas (in continuous-type accumulations and coal-bed gas) in onshore and State offshore areas of the United States. Solid line represents undiscovered conventional non-associated gas, and dashed line represents total of undiscovered conventional and unconventional gas.

The economic analysis ties costs to the volumes of hydrocarbons that are fully identified and where wells and production facilities are installed with the anticipation that actual production will repay all operating costs, including taxes, all investment expenditures, and provide an after-tax rate of return of at least 12 percent on the investment. This specification, which is equivalent to *proved reserves*, narrows the volume of hydrocarbons to a well-defined producibility standard. Individual wells are physically limited by the amount of hydrocarbons that can be accessed at any given time, and no more than 10 to 15 percent of the proved reserves of individual fields can be extracted annually without risking reservoir damage and reducing ultimate field recovery. The "proven reserves" standard limits annual production to an amount well below absolute resource levels.

RESOURCES ASSESSED

Geologists assessed the numbers and size distribution of undiscovered conventional oil and gas plays. They also assessed technically recoverable unconventional resources in continuous-type oil and gas plays and coal-bed gas plays. Projections of future additions to proved reserves of discovered conventional fields (inferred reserves) were prepared using statistical extrapolations of historical trends. Commodities assessed were crude oil, natural gas (associated and non-associated), and natural gas liquids from associated and non-associated gas. All gas quantities are expressed as *dry gas*, that is, gas that has been stripped of natural gas liquids. Gas dissolved in geopressured brines, oil in tar deposits, and oil shales are excluded from the analysis. Gas from low-permeability "tight" sandstone reservoirs, oil and gas from shale reservoirs, and coal-bed gas were specifically assessed.

The commercial value of a new conventional discovery or a continuous-type accumulation depends on whether it is

[1]These functions are often referred to in the popular literature as marginal cost or price-supply functions. However, they differ from the economist's marginal cost or supply functions in that resource quantities are not expressed in terms of rate of resource supply, that is, the number of barrels per year, but rather in terms of cumulative barrels added to reserves or production.

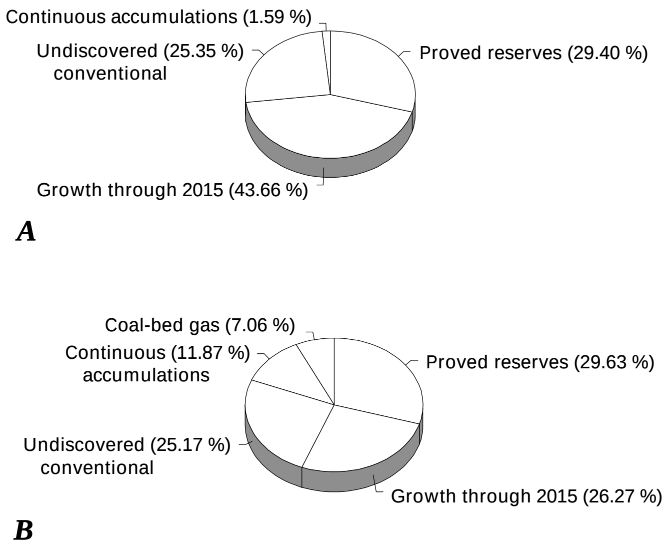


Figure 2. *A*, Estimated shares, as of January 1994, of crude oil that could be available for production during the next 2 decades (through 2015). Sources consist of proved crude oil reserves, projected crude oil reserve additions through 2015 for fields discovered before 1992, estimates of economic crude oil in undiscovered conventional oil fields, and economic crude oil from continuous-type oil accumulations. Estimates of economic oil assumed incremental costs of $30 per barrel. Total crude oil represented is 69 billion barrels. *B*, Estimated shares, as of January 1994, of non-associated gas that could be available for production during the next 2 decades (through 2015). Sources consist of proved non-associated gas reserves, projected non-associated gas reserve additions through 2015 for fields discovered before 1992, estimates of economic non-associated gas in undiscovered conventional gas fields, economic gas in continuous-type gas accumulations, and economic coal-bed gas. Estimates of economic gas assumed incremental costs of $3.34 per thousand cubic feet. Total quantity of non-associated gas represented is 381 trillion cubic feet.

oil or gas, its depth, location, well production profiles, and by-products. Technology and costs associated with oil fields differ from gas fields so it was important to classify the source of hydrocarbons by type. Fields and accumulations having at least 20,000 cubic feet of gas per barrel of crude oil were classified as gas fields and accumulations; otherwise, they were classified as oil fields.

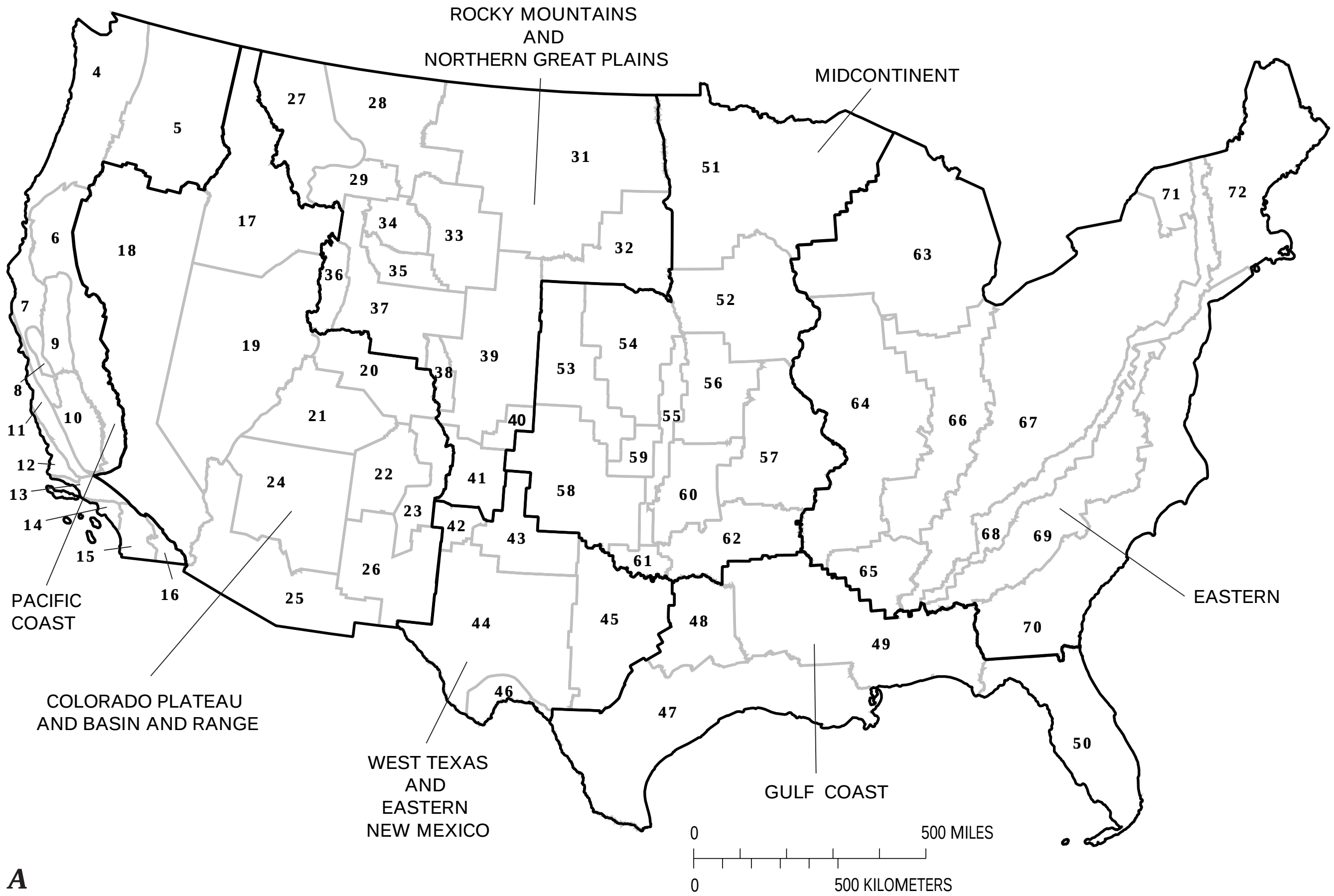
For the 1995 National Assessment, *undiscovered technically recoverable resources* are defined as estimated quantities of resources hypothesized to exist on the basis of geologic knowledge, data on past discoveries, or theory—these resources are contained in undiscovered accumulations outside of known fields. Estimated resource quantities are producible using current recovery technology but without reference to economic viability. Posited *undiscovered accumulation sizes* include all components of field growth that might occur during field development and production. *Conventional accumulations* are oil and gas accumulations that are typically bounded by a downdip water contact and from which oil, gas, and natural gas liquids (NGL) can be extracted using traditional development and production practices. *Accumulations assessed by geologists as occurring outside of existing fields were considered for the purposes of the economic analysis as separate and discrete new fields*. Onshore and State offshore areas of the United States were divided into eight regions and further subdivided onto a total of 71 provinces (fig. 3). For the 71 provinces, about 460 conventional plays were assessed. The economic analysis evaluated undiscovered conventional resources at the province level.

Inferred reserves, more commonly called field growth, include resources expected to be added to reserves of discovered fields as a consequence of their extension, periodic revisions of their reserve estimates, improvements in recovery technology, and additions of new pools. Forecasts of reserve growth apply only to conventional fields discovered before 1992 .

Continuous-type accumulations are hydrocarbon accumulations that are pervasive throughout a large area or region and that do not owe their existence to the buoyancy of hydrocarbons in water as conventional accumulations do. Coal-bed gas was assessed separately, although it is also a form of continuous-type accumulation. Figures 4*A*, 4*B* and 5 show locations of assessed continuous-type gas and oil accumulations and coal-bed gas accumulations, respectively. The figures show the areal extent of these accumulations to be regional in nature and cover hundreds of square miles. Continuous-type accumulations have no downdip hydrocarbon-water contact, whereas conventional accumulations have well-defined hydrocarbon-water contacts and seals that hold the hydrocarbons. Figure 6 shows conventional structural and stratigraphic deposits in relation to a “basin center” continuous-type accumulation. A dominant characteristic of the reservoir rock of a continuous-type accumulation is that it is everywhere oil or gas charged. Other geologic characteristics include positioning of the accumulation downdip from water-saturated rocks, low reservoir permeability, abnormal (high or low) pressures, and close association of the reservoir with source rocks from which hydrocarbons were generated. These accumulations are contained in sandstone, siltstone, shale, chalk, or coal, but their areal extent and heterogeneity remain uncertain. Large portions remain undrilled. Conventional play assessment methods that typically rely on historical discovery size distributions are not applicable. New geologic and economic assessment methods were devised for assessing technically and commercially recoverable oil and gas from continuous-type plays. Economic evaluations were prepared at the play level.

METHODOLOGY

More detailed descriptions of methodologies applied to assessing the technically recoverable and economic undiscovered conventional resources and unconventional



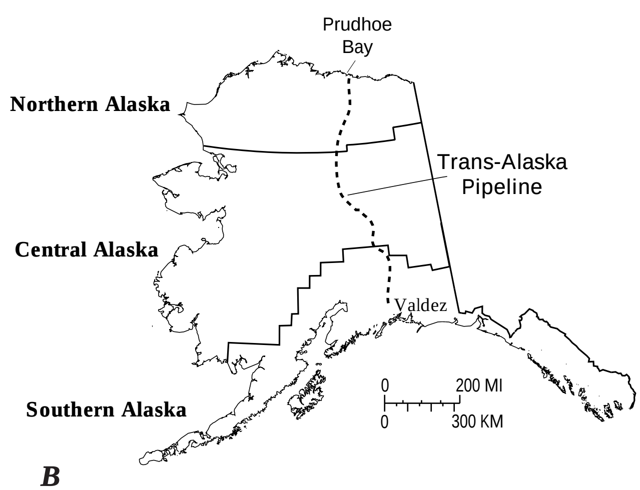


Figure 3. *A*, Petroleum regions and provinces in onshore and State offshore areas in the conterminous United States. Heavy lines are region boundaries; lighter lines are province boundaries. *B*, Petroleum provinces of onshore and State offshore areas of Alaska. Regions and provinces are listed by name and number in table B-1, Appendix B.

resources are provided in Appendix C. Complete explanations are provided in a series of USGS Open-File Reports referenced in those sections. Estimation of inferred reserves (field growth) is described in detail in Root and others (1996).

UNDISCOVERED CONVENTIONAL OIL AND GAS FIELDS

The geologic assessment posited undiscovered conventional oil and gas field size-frequency distributions from which quantities of oil, associated gas, associated gas liquids, non-associated gas, and non-associated gas liquids were computed. The incremental cost functions were prepared at the province level using the *expected or mean value* of the assessed size-frequency distributions of undiscovered accumulations grouped by 5,000-ft depth interval. The size frequency distributions of new discoveries (by field type and depth) were projected for successive increments of wildcat wells using a set of finding-rate functions and the geologic assessment. A standard application of discounted cash flow (DCF) analysis determined commercial developability of newly discovered fields. The net after-tax cash flow consisted of revenues from the production of oil and (or) gas less the operating costs, investment costs in the year incurred, and all taxes. All new discoveries of a particular size and

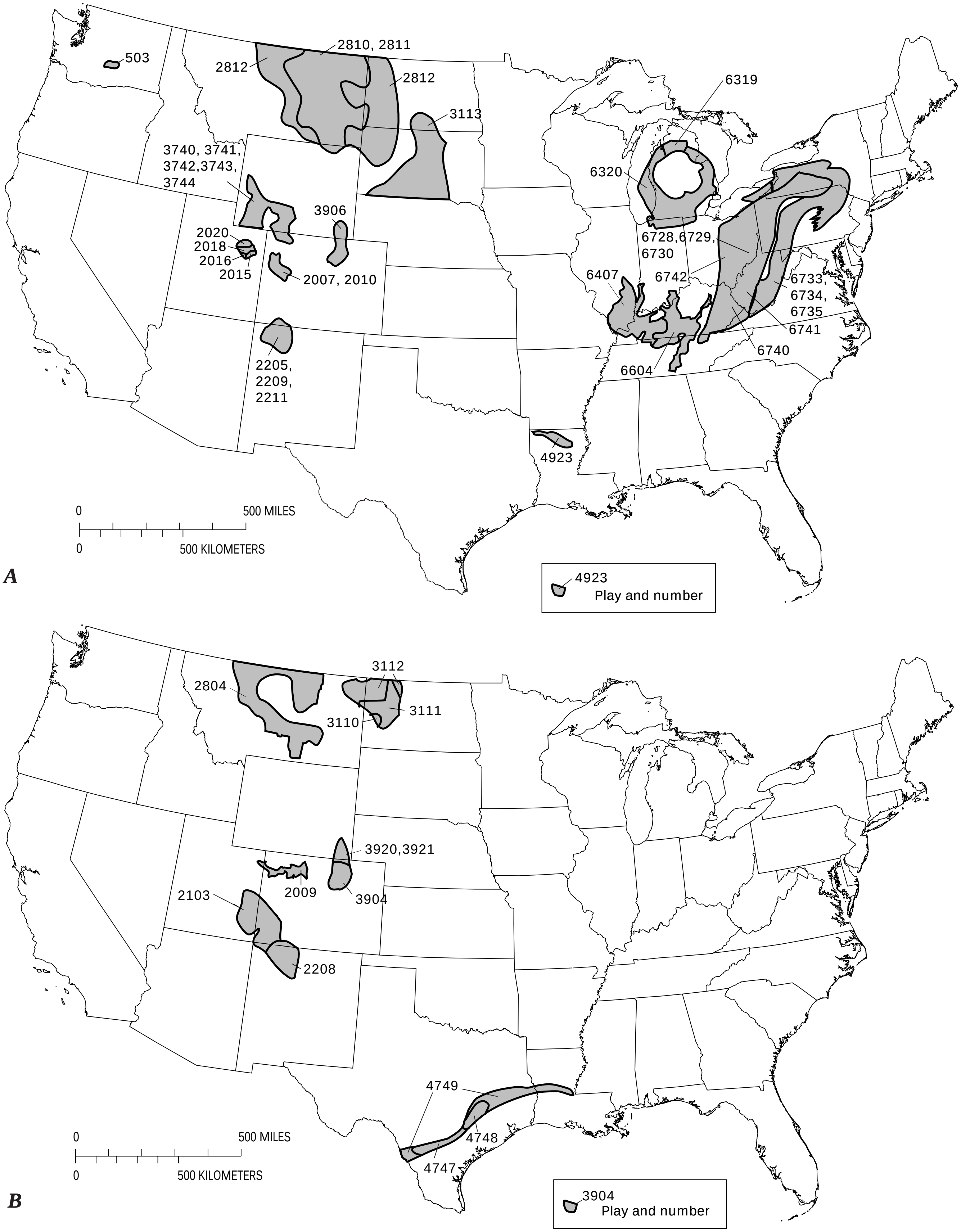


Figure 4. Assessed continuous-type plays from the USGS 1995 National Assessment for which the predominant reservoir rock is sandstone, siltstone, shale, or chalk. *A*, gas plays; *B*, oil plays. Tables B-2 and B-3, Appendix B, list provinces and play names associated with play numbers.

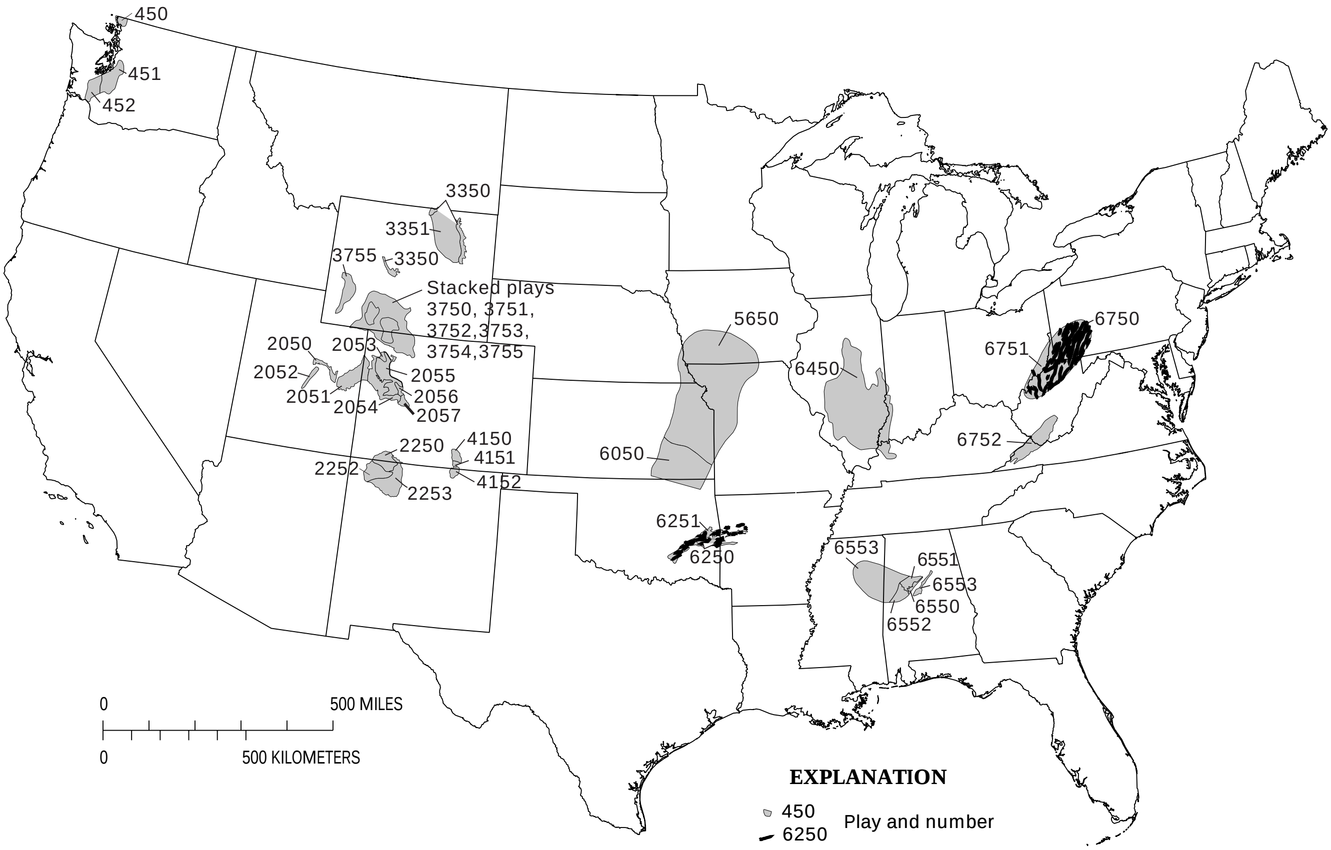


Figure 5. Assessed coal-bed gas plays from the USGS 1995 National Assessment. Table B-4, Appendix B, lists province and play names and numbers.

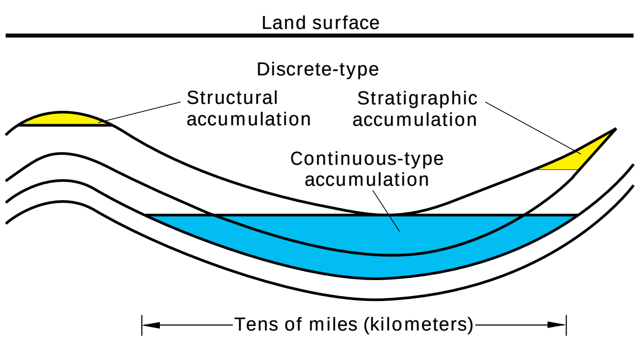


Figure 6. Geologic setting of a continuous-type accumulation and discrete conventional accumulations in a structural trap and a stratigraphic trap (U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995)

depth class are assumed to be developed and added to producible reserves if the representative field is found to be commercially developable, that is, if it has an after-tax net present value greater than zero. The discount rate included the cost of capital and the industry's required return.

Finding-rate functions predicted, for each increment of wildcat drilling, a distribution of oil and gas discoveries. For successive discovery distributions, average discoveries became smaller and (or) were found in deeper horizons, resulting in increasing finding costs. Increments of 50 wildcat wells (or 20 wildcat wells for State offshore areas) are assumed to be drilled until the exploration cost associated with the wildcat well increment is equal to or greater than the after-tax net present value of the commercially developed fields discovered by that increment of wildcat wells. For each increment of wildcat drilling, the allocation or targeting of wildcat wells to specific depth intervals maximized the after-tax net present value of the oil and gas discovered. As prices/incremental costs are allowed to increase, additional increments of wildcat wells are economic to drill and the marginal economic field size declines—this adds more commercially developable fields. Both effects add to producible reserves. The basis for the estimates of recoverable undiscovered petroleum as a function of well-head price is that incremental units of exploration, development, and production effort will not take place unless the revenues expected to be received from the eventual production will cover the incremental costs, including a normal return on the incremental investment.

UNCONVENTIONAL RESOURCES

Geologic assessment of continuous-type plays and coal-bed gas plays started with partitioning the postulated play area into equal-area cells. For continuous-type plays, cell spacing corresponded to the median drainage area of production wells in the play, and, for coal-bed gas plays, it corresponded to well spacing set by the State regulatory commission. Geologists interpreted past drilling results and production records to assess technically recoverable resources in remaining untested cells. The assessment results are expressed in terms of a size-frequency distribution of productive untested cells, where “cell size” here means quantity of hydrocarbons recovered. For calculating incremental costs, the geologic play assessment results were transformed into the *expected* size-frequency distribution of untested (productive) cells computed in 5,000-ft depth intervals. To determine the part of the cell frequency-size distribution of each 5,000-ft depth interval within a play that is commercially developable, a cash-flow analysis was applied to each cell-size category. After evaluation of all the cell-size classes within a specific depth interval, if the computed after-tax net present value of the aggregate developable cells is sufficient to cover the costs of drilling all cells, that is, the cost of exploration, then the aggregate resources in the commercially developable wells are added to reserves. Otherwise, drilling is not justified and resources are not added to reserves. Calculations were repeated assuming progressively higher well-head prices, and results were aggregated from depth intervals to the play level and then to the province level to arrive at incremental cost functions.

INFERRED RESERVES

Inferred reserves (or field growth) are those resources in identified fields over and above current proved (measured) reserves. They are expected to be added to discovered conventional fields through extensions, revisions, improved efficiency, and the addition of new pools or reservoirs. In the discussion of field growth, estimates of field size (or known field recovery) are computed as the sum of past cumulative field production and the field’s proved reserves. When fields are grouped by their year of discovery, the sum of the estimates of known recovery for each group tends to increase systematically over time or years of observations. This observed systematic nature of the “field-growth phenomenon” suggested a modeling approach that was statistical rather than geologic in nature. To model this process, *cumulative growth functions* were specified and calibrated.

Cumulative field-growth functions show the estimated field size at age *n*, that is, *n* years after discovery, as a multiple of the field’s initially estimated size. Cumulative growth functions were calibrated using yearly field-size estimates from 1977 through 1991 of conventional fields (grouped by discovery year from 1901 to 1991) in the lower 48 States.[2] The cumulative growth function was then applied to the 1991 field-size estimates to project future annual reserve additions for pre-1992 discoveries for the next 80 years. Alaska’s oil field growth was calculated using the lower-48-States growth function (U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995). The form of the cumulative growth function assumed that the annual rate of growth of older fields will not exceed that of younger fields and that fields continued to grow for as long as 90 years after their discovery. Also implicit in the application of the calibrated cumulative growth function is the assumption that the rate of technological improvement and economic conditions occurring during the observation period will prevail in the future.

Studies designed to tie estimated costs of drilling activity to historical field growth for a sample of fields failed to yield a credible costing scheme that could be applied to estimate costs of future reserve additions from inferred reserves. The 60 BBO and 322 TCFG (U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995) of estimated future reserve additions are expected to occur over an 80-year period to 2071. Only a small fraction of these resources can be added to reserves annually (Root and others, 1996). For purposes of comparison with the economic undiscovered conventional and unconventional resources, regional field-growth projections prepared for the period from 1994 to 2015 are presented and discussed.

ASSUMPTIONS

GENERAL ASSUMPTIONS

1. The economic analysis uses the *mean or expected value* of the assessed hydrocarbons.
2. Industry exhibits rational behavior, so that investment will not be undertaken unless the full operating costs, investment costs, and the cost of capital can be recovered.
3. Industry was assumed to use a 12 percent after-tax rate of return as a hurdle rate or required rate of return to undertake new investment. The cash-flow analysis was specific to individual projects and ignored minimum income taxes and tax preference items that might be important from a corporate accounting stance. Cost levels prevailing in 1993 were assumed.
4. Federal taxes are based on the 1986 Tax Reform Act and the 1993 revision. State tax rates are as of 1993.
5. Royalty payment to the resource owner is 12.5 percent of gross revenues for onshore areas and 16.67 percent of State offshore areas.

[2]Data used for calibrating cumulative growth functions typically consist of short time-series (6 to 15 years) of estimates of ultimate field recoveries for sets of fields grouped by discovery year. For example, with such a series, the expected percent field growth for a field going from age 19 to 20 is computed using estimates of known recovery for all those fields that passed from age 19 to 20 during the sample period. An entirely different set of fields may be used in calculating expected field growth from age 4 to age 5. Field-size estimates were from the Energy Information Administration’s proprietary Oil and Gas Integrated Field File (OGIFF), issued in 1993.

6. Dry gas (gas without natural gas liquids) prices were assumed to be two-thirds the price of oil when expressed on an equivalent energy basis. For example, if oil prices are $18 per barrel, the implied price of gas would be $2 per mcf. This relationship between oil and gas prices corresponds roughly to the historical average. The analysis also focused on prices between $18 per barrel ($2 per mcf) and $30 per barrel ($3.34 per mcf). Also, the well-head price of natural gas liquids is assumed to be three-fourths the per-barrel price of crude oil.
7. By-product revenues from associated gas and natural gas liquids are credited in the economic evaluation to the primary products of either crude oil or non-associated natural gas in the calculation of the incremental cost functions.

SPECIFIC ASSUMPTIONS: UNDISCOVERED CONVENTIONAL OIL AND GAS PLAYS

1. Economic evaluation of undiscovered conventional oil and gas fields were generally prepared at the province level and based on the assessed field-size distribution of undiscovered fields within 5,000-ft depth intervals.
2. Exploration continues until the expected net present value of the commercially developable resources discovered by the last increment of wildcat drilling is insufficient to pay for that increment of wildcat drilling.
3. Except in the Northern Alaska province, oil and gas prices used in the economic evaluation were well-head prices. For the Northern Alaska province, the oil price used in the economic evaluation was the lower-48-States-West-Coast price, rather than the well-head price, so incremental costs include transportation from the field to the lower 48 States West Coast. Oil produced in Northern Alaska is transported through the Trans-Alaska Pipeline System (TAPS).
4. Because of the absence of a market for the gas resources of Northern Alaska, non-associated gas fields were not evaluated and a zero price was attached to the extracted associated gas from oil fields.
5. The oil and gas resources of the Central Alaska province and of the Southern Alaska province outside the Cook Inlet were not evaluated by the economic analysis because these areas have very limited potential and expected discovery sizes are insufficient to offset cost barriers imposed by the hostile climate, primitive infrastructure, and remoteness from markets.
6. Technically recoverable resources assigned to Lake Michigan and Lake Erie were not evaluated. These resources amounted to 0.67 BBO and 3.0 TCFG.

SPECIFIC ASSUMPTIONS: CONTINUOUS-TYPE AND COAL-BED GAS PLAYS

1. Economic evaluations of continuous-type accumulations and coal-bed gas were prepared at the play level and based on the expected cell-size frequency distribution of untested cells for each 5,000-ft depth interval over which the play extends.
2. Each untested cell requires a new well; recompletions to the target plays of producing wells were not considered.
3. Within continuous-type or coal-bed gas plays, it is assumed there is no trend in the discovery rate or well productivities as drilling progresses. In particular, it is assumed that within a play, operators cannot high-grade areas except by restricting drilling to specific depth intervals. To the extent possible, so-called sweet spots should be separate plays.

INCREMENTAL COSTS

OVERVIEW: UNDISCOVERED CONVENTIONAL FIELDS AND CONTINUOUS-TYPE ACCUMULATIONS

Table 1 shows regional estimates of economic quantities of oil, gas, and natural gas liquids in conventional undiscovered oil and gas fields, continuous-type accumulations and coal-bed gas accumulations having incremental costs of $18 per barrel or $2 per mcf and $30 per barrel or $3.34 per mcf. Figures 7 and 8 depict estimates of oil in oil fields and accumulations and gas in gas fields and accumulations. Figures 9 and 10 show regional incremental cost functions for of oil and non-associated gas, respectively.

At $18 per barrel and $2 per mcf, 9.2 BBO, 15.8 TCF associated gas, and 1.1 BBL NGL from undiscovered oil fields and 61.7 TCFG and 2.0 BBL NGL from undiscovered gas fields can be found, developed, and produced. Similarly, at $30 per barrel and $3.34 mcf, 17.4 BBO, 25.9 TCF associated gas, and 1.6 BBL NGL in undiscovered oil fields and 95.9 TCFG and 2.9 BBL NGL in undiscovered gas fields is economic. Associated gas represents 20 percent of the total gas estimated at both cost levels. Additionally, NGL from associated and non-associated gas accounts for one-fifth to one-fourth of total economic hydrocarbon liquids (crude oil plus natural gas liquids).

Crude oil in continuous-type oil accumulations, even at the high cost level, adds less than 6 percent to economic crude oil. At $2 per mcf, continuous-type gas accumulations

Table 1. Estimated economic oil, gas, and natural gas liquids (NGL) in undiscovered conventional oil and gas fields and in unconventional oil and gas accumulations in onshore and State offshore areas of the United States as of January 1994.

[mcf, thousand cubic feet; Assoc., Associated; NGL, Natural gas liquids; BBO, billions of barrels of oil; TCF, trillions of cubic feet; BBL, billions of barrels. Unconventional oil and gas are from continuous-type oil and gas accumulations and coal-bed gas]

Region	Conventional undiscovered oil fields						Unconventional oil accumulations			
	$18/bbl and $2/mcf			$30/bbl and $3.34/mcf			$18/bbl and $2/mcf		$30/bbl and $3.34/mcf	
	Oil (BBO)	Assoc. gas (TCF)	NGL (BBL)	Oil (BBO)	Assoc. gas (TCF)	NGL (BBL)	Oil (BBO)	Assoc. gas (TCF)	Oil (BBO)	Assoc. gas (TCF)
1 Alaska	0.913	0.913	0.009	3.828	3.273	0.058	0.000	0.000	0.000	0.000
2 Pacific Coast	1.669	2.206	0.091	2.590	3.413	0.143	0.000	0.000	0.000	0.000
3 Colorado Plateau and Basin and Range	0.572	1.807	0.077	0.840	2.275	0.106	0.145	0.072	0.374	0.254
4 Rocky Mountains and Northern Great Plains	1.730	2.911	0.411	2.975	4.049	0.596	0.000	0.000	0.040	0.398
5 West Texas and Eastern New Mexico	2.023	3.000	0.305	2.748	4.007	0.395	0.000	0.000	0.000	0.000
6 Gulf Coast	1.767	3.525	0.117	3.174	6.173	0.205	0.000	0.000	0.678	1.641
7 Midcontinent	0.329	1.141	0.052	0.727	2.119	0.105	0.000	0.000	0.000	0.000
8 Eastern	0.237	0.292	0.019	0.535	0.612	0.035	0.000	0.000	0.000	0.000
TOTAL, UNITED STATES	9.239	15.795	1.081	17.417	25.922	1.643	0.145	0.072	1.092	2.293

Region	Conventional undiscovered gas fields				Unconventional gas accumulations			
	$2/mcf		$3.34/mcf		$2/mcf		$3.34/mcf	
	Gas (TCF)	NGL (BBL)	Gas (TCF)	NGL (BBL)	Gas (TCF)	NGL (BBL)	Gas (TCF)	NGL (BBL)
1 Alaska	0.120	0.000	0.283	0.000	0.000	0.000	0.000	0.000
2 Pacific Coast	1.201	0.013	2.726	0.024	0.000	0.000	0.330	0.000
3 Colorado Plateau and Basin and Range	1.667	0.017	3.062	0.033	20.793	0.014	29.600	0.017
4 Rocky Mountains and Northern Great Plains	8.473	0.688	10.996	0.808	6.887	0.000	13.622	0.049
5 West Texas and Eastern New Mexico	6.070	0.133	8.999	0.206	0.000	0.000	0.000	0.000
6 Gulf Coast	36.899	0.982	57.211	1.627	5.373	0.134	5.520	0.138
7 Midcontinent	6.347	0.116	9.949	0.170	0.268	0.000	2.106	0.000
8 Eastern	0.935	0.018	2.680	0.043	2.538	0.000	20.956	0.000
TOTAL, UNITED STATES	61.710	1.967	95.904	2.912	35.859	0.148	72.134	0.204

add 35.9 TCFG to economic resources, and, at $3.34 per mcf, 72 TCFG is added. Assessed NGL resources in unconventional gas were very small. Quantities of economic unconventional gas are significant, even at low incremental costs. Total economic gas resources at $2 per mcf are 113.4 TCFG and, at $3.34, are 196.3 TCFG.

The economic analysis treated the Northern Alaska province (Alaska, Region 1) at the play level (see Attanasi and Bird, 1996) because it is still a frontier area with little infrastructure and is remote from markets. Incremental costs for this province included product transport costs from the field to the lower 48 States West Coast. These costs ranged from $5.41 to $9.38 per barrel. Assessed non-associated gas fields in the Northern Alaska province were not evaluated by the economic analysis because markets and a product transportation system for new gas appear at least 2 decades away (see Attanasi, 1994). There is at least 30 TCF associated gas already discovered that can be produced cheaply if a market should develop. Although no commercial value was imputed to the associated gas in oil fields in the Northern Alaska province, by-product revenues for natural gas liquids were credited. The Cook Inlet area has local oil and gas markets, so that, for the marginal unit of resources added to reserves, incremental costs equaled well-head price. For the Alaska Region, at $18 per barrel, 11 percent of the technically recoverable oil is economic. Similarly at $30 per barrel, 45 percent of the assessed oil is economic.

Nearly all the economic oil shown in table 1 is in conventional undiscovered oil fields. For the lower 48 States, about 36 percent of the geologically assessed oil in undiscovered conventional fields and continuous-type oil accumulations can be found, developed, and produced at $18 per barrel. As costs increase to $30 per barrel, 62 percent of the technically recoverable oil is economic.

Assessed coal-bed gas and gas in continuous-type accumulations (unconventional gas) amounted to more than three-fifths of the 507 TCF of technically recoverable non-associated gas assessed in conterminous U.S. onshore and

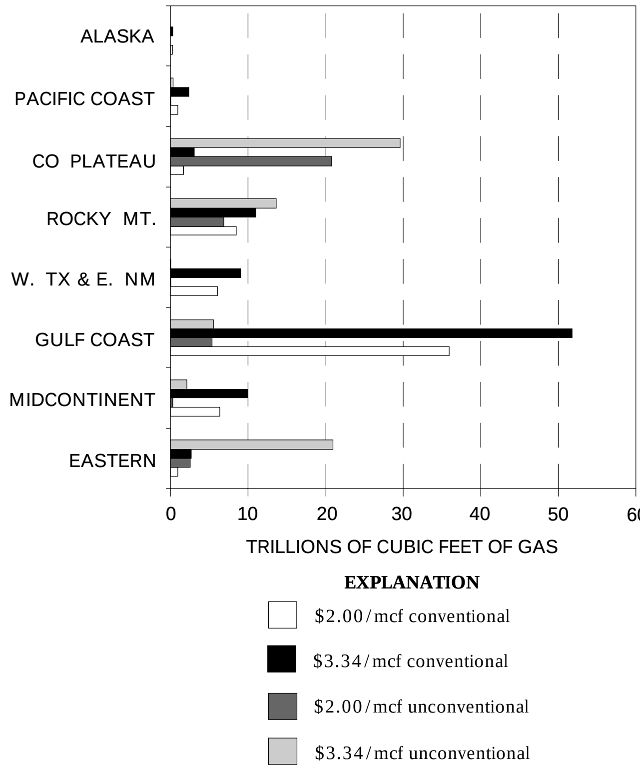


Figure 8. Estimates of quantities of non-associated gas, by petroleum region, from undiscovered conventional gas fields and from assessed continuous-type gas accumulations having incremental costs of $2 and $3.34 per thousand cubic feet, respectively.

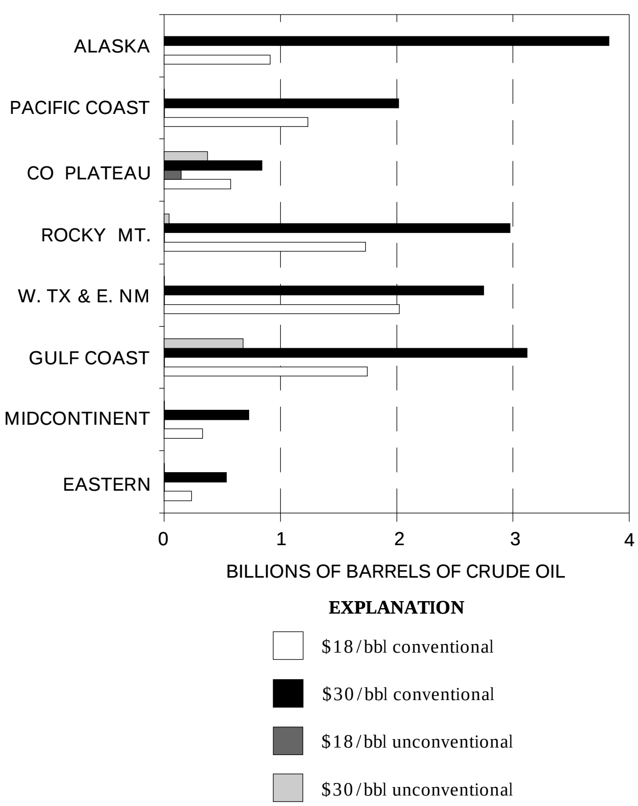
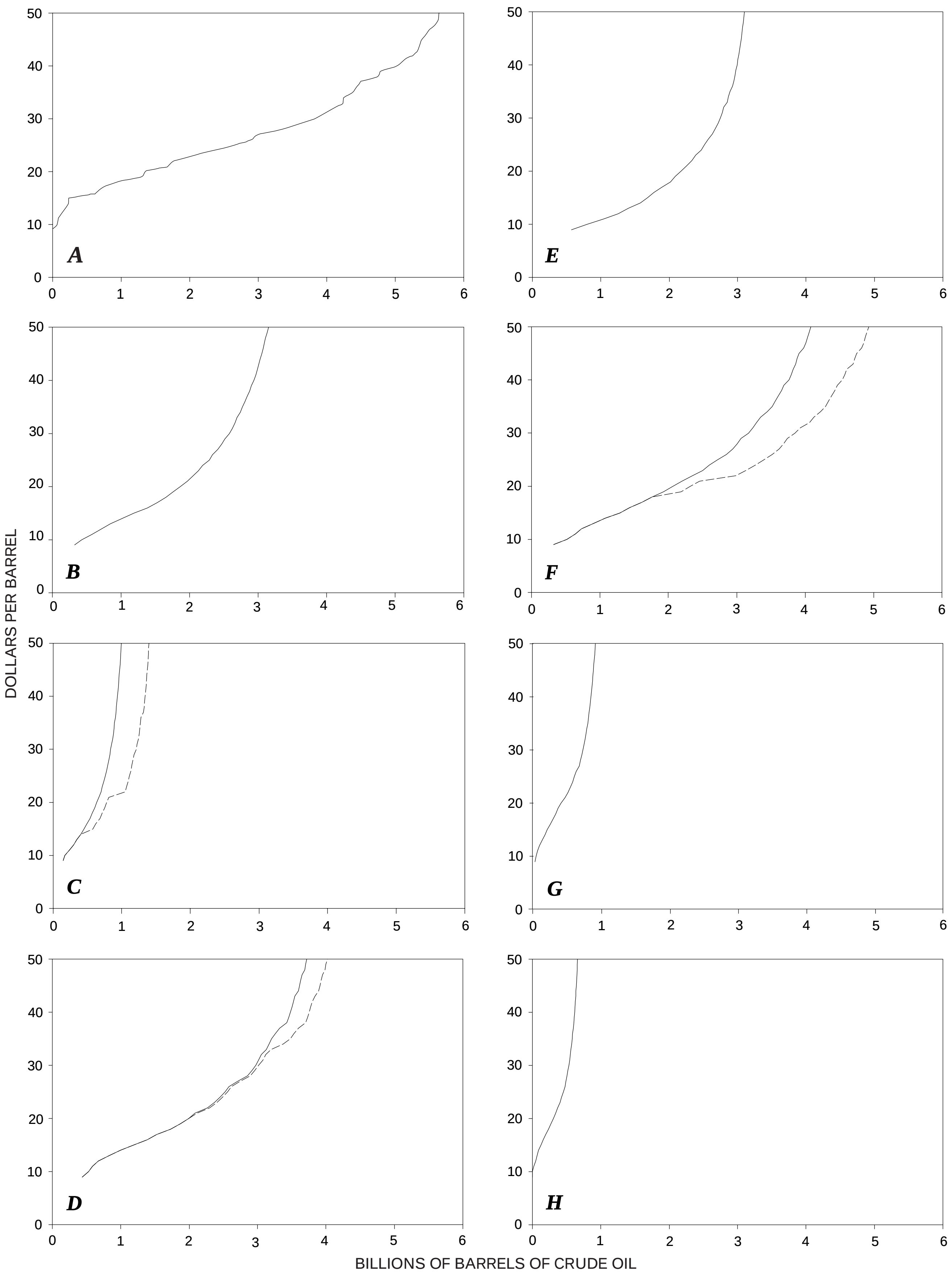
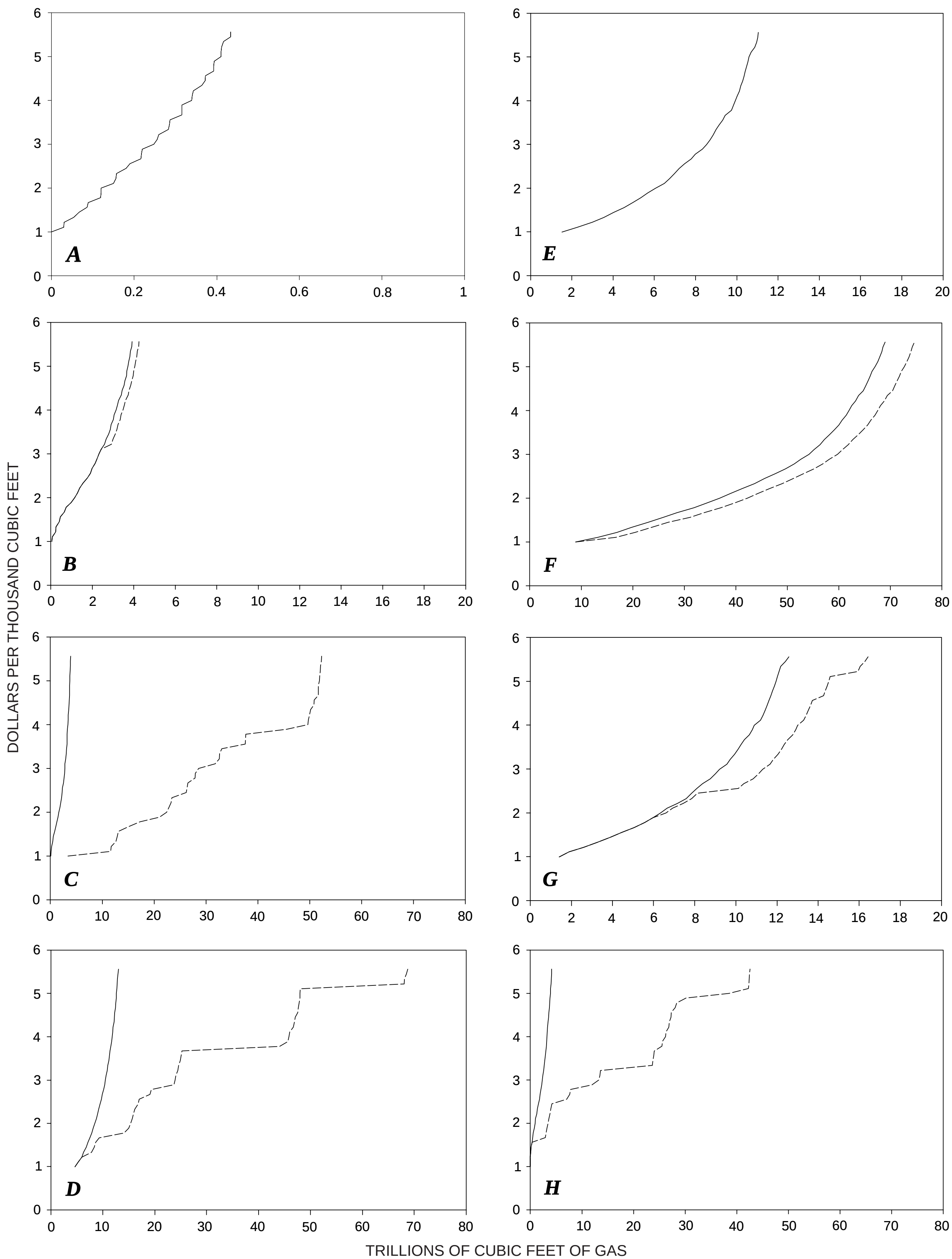


Figure 7. Estimates of quantities of crude oil, by petroleum region, from undiscovered conventional oil fields and from assessed continuous-type oil accumulations having incremental costs of $18 and $30 per barrel, respectively.

Figure 9 (facing page). Incremental cost of finding, developing, and producing crude oil from undiscovered conventional oil fields and crude oil from continuous-type oil accumulations in U.S. petroleum regions: *A*, Region 1 (Alaska); *B*, Region 2 (Pacific Coast); *C*, Region 3 (Colorado Plateau and Basin and Range); *D*, Region 4 (Rocky Mountains and Northern Great Plains); *E*, Region 5 (West Texas and Eastern New Mexico); *F*, Region 6 (Gulf Coast); *G*, Region 7 (Midcontinent); *H*, Region 8 (Eastern). Solid line represents undiscovered conventional oil, and dashed line represents the total of undiscovered conventional oil and oil in continuous-type accumulations.


DOLLARS PER BARREL
A
B
C
D
E
F
G
H
BILLIONS OF BARRELS OF CRUDE OIL



A
B
C
D
E
F
G
H
DOLLARS PER THOUSAND CUBIC FEET
TRILLIONS OF CUBIC FEET OF GAS

Figure 10 (facing page). Incremental cost of finding, developing, and producing non-associated gas from undiscovered conventional gas fields and unconventional gas from assessed continuous-type gas accumulations and coal-bed gas in U.S. petroleum regions: *A*, Region 1 (Alaska); *B*, Region 2 (Pacific Coast); *C*, Region 3 (Colorado Plateau and Basin and Range); *D*, Region 4 (Rocky Mountains and Northern Great Plains); *E*, Region 5 (West Texas and Eastern New Mexico); *F*, Region 6 (Gulf Coast); *G*, Region 7 (Midcontinent); *H*, Region 8 (Eastern). Solid line represents undiscovered conventional non-associated gas, and dashed line represents the total of undiscovered conventional non-associated gas, gas in continuous-type gas accumulations, and coal-bed gas.

State offshore areas. Table 1 shows that, even at a cost of $2 per mcf, the unconventional gas accounts for 36 percent of the economic non-associated gas. As prices increase, the proportion of economic gas coming from these accumulations increases because of the much larger quantity of technically recoverable gas in unconventional accumulations. Regions where unconventional gas is expected to dominate, that is, Colorado Plateau (Region 3) and Rocky Mountain (Region 4), are strategically located to contribute to West Coast gas supplies. Eastern Region (Region 8) gas from Antrim Shales of the Michigan Basin and coal-bed gas in Central Appalachia will also find a ready market in the industrial Northeast. Moreover, locational advantages of Eastern Region gas permit higher well-head prices to partially offset typically higher costs of unconventional gas. By source, economic non-associated gas at $2 per mcf amounted to 39 percent of the assessed technically recoverable undiscovered conventional gas and 10 percent of the assessed technically recoverable unconventional gas. Similarly, at $3.34 per mcf, 61 percent of undiscovered conventional and 20 percent of unconventional gas is economic.

UNDISCOVERED CONVENTIONAL OIL AND GAS

CHARACTERISTICS OF TECHNICALLY RECOVERABLE RESOURCES

Characteristics of the geologic assessment important for understanding the economic analysis are highlighted here. Table A-1, Appendix A, shows the combined mean values of assessed conventional undiscovered recoverable resources for U.S. onshore and State offshore areas. Federal offshore areas are not included. Oil and gas estimates shown in the table are small revisions to the estimates presented in U.S. Geological Survey Circular 1118 (U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995). The technically recoverable natural gas liquids estimates shown here, however, correct estimates presented in Circular 1118. The estimates are presented by field-type because cost and technology for oil and gas field development are different. Non-associated gas, that is gas in gas fields, accounts for more than four-fifths of total undiscovered gas.

Region 1.—The Northern Alaska province was assigned mean values of 7.40 BBO and 63.5 TCFG, the Central Alaska province 0.06 BBO and 2.7 TCFG, and the Southern Alaska province 1.0 BBO and 2.1 TCFG. To place these estimates in perspective, through-1990 cumulative discoveries in the Northern Alaska province amount to more than 14 BBO and 32 TCFG, and, in the Southern Alaska province, discoveries amount to about 1.2 BBO and 6.8 TCFG (NRG Associates, 1993, 1994). Alaska accounts for about 30 percent of the assessed technically recoverable undiscovered oil and 26 percent of the undiscovered gas resources in the 1995 National Assessment. Plays in the Central Alaska province and in the Southern Alaska province (outside of the Cook Inlet area) have very limited potential, and expected discovery sizes are unlikely to be large enough to offset cost barriers imposed by the hostile climate, primitive infrastructure, and remoteness from markets. Consequently, these plays were not further evaluated by economic analysis.

At the mean value, the 1995 Northern Alaska province assessment of undiscovered oil of 7.40 BBO is a 41 percent reduction from the 12.6 BBO estimated in the 1989 assessment (see Mast and others, 1989). Assessed undiscovered gas increased by about 10 percent over the 1989 analysis. This revision resulted from new drilling information and an alternative interpretation of the thermal history of the province (U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995) that reduced the perceived maximum depths where oil was thought to occur. For the 1995 Assessment, more than three-fourths of the estimated undiscovered oil was assigned to depths shallower than 10,000 ft and only 2 percent was assigned to depths greater than 15,000 ft. A high degree of uncertainty was attached to geologic estimates for both oil and gas in the Northern Alaska province.

Regions 2, 3, 4, 5, 6, 7, and 8.—Table A-1, Appendix A, shows more than 21 billion barrels of oil and 190 trillion cubic feet of gas remain to be discovered in the onshore and State offshore areas in the conterminous United States. For this area, undiscovered resources amount to only 13 percent of the oil and 23 percent of the gas already discovered. Nearly all of these areas have been rather thoroughly explored for conventional resources. State offshore areas account for about 10 percent of the undiscovered resources in the lower 48 States. Of the 55 provinces listed for the lower 48 States, 45 percent of the oil is contained in just four provinces (Permian Basin (044), Western Gulf (047), Louisiana-Mississippi Salt Basins (049), and Powder River (033)) and more than half the non-associated gas is contained in the Western Gulf (047) province and the Louisiana-Mississippi Salt Basins (049).

Figure 11*A* shows the mean field-size frequency distribution of the ultimate (discovered plus undiscovered) and undiscovered numbers of fields containing at least 1 million barrels of oil equivalent (1 MMBOE). Similarly, figure 11*B* shows the frequencies for all field-size classes. Table A-4, Appendix A, provides size class definitions. Data in the figures show future discoveries to be dominated by smaller fields. Though only 10 percent of hydrocarbons discovered in the past were in fields of less than 8 MMBOE, half the undiscovered hydrocarbons were assigned to these size classes. Field-size classes smaller than 1 MMBOE (classes 1-5) contain less than 3 percent of *discovered hydrocarbons* but account for 23 percent of the undiscovered hydrocarbons. Because finding, development, and production costs typically vary inversely with field size, data behind the figures imply increases in costs are associated with future discoveres.

INCREMENTAL COSTS OF OIL AND GAS FROM UNDISCOVERED CONVENTIONAL OIL AND GAS FIELDS

Computation of incremental cost functions started with the economic evaluation of the assessed distribution of undiscovered oil and gas fields: the economic target for exploration. Province-level finding-rate functions were used to predict the ordering and arrival rate of discoveries. For each increment of wildcat wells, the finding-rate function generates a distribution of discoveries by size and depth, some of which will be commercially developable and some not. The computational algorithm assumes exploration continues until the expected economic value of the resources discovered by the last increment of wildcat wells is insufficient to pay for that exploration increment. The targeting of wildcat wells by depth interval for each well increment maximized the expected after-tax net present value of oil and gas discovered. Successive increments of wildcat wells generate smaller discoveries and (or) discoveries in deeper horizons that typically lead to increasing finding costs. All this implies that it is not valid to simply add a flat finding cost to development cost to arrive at the full incremental costs.

Tables A-2 and A-3, Appendix A, show province-level estimates of economic resources by commodity. Table A-2 shows that, at $18 per barrel ($2 per mcf), it will be economic to find, develop, and produce 9.2 BBO, 15.8 TCF associated gas, and 1 BBL NGL from undiscovered conventional oil fields and 61.7 TCFG and 2 BBL NGL from undiscovered conventional gas fields. Table A-3 shows estimates of economic oil increase by 85 percent and total economic gas increases by 57 percent as incremental costs are allowed to increase to $30 per barrel ($3.34 per mcf). Associated gas accounts for about one-fifth of total economic undiscovered conventional gas, and NGL from associated and non-associated gas contributes 20 to 25 percent to total conventional liquid hydrocarbons (crude oil plus NGL).

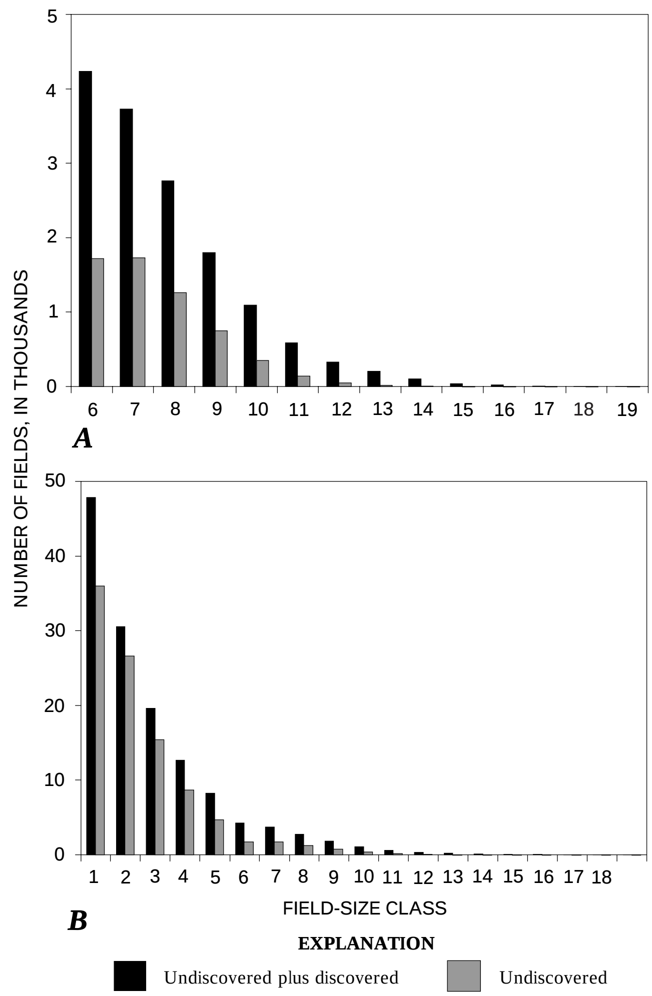


Figure 11. Field-size distribution of ultimate (discovered plus undiscovered) and undiscovered conventional oil and gas fields in onshore and State offshore areas of the conterminous United States. *A*, part of distribution for fields containing at least 1 million barrels of oil equivalent. *B*, entire distribution. Size classes, in terms of millions of barrels of oil equivalent, are defined in table A-4, Appendix A.

For the Northern Alaska province, at a lower-48-States-West-Coast price of $18 per barrel, only 8 percent of the technically recoverable undiscovered oil is economic; at $30 per barrel, about 43 percent is economic. For the lower 48 States, 38 percent of the technically recoverable undiscovered oil and 39 percent of the technically recoverable undiscovered non-associated gas can be found, developed, and produced at incremental costs of $18 per barrel ($2 per mcf). At an incremental cost of $30 per barrel ($3.34 per mcf), two-thirds of the technically recoverable oil and gas is economic.

The Alaska and Gulf Coast Regions have the largest quantities of economic undiscovered oil at $30 per barrel, followed by (1) the Rocky Mountain Region and (2) the West Texas and Eastern New Mexico Region. Tables A-2 and A-3, Appendix A, show that, within most regions, one or two provinces dominate potential reserve additions. Based on the incremental cost functions and the fraction of technically recoverable oil that is economic to find, develop, and produce at an incremental cost of $18 per barrel, the Permian Basin province (044) in the West Texas and Eastern New Mexico Region has the lowest cost oil, followed by the Western Gulf province (047) in the Gulf Coast Region. The Northern Alaska province was assigned the largest quantity of oil of any U.S. province; however, transport of the product to market increases costs substantially.

For economic undiscovered non-associated gas, the Gulf Coast Region is the dominant region, followed by the Rocky Mountain, Midcontinent, and West Texas and Eastern New Mexico Regions. The Western Gulf province of the Gulf Coast Region has lowest costs. Half of the technically recoverable gas in the Gulf Coast Region is economic to find, develop, and produce for $2 per mcf. That quantity of gas is more than all the other regions combined at that cost level.

Even at low well-head prices, improvements in exploration technology are likely to occur during the next 2 decades. Though undiscovered resources are unchanged, improvements in exploration efficiencies can increase the quantity of resources found and developed at nearly every cost level. If the analysis for the conterminous United States is repeated assuming exploration efficiency is doubled, the quantity of crude oil and non-associated gas that is economic at $18 per barrel ($2 per mcf) increases by more than one-third, so 54 percent of the technically recoverable resources are economic. At the $30 per barrel ($3.34 per mcf), almost three-fourths of the assessed resources are economic.

CONTINUOUS-TYPE ACCUMULATIONS AND COAL-BED GAS

CHARACTERISTICS OF TECHNICALLY RECOVERABLE RESOURCES

Tables 2 and 3 show the expected values of the assessed technically recoverable oil and gas in continuous-type plays and in coal-bed gas plays, respectively. The 302 TCF assessed in sandstone/siltstone, shale, and chalk continuous-type plays and the 50 TCF in coal-bed gas together represent *more than twice* the estimated technically recoverable undiscovered conventional gas assessed in the lower 48 States. The 2 BBO assessed in continuous-type oil plays is small compared to oil in undiscovered conventional fields. More than half this oil was in the Austin Chalk plays of the Western Gulf province (047).

The geographical concentration of the resources assessed in continuous-type gas and in coal-bed gas plays is very uneven. Three of the twelve provinces with assessed continuous-type gas accumulations accounted for two-thirds of the gas. These dominant provinces include Southwestern Wyoming (037), Appalachian Basin (067), and Central Montana (028). Similarly, of the 13 provinces with assessed coal-bed gas plays, the Uinta-Piceance (020), the San Juan (022), and the Appalachian (067) Basins accounted two-thirds of the total gas.

With few exceptions the coal-bed gas assessed by geologists was restricted to depths of 6,000 ft or less. One-third of the 302 TCF of technically recoverable gas assessed in continuous-type plays is shallower than 5,000 ft and one-fifth is deeper than 15,000 ft. Coal-bed gas and shallow gas in continuous-type gas plays together account more than 150 TCFG. The in-place volumes of hydrocarbons in unconventional plays are overwhelming. Some unconventional plays were not assessed because the geologic and production data were simply not sufficient or because the inferior quality of the resources, in the assessor's judgment, was outside the practical limits of recovery technology.

INCREMENTAL COSTS OF OIL AND GAS FROM CONTINUOUS-TYPE AND COAL-BED GAS ACCUMULATIONS

For unconventional resources, incremental costs represent the full costs of exploring, developing, and producing the commercially developable cells in a specific 5,000-ft depth interval of a continuous-type or coal-bed gas play. Individual depth intervals of continuous-type or coal-bed gas plays will not be explored unless the aggregate expected after-tax net present value of the commercially developable cells is sufficient to cover costs of testing all cells in the depth interval.

Gas resources in continuous-type gas accumulations are massive, but are also dilute, as evidenced by typically low well productivities. Only 7 percent of the assessed technically recoverable gas is economic to find, develop, and produce at $2 per mcf. At $3.34 per mcf, 15 percent of the assessed gas is economic (see table 2). At $2 per mcf, plays in the San Juan Basin (022), the Louisiana-Mississippi Salt Basins (049), the Uinta-Piceance Basin (020), and the Central Montana (028) provinces account for 85 percent of the economic resources in continuous-type gas accumulations (see table 2). These provinces continue to dominate as costs increase to $3.34 per mcf and plays from the Michigan (063), Appalachian (067), and Southwestern Wyoming (037) provinces are added. The lowest cost continuous-type gas plays evaluated were in the San Juan and Louisiana-Mississippi Salt Basins, having costs of $1.10 per mcf.

The quantity of oil assessed in continuous-type oil accumulations is small. For continuous-type oil accumulations at $18 per barrel and $30 per barrel, about 7 percent and 50 percent, respectively, of the assessed technically recoverable oil is economic (see table 2).

Table 3 shows, at $2 per mcf, 30 percent of the assessed coal-bed gas is economic. The San Juan (022), Uinta-Piceance (020), and Appalachian (067) Basins account for 86 percent of the economic resources. As incremental costs

Table 2. Estimates of technically recoverable and economic oil, gas, and natural gas liquids (NGL) in continuous-type oil and gas accumulations in onshore areas of the conterminous United States as of January 1994.

[mcf, thousand cubic feet; NGL, Natural gas liquids; TCF, trillions of cubic feet; BBL, billions of barrels; BBO, billions of barrels of oil; bbl, barrel]

CONTINUOUS-TYPE GAS ACCUMULATIONS

Province Number	Province Name	Technically recoverable		$2/mcf		$3.34/mcf	
		Nonassociated gas (TCF)	NGL (BBL)	Nonassociated gas (TCF)	NGL (BBL)	Nonassociated gas (TCF)	NGL (BBL)
	Region 2—Pacific Coast						
005	E. Oregon-Wasington	12.200	0.122	0.000	0.000	0.000	0.000
TOTAL, Region 2		12.200	0.122	0.000	0.000	0.000	0.000
	Region 3—Colorado Plateau and Basin and Range						
020	Uinta-Piceance Basin	16.713	0.096	1.845	0.014	2.146	0.016
022	San Juan Basin	21.060	0.001	8.749	0.000	11.681	0.001
TOTAL, Region 3		37.773	0.096	10.594	0.014	13.827	0.017
	Region 4—Rocky Mountains and Northern Great Plains						
028	Central Montana	41.270	0.000	5.012	0.000	5.241	0.000
031	Williston Basin	1.894	0.000	0.000	0.000	0.000	0.000
037	Southwestern Wyoming	119.171	1.732	0.000	0.000	3.278	0.049
039	Denver Basin	0.831	0.000	0.000	0.000	0.631	0.000
TOTAL, Region 4		163.165	1.732	5.012	0.000	9.150	0.049
	Region 6—Gulf Coast						
049	Louisiana-Mississippi Salt Basins	6.035	0.151	5.373	0.134	5.520	0.138
TOTAL, Region 6		6.035	0.151	5.373	0.134	5.520	0.138
	Region 8—Eastern						
063	Michigan Basin	18.870	0.000	0.000	0.000	13.672	0.000
064	Illinois Basin	1.889	0.002	0.000	0.000	0.000	0.000
066	Cincinnati Arch	1.389	0.000	0.000	0.000	0.000	0.000
067	Appalachian Basin	61.209	0.015	0.000	0.000	3.061	0.000
TOTAL, Region 8		83.357	0.017	0.000	0.000	16.733	0.000
TOTAL, CONTERMINOUS UNITED STATES		302.530	2.118	20.979	0.148	45.230	0.204

CONTINUOUS-TYPE OIL ACCUMULATIONS

Province Number	Province Name	Technically recoverable		$18/bbl		$30/bbl	
		Oil (BBO)	Associated gas (TCF)	Oil (BBO)	Associated gas (TCF)	Oil (BBO)	Associated gas (TCF)
	Region 3—Colorado Plateau and Basin and Range						
020	Uinta-Piceance Basin	0.094	0.028	0.000	0.000	0.000	0.000
021	Paradox Basin	0.242	0.194	0.000	0.000	0.225	0.180
022	San Juan Basin	0.189	0.094	0.145	0.072	0.149	0.074
TOTAL. Region 3		0.525	0.316	0.145	0.072	0.374	0.254
	Region 4—Rocky Mountains and Northern Great Plains						
028	Central Montana	0.016	0.013	0.000	0.000	0.000	0.000
031	Williston Basin	0.151	0.128	0.000	0.000	0.000	0.000
039	Denver Basin	0.285	2.325	0.000	0.000	0.040	0.398
TOTAL, Region 4		0.452	2.466	0.000	0.000	0.040	0.398
	Region 6—Gulf Coast						
047	Western Gulf	1.089	2.633	0.000	0.000	0.678	1.641
TOTAL, Region 6		1.089	2.633	0.000	0.000	0.678	1.641
TOTAL, CONTERMINOUS UNITED STATES		2.066	5.416	0.145	0.072	1.092	2.293

Table 3. Estimates of technically recoverable and economic gas in assessed coal beds in onshore areas of the conterminous United States as of January 1994.

[TCF, trillions of cubic feet; mcf, thousands of cubic feet]

Province number	Province name	Technically recoverable gas (TCF)	$2/mcf gas (TCF)	$3.34/mcf gas (TCF)
	Region 2—Pacific Coast			
004	Western Washington	0.697	0.000	0.330
TOTAL, Region 2		0.697	0.000	0.330
	Region 3—Colorado Plateau and Basin and Range			
020	Uinta-Piceance	10.705	4.229	8.506
022	San Juan	7.533	5.970	7.267
TOTAL, Region 3		18.238	10.199	15.773
	Region 4—Rocky Mountains and Northern Great Plains			
033	Powder River	1.107	0.000	0.534
035	Wind River	0.426	0.000	0.398
037	Southwest Wyoming	3.889	1.093	1.831
041	Raton Basin	1.775	0.782	1.709
TOTAL, Region 4		7.196	1.875	4.472
	Region 7—Midcontinent			
056	Forest City Basin	0.452	0.000	0.000
060	Cherokee Basin	1.914	0.000	0.000
062	Arkoma Basin	2.640	0.268	2.109
TOTAL, Region 7		5.006	0.268	2.109
	Region 8—Eastern			
064	Illinois Basin	1.628	0.000	0.000
065	Black Warrior Basin	2.303	0.000	1.200
067	Appalachian Basin	14.846	2.538	3.023
TOTAL, Region 8		18.777	2.538	4.223
TOTAL, CONTERMINOUS UNITED STATES		49.914	14.880	26.907

increase to $3.34 per mcf, more than half of all the assessed coal-bed gas becomes economic. The lowest cost plays (with costs of $1 per mcf) were located in the San Juan Basin.

The regional distribution of economic gas in continuous-type gas accumulations and coal-bed gas is notable. The San Juan and the Uinta-Piceance Basins can supply West Coast markets. Gas from the Michigan Basin Antrim Shale and Central Appalachian coal-bed gas plays have ready markets in the industrial Northeast. Economic undiscovered conventional gas in these provinces is very modest. Locational advantages, particularly in the Eastern Region, permit higher well-head prices to offset the generally higher costs of developing these unconventional gas resources.

Assumptions applied in the economic evaluation assured conservative estimates of economic resources. For example, it was assumed that the industry could not selectively drill a continuous-type play. However, an individual firm may have site-specific or specialized knowledge that allows it to high-grade a play by identifying "sweet spots." At the time of the 1995 National Assessment, the occurrence and extent of these local sweet spots were not known with sufficient detail to incorporate them. Selective drilling reduces costs by siting wells in high-productivity areas and avoiding noncommercial wells. For some plays, industry production experience gained since the 1995 National Assessment suggests more efficient well spacing (cell size) than assumed. Although it was assumed that new wells are required to test and produce each cell in a continuous-type accumulation, in practice, the industry has recompleted existing wells to produce these resources.

INFERRED RESERVE ESTIMATES

FIELD GROWTH: ORIGINS AND QUALIFICATIONS

Field-growth projections are applied only to conventional pre-1992 discoveries. Inferred reserves (field growth) are recoverable resources in discovered fields beyond *current proved reserves* that are expected to be added in the future *as proved reserves*. Because proved reserves are reported in financial statements, commercial transactions, legal contracts, and in response to regulatory mandates by governmental entities, traditionally its definition reflects the highest degree of certainty about economically recoverable volumes of the resource in identified fields. Although worded slightly differently, standards of reporting proved reserves published by the Securities and Exchange Commission (1981), the Society of Petroleum Engineers (1987), and Energy Information Administration (1994) convey essentially the same narrow definition. The Energy Information Administration (1994) defines proved reserves as *estimated volumes of the resource which geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic, operating and, regulatory conditions. Reservoirs are proved if commercial producibility is supported by actual production or conclusive formation tests (drill stem or wire line), core analysis, and (or) electric or other log interpretations.*

Proved reserves increase with normal field development as boundaries of proved areas are extended by drilling; as new pay zones, pools, or reservoirs are found and confirmed by drilling; as new infill wells (vertical and horizontal) or well-stimulation procedures contact previously inaccessible hydrocarbons; and with the introduction of water-flood or other fluid-injection programs. Data used in calibrating cumulative growth functions (see earlier discussion) and estimating field growth, however, do not allow identification of the source of reserve additions with level of effort expended to increase reserves. Hence, costs were not definitively tied to either past or projected field growth.

Field-growth projections are also not very robust to changes in assumptions implicit in the calibration and application of the cumulative field growth function. The 1995 National Assessment, for example, assigned three times as much oil and gas to inferred reserves than the 1989 USGS Assessment (Mast and others, 1989). Part of the reason for this increase is that newly available data from the 1977-1991 period show some fields continuing to grow 90 years after discovery—well beyond the 60-year cutoff used in 1989 (see footnote 2). *In fact, if a 60-year field-growth cutoff is imposed on these data, the inferred oil estimate is about one-third of 1995 estimate and the gas estimate is one-half of the 1995 estimate.* The shape of the cumulative growth function is also sensitive to the sample period used in calibration (National Petroleum Council, 1992, p. 45–46).

Fields are not well-defined entities and, as a fundamental unit of observation, are frequently defined in an ad hoc manner for the convenience of regulatory agencies or of operators, or they are simply artifacts of the historical discovery process. If the unit of observation is narrowed to the level of the pool, as it is in Canada, reserve growth is limited to extensions, infill drilling, well stimulation, and efforts to enhance recovery. On average, pools reach full development earlier than fields. Cumulative growth functions calibrated with Canadian data on pools show gas pools reached 85 percent of full size 7 years after discovery and oil pools reached 85 percent of full size 27 years after discovery (K. Drummond, National Energy Board of Canada, written commun., 1996). In contrast, U.S. gas fields did not attain 85 percent of their 90-year size until 61 years, and oil fields did not attain 85 percent of their 90-year size until 66 years after discovery. Growth is sustained over a longer time period in oil accumulations than in gas accumulations. The low initial recovery of oil, typically less than 35 percent of in situ hydrocarbons rather than the 70 to 80 percent for gas fields, makes the remaining oil an attractive target for progressively more intensive development efforts, particularly for very large fields.

The unknown effects of model specification and errors in the data have not been sufficiently formalized to quantify the uncertainty in projected field-growth estimates. Costs were not estimated because past or projected future field growth could not be related to specific development efforts.[3] However, within a province, continuing simultaneous new field exploration, field development, and investment in pre-1992 discoveries indicates costs associated with the marginal quantities of oil and gas produced in each project are comparable. In order to study potential reserves that might be available for production during the next 2 decades, inferred reserve projections from 1994 through 2015 were calculated. Projected field-growth reserve additions through 2015 amount to about one-half the total oil and gas projected through 2071 (see U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995).

FIELD GROWTH THROUGH 2015: A COMPARATIVE ANALYSIS

Figure 12 shows regional estimates of proved reserves, projected oil growth though 2015, and estimated oil from undiscovered conventional oil fields and continuous-type accumulations with incremental costs of $30 per barrel ($3.34 per mcf). Figure 13 is similar but shows amounts of non-associated gas. Only the non-associated gas growth in the Cook Inlet area was projected for Alaska because gas is not under development in the Northern Alaska province. Proved reserve estimates, prepared by the Energy Information Administration (1994), are as of January 1994 and include proved reserves of oil and gas from conventional fields, continuous-type accumulations, and coal-bed gas. Field-growth projections from pre-1992 discoveries started

[3]Investments in field development and enhanced recovery are site specific, so the technical characteristics of the discovered pools or fields must be known in some detail to choose among alternative technologies. One approach is to develop a series of sceening criteria and engineering cost models to apply to candidate fields to a priori estimate costs of future growth in reserves. Such an approach was used by Bowers and Drummond (1994) and the National Petroleum Council (1984).

in 1994. Figures 12 and 13 are useful because they show quantities and sources of oil and gas that could be available for production during the next 2 decades through 2015.

Overall, projected growth (of pre-1992 oil discoveries) through 2015 accounts for about 44 percent of the 69 BB of the crude oil represented by regions and sources shown in figure 12. Proved reserves account for 29 percent, and economic oil discoveries and continuous-type accumulations accounted for the rest. Regional shares of oil growth in the lower 48 States mimic the pattern observed during the 1977 to 1991 data period. The Alaska, Pacific Coast, and West Texas and Eastern New Mexico Regions account for almost three-fourths of projected oil growth. The Gulf Coast Region has almost 30 percent of the oil discovered to date but accounts for only 5 percent of the projected growth (see fig. D-1, Appendix D). Its disproportionately low oil growth may result because the region has higher initial recovery of the in-place oil, leaving less oil for enhanced recovery.

Projected field growth (of pre-1992 gas discoveries) through 2015 accounts for about a quarter of the 381 TCF of non-associated gas represented in figure 13. Proved reserves account for 30 percent, and economic gas from new gas discoveries, continuous-type accumulations, and coal-bed gas account for 44 percent. In the lower 48 States, projected regional shares of growth almost duplicates the pattern observed for growth of non-associated gas during the 1977 to 1991 period. The Gulf Coast and Midcontinent Regions account for 80 percent of non-associated gas growth through 2015.

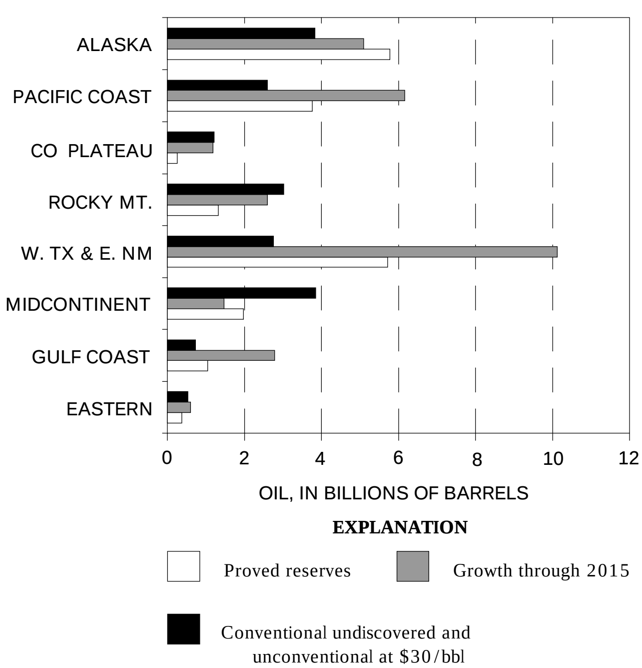


Figure 12. Estimates, as of January 1994, of proved crude oil reserves, projected crude oil reserve additions through 2015 for oil fields discovered before 1992, and the combined estimates of crude oil in undiscovered conventional oil fields and from continuous-type oil accumulations having incremental costs of $30 per barrel.

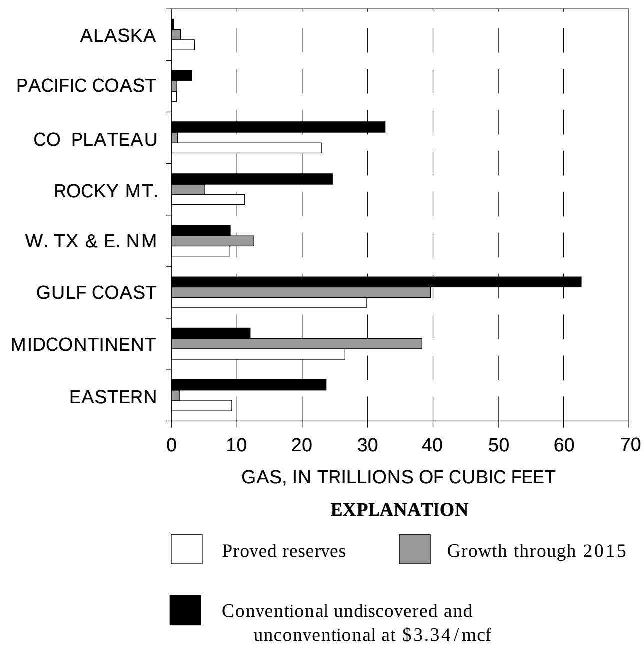


Figure 13. Estimates, as of January 1994, of proved non-associated gas reserves, projected non-associated gas reserve additions through 2015 for gas fields discovered before 1992, and the combined estimates of non-associated gas in undiscovered conventional gas fields and from continuous-type gas accumulations having incremental costs of $3.34 per thousand cubic feet.

In summary, quantities of oil and gas from field growth could account for 44 percent of the oil and a quarter of the non-associated gas available for production during the next 2 decades. Estimated quantities of oil are large but the deliverability or flow rates of the resource from enhanced recovery projects are typically inferior to flow rates that can be achieved in newly discovered conventional fields of comparable size. In comparison to assessed quantities of economic undiscovered oil resources, break-throughs in improvements in recovery efficiency of oil-in-place would make old fields into even more important sources of future domestic supplies than suggested above.

IMPLICATIONS AND LIMITATIONS

Several findings are worth further elaboration. The 1994 proved reserves of oil, non-associated gas, and total gas amount to roughly 10 times their 1994 production, respectively. Assuming this reserves-to-production ratio is sustained in the future, then, in order to maintain 1994 production through 2015 (that is, 22 years), additions to oil and gas reserves from field growth and economic undiscovered conventional and unconventional resources must amount to 42.8 BBO and 259.5 TCF non-associated gas (or 298.2 TCF total non-associated and associated gas). Even if the quantities projected from field growth are added to reserves during this time, expected total additions from economic undiscovered conventional and unconventional oil and gas at $18 per barrel ($2 per mcf) would not be enough to maintain 1994 production. When prices are $30 per barrel ($3.34 per mcf), projected growth and total reserve additions from economic oil and gas barely meet these requirements. Moreover, the development of newly discovered conventional fields would not likely add their entire ultimate recovery to proved reserves during this time period without greatly accelerated development. Projected reserve additions from pre-1992 discoveries (field growth) may also be optimistic—half of the hydrocarbons from field growth expected during the next 80 years were projected in the period to 2015. In summary, even though it appears possible with increases in real prices to $30 per barrel ($3.34 per mcf) to maintain production at levels comparable to that of 1994 production, this production level will be very difficult to achieve without significant improvements in exploration and production technology.

Analysis shows that gas from continuous-type accumulations and coal-bed gas can make significant contributions to supply and identifies provinces where this gas is currently produced at competitive costs. By virtue of the large quantity of technically recoverable unconventional gas assessed, its share of total gas supplies is expected to increase as prices increase. These accumulations are generally large, disperse, hydrocarbon resources. Extraction costs for unconventional gas are typically higher than costs for conventional accumulations; however, improvements in well-stimulation technology and practices could significantly increase the volume of resources that can be accessed by an individual well, and thus reduce unit costs.

The abundance of oil and gas produced from conventional fields at high flow rates in the early years of the twentieth century permitted the U.S. economy to move from coal to petroleum fuels as its basic energy source. However, the 1995 National Assessment showed that oil field growth and unconventional gas account for the largest quantities of estimated technically recoverable crude oil and gas resources. While there are some exceptions, reserve additions from these sources are not characterized by high deliverability. The characteristic of *deliverability* bridges the gap between economic reserves and actual production. Generally, lower quality resources require much larger amounts of capital to produce at the same level as high-flow-rate conventional resources. In particular, because their production characteristics are typically inferior to conventional accumulations of similar size, they require *larger amounts of proved reserves per unit of daily production*. Consequently, even though these resources meet the standards of economic reserves, they probably will not be produced rapidly.

Estimates of economic oil and gas from conventional undiscovered fields and unconventional plays were based on the mean or expected value reported in the geologic assessment. It is appropriate to use this point estimate in the computations and for ease of communicating results; however, it tends to convey a mistaken sense of precision in the results. The economic analysis could also have been prepared using distributions associated with the 5th or 95th fractiles of the assessment. Indeed, there is also uncertainty in the costs and technical relationships used in the economic analysis, as well as the field-growth analysis that is yet to be quantified.

Economic models are also limited in that they are abstractions designed to characterize a real economic system, but they are typically detailed enough to only roughly approximate the outcomes of interactions between economic agents. Only the general direction and the approximate magnitude of the reaction of the system to change can be modeled. Incremental cost functions are time independent and should not be confused with the firm supply functions that relate marginal cost to production per unit time period. Because of the time-independent nature of the incremental cost functions and the absence of market-demand conditions in the analysis, user costs or the opportunity costs of future resource use are not computed. However, the incremental cost functions and the data that underlie the functions can provide the basis for market-supply models.

For a national perspective, the resources estimated by the Minerals Management Service (1996) in undiscovered conventional oil and gas for the Federal Outer Continental Shelf (OCS) should be added to the estimates presented here. At $18 per barrel ($2 per mcf dry gas) the Minerals Management Service assessed a total of 14.4 BBO and 72.5 TCFG for the U.S. OCS. At $30 per barrel ($3.34 per mcf dry gas), economic resources were estimated at about 21 BBO and 100 TCFG. Alaska's OCS was assigned 3.8 BBO at $18 per barrel and about 6.6 BBO at $30 per barrel. Amounts of economic gas assigned to Alaska were very small. Based on the analysis presented here, for onshore and State water areas at the $18 per barrel ($2 per mcf) level, total economic oil and gas assessed in undiscovered conventional and unconventional accumulations was 9.3 BBO and 113 TCFG, respectively. At the higher price level, economic oil is estimated at 18.5 BBO and total gas is 196.3 TCFG.

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GLOSSARY OF SELECTED TERMS

barrels of oil equivalent (BOE).—gas volume and NGL volume that is expressed in terms of its energy equivalent in barrels of crude oil. For this assessment, 6,000 cubic feet of gas equals 1 barrel of crude oil, and 1 barrel of NGL equal 0.667 barrels of crude oil.

cell.—a subdivision of a continuous-type oil or gas play, the area of which is equivalent to the median drainage area of wells producing from the play. A productive cell has at least one well with reported production. A nonproductive cell is a cell that was evaluated with drilling but where none of the wells have reported production. An untested cell is one that has not been evaluated by a well. The number of cells in a play is equal to the area of the play divided by the cell area.

conditional estimates.—sizes, numbers, or volumes of oil or natural gas that are estimated to exist in an area, assuming that at least some oil and gas is present. Conditional estimates do not incorporate the risk that the area may be devoid of oil or natural gas.

continuous-type accumulation.—a hydrocarbon accumulation that is pervasive throughout a large area, that is not significantly affected by hydrodynamic influences, and for which the standard methodology for assessment of sizes and numbers of discrete accumulations is not appropriate.

conventional accumulations.—discrete deposits having a well-defined downdip oil or gas water contact, from which oil, gas, or NGL can be extracted using traditional development practices.

crude oil.—a mixture of hydrocarbons that exist in the liquid phase in underground reservoirs and remain liquid at atmospheric pressure after passing through surface separating facilities.

estimated ultimate recovery (EUR) probability distribution.—a probability distribution of ultimate recoveries of oil or gas that characterizes the distribution of gas recoveries in productive cells within a play. An *empirical EUR distribution* is based on the estimated ultimate recoveries of wells thought to be representative of the play's range of recoveries. The *reported EUR distribution for untested cells* is assigned by the geologist to represent the distribution of recoveries from potentially productive, but as of yet untested, cells within the play.

field.—an individual producing unit consisting of a single pool or multiple pools of hydrocarbons grouped on, or related to, a single structural or stratigraphic feature.

crude oil fields.—fields where the ratio of natural gas to crude oil is less than 20 thousand cubic feet of gas per barrel of crude oil.

non-associated gas fields.—fields where the ratio of natural gas to crude oil is at least 20 thousand cubic feet of gas per barrel of crude oil.

field growth (inferred reserves).–that part of identified conventional resources over and above proved (measured) reserves, expected to be added to existing conventional fields through extension, revision, improved efficiency, and addition of new pools or reservoirs.

gas-oil ratio (GOR).—average ratio of associated-dissolved gas to oil.

growth function.—cumulative growth function relates a multiple of a field's initially estimated size to the number of years after discovery. A field age of zero is assigned to the year of discovery. If the cumulative growth function has the property that older fields experience a smaller percentage of growth than younger fields, then the cumulative growth function is monotonic. An "annual growth function" expresses annual percentage field growth as a function of the estimated field size at the end of the previous year.

NGL to non-associated gas ratio.—volume of natural gas liquids (NGL), in barrels, contained in 1 million cubic feet of wet gas in a known or postulated gas accumulation.

NGL to associated-dissolved gas ratio.—volume of natural gas liquids, in barrels, in 1 million cubic feet of associated-dissolved wet gas in a known or postulated oil accumulation.

natural gas.—a mixture of hydrocarbon compounds and small quantities of non-hydrocarbons existing in 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.

natural gas liquids (NGL).—those hydrocarbons in natural gas that 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 natural gasoline or liquefied petroleum gases. After separation of natural gas liquids from the gas, the gas is called "dry."

play.—set of known or postulated oil and (or) gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration patterns, timing, trapping mechanism, and hydrocarbon type.

confirmed plays.—plays where one or more accumulations of minimum size (1 million barrels of oil or 6 billion cubic feet of gas) have been discovered in the play.

hypothetical plays.—plays identified and defined based on geologic information but for which no accumulations at minimum size (1 MMBO or 6 BCFG) have, as yet, been discovered.

play attributes.—geologic characteristics thought to characterize the principal elements necessary for occurrence of oil and (or) gas accumulations of some minimum size. Attributes used in this assessment (charge, reservoir, and trap) are defined as:

charge.—occurrence of conditions of hydrocarbon generation and migration adequate to cause an accumulation of the minimum size. Subsidiary elements of charge are source rocks with sufficient organic matter, temperature, and duration of heating for expulsion of sufficient quantities of oil and (or) gas and timing of expulsion of hydrocarbons to available traps.

reservoir.—occurrence of reservoir rocks of sufficient quantity and quality to permit containment of oil and (or) gas in volumes sufficient for an accumulation of the minimum size.

trap.—occurrence of those structures, pinch-outs, permeability changes, and similar features necessary for the entrapment and sealing of hydrocarbons in at least one accumulation of the minimum size.

play probability.—for recoverable resources, represents the likelihood that technically recoverable quantities of oil or natural gas exist in at least one undiscovered accumulation of the minimum size (1 MMBO or 6 BCFG) in the play being assessed.

proved (measured) reserves.—estimated quantities of crude oil, natural gas, or natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Reserves are proved if economic productivity is supported by actual production or conclusive formation tests (drill stem or wireline), or if economic producibility is supported by core analyses and (or) electric or other log interpretations.

reservoir.—a porous and permeable underground formation containing an individual and separate accumulation of producible hydrocarbons that is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.

risked (unconditional) estimates.—resources estimated to exist, including the possibility that the area of the play may be devoid of oil or natural gas. For example, the risked mean may be determined by multiplication of the mean of a conditional distribution by the related probability of occurrence. Resource estimates presented in this report are risked estimates.

technically recoverable.—estimated to be producible using current technology but without reference to economic profitability.

ultimate field size (known recovery).—the sum of cumulative past production and estimated current reserves.

unconventional oil and gas accumulations.—a broad class of hydrocarbon deposits of a type that traditionally have not been produced using standard development practices. Unconventional deposits include continuous-type oil and gas accumulations and coal-bed gas. Standard definitions of unconventional oil and gas accumulations often hinge on gravity of oil or the permeability of the oil and gas reservoir rock. Even though most continuous-type accumulations are characterized by poor reservoir permeability, not all low-permeability deposits are continuous-type accumulations.

undiscovered resources.—resources postulated from geologic information and theory to exist outside of known oil and (or) gas fields.

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APPENDIX A—TABLES OF PROVINCE-LEVEL CONVENTIONAL UNDISCOVERED RESOURCE ESTIMATES

Table A-1. Mean values of undiscovered technically recoverable conventional oil, gas,* and natural gas liquids (NGL) in onshore and State offshore areas of U.S. oil and gas fields as of January 1994.

[MMBO, millions of barrels of oil; BCF, billions of cubic feet; MMBL, millions of barrels]

Province number and name**	Oil fields			Gas fields	
	Oil (MMBO)	Gas (BCF)	NGL (MMBL)	Gas (BCF)	NGL (MMBL)
Region 1—Alaska					
001 Northern Alaska	7,399	5,933	127	57,620	1,024
002 Central Alaska	63	63	0	2,700	0
003 Southern Alaska	964	964	0	1,196	0
TOTAL, Region 1	8,426	6,960	127	61,516	1,024
Region 2—Pacific Coast					
004 Western Oregon-Wash	25	37	2	759	0
005 Eastern Oregon-Wash	0	0	0	392	1
007 Northern Coastal	30	10	0	1,074	0
008 Sonoma-Livermore Basin	9	9	0	53	0
009 Sacramento Basin	2	0	0	3,328	9
010 San Joaquin Basin	1,214	2,027	105	537	0
011 Central Coastal	493	147	5	5	0
012 Santa Maria Basin	210	123	10	0	0
013 Ventura Basin	1,064	1,064	34	834	33
014 Los Angeles Basin	977	1,605	56	0	0
TOTAL, Region 2	4,024	5,022	212	6,982	43
Region 3—Colorado Plateau and Basin and Range					
017 Idaho-Snake R. Downwarp	1	0	0	12	0
018 W. Great Basin	1	0	0	5	0
019 E. Great Basin	488	78	1	261	6
020 Uinta-Piceance Basin	211	1,737	64	2,791	12
021 Paradox Basin	307	750	78	1,234	9
022 San Juan Basin	162	293	6	661	25
023 Albuquerque-Santa Fe Rift	45	86	3	267	16
024 N. Arizona	65	41	2	133	13
025 S. Ariz.-S.W. New Mexico	24	2	0	203	20
TOTAL, Region 3	1,304	2,987	154	5,567	101
Region 4—Rocky Mountains and Northern Great Plains					
027 Montana Thrust Belt	4	4	0	1,919	6
028 Central Montana	268	97	2	749	0
029 S.W. Montana	27	25	1	382	2
031 Williston Basin	663	720	54	1,003	125
033 Powder River Basin	1,938	1,220	77	401	24
034 Big Horn Basin	387	69	2	553	11
035 Wind River Basin	155	310	8	929	6
036 Wyoming Thrust Belt	625	2,459	383	8,222	784
037 S.W. Wyoming	167	333	4	1,242	22
038 Park Basins	30	19	0	0	0
039 Denver Basin	228	192	20	563	6
040 Las Animas Arch	137	113	3	418	11
041 Raton Basin-Sierra Grande Uplift	0	0	0	42	1
TOTAL, Region 4	4,629	5,561	554	16,423	998

Table A-1. Mean values of undiscovered technically recoverable conventional oil, gas,* and natural gas liquids (NGL) in onshore and State offshore areas of U.S. oil and gas fields as of January 1994—*Continued.*

Province number and name**	Oil fields: Oil (MMBO)	Oil fields: Gas (BCF)	Oil fields: NGL (MMBL)	Gas fields: Gas (BCF)	Gas fields: NGL (MMBL)
Region 5—West Texas and Eastern New Mexico					
043 Palo Duro Basin	33	3	0	6	0
044 Permian Basin	2,882	4,294	441	12,108	200
045 Bend Arch-Ft. Worth Basin	638	802	48	1,350	98
046 Marathon Thrust Belt	17	45	4	104	6
TOTAL, Region 5	3,570	5,144	493	13,568	304
Region 6—Gulf Coast					
047 Western Gulf	2,287	6,124	195	62,287	1,631
049 Louisiana-Mississippi Salt Basins	2,685	4,008	159	25,562	1,340
050 Florida Peninsula	419	40	0	0	0
TOTAL, Region 6	5,391	10,172	354	87,849	2,971
Region 7—Midcontinent					
051 Superior	53	32	0	387	0
053 Cambridge Arch-Central Kansas	203	286	16	128	3
055 Nemaha Uplift	123	352	25	123	3
056 Forest City Basin	22	66	4	0	0
058 Anadarko Basin	383	1,808	75	12,398	143
059 Sedgwick Basin	61	165	14	134	1
060 Cherokee Basin	77	133	10	52	1
061 Southern Oklahoma	241	385	19	629	7
062 Arkoma Basin	11	18	1	2,477	93
TOTAL, Region 7	1,174	3,245	164	16,328	251
Region 8—Eastern					
063 Michigan Basin	1,113	1,995	136	4,152	146
064 Illinois Basin	255	192	0	312	0
065 Black Warrior Basin	34	17	0	2,012	8
066 Cincinnati Arch	18	18	0	0	0
067 Appalachian Basin	106	121	1	2,298	3
068 Blue Ridge Thrust Belt	0	0	0	30	0
069 Piedmont	0	0	0	390	0
TOTAL, Region 8	1,526	2,343	137	9,194	157
TOTAL, UNITED STATES	30,044	41,434	2,195	217,427	5,849

* Gas quantities are dry and do not include NGL.

** Provinces not listed include the Klamath-Sierra Nevada (006) and Salton Trough (016), where no resources were assigned; South-Central New Mexico (026), Sioux Arch (032), Pedernal Uplift (042), Iowa Shelf (052), and Ozark Uplift (057), where negligible resources were assessed; and the San Diego-Oceanside (015), which was assessed by Minerals Management Service. The assessment of the East Texas Basin (048) is included in the values shown for the Louisiana-Mississippi Salt Basins (049), and the assessment for the Salina Basin (054) is included in the values shown for the Sedgwick Basin (059).

Table A-2. Oil, gas,* and natural gas liquids (NGL) in undiscovered conventional oil and gas fields in onshore and State offshore areas of the United States with incremental costs of $18 per barrel oil and $2 per thousand cubic feet gas as of January 1994.

[MMBO, millions of barrels of oil; BCF, billions of cubic feet; MMBL, millions of barrels. See footnote **, table A-1, regarding provinces not listed]

Province number and name	Oil fields: Oil (MMBO)	Oil fields: Gas (BCF)	Oil fields: NGL (MMBL)	Gas fields: Gas (BCF)	Gas fields: NGL (MMBL)
Region 1—Alaska					
001 Northern Alaska	592	592	9	0	0

Table A-2. Oil, gas,* and natural gas liquids (NGL) in undiscovered conventional oil and gas fields in onshore and State offshore areas of the United States with incremental costs of $18 per barrel oil and $2 per thousand cubic feet gas as of January 1994—*Continued.*

Province number and name	Oil fields			Gas fields	
	Oil (MMBO)	Gas (BCF)	NGL (MMBL)	Gas (BCF)	NGL (MMBL)
Region 1—Alaska *(Continued)*					
002 Central Alaska	0	0	0	0	0
003 Southern Alaska	321	321	0	120	0
TOTAL, Region 1	913	913	9	120	0
Region 2—Pacific Coast					
004 Western Oregon-Wash.	0	0	0	0	0
005 Eastern Oregon-Wash.	0	0	0	0	0
007 Northern Coastal	0	0	0	0	0
008 Sonoma-Livermore Basin	9	9	0	53	0
009 Sacramento Basin	0	0	0	740	2
010 San Joaquin Basin	549	880	45	138	0
011 Central Coastal	149	36	1	0	0
012 Santa Maria Basin	8	5	0	0	0
013 Ventura Basin	482	482	16	269	11
014 Los Angeles Basin	472	793	28	0	0
TOTAL, Region 2	1,669	2,206	91	1,201	13
Region 3—Colorado Plateau and Basin and Range					
017 Idaho-Snake R. Downwarp	0	0	0	0	0
018 W. Great Basin	0	0	0	0	0
019 E. Great Basin	225	33	0	47	1
020 Uinta-Piceance Basin	169	1,395	51	1,112	5
021 Paradox Basin	100	226	22	214	0
022 San Juan Basin	79	154	3	294	11
023 Albuquerque-Santa Fe Rift	0	0	0	0	0
024 N. Arizona	0	0	0	0	0
025 S. Ariz.-S.W. New Mexico	0	0	0	0	0
TOTAL, Region 3	572	1,807	77	1,667	17
Region 4—Rocky Mountains and Northern Great Plains					
027 Montana Thrust Belt	1	0	0	914	3
028 Central Montana	33	12	0	92	0
029 S.W. Montana	0	0	0	0	0
031 Williston Basin	130	146	11	270	38
033 Powder River Basin	666	400	25	0	0
034 Big Horn Basin	229	30	1	106	1
035 Wind River Basin	48	134	4	133	1
036 Wyoming Thrust Belt	506	2,055	321	6,576	635
037 S.W. Wyoming	22	53	48	104	2
038 Park Basins	0	0	0	0	0
039 Denver Basin	4	3	0	2	0
040 Las Animas Arch	92	77	2	275	7
041 Raton Basin-Sierra Grande Uplift	0	0	0	0	0
TOTAL, Region 4	1,730	2,911	411	8,473	688
Region 5—West Texas and Eastern New Mexico					
043 Palo Duro Basin	0	0	0	0	0
044 Permian Basin	1,950	2,914	300	5,889	120
045 Bend Arch-Ft. Worth Basin	72	86	5	181	13
046 Marathon Thrust Belt	0	0	0	0	0
TOTAL, Region 5	2,023	3,000	305	6,070	133
Region 6—Gulf Coast					
047 Western Gulf	1,039	2,794	93	31,939	795

Table A-2. Oil, gas,* and natural gas liquids (NGL) in undiscovered conventional oil and gas fields in onshore and State offshore areas of the United States with incremental costs of $18 per barrel oil and $2 per thousand cubic feet gas as of January 1994—*Continued.*

Province number and name	Oil fields			Gas fields	
	Oil (MMBO)	Gas (BCF)	NGL (MMBL)	Gas (BCF)	NGL (MMBL)
Region 6—Gulf Coast *(Continued)*					
049 Louisiana-Mississippi Salt Basins	475	707	24	4,960	187
050 Florida Peninsula	253	24	0	0	0
TOTAL, Region 6	1,767	3,525	117	36,899	982
Region 7—Midcontinent					
051 Superior	9	5	0	47	0
053 Cambridge Arch-Central Kansas	24	33	2	18	0
055 Nemaha Uplift	18	52	4	13	0
056 Forest City Basin	0	0	0	0	0
058 Anadarko Basin	189	896	37	4,824	64
059 Sedgwick Basin	12	31	3	15	0
060 Cherokee Basin	15	28	2	7	0
061 Southern Oklahoma	60	92	5	63	1
062 Arkoma Basin	2	3	0	1,360	50
TOTAL, Region 7	329	1,141	52	6,347	116
Region 8—Eastern					
063 Michigan Basin	176	252	18	453	16
064 Illinois Basin	35	26	0	3	0
065 Black Warrior Basin	4	2	0	229	1
066 Cincinnati Arch	0	0	0	0	0
067 Appalachian Basin	23	12	0	250	0
068 Blue Ridge Thrust Belt	0	0	0	0	0
069 Piedmont	0	0	0	0	0
TOTAL, Region 8	237	292	19	935	18
TOTAL, UNITED STATES	9,239	15,795	1,081	61,710	1,967

* Gas quantities are dry and do not include NGL.

Table A-3. Oil, gas,* and natural gas liquids (NGL) in undiscovered conventional oil and gas fields in onshore and State offshore areas of the United States with incremental costs of $30 per barrel oil and $3.34 per thousand cubic feet gas as of January 1994.

[MMBO, millions of barrels of oil; BCF, billions of cubic feet; MMBL, millions of barrels. See footnote **, table A-1, regarding provinces not listed]

Province number and name	Oil fields			Gas fields	
	Oil (MMBO)	Gas (BCF)	NGL (MMBL)	Gas (BCF)	NGL (MMBL)
Region 1—Alaska					
001 Northern Alaska	3,332	2,777	58	0	0
002 Central Alaska	0	0	0	0	0
003 Southern Alaska	496	496	0	283	0
TOTAL, Region 1	3,828	3,273	58	283	0
Region 2—Pacific Coast					
004 Western Oregon-Wash.	0	1	0	35	0
005 Eastern Oregon-Wash.	0	0	0	0	0
007 Northern Coastal	4	1	0	94	0
008 Sonoma-Livermore Basin	9	9	0	53	0
009 Sacramento Basin	0	0	0	1,779	5
010 San Joaquin Basin	884	1,450	75	302	0
011 Central Coastal	263	73	3	0	0
012 Santa Maria Basin	39	23	2	0	0

Table A-3. Oil, gas,* and natural gas liquids (NGL) in undiscovered conventional oil and gas fields in onshore and State offshore areas of the United States with incremental costs of $30 per barrel oil and $3.34 per thousand cubic feet gas as of January 1994—*Continued.*

Province number and name		Oil fields			Gas fields	
		Oil (MMBO)	Gas (BCF)	NGL (MMBL)	Gas (BCF)	NGL (MMBL)
	Region 2—Pacific Coast *(Continued)*					
013	Ventura Basin	697	697	22	463	19
014	Los Angeles Basin	695	1,159	41	0	0
TOTAL, Region 2		2,590	3,413	143	2,726	24
	Region 3—Colorado Plateau and Basin and Range					
017	Idaho-Snake R. Downwarp	0	0	0	0	0
018	W. Great Basin	0	0	0	0	0
019	E. Great Basin	323	49	1	93	2
020	Uinta-Piceance Basin	193	1,546	56	1,963	9
021	Paradox Basin	188	442	45	492	2
022	San Juan Basin	127	231	4	481	18
023	Albuquerque-Santa Fe Rift	2	3	0	20	1
024	N. Arizona	7	4	0	13	1
025	S. Ariz.-S.W. New Mexico	0	0	0	0	0
TOTAL, Region 3		840	2,275	106	3,062	33
	Region 7—Rocky Mountains and Northern Great Plains					
027	Montana Thrust Belt	1	1	0	1,254	4
028	Central Montana	121	43	1	373	0
029	S.W. Montana	0	0	0	0	0
031	Williston Basin	368	405	30	540	77
033	Powder River Basin	1,242	756	47	78	5
034	Big Horn Basin	317	51	1	285	5
035	Wind River Basin	88	201	5	343	2
036	Wyoming Thrust Belt	565	2,262	353	7,237	697
037	S.W. Wyoming	79	172	149	415	8
038	Park Basins	0	0	0	0	0
039	Denver Basin	77	63	6	124	2
040	Las Animas Arch	116	96	2	346	9
041	Raton Basin-Sierra Grande Uplift	0	0	0	0	0
TOTAL, Region 4		2,975	4,049	596	10,996	808
	Region 5—West Texas and Eastern New Mexico					
043	Palo Duro Basin	0	0	0	0	0
044	Permian Basin	2,421	3,604	371	8,300	156
045	Bend Arch-Ft. Worth Basin	327	403	24	699	51
046	Marathon Thrust Belt	0	0	0	0	0
TOTAL, Region 5		2,748	4,007	395	8,999	206
	Region 6—Gulf Coast					
047	Western Gulf	1,581	4,197	138	44,018	1,095
049	Louisiana-Mississippi Salt Basins	1,302	1,949	67	13,193	532
050	Florida Peninsula	290	28	0	0	0
TOTAL, Region 6		3,174	6,173	205	57,211	1,627
	Region 7—Midcontinent					
051	Superior	23	14	0	124	0
053	Cambridge Arch-Central Kansas	139	195	11	83	2
055	Nemaha Uplift	62	180	13	53	1
056	Forest City Basin	1	4	0	0	0
058	Anadarko Basin	280	1,325	55	7,676	98
059	Sedgwick Basin	39	104	9	65	0
060	Cherokee Basin	39	72	5	20	1
061	Southern Oklahoma	140	219	11	187	3

Table A-3. Oil, gas,* and natural gas liquids (NGL) in undiscovered conventional oil and gas fields in onshore and State offshore areas of the United States with incremental costs of $30 per barrel oil and $3.34 per thousand cubic feet gas as of January 1994—*Continued.*

Province number and name	Oil fields			Gas fields	
	Oil (MMBO)	Gas (BCF)	NGL (MMBL)	Gas (BCF)	NGL (MMBL)
Region 7—Midcontinent *(Continued)*					
062 Arkoma Basin	4	6	0	1,740	65
TOTAL, Region 7	727	2,119	105	9,949	170
Region 8—Eastern					
063 Michigan Basin	325	470	35	1,120	39
064 Illinois Basin	140	105	0	12	0
065 Black Warrior Basin	16	8	0	832	4
066 Cincinnati Arch	0	0	0	0	0
067 Appalachian Basin	55	29	0	716	1
068 Blue Ridge Thrust Belt	0	0	0	0	0
069 Piedmont	0	0	0	0	0
TOTAL, Region 8	535	612	35	2,680	43
TOTAL, UNITES STATES	17,417	25,922	1,643	95,904	2,912

* Gas quantities are dry and do not include NGL.

Table A-4. Conventional field-size class definitions.

Class	Oil field size (millions of barrels)	Gas field size (billions of cubic feet)
1	0.03125–0.0625	0.1875–0.375
2	0.0625–0.125	0.375–0.750
3	0.125–0.25	0.75–1.50
4	0.25–0.5	1.50–3.00
5	0.5–1	3–6
6	1–2	6–12
7	2–4	12–24
8	4–8	24–48
9	8–16	48–96
10	16–32	96–192
11	32–64	192–384
12	64–128	384–768
13	128–256	768–1,536
14	256–512	1,536–3,072
15	512–1,024	3,072–6,144
16	1,024–2,048	6,144–12,288
17	2,048–4,096	12,288–24,576
18	4,096–8,192	24,576–49,152

APPENDIX B—TABLES SHOWING REGIONS, PROVINCES, PROVINCE NUMBERS, AND PLAY NUMBERS FOR CONTINUOUS-TYPE PLAYS AND COAL-BED GAS PLAYS

Table B-1. List of petroleum provinces of onshore and State offshore areas in the conterminous United States.

Province number	Province name
Region 2—Pacific Coast	
004	Western Oregon-Washington
005	Eastern Oregon-Washington
006	Klamath-Sierra Nevada
007	Northern Coastal
008	Sonoma-Livermore Basin
009	Sacramento Basin
010	San Joaquin Basin
011	Central Coastal
012	Santa Maria Basin
013	Ventura Basin
014	Los Angeles Basin
015	San Diego-Oceanside
016	Salton Trough
Region 3—Colorado Plateau and Basin and Range	
017	Idaho-Snake River Downwarp
018	Western Great Basin
019	Eastern Great Basin
020	Uinta-Piceance Basin
021	Paradox Basin
022	San Juan Basin
023	Albuquerque-Santa Fe Rift
024	Northern Arizona
025	Southern Arizona-South West New Mexico
026	South-Central New Mexico
Region 4—Rocky Mountains and Northern Great Plains	
027	Montana Thrust Belt
028	Central Montana
029	Southwest Montana
031	Williston Basin
032	Sioux Arch
033	Powder River Basin
034	Big Horn Basin
035	Wind River Basin
036	Wyoming Thrust Belt
037	Southwest Wyoming
038	Park Basins
039	Denver Basin
040	Las Animas Arch
041	Raton Basin-Sierra Grande Uplift
Region 5—West Texas and Eastern New Mexico	
042	Pedernal Uplift
043	Palo Duro Basin
044	Permian Basin
045	Bend Arch-Fort Worth Basin
046	Marathon Thrust Belt
Region 6—Gulf Coast	
047	Western Gulf
048	East Texas Basin
049	Louisiana - Mississippi Salt Basins
050	Florida Peninsula
Region 7—Midcontinent	
051	Superior
052	Iowa Shelf
053	Cambridge Arch-Central Kansas
054	Salina Basin
055	Nemaha Uplift
056	Forest City Basin
057	Ozark Uplift
058	Anadarko Basin
059	Sedgwick Basin
060	Cherokee Basin
061	Southern Oklahoma
062	Arkoma Basin
Region 8—Eastern	
063	Michigan Basin
064	Illinois Basin
065	Black Warrior Basin
066	Cincinnati Arch
067	Appalachian Basin
068	Blue Ridge Thrust Belt
069	Piedmont

Table B-2. Provinces, play numbers, and play names for continuous-type gas plays assessed in the 1995 USGS National Oil and Gas Assessment.

Province	Play number	Play name
Eastern Oregon-Washington	503	Columbia Basin—Basin-Centered Gas
Uinta-Piceance Basin	2007	Tight Gas Piceance Mesaverde Williams Fork
Uinta-Piceance Basin	2010	Tight Gas Piceance Mesaverde Iles
Uinta-Piceance Basin	2015	Tight Gas Uinta Tertiary East
Uinta-Piceance Basin	2016	Tight Gas Uinta Tertiary West
Uinta-Piceance Basin	2018	Basin Flank Uinta Mesaverde
Uinta-Piceance Basin	2020	Deep Synclinal Uinta Mesaverde
San Juan Basin	2205	Dakota Central Basin Gas
San Juan Basin	2209	Central Basin Mesaverde Gas
San Juan Basin	2211	Pictured Cliffs Gas
Central Montana	2810	Northern Great Plains Biogenic Gas, High Potential
Central Montana	2811	Northern Great Plains Biogenic Gas, Moderate Potential (Suffield block analog)
Central Montana	2812	Northern Great Plains Biogenic Gas, Low Potential
Williston Basin	3113	Southern Williston Basin Margin—Niobrara Shallow Biogenic
Southwestern Wyoming	3740	Greater Green River Basin—Cloverly-Frontier
Southwestern Wyoming	3741	Greater Green River Basin—Mesaverde
Southwestern Wyoming	3742	Greater Green River Basin—Lewis
Southwestern Wyoming	3743	Greater Green River Basin—Fox Hills-Lance
Southwestern Wyoming	3744	Greater Green River Basin—Fort Union
Denver Basin	3906	J Sandstone Deep Gas (Wattenberg)
Louisiana-Miss. Salt Basins	4923	Cotton Valley Blanket Sandstones Gas
Michigan Basin	6319	Antrim Shale Gas, Developed Area
Michigan Basin	6320	Antrim Shale Gas, Undeveloped Area
Illinois Basin	6407	Illinois Basin—New Albany Shale Gas
Cincinnati Arch	6604	Devonian Black Shale Gas
Appalachian Basin	6728	Clinton/Medina Sandstone Gas High Potential
Appalachian Basin	6729	Clinton/Medina Sandstone Gas Medium Potential
Appalachian Basin	6730	Clinton/Medina Sandstone Gas Medium-Low Potential
Appalachian Basin	6733	Upper Devonian Sandstone Gas High Potential
Appalachian Basin	6734	Upper Devonian Sandstone Gas Medium Potential
Appalachian Basin	6735	Upper Devonian Sandstone Gas Medium-Low Potential
Appalachian Basin	6740	Devonian Black Shale—Greater Big Sandy
Appalachian Basin	6741	Devonian Black Shale—Greater Siltstone Content
Appalachian Basin	6742	Devonian Black Shale—Lower Thermal Maturity

Table B-3. Provinces, play numbers, and play names for continuous-type oil plays assessed in the 1995 USGS National Oil and Gas Assessment.

Province	Play number	Play name
Uinta-Piceance Basin	2009	Cretaceous Self-Sourced Fractured Shales
Paradox Basin	2103	Fractured Interbed
San Juan Basin	2208	Mancos Fractured Shale
Central Montana	2804	Bakken Shale Fracture Systems
Williston Basin	3110	Bakken Fairway
Williston Basin	3111	Bakken Intermediate
Williston Basin	3112	Bakken Outlying
Denver Basin	3904	Greater Wattenberg Codell/Niobrara Oil and Gas
Denver Basin	3920	Fractured Niobrara-Greater Silo/Dale Salt-Edge Oil
Denver Basin	3921	Fractured Niobrara-Greater Northern Denver Basin Oil
Western Gulf	4747	Austin Chalk-Pearsall
Western Gulf	4748	Austin Chalk-Giddings
Western Gulf	4749	Austin Chalk-Outlying

Table B-4. Provinces, play numbers, and play names for coal-bed gas plays assessed in the 1995 USGS National Oil and Gas Assessment.

Province	Play number	Play name
W. Oregon-Washington	450	Bellingham
W. Oregon-Washington	451	W. Cascade Mountains
W. Oregon-Washington	452	Southern Puget Lowlands
Uinta-Piceance	2050	Uinta—Book Cliffs
Uinta-Piceance	2051	Uinta—Sego
Uinta-Piceance	2052	Uinta—Emery
Uinta-Piceance	2053	Piceance—White River Dome
Uinta-Piceance	2054	Piceance—Western Basin Margin
Uinta-Piceance	2055	Piceance—Grand Hogback
Uinta-Piceance	2056	Piceance—Divide Creek Anticline
San Juan	2250	Overpressured
San Juan	2252	Underpressured Discharge
San Juan	2253	Underpressured
Powder River	3350	Shallow Mining Related
Powder River	3351	Central Basin
Wind River	3550	Mesaverde
Southwestern Wyoming	3750	Rock Springs
Southwestern Wyoming	3751	Iles
Southwestern Wyoming	3752	Williams Fork
Southwestern Wyoming	3753	Almond
Southwestern Wyoming	3754	Lance
Southwestern Wyoming	3755	Fort Union
Raton	4150	Northern Raton
Raton	4151	Purgtoire River
Raton	4152	Southern Raton
Forest City	5650	Central Basin
Cherokee Platform	6050	Central Basin
Arkoma	6250	Anticline
Arkoma	6251	Syncline
Illinois	6450	Central Basin
Black Warrior	6550	Recharge
Black Warrior	6551	Southeastern Basin
Black Warrior	6552	Coastal Plain
Black Warrior	6553	Central and Western Basin
Appalachian	6750	Northern Appalachian Anticline
Appalachian	6751	Northern Appalachian Syncline
Appalachian	6752	Central Appalachian
Appalachian	6753	Canhaba Field

APPENDIX C—METHODOLOGY

UNDISCOVERED CONVENTIONAL OIL AND GAS RESOURCES

Geologists assessed conventional undiscovered accumulations having technically recoverable hydrocarbons of at least 1 million barrels of oil (MMBO) or 6 billion cubic feet of gas (BCFG) *at the play level* (see Gautier and Dolton, 1995, for more detail). Initial play definitions were based on the assessor's interpretations of the geology and hydrocarbon generation, past discovery information, and past drilling information. Each play definition included a description of the geographic location and geologic characteristics of the play (see Gautier and others, 1995, for play descriptions). In the case of *confirmed plays*, that is plays already having discoveries of at least 1 MMBO or 6 BCFG, the geologist reviewed drilling penetration maps and historical discovery data. For confirmed plays, a *play probability* of 1.0 was assigned. In cases where the geologist posited a hypothetical play, the play probability was computed as the product of the occurrence probabilities of the three play attributes of *charge*, *reservoir*, and *trap.* The play probability is multiplied by conditional resource estimates, which assumed the occurrence of the threshold quantity of oil or gas remained.

The size distribution of undiscovered accumulations for each play was modeled with a Truncated Shifted Pareto (TSP) distribution (Houghton and others, 1993). The geologist chose a median and shape class for the TSP distribution along with the minimum (95 percent), median (50 percent), and largest (5 percent) *numbers* of undiscovered accumulations. The assessor also chose a minimum, median, and maximum depth for remaining resources in the play. Simulations were used to combine distributions of size and numbers of undiscovered accumulations to generate field size-frequency distributions and to estimate the fractiles of the quantities of oil, associated gas, associated gas liquids, non-associated gas, and non-associated gas liquids. For an individual province, dependencies among plays were characterized by pairwise correlations. Simulations were used to aggregate plays to the province level.

At the province level, the size-frequency distribution of undiscovered "small fields," that is fields smaller than 1 MMBO (or 6 BCFG), was derived with a statistical extrapolation procedure described by Root and Attanasi (1993). The underlying assumption is the province size-frequency distribution of small fields can be described with a log-geometric size distribution. The minimum estimated field size of the smallest field-size class for which numbers of fields were estimated was 32,000 barrels oil or 192,000 cubic feet gas.

The economic analysis of province assessments used the discrete size-frequency distributions of expected (mean) numbers of undiscovered oil and gas fields classified by 5,000-ft depth intervals. Table A-4, Appendix A, shows field size classification for undiscovered conventional oil and gas fields. Province-specific data, such as gas-to-oil ratios and natural-gas-liquids-to-natural-gas ratios and expected sulfur levels, were derived from data provided by the geologic play assessments. Field size, depth, regional costs, and co-product ratios as well as well-head prices and hurdle rate of return determine whether a new discovery will be commercially developable.

The incremental cost algorithm used a finding-rate model to predict, for successive increments of wildcat wells, the size distribution and depths of new oil and gas field discoveries at the province level. Economic analysis of the newly discovered fields of specific size and depth categories is a standard application of discounted cash flow (DCF) analysis. The net after-tax cash flow consists of revenues from the production of oil and (or) gas less the operating costs, capital costs in the year incurred, and all taxes. All new discoveries of a particular size and depth class are assumed to be developed if the representative field is found to be commercially developable, that is, if it has an after-tax net present value greater than zero, where the discount rate includes a hurdle rate representing the cost of capital and the industry's required return. When field-production decline causes operator income to decline to the sum of direct operating costs and the operator's production-related taxes, the economic limit rate is reached and field production stops. Newly discovered commercially developable fields are aggregated to provide an estimate of potential reserves from undiscovered fields at a given price and required rate of return. Additional increments of, for example, 100 wildcat wells are assumed to be drilled until the costs of drilling wildcat wells are equal to or greater than the after-tax net present value of the commercially developed fields discovered by that increment of wildcat wells.

The basis for the estimates of recoverable undiscovered petroleum as a function of price is that incremental units of exploration, development, and production effort will not take place unless the revenues expected to be received from the eventual production will cover the incremental costs, including a normal return on the incremental investment. Also, for the last increment of oil and gas produced from a field, operating costs (including production-related taxes) per barrel of oil equivalent are equal to price. These two assumptions together imply that, for the commercially developable resources discovered by the last economic increment of wildcat wells, the sum of finding costs and development and production costs per barrel (that is, the "incremental cost of the barrel") is equal to the well-head price. Alternatively, these costs are sometimes called the marginal finding costs and the marginal development and production costs. Marginal finding costs are calculated by dividing the cost of the last increment of wildcat wells (which is approximately equal to the sum of the after-tax net present value of all commercially developable fields discovered in that last increment of exploration) by the amount of economic resources discovered by the last increment of exploration. Marginal development and production cost per barrel (for the economic resources discovered in that last increment of exploration) are calculated by subtracting the incremental finding costs from the well-head price.

Finding-rate functions were calibrated for each province (see Attanasi, Gautier, and Root, 1996, for details of these models). Because the size, depth, and number of undiscovered fields were calculated from the geologic assessment data, the finding-rate functions determined the ordering of new discoveries as well as the rate at which these fields would be found as a function of cumulative wildcats drilled in a particular depth interval. The allocations of wildcat wells by depth interval was made in such a way that, for each increment of wildcat wells evaluated, the after-tax net present value of the oil and gas fields discovered was maximized.

CONTINUOUS-TYPE ACCUMULATIONS IN SANDSTONE, SHALES, CHALKS, AND COAL

Geologic assessment of technically recoverable resources required partitioning the continuous-type play into equal-area cells equivalent either to the median drainage area of productive wells in the play or the well spacing imposed by the State regulatory authority. Data on results of past drilling and estimated recoveries of wells producing from the play were assembled, interpreted, and used to calculate the empirical drilling success ratio and the fractiles of the empirical distribution of estimated ultimate recoveries (EUR) of productive cells. With these data as a guide, the geologist subjectively estimated a drilling success ratio for undrilled cells and assigned values to fractiles of distributions representing numbers of undrilled cells, the EUR distribution of undrilled cells expected to be productive, and depths of undrilled cells. Estimates and distributions describing the undrilled cells were used to generate an expected discrete frequency-size (where size is hydrocarbon recovery) distribution of productive undrilled cells for the play at 5,000-ft depth intervals. For each play, production flow rates of wells having recoveries corresponding to the fractiles of the EUR distribution were modeled using historical production data, or the results of a reservoir-simulation model were calibrated by matching well histories.

The procedure for calculating incremental costs relied on results of a discounted cash flow analysis applied to wells corresponding to the *expected or mean* cell frequency-size distribution of undrilled cells. For a specific well-head oil and gas price and required rate of return, the after-tax net present value of commercially developable cells was calculated. Exploration of a play at a particular depth interval is assumed to be economic if the expected aggregate after-tax net present value of the developable cells would at least pay for the cost of exploration, that is, the cost of drilling noncommercial cells in that depth interval. If the aggregate after-tax net present value of the commercially developable cells was sufficient to cover such costs, the aggregate resources in the commercially developable cells would be added to the incremental cost function. Calculations were repeated assuming progressively higher prices and aggregated by depth intervals across plays to arrive at province incremental cost functions. Industry, as a whole, has not generally been successful in drilling the more productive cells in preference to the less productive cells within an individual play, so, with the exception of target depth, no high-grading or selective drilling of cells within plays was assumed. The computational algorithm assumed that, for the last increment of hydrocarbons added to reserves, the sum of marginal finding, development, and production costs were approximately equal to the assumed well-head price. For details of the geologic and economic assessment methods for coal-bed gas see Rice and others (1995) and Attanasi and Rice (1995); for other continuous-type plays see Schmoker (1995) and Attanasi, Schmoker, and Quinn (1995).

APPENDIX D—ASSESSED TECHNICALLY RECOVERABLE RESOURCES, PROVED RESERVES, AND PAST PRODUCTION

Figures D-1 and D-2 place the quantities of assessed technically recoverable resources in perspective by comparing them to past cumulative production by USGS petroleum region. From the bottom to the top of each bar, the figures show cumulative production, proved reserves, inferred reserves, and assessed technically recoverable oil and total gas (associated and non-associated). Cumulative production and proved reserves include conventional and assessed unconventional sources of oil and gas. Inferred reserves represent the amounts of oil and gas expected to be added to reserves in pre-1992 conventional discoveries during the 80 years following 1991. Items below the "zero" horizontal line are identified technically recoverable oil and gas resources.

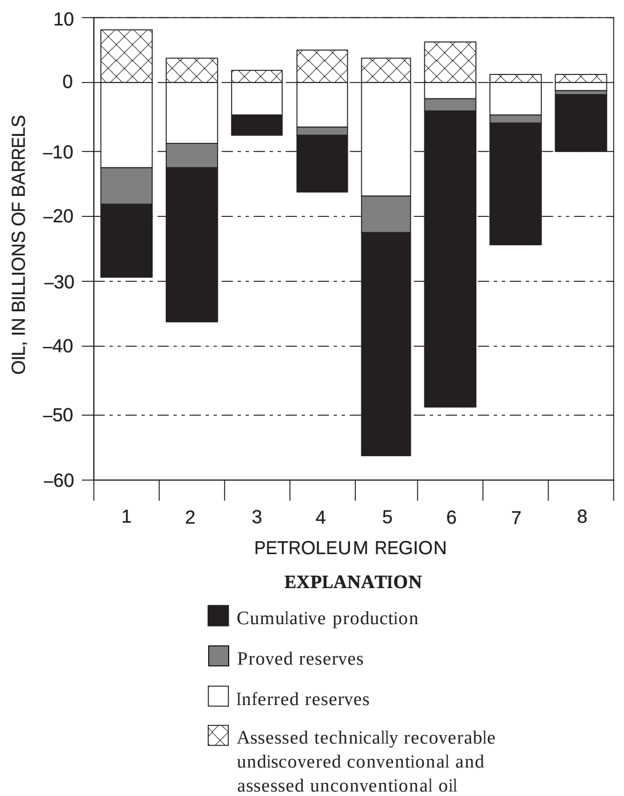

Figure D-1. Estimates, as of January 1994, by petroleum region, of discovered crude oil (i.e., cumulative production and proved reserves), inferred reserves, and the combined mean estimates of assessed technically recoverable undeveloped crude oil in undiscovered conventional oil fields and crude oil in continuous-type oil accumulations. Bars representing discovered crude oil and inferred reserves are below the "zero" horizontal line; bars representing assessed technically recoverable undeveloped crude oil in undiscovered conventional oil fields and crude oil in continuous-type oil accumulations are above the "zero" horizontal line. Petroleum regions are identified by number and name in table B-1, Appendix B.

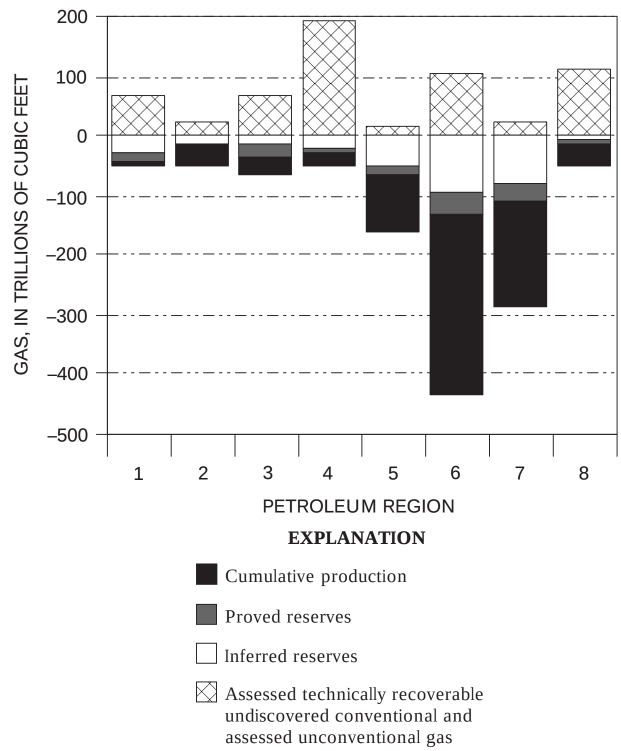

Figure D-2. Estimates, as of January 1994, by petroleum region, of discovered gas (i.e., cumulative production and proved reserves), inferred reserves, and the combined mean estimates of assessed technically recoverable undeveloped gas in undiscovered conventional oil and gas fields, gas in continuous-type oil and gas accumulations, and coal-bed gas. Bars representing discovered gas and inferred reserves are below the "zero" horizontal line; bars representing assessed technically recoverable undeveloped gas in undiscovered conventional oil and gas fields, gas in continuous-type oil and gas accumulations, and coal-bed gas are above the "zero" horizontal line. Gas does not include natural gas liquids. Petroleum regions are identified by number and name in table B-1, Appendix B. Inferred reserves of Region 1 include some gas discovered in the Northern Alaska province not counted as proved reserves.

The assessed mean value of technically recoverable resources in conventional undiscovered fields and in continuous-type accumulations are represented by bars above the "zero" horizontal line.

For all regions combined, cumulative past oil production accounts for 58 percent of the total oil depicted in figure D-1 (62 pecent in regions in the lower 48 States). The area above the "zero" horizontal line accounts for only 12 percent of the oil, leaving 30 percent in proved reserves and projected field growth. For all regions combined, cumulative past gas production accounts for 40 percent of the gas shown in figure D-2. The area above the "zero" horizontal line accounts for 35 percent of the total gas, leaving 25 percent assigned to proved reserves and field growth.