1995 NATIONAL ASSESSMENT OF UNITED STATES OIL AND GAS RESOURCES

By **U.S. Geological Survey National Oil and Gas Resource Assessment Team**

CONTENTS

METRIC CONVERSION FACTORS

[For this assessment, 6,000 cubic feet of gas equals 1 barrel of oil equivalent (BOE)]

Multiply inch-pound unit	By	To obtain metric unit
barrel	1.590 x 10 exp -1	cubic meter
cubic foot	2.832 x 10 exp -2	cubic meter
mile	1.609 x 10 exp 3	meter
foot	3.048 x 10 exp -1	meter

UNIT ABBREVIATIONS

BBNGL	Billion barrels of natural gas liquids
BOE	Barrel of oil equivalent
BBO	Billion barrels of oil
MMBO	Million barrels of oil
BCFG	Billion cubic feet of gas
TCFG	Trillion cubic feet of gas

ACRONYMS

ANWR	Arctic National Wildlife Refuge
NGL	Natural gas liquids
API	American Petroleum Institute
OGIFF	Oil and Gas Integrated Field File
EIA	Energy Information Administration
PI	Petroleum Information Corp.
EUR	Estimated ultimate recovery
TSP	Truncated Shifted Pareto (model)
FERC	Federal Energy Regulatory Commission
USGS	U.S. Geological Survey
GOR	Gas-oil ratio
WHCS	Well History Control System
MMS	Minerals Management Service

MEMBERS OF THE U.S. GEOLOGICAL SURVEY 1995 NATIONAL OIL AND GAS RESOURCE ASSESSMENT TEAM

Project Chief	Donald L. Gautier
Co-Chief Scientist	Gordon L. Dolton
Methodology Ronald R. Charpentier Gordon L. Dolton Lawrence J. Drew Donald L. Gautier John D. Grace (consultant) Caroline M. Isaacs Richard F. Mast Dudley D. Rice David H. Root James W. Schmoker John H. Schuenemeyer	Emil D. Attanasi
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Computing and Programming Raymond C. Obuch David H. Root	Ronald R. Charpentier
Computer Specialist James D. Brewton	Richard H. Balay
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GIS Assistant Diane L. Barnett Scarlet Tang Zenon C. Valin David Vaughan	Kerry L. Aggen
Graphic Data Display	Timothy R. Klett
Graphics Alice A. Springfield Joseph T. Springfield	Laura L. Zink
Video Production	
Producer, Director, Writer	Jonathan Swinchatt
Co-Producer	David G. Howell
Associate Producer	Nick Hardigg
Computer Graphics and Animation	Jose Vigil
Geological Coordination	
Alaska Region	Kenneth J. Bird
Pacific Coast Region	Caroline M. Isaacs Marilyn E. Tennyson
Colorado Plateau and Basin and Range Region	John A. Grow James A. Peterson
Rocky Mountains and Northern Great Plains Region	Cornelius M. Molenaar Charles W. Spencer
Midcontinent Region	Ronald R. Charpentier

	James W. Schmoker
West Texas and Eastern New Mexico Region	Mahlon M.Ball
Gulf Coast Region	Christopher J. Schenk
Eastern Region	Robert T. Ryder
Coordinator, Continuous-Type Deposits	James W. Schmoker
Geologic Specialist, Continuous-Type Deposits Ben E. Law	Thomas D. Fouch
Statistics, Continuous-Type Deposits	Robert A. Crovelli
Computation, Continuous-Type Deposits	Richard H. Balay
Petroleum Engineer John C. Quinn	Lynn E. Boone
Coordinator, Coal-Bed Gas	Dudley D. Rice
Geologic Specialist, Coal-Bed Gas William B. Cashion	Ronald. C. Johnson
Assistant, Coal-Bed Gas	Thomas M. Finn
Resource Specialist, Coal-Bed Gas	Advanced Resources International, Inc.
Geologic Specialist, Gas Hydrates	Timothy S. Collett
Geologic Specialist, Deep Gas Michael S. Wilson	Thaddeus S. Dyman
Geologic Specialist, Heavy Oil Christopher J. Schenk	Mark J. Pawlewicz
Geochemical Specialist Joseph R. Hatch Michael D. Lewan James G. Palacas	Jerry L. Clayton
Economics John D. Grace (consultant) Keith R. Long	Emil D. Attanasi
Discovery-Process Models Richard F. Mast John H. Schuenemeyer	Lawrence J. Drew
Fractal Methodology	Christopher C. Barton

Assistant, Fractal Methodology	Steven K. Faust
Grigori L. Troussov	
Inferred Reserves	Emil D. Attanasi
Richard F. Mast	
David H. Root	
Aggregation Models	David H. Root
John H. Schuenemeyer	
Province Geologists	
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Central Alaska (002)	Richard G. Stanley David G. Howell
Southern Alaska (003)	Leslie B. Magoon III Terry R. Bruns Michael A. Fisher Cornelius M. Molenaar
Western Oregon–Washington (004)	Samuel Y. Johnson Marilyn E. Tennyson
Eastern Oregon–Washington (005)	Marilyn E. Tennyson
Klamath-Sierra Nevada (006)	Marilyn E. Tennyson
Northern Coastal (007)	Richard G. Stanley
Sonoma-Livermore Basin (008)	Leslie B. Magoon, III
Sacramento Basin (009)	Leslie B. Magoon, III
San Joaquin Basin (010)	Larry A. Beyer
Central Coastal (011)	Richard G. Stanley
Santa Maria Basin (012)	Marilyn E. Tennyson
Ventura Basin (013)	Margaret A. Keller
Los Angeles Basin (014)	Larry A. Beyer
Salton Trough (016)	Charles E. Barker
Idaho–Snake River Downwarp (017)	James A. Peterson
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Eastern Great Basin (019)

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John A. Grow

Uinta-Piceance Basin (020)	Charles W. Spencer Thomas D. Fouch
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San Juan Basin (022)	A. Curtis Huffman, Jr.
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Park Basins (038)	Craig J. Wandrey
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Las Animas Arch (040)	C. William Keighin
Raton Basin–Sierra Grande Uplift (041)	C. William Keighin

Pedernal Uplift (042)	Mahlon M. Ball Mitchell E. Henry
Palo Duro Basin (043)	Mahlon M. Ball Mitchell E. Henry
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Marathon Thrust Belt (046)	William J. Perry, Jr.
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Superior (051)	James G. Palacas
Iowa Shelf (052)	James G. Palacas
Cambridge Arch–Central Kansas Uplift (053)	Debra K. Higley
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SUMMARY OF RESULTS

This report summarizes the results of a 3-year study of the oil and gas resources of onshore areas and State waters of the United States by the U.S. Geological Survey (USGS). A parallel study of the Federal offshore is being conducted by the Minerals Management Service (MMS).

Assuming existing technology, there are approximately 110 billion barrels of technically recoverable oil onshore and in State waters. This includes measured (proved) reserves, future additions to reserves in existing fields, and undiscovered resources.

The technically recoverable conventional resources of natural gas in measured reserves, future additions to reserves in existing fields, and undiscovered accumulations equal approximately 715 trillion cubic feet of gas.

In addition to conventional gas resources, the USGS has made an assessment of technically recoverable resources in continuous-type (largely unconventional) accumulations. We estimate about 300 TCFG (trillion cubic feet of gas) of technically recoverable natural gas in continuous-type deposits in sandstones, shales, and chalks, and almost 50 TCFG of technically recoverable gas in coal beds.

The total technically recoverable oil and gas resource base onshore and in State waters of the United States is listed in and shown on figures 1 and 2.

Table 1. Estimates of national totals for undiscovered technically recoverable conventional oil, gas, and NGL resources; growth of reserves in known fields; technically recoverable resources in continuous-type (unconventional) accumulations; and measured reserves.

[Mean value totals may not be equal to the sums of the component means given elsewhere because numbers have been independently rounded. Gas includes both non-associated and associated-dissolved gas. Fractile values (F_{95}, F_5) are not additive. F_{95} represents a 19 in 20 chance and F_5 represents a 1 in 20 chance of the occurrence of at least the amount tabulated. NGL, natural gas liquids. NA, not applicable]

Category	Crude oil (billion barrels)			Gas (trillion cubic feet)			NGL (billion barrels)		
	F_{95}	F_5	Mean	F_{95}	F_5	Mean	F_{95}	F_5	Mean
Undiscovered conventional resources	23.4	39.4	30.0	206.3	328.4	258.9	6.5	9.9	8.0
Reserve growth in conventional fields	NA	NA	60.0	NA	NA	322.0	NA	NA	13.4
Continuous-type accumulations in sandstones, shales, and chalks	1.5	2.7	2.1	219.4	416.6	308.1	1.1	3.5	2.1
Continuous-type accumulations in coal beds	NA	NA	NA	42.9	57.6	49.9	NA	NA	NA
Measured (proved) reserves	NA	NA	20.2	NA	NA	135.1	NA	NA	6.6
TOTAL, onshore areas and State waters of the United States			**112.3**			**1,074.0**			**30.1**

INTRODUCTION

The purpose of the National Oil and Gas Resource Assessment Project is to develop a set of scientifically based hypotheses concerning the quantities of oil and gas that could be added to the measured (proved) reserves of the United States.

The word assessment sometimes has the connotation of an inventory. But this is not the case in this study. The quantities being evaluated here are largely unknown. This assessment is an attempt to bound the uncertainties concerning potential additions to oil and gas reserves under specified conditions. As such, the assessment consists of a set of constructs, based on the best information and theory available to the USGS scientists charged with this effort.

The U.S. Geological Survey has occasionally conducted assessments of the oil and gas resources of the United States since shortly after the turn of the century. Each successive assessment is a refinement of previous work. Systematic National Assessments have been conducted more regularly since 1975. In 1982, the Minerals Management Service was formed and given responsibility for resource evaluation in the Federal offshore areas of the United States. The USGS retained responsibility for onshore areas and State waters. In 1991, the two organizations (USGS and MMS) began their second joint study of the oil and gas resources of the United States. This report summarizes the results of the USGS part of that study and reports estimates of potential additions to reserves onshore and under State waters of the United States. Documentation for this assessment is available on this CD-ROM that supports this report (Gautier and others, 1995).

The previous USGS/MMS assessment (Mast and others, 1989) encompassed estimates of both technically recoverable and economically recoverable resources. The present report concerns only technically recoverable resources. A parallel study concerns the economic evaluation of the resources described in this report. The geological assessment of technically recoverable resources makes no attempt to predict at what time or what part of potential additions will be added to reserves. For the National Assessment, resources and potential reserve additions are evaluated regardless of political, economic, and other considerations.

The onshore and State water areas of the United States were divided into eight regions consisting of 71 provinces (fig. 3). These regions and provinces are similar, but not identical, to those addressed by U.S. Geological Survey Circular 860 (Dolton and others, 1981) and the U.S. Department of the Interior report from the previous National Assessment of oil and gas resources(Mast and others, 1989). Within these provinces, about 560 plays were assessed, of which about 100 were in continuous-type deposits;

the remainder were hypothetical and confirmed conventional plays.

The estimates presented in this document reflect USGS understanding as of January 1, 1994, and are intended to capture the range of uncertainty, to provide indicators of the relative potential of various petroleum provinces, and to provide a guide useful in considering possible effects of future oil- and gas-related activities within the United States.

COMMODITIES ASSESSED

The commodities considered in this study were crude oil, natural gas, and natural gas liquids that can be expected to be produced from the subsurface through a well. Most heavy oil deposits were assessed as conventional resources. Specifically excluded from consideration were gas dissolved in geopressured brines and resources in tar deposits and oil shales. Gas in clathrate structures (gas hydrates) were not assessed as technically recoverable resources; however, a chapter concerning these in-place volumes of gas is included in this CD-ROM (Gautier and others, 1995). Specifically included in this assessment were technically recoverable gas from low-permeability "tight" sandstone reservoirs, gas and oil from fractured shale reservoirs, and coal-bed gas. The systematic inclusion of unconventional resources marks a significant departure from previous USGS assessments.

Crude oil, as considered in this assessment, is a natural liquid consisting mainly of a mixture of complex hydrocarbon molecules. Natural gas is a mixture of hydrocarbon gases, mainly methane, and certain non-hydrocarbon gases such as carbon dioxide, hydrogen sulfide, nitrogen, and helium. This analysis assessed hydrocarbon gases, although minor amounts of non-hydrocarbon gases may be included. Natural gas liquids (NGL) are the heavier homologs of methane, which are in the gas-phase under reservoir pressure and temperature conditions. NGL includes those portions of the reservoir gas that are liquefied at the surface in various field facilities and in gas-processing plants. NGL commonly includes propane, ethane, butane, pentane, natural gasoline, and condensate.

ASSESSMENT CATEGORIES

The resource classification used in this study is illustrated in figure 4, a modified "McKelvey box." Resources can be classified along two axes: geologic assurance and economic feasibility. The degree of geologic certainty increases to the left from undiscovered resources, through inferred reserves (reserve growth[1]) to measured (proved) reserves. Degree of economic feasibility increases vertically upward from subeconomic to economic resources.

Previous USGS assessments focused on undiscovered conventional accumulations of oil and gas and additions to reserves in known fields. This assessment is broader in scope because it considers three categories of resources: (1) undiscovered conventional accumulations of oil and gas, (2) future additions to reserves of known fields, and (3) oil and gas in continuous-type accumulations (largely equivalent to "unconventional" categories of other analysts).

UNDISCOVERED CONVENTIONAL ACCUMULATIONS

Undiscovered conventional accumulations of oil and gas are the traditional fare of the oil and gas industry and have been the focus of most previous USGS oil and gas assessments. These resources include those postulated to exist outside known fields or accumulations, and that, if found, could be extracted using traditional development practices. These accumulations generally exist as discrete accumulations, which are usually, but not invariably, defined, controlled, or limited by hydrocarbon/water contacts. Undiscovered accumulations are shown in the right third of the McKelvey box (fig. 4). Undiscovered technically recoverable accumulations, those assessed in this report, are within the hachured area shown on figure 4.

INFERRED RESERVES (RESERVE GROWTH)

Inferred reserves (reserve growth) include those resources expected to be added to reserves as a consequence of extension of known fields, through revisions of reserve estimates, and by additions of new pools in discovered fields. Also included in this category are resources expected to be added to reserves through application of improved recovery techniques. This category thus includes both the "indicated reserves" and the "inferred reserves" described in earlier USGS assessment publications (e.g., Mast and others, 1989). Predictions of reserve growth refer to fields found before 1992 (the date of most reserve data used in this report). The analysis of reserve growth in discrete conventional accumulations is based on the proprietary Oil and Gas Integrated Field File (OGIFF) of the Energy Information Administration (EIA). Inferred reserves are shown in the stippled area of the middle third of the McKelvey box (fig. 4).

[1]Throughout this report, the terms "reserve growth" and "field growth" are used interchangeably. Both terms indicate growth of reserves in known fields.

CONTINUOUS-TYPE (UNCONVENTIONAL) ACCUMULATIONS

Continuous-type (unconventional) accumulations are, for the purposes of this assessment, defined to include those oil and gas resources that exist as geographically extensive accumulations that generally lack well-defined oil/water or gas/water contacts (fig. 5). This geologically grounded definition provides a set of consistent criteria to be applied in the determination of whether a specific accumulation is or is not conventional. This geologic definition intentionally avoids the regulatory criteria of the Federal Energy Regulatory Commission (FERC) designations and does not rely on any specific permeability as a defining criterion. Included in this category are coal-bed gas, gas in many of the so-called "tight sandstone" reservoirs, and auto-sourced oil- and gas-shale reservoirs. Because of the immense quantities of oil and gas that can be included in this category, only those resources that, in our judgment, are technically recoverable and could be added to U.S. oil and gas reserves were reported in this study. Those resources judged to be potential additions to reserves are further subdivided into undiscovered and reserve growth categories. Existing technology and development practices as of the date of this assessment (January 1994) were assumed. In this study, inferred reserves and undiscovered resources in continuous-type accumulations were not differentiated. Therefore, the volumes of resources estimated for continuous-type deposits occur over both the hachured and stippled areas of the McKelvey box (fig. 4).

Each of the three broad categories of resources (undiscovered conventional accumulations, inferred reserves, and continuous-type accumulations) requires a different technique for evaluation. Each of these resources is thus described and considered in separate sections of this report. The methods for assessment of the undiscovered recoverable discrete conventional accumulations is discussed further in the CD-ROM chapter on methodology by Gautier and Dolton (Gautier and others, 1995). The techniques used for evaluation of various continuous-type resources are discussed in CD-ROM chapters by Schmoker and by Rice (Gautier and others, 1995). Results of the assessment of these various resources are generally reported in separate categories.

TERMINOLOGY

The terminology used in this report is intended to represent standard definitions and usage of the oil and natural gas industry and the resource-assessment community. No attempt has been made to include a detailed listing of common industry definitions; however, several definitions that are essential to the proper understanding of this report are presented. The definitions are intended to be generally explanatory rather than strictly technical.

Undiscovered resources.--Resources postulated from geologic information and theory to exist outside of known oil and (or) gas fields.

Technically recoverable resources.--Resources in accumulations producible using current recovery technology but without reference to economic profitability. These are oil and natural gas resources that may be produced at the surface from a well as a consequence of natural pressure within the subsurface reservoir, artificial lifting of oil from the reservoir to the surface, and the maintenance of reservoir pressure by fluid injection. (This definition is modified from that of the National Petroleum Council.) These resources are generally conceived as existing in accumulations of sufficient size to be amenable to the application of existing recovery technology.

Measured (proved) reserves.--That part of the identified economic resource that is estimated from geologic evidence supported directly by engineering data. Measured reserves are demonstrated with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Resources in this category are not a principal focus of this assessment. Data reported are from the Energy Information Administration (Energy Information Administration, 1994).

Conventional accumulation.--A discrete deposit, usually bounded by a downdip water contact, from which oil, gas, or NGL can be extracted using traditional development practices, including production at the surface from a well as a consequence of natural pressure within the subsurface reservoir, artificial lifting of oil from the reservoir to the surface where applicable, and the maintenance of reservoir pressure by means of water or gas injection.

Continuous-type deposit.--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.

Unconventional accumulation.--A broad class of hydrocarbon deposits of a type (such as gas in "tight" sandstones, gas shales, and coal-bed gas) that historically has not been produced using traditional development practices. Such accumulations include most continuous-type deposits.

Field growth (inferred reserves).--That part of the identified resources over and above measured (proved) reserves that will be added to existing fields through extension, revision, improved recovery efficiency, and the addition of new pools or reservoirs.

Inferred reserves.--For this report, inferred reserves is the difference between proved reserves in known fields and the remaining recoverable resources in known fields--this definition of inferred reserves includes two resource categories used in previous USGS oil and gas assessment documents (e.g., Mast and others, 1989): "indicated reserves" and "inferred reserves."

Indicated reserves.--That part of identified oil resources in known productive reservoirs in existing fields in addition to measured reserves that are expected to respond to improved recovery techniques. For this report, indicated reserves are included as part of inferred reserves.

Barrels of oil equivalent (BOE).--Gas volume that is expressed in terms of its energy equivalent in barrels of oil. For this assessment, 6,000 cubic feet of gas equals 1 barrel of oil equivalent (BOE).

Gas-oil ratio (GOR).--Average ratio of associated-dissolved gas to oil; a point estimate of the volume of gas (in cubic feet) dissolved in oil or otherwise associated with a barrel of oil in known or postulated oil accumulations. As in the most recent National Assessment (Mast and others, 1989), an accumulation with a GOR in excess of 20,000 is considered a gas accumulation.

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

NGL to associated-dissolved gas ratio.--The volume of natural gas liquids (in barrels) contained in 1 million cubic feet of associated-dissolved gas in a known or postulated oil accumulation.

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.

Accumulation.--A single oil or gas deposit as defined by the trap, charge, and reservoir characteristics of the play.

Play.--A play is a set of known or postulated oil and (or) gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type.

Play area.--The two-dimensional plan extent over which a play concept is considered to be valid and within which all known accumulations and potential for undiscovered accumulations or other additions to reserves within the play exist.

Play attributes.--Geologic characteristics that describe principal properties of and necessary conditions for the occurrence of oil and (or) gas accumulations of the minimum size (1 MMBO [million barrels of oil] or 6 BCFG [billion cubic feet of gas]) within the defined parameters of a play. Although many combinations of individual underlying elements are possible, three attributes were considered in the evaluation of play risk in this assessment. These attributes are as follows:

1. ***Charge***.--The occurrence of conditions of hydrocarbon generation and migration adequate to cause an accumulation of the minimum size. Included in this attribute are subsidiary elements, including existence of source rocks with sufficient organic matter of the appropriate composition, appropriate temperature and duration of heating to generate and expel sufficient quantities of oil and (or) gas, and timing of expulsion of oil and gas from source rocks appropriate for filling available traps.
2. ***Reservoir***.--The occurrence of reservoir rocks of sufficient quantity and quality to permit the containment of oil and (or) gas in volumes sufficient for an accumulation of the minimum size.
3. ***Trap***.--The occurrence of those structures, pinch-outs, permeability changes, and similar features necessary for the entrapment of oil and (or) gas in at least one accumulation of the minimum size. Included in this attribute are existence of seals sufficient for entrapping hydrocarbons and capable of holding oil and gas accumulations during appropriate ranges of geologic time.

Play probability.--Play probability represents the product of the probabilities of the three play attributes considered in this assessment (charge, reservoir, and trap). It is an estimate, expressed as a decimal fraction, of the chance that oil or natural gas exist within the particular play. For recoverable resources, the play probability represents the likelihood that technically recoverable quantities of oil or natural gas exist in at least one accumulation of the minimum size (1 MMBO or 6 BCFG) in the area being assessed.

Conditional estimates.--Sizes, numbers, or volumes of oil or natural gas that are estimated to exist in an area, assuming that they are present. Conditional estimates, therefore, do not incorporate the risk that the area may be devoid of oil or natural gas.

Risked (unconditional) estimates.--Resources that are estimated to exist, including the possibility that the area may be devoid of oil or natural gas. Statistically, the risked mean may be determined through multiplication of the mean of a conditional distribution by the related probability of occurrence. Resource estimates presented in this report are risked estimates.

Cumulative probability distributions for resource estimates.--Graphical depictions of estimated resource volumes presented with associated cumulative probabilities of occurrence. These distributions are used to derive the 95 percent, 5 percent, and mean resource levels reported in this publication: a low case, with a 95 percent probability of that amount or more occurring (a 19 in 20 chance); a high case, with a 5 percent probability of that amount or more occurring (a 1 in 20 chance); and a mean case representing an arithmetic average of all possible resource outcomes weighted by their probabilities.

DATA SOURCES

The USGS portion of the National Assessment Project relies largely on data that are either published or commercially available. Some USGS geologic data are from in-progress studies and have not necessarily been published. In several areas, drilling and production information was especially sparse or unreliable. Seven major data sources were used in this assessment:

1. USGS geologic data, both published and unpublished, were used in the development of play definitions, play boundaries, and in the analysis of geologic information concerning undiscovered conventional oil and gas accumulations and possible future developments in continuous-type oil and gas accumulations.

2. The Significant Oil and Gas Fields of the United States file (NRG) is a database commercially available from NRG Associates, Inc., which includes reserves, cumulative production, and various other types of information for most oil and gas fields of the United States larger than 1 million BOE (NRG Associates, Inc., 1993 and 1994). The NRG release current as of December 31, 1992 (NRG Associates, Inc., 1993), was a major source of reservoir-level information for this assessment.

3. The Well History Control System (WHCS) is a commercially available database of computerized drilling and completion data from almost 2.5 million exploratory and development wells available from Petroleum Information Corp. (PI). Data were used to construct various exploration- and development-intensity maps and plots and statistical analyses of drilling and discovery. For most of the areas assessed, the 1993 and 1994 versions of WHCS were used (Petroleum Information Corp., 1993 and 1994). In most provinces, the WHCS contains essentially all wells drilled. However, in certain areas, especially the Eastern Region, California, and parts of Oklahoma and Louisiana, drilling information is incomplete.

4. Petroleum Information Corp. production data files, including monthly, yearly, and cumulative production information from numerous recent wells in the United States, were employed to construct decline curves and estimated ultimate recovery (EUR) distributions used in the analysis of potential additions to reserves from continuous-type deposits (Petroleum Information Corp., 1994).

5. Energy Information Administration (EIA) Oil and Gas Integrated Field File (OGIFF) is a proprietary file of field-level reserves and production information. The data in OGIFF are collected according to legal mandate by the Department of Energy from operators of oil and gas fields of the United States. This file, which includes yearly estimates of reserves from fields in the United States was used mainly as a database for the prediction of potential additions to reserves of known fields. In a few areas of sparse data, especially Oklahoma and the Appalachian region, the OGIFF was used to supplement NRG for estimation of field sizes. Because of the sensitivity of the OGIFF data, however, the output provided in this report has been generalized, rounded, or eliminated to avoid releasing any of those data. This is particularly apparent in the output for provinces 055 (Nemaha Uplift), 056 (Forest City Basin), 060 (Cherokee Platform), and 067 (Appalachian Basin).

6. The Energy Information Administration 1993 Annual Report (Energy Information Administration, 1994) is the basis of all measured (proved) reserve information reported here.

7. Other data, including publications, State records, proprietary energy company reports, and other sources, were used by individual province geologists. Contributions of time, information, and insight by numerous individuals working in the U.S. oil and gas industry and State geological surveys were particularly helpful in play definition. In certain areas of the country where drilling, completion, reserve, or production data are sparse, absent, or unreliable, province geologists devoted significant effort to compiling original databases for reservoir- and field-level information. This was particularly the case for Oklahoma, the States of the Appalachian Basin, Louisiana, and California.

AREAS OF STUDY

The oil and gas resources of the United States were evaluated on the basis of interpretation of the geology of its petroleum provinces. For this study, the United

States was divided into eight regions, which, in turn, encompassed 71 separate provinces. Regional and provincial boundaries are illustrated in figure 3. The regions are basically geographic but are intended to provide broad geologic groupings of provinces. The provinces themselves are based on natural geologic entities and may include a single dominant structural element or a number of contiguous elements. The provinces are named for structural or geographic features within their boundaries.

The regions and provinces used in this study are generally similar to those used in recent USGS assessments, with a few changes. Notable among these changes are the consolidation of the provinces of Alaska into a simpler three-province scheme, the merging of the Atlantic Coast and Eastern Interior into a single region, the inclusion and assessment of Florida with the rest of the Gulf Coast, and the movement of the boundary between the Pacific Coast Region and the Colorado Plateau and Basin and Range Region along more geologically defined boundaries, such as the San Andreas fault in southern California. A few other smaller changes have also been made and are described in the supporting play-level documentation included in this CD-ROM (Gautier and others, 1995).

METHODS OF ASSESSMENT

Distinct methodologies were used for assessment of large and small conventional accumulations, continuous-type (unconventional) accumulations, and field growth. The following brief summaries of methodology are provided for convenience, but for a more detailed treatment, the interested reader should refer elsewhere in this CD-ROM.

UNDISCOVERED CONVENTIONAL ACCUMULATIONS

The assessment of undiscovered conventional resources was conducted at the play level. The methodology employed required estimation of the sizes, numbers, and types of undiscovered conventional accumulations of oil and gas and estimation of play risk. Numerous techniques were employed to make these estimates. These include reservoir-simulation modeling, discovery-process modeling, application of analogs, and spatial analysis. The method provides for a systematic integration and analysis of the geologic factors essential for the occurrence of oil and gas, a thorough documentation of the analysis, and an assessment containing information on the size, depth distribution, and number of hydrocarbon accumulations, as well as the quantity of estimated resources. Two principal categories of conventional plays were assessed: confirmed plays and hypothetical plays.

A play was considered confirmed if one or more accumulations of the minimum size (1 MMBO or 6 BCFG) had been discovered in the play. Confirmed plays were commonly assessed by extrapolation or approximation based on sizes, numbers, depths, drilling history, and other properties of known accumulations.

Hypothetical plays were those that were identified and defined based on geologic information but for which no accumulations of the minimum size had, as yet, been discovered. In contrast to confirmed plays, these hypothetical plays cannot, of course, be analyzed based on trends of known accumulations. Rather, properties of undiscovered accumulations must be postulated based on other types of information, including reservoir simulation and application of analog data sets from areas of similar geologic properties and known oil and (or) gas accumulations. Hypothetical plays characteristically carry a much broader degree of uncertainty, as recorded in the range of possible resources reported, than do confirmed plays. In addition to the greater range of reported resources, virtually all hypothetical plays carry a play-level probability of less than one.

Risking Structure

It is by no means certain that any given play will contain an undiscovered accumulation. In order to express this uncertainty, a risking structure was developed based on the three geologic play attributes of charge, reservoir, and trap.

Estimates of the probability of occurrence for each of the three attributes were expressed as decimal fractions between zero and one. The product of the three values is the play probability (risk = 1 – probability). Because the three play attributes are not necessarily independent, care was taken not to apply multiple risks resulting from a single cause or event.

In addition to the strictly hypothetical plays, the risking structure was also occasionally applied to intensely explored and largely exhausted plays within which the existence of yet another accumulation of the minimum size was uncertain. When calculating resources for hypothetical and largely exhausted plays, the play probability is applied against the product of the size and number of undiscovered accumulations estimated to exist in the play. For confirmed plays, other than those that were nearly exhausted, the play probability was 1. Plays were not quantitatively assessed when the play probability was 0.10 or less.

Truncated Shifted Pareto Model

For the purposes of this assessment, as in the previous USGS assessment (Mast and others, 1989), a model of the size-frequency distribution of the population of oil and (or) gas accumulations was assumed. The Truncated Shifted Pareto (TSP) model describes a "J-shaped" distribution in which ever-increasing numbers of accumulations occur in successively smaller size classes. The distribution is called shifted because it has been statistically moved to have its origin at the minimum accumulation size, in this case 1 MMBO or 6 BCFG. The TSP distribution is referred to as truncated because, for the purposes of analysis, the distribution is cut off at the size of the largest accumulation in the distribution. For a detailed discussion of the TSP distribution, see Houghton and others (1993).

An important use of the TSP distribution in this assessment was to provide a guide to province geologists in their development of estimates of undiscovered accumulations. A TSP distribution was fit to the population of accumulations known from each play and, in chronological order of discovery, to the first third of the accumulations discovered, the second third discovered, and the last third. The results of these fitted populations were provided to province geologists and review panels as source information regarding the changing size distribution of accumulations within the play as a function of time.

The TSP distribution was also commonly used to model the field-size distribution of the undiscovered population. Unless the province geologist had another specific model in mind, a TSP was fit to the estimated median size and to the estimated largest accumulation expected at a 5 percent probability within the postulated population of undiscovered accumulations, also considering the estimated limiting maximum size. The resulting TSP distribution was used to determine the remaining fractiles of the size distribution of the undiscovered population.

Based on sizes and numbers of accumulations of oil and (or) non-associated gas estimated as undiscovered in each play, resources of each of these commodities were calculated using a Monte Carlo simulation technique and application of play risk. Estimates of undiscovered resources are presented as a range of values corresponding to probabilities of occurrence in order to express the uncertainty inherent in assessment of unknown quantities. The input variables of accumulation sizes and numbers are themselves expressed as density functions of uncertain quantities. The resulting cumulative probability distributions represent the estimated quantity of undiscovered resources--from these distributions, various fractiles (including the low (F_{95}), the high

(F_5), and the mean estimates) are obtained.

Resources of gas associated with or dissolved in oil (associated-dissolved gas) were derived through use of estimated GOR's as applied to the calculated oil. Similarly, estimates of NGL were separately calculated for associated and non-associated gas by applying ratios provided by the estimators. Total gas and NGL at the play level were determined through summation.

Small Field Assessment

Probabilistic estimates of recoverable oil and gas in accumulations smaller than 1 MMBO or 6 BCFG of gas were made separately. The method for small field estimation in this assessment is essentially the same as that used by Mast and others (1989) and described by Root and Attanasi (1993). The estimates were based on extrapolations of numbers of fields in field-size classes smaller than the play-analysis cutoffs (1 MMBO, 6 BCFG) using a log-geometric model. The minimum size estimated was 32,000 barrels of oil and 192,000 cubic feet of gas. Estimates were made for provinces.

Aggregation and Dependency

To arrive at the estimated quantity of undiscovered resources for large areas, such as provinces, regions, or the Nation as a whole, distributions estimated for basic assessment units were progressively aggregated, with geological dependency incorporated at each level. In order to aggregate plays within provinces, geologic dependencies between plays were established for the three basic attributes of charge, reservoir, and trap. Province geologists determined for each pair of plays in their province whether the correlation was high (0.9), moderate (0.5), or low (0.1) for each attribute. Thus, to determine the degree of dependency of plays A and B, if highly correlated with respect to charge (0.9), poorly correlated with respect to reservoirs (0.1), and moderately correlated with respect to trap (0.5), the mean correlation value was calculated to be (0.9+0.1+0.5)/3, or 0.5. This value of dependency would be used in aggregating plays A and B. For the aggregation of province-level estimates, the provinces within each region were assigned a dependency of 0.5. In aggregation of regions for a national total, regions were considered to be independent.

RESERVE GROWTH (INFERRED RESERVES)

Measured reserves of oil or gas are the estimated quantities that analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known fields under existing economic and operating conditions. This definition of reserves more often leads to underestimates than to overestimates of the remaining resources in a known field. The difference between proved reserves in known fields and remaining recoverable resources in known fields is here called inferred reserves.

In the onshore areas and State water areas of the lower 48 States, the reestimation of reserves in old fields each year has added far more to measured (proved) reserves than have new discoveries. Therefore, the future growth of discovered fields will be an important source of additions to reserves. The estimate of this growth for conventional fields is provided as inferred reserves. Growth of reserves in continuous-type deposits is included within the estimates of technically recoverable resources from those types of deposits.

The Energy Information Administration has created the Oil and Gas Integrated Field File (OGIFF), which lists the estimated size (cumulative production plus proved reserves) for each oil and gas field in the United States. Fifteen estimates of size, as estimated in each of the 15 years from 1977 through 1991, are given for each field. These are the basic data from which the pattern of field growth is calculated.

For the purpose of estimating inferred reserves, the lower 48 States were divided into five areas, and the fields in these areas were divided into oil fields and gas fields. The five areas consisted of the assessment Regions 2, 3 and 4, 5 and 7, 6, and 8 (see fig. 3). Growth functions were calculated for each area for the primary commodities, i.e., oil in oil fields and gas in gas fields. The secondary commodities (associated-dissolved gas and NGL) were assumed to grow proportionally to the primary commodities. Alaska growth was calculated using national growth functions for oil and gas because there were inadequate data to construct specific growth functions for that region.

CONTINUOUS-TYPE ACCUMULATIONS

Sandstones, Shales, and Chalks

Continuous-type accumulations may have spatial dimensions approaching those of plays and cannot be represented in terms of discrete, countable entities delineated by downdip hydrocarbon/water contacts, as are conventional accumulations. The identification of a continuous-type hydrocarbon accumulation is based on its geologic setting and does not incorporate somewhat ephemeral criteria, such as specified low API gravity[2], low permeability ("tight"), special regulatory status, or need for unusual engineering techniques. A low-permeability reservoir may or may not be a continuous-type accumulation.

The geologic setting typical of continuous-type accumulations is illustrated by figure 5. Common geologic characteristics of a continuous-type accumulation include occurrence downdip from water-saturated rocks, lack of obvious trap and seal, crosscutting of lithologic boundaries, large areal extent, relatively low matrix permeability, abnormal pressure (high or low), and close association with source rocks. Aspects of hydrocarbon production common to a continuous-type accumulation include a large in-place hydrocarbon volume, a low recovery factor, and a heterogeneous "hit-or-miss" character for production rates and ultimate recoveries of wells.

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[2] A standard adopted by the American Petroleum Institute for expressing the specific weight of oils.

In the case of continuous-type accumulations, the distinction between undiscovered resources and inferred reserves is blurred. The locations of continuous-type accumulations are commonly well known (implying inferred reserves) (fig. 6), but hydrocarbon estimates may be broadly dependent on geologic knowledge and theory (implying undiscovered resources).

The first step of the assessment procedure is to represent the continuous-type accumulation by a play or plays. As in the case of conventional accumulations, geologic risk is assigned to each play. A gas-to-oil ratio of 20,000 cubic feet of gas per barrel of oil separates gas plays from oil plays.

It is advantageous to envision the hydrocarbons of a continuous-type accumulation as residing areally in cells. A play is then regarded as a collection of cells (fig. 7). The cell area or size is equal to the median spacing, as dictated by drainage area, expected for wells of the play. Virtually all cells in a continuous-type accumulation are capable of producing some hydrocarbons. For purposes of this assessment, however, a productive cell is one for which production from the play is formally reported. An untested cell is one in which the play in question has not been evaluated by a well.

The second step of the assessment procedure is to estimate the number of untested cells in a play and the fraction of untested cells expected to become productive (success ratio). Realistic consideration of the uncertainties associated with the number of untested cells in a play usually leads to a substantial range between the minimum and maximum number of untested cells. Therefore, the number of untested cells is treated as a probability distribution.

The third step of the assessment procedure is to establish a probability distribution for estimated ultimate recovery (EUR) for untested cells of the play that are expected to become productive. This distribution provides a reference model for production from cells yet to be drilled. Of course, this statistical model provides no insight as to which untested cells are expected to become productive.

Finally, the combination of play probability, success ratio, number of untested cells, and EUR probability distribution yields the potential additions to reserves expected for the continuous-type play. The in-place hydrocarbon volume is not used in this assessment procedure.

A salient aspect of the assessment method is that production and development patterns of the past are projected into the future. No assumptions regarding technology or economics are incorporated into the model.

The information required for the assessment of continuous-type accumulations is supplied by earth scientists who are knowledgeable about the petroleum geology and engineering of the province under consideration. These regional experts complete a data form for each play, which is the source of the input data required for assessment-computation programs. In those few cases in which there were seriously discordant views regarding a continuous-type play, the opinion of the province geologist has been used.

In order to aggregate continuous-type accumulations, a slight modification of the procedure used for conventional accumulations was employed: (1) the three basic attributes of geologic dependency of the assessment units considered were charge, reservoir, and areal extent (note that the dependency associated with areal extent could be negative), (2) correlations could assume any value between 1.0 and –1.0, and (3) dependencies at all aggregation levels were estimated in the same manner as that described for conventional plays.

Coal-Bed Gas

The unit of assessment of potential additions to reserves of coal-bed gas was the play. Coal-bed gas plays were defined as areas within widespread, commonly basin-wide, accumulations that have similar conditions of generation, accumulation, and production of gas (fig. 8). The factors that define the plays include coal-bed thickness, heterogeneity, depth, and composition; seals; gas content; gas composition; permeability; pressure regime; structural setting; and hydrology; as well as conventional trapping mechanisms. It is postulated that recoverable coal-bed gas reserves are generally restricted to present-day depths of burial of 500 to 6,000 ft because of gas content and formation permeability.

The assessment of potential additions to reserves of coal-bed gas was based on the estimation of the number and estimated ultimate recoveries (EUR's) of untested cells within each assessed play. The procedure is similar, in part, to that used in assessment of continuous-type accumulations in sandstones, shales, and chalks that is described above and by Schmoker in the supporting CD-ROM (Gautier and others, 1995). However, the coal-bed gas assessment relied heavily on production forecasting using a reservoir simulator. A range of EUR's and production rates of both gas and water were projected on a "per-well" and "per-foot-of-coal" basis for each play. The reservoir simulator was used because: (1) coal-bed gas accumulations are in early stages of development, and long-term production histories are generally not available, and (2) other methods, such as decline curve analysis and material balance are not adequate for expressing the complex movement of gas and water in coal.

Input parameters for modeling in this study were based on actual data, analog information, and judgments of geologists and engineers. To resolve some of the data uncertainty, particularly for key reservoir parameters such as gas content and permeability, well production was compared to that predicted by the simulator for selected wells. This process is known as "history matching" because the initial data estimates commonly are adjusted to obtain simulated results that are characteristic of actual well performance.

For most plays, long-term production from vertical wells, with a variety of completion techniques, was forecasted. In mining areas, production from wells was modeled. The EUR's predicted by reservoir simulation were used in conjunction with coal thicknesses to establish an EUR probability distribution for potentially productive, untested cells in each play. Seven fractiles (100th, 95th, 75th, 50th, 25th, 5th, and 0th) were provided for the computational model, and the distribution was assumed to be lognormal. For plays in which no reservoir simulation was performed, EUR's on a per-foot-of-coal basis from analog plays were scaled, and a similar procedure was used. The assessment of coal-bed gas is based on existing technology.

RESULTS OF THE ASSESSMENT

TECHNICALLY RECOVERABLE CONVENTIONAL RESOURCES

Approximately four hundred sixty conventional plays were defined for the 1995 National Assessment, of which 373 were assessed. Of these assessed plays, 290 were confirmed plays and 83 were hypothetical plays.

Oil

We estimate the undiscovered technically recoverable conventional oil resources of the United States to range from 23.4 BBO (billion barrels of oil) at a 95 percent probability to as much as 39.4 BBO at a 5 percent probability. The mean estimate of undiscovered conventional oil is 30.0 BBO. Of this amount, approximately 6.1 BBO exist in accumulations smaller than 1 MMBO. Estimated conventional oil resources are listed by region and by province in table 2 and illustrated in figure 9.

Table 2. Estimates of undiscovered technically recoverable conventional oil, gas, and NGL resources by petroleum region and province. [Mean value totals may not be equal to the sums of the component means given elsewhere because numbers have been independently rounded. Gas includes both non-associated and associated-dissolved gas. Fractile values (F_{95}, F_5) are not additive. F_{95} represents a 19 in 20 chance and F_5 represents a 1 in 20 chance of the occurrence of at least the amount tabulated. NGL, natural gas liquids]

Province number and name	Crude oil (billion barrels)			Gas (trillion cubic feet)			NGL (billion barrels)		
	F_{95}	F_5	Mean	F_{95}	F_5	Mean	F_{95}	F_5	Mean
Region 1--Alaska									
001, Northern Alaska	2.33	15.42	7.40	23.29	124.44	63.55	0.45	2.15	1.15
002, Central Alaska	0.00	0.32	0.06	0.51	7.31	2.76	0.00	0.00	0.00
003, Southern Alaska	0.19	2.20	0.96	0.69	4.38	2.16	0.00	0.00	0.00
Total, Region 1	**3.19**	**16.74**	**8.43**	**27.92**	**129.34**	**68.48**	**0.45**	**2.14**	**1.15**
Region 2--Pacific Coast									
004, Western Oregon–Wash.	0.00	0.12	0.02	0.10	1.95	0.80	0.00	0.01	< 0.01
005, Eastern Oregon–Wash.	0.00	0.00	0.00	0.00	1.62	0.39	0.00	< 0.01	< 0.01
006, Klamath–Sierra Nevada[1]									
007, Northern Coastal	< 0.01	0.09	0.03	0.34	2.32	1.08	0.00	< 0.01	< 0.01
008, Sonoma–Livermore Basin	0.00	0.06	0.01	0.00	0.42	0.06	0.00	0.00	0.00
009, Sacramento Basin	0.00	0.00	< 0.01	0.62	7.84	3.33	< 0.01	0.03	0.01
010, San Joaquin Basin	0.51	2.16	1.21	1.08	4.60	2.56	0.04	0.20	0.11
011, Central Coastal	0.10	1.17	0.49	0.03	0.37	0.15	< 0.01	0.01	0.01
012, Santa Maria Basin	0.02	0.60	0.21	0.01	0.35	0.12	< 0.01	0.03	0.01
013, Ventura Basin	0.28	2.27	1.06	0.66	3.66	1.90	0.02	0.13	0.07
014, Los Angeles Basin	0.41	1.78	0.98	0.61	3.08	1.61	0.02	0.11	0.06
015, San Diego–Oceanside[2]									
016, Salton Trough[1]									
Total, Region 2	**2.55**	**5.93**	**4.02**	**7.67**	**17.68**	**12.00**	**0.16**	**0.39**	**0.26**
Region 3--Colorado Plateau and Basin and Range									
017, Idaho–Snake River Downwarp	0.00	0.01	< 0.01	0.00	0.09	0.01	0.00	0.00	0.00
018, Western Great Basin	0.00	< 0.01	< 0.01	0.00	0.03	< 0.01	0.00	0.00	0.00
019, Eastern Great Basin	0.06	1.35	0.49	0.01	1.14	0.34	0.00	0.03	0.01
020, Uinta-Piceance Basin	0.04	0.60	0.21	1.94	9.54	4.53	0.01	0.22	0.08
021, Paradox Basin	0.11	0.60	0.31	0.92	3.41	1.98	0.03	0.17	0.09
022, San Juan Basin	0.07	0.28	0.16	0.51	1.49	0.95	0.01	0.05	0.03
023, Albuquerque–Santa Fe Rift	0.00	0.15	0.04	0.00	1.26	0.35	0.00	0.07	0.02
024, Northern Arizona	0.00	0.32	0.06	0.00	0.97	0.17	0.00	0.09	0.02
025, S. Ariz.–S.W. New Mexico	0.00	0.06	0.02	< 0.01	0.53	0.21	< 0.01	0.05	0.02
026, South-Central New Mexico	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total, Region 3	**0.64**	**2.33**	**1.30**	**5.27**	**13.98**	**8.56**	**0.13**	**0.44**	**0.26**
Region 4--Rocky Mountains and Northern Great Plains									
027, Montana Thrust Belt	0.00	0.02	< 0.01	0.00	8.51	1.92	0.00	0.03	0.01
028, North-Central Montana	0.13	0.42	0.27	0.40	1.37	0.85	< 0.01	< 0.01	< 0.01
029, Southwest Montana	0.00	0.13	0.03	0.12	0.78	0.41	< 0.01	0.01	< 0.01
031, Williston Basin	0.25	1.18	0.66	0.90	2.66	1.72	0.08	0.30	0.18
032, Sioux Arch	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
033, Powder River Basin	0.70	3.87	1.94	0.67	2.93	1.62	0.04	0.18	0.10
034, Big Horn Basin	0.08	0.87	0.39	0.24	1.20	0.62	< 0.01	0.03	0.01
035, Wind River Basin	0.05	0.32	0.16	0.57	2.21	1.24	0.01	0.02	0.01
036, Wyoming Thrust Belt	0.21	1.16	0.62	5.55	16.59	10.68	0.53	1.91	1.17
037, S.W. Wyoming	0.04	0.40	0.17	0.70	2.86	1.57	0.01	0.05	0.03
038, Park Basins	< 0.01	0.11	0.03	< 0.01	0.07	0.02	0.00	< 0.01	0.00

039, Denver Basin	0.09	0.42	0.23	0.34	1.40	0.76	0.01	0.04	0.03
040, Las Animas Arch	0.04	0.28	0.14	0.20	1.06	0.53	0.01	0.03	0.01
041, Raton Basin–Sierra Grande Uplift	0.00	0.00	0.00	0.00	0.12	0.04	0.00	< 0.01	< 0.01
Total, Region 4	**3.07**	**6.84**	**4.63**	**15.30**	**31.18**	**21.98**	**0.90**	**2.31**	**1.55**

Province number and name	Crude oil (billion barrels)			Gas (trillion cubic feet)			NGL (billion barrels)		
	F_{95}	F_5	Mean	F_{95}	F_5	Mean	F_{95}	F_5	Mean
Region 5--West Texas and Eastern New Mexico									
042, Pedernal Uplift	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
043, Palo Duro Basin	0.01	0.07	0.03	< 0.01	0.02	0.01	0.00	0.00	0.00
044, Permian Basin	1.59	4.50	2.88	10.53	23.21	16.40	0.41	0.92	0.64
045, Bend Arch–Fort Worth Basin	0.29	1.13	0.64	1.19	3.36	2.15	0.08	0.23	0.15
046, Marathon Thrust Belt	< 0.01	0.04	0.02	0.06	0.29	0.15	< 0.01	0.02	0.01
Total, Region 5	**2.22**	**5.26**	**3.57**	**12.89**	**25.67**	**18.71**	**0.55**	**1.10**	**0.80**
Region 6--Gulf Coast									
047, Western Gulf	0.73	4.54	2.29	44.27	96.68	68.41	1.17	2.59	1.83
048, East Texas Basin[3]									
049, Louisiana-Mississippi Salt Basins	0.86	5.24	2.69	18.64	41.83	29.57	0.68	2.61	1.50
050, Florida Peninsula	0.05	1.20	0.42	< 0.01	0.11	0.04	0.00	0.00	0.00
Total, Region 6	**2.66**	**8.80**	**5.39**	**70.88**	**130.31**	**98.02**	**2.22**	**4.70**	**3.32**
Region 7--Midcontinent									
051, Superior	0.00	0.44	0.05	0.00	2.95	0.42	0.00	< 0.01	< 0.01
052, Iowa Shelf	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
053, Cambridge Arch–Central Kansas	0.04	0.43	0.20	0.08	1.04	0.41	< 0.01	0.04	0.02
054, Salina Basin[4]									
055, Nemaha Uplift	0.03	0.29	0.12	0.17	0.97	0.48	0.01	0.06	0.03
056, Forest City Basin	0.00	0.06	0.02	0.00	0.19	0.07	0.00	0.01	< 0.01
057, Ozark Uplift	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
058, Anadarko Basin	0.20	0.63	0.38	8.72	21.29	14.21	0.14	0.31	0.22
059, Sedgwick Basin	0.02	0.11	0.06	0.13	0.48	0.30	< 0.01	0.03	0.01
060, Cherokee Platform	0.02	0.17	0.08	0.07	0.35	0.19	< 0.01	0.02	0.01
061, Southern Oklahoma	0.05	0.57	0.24	0.47	1.78	1.01	0.01	0.05	0.03
062, Arkoma Basin	0.00	0.07	0.01	1.18	4.26	2.50	0.04	0.16	0.09
Total, Region 7	**0.75**	**1.82**	**1.18**	**13.61**	**27.51**	**19.58**	**0.31**	**0.54**	**0.42**
Region 8--Eastern									
063, Michigan Basin	0.49	1.96	1.11	3.41	9.61	6.15	0.16	0.42	0.28
064, Illinois Basin	0.05	0.56	0.26	0.01	3.32	0.50	0.00	0.00	0.00
065, Black Warrior Basin	0.01	0.07	0.03	0.97	3.31	2.03	< 0.01	0.02	0.01
066, Cincinnati Arch	< 0.01	0.04	0.02	< 0.01	0.04	0.02	0.00	< 0.01	< 0.01
067, Appalachian Basin	0.03	0.24	0.10	1.55	3.43	2.42	< 0.01	0.01	< 0.01
068, Blue Ridge Thrust Belt	0.00	0.00	0.00	0.00	0.15	0.03	0.00	0.00	0.00
069, Piedmont	0.00	0.00	0.00	0.00	1.19	0.39	0.00	0.00	0.00
Total, Region 8	**0.84**	**2.41**	**1.53**	**7.98**	**16.10**	**11.54**	**0.18**	**0.44**	**0.30**
TOTAL, United States	**23.37**	**39.41**	**30.05**	**206.26**	**328.39**	**258.86**	**6.46**	**9.94**	**8.05**

[1]No resources assessed.
[2]Assessed by Minerals Management Service.
[3]Assessed with Province 049.
[4]Assessed with Province 059.

Gas

Undiscovered technically recoverable conventional gas resources, including both non-associated gas and associated-dissolved gas, range from 206.3 TCFG at a 95 percent probability to as much as 328.4 TCFG at a 5 percent probability. The mean estimate of undiscovered conventional natural gas is 258.9 TCFG. Of this amount, approximately 45.0 TCFG exist in accumulations smaller than 6 BCFG. Estimated conventional gas resources are tabulated by region and by province in table 2 and illustrated in figure 10.

NGL

We estimate the undiscovered technically recoverable resources of natural gas liquids in conventional accumulations to range from 6.5 BBNGL (billion barrels of natural gas liquids) at a 95 percent probability to as much as 9.9 BBNGL at a 5 percent probability. The mean estimate of undiscovered NGL is 8.0 BBNGL. Estimated NGL resources are tabulated by region and by province in table 2.

Figures 9 and 10 show, by use of mean values, the distribution of undiscovered resources of oil and gas by region. We estimate that approximately 28 percent of the undiscovered oil resources and 26 percent of the undiscovered gas resources exist in Alaska (Region 1--see fig. 3); approximately 13 percent of undiscovered oil resources and 5 percent of undiscovered gas resources exist in California and the remainder of the Pacific Coast (Region 2--see fig. 3); and 18 percent of the undiscovered oil resources and 38 percent of the undiscovered gas resources exist in the Gulf Coast (Region 6--see fig. 3). Of the remaining undiscovered resources, approximately 41 percent of the oil resources and 31 percent of the natural gas resources are distributed among the remaining five regions (Regions 3, 4, 5, 7, and 8--see fig. 3).

Undiscovered conventional oil and gas resources are estimated within ranges of probability. Estimated national totals for undiscovered conventional oil and gas resources of the onshore and State waters of the United States are listed in table 1 and illustrated in figures 11 and 12. Ranges of probability for resources by region and province are listed in table 2.

INFERRED RESERVES (GROWTH OF CONVENTIONAL FIELDS)

Growth functions were calculated and applied to the 1992 estimates from the OGIFF data for oil and gas for each year of discovery for each region and commodity. The results are summarized in table 3. It is estimated that 60.0 BBO will be added to oil reserves and 322.0 TCFG to gas reserves during the 80 years following 1991.

Table 3. Estimated future growth (inferred reserves) of conventional fields as of December 31, 1991.

Region	Crude oil (billion barrels)	Gas (trillion cubic feet)	NGL (billion barrels)
Region 1, Alaska	13.0	32.0	0.5
Regions 2–8, lower 48 States	47.0	290.0	12.9
TOTAL, onshore areas and State waters of the United States	**60.0**	**322.0**	**13.4**

TECHNICALLY RECOVERABLE RESOURCES IN CONTINUOUS-TYPE DEPOSITS

Sandstones, Shales, and Chalks

Sixty-one continuous-type plays were defined for the 1995 National Assessment, of which 47 were assessed. Of the assessed plays, 34 were gas plays and 13 were oil plays. The predominant reservoir rock is sandstone for 33 plays, shale for 20 plays, and carbonate for 9 plays. Although the plays are geographically diverse, none are in Alaska and none extend into State offshore waters (fig. 6).

Technically recoverable hydrocarbon resources from continuous-type accumulations are substantial (table 4). Estimated natural gas resources range between 219 TCFG (95th fractile) and 417 TCFG (5th fractile), with a mean of 308 TCFG; those for crude oil range between 1.5 and 2.7 BBO, with a mean of 2.1 BBO; those for natural gas liquids range between 1.1 and 3.5 BBNGL, with a mean of 2.1 BBNGL.

Table 4. Technically recoverable resources estimated for continuous-type plays in sandstones, shales, and chalks, onshore United States.[Gas includes both non-associated and associated-dissolved gas. Mean value totals may not be equal to the sums of the component means given elsewhere because numbers have been independently rounded. Fractile values (F_{95}, F_5) are not additive. F_{95} represents a 19 in 20 chance and F_5 represents a 1 in 20 chance of the occurrence of at least the amount tabulated. NGL, natural gas liquids. Leaders (--) indicate less than 0.5 million barrels]

Province number and name	Crude oil (million barrels)			Gas (trillion cubic feet)			NGL (million barrels)		
	F_{95}	F_5	Mean	F_{95}	F_5	Mean	F_{95}	F_5	Mean
Region 2--Pacific Coast									
005, Oregon-Washington	0	0	0	2.80	30.87	12.20	28	309	122
Total, Region 2	**0**	**0**	**0**	**2.80**	**30.87**	**12.20**	**28**	**309**	**122**
Region 3--Colorado Plateau and Basin and Range									
020, Uinta-Piceance Basin	59	139	94	11.55	23.38	16.74	63	139	96
021, Paradox Basin	61	597	242	0.05	0.48	0.19	0	0	0
022, San Juan Basin	68	394	189	10.66	36.84	21.15	--	2	1
Total, Region 3	**249**	**940**	**525**	**24.88**	**55.02**	**38.09**	**63**	**140**	**96**
Region 4--Rocky Mountains and Northern Great Plains									
028, North-Central Montana	0	0	0	19.92	79.03	43.16	0	0	0
031, Williston Basin	97	283	167	0.08	0.24	0.14	0	0	0
037, S.W. Wyoming	0	0	0	55.95	213.51	119.30	810	3104	1733
039, Denver Basin	139	502	285	1.49	5.69	3.16	--	--	--
Total, Region 4	**271**	**695**	**452**	**91.86**	**268.89**	**165.76**	**810**	**3,104**	**1,733**
Region 6--Gulf Coast									
047, Western Gulf	752	1516	1089	1.82	3.67	2.63	0	0	0
049, East Texas Basin	0	0	0	3.55	9.40	6.03	89	235	151
Total, Region 6	**752**	**1,516**	**1,089**	**5.91**	**12.13**	**8.67**	**89**	**235**	**151**
Region 8--Eastern									
063, Michigan Basin	0	0	0	5.82	42.60	18.87	0	0	0
064, Illinois Basin	0	0	0	0.91	7.59	3.28	1	4	2
067, Appalachian Basin	0	0	0	43.12	83.66	61.21	9	23	15
Total, Region 8	**0**	**0**	**0**	**56.08**	**118.70**	**83.36**	**11**	**25**	**17**
TOTAL, onshore United States	**1,539**	**2,695**	**2,066**	**219.36**	**416.55**	**308.08**	**1,122**	**3,542**	**2,119**

Coal-Bed Gas

Major coal-bearing areas in the lower 48 States are shown in figure 8. The in-place resources of coal-bed gas are determined by the product of the coal tonnage and gas content. Although the in-place resources are very large for this type of accumulation, the main concern is recoverability. Figure 8 also shows the location of areas within which potential additions to reserves of coal-bed gas were quantitatively assessed for 39 plays. For this assessment, technically recoverable resources of coal-bed gas for the lower 48 States are estimated to range from 42.9 TCFG to 57.6 TCFG, with a mean estimate of 49.9 TCFG. Estimates for individual provinces and regions are presented in table 5.

Table 5. Technically recoverable resources of gas estimated for continuous-type plays in coal beds, onshore United States. [Gas includes both non-associated and associated-dissolved gas. Mean value totals may not be equal to the sums of the component means given elsewhere because numbers have been independently rounded. Fractile values (F_{95}, F_5) are not additive. F_{95} represents a 19 in 20 chance and F_5 represents a 1 in 20 chance of the occurrence of at least the amount tabulated. NGL, natural gas liquids]

Province number and name	Gas (trillion cubic feet)		
	F_{95}	F_5	Mean
Region 2--Pacific Coast			
004, Bellingham	0	0.09	0.04
004, West Cascade	0	1.20	0.66
Total, Region 2	**0.26**	**1.30**	**0.70**
Region 3--Colorado Plateau and Basin and Range			
020, Uinta Basin	1.86	4.82	3.21
020, Piceance Basin	5.47	10.09	7.49
022, San Juan Basin	5.76	9.67	7.53
Total, Region 3	**15.00**	**21.88**	**18.24**
Region 4--Rocky Mountains and Northern Great Plains			
033, Powder River Basin	0.32	2.90	1.11
035, Wind River Basin	0.22	0.72	0.43
037, S.W. Wyoming	0.83	7.66	3.89
041, Raton Basin	1.39	2.23	1.78
Total, Region 4	**3.97**	**11.71**	**7.20**
Region 7--Midcontinent			
056, Forest City Basin	0	1.44	0.45
060, Cherokee Platform	1.07	3.08	1.91
062, Arkoma Basin	1.87	3.58	2.64
Total, Region 7	**3.57**	**6.76**	**5.01**
Region 8--Eastern			
064, Illinois Basin	0.84	2.77	1.63
065, Black Warrior Basin	1.49	3.43	2.30
067, North Appalachian	7.68	16.36	11.48
067, Central Appalachian	1.88	4.64	3.07
067, Cahaba	0.14	0.54	0.29
Total, Region 8	**14.34**	**24.00**	**18.78**
TOTAL, lower 48 States	**42.89**	**57.63**	**49.91**

DISCUSSION AND COMPARISON OF RESULTS WITH THE PREVIOUS USGS/MMS ASSESSMENT

Oil

On the basis of existing technology and geologic concepts, there are, in total, approximately 110 billion barrels of technically recoverable oil, largely in existing and undiscovered conventional accumulations onshore and in State waters of the United States--this includes measured reserves and inferred reserves in existing fields as well as undiscovered accumulations. This number is significantly larger than the comparable number of about 78 billion barrels of technically recoverable oil recognized at the time of the previous assessment (Mast and others, 1989). In 1993, the United States produced about 2.4 BBO, approximately 50 percent of national consumption. At the time of the last National Assessment (1989), yearly production stood at approximately 2.5 BBO. The significant increase in technically recoverable oil reported in this assessment largely reflects anticipated increases in reserves of known fields.

Estimated mean amounts of undiscovered conventional oil resources onshore and in State waters of the United States are about 10 percent lower than those reported in the 1989 National Assessment of oil and gas resources (Mast and others, 1989) (30.0 BBO vs. 33.3 BBO, respectively). Since the last assessment, more than 2 BBO has been discovered in new fields, thereby reducing previous undiscovered quantities by that amount. The change in estimated conventional oil resources is also due to a reduction in our estimates of the undiscovered oil resources in part of northern Alaska.

Our understanding of the thermal history and geochemical makeup of the rocks of northern Alaska leads us to expect more natural gas and less oil in the foothills region, an area that includes most of the Arctic National Wildlife Refuge (ANWR) as well as the southern part of the National Petroleum Reserve in Alaska. This information comes from results of drilling the Tenneco Aurora well, located just offshore from the ANWR; results of a major USGS study that summarized all thermal data in Alaska; and USGS studies in the foothills region (which combine thermal-history information with that of the time of origin of rock structure and reveal an unfavorable relationship for the development of hydrocarbon traps). This unfavorable relation has resulted in the downgrading of oil resource potential in the foothills region but not in the coastal plain to the north.

The reduction in Alaska is, in part, offset in the national total by small increases in a number of other regions of the United States (table 2). Estimates of undiscovered conventional oil resources in most other regions of the United States are, in general, similar to those published in the past, although they differ somewhat in detail. For further information, refer to play-level documentation in this CD-ROM (Gautier and others, 1995). It should be emphasized that substantial overlap exists in the resource-range values estimated in the two studies.

Estimates of anticipated inferred reserves are significantly greater than those reported in 1989 (60 BBO vs. 21 BBO). This increase reflects our employment of an entirely different and newer set of field-level reserves data in this assessment. The last National Assessment (Mast and others, 1989) relied on the American Petroleum Institute–American Gas Association data collected during the 10-year period 1969–79, whereas, in this assessment, we had access to the last 15 years of data collected by the Energy Information Administration (EIA) in its Oil and Gas Integrated Field File (OGIFF). The OGIFF file was collected during a period of extraordinary variations of activity in the U.S. oil and gas industry, including significant changes in oil and gas prices, drilling activity, and development efficiency.

For the first time, the USGS has assessed technically recoverable resources in continuous-type (unconventional) accumulations. Included are about 2 BBO in continuous-type deposits, mostly in fractured shale reservoirs of the Bakken, Niobrara, Austin, and similar formations. These resources in unconventional reservoirs may have been partially accounted for as undiscovered resources in the previous National Assessment (Mast and others, 1989).

Proved reserves of the United States onshore and in State waters, at the time of this assessment, amounted to approximately 20 BBO, according to EIA. These values are significantly lower than those reported in 1989, when they stood at 24 BBO.

Gas

The technically recoverable conventional resources of natural gas from both growth of reserves in existing fields and from undiscovered accumulations onshore and in State waters, as of this assessment, is approximately 580 TCFG, compared with 347 TCFG at the time of the previous National Assessment (1989). Proved reserves of natural gas in the United States stand at approximately 135 TCFG, compared to 157 TCFG in 1989. Natural gas annual production has increased significantly in the intervening years from 17.0 TCFG in 1989 to about 17.8 TCFG in 1993.

Estimated mean amounts of undiscovered technically recoverable conventional gas resources onshore and in State waters are approximately the same as those reported in the previous National Assessment (Mast and others, 1989) (259 vs. 254 TCFG, respectively). Although estimates of conventional natural gas have actually been reduced in a few significant areas, such as the Anadarko Basin, estimates have been raised in a number of others (table 2). The overall change probably reflects the discovery of about 26 TCFG during the past 7 years and movement of certain resources previously estimated under conventional categories to plays in continuous-type deposits for this assessment.

Estimates of future growth of gas reserves in known fields are up significantly for this assessment, having increased from 93 TCFG in 1989 to approximately 322 TCFG for this assessment. As with oil, this increase reflects, more than anything else, the use of the EIA OGIFF data set rather than American Petroleum Institute–American Gas Association data.

In addition to conventional gas resources, the USGS has, for the first time, made a systematic assessment of potential additions to technically recoverable resources deriving from continuous-type, largely unconventional, reservoirs of natural gas. Resources in this category were not evaluated in the previous assessment (Mast and others, 1989) because of the difficulties in developing adequate methodologies and data. Historically, these resources have contributed little to the national energy supply. However, we estimate there exists, at a mean value, 308 TCFG of technically recoverable natural gas in continuous-type deposits in sandstones, shales, and chalks, and almost 50 TCFG of technically recoverable gas in coal-bed deposits. These resources are thus comparable in magnitude to conventional resources, although their anticipated deliverability and development economics will be very different than gas in conventional accumulations.

The 1995 National Assessment documents large, technically recoverable resources of non-associated gas in continuous-type deposits. Significant extraction effort will be required to obtain this gas. Based on existing technology, the assessment indicates that approximately 960,000 productive wells will be required to recover potential reserve additions of 300 TCFG, based on the distribution of EUR's shown in figure 13. Furthermore, extrapolation of present-day success ratios implies that roughly 570,000 "dry" holes would have to be drilled along with the productive wells. By way of perspective, the most oil and gas wells of all kinds drilled in the United States in 1 year is about 92,000, and from 1986 to the present the total has been less than 40,000 wells per year. In the case of discrete (conventional) fields, most resources have been recovered from relatively few, large fields. Analogously, in the case of continuous-type gas accumulations, most gas is expected to be recovered from a relatively small subset of productive wells. The assessment data show that one-half of the mean potential recoverable resources of 300 TCFG will be produced by about 100,000 wells, 25 percent will be produced by an additional 150,000 wells, and the remaining 25 percent will require some 700,000 producing wells (fig. 13).

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