OCS Report
BOEM 2012-103

Outer Continental Shelf

Estimated Oil and Gas Reserves Gulf of Mexico OCS Region December 31, 2008

U.S. Department of the Interior
Bureau of Ocean Energy Management
Gulf of Mexico OCS Region

ON COVER- Shell-operated Perdido Regional Development Spar (moored in 7,817 ft of water) arrived at Alaminos Canyon Block 857 in August 2008. Photo courtesy of Shell.

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ABBREVIATIONS AND ACRONYMS

AAPG	American Association of Petroleum Geologists
AL	Alabama
Bbbl	Billion barrels
Bbl	barrels
BBO	billion barrels of oil
BBOE	billion barrels of oil equivalent
Bcf	billion cubic feet
BOE	barrels of oil equivalent
BOEM	Bureau of Ocean Energy Management
BOEMRE	Bureau of Ocean Energy Management, Regulation and Enforcement
CFR	Code of Federal Regulations
DOCD	Development Operations Coordination Document
DOI	U.S. Department of the Interior
DPP	Development and Production Plan
^{0}F	degrees Fahrenheit
FL	Florida
ft	feet
GOM	Gulf of Mexico
GOMR	Gulf of Mexico Region
GOR	gas oil ratio
LA	Louisiana
MMbbl	million barrels
MMBOE	million barrels of oil equivalent
MMcf	million cubic feet
MMS	Minerals Management Service
MS	Mississippi
N	north
OAP	Offshore Atlas Project
OCS	Outer Continental Shelf
PDN	proved developed non-producing
PDP	proved developed producing
psia	pounds per square inch
PU	proved undeveloped
P/Z	pressure/gas compressibility factor
RE	Resource Evaluation
SCF/STB	standard cubic feet per stock tank barrel
SPE	Society of Petroleum Engineers
SPE-PRMS	Society of Petroleum Engineers Petroleum Resources Management System
SPEE	Society of Petroleum Evaluation Engineers
Tcf	trillion cubic feet
TVDSS	true vertical depth subsea
TX	Texas
U.S.	United States
USGS	United States Geological Survey
WPC	World Petroleum Congress

ABSTRACT

This is the annual publication that presents the Bureau of Ocean Energy Management (BOEM) estimates of oil and gas reserves in the Gulf of Mexico Outer Continental Shelf. As of December 31, 2008, it is estimated that the Original Proved Reserves are 21.24 billion barrels of oil and 188.4 trillion cubic feet of gas from 1,270 proved fields. Original Proved Reserves are the total of the Cumulative Production plus Proved Reserves. This number includes 19 proved fields that were added during 2008. It also includes the 338 proved fields that have produced and expired. Estimates are derived for individual reservoirs from geologic interpretation and reserve evaluation. Cumulative Production from the proved fields accounts for 15.96 billion barrels of oil and 171.8 trillion cubic feet of gas. Proved Reserves are estimated to be 5.28 billion barrels of oil and 16.6 trillion cubic feet of gas. These reserves are recoverable from 932 proved active fields. For any field spanning State and Federal waters, reserves are estimated for the Federal portion only.

Reserves Justified for Development are estimated to be 0.27 billion barrels of oil and 1.2 trillion cubic feet of gas. These reserves are associated with 137 active fields. In total, there are 934 proved and justified for development active fields located in Federal waters. The Reserves Justified for Development are not added to Original Proved Reserves because of decreasing levels of economic certainty and hydrocarbon assurance.

In addition to the Proved Reserves and the Reserves Justified for Development discussed above, there are an estimated 6.16 billion barrels of oil and 16.3 trillion cubic feet of gas resources that are not presented in the tables and figures of this report. These Contingent Resources can be found in leases that have not yet qualified (and therefore have not been placed in a field) or they can be found in proved fields and in fields justified for development. As additional drilling and development occur, additional hydrocarbon volumes will become reportable, and BOEM anticipates future proved reserves and reserves justified for development to increase.

The estimates of reserves for this report were completed in December 2011 and represent the combined efforts of engineers, geologists, geophysicists, paleontologists, and other personnel of the BOEM Gulf of Mexico Region, Office of Resource Evaluation, in New Orleans, Louisiana.

INTRODUCTION

Title VI Section 606 of the Outer Continental Shelf Lands Act September 18, 1978, requires the Secretary of the Interior to conduct a continuing investigation for the purpose of determining the availability of all oil and natural gas produced or located on the Outer Continental Shelf (OCS). The Department of the Interior's (DOI), Bureau of Ocean Energy Management (BOEM), formerly the Bureau of Ocean Energy Management Regulation and Enforcement (BOEMRE) and previously Mineral Management Service (MMS), is the federal agency responsible for overseeing the safe and environmentally responsible development of energy and mineral resources on the OCS. This responsibility includes the Federal portion of Gulf of Mexico (GOM) waters. The acronym GOM used throughout this report refers only to Federal waters. BOEM Reserves inventory, a major component of the Resource Evaluation (RE) Program, is the basic foundation for energy supply, forecasting, public policy decisions, independent assessment/verification, and the assuring of fair value in public/private transactions. For an overview of the Reserves Inventory Program visit BOEM's Web site at:
http://www.boem.gov/Oil-and-Gas-Energy-Program/Resource-Evaluation/Reserves-Inventory/Index.aspx.

This report supersedes the *Estimated Oil and Gas Reserves, Gulf of Mexico, December 31, 2007 (Crawford et al., 2011)***.** It presents estimated Original Proved Reserves, Cumulative Production, Proved Reserves, and Reserves Justified for Development as of December 31, 2008, for the GOM. **Figure 1** represents the percentages of Cumulative Production, Proved Reserves, Reserves Justified for Development, and Contingent Resources in the GOM. Estimates of reserves growth (an observed phenomenon that occurs when there is an incremental increase through time in the estimates of proved reserves) as well as undiscovered and known resources are not presented in detail in this report.

As of December 31, 2008, the 1,270 proved oil and gas fields in the federally regulated part of the GOM OCS contained Original Proved Reserves estimated to be 21.24 billion barrels of oil (BBO) and 188.4 trillion cubic feet (Tcf) of gas. Cumulative Production from the proved fields accounts for 15.96 BBO and 171.8 Tcf of gas. Proved Reserves are estimated to be 5.28 BBO and 16.6 Tcf of gas for the 932 proved active fields. Proved oil reserves have increased 8 percent and the proved gas reserves have increased 9 percent from the 2007 report. Reserves Justified for Development in the federally regulated part of the GOM OCS are estimated to be 0.27 BBO and 1.2 Tcf of gas. Reserves Justified for Development in water depths greater than 1,000 feet (ft) represent 76 percent of the total oil and 60 percent of the total gas Reserves Justified for Development.

In addition to the Proved Reserves and the Reserves Justified for Development discussed above, there are an estimated 6.16 billion barrels of oil and 16.3 trillion cubic feet of gas resources that are not presented in the tables and figures of this report. These Contingent Resources can be found in leases that have not yet qualified (and therefore have not been placed in a field) or they can be found in proved fields and in fields justified for development. As additional drilling and development occur, additional hydrocarbon volumes will become reportable, and BOEM anticipates future proved reserves to increase.

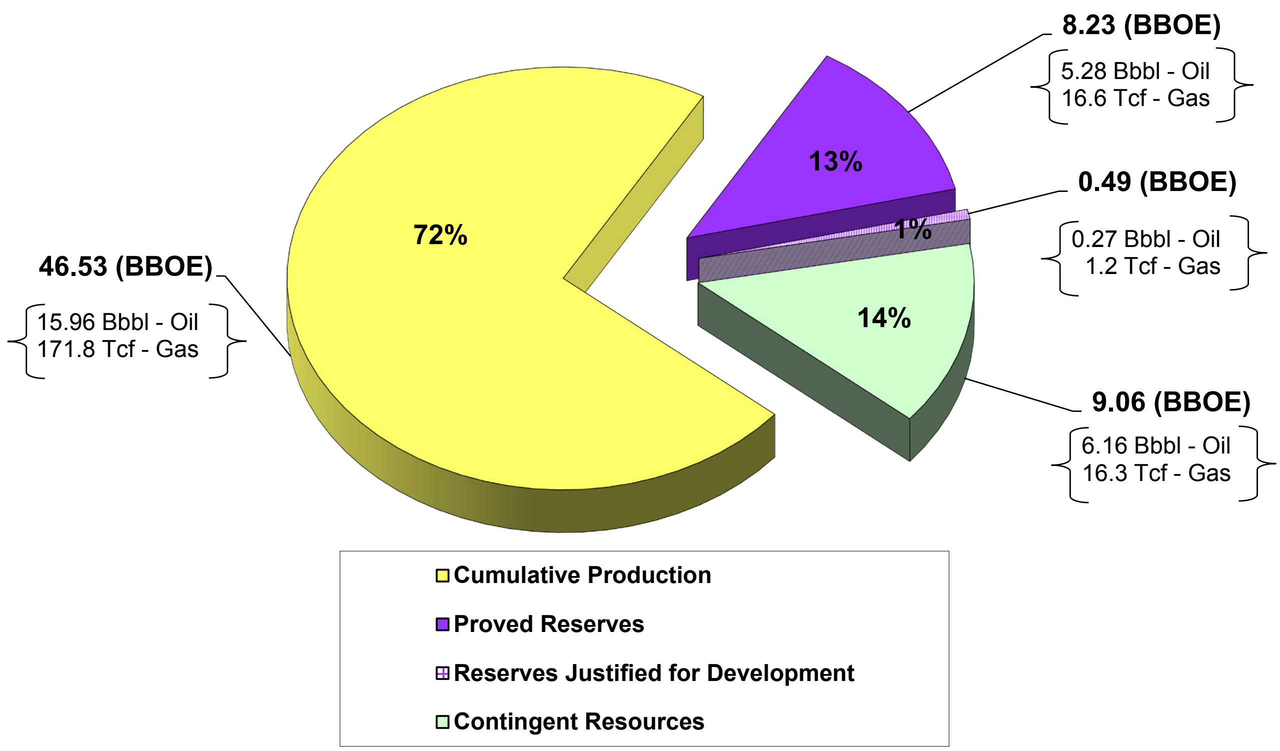


Figure 1. BOEM GOM production, reserves, and resources.

BACKGROUND

Definition of Resource and Reserve Terminology

To assure that BOEM reserve studies are relevant and useful to the widest possible audience BOEM has revised its classification system to conform to the Petroleum Resources Management System (SPE-PRMS) sponsored by the Society of Petroleum Engineers (SPE), the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC), and the Society of Petroleum Evaluation Engineers (SPEE). The SPE-PRMS was published in 2007 and is designed to provide a common reference for the petroleum industry and regulatory disclosure agencies (SPE, 2007).

Starting with this report, all BOEM OCS reserves reports will use the SPE-PRMS schema. SPE-PRMS was designed to allow some flexibility to meet the users' and agencies' specific needs. Accordingly, BOEM has modified the terminology of some categories and sub-classes to meet its program requirements. Despite subtle differences in naming conventions and definitions the overall format and classification criteria between BOEM and SPE-PRMS are closely aligned. This is shown in **Figure 2**. Definitions for each reserves category are presented at the end of this section.

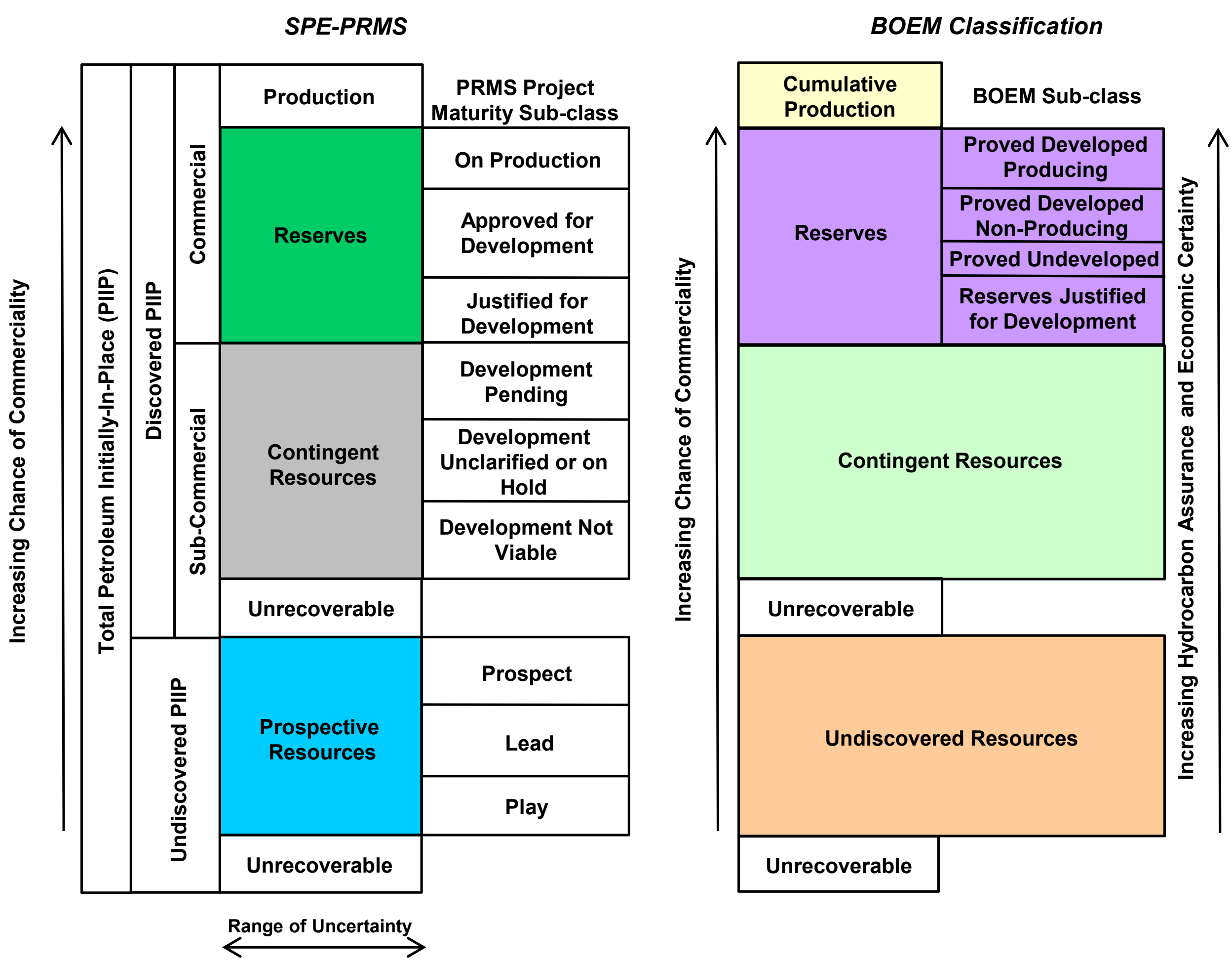


Figure 2. Comparison of SPE-PRMS and BOEM categories.

Classification of Resources and Reserves

Under SPE-PRMS, the development project is the primary element in classifying Resources and Reserves. This system considers both the technical and commercial factors that impact a project's economics, productive life, and associated cash flows. As the project matures (from the initial planning phases to infrastructure construction to production and sales) Resources and Reserves are re-categorized based on their increasing chances of commerciality.

As shown in **Figure 2**, Reserves represent the highest level of commerciality of resource categories and are defined as *those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions*. In order to be classified as Reserves, petroleum accumulations must satisfy four criteria: they must be discovered, they must be recoverable, they must exist in commercial quantities, and they must be remaining (as of a given date) based on the development project(s) applied (SPE 2007). Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity, reserves status, or by economic status.

The BOEM classification process under SPE-PRMS is shown in **Figure 3**. At the point in time a discovery is made, the identified accumulation of hydrocarbons is classified a Contingent Resource, as a development project has not yet been identified. When the lessee makes a formal commitment to develop and produce the accumulation it is classified as a Reserves Justified for Development. During the period when infrastructure is being constructed and installed, the accumulation is classified as Proved Undeveloped Reserves. After the equipment is in place and production of the accumulation has begun, the status becomes Proved Developed Producing Reserves. All hydrocarbons produced and sold are included in Cumulative Production category. Should the development be abandoned at any phase of the project, the remaining hydrocarbons will be re-categorized to Contingent Resources category.

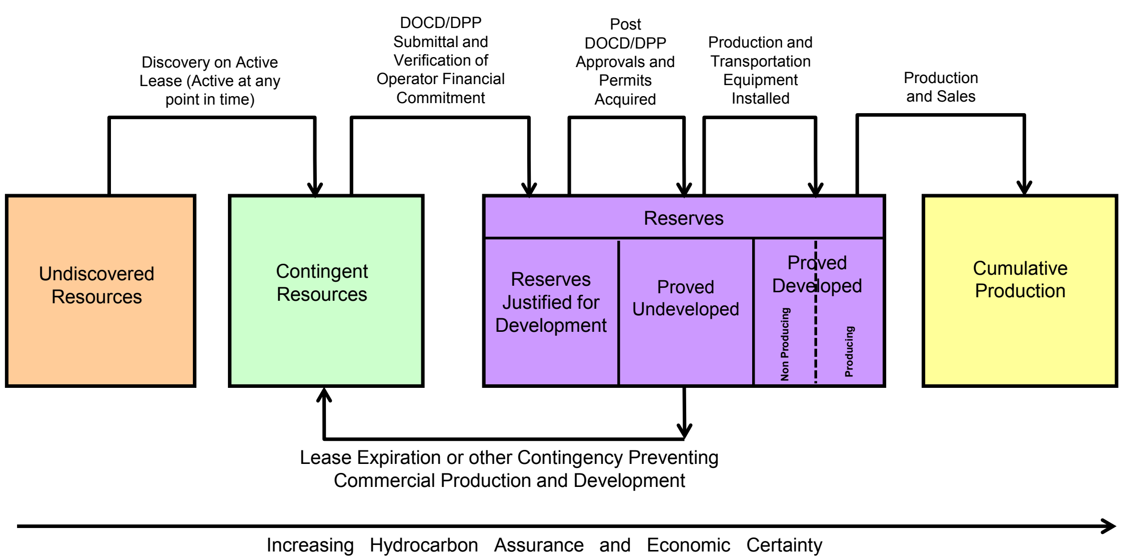


Figure 3. BOEM reserves classification process.

Comparison with Previous BOEM Reserves Reports

Prior to this report BOEM had standardized its definitions of resources (*Estimates of Undiscovered Conventional Oil and Gas Resources in the United States—A Part of the Nation's Energy Endowment*, U.S. Geological Survey (USGS) and MMS, 1989). The Society of Petroleum Engineers (SPE) and World Petroleum Congresses (WPC) had also adopted a standardized set of reserve categories and definitions (SPE and WPC, 1997), and the definitions used by BOEM conformed to both of these sources.

Figure 4 maps the previous classification system used by BOEM (on the left) with the SPE-PRMS structure that BOEM has adopted going forward. The major differences between the current and previous BOEM systems are in using the status of the development project(s) as the basis of re-classification (specifically the operator must submit a DOCD/DPP before the project moves from Resource to Reserves), and in the elimination of the Unproved Reserves category.

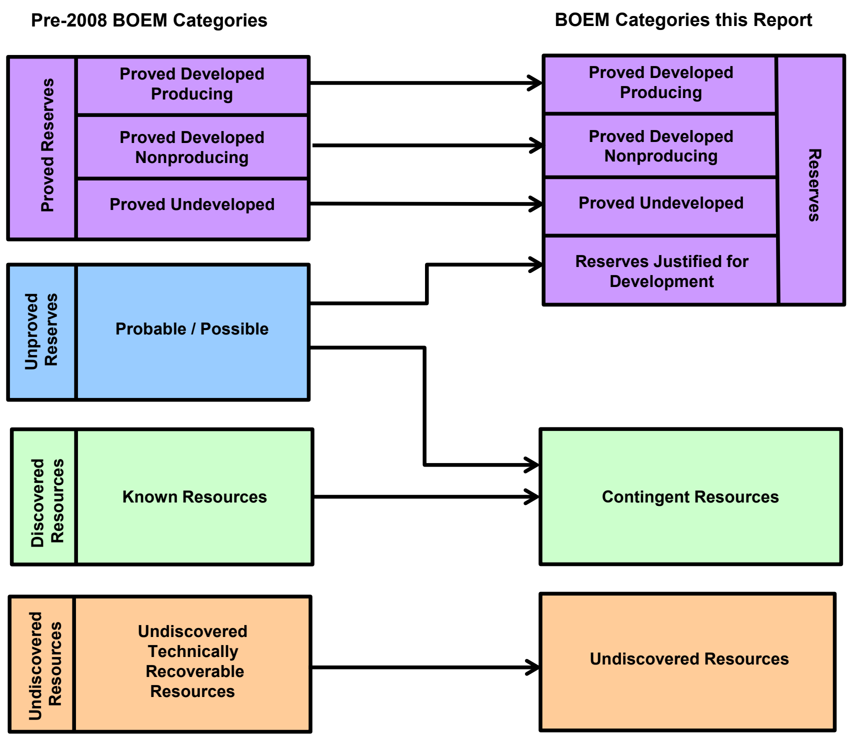


Figure 4: Comparison of Pre-2008 and current BOEM reserves categories.

The categorization of an accumulation as Unproved Reserves occurred when BOEM first considered a lease to be producible, which in most cases was prior to the commitment to proceed with commercial development. This category was based on geological and engineering analyses, but also considered the technical, economic, contractual, and regulatory uncertainties that precluded such reserves from being classified at a higher certainty level. Under SPE-PRMS, the project status determines the classification and a firm, tangible commitment to develop the accumulation is required in order to be classified as Reserves. Because of this, most accumulations that were previously classified as Unproved Reserves were migrated into the Contingent Resources category. In the few cases where there was a reasonable commitment that a development project was moving forward, Unproved Reserves were migrated to Reserves Justified for Development.

Definitions of Field, Resource and Reserves Terms

The following definitions as used in this report have been modified from SPE-PRMS and other sources where necessary to conform to requirements of the BOEM Reserves Inventory Program.

Field

A *Field* is an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same general geologic structural feature and/or stratigraphic trapping condition. There may be two or more reservoirs in a field that are separated vertically by impervious strata, laterally by local geologic barriers, or by both. The area may include one OCS lease, a portion of an OCS lease, or a group of OCS leases with one or more wells that have been approved as producible by the BOEM pursuant to the requirements of Title 30 Code of Federal Regulations (CFR) 550.115/116, Determination of Well Producibility (*Federal Register, 2011*). A field is usually named after the area and block on which the discovery well is located. Field names and/or field boundaries may be changed when additional geologic and/or production data initiate such a change. Using geological criteria, BOEM designates a new producible lease as a new field or assigns it to an existing field. A further explanation of field naming convention can be found in the "Reserves and Related Data Reported by Planning Area" section on page 11 and in the Field Naming Handbook available from BOEM's Gulf of Mexico Region (GOMR) Web site: http://www.boem.gov/BOEM-Newsroom/Offshore-Stats-and-Facts/Gulf-of-Mexico-Region/Field-Naming-Handbook---March-1996.aspx.

Project

A *Project* represents the link between the petroleum accumulation and the decision-making process, including budget allocation. A project, for BOEM's classification of Resources and Reserves, is the Field (see also Field).

Resources

Resources encompass all quantities of petroleum (recoverable and unrecoverable) naturally occurring on or within the Earth's crust, discovered and undiscovered, plus those quantities already produced. Further, it includes all types of petroleum whether currently considered conventional or unconventional.

Undiscovered Resources

Resources postulated, on the basis of geologic knowledge and theory, to exist outside of known fields or accumulations. Included also are resources from undiscovered pools within known fields to the extent that they occur within separate plays. BOEM assesses two types of undiscovered resources, *Undiscovered Technically Recoverable Resources (UTRR)* and *Undiscovered Economically Recoverable Resources (UERR).*

Discovered Resources

Hydrocarbons whose location and quantity are known or estimated from specific geologic evidence are *Discovered Resources*. Included are *Contingent Resources* and *Reserves* depending upon economic, technical, contractual, or regulatory criteria.

Contingent Resources

Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies.

Unrecoverable

The portion of discovered or undiscovered petroleum-initially-in-place quantities which are estimated, as of a given date, not to be recoverable. A portion of these quantities may become recoverable in the future as commercial circumstances change, technological developments occur, or additional data are acquired.

Reserves	*Reserves* are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. *Reserves* must further satisfy four criteria: They must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied. *Reserves* are further sub-classified based on economic certainty.
Original Proved Reserves	*Original Proved Reserves* are the total of the *Cumulative Production* plus *Proved Reserves*, as of a specified date.
Reserves Justified for Development	The lowest level of reserves certainty. Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting and that there are reasonable expectations that all necessary approvals/contracts will be obtained.
Proved Reserves	*Proved Reserves* are those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. *Proved Reserves* are classified as *Proved Undeveloped Reserves* or *Proved Developed Reserves*.
Proved Undeveloped Reserves	*Proved Undeveloped Reserves* are those *Proved Reserves* that are expected to be recovered from future wells and facilities, including future improved recovery projects which are anticipated with a high degree of certainty in reservoirs which have previously shown favorable response to improved recovery projects.
Proved Developed Reserves	*Proved Developed Reserves* can be expected to be recovered through existing wells and facilities and by existing operating methods. Improved recovery reserves can be considered as *Proved Developed Reserves* only after an improved recovery project has been installed and favorable response has occurred or is expected with a reasonable degree of certainty. Developed reserves are expected to be recovered from existing wells, including reserves behind pipe. Improved recovery reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor. *Proved Developed Reserves* may be sub-categorized as *Producing* or *Non-producing*.
Proved Developed Non-producing Reserves	*Proved Non-producing Reserves* are precluded from producing due to being *shut-in* or *behind-pipe*. *Shut-in* includes (1) completion intervals which are open at the time of the estimate, but which have not started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. *Behind-pipe* refers to zones in existing wells which will require additional completion work or future re-completion prior to the start of production. In both cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Proved Developed Producing Reserves	*Proved Developed Producing Reserves* are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Cumulative Production

Cumulative Production is the sum of all produced volumes of oil and gas prior to a specified date.

Reference Standard Conditions for Production and Reserves

Production data are the metered volumes of raw liquids and gas reported to the BOEM by Federal unit and lease operators. Oil and gas volume measurements and reserves are corrected to reference standard conditions of 60°F and one atmosphere (14.73 pounds per square inch absolute [psia]). Prior to September 1998, gas was reported at 15.025 psia. Beginning with the production month of September 1998, gas production was reported at a pressure base of 14.73 psia. BOEM has completed the process of converting all historical gas production to the 14.73 pressure base. Continuously measured volumes from production platforms and/or leases are allocated to individual wells and reservoirs on the basis of periodic well test gauges. These procedures introduce approximations in both production and remaining reserves data.

METHODOLOGY

Methods Used for Estimating Reserves

The Reserves inventory component of the RE Program assigns new producible leases to fields and establishes field limits**.** The RE Program also develops independent estimates of original amounts of natural gas and oil in discovered fields by conducting field reserve studies and reviews of fields, sands, and reservoirs on the OCS. The Program periodically revises the estimates of natural gas and oil to reflect new discoveries, development information and annual production.

This report, *Estimated Oil and Gas Reserves, Gulf of Mexico, December 31, 2008*, is based on aggregation of BOEM internal field studies completed at the reservoir and sand levels. All of the reservoir level data have been linked to the sand, pool, play, chronozone, and series level to support the Offshore Atlas Project (OAP).

Two additional reports address GOM reserves. The MMS OCS Report, *Atlas of Gulf of Mexico Gas and Oil Sands as of January 1, 1999 (Bascle et al., 2001*) provides a detailed geologic reporting of oil and gas reserves. The MMS OCS Report, *2000 Assessment of Conventionally Recoverable Hydrocarbon Resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 1999 (Lore et al., 2001)* also known as the National Assessment, and its update, *Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, 2006 (Lore, 2006)* address reserves, reserves appreciation, and undiscovered resources. For information on these reports, contact the BOEM's GOMR Public Information Office at 1-800-200-GULF or visit BOEM's GOMR Web site at http://www.boem.gov/About-BOEM/BOEM-Regions/Gulf-of-Mexico-Region/Index.aspx.

Reserve estimates from geological and engineering analyses have been completed for the 1,270 proved fields. Reserves accountability is dependent on the drilling and development phases of fields. When a field is in the Justified for Development category, geophysical mapping and available well data are the basis for defining reservoir limits. Once a field is moved into the proved category and more data become available, the reserve estimate is re-evaluated. Well logs, well file data, seismic data, and production data are periodically analyzed to improve the accuracy of the reserve estimate. As a field is depleted and/or abandoned, the Proved Reserves of productive reservoirs are assigned a value equal to the amount produced and the unrecovered reserve volumes are converted to Contingent Resources. Currently, there are 338 proved expired, depleted fields.

Estimation of reserves is done under conditions of uncertainty. Deterministic estimates provide a single "best estimate" based on known geological, engineering, and economic data. Probabilistic estimates generate a continuous range of estimates and their associated probabilities when the known geoscience, engineering, and economic data are used (SPE/WPC/AAPG/SPEE, 2007). Reserve estimates in this report are deterministic.

Methods used for estimating reserves can be categorized into three groups: analog, volumetric, and performance. The accuracy of the proved reserve estimate improves as more reservoir data become available to geoscientists and engineers. Reserve estimates in this report are based primarily on volumetric and performance methods.

Analog

In the estimation of resources/reserves by analogy, geoscientists use seismic data to generate maps of the extent of subsurface formations. Estimates of undiscovered resources are based on analogy with similar fields, reservoirs, or wells in the same area before any wells have been drilled on a prospect. The seismic data help geoscientists identify prospects and resources, but do not provide enough direct data alone to estimate reserves.

The effective pore space, water saturation, net hydrocarbon thickness, pressure, volume, and temperature data, all necessary to complete resource estimates for prospects, come from nearby field and reservoir well data. After one or more wells are drilled and found producible, a volumetric estimate is done. These estimates, while incorporating existing data, still rely on some information obtained from analogs.

Volumetric

In a volumetric reserve estimate, data from drilled wells and seismic surveys are used to develop geologic models. The effective pore space (porosity), water saturation, and net hydrocarbon thickness of the subsurface formations are calculated through evaluation of well logs, core analysis, and formation test data. Subsurface formations are mapped to determine area and net hydrocarbon thickness for each reservoir. Reservoir pressure, fluid volume, and temperature data from formation fluid samples are used to determine the change in volume of oil and gas that flow from higher pressure and temperature conditions deep underground to lower pressure and temperature conditions at the surface. All of these data are compiled, analyzed, and applied to standard equations for the calculation of hydrocarbons in place within the reservoirs. Standard recovery factor equations are then applied to the in-place estimates to calculate proved and unproved reserves.

Performance Methods

In performance-technique methods, reserves are estimated by using mathematical or graphical techniques of production decline curve analysis and material balance. These techniques are used throughout the oil industry in assessing individual well, reservoir, or field performance, and in forecasting future reserves. In decline analysis, a plot of daily production rate against time is most frequently used. Once a well or reservoir can no longer produce at its maximum capacity, the production rate declines. This production rate plotted against time can be extrapolated into the future to predict the remaining reserves. Another type of decline analysis is daily production rate plotted against cumulative production, which can also be used to predict remaining reserves. The declining daily rate is extrapolated to predict remaining reserves.

Material balance, another performance method, is used to estimate the amount of hydrocarbons in place. Given the premise that the pressure-volume relationship of a reservoir remains constant as hydrocarbons are produced, it is possible to equate expansion of reservoir fluids with reservoir voidage caused by fluid withdrawal minus any water influx. For depletion-drive gas reservoirs, a plot of the pressure/gas compressibility factor (P/Z) versus cumulative gas production provides an estimate of gas-in-place. Recoverable gas reserves are extrapolated to an abandonment reservoir pressure.

RESERVES AND RELATED DATA BY PLANNING AREA

The GOM OCS is divided into three planning areas for administrative purposes (**Figure 5**). This figure displays the reconfigured administrative planning area boundaries designated by BOEM (*Federal Register, 2006*). Each planning area is subdivided into protractions, which in turn are divided into numbered blocks. Fields in the GOM are identified by the protraction area name and block number of discovery – for example, East Cameron Block 271 (EC 271) Field.

As the field is developed, the limits may expand into adjacent blocks and areas. These adjacent blocks are then identified as part of the original field and are given that field name. Statistics in this report are presented as area totals compiled under each field name. All of the data associated with EC 271 Field are therefore included in the East Cameron (EC) totals, although part of the field extends into the adjacent area of Vermilion (VR). There are four exceptions to the above field-naming techniques: Tiger Shoal and Lighthouse Point, included in South Marsh Island (SM); Coon Point, included in Ship Shoal (SS); and Bay Marchand, included in South Timbalier (ST).

Through December 31, 2008, there were 934 proved and justified for development fields active in the federally regulated part of the GOM. A list, updated quarterly, of the active and expired fields can be found in the *OCS Operations Field Directory,* available from BOEM's GOMR Web site at http://www.boem.gov/BOEM-Newsroom/Offshore-Stats-and-Facts/Gulf-of-Mexico-Region/OCS-Operations-Field-Directory.aspx. There were 932 proved, active (producing and non-producing) fields and 2 justified for development active fields studied. Included are the 338 proved expired, depleted fields, abandoned after producing 3.9 percent barrels oil equivalent (BOE) of the total cumulative oil and gas production. Not studied were 94 fields expired, relinquished, or terminated without production. These fields may also be included in the *Indicated Hydrocarbon List* that can be found by visiting the BOEM's GOMR Web site at http://www.boem.gov/Oil-and-Gas-Energy-Program/Resource-Evaluation/Gulf-OCS-Region-Activities/Indicated-Hydrocarbon-List.aspx. In 2008, 51 proved fields expired including 34 proved fields that had no production during the year.

Reserves data and various classifications of fields, leases, boreholes, and completions are presented as area totals in **Tables 1, 2**, and **3**. (**Table 3** is discussed in the section "Reserves by Geologic Age," beginning on page 15.)

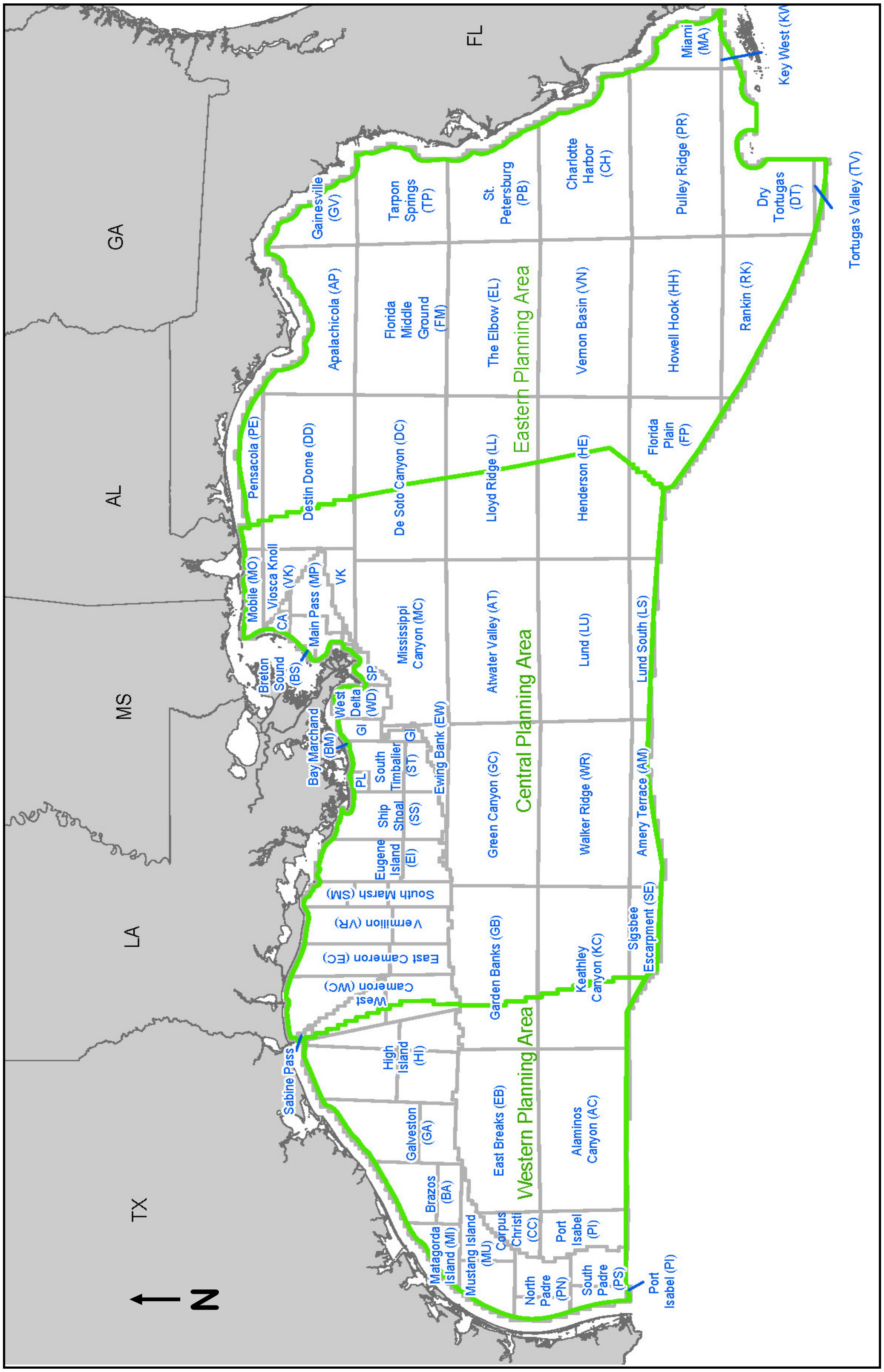


Figure 5. BOEM GOM OCS Planning Areas.

Reserves and Related Data by Planning Area

Table 1. Estimated oil and gas reserves for 1,270 proved fields by area, December 31, 2008.

Area(s) (Fig. 5)	Number of fields: Proved active prod	Proved active nonprod	Proved expired depleted	Justified active	Expired nonprod	Original Proved Reserves: Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)	Cumulative Production through 2008: Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)	Proved Reserves: Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)	Reserves Justified for Development: Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
Western Planning Area																	
Alaminos Canyon	3	2	0	0	2	398	474	482	67	112	87	331	362	395	57	104	76
Brazos	20	2	16	0	2	11	3,669	662	10	3,496	632	1	173	30	0	0	0
East Breaks	16	3	0	0	3	279	2,231	675	206	1,794	525	73	437	150	0	0	0
Galveston	21	2	25	0	2	67	2,295	476	57	2,033	418	10	262	58	0	0	0
Garden Banks	6	0	2	0	2	44	362	109	24	287	75	20	75	34	0	0	0
High Island and Sabine Pass	67	8	53	0	10	415	15,469	3,167	388	14,724	3,008	27	745	159	0	0	0
Matagorda Island	19	1	9	0	2	24	5,274	963	23	5,066	925	1	208	38	0	0	0
Mustang Island	11	0	18	0	5	9	1,806	330	7	1,714	312	2	92	18	0	0	0
N.& S.Padre Island	9	2	8	0	0	0	665	119	0	583	104	0	82	15	0	0	0
West Cameron and Sabine Pass	17	2	7	0	0	35	2,931	557	33	2,829	537	2	102	20	0	2	0
Western Planning Area (Other)*	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
Western Planning Area Subtotal	***189***	***22***	***138***	***0***	***29***	***1,282***	***35,176***	***7,540***	***815***	***32,638***	***6,623***	***467***	***2,538***	***917***	***57***	***106***	***76***
Central Planning Area																	
Atwater Valley	5	0	0	0	5	49	685	171	5	141	30	44	544	141	8	5	9
Chandeleur	5	1	7	0	0	0	376	67	0	366	65	0	10	2	0	4	1
East Cameron	40	6	21	0	0	357	10,924	2,301	333	10,561	2,212	24	363	89	0	4	1
Eugene Island	67	9	12	0	3	1,668	19,733	5,179	1,615	19,108	5,015	53	625	164	25	148	51
Ewing Bank	15	2	0	0	2	378	748	511	289	581	393	89	167	118	0	0	0
Garden Banks	21	3	6	0	4	716	3,960	1,420	531	3,145	1,090	185	815	330	0	0	0
Grand Isle	13	3	6	0	1	997	4,923	1,873	962	4,704	1,800	35	219	73	14	101	32
Green Canyon	31	4	5	1	18	2,743	3,806	3,420	1,038	2,450	1,474	1,705	1,356	1,946	76	124	98
Main Pass and Breton Sound	58	7	25	0	5	1,143	6,828	2,358	1,061	6,355	2,191	82	473	167	4	18	7
Mississippi Canyon	40	4	3	0	6	3,786	10,265	5,612	1,779	6,797	2,988	2,007	3,468	2,624	55	444	134
Mobile	21	6	7	0	2	0	2,329	415	0	1,978	352	0	351	63	0	1	0
Ship Shoal	53	4	12	0	2	1,408	12,302	3,597	1,365	11,881	3,479	43	421	118	12	105	31
South Marsh Island	38	6	7	0	0	959	14,875	3,606	889	13,884	3,360	70	991	246	0	5	1
South Pass	9	0	4	0	1	1,117	4,420	1,903	1,064	4,272	1,824	53	148	79	1	6	2
South Pelto	9	0	0	0	0	163	1,221	381	152	1,103	349	11	118	32	1	5	2
South Timbalier	43	4	14	1	1	1,639	10,684	3,540	1,516	9,615	3,227	123	1,069	313	0	4	1
Vermilion	56	4	24	0	1	568	16,524	3,509	535	16,008	3,383	33	516	126	0	0	0
Viosca Knoll	33	2	18	0	7	578	3,430	1,189	466	3,052	1,010	112	378	179	14	71	26
West Cameron and Sabine Pass	62	6	26	0	0	199	18,684	3,523	181	17,473	3,290	18	1,211	233	0	0	0
West Delta	19	2	3	0	3	1,393	5,637	2,395	1,360	5,440	2,328	33	197	67	7	46	15
Central Planning Area (Other)**	7	3	0	0	3	94	866	248	0	265	47	94	601	201	0	4	1
Central Planning Area Subtotal	***645***	***76***	***200***	***2***	***64***	***19,955***	***153,220***	***47,218***	***15,141***	***139,179***	***39,907***	***4,814***	***14,041***	***7,311***	***217***	***1,095***	***412***
Eastern Planning Area Subtotal*	***0***	***0***	***0***	***0***	***1***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***
GOM Total:	***834***	***98***	***338***	***2***	***94***	***21,237***	***188,396***	***54,758***	***15,956***	***171,817***	***46,530***	***5,281***	***16,579***	***8,228***	***274***	***1,201***	***488***
		1,270															

*Western Planning Area (Other) includes Corpus Christi, portions of Keathley Canyon, and Port Isabel.

**Central Planning Area (Other) includes Lund,Walker Ridge, and portions of Destin Dome, Desoto Canyon, Keathley Canyon, Lloyd Ridge, and others.

***Eastern Planning Area includes portions of DeSoto Canyon, Destin Dome, Lloyd Ridge, and others.

Figure 6 provides a geographical representation of locations for the proved fields discovered in the GOM beginning in 1975 (year of the first *Estimated Oil and Gas Reserves Report*). The bar heights in the figure are relative to the total proved reserves BOE for each proved field by decade.

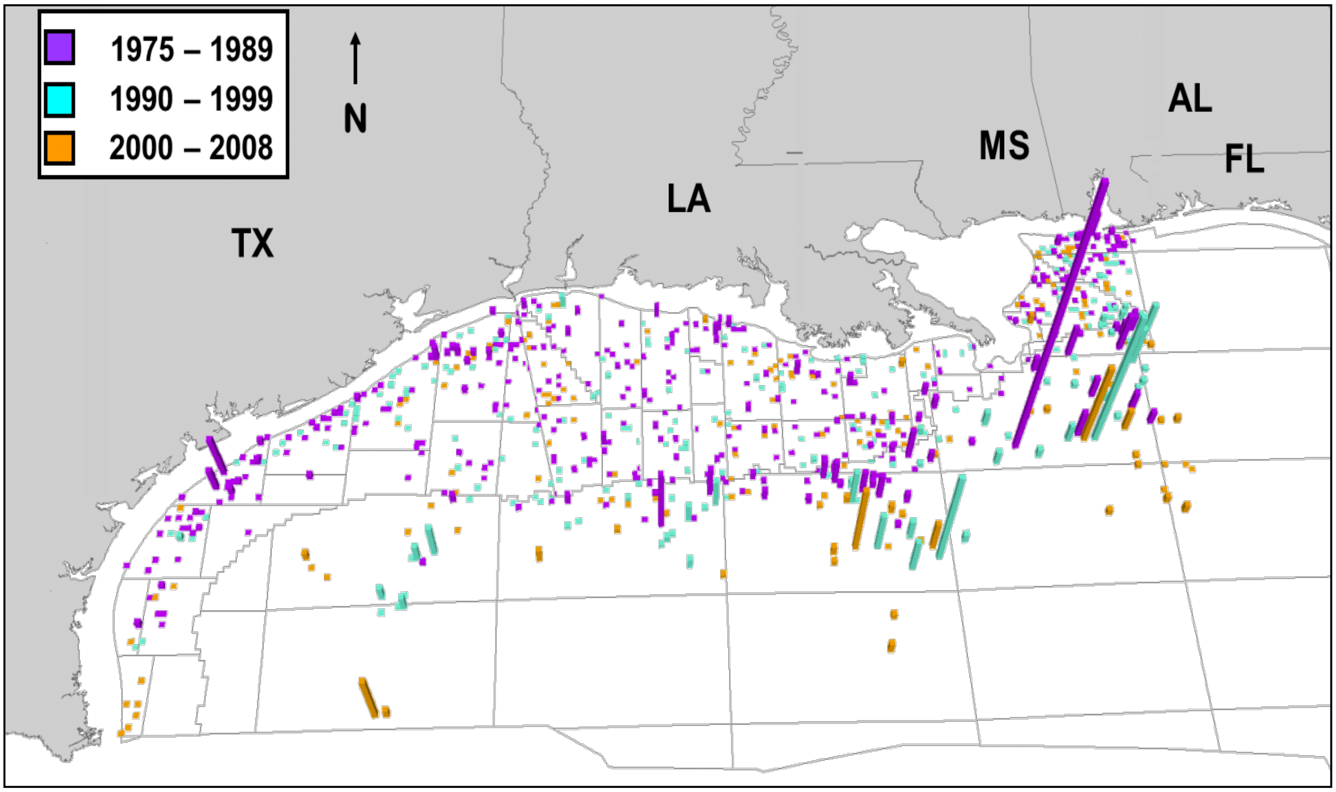


Figure 6. Proved fields discovered.

The status of GOM OCS Federal oil and gas leases as of December 31, 2008, is presented in Table 2. There are 8,361 active leases (2,167 proved active and 6,194 unqualified active) and 16,968 expired leases (1,847 proved depleted and 15,121 expired).

Table 2. Status of oil and gas leases, boreholes, and completions by area, December 31, 2008.

(All statistics associated with fields are presented within area totals compiled under each field name.)

Area(s) (Fig. 5)	Number of leases				Number of boreholes		Number of active completions
	Proved active	Proved depleted	Other active	Expired	Drilled	Abandoned	
Western Planning Area							
Alaminos Canyon	12	4	271	565	60	37	10
Brazos	33	62	9	436	604	512	136
East Breaks	38	8	261	646	389	269	125
Galveston	34	75	7	734	675	592	101
Garden Banks	52	28	222	1,312	699	543	167
High Island and Sabine Pass	158	215	54	1,290	3,721	2,982	918
Matagorda Island	39	49	5	214	668	559	229
Mustang Island	23	31	3	486	506	424	136
N.& S.Padre Island	15	17	2	396	204	160	63
West Cameron and Sabine Pass	1	0	1	12	10	7	17
Western Planning Area (Other)*	12	0	371	778	27	24	0
Western Planning Area Subtotal	***417***	***489***	***1,206***	***6,869***	***7,563***	***6,109***	***1,902***
Central Planning Area							
Atwater Valley	11	0	173	638	104	83	16
Chandeleur	8	17	0	55	90	76	21
East Cameron	113	160	21	766	2,408	1,953	644
Eugene Island	208	161	29	630	5,802	4,618	1,625
Ewing Bank	36	7	16	313	397	285	125
Garden Banks	0	0	147	6	9	4	0
Grand Isle	48	35	7	195	1,651	1,331	514
Green Canyon	102	15	450	1,150	1,176	871	264
Main Pass and Breton Sound	154	121	36	516	3,012	1,976	1,194
Mississippi Canyon	136	26	297	1,089	1,554	1,097	425
Mobile	38	19	6	114	184	142	58
Ship Shoal	174	112	39	647	4,028	2,849	1,327
South Marsh Island	434	92	17	434	3,197	2,326	1,023
South Pass	42	21	6	125	2,318	1,596	888
South Pelto	24	5	0	36	428	322	156
South Timbalier	144	72	24	617	3,577	2,595	1,255
Vermilion	143	176	31	777	3,389	2,700	914
Viosca Knoll	59	31	21	480	627	407	182
West Cameron and Sabine Pass	205	286	40	1,269	3,887	3,150	1,008
West Delta	89	53	6	237	3,181	2,374	868
Central Planning Area (Other)**	35	0	544	552	67	53	0
Central Planning Area Subtotal	***2,203***	***1,409***	***1,910***	***10,646***	***41,086***	***30,808***	***12,507***
Eastern Planning Area Subtotal*	***11***	***6***	***214***	***408***	***88***	***70***	***17***
GOM Total:	***2,631***	***1,904***	***3,330***	***17,923***	***48,737***	***36,987***	***14,426***

*Western Planning Area (Other) includes Corpus Christi, portions of Keathley Canyon, and Port Isabel.

**Central Planning Area (Other) includes Lund,Walker Ridge, and portions of Destin Dome, Desoto Canyon, Keathley Canyon, Lloyd Ridge, and others.

***Eastern Planning Area includes portions of DeSoto Canyon, Destin Dome, Lloyd Ridge, and others.

Definitions for the lease subgroups of **Table 2** are:

Proved Active — Leases within the designated 953 proved active fields presented in **Table 1**.

Proved Depleted — Leases associated with the 338 depleted fields and the leases that expired, terminated, or relinquished that produced and are part of currently active fields.

***Other Active* —** Active leases with Reserves Justified for Development or exploratory leases not yet qualified as producible or associated with any field.

***Expired* —** Leases expired, terminated, or relinquished by the operator without having produced any oil or gas, although some may have qualified as producible under 30 CFR 550.115/116. There are 94 expired fields with no production.

The total number of boreholes drilled and the number of boreholes plugged and abandoned are also shown in **Table 2**. There were 561 boreholes spudded during 2008, compared with 596 boreholes spudded during 2007, and 760 during 2006. The last column of **Table 2** presents the total number of active completions per area. Active completions are defined as those with perforations open to the formation and not isolated by permanent plugs; service wells (injection, disposal, or water source) are included. The presence or absence of production or injection is not considered. The number of boreholes and the number of active completions listed in this report are based on reports received by the BOEM at the time the count was made in 2011. These numbers may change as data are received, processed, and edited.

RESERVES BY GEOLOGIC AGE

In this report, the 1,270 proved and 2 justified for development fields have been classified at the geologic series level. The different geologic age classifications currently in use by BOEM are shown in **Figure 7**. Paleontological examinations of borehole cuttings, along with regional analysis of geological and geophysical data, were used in determining the age classifications. Figures displaying trend information in this report are color-coded to match the series in the biostratigraphic chart.

Table 3 shows the distribution of reserves and production data by geologic age and planning area. Please note that this report contains the term "Span Ages," which is used to denote a geologic age classification that spans more than one series.

Table 3. Estimated oil and gas reserves for 1,270 proved fields by geologic age, December 31, 2008.

Area	Number of proved reservoirs	Original Proved Reserves			Cumulative Production through 2008			Proved Reserves			Number of Justified for Development reservoirs	Reserves Justified for Development		
		Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)		Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
Western Planning Area														
Pleistocene	1,192	186	8,172	1,640	166	7,802	1,555	20	370	85	1	0	2	0
Pliocene	973	616	7,287	1,912	503	6,634	1,683	113	653	229	0	0	0	0
Miocene	2,489	165	19,360	3,610	146	18,180	3,381	19	1,180	229	0	0	0	0
Pre-Miocene	6	1	25	5	0	22	4	1	3	1	0	0	0	0
Span Ages	8	314	332	373	0	0	0	314	332	373	7	57	104	76
Western Planning Area Subtotal	***4,668***	***1,282***	***35,176***	***7,540***	***815***	***32,638***	***6,623***	***467***	***2,538***	***917***	***8***	***57***	***106***	***76***
Central Planning Area														
Pleistocene	3,420	1,216	20,773	4,912	1,117	19,629	4,610	99	1,144	302	69	6	38	13
Pliocene	9,159	6,699	50,196	15,631	5,932	47,251	14,340	767	2,945	1,291	262	46	300	99
Miocene	11,264	10,432	79,073	24,502	7,970	70,328	20,484	2,462	8,745	4,018	375	101	689	224
Pre-Miocene	34	1	2,274	405	0	1,908	340	1	366	65	2	0	5	1
Span Ages	43	1,607	904	1,768	122	63	133	1,485	841	1,635	7	64	63	75
Central Planning Area Subtotal	***23,920***	***19,955***	***153,220***	***47,218***	***15,141***	***139,179***	***39,907***	***4,814***	***14,041***	***7,311***	***715***	***217***	***1,095***	***412***
Eastern Planning Area														
Eastern Planning Area Subtotal	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***
GOM Planning Areas														
Pleistocene	4,612	1,402	28,945	6,552	1,283	27,431	6,165	119	1,514	387	70	6	40	13
Pliocene	10,132	7,315	57,483	17,543	6,435	53,885	16,023	880	3,598	1,520	262	46	300	99
Miocene	13,753	10,597	98,433	28,112	8,116	88,508	23,865	2,481	9,925	4,247	375	101	689	224
Pre-Miocene	40	2	2,299	410	0	1,930	344	2	369	66	2	0	5	1
Span Ages	51	1,921	1,236	2,141	122	63	133	1,799	1,173	2,008	14	121	167	151
GOM Total	***28,588***	***21,237***	***188,396***	***54,758***	***15,956***	***171,817***	***46,530***	***5,281***	***16,579***	***8,228***	***723***	***274***	***1,201***	***488***

Data from the producing reservoirs were used to generate **Table 3** and the original proved reserve trends for each geologic age presented in **Figure 8**. The Pleistocene reserves trend presented in **Figure 8** corresponds to the *Globorotalia flexuosa* through *Uvigerina hispida* biozones. Production within the Pleistocene extends from the Galveston area to east of the modern-day mouth of the Mississippi River. Deepwater Pleistocene production occurs in the East Breaks through Mississippi Canyon areas. Through December 31, 2008, the Pleistocene produced from 389 fields. Original Proved Reserves were 1.40 BBO and 28.9 Tcf. Proved Reserves were 0.12 BBO and 1.5 Tcf.

Chronostratigraphy					Biostratigraphy		BOEM Chronozone
Province	System	Subsystem	Series		Foraminifer & Ostracod (O)	Nannoplanktin	
			Holocene		Globorotalia inflata		
Cenozoic	Quaternary		Pleistocene	Upper	Globorotalia flexuosa Sangamon fauna	Emiliania huxleyi (base of acme) Gephyrocapsa oceanica (flood) Gephyrocapsa caribbeanica (flood)	PLU
				Middle	Trimosina "A"	Helicosphaera inversa Gephyrocapsa parallela Pseudoemiliania ovata	PLM
				Lower	Stilostomella antillea Trimosina "A" (acme) Hyalinea "B" / Trimosina "B" Angulogerina "B" Uvigerina hispida	Pseudoemiliania lacunosa "C" (acme) Calcidiscus macintyrei	PLL
	Tertiary	Neocene	Pliocene	Upper	Globorotalia crassula (acme) Lenticulina 1 Globoquadrina altispira Textularia 1	Discoaster brouweri	PU
				Lower	Buccella hannai (acme) Buliminella 1 Globorotalia plesiotumida (acme)	Sphenolithus abies Sphenolithus abies "B" Discoaster quintatus	PL
			Miocene	Upper	Globorotalia menardii (coiling change right-to-left) Textularia "X" Robulus "E" Bigenerina "A" Cristellaria "K" Bolivina thalmanni	Discoaster quinqueramus Discoaster berggrenii "A" Minylithus convallis Catinaster mexicanus Discoaster prepentaradiatus (increase)	MUU
					Discorbis 12 Bigenerina 2 Uvigerina 3	Helicosphaera walbersdorfensis Coccolithus miopelagicus	MLU
				Middle	Globorotalia fohsi robusta Textularia "W" Globorotalia peripheroacuta	Discoaster kugleri Discoaster kugleri (acme) Discoaster sanmiguelensis (increase)	MUM
					Bigenerina humblei Cristellaria "I" Cibicides opima	Sphenolithus heteromorphus Sphenolithus heteromorphus (acme)	MMM
					Cristellaria / Robulus / Lenticulina 53 Amphistegina "B" Robulus 43 Cibicides 38	Helicosphaera ampliaperta Discoaster deflandrei (acme) Discoaster calculosus	MLM
				Lower	Cristellaria 54 / Eponides 14 Gyroidina "K" Catapsydrax stainforthi	Reticulofenestra gartneri Sphenolithus disbelemnos	MUL
					Discorbis "B" Marginulina "A"	Orthorhabdus serratus Triquetrorhabdulus carinatus	MML
					Siphonina davisi Lenticulina hanseni	Discoaster saundersi Helicosphaera recta	MLL
		Paleogene	Oligocene	Upper	Robulus "A" Heterostegina texana Camerina "A" Bolivina mexicana	Dictyococcites bisectus Sphenolithus delphix	OU
				Lower	Nonion struma Textularia warreni	Sphenolithus pseudoradians Ismolithus recurvus	OL
			Eocene	Upper	Hantkenina alabamensis Camerina moodybranchensis	Discoaster saipanensis Cribrocentrum reticulatum Sphenolithus obtusus	EU
				Middle	Nonionella cockfieldensis Discorbis yeguaensis	Micrantholithus procerus Pemma basquensis Discoaster lodoensis	EM
				Lower	Globorotalia wilcoxensis	Chiasmolithus californicus Toweius crassus Discoaster multiradiatus	EL
			Paleocene	Upper	Morozovella velascoensis Vaginulina longiforma Vaginulina midwayana	Fasciculithus tympaniformis	LU
				Lower	Globorotalia trinidadensis Globigerina eugubina	Chiasmolithus danicus	LL
Mesozoic	Cretaceous	Upper	Gulfian		Abathomphalus mayaroensis Rosita fornicata Dicarinella concavata Hedbergella amabilis	Micula decussata Micula prinsii FAD Lithastrinus moratus Stoverius achylosus	KUU
					Dicarinella hagni Planulina eaglefordensis Rotalipora cushmani Favusella washitaensis Rotalipora gandolfii	Lithraphidites acutus	KLU
		Lower	Comanchean		Cythereis fredericksburgensis (O) Ammobaculites goodlandensis	Hayesites albiensis Braarudosphaera hockwoldensis	KUL
					Dictyoconus walnutensis Eocytheropteron trinitiensis (O) Orbitolina texana Rehacythereis? aff. R. glabrella (O)	Rucinolithus irregularis	KML
			Coahuilan		Ticinella bejaouaensis Choffatella decipiens Schuleridea acuminata (O)	Diadorhombus rectus Polycostella beckmanni	KLL
	Jurassic	Upper			Gallaecytheridea postrotunda (O) Epistomina uhligi Epistomina mosquensis Alveosepta jaccardi Paalzowella feifeli	Stephanolithion bigotii bigotii Stephanolithion bigotii maximum Stephanolithion speciosum	JU
		Middle			Reinholdella crebra	Watznaueria crucicentralis	JM

Abbreviated BOEM Gulf of Mexico biostratigraphic chart illustrating chronostratigraphy, biostratigraphy, and BOEM chronozones codes. For the complete chart visit : http://www.data.boem.gov/homepg/data_center/other/biochart.pdf.

Figure 7. BOEM GOM biostratigraphic chart.

The Pliocene reserves trend presented in **Figure 8** corresponds to *the Globorotalia crassula (acme)* through *Globorotalia plesiotumida (acme)* biozones. Production within the Pliocene extends from south of Galveston in the west to south of Mobile Bay in the east. Pliocene deepwater production extends into the areas of East Breaks, Garden Banks, Green Canyon, Ewing Bank, and Mississippi Canyon. Through December 31, 2008, the Pliocene produced from 542 fields. Original Proved Reserves were 7.31 BBO and 57.5 Tcf. Proved Reserves were 0.88 BBO and 3.6 Tcf.

The Miocene reserves trend presented in **Figure 8** corresponds to the *Globorotalia menardii (coiling change right-to-left)* through *Lenticulina hanseni* biozones. Production within the Miocene extends from North Padre Island in the west to east of the Mississippi River. Miocene productive sands also extend into deepwater from East Breaks and Garden Banks in the west to Ewing Bank, Green Canyon, Viosca Knoll, Mississippi Canyon, Atwater Valley, Destin Dome, Desoto Canyon, and Lloyd Ridge in the east. Through December 31, 2008 the Miocene produced from 725 fields. Original Proved Reserves were 10.60 BBO and 98.4 Tcf. Proved Reserves were 2.48 BBO and 9.9 Tcf.

The Pre-Miocene reserves trend presented in **Figure 8** includes the Oligocene, Eocene, and Paleocene in the Tertiary series, and the Cretaceous and Jurassic series. These reservoirs include Jurassic Norphlet sands and Lower Cretaceous Carbonates. Production within the Jurassic is limited to east of the Mississippi River in the Mobile area. Through December 31, 2008, these trends produced from 24 fields. Original Proved Reserves were less than 0.01 BBO and 2.3 Tcf. Proved Reserves were less than 0.01 BBO and more than 0.4 Tcf.

The Span Ages Proved Reserves include reservoirs from the Upper Pleistocene to the Lower Paleogene. Original Proved Reserves were 1.92 BBO and 1.2 Tcf. Proved Reserves are 1.80 BBO and 1.2 Tcf.

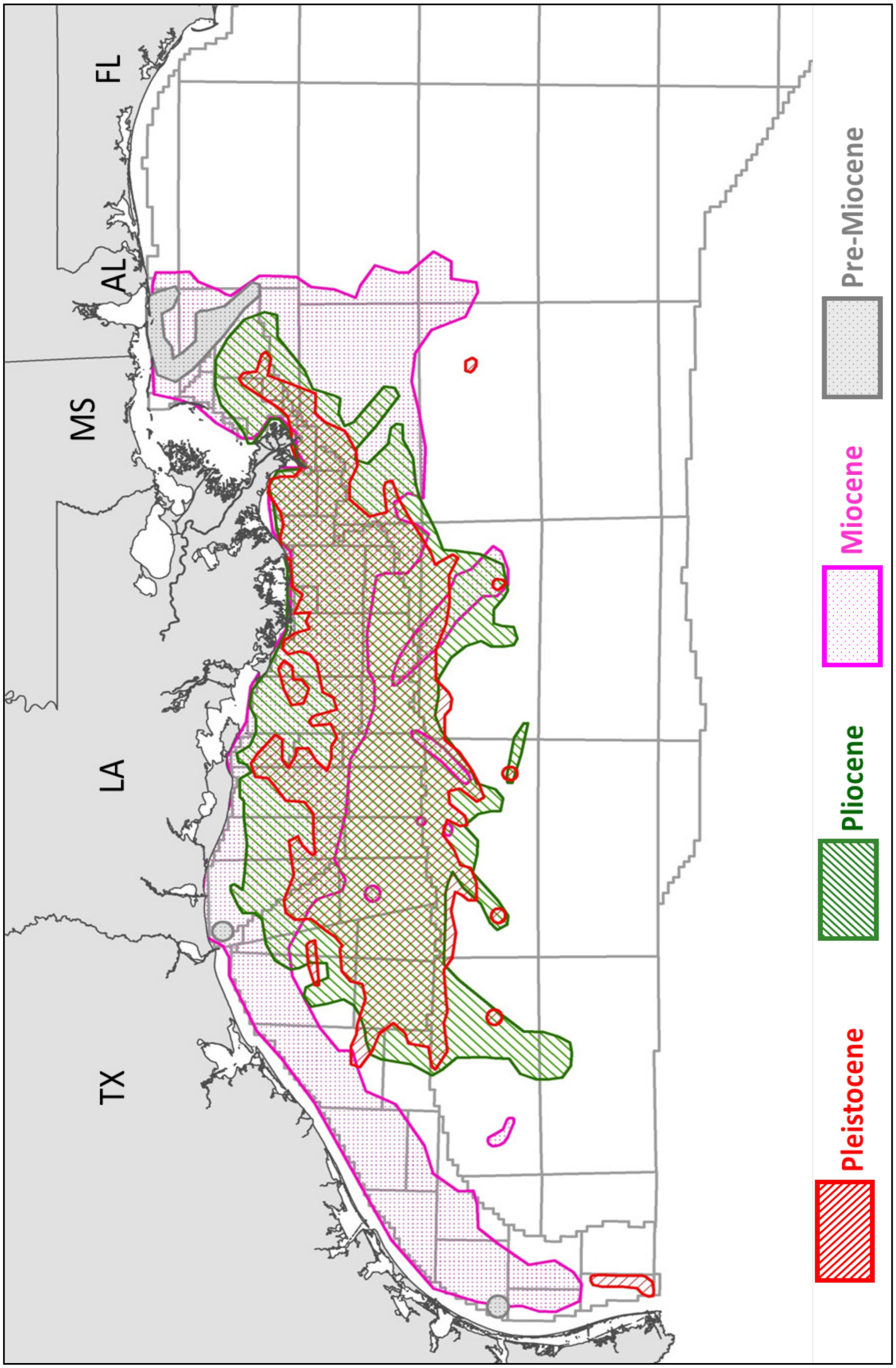
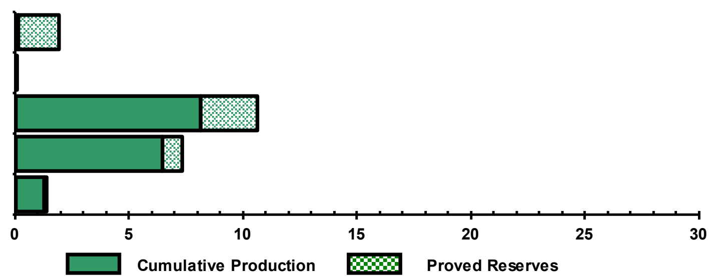


Figure 8. Original proved reserves trends.

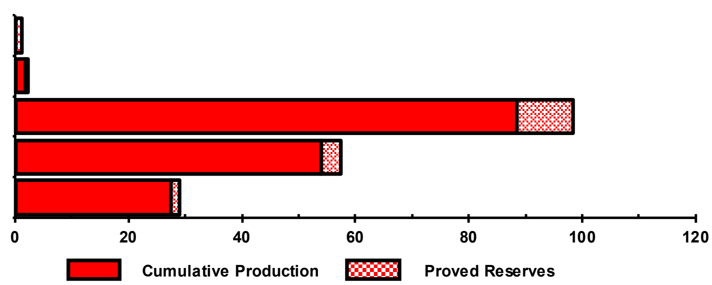
Figures 9(a), **9(b)**, and **9(c)** present Proved Reserves and Cumulative Production data by geologic age. This figure matches the chronostratigraphy by the BOEM in the abbreviated GOM biostratigraphic chart presented in **Figure 7**. This figure demonstrates that Miocene is the predominant reserves trend in the GOM, with the largest amount of Original Proved Reserves, Cumulative Production, and Proved Reserves.

	Proved Oil Reserves (BBO)		
	Cumulative Production	Proved Reserves	Original Proved Reserves
SPAN AGES	0.122	1.799	1.921
PRE-MIOCENE	0.000	0.002	0.002
MIOCENE	8.116	2.481	10.597
PLIOCENE	6.435	0.880	7.315
PLEISTOCENE	1.283	0.119	1.402
TOTAL	**15.956**	**5.281**	**21.237**



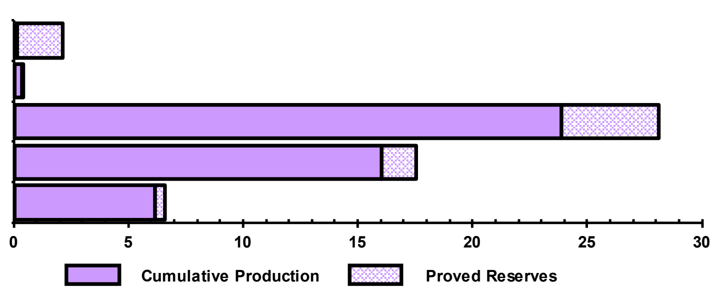
9(a). Proved oil reserves and production data, BBO.

	Proved Gas Reserves (TCF)		
	Cumulative Production	Proved Reserves	Original Proved Reserves
SPAN AGES	0.063	1.173	1.236
PRE-MIOCENE	1.930	0.369	2.299
MIOCENE	88.508	9.925	98.433
PLIOCENE	53.885	3.598	57.483
PLEISTOCENE	27.431	1.514	28.945
TOTAL	**171.817**	**16.579**	**188.396**



9(b). Proved gas reserves and production data, Tcf.

	Proved BOE Reserves (BBOE)		
	Cumulative Production	Proved Reserves	Original Proved Reserves
SPAN AGES	0.133	2.008	2.141
PRE-MIOCENE	0.344	0.066	0.410
MIOCENE	23.865	4.247	28.112
PLIOCENE	16.023	1.520	17.543
PLEISTOCENE	6.165	0.387	6.552
TOTAL	**46.530**	**8.228**	**54.758**



9(c). Proved BOE reserves and production data, BBOE.

Figure 9. Distribution of proved reserves and production data by geologic age.

RESERVES BY RESERVOIR DEPTH

In the last few years, operators have not only moved their operational activities farther offshore, but are also developing exploration targets that are deeper beneath the sea floor. The Wilcox sands found onshore are being targeted in ultra-deep plays on the shelf and in deepwater. For this report, deep gas reservoirs and deep oil reservoirs are defined as a reservoir with a datum depth (the subsea depth to the average depth of the reservoir) at or greater than 15,000 ft true vertical depth subsea (TVDSS). The reservoirs were aggregated to the field level for this analysis. While only 3.8 percent of all proved oil and gas reservoirs have a datum depth of 15,000 ft TVDSS or greater, these reservoirs account for 16.5 percent of the total proved reserves in the GOM.

Deep Gas

The interest in deeper gas targets was spurred, in part, when the Federal Government offered shallow water deep gas royalty relief incentives beginning with leases acquired in Central Gulf Lease Sale 178 in 2001. On January 26, 2004, a new incentive for existing leases was published. This rule provided for royalty suspensions for wells drilled to deep depths on existing shallow water [less than 200 meters (656 ft)] leases. Deep depths were defined as 15,000 ft or deeper TVDSS when a well is completed and produces from a reservoir entirely below that depth, or as 18,000 ft TVD SS when a well without completions penetrates a reservoir target entirely below that deeper depth. Since the initial ruling, additional modifications have been added to encourage exploration. Effective December 18, 2008, a third well depth category – an ultra-deep well (defined as wells with a perforated interval the top of which is at least 20,000 feet TVD SS) was added. More information is available from the BOEM Web site at http://www.boem.gov/Oil-and-Gas-Energy-Program/Energy-Economics/Royalty-Relief/Index.aspx. Industry announced two deep shelf gas discoveries in 2008: W&T Offshore Inc. drilled a non-commercial deep shelf well at Eugene Island Block 186 and McMoRan Exploration Co. drilled the ultra-deep Blackbeard West No. 1 in South Timbalier Block 168. Five deepwater deep gas discoveries were announced in 2008, the Diamond prospect in Lloyd Ridge 370, the Tortuga prospect in Mississippi Canyon Blocks 561/605, the Geauxpher prospect in Garden Banks Block 462, the Gladden Prospect in Mississippi Canyon Block 800, and Mississippi Canyon Block 503.

Figures 10(a), **10(b**), and **10(c)** show proved gas reservoirs at datum depths 15,000 to 17,999 ft, 18,000 to 19,999 ft, and 20,000 ft or greater. The size of the bubble corresponds to Original Proved Reserves at the field level as of December 31, 2008. The Original Proved Reserves from reservoir depths of 15,000 ft or greater is 9.4 percent of all proved gas reserves. Mobile Block 823 (MO 823) Field contains the reservoirs with the largest proved gas reserves on the shelf. Mississippi Canyon Block 731 (MC 731) Field contains the reservoirs with the largest proved gas reserves in deepwater.

Deep Oil

In 2008 industry announced two deepwater, deep oil discoveries: the Freedom Prospect in Mississippi Canyon Block 948 and the Kodiak prospect in Mississippi Canyon Block 771. Both encountered oil sands in Middle and Lower Miocene reservoirs.

Figures 11(a), **11(b)**, and **11(c)** show oil reservoirs at datum depths 15,000 to 17,999 ft, 18,000 to 19,999 ft, and 20,000 ft or greater. The size of the bubble corresponds to Original Proved Reserves at the field level as of December 31, 2008. The Original Proved Reserves from target depths of 15,000 ft or greater is 24.8 percent of all proved oil reserves. South Pass Block 89 (SP 89) Field contains the reservoir with the largest proved oil reserves on the shelf. Mississippi Canyon Block 807 (MC 807) Field contains the reservoir with the largest proved oil reserves in deepwater.

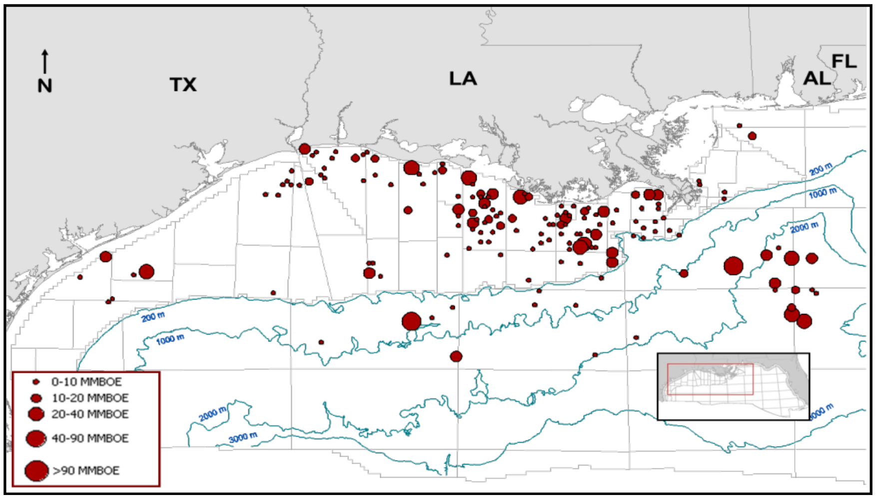


Figure 10(a). Gas reservoirs datum depth 15,000 - 17,999 ft.

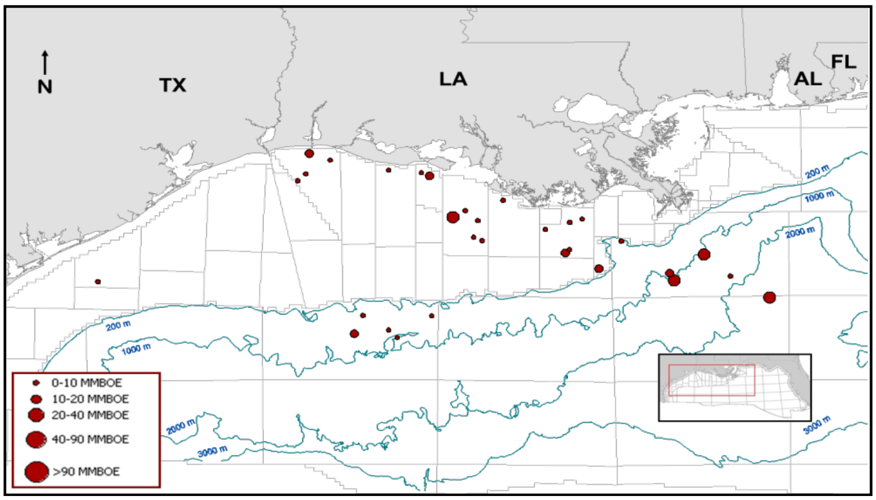


Figure 10(b). Gas reservoirs datum depth 18,000 - 20,000 ft.

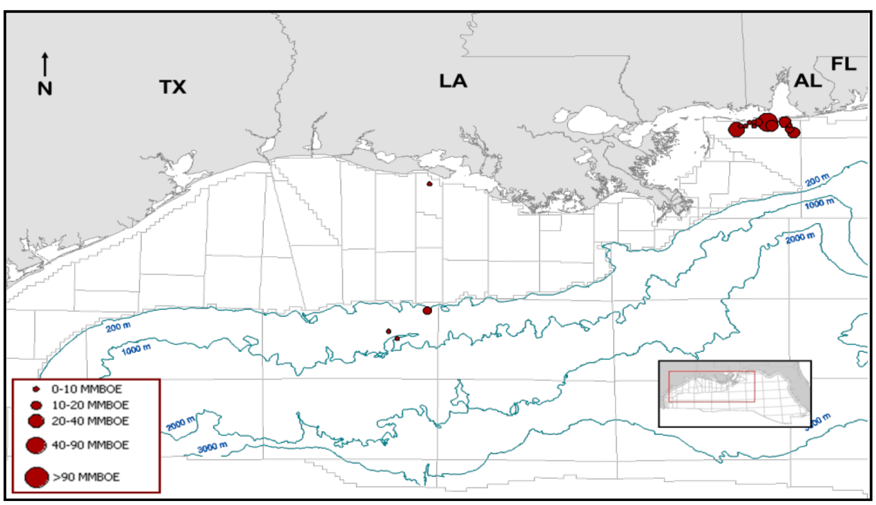


Figure 10(c). Gas reservoirs datum depth > 20,000 ft.

Figure 10. Deep gas reservoirs by datum depth summed to field level.

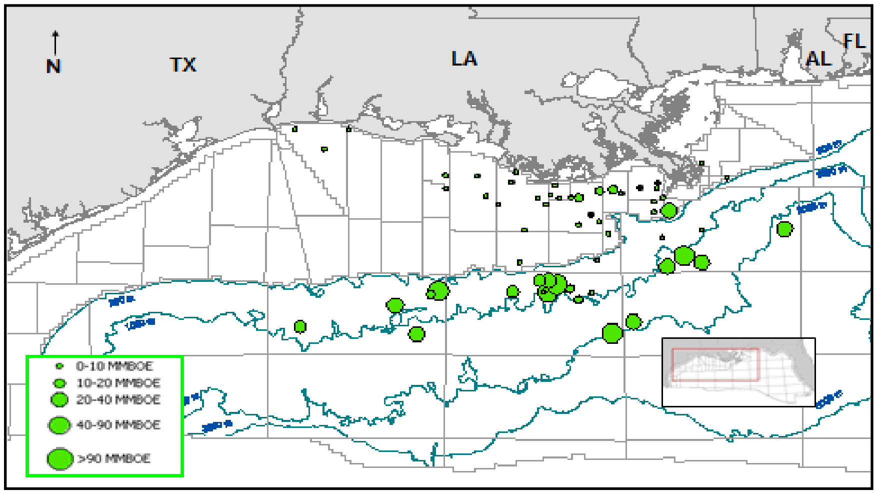


Figure 11(a). Oil reservoirs datum depth 15,000-17,999 ft.

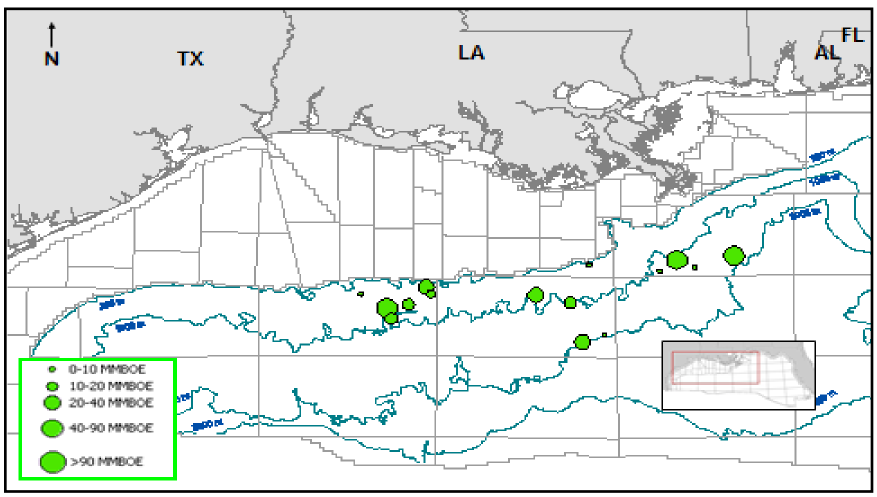


Figure 11(b). Oil reservoirs datum depth 18,000-20,000 ft.

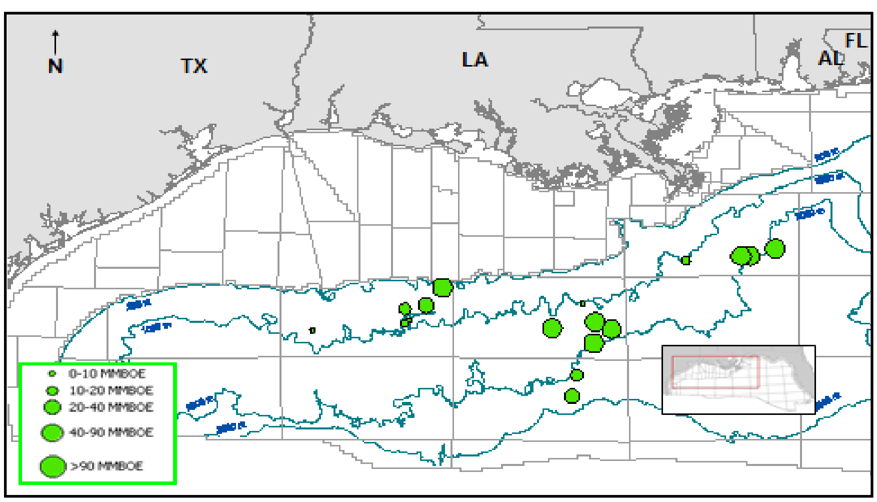


Figure 11(c). Oil reservoirs datum depth > 20,000 ft.

Figure 11. Deep oil reservoirs by datum depth summed to field level.

FIELD-SIZE DISTRIBUTION

Reserve sizes are expressed in terms of BOE. Gas reserves are converted to BOE and added to the liquid reserves for the convenience of comparison. The conversion factor of 5,620 standard cubic feet of gas equals 1 BOE is based on the average heating values of domestic hydrocarbons. A geometric progression, developed by the USGS (Attanasi, 1998), was selected for field-size (deposit-size) distribution ranges (**Table 4**).

In this report, fields are classified as either oil or gas; some fields do produce both products, making a field type determination difficult. Generally, fields with a gas/oil ratio (GOR) less than 9,700 standard cubic feet per stock tank barrel (SCF/STB) are classified as oil.

Table 4. Description of deposit-size classes.

Class	Deposit-size range*	Class	Deposit-size range*	Class	Deposit-size range*
1	0.031 - 0.062	10	16 - 32	18	4,096 - 8,192
2	0.062 - 0.125	11	32 -64	19	8,192 - 16,384
3	0.125 - 0.25	12	64 - 128	20	16,384 - 32,768
4	0.25 - 0.50	13	128 - 256	21	32,768 - 65,536
5	0.50 - 1.00	14	256 - 512	22	65,536 - 131,072
6	1 - 2	15	512 - 1,024	23	131,072 - 262,144
7	2 - 4	16	1,024 - 2,048	24	262,144 - 524,288
8	4 - 8	17	2,048 - 4,096	25	524,288 - 1,048,576
9	8 - 16	*Million Barrels of Oil Equivalent (MMBOE)			

The field-size distribution based on Original Proved Reserves (in BOE) for 1,270 proved fields is shown in **Figure 12(a)**. Of the 1,270 proved oil and gas fields, there are 234 proved oil fields represented in **Figure 13(a)** and 1,036 gas fields shown in **Figure 14(a)**. The Western Gulf of Mexico field-size distributions are displayed on **Figures 12(b)**, **13(b)**, and **14(b)**. **Figures 12(c)**, **13(c)**, and **14(c)** present the Central GOM field-size distributions of Original Proved Reserves including one field in the Eastern GOM. The field-size distribution, derived from the 137 fields containing Reserves Justified for Development, is shown in **Figure 15(a)**. There are 65 oil fields in **Figure 15(b)** and 72 gas fields containing Reserves Justified for Development in **Figure 15(c)**.

Analysis of the 1,270 proved oil and gas fields indicates that the GOM is historically a gas-prone basin. **Table 5** presents the median (exceeded by 50%) and the mean (arithmetic average) reserves from the field-size distributions. This figure also provides information on the largest two field-size ranges from **Figures 12-15**. The cumulative GOR of the 234 proved oil fields is 2,505 SCF/STB. The GOR of the 65 oil fields containing Reserves Justified for Development is 2,779 SCF/STB. The yield (condensate divided by gas) for the 1,036 proved gas fields is 23.8 barrels (Bbl) of condensate per million cubic feet (MMcf) of gas. The yield of the 72 gas fields containing Reserves Justified for Development is 56.2 Bbl of condensate per MMcf.

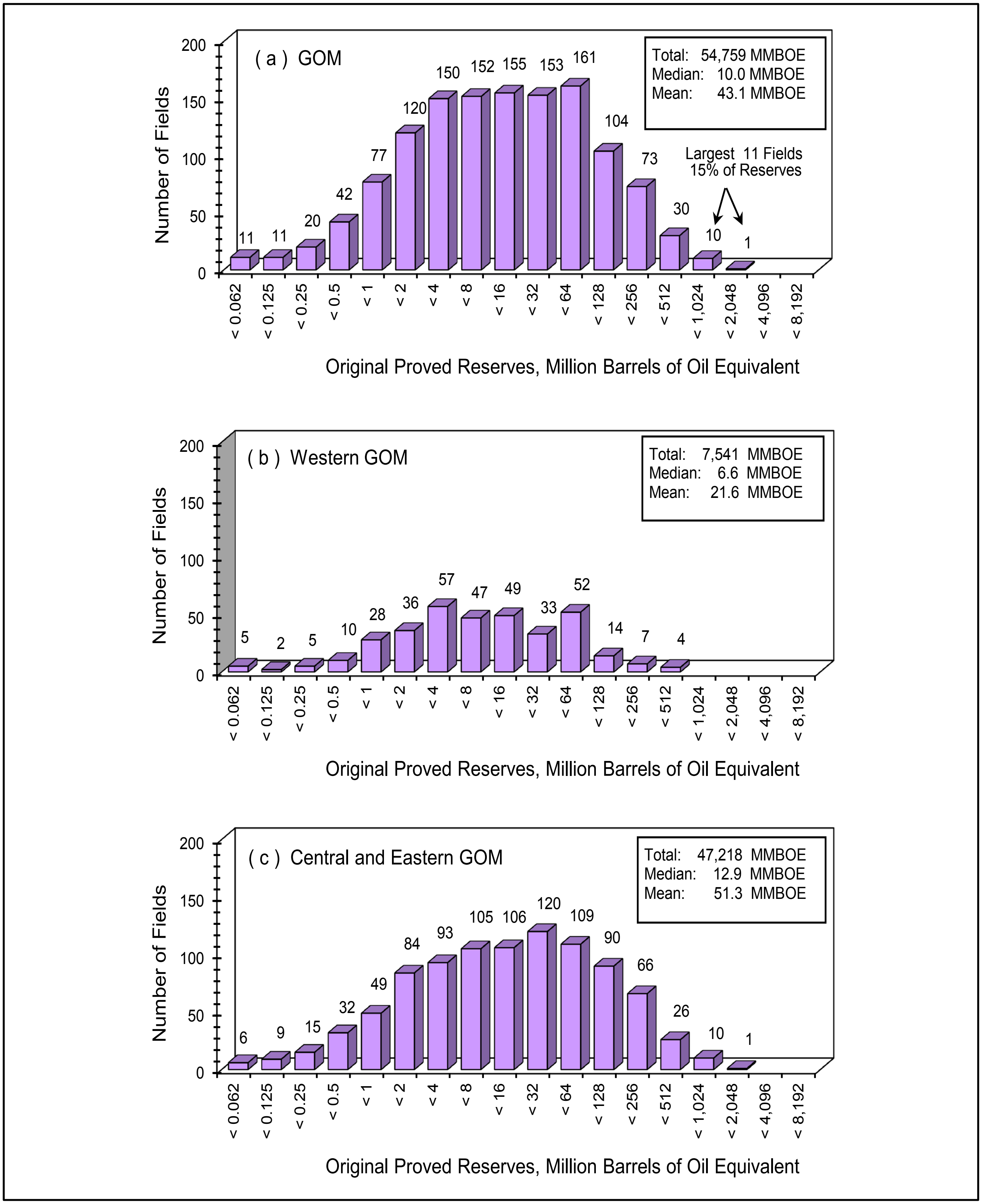


Figure 12. Field-size distribution of proved fields: (a) GOM, 1,270 fields; (b) Western GOM, 349 fields; (c) Central and Eastern GOM, 921 fields.

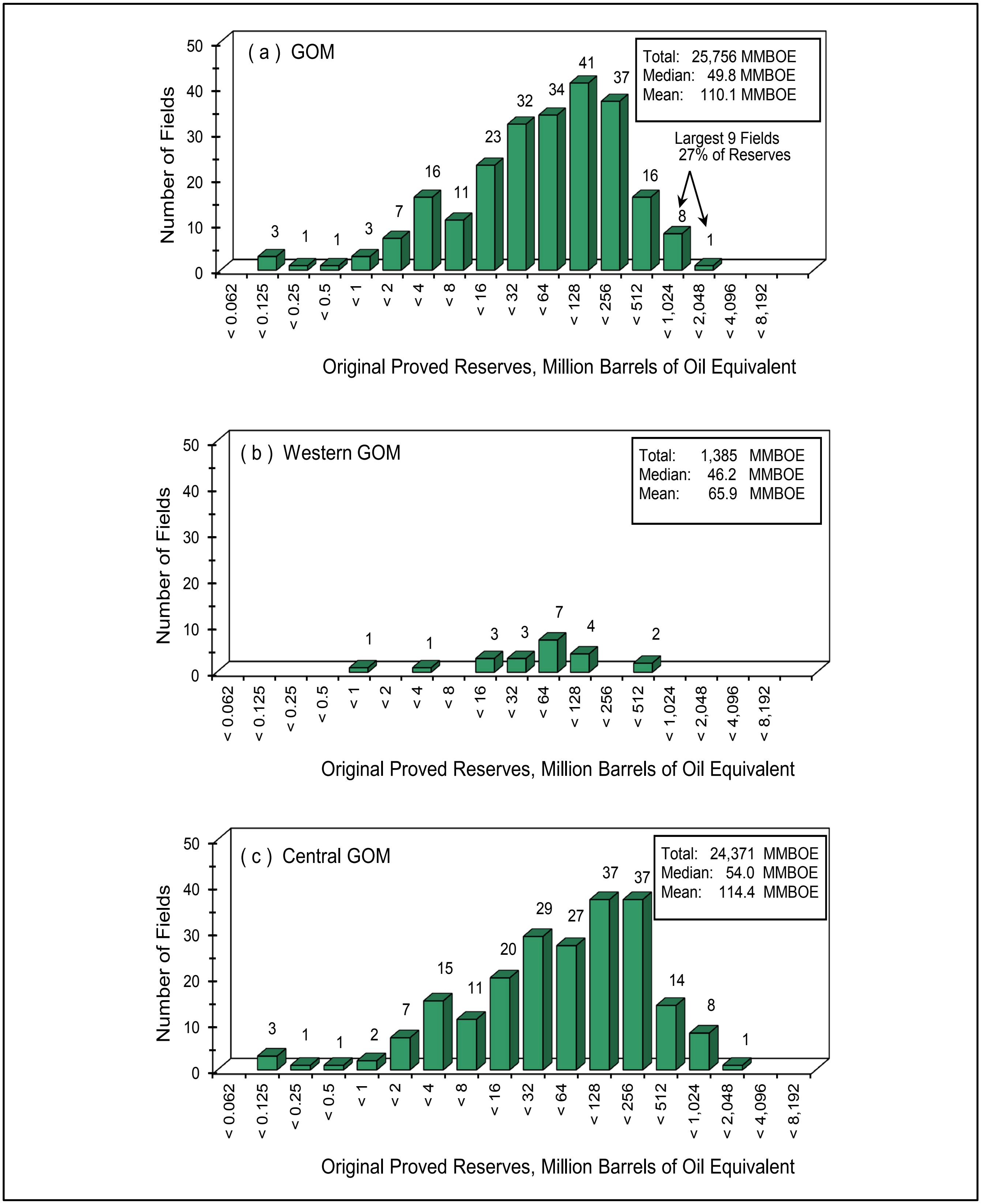


Figure 13. Field-size distribution of proved oil fields: (a) GOM, 234 fields; (b) Western GOM, 21 fields; (c) Central GOM, 213 fields.

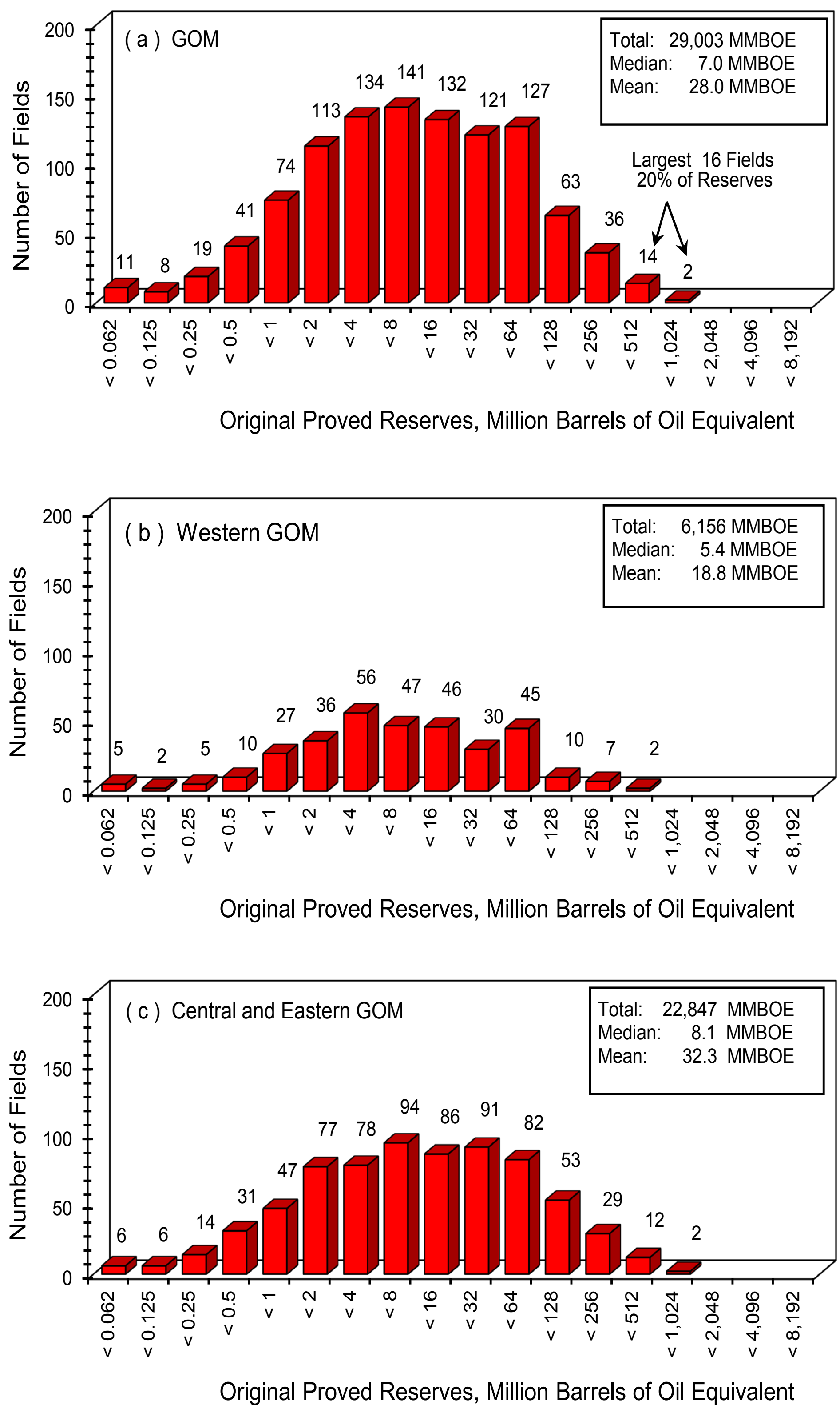


Figure 14. Field-size distribution of proved gas fields: (a) GOM, 1,036 fields; (b) Western GOM, 328 fields; (c) Central and Eastern GOM, 708 fields.

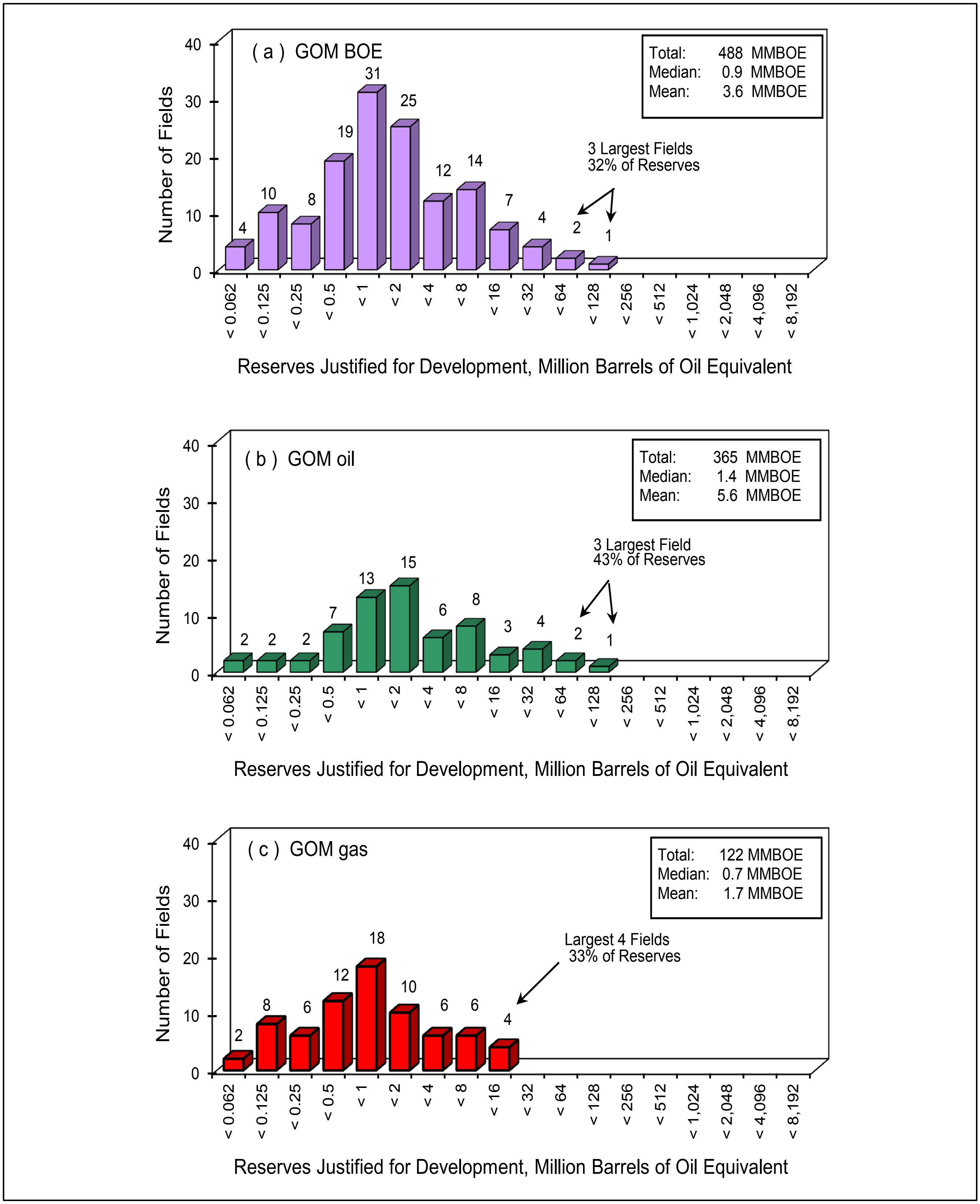


Figure 15. Field-size distribution of fields containing Reserves Justified for Development:
(a) GOM BOE, 137 oil and gas fields; (b) GOM oil, 65 fields; (c) GOM gas, 72 fields.

Table 5. Field-size distributions.

Description of Fields	Figure Number	Median*	Mean*	Largest Fields	
				Number	Reserves %
1,270 Proved Fields	Fig. 12a	10.0	43.1	11	15%
234 Proved Oil Fields	Fig. 13a	49.8	110.1	9	27%
1,036 Proved Gas Fields	Fig. 14a	7.0	28.0	16	20%
137 Fields with Reserves Justified for Development	Fig. 15a	0.9	3.6	3	32%
65 Oil Fields with Reserves Justified for Development	Fig. 15b	1.4	5.6	3	43%
72 Gas Fields with Reserves Justified for Development	Fig. 15c	0.7	1.7	4	33%
* Million barrels of oil equivalent (MMBOE)					

Figure 16 shows the cumulative percent distribution of Original Proved Reserves in billion barrels of oil equivalent (BBOE), by field rank. All 1,270 proved fields in the GOM OCS are included in this figure. A phenomenon often observed in hydrocarbon-producing basins is a rapid drop-off in size from that of largest known field to smallest. Twenty-five percent of the Original Proved Reserves are contained in the 25 largest fields. Fifty percent of the Original Proved Reserves are contained in the 86 largest fields. Ninety percent of the Original Proved Reserves are contained in the 428 largest fields.

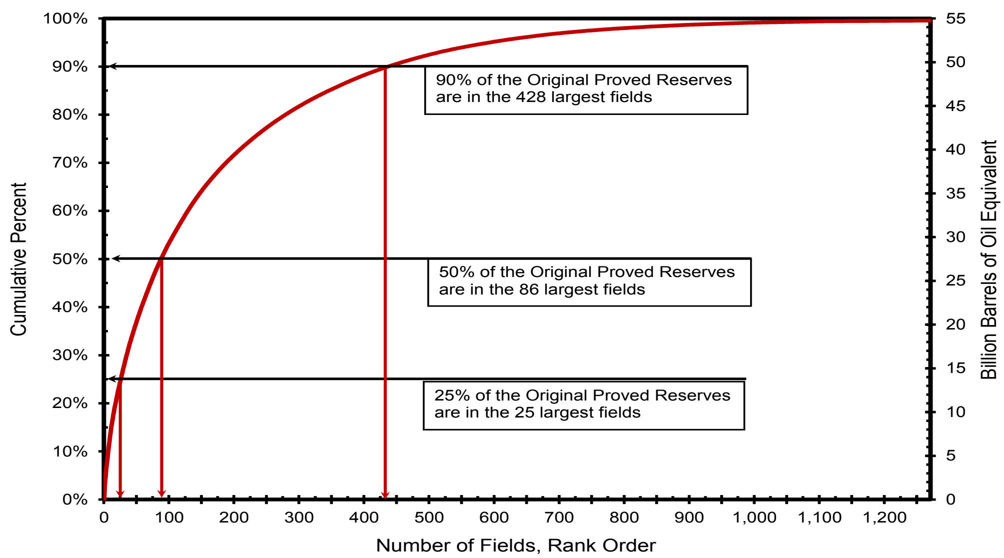


Figure 16. Cumulative percent total reserves versus rank order of field size for 1,270 proved fields.

Table 6 shows the distribution of the number of fields and Original Proved Reserves by water depth. A field's water depth is determined by averaging the water depth of the wells drilled in the field. The water depth ranges used in this figure are less than 500 ft, 500-999 ft, 1,000-1,499 ft, 1,500-4,999 ft, 5,000-7,499 ft and greater than or equal to 7,500 ft. Original Proved Reserves, reported in MMBOE, are associated with the 1,270 proved fields. Original Proved Reserves located in less than 500 ft of water accounts for 75 percent of the total GOM Original Proved Reserves. Development beyond 500 ft reflects a sizeable amount of Original Proved Reserves associated with a few fields. The mean Original Proved Reserves per field is 43.1 MMBOE. For water depths less than 500 ft it is 38.5 MMBOE; for 500-999 ft it is 23.6 MMBOE; for 1,000-1,499 ft it is 58.3 MMBOE, for 1,500-4,999 ft it is 79.3 MMBOE; for 5,000-7,499 ft it is 155.8 MMBOE; and greater than or equal to 7,500 ft it is 52.1 MMBOE.

Table 6. Field and reserves distribution by water depth.

Water Depth Range (Feet)	Number of Proved Fields	Original Proved Reserves (MMBOE)	Mean Original Proved Reserves per Proved Field	Proved Reserves (MMBOE)	Number of Fields with Reserves Justified for Development	Reserves Justified for Development (MMBOE)
< 500	1,071	41,271	38.5	2,147	92	146
500 - 999	54	1,272	23.6	107	2	3
1,000 - 1,499	23	1,340	58.3	186	8	9
1,500 - 4,999	86	6,823	79.3	2,603	23	216
5,000 - 7,499	21	3,271	155.8	2,495	8	33
>= 7,500	15	781	52.1	690	4	82
Totals:	1,270	54,758	43.1	8,228	137	488

Figure 17 shows the largest 20 fields ranked in order by Proved Reserves. Eighteen of the 20 fields lie in water depths of greater than or equal to 1,500 ft and account for 55 percent of the Proved Reserves in the GOM.

The trend of increasing estimates of Original Proved Reserves in water greater than 500 ft is expected to continue with additional exploration and development. Of the 199 proved fields in water depths greater than 500 ft, 159 are producing, 28 are depleted, and 12 have yet to produce.

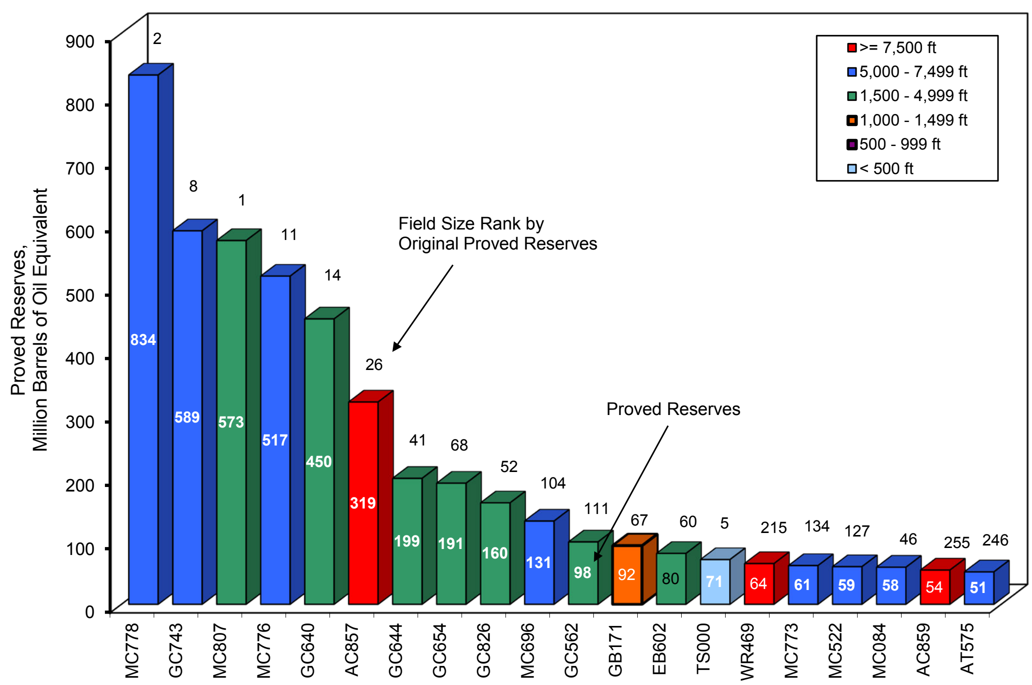


Figure 17. Largest 20 fields ranked by Proved Reserves.

Table 7 lists the 50 largest proved fields ranked by Original Proved Reserves expressed in BOE. Rank, field name, field nickname, discovery year, water depth, field classification, field type, field GOR, original proved reserves, cumulative production through 2008, and proved reserves are presented. A complete listing of all 1,270 proved fields, ranked by proved reserves, is available by contacting the BOEM at 1-800-200-GULF or from BOEM's GOMR Web site at: http://www.gomr.BOEM.gov/homepg/pubinfo/freeasci/geologic/estimated 2008.html.

Table 7. Proved fields by rank order, based on original proved BOE reserves, top 50 fields.

(For proved fields not qualified in 2008 the names are replaced with asterisks to preserve the proprietary nature of the data.)
(Field class: PDP - Proved Developed Producing; PDN - Proved Developed Non-Producing; PU - Proved Undeveloped)
(Field type: O - Oil; G - Gas)

Rank	Field name	Field Nickname	Disc year	Water depth (feet)	Field class	Field type	Field GOR SCF/STB	Original Proved Reserves Oil (MMbbl)	Original Proved Reserves Gas (Bcf)	Original Proved Reserves BOE (MMbbl)	Cumulative Production through 2008 Oil (MMbbl)	Cumulative Production through 2008 Gas (Bcf)	Cumulative Production through 2008 BOE (MMbbl)	Proved Reserves Oil (MMbbl)	Proved Reserves Gas (Bcf)	Proved Reserves BOE (MMbbl)
1	MC807	MARS-URSA	1989	3,377	PDP	O	1,411	1,316.5	1,857.5	1,647.0	871.8	1,135.2	1,073.8	444.8	722.2	573.3
2	MC778	THUNDER HORSE	1999	6,080	PDP	O	883	733.1	647.7	848.4	12.5	9.1	14.2	720.6	638.6	834.2
3	EI330		1971	247	PDP	O	4,232	429.7	1,818.6	753.3	427.3	1,813.2	750.0	2.3	5.3	3.3
4	WD030		1949	48	PDP	O	1,637	579.9	949.6	748.9	567.5	907.6	729.0	12.4	42.0	19.9
5	TS000		1958	13	PDP	G	79,428	44.6	3,540.6	674.6	38.0	3,181.7	604.1	6.6	359.0	70.5
6	GI043		1956	140	PDP	O	4,281	381.9	1,634.7	672.7	365.0	1,552.8	641.3	16.9	81.9	31.5
7	BM002		1949	50	PDP	O	1,039	534.5	555.5	633.3	526.7	542.4	623.2	7.7	13.1	10.1
8	GC743	ATLANTIS	1998	6,413	PDP	O	647	558.6	361.4	623.0	31.0	19.2	34.4	527.7	342.2	588.6
9	VR014		1956	26	PDP	G	64,039	48.1	3,082.8	596.7	47.9	3,060.7	592.5	0.3	22.1	4.2
10	MP041		1956	42	PDP	O	5,669	267.7	1,517.5	537.7	256.5	1,463.9	517.0	11.2	53.6	20.7
11	MC776	N.THUNDER HORSE	2000	5,664	PU	O	1,142	429.9	491.0	517.2	0.0	0.0	0.0	429.9	491.0	517.2
12	VR039		1948	38	PDP	G	80,292	31.9	2,561.3	487.7	31.3	2,545.8	484.3	0.6	15.5	3.3
13	SS208		1960	102	PDP	O	6,213	220.5	1,370.0	464.3	217.6	1,344.8	456.9	2.9	25.1	7.4
14	GC640	TAHITI	2002	4,312	PDP	O	487	414.0	201.6	449.9	0.0	0.0	0.0	414.0	201.5	449.8
15	GB426	AUGER	1987	2,860	PDP	O	3,642	240.6	882.5	397.6	221.1	792.9	362.1	19.5	89.5	35.5
16	WD073		1962	178	PDP	O	2,484	266.2	661.2	383.8	261.8	640.7	375.8	4.3	20.4	8.0
17	SP061		1967	220	PDP	O	1,851	283.7	525.2	377.1	263.2	510.2	354.0	20.5	15.0	23.2
18	GI016		1948	53	PDP	O	1,271	303.3	385.4	371.9	300.7	379.2	368.2	2.6	6.1	3.7
19	EI238		1964	147	PDP	G	16,073	94.3	1,516.1	364.1	87.5	1,447.3	345.1	6.8	68.8	19.0
20	ST172		1962	98	PDP	G	134,020	14.3	1,920.1	356.0	11.7	1,841.9	339.5	2.6	78.1	16.5
21	ST021		1957	46	PDP	O	1,647	270.0	444.5	349.1	251.0	407.0	323.4	18.9	37.5	25.6
22	SP089		1969	422	PDP	O	4,402	193.5	851.8	345.1	190.0	841.2	339.7	3.5	10.6	5.3
23	WC180		1961	49	PDP	G	134,415	13.6	1,827.5	338.8	12.9	1,779.2	329.5	0.7	48.3	9.3
24	ST176		1963	127	PDP	G	14,175	93.0	1,318.7	327.7	83.3	1,202.9	297.3	9.8	115.9	30.4
25	SS169		1960	63	PDP	O	5,449	164.4	895.6	323.7	158.3	846.1	308.9	6.0	49.5	14.8
26	AC857	GREAT WHITE	2002	7,925	PU	O	1,707	264.1	307.1	318.8	0.0	0.0	0.0	264.1	307.1	318.8
27	MC194	COGNAC	1975	1,022	PDP	O	4,174	179.9	751.1	313.6	177.9	743.7	310.2	2.1	7.3	3.4
28	SM048		1961	101	PDP	G	55,963	28.6	1,601.4	313.6	27.9	1,522.3	298.8	0.7	79.1	14.8
29	EC064		1957	50	PDP	G	58,077	27.3	1,583.7	309.1	26.8	1,553.5	303.2	0.4	30.3	5.8
30	EI292		1964	212	PDP	G	84,605	19.1	1,616.6	306.8	18.5	1,613.4	305.6	0.6	3.2	1.2
31	EC271		1971	171	PDP	G	18,841	70.3	1,324.8	306.0	68.4	1,313.4	302.1	1.9	11.4	4.0
32	SS176		1956	101	PDP	G	19,870	65.2	1,295.5	295.7	64.2	1,273.3	290.8	1.0	22.2	4.9
33	SP027	EAST BAY	1954	64	PDP	O	5,225	151.8	793.1	292.9	150.6	764.6	286.7	1.2	28.5	6.2
34	WC587		1971	210	PDP	G	115,893	13.4	1,558.7	290.8	13.1	1,535.5	286.3	0.3	23.2	4.5
35	WC192		1954	57	PDP	G	61,658	23.9	1,476.6	286.7	22.7	1,370.1	266.5	1.3	106.4	20.2
36	ST135		1956	129	PDP	O	3,681	171.4	630.4	283.5	166.6	592.4	272.0	4.8	37.9	11.5
37	EI296		1971	214	PDP	G	69,705	20.6	1,433.7	275.7	20.4	1,421.2	273.3	0.2	12.5	2.4
38	WD079		1966	123	PDP	O	3,795	163.7	621.1	274.2	161.1	612.1	270.1	2.5	9.0	4.1
39	HI573A		1973	340	PDP	O	7,597	113.3	860.9	266.5	109.3	853.2	261.1	4.1	7.7	5.4
40	MI623		1980	83	PDP	G	101,140	13.9	1,401.3	263.2	13.5	1,356.2	254.8	0.4	45.2	8.4
41	GC644	HOLSTEIN	1999	4,341	PDP	O	1,237	211.7	262.0	258.4	50.7	51.5	59.9	161.0	210.5	198.5
42	GI047		1955	88	PDP	O	3,748	152.0	569.9	253.4	146.8	540.5	242.9	5.3	29.4	10.5
43	SP078		1972	202	PDP	G	11,292	79.7	900.2	239.9	75.4	890.4	233.8	4.4	9.9	6.1
44	PL020		1951	33	PDP	O	5,768	117.8	679.7	238.8	110.3	625.0	221.6	7.5	54.7	17.2
45	SM023		1960	82	PDP	G	38,738	29.9	1,160.1	236.4	29.6	1,147.2	233.7	0.3	12.9	2.6
46	MC084	KING/HORN MT.	1993	5,300	PDP	O	1,140	195.7	223.1	235.4	148.2	162.2	177.0	47.6	61.0	58.4
47	SM130		1973	214	PDP	O	1,367	187.9	256.8	233.5	184.1	246.9	228.0	3.8	9.9	5.5
48	VK956	RAM-POWELL	1985	3,254	PDP	O	8,768	90.4	792.8	231.5	84.9	770.6	222.0	5.5	22.2	9.5
49	GC244	TROIKA	1994	2,795	PDP	O	2,005	170.3	341.5	231.0	162.3	322.8	219.7	8.0	18.7	11.3
50	VR076		1949	31	PDP	G	141,345	8.8	1,242.3	229.8	7.8	1,186.2	218.9	1.0	56.1	11.0

RESERVOIR-SIZE DISTRIBUTION

The size distributions of the proved reservoirs are shown in **Figures 18**, **19**, and **20**. The size ranges are based on Original Proved Reserves and are presented on a geometrically progressing horizontal scale. These sizes correspond with the USGS deposit-size ranges shown in **Table 4** with a modification to reflect small reservoirs in a finer distribution. For **Figures 19** and **20**, the Original Proved Reserves are presented in million barrels (MMbbl) and billion cubic feet (Bcf), respectively. The number of reservoirs in each size grouping, shown as percentages of the total, is presented on a linear vertical scale. For the combination reservoirs (saturated oil rims with associated gas caps), shown in **Figure 18**, gas is converted to BOE and added to the liquid reserves.

Figure 18 shows the reservoir-size distribution, on the basis of original proved BOE, for 2,282 proved combination reservoirs. The median is 0.9 MMBOE and the mean is 2.9 MMBOE. The GOR for the oil portion of the reservoirs is 1,185 SCF/STB, and the yield for the gas cap is 22.2 Bbl of condensate per MMcf of gas.

Figure 19 shows the reservoir-size distribution, on the basis of original proved oil, for 8,169 proved undersaturated oil reservoirs. The median is 0.3 MMbbl, the mean is 1.9 MMbbl, and the GOR is 1,212 SCF/STB.

Figure 20 shows the reservoir-size distribution, on the basis of original proved gas, for 18,137 gas reservoirs. The median is 2.1 Bcf of gas, the mean is 8.5 Bcf, and the yield is 12.1 Bbl of condensate per MMcf of gas.

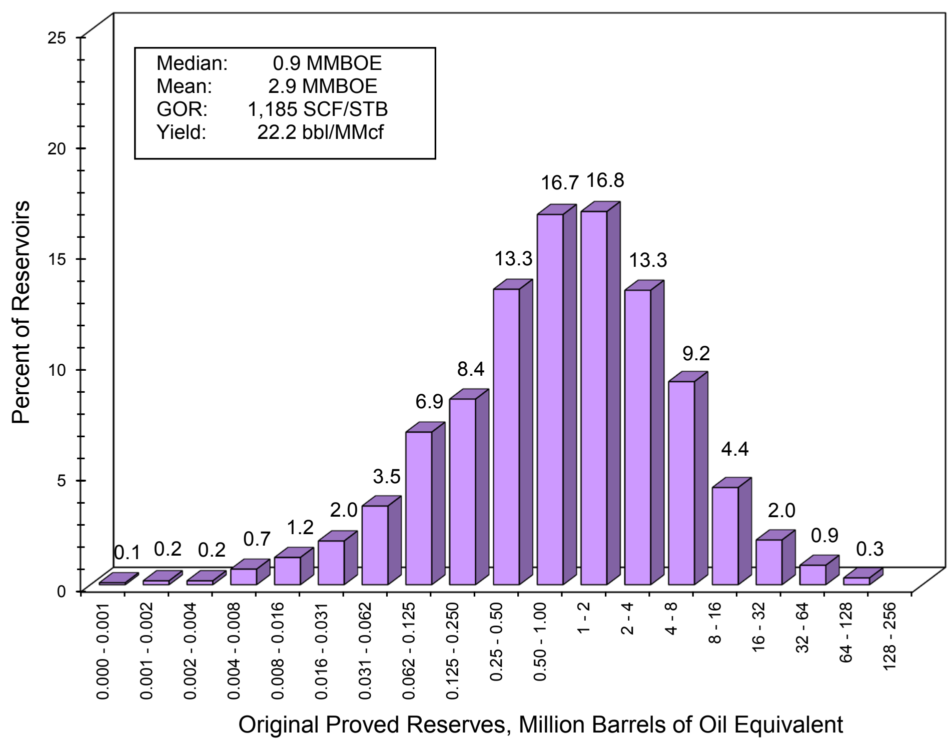


Figure 18. Reservoir-size distribution, 2,282 proved combination reservoirs.

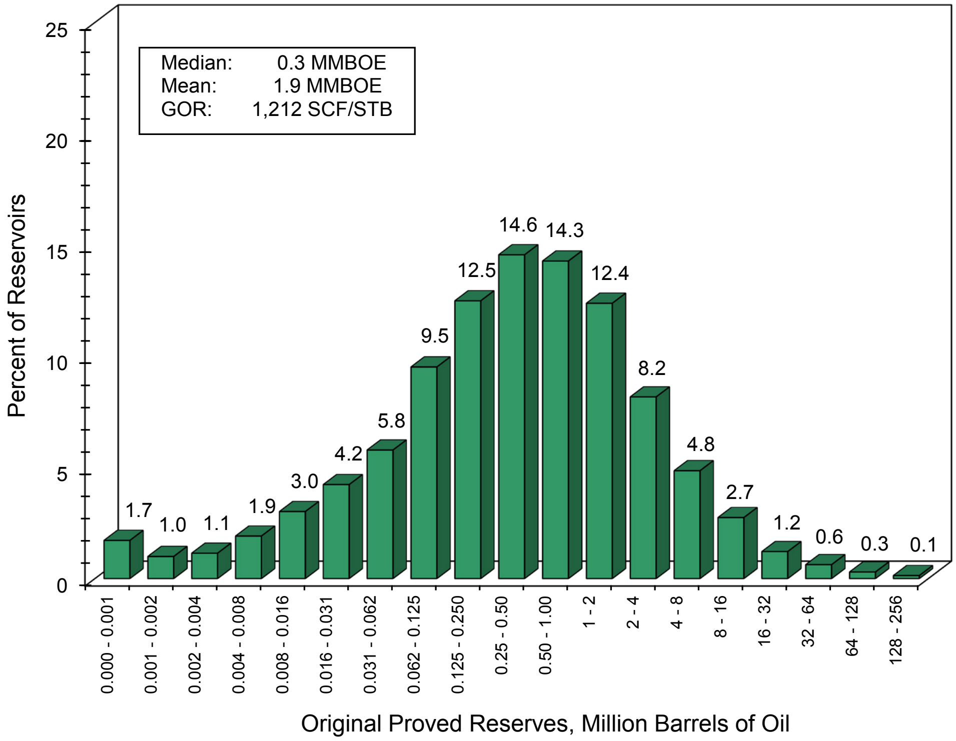


Figure 19. Reservoir-size distribution, 8,169 proved oil reservoirs.

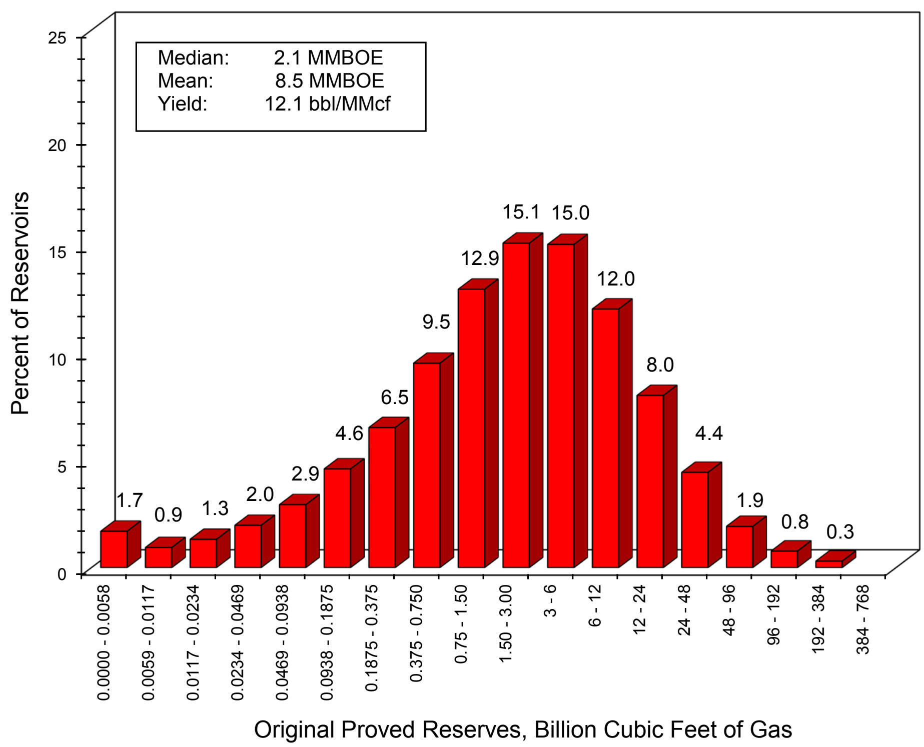


Figure 20. Reservoir-size distribution, 18,137 proved gas reservoirs.

DISCOVERY AND PRODUCTION PATTERNS AND TRENDS

It is informative to review the historic exploration and development activities that resulted in the world-class hydrocarbon-producing basin that is the GOM. Activity in the GOM will be examined by reviewing the status of exploration and development, the number of fields and quantities of Original Proved Reserves discovered during each decade. The discovery year for a field is defined as the year in which the first well reached total depth and encountered significant hydrocarbons. This date may differ from the year in which the field discovery was announced.

Discovery of Proved Fields

The BOEM first reported estimates of the GOM's oil and gas reserves in 1975 (*USGS Open File Report 77-71 (Bryan and Knipmeyer, 1977)*. As expected, initial development was in shallow, nearshore waters concentrated mainly in the Federal waters off central and western Louisiana. This primarily reflected the gradual extension of existing inland drilling and development technologies into the open-water marine environments, and the infancy of marine seismic acquisition activities. Early exploratory drilling in very shallow water on the shelf utilized barges and platforms. The mid-1950's witnessed the introduction of submersible and jack-up drilling rigs. Though still confined to the shelf (656 ft or less), field discoveries in the 1960's and early 1970's advanced seaward into deeper waters. Prior to 1975, 3,885 exploratory wells were drilled, culminating in the discovery of 343 proved fields. It was also during this period that 7 of the top 10 fields in the GOM, based on Original Proved Reserves, were discovered, the largest being Eugene Island Block 330 (EI 330).

Figures 21-23 depict locations of proved fields beginning in 1975 with bar heights proportional to total Original Proved Reserves in BOE.

Figure 21 shows the location of the proved fields discovered from 1975 through 1989. This period reflects continued drilling and development on the shelf, with an increase in field discoveries further offshore, predominantly of Pleistocene age. In addition, the first Norphlet fields and a Miocene shallow bright spot play were discovered in the eastern Central GOM planning area. Exploratory drilling had reached water depths deeper than 6,000 ft. During this period, 6,258 exploratory wells were drilled, resulting in the discovery of 539 proved fields. Thirty-eight of these fields were discovered in water depths greater than 1,000 ft. Deepwater activity is discussed in more detail in MMS OCS Report, *Deepwater Gulf of Mexico 2008: America's Offshore Energy Future (Richardson et al., 2008).* Significant discoveries in the GOM occurred during this time period: MC 194, the first field in over 1,000 ft of water; and, the largest field in the GOM, MC 807, in 3,400 ft of water.

For the 1990's (**Figure 22**), 4,151 exploration wells were drilled, resulting in the discovery of 223 proved fields (53 were discovered in water depths greater than 1,000 ft). The 1990's saw the refinement and reduction in cost of tension leg platform design and an expanded use of subsea completions. Available production histories have documented high production rates for deepwater fields. The expanding use of horizontal drilling increased productivity of specific reservoirs. Computer workstation technology using three-dimensional seismic data allowed for reduced risk and greater geologic assurance in exploration and field development, as well as exploration of new plays. The second largest field in the GOM, MC 778, was discovered during this time period.

From 2000 to 2008 (**Figure 23**), 3,208 exploration wells were drilled, resulting in the discovery of 165 proved fields. More than 30 percent of those fields were in greater than 1,000 ft of water. Reserve estimates for field discoveries during this period may have significant increases because of increased well control, reservoir management, and in-field exploration. MC 776, the eleventh largest field in the GOM, was discovered during this time period.

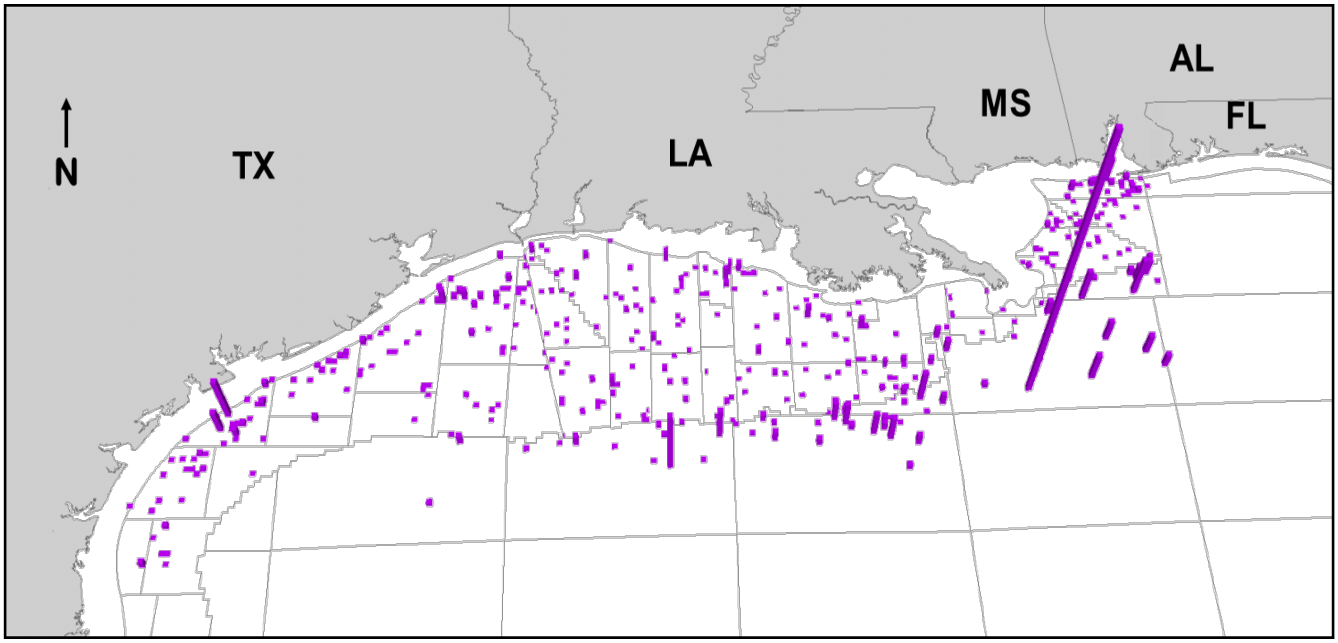


Figure 21. Location of proved fields discovered 1975-1989.

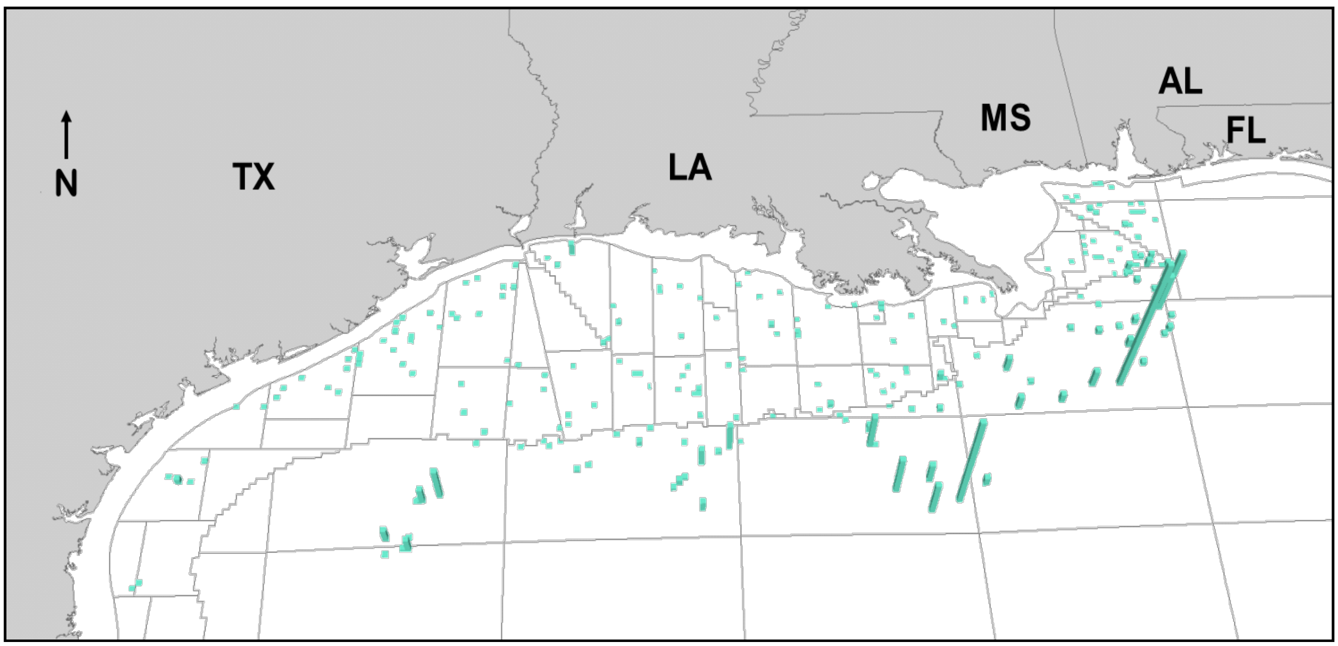


Figure 22. Location of proved fields discovered 1990-1999.

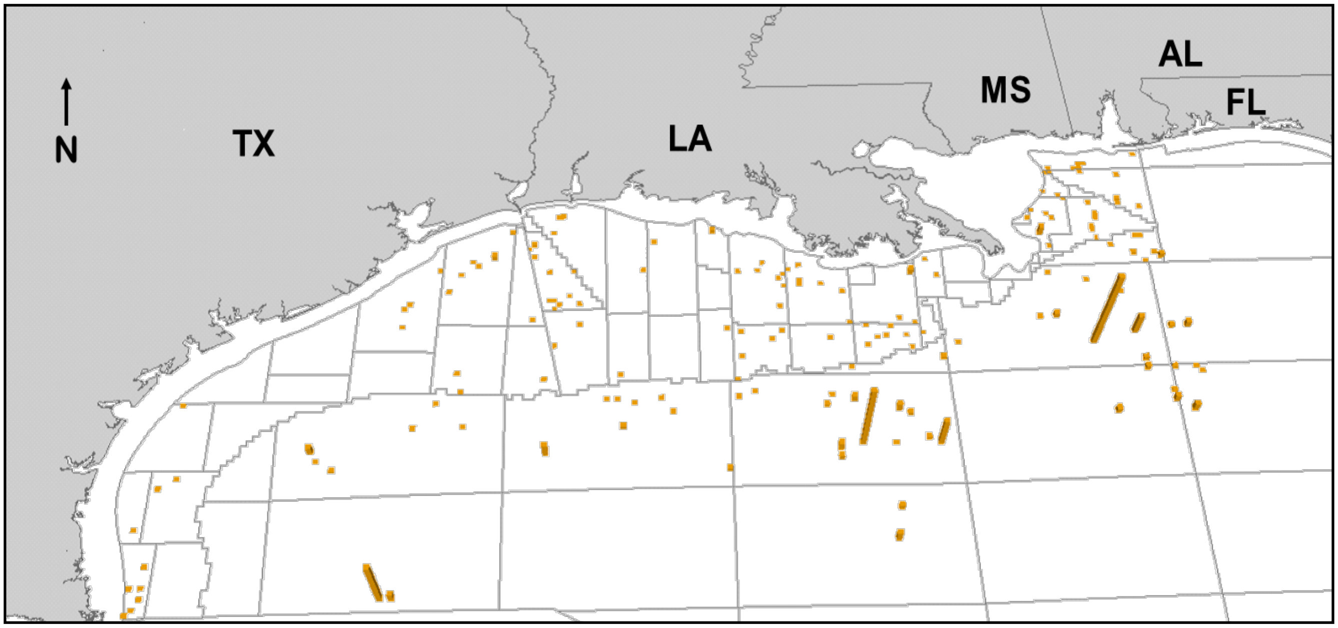


Figure 23. Location of proved fields discovered 2000-2008.

Production and Completion Trends

The mean daily production in the GOM OCS during 2008 was 1.00 MMbbl of crude oil, 0.16 MMbbl of gas condensate, 1.34 Bcf of casinghead gas, and 5.06 Bcf of gas-well gas. The mean GOR of oil wells was 1,340 SCF/STB, and the mean yield from gas wells was 30.91 Bbl of condensate per MMcf of gas.

Table 8 summarizes the data from monthly distributions of oil and gas production rates. The highest reported monthly oil production volume was from a Miocene reservoir in MC 778 with a subsea depth of 22,250 ft, during the month of December. The highest reported monthly gas production volume was from a Miocene reservoir in MC 731, with a subsea depth of 15,395 ft, during the month of January. The mean number of oil completions producing more than 1,000 bbl per day was 194, and the mean number of gas completions producing more than 10 MMcf per day was 96.

Table 8. Monthly completion and production data.

2008	Oil		Gas	
Mean Number of Producing Completions	2,348 (194 > 1,000 bbls per day)		2,138 (96 > 10 MMcf per day)	
Mean Number of Continuously Producing Completions	1,567		1,334	
Highest Monthly Mean Number of Producing Completions	2,778 (June)		2,550 (March)	
Lowest Monthly Mean Number of Producing Completions	1,385 (September)		1,236 (October)	
Mean Production Volume Mean Producing Rate	12,964 bbl (506 bbl per day)		71.7 MMcf (2.9 MMcf per day)	
Median Production Volume Median Producing Rate	2,001 bbl (79 bbl per day)		17.4 MMcf (0.8 MMcf per day)	
	Field		Field	
Highest Production Volume Highest Producing Rate Highest Producing Month Highest Production Volume Trend Highest Production Volume Subsea Depth	MC778	1,282,182 bbl (44,213 bbl per day) (December) (MIOCENE) (22,250 feet)	MC731	3,725,193 MMcf (120,167 MMcf per day) (January) (MIOCENE) (15,395 feet)

Production Rates

Annual production in the GOM OCS is shown in **Figure 24**. The oil plot includes condensate and the gas plot includes casinghead gas. Annual production for oil and gas is presented as a total, in shallow water (less than 1,000 ft), and in deepwater (greater than 1,000 ft). From 1986 through 1990, annual oil production declined 23 percent. From 1990 through 2002, annual oil production increased 106 percent, from 275 MMbbl to 567 MMbbl. From 2002 to 2008 annual oil production decreased 25 percent to 423 MMbbl.

From 1990 through 1993, annual gas production declined 5 percent. From 1993 through 2001, annual gas production rose from 4.7 Tcf, peaking at 5.1 Tcf in 1997, a 9-percent increase. Annual gas production reached at least 5.0 Tcf per year from 1996 through 1999 and in 2001. From 2001 to 2008, annual gas production declined 54 percent to 2.3 Tcf. For further analysis of the gas production decline, see the MMS OCS Report, *Gulf of Mexico Oil and Gas Production Forecast: 2007-2016 (Brewton et al., 2007)*, available from BOEM's GOMR Web site at http://www.boem.gov/BOEM-Newsroom/Library/Publications/2007/2007-020.aspx.

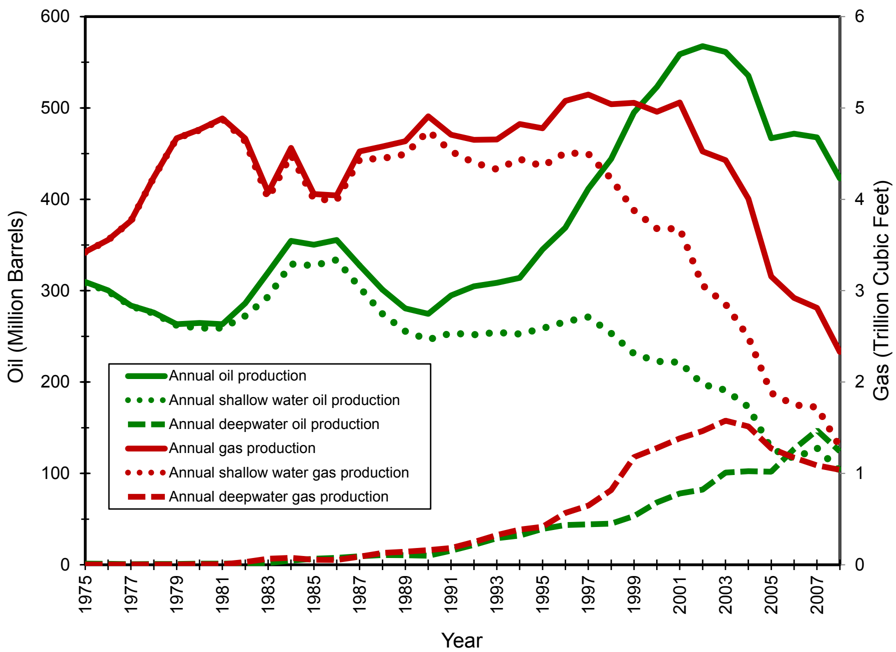


Figure 24. Annual oil and gas production.

Figure 25 is a plot of the number of proved gas and oil fields by discovery year. The annual number of gas fields discovered peaked in 1984, and has steadily declined through 2008. The number of oil fields discovered has not varied much from year to year, never exceeding 11, and averaging only about 4 discoveries per year.

Figure 26 presents Original Proved Reserves, Cumulative Production, and Proved Reserves in BBOE as of December 31, 2008, summed according to field discovery year. Field depletion may be estimated by the relative positions of the Cumulative Production curve and the Proved Reserves curve. For example, if the value of the Proved Reserves is higher than the value of Cumulative Production for a given year, the aggregate depletion for fields discovered that year is less than 50 percent. The plot demonstrates that fields discovered after 1996 are less than 50 percent depleted.

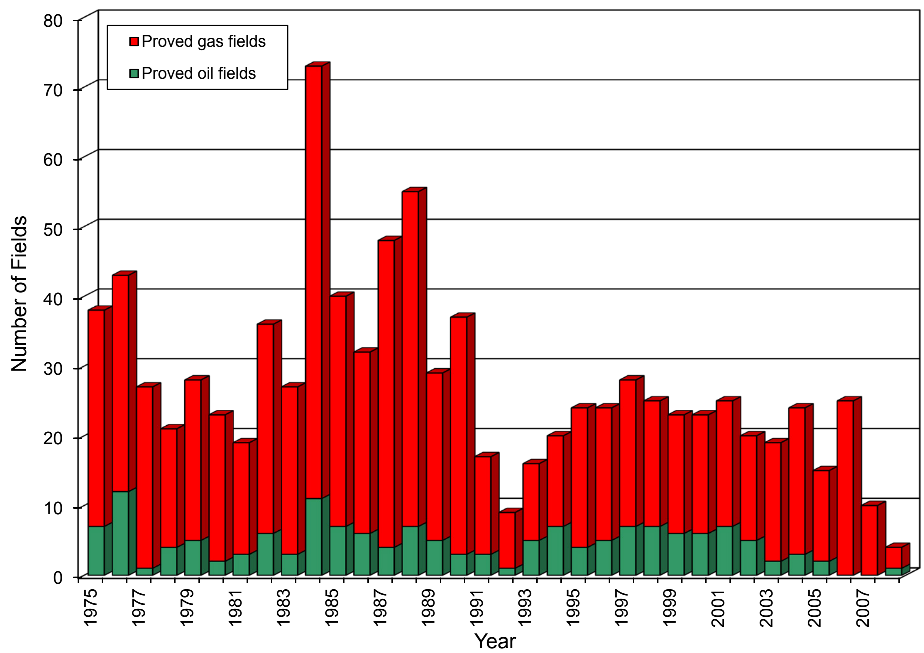


Figure 25. Annual number of proved oil and gas field discoveries.

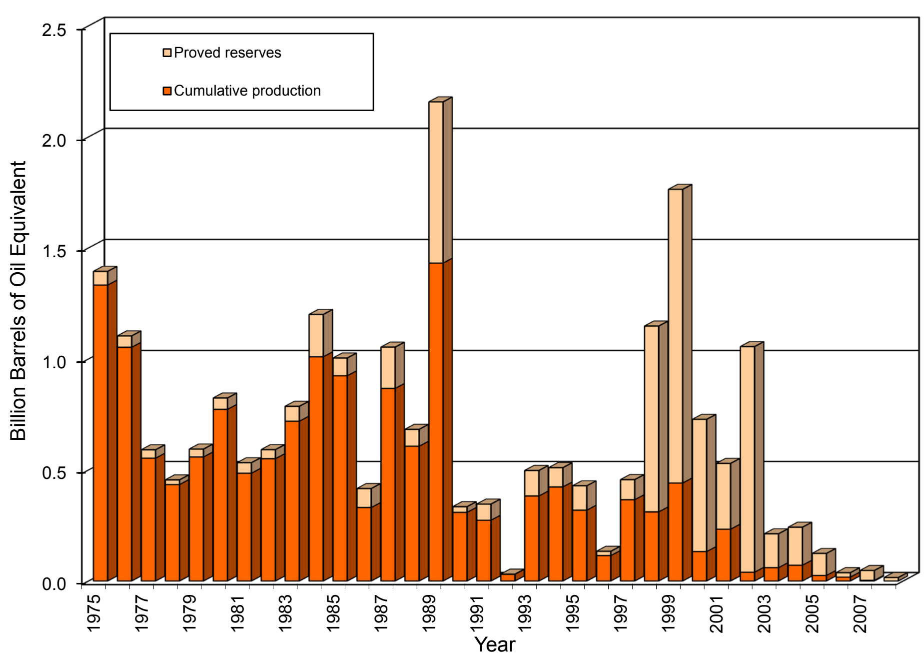


Figure 26. Proved Reserves and Cumulative Production by field discovery year.

Figure 27 presents the number of proved fields and the mean field size by field discovery year. This plot shows that the number of discovered fields steadily declined since 1997, and the mean size of the fields has been getting smaller except for 1989 and for the period 1998 through 2002. The mean field size is expected to increase because of reserves growth and additions in proved fields and reserves from fields that become proved.

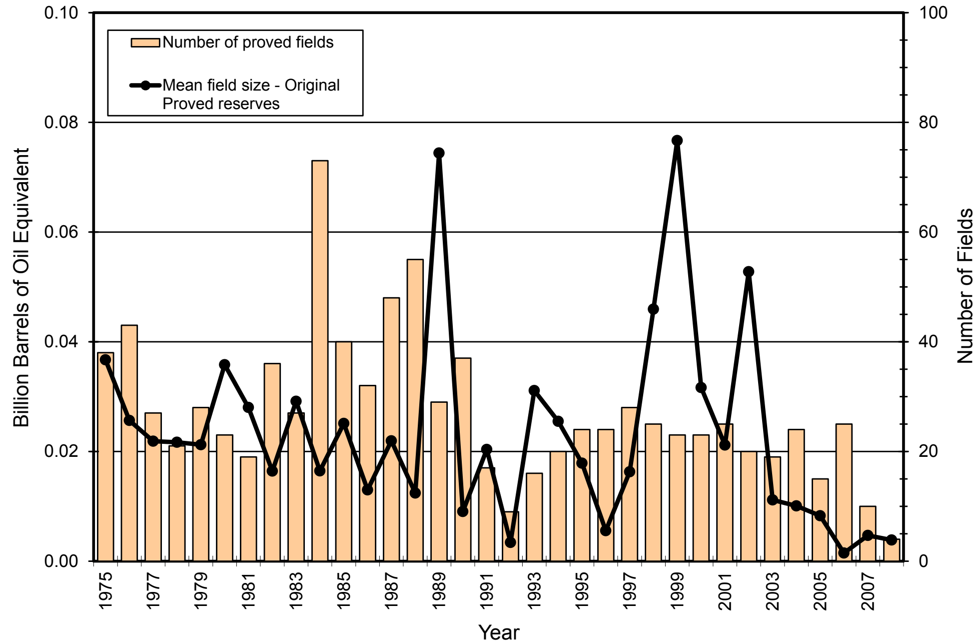


Figure 27. Number of proved fields and mean field size by field discovery year.

Figure 28 presents the number of proved fields and the average water depth of the fields discovered in each year. For 2001, the mean water depth for the fields discovered peaked at nearly 3,200 ft. Since 1995, the mean water depth has been greater than 1,000 ft, indicating that exploration and resulting production have moved into deeper water.

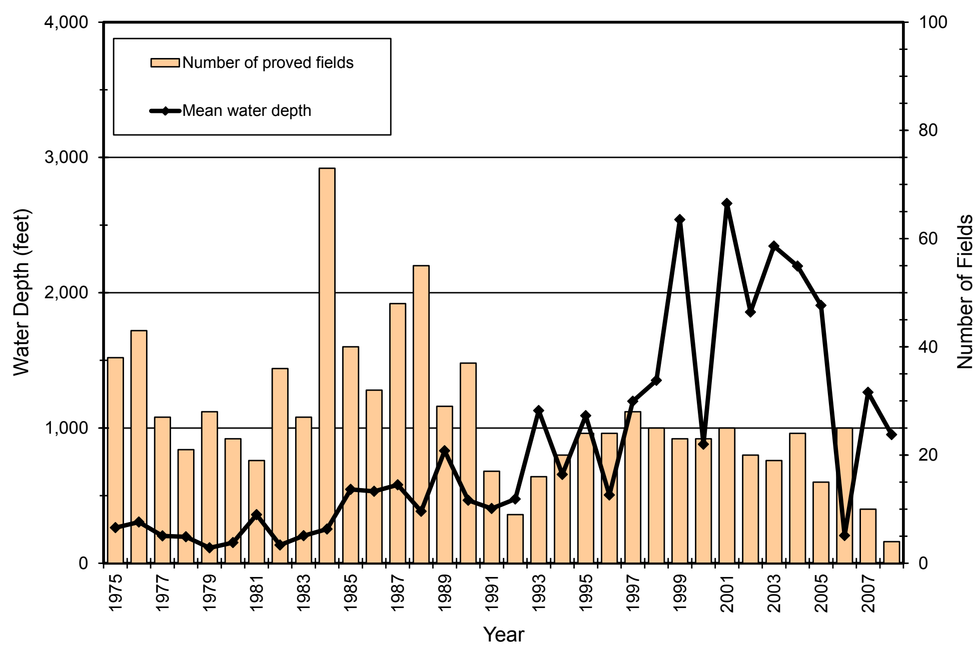


Figure 28. Number of proved fields and mean water depth by field discovery year.

Figures 29 and **30** show original proved oil and gas reserves and annual production by reservoir discovery year. Data presented in **Figure 29** include crude oil and condensate, and data presented in **Figure 30** include associated and nonassociated gas. The year of discovery assigned to a reservoir is the year in which the first well encountering hydrocarbons penetrated the reservoir. For comparison with the rate of discoveries, the annual production of oil and gas is also shown. In five of the last ten years, annual proved oil reserve additions have exceeded annual oil production, resulting in an increase in proved oil reserves. Since 1985, annual gas production has exceeded annual proved reserve additions for gas. In general, annual proved gas reserve additions have declined since the mid 1970's.

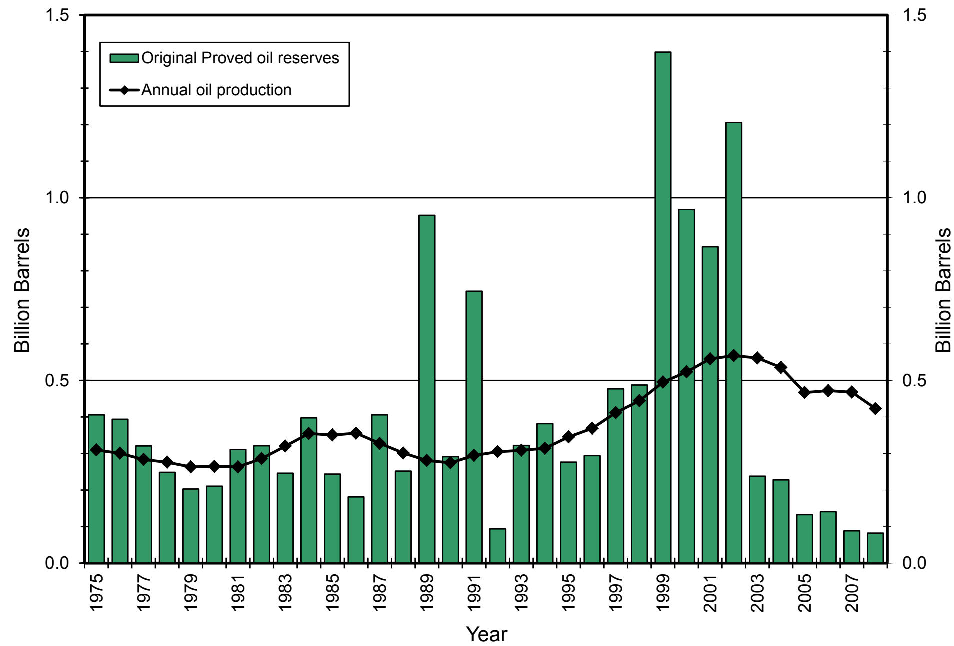


Figure 29. Proved oil reserves by reservoir discovery year and annual oil production.

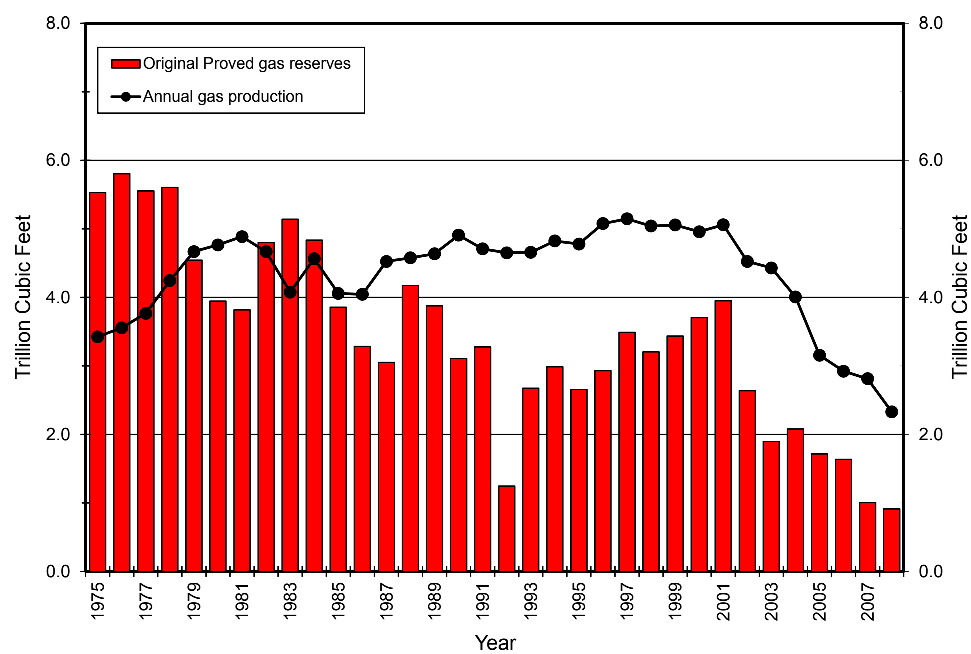


Figure 30. Proved gas reserves by reservoir discovery year and annual gas production.

Figure 31 presents Original Proved Reserves in BBOE for water depth categories by reservoir discovery year. From 1975 to 1985, the majority of reserves discovered were in less than 500 ft of water. From 1999 through 2002, the majority of reserves discovered occurred in greater than 1,500 ft of water. Since 2003, the majority of reserve discoveries are located in less than 500 ft of water. As mentioned earlier, reserves are expected to increase because of reserves growth and additional development in proved fields and Reserves Justified for Development that become proved.

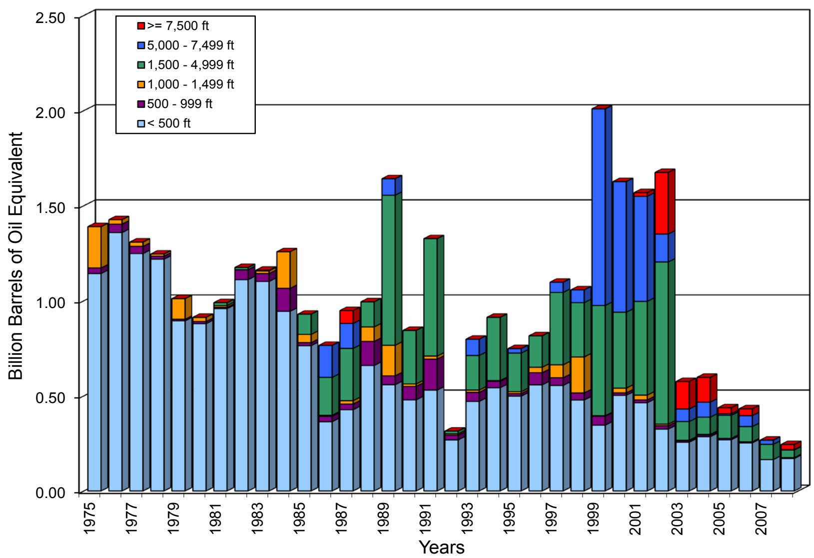


Figure 31. Original Proved Reserves water depth categories by reservoir discovery year.

Figure 32 presents the total footage drilled and the number of exploratory and development wells drilled in the GOM OCS each year. Since 2000, the number of exploratory wells drilled has remained mostly constant. The number of development wells drilled per year has decreased, and the total footage drilled has decreased.

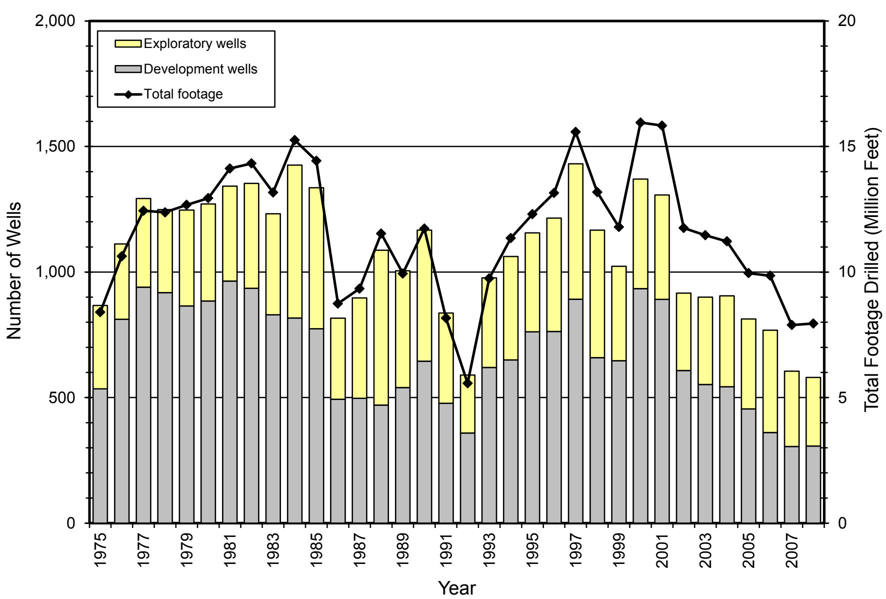


Figure 32. Number of wells and total footage drilled by year.

Figure 33 presents the number of exploratory wells drilled each year by water depth category. The plot shows an increase of drilling in deeper water, but also illustrates continued drilling in water depths less than 500 ft. From 1997 through 2008, the number of exploratory wells drilled in water depths less than 500 ft decreased by nearly 50 percent. Exploratory wells drilled in water depths greater than 1,000 ft have more than doubled since 1995.

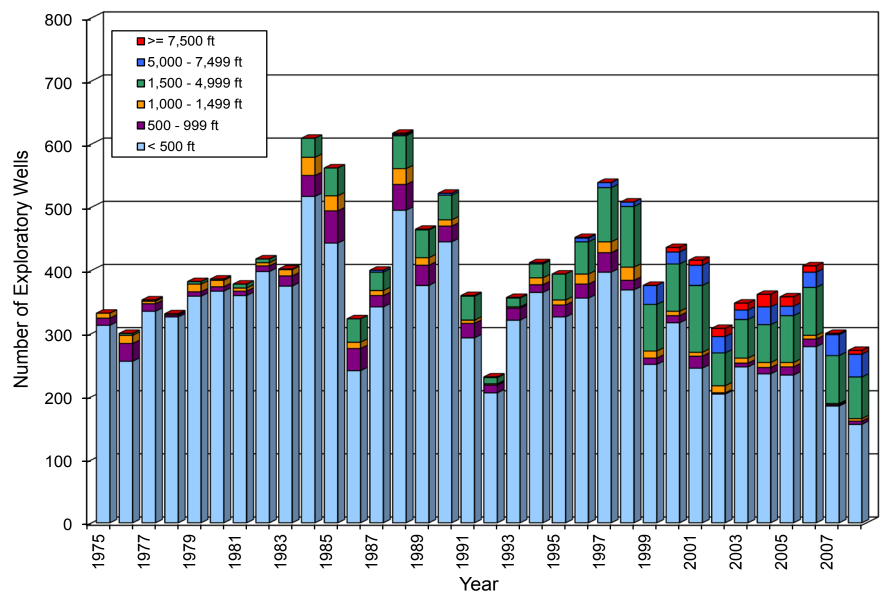


Figure 33. Number of exploratory wells drilled by water depth.

Figure 34 presents the number of development wells drilled each year by water depth category. For water depths less than 500 ft development drilling peaked in 1997 to nearly 800 wells. For water depths greater than 1,000 ft development drilling peaked in 2001 to nearly 170 wells. From 2000 to 2008, the number of development wells drilled in water depths less than 500 ft decreased nearly 65 percent. Development wells drilled in water depths greater than 1,000 ft have decreased nearly two-thirds since 2001.

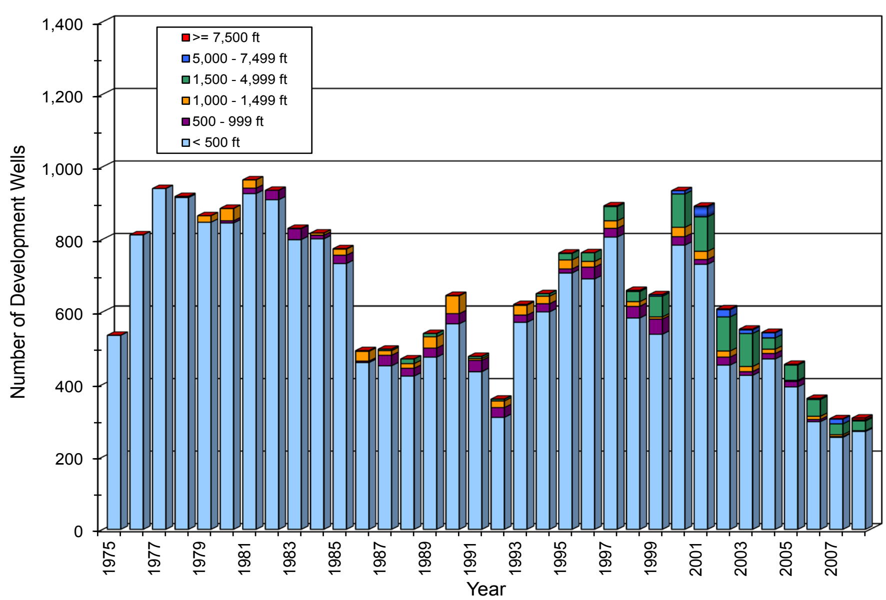


Figure 34. Number of development wells drilled by water depth.

SUMMARY AND CONCLUSIONS

A summary of the Original Proved Reserve estimates for 2008 and a comparison with estimates from the previous year's report (December 31, 2007) are shown in **Table 9**. There were 19 proved fields added during 2008 (5 oil fields and 14 gas fields), which are summarized and tabulated as increases to Original Proved Reserves. Fifteen of the proved fields added were discovered prior to 2008.

Comparison of Proved Reserves

Proved reserve estimates are revised as additional wells are drilled and new leases are added to existing fields, and as reservoirs are depleted and leases expired, terminated, or relinquished. Complete re-evaluations of existing field studies are conducted on the basis of changes in field development and/or production history. Revisions of Original Proved Reserves are summarized and presented as changes in **Table 9**. Based on periodic reviews and revisions of field studies conducted since the 2007 report, the reserves revisions have resulted in a net increase. A net change in the reserves is a result of combining the discoveries and the revisions. Proved Reserves are presented in **Figures 35(a)**, **35(b)**, and **35(c)**.

Table 9 demonstrates that the 2008 proved oil and gas discoveries and field revisions did exceed production, resulting in a net increase in Proved Reserves. The Proved Reserves increased 8 percent for oil and increased 9 percent for gas since the 2007 report.

Table 9. Summary and comparison of GOM proved oil and gas reserves as of December 31, 2007, and December 31, 2008.

	Oil (billion bbl)	Gas (trillion cu ft)	BOE (billion bbl)
Original Proved reserves:			
Previous estimates, as of 12/31/2007*	**20.43**	**184.6**	**53.28**
Discoveries	0.18	0.3	0.23
Revisions	0.63	3.5	1.25
Estimate, as of 12/31/2008 (this report)	**21.24**	**188.4**	**54.76**
Cumulative production:			
Previous estimates, as of 12/31/2007*	**15.55**	**169.5**	**45.71**
Discoveries	0.00	0.0	0.00
Revisions	0.41	2.3	0.82
Estimate, as of 12/31/2008 (this report)	**15.96**	**171.8**	**46.53**
Proved reserves:			
Previous estimates, as of 12/31/2007*	**4.88**	**15.1**	**7.57**
Discoveries	0.18	0.3	0.23
Revisions	0.63	3.5	1.25
Production during 2008	-0.41	-2.3	-0.82
Estimate, as of 12/31/2008 (this report)	**5.28**	**16.6**	**8.23**

*Crawford et.al., 2011

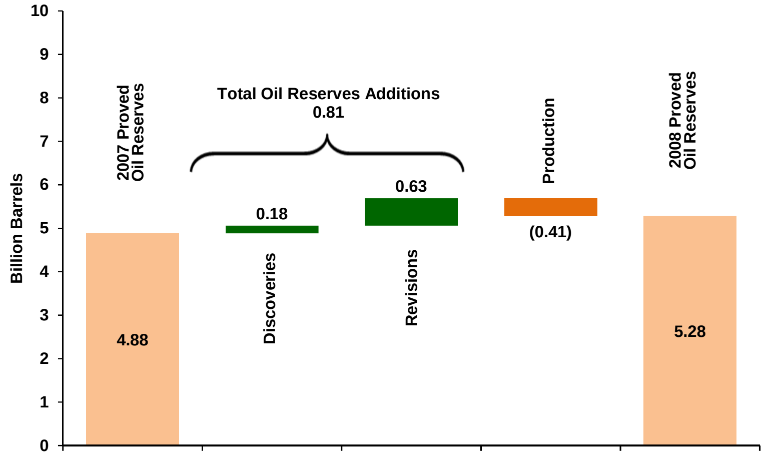


Figure 35(a). Proved oil reserves

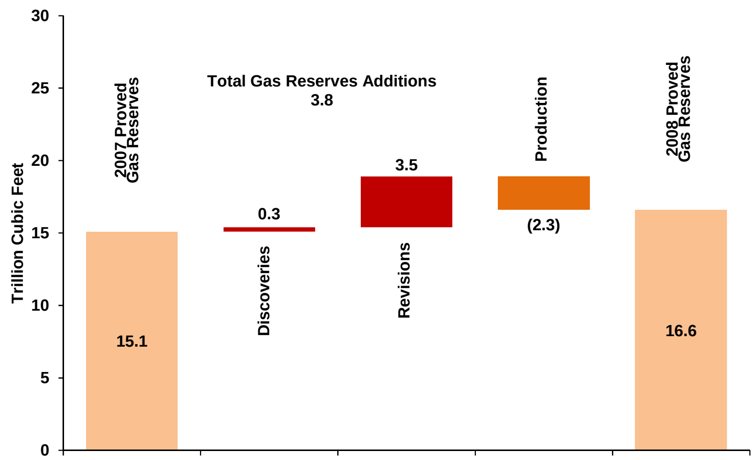


Figure 35(b). Proved gas reserves

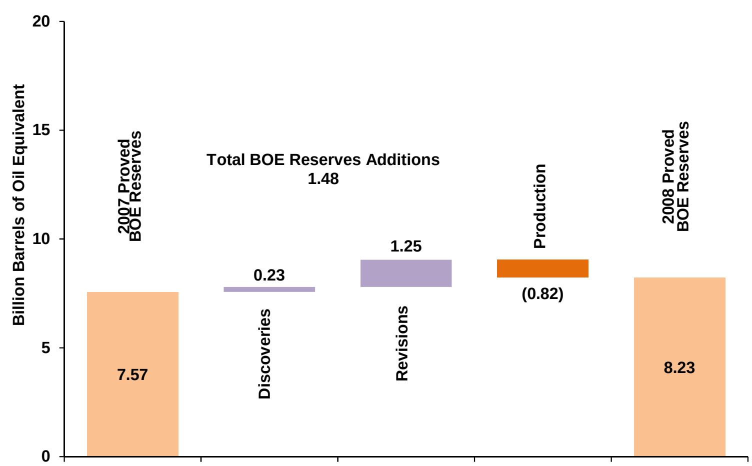


Figure 35(c). Proved BOE reserves

Figure 35. Remaining proved reserves

Table 10 presents all previous reserve estimates by year. Because of adjustments and corrections to production data submitted by Gulf of Mexico OCS operators, the difference between historical cumulative production for successive years does not always equal the annual production for the latter year. No comparisons are made for Reserves Justified for Development.

Table 10. Proved oil and gas reserves and cumulative production at end of year, 1975-2008.

Oil" includes crude oil and condensate; "gas" includes associated and nonassociated gas. Proved reserves estimated as of December 31 each year.

Year	Number of fields included	Original Proved Reserves			Historical Cumulative Production			Proved Reserves		
		Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
1975	255	6.61	59.9	17.27	3.82	27.2	8.66	2.79	32.7	8.61
1976	306	6.86	65.5	18.51	4.12	30.8	9.60	2.74	34.7	8.91
1977	334	7.18	69.2	19.49	4.47	35.0	10.70	2.71	34.2	8.80
1978	385	7.52	76.2	21.08	4.76	39.0	11.70	2.76	37.2	9.38
1979 *	417	7.71	82.2	22.34	4.83	44.2	12.69	2.88	38.0	9.64
1980	435	8.04	88.9	23.86	4.99	48.7	13.66	3.05	40.2	10.20
1981	461	8.17	93.4	24.79	5.27	53.6	14.81	2.90	39.8	9.98
1982	484	8.56	98.1	26.02	5.58	58.3	15.95	2.98	39.8	10.06
1983	521	9.31	106.2	28.21	5.90	62.5	17.02	3.41	43.7	11.19
1984	551	9.91	111.6	29.77	6.24	67.1	18.18	3.67	44.5	11.59
1985	575	10.63	116.7	31.40	6.58	71.1	19.23	4.05	45.6	12.16
1986	645	10.81	121.0	32.34	6.93	75.2	20.31	3.88	45.8	12.03
1987	704	10.76	122.1	32.49	7.26	79.7	21.44	3.50	42.4	11.04
1988 †	678	10.95	126.7	33.49	7.56	84.3	22.56	3.39	42.4	10.93
1989	739	10.87	129.1	33.84	7.84	88.9	23.66	3.03	40.2	10.18
1990	782	10.64	129.9	33.75	8.11	93.8	24.80	2.53	36.1	8.95
1991	819	10.74	130.5	33.96	8.41	98.5	25.94	2.33	32.0	8.02
1992	835	11.08	132.7	34.69	8.71	103.2	27.07	2.37	29.5	7.62
1993	849	11.15	136.8	35.49	9.01	107.7	28.17	2.14	29.1	7.32
1994	876	11.86	141.9	37.11	9.34	112.6	29.38	2.52	29.3	7.73
1995	899	12.01	144.9	37.79	9.68	117.4	30.57	2.33	27.5	7.22
1996	920	12.79	151.9	39.82	10.05	122.5	31.85	2.74	29.4	7.97
1997	957	13.67	158.4	41.86	10.46	127.6	33.17	3.21	30.8	8.69
1998	984	14.27	162.7	43.22	10.91	132.7	34.52	3.36	30.0	8.70
1999	1,003	14.38	161.3	43.08	11.40	137.7	35.90	2.98	23.6	7.18
2000	1,050	14.93	167.3	44.70	11.93	142.7	37.32	3.00	24.6	7.38
2001	1,086	16.51	172.0	47.11	12.48	147.7	38.77	4.03	24.3	8.35
2002	1,112	18.75	176.8	50.21	13.05	152.3	40.15	5.71	24.6	10.09
2003	1,141	18.48	178.2	50.19	13.61	156.7	41.49	4.87	21.5	8.70
2004	1,172	18.96	178.4	50.70	14.14	160.7	42.73	4.82	17.7	7.97
2005	1,196	19.80	181.8	52.15	14.61	163.9	43.77	5.19	17.9	8.38
2006	1,229	20.30	183.6	52.97	15.08	166.7	44.74	5.22	16.9	8.23
2007	1,251	20.43	184.6	53.28	15.55	169.5	45.71	4.88	15.1	7.57
2008	1,270	21.24	188.4	54.76	15.96	171.8	46.53	5.28	16.6	8.23

* Gas plant liquids dropped from system
\+ Basis of reserves changed from demonstrated to SPE proved.

Conclusions

As of December 31, 2008, the 1,270 proved oil and gas fields in the federally regulated part of the GOM OCS contained Original Proved Reserves estimated to be 21.24 BBO and 188.4 Tcf of gas. Cumulative Production from the proved fields accounts for 15.96 BBO and 171.8 Tcf of gas. Proved Reserves are estimated to be 5.28 BBO and 16.6 Tcf of gas for the 932 proved active fields. Proved oil reserves have increased 8 percent and the proved gas reserves have increased 9 percent from the 2007 report. Reserves Justified for Development in the federally regulated part of the GOM OCS are estimated to be 0.27 BBO and 1.2 Tcf of gas in 137 active fields.

In addition to the Proved Reserves and the Reserves Justified for Development discussed above, there are an estimated 6.16 billion barrels of oil and 16.3 trillion cubic feet of gas resources that are not presented in the tables and figures of this report. These Contingent Resources can be found in leases that have not yet qualified (and therefore have not been placed in a field) or they can be found in proved fields and in fields justified for development. As additional drilling and development occur, additional hydrocarbon volumes will become reportable, and BOEM anticipates future proved reserves to increase.

CONTRIBUTING PERSONNEL

This report includes contributions from the following Gulf of Mexico Region, Office of Resource Evaluation, personnel.

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Notice

This report, *Estimated Oil and Gas Reserves, Gulf of Mexico, December 31, 2008,* has undergone numerous changes over the last few years. We are continually striving to provide meaningful information to the users of this document. Suggested changes, additions, or deletions to our data or statistical presentations are encouraged so we can publish the most useful report possible. Please contact the Reserves Section Chief at (504) 736-2891 at the Bureau of Ocean Energy Management, 1201 Elmwood Park Boulevard, MS GM773E, New Orleans, Louisiana 70123-2394, to communicate your ideas for consideration in our next report.

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As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally owned public lands and natural resources. This includes fostering sound use of our land and water resources; protecting our fish, wildlife and biological diversity; preserving the environmental and cultural values of our national parks and historical places; and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to ensure that their development is in the best interests of all our people by encouraging stewardship and citizen participation in their care. The Department also has a major responsibility for American Indian reservation communities and for people who live in island communities.

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