OCS Report
BOEM 2021-052

Outer Continental Shelf

Estimated Oil and Gas Reserves Gulf of Mexico OCS Region December 31, 2019

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

ON COVER- The Appomattox field in Mississippi Canyon was discovered in December 2009. Shell Offshore Inc began production, months ahead of schedule, in May 2019. Appomattox, Shell's largest floating platform in the Gulf of Mexico, represents the first production in the deep-water Gulf of Mexico Norphlet formation. Photo courtesy of Shell Oil.

OCS Report
BOEM 2021-052

Outer Continental Shelf

Estimated Oil and Gas Reserves Gulf of Mexico OCS Region December 31, 2019

Authors

Grant L. Burgess
Kellie K. Cross
Eric G. Kazanis

The Office of Resource Evaluation
Reserves Section

Published by

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

New Orleans
September 2021

TABLE OF CONTENTS

FIGURES

TABLES

ABBREVIATIONS AND ACRONYMS

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
DOI	U.S. Department of the Interior
^0F	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
ONRR	Office of Natural Resources Revenue
psia	pounds per square inch absolute
P/Z	pressure/gas compressibility factor
RE	Resource Evaluation
SCF/STB	standard cubic feet per stock tank barrel
SPE-PRMS	Society of Petroleum Engineers - Petroleum Resources Management System
Tcf	trillion cubic feet
TX	Texas
U.S.	United States
USGS	United States Geological Survey

ABSTRACT

This publication presents the Bureau of Ocean Energy Management's (BOEM) estimates of oil and gas reserves in the Gulf of Mexico Outer Continental Shelf. As of December 31, 2019, it is estimated that the *Original Reserves* are 26.77 billion barrels of oil and 197.0 trillion cubic feet of gas from 1,325 fields. *Original Reserves* are the total of the *Cumulative Production* and the *Reserves*. This report also includes 911 fields that have produced and expired. C*umulative Production* from all field's accounts for 22.12 billion barrels of oil and 190.9 trillion cubic feet of gas.

Reserves are estimated to be 4.65 billion barrels of oil and 6.1 trillion cubic feet of gas. These reserves are recoverable from 414 active fields. *Reserves* in this report are proved plus probable (2P) reserves estimates. The reserves must be discovered, recoverable, commercial and remaining. *Reserves*, starting with the 2011 report, now include *Reserves Justified for Development.*

The estimates of reserves for this report represent the combined efforts of engineers, geoscientists, paleontologists, petrophysicists, and other personnel of the BOEM Gulf of Mexico Region, Office of Resource Evaluation, in New Orleans, Louisiana. Reserves estimates are derived for individual reservoirs from geologic and engineering calculations. For any field spanning State and Federal waters, reserves are estimated for the Federal portion only.

INTRODUCTION

This report supersedes the *Estimated Oil and Gas Reserves, Gulf of Mexico OCS Region, December 31, 2018* (Burgess et al., 2020). It presents estimated Original Reserves, Cumulative Production, and Reserves as of December 31, 2019, for the Gulf of Mexico (GOM). **Figure 1** represents the percentages of Cumulative Production and Reserves in the GOM. Contingent and Undiscovered Resources are not included in this report.

As of December 31, 2019, the 1,325 oil and gas fields in the federally regulated part of the Gulf of Mexico Outer Continental Shelf (GOM OCS) contained Original Reserves estimated to be 26.77 billion barrels of oil (BBO) and 197.0 trillion cubic feet (Tcf) of gas. Cumulative Production from the fields accounts for 22.12 BBO and 190.9 Tcf of gas. Reserves are estimated to be 4.65 BBO and 6.1 Tcf of gas for the 414 active fields. Oil Reserves have increased 35.2 percent and the Gas Reserves have increased 7.0 percent since the 2018 report. These increases are the result of new fields added, and field revisions and expirations over the course of 2019.

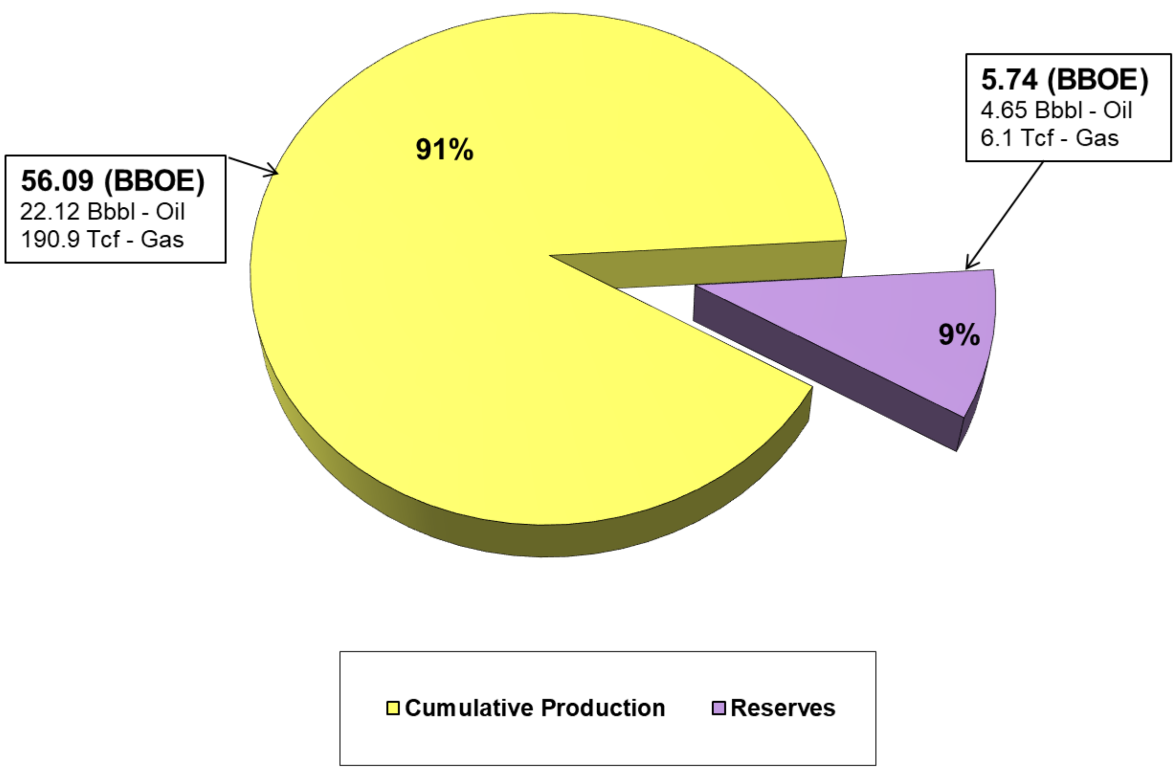

Figure 1. BOEM GOM Production and Reserves

BACKGROUND

Classification of Resources and Reserves

The BOEM resource classification framework is shown in **Figure 2**. Definitions for each resource class are presented in **Appendix A**. At the point in time a discovery is made, the identified accumulation of hydrocarbons is classified as a Contingent Resource, since 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 Undeveloped Reserves. After the equipment is in place, the accumulation is classified as Developed Non-Producing Reserves, and when production of the accumulation has begun, the status becomes Developed Producing Reserves. If an accumulation goes off production, for a year or more, for any reason, the classification changes back to Developed Non-Producing. *Reserves* in this report are proved plus probable (2P) reserves estimates. This is based on the classifications recommended in *Petroleum Resource Management System* (2007), which account for the range of uncertainty associated with reserve/resource estimation. For example, a 1P estimate would include only proved reserves, while a 3P estimate would incorporate proved, probable, and possible reserves. The reserves must be discovered, recoverable, commercial, and remaining. *Reserves*, starting with the 2011 report, now include *Reserves Justified for Development.* All hydrocarbons produced and sold are included in the Cumulative Production category. Should a project be abandoned, at any phase of development, any estimates of remaining hydrocarbon volumes could be re-classified to Contingent Resources.

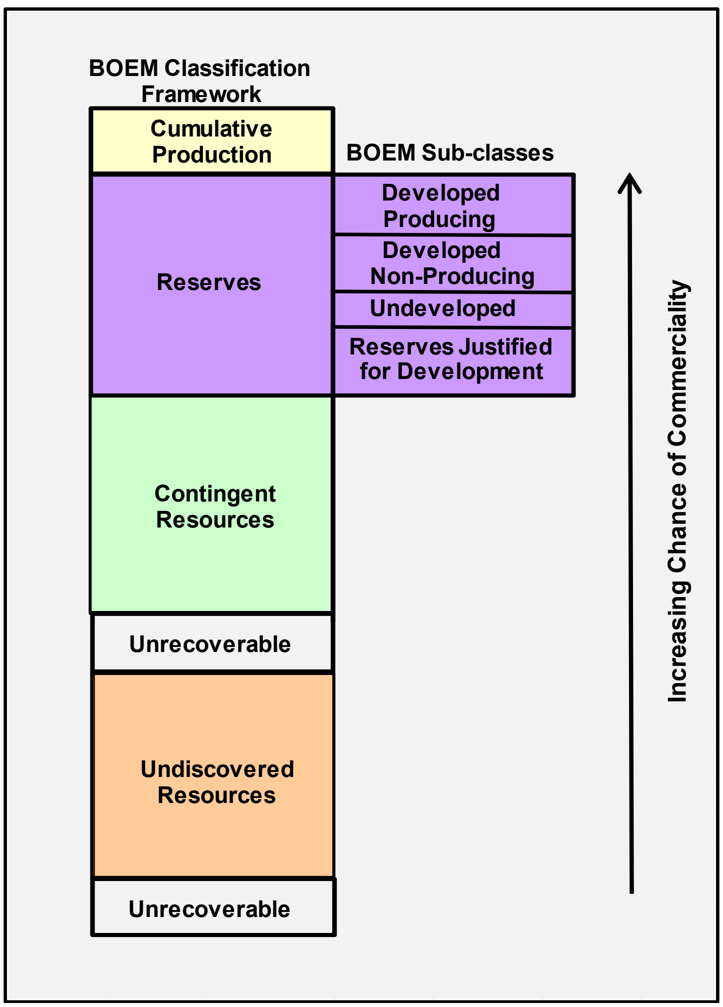

Figure 2. BOEM resource classification framework.

Methods Used for Estimating Reserves

The Reserves inventory component of the Resource Evaluation (RE) Program incorporates new producible leases into fields and develops independent estimates of recoverable amounts of oil and gas contained within discovered fields**.** The RE Program also develops independent estimates of natural gas and oil in previously discovered OCS fields by conducting field reserve studies and reviews of fields, sands, and reservoirs. The Program periodically revises the estimates of natural gas and oil volumes to reflect new discoveries, development, and annual production. This report, *Estimated Oil and Gas Reserves, Gulf of Mexico OCS Region, December 31, 2019*, is based on field studies completed at the reservoir and sand levels. All the reservoir level data have been linked to the sand, pool, play, chronozone, and series level to support the Offshore Atlas Project (OAP).

Additional reports address GOM reserves and undiscovered resources on the OCS. Minerals Management Service (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. A brief summary of the Atlas is available on the BOEM's Web site at http://www.boem.gov/BOEM-Newsroom/Library/Publications/2001/2001-086.aspx and current Atlas data associated with the 2019 Estimated Oil and Gas Report are available at https://www.data.boem.gov/Main/GandG.aspx.The BOEM Report, *2016a National Assessment of Undiscovered Oil and Gas Resources of the U.S. Outer Continental Shelf,* summarizes the results of the Bureau of Ocean Energy Management 2016 assessment of the undiscovered oil and gas resources for the U.S. Outer Continental Shelf. For more information visit BOEM's Web site at https://www.boem.gov/National-Assessment-2016/.

Reserve estimates from geological and engineering analyses have been completed for the 1,325 fields. The accuracy of the reserve estimate improves as additional reservoir data becomes available. 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 Original Reserves of productive reservoirs are assigned a value equal to the amount produced and any unrecovered reserve volumes may be converted to Contingent Resources. Currently, there are 911 expired, depleted fields.

Methods used for estimating reserves can be categorized into three groups: analog, volumetric, and performance. Reserve estimates in this report are based primarily on volumetric and performance methods. Reserve estimates are reported deterministically, providing a single "best estimate" based on known geological, engineering, and economic data.

Production data are the metered volumes of raw liquids and gas reported to BOEM (from ONRR, Office of Natural Resources Revenue) by Federal OCS unit and lease operators. Metered volumes from production platforms and/or leases are allocated to individual wells and reservoirs based on periodic well test gauges. These procedures introduce approximations in both production and remaining reserves volumes.

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. BOEM has converted all historical gas production volumes to the 14.73 pressure base.

RESERVES AND RELATED DATA BY PLANNING AREA

The GOM OCS is divided into three planning areas for administrative purposes (**Figure 3**). 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 the discovery – for example, East Cameron Block 271 (EC 271) Field. As the field is developed, the limits may expand into adjacent blocks and planning areas. These adjacent blocks are then identified as part of the original field and are added to that field. Statistics in this report are presented as area totals compiled under each field name. For example, all the data associated with EC 271 Field are included in the East Cameron totals, although part of the field extends into the adjacent area of Vermilion. There are four exceptions: Tiger Shoal and Lighthouse Point, included in South Marsh Island; Coon Point, included in Ship Shoal; and Bay Marchand, included in South Timbalier.

As of December 31, 2019, there were 414 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*. Included are the 911 expired, depleted and/or abandoned fields that produced 28.2 percent of the total cumulative GOM oil and gas production (by barrels oil equivalent (BOE)). One hundred sixteen fields expired, relinquished, or terminated without production. These fields may be included in the *Indicated Hydrocarbon List*. Reserves data are presented as area totals in **Table 1.**

Table 1. Estimated oil and gas reserves by area, December 31, 2019.

Area(s) (Fig. 3)	Number of fields				Original Reserves			Cumulative Production through 2019			Reserves		
	Active prod	Active nonprod	Expired depleted	Expired nonprod	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
Western Planning Area													
Alaminos Canyon	4	0	1	2	366	584	470	305	518	397	61	66	73
Brazos	3	0	35	3	10	3,759	680	10	3,746	677	0	13	3
East Breaks	9	0	12	3	274	2,230	671	269	2,176	656	5	54	15
Galveston	2	0	48	2	68	2,223	464	67	2,217	462	1	6	2
Garden Banks	1	0	6	2	40	331	99	38	328	96	2	3	3
High Island and Sabine Pass	19	1	109	10	427	15,532	3,191	423	15,498	3,181	4	34	10
Keathley Canyon	0	0	0	1	0	0	0	0	0	0	0	0	0
Matagorda Island	0	0	29	2	24	5,261	960	24	5,261	960	0	0	0
Mustang Island	1	0	28	5	8	1,794	327	8	1,787	326	0	7	1
N.& S.Padre Island	0	0	19	0	0	625	112	0	625	112	0	0	0
Port Isabel	0	0	0	1	0	0	0	0	0	0	0	0	0
West Cameron and Sabine Pass	2	0	24	1	37	2,928	558	35	2,921	555	2	7	3
Western Planning Area Subtotal	***41***	***1***	***311***	***32***	***1,254***	***35,267***	***7,532***	***1,179***	***35,077***	***7,422***	***75***	***190***	***110***
Central Planning Area													
Atwater Valley	1	0	5	5	70	613	179	43	594	149	27	19	30
Chandeleur	1	0	13	0	0	387	69	0	385	69	0	2	0
Desoto Canyon	2	0	4	1	37	541	133	12	514	103	25	27	30
Destin Dome	0	0	0	1	0	0	0	0	0	0	0	0	0
East Cameron	10	0	57	0	368	11,019	2,329	360	10,969	2,312	8	50	17
Eugene Island	27	3	59	4	1,785	20,720	5,471	1,741	20,414	5,373	44	306	98
Ewing Bank	11	2	5	2	445	853	597	391	750	525	54	103	72
Garden Banks	14	0	18	4	916	4,607	1,736	859	4,395	1,641	57	212	95
Grand Isle	6	0	17	1	1,037	5,158	1,955	1,008	5,041	1,905	29	117	50
Green Canyon	33	0	14	23	3,888	4,666	4,718	2,834	3,785	3,507	1,054	881	1,211
Keathley Canyon	2	0	1	3	472	591	577	99	357	162	373	234	415
Lloyd Ridge	0	0	4	0	0	330	59	0	330	59	0	0	0
Main Pass and Breton Sound	27	3	62	4	1,228	7,157	2,501	1,199	7,058	2,455	29	99	46
Mississippi Canyon	42	3	22	12	5,980	12,630	8,228	3,876	10,245	5,699	2,104	2,385	2,529
Mobile	7	1	26	2	0	2,462	438	0	2,404	428	0	58	10
Pensacola	0	0	1	0	0	8	1	0	8	1	0	0	0
Ship Shoal	34	1	34	3	1,523	12,988	3,835	1,483	12,728	3,748	40	260	87
Sigsbee Escarpment	0	0	0	1				0	0	0	0	0	0
South Marsh Island	26	5	20	0	1,003	15,056	3,682	978	14,886	3,627	25	170	55
South Pass	8	0	5	1	1,127	4,570	1,940	1,113	4,535	1,920	14	35	20
South Pelto	3	0	6	0	160	1,185	371	159	1,175	368	1	10	3
South Timbalier	19	2	42	2	1,660	10,617	3,550	1,623	10,424	3,478	37	193	72
Vermilion	23	4	58	1	608	16,901	3,614	590	16,719	3,564	18	182	50
Viosca Knoll	15	1	38	8	697	3,883	1,388	642	3,702	1,301	55	181	87
Walker Ridge	7	0	0	2	863	186	897	300	63	312	563	123	585
West Cameron and Sabine Pass	15	2	77	0	199	18,732	3,532	196	18,554	3,497	3	178	35
West Delta	10	2	12	3	1,449	5,861	2,493	1,432	5,773	2,460	17	88	33
Central Planning Area Subtotal	***343***	***29***	***600***	***83***	***25,515***	***161,721***	***54,293***	***20,938***	***155,808***	***48,663***	***4,577***	***5,913***	***5,630***
Eastern Planning Area													
Destin Dome	0	0	0	1	0	0	0	0	0	0	0	0	0
Eastern Planning Area Subtotal*	***0***	***0***	***0***	***1***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***
GOM Total:	***384***	***30***	***911***	***116***	***26,769***	***196,988***	***61,825***	***22,117***	***190,885***	***56,085***	***4,652***	***6,103***	***5,740***
		1,325											

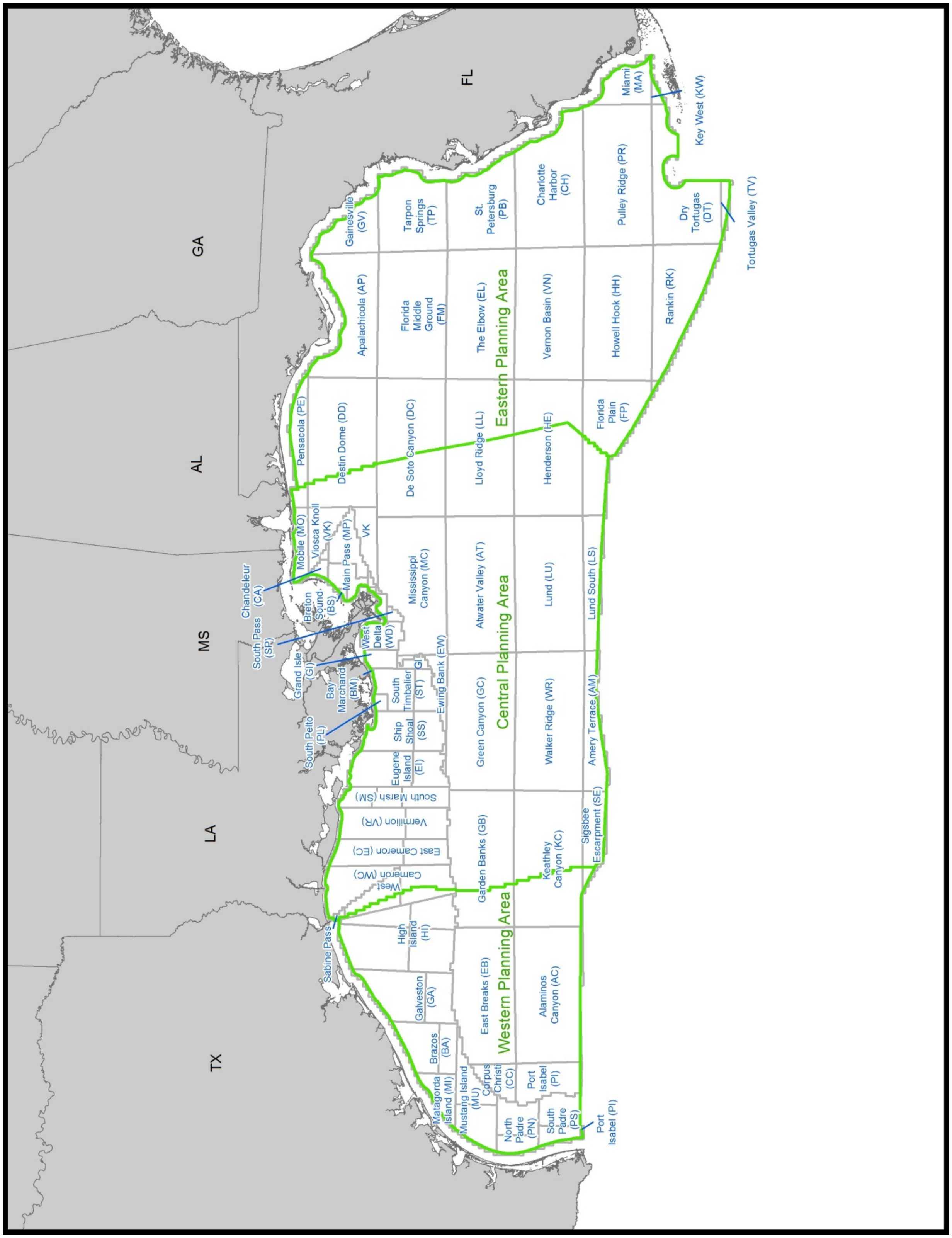

Figure 3. BOEM GOM OCS Planning Areas and Protraction Areas.

FIELD-SIZE DISTRIBUTION

Field Reserve volumes 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 United States Geological Survey (USGS) (Attanasi, 1998), was selected for field-size (deposit-size) distribution ranges (**Table 2**).

In this report, fields are classified as either oil or gas; some fields do produce both products, making a field type classification difficult. The classification is made on a case-by-case basis by analysis of the field's reservoirs and their fluid distributions.

Table 2. 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 Reserves (in BOE) for 1,325 fields is shown in **Figure 4,** along with the planning area distributions. Of the 1,325 oil and gas fields, there are 293 oil fields represented in **Figure 5** and 1,032 gas fields shown in **Figure 6**. These figures also display the planning area distributions.

Analysis of the 1,325 oil and gas fields indicates that the GOM is historically a gas-prone basin. The GOR, based on original reserves of the 293 oil fields, is 2,250 SCF/STB. The yield (condensate divided by gas), based on original reserves for the 1,032 gas fields, is 22.7 barrels (Bbl) of condensate per million cubic feet (MMcf) of gas.

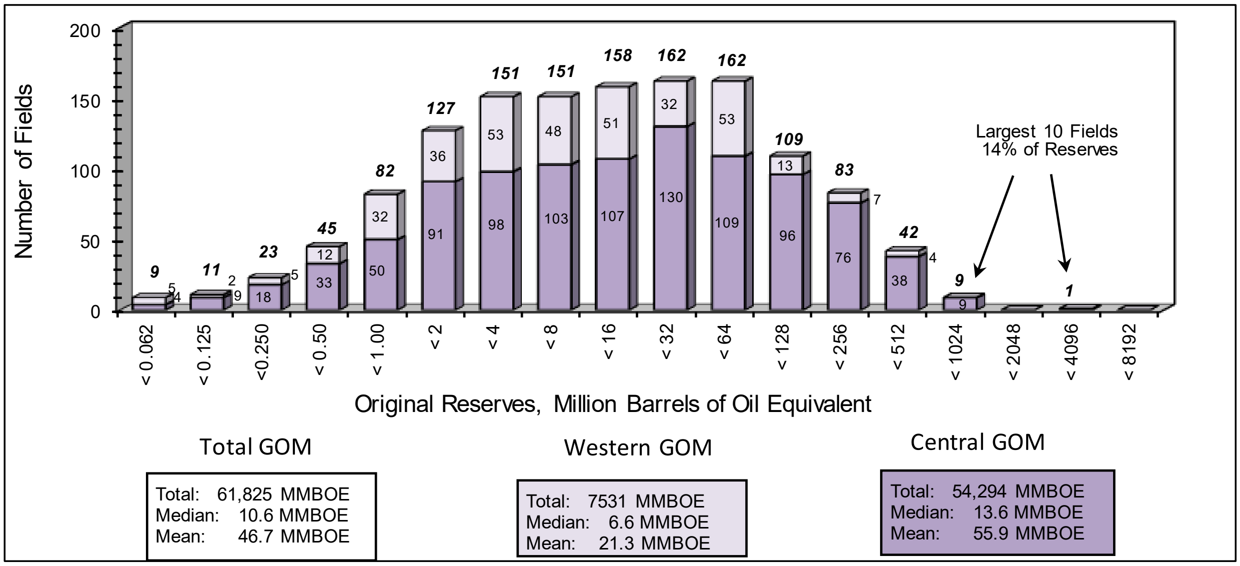

Figure 4. Field-size Distribution of all GOM Fields by Planning Area

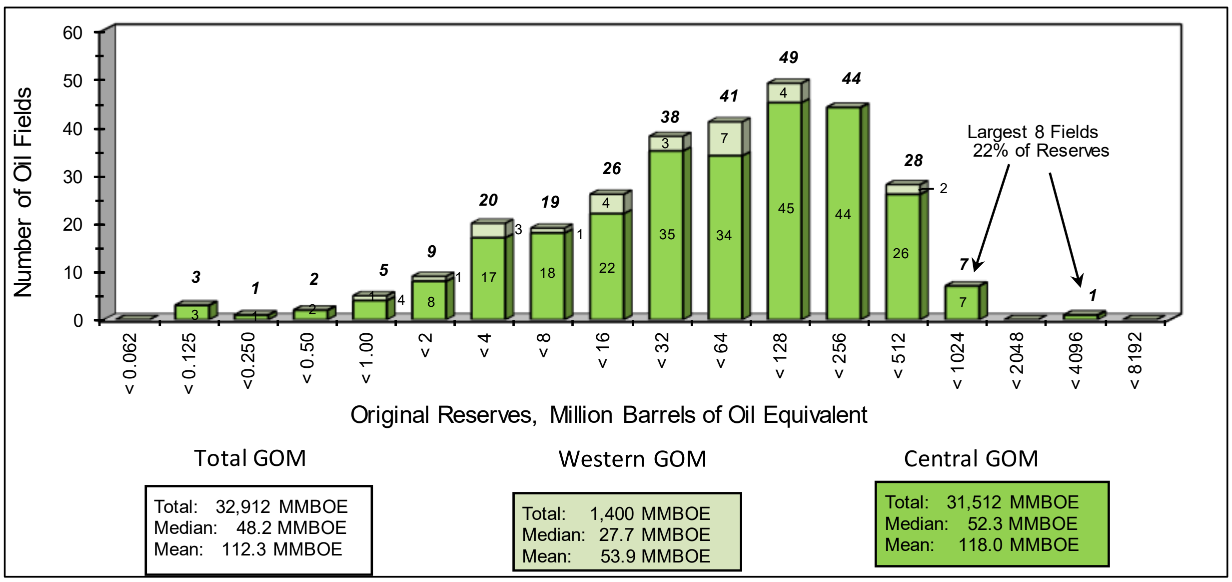

Figure 5. Field-size Distribution of GOM Oil Fields by Planning Area

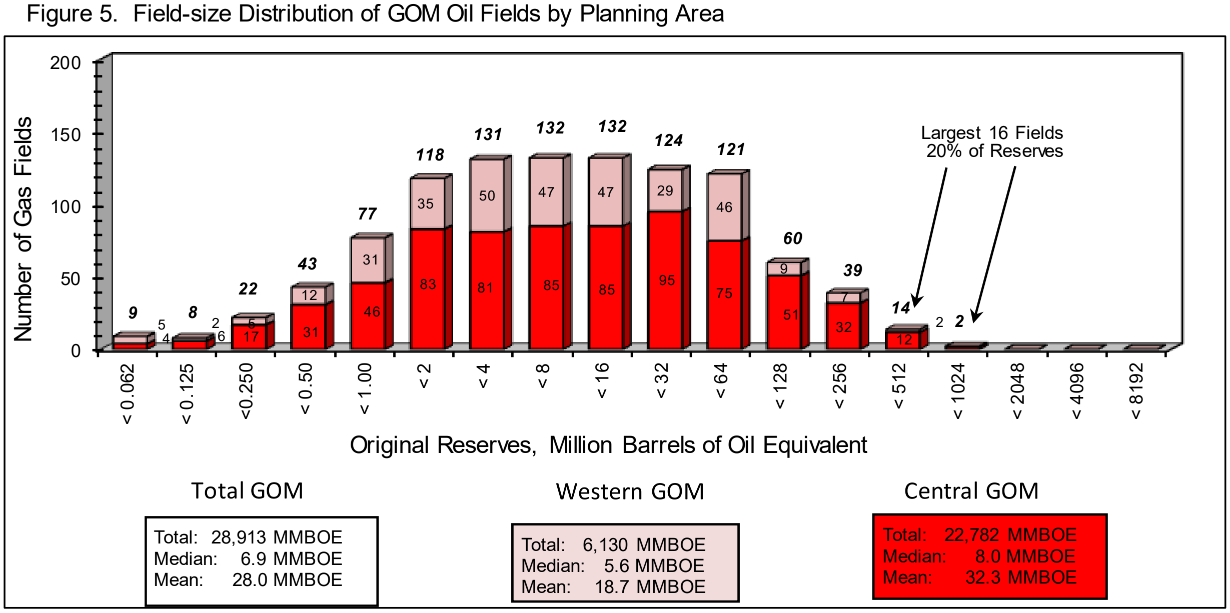

Figure 6. Field-size Distribution of GOM Gas Fields by Planning Area

Figure 7 shows the cumulative percent distribution of Original Reserves in billion barrels of oil equivalent (BBOE), by field size rank. All 1,325 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 Reserves are contained in the 27 largest fields. Fifty percent of the Original Reserves are contained in the 89 largest fields. Ninety percent of the Original Reserves are contained in the 436 largest fields.

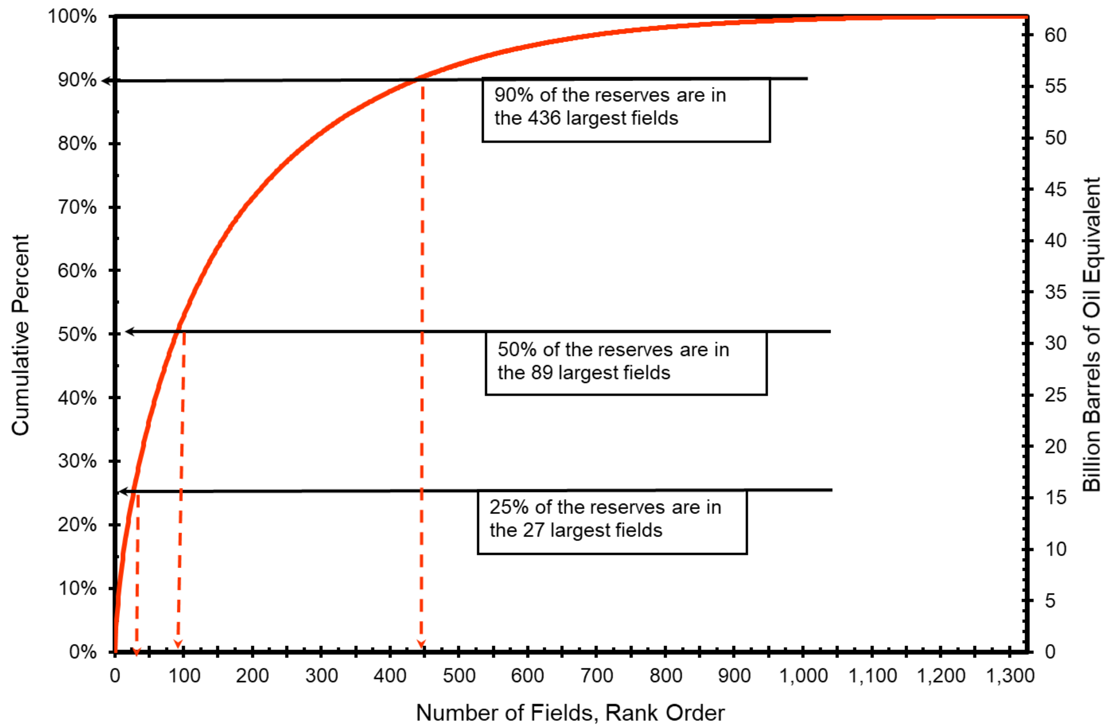

Figure 7. Cumulative percent total reserves versus rank order of field size.

Table 3 shows the distribution of the number of fields and reserves by water depth. A field's water depth is determined by averaging the water depth where the wells are drilled in the field. Reserves and production, reported in MMBOE, are associated with the 1,325 fields. Reserves located in greater than or equal to 1,500 ft of water accounts for 86 percent of the total GOM Reserves. Of the 243 fields in water depths greater than 500 ft, 136 are producing, 106 are depleted or expired, and one is yet to produce.

Table 3. Field and reserves distribution by water depth.

Water Depth Range (Feet)	**Number of Fields**	**Cumulative Production (MMBOE)**	**Reserves (MMBOE)**
< 500	1,082	41,838	612
500 - 999	54	1,293	32
1,000 - 1,499	28	1,500	132
1,500 - 4,999	102	7,741	2,380
5,000 - 7,499	41	3,006	2,443
>= 7,500	18	707	141
Totals:	1,325	56,085	5,740

Figure 8 shows the largest 20 fields ranked in order by Reserves. All 20 of the fields lie in water depths of greater than or equal to 1,500 ft and account for 88.0 percent of the Reserves in the GOM.

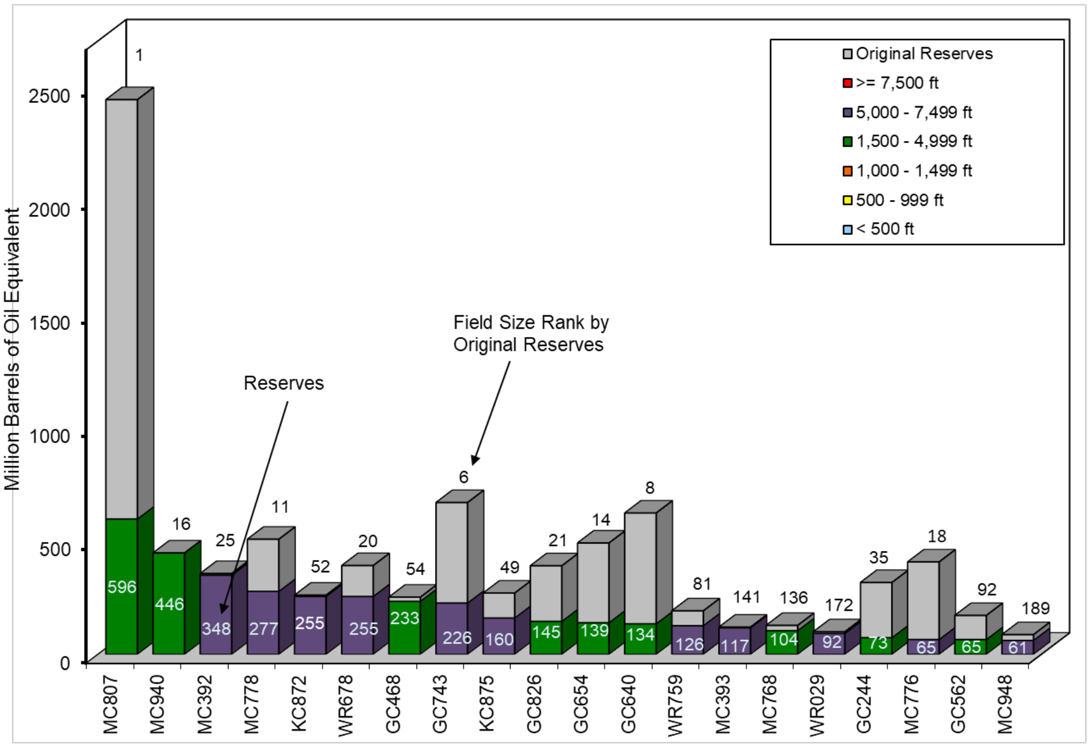

Figure 8. Largest 20 fields, with associated water depths, ranked by Reserves and compared to Original Reserves.

Table 4 ranks the 50 largest fields based on Original Reserves expressed in BOE. Rank, Field name, Field Nickname, Discovery year, Water depth, Field Classification, Field type, Field GOR, Original Reserves, Cumulative Production through 2019 and Reserves are presented. A complete listing of all 1,325 fields is available on the BOEM Web site at: https://www.data.boem.gov/Main/HtmlPage.aspx?page=estimated2019.

Table 4. A listing of Gulf of Mexico fields by rank order, based on Original BOE reserves, top 50 fields.

Field class: P (PDP - Developed Producing, PDN - Developed Non-Producing and PU - Undeveloped) ; J (RJD- Reserves Justified for Development)

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 Reserves Oil (MMbbl)	Original Reserves Gas (Bcf)	Original Reserves BOE (MMbbl)	Cumulative Production through 2019 Oil (MMbbl)	Cumulative Production through 2019 Gas (Bcf)	Cumulative Production through 2019 BOE (MMbbl)	Reserves Oil (MMbbl)	Reserves Gas (Bcf)	Reserves BOE (MMbbl)
1	MC807	MARS-URSA	1989	3,340	P	O	1,320	1977.2	2609.4	2441.4	1504.0	1921.8	1845.9	473.2	687.6	595.5
2	EI330		1971	248	P	O	4,082	470.7	1921.1	812.5	461.8	1902.2	800.2	8.9	18.9	12.3
3	WD030		1949	48	P	O	1,649	596.3	985.4	771.7	592.9	977.3	766.8	3.4	8.1	4.9
4	GI043		1956	140	P	O	4,354	403.6	1746.3	714.3	381.7	1657.5	676.6	21.9	88.8	37.7
5	TS000		1958	13	P	G	79,938	46.2	3692.2	703.1	45.6	3653.5	695.7	0.6	38.7	7.4
6	GC743	ATLANTIS	1998	6,331	P	O	819	583.1	477.6	668.1	395.0	266.2	442.4	188.1	211.4	225.7
7	BM002		1949	50	P	O	1,052	549.6	578.3	652.5	546.9	575.8	649.4	2.7	2.5	3.1
8	GC640	TAHITI/CAE/TONG	2002	4,337	P	O	670	555.6	372.5	621.8	436.0	289.4	487.4	120	83.1	134
9	VR014		1956	26	P	G	65,255	47.9	3126.5	604.2	47.9	3126.5	604.2	0.0	0.0	0.0
10	MP041		1956	42	P	O	5,658	276.8	1566.1	555.5	274.1	1560.2	551.7	2.7	5.9	3.8
11	MC778	THUNDER HORSE	1999	6,095	P	O	730	448.5	327.4	506.7	203.1	148.4	229.5	245.4	179.0	277.2
12	GB426	AUGER	1987	2,845	P	O	3,525	305.4	1076.6	496.9	286.3	1014.4	466.8	19.1	62.2	30.1
13	VR039		1948	38	P	G	79,958	32.6	2606.9	496.4	32.3	2603.9	495.6	0.3	3.0	0.8
14	GC654	SHENZI	2002	4,303	P	O	394	458.0	180.3	490.1	327.9	129.9	351.0	130.1	50.4	139.1
15	SS208		1960	102	P	O	6,149	232.6	1434.3	487.8	227.7	1402.5	477.2	4.9	31.8	10.6
16	MC940	VITO	2010	4,009	P	O	488	410.5	200.4	446.2	0.0	0.0	0.0	410.5	200.4	446.2
17	WD073		1962	177	P	O	2,458	283.4	701.1	408.1	279.8	692.4	403.0	3.6	8.7	5.1
18	MC776	N.THUNDER HORSE	2000	5,672	P	O	982	346.3	340.0	406.8	290.9	284.6	341.5	55.4	55.4	65.3
19	EI238		1964	147	P	G	16,587	99.9	1650.6	393.7	95.6	1559.9	373.2	4.3	90.7	20.5
20	WR678	SAINT MALO	2003	6,953	P	O	240	374.7	89.9	390.7	130.4	31.7	136.1	244.3	58.2	254.6
21	GC826	MAD DOG	1998	4,864	P	O	419	362.8	151.9	389.8	232.6	68.0	244.7	130.2	83.9	145.1
22	GI016		1948	54	P	O	1,300	310.4	403.1	382.1	307.9	397.6	378.6	2.5	5.5	3.5
23	MC084	KING/HORN MT.	1993	5,315	P	O	1,007	318.6	320.8	375.7	270.7	285.2	321.5	47.9	35.6	54.2
24	SP061		1967	220	P	O	1,923	277.5	533.5	372.4	273	530	367	4.4	3.6	5.0
25	MC392	APPOMATTOX	2009	7,221	P	O	519	325.4	168.9	355.5	6.4	4.3	7.2	319.0	164.6	348.3
26	SP089		1969	421	P	O	4,417	199.0	878.9	355.4	197.2	875.1	352.9	1.8	3.8	2.5
27	ST172		1962	98	P	G	158,376	12.0	1898.9	349.9	12.0	1898.9	349.9	0.0	0.0	0.0
28	WC180		1961	48	P	G	139,651	13.2	1845.8	341.7	13.2	1845.8	341.7	0.0	0.0	0.0
29	ST021		1957	46	P	O	1,647	259.9	428.0	336.1	259.3	427.3	335.4	0.6	0.7	0.7
30	SS169		1960	63	P	O	5,256	173.4	911.2	335.5	170.3	900.9	330.6	3.1	10.3	4.9
31	EI292		1964	214	P	G	57,933	28.6	1658.8	323.8	25.8	1652.1	319.8	2.8	6.7	4.0
32	MC194	COGNAC	1975	1,022	P	O	4,152	185.6	770.6	322.7	182.9	763.7	318.8	2.7	6.9	3.9
33	ST176		1963	127	P	G	13,873	92.8	1287.7	321.9	91.2	1277.0	318.4	1.6	10.7	3.5
34	EC271		1971	172	P	G	17,815	75.8	1351.3	316.3	73.6	1345.0	313.0	2.2	6.3	3.3
35	GC244	TROIKA	1994	2,795	P	O	1,836	238.3	437.6	316.2	181.3	345.4	242.8	57.0	92.2	73.4
36	EC064		1957	50	P	G	56,112	28.7	1609.0	315.0	27.4	1607.4	313.4	1.3	1.6	1.6
37	SS176		1956	101	P	G	18,438	73.3	1350.2	313.5	70.1	1323.8	305.6	3.2	26.4	7.9
38	SM048		1961	100	P	G	51,549	30.4	1566.3	309.1	29.5	1560.1	307.1	0.9	6.2	2.0
39	GB171	SALSA	1984	1,206	P	O	3,922	180.6	708.3	306.6	156.2	618.1	266.2	24.4	90.2	40.4
40	WC587		1971	210	P	G	118,356	13.4	1581.1	294.7	13.4	1581.1	294.7	0.0	0.0	0.0
41	SP027	EAST BAY	1954	64	P	O	5,158	153.3	791.7	294.2	152.4	784.1	291.9	0.9	7.6	2.3
42	AC857	GREAT WHITE	2002	7,921	P	O	1,707	220.4	376.1	287.3	181.5	331.1	240.4	38.9	45.0	46.9
43	ST135		1956	129	P	O	3,683	172.2	634.2	285.0	170.4	627.9	282.1	1.8	6.3	2.9
44	WD079		1966	123	P	O	3,878	168.5	650.2	284.2	165.7	640.8	279.7	2.8	9.4	4.5
45	EI296		1971	214	P	G	71,230	20.6	1464.0	281.1	20.6	1464.0	281.1	0.0	0.0	0.0
46	WC192		1954	57	P	G	60,168	23.6	1420.5	276.4	23.4	1416.4	275.4	0.2	4.1	1.0
47	HI573A		1973	341	P	O	7,428	118.6	881.2	275.4	117.2	878.5	273.5	1.4	2.7	1.9
48	VK956	RAM-POWELL	1985	3,238	P	O	8,794	107.3	943.5	275.1	102.5	919.7	266.1	4.8	23.8	9.0
49	KC875	LUCIUS	2010	7,106	P	O	1,197	222.2	265.9	269.6	91.5	102.2	109.7	130.7	163.7	159.9
50	GI047		1955	88	P	O	3,822	157.9	604.9	265.6	155.4	595.7	261.4	2.5	9.2	4.2

RESERVOIR-SIZE DISTRIBUTION

The size distributions of the reservoirs are shown in **Figures 9, 10, and 11**. The size ranges are based on Original Reserves and are presented on a geometrically progressing horizontal scale. These sizes correspond with the USGS deposit-size ranges shown in **Table 2,** with a modification to subdivide small reservoirs into finer distributions. In **Figure 9**, the Original Reserves are presented in million barrels of Oil Equivalent (MMBOE). For the combination reservoirs (saturated oil rims with associated gas caps), shown in **Figure 9**, gas is converted to BOE and added to the liquid reserves. **Figures 10 and 11** are presented in million barrels of Oil (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.

Figure 9 shows the reservoir-size distribution, on the basis of Original BOE, for 2,374 combination reservoirs. The median is 0.9 MMBOE and the mean is 3.1 MMBOE. The GOR, based on Original Reserves, for the oil portion of the reservoirs is 1,201 SCF/STB, and the yield, based on Original Reserves, for the gas cap is 22.2 Bbl of condensate per MMcf of gas.

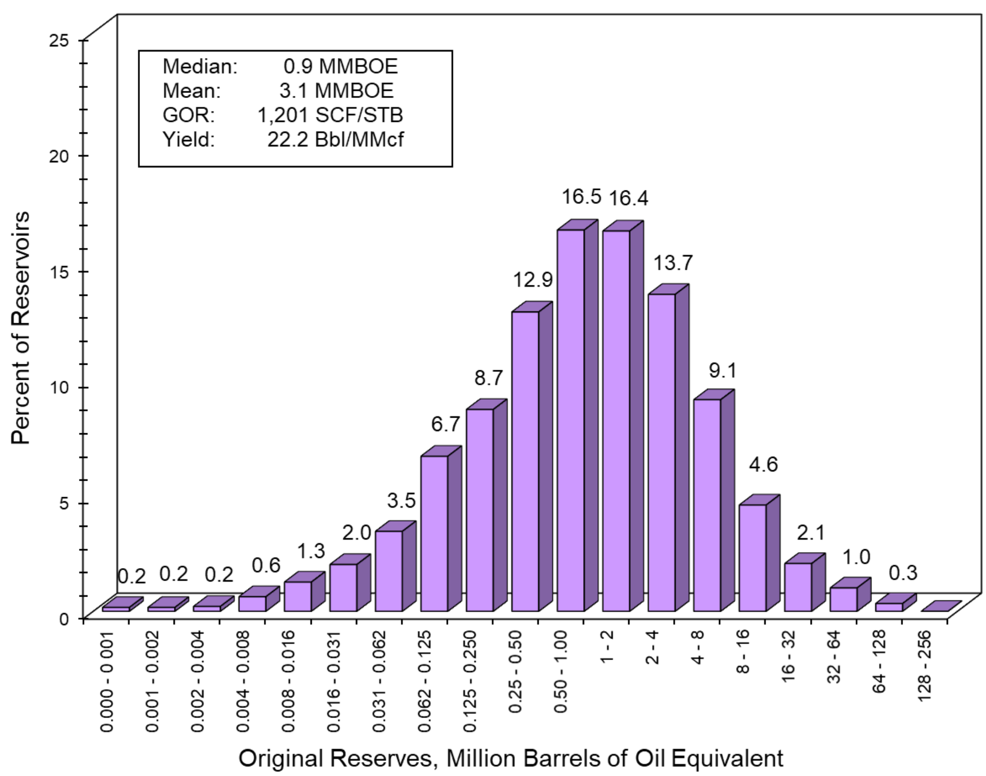

Figure 9. Reservoir-size distribution, combination reservoirs.

Figure 10 shows the reservoir-size distribution, on the basis of Original Oil reserves, for 8,957 undersaturated oil reservoirs. The median is 0.3 MMbbl, the mean is 2.3 MMbbl, and the GOR, based on Original Oil reserves, is 1,140 SCF/STB. **Figure 11** shows the reservoir-size distribution, on the basis of Original Gas reserves, for 18,702 gas reservoirs. The median is 2.0 Bcf of gas, the mean is 8.4 Bcf, and the yield, based on Original Reserves, is 12.3 Bbl of condensate per MMcf of gas.

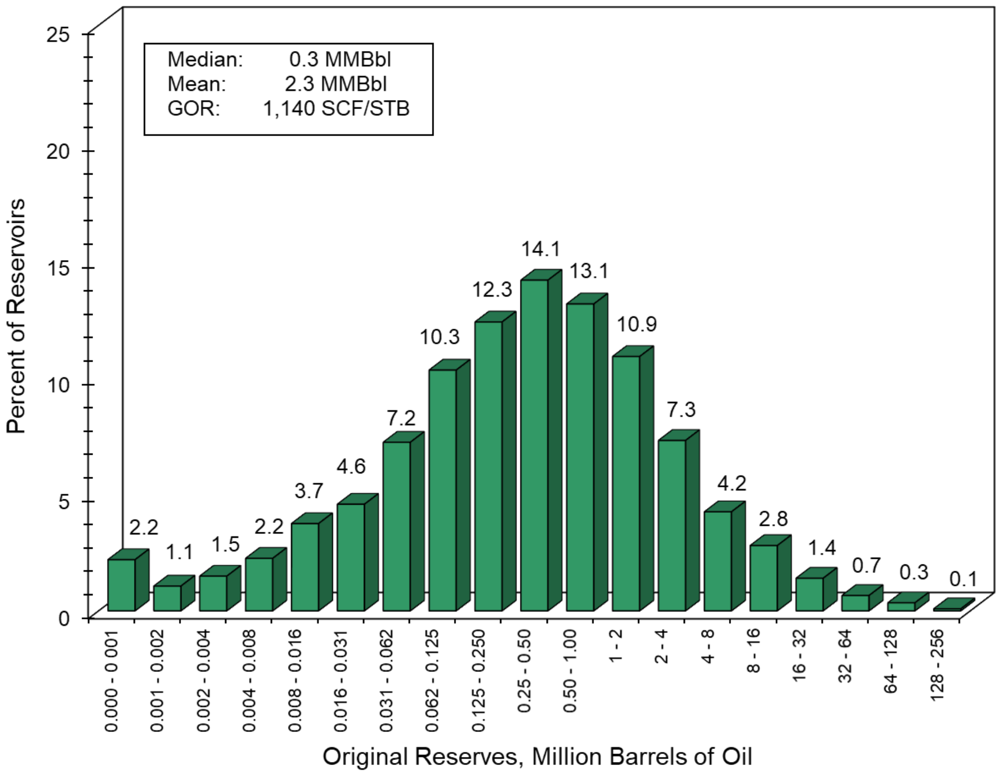

Figure 10. Reservoir-size distribution, oil reservoirs.

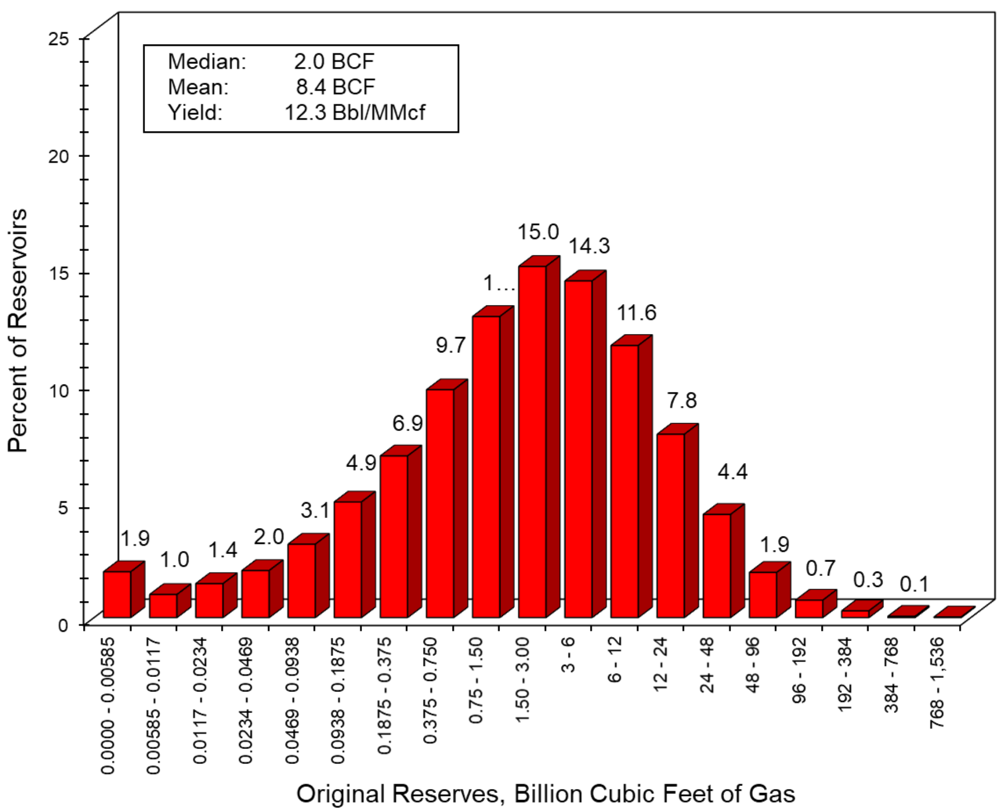

Figure 11. Reservoir-size distribution, gas reservoirs.

DRILLING AND PRODUCTION TRENDS

Figure 12 presents the number of exploratory wells drilled each year by water depth category. The total footage drilled in 2019 was 1.72 million feet, compared to 1.65 million feet in 2018.

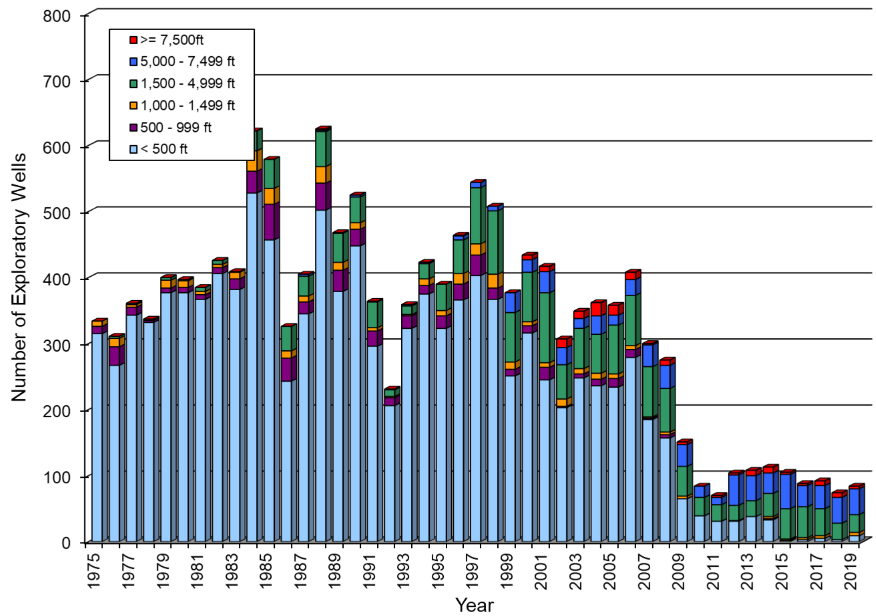

Figure 12. Number of exploratory wells drilled by water depth.

Figure 13 presents the number of development wells drilled each year by water depth category. The total footage drilled in 2019 was 1.63 million feet, compared to 1.76 million feet in 2018.

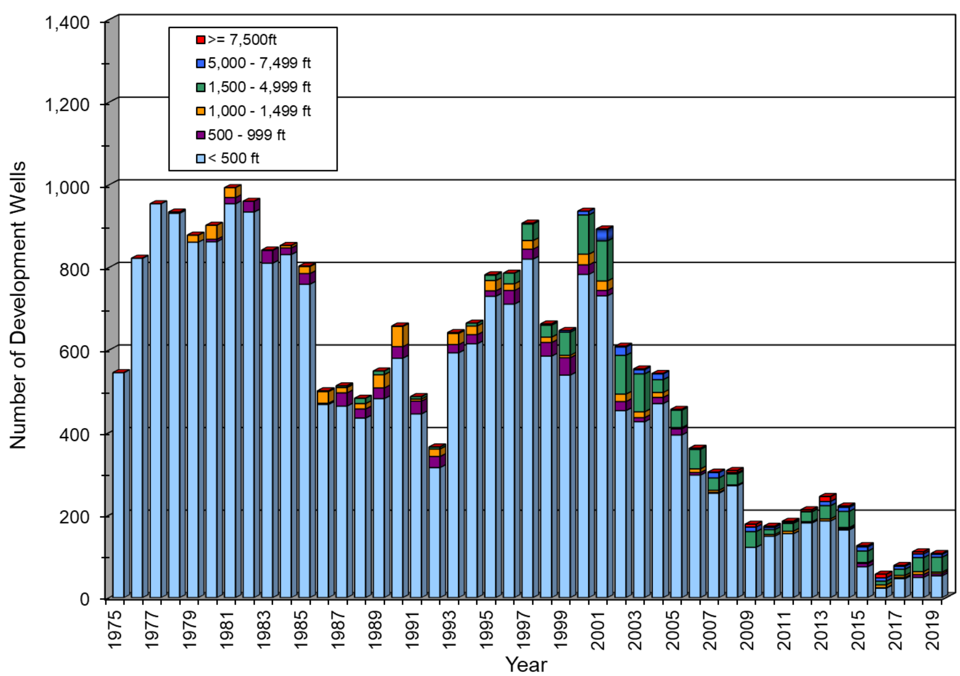

Figure 13. Number of development wells drilled by water depth.

Original Reserves in BBOE for water depth categories by reservoir discovery year are presented in **Figure 14**.

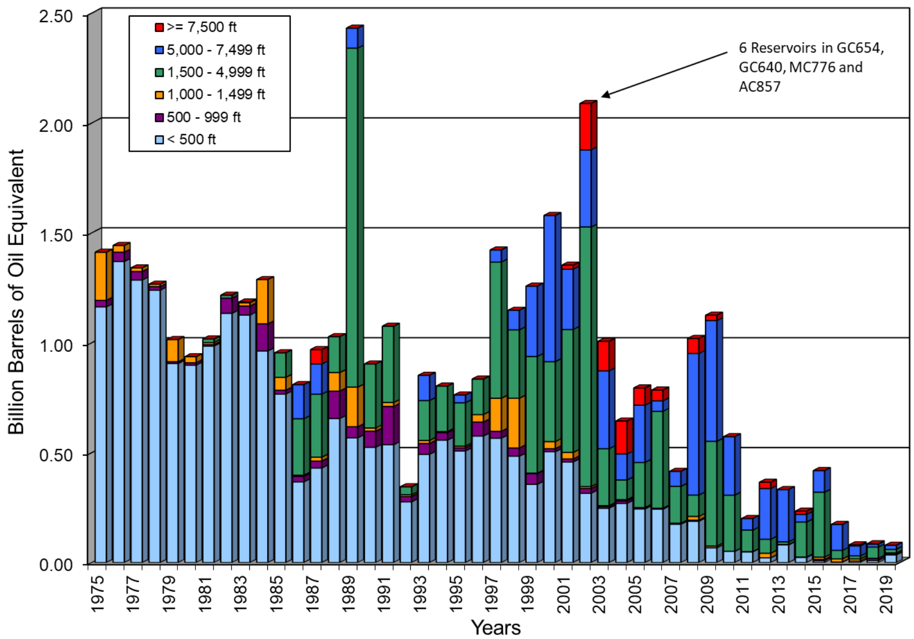

Figure 14. Original Reserves categorized by water depth and reservoir discovery year.

Annual production in the GOM is shown in **Figure 15**. 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 2018 to 2019, annual oil production increased 7.8 percent to 692 MMbbl and annual gas production increased 4.1 percent to 1.0 Tcf. The mean daily production in the GOM during 2019 was 1.80 MMbbl of crude oil, 0.10 MMbbl of gas condensate, 1.83 Bcf of casinghead gas, and 1.00 Bcf of gas-well gas. The mean GOR of oil wells was 1,019 SCF/STB, and the mean yield from gas wells was 96.14 Bbl of condensate per MMcf of gas.

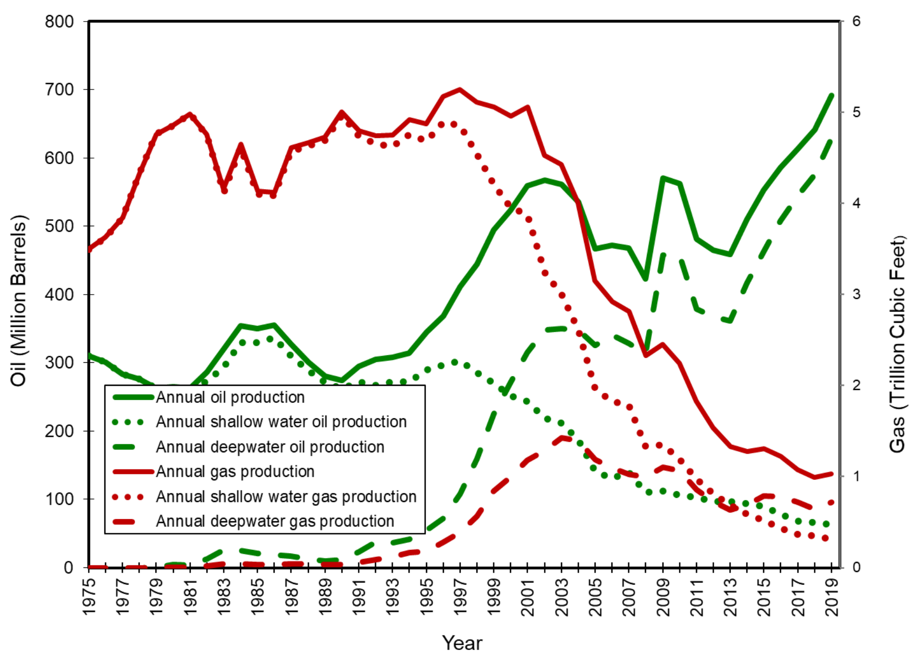

Figure 15. Annual oil and gas production.

DEVELOPMENT BY ASSESSMENT UNIT

Graphical displays of reservoir and production data within assessment units and plays are provided in this section. The assessment units represent a group of geologically related hydrocarbon accumulations; the term Assessment Unit can refer to groupings of chronozone(s) and/or geologic play(s). The data from each reservoir within an assessment unit or play were combined to create graphs displaying: the total reserves volume discovered each year, the number of reservoirs discovered within the unit, the production from the reservoirs in the unit, and the average size of each reservoir in that unit.

Assessment units are based on current water depths (shelf <=200m, slope >200m), and relative geologic age of Cenozoic sediments in the U.S. Gulf of Mexico OCS. Using these criteria, Cenozoic sediments are further divided into 12 assessment units as shown below; however, only 11 of these units have figures associated with them since the Lower Tertiary Shelf unit lacks reserves or production.

Pleistocene Shelf	Pleistocene Slope
Pliocene Shelf	Pliocene Slope
Upper Miocene Shelf	Upper Miocene Slope
Middle Miocene Shelf	Middle Miocene Slope
Lower Miocene Shelf	Lower Miocene Slope
Lower Tertiary Shelf	Lower Tertiary Slope

Unlike the aggregated assessment units of Cenozoic sediments, the Mesozoic sediments of the U.S. Gulf of Mexico OCS were differentiated by specific rock units or plays. Although 19 Mesozoic rock units and plays are identified in, *Assessment of Technically and Economically Recoverable Hydrocarbon Resources of the Gulf of Mexico Outer Continental Shelf as of January 1, 2014*, only two are included in this report: the James Play and the Norphlet Play. These two plays are included because there are reserves and production associated with them.

Figures 16 through 23 depict reservoir and production data for the 11 Cenozoic assessment units described above, and the 2 Mesozoic plays. These data exhibit the lag time from reserves discovery to production, and show exploration and development moving from shallow-water to deepwater. Shallow-water Cenozoic data exhibit significant production decline rates; however, the development of discoveries in deepwater Cenozoic sediments have offset these declines.

In Mesozoic sediments, reserves and production data exist for only 2 assessment units. These data show production rates declining in both the James Play and the Norphlet Play (Figures 22 and 23); however, additional opportunities are expected in these plays and in other Mesozoic assessment units. Expected ranges of resources to be discovered in these, and other GOM assessment units, are reported in *Assessment of Technically and Economically Recoverable Hydrocarbon Resources of the Gulf of Mexico Outer Continental Shelf as of January 1, 2014*.

Figures 16A and 16B show the decline in volume of reserves discovered, number of reservoirs discovered, and production for the shallow-water and deepwater Pleistocene assessment units. The largest total reserves discovered (MMBOE) in a single year in the Pleistocene occurred in 1971, which included two large shallow water reservoirs, one in the EI296 Field and two in the EI330 Field, containing 203 MMBOE. All three reservoirs are now depleted. As of the 2018 report, there was a re-alignment of the Pleistocene and Pliocene assessment units in correspondence with BOEM's current Biostratigraphic chart of the Gulf of Mexico offshore region, Jurassic to Quaternary. A peak in the volume of reserves occurs in the 1997 reservoir discovery year. This can be associated with the GC244 and AC025 fields and is also reflected in the average reservoir size, the third largest in the Pleistocene slope development. Production in deepwater peaked in 2001, but volumes have been on an overall decline since on both the shelf and the slope. The data indicate this is associated with significant decreases in reserves discovered in both shallow-water and deepwater.

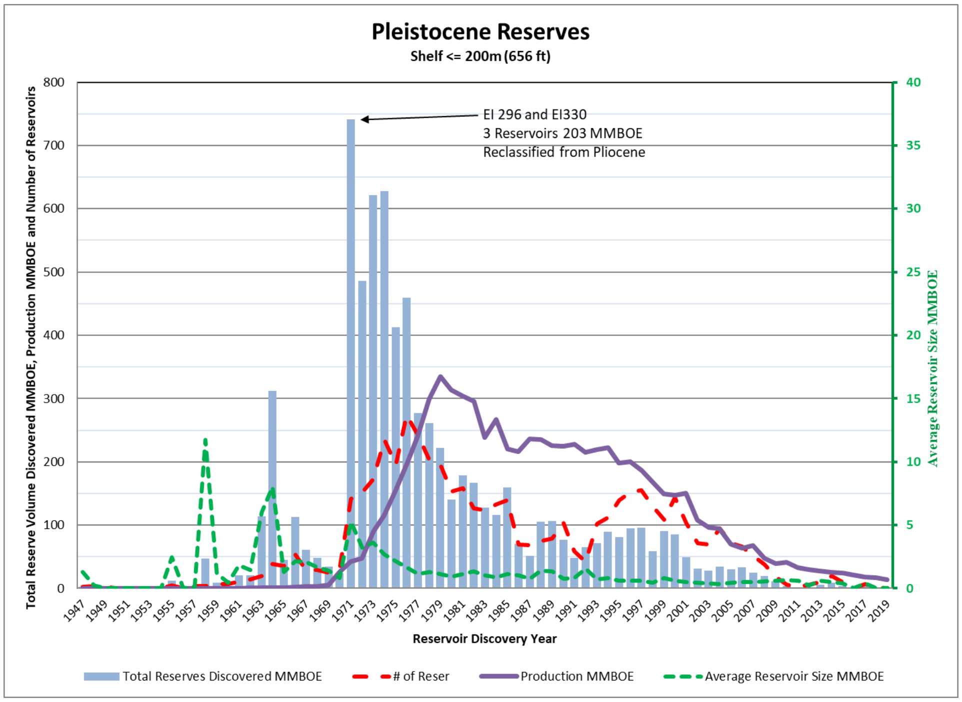

Figure 16A. Pleistocene Shelf Development

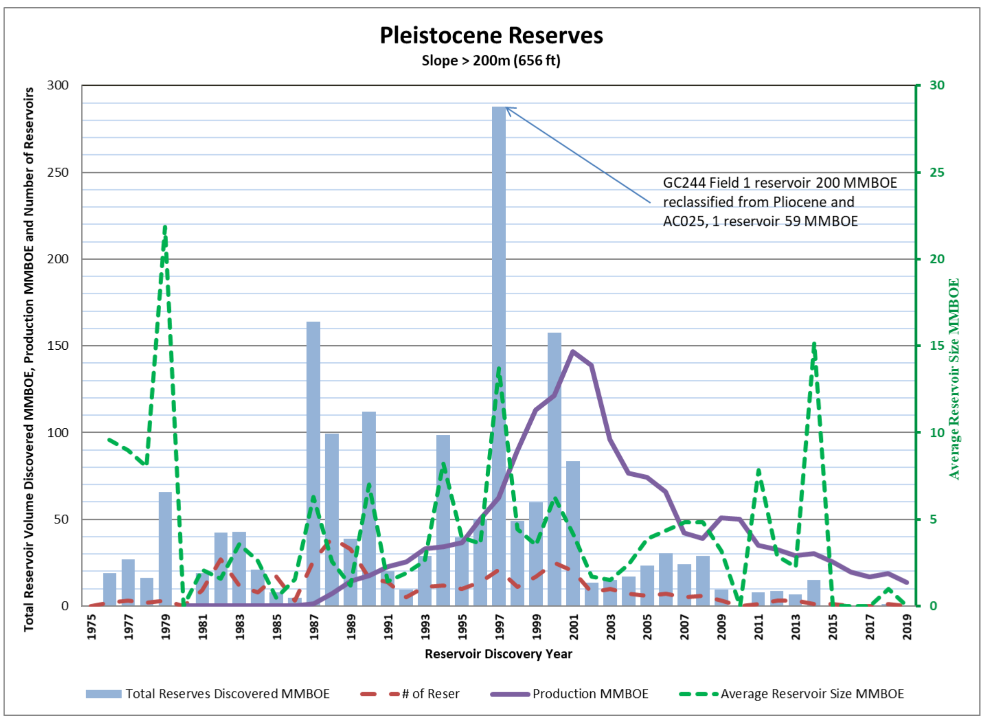

Figure 16B. Pleistocene Slope Development

A marked increase in both total reserves discovered and average reservoir size can be seen from 2018 to 2019 in Pliocene shelf fields. Total reserves discovered for 2019 increased by five times that of 2018, while the average reservoir size increased tenfold. In deepwater, Pliocene production rates have been considerably higher than in shallow-water (Figure 17B). Deepwater production rates have remained within 75-125 MMBOE since 2009 and have increased from 2018 to date as of this report.

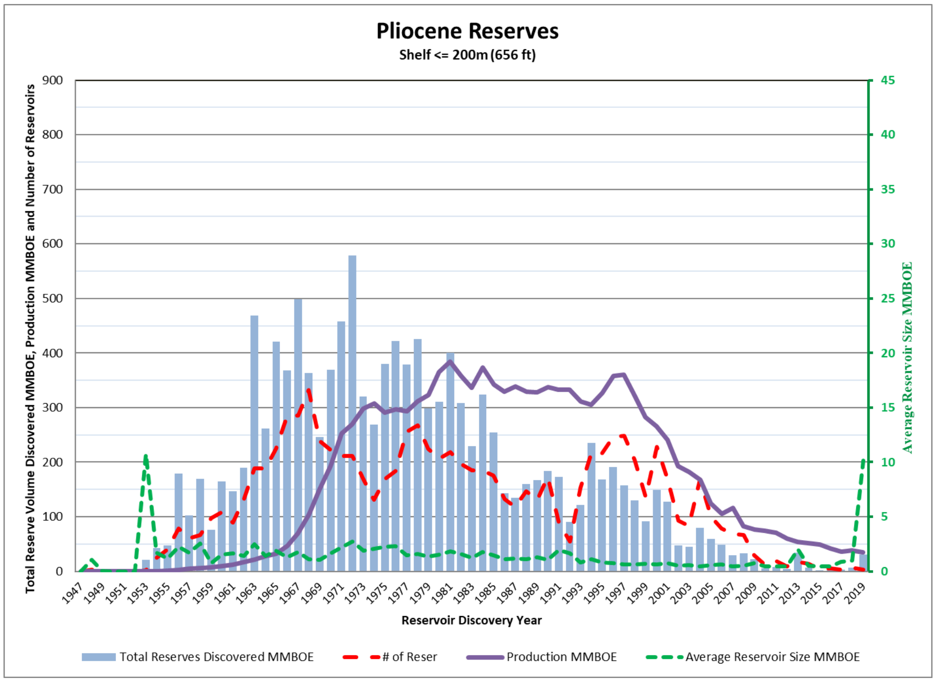

Figure 17A. Pliocene Shelf Development

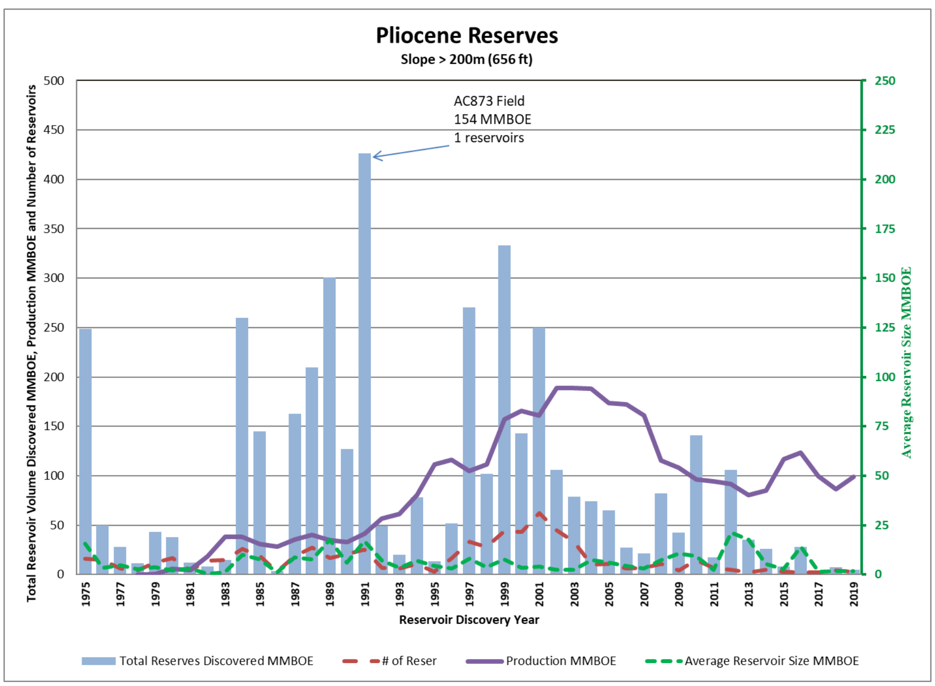

Figure 17B. Pliocene Slope Development

For the Upper Miocene in shallow-water, both the production and number of reservoirs discovered have decreased since the year 2000 (Figure 18A). In deepwater, the number of reservoirs discovered has remained consistent; however, production has been decreasing very slightly over the last decade (Figure 18B). A large discovery in

2014 in the MC768 field caused the average reservoir size to spike in that year. While there has been decrease in the average reservoir size from 2018, there has been an increase in the production rate.

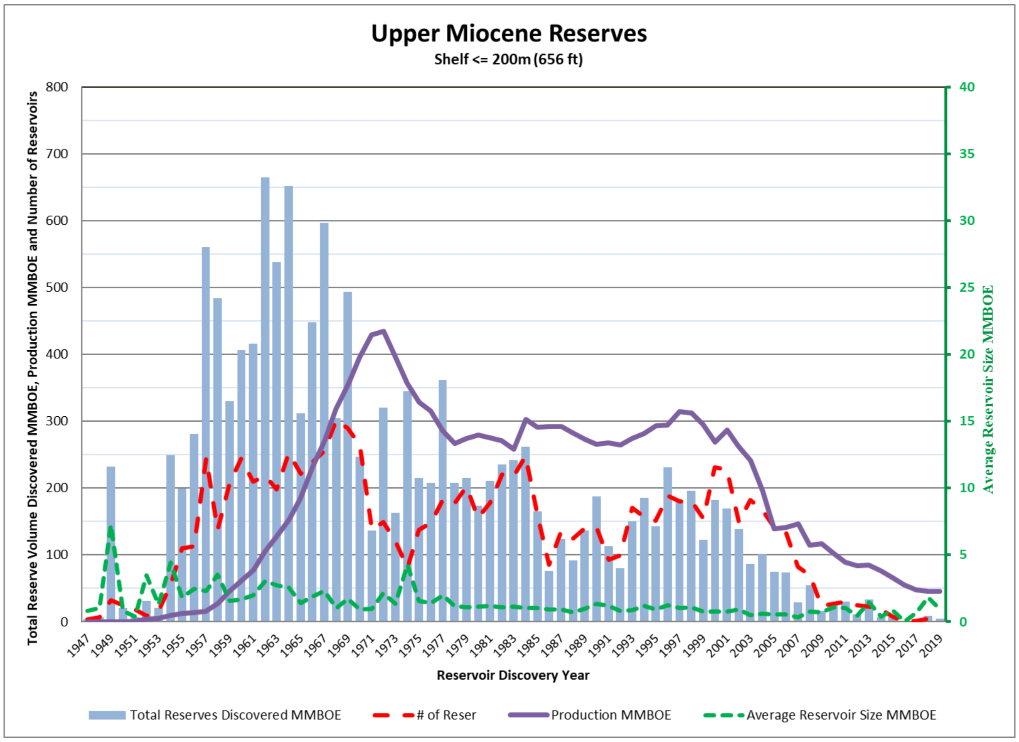

Figure 18A. Upper Miocene Shelf Development

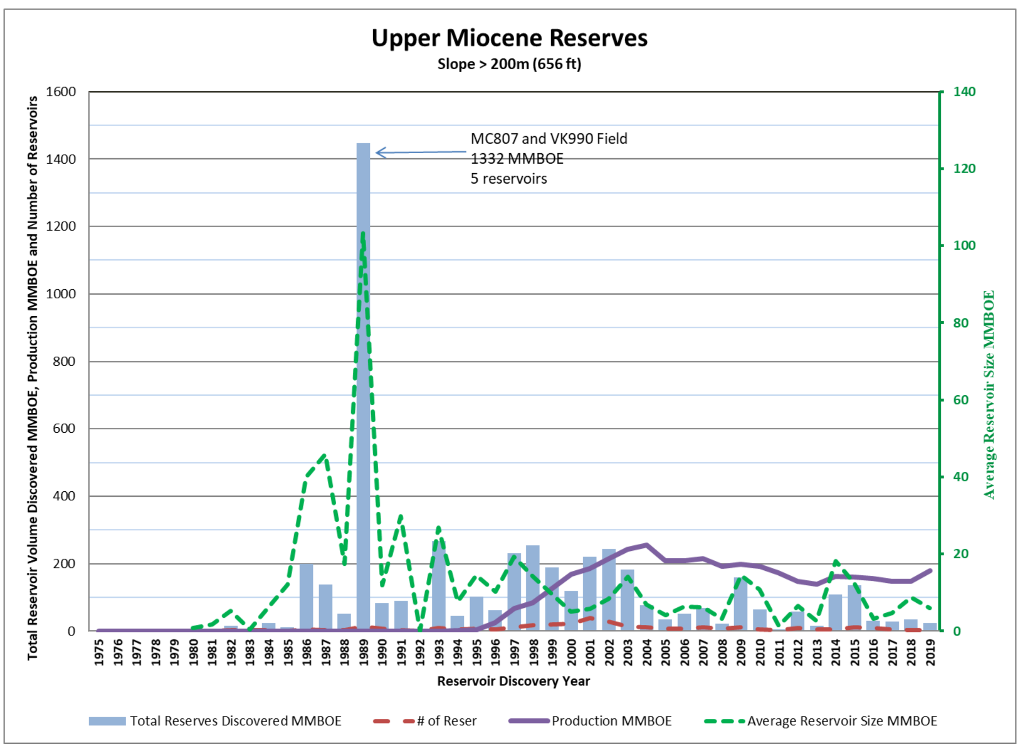

Figure 18B. Upper Miocene Slope Development

The total reserves discovered (MMBOE), as well as average reservoir size and production in the shallow-water Middle Miocene have all remained consistently low over the last decade (Figure 19A). In contrast, the Middle Miocene in deepwater, while seeing its maximum total reserves discovered in 2002 with the addition of 384 MMBOE in the GC640 Field, has experienced a renewed rise in production since 2013 (Figure 19B).

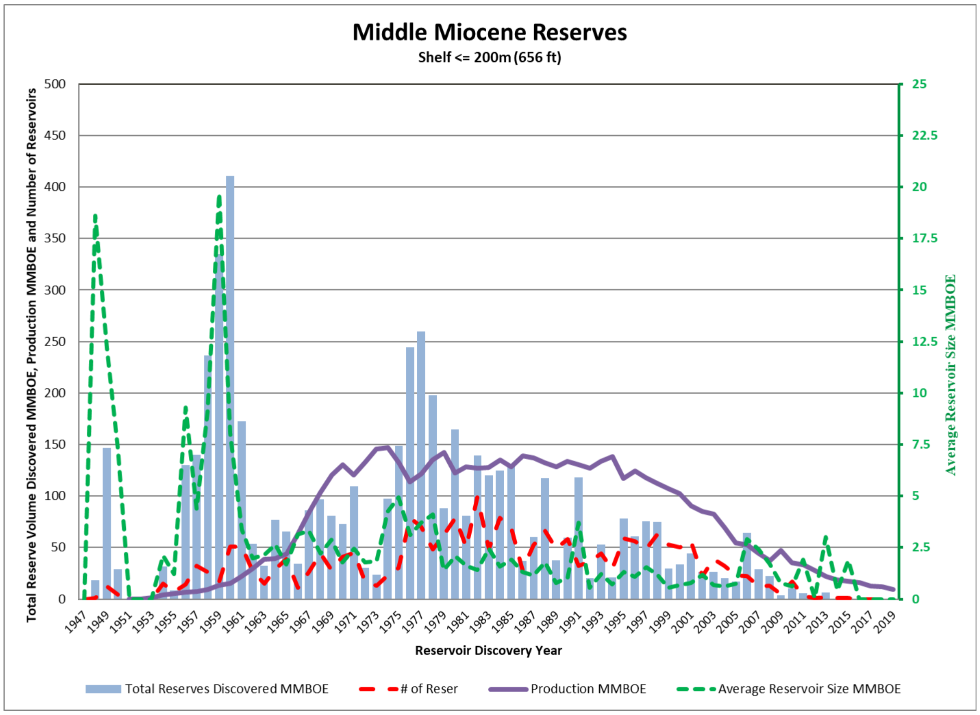

Figure 19A. Middle Miocene Shelf Development

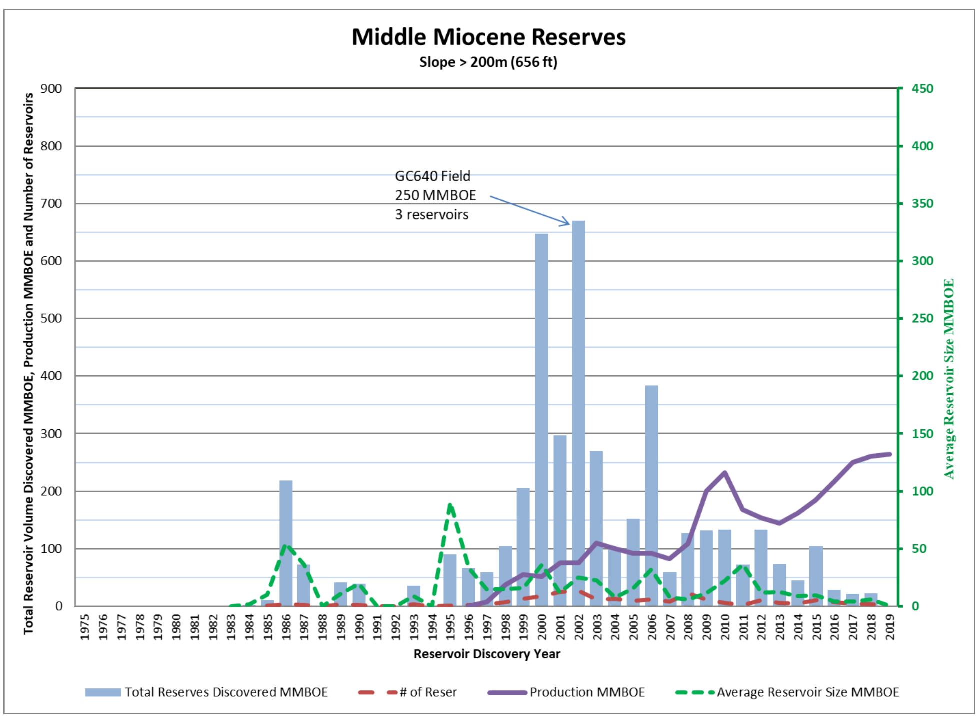

Figure 19B. Middle Miocene Slope Development

The shallow-water Lower Miocene's reserves discovered (MMBOE) peaked in 1982 and 1983 (Figure 20A). A peak in production occurred in 1990, followed by an overall decline to date.

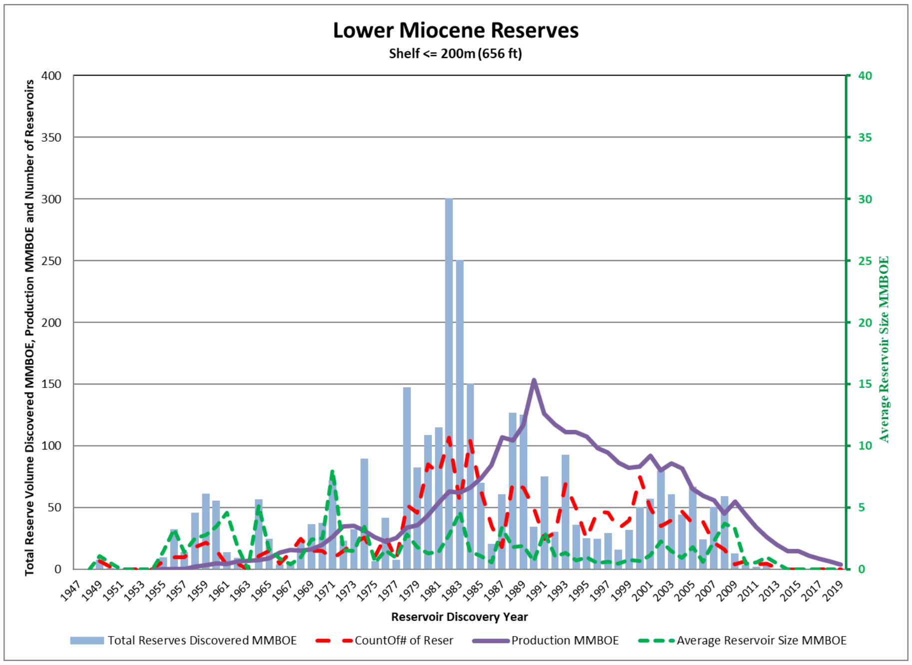

Figure 20A. Lower Miocene Shelf Development

The initial discovery of deepwater Lower Miocene reserves in 1998 yielded both the fourth greatest average reservoir size and forth largest total reserves discovered in a single year for the assessment unit (Figure 20B). In 2002, the greatest total reserves for this play were discovered, including 370 MMBOE in a single reservoir, in the GC 654 Field. The year 2010 saw the largest average reservoir size, just under 181.5 MMBOE. While production for the Lower Miocene peaked in 2009, with a slight decline in the two years that followed, it increased from 2011 to 2017, and has remained consistent to date. The average reservoir size spiked in 2015 due to discoveries in the MC768 Field, but has since decreased to date.

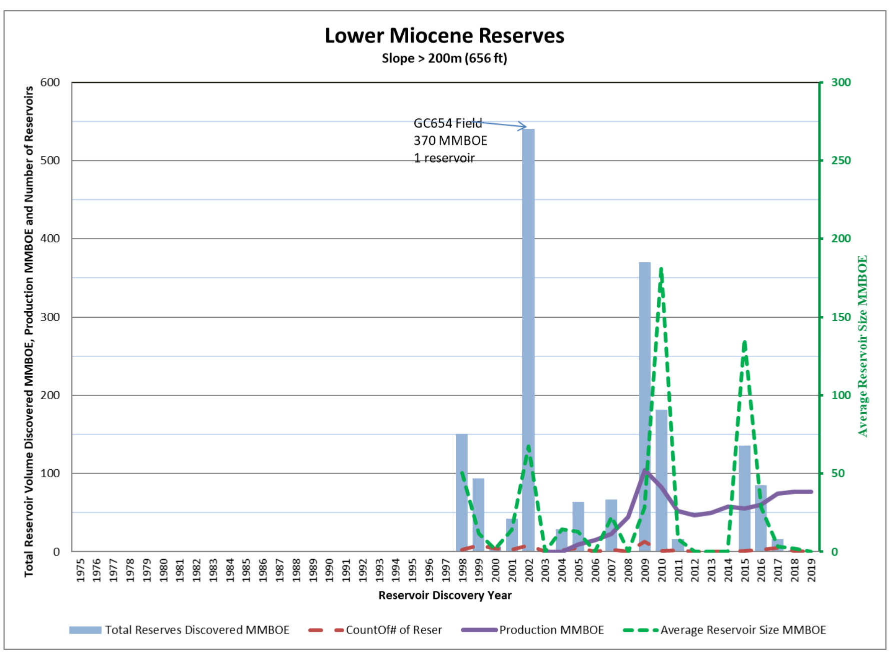

Figure 20B. Lower Miocene Slope Development

The Lower Tertiary deepwater play was discovered in 2002. This included discovery of a reservoir over 130 MMBOE in the AC857 Field. The largest average reservoir size of 70 MMBOE in the play (Figure 21) occurred in 2003 with the discovery of a single reservoir in the AC857 Field. The discovery of the largest total reserves in a single year for the Lower Tertiary occurred in 2008, which included the addition of 211 MMBOE from two reservoirs in the WR678 Field. Production in this play began in 2010 and has been increasing steadily to date.

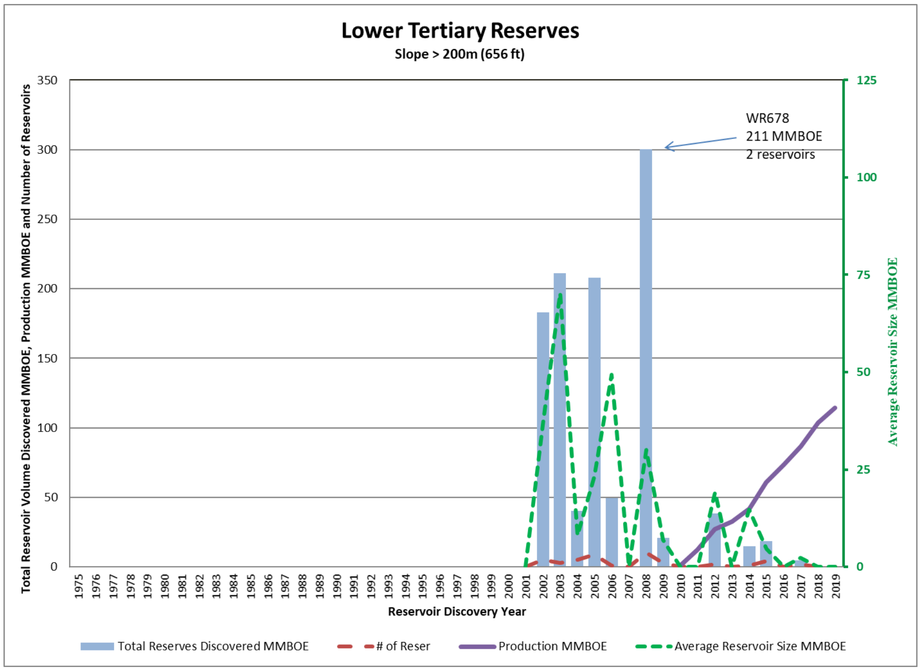

Figure 21. Lower Tertiary Slope Development

The first discovery in the James play came in 1993. In 1997, four fields yielded the largest number of reservoirs, as well as the greatest total reserves discovered (MMBOE) for the play (Figure 22). The year 1997 also yielded the largest average reservoir size. Maximum production (MMBOE) in this play peaked in 2002 with a subsequent rapid decline.

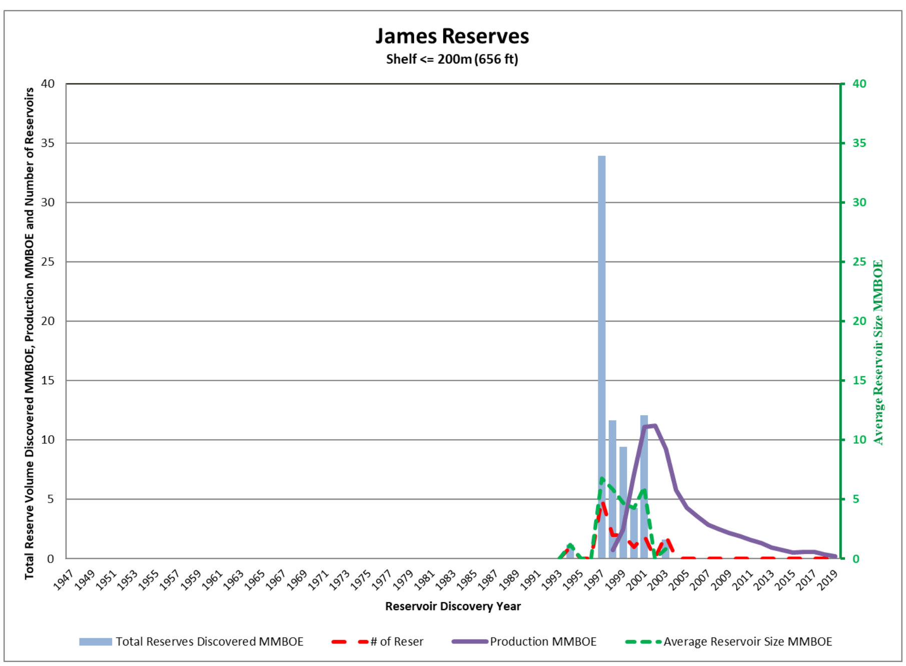

Figure 22. James Play Development

The initial Norphlet discovery in the MO823 Field in 1983 resulted in the greatest total reserves discovered for this play, along with the largest single reservoir size (Figure 23). First production began in 1991 with discoveries continuing through the mid-nineties. Peak production in this play was reached in 1997 and, while declining through the first decade of the century, has remained steady to date. There have been several deepwater Norphlet discoveries to date (as of this report), with the first production beginning in 2019 in the MC392 field.

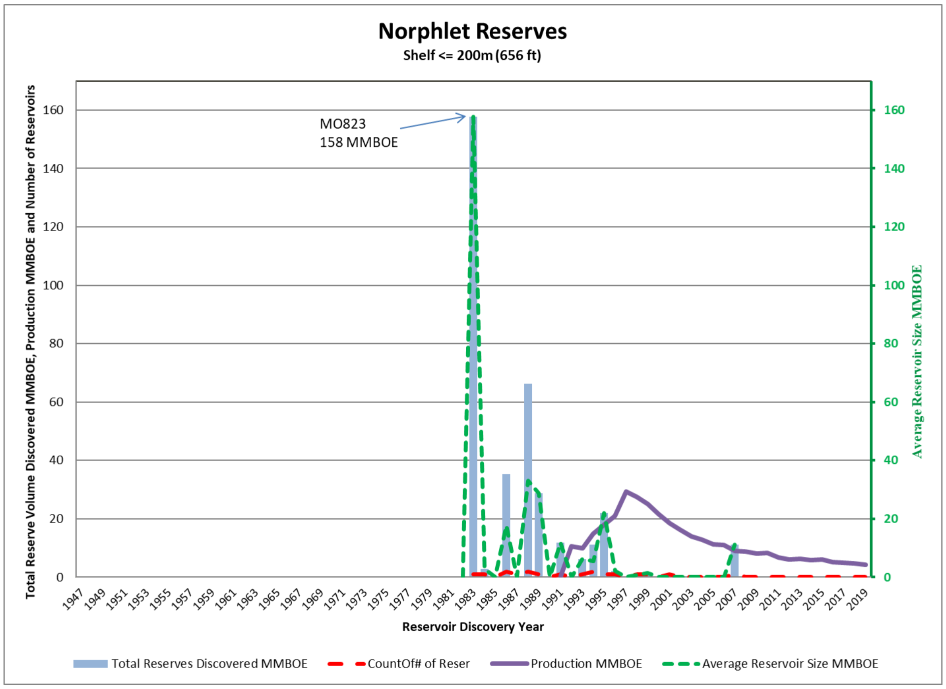

Figure 23. Norphlet Play Development

SUMMARY AND CONCLUSIONS

A summary of the Reserve estimates for 2019 and a comparison with estimates from the previous year's report are shown in **Table 5**. Six new fields were added this year. An increase in Original Reserves and in Reserves occurred between December 31, 2018 and December 31, 2019.

Comparison of Reserves

A net change in the Original Reserve estimates is a result of fields, revisions, and additions. Reserve estimates may increase or decrease with additional information (e.g., additional wells are drilled, leases are added or expire, placing new discoveries into existing fields, and/or reservoirs are depleted). Re-evaluations of existing field studies are conducted using field development and/or production history to capture the changes in reserve estimates. Changes in Original Reserves are presented in **Table 5**. Reviews and revisions of field studies conducted in 2019 resulted in a slight increase in Original Reserves.

The table also demonstrates that the increased volumes from field revisions were more than production, and 1.20 BBOE from six new fields were added during the reporting period. The new fields are KC872, MC257, MC392, MC393, MC940, and VK999. This resulted in a net increase in Reserves. Oil reserves increased 35.2 percent and gas reserves increased by 7.0 percent.

Table 5. Summary and comparison of GOM oil and gas reserves as of December 31, 2018 and December 31, 2019.

	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Original Reserves:			
Previous estimate, as of 12/31/2018*	**24.86**	**195.5**	**59.66**
Fields Added in 2019	1.11	0.5	1.20
Revisions	0.80	1.0	0.97
Estimate, as of 12/31/2019 (this report)	**26.77**	**197.0**	**61.83**
Cumulative production:			
Previous estimate, as of 12/31/2018*	**21.42**	**189.8**	**55.21**
Revisions	0.01	0.1	0.00
Production during 2019	0.69	1.0	0.88
Estimate, as of 12/31/2019 (this report)	**22.12**	**190.9**	**56.09**
Reserves:			
Previous estimate, as of 12/31/2018*	**3.44**	**5.7**	**4.45**
Fields Added in 2019	1.11	0.5	1.20
Revisions	0.79	0.9	0.97
Production during 2019	-0.69	-1.0	-0.88
Estimate, as of 12/31/2019 (this report)	**4.65**	**6.1**	**5.74**

Table 6 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.

Table 6. Oil and gas reserves and cumulative production at end of year, 1975-2019.

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

Year	Number of fields included	Original Reserves			Historical Cumulative Production			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 (1)	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
2009 (2)	1,278	21.20	190.2	55.03	16.53	176.8	47.99	4.67	13.3	7.04
2010	1,282	21.50	191.1	55.50	17.11	179.3	49.01	4.39	11.8	6.49
2011 (3)	1,292	21.91	192.4	56.15	17.59	181.1	49.81	4.32	11.3	6.34
2012	1,297	22.11	193.0	56.46	18.06	182.6	50.56	4.05	10.4	5.90
2013	1,300	22.19	193.0	56.53	18.52	184.0	51.25	3.67	9.0	5.28
2014	1,306	22.37	193.4	56.79	19.03	185.2	51.99	3.34	8.2	4.80
2015	1,312	23.06	193.8	57.56	19.58	186.5	52.78	3.48	7.3	4.78
2016	1,315	23.73	194.6	58.37	20.16	187.8	53.58	3.57	6.8	4.79
2017	1,319	24.65	195.2	59.39	20.78	188.9	54.39	3.87	6.3	5.00
2018	1,319	24.86	195.5	59.66	21.42	189.8	55.21	3.44	5.7	4.45
2019	1,325	26.77	197.0	61.83	22.12	190.9	56.09	4.65	6.1	5.74

(1) Gas plant liquids dropped from system
(2) Conversion of historical gas production to 14.73 pressure base.
(3) Includes Reserves Justified for Development

Conclusions

As of December 31, 2019, the 1,325 oil and gas fields in the federally regulated part of the Gulf of Mexico Outer Continental Shelf (GOM OCS) contained Original Reserves estimated to be 26.77 billion barrels of oil (BBO) and 197.0 trillion cubic feet (Tcf) of gas. Cumulative Production from the fields accounts for 22.12 BBO and 190.9 Tcf of gas. Reserves are estimated to be 4.65 BBO and 6.1 Tcf of gas for the 414 active fields. Oil Reserves have increased 35.2 percent and the Gas Reserves have increased 7.0 percent since the 2018 report. These increases are the result of six new fields added, and field revisions and 31 fields expiring over the course of 2019.

CONTRIBUTING PERSONNEL

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

Holly A. Karrigan

Gregory D. Klocek

Scott M. Palazzo

Mary A. Rather

Jack L. Shanks

Chee W. Yu

REFERENCES

Attanasi, E.D., 1998, *Economics and the National Assessment of United States Oil and Gas Resources*, U.S. Geological Survey Circular 1145, United States Government Printing Office, Washington, D.C.,Table A-4, p. 29.

Bascle, B.J., L.D. Nixon, and K.M. Ross, 2001, *Atlas of Gulf of Mexico Gas and Oil Sands as of January 1, 1999*, U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Regional Office, Office of Resource Evaluation, OCS Report MMS 2001-086, New Orleans, 342 p.

[BOEM] Bureau of Ocean Energy Management. 2017: *2016a National Assessment of Undiscovered Oil and Gas Resources of the U.S. Outer Continental Shelf*, US Department of the Interior, Bureau of Ocean Energy Management. OCS Report BOEM 2017-085.
Web site: https://www.boem.gov/National-Assessment-2016/

[BOEM] Bureau of Ocean Energy Management. 2017: *Assessment of Technically and Economically Recoverable Hydrocarbon Resources of the Gulf of Mexico Outer Continental Shelf as of January 1, 2014*, US Department of the Interior, Bureau of Ocean Energy Management. OCS Report BOEM 2017-005.
Web site: https://www.boem.gov/BOEM-2017-005/

Burgess, G. L., E.G. Kazanis, and K.K. Cross, 2020, *Estimated Oil and Gas Reserves, Gulf of Mexico OCS Region, December 31, 2018,* U. S. Department of the Interior, Bureau of Ocean Energy Management, Gulf of Mexico OCS Region, OCS Report BOEM 2020-028, New Orleans, 30p. Web site: https://www.boem.gov/BOEM-2020-028/

Office of the Federal Register, National Archives and Records Administration, 2018, *Code of Federal Regulations, 30 CFR, Mineral Resources,* U.S. Government Printing Office, Washington, D.C. Web site: https://www.govinfo.gov/content/pkg/CFR-2018-title30-vol2/pdf/CFR-2018-title30-vol2.pdf

Society of Petroleum Engineers (SPE), American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC), and Society of Petroleum Evaluation Engineers (SPEE), 2007, *Petroleum Resource Management System*, 49 p. Web site: https://www.spe.org/industry/docs/Petroleum-Resources-Management-System-2007.pdf

Witrock, R. B., 2017, Biostratigraphic chart of the Gulf of Mexico offshore region, Jurassic to Quaternary, U. S. Department of the Interior, Bureau of Ocean Energy Management, New Orleans, Louisiana.
Web site: https://www.data.boem.gov/Paleo/Files/biochart.pdf

APPENDIX A: 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 BOEM (see New Producible Lease). 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. http://www.boem.gov/BOEM-Newsroom/Offshore-Stats-and-Facts/Gulf-of-Mexico-Region/Field-Naming-Handbook---March-1996.aspx.

New Producible Lease A lease that contains at least one well which an operator has requested a well producibility determination, and BOEM has determined that well meets the criteria of producible hydrocarbons defined by 30 CFR 550.115 or 30 CFR 550.116, or a lease that has begun producing.

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.

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 Reserves	*Original Reserves* are the total of the *Cumulative Production* and *Reserves*, as of a specified date.
Proved plus Probable Reserves (2P)	The sum of the estimated proved reserves and any additional probable reserves (2P). *Proved Reserves* are commonly defined as 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. *Probable Reserves* are commonly defined as those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves.
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.
Undeveloped Reserves	*Undeveloped Reserves* are those *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.
Developed Reserves	*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 *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*.
Developed Non-producing Reserves	*Developed 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.
Developed Producing Reserves	*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.
Un-recoverable	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.

BOEM Chronozone	A body of rock formed during the same time span, bounded by biostratigraphic or correlative seismic markers. Definition taken from BOEM Biostratigraphic Chart of the Gulf of Mexico Region
Assessment Unit	A group of geologically related hydrocarbon accumulations; the term Assessment Unit can refer to groupings of chronozone(s) and/or geologic play(s). Definition modified from the report: *2016a National Assessment of Undiscovered Oil and Gas Resources of the U.S. Outer Continental Shelf*
Play	A group of pools that share a common history of hydrocarbon generation, migration, reservoir development, and entrapment. Definition from 2016 National Assessment of Undiscovered Oil and Gas Resources of the U.S. Outer Continental Shelf

Notice

This report, *Estimated Oil and Gas Reserves, Gulf of Mexico OCS Region, December 31, 2019,* 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 that we can publish the most useful report possible. Please contact the Reserves Section Chief, Grant L. Burgess, at (504) 736-2948 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. An overview of the Reserves Inventory Program is available on BOEM's Website.

For free publication and digital data, visit the Gulf of Mexico Web site. The report can be accessed as an Acrobat .pdf (portable document format) file, which allows you to view, print, navigate, and search the document with the free downloadable Acrobat Reader. Digital data used to create the tables and figures presented in the document are also accessible as Excel 2016 spreadsheet files (.xlsx; using Microsoft's Excel spreadsheet viewer, a free file viewer for users without access to Excel). These files are made available in a zipped format, which can be unzipped with the downloadable WinZip program.

For information on this publication contact:

Bureau of Ocean Energy Management
Gulf of Mexico OCS Region
Attn: Public Information Unit (MS GM250I)
1201 Elmwood Park Boulevard
New Orleans, Louisiana 70123-2394
1-800-200-GULF
http://www.BOEM.gov

Matthew G. Wilson
Regional Supervisor
Resource Evaluation