GULF OF AMERICA, OUTER CONTINENTAL SHELF

2026 ESTIMATED OIL AND GAS RESERVES REPORT

BUREAU OF OCEAN ENERGY MANAGEMENT*

OCS Report
BOEM-2026-017

* As of July 10, 2026, the Department of the Interior has reunified the Bureau of Ocean Energy Management and the Bureau of Safety and Environmental Enforcement into the Marine Minerals Administration, which oversees the responsible development of the nation's offshore energy and marine mineral resources with an integrated focus on safety, environmental protection and efficient oversight. For more information, visit DOI.gov/mma-reunification.

UNITED STATES DEPARTMENT OF THE INTERIOR

BUREAU OF OCEAN ENERGY MANAGEMENT

GULF OF AMERICA REGION

NEW ORLEANS, LOUISIANA

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ACRONYMS

API	American Petroleum Institute
bbl	Barrel(s)
Bbbl	Billion 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
CDF	Cumulative Distribution Function
CGA	Central Gulf of America
EGA	Eastern Gulf of America
EOGR	Estimated Oil and Gas Reserves
GOA	Gulf of America
GOAR	Gulf of America Region
GOR	Gas-to-Oil Ratio
MMbbl	Million barrels
MMBOE	Million barrels of oil equivalent
MMcf	Million cubic feet
MS	Mail Stop
nonprod	Non-Producing
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
P0	Corresponds to the minimum possible reserves volume, reflecting the most conservative estimate.

P10	A low-case estimate. There is a 90% probability that the actual quantity recovered will exceed this reserves volume. Represents a conservative scenario.
P50	The best estimate or median case. There is a 50% probability that the actual quantity recovered will be greater than or less than this reserves' volume.
P90	A high-case estimate. There is a 10% probability that the actual quantity recovered will exceed this reserves' volume. Represents an optimistic scenario.
P100	Corresponds to the maximum possible reserves volume, reflecting the most optimistic estimate.
PRMS	Petroleum Resources Management System
prod	Producing
psia	Pounds per square inch absolute
RE	Resource Evaluation
scf	Standard cubic feet
SPE	Society of Petroleum Engineers
stb	Stock tank barrel
Tcf	Trillion cubic feet
WGA	Western Gulf of America

ABSTRACT

The Submerged Lands Act and the Outer Continental Shelf Lands Act (OCSLA) of 1953 initiated the foundation for state and federal jurisdiction over offshore area leasing. Since their enactment, Congress has periodically revised these statutes to enhance oversight and promote responsible management of Outer Continental Shelf (OCS) resources. Amendments such as Public Law 99-367 further strengthened OCSLA by streamlining reporting obligations and reinforcing the Department of the Interior's responsibility to conduct continuing assessments of Outer Continental Shelf oil and gas resources. Building on this framework, Section 357 of the Energy Policy Act of 2005 expanded the federal role by mandating comprehensive, technology-based inventories of OCS oil and natural gas resources and requiring periodic updates to ensure resource assessments remain current and accurately inform policy and leasing decisions. This publication presents the Bureau of Ocean Energy Management's (BOEM) probabilistic estimates of oil and gas reserves in the Gulf of America (GOA) OCS as of December 31, 2024. Total mean Original Reserves are estimated at 31.81 billion barrels of oil (BBO), 202.05 trillion cubic feet (Tcf) of gas, or 67.76 billion barrels of oil equivalent (BBOE) from 1,342 fields, including 1,022 fields that have produced and expired. Fields are defined as areas containing single or multiple reservoirs associated with the same geological structure and/or stratigraphic trapping condition. Original Reserves consist of the total cumulative production plus remaining reserves. Cumulative production accounts for 25.32 BBO, 194.7 Tcf of gas, or 59.96 BBOE. Additionally, total mean Contingent Resources on the GOA slope are estimated to be 2.55 BBO and 3.92 Tcf of gas, or 3.25 BBOE.

Mean remaining reserves are estimated at 6.49 BBO, 7.35 Tcf of gas, or 7.8 BBOE. These remaining reserves are recoverable from 320 active fields. Mean reserves for the 2026 Estimated Oil and Gas Reserves (EOGR) Report are derived starting at the reservoir level. Reservoir level estimates account for the full range of uncertainty from P0 to P100. Once finalized, reservoir estimates are aggregated to the field level to obtain mean reserve estimates for each field. Mean reserves for each field are then summed with cumulative production to get Original Reserves estimates. BOEM then subtracts produced volumes to calculate remaining reserves for the GOA. Reserves must be discovered and estimated to be commercially recoverable.

Estimates of reserves for this report represent the collaborative efforts of engineers, geoscientists, paleontologists, petrophysicists, and other personnel of the BOEM GOA Region (GOAR), Office of Resource Evaluation (RE), in New Orleans, Louisiana. Reserves estimates are derived for individual reservoirs from geologic and engineering calculations using a probabilistic methodology. For any field spanning state and federal waters, reserves are estimated for the federal portion only.

1.0 INTRODUCTION

This report supersedes the "2025 Estimated Oil and Gas Reserves Report (Palazzo et al., 2025)". It presents estimated Original Reserves, cumulative production, remaining reserves, and slope contingent resources as of December 31, 2024.

As of December 31, 2024, the 1,342 oil and gas fields in the federally regulated portion of the GOA OCS contained a mean Original Reserves estimate of 31.81 BBO, 202.05 Tcf of gas, or 67.76 BBOE. Cumulative production from the fields accounts for 25.32 BBO, 194.70 Tcf of gas, or 59.96 BBOE. Remaining reserves are estimated to be 6.49 BBO and 7.35 Tcf of gas, or 7.80 BBOE for the 320 active fields. Oil remaining reserves have increased 12.5 percent, and the gas reserves have increased by 3 percent since the 2025 report. These increases reflect fields that were newly captured and incorporated into the database during the January 1, 2024 through December 31, 2024 reporting period, and integrated technical updates reflected in the 2024 dataset, including field reserve studies, analyses, revisions, and other database improvements. Figure 1 shows GOA cumulative production along with remaining reserves estimates.

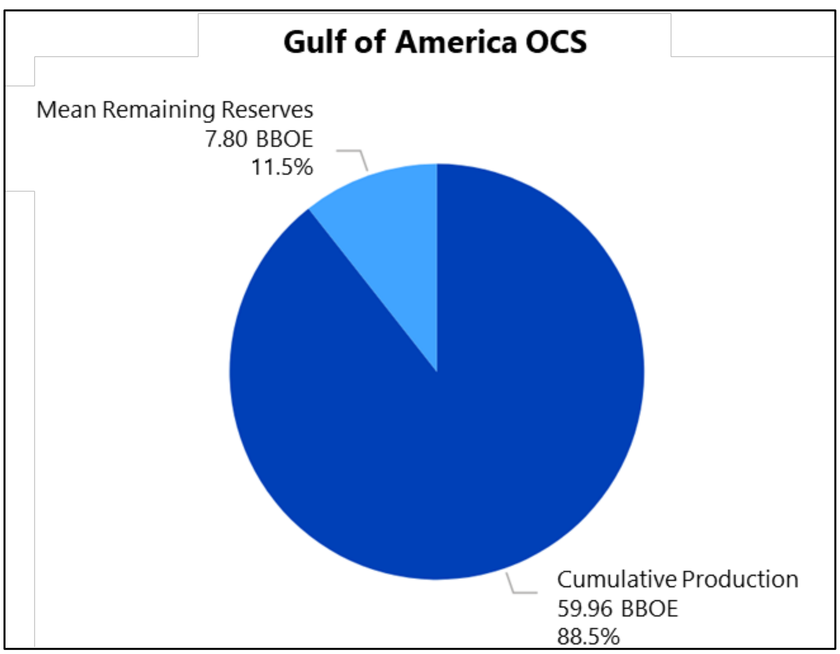

Figure 1. GOA Cumulative Production and Mean Remaining Reserves Estimates

2.0 BACKGROUND

The Submerged Lands Act, OCSLA, and the Energy Policy Act of 2005 collectively provide the legal framework for the management of offshore energy resources. These statutes clearly define federal and state jurisdictions regarding offshore leasing and require ongoing, technology driven evaluations to enable accurate and responsible assessments of oil and gas resources on the OCS. To meet these requirements, the Reserves Inventory component of the RE Program incorporates new producible leases into fields and develops independent estimates of recoverable amounts of oil and gas contained within discovered fields. RE 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. RE periodically revises the estimates of natural gas and oil volumes to reflect new discoveries, development activities, and annual production. RE publishes an *Estimated Oil and Gas Reserves Report* based on field studies completed at the reservoir and sand levels. All the reservoir level data have been linked to the sand, pool, play, and chronozone levels to support the Offshore Atlas Project. Current Atlas data associated with all *Estimated Oil and Gas Reserves Reports* are available at Atlas of Gulf of America Gas and Oil Sands Data. These data also support the National Assessment of Undiscovered Oil and Gas Resources of the U.S. Outer Continental Shelf. Published every five years in accordance with statutory requirements, the assessment provides BOEM's estimates of undiscovered oil and gas resources on the U.S. OCS. For more information visit BOEM's web site at https://www.boem.gov/oil-gas-energy/resource-evaluation/undiscovered-resources.

3.0 CLASSIFICATION OF RESOURCES AND RESERVES

BOEM's Reserves Classification Framework allows for accurate and understandable reporting of oil and gas volumes (Figure 2). BOEM classifies accumulations based on specific definitions, which are presented in Appendix A. This classification system closely aligns with guidelines set forth by the Society of Petroleum Engineer's Petroleum Resources Management System (SPE-PRMS). BOEM has adjusted the terminology for some categories and sub-classes to better align with its program requirements. The relationship among the various categories is shown in Figure 2.

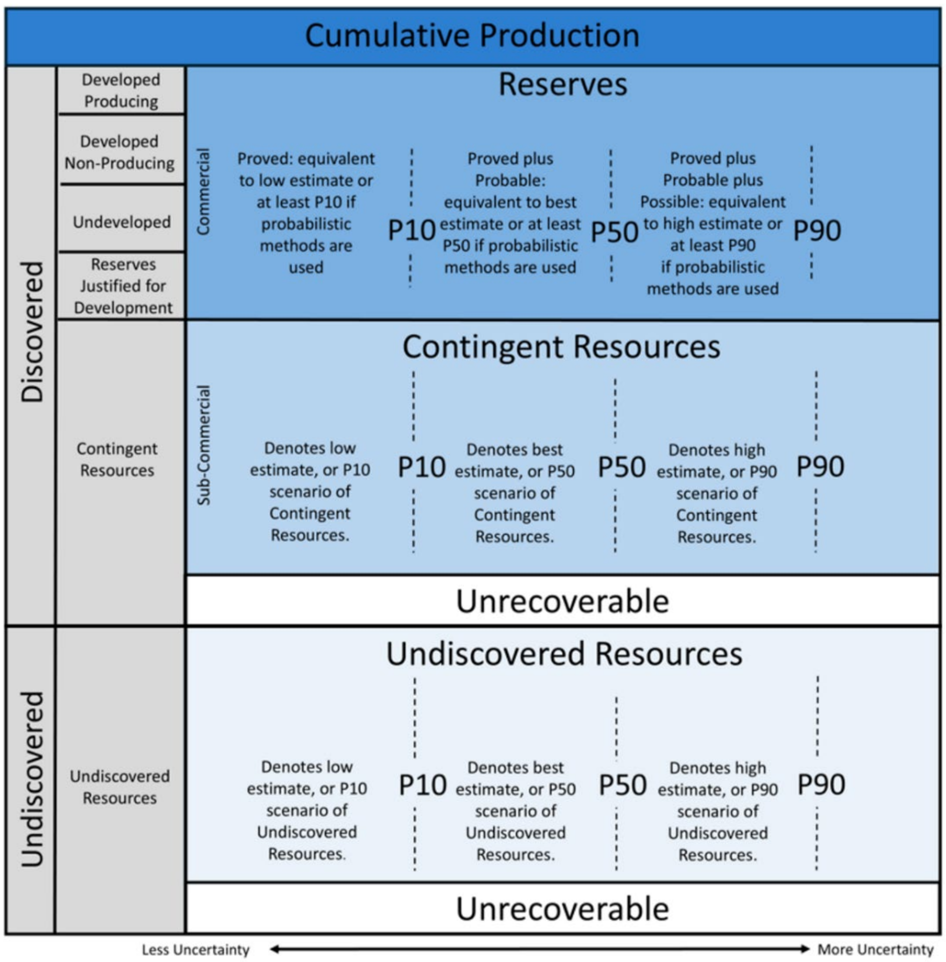

Figure 2: BOEM Reserves Classification Framework

The framework incorporates elements of uncertainty. One component of uncertainty depends on the amount of reliable geological and petroleum engineering data available at the time of the estimate and the interpretation of these data. The second component is the technical and economic factors that impact the likelihood of the commercial development of a project. Oil and natural gas deposits believed to exist based on play-based geologic knowledge and theory but have not yet been discovered are categorized as Undiscovered Resources. These resources are located outside of known fields or accumulations on the GOA OCS and are considered technically and economically recoverable. Undiscovered Resource estimates are not presented in this report; however, they can be found in the report titled “2026 National Assessment of Undiscovered Oil and Gas Resources of the U.S. Outer Continental Shelf: OCS Report BOEM 2026-012.” Upon initial discovery, an identified hydrocarbon accumulation is classified as a Contingent Resource. In this category, reservoir boundaries and resource estimates are determined using geophysical mapping along with rock and fluid data from both the target reservoir and analogous reservoirs of similar age and depositional environment. Once a development project is identified, sanctioned, and approved, Contingent Resources may be moved into the Reserves category. In alignment with SPE-PRMS, BOEM defines Reserves 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. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of a given evaluation date) based on the development project(s) applied. At the time a lessee makes a formal commitment to develop and produce the accumulation, it is classified as Reserves Justified for Development. During the period when infrastructure is being constructed and installed, the accumulation is classified as Undeveloped Reserves. Once the necessary production equipment is in place, reserves may be classified as Developed Non-producing Reserves or Developed Producing Reserves. Developed Non-producing Reserves are reserves that are developed but not currently producing because they are shut-in or behind-pipe and can be brought into production with relatively low additional expenditure. After production of the accumulation has begun, the status becomes Developed Producing Reserves.

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 back to a Contingent Resource. Currently, there are 1,022 expired and depleted fields.

4.0 METHODS USED FOR ESTIMATING RESERVES

Methods for estimating reserves can be classified into three categories: analog, volumetric, and performance. Reserve estimates presented in this report primarily rely on volumetric and performance methodologies. Volumetric reservoir analysis employs a geological model derived from subsurface data interpretation and petrophysical well log analysis to define the vertical and lateral boundaries of a hydrocarbon-bearing reservoir to calculate bulk volume. The Reserves evaluation process considers 22 different variables in total. To estimate a range of recoverable reserves, a Monte Carlo simulation is performed using probability distributions for all applicable variables. These variables may include pressure, temperature, porosity, water saturation, depth to the top of the structure, datum depth, contact depth, American Petroleum Institute (API) gravity, gas gravity, reservoir volume, recovery factor, and gas-oil ratio, among others. For each variable, a cumulative distribution function (CDF) is constructed, with the distribution type selected based on the shape, quality, and quantity of the available data.

Once calculated, individual reservoir reserve estimates are aggregated to the field level and reported at the P10, P50, P90, and mean statistical percentiles, reflecting different probabilities of recoverable reserves. Within BOEM, the P10 value represents a 90% probability that this reserve estimate will be achieved or be greater than this value. Conversely, the P90 estimate has only a 10% chance of being attained or exceeded. Once aggregated to the field level, mean reserves for each field are summed to get Original Reserves estimates. BOEM then subtracts produced volumes to calculate remaining reserves. The total volume of oil and oil-equivalent gas is referred to as barrels of oil equivalent (BOE) and is reported in barrels at standard conditions. Beginning with the 2026 EOGR Report, BOEM refined the methodology used to aggregate reservoir level probabilistic reserve estimates to the field level. The updated approach aggregates the underlying reservoir reserve estimates directly, providing a more consistent representation of field level uncertainty while maintaining the core geologic and engineering analysis used to estimate reserves. As a result, the uncertainty ranges for some fields are more constrained than those presented in the 2025 EOGR Report, where field level uncertainty ranges were developed using an interval-based approximation rather than direct aggregation of the reservoir level reserve estimates.

Reserve estimates are formulated for reservoirs at various life cycle stages. Upon discovery, the uncertainty of the reserves estimate is high. As additional wells are drilled, the reservoir becomes better defined and characterized leading to a substantial reduction in volumetric uncertainty (Figure 3). Once a reservoir begins producing and a production trend is observed, decline curve analysis is utilized to forecast future reservoir performance.

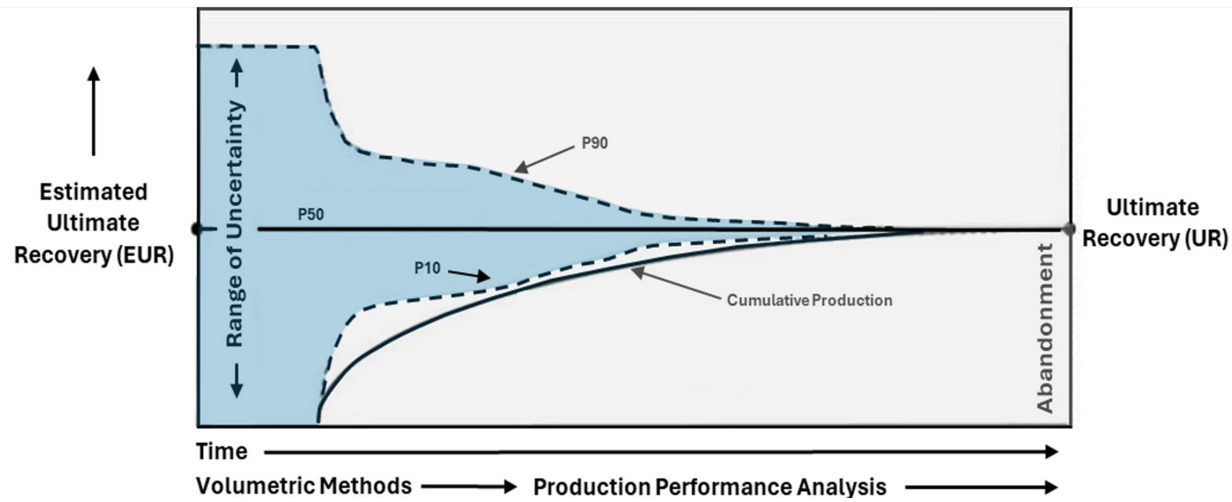

Figure 3. Change in Uncertainty & Examples of Assessment Methods over a Reservoir's Life Cycle

As reservoirs mature, production data become increasingly important to the reservoir evaluation process. Production history, pressure measurements, and both formation and well test results provide additional constraints on reservoir performance and are incorporated into periodic updates of reserve estimates.

Production data are the metered volumes of raw liquids and gas reported to the 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.

5.0 RESERVES DATA BY PLANNING AREA

The GOA OCS is divided into three administrative planning areas: the Western Gulf of America (WGA), Central Gulf of America (CGA), and Eastern Gulf of America (EGA). Figure 4 illustrates the geographic boundaries of these areas and includes reserve estimates for the WGA and CGA. The EGA is currently under a leasing moratorium and currently contains no booked reserves. Each planning area is subdivided into protractions, which in turn are divided into numbered blocks. Fields 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. Reserve estimates in this report are presented as protraction area totals associated with each field name. For example, EC 271 Field reserve estimates are included in the East Cameron totals, although part of the field extends into the adjacent area of Vermilion. There are four exceptions: data from Tiger Shoal and Lighthouse Point are included in the South Marsh Island reserve totals; data from Coon Point is included in the Ship Shoal reserve totals; and data from Bay Marchand is included in the South Timbalier reserve totals.

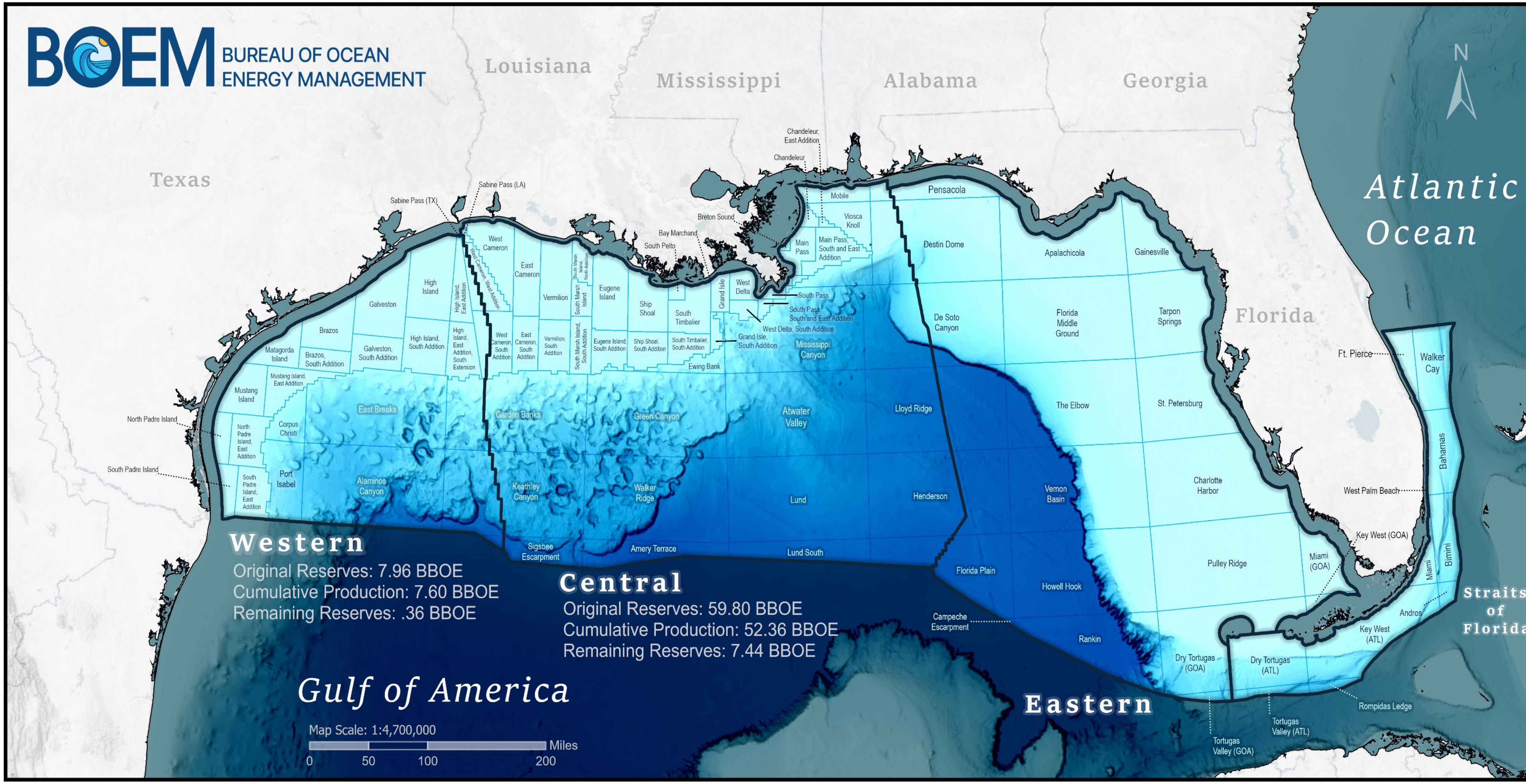

Figure 4. GOA U.S. Outer Continental Shelf

As of December 31, 2024, there were 320 active fields located in the federally regulated portion of the GOA. A list of active and expired fields is maintained and updated quarterly in the OCS Operations Field Directory. Additionally, there are 1,022 expired, depleted and/or abandoned fields that produced 38.1 percent of the total cumulative GOA oil and gas production. One hundred twenty-one fields expired, relinquished, or terminated without production. Table 1 presents the mean estimated oil and gas reserves for each protraction area. Mean estimates for each field are summed to the protraction area level. Protraction area estimates are then aggregated to determine the mean reserves for each planning area, ultimately resulting in the total reserves for the GOA.

Table 1. Estimated Oil and Gas Reserves by Planning and Protraction Areas, December 31, 2024*

Administrative Planning Area (Fig 4)	Number of fields				Original Reserves			Cumulative Production			Remaining 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 Gulf of America													
Alaminos Canyon	5	0	1	4	686.8	1,049.4	873.6	433.4	676.7	553.8	253.5	372.7	319.8
Brazos	1	0	37	3	10.3	3,779.7	682.9	10.3	3,756.0	678.6	0.0	23.6	4.3
East Breaks	5	0	16	3	282.0	2,217.1	676.5	272.8	2,182.4	661.1	9.2	34.7	15.4
Galveston	1	0	49	2	71.2	2,242.2	470.2	69.8	2,230.8	466.7	1.4	11.4	3.4
Garden Banks	1	0	6	2	37.6	328.9	96.1	37.6	328.9	96.1	0.0	0.0	0.0
High Island and Sabine Pass	13	0	118	9	437.2	16,107.5	3,303.3	430.6	16,050.9	3,286.7	6.6	56.6	16.7
Keathley Canyon	0	0	0	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Matagorda Island	0	0	28	2	23.9	5,261.4	960.1	23.9	5,261.4	960.1	0.0	0.0	0.0
Mustang Island	0	0	28	5	8.2	1,786.9	326.2	8.2	1,786.9	326.2	0.0	0.0	0.0
N.& S.Padre Island	0	0	19	0	0.4	625.3	111.6	0.4	625.3	111.6	0.0	0.0	0.0
Port Isabel	0	0	0	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Cameron and Sabine Pass	0	0	24	1	33.2	2,415.0	462.9	31.4	2,407.7	459.9	1.7	7.3	3.0
Western Gulf of America Subtotal	**26**	**0**	**326**	**33**	***1,590.8***	***35,813.4***	***7,963.4***	***1,318.4***	***35,307.0***	***7,600.8***	***272.4***	***506.3***	***362.6***
Central Gulf of America													
Atwater Valley	1	0	5	5	61.5	610.2	170.1	49.3	598.6	155.8	12.2	11.6	14.3
Chandeleur	1	0	13	0	0.2	392.9	70.2	0.2	386.5	69.0	0.0	6.4	1.2
Desoto Canyon	2	0	4	1	41.1	540.0	137.2	24.6	525.6	118.2	16.4	14.3	19.0
Destin Dome	0	0	0	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
East Cameron	5	0	62	0	373.9	11,029.0	2,336.3	364.6	10,974.7	2,317.4	9.3	54.3	19.0
Eugene Island	20	0	69	4	1,823.7	20,710.0	5,508.8	1,768.0	20,547.0	5,423.8	55.7	163.0	85.0
Ewing Bank	11	0	7	2	511.1	941.3	678.6	457.8	859.3	610.7	53.3	82.0	67.9
Garden Banks	11	0	21	4	1,014.5	4,954.0	1,896.0	939.7	4,684.0	1,773.2	74.8	270.1	122.9
Grand Isle	6	0	17	1	1,057.7	5,226.9	1,987.7	1,015.7	5,070.1	1,917.9	42.0	156.8	69.9
Green Canyon	37	1	17	25	5,945.2	6,122.9	7,034.7	3,735.5	4,486.7	4,533.9	2,209.7	1,636.2	2,500.8
Keathley Canyon	3	0	0	2	656.7	717.8	784.4	211.4	429.7	287.9	445.3	288.1	496.5
Lloyd Ridge	0	0	4	0	0.1	330.5	58.9	0.1	330.5	58.9	0.0	0.0	0.0
Main Pass and Breton Sound	26	0	66	4	1,322.3	7,320.8	2,624.9	1,231.3	7,127.5	2,499.5	91.0	193.3	125.4
Mississippi Canyon	47	1	27	14	7,325.1	13,869.4	9,793.0	5,175.0	11,737.0	7,263.5	2,150.1	2,132.4	2,529.5
Mobile	8	0	26	4	0.4	2,609.9	464.7	0.3	2,494.5	444.2	0.0	115.4	20.6
Pensacola	0	0	1	0	0.0	7.7	1.4	0.0	7.7	1.4	0.0	0.0	0.0
Ship Shoal	21	0	48	3	1,566.1	13,029.8	3,884.6	1,508.5	12,800.9	3,786.2	57.6	228.9	98.4
Sigsbee Escarpment	0	0	0	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Marsh Island	23	0	28	0	1,042.0	15,295.5	3,763.6	998.3	14,957.7	3,659.9	43.6	337.8	103.7
South Pass	7	0	6	1	1,140.8	4,590.1	1,957.6	1,118.7	4,540.2	1,926.6	22.1	49.9	31.0
South Pelto	1	0	8	0	159.8	1,179.6	369.7	159.4	1,175.8	368.6	0.4	3.9	1.1
South Timbalier	18	0	45	2	1,744.0	10,766.9	3,659.8	1,649.3	10,588.1	3,533.3	94.7	178.8	126.5
Vermilion	11	0	74	0	611.5	16,877.8	3,614.6	594.3	16,752.6	3,575.2	17.2	125.3	39.4
Viosca Knoll	12	0	43	8	741.0	4,047.8	1,461.3	678.8	3,815.4	1,357.7	62.2	232.4	103.6
Walker Ridge	8	0	0	2	1,367.5	427.0	1,443.5	682.3	140.6	707.3	685.2	286.4	736.1
West Cameron and Sabine Pass	6	0	88	0	200.2	18,709.0	3,529.2	196.0	18,571.6	3,500.5	4.2	137.5	28.7
West Delta	7	0	17	3	1,509.3	5,929.9	2,564.4	1,441.4	5,792.3	2,472.1	67.9	137.6	92.3
Central Gulf of America Subtotal	**292**	**2**	**696**	**87**	***30,215.7***	***166,236.7***	***59,795.2***	***24,000.5***	***159,394.6***	***52,362.7***	***6,214.9***	***6,842.4***	***7,432.8***
Eastern Gulf of America													
Destin Dome	0	0	0	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Eastern Gulf of America Subtotal*	0	0	0	1	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***
Gulf of America Total:	***318***	***2***	***1,022***	***121***	***31,806.5***	***202,050.1***	***67,758.6***	***25,318.9***	***194,701.6***	***59,963.5***	***6,487.3***	***7,348.7***	***7,795.4***
	1,342												

Values are rounded independently; therefore, subtotals and differences may not exactly equal the sum or subtraction of displayed values. A table with complete values can be obtained at the BOEM Data Center under the Field widget.

Figure 5 shows the spatial distribution of all active and expired oil and gas fields in the GOA, while Figure 6 displays the distribution of active oil and gas fields, categorized by water depth: shelf areas (less than 656 feet or 200 meters) and slope areas (greater than or equal to 656 feet or 200 meters).

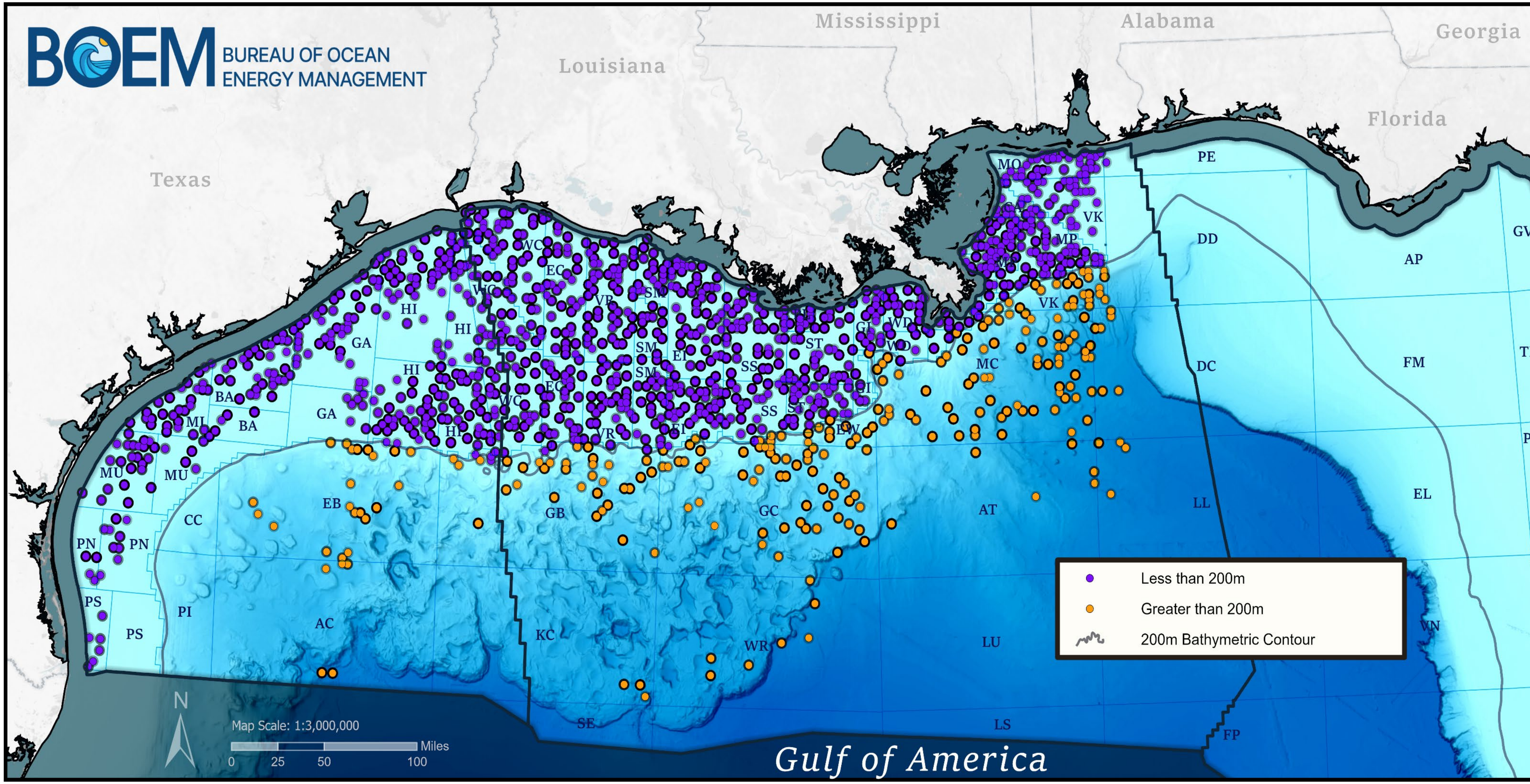

Figure 5. Active and Expired Oil and Gas Fields by Water Depth

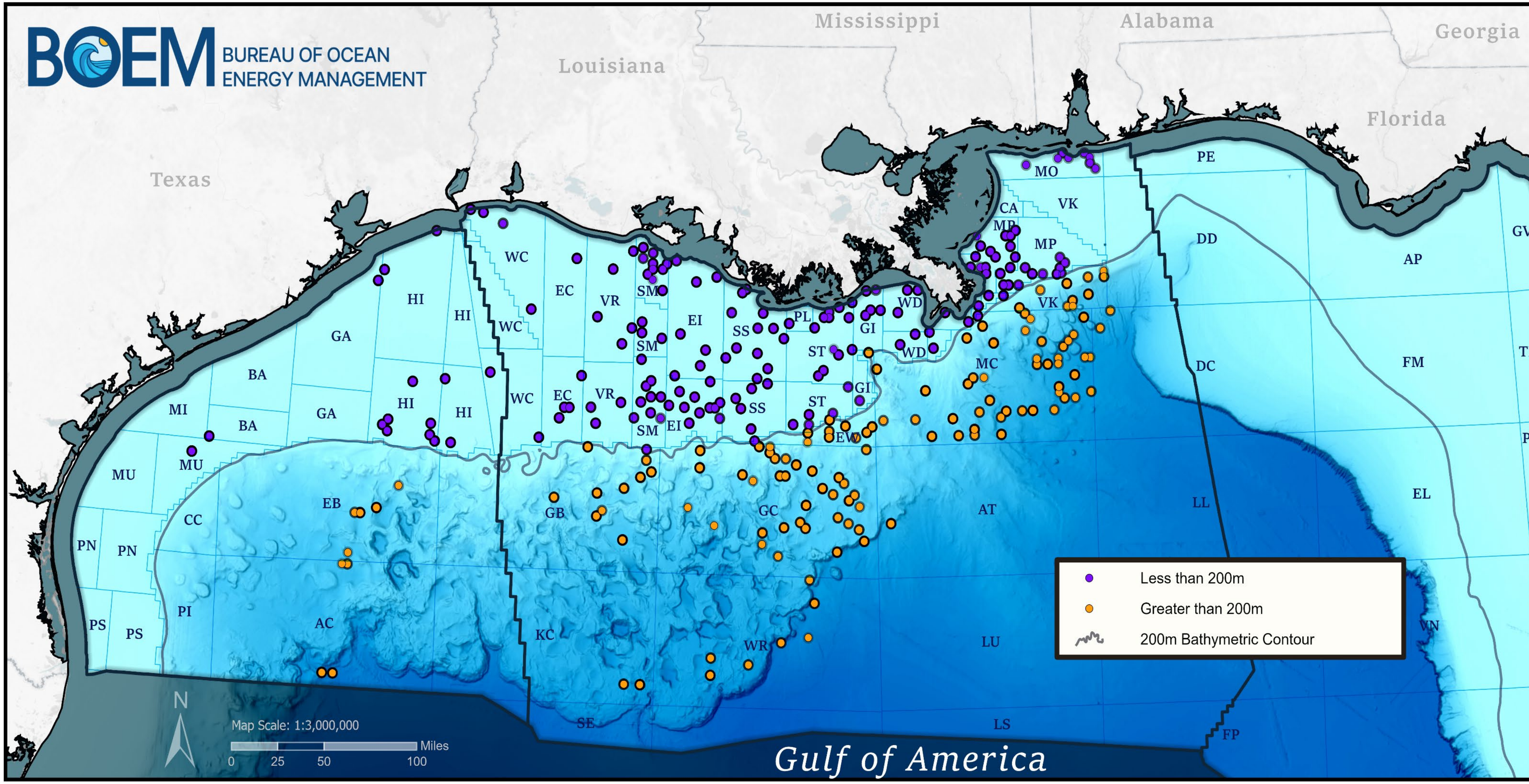

Figure 6. Active Oil and Gas Fields by Water Depth

6.0 FIELD SIZE DISTRIBUTION

Field size distributions are presented as Original Reserves in millions of barrels of oil equivalent (MMBOE). Fields are categorized as either oil or gas, with each field classified individually based on an analysis of its reservoirs and fluid distributions. However, some fields produce both, complicating the classification process. For ease of comparison, gas reserves are converted to MMBOE and combined with liquid reserves. The conversion factor used is 5,620 standard cubic feet of gas per 1 BOE, reflecting the average heating values of domestic hydrocarbons.

A geometric progression, developed by the United States Geological Survey (Attanasi, 1998), was selected for field-size (deposit-size) distribution ranges (Table 2). This model, along with its associated ranges, helps in understanding the distribution and frequency of various field sizes for oil and gas deposits.

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 MMBOE for 1,342 fields is shown in Figure 7, along with the CGA and WGA planning area distributions. Of the 1,342 oil and gas fields, there are 309 oil fields represented in Figure 8 and 1,033 gas fields shown in Figure 9. These figures also display the planning area distributions.

Analysis of the 1,342 oil and gas fields shows that the GOA has transitioned from being predominantly gas-prone to increasingly oil-focused, driven by the expansion of slope resources. This shift highlights distinct regional differences shaped by the contrasting geology of the shelf and slope. In the WGA, gas production once dominated due to prolific shelf fields. However, as these fields declined, new slope developments have shifted the region's output toward oil. The CGA is now the most oil-prone area, with deepwater slope reservoirs making it the heart of U.S. offshore crude production; gas here plays a secondary role.

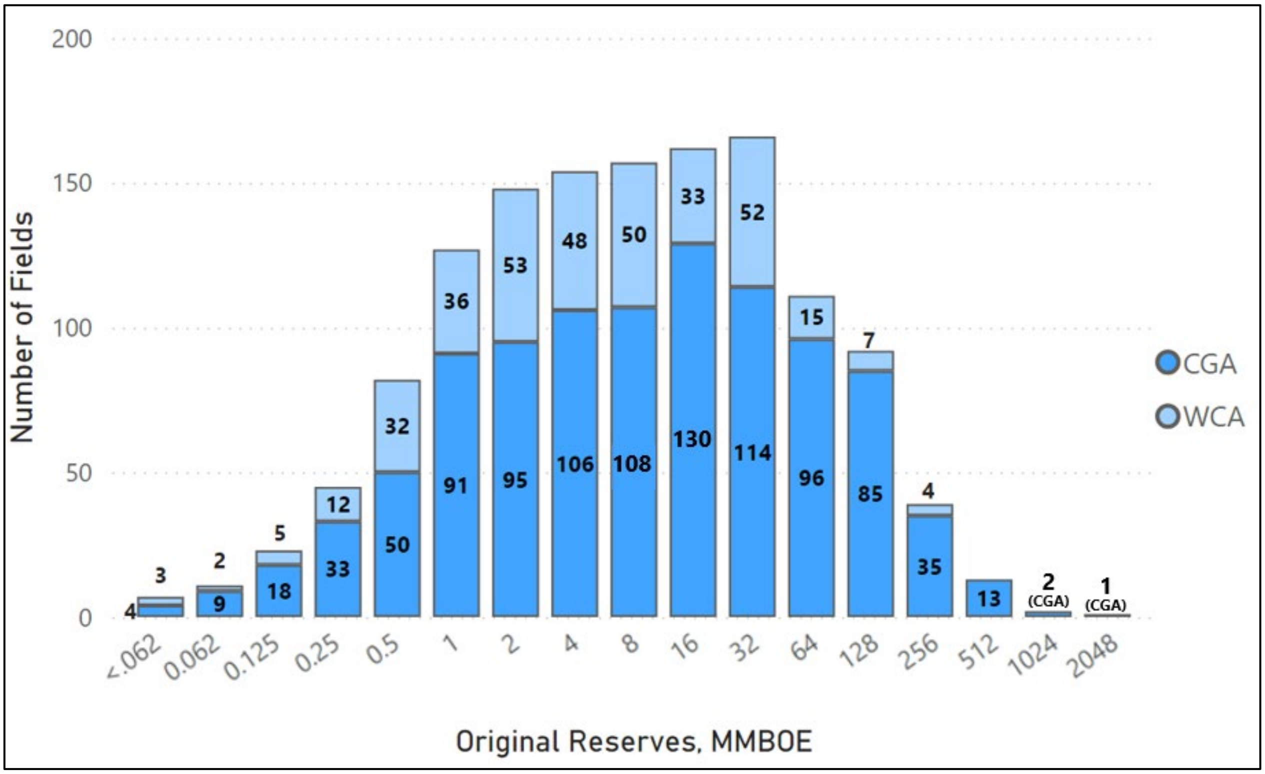

Figure 7. Field Size Distribution of GOA Fields by Planning Area

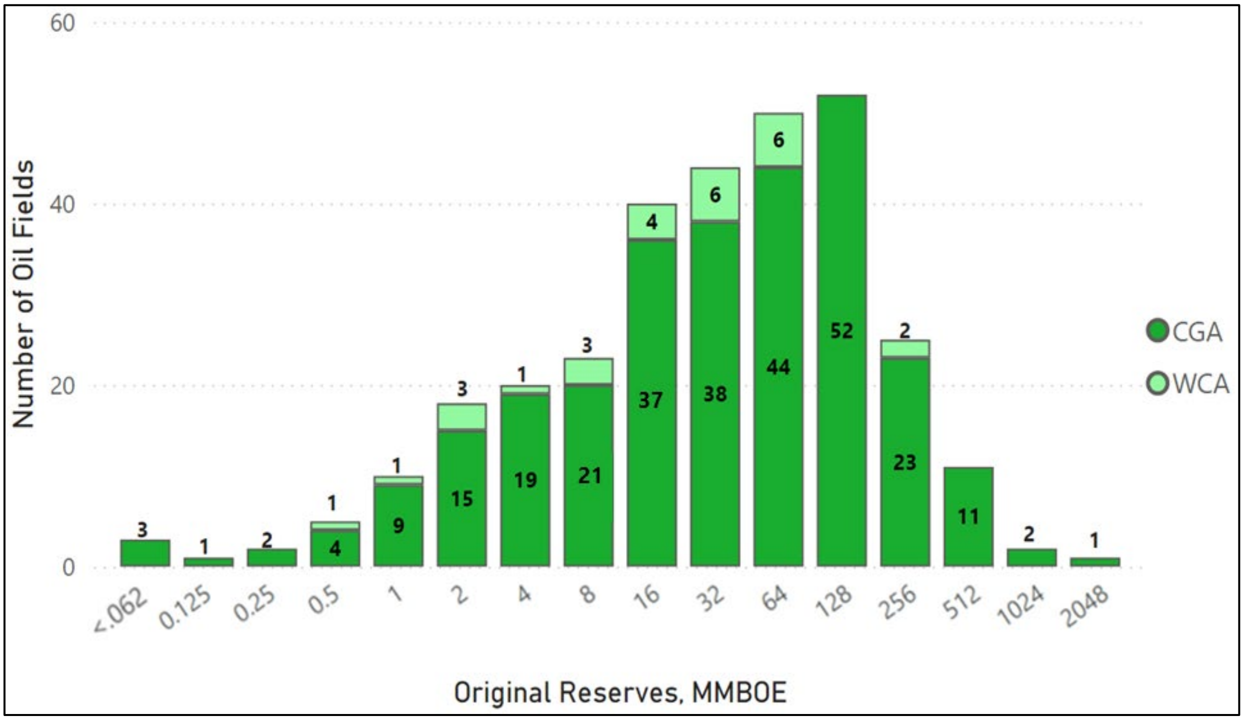

Figure 8. Field Size Distribution of GOA Oil Fields by Planning Area

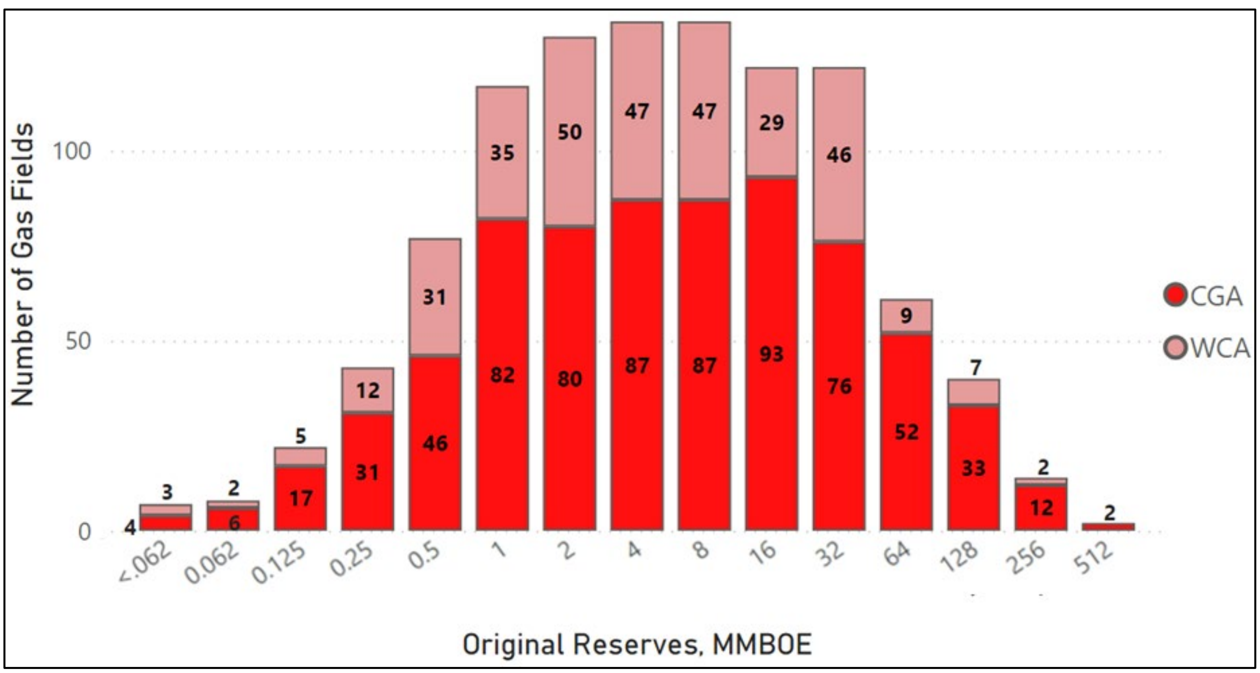

Figure 9. Field Size Distribution of GOA Gas Fields by Planning Area

Figure 10 shows the cumulative percent distribution of Original Reserves (BBOE), by field size rank. All 1,342 fields in the GOA OCS are included in Figure 10. 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 24 largest fields. Fifty percent of the Original Reserves are contained in the 86 largest fields. Ninety percent of the Original Reserves are contained in the 434 largest fields.

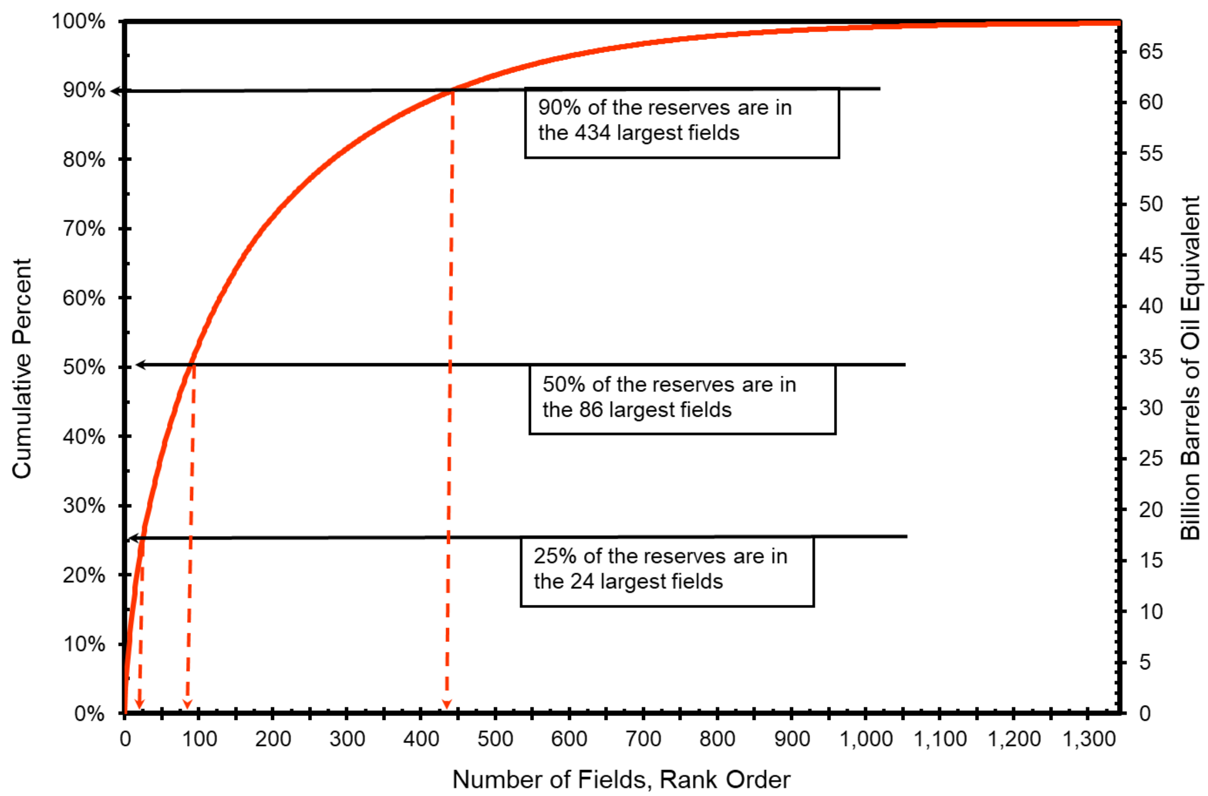

Figure 10. Cumulative Percent Original Reserves vs. Rank Order of Field Size

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 1,342 fields. Eighty-eight percent of the remaining reserves are found in water depths greater than 656 ft. Of the 241 fields at these depths, 134 are producing, 105 are depleted or expired, and 2 have yet to produce.

Table 3. Number of Fields, Cumulative Production, and Remaining Reserves by Water Depth

Water Depth Range (Feet)	Number of Fields	Number of Active Fields	Cumulative Production (MMBOE)	Remaining Reserves (MMBOE)
< 656	1,101	183	42,479	898
656 - 999	33	4	1,015	51
1,000 - 1,499	29	13	1,619	183
1,500 - 4,999	111	71	9,369	3,309
5,000 - 7,499	49	41	4,522	2,972
>= 7,500	19	8	959	382
TOTALS:	**1,342**	**320**	**59,963**	**7,795**

Table 4 ranks the 50 largest fields by mean Original Reserves, measured in MMBOE. It includes details such as rank, field name, field nickname, discovery year, water depth, field classification, field type, distribution of Original Reserves, cumulative production through 2024, and distribution of remaining reserves. A complete listing of all 1,342 fields is available on the BOEM Web site at https://www.boem.gov/oil-gas-energy/resource-evaluation/discovered-resources.

*Table 4. Top 50 GOA Fields by Rank Order, Based on Mean Original Reserves, MMBOE**

Rank	Field name	Field Nickname	Disc year	Water depth (feet)	Field type	Original Reserves (MMBOE)				Cumulative Production through 2024 (MMBOE)	Remaining Reserves (MMBOE)			
						P10	P50	P90	MEAN		P10	P50	P90	MEAN
1	MC807	MARS-URSA	1989	3341	O	2,523.8	2,569.4	2,621.5	2,575.8	2,205.6	318.2	363.8	415.9	370.2
2	GC826	MAD DOG	1998	4850	O	1,060.6	1,110.1	1,158.1	1,122.7	399.4	661.2	710.7	758.7	723.3
3	GC640	TAHITI/CAE/TONG	2002	4350	O	983.0	1,041.6	1,105.0	1,045.7	750.8	232.2	290.8	354.2	294.9
4	EI330		1971	248	O	851.9	858.7	866.6	854.3	811.3	40.6	47.4	55.3	43.0
5	WD030		1949	48	O	797.9	808.5	817.7	808.8	770.4	27.5	38.1	47.3	38.4
6	GC743	ATLANTIS	1998	6362	O	772.5	794.6	821.7	793.2	595.6	176.9	199.0	226.1	197.6
7	TS000		1958	12	G	717.9	724.1	734.9	725.1	698.0	19.9	26.1	36.9	27.1
8	BM002		1949	50	O	704.4	717.4	734.2	718.7	656.0	48.4	61.4	78.2	62.7
9	GI043		1956	140	O	714.4	718.0	723.9	718.5	680.8	33.6	37.2	43.1	37.7
10	GC654	SHENZI	2002	4299	O	639.8	676.4	707.7	674.1	427.4	212.4	249.0	280.3	246.7
11	MC778	THUNDER HORSE	1999	6143	O	587.5	617.1	657.5	619.5	408.5	179.0	208.6	249.0	211.0
12	VR014		1956	26	G	604.2	604.2	604.2	604.2	604.2	0.0	0.0	0.0	0.0
13	MC940	VITO	2010	4006	O	563.5	603.2	649.0	604.1	45.2	518.3	558.0	603.8	558.9
14	MP041		1956	43	O	576.3	579.5	582.9	579.4	558.1	18.2	21.4	24.8	21.3
15	MC084	KING/HORN MT.	1993	5151	O	543.2	555.9	570.5	557.3	415.1	128.1	140.8	155.4	142.2
16	GB426	AUGER	1987	2843	O	529.0	542.5	553.9	543.9	496.8	32.2	45.7	57.1	47.1
17	AC857	GREAT WHITE	2002	7919	O	449.5	489.5	583.5	501.6	374.3	75.2	115.2	209.2	127.3
18	MC776	N.THUNDER HORSE	2000	5671	O	489.9	499.2	511.0	499.8	428.9	61.0	70.3	82.1	70.9
19	SS208		1960	102	O	494.0	497.5	500.5	497.3	480.6	13.4	16.9	19.9	16.7
20	VR039		1948	38	G	495.9	496.1	496.2	496.1	495.6	0.3	0.5	0.6	0.5
21	KC872	BUCKSKIN	2008	6641	O	403.7	457.0	521.1	456.6	61.7	342.0	395.3	459.4	394.9
22	WD073		1962	177	O	423.1	428.4	434.4	428.3	406.6	16.5	21.8	27.8	21.7
23	EI238		1964	147	G	391.8	393.4	395.9	393.7	382.8	9.0	10.6	13.1	10.9
24	GI016		1948	54	O	381.1	381.5	381.7	381.5	379.7	1.4	1.8	2.0	1.8
25	SP061		1967	220	O	371.9	373.2	374.5	373.3	367.8	4.1	5.4	6.7	5.5
26	WR678	SAINT MALO	2003	6939	O	359.3	369.9	388.6	371.8	261.3	98.0	108.6	127.3	110.5
27	SP089		1969	421	O	355.5	356.5	357.3	356.5	353.2	2.3	3.3	4.1	3.3
28	WR759	JACK	2004	6966	O	332.2	352.6	375.0	352.8	147.5	184.7	205.1	227.5	205.3
29	ST172		1962	98	G	349.9	349.9	349.9	349.9	349.9	0.0	0.0	0.0	0.0
30	WC180		1961	48	G	341.7	341.7	341.7	341.7	341.7	0.0	0.0	0.0	0.0
31	SS169		1960	63	O	338.4	338.6	339.3	338.7	334.0	4.4	4.6	5.3	4.7
32	ST021		1957	46	O	335.7	335.7	335.7	335.7	335.6	0.1	0.1	0.1	0.1
33	MC194	COGNAC	1975	1022	O	329.6	330.5	331.6	330.7	323.5	6.1	7.0	8.1	7.2
34	GC807	ANCHOR	2014	5009	O	280.1	324.2	385.4	329.9	2.0	278.1	322.2	383.4	327.9
35	EI292		1964	214	G	324.5	325.1	326.2	325.3	321.5	3.0	3.6	4.7	3.8
36	ST176		1963	127	G	322.8	324.0	326.0	324.1	320.0	2.8	4.0	6.0	4.1
37	GB171	CONGER	1984	1330	O	310.9	316.9	330.2	319.6	309.5	1.4	7.4	20.7	10.1
38	EC271		1971	172	G	318.1	318.5	318.7	318.2	314.5	3.6	4.0	4.2	3.7
39	EC064		1957	50	G	313.4	313.4	313.4	313.4	313.4	0.0	0.0	0.0	0.0
40	SS176		1956	101	G	309.0	309.3	309.4	309.4	307.1	1.9	2.2	2.3	2.3
41	SM048		1961	100	G	307.8	308.0	308.1	308.0	307.3	0.5	0.7	0.8	0.7
42	MC392	APPOMATTOX	2009	7221	O	286.0	304.1	326.1	305.3	155.4	130.6	148.7	170.7	149.9
43	VK956	RAM-POWELL	1985	3209	O	294.0	294.3	299.8	294.9	276.5	17.5	17.8	23.3	18.4
44	WC587		1971	210	G	294.7	294.7	294.7	294.7	294.7	0.0	0.0	0.0	0.0
45	SP027	EAST BAY	1954	64	O	293.4	293.5	294.1	293.9	292.2	1.2	1.3	1.9	1.7
46	ST135		1956	129	O	285.9	290.1	297.5	290.7	283.0	2.9	7.1	14.5	7.7
47	WD079		1966	123	O	287.1	291.5	293.1	290.7	279.7	7.4	11.8	13.4	11.0
48	GC244	TROIKA	1994	2750	O	269.5	286.6	310.8	288.1	253.1	16.4	33.5	57.7	35.0
49	GI047		1955	88	O	277.6	280.2	285.5	281.1	263.0	14.6	17.2	22.5	18.1
50	KC875	LUCIUS	2010	7088	O	269.5	281.0	295.2	281.1	179.5	90.0	101.5	115.7	101.6

**A table with complete values can be obtained at the BOEM Data Center under the Field widget.*

Figure 11 highlights the 20 largest fields based on Original Reserves, while Figure 12 provides a spatial overview of the location of all 50 fields.

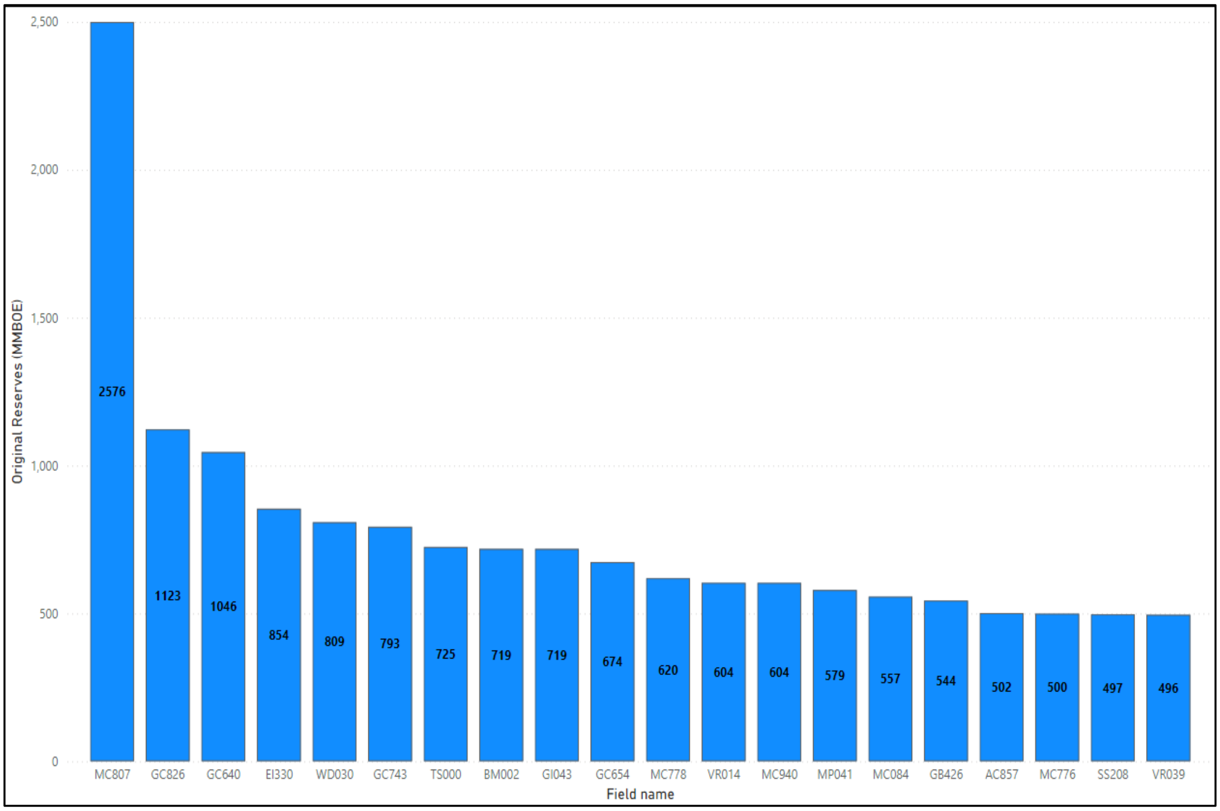

Figure 11. Largest 20 Fields by Original Reserves

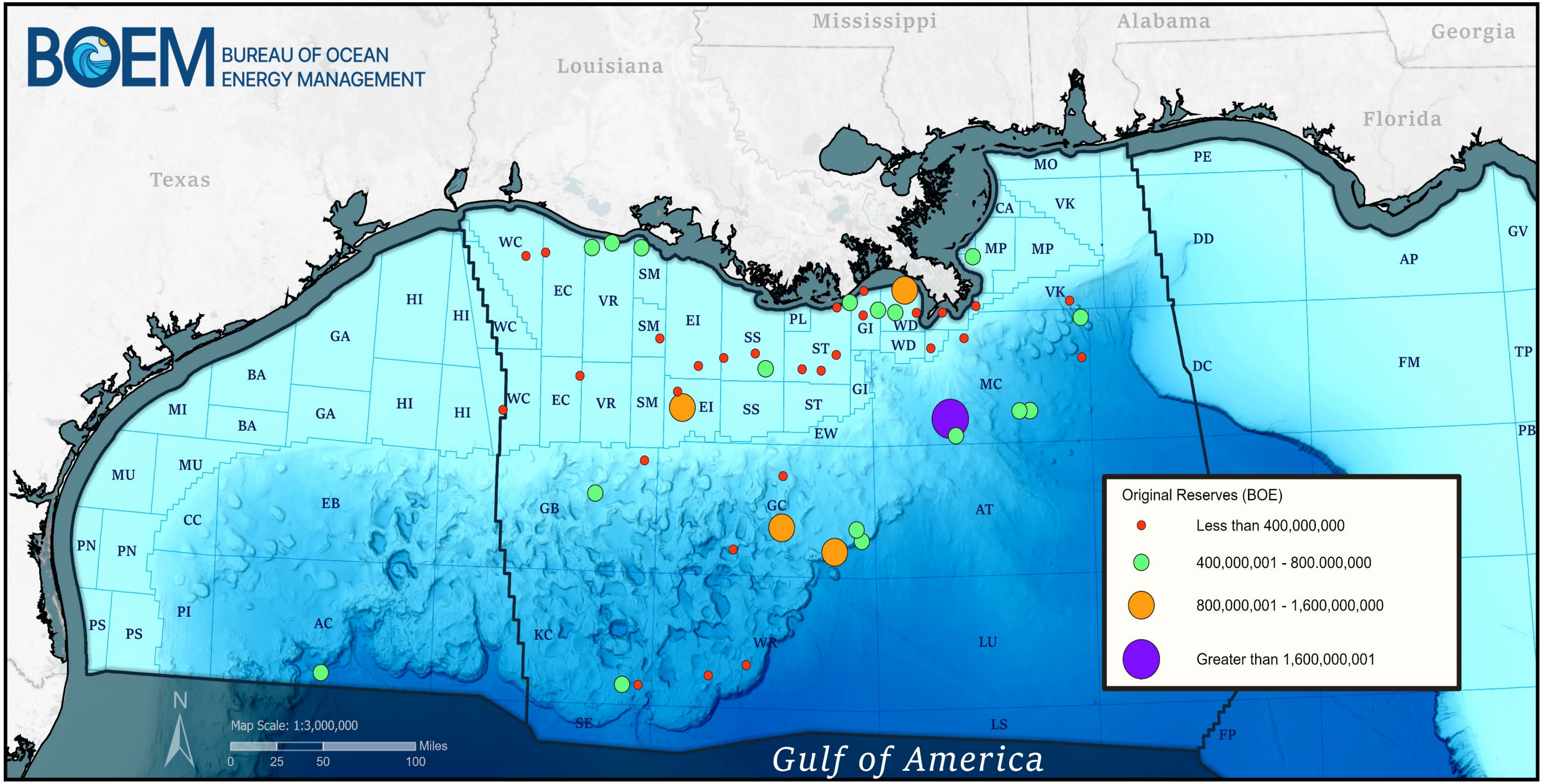

Figure 12. Largest 50 Fields by Original Reserves (BOE)

Table 5 ranks the 50 largest fields by mean remaining reserves, measured in MMBOE. It includes details such as rank, field name, field nickname, discovery year, water depth, field classification, field type, distribution of Original Reserves, cumulative production through 2024, and distribution of remaining reserves.

*Table 5. Top 50 GOA Fields by Rank Order, Based on Mean Remaining Reserves, MMBOE**

Rank	Field name	Field Nickname	Disc year	Water depth (feet)	Field type	Original Reserves (MMBOE)				Cumulative Production through 2024 (MMBOE)	Remaining Reserves (MMBOE)			
						P10	P50	P90	MEAN		P10	P50	P90	MEAN
1	GC826	MAD DOG	1998	4850	O	1,060.6	1,110.1	1,158.1	1,122.7	399.4	661.2	710.7	758.7	723.3
2	MC940	VITO	2010	4006	O	563.5	603.2	649.0	604.1	45.2	518.3	558.0	603.8	558.9
3	KC872	BUCKSKIN	2008	6641	O	403.7	457.0	521.1	456.6	61.7	342.0	395.3	459.4	394.9
4	MC807	MARS-URSA	1989	3341	O	2,523.8	2,569.4	2,621.5	2,575.8	2,205.6	318.2	363.8	415.9	370.2
5	GC807	ANCHOR	2014	5009	O	280.1	324.2	385.4	329.9	2.0	278.1	322.2	383.4	327.9
6	GC640	TAHITI/CAE/TONG	2002	4350	O	983.0	1,041.6	1,105.0	1,045.7	750.8	232.2	290.8	354.2	294.9
7	GC654	SHENZI	2002	4299	O	639.8	676.4	707.7	674.1	427.4	212.4	249.0	280.3	246.7
8	MC778	THUNDER HORSE	1999	6143	O	587.5	617.1	657.5	619.5	408.5	179.0	208.6	249.0	211.0
9	WR759	JACK	2004	6966	O	332.2	352.6	375.0	352.8	147.5	184.7	205.1	227.5	205.3
10	GC743	ATLANTIS	1998	6362	O	772.5	794.6	821.7	793.2	595.6	176.9	199.0	226.1	197.6
11	WR051	SHENANDOAH	2013	5855	O	171.4	195.7	222.6	195.6	0.0	171.4	195.7	222.6	195.6
12	MC651	Ballymore	2017	6540	O	129.8	182.1	225.4	180.0	0.0	129.8	182.1	225.4	180.0
13	MC392	APPOMATTOX	2009	7221	O	286.0	304.1	326.1	305.3	155.4	130.6	148.7	170.7	149.9
14	MC084	KING/HORN MT.	1993	5151	O	543.2	555.9	570.5	557.3	415.1	128.1	140.8	155.4	142.2
15	AC857	GREAT WHITE	2002	7919	O	449.5	489.5	583.5	501.6	374.3	75.2	115.2	209.2	127.3
16	WR029	BIG FOOT	2005	5368	O	141.2	181.8	223.7	183.2	63.7	77.5	118.1	160.0	119.5
17	MC393	VICKSBURG A	2013	7410	O	100.0	155.1	203.3	154.6	43.3	56.7	111.8	160.0	111.3
18	WR678	SAINT MALO	2003	6939	O	359.3	369.9	388.6	371.8	261.3	98.0	108.6	127.3	110.5
19	GC468	STAMPEDE	2006	3518	O	156.6	176.6	196.8	176.5	72.4	84.2	104.2	124.4	104.1
20	KC875	LUCIUS	2010	7088	O	269.5	281.0	295.2	281.1	179.5	90.0	101.5	115.7	101.6
21	AC772	WHALE	2017	8639	O	69.0	88.6	116.4	91.4	0.0	69.0	88.6	116.4	91.4
22	GC562	K2	1999	4039	O	195.9	221.5	238.7	220.0	143.6	52.3	77.9	95.1	76.4
23	AC859	TOBAGO	2004	9319	O	112.9	124.0	142.4	125.8	52.1	60.8	71.9	90.3	73.7
24	MC776	N.THUNDER HORSE	2000	5671	O	489.9	499.2	511.0	499.8	428.9	61.0	70.3	82.1	70.9
25	MC546	LONGHORN	1986	2543	O	252.8	259.5	267.4	259.7	196.8	56.0	62.7	70.6	62.9
26	BM002		1949	50	O	704.4	717.4	734.2	718.7	656.0	48.4	61.4	78.2	62.7
27	MC109	AMBERJACK	1983	1044	O	160.0	168.0	178.0	168.8	108.1	51.9	59.9	69.9	60.7
28	MC525	RYDBERG	2014	7436	O	42.5	64.3	81.4	62.6	2.0	40.5	62.3	79.4	60.6
29	MC943	POWER NAP	2014	4209	O	36.1	61.7	87.0	62.5	8.8	27.3	52.9	78.2	53.7
30	GC039		1984	1967	O	60.1	74.2	91.9	75.3	23.9	36.2	50.3	68.0	51.4
31	GC478	MORMONT	2017	3770	O	64.7	80.2	99.7	81.3	30.4	34.3	49.8	69.3	50.9
32	MC768	KAIKIAS	2014	4479	O	113.8	134.7	155.0	133.6	83.1	30.7	51.6	71.9	50.5
33	MC612	DOVER	2018	7372	O	34.9	49.4	65.8	50.1	0.0	34.9	49.4	65.8	50.1
34	MC773	DEVILS TOWER	1999	5345	O	200.4	205.2	211.0	205.7	156.8	43.6	48.4	54.2	48.9
35	GB426	AUGER	1987	2843	O	529.0	542.5	553.9	543.9	496.8	32.2	45.7	57.1	47.1
36	WR627	JULIA	2007	7135	O	116.7	127.1	139.8	127.6	82.7	34.0	44.4	57.1	44.9
37	EI330		1971	248	O	851.9	858.7	866.6	854.3	811.3	40.6	47.4	55.3	43.0
38	WR508	STONES	2005	9317	O	114.2	129.3	139.2	128.1	85.3	28.9	44.0	53.9	42.8
39	GC236	PHOENIX	1984	2205	O	150.9	163.0	176.4	163.4	124.5	26.4	38.5	51.9	38.9
40	WD030		1949	48	O	797.9	808.5	817.7	808.8	770.4	27.5	38.1	47.3	38.4
41	GI043		1956	140	O	714.4	718.0	723.9	718.5	680.8	33.6	37.2	43.1	37.7
42	VK990	POMPANO	1981	1447	O	240.2	245.1	251.9	246.3	210.8	29.4	34.3	41.1	35.5
43	MC243	MATTERHORN	1990	2749	O	72.7	79.7	86.3	76.5	41.1	31.6	38.6	45.2	35.4
44	GC244	TROIKA	1994	2750	O	269.5	286.6	310.8	288.1	253.1	16.4	33.5	57.7	35.0
45	GC627	HOPKINS	2014	4385	O	40.4	62.8	81.7	61.1	26.4	14.0	36.4	55.3	34.7
46	GC389	KHALEESI	2017	3576	O	72.4	73.1	77.4	74.5	39.9	32.5	33.2	37.5	34.6
47	GB260	BALDPATE	1991	1585	O	227.9	239.9	258.6	242.2	208.2	19.7	31.7	50.4	34.0
48	GC432	SAMURAI	2009	3448	O	44.3	47.7	53.4	48.2	16.6	27.7	31.1	36.8	31.6
49	GC019	BOXER	1980	758	O	165.3	171.7	177.1	171.5	140.9	24.4	30.8	36.2	30.6
50	MC682	TUBULAR BELLS	2003	4494	O	109.7	116.0	124.4	116.7	86.2	23.5	29.8	38.2	30.5

**A table with complete values can be obtained at the BOEM Data Center under the Field widget.*

Figure 13 highlights the 20 largest fields based on remaining reserves, while Figure 14 provides a spatial overview of the location of all 50 fields.

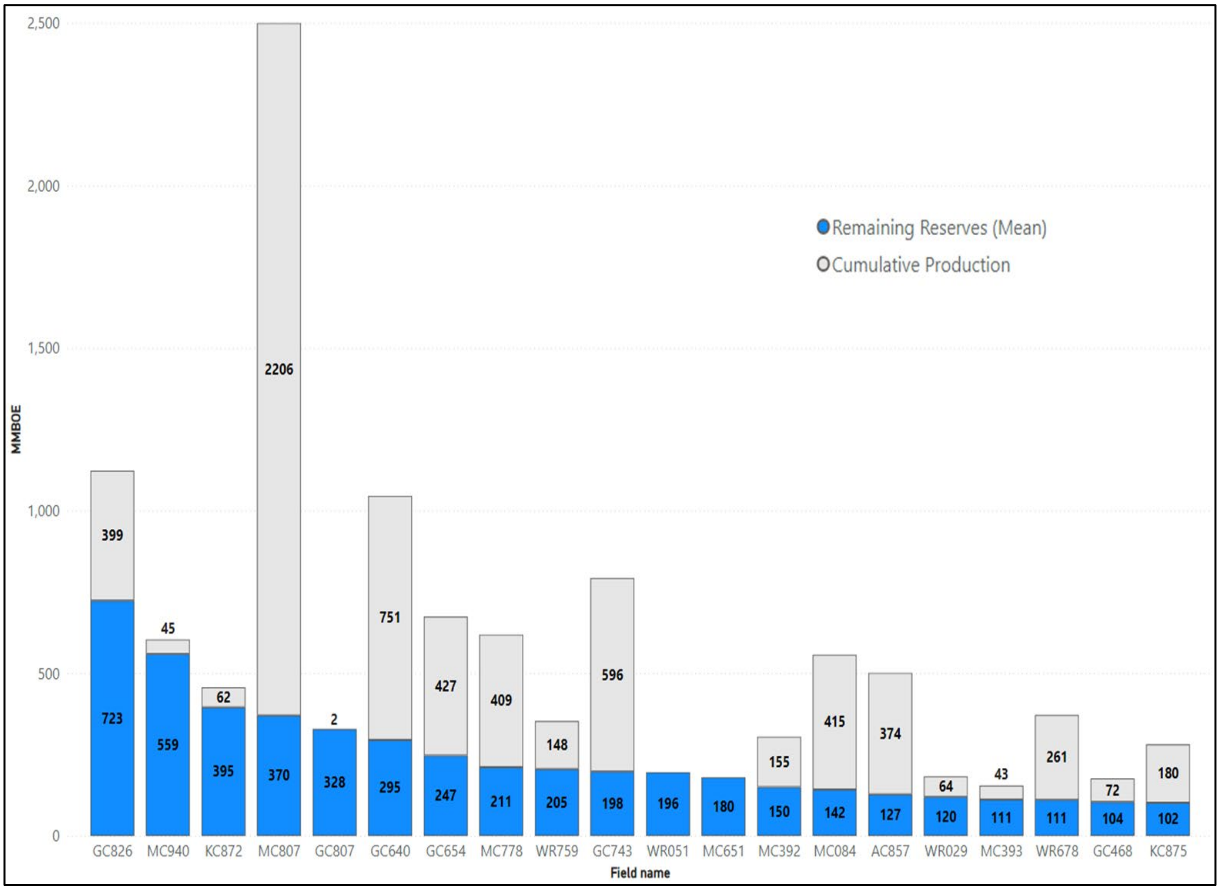

Figure 13. Largest 20 Fields by Remaining Reserves

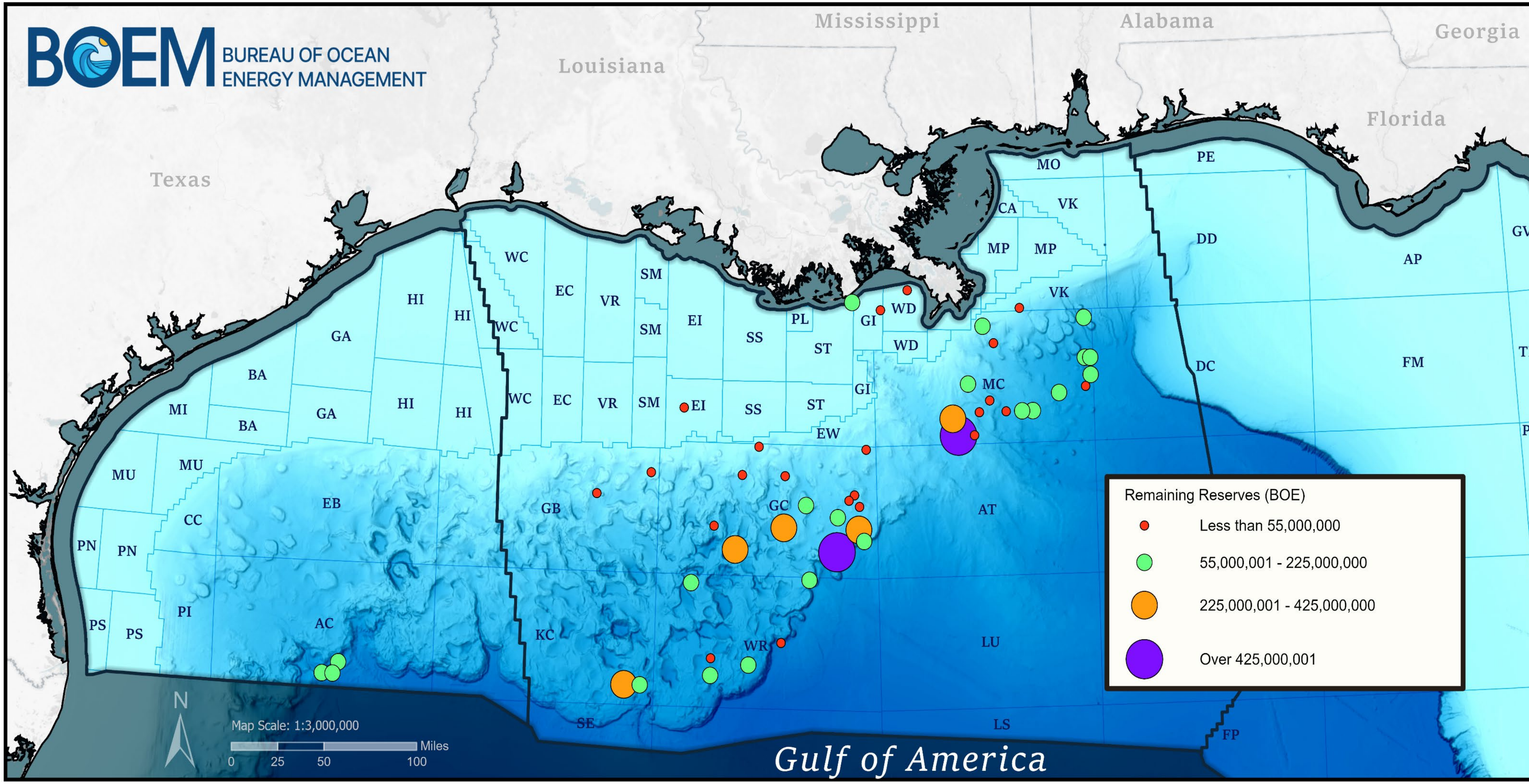

Figure 14. Largest 50 Fields by Remaining Reserves (BOE)

7.0 DRILLING AND PRODUCTION TRENDS

Exploration and development drilling in the GOA has steadily advanced into deeper waters over time. The first well drilled in water depths exceeding 1,000 feet reached total depth in 1975 at the Cognac Field (Mississippi Canyon 194). Since then, maximum drilling depths along the GOA slope have continued to increase, with true vertical subsea depths surpassing 35,000 feet. This progression reflects significant improvements in rig capabilities, the pursuit of deeper exploration targets, and ongoing technological advancements across the industry.

7.1 EXPLORATORY WELLS DRILLED BY WATER DEPTH OVER TIME

Figure 15 and Figure 16 show the number of exploratory wells drilled over time by water depth category. Shelf exploratory drilling increased steadily from the 1950s through the 1980s, remained comparatively high through the 1990s and early 2000s, and then declined sharply after 2008 to only sporadic activity in recent years. Exploratory drilling on the slope began in the mid-1970s, expanded substantially during the late 1990s and 2000s, and surpassed shelf exploratory drilling in 2009. Over the last decade, exploratory activity has been concentrated primarily on the slope, averaging approximately 67 slope wells annually compared with 8 shelf wells annually. The total footage of exploratory wells drilled in 2024 was 1.22 million feet, compared to 1.31 million feet in 2023. Figure 17 through Figure 25 provide a spatial overview of exploratory wells drilled by decade, showing how oil and gas activity has progressively moved into deeper waters over time.

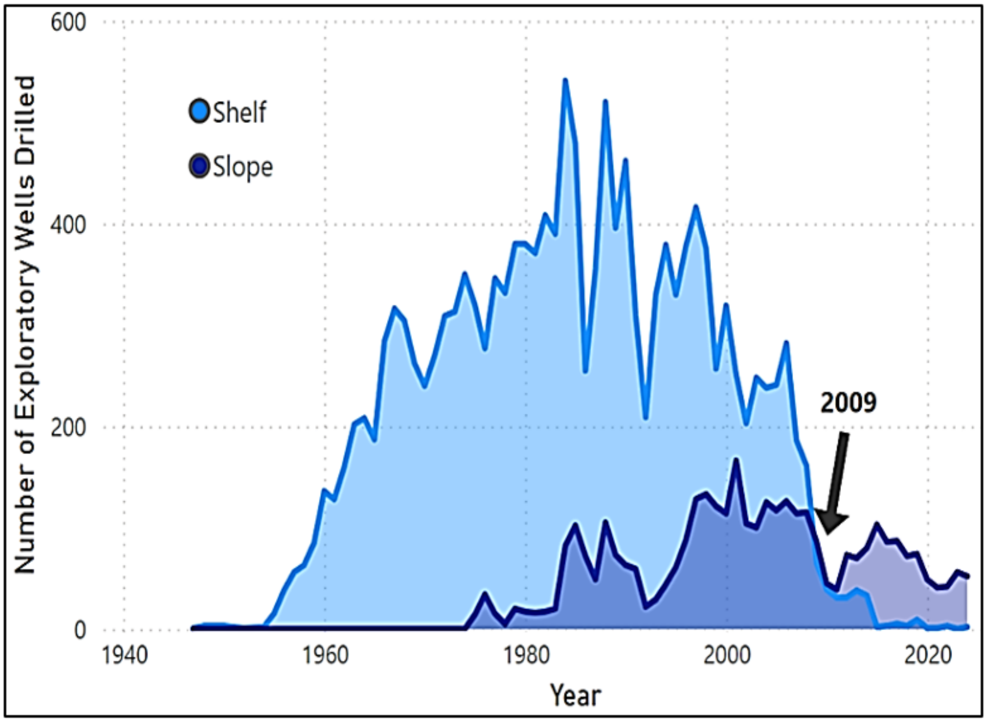

Figure 15. Exploratory Wells Drilled by Water Depth Over Time

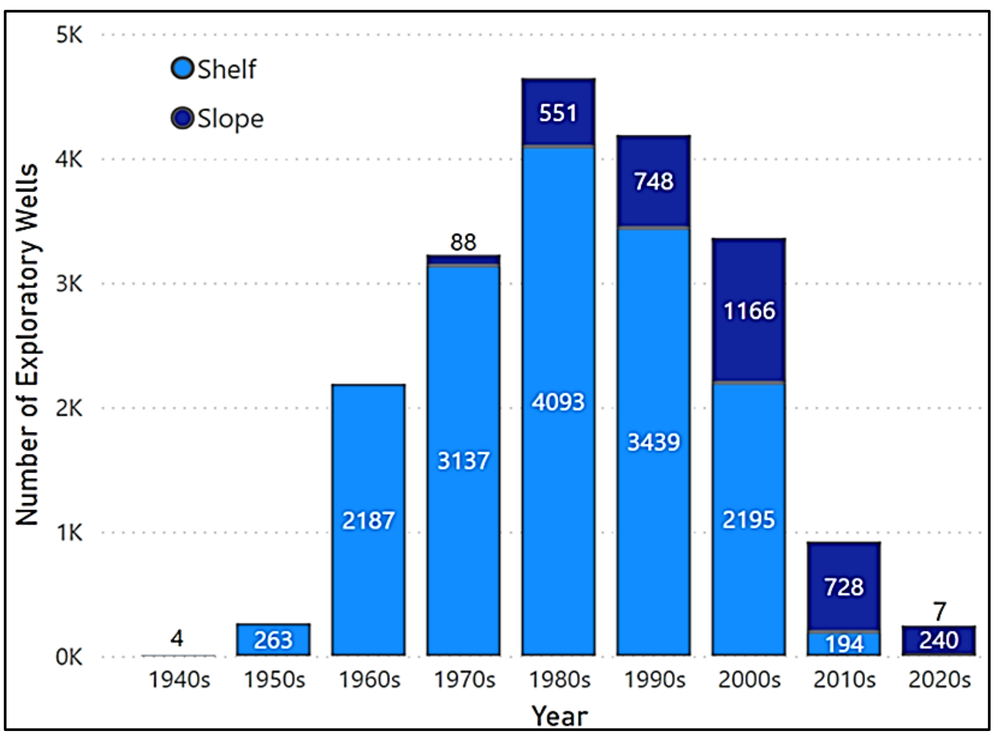

Figure 16. Number of Exploratory Wells Drilled by Water Depth Over Time

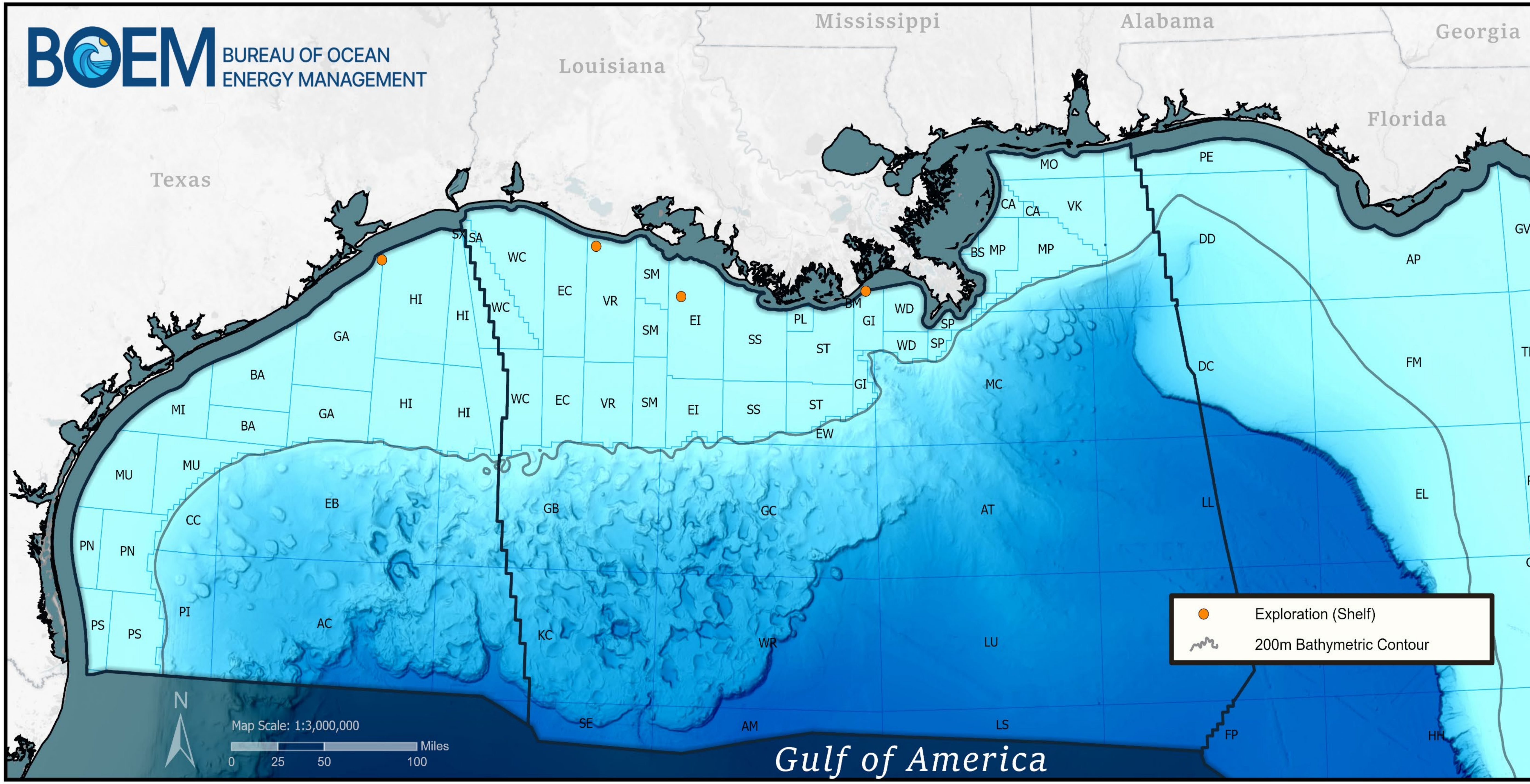

Figure 17. Exploratory Wells Drilled Over Time, 1940s

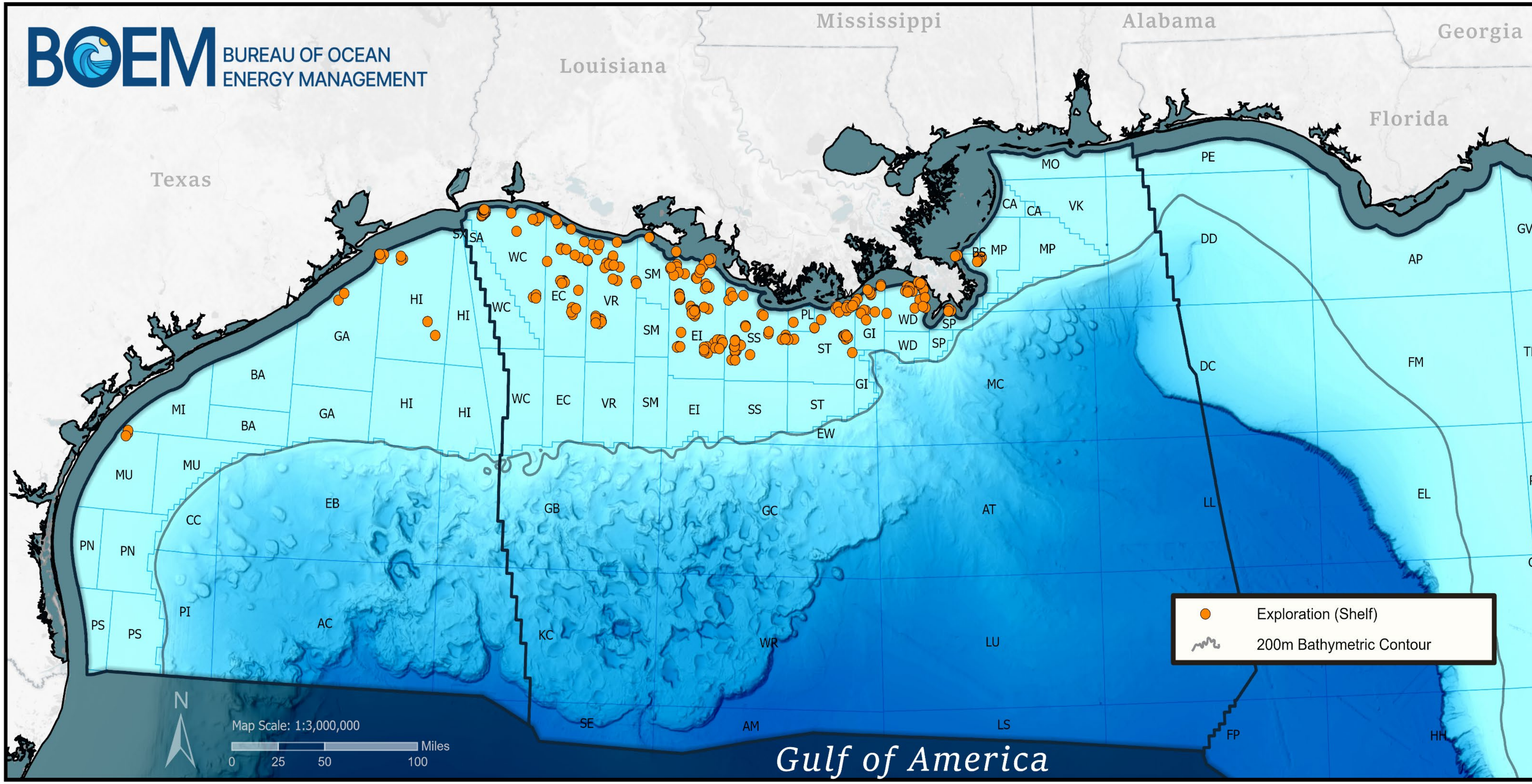

Figure 18. Exploratory Wells Drilled Over Time, 1950s

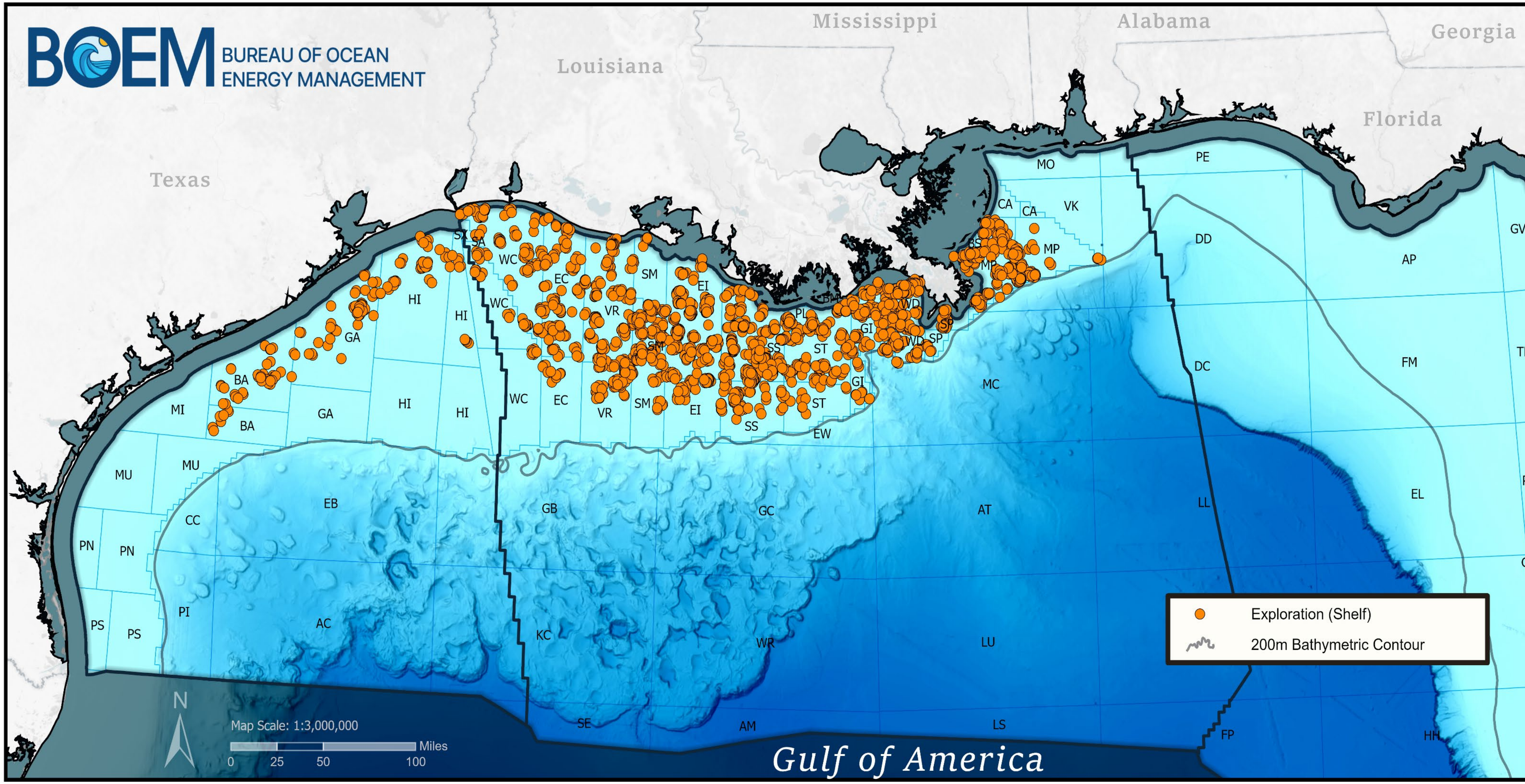

Figure 19. Exploratory Wells Drilled Over Time, 1960s

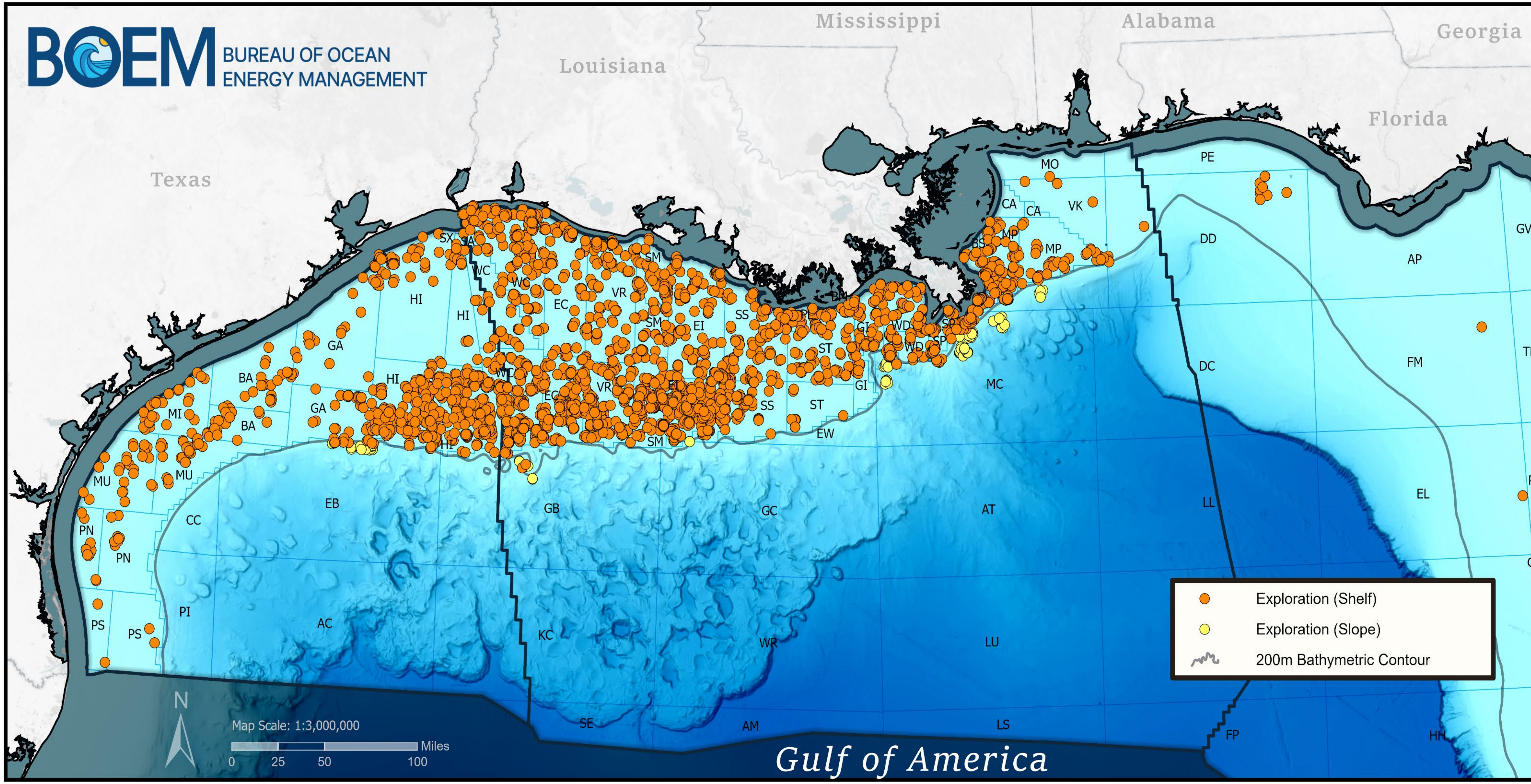

Figure 20. Exploratory Wells Drilled Over Time, 1970s

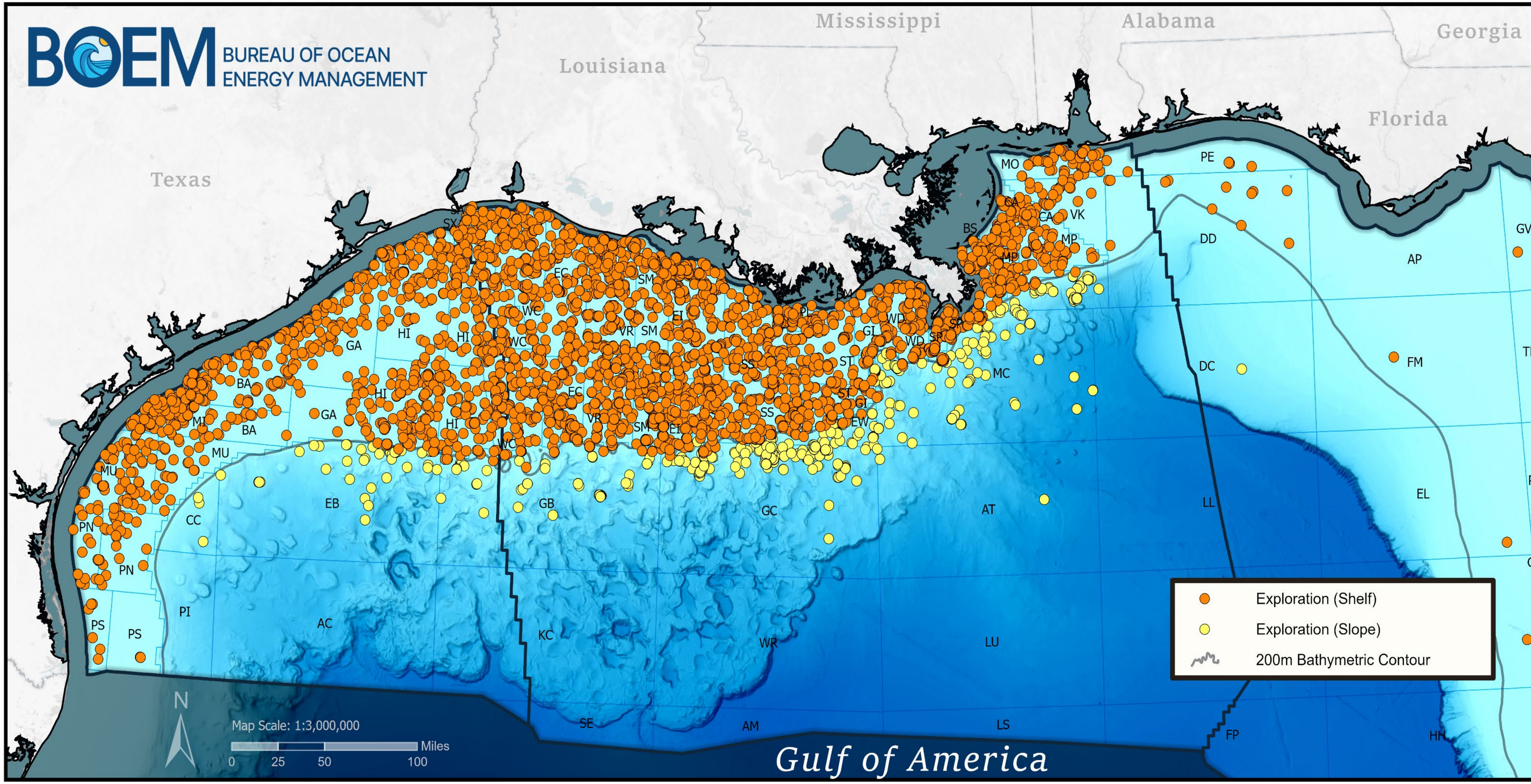

Figure 21. Exploratory Wells Drilled Over Time, 1980s

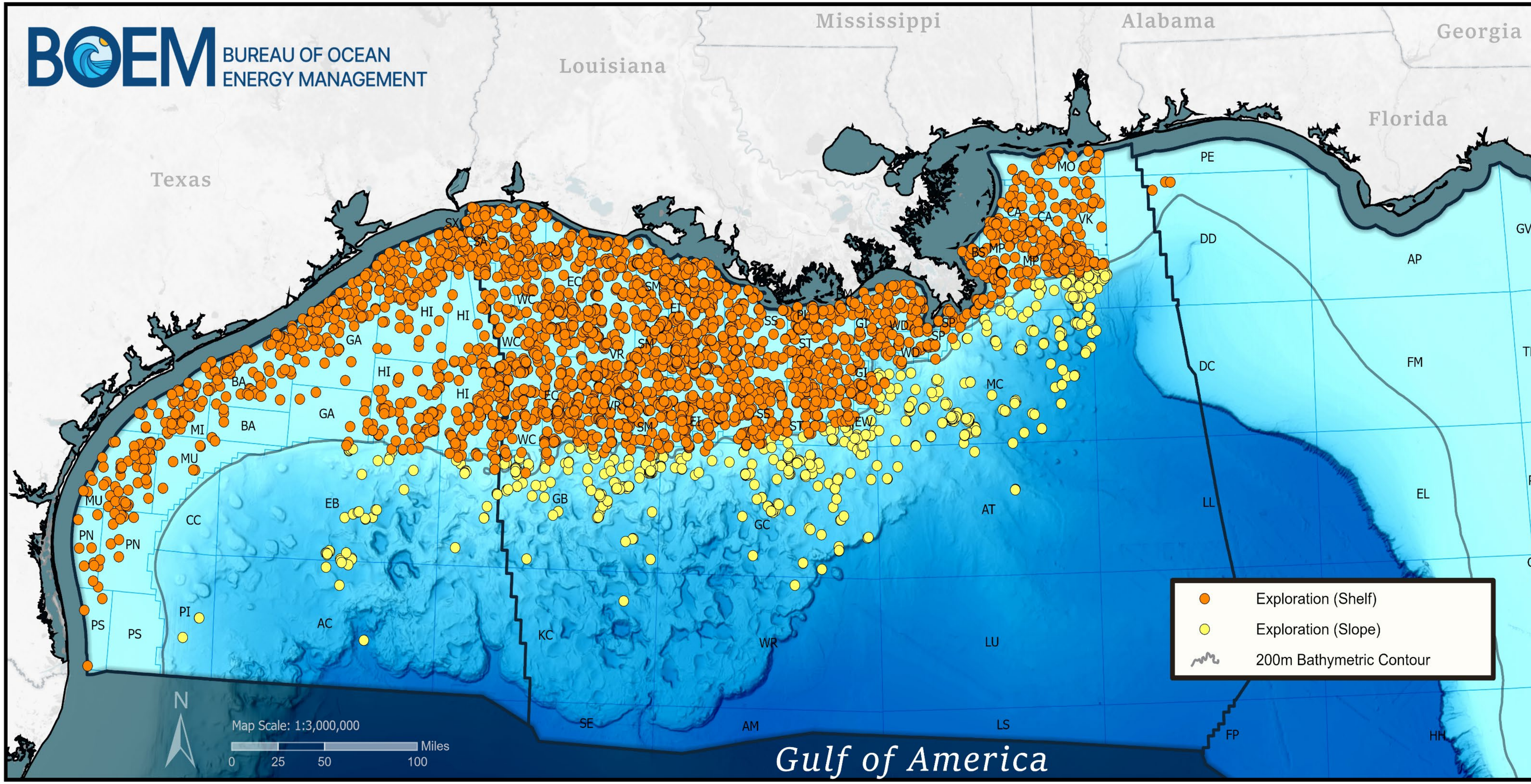

Figure 22. Exploratory Wells Drilled Over Time, 1990s

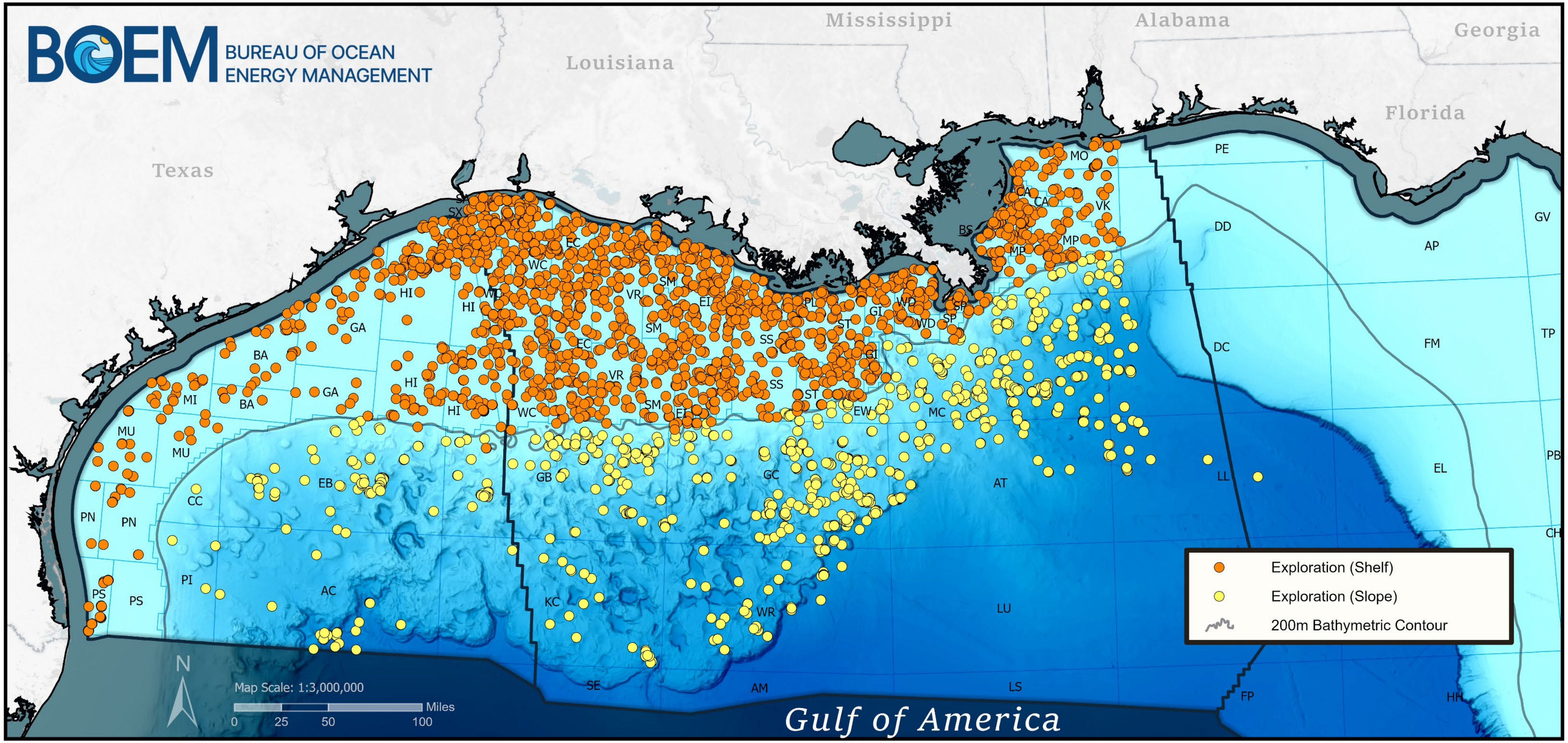

Figure 23. Exploratory Wells Drilled Over Time, 2000s

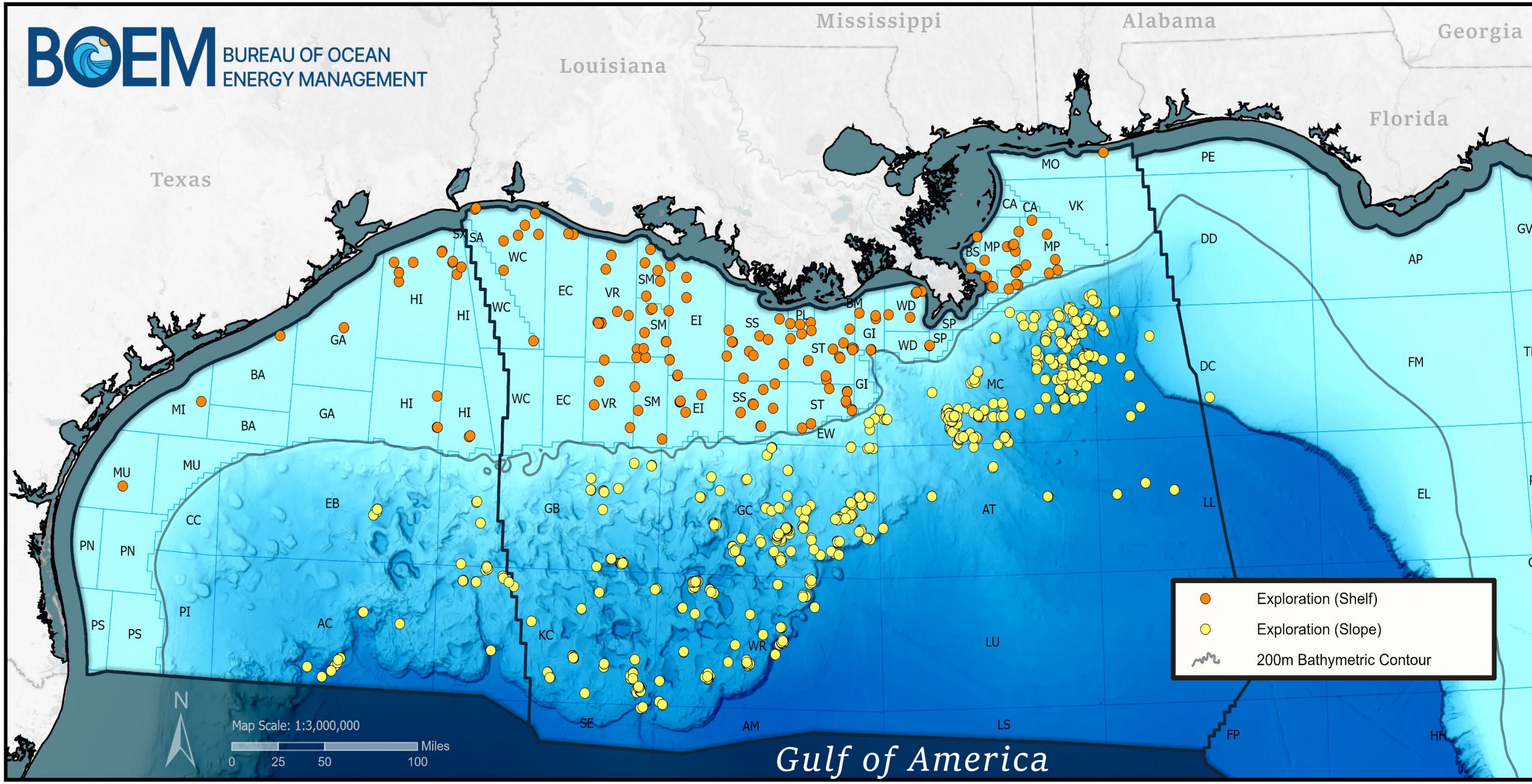

Figure 24. Exploratory Wells Drilled Over Time, 2010s

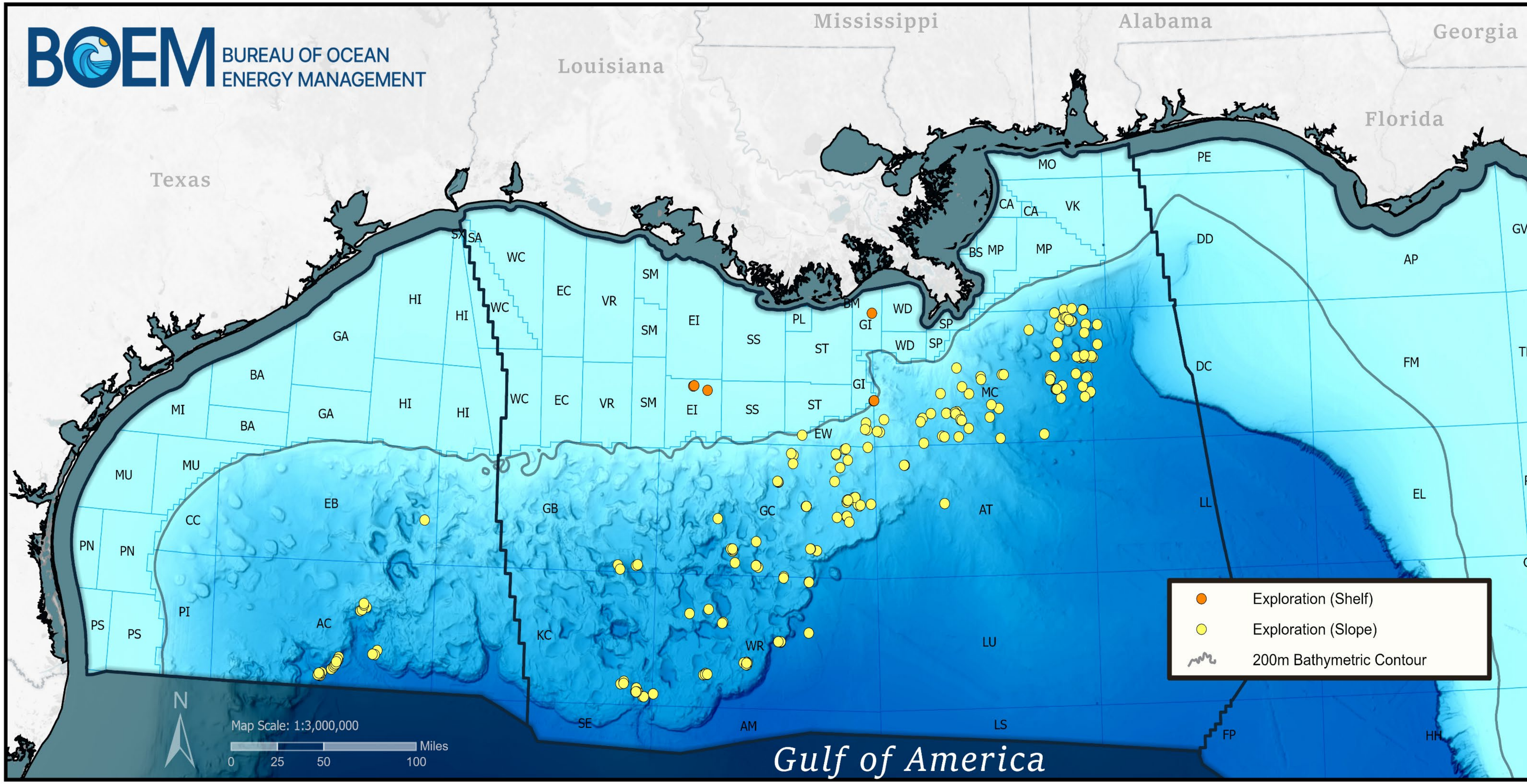

Figure 25. Exploratory Wells Drilled Over Time, 2020s

7.2 Development Wells Drilled by Water Depth Over Time

Historically, the GOA shelf was the center of offshore oil and gas production due to accessible reserves and simpler technology. As these mature shelf reserves declined, the industry began targeting deeper, less accessible resources. Today, technological advances have enabled the exploitation of high-volume reservoirs on the GOA slope. This shift makes the slope the leading source of production, despite requiring fewer, but more complex and expensive development wells.

Figure 26 and Figure 27 present the number of development wells drilled over time by water depth category. Development drilling on the shelf increased rapidly from the 1950s through the 1970s, peaked in the early 1980s, and has since experienced an overall decline. Development drilling on the slope began in the late 1970s and expanded gradually through the 1990s and early 2000s, surpassing shelf development drilling in 2018. Over the last decade, development activity has remained stable across both regions, averaging approximately 53 shelf wells and 44 slope wells annually. The total footage of development wells drilled in 2024 was 1.01 million feet, compared to 1.43 million feet in 2023. Figure 28 through Figure 36 provide a spatial overview of development wells drilled by decade, showing a clear trend of oil and gas operations expanding into progressively deeper waters over time.

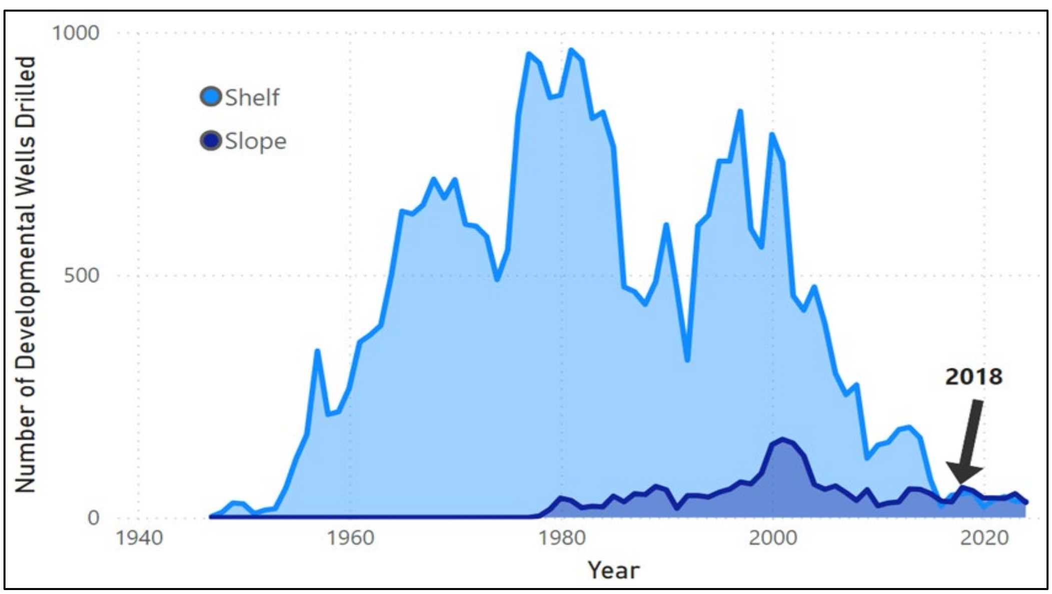

Figure 26. Development Wells Drilled by Water Depth Over Time

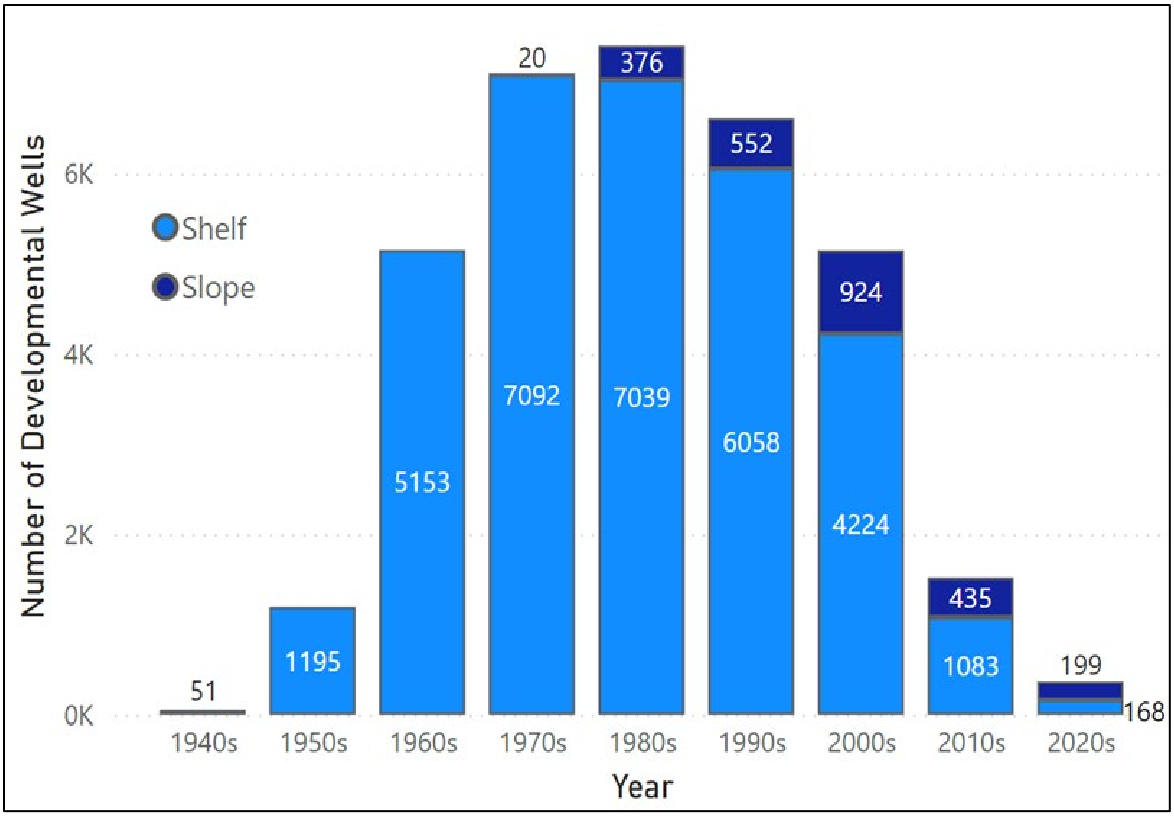

Figure 27. Number of Development Wells Drilled by Water Depth Over Time

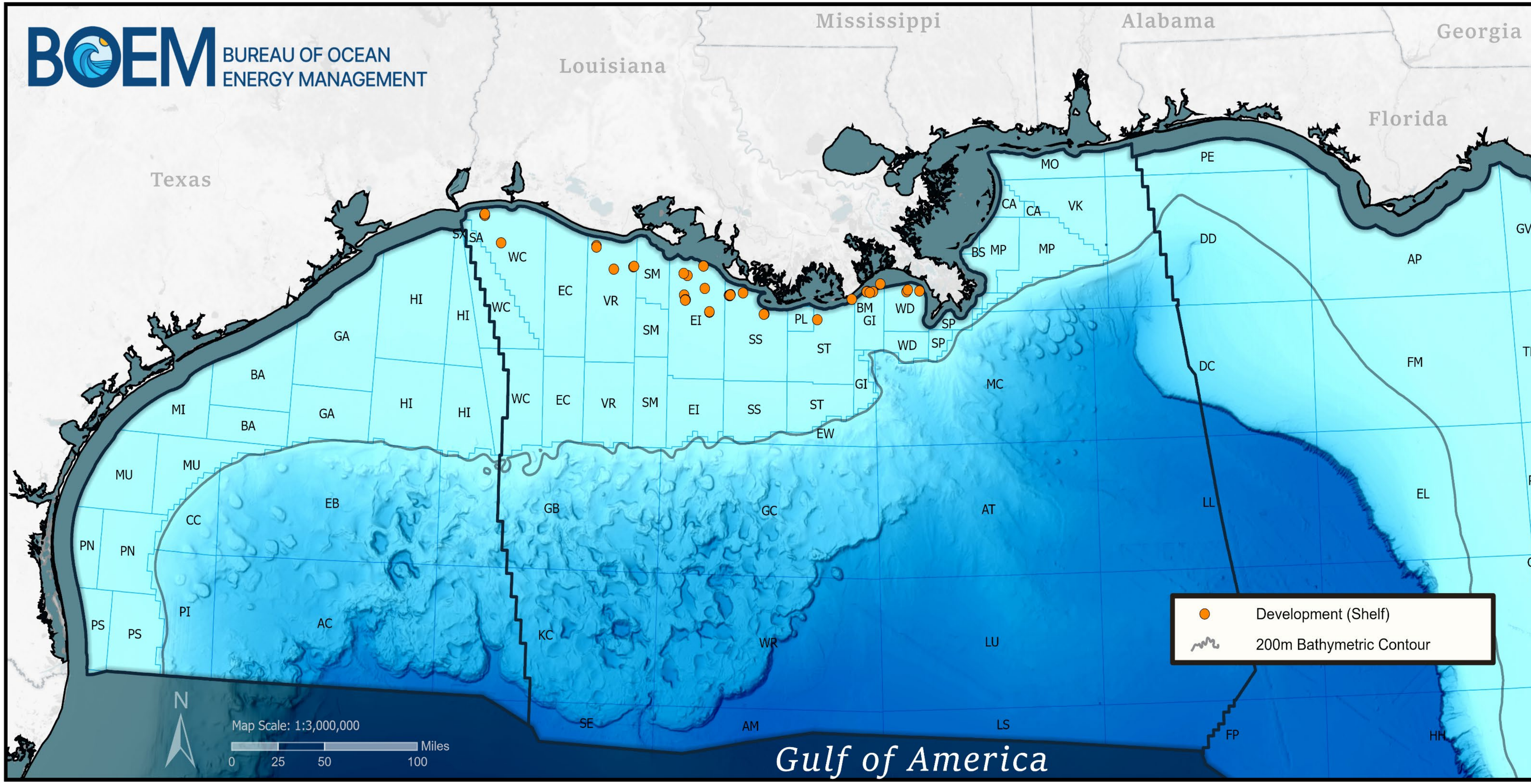

Figure 28. Development Wells Drilled Over Time, 1940s

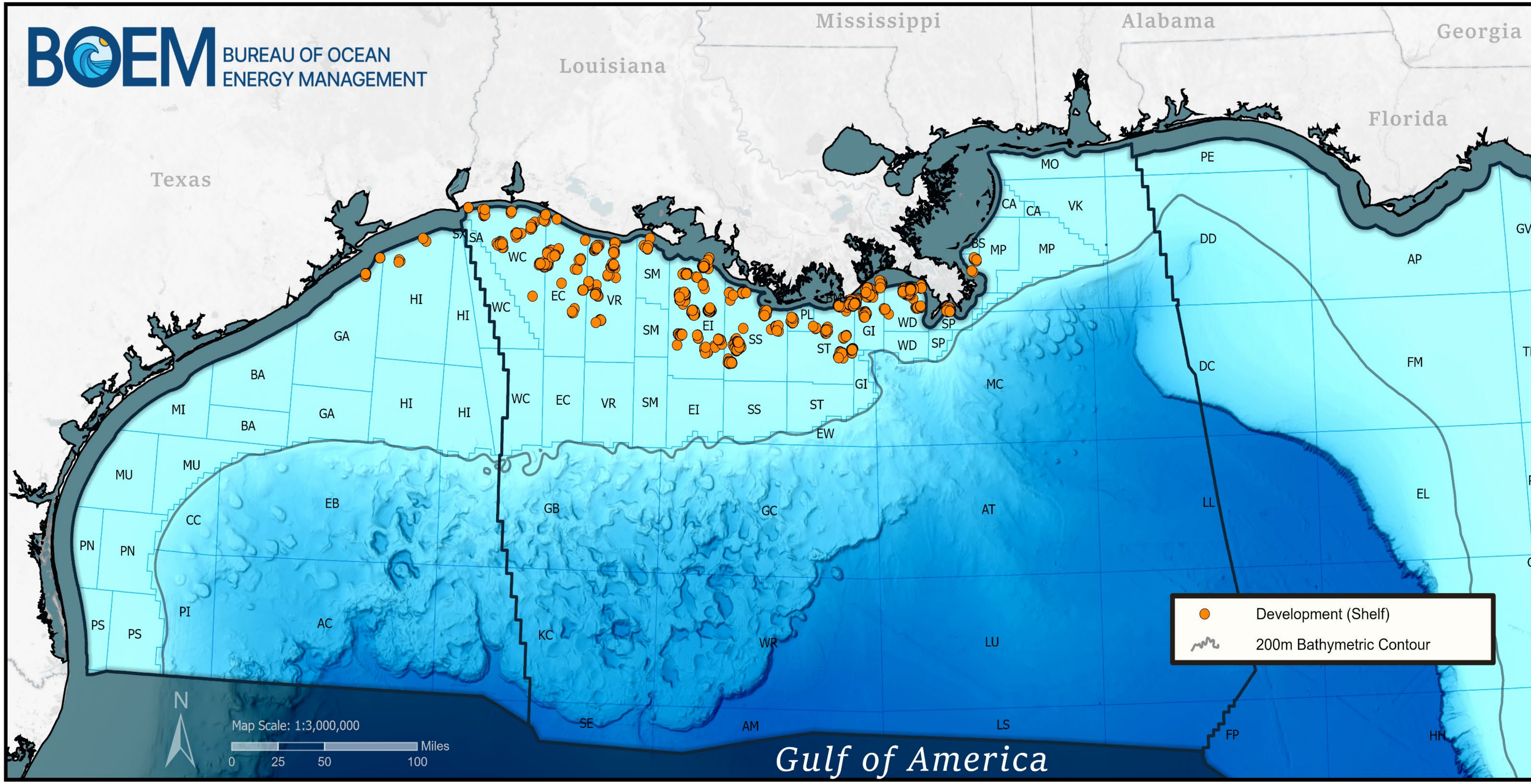

Figure 29. Development Wells Drilled Over Time, 1950s

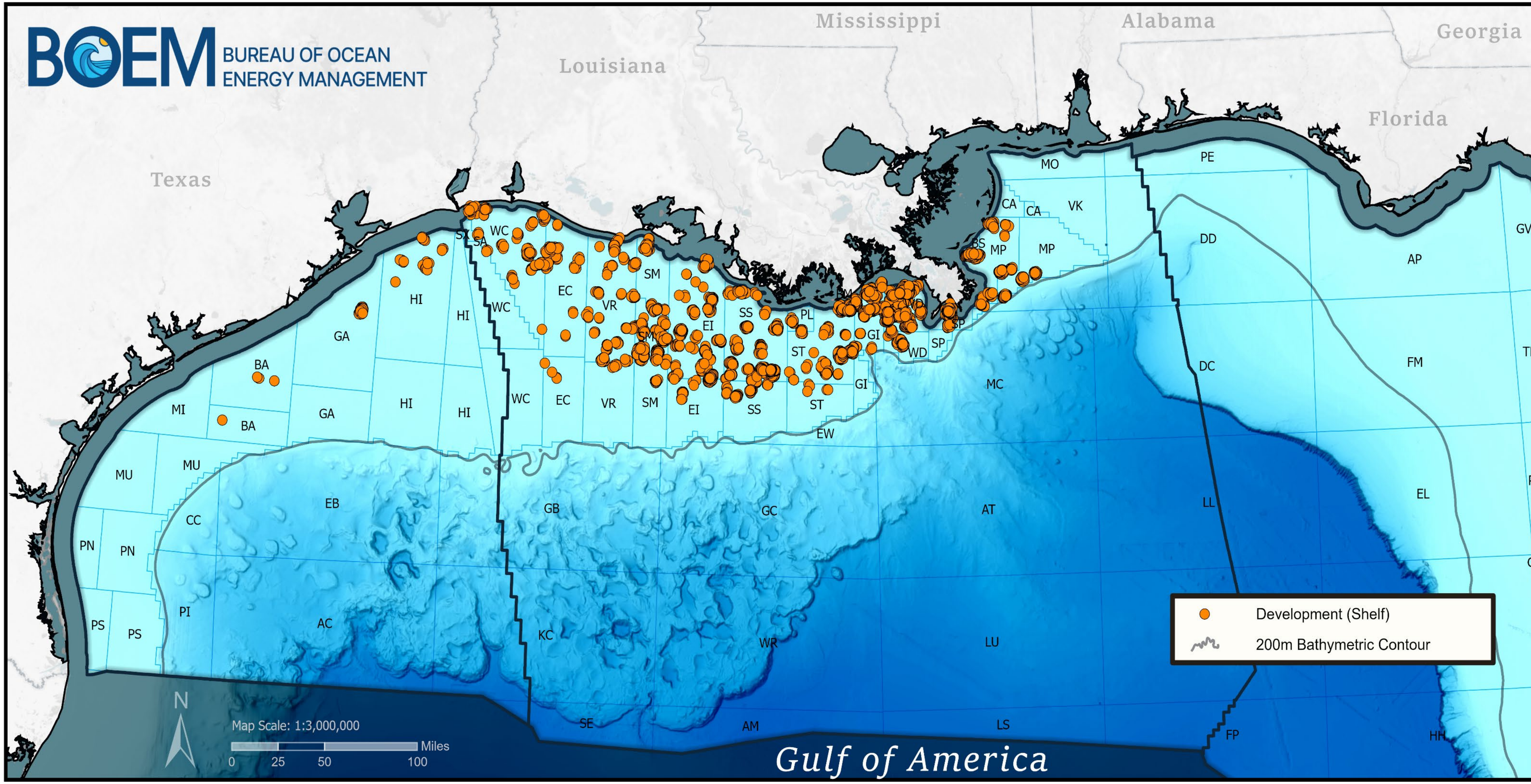

Figure 30. Development Wells Drilled Over Time, 1960s

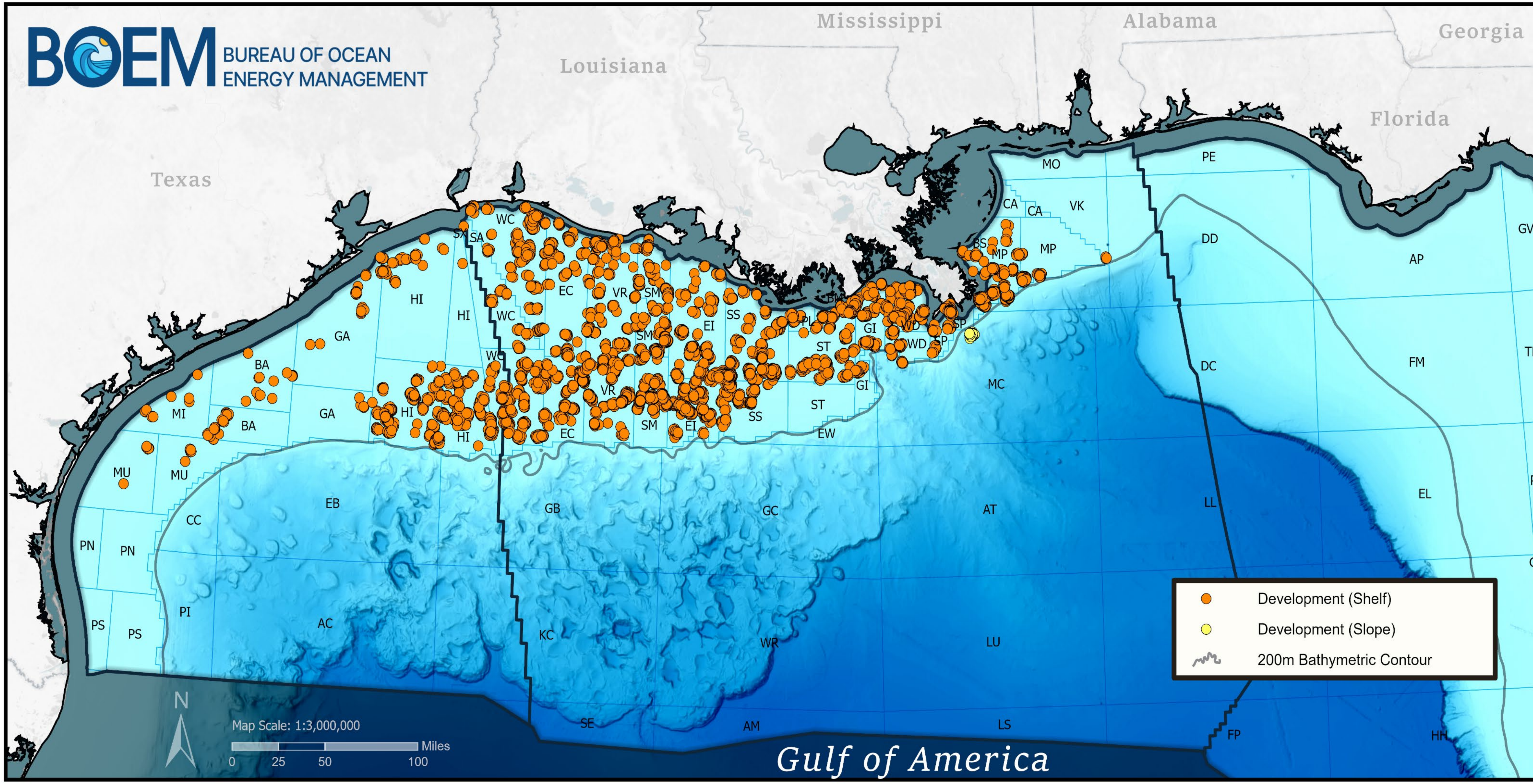

Figure 31. Development Wells Drilled Over Time, 1970s

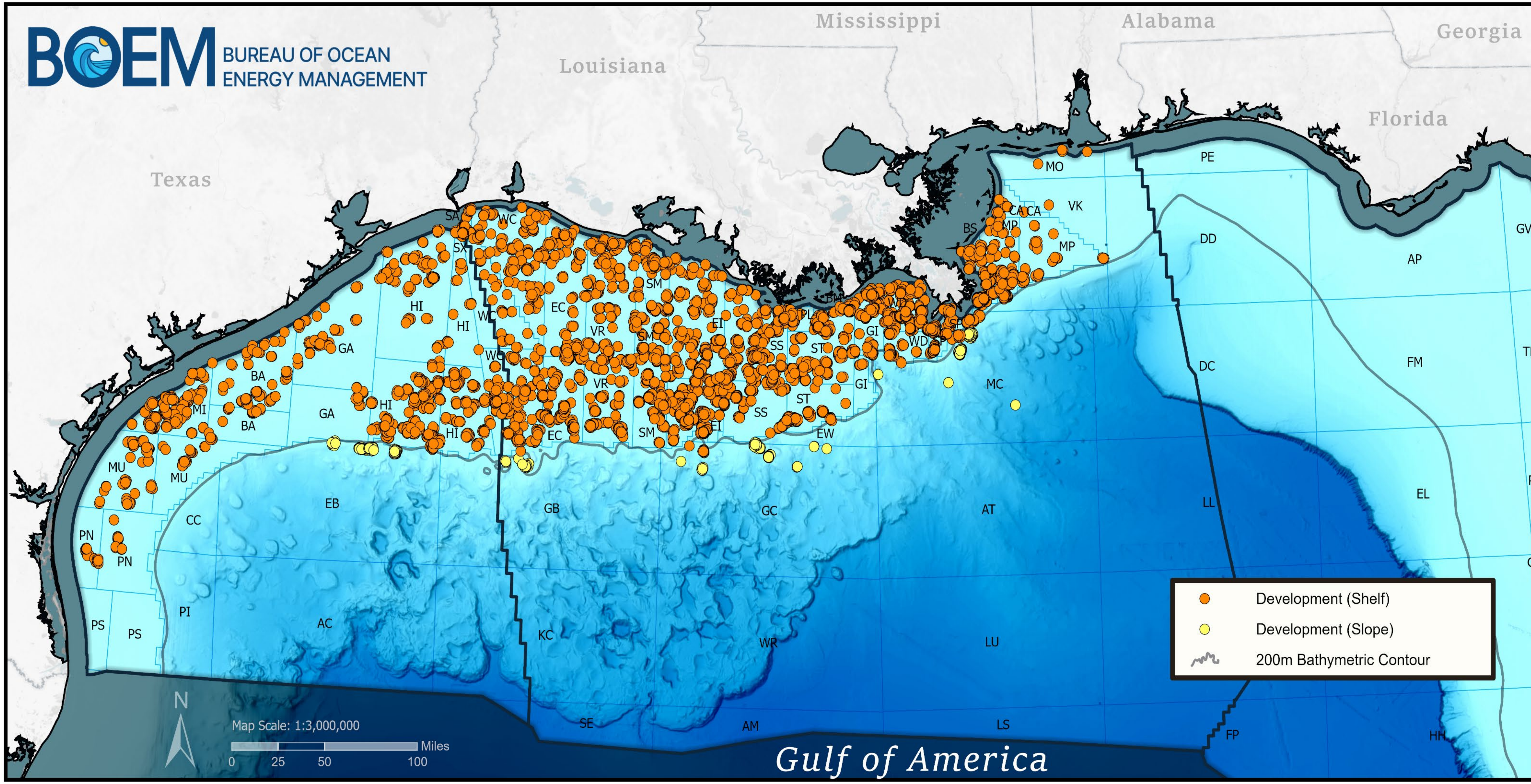

Figure 32. Development Wells Drilled Over Time, 1980s

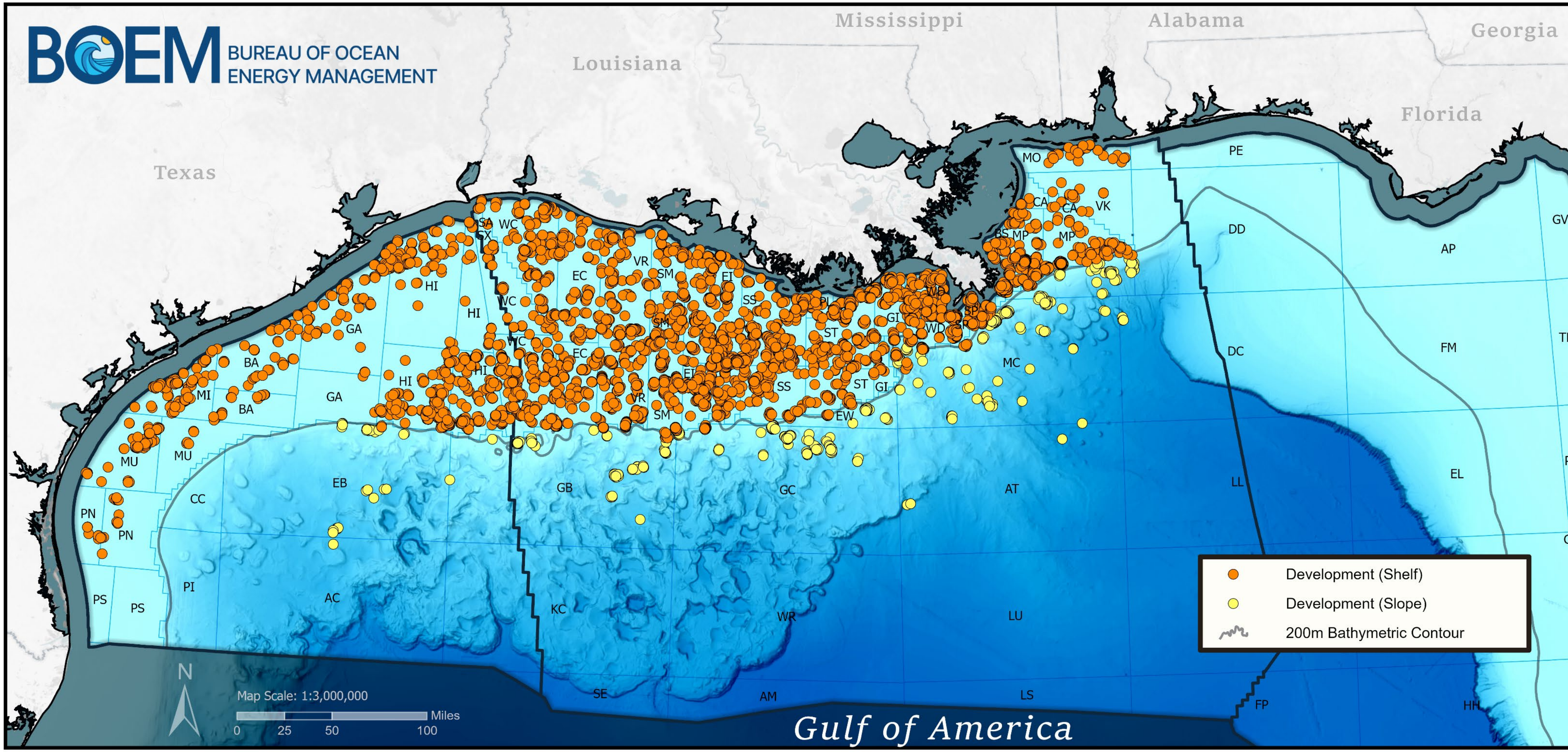

Figure 33. Development Wells Drilled Over Time, 1990s

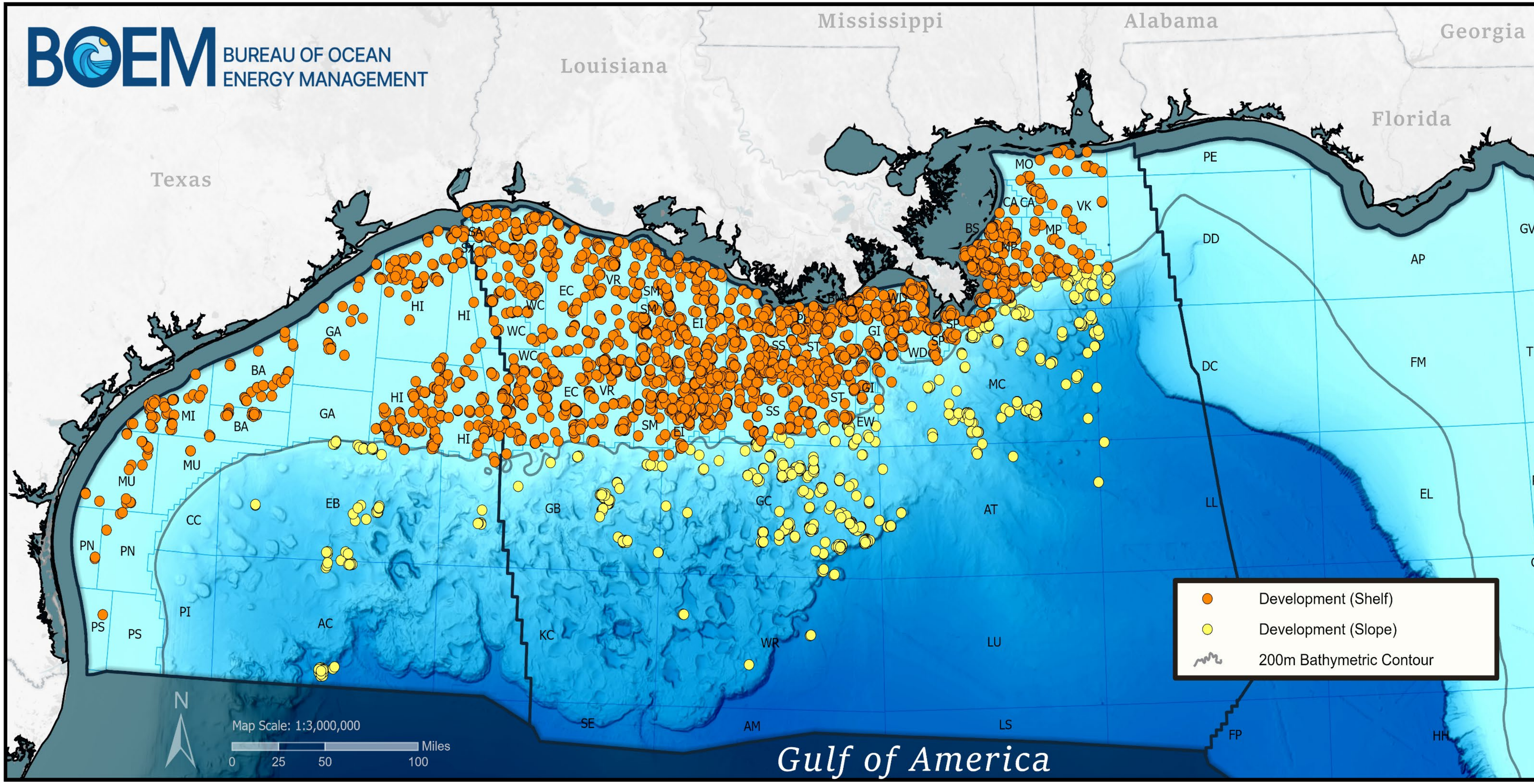

Figure 34. Development Wells Drilled Over Time, 2000s

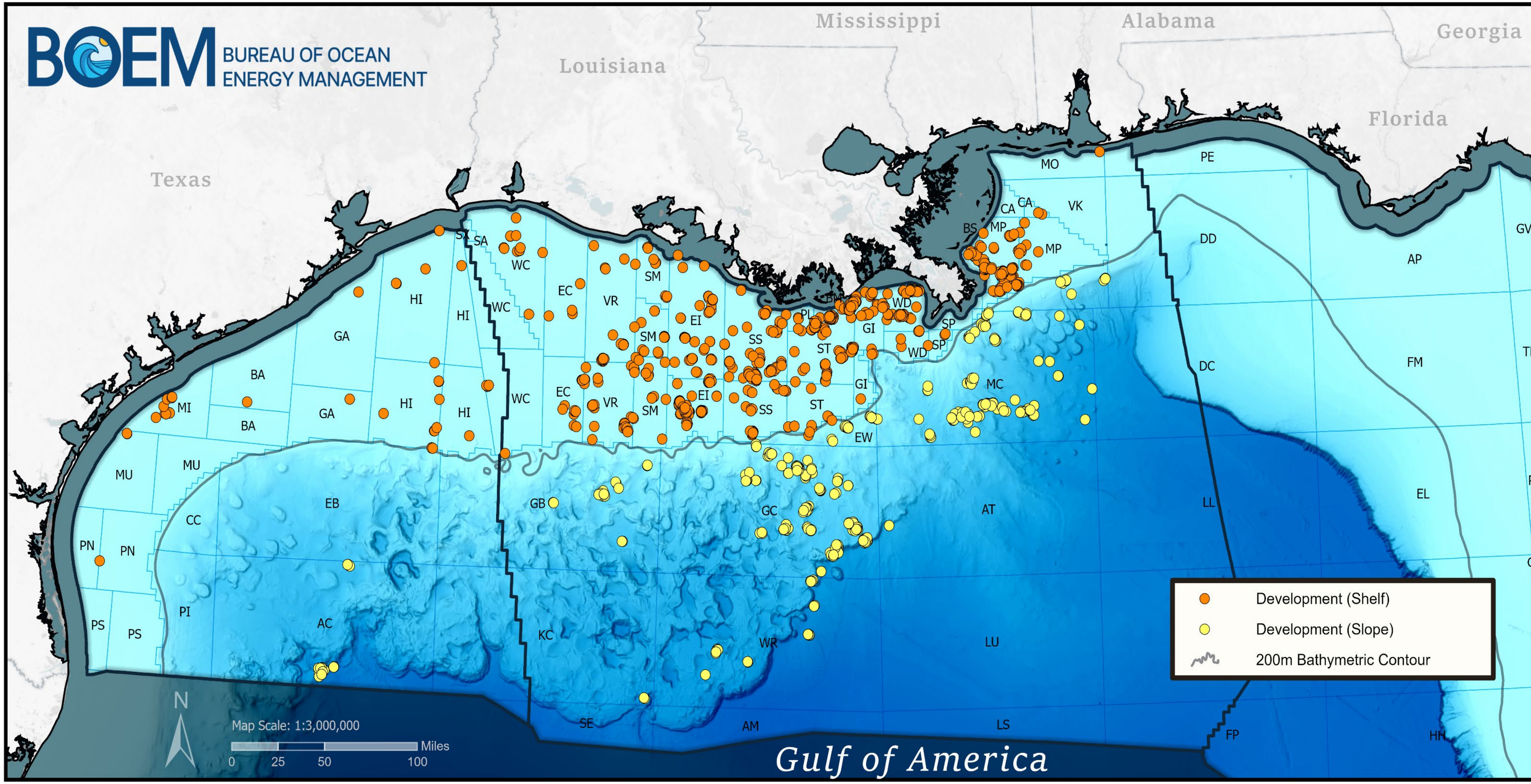

Figure 35. Development Wells Drilled Over Time, 2010s

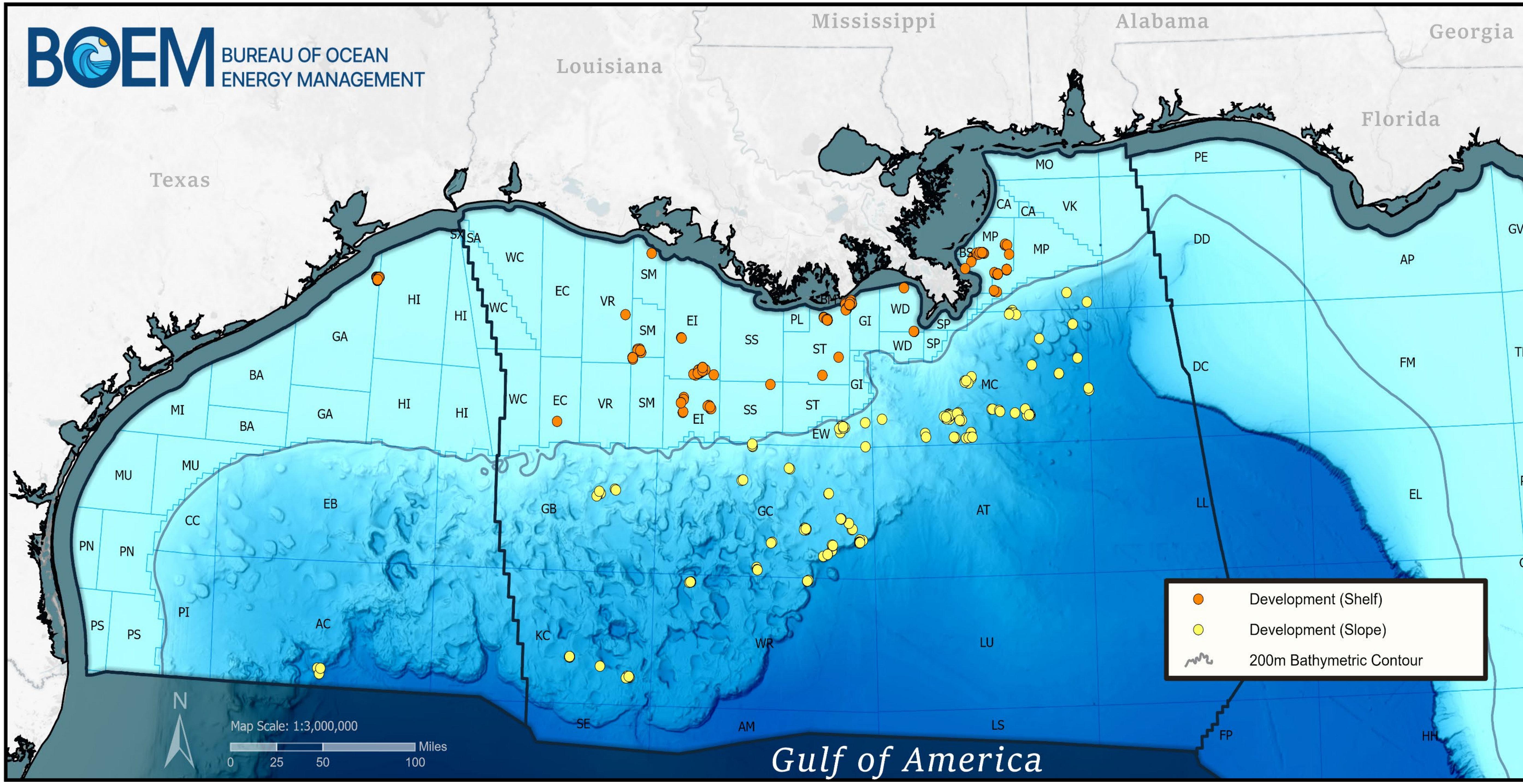

Figure 36. Development Wells Drilled Over Time, 2020s

8.0 ORIGINAL RESERVES BY WATER DEPTH OVER TIME

Figure 37 presents annual discoveries of Original Reserves in BBOE on the GOA shelf and slope over multiple decades. Discovery years shown correspond to the year in which a reservoir was first discovered, rather than the year in which reserves were formally recognized or booked. This highlights a distinct spatial shift in exploration and discovery activity. In earlier years, most discoveries were concentrated on the shelf, reflecting the initial focus of offshore development. However, over time, the data clearly shows a migration of exploration efforts toward the deeper waters of the GOA slope. This trend underscores the industry's response to maturing shelf plays, advancements in deepwater technology, and the pursuit of untapped hydrocarbon potential in more geologically complex and technically challenging environments on the slope.

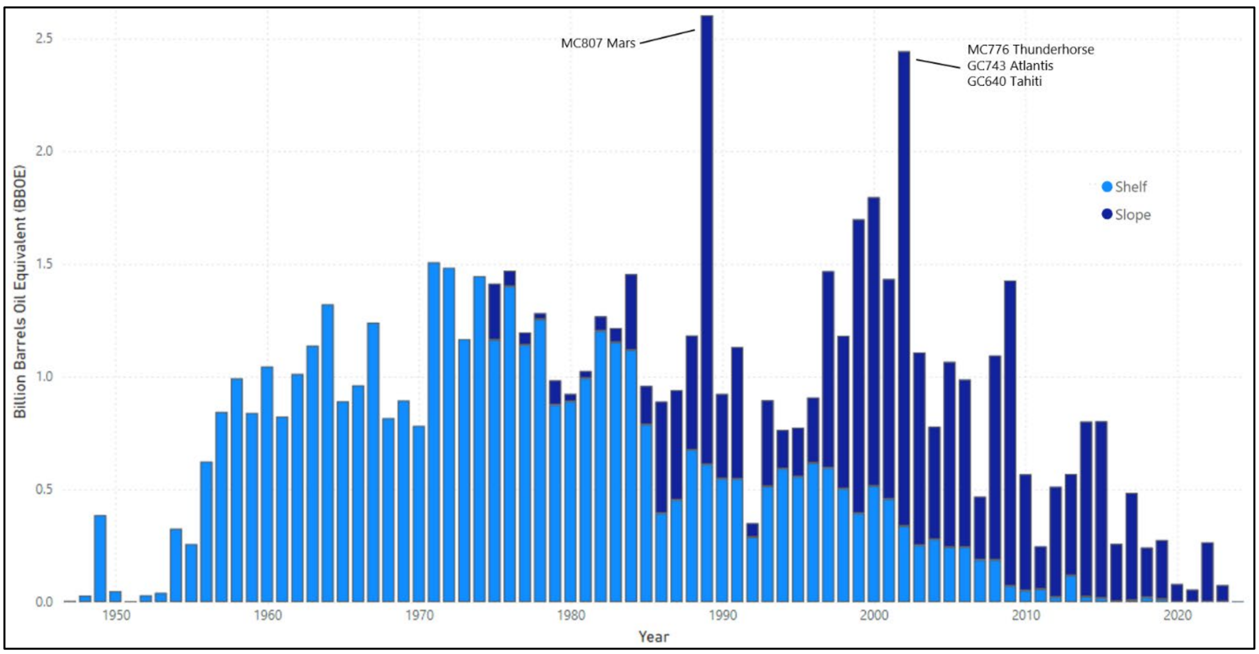

Figure 37. Original Reserves Discovered by Year on the Shelf vs Slope

9.0 ANNUAL OIL AND GAS PRODUCTION

Annual production in the GOA is shown on Figure 38 through Figure 40. The oil plot includes condensate, and the gas plot includes casinghead gas. From a peak of 693 million barrels (MMbbl) in 2019, annual oil production showed an overall decrease of 5% to 656 MMbbl in 2024. Annual gas production has experienced an overall decrease following its peak in 1997. In 2024, gas production amounted to 0.68 Tcf. The mean daily production during 2024 was 1.76 MMbbl of crude oil, 0.03 MMbbl of gas condensate, 1.63 billion cubic feet (Bcf) of casinghead gas, and 0.24 Bcf of gas-well gas. The mean GOR of oil wells was 923 scf/stb, and the mean yield from gas wells was 133 bbl of condensate per MMcf of gas. These figures further illustrate a shift in oil and gas activity toward the deeper waters of the GOA slope, with slope oil production overtaking shelf production in 1999, and slope gas production surpassing shelf gas production in 2014†.

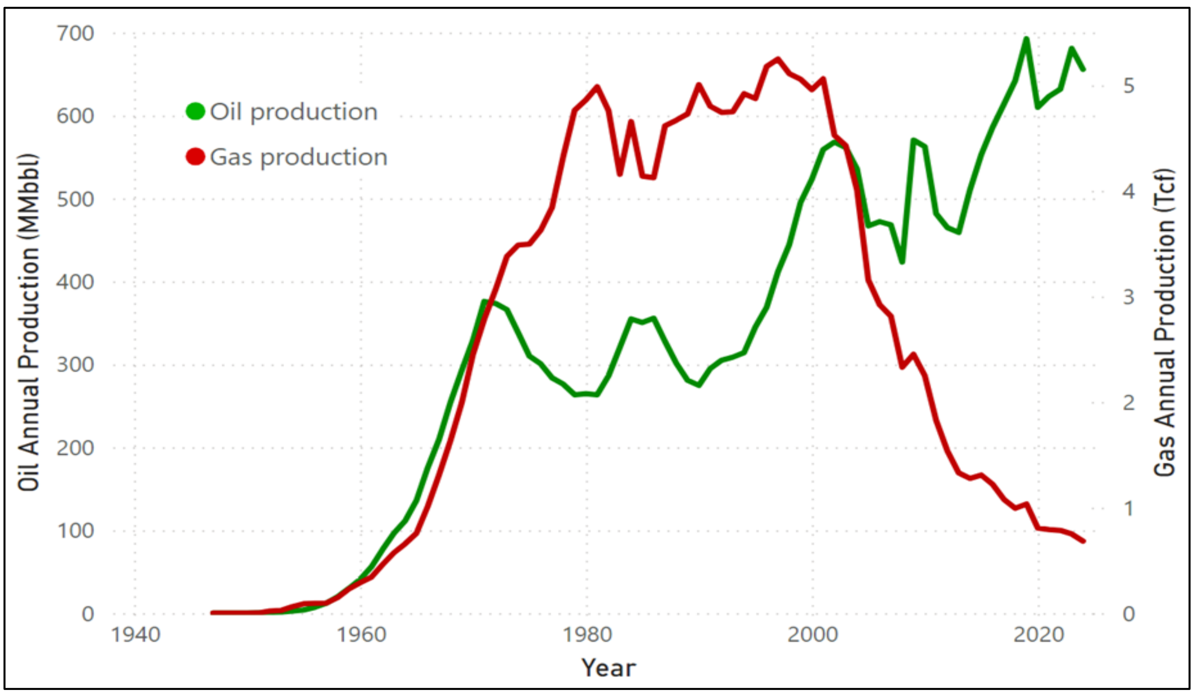

Figure 38. Annual Oil and Gas Production in the GOA

† In the 2025 EOGR Report, slope oil production was reported as overtaking shelf production in 2000; the correct year is 1999.

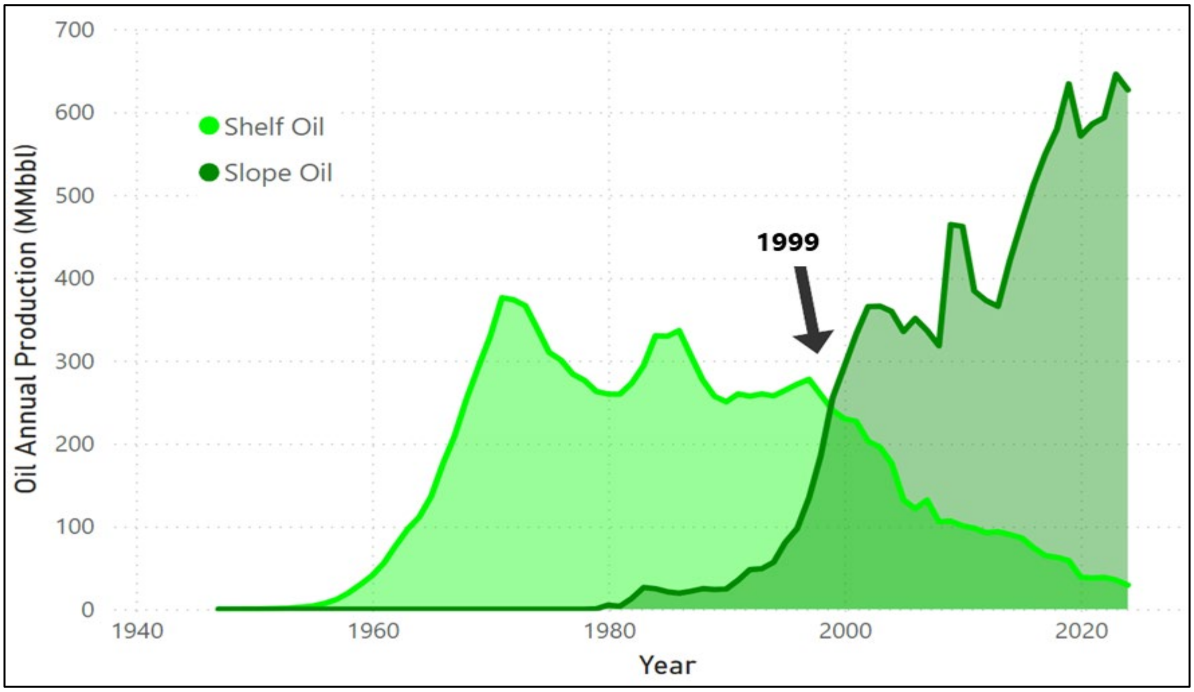

Figure 39. Shelf versus Slope Oil Production Over Time (denoted on the chart is the shelf/slope intersect)

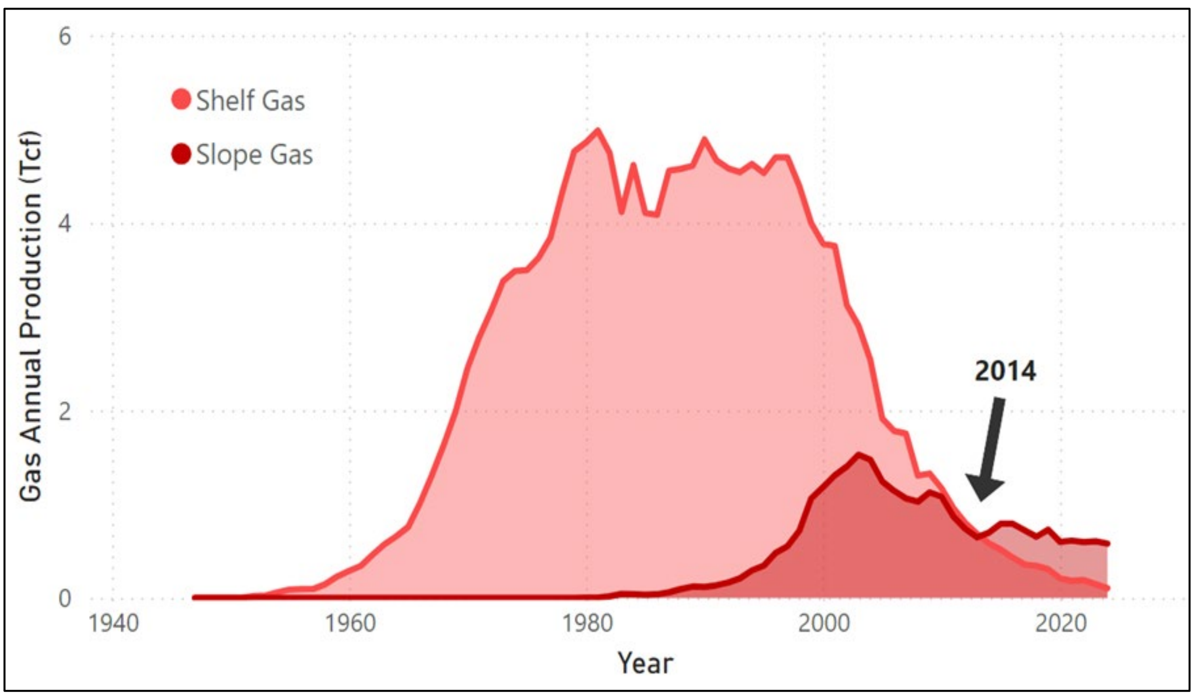

Figure 40. Shelf versus Slope Gas Production Over Time (denoted on the chart is the shelf/slope intersect)

10.0 DEVELOPMENT BY ASSESSMENT UNIT

This section provides graphical representations of reservoir and production data for 11 Cenozoic and 2 Mesozoic assessment units. Assessment units consist of groups of geologically related hydrocarbon accumulations, with the term "Assessment Unit" referring to classifications based on chronozones and/or geological plays. The mean reserves volume from each reservoir within an assessment unit or play were aggregated to create graphs that illustrate the total volume discovered each year (2024 reserves are represented by total mean reserves) and the production from these reservoirs.

Assessment units are delineated based on water depth distinctions between the shelf and slope (Figure 36), as well as the geological age of Cenozoic sediments within the GOA OCS. Using these criteria, the Cenozoic section is subdivided into 12 assessment units, as detailed in Table 6. However, only 11 of these units are accompanied by figures, since the Lower Tertiary Shelf unit lacks reserves or production data. As of the 2018 EOGR Report, there was a re-alignment of the Pleistocene and Pliocene assessment units in correspondence with the BOEM's current biostratigraphic chart of the GOA offshore region, Jurassic to Quaternary (Whitrock, 2017).

Table 6. Twelve Cenozoic Assessment Units

Shelf Assessment Units	Slope Assessment Units
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

In contrast to the aggregated assessment units of Cenozoic sediments, the Mesozoic sediments of the GOA OCS are classified by specific rock units or plays. This report specifically highlights two Mesozoic plays: the James Play and the Norphlet Play. These plays are included due to their associated reserves and production.

The data presented in this section reveals the lag time between reserves discovery and production and highlights the shift in exploration and development from shelf to slope areas. While shelf Cenozoic data shows a significant annual production decline, the development of discoveries in slope Cenozoic sediments has helped to mitigate these declines. Reserves and annual production data for the two assessment units within Mesozoic-aged sediments indicate the James play has matured with few additional opportunities anticipated. The Norphlet Play, however, has future opportunities. The expected range of undiscovered resources are described in the report titled “2026 National Assessment of Undiscovered Oil and Gas Resources of the U.S. Outer Continental Shelf: OCS Report BOEM 2026-012.”

Pleistocene

Figure 41 and Figure 42 show the decline in volume of reserves discovered and production for the shelf and slope Pleistocene assessment units. The largest total Pleistocene shelf reserves discovered in a single year occurred in 1971, which included 2 large shelf reservoirs, one in the Eugene Island 296 Field and two in the Eugene Island 330 Field, containing 203 million barrels of oil equivalent (MMBOE). All three reservoirs are now depleted. The volume of Pleistocene reserves on the slope reached its peak in 1997, driven by discoveries in the Troika (Green Canyon 244) and Hoover (Alaminos Canyon 25) fields. Production on the slope reached its peak in 2001 and has since experienced a sustained decline, a trend that the data indicates is attributable to a significant reduction in newly discovered slope reserves.

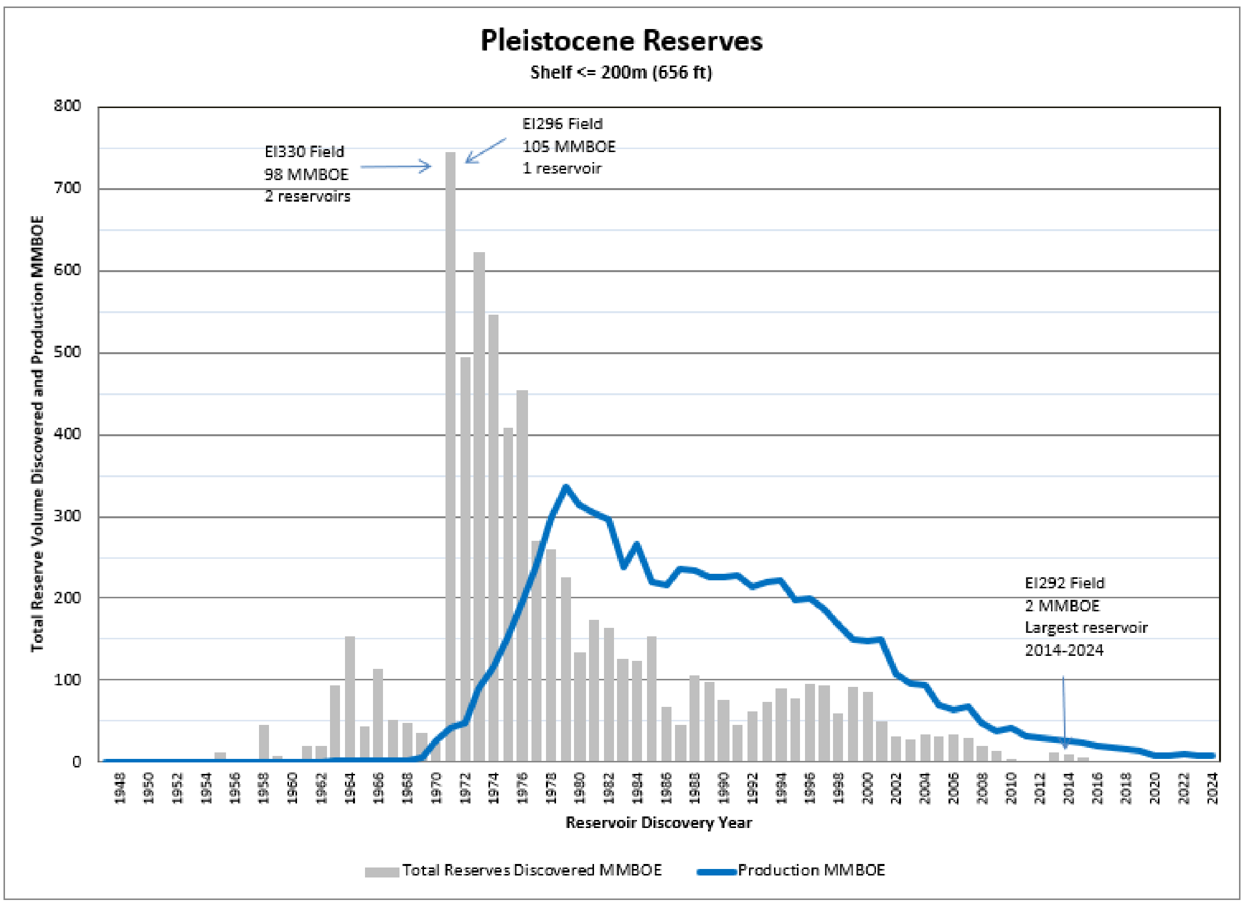

Figure 41. Pleistocene Shelf Development

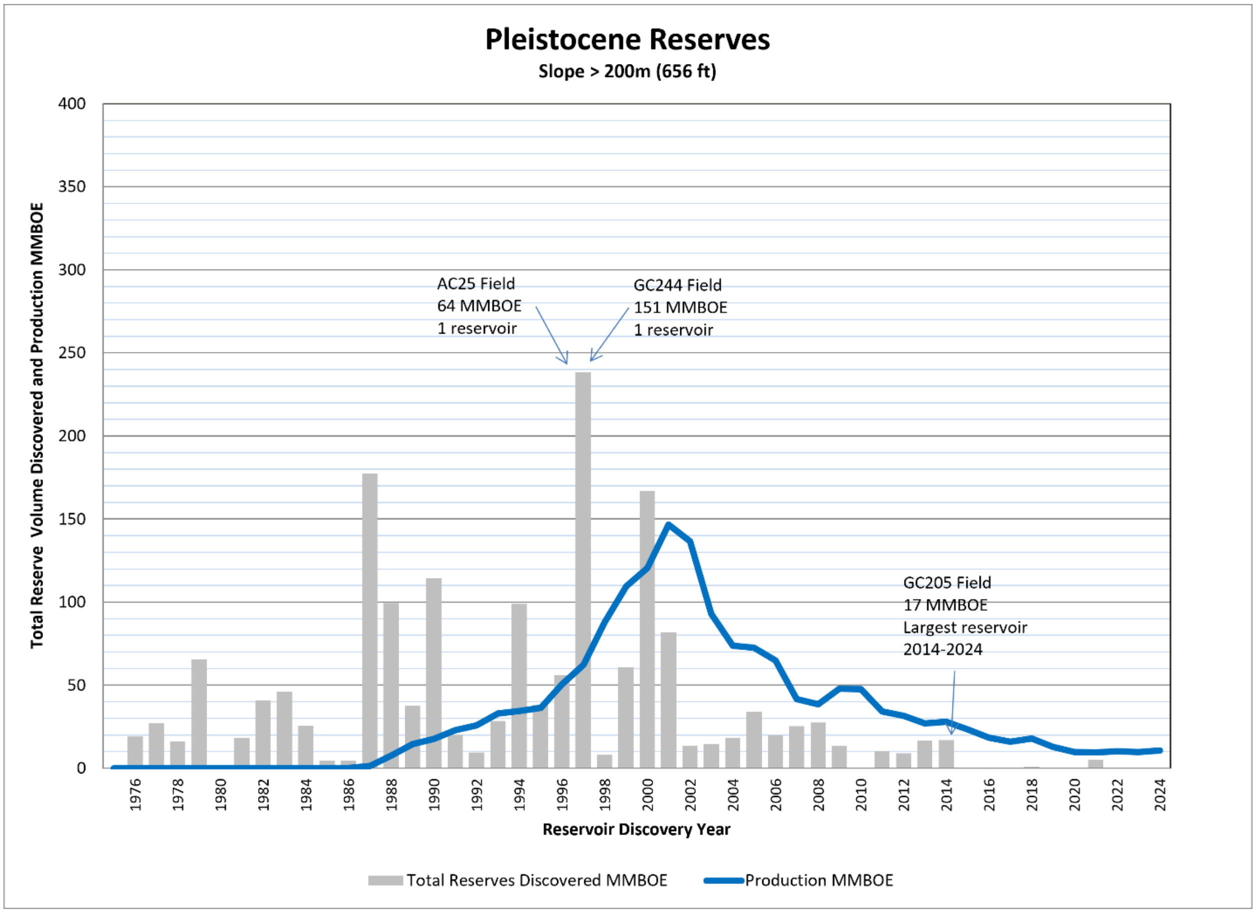

Figure 42. Pleistocene Slope Development

Pliocene

Discovered reserves and production on the Pliocene shelf have steadily decreased from 1997 through 2024. The largest annual discovery of total Pliocene shelf reserves occurred in 1972, highlighted by discoveries in the East Cameron 334 Field and the Eugene Island 330 Field, collectively amounting to 225 million barrels of oil equivalent (MMBOE). Pliocene reserves on the slope peaked in 1991 with a significant discovery in the Lobster (Ewing Bank 873) Field, followed by another major discovery in 1999 at the Holstein (Green Canyon 644) Field. The Lucius (Keathley Canyon 875) Field subsequently yielded another significant discovery in the following years. Pliocene annual production rates on the slope have consistently exceeded those on the shelf (Figure 43), with slope production ranging from 66 to 125 MMBOE over the past decade (Figure 44).

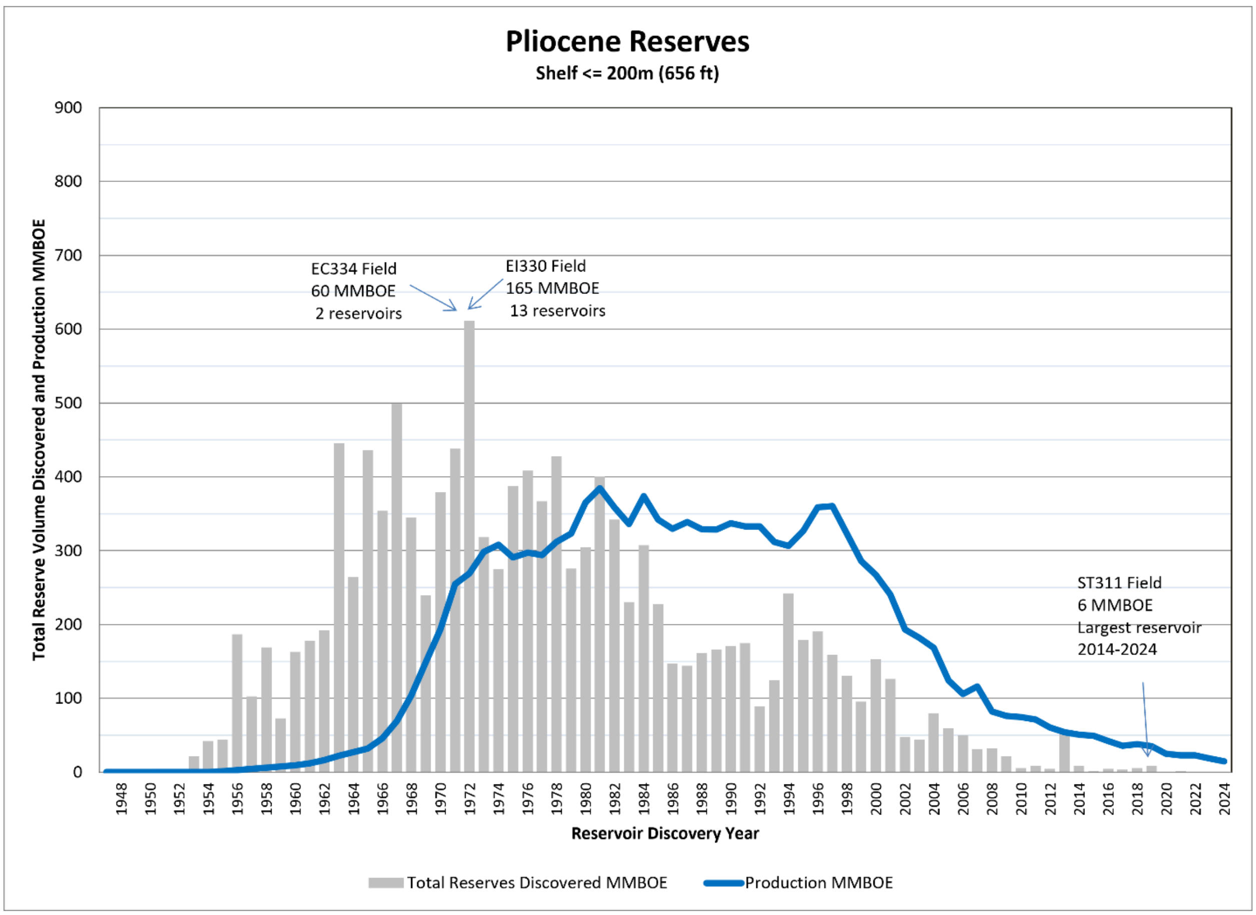

Figure 43. Pliocene Shelf Development

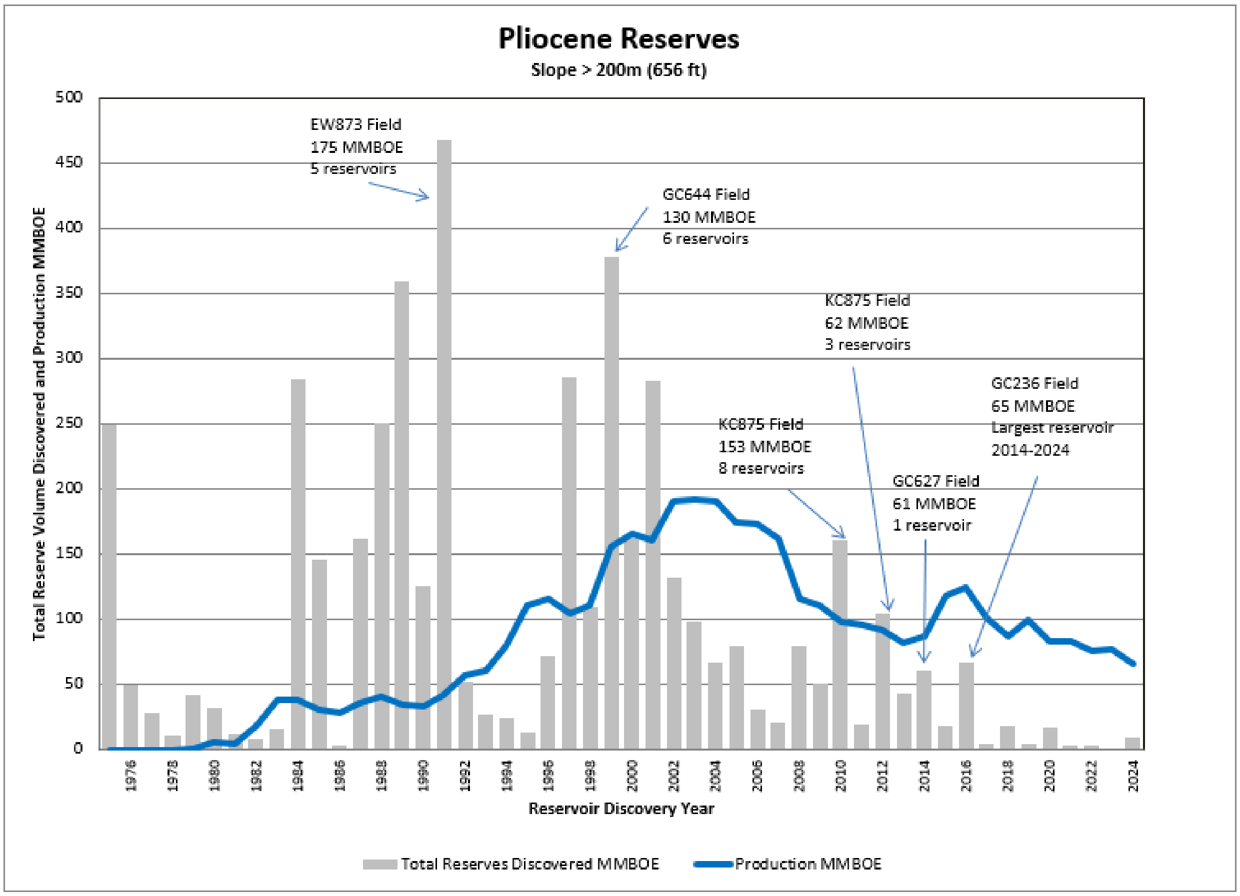

Figure 44. Pliocene Slope Development

Upper Miocene

Since 1998, production from the Upper Miocene shelf has experienced a decline (Figure 45). Reserves discovered on the Upper Miocene slope reached their highest point in 1989, following significant discoveries at the Mars (Mississippi Canyon 807) and Pompano (Viosca Knoll 990) Fields (Figure 46). Later discoveries at the Kaikias (Mississippi Canyon 768) Field in 2014 and 2015 contributed to an increase in overall discovered reserves. Annual production rates from the Upper Miocene slope have remained stable since 2015.

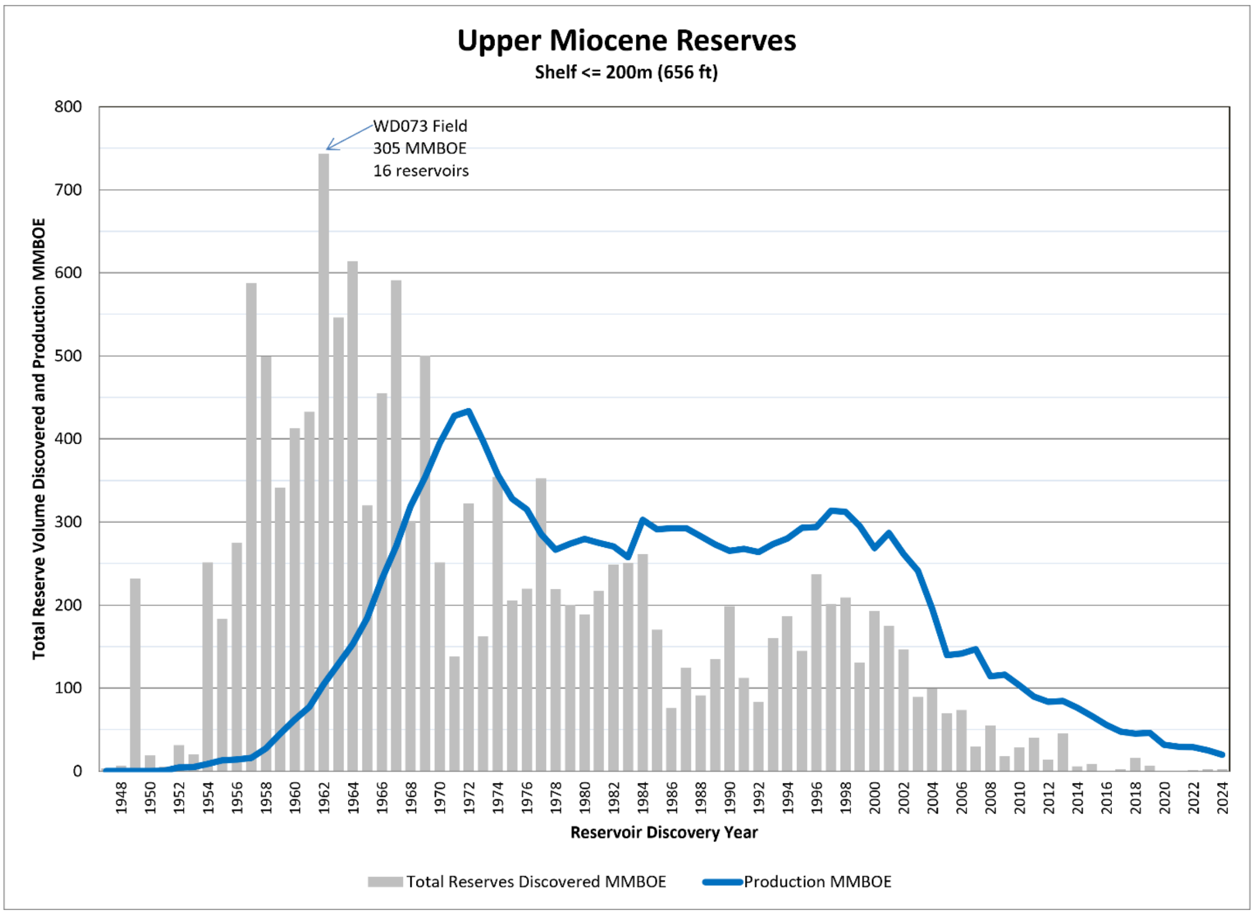

Figure 45. Upper Miocene Shelf Development

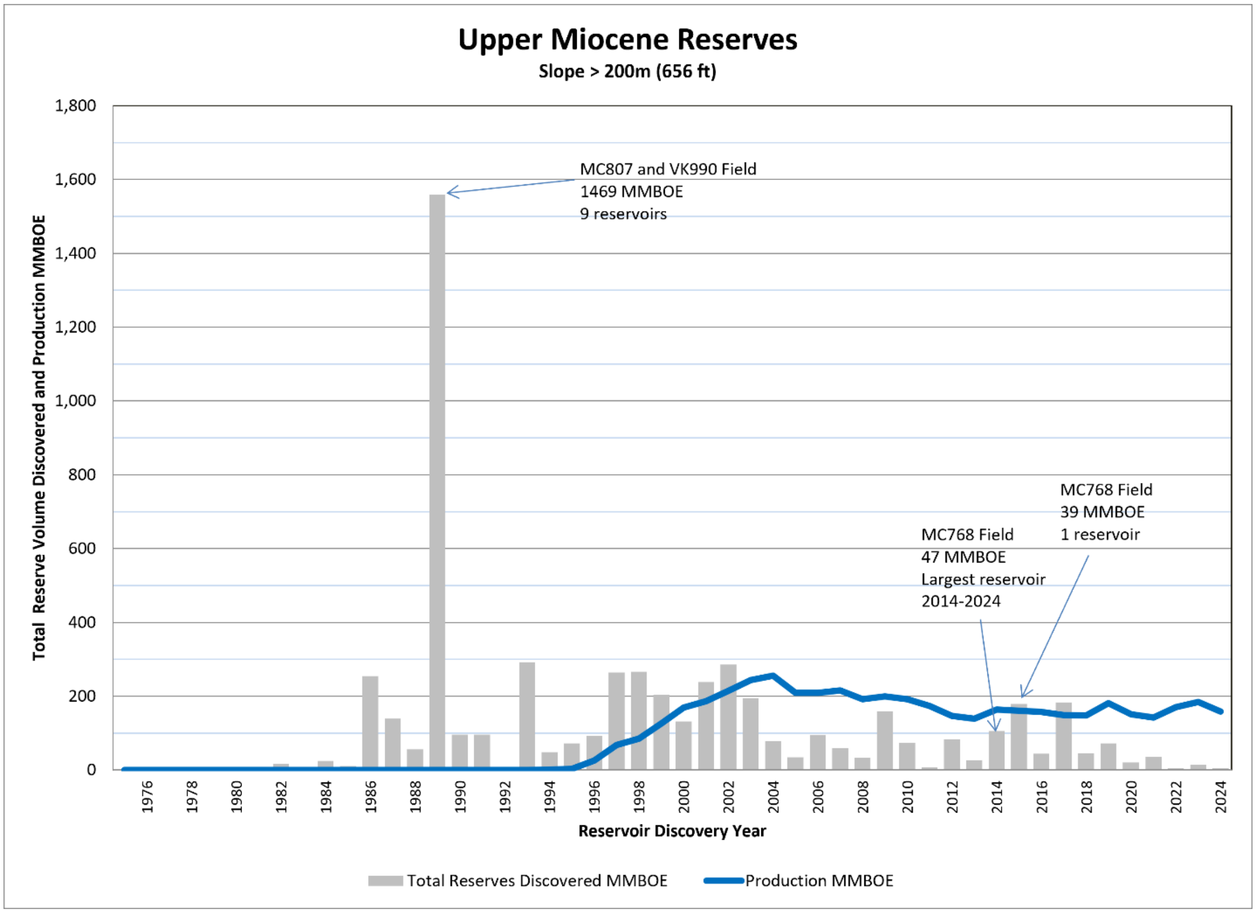

Figure 46. Upper Miocene Slope Development

Middle Miocene

The total reserves discovered on the Middle Miocene shelf remained consistently low over the last decade (Figure 47). The Middle Miocene slope is highlighted by discoveries in the Thunder Horse North (Mississippi Canyon 776) Field, the Atlantis (Green Canyon 743) Field, and the Tahiti (Green Canyon 640) Field. The Middle Miocene slope has experienced an overall rise in production over the last decade (Figure 48).

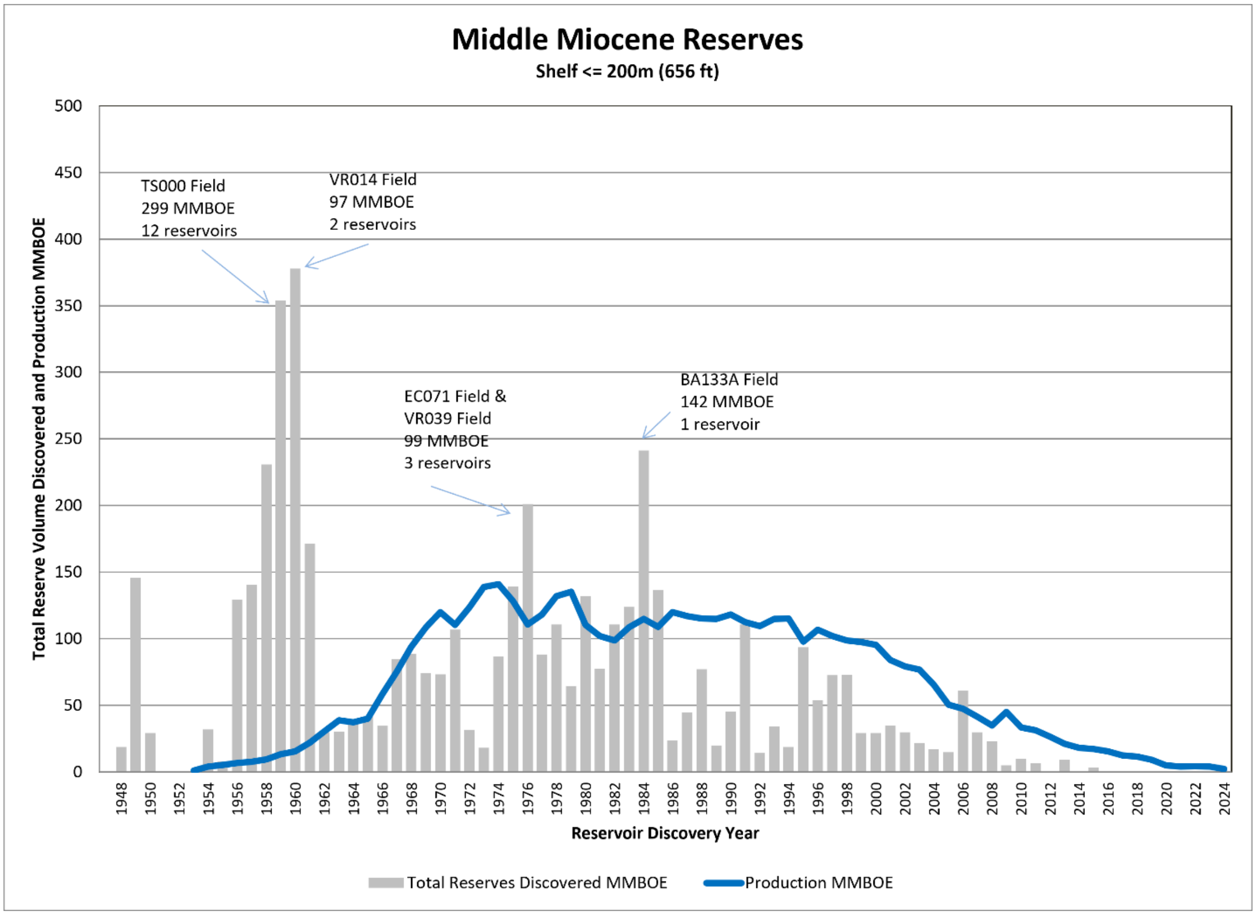

Figure 47. Middle Miocene Shelf Development

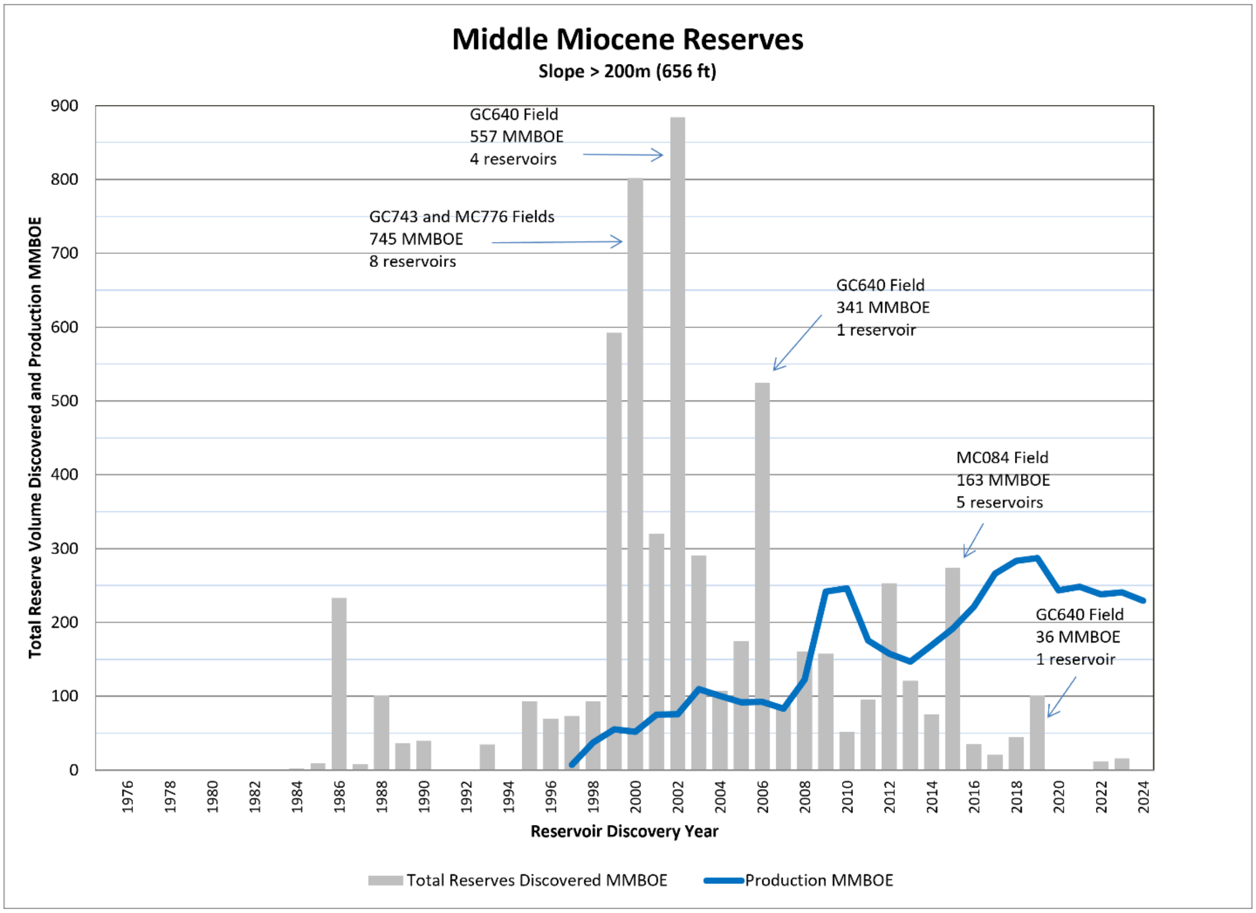

Figure 48. Middle Miocene Slope Development

Lower Miocene

Reserves discovered on the Lower Miocene shelf peaked in 1982 (Figure 49), with a peak in production occurring in 1990, followed by an overall decline to date. The first discoveries on the Lower Miocene slope occurred in the Neptune (Atwater Valley 575) Field and Mad Dog (Green Canyon 826) Field. A major discovery of 386 MMBOE was later made in the Shenzi (Green Canyon 654) Field, followed by the discovery of 361 MMBOE in the Vito (Mississippi Canyon 940) Field in 2009 (Figure 50). Lower Miocene slope production reached its highest point in 2009 and remained relatively stable until 2022, when it surged past the previous peak as the Vito, Shenzi, and Mad Dog phase 2 projects increased production.

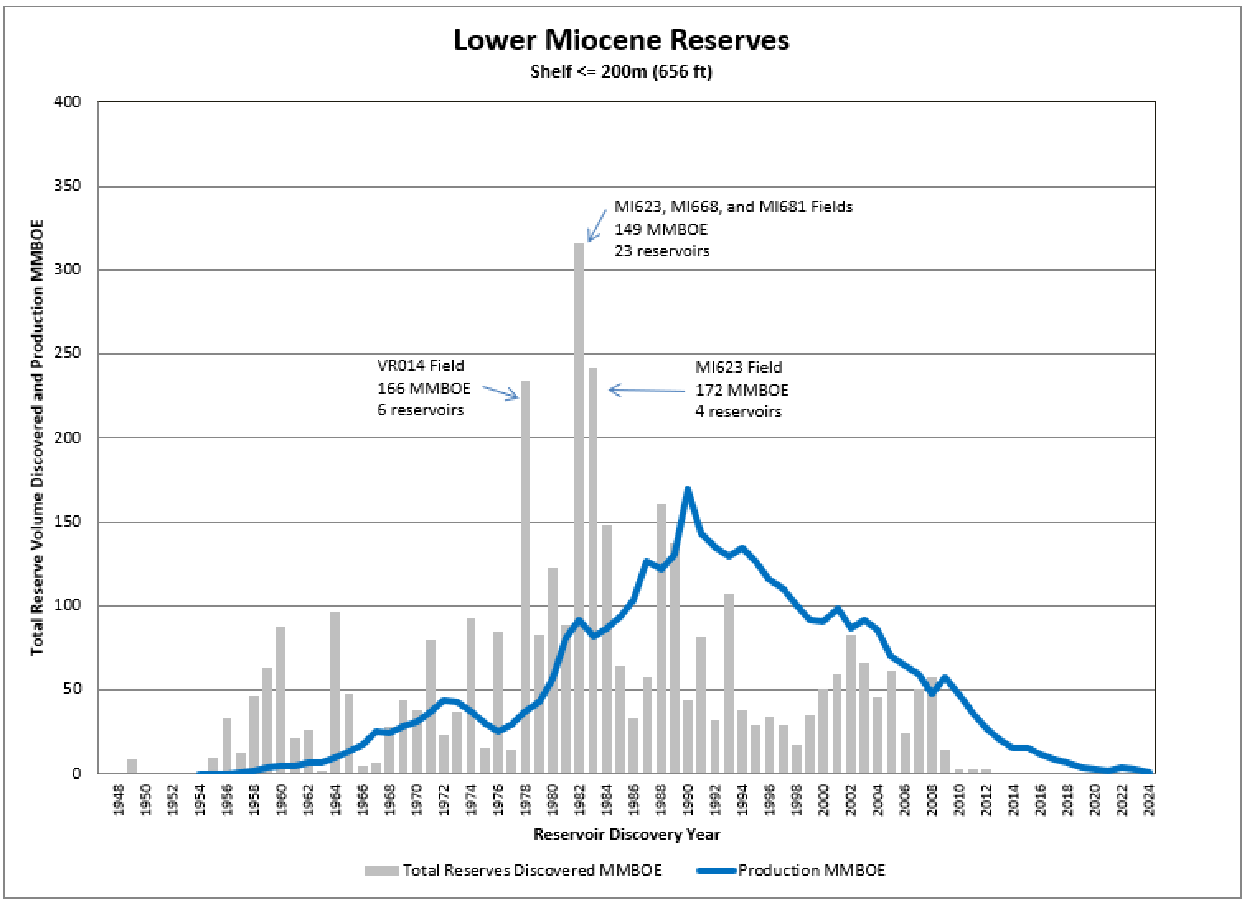

Figure 49. Lower Miocene Shelf Development

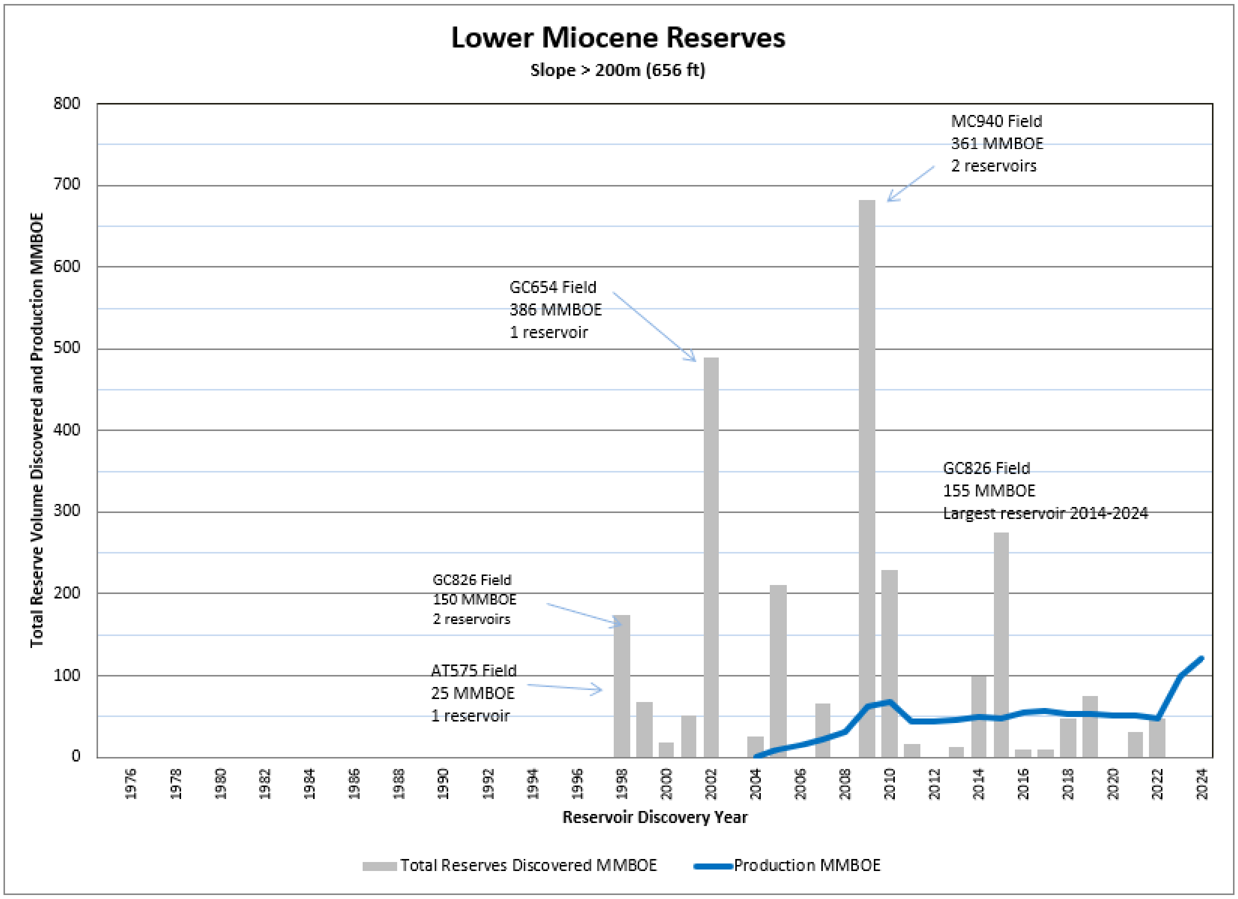

Figure 50. Lower Miocene Slope Development

Lower Tertiary

The Lower Tertiary play (Figure 51) was first confirmed in 1996 at the Baha prospect in Alaminos Canyon Block 600, proving a new exploration play in the deepwater. In 2002, a reservoir containing over 165 MMBOE was discovered in the Great White (Alaminos Canyon 857) Field. Subsequent significant discoveries in this play included the St. Malo (Walker Ridge 678), Anchor (Green Canyon 807), and Buckskin (Keathley Canyon 872) Fields. Production commenced in 2010, experienced consistent growth until 2019, and has since remained stable to date.

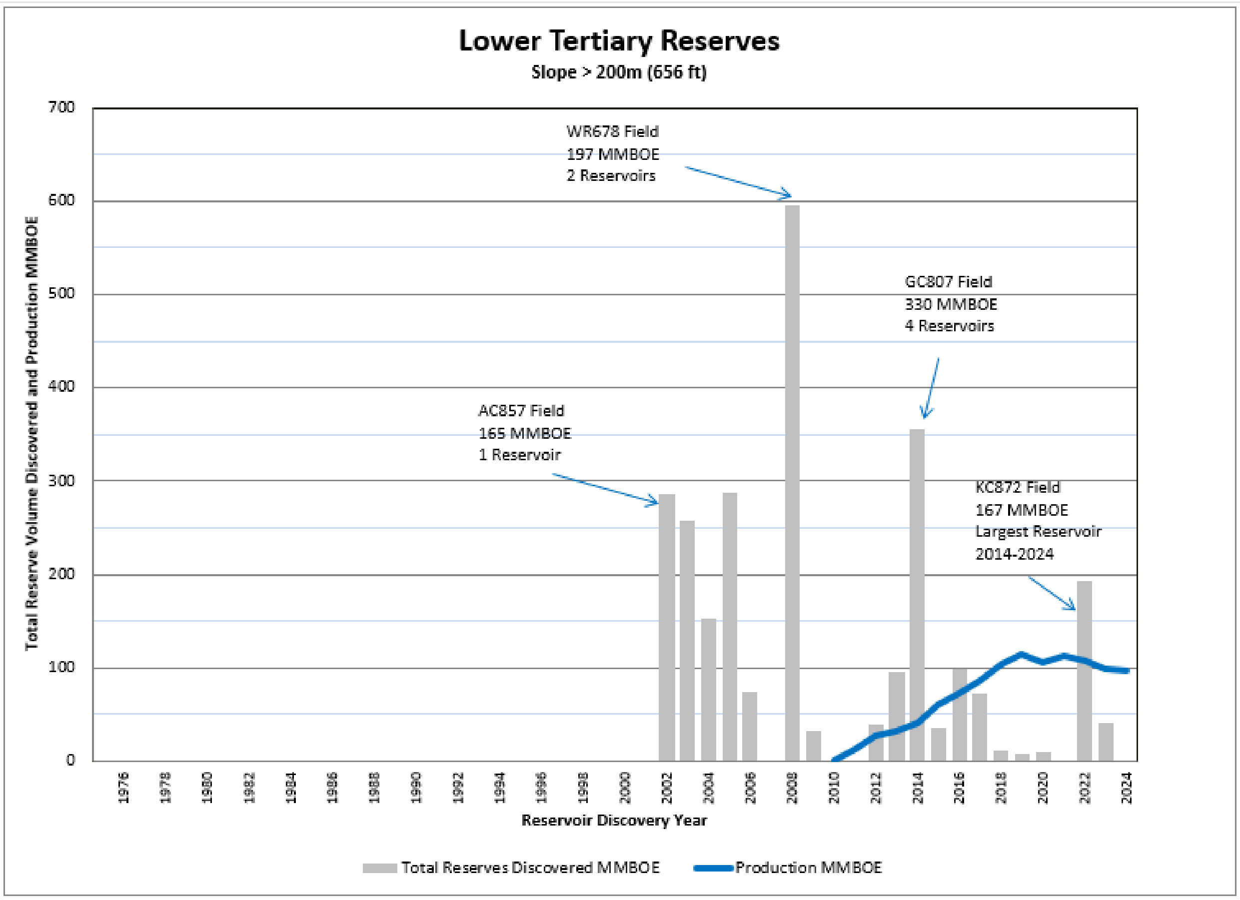

Figure 51. Lower Tertiary Slope Development

James

The initial discovery within the James play occurred in 1994. Subsequently, in 1997, five reservoirs were identified across the VK069, VK114, and VK251 fields, collectively containing 33 MMBOE, which is the largest annual reserve addition recorded in this play (Figure 52). Production reached its peak in 2002, followed by a significant and rapid decline.

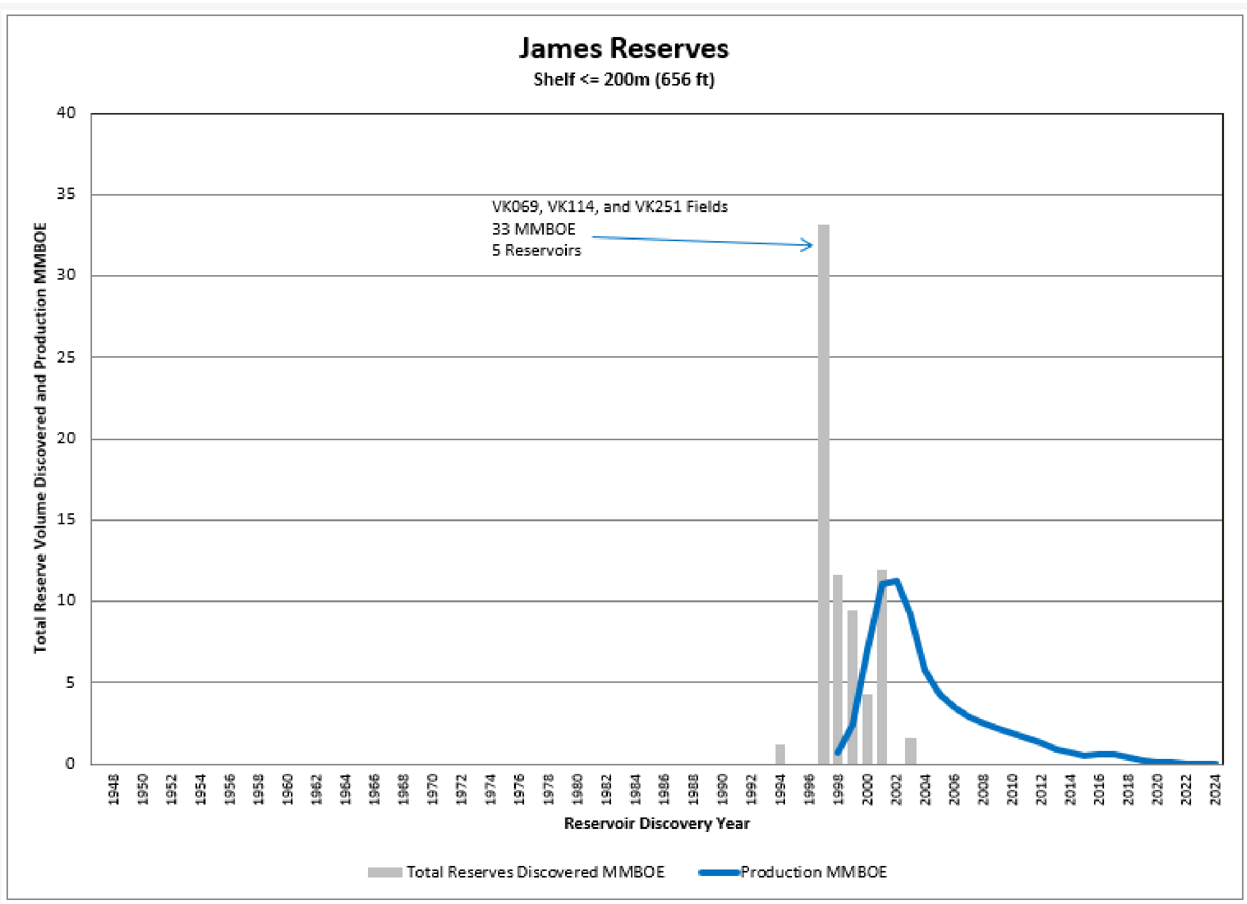

Figure 52. James Shelf Development

Norphlet

The 1983 discovery in the MO823 Field yielded the largest annual total reserves from the Norphlet shelf (Figure 53). All fields discovered on the Norphlet Shelf were gas, with production beginning in 1991 and additional discoveries continuing until 2007. Norphlet shelf production peaked in 1997 and has steadily declined since. The initial Norphlet slope discovery was made in 2003 with the Shiloh prospect in DeSoto Canyon Block 269; however, the discovery did not contain commercial quantities of oil. In 2007, a discovery was made in the Vicksburg (Mississippi Canyon 393) Field, with subsequent reserve additions in this field confirmed in 2013 through further appraisal and delineation. This was followed by a discovery in 2010 in the Appomattox (Mississippi Canyon 392) Field, which holds the largest total discovered reserves in the play. Appomattox was also the first field to start producing on the Norphlet slope, beginning in 2019. Overall production on the Norphlet slope rose sharply until 2022, experienced a minor dip through 2023, then rebounded in 2024, approaching the levels seen in 2022 (Figure 54). All discoveries on the Norphlet slope are oil reservoirs, underscoring the region's significance as a major oil-producing trend.

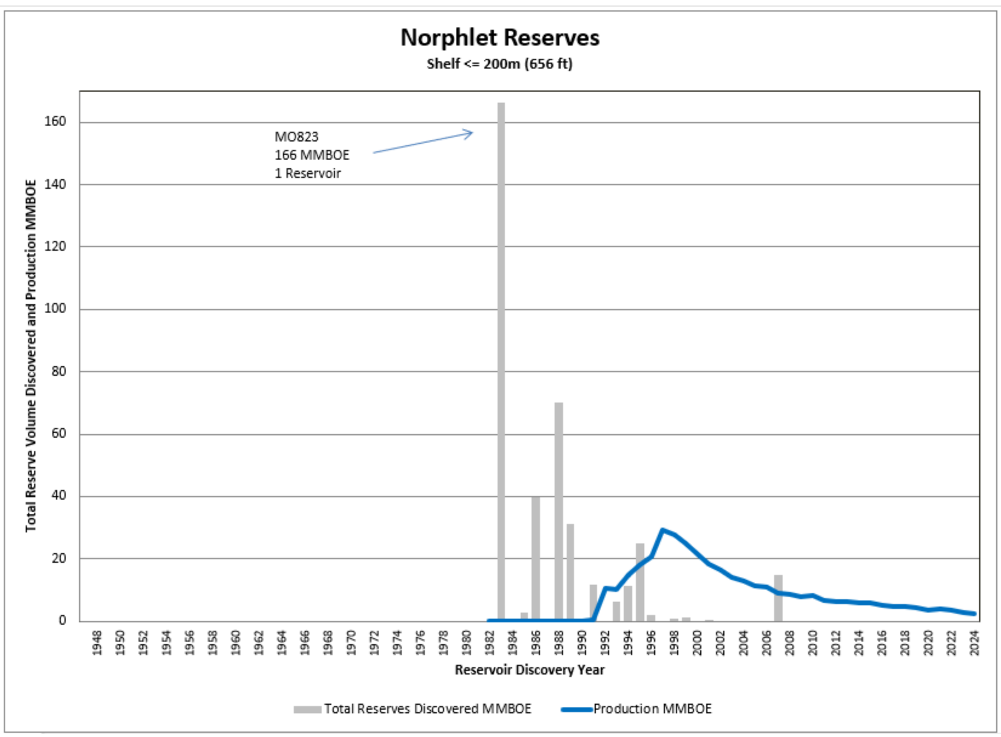

Figure 53. Norphlet Shelf Development

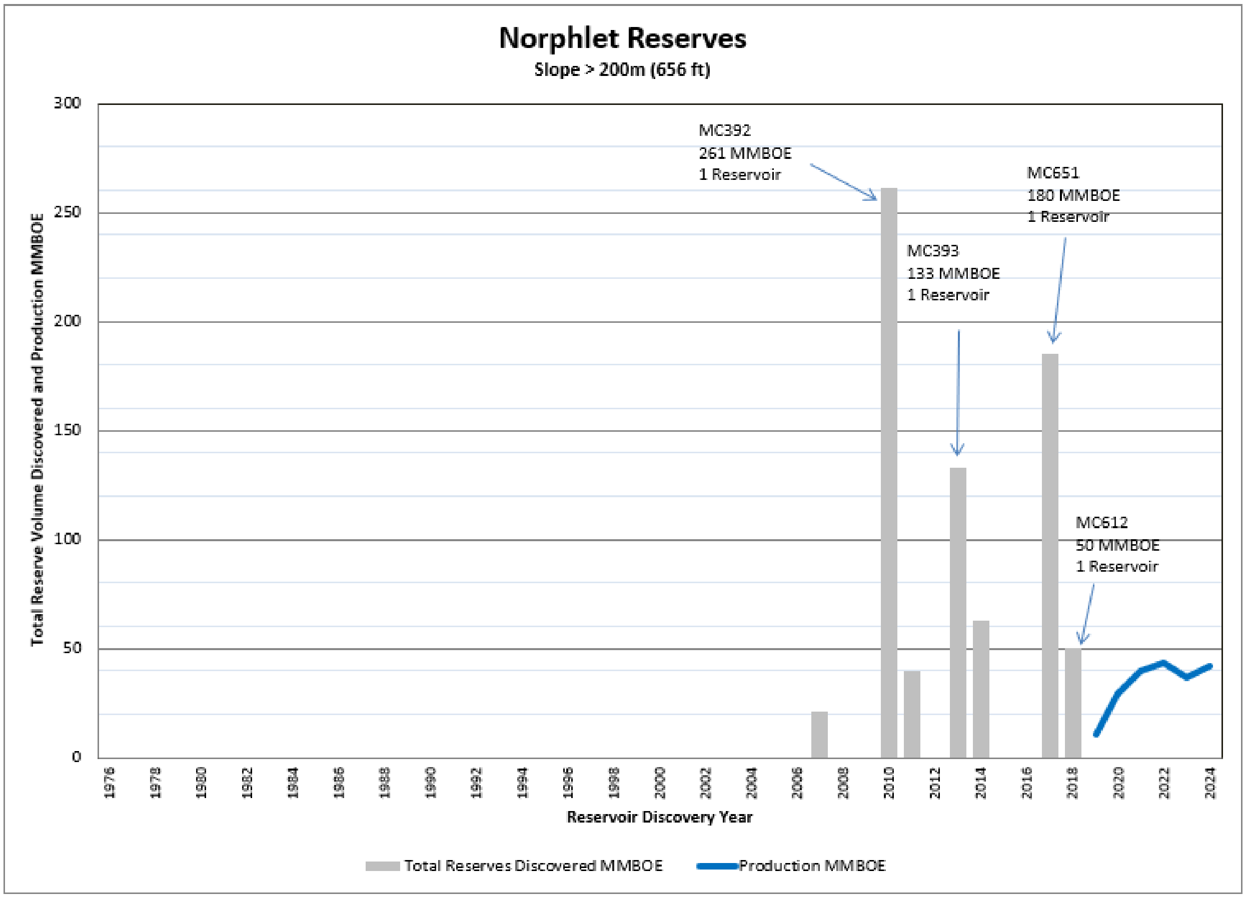

Figure 54. Norphlet Slope Development

11.0 CONTINGENT RESOURCES

Contingent Resources are defined as hydrocarbon accumulations that are estimated, as of a specified date, to be potentially recoverable from known accumulations through development projects. The Contingent Resources reported in the EOGR Report are discovered volumes with at least one well penetration but are not currently considered recoverable due to one or more contingencies. Contingent Resources in this report are limited to the GOA slope. This decision reflects the maturity and economic realities of the basin. On the GOA shelf, many Contingent Resources are relatively small, technically mature, and often uneconomic to develop under current market conditions. These resources generally lack the scale needed to justify new infrastructure or significant investment, especially in a region with extensive existing production and declining marginal returns. In contrast, the GOA slope holds larger, less developed Contingent Resources with greater upside potential. Although these projects require higher capital expenditure due to deepwater drilling and complex development scenarios, they offer a more attractive return on investment. As a result, operators are more likely to prioritize and invest in slope resources, making them more relevant for forward-looking resource planning and reporting. Total mean Contingent Resources on the GOA slope are estimated to be 2.55 BBO and 3.92 Tcf of gas, or 3.25 BBOE as of December 31, 2024. As shown in Table 7 below, 1.99 BBOE, representing 61 percent of Contingent Resources, are on leased (active) blocks, while 1.26 BBOE, or 39 percent, are found in unleased blocks as of December 31, 2024. Table 7 provides a detailed breakdown of Contingent Resources on the GOA slope.

Table 7. GOA Mean Contingent Resources (>200 meters or 656 feet)

Contingent Resources in the Deepwater Gulf of America (>200 meters or 656 feet)			
Contingent Resources	Oil (Bbbl)	Gas (Tcf)	BOE (BBOE)
Contingent Resources on Active Leases	1.66	1.88	1.99
Contingent Resources on Unleased Blocks	0.89	2.04	1.26
Total Contingent Resources Deepwater GOA	**2.55**	**3.92**	**3.25**

BOEM may classify a reservoir as a Contingent Resource either upon discovery on an active lease or if all leases within the field have expired, terminated, or relinquished. The development of Contingent Resources is dependent on evaluating uncertainties related to the technical and economic aspects of projects. A clear understanding of the uncertainties that influence the viability and recovery of Contingent Resources, particularly geological uncertainties and technological limitations, is vital for determining commercial recovery potential, as many hydrocarbon accumulations once considered unfeasible can be revisited as exploration technologies improve and knowledge of subsurface geology advances. Continuous investment in geophysical surveys and exploratory drilling is critical for assessing the commercial viability of these resources. There is significant potential for Contingent Resources to transition into Reserves if the associated uncertainties are resolved through technological advancements and evaluations.

When an operator decides to move forward with commercial development, a Development Operations Coordination Document or a Development and Production Plan is submitted. At this time, the Contingent Resource will be classified as a Reserve. Additionally, if a known hydrocarbon accumulation is on a lease that is terminated, relinquished, or expired, the accumulation is also considered a Contingent Resource.

The development of Contingent Resources presents both opportunities and challenges. Contingent Resources play a key role in meeting energy demands and enhancing energy security. However, external factors, such as fluctuating oil prices, can influence the pace and viability of development. A spatial representation of Contingent Resources on active and expired leases on the GOA slope as of December 31, 2024 is provided below (Figure 55).

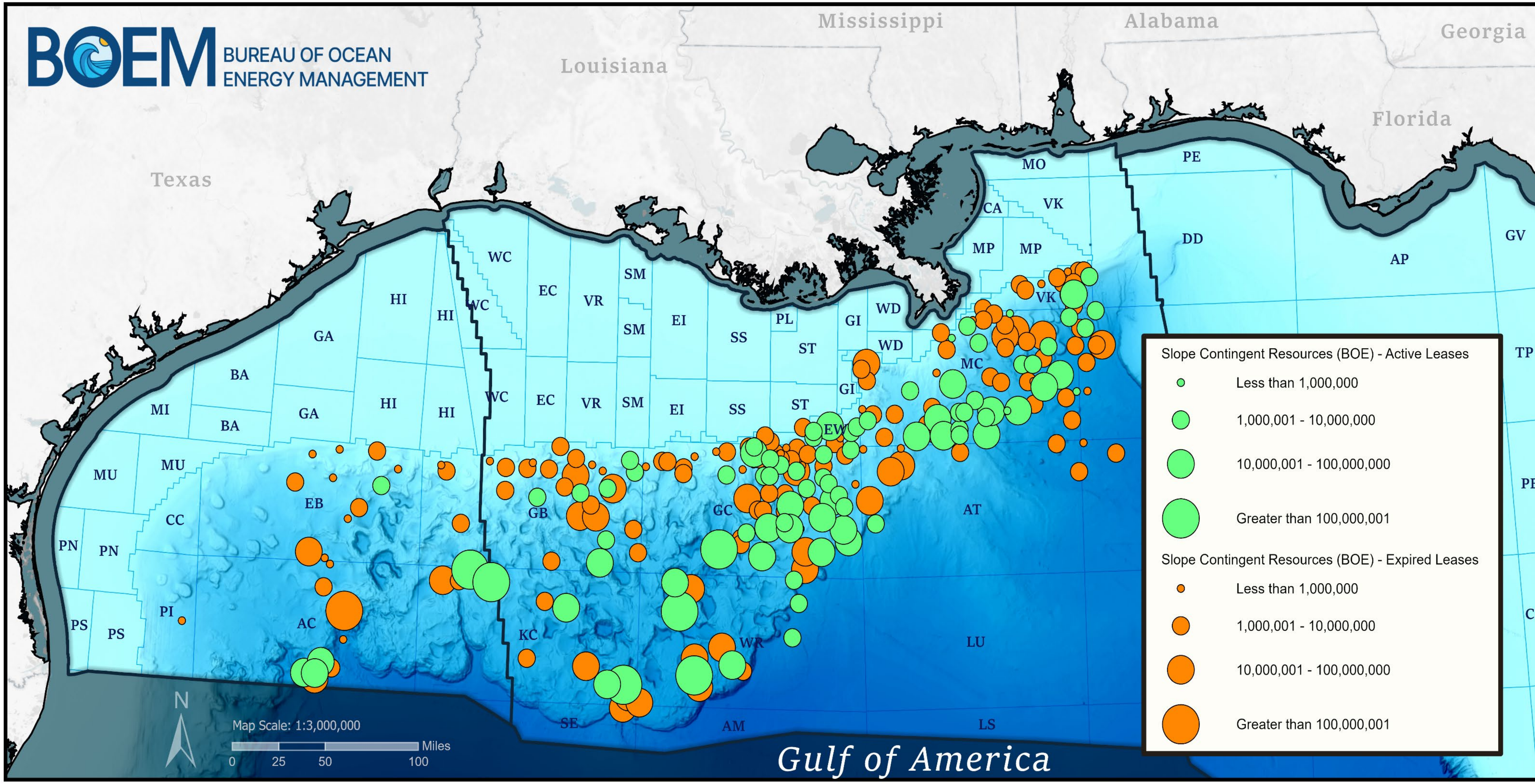

Figure 55. GOA Slope Contingent Resources on Active Leases and Non-leased Acreage

12.0 RESERVES AND CONTINGENT RESOURCES, COMPARISONS AND CONCLUSIONS

As of December 31, 2024, the federally regulated portion of the GOA OCS encompasses 1,342 oil and gas fields. These fields have mean Original Reserves estimated at 31.81 BBO, 202.05 Tcf of gas, or 67.76 BBOE. Cumulative production from these fields totals 25.32 BBO, 194.7 Tcf of gas, or 59.96 BBOE. The mean remaining reserves for the 320 active fields are estimated at 6.49 BBO, 7.35 Tcf of gas, or 7.8 BBOE. Total mean Contingent Resources on the GOA slope are estimated to be 2.55 BBO and 3.92 Tcf of gas, or 3.25 BBOE. Table 8 provides a comprehensive summary and comparison of mean oil and gas Reserves and slope Contingent Resources on the GOA OCS as of December 31, 2024.

Table 8. Summary of GOA Mean Oil and Gas Reserves and Slope Contingent Resources December 31, 2024

	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Original Reserves:			
Previous Estimate, as of 12/31/2023	**30.43**	**201.17**	**66.22**
Reserves from Added Fields	0.78	0.54	0.88
Integrated Technical Updates	0.60	0.34	0.66
Estimate, as of 12/31/2024	**31.81**	**202.05**	**67.76**
Cumulative Production:			
Previous Estimate, as of 12/31/2023	**24.66**	**194.02**	**59.18**
Production during 2024	0.66	0.68	0.78
Estimate, as of 12/31/2024	**25.32**	**194.7**	**59.96**
Remaining Reserves:			
Previous Estimate, as of 12/31/2023	**5.77**	**7.15**	**7.04**
Reserves from Added Fields	0.78	0.54	0.88
Integrated Technical Updates	0.60	0.34	0.66
Production during 2024	-0.66	-0.68	-0.78
Estimate, as of 12/31/2024	**6.49**	**7.35**	**7.8**
Contingent Resources in the Deepwater Gulf of America (>200 meters or 656 feet)			
Contingent Resources	Oil (Bbbl)	Gas (Tcf)	BOE (BBOE)
Contingent Resources on Active Leases	1.66	1.88	1.99
Contingent Resources on Unleased Blocks	0.89	2.04	1.26
Total Contingent Resources Deepwater GOA	**2.55**	**3.92**	**3.25**

Table 9 and Figure 56 present historical reserve estimates. Due to adjustments and corrections to production data submitted by GOA OCS operators, the difference between historical cumulative production for successive years does not always equal the annual production for the latter year.

*Table 9. Oil and Gas Reserves and Cumulative Production at End of Year, 1975-2024**

Year	Number of fields included	Original Reserves			Historical Cumulative Production			Remaining 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
1980	435	8.04	88.9	23.86	4.99	48.7	13.66	3.05	40.2	10.20
1985	575	10.63	116.7	31.40	6.58	71.1	19.23	4.05	45.6	12.16
1990	782	10.64	129.9	33.75	8.11	93.8	24.80	2.53	36.1	8.95
1995	899	12.01	144.9	37.79	9.68	117.4	30.57	2.33	27.5	7.22
2000	1,050	14.93	167.3	44.70	11.93	142.7	37.32	3.00	24.6	7.38
2005	1,196	19.80	181.8	52.15	14.61	163.9	43.77	5.19	17.9	8.38
2010	1,282	21.50	191.1	55.50	17.11	179.3	49.01	4.39	11.8	6.49
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
2023	1,336	30.43	201.17	66.22	24.66	194.0	59.18	5.77	7.15	7.04
2024	1,342	31.81	202.05	67.76	25.32	194.7	59.96	6.49	7.35	7.80

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

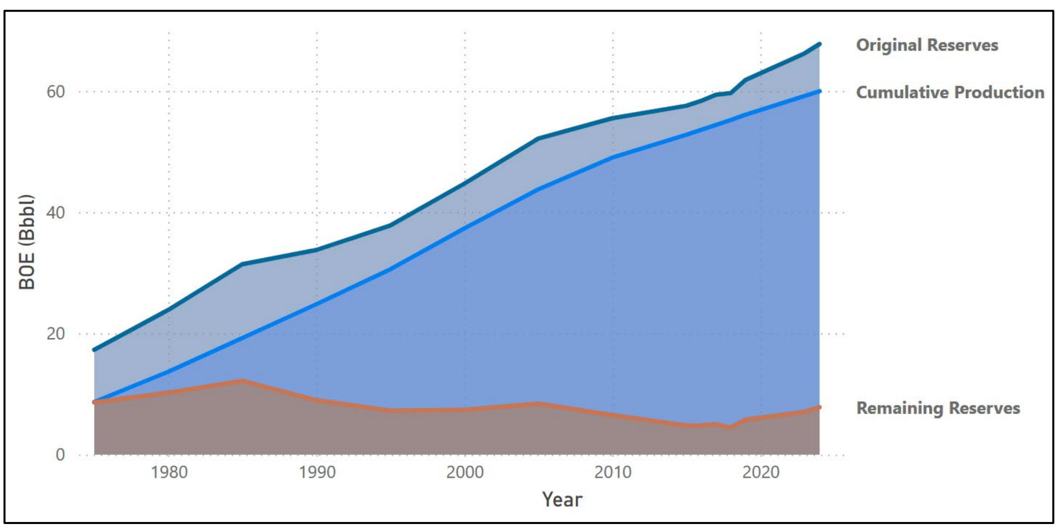

Figure 56. Oil and Gas Reserves and Cumulative Production at End of Year, 1975-2024

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Appendix A - Definitions of Field, Resource and Reserves Terms

Aggregation – The process of summing well, reservoir, or project-level estimates of resources quantities to higher levels or combinations, such as field, country, or company totals.

Analogs – Reservoirs that have similar rock properties (e.g., petrophysical, lithological, depositional, diagenetic, and structural), fluid properties (e.g., type, composition, density, and viscosity), reservoir conditions (e.g., depth, temperature, and pressure), and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide insight and comparative data to assist in estimation of recoverable resources.

API Gravity – A measure of how heavy or light petroleum liquid is compared to water.

Assessment Unit – A group of pools that share a common history of hydrocarbon generation, migration, reservoir development, and entrapment; also referred to as a “play”.

Barrels of Oil Equivalent (BOE) – A unit of measurement used to compare the energy produced by oil and gas.

Bureau of Ocean Energy Management (BOEM) – The U.S. agency responsible for the management of the nation's ocean resources and the regulation of offshore energy development.

Chronozone – A body of rock formed during the same time span, bounded by biostratigraphic or correlative seismic markers.

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.

Cumulative distribution functions (CDF) – Represents the accumulated probability up to a specific point.

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

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. 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.

Estimated Oil and Gas Reserves (EOGR) Report – A BOEM publication reporting estimates of oil and gas reserves and Contingent Resources.

Field – A concentration of oil and/or gas accumulations that share a common geologic structure or stratigraphic condition and are typically developed as a single unit.

Field Classification Framework – The systematic categorization of oil and gas fields based on certain criteria, such as production status, type, and economic viability.

Flow Rate – The volume of oil or gas that is produced over a specified time.

Gas-Oil Ratio (GOR) – The relationship between the volume of gas produced and the volume of oil produced.

Mean – Measure of central tendency that represents the average value of a set of numbers.

Monte Carlo Simulation – A type of stochastic mathematical simulation that randomly and repeatedly samples input distributions to generate a resulting distribution.

Original Gas in Place – The total estimated volume of gas in a reservoir, both recoverable and non-recoverable, prior to production.

Original Oil in Place – The total estimated volume of oil in a reservoir, both recoverable and non-recoverable, prior to production.

Original Reserves – Equivalent to the sum of cumulative production and remaining reserves.

Outer Continental Shelf (OCS) – All submerged lands lying seaward and outside of the area of lands beneath navigable waters, and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control or within the exclusive economic zone of the United States and adjacent to any territory of the United States; and does not include any area conveyed by Congress to a territorial government for administration.

P10, P50, P90 – Probabilistic estimates indicating that there is a 90%, 50%, and 10% chance of achieving or exceeding those reserve estimates, respectively.

Play – A group of pools that share a common history of hydrocarbon generation, migration, reservoir development, and entrapment.

Probabilistic Estimates – Statistical methods used to assess the likelihood of various outcomes based on uncertainties in data.

Project – A Project represents the link between 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).

Remaining Reserves – Remaining 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.

Reserves Justified for Development – The lowest level of Reserves' certainty. Implementation of the development project is justified based on a reasonable forecast of commercial conditions at the time of reporting and that there are reasonable expectations that all necessary approvals/contracts will be obtained.

Reservoir – A subsurface rock formation that contains an individual and separate natural accumulation of petroleum that is confined by impermeable barriers, pressure systems, fluid regimes (conventional reservoirs), or is confined by hydraulic fracture barriers or fluid regimes (unconventional reservoirs).

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.

Shelf – The portion of the OCS with a water depth of less than 200 meters.

Slope – The portion of the OCS with a water depth equal to or greater than 200 meters.

Stock Tank Oil Originally in Place – The total estimated volume of oil in a reservoir before any production takes place.

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.

Undiscovered Resources – Resources postulated, based on 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 and Undiscovered Economically Recoverable Resources.

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

Notice

This report, Estimated Oil and Gas Reserves, GOA OCS Region, December 31, 2024, 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 Office of Resource Evaluation at (800) 200-4853 or BOEMGulfResourceEvaluation@boem.gov, to communicate your ideas for consideration in our next report. An overview of the Reserves Inventory Program is available at https://www.boem.gov/oil-gas-energy/resource-evaluation/discovered-resources.

For free publication and digital data, visit the BOEM Data Center under the Field widget. 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® Worksheet file (.xlsx; using the Microsoft® 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.

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