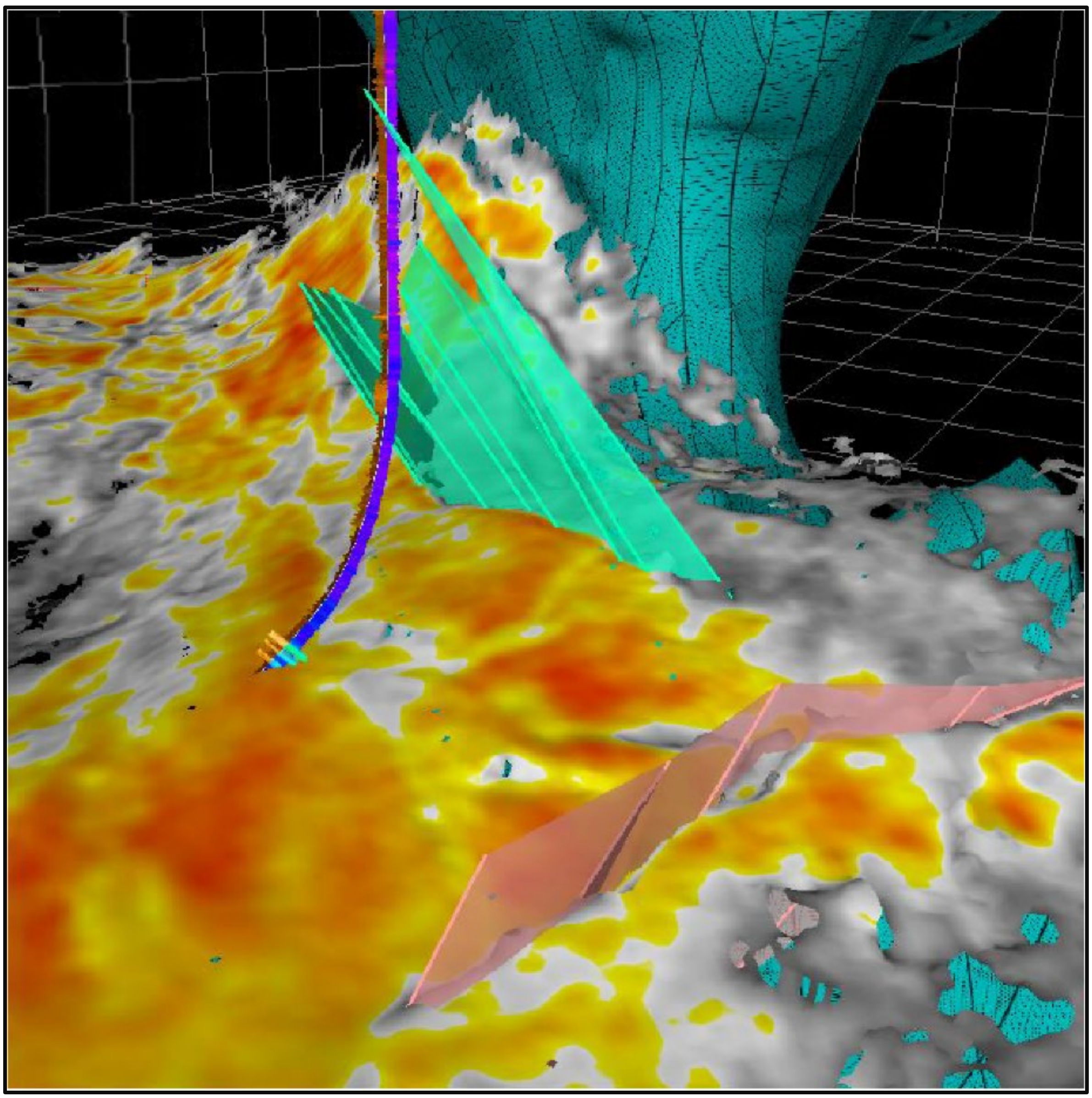
Report to Congress

Comprehensive Inventory of U.S. Outer Continental Shelf Oil & Natural Gas Resources: 2023 Update

Energy Policy Act of 2005 – Section 357



Cover illustration: A three-dimensional rendering of hydrocarbon exploration on the Outer Continental Shelf. Source: BOEM Interpretation.

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Energy Policy Act of 2005 – Section 357

Prepared by
Bureau of Ocean Energy Management

For the
U.S. Congress

U.S. Department of the Interior
Bureau of Ocean Energy Management

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PREFACE

Section 357 of the Energy Policy Act of 2005 (EPAct) directs the Secretary of the Interior to conduct an inventory and analysis of oil and natural gas resources contained within the submerged lands of the United States (U.S.) Outer Continental Shelf (OCS). The Secretary was required to submit a report to Congress within six months of the date of enactment (i.e., by August 8, 2005), and must update the report at least every 5 years. The *Comprehensive Inventory of Outer Continental Shelf Oil and Natural Gas Resources: 2023 Update* report provides the required updates to the previous 2018 inventory report.

The statute mandates that the inventory and report provide the following:

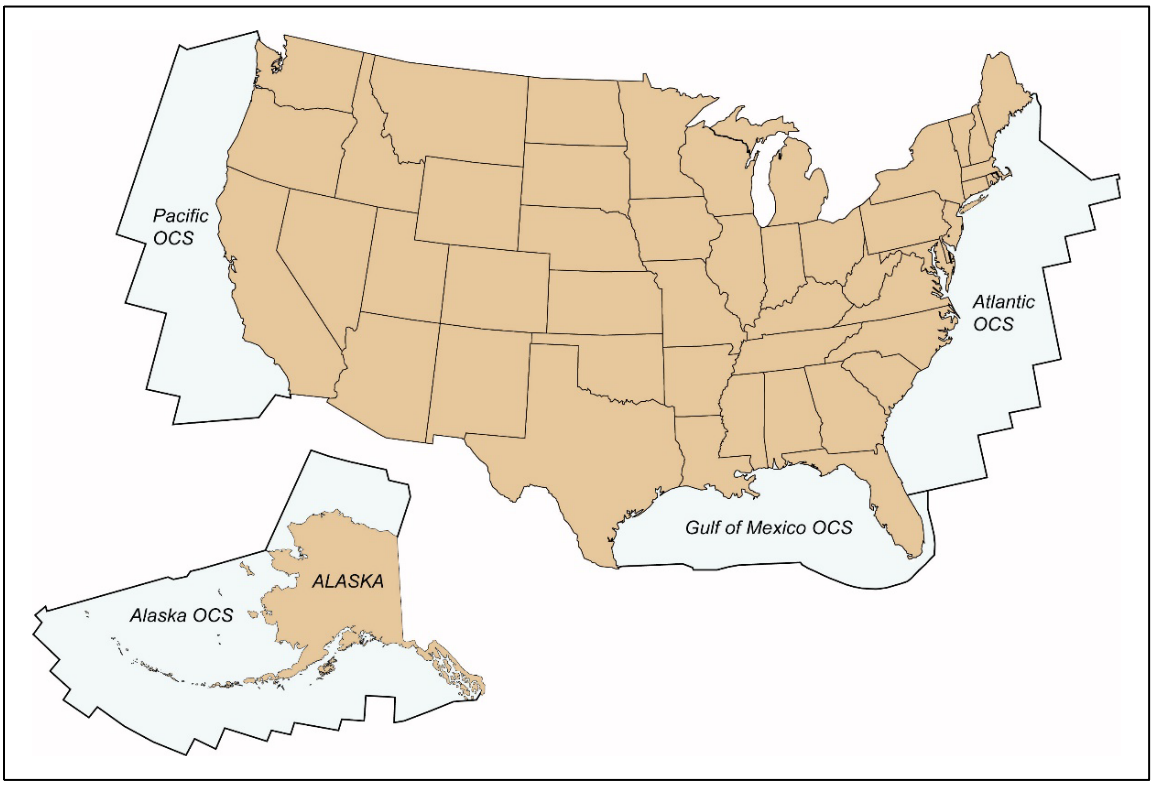
1. incorporate available data on oil and natural gas resources in areas offshore of Mexico and Canada that are relevant to estimate the resource potential of the OCS;
2. use any available technology except drilling to obtain accurate resource estimates;
3. analyze how OCS resource estimates have changed over time in relation to available data and exploration and development activities;
4. estimate the effect of understated oil and natural gas resource estimates on domestic energy investments; and
5. identify and explain how legislative, regulatory, and administrative programs or processes restrict or impede resource development and affect domestic supply.

This report was authored by the U.S. Department of the Interior's Bureau of Ocean Energy Management (BOEM).

Executive Summary

The *Comprehensive Inventory of U.S. Outer Continental Shelf Oil and Natural Gas Resources: 2023 Update* (2023 Inventory) represents an update of the *Comprehensive Inventory of U.S. Outer Continental Shelf Oil and Natural Gas Resources: 2018 Update* (2018 Inventory, BOEM 2018) and reflects information consistent with the BOEM's latest 2021 *National Assessment of Undiscovered Technically Recoverable Oil and Gas Resources on the OCS* (2021 Assessment, BOEM 2021a). Technically recoverable resources are hydrocarbons potentially recoverable by conventional production methods regardless of the size, accessibility, and economics of the accumulations assessed. The 2021 Assessment is a comprehensive appraisal that considered relevant data and information available as of January 1, 2019. The 2023 Inventory also includes information related to discovered OCS oil and gas, including produced oil and gas and reserves remaining in the ground. The OCS comprises the portion of the submerged seabed whose mineral estate is subject to Federal jurisdiction (see **Figure 1**).

Figure 1. OCS of the United States



The commodities assessed in the 2023 Inventory are crude oil, natural gas liquids (i.e., condensates), and natural gas that exist in conventional reservoirs and are producible with conventional recovery techniques. The terms natural gas and gas are used interchangeably in this report. The estimates of oil resources reported represent combined volumes of crude oil and condensate.

It is necessary to make fundamental assumptions regarding future technology and economic conditions when developing these estimates. Attempting to predict the future magnitude and directional impact of external factors introduces uncertainty to all resource assessments.

All methods of assessing potential quantities of technically recoverable resources are efforts to quantify a value not reliably known until the resource is nearly depleted. Most resource estimates incorporate uncertainty and quantify the probability that undiscovered resources will be discovered, but they cannot account for the unforeseen. As such, resource estimates should be used as general indicators and not predictors of absolute volumes. All resource estimates are subject to continuing revision as undiscovered resources are converted to reserves and reserves to production, and as improvements in data and assessment methods occur.

The assessment results do not imply a rate of discovery, or a likelihood of discovery, or production within a specific time frame. However, uncertainty surrounding the estimates typically decreases as the asset progresses through this cycle. Resource estimates should be viewed from the perspective of the point in time the assessment was performed—based on the data, information, and methodology available at that time.

In general, the geologic risk of not finding hydrocarbons, and uncertainty in estimates of undiscovered oil and natural gas, are greatest for frontier areas that have little or no past exploratory effort. For areas that have been extensively explored and are in a mature development stage, many of the geologic and economic risks have been reduced or eliminated. As a result, resource potential can be evaluated with much more confidence and certainty. However, even in some mature producing areas such as the Gulf of Mexico (GOM) OCS, considerable uncertainty remains about the petroleum potential at greater drilling depths and in unexplored geologic plays in ultradeep water.

The results of the 2023 Inventory are presented in **Table 1a**. This includes information derived from the 2021 Assessment (undiscovered resources) and various BOEM reports and internal data sources (discovered resources); no government-sponsored geological or geophysical data acquisition was undertaken for this inventory. The total endowment of technically recoverable OCS oil and gas is comprised of known resources—cumulative production and estimates of remaining reserves, contingent resources, and reserves appreciation—plus estimates of undiscovered technically recoverable resources. The total endowment is estimated to equal 108.31 billion barrels of oil (Bbo) and 461.15 trillion cubic feet of gas (Tcfg). On a barrel of oil-equivalent (BOE) basis, approximately two-thirds of the total hydrocarbon endowment is projected to be in the GOM region. The data cutoff for all reported numbers is January 1, 2019, to align with the cutoff date used for the 2021 Assessment. Actual OCS production data through calendar year 2022 are available and described in Section III of this report but cannot be included in the total endowment because UTRR, reserve, and contingent resource numbers have not been adjusted for this additional production.

Table 1a. Total Endowment of Technically Recoverable OCS Oil and Gas as of January 1, 2019

OCS Region	*Discovered Resources*				*Undiscovered Resources (UTRR)*	*Total Endowment*
	Cumulative Production	*Remaining Reserves*	*Contingent Resources*	*Reserves Appreciation*	*(Mean Estimate)*	
OIL (billion barrels)						
Alaska	0.03	0.01	0.18	0	24.69	24.91
Atlantic	0	0	0	0	4.31	4.31
GOM	21.42	3.44	2.65	8.84	29.59	65.94
Pacific	1.36	0.24	1.35	0	10.20	13.15
Total OCS Oil	**22.81**	**3.69**	**4.18**	**8.84**	**68.79**	**108.31**
GAS (trillion cubic feet)						
Alaska	0	0	0	0	124.03	124.03
Atlantic	0	0	0	0	34.09	34.09
GOM	189.80	5.71	3.04	30.35	54.84	283.74
Pacific	1.85	0.34	1.03	0	16.07	19.29
Total OCS Gas	**191.65**	**6.05**	**4.07**	**30.35**	**229.03**	**461.15**

Discovered Resources: Discovered resources in known fields, or the total of cumulative production, remaining reserves, contingent resources, and reserves appreciation, comprise approximately 39.52 Bbo and 232.12 Tcfg, which together make up approximately 42% of the total endowment on a BOE basis.

As of January 1, 2019, cumulative OCS production totaled approximately 22.81 Bbo and 191.65 Tcfg, of which 94% of the oil and 99% of the gas were produced in the GOM. The production represents 30% of the estimated total endowment on a BOE basis.

Estimates of the discovered resources remaining to be produced (i.e., remaining reserves, contingent resources, and reserves appreciation) total 16.71 Bbo and 40.47 Tcfg across 1,319 OCS fields. Reserves growth or appreciation account for 8.84 Bbo and 30.35 Tcfg of this total and represents the projected increase in current reserves estimates within existing fields based on statistical analysis of historical trends. This growth occurs primarily from the discovery of new reservoirs and an increase in the estimate of the recoverable portion of in-place hydrocarbons within known fields due to future advances in technology, an increased understanding of reservoir performance, and improved economic viability.

Undiscovered Resources: The mean estimate[1] for undiscovered resources totals 68.79 Bbo and 229.03 Tcfg, as shown in **Table 1a**. The full range of estimates corresponding to different

[1] BOEM UTRR estimates are stochastically generated and are reported at the mean value and at the 95th and 5th percentile values. This range of estimates corresponds to a 95% probability (i.e., a 19 in 20 chance) and a 5% probability (i.e., a one in 20 chance) of there being more than those amounts present, respectively. The 95th and 5th percent probabilities are considered reasonable minimum and maximum values, and the mean is the average or expected value.

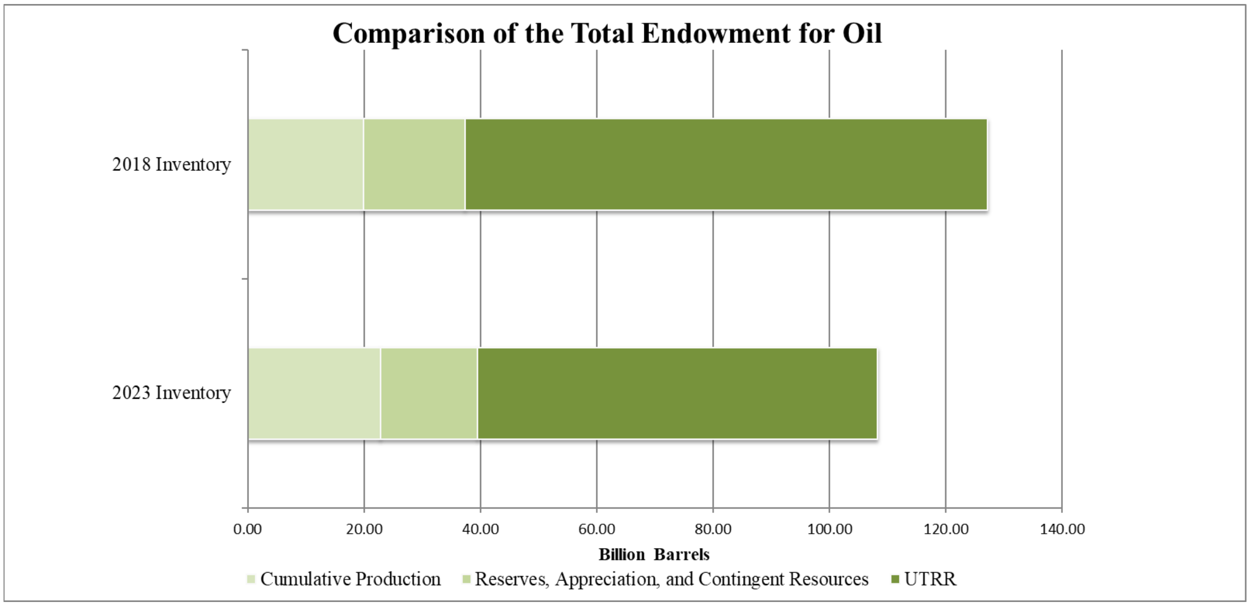
probabilities of occurrence can be found in Section III. On a BOE basis, the largest percentage of the mean UTRR is projected to exist in the Alaska region. **Table 1b** shows the UTRR from the 2021 Assessment for each OCS region and planning area. Note that the UTRR from the Straits of Florida are aggregated with the UTRR in the GOM due to similarities in geologic plays; for other administrative purposes, the Straits of Florida is associated with the Atlantic OCS region.

Table 1b. Undiscovered Technically Recoverable Oil and Gas Resources by Planning Area

Region	Oil (Billion Barrels) (Mean Estimate)	Gas (Trillion Cubic Feet) (Mean Estimate)
Alaska OCS	**24.69**	**124.03**
Chukchi Sea	15.72	79.58
Beaufort Sea	5.74	16.10
Hope Basin	0.14	3.51
Navarin Basin	0.26	2.14
North Aleutian Basin	0.79	9.02
St. George Basin	0.22	2.81
Norton Basin	0.06	3.35
Cook Inlet	1.04	1.18
Gulf of Alaska	0.66	4.33
Shumagin	0.01	0.41
Kodiak	0.04	1.60
Atlantic OCS	**4.31**	**34.09**
North Atlantic	1.87	11.50
Mid-Atlantic	2.25	21.42
South Atlantic	0.20	1.17
Gulf of Mexico OCS	**29.59**	**54.84**
Western Gulf of Mexico	6.05	11.39
Central Gulf of Mexico	18.65	31.19
Eastern Gulf of Mexico	4.87	12.25
Straits of Florida	0.02	0.01
Pacific OCS	**10.20**	**16.07**
Washington/Oregon	0.40	2.25
Northern California	2.07	3.55
Central California	2.41	2.49
Southern California	5.33	7.78

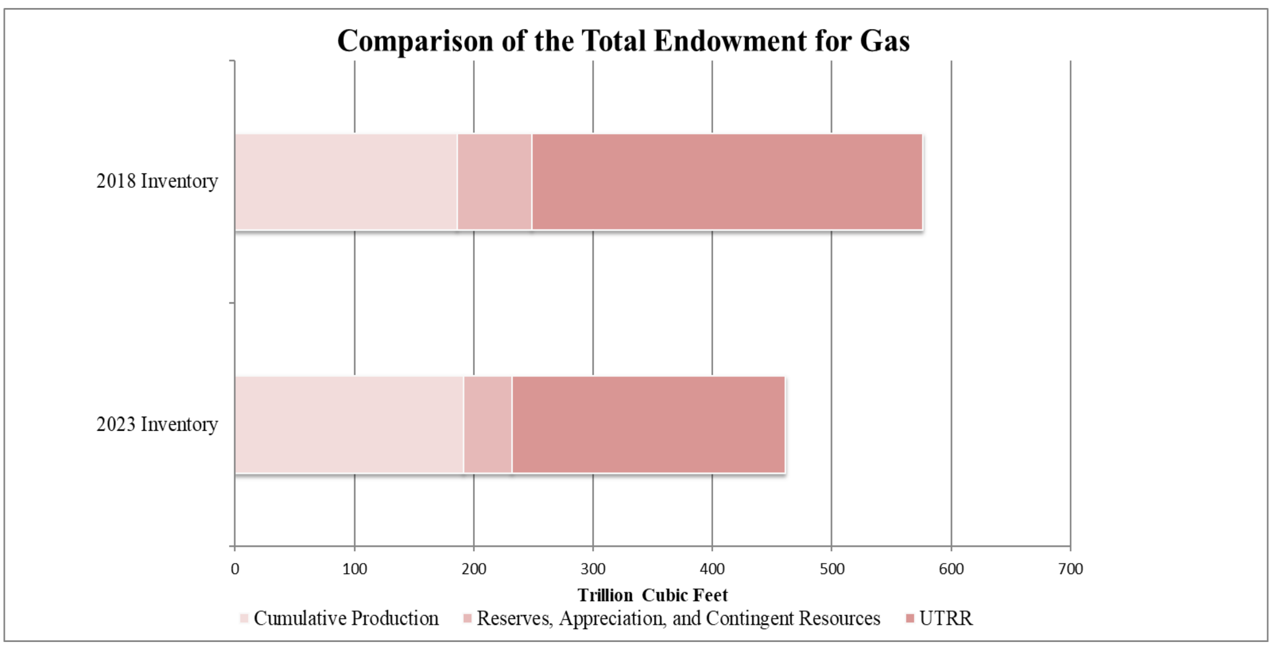
Figures 2a and **2b** compare the total endowment of both oil and natural gas included in the 2018 and 2023 Inventories. For the entire OCS, total estimated endowment of oil and gas decreased by approximately 15% and 20%, respectively, largely as a result of reductions in UTRR in the GOM. Section III of this report includes a broader discussion comparing the results of the 2023 Inventory with the results of the 2018 Inventory.

Figure 2a. Comparison of Estimates of Total Endowment Oil Resources on the OCS for the 2018 and 2023 Inventories



Notes: For this 2023 Inventory, UTRR estimates are derived from the 2021 Assessment (BOEM, 2021a) and all other numbers are current as of January 1, 2019. For the 2018 Inventory, UTRR estimates are from the 2016 Assessment (BOEM, 2016) and all other numbers are current as of January 1, 2014.

Figure 2b. Comparison of Estimates of Total Endowment Gas Resources on the OCS for the 2018 Inventory and 2023 Inventory



Notes: For the 2023 Inventory, UTRR estimates are derived from the 2021 Assessment (BOEM, 2021a); all other numbers are current as of January 1, 2019. For the 2018 Inventory, UTRR estimates are derived from the 2016 Assessment (BOEM, 2016), and all other numbers are current as of January 1, 2014.

Compared to the 2018 Inventory, BOEM's estimate for undiscovered technically recoverable OCS oil resources has decreased more than 23%, and the volume estimate of undiscovered technically recoverable gas resources decreased 30%. These changes are primarily attributable to the GOM region, where mean UTRR oil volumes dropped by 38.9%, and mean gas decreased by 61%. The overall decrease in UTRR is due in part to refining field size distributions and the estimated number of prospects for some mature geologic plays in the GOM OCS, particularly on the shallow water shelf. The refinements reflect a better understanding of recent exploratory well results, the size of recently discovered gas fields, and the range of prospect sizes receiving bids in recent GOM lease sales.

Since 1975, the Department of the Interior (DOI) completed 11 comprehensive OCS assessments of undiscovered resources. Section IV of this report addresses in detail the historical change in BOEM assessments of undiscovered resources over time. During this period, the geological and geophysical (G&G) information available to BOEM assessors has dramatically increased. These data have increased BOEM's knowledge regarding OCS resource potential, particularly in the more mature areas of the central and western GOM and Southern California.

Early DOI resource assessments focused on reporting estimates of undiscovered economically recoverable resources (UERR). UERR refers to the portion of the UTRR that is economically recoverable under imposed economic and technologic conditions. While oil and natural gas prices have experienced considerable volatility over the years, BOEM does not produce a new assessment of UERR to accommodate commodity price shifts. Rather, assessments reporting UERR use a range of different prices and sets of economic conditions. Oil and gas price pairs for assessment models have varied, making year-over-year comparisons difficult. Beginning with the 1996 assessment of undiscovered resources, BOEM[2] focused primarily on estimates of UTRR instead of UERR to remove the effect of economic volatility on resource estimates. In an attempt to present a more complete picture of the total hydrocarbon endowment, assessment reports sometimes included estimates of cumulative production, reserves, and reserves appreciation.

The period covered by OCS oil and gas assessments is also one in which the industry's technological capabilities expanded considerably. Today, the oil and gas industry possesses the ability to drill both exploration and production wells in water depths exceeding 10,000 feet. The use of three-dimensional (3-D) and other advanced seismic data and interpretation techniques has served as a catalyst to transform the geosciences and the petroleum industry by providing more accurate subsurface imaging. Resource assessment techniques have also become more sophisticated during this period.

In this report, DOI is required to analyze how OCS resource estimates have changed over time in relation to available data and exploration and development activities. Given the incremental advances that have occurred over the past 40 years, it is difficult to determine to what degree changes in the assessments are attributable to specific changes in G&G data and information or any other particular individual technological advances.

The differences in assessments point to different perceptions concerning the overall depth of knowledge used to estimate the UTRR and UERR on the OCS. Due to sparse data in the Alaska, Atlantic, and part of the Pacific OCS Regions, assessors must seek out geologic and geophysical information from both domestic and worldwide oil and gas discoveries to develop

[2] Prior to the creation of BOEM in 2011, OCS oil and gas resource assessments were led by the Minerals Management Service (MMS; 1982 – 2009) and the U.S. Geological Survey (USGS; prior to 1982).

information analogous to the geologic plays being assessed on the OCS. This analog information is then used in a more subjective manner to cover the wider range of uncertainties typical of frontier OCS areas. For mature areas with significant amounts of data, such as the GOM and Southern California, a subjective methodology using geologic parameters from historical trends is typically combined with a discovery-based approach to account for what is known in existing discovered pools.

Section V of this report addresses how BOEM resource assessments are used and the extent to which they affect domestic investment decisions. Section 357(a)(4) of the EPAct directs the Secretary of the Interior to "...estimate the effect that understated oil and gas resource inventories have on domestic energy investments."

Each assessment reflects a snapshot in time that should not be viewed as either understated or overstated when compared to later assessments that will reflect additional information and a better understanding of the OCS subsurface. The actual volume of oil and natural gas resources recoverable from the OCS are not definitively known until the resources are nearly depleted. Evolving technological capabilities and improved G&G data can lead to higher or lower estimates when the assessments are updated in later years. For example, frontier areas offer potential for larger field-size discoveries, but G&G data are limited, so potential resource estimates must account for the higher uncertainty and the geologic risk of hydrocarbons not being present. As such, the resulting risk-weighted estimates of oil and natural gas in frontier areas could be seen as too conservative if later exploration demonstrates that the area does indeed contain hydrocarbon accumulations.

Industry and private investors take into account other sources of information when considering alternative investment opportunities, and often conduct independent resource assessments. The same factors that can serve to moderate the government's assessment of the resource potential of certain OCS areas (e.g., lack of data, uncertainty) also influence industry's assessments and conclusions, and ultimately their willingness to invest in those areas.

The actual discovery, development, and production of oil and natural gas resources results not from the inventory and data compiled by BOEM and other government regulators, but from efforts by a diverse set of companies working to identify oil and natural gas prospects that warrant investment. When examining alternative investment opportunities, companies consider not only the oil and gas potential of an area, but also the expected costs of development relative to alternative investments. The expected profitability of specific projects is affected by a company's determination of geologic and economic risk, which will be lower in areas with proven resource potential. Geopolitical risk also influences company investment decisions related to oil and gas exploration, where uncertainty in the ability to acquire acreage or produce oil and gas from acreage under lease can reduce the perceived economic value of exploration opportunities.

Section VI of this report describes oil and gas leasing policy (EPAct Sec. 357(a)(5)). BOEM's resource assessment is one of a number of information sources used by policymakers when considering energy policy options. Under Section 18 of the Outer Continental Shelf Lands Act (OCSLA), the Secretary of the Interior is responsible for establishing a schedule of lease sales for a 5-year period in a National OCS Oil and Gas Leasing Program (National OCS Program) by evaluating specified attributes of OCS areas. The Secretary is authorized to select the size, timing, and location of proposed OCS lease sales that best meet national energy needs and that balances, to the maximum extent practicable, the potential for environmental damage, discovery of oil and gas, and adverse impact on the coastal zone.

The OCSLA grants the Secretary discretion in weighting the specific Section 18 requirements and factors, where final decisions reflect a balancing of the potential for the discovery of OCS oil and gas resources with the potential for environmental damage and adverse impact on the coastal zone, as required by OCSLA Section 18(a)(3). Only those areas included in an approved National OCS Program are available for oil and gas leasing consideration.

Culminating a nearly 7-year process beginning with a Request for Information (RFI) published in the Federal Register on July 3, 2017, DOI announced in the Federal Register on September 29, 2023, the availability of the Proposed Final Program (PFP) for the 2024–2029 National OCS Program, as well as the Final Programmatic Environmental Impact Statement (EIS) for the 2024–2029 Program. The PFP proposes a schedule of oil and gas lease sales for the 2024–2029 period, including three lease sales in the GOM. On September 29, 2023, BOEM submitted the PFP to the President and Congress, along with the Final Programmatic EIS and copies of all comments received on the Proposed Program and responses to comments on the Proposed Program received from state and local governments and Federal agencies. The Secretary approved the PFP on December 14, 2023.

There are a number of administrative reasons why access to parts of the OCS may be prohibited, including the need for national defense purposes or to preserve marine resources with important archaeological, cultural, or environmental values. For example, Congress, through Section 104 of the Gulf of Mexico Energy Security Act (GOMESA) of 2006, established restrictions on oil and gas leasing in a portion of the Central Gulf of Mexico Planning Area and most of the Eastern GOM Planning Area, which remained in effect through June 30, 2022. The September 8, 2020, Presidential Memorandum withdrew this area from leasing through June 30, 2032.

Presidential withdrawals created through executive orders (E.O.s) or mandates have identified large areas of the OCS that are also unavailable for oil and gas leasing. In Alaska, Presidential Withdrawals are in place for the North Aleutian Basin Planning Area, the Chukchi Sea Planning Area, the Beaufort Sea Planning Area, and the Northern Bering Sea Climate Resiliency Area. Several areas in the Atlantic OCS are currently subject to Presidential withdrawal, including the South Atlantic Planning Area, the Straits of Florida Planning Area, part of the Mid-Atlantic Planning Area, and an area designated as the Atlantic Canyons. In the GOM, Presidential withdrawals include portions of the Central and Eastern GOM planning areas. Other parts of the OCS are unavailable for oil and gas leasing due to various mechanisms, including the establishment of National Marine Sanctuaries (NMSs). Areas unavailable for oil and gas leasing are shown at https://www.boem.gov/oil-gas-energy/leasing/areas-under-restriction.

Much of the OCS's oil and gas resources exist in environmentally sensitive areas, and any development of those resources must be considered against the potential for environmental impacts. Proposed OCS oil and gas activities must comply with a variety of Federal and state statutes, regulations, and administrative orders that are designed to provide for safe and responsible resource development with appropriate environmental protection.

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I. Introduction

As the DOI OCS resource management agency, BOEM manages the exploration and development of the Nation's offshore mineral resources and seeks to appropriately balance economic development, energy independence, and environmental protection through energy and mineral leasing and environmental reviews and studies.

Section 357 of EPAct directed the Secretary of the Interior to prepare and submit to Congress within six months of the date of enactment a comprehensive inventory of OCS oil and natural gas resources, and that the report shall be publicly available and updated at least every 5 years. This report (2023 Inventory) is an update of the *Comprehensive Inventory of U.S. Outer Continental Shelf Oil and Natural Gas Resources: 2018 Update* (2018 Inventory) and reflects information consistent with BOEM's latest *2021 National Assessment of Undiscovered Technically Recoverable Oil and Gas Resources on the OCS*.

The following sections address each statutory requirement in EPAct and frame the discussion with background information about BOEM's OCS program:

- Section II provides background discussion on BOEM's OCS oil and gas leasing program.
- Section III presents the OCS oil and natural gas inventory (Section 357(a)(1) and (a)(2)).
- Section IV discusses historical changes in resource estimates (Section 357(a)(3)).
- Section V discusses possible effects of understated resource estimates on domestic investments (Section 357(a)(4)).
- Section VI describes the various types of impediments and restrictions affecting OCS oil and gas activities (Section 357(a)(5)).
- Appendix A presents a glossary of relevant terms used in this report.
- Appendix B presents a list of acronyms used throughout this report.
- Appendix C contains a list of the units used within this report.
- Appendix D lists the references cited for this report.

II. Background on the OCS Oil and Gas Leasing Program

The passage of OCSLA in 1953 established Federal jurisdiction over the mineral resources of the OCS and authorized the Secretary of the Interior to manage oil and natural gas and other marine minerals activity seaward of state submerged lands. In most cases, the OCS extends from 3 nautical miles from the coastline to the seaward extent of the jurisdiction of the United States, which is typically 200 nautical miles from the coastline. As of December 1, 2023, more than 12 million acres of the OCS are currently under lease for oil and gas exploration and development; of the 2,260 active oil and gas leases, 554 are considered to be producing.[3]

The OCSLA, as amended, establishes a comprehensive framework for oil and gas resource management. It provides for development of a National OCS Program and supporting environmental analysis that is used to establish the size, timing, and location of OCS leasing over a 5-year time frame. The intensive planning process is designed to consider the laws and policies of affected coastal states and balance multiple objectives among geographic areas in terms of hydrocarbon potential, environmental sensitivity, and other factors. Development of the National OCS Program and planning for individual lease sales involves extensive consultation and public comment. Individual oil and gas lease sales offer industry access to OCS acreage for leasing by competitive bid, providing for potential future exploration and development of oil and gas resources.

As of December 1, 2023, the Atlantic OCS had zero active leases and no oil and gas production.

As of December 1, 2023, the Alaska OCS had 21 active leases, of which three are producing oil and gas. The U.S. OCS share of the oil production averaged 1,000 barrels per day and gas production averaged 6 million cubic feet (MMcf) per day in 2022.

As of December 1, 2023, the Pacific OCS had 30 active leases with all of these leases producing oil and gas from 23 platforms. Oil production averaged 7,000 barrels per day and gas production averaged 7 MMcf per day in 2022.

As of December 1, 2023, the Gulf of Mexico (GOM) OCS had approximately 2,209 active leases, of which 521 are currently producing oil and gas from approximately 1,500 platforms. Oil production averaged 1.7 million barrels per day and gas production averaged 2.1 billion cubic feet (Bcf) per day in 2022.

OCS oil and gas production from 1954 to 2022 totaled approximately 24 billion barrels of oil and 191 trillion cubic feet of gas. Total U.S production (including onshore) from 1954 to 2022 was about 195 billion barrels of oil and 1,429 trillion cubic feet of gas. Over this 68-year period, the OCS contribution to the total U.S. production was approximately 12% for oil and 13% for gas. In calendar year 2022, total OCS production was about 633 million barrels of oil and about 788 billion cubic feet of gas, representing 15% of total U.S. oil production and 2% of total U.S. gas production.

OCS oil and gas leasing, exploration, and production activities are subject to a number of environmental reviews by Federal, state, and local agencies. The OCSLA and other applicable statutes like the National Environmental Policy Act (NEPA), the Coastal Zone Management Act (CZMA),

[3] https://www.boem.gov/sites/default/files/documents/oil-gas-energy/leasing/Lease%20stats%2012-1-23.pdf

the Endangered Species Act (ESA), the Marine Mammal Protection Act (MMPA), the Clean Air Act (CAA), and the Clean Water Act (CWA), as well as authorities of other agencies and departments, govern the conduct of OCS activities. BOEM has decades of experience working with coastal states on coastal zone and other issues related to offshore development.

Under Section 12(a) of OCSLA, 43 United States Code (U.S.C.) §1341, the President of the United States may, from time to time, withdraw from disposition any of the unleased lands of the OCS. The time period for existing Presidential withdrawals varies, as some have very specific expiration dates and others are noted as "for a time period without specific expiration." The existing Presidential withdrawals are as follows:

- **Alaska OCS Presidential Withdrawals:**
  - North Aleutian Basin Planning Area and Bristol Bay; dated December 16, 2014
  - Chukchi Sea and a Portion of Beaufort Sea planning areas; dated December 20, 2016
  - Northern Bering Sea Climate Resiliency Area; dated January 20, 2021
  - Remaining Portion of the Beaufort Sea Planning Area dated March 13, 2023.
- **Atlantic OCS Presidential Withdrawals:**
  - The Atlantic Canyons; dated December 20, 2016
  - The South Atlantic and Straits of Florida planning areas; dated September 8, 2020
  - A portion of the Mid-Atlantic Planning Area; dated September 25, 2020.
- **Gulf of Mexico Presidential Withdrawals:**
  - Portions of the Central GOM Planning Area and Eastern GOM Planning Area that are subject to the restrictions under GOMESA were further withdrawn until June 30, 2032.

NMSs may be designated by the Department of Commerce pursuant to the National Marine Sanctuaries Act (NMSA), 16 U.S.C. §§ 1431-1434, 33 U.S.C. 1401 et seq. Pursuant to the Presidential Memorandum issued on July 14, 2008, any NMS that was designated prior to that date is withdrawn from disposition from leasing under Section 12(a) of OCSLA. Additionally, rules and regulations governing the designation and management of a specific NMS may restrict or prohibit certain activities within that sanctuary, such as leasing, exploration, and production of oil and gas resources. The following NMS have been established under the NMSA and are on the U.S. OCS:

- **Pacific NMS**
  - American Samoa NMS; 51 FR 15878; April 29, 1986;
  - Hawaiian Islands Humpback Whale NMS; 64 FR 66570; November 29, 1999;
  - Monterey Bay NMS; 73 FR 70535; November 20, 2008;
  - Channel Islands NMS; 74 FR 3260; January 16, 2009;
  - Olympic Coast NMS; 60 FR 66877; November 1, 2011;
  - Cordell Bank NMS; 80 FR 13115; March 12, 2015;
  - Greater Farallones NMS; 80 FR 13108; March 12, 2015.

- **Atlantic NMS**
  - Gray's Reef; 15 CFR 922, Subpart I;
  - Monitor NMS; 15 CFR 922, Subpart F;
  - Florida Keys NMS; 62 FR 32161; June 12, 1997;
  - Stellawagen Bank NMS; Presidential Proclamation; September 15, 2016.

- **Gulf of Mexico NMS**
  - Flower Garden Banks NMS; 15 CFR 922, Subpart L;
  - Florida Keys NMS; 62 FR 32161; June 12, 1997.

There are five designated Marine National Monuments (MNMs): four in the Pacific and one in the Atlantic. MNMs can be designated through legislation or through Presidential Proclamation pursuant to the Antiquities Act, 54 U.S.C. § 320301. Management responsibilities are jointly shared between the Department of Commerce's National Oceanic and Atmospheric Administration (NOAA) and DOI. All five MNMs specifically prohibit oil and gas leasing and development activities, as follows:

- Papahānaumokuākea MNM (Pacific Region); Presidential Proclamation 8031, dated June 15, 2006, and updated February 28, 2007;
- Rose Atoll MNM (Pacific Region); Presidential Proclamation 8337, dated January 6, 2009;
- Marianas Trench MNM (Pacific Region); Presidential Proclamation 8335, dated January 12, 2009;
- Pacific Remote Islands MNM (Pacific Region); Presidential Proclamation 8336 dated January 12, 2009, and Presidential Proclamation 9173, dated September 25, 2014; and
- Northeast Canyons and Seamounts MNM (Atlantic Region); Presidential Proclamation 9496, dated September 15, 2016.

The Santa Barbara Channel Ecological Preserve (Pacific Region) is withdrawn from leasing and is reserved for scientific, recreational, and other similar uses as an ecological preserve pursuant to Public Land Order 4587, 34 FR 5655, dated March 21,1969.

The Phillip Burton Wilderness Area (Pacific Region) has a 15-mile buffer zone withdrawn from leasing pursuant to 2021 43 U.S.C. §1341(h).

Biscayne Bay National Park (Atlantic Region) was established as part of the National Park System under P.L. 96-287 (1980), and a portion of the park extends onto the OCS. Pursuant to the Mineral Leasing Act of 1920, as amended, the park is withdrawn from leasing (30 U.S.C. § 181).

Additional information on areas under restriction from oil and gas leasing and development can be found at: https://www.boem.gov/oil-gas-energy/leasing/areas-under-restriction.

III. OCS Oil and Natural Gas Inventory

A. Background

Resource evaluations have been carried out by geologists, statisticians, and economists for decades to offer insights into petroleum supply. To tackle the challenge, increasingly complex quantitative techniques and procedures have been developed in response to the needs and uses for these assessments. In general, over time, resource assessments have transitioned from deterministic to stochastic approaches that include uncertainty and quantitative risk analyses. Scientific disciplines involved in the assessment process have evolved in parallel with the methodology, from primarily geology in the early assessments to a complex multi-disciplinary array of geology, geophysics, petroleum engineering, economics, and statistics in more recent assessments.

1. Purposes of Resource Assessments: Resource assessments are performed by BOEM at various scales and for many purposes. Regional assessments can be prepared to develop an inventory of potential oil and natural gas resources as part of an evaluation of future supply options. Assessments can be undertaken to analyze the relative merits of oil and gas development proposals and alternatives versus other competing uses. Resource estimates provide critical input to decision-makers and inform various policy alternatives. Detailed site-specific assessments provide data essential for valuing U.S. OCS lands prior to leasing or analyzing industry exploration or development proposals.

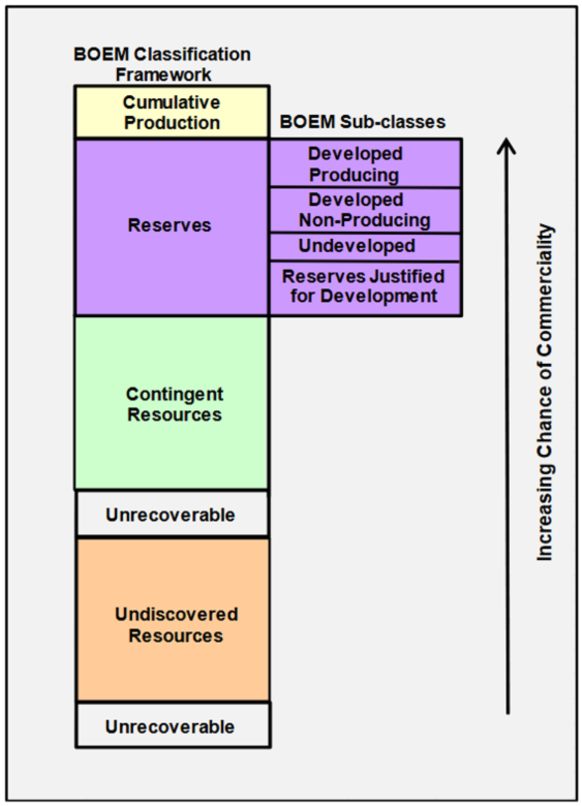
Corporations and financial institutions use resource estimates to inform long-term planning, analyze investment options, and evaluate the future health of the oil and gas industry. Exploration companies use resource assessments to design exploration strategies and target expenditures. Resource estimates provide the supply-side component concerning the amount of oil and natural gas that could be available for future domestic consumption.

BOEM assessments of undiscovered resources aggregate the results of a regional, play-based assessment of the entire U.S. OCS. Resource assessments represent the results of a thorough investigation of the petroleum geology of each province and an identification of appropriate domestic and international analogs, coupled with a probabilistic methodology to estimate the remaining hydrocarbon potential.

2. Terminology and Classification Schema: BOEM uses a classification system that conforms with the Petroleum Resources Management System (PRMS) sponsored by the Society of Petroleum Engineers (SPE), the American Association of Petroleum Geologists (AAPG), the World Petroleum Council, and the Society of Petroleum Evaluation Engineers (SPEE). The SPE-PRMS was published in 2007 and is designed to provide a common reference for the petroleum industry and regulatory disclosure agencies (SPE, 2007). Under SPE-PRMS, the development project is the primary element in classifying resources and reserves. This system considers both the technical and commercial factors impacting a project's economics, productive life, and associated cash flows. As the project matures (from the initial planning phases to infrastructure construction to production and sales), resources and reserves are re-categorized based on their increasing geologic certainty and chances of commerciality. Terms related to resource characterization are included in a glossary in Appendix A.

The BOEM resource classification framework for the U.S. OCS is shown in **Figure 3**. When a discovery is made, the identified hydrocarbon accumulation is classified as a "contingent resource" until a development project is identified. When an operator 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." 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, for any reason, an accumulation goes off production for a year or more, the classification changes back to "developed non-producing reserves." 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 3. BOEM Resource Classification Schema



The overall movement of petroleum resources within the classification schema is upward as development and production ensue. The degree of certainty as to the existence of resources increases upwards in the diagram. Similarly, the degree of economic viability and technologic recoverability also increases upwards in the classification schema.

The assessments of undiscovered and discovered resources discussed in this report exclude oil and natural gas that are producible only through the use of more exotic and expensive unconventional technologies. This distinction sometimes eliminates from consideration significant portions of the resource base, some portion of which could be developed in the future. Resource assessments that are intended for more than scientific interest are generally limited to accumulations that are believed to be amenable to discovery and production employing conventional techniques under reasonably foreseeable technological and economic conditions.

3. Commodities Assessed: The petroleum commodities assessed in this inventory are crude oil, natural gas liquids (condensate), and natural gas that exist in conventional reservoirs and are producible with conventional recovery techniques.

Crude oil exists in a liquid state in the subsurface and at the surface; it can be described on the basis of its American Petroleum Institute (API) gravity as "light" (i.e., approximately 20° to 50° API) or "heavy" (i.e., generally less than 20° API). Condensate is a very high-gravity (i.e., generally greater than 50° API) liquid; it could exist in a dissolved gaseous state in the subsurface but liquefy at the surface. Crude oil with oil gravity greater than 10° API and condensate removed from the subsurface with conventional extraction techniques have been assessed for this effort.

Natural gas is a gaseous hydrocarbon resource, including both associated and non-associated gas; the terms natural gas and gas are used interchangeably in this report. Associated gas exists in spatial association with crude oil; it could exist in the subsurface as undissolved gas within a gas cap or as gas that is dissolved in crude oil (solution gas). Non-associated gas does not exist in association with crude oil. Gas resources that can be removed from the subsurface with conventional extraction techniques have been assessed for this inventory.

Crude oil and condensate are reported jointly as oil; associated and non-associated gases are reported as gas. Oil volumes are reported as stock tank barrels and gas as standard cubic feet. Oil-equivalent gas is a volume of gas (associated and/or non-associated) expressed in terms of its energy equivalence to oil (i.e., 5,620 cubic feet of gas per barrel of oil) and is reported in barrels. The combined volume of oil and oil-equivalent gas resources is referred to as barrel of oil equivalent (BOE) and is reported in barrels.

This 2023 Inventory does not include potentially large quantities of hydrocarbon resources that could be recovered from known and future fields by enhanced recovery techniques, gas in geopressured brines, natural gas hydrates,[4] or oil and natural gas that could be present in insufficient quantities or quality (e.g., low permeability "tight" reservoirs) to be produced by conventional recovery techniques. In some instances, the boundary between these resources is somewhat indistinct; however, not included in this assessment is any significant volume of resources produced using unconventional recovery techniques.

4. Data Sources: This 2023 Inventory is based on the analysis of both public information and a significant amount of proprietary geologic, geophysical, and engineering data. BOEM has access to all subsurface data obtained by industry from operations and activities performed under permits or mineral leases (e.g., 30 Code of Federal Regulations [CFR] 551.11). As of December 1, 2023, BOEM held 180 OCS lease sales awarding 32,332 tracts to industry for the exploration, development, and production of oil and natural gas since 1954. As a condition of these leases and associated permitted activity, BOEM acquired approximately 3.4 million line-miles of two-dimensional (2-D) seismic data and nearly 380,000 OCS blocks of three-dimensional (3-D) seismic data. Moreover, BOEM has accumulated geologic and reservoir engineering information from more than 50,000 wells drilled on the OCS.

The industry exploration activities have resulted in the discovery of more than 1,300 fields that provide a long history of oil and gas production data. Additionally, BOEM has purchased much of

[4] BOEM has assessed in-place gas hydrate resources on the OCS (BOEM Factsheet RED-2012-01) but has not quantified the portion of those resources that could be technically or economically recoverable.

the seismic and well data from offshore the Canadian Arctic, Canadian North Atlantic, Bahamas, and Cuba. BOEM evaluated and considered publicly available information from the onshore portions of the OCS basins, as well as international geologic analogs including the North Sea, North Africa, Angola, Australia, Brazil, Norway, Canada, and Mexico. The BOEM database of geologic, geophysical, and engineering data serves as the foundation for the assessment of geologic plays and undiscovered resources and the delineation of discovered resources and reserves.

5. Limitations of Resource Assessments: Assessments of undiscovered and, to a lesser extent, discovered, resources are an attempt to quantify something that cannot be accurately known until the resource has been essentially depleted. Despite this uncertainty, resource assessments are a valuable input to develop energy policy and for corporate planning, such as for ranking exploration opportunities, as a basis for economic analyses, and assessments of technology and capital needs. Resource assessment results do not imply a rate of discovery or a likelihood of discovery and production within a specific time frame. In other words, resource assessments cannot be used directly to draw conclusions or forecasts related to the rate of conversion of these undiscovered resources to reserves and ultimately production. However, to the extent that industry relies on its own assessment results and external assessments for a given area, increases in resource estimates could change perceptions of expected returns on capital and ultimately result in increased exploration activity.

Imperfect knowledge is associated with almost every facet of the assessment process. Dreyfus and Ashby (1989) noted that resource assessments are performed at widely varying levels of detail and precision. At one end of the spectrum lie estimates of proved reserves. These assessments rely primarily upon detailed investigations incorporating relatively abundant subsurface G&G data, as well as actual reservoir performance information associated with each reservoir. At the other end of the spectrum is the appraisal of undiscovered resources that might exist in areas of regional, national, or even global scope. While dealing with a similar type of data as reserve estimates, the scope is extended to a generalized inference of the probable quantities of undiscovered hydrocarbon resources that may exist in broad areas. All resource estimates are subject to continuing revision as undiscovered resources are converted to reserves and reserves to production, and as improvements in data and assessment methods occur. Uncertainty surrounding the estimates also decreases as the asset progresses through this cycle.

It is implied in the assessment of undiscovered resource volumes that an unknown portion of the undiscovered resources may never be produced or even found, resulting in fewer resources being recovered than are in place. Conversely, some resources may never be accounted for, which could lead to an underestimation of the total. In sum, resource estimates should be viewed from the perspective of the point in time the assessment was performed based on the data, information, and methodology available at that time.

6. Role of Risk and Uncertainty in Resource Assessments: Hydrocarbon exploration is a process that includes an often-high probability of not finding oil or gas as predicted; this is referred to as geologic risk. Nearly every component of the assessment process incorporates a consideration of risk and uncertainty. The accumulation of petroleum in significant quantities requires the juxtaposition of many complex geologic events: the accumulation of organic matter in a source rock; the maturation of this organic matter into petroleum; the presence of a reservoir rock with sufficient thickness, porosity, and permeability; the migration of the petroleum into a trap with adequate size and seals; and the preservation of the petroleum in the trap. Prior to drilling, especially in frontier or unexplored areas, the actual existence of these geologic conditions can be largely unknown. Not only must all of these conditions coexist, but they must also converge at a particular location, an unlikely event that results in a high probability of failure. Even if all of these conditions coexist at a particular location, there remains considerable uncertainty regarding the effectiveness of a seal, the size of a trap, the quality and thickness of the reservoir, and the volume and type of hydrocarbons that not only migrated into the trap but were preserved and still remain to be recovered.

In general, geologic risk and uncertainty in estimates of undiscovered oil and natural gas are greatest for frontier areas that have had little or no past exploratory effort. For areas that have been extensively explored and are in a mature development stage, many of the geologic risks have been reduced or eliminated and the degree of uncertainty in possible outcomes narrowed considerably. As a result, resource potential can be evaluated with much more confidence. However, even in some mature producing areas, such as the GOM shelf, considerable uncertainty remains about the petroleum potential at greater drilling depths. Uncertainty also pervades projections of whether potential reservoirs have been unrecognized or bypassed in past drilling. Similarly, in frontier areas where resource estimates are largely based on analog comparisons between maturely explored areas and unexplored areas, uncertainty is introduced because each area or basin has unique characteristics.

Additionally, although scientists can estimate the quantity of undiscovered resources based on the present state of geological and engineering knowledge, modified by a consideration of future technological advancement, the percentage of that quantity that could actually be discovered and produced is ultimately driven by the economics of supply and demand. In BOEM resource assessments, undiscovered economical recoverable resources (UERR) refer to the portion of the undiscovered technically recoverable resources that BOEM estimates is economically recoverable under imposed economic and technologic conditions. However, uncertainties about future crude oil and natural gas prices and the costs of exploration and development (including the impacts of technology advances on costs) adversely affect all economic resource estimates. In terms of the commercial viability of an accumulation, there is substantial uncertainty concerning total costs and future market prices, resulting in additional economic risk and uncertainty for a project. In short, uncertainties embodied in economic assumptions lead to significant uncertainties in estimates of economically recoverable resources and account for some of the large differences among published estimates.

Finally, there are no foolproof, completely mechanical methods to estimate potential quantities of undiscovered hydrocarbon resources. Because all methods contain elements of subjective judgment or expert opinion, the risk analysis and degree of uncertainty reflected in an estimate is affected by the knowledge, experience, and assessment expertise of the personnel performing the assessment. This expertise is continually refined as new information tests the validity of previous assumptions.

The BOEM stochastic resource assessment methodology incorporates geologic risk and uncertainty at both the prospect and geologic play level. The level of uncertainty is reflected in the frequency distributions for uncertain variables affecting the volume of hydrocarbons that could exist in a prospect and the number of accumulations that could exist in a play if technically recoverable hydrocarbons are present. Resource volumes are estimated under the condition that the hydrocarbons are present in a prospect and play. These conditional assessments are then weighted by the appropriate risk analysis, which considers the probability that hydrocarbons could in fact not be present in a prospect or play. Key factors in this analysis include the potential for the existence of reservoir quality rock, adequate trapping mechanisms, mature source rock, and the presence of effective migration pathways for moving the hydrocarbons from the source rock to the trap. Prior to the 2021

Assessment, BOEM incorporated changes into the qualitative and quantitative risk assessment process in an effort to improve consistency across OCS regions (BOEM, 2021b).

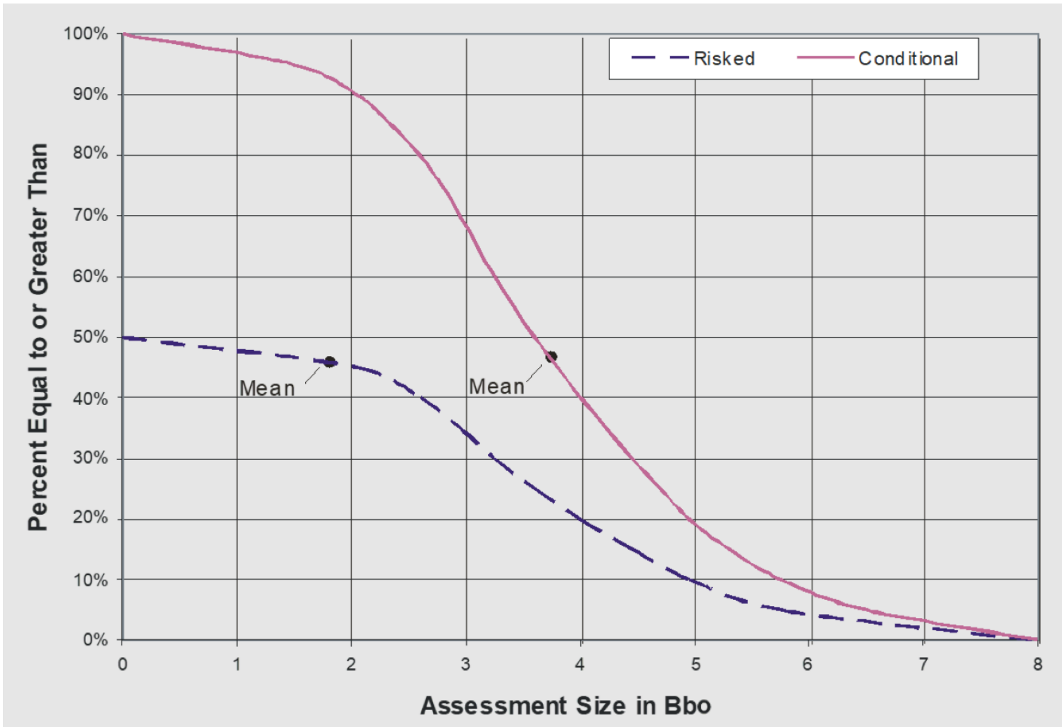
Users of petroleum assessments sometimes focus on only one number, the mean value, as providing a definitive answer to the question of how much undiscovered petroleum could exist on the OCS. In reality, an assessment offers a broad range of possible values that can be reported out at various fractiles. BOEM estimates of undiscovered resources are generated stochastically and are reported out at the mean value and at the 95th and 5th percentile values. This range of estimates corresponds to a 95% probability (i.e., a 19 in 20 chance) and a 5% probability (i.e., a one in 20 chance) of there being more than those amounts present, respectively. The 95th and 5th percent probabilities are considered reasonable minimum and maximum values, and the mean is the average or expected value.

BOEM assessments of undiscovered resources are developed at the geologic play level. For each play, BOEM estimates the probability of geologic success by subjectively estimating the chance that at least a single hydrocarbon accumulation exists somewhere in the play; this is referred to as the marginal probability of hydrocarbons for the play (MP_{hc}). For geologic plays where hydrocarbons have previously been discovered, the MP_{hc} equals 100%. For conceptual geologic plays, where conditions favorable for the hydrocarbon development are likely to exist but hydrocarbons have not yet been discovered, the MP_{hc} is less than 100%.

The play-level assessment of MP_{hc} is comprised of a subjective analysis performed on each of the critical components necessary for the existence of a productive play: the hydrocarbon source, reservoir, and trap components. The MP_{hc} or play chance (White, 1980) analysis assesses individually the probability of existence for each of the critical geologic factors. If a play contains more than a minimal show of hydrocarbons, as in an established play, all critical geological factors are known to be present. If any of these essential factors are not present or favorable, the play will not exist. The probability of the presence of each factor is subjectively estimated by the assessment team, where each component is typically considered to be geologically and statistically independent from the others. For a complete description of BOEM's process for quantifying geologic risk, refer to BOEM (2021b).

This play-level MP_{hc} is in addition to the prospect-level MP_{hc}, which relates the chance of all critical geologic factors being simultaneously present in an individual prospect, assuming that the play exists. The play-level MP_{hc} reflects the regional play-level controls affecting all prospects within the play. The prospect-level MP_{hc} incorporates prospect-specific considerations. The realization that an individual prospect could be devoid of hydrocarbons does not mean that the play is non-productive, nor does the existence of hydrocarbons in a play assure their existence in a particular prospect. However, if the play is devoid of hydrocarbons, so are all of the prospects contained within that play. BOEM assessments of undiscovered resources (BOEM, 2021a) report volumes of oil and natural gas that are discounted by the probability that the area assessed is devoid of technically recoverable hydrocarbons. **Figure 4** illustrates the effect of this risking process on reported resource estimates.

Figure 4. Sample Cumulative Probability Distribution for a Basin showing Risked and Conditional (Unrisked) Results



Note: The MP_{hc} at the basin level for this example is 0.5.

Risked estimates reflect the long-term expected outcome from repeated exploration in areas identical to the one being assessed. For example, an MP_{hc} of 0.5 means that 50% of the time the basin will not contain hydrocarbons and the other 50% of the time technically recoverable hydrocarbons will be present. In cases where exploration is successful, the volume that would be discovered is represented by the solid curve labeled "Conditional." The conditional success case in **Figure 4** shows there is a 95% chance that at least 1.5 billion barrels of oil (Bbo) will be found and a 5% chance that the amount found will be at least 6.5 Bbo. The average or mean volume is assessed at 3.75 Bbo. The dashed curve labeled "Risked" depicts the application of geologic risk to this play, which accounts for the possibility that hydrocarbons may not be found. Note that on this curve there is a 50% chance that the volume of resources discovered will be greater than zero, and the corresponding 95th percentile (F95) and 5th percentile (F5) estimates are zero and 5.5 Bbo, respectively. The reported mean estimate is 1.88 Bbo, half of the mean value of the conditional success case.

7. Role of Technology and Economics in Resource Assessment: The 2023 Inventory assesses only technically recoverable hydrocarbon resources, both discovered and undiscovered. In developing these estimates, BOEM makes fundamental assumptions regarding future technology and economics, particularly as they relate to undiscovered resources. The variability associated with the magnitude and effect of these factors introduces additional uncertainty to the resource assessment. Thus, the interplay of technological advancement and changing economic conditions plays not only a crucial role in assessing discovered and undiscovered technically recoverable resources, but also determines the extent of the commercial frontier of hydrocarbon resources. Newer, improved, and emerging technologies used to enhance the efficiency of exploration programs, and those employed to increase the volume of hydrocarbons production, are discussed below.

BOEM estimates the quantity of technically recoverable resources on the basis of the present state of geologic and engineering knowledge, modified by a subjective consideration of future technologic advancement. However, the quantity of resources that could ever actually be produced depends in large part on the economic market driven by consumer demand. New capital-intensive exploration and development technologies require higher product prices for implementation. Typically, as these high-cost technologies are more widely employed, costs decrease, resulting in even more widespread use of these techniques. On the other hand, new modest-cost exploitation technologies that increase recoveries or decrease finding, development, or operating costs can markedly increase estimates of technically recoverable resources without requiring an increase in product prices. A decrease in price, as experienced in the late 1980s, can be moderated or offset by the implementation of a technology that reduces unit costs or vice versa. Rogner (1997) concluded that "over the last century technology has probably had a more profound and lasting impact on prices than prices have had on technology."

Generally, the effects of price and technology can be considered interchangeable within the context of a resource assessment. There is a technological and economic limit to the amount of in-place oil and natural gas resources that can be physically recovered from a reservoir. Within conventional reservoirs, approximately 30 to 45% of the in-place oil and 60 to 80% of the in-place natural gas resources are typically recovered through both primary and secondary recovery mechanisms. Three principal factors affect the amount of oil or gas that can be recovered from a known reservoir: (1) rock and fluid properties; (2) technology; and (3) economics. While industry cannot change the properties of the rock and fluid, it can develop new or improved techniques to recover more oil from the subsurface, thus adding to the resource base.

For instance, technological progress and innovation are the key factors enabling development and production of oil and gas in new frontier regions in deepwater and in deeper reservoirs. Most recently, technologies adapted to high pressure and high temperature (HPHT) environments are the key drivers for large oil and gas resources hosted in the Lower Tertiary formations of the GOM. Subsea technology and extended architecture systems have enhanced production of offshore oil and gas in remote and challenging environments of the deep and ultra-deepwater areas where infrastructure needed to produce and transport hydrocarbons to shore is limited.

These new technologies contribute to the reduction of exploration and development costs associated with previously un-economical resources. For example, deepwater drilling costs are showing a downward trend as producers streamline operations and prioritize drilling in core areas.

Another important aspect of the role of technology in a resource assessment is the ability to re-think fundamental approaches to developing exploration play concepts through the deployment of new technologies. Scientific advances aided by new technologies have improved the ability to identify previously unknown potential exploration plays. The introduction of new seismic data acquisition techniques, high end computing technology, and new data processing algorithms have resulted in the ability for geoscientists to analyze areas below massive salt bodies underlying a large portion of the GOM OCS. These innovative seismic technologies allow for better imaging of the sub-salt horizons in the GOM and have enabled many additional hydrocarbon discoveries.

Progress in drilling technology has allowed for expanded exploration into deeper water depths and extended total drilling depth. Techniques such as ultra-deep and extended-reach drilling increase both the resource base and the amount of hydrocarbon production. Examples of these include Cobalt International Energy's drilling of the Ardennes prospect in the Green Canyon protraction area in the

GOM to a depth of 35,935 feet true vertical depth subsea in 2013 and Exxon's extended reach drilling of more than 40,000 feet at the Odoptu field off Sakhalin Island, Russia. These continually evolving drilling technologies allow for the capture of resources that would have otherwise been left undiscovered and undeveloped. The introduction of drill ships and semi-submersibles capable of drilling in up to 12,000 feet of water, coupled with dual-gradient drilling techniques, could expand the envelope of producible oil and gas resources in very challenging environments.

As the search for oil and gas leads to even more challenging environments, newer technologies are required for HPHT wells that pose drilling and completion issues for casing, tubing, fluids, packers, perforating equipment, blow-out preventers, safety valves, and intelligent well monitoring. The HPHT technologies, currently applying to 10,000–15,000 pounds per square inch (psi) and 250–400 degrees Fahrenheit (°F), are being pushed out further to 20,000–30,000 psi and 400–500°F, which could open up increased access to hydrocarbon resources.

In all resource assessments, BOEM incorporates the most recent empirical information related to the technological limits of oil and gas exploration and production. Technology improvements typically unlock new opportunities for exploration and production companies to find and produce additional resources, and these opportunities are reflected in BOEM's updated volumetric assessments of discovered and undiscovered oil and gas resources.

B. Inventory Results

The 2023 Inventory reflects information consistent with BOEM's most recent assessment of undiscovered oil and gas resources (BOEM, 2021a), which is a comprehensive appraisal that considers relevant data and information available as of January 1, 2019. This 2023 Inventory also includes information related to discovered oil and gas on the OCS, including produced oil and gas, contingent resources, reserves remaining in the ground, and expected growth of the reserves. Cutoff dates to estimate discovered resources are also set to January 1, 2019, to maintain data fidelity as resource categories are aggregated into a total endowment by region and for the entire OCS.

1. Cumulative Production: Cumulative production of oil and gas from the OCS is a measured quantity that can be reported with relative precision. Each month, companies operating on the OCS report data to the Office of Natural Resources Revenue (ONRR) on the oil and gas resources they produced. This includes the amount produced, the value of their production, and the amount of royalties they owe. The Bureau of Safety and Environmental Enforcement (BSEE) provides comprehensive reporting on production volumes based on data obtained from Oil & Gas Operations Reports (OGORs) submitted by offshore operators to ONRR.

As of January 1, 2019, 22.81 Bbo and 191.65 Tcfg have been produced from the U.S. OCS (**Table 2a**); of this total, 56.9 billion barrels of oil-equivalent (BBOE) production, more than 95%, came from the GOM OCS. **Table 2b** shows additional yearly production data beyond January 1, 2019, and cumulative production as of January 1, 2023. The 2019 through 2022 produced volume data were not included in the total endowment due to the availability date of undiscovered resources and discovered reserves and contingent resources, where an addition of produced volumes would require a volume reduction to another resource category.

Table 2a. Cumulative Oil and Gas Production on the OCS as of January 1, 2019

OCS Region	***Cumulative Production***	
	Oil	***Gas***
	(Billion Barrels)	***(Trillion Cubic Feet)***
Alaska	0.03	0.00
Atlantic	0.00	0.00
Gulf of Mexico	21.42	189.80
Pacific	1.36	1.85
Total	**22.81**	**191.65**

Table 2b. Additional Oil and Gas Production Data by Region through January 1, 2023

Year	Alaska	Pacific	GOM	Total
Oil (Billion Barrels)				
Cumulative-2018	0.03	1.36	21.42	22.81
2019	0.0005	0.0044	0.6927	0.6977
2020	0.0005	0.0046	0.6097	0.6148
2021	0.0004	0.0040	0.6230	0.6274
2022	0.0004	0.0027	0.6302	0.6333
Cumulative Production (January 1, 2023) (Bbo)	**0.03**	**1.38**	**23.98**	**25.38**
Gas (Trillion Cubic Feet)				
Cumulative-2018	0	1.85	189.90	191.65
2019	0.0027	0.0029	1.0342	1.0399
2020	0.0022	0.0028	0.8064	0.8113
2021	0.0025	0.0028	0.7920	0.7972
2022	0.0023	0.0024	0.7829	0.7876
Cumulative Production (January 1, 2023) (Tcf)	**0.01**	**1.86**	**193.32**	**195.09**

Notes: The annual production numbers were rounded off to four digits while the cumulative totals remain rounded at two digits; this was done to ensure the yearly production numbers do not round to 0 when production was present. No oil or gas volumes have been produced on the Atlantic OCS.

2. Reserves: Reserves are discovered oil and gas resources that meet the criteria of being recoverable, commercial, and remaining. Reserves are estimated at different stages during the exploration and development cycle of a hydrocarbon accumulation (i.e., after exploration and delineation drilling, during development drilling, after initial production, and, finally, after production has been established). Different quantitative methods of estimating the volume of reserves are appropriate at each stage, where reserve estimating procedures generally progress from volumetric assessment to performance-based techniques as the field matures (Society of Petroleum Engineers, 2007). The relative uncertainty associated with these estimates decreases as more subsurface information and production history become available. Estimates of reserves are uncertain; however, traditional industry practice has been to calculate reserves through a deterministic process and present the results as single point estimates.[5] The total remaining reserves in more than 1,300 fields on the OCS are estimated to be 3.69 Bbo and 6.05 Tcfg (4.77 BBOE); more than 90% of these reserves are present within the GOM (see **Figures 5a** and **5b**).

3. Contingent Resources: Contingent resources are discovered resources estimated to be potentially recoverable from known accumulations but are not available for commercial development due to one or more contingencies. When a discovery is made, the identified hydrocarbon accumulation is classified as a contingent resource since a development project has not yet been identified. Should a commercial project be abandoned at any phase of development, any estimates of remaining hydrocarbon volumes could be re-classified to contingent resources (BOEM, 2020a). The contingent resources for the entire OCS are estimated to be 4.18 Bbo and 4.07 Tcfg.

4. Reserves Appreciation: Cumulative production plus total estimated future production (from reserves) equals the estimate of the ultimate recovery (EUR) from a field. Predicting a field's true EUR requires an estimate of its future reserves growth or appreciation. The reserves appreciation phenomenon has been observed in onshore and offshore basins for years. During the initial years after discovery, reserve estimates typically increase rapidly. In later years, the rate of growth tends to level off at a much smaller annual rate of increase. Appreciation is the result of numerous factors, including the following:

- Standard industry practices for reporting initial proved reserves are often conservative in the early stages of development;
- Future drilling provides additional reservoir and drill stem test information to improve knowledge of the petrophysical properties and producibility of the petroleum reservoir;
- When physical expansion of the field occurs through the discovery of new reservoirs or the extension of existing reservoirs; and
- Experience from actual field performance, the implementation of new technology, and reductions in cost for production techniques resulting in improved recoveries.

Reserves appreciation in the GOM routinely exceeds new field discoveries and contributes the bulk of annual additions to proven reserves. Reserves appreciation is an important consideration in any analysis of future oil and natural gas supplies. Future reserves appreciation within the existing active fields in the GOM OCS is estimated at 8.84 Bbo and 30.35 Tcfg (14.24 BBOE).

Reserves appreciation has not been estimated for the existing fields on the Pacific and Alaska OCS. At the time of this report, those fields have not exhibited significant growth in EUR that could be used to project future appreciation.

5. Undiscovered Technically Recoverable Resources (UTRR): BOEM publishes a formal national assessment of UTRR and UERR every 5 years. BOEM's most current assessment of undiscovered resources was finalized in 2021 (BOEM, 2021a), and work is underway to prepare for the 2026 Assessment. Resource estimates are calculated using a stochastic approach and results are presented as a range, where the mean is the expected value. As shown in **Table 3**, UTRR estimates for the entire OCS range from 57.32 Bbo at the F_{95} fractile to 81.75 Bbo at the F_5 fractile, with a

[5] The BOEM reserves database in the GOM OCS is being revised to allow for a probabilistic reporting of reserves to better capture the uncertainty of the volume estimates.

mean of 68.79 Bbo. Similarly, natural gas estimates range from 183.46 at the F_{95} fractile to 278.22 Tcfg at the F_5 fractile, with a mean of 229.03 Tcfg.

Table 3. Undiscovered Technically Recoverable Oil and Gas Resources by Planning Area

Region	Oil (Bbo)			Gas (Tcfg)		
	F_5	Mean	F_{95}	F_5	Mean	F_{95}
Alaska OCS	**34.08**	**24.69**	**17.00**	**161.63**	**124.03**	**91.07**
Chukchi Sea	23.69	15.72	9.69	113.94	79.58	51.31
Beaufort Sea	11.19	5.74	2.30	30.18	16.10	6.57
Hope Basin	0.41	0.14	0.00	9.92	3.51	0.00
Navarin Basin	0.75	0.26	0.00	5.70	2.14	0.00
North Aleutian Basin	1.96	0.79	0.10	18.45	9.02	1.33
St. George Basin	0.52	0.22	0.02	6.66	2.81	0.31
Norton Basin	0.20	0.06	0.00	11.10	3.35	0.00
Cook Inlet	1.94	1.04	0.38	1.76	1.18	0.63
Gulf of Alaska	1.59	0.66	0.11	10.27	4.33	0.67
Shumagin	0.05	0.01	0.00	1.75	0.41	0.00
Kodiak	0.17	0.04	0.00	6.76	1.60	0.00
Atlantic OCS	**9.94**	**4.31**	**0.64**	**70.10**	**34.09**	**5.94**
North Atlantic	6.36	1.87	0.04	38.00	11.50	0.35
Mid-Atlantic	6.30	2.25	0.00	49.02	21.42	0.04
South Atlantic	0.57	0.20	0.00	3.62	1.17	0.00
Gulf Of Mexico OCS	**36.27**	**29.59**	**23.31**	**62.56**	**54.84**	**46.88**
Western Gulf of Mexico	7.80	6.05	4.45	13.36	11.39	9.33
Central Gulf of Mexico	22.99	18.65	14.59	36.17	31.19	26.37
Eastern Gulf of Mexico	6.78	4.87	3.27	17.06	12.25	7.86
Straits of Florida	0.05	0.02	0.00	0.04	0.01	0.00
Pacific OCS	**14.20**	**10.20**	**6.91**	**23.43**	**16.07**	**10.15**
Washington/Oregon	1.14	0.40	0.00	5.89	2.25	0.03
Northern California	3.49	2.07	1.06	5.32	3.55	2.13
Central California	3.89	2.41	1.22	4.19	2.49	1.18
Southern California	8.81	5.33	2.58	13.75	7.78	3.51
Total OCS	**81.75**	**68.79**	**57.32**	**278.22**	**229.03**	**183.46**

Source: BOEM, 2021a
Note: Only mean values are additive.

6. Total Endowment: The total endowment of hydrocarbons on the OCS comprises 108.31 Bbo and 461.15 Tcfg (190.36 BBOE). The total endowment includes production, reserves, reserves appreciation, contingent resources, and the mean value of the distribution of undiscovered resources (**Figures 5a** and **5b** and **Table 4**). Approximately 30% of the total endowment in terms of BOE has already been produced, with an additional 13% attributed to remaining reserves, contingent resources, and reserves appreciation. After nearly 75 years of exploration and development, 58% of the BOE total endowment on the OCS remains as undiscovered resources.

Figure 5a. Distribution of Total Oil Hydrocarbon Endowment by Region and Resource Category

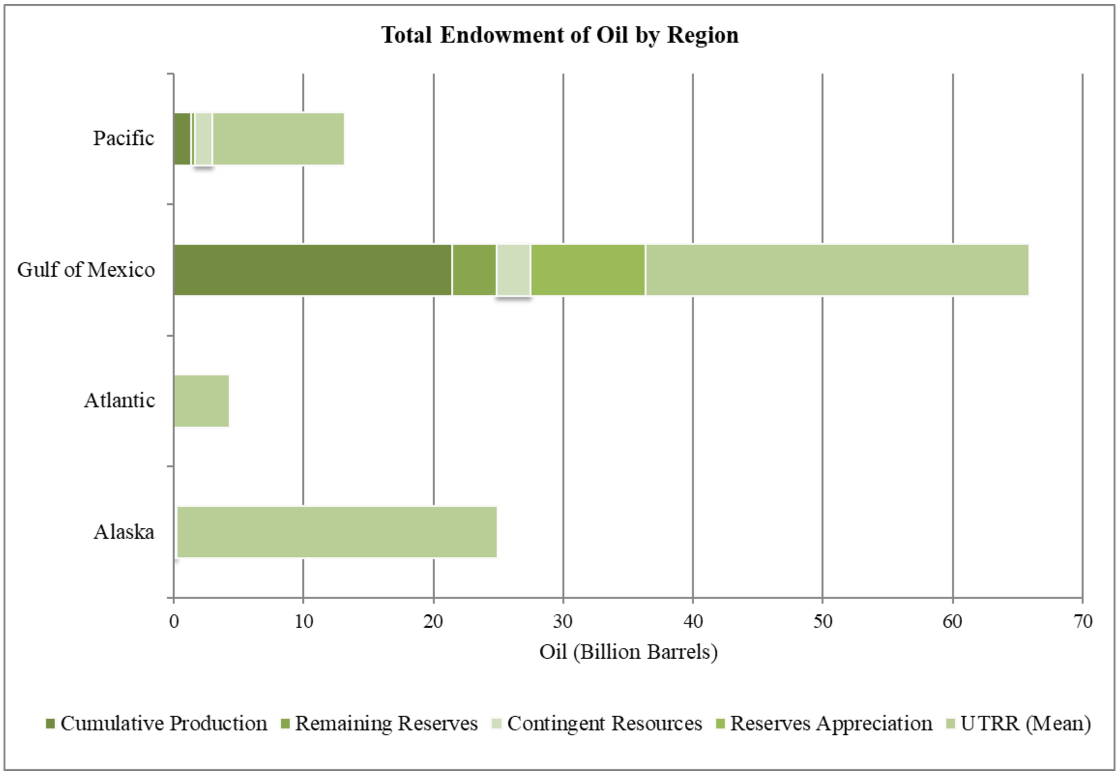


Figure 5b. Distribution of Total Gas Hydrocarbon Endowment by Region and Resource Category

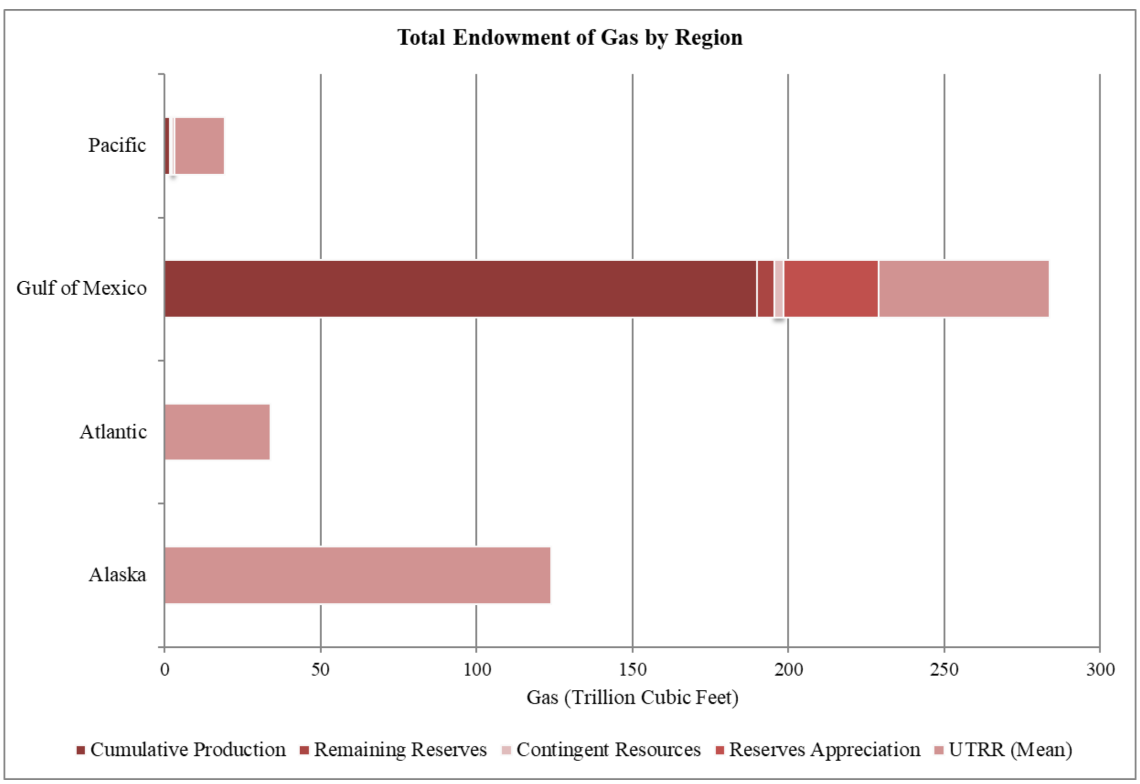


Table 4. Total Endowment of Technically Recoverable Oil and Gas on the OCS

OCS Region	Cumulative Production		Remaining Reserves		Contingent Resources		Reserves Appreciation		Undiscovered Technically Recoverable Resources						Total Endowment	
	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil (Bbo)			Gas (Tcfg)			Oil	Gas
	(Bbo)	(Tcfg)	(Bbo)	(Tcfg)	(Bbo)	(Tcfg)	(Bbo)	(Tcfg)	F_5	Mean	F_{95}	F_5	Mean	F_{95}	(Bbo)	(Tcfg)
Alaska	0.03	0	0.01	0	0.18	0	0	0	34.08	24.69	17.00	161.63	124.03	91.07	24.91	124.03
Atlantic	0	0	0	0	0	0	0	0	9.94	4.31	0.64	70.10	34.09	5.94	4.31	34.09
GOM	21.42	189.80	3.44	5.71	2.65	3.04	8.84	30.35	36.27	29.59	23.31	62.56	54.84	46.88	65.94	283.74
Pacific	1.36	1.85	0.24	0.34	1.35	1.03	0	0	14.20	10.20	6.91	23.43	16.07	10.15	13.15	19.29
Total OCS	**22.81**	**191.65**	**3.69**	**6.05**	**4.18**	**4.07**	**8.84**	**30.35**	**81.5**	**68.79**	**57.32**	**278.22**	**229.03**	**183.46**	**108.31**	**461.15**

Notes: Figures reflect the 2021 National Assessment (BOEM, 2021a) and internal data from the BOEM regional offices with a cutoff date of January 1, 2019.

7. Comparison of the 2023 Inventory with the 2018 Inventory: In the reporting window between the 2018 Inventory and the 2023 Inventory, 2.95 Bbo and 5.85 Tcfg were produced from the OCS, with the GOM accounting for almost the entire increase in production. The volume of reserves and reserves appreciation for both oil and gas in the 2023 Inventory decreased in comparison with the 2018 Inventory.

The sum of reserves, reserves appreciation, and contingent resources for the 2023 Inventory equals 16.71 Bbo and 40.47 Tcfg, compared to 17.51 Bbo and 63.12 Tcfg reported in the 2018 Inventory. Despite producing 2.95 Bbo in the GOM since the last report, the estimate of GOM oil reserves, reserves appreciation, and contingent resources decreased by only 0.80 Bbo. Estimates of natural gas reserves, reserves appreciation, and contingent resources in the GOM decreased by 22.65 Tcfg while 5.85 Tcfg were produced in the GOM. In other words, while new discovered oil resources were added to offset oil production, discovered gas resources decreased through both production and re-assessment of the resource base.

Figures 6a and **6b** compare the mean estimates along with the 5th and 95th percentile of UTRR from BOEM's two most recent assessments of undiscovered resources (2016 and 2021) for oil and gas, respectively. For the entire OCS, mean UTRR estimates decreased 23% for oil and decreased 30% for gas.

In the GOM, the UTRR mean estimate for oil dropped 39% and the mean estimate for gas decreased by approximately 61%. The decrease in UTRR gas is attributed to a refinement of prospect size on the shelf and field size distributions for geologic plays in shallow water that better represent BOEM's understanding of recent exploratory well results, the size of recently discovered gas fields, and the range of prospect sizes that have received bids in recent GOM lease sales.

Mean estimates of UTRR on the Alaska, Atlantic, and Pacific OCS in the 2021 Assessment either decreased slightly or remain unchanged compared to the 2016 Assessment. Changes are largely due to refinements in analog geologic play analysis and a re-evaluation of geologic risk prior to the 2021 Assessment.

Figure 6a. Comparison of UTRR for oil, 2016 and 2021 National Assessments

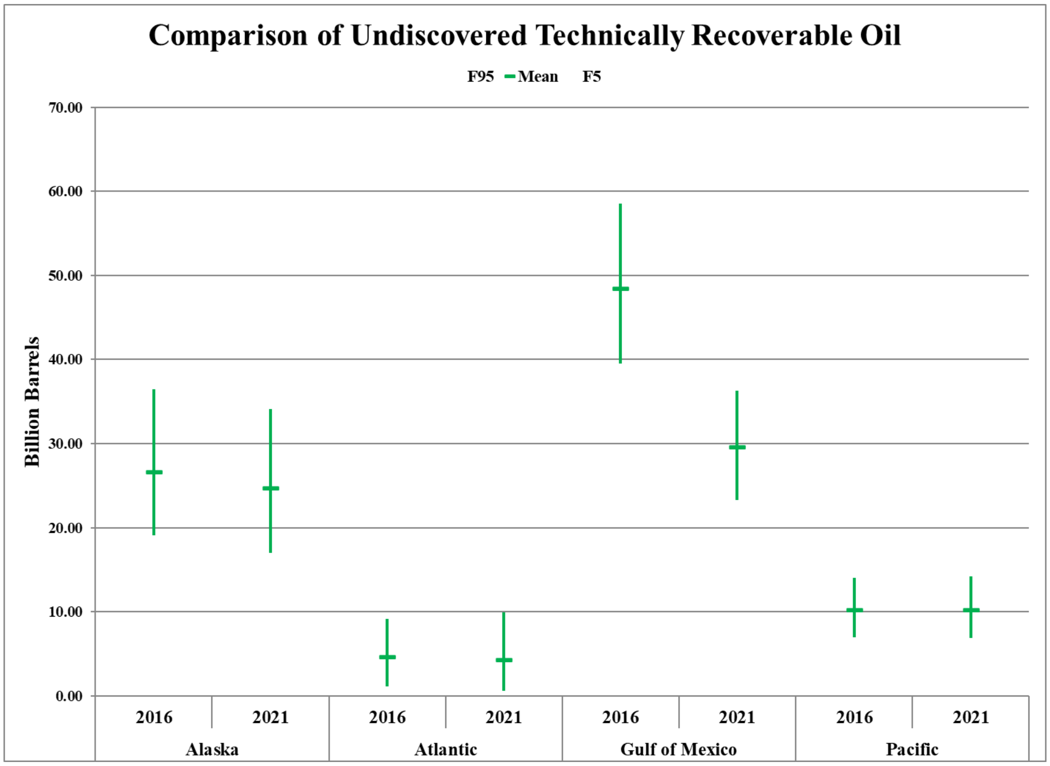
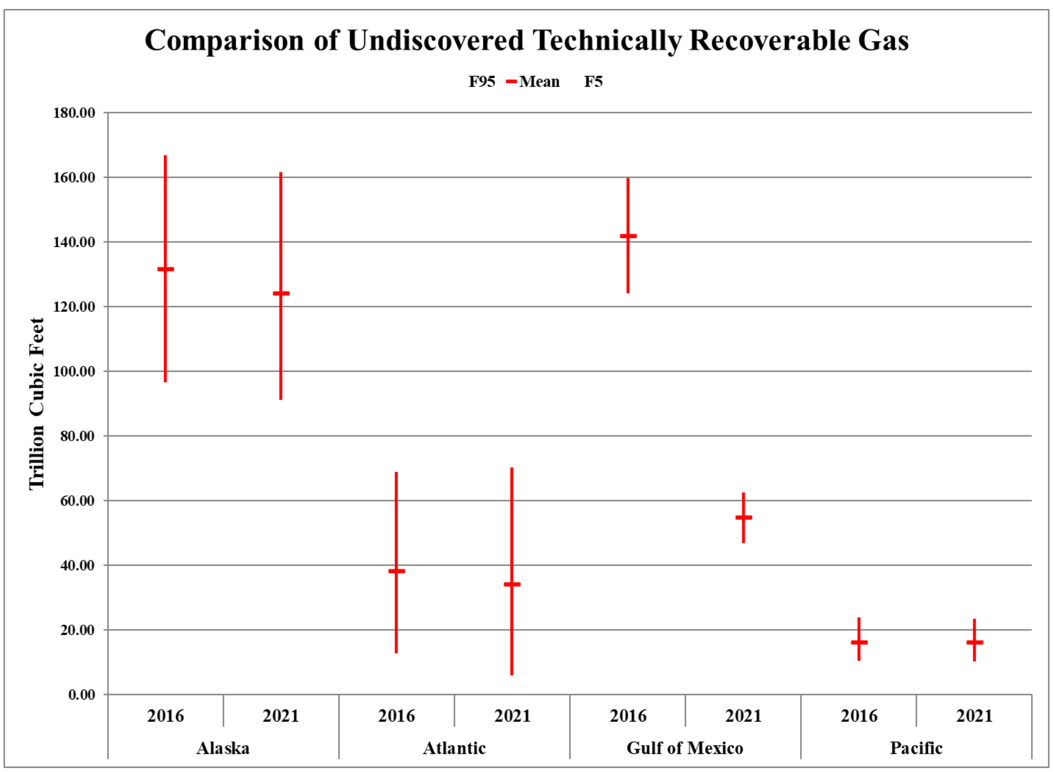


Figure 6b. Comparison of UTRR for gas, 2016 and 2021 National Assessments



IV. Historical Changes to Resource Estimates

Since 1975, DOI has completed 11 comprehensive, large-scale assessments of the undiscovered petroleum potential of the OCS. These estimates were prepared by different bureaus in some cases, using assessment methods that continued to evolve over time as more information became available and technology improved. The techniques used vary from simple Delphi and volumetric yield approaches to geologic analogy, to statistical techniques that use finding rates and discovery process models, to summation of prospects and play assessment approaches employing sophisticated discounted cash flow analysis. The estimates presented all appear to have no time limit regarding realization, although they assume discovery and recovery under the economic and technologic trends prevailing at the time of the assessment. The assessments also cover different areas, measure different resources, (e.g., UTRR versus UERR), and employ different assumptions developed from the perspective of different analytical information available at a particular point in time.

To effectively compare resource estimates over time, one must develop an understanding of how the estimates were prepared; the extent and reliability of the data upon which they were based; the expertise of the assessors; the implications and limitations of the methodology used; and the nature of any geographic, economic, technologic, or time limitations and assumptions that could apply. While many of the DOI assessments conducted from 1975–2021 include comprehensive reporting on methods and inputs that allow for an understanding of the factors above, some do not. However, an attempt to compare the changes in the estimates can be made in light of the geologic knowledge base available to each assessment team, the state of exploration and production technology, choice of assessment methodologies, and the portion of the resource base assessed between successive assessments.

The degree to which variations among the reported assessments are attributable to different perceptions of the resource base magnitude and distribution is impossible to determine. Estimates have a time dimension that impacts the degree of basic geologic knowledge available to the assessors, as well as their technologic and economic perceptions. During the period covered by the assessments between 1975 and 2021, there were approximately 40,000 wells drilled and more than 1,125 fields discovered in the GOM region. During the 1968–2021 timeframe, more than 3.3 million line-miles of 2-D seismic and nearly 370,000 blocks of 3-D seismic were acquired on the OCS (BOEM, 2023). These examples help to demonstrate the evolving conditions and varying levels of available information that assessors must strive to account for in their evaluations.

The first two assessments (1975 and 1980) were performed by the U.S. Geological Survey (USGS), the next six assessments (1985, 1990, 1991, 1996, 2001 and 2006) were performed by the Minerals Management Service (MMS), and the remainder by BOEM (a successor agency to the MMS). **Tables 5a** and **5b** summarize the results from each assessment. Note that only UERR were reported for the 1975, 1981, 1985, and 1991 assessments. While **Tables 5a** and **5b** do not report out on UERR for assessments beginning in 2001, each of these recent assessments include an analysis of both UTRR and UERR. BOEM has shifted the focus of reporting to UTRR as it provides a more reliable resource comparison between assessments without having to consider differences in cost and price assumptions. BOEM has, in recent assessments, supplemented the primary UTRR estimates with price-supply curves that demonstrate the sensitivity of resources to changes in the cost-price relationship.

Table 5a. Summary of DOI OCS Resource Assessments, 1975–1991

Organization	Effective Date	OCS Region	Risked Estimates of Undiscovered Resources									Total Endowment (Mean)		
			Oil (Bbo)[1]			Gas (Tcf)			BOE (Bbo)			Oil	Gas	BOE
			F_{95}	Mean	F_5	F_{95}	Mean	F_5	F_{95}	Mean	F_5	(Bbo)	*(Tcf)*	(Bbo)
USGS Miller et al., 1975	1/1/1975 UERR	Alaska	3.20	16.10	33.00	8.00	44.00	80.00	–	23.93	–	16.72	44.57	24.65
		Atlantic	0.00	3.25	6.55	0.00	10.00	22.00	–	5.03	–	3.25	10.00	5.03
		GOM	3.45	6.25	10.23	18.00	50.00	91.00	–	15.15	–	15.05	184.49	47.87
		Pacific	2.00	3.00	5.00	2.00	3.00	6.00	–	3.53	–	5.81	5.28	6.75
		Total OCS	**11.05**	**28.60**	**53.53**	**42.00**	**107.00**	**181.00**	–	**47.64**	–	**40.82**	**244.33**	**84.30**
USGS Dolton et al., 1981	mid-1980 UERR	Alaska	5.67	14.33	27.60	33.32	64.61	109.65	–	25.83	–	15.33	68.41	27.50
		Atlantic	1.37	5.51	14.17	9.17	23.66	42.82	–	9.72	–	5.51	23.66	9.72
		GOM	5.01	8.09	16.20	41.66	71.84	114.15	–	20.87	–	16.39	201.04	52.16
		Pacific	1.83	4.04	8.33	3.73	6.89	13.55	–	5.27	–	7.64	10.69	9.54
		Total OCS	**21.03**	**31.97**	**51.68**	**117.42**	**167.00**	**230.65**	–	**61.69**	–	**44.87**	**303.80**	**98.93**
MMS Cooke, 1985	7/1/1984 UERR	Alaska	–	3.33	–	–	13.85	–	–	5.79	–	3.33	13.85	5.79
		Atlantic	–	0.68	–	–	12.31	–	–	2.87	–	0.68	12.31	2.87
		GOM	–	6.03	–	–	59.64	–	–	16.64	–	15.34	165.84	44.85
		Pacific	–	2.19	–	–	4.70	–	–	3.03	–	3.62	7.00	4.87
		Total OCS	–	**12.23**	–	–	**90.50**	–	–	**28.33**	–	**22.97**	**199.00**	**58.38**
MMS Cooke, 1990	1/1/1987 UTRR	Alaska	0.59	3.84	11.21	4.67	16.75	39.42	–	6.82	–	3.84	16.75	6.82
		Atlantic	0.09	0.96	3.15	6.78	17.03	33.71	–	3.99	–	0.96	17.03	3.99
		GOM	5.52	9.57	15.12	63.02	103.34	156.92	–	27.96	–	20.45	225.54	60.58
		Pacific	0.81	3.51	8.92	3.50	8.01	15.07	–	4.94	–	5.18	10.48	7.04
		Total OCS	**9.20**	**17.88**	**25.60**	**97.80**	**145.13**	**204.80**	–	**43.70**	–	**30.43**	**269.80**	**78.44**
	1/1/1987 UERR Primary Case	Alaska	0.00	0.92	4.76	0.00	0.00	0.00	–	0.92	–	0.92	0.00	0.92
		Atlantic	0.00	0.25	1.01	0.00	4.51	9.77	–	1.05	–	0.25	4.51	1.05
		GOM	2.77	5.64	9.88	36.01	64.33	103.65	–	17.09	–	16.52	186.53	49.71
		Pacific	1.78	2.10	6.02	1.78	5.17	11.04	–	3.02	–	3.77	7.64	5.13
		Total OCS	**4.00**	**8.91**	**14.30**	**44.30**	**74.01**	**113.84**	–	**22.08**	–	**21.46**	**198.68**	**56.81**
MMS Cooke, 1991	1/1/1990 UERR	Alaska	0.00	1.87	7.16	0.00	0.00	0.00	–	1.87	–	1.87	0.00	1.87
		Atlantic	0.00	0.25	1.01	0.00	4.51	9.77	–	1.05	–	0.25	4.51	1.05
		GOM	1.24	6.34	17.16	27.90	64.74	122.68	–	17.86	–	17.21	193.84	51.70
		Pacific	0.63	2.49	6.12	2.46	6.15	12.14	–	3.58	–	4.43	8.83	6.00
		Total OCS	**3.56**	**10.95**	**23.93**	**46.44**	**75.40**	**133.68**	–	**24.36**	–	**23.76**	**207.18**	**60.62**

⋆ = Includes oil and condensate (natural gas liquids)

Table 5b. Summary of DOI OCS Resource Assessments, 1996 – 2021

Organization	Effective Date	OCS Region	Risked Estimates of Undiscovered Resources									Total Endowment (Mean)		
			Oil (Bbo)[1]			Gas (Tcf)			BOE (Bbo)			Oil (Bbo)	Gas (Tcf)	BOE (Bbo)
			F_{95}	Mean	F_5	F_{95}	Mean	F_5	F_{95}	Mean	F_5			
MMS, 1996	1/1/1995 UTRR	Alaska	16.85	24.31	33.57	58.01	125.93	229.53	28.68	46.72	70.61	24.35	126.63	46.88
		Atlantic	1.30	2.30	3.70	15.90	27.50	43.40	4.50	7.20	10.70	2.30	27.50	7.20
		GOM	6.00	8.30	11.10	82.30	95.70	110.30	21.20	25.40	30.00	26.24	273.90	75.05
		Pacific	9.00	10.70	12.60	15.20	18.90	23.20	11.80	14.10	16.60	12.61	21.58	16.48
		Total OCS	**37.10**	**45.61**	**55.30**	**186.30**	**268.03**	**369.20**	**72.90**	**93.42**	**117.00**	**65.50**	**449.61**	**145.62**
	1/1/1995 UERR	Alaska	1.41	3.75	7.65	0.02	1.11	4.33	1.43	3.95	8.20	3.79	1.81	4.11
		Atlantic	–	0.40	–	–	5.20	–	–	1.33	–	0.40	5.20	1.33
		GOM	–	4.90	–	–	57.90	–	–	15.20	–	22.84	236.10	64.85
		Pacific	–	5.30	–	–	8.30	–	–	6.78	–	7.21	10.98	9.16
		Total OCS	–	**14.35**	–	–	**72.51**	–	–	**27.25**	–	**34.24**	**254.09**	**79.45**
MMS, 2001	1/1/1999 UTRR	Alaska	16.50	24.90	35.40	55.00	122.60	226.80	28.00	46.70	71.90	24.90	122.60	46.70
		Atlantic	1.90	2.30	2.80	23.90	28.00	34.10	6.20	7.30	8.90	2.30	28.00	7.30
		GOM	33.40	37.10	44.90	180.40	192.70	207.20	65.50	71.40	81.80	60.10	428.63	136.38
		Pacific	9.00	10.70	12.60	15.20	18.90	23.20	11.80	14.10	16.60	13.20	21.77	17.11
		Total OCS	**63.70**	**75.00**	**88.30**	**292.10**	**362.20**	**468.60**	**117.80**	**139.50**	**166.90**	**100.50**	**601.00**	**207.49**
MMS, 2006	1/1/2003 UTRR	Alaska	8.66	26.61	55.14	48.28	132.06	279.62	17.25	50.11	104.89	26.65	132.06	50.15
		Atlantic	1.12	3.82	7.57	14.30	36.99	66.46	3.67	10.40	19.39	3.82	36.99	10.40
		GOM	41.21	44.92	49.11	218.83	232.54	249.08	80.15	86.30	93.43	71.91	443.40	150.81
		Pacific	7.55	10.53	13.94	13.29	18.29	24.12	9.91	13.79	18.24	13.05	21.17	16.82
		Total OCS	**66.60**	**85.88**	**115.13**	**326.40**	**419.88**	**565.87**	**124.68**	**160.60**	**215.82**	**115.43**	**633.62**	**228.18**
BOEM, 2011[2]	1/1/2009 UTRR	Alaska	8.81	26.61	55.53	47.43	131.45	271.04	17.25	50.00	103.76	26.67	131.45	50.06
		Atlantic	1.32	4.72	9.23	11.81	37.51	67.69	3.42	11.39	21.27	4.72	37.51	11.39
		GOM	38.86	48.40	59.18	193.99	219.46	245.25	73.38	87.45	102.82	85.03	472.75	169.15
		Pacific	6.73	10.20	14.30	10.11	16.10	23.75	8.53	13.06	18.53	13.12	19.40	16.57
		Total OCS	65.16	89.93	121.72	307.86	404.52	556.51	119.94	161.91	220.74	129.54	661.11	247.17
BOEM, 2016a	1/1/2014 UTRR	Alaska	19.09	27.28	37.43	96.76	131.55	167.98	36.30	50.70	67.32	26.65	131.45	50.04
		Atlantic	1.15	4.59	9.19	12.80	38.17	68.71	3.43	11.39	21.41	4.59	38.17	11.39
		GOM	39.48	48.46	58.53	124.01	141.76	159.63	61.55	73.69	86.93	82.88	387.37	151.82
		Pacific	6.96	10.20	14.03	10.52	16.10	23.92	8.83	13.07	18.28	13.11	19.41	16.56
		Total OCS	**76.69**	**90.55**	**105.59**	**284.41**	**327.58**	**375.87**	**127.29**	**148.83**	**172.47**	**127.23**	**576.40**	**229.81**
BOEM, 2021	1/1/2019 UTRR	Alaska	17.00	24.69	34.08	91.07	124.03	161.63	33.21	46.76	62.84	24.72	124.03	46.79
		Atlantic	0.64	4.31	9.94	5.94	34.09	70.10	1.70	10.38	22.41	4.31	34.09	10.38
		GOM	23.31	29.59	36.27	46.88	54.84	62.56	31.65	39.35	47.40	54.45	250.34	99.01
		Pacific	6.91	10.20	14.20	10.15	16.07	23.43	8.72	13.06	18.37	11.80	18.26	15.06
		Total OCS	57.32	68.79	81.75	183.46	229.03	278.22	89.96	109.54	131.25	95.29	426.72	171.24

[1] Includes oil and condensate (natural gas liquids) [2]The Atlantic OCS figures reflect those from the 2014 Atlantic Assessment Update (BOEM, 2014)

A. USGS 1975 Assessment (Miller et al., 1975)

This assessment used a Delphi technique incorporating subjective judgment by a group of appraisers to directly estimate probabilities of occurrence and the undiscovered resource potential of an area. The assessors relied on various analyses to guide their judgments. These estimates were primarily analog-based (e.g., volumetric yields, finding rates), comparing more mature, geologically similar basins to the frontier OCS basins being assessed. The USGS relied on publicly available data to perform this assessment. Outside of the shelf portion of the central and western GOM and the Santa Barbara Channel, there was little OCS geological data available for use in this assessment.

At the time of the 1975 Assessment, only a single deep stratigraphic test well had been drilled on the Alaska OCS in the Gulf of Alaska. Twenty exploratory wells had been drilled off central and northern California and 12 off Oregon-Washington from 1963 to 1969. Just three wells in the Atlantic OCS had been drilled in the current Straits of Florida Planning Area: off the Marquessa Keys in 1960 and 1961. At least 17 other wells were drilled in state waters or onshore adjacent to this area. All of the wells mentioned above were considered to be dry holes. Elsewhere, in the Eastern GOM four dry holes had recently been drilled on the eastern crest of the Destin Dome structure and two other dry holes were drilled on other prospects within the planning area.

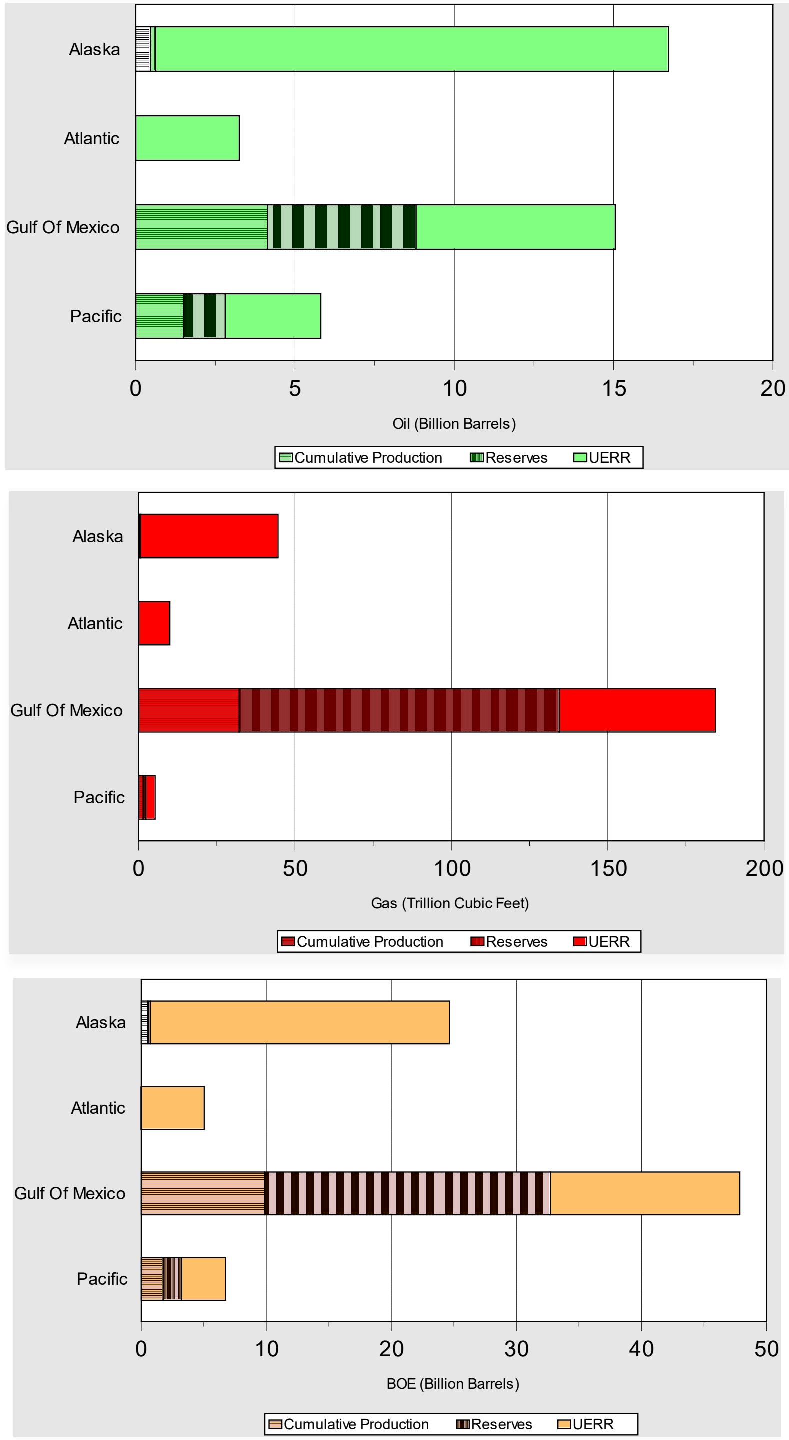
In the Central and Western GOM planning areas, industry was steadily proceeding into deeper waters on the continental shelf (less than 200-meter water depths). Discoveries were primarily off Louisiana, but industry activity along the shelf edge was beginning to move westward off Texas. Eleven of the 12 discovered Pacific OCS oil and gas fields, including both producing fields, were in the Santa Barbara Channel. The other discovery was to the south in the Los Angeles basin.

Industry's technological capabilities were just beginning to expand beyond the shallow waters of the OCS. The first pipeline in water depths exceeding 1,000 feet was constructed in 1975. The Hondo platform, installed in 1976 in 850 feet of water in the Santa Barbara Channel, was being fabricated at the time of the 1975 Assessment. The introduction of dynamic positioning systems, used on drill ships and semi-submersible drilling rigs, was opening up deepwater exploration.

The assessment included only those portions of the OCS in water depths of less than 200 meters. The offshore portion of the assessment also included state waters. UERR estimates were defined as economically recoverable under price-cost relationships and technological trends prevailing at the time of the assessment. The assessment assumed that prevailing pre-1974 cost-and-price relationships would continue. The 1973 average refiner's acquisition cost for crude oil was $4.17 per barrel and the average wellhead price for gas was $0.22 per Mcf (thousand cubic feet). The price, cost, and technology considerations were not a quantitative part of the assessment procedure, but rather considered subjectively by each assessor in formulating their judgments.

UERR estimates (see **Table 5a**) ranged from 11.1 to 53.5 Bbo and 42.0 to 181.0 Tcfg, with a mean estimate of 28.6 Bbo and 107.0 Tcfg. The GOM was forecast to contain 22% of the oil, and the area offshore Alaska 45%, with the remainder split between the Atlantic and Pacific OCS (see **Figure 7**). The assessment forecast that 47% of the undiscovered economically recoverable gas was in the GOM, followed by the area offshore Alaska with 41%. The mean estimate of total endowment was projected at 40.8 Bbo and 244.3 Tcfg (84.3 BBOE).

Figure 7. Distribution of Total Hydrocarbon Endowment by Type, Region, and Resource Category



B. USGS 1981 Assessment (Dolton et al., 1981)

The USGS completed its second national resource assessment in 1981, employing an updated version of its Delphi assessment technique. For this assessment, USGS was able to incorporate information resulting from industry's early seismic and exploratory drilling activities in many frontier basins. During the period since the previous assessment, eight additional deep stratigraphic test wells were drilled in Alaska basins (one in St. George, six in Kodiak, and one in the lower Cook Inlet). The results from follow-on industry exploration drilling in each of these basins were discouraging. The initial industry interest was in the Gulf of Alaska, where 11 dry exploratory wells were drilled between 1976 and 1978.

Industry then moved on to the lower Cook Inlet, where an additional nine dry holes were drilled in the first cycle of exploration for this basin. In the South Atlantic, one deep stratigraphic test well was followed up by six dry holes within the southeastern Georgia embayment. Two deep stratigraphic tests were drilled in the North Atlantic, providing direct geologic data for this assessment. During this period, industry's primary interest in the Atlantic OCS was in the Baltimore Canyon trough offshore New Jersey, where two deep stratigraphic tests (one with an announced hydrocarbon show) and 23 exploratory wells were drilled. Tests on the "Great Stone Dome" structure were dry. Five wells, drilled by Tenneco and Texaco on a single separate structure, also in the Baltimore Canyon trough, flowed significant quantities of natural gas and some oil during testing.

In the Santa Barbara Channel, industry was in the midst of a string of new field discoveries. Four of the five producing OCS fields were in the Santa Barbara Channel. Exxon installed Platform Hondo in 1976 in 842 feet of water, a world record water depth at the time. Two deep stratigraphic tests were drilled off Southern California, one on the Cortes Bank about 90 miles southwest of Los Angeles, and the other in the Point Conception area of the Santa Maria Basin. A hydrocarbon show was encountered in the Point Conception test. Based on favorable stratigraphy in the Cortes Bank test, a series of nine exploratory wells were drilled on the Southern California borderland. All of these wells were dry holes. The first OCS discovery in the Santa Maria Basin, the Point Arguello Field, was made in late 1980. The northernmost block of this field was leased after the field discovery in 1981 for a record bonus bid of $333,596,200.

Industry continued to drill additional dry holes on and around the Destin Dome structure and elsewhere in the Eastern GOM Planning Area. By October 1975, drilling in the area had halted after a total of 15 dry holes. However, the penetration of the Norphlet Formation revealed the presence of a massive reservoir-quality sandstone. This dry hole became even more important to industry with the 1979 discovery of the Mary Ann Field in state waters offshore Alabama, which generated interest in the probable extension of the prolific Norphlet trend into adjacent Federal waters. In the Central and Western GOM planning areas, industry interest was focused on the Flexure trend, located at the outer edge of the continental shelf offshore Louisiana and Texas and the Corsair trend on the Texas shelf.

Industry exploration and production activity in the Flexure trend in the GOM, the Santa Barbara Channel, and elsewhere had exceeded the 200-meter water depth technology limit used in the previous assessment. The first OCS deepwater production facility, Shell's Cognac fixed-leg platform, was installed in the GOM in 1979 in 1,023 feet of water. Acknowledging this advancement in deepwater exploration and production technology, the USGS expanded the extent of the offshore area included in this assessment to include all areas in water depths less than 2,500 meters (again including state waters). The water depth limit of 2,500 meters, in conjunction with a consideration of only those sediments shallower than 30,000 feet, represented two high-level technology limits imposed in this assessment.

UERR estimates were again reported. The assessment assumed that prevailing 1980 costs and price relationships would continue. During 1980, prices averaged $28/barrel (bbl) and $1.60/Mcf, more than seven times the 1974 averages assumed in the prior report. The USGS introduced the concept of a "minimum economic field size" (MEFS) for the various OCS regions. This MEFS quantitatively incorporated a consideration of local costs, prevailing prices, and foreseeable technologies. The USGS applied individual threshold sizes across a broad range of locations, geologic conditions, and water depths. Resources in accumulations below the appropriate MEFS were excluded from consideration in the assessment. The MEFS were subjectively considered by each individual assessor.

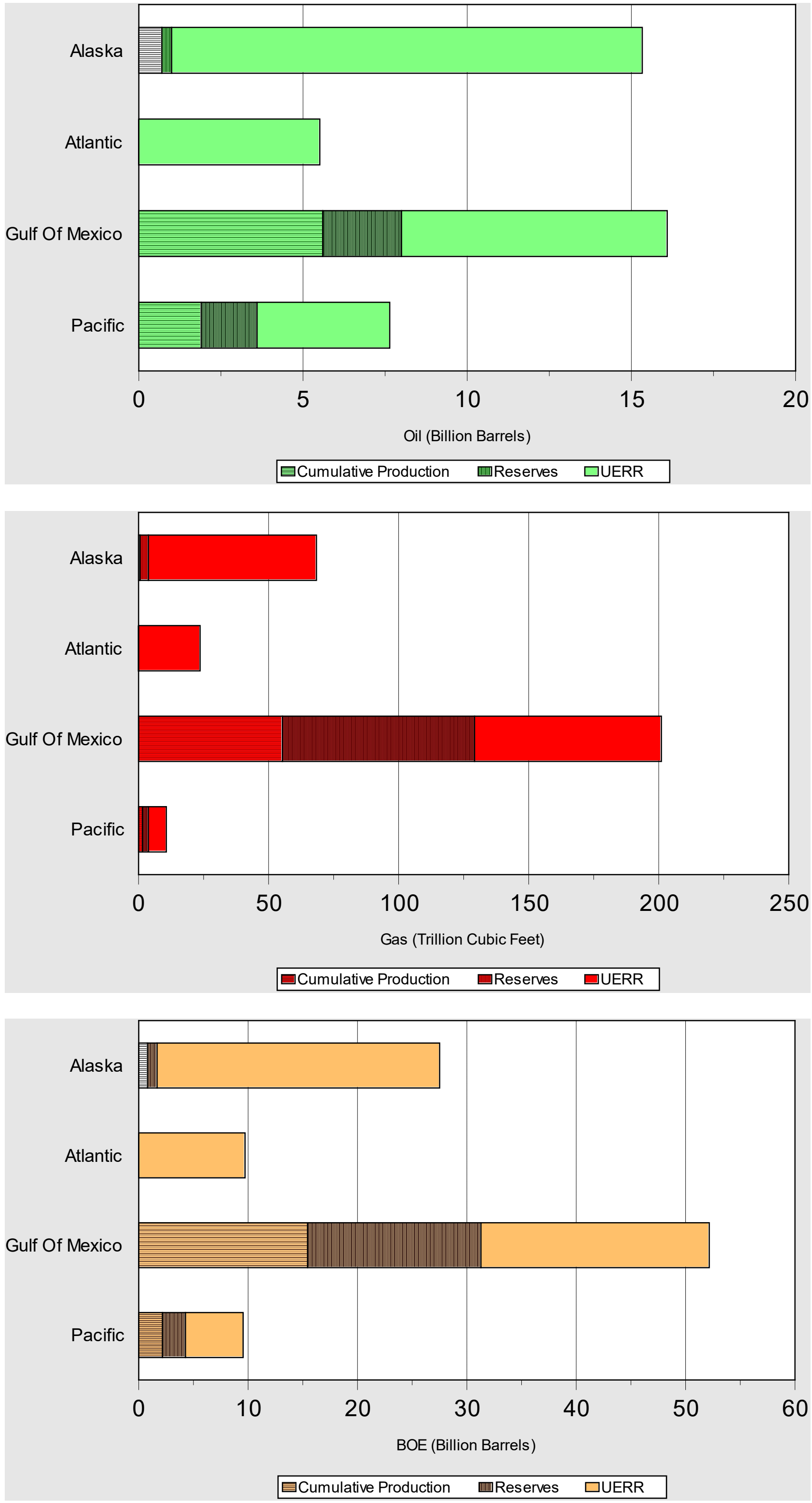
UERR estimates ranged from 21.0 to 51.7 Bbo and 117.4 to 230.7 Tcfg, with a mean estimate of 32.0 Bbo and 167.0 Tcfg (**Table 5a**). Despite low exploration results from drilling in the frontier basins in the Gulf of Alaska, Southern California borderland, and the southeastern Georgia embayment, mean estimates of overall UERR increased by 14% for oil and 56% for gas.

The mean oil and gas estimates for UERR on the shelf (0–200 meters water depth) in this assessment were 20.8 Bbo and 113.4 Tcfg (41.0 BBOE) versus 28.6 Bbo and 107.0 Tcfg (47.6 BBOE) in the prior assessment, a decrease of 38% for oil and 14% for BOE. The total mean estimate for gas increased slightly in this assessment. A closer look shows that UERR estimates for oil were down in every region, as was gas with the exception of offshore Alaska, where the estimates increased by 13 Tcfg, or almost 30%.

The increase in the estimate of potential quantities of gas in the shallow waters offshore Alaska was probably the result of a combination of factors. The drilling results off Alaska, while generally unsuccessful, indicate that the Bering Sea basins were probably more gas-prone than previously assumed. The considerably higher gas prices incorporated in this assessment and the lower economic risk and MEFS thresholds associated with gas discoveries more than offset any increase in geologic risk imposed. The remainder of the increase in UERR is attributable to the inclusion of the continental slope in this assessment; approximately one-third of the total UERR estimate was for the deeper water portion of the OCS. Finally, of particular note at the time of this assessment was the announcement by USGS scientists of the existence of a buried Mesozoic shelf-edge reef complex that extended intermittently along much of the Atlantic continental margin (Scholle, A.P., 1980.). Comparisons were made with similar features in prolific producing trends in Mexico and the onshore U.S. Gulf Coast.

Mean estimates of the total OCS hydrocarbon endowment included in this assessment were 44.9 Bbo and 303.8 Tcfg (98.9 BBOE), corresponding to an increase of 11% for oil and 24% for gas (18% for BOE) since the 1975 Assessment. The mean value for oil UERR was 71% of the mean estimate for the total oil endowment. Corresponding estimates for gas and BOE were 55 and 63%, respectively. The GOM was forecast to contain nearly one-quarter of the UERR for oil and offshore Alaska was forecast to contain 44% (**Figure 8**). The assessment forecast that 43% of the UERR for gas was in the GOM, followed by offshore Alaska with 39%.

Figure 8. Distribution of Total Hydrocarbon Endowment by Type, Region, and Resource Category



C. MMS 1985 Assessment (Cooke, 1985)

This assessment was performed as the initial phase in the development of a new proposed 5-year oil and gas leasing program (now called the National OCS Program). It was the first systematic assessment of the entire OCS performed by the newly created MMS.[6] The resource assessment was completed primarily by a portion of the organization that was within the former Conservation Division of the USGS.

Prior to this effort, staff assessment experience was confined to assessing the potential of smaller portions of the OCS to analyze environmental and policy concerns related to individual lease sales and to determine the adequacy of industry bids for leases. The MMS assessment methodologies at the time were, in comparison to the broad regional analysis employed by the USGS, very data intensive, requiring extensive site-specific G&G information. USGS's assessments relied almost exclusively on data and information within the public domain, while the MMS assessment relied extensively on proprietary OCS G&G data acquired by the oil and gas industry. The analysis also incorporated a more quantitative consideration of economic and cost information.

MMS initially considered continuing the use of the classic Delphi approach to regional resource assessment that was employed by the USGS. Because of its leasing responsibilities and a desire to employ an internally consistent and repeatable assessment technique for all analyses supporting leasing decisions, the MMS ultimately chose to pursue another direction. Previous resource assessments presented risked resource estimates that incorporated the probability that the area under consideration could be devoid of hydrocarbons. MMS program analyses typically required the use of conditional resource estimates in association with their corresponding marginal probability. To support these analyses, the assessment focused on developing and presenting conditional resource estimates. Because of this focus, a complete risked resource distribution was not included as part of the assessment products, only the mean values were reported. A more complete discussion of the differences between conditional and risked estimates is presented in Section V.

The assessment technique employed by MMS was a summation of prospects approach incorporated in a Monte Carlo simulation model called Probabilistic Resource Estimates Offshore (PRESTO). This mathematical model enabled assessors to make judgments concerning each of the variables affecting the assessment. These individual judgments were then subjected to the model simulation to derive a resource estimate. Unlike the Delphi subjective assessment approach, this model allowed the incorporation of new information in a quantifiable and repeatable way. This assessment approach as implemented did, however, require that individual exploration targets be identified using existing G&G information.

Instead of considering flat prevailing product prices, MMS incorporated in its economic analyses long-term price forecasts that incorporated inflation and real price changes. Starting prices used in this assessment were $29/barrel and $2.90/Mcf. Project economics and technology were largely considered through the use of the MEFS (see Appendix A) cut-offs that were rigorously applied within the simulation model. In this assessment, the use of the MEFS was fine-tuned for much smaller portions of planning areas than previous assessments. These areas and the MEFS were

[6] The MMS was established on January 19, 1982, by Secretarial order.

defined primarily in terms of production characteristics, water depths, and distance from shore. For the first time, only offshore areas under Federal jurisdiction were included in the assessment. The area assessed in both the Chukchi and Beaufort seas was limited to water depths of less than 200 meters, which was considered to be the foreseeable limit on exploitation technology. The assessed area in the Atlantic OCS was also reduced from that considered in the prior assessment, in response to the World Court decision establishing the U.S./Canada maritime boundary. UERR estimates were again reported.

The effective date of this assessment in terms of G&G data and information considered was July 1, 1984. Since the previous assessment, five additional deep stratigraphic test wells had been drilled in three Alaskan frontier basins (two wells in the Norton Basin, one well in the St. George Basin, one well in North Aleutian, and one well in the Navarin Basin). An additional six exploratory wells were drilled in the Beaufort Sea, and a final dry hole was drilled in the Gulf of Alaska. In 1983, industry drilled a single unsuccessful $140 million exploratory well on the "Mukluk" prospect in the Beaufort Sea, where it had previously invested $1.5 billion to acquire leases. With the exception of the Beaufort and Chukchi seas and a final well in the lower Cook Inlet, this period marked the end of exploration interest in other Alaska OCS basins.

All eight exploratory wells drilled in the North Atlantic were dry holes. In the Mid-Atlantic, an additional 15 exploratory wells were drilled since the previous assessment was completed. Three of these wells were drilled on the "Tenneco-Texaco" discovery. The last, drilled on the structural crest, was a dry hole. A 3-D seismic survey was acquired over the structure in an attempt to resolve structural and stratigraphic complexities and determine if additional effort would be merited. The leases were subsequently relinquished in April 1984. During this period, Shell undertook an ambitious, multi-well, deepwater drilling program that set several world water depth records. The target was the buried Mesozoic shelf-edge reef complex and associated features. All of these wells were also deemed to be dry holes. Industry acquisition of seismic data in the Atlantic virtually ceased after the 1984 acquisition season.

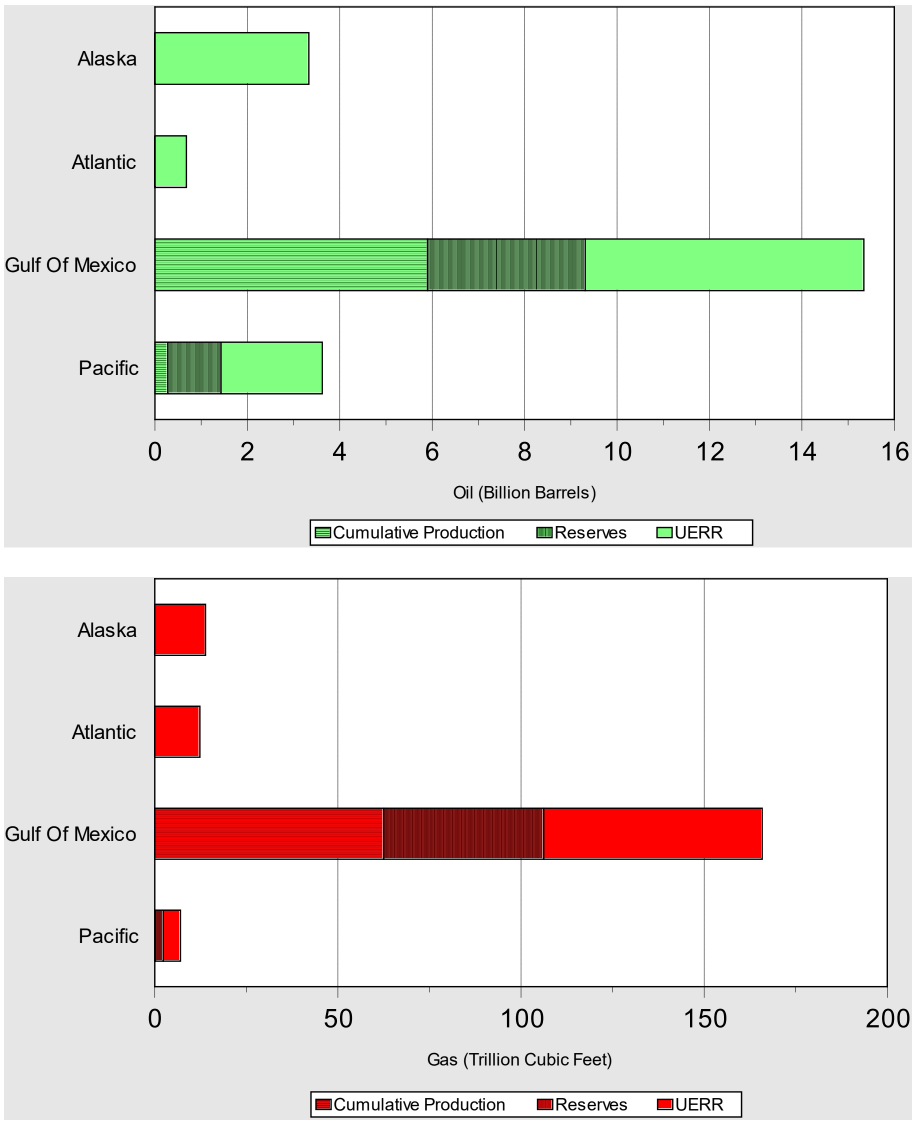
The Santa Maria Basin in the Pacific underwent extensive exploration from 1980 through 1986. More than 40 exploration and delineation wells were drilled in the Santa Maria Basin during this time. By mid-1984, seven oil and gas fields had been discovered.

Exploration in the Eastern GOM continued to yield generally limited results. Eleven exploratory wells were drilled (six within the Charlotte Harbor area) without a commercial discovery. However, there was a discovery in 1983 of the Mobile 823 Field, which extended the Norphlet trend eastward into the Eastern GOM.

On the technology front, the first artificial drilling island was constructed in Alaska in 1981 and was used to drill two exploratory wells in 18 feet of water. During 1983, the Lena platform, a compliant tower, was installed in the GOM in 1,017 feet of water. While this structure did not set a water depth record, it did prove a technology that could be extended to water depths of as much as 3,000 feet, well beyond the capabilities of bottom-founded, fixed-leg platforms that had approached their water depth limit. On the drilling front, Tenneco had recently drilled the first exploration well in the GOM to exceed 25,000 feet subsea in depth. The Bullwinkle Field was discovered in 1983 in 1,331 feet of water. The Bullwinkle platform was designed as one of the first deepwater production hubs. The Amberjack Field was also discovered in 1983 in 1,049 feet of water.

As explained previously, in this 1985 Assessment, region-level estimates of UERR were reported only at the mean value. The GOM was forecast to contain nearly 50% of the UERR for oil while offshore Alaska was forecast to contain 27% (see **Figure 9**). Two-thirds of the natural gas UERR was in the GOM, whereas offshore Alaska and the Atlantic each contained about 15% of the total. Estimates of the undiscovered resource potential of the OCS decreased dramatically to 12.2 Bbo and 90.5 Tcfg (28.3 BBOE).

Figure 9. Distribution of Total Hydrocarbon Endowment by Type, Region, and Resource Category



Direct comparisons of the 1985 Assessment with the previous assessment are challenging, as there were major differences in the methodologies employed, information base available, technology and economic assumptions, and areas assessed. Estimates of the undiscovered resource potential in the 1983 Assessment represented a decrease of 62% for oil and 46% for natural gas (55% for BOE) from the earlier assessment. Cooke (1985) adjusted the previous assessment results in the lower 48 to remove the effect of excluding state waters. After this adjustment, the overall differences are slightly smaller, 55% for oil and 44% for natural gas. The decreases were greatest in the Alaska (about 75% for both oil and gas) and Atlantic (87% for oil and 48% for natural gas) OCS. Decreases in the Pacific estimates were more modest at 31% for oil and 24% for gas. The GOM estimates of UERR decreased slightly for oil (3%) and gas (13%).

A significant portion of the difference can be attributed to different methodologies and objectives. MMS was highly dependent on the existing proprietary information base and the near-term decision-making considerations related to the OCS leasing program that must reflect current market realities. In hindsight, this assessment displayed a conservative, short-term view of potential exploration opportunities. The large decreases in the estimates for Alaska reflected the unsuccessful results of OCS drilling efforts. The only exploration successes offshore Alaska at the time of the 1985 Assessment were in state waters in the upper Cook Inlet and Beaufort Sea.

MMS risk analysis reflected low probabilities of encountering commercial quantities of hydrocarbons outside the Beaufort Sea. Even in the Beaufort Sea, the probability of encountering commercial quantities of hydrocarbons was only 0.70. The area with the next highest probability, 0.27, was the Navarin Basin, which had yet to have an exploratory well drilled. As discussed earlier, an increase in geologic risk greatly lowers the assessed volumes.

The story for the Atlantic is similar—unsuccessful exploration results were reflected in increases in the perceived levels of risk, which dramatically lowered reported resource expectations. In both the Pacific and GOM regions, estimates of the total hydrocarbon endowment, which consider the volumes of hydrocarbons discovered and produced during the period between assessments, also decreased, although less markedly. These decreases likely primarily reflect the removal of state waters from consideration. Secondary factors contributing to the reduction were the heavy focus on prospects in combination with a more rigorous consideration of economic factors.

Mean estimates of total OCS hydrocarbon endowment developed from this 1985 Assessment were 23 Bbo and 199 Tcfg (58.4 BBOE), corresponding to a decrease of 50% for oil and 35% for natural gas (42% for BOE) from the prior assessment. Despite the discoveries made in the intervening years, estimates for oil reserves were down slightly; reported gas reserves decreased by 34 Tcfg. Cumulative production reported was significantly lower for oil, but higher for gas.

D. MMS 1990 Assessment (Cooke et al., 1990)

After MMS completed its first OCS-wide resource assessment, it requested that the National Research Council of the National Academy of Sciences (NAS) review the methodology that it had employed. The NAS review (National Research Council, 1986) was generally favorable, but offered a number of suggestions to improve future assessments. These included: (1) pursuing a grouped-prospect play assessment methodology compatible with existing MMS models; (2) reporting the undiscovered resource base in addition to the economically attainable potential; and (3) developing a systematic process for including the resource potential from unmapped or unidentified prospects. MMS incorporated each of these recommendations in the 1990 Assessment.

The 1990 Assessment was the first attempt by DOI to assess the underlying conventionally recoverable resource base instead of just that portion perceived to be economically recoverable given a certain set of assumptions regarding future economic conditions. This assessment continued to rely on the MMS prospect-oriented analyses and databases, but was supplemented by an additional consideration of unmapped prospects that could be anticipated to exist.

This methodology used an updated version of the PRESTO model and an additional model to account for the resource potential of any unmapped prospects. Cooke and Dellagiarino (1990) and Lore and Peccora (1988) further describe this technique. The PRESTO model was modified to incorporate economic considerations beyond the field level. In frontier areas in particular, discoveries could be large enough to cover prospect-specific costs, but because of a lack of existing infrastructure, could be abandoned as uneconomic. Additional economic screens were incorporated to test more rigorously to assure that resources discovered could support the necessary costs to bring the product to market. This additional consideration tended to raise the economic risk associated with frontier portions of the OCS.

The effective date for the information base used in this assessment was January 1, 1987. There was a dramatic decrease in oil and gas prices in 1986, which served to heighten interest in price volatility and its effects on resource assessments. In this assessment, MMS reported three different categories of resource estimates: (1) the undiscovered "resource base," synonymous with an undiscovered conventionally recoverable resources (and UTRR); (2) a primary economic case based on prevailing conditions; and (3) an alternative economic case based on significantly higher oil and gas prices. The primary economic case again incorporated a price forecast, where the starting prices were $18/barrel and $1.80/Mcf. The first two cases are presented in **Table 5a**.

Exploration activity peaked on the Alaska OCS during the mid-1980s. Industry interest was now focused on Arctic areas. Eleven exploratory wells had been drilled in the Beaufort Sea since the previous assessment. Industry had by now made several non-commercial discoveries in this area. Since the prior assessment, there had been an initial exploration period in the three basins in the Bering Sea. The most promising prospects were drilled first and the results were extremely disappointing. Twenty-four exploratory wells were drilled during the period between assessments in the Norton Sound (six wells), Navarin basin (eight wells), and the St. George Basin (ten wells); none encountered commercial quantities of hydrocarbons. The final two dry holes were drilled in the lower Cook Inlet as part of the second industry exploration campaign in the area.

Industry interest in much of the Alaska OCS began to wane in the latter half of the 1980s. This lower level of interest was reflected in the sharp drop in 1986 in the annual number of geophysical exploration permits issued. The results of the initial Alaska exploration rounds condemned many very large prospects and some play concepts. For other plays and prospects, geologic risk was significantly increased. In some plays previously thought to be oil-prone, analysis of the drilling results indicated that if hydrocarbons were present, they were more likely to be gas-prone. The limited activity in the Cook Inlet primarily confirmed the previous MMS geologic models.

A final deepwater dry hole was drilled in the mid-Atlantic. Since subsequent efforts to drill the large "Manteo" structure in the Carolina trough off North Carolina were unsuccessful, this period essentially marked the end of all industry exploration activity on the U.S. Atlantic continental margin.

In the Pacific, the exploration drilling program in the Santa Maria Basin concluded in 1986, resulting in the discovery of 14 oil and gas fields with reserves of greater than 1 Bbo of mostly heavy oil. The Point Pedernales Field was the first of these discoveries to produce, beginning in the first quarter of 1987.

In the GOM, industry was actively extending the deepwater Flexure trend westward into the western GOM and aggressively pursuing additional opportunities associated with the Corsair trend off the Texas coast. The Ram-Powell Field was discovered in 1985 in 3,239 feet of water and the Allegheny Field was discovered in 3,254 feet of water. It took 10 years to achieve first production from Ram-Powell. Mensa, one of the largest natural gas accumulations in the deepwater Gulf, was discovered in December 1986 in 5,280 feet of water.

UERR estimates for oil ranged between 4.0 and 14.3 Bbo with a mean value of 8.9 Bbo. Natural gas estimates ranged from 44.3 to 113.8 Tcfg, with a mean of 74.0 Tcfg. Approximately 63% of the UERR was projected to be present in the GOM. Nearly a quarter of the estimate was projected to be present in the Pacific region. Nearly 87% of the undiscovered gas estimated to be economically recoverable was projected to be present in the GOM. Nowhere on the Alaskan OCS was natural gas considered to be economic under the economic conditions. Poor exploration results, coupled with the economics of gas, led to another round of increases in risk assessments associated with Alaskan basins.

At the mean level, UERR estimates represented a decrease compared to the previous assessment of 27% for oil and 18% for gas. Despite the significant decrease in price expectations, oil estimates decreased only slightly for those areas outside of Alaska. The decreases in the Pacific and GOM estimates were offset by new discoveries during the intervening period. Dismal exploration results in the frontier areas of Alaska and the Atlantic combined with the recent oil price collapse resulted in a lowered assessment of UERR potential. Notwithstanding the decrease in the UERR estimates for oil and natural gas in this 1990 Assessment, mean estimates of the total hydrocarbon endowment remained virtually unchanged between assessments.

UTRR estimates ("undiscovered resource base" in this assessment) were presented for the first time. Estimates ranged from 9.2 to 25.6 Bbo, with a mean of 17.9 Bbo and 97.8 to 204.8 Tcfg, with a mean value of 145.1 Tcfg. More than half of the undiscovered oil and two-thirds of the gas estimate were in the GOM. Alaska was next with 21% of the oil and 11% of the gas.

In the mean primary case economic analysis, 50% of the OCS total UTRR was found to be economically recoverable (see **Figure 10**). In the GOM, 60% of the oil and gas UTRR was found to be economically recoverable. In Alaska, less than a quarter of the 3.8 Bbo and none of the 16.8 Tcfg were considered to be economically recoverable. The Pacific and Atlantic OCS fell in between.

E. MMS 1991 Assessment (Cooke, 1991)

In response to industry concerns expressed about the prior assessment, the MMS asked the Association of American State Geologists (AASG) to review the geologic information that formed the foundation for the 1990 Assessment. The review concluded that "The assessment of undiscovered, conventionally recoverable oil and gas resources on the OCS is supported by an adequate data base, personnel with suitable expertise and training, and a disciplined, structured process that produced results that inspire confidence" (AASG, 1988, p. 2). DOI also requested that the NAS review the assumptions and procedures employed by both MMS and USGS in recent assessments. The findings from this review were not available when the 1991 Assessment was performed.

In preparation for the 1992 to 1997 5-year oil and gas leasing program, MMS reviewed the existing resource estimates to determine if they were still adequate. MMS determined that the estimates should be updated in five planning areas where significant new data had become available since 1987. The planning areas updated were the Beaufort Sea, Chukchi Sea, Hope Basin, Northern California, and Eastern GOM.

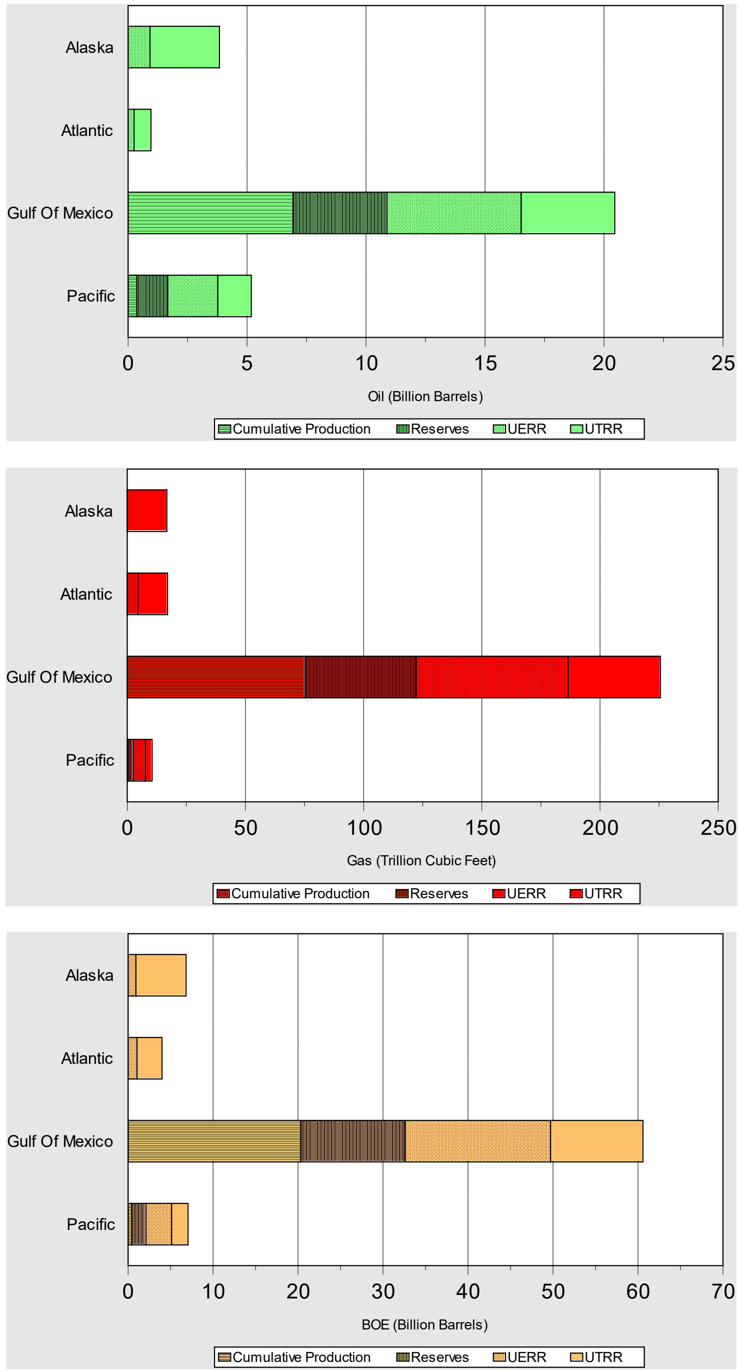
The amount of seismic data available in the Chukchi Sea had more than doubled since the previous assessment was completed. As a result, more prospects were identified, and the existence of some of the larger prospects was confirmed by the new data. There were also three new exploratory wells drilled in the basin since the prior assessment. In the Beaufort Sea, three additional wells had been drilled and a number of changes were incorporated in the geologic model, the most significant of which was an increase in the probability of success.

Activities from this time onward in the Pacific OCS consisted mainly of establishing and maximizing production of previously discovered oil and gas fields. The last Pacific OCS lease sale was held in 1984 and the last exploration well in the Pacific OCS was drilled in 1990. By 1995, there were 11 producing fields in Pacific Region: in the Santa Barbara Channel, Santa Maria Basin, and Los Angeles Basin.

In preparation of an upcoming Eastern GOM lease sale, a significant amount of new seismic data were acquired and interpreted by MMS. In 1987, Amoco drilled the first discovery (non-commercial) well in the Norphlet Formation in the Eastern GOM. In 1987 and 1989, Chevron drilled two discovery wells in the Eastern GOM in Destin Dome Block 56, approximately 25 miles south of Pensacola, Florida. Both wells found significant quantities of natural gas in the Norphlet Formation below 22,000 feet. This discovery was part of the same play that was productive in adjacent state and Federal waters. Several discoveries were also made in the eastern extension of the shallow Miocene “bright spot” play. These discoveries increased the marginal probability of success for the Eastern GOM area to 1.00.

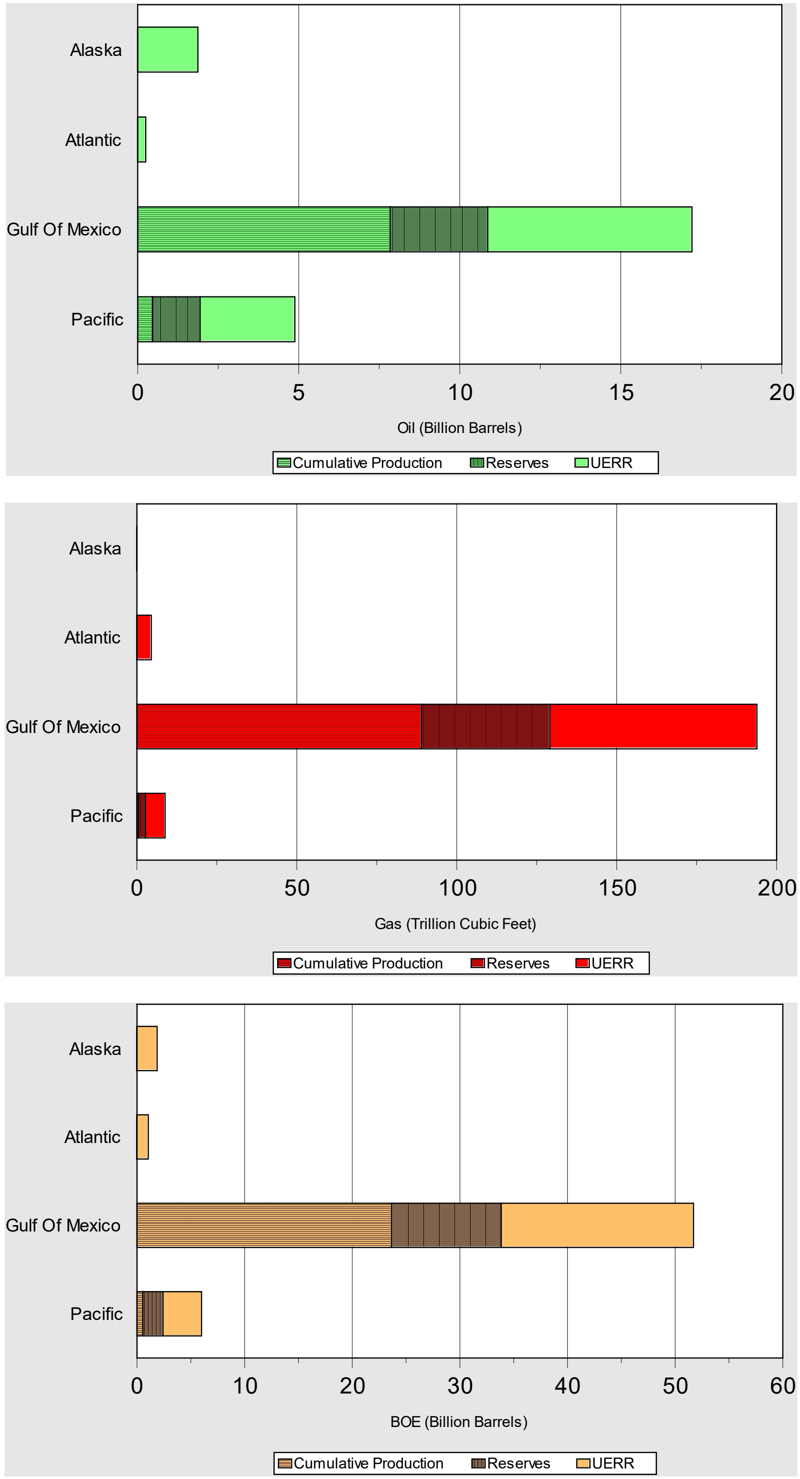
MMS once again only reported UERR estimates in 1991. The largest change in estimates occurred in the Chukchi Sea portion of the Alaskan OCS. Resource estimates for the Beaufort Sea increased modestly, while Hope Basin estimates decreased by about 25%. Overall, mean UERR estimates for Alaska more than doubled compared to the earlier assessment (see **Figures 10** and **11**).

Figure 10. Distribution of Total Hydrocarbon Endowment by Type, Region, and Resource Category



Note: All UERR are also considered as part of the UTRR.

Figure 11. Distribution of Total Hydrocarbon Endowment by Type, Region, and Resource Category



Mean UERR estimates for the Eastern GOM more than tripled to 1.25 BBOE. In the entire GOM, the oil estimate increased 12% and the gas estimate remained unchanged. The Northern California UERR estimates also increased substantially, primarily due to changes in the geologic model for the Point Arena Basin. Mean estimates for both oil and gas UERR in the Pacific estimate increased by about 18%.

For the OCS as a whole, mean UERR estimates increased modestly from 8.9 to 10.9 Bbo, from 74.0 to 75.4 Tcfg, and from 22.1 to 24.4 BBOE.

F. MMS 1996 Assessment (MMS, 1996)

The 1996 Assessment represented a watershed event in the MMS resource assessment process. It incorporated major changes in the basic underlying approach to resource assessment and shifted the principal focus from assessing UERR to undiscovered conventionally (or technically) recoverable resources. The recommendations of the 1991 NAS review were available for consideration in this assessment. In contrast to the AASG, the NAS stated "…that there may have been a systematic bias toward overly conservative estimates. Eliminating the probable sources of this bias will improve the accuracy and credibility of future assessments." (National Research Council, 1991). The primary concerns identified by the NAS included: (1) concerns regarding play definition, (2) use of conceptual plays, (3) treatment of dependencies among variables, and (4) unintended imposition of economic constraints on UTRR estimates.

The recommendations of the 1991 NAS study were fully incorporated in the 1996 Assessment. Previous MMS resource assessments employed play concepts, but the focus was on groupings of prospects within the context of a play and the analysis was still prospect-oriented. The modeling emphasis for this assessment was reversed, and represented the first time MMS geoscientists applied an assessment method called "play analysis" on a national scale.

This method evaluates the resource potential of "plays"—families of prospective and/or discovered petroleum accumulations that share a common history of oil or gas generation, migration, reservoir development, and trap configuration (White, 1980). In play analysis, statistical methods are used to translate the judgments of geologists into a set of probabilities that given petroleum volumes exist within the plays. Databases were constructed and subsequent analyses were performed from this viewpoint. A new play-based computer model, Geologic Resource Assessment Program (GRASP), derived from the Canadian Geological Survey's Petroleum Resources Information Management and Evaluation System (PETRIMES) suite of programs, was used for the first time.

The NAS recommendations adopted by the MMS generally provided for a more expansive interpretation of the UTRR potential of the OCS, resulting in significant increases in the resource estimates. For example, comparing this assessment with the 1990 UTRR, in Alaska the mean estimates for oil increased from 3.8 Bbo to 24.3 Bbo. Similarly, the mean gas estimates increased from 16.8 to 125.9 Tcfg. The majority of this increase occurred in the estimates for the Beaufort and Chukchi seas. All exploratory drilling on the Alaskan OCS since the previous assessment occurred in these two areas, seven new wells were drilled in the Beaufort Sea and four wells in the Chukchi Sea. Although none of the wells were deemed to be commercial successes, the results confirmed play concepts and reduced geologic risks. A detailed discussion of the impacts of these methodological changes on MMS estimates is contained in MMS (1996) and Sherwood et al. (1998).

In the GOM, several individual companies continued to expand their deepwater portfolios and invest in the development of technology. In 1987, Shell made a world record deepwater field discovery at the Coulomb Field in 7,558 feet of water. Furthermore, Shell found another deepwater discovery called Auger, a field that contains approximately 500 million BOE. The discovery of the Auger Field and other promising finds gave rise to the view that the deepwater GOM had un-realized resource potential. What was particularly striking was not only the size of the fields, but also the high flow rates of individual wells.

Several new production technologies were introduced in the GOM since the completion of the previous assessment. A floating production system (FPS) was installed in 2,172 feet of water and a semi-submersible in 1,554 feet of water. The first U.S. tension-leg platform (TLP) was installed at the Joliet Field in 1,722 feet of water. Shell pushed the limit of fixed-leg platforms with the massive Bullwinkle platform, which was installed in 1,330 feet of water. Subsea production technology continued to evolve during this period. Prior to 1988, the deepest subsea completion was in 350 feet of water. This jumped to 2,243 feet of water with the Oryx Green Canyon (GC) 75 Field development.

Elsewhere, the pace of drilling in the GOM had dropped to levels not seen in 30 years. This was not the case with geophysical exploration. The impact on this assessment of 3-D seismic imaging technology and new computerized mapping, modeling, and interpretation programs was significant. Marine 3-D seismic data had been in use since the early 1980s, primarily acquired as an exclusive proprietary survey by an operator to improve field development after a discovery is made. The proprietary 3-D surveys were more expensive than older 2-D seismic surveys. By the mid-1980s, there was a noticeable industry-wide trend in increased success rates for field development wells drilled on the basis of 3-D seismic data. This realization, coupled with the initial availability of low-cost speculative 3-D seismic data and the emerging workstation technologies combined to fuel an explosion in speculative 3-D data acquisition. The technology was viewed by industry as a primary way to control costs and risks in an era of price uncertainty and quickly became a standard tool for exploration.

The continued evolution of the computational and graphical power of workstation technology coupled with decreasing computer processing unit costs placed a powerful interpretation tool that could handle the vast amounts of data necessary to build 3-D models within the grasp of most geoscientists. This capability in turn created additional demands for 3-D seismic data as both an exploitation and exploration tool. Sophisticated workstations allowed geologists, geophysicists, and petroleum engineers for the first time to fully integrate data previously exclusive to their individual disciplines into a composite 3-D geologic and petrophysical model of a prospect or field. This new capability created opportunities to more fully exploit existing discoveries, identify new targets in old fields, and re-evaluate prospects that were previously drilled unsuccessfully on the basis of 2-D seismic data and less than full integration of available geologic data. This focus was clearly in evidence in terms of actual drilling activity.

Industry as a whole was backing off risky investments during this period, but a few companies continued to pursue high-risk, high-cost exploration opportunities. Following closely on the heels of advances in 3-D seismic data acquisition, interpretation tools, and the computational power of computers was the emergence of the "subsalt play" as the next hot exploration play in the GOM. The play extended across the outer portion of the central GOM shelf and onto the upper slope encompassing an area of approximately 36,000 square miles. This area is characterized by relatively shallow water depths (300 to 2,000 feet) within areas of extensive existing infrastructure related to the Flexure trend activity, as well as recent deepwater discoveries. This proximity made for attractive project economics. Despite the extensive publicity, this play was not a totally new phenomenon in terms of geologic targets.

The subsalt play is a technology-driven play defined principally by the presence of tabular salt bodies, commonly referred to as salt sheets, sills, lenses, canopies, or tongues. Unlike traditional salt domes, which had been exploration targets since the earliest OCS wells were drilled, these salt bodies are often detached from deep rooted autochthonous salt layers. Typical mid-1980s vintage 2-D time-migrated seismic geophysical processing techniques frustrated subsalt explorationists for years. They could not properly image the base of the salt body, strata below the salt, or correctly characterize salt and sediment geometries. They also created problems in the conversion to depth from seismic travel time due to high salt velocity. As a result, wells could not be precisely located, greatly increasing operator risk. It was only through the use of advanced 3-D seismic acquisition and the raw processing power of massively parallel processor (MPP) supercomputers that explorationists were able to reprocess seismic to accurately see through these salt bodies.

At least 20 wells were drilled to subsalt objectives between 1979 and the first discovery in 1990 at Exxon and Conoco's Mickey (since renamed Mica) prospect. Despite a modest number of wells drilled every year, it was not until 1986 that the first substantial reservoir quality sands were encountered by Diamond Shamrock after drilling through 1,000 feet of salt. At Mickey, Exxon drilled through nearly 3,300 feet of salt before encountering hydrocarbons. This was seen as a significant breakthrough in the history of exploration and exploitation of the GOM since it opened a huge volume of sediment to prudent, reasonable risk exploration for the first time. The discovery, however, was in 4,350 feet of water making commercial exploitation uncertain.

The major technological breakthrough that put this play within reach of larger independent companies occurred in 1992 and 1993 when the first MPP supercomputers became available outside of the government and defense industries. These computers made practical for the first time pre-stack depth migration processing of 3-D data sets on a non-proprietary basis. An indication of the raw computing power of the new supercomputers was the ability to process in about three weeks what a 1980 vintage mainframe would take about 5 years to accomplish.

In 1993, Phillips, Anadarko, and Amoco drilled the Mahogany prospect. They drilled through 3,500 feet of salt before encountering significant oil and natural gas pays. This discovery touched off a frenzy of subsalt leasing and drilling activity. Despite the high levels of risk and uncertainty associated with prospect definition, high exploratory well costs, use of cutting-edge drilling and processing technologies, and the larger-than-usual upfront data processing costs, the play was of significant interest. It offered the potential for world class reserves in a mature producing area located in proximity to existing infrastructure. The relatively shallow water depths greatly reduced the MEFS and increased the profitability of otherwise commercial finds.

Following this initial strong interest, subsequent subsalt exploration yielded mixed results. The immediate follow-up drilling at the Mattaponi, Mesquite, and Ship Shoal 250 prospects were announced as dry holes. The only announced discovery in the immediate flurry of drilling was the

Teak prospect. The results from the first round of drilling activity led to a re-evaluation of the geologic complexities, seismic uncertainties, and drilling difficulties associated with subsalt exploration.

On other technology fronts, industry continued to push the envelope on deepwater production technology. The Auger TLP was installed in 2,864 feet of water. The use of subsea production systems in deepwater was becoming more common, including remote wells with tie-backs to host systems. A subsea completion was installed at Mars in 2,956 feet of water in 1996, and at Mensa in 1997 in 5,295 feet of water. The distance from subsea completion to host facility was also increasing during this period, achieving a record of 68 miles (for natural gas production) with the Mensa development.

Additionally, the first horizontal well had been drilled in the GOM. This technology initially allowed the exploitation of marginal accumulations on the shelf, but soon became a part of many deepwater developments.

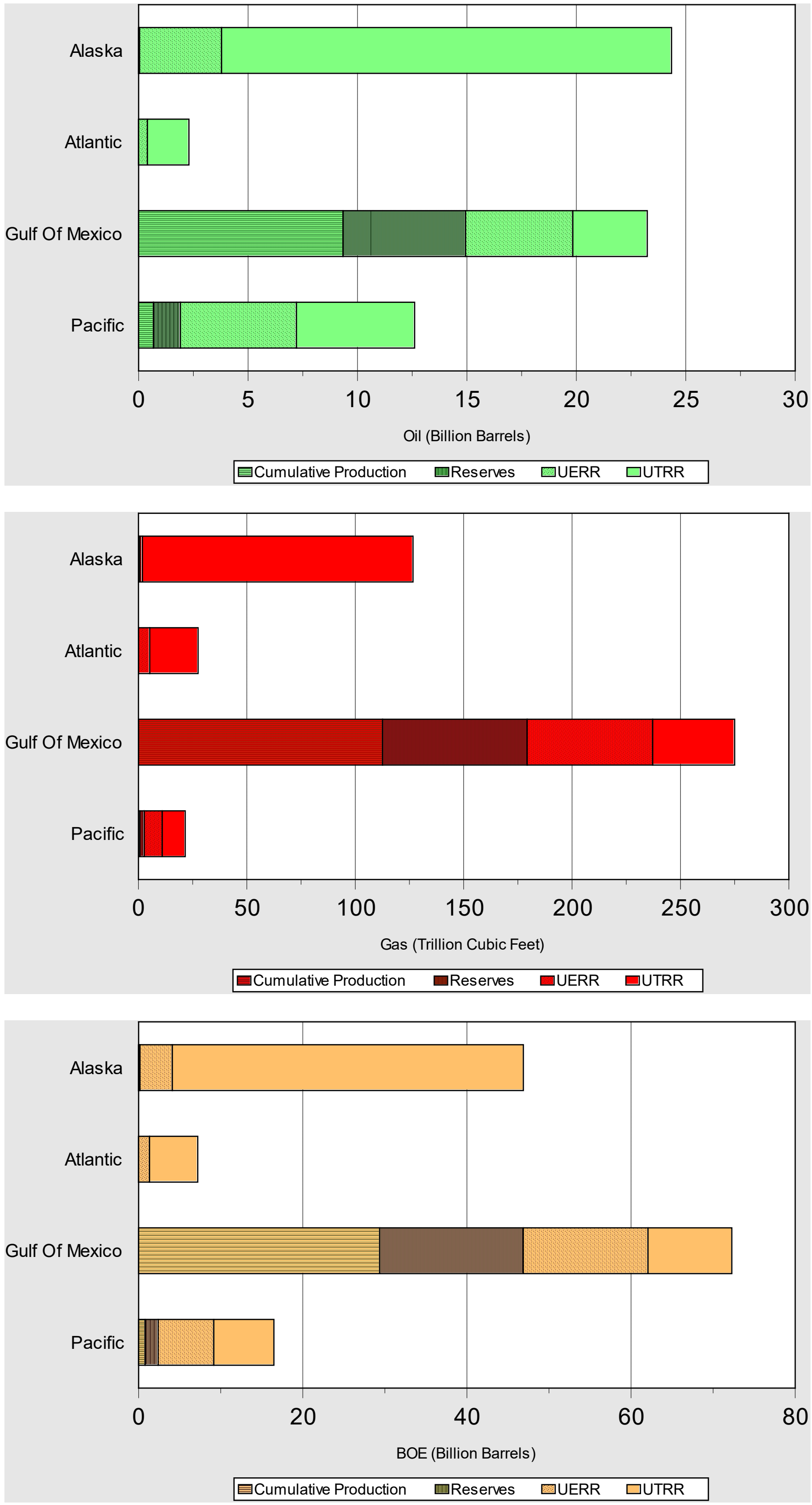
For the entire OCS, UTRR estimates for oil ranged between 37.1 and 55.3 Bbo with a mean value of 45.6 Bbo. Gas estimates ranged from 186.3 to 369.2 Tcfg, with a mean of 268 Tcfg. Comparable estimates for BOE were 72.9 to 117.0 BBOE with a mean of 93.4 BBOE. Fifty percent of the UTRR mean estimate on a BOE basis was projected to be present in the Alaska OCS (see **Figure 12**). The GOM, Pacific, and Atlantic OCS comprised 27%, 15%, and 8%, respectively of the total UTRR.

At the mean level, the 1996 estimates of UTRR for the OCS represented an increase compared to the previous assessment of 155% for oil and 85% for gas. The vast majority of this increase occurred in the Alaska estimates where oil increased by 20.5 Bbo and natural gas by 109.2 Tcfg. The increase in Alaska OCS estimates was primarily the result of a concerted effort in response to the NAS recommendations to further remove any consideration of economic constraints from the estimates. Ninety percent of the Alaska endowment was in the Beaufort and Chukchi seas. Mean UTRR estimates in the Atlantic OCS increased by 1.4 Bbo and 10.8 Tcfg (3.32 BBOE), a 158% and 65% increase respectively, for oil and gas. There were no new G&G data acquired in the area. The increase was primarily the result of a fundamental reassessment of the area's prospectivity and the use of the new assessment approach. The reassessment included acquiring G&G data and information from Canada's Scotian shelf and from a consideration of additional analog basins for the Atlantic margin.

The mean UTRR estimate in the Pacific Region increased by 7.1 Bbo, an approximate tripling from the prior assessment, and 8.08 Tcfg, almost double the prior estimate. A portion of this increase was attributable to a new analysis of the Monterey formation that indicated a potentially much larger volume of reservoir rock than previously estimated. The major cause of the increase, however, was likely due to the new assessment approach employed by MMS for this assessment.

In the GOM Region, the mean UTRR estimates decreased by 1.3 Bbo and 8.1 Tcfg (2.7 BBOE) when compared to the 1990 Assessment. However, considering the discoveries made between the 1990 and 1996 Assessments, the GOM resource endowment actually increased by 9 Bbo and 80 Tcfg (23.4 BBOE).

Figure 12. Distribution of Total Hydrocarbon Endowment by Type, Region, and Resource Category



Note: All UERR are also considered as part of the UTRR.

G. MMS 2001 Assessment (MMS, 2001)

Leading up to the 2001 Assessment, deepwater GOM areas increasingly became the focus on the OCS for leasing, seismic acquisition, drilling, and production activity. The major oil companies forged the way until 1996 when independent companies joined in. This interest was spurred by a number of large deepwater field discoveries and technological advances in drilling and development systems. Many of these discoveries were among the largest in the GOM in decades.

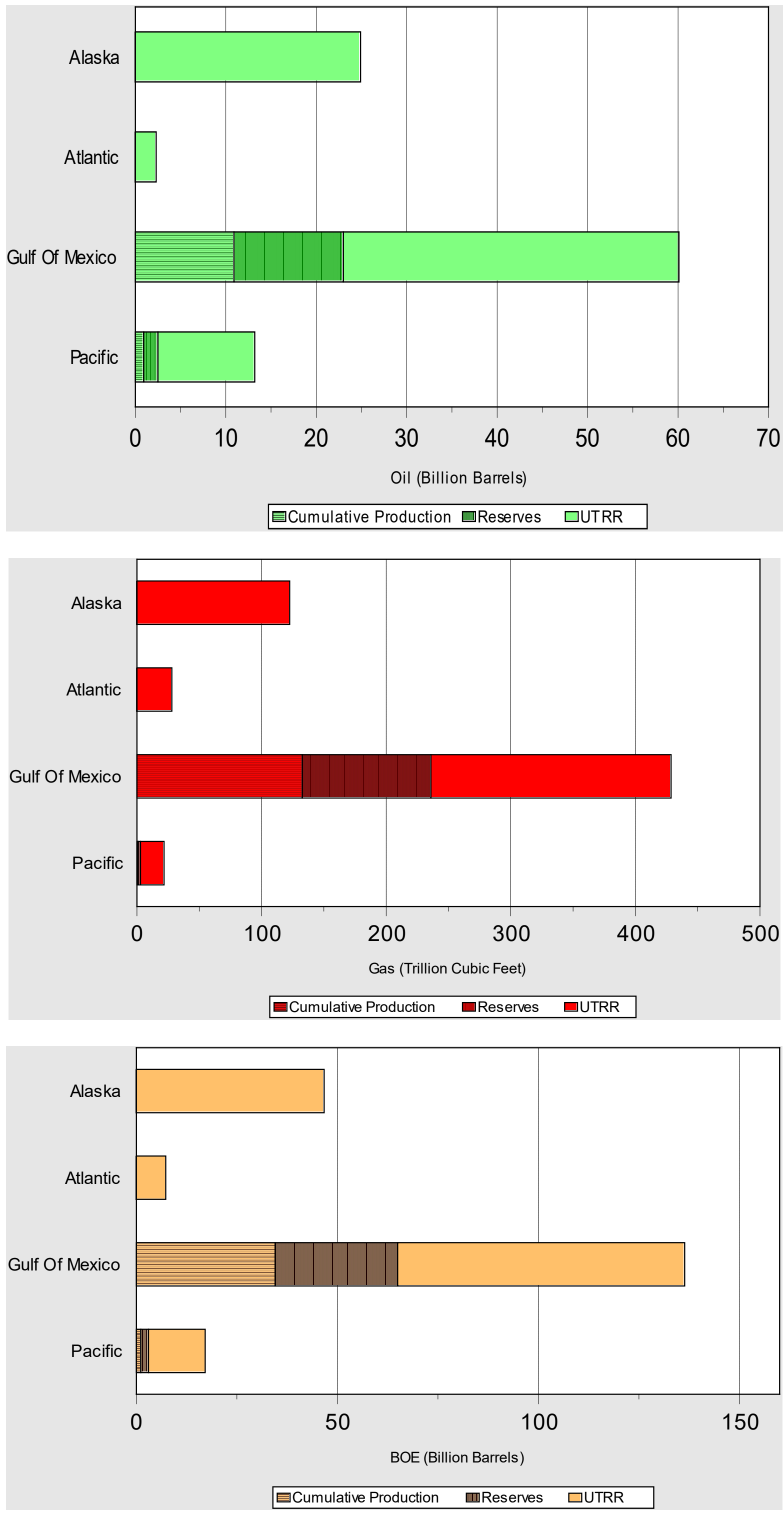
The total number of deepwater discoveries with an EUR of more than 100 million BOE (e.g., Neptune, Nansen, Holstein, Mad Dog, Medusa, and Thunder Horse) more than doubled between January 1, 1995, and this assessment. During the 9 years between 1989 and 1997, 175 fields containing total resources of 1.2 BBOE were discovered in the shallower waters of the GOM. The mean size of these discoveries was 6.9 million BOE. During this same period, 44 fields containing resources of more than 2.4 BBOE, with a mean field size of 55.5 million BOE, were discovered in deepwater areas—double the total resource volume discovered in the shallow water fields in only 25% of the number of fields.

UTRR estimates ranged from 63.7 to 88.3 Bbo and 292.1 to 468.6 Tcfg, with a mean estimate of 75.0 Bbo and 362.2 Tcfg (see **Table 5b**). The GOM OCS was forecast to contain one-half of the mean UTRR estimates of oil and offshore Alaska one-third (see **Figure 13**). The assessment forecast that 53% of the mean UTRR gas was in the GOM. Offshore Alaska followed with 34% of the total. This assessment resulted in an increase of the mean values by 29.4 Bbo and 94.2 Tcfg over the earlier 1996 assessment.

The increase occurred almost entirely in the deepwater GOM. In the 1996 Assessment, the mean UTRR estimates for the deepwater (water depths greater than 800 meters) portions of the GOM were 3.6 Bbo and 36.5 Tcfg (10.1 BBOE). In this assessment, the comparable deepwater estimates increased to 28.0 Bbo and 115.2 Tcfg (48.5 BBOE).

Mean estimates of total OCS hydrocarbon endowment developed from this assessment were 100.5 Bbo and 600.1 Tcfg (207.5 BBOE), corresponding to an increase of 53% for oil and 34% for natural gas (42% for BOE) since the prior assessment. The mean UTRR value for oil represented 75% of the mean estimate for the total oil endowment. Corresponding estimates for the increases in gas and BOE were 60% and 67%. More than 65% of the total endowment was projected in the GOM. Only 38% of the total oil endowment and 55% of the natural gas endowment in the GOM were represented by discovered resources.

Figure 13. Distribution of Total Hydrocarbon Endowment by Type, Region, and Resource Category



Note: All UERR are also considered as part of the UTRR.

H. MMS 2006 Assessment (MMS, 2006)

The first Alaskan OCS production occurred in 2001 from the joint state/Federal Northstar unit in the Beaufort Sea. Several new play concepts were introduced in the GOM since the previous assessment, and others continued to evolve. Play concepts were being refined in the ultra-deep (>20,000 feet) sediments on the shelf where discoveries such as JB Mountain and Mounds Point had recently been announced (MMS, 2001; MMS, 2003). In the deepwater areas, there were several new discoveries, including several hydrocarbon finds in the Lower Tertiary reservoirs for the first time. In the western GOM, several discoveries were made in the Perdido foldbelt, including Trident and Great White. Additional Lower Tertiary discoveries in the Central GOM included St. Malo and Cascade.

Deepwater exploratory drilling capabilities continued to increase. A new short-lived water depth record of 7,718 feet for an exploratory well was set by Chevron in August 1998, eclipsing the previous record of 7,620 feet set in 1996 at the BAHA prospect. Kerr McGee established a new water depth record at its Merganser discovery in 7,950 feet of water. This record would also be quickly surpassed as the first well to be drilled in water depths exceeding 10,000 feet was permitted.

The technical limits of deepwater production technology also continued to expand. In March 1999, Shell (and partners Exxon, BP, and Conoco) began production from another TLP for the Ursa project in 3,885 feet of water. New production concepts were also introduced; the world's first production SPAR, Oryx/CNG's Neptune platform, was installed in 1997 in 1,930 feet of water. A second SPAR system, Genesis, was brought on production in 1998 in 2,597 feet of water. Diana-Hoover, a drilling and production SPAR, was installed in 4,800 feet of water in 2000. British-Borneo Exploration installed Morpeth, the world's first mini-TLP, in 1,700 feet of water in 1998. This effort was followed in 1999 with another mini-TLP at its Allegheny project in 3,186 feet of water. Another new development technology was introduced to the Gulf when Amerada Hess installed a compliant tower in 1998 on its Baldpate project in 1,619 feet of water. This was quickly followed by Petronius in 1,754 feet of water.

The advances in 3-D seismic data acquisition and processing technologies driven by the special requirements in the subsalt play and in areas proximal to steeply dipping salt bodies fueled a resurgence in the acquisition of modern data in areas previously shot with older data acquisition techniques. As a result, whole new families of previously unidentified or poorly defined exploration prospects were targeted. The new data and interpretation techniques reduced risk and uncertainty to levels that permitted companies to pursue these prospects.

On the information technology front, impacts were felt throughout the industry. The speed, volume, and scale of access to geotechnical data and information continued to expand within the exploration and production industry with enormous advances in computational power. Geoscientists and engineers experienced a fundamental revolution in the applied earth sciences that radically altered their ability to integrate, adapt, and analyze a broad spectrum of G&G data. The petroleum industry saw the value of these new technologies as a tool to drive down cost, risk, and uncertainty, as well as increase productivity. The technology was focused on data acquisition and manipulation, analysis applications, visualization, and integration.

For the entire OCS, UTRR estimates for oil ranged from 66.6 to 115.3 Bbo with a mean value of 85.9 Bbo (refer to **Table 5b**). Natural gas estimates ranged from 326.4 to 565.9 Tcfg with a mean of 419.9 Tcfg. Comparable estimates for BOE were 125.7 to 215.9 BBOE with a mean of 160.6 BBOE. Fifty-four percent of the mean UTRR estimate on a BOE basis was projected to be present in the GOM OCS. The Alaska, Pacific, and Atlantic OCS comprised 31, 9, and 6%, respectively, of the total UTRR.

At the mean level, the UTRR estimates for the OCS represented an increase of 10.9 Bbo and 57.7 Tcfg compared to the previous assessment, or about 15% for oil and 16% for gas. The vast majority of this increase occurred in the GOM where estimates of UTRR ranged from 41.2 to 49.1 Bbo and 218.8 to 249.1 Tcfg with a mean of 44.9 Bbo and 232.5 Tcfg. This represented a 21% increase in oil resources and a slightly greater percent increase in natural gas resources since the previous assessment. Significant increases in the estimates for the deepwater areas were the major contributor to the overall growth in the UTRR estimates. The mean UTRR estimates in the deepwater areas were 38.8 Bbo and 125.2 Tcfg (61.1 BBOE), which represented an increase over the previous assessment of 10.8 Bbo and 10.0 Tcfg (12.6 BBOE). This increase in UTRR was also accompanied by approximately 4.5 Bbo and 14 Tcfg that were discovered in fields, such as Thunder Horse and Holstein, whose resources were moved to the reserve category during this time period.

In the Pacific Region, the mean estimate for UTRR of 10.5 Bbo and 18.3 Tcfg represented a slight decrease for both oil and natural gas. The Atlantic UTRR estimate ranged from 1.1 to 7.6 Bbo and 14.3 to 66.5 Tcfg with a mean of 3.8 Bbo and 37.0 Tcfg. The estimates represented a 66% increase in oil resources and a 33% increase in gas resources in the Atlantic OCS, when compared with the 2001 Assessment. The last remaining leases in the Atlantic OCS, on the Manteo prospect, expired in 2002 without a well being drilled.

However, significant new analog information was available as the result of recent exploration in the Scotian shelf offshore Canada and the West African continental slope offshore Mauritania. Applying these new exploration ideas to the older Atlantic play models led to adjustments to risks in previously defined plays and the identification of additional new plays.

UTRR estimates on the Alaska OCS changed only slightly compared to the previous assessment. The mean oil estimates increased at mean level by 1.7 Bbo, while the natural gas estimate declined by 6.7 Tcfg.

Mean estimates of total OCS hydrocarbon endowment developed from this assessment were 115.4 Bbo and 633.7 Tcfg (228.2 BBOE), corresponding to an increase of 15% for oil and 5% for gas (10% for BOE) since the prior assessment. The mean value for oil UTRR represented 74% of the mean estimate for the total oil endowment (see **Figure 14**). Corresponding estimates for gas and BOE were 66 and 70%, respectively. More than two-thirds of the total endowment was projected in the GOM. Only 37% of the total oil endowment and 48% of the natural gas endowment in the GOM was represented by discovered resources.

I. BOEM 2011 Assessment (BOEM, 2011)

Leading up to BOEM's 2011 Assessment, the AAPG Committee on Resource Evaluation (CORE) reviewed BOEM's resource assessment methodology. This followed an initial review conducted by the CORE in 2003 prior to the 2006 Assessment, after which BOEM substantially revised the methodology based on recommendations made by the CORE at that time. This was subsequently endorsed by the CORE. The CORE noted that the methodology proposed for BOEM's 2011 Assessment was more driven by geology compared to the methodology used in BOEM's 2006 Assessment. This also brought the methodology closer to that applied by the USGS, which the CORE had endorsed earlier, and abandoned purely statistical methods to estimate the distribution of numbers and sizes of undiscovered fields in mature geologic plays.

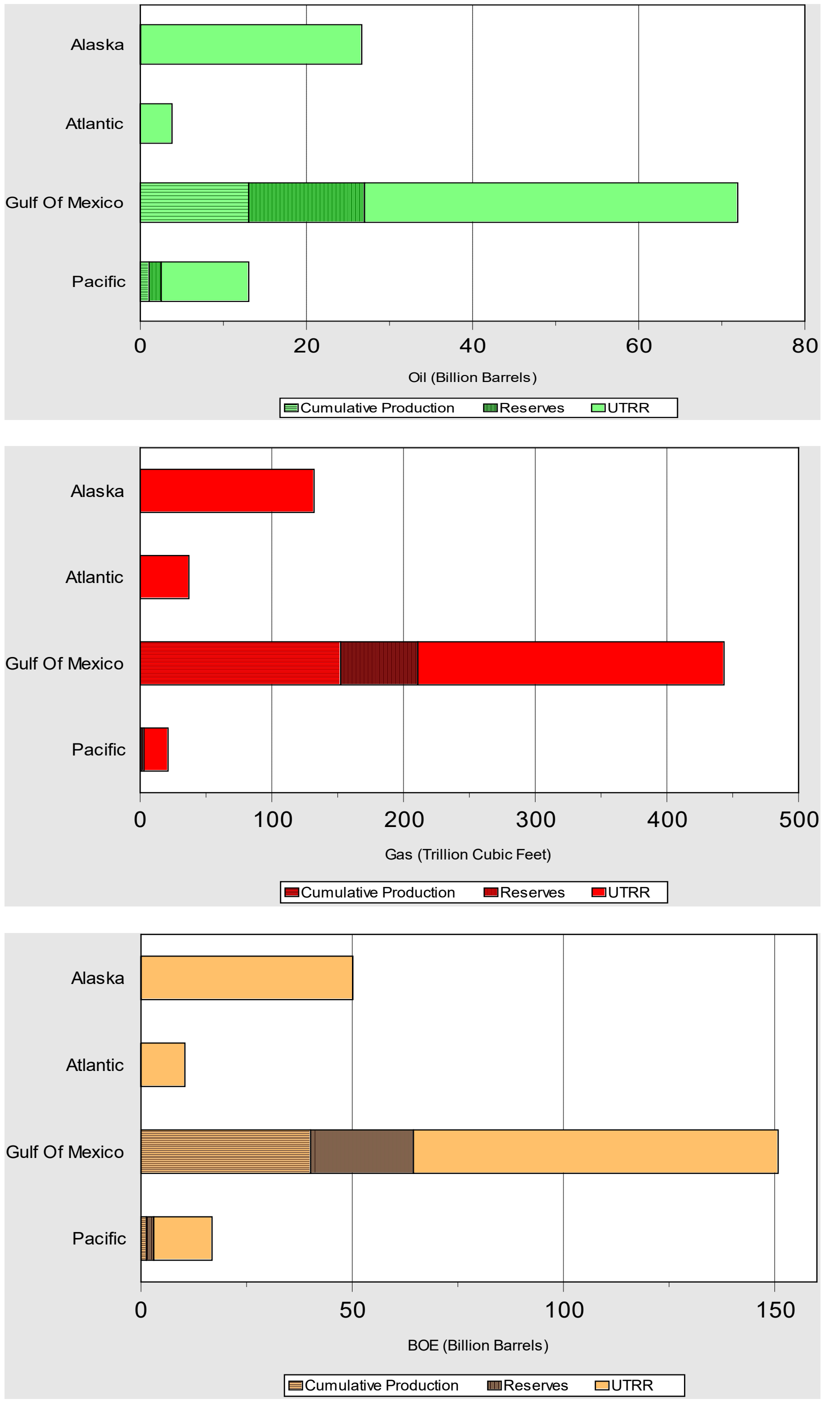
The CORE commented on a few areas of concern related to incorporating a wider range of possibilities for the number of undiscovered fields and their respective sizes in BOEM's assessment methodology. These concerns were separated into categories of (1) conceptual and frontier plays and (2) discovered plays. The CORE used the Atlantic OCS as an example of a conceptual and frontier play as it has no established production, had very limited well control, and lacked modern seismic data, thus relying on seismic data acquired more than 20 years previously.

The CORE commented that BOEM had done an excellent job of synthesizing the stratigraphy, tectonic, and basin evolution through use of reprocessed legacy seismic data and integrating with existing well information. Furthermore, to evaluate the play chance factors, the CORE noted that BOEM assessors used analogues in Canada or in the North African conjugate margin, as well as in other similar regions. The CORE felt that that the geologic analysis was excellent and on par with similar work done by the USGS on conceptual and frontier plays worldwide.

However, CORE raised some concerns related to frontier play assessment in the GOM and Atlantic, recommending that BOEM consider reducing the lower limit risk factors for which a specific play's components were to be evaluated (e.g., reservoir, source, seal, timing) and explain its use of analogues and risk of oil-vs-gas in some of the conceptual plays more precisely.

In discovered plays in the GOM, CORE noted the following concerns: BOEM scientists stated that their 2011 Assessment would now "roll-up" paleo-facies play information to the sequence boundary to form the basis of their analysis. Previous assessments used a more "finely divided" facies approach and each of these facies independently formed the basis of its analysis. Some of the committee questioned this methodology, while the others felt that because these are shallow plays with minor discovery potential, combining these packages may not affect the final results.

Figure 14. Distribution of Total Hydrocarbon Endowment by Type, Region, and Resource Category



Following the suggestion of the CORE, BOEM tested this concept by carrying out a test assessment on individual packages and combining them for a play, and also assessed that play without subdividing it further. The effect of lumping the sub-plays was considered inconsequential to the overall assessment results. Another concern dealt with the possibility that lumping sub-play characteristics could effectively ignore some key aspects of a play. Specifically, field sizes, recoveries, and success rates could vary within different parts of the sequence, yet these data might be "smoothed" by lumping. BOEM was encouraged to test this concern further in its work. Additionally, the CORE felt that the logic and approach to reserve growth was not clearly explained and encouraged consultation with the USGS on this matter.

The CORE recommended that BOEM describe the process by which success rate is ascribed to a given discovered play. A range might be used for recovery rates in a single play. This would allow for a wide range of outcomes rather than a concentration toward a narrow mean, independent of how many times a distribution of individual wells or prospects is sampled. Additionally, the CORE recommended that BOEM explicitly state the methodology by which BOEM addresses dependency among recognized plays.

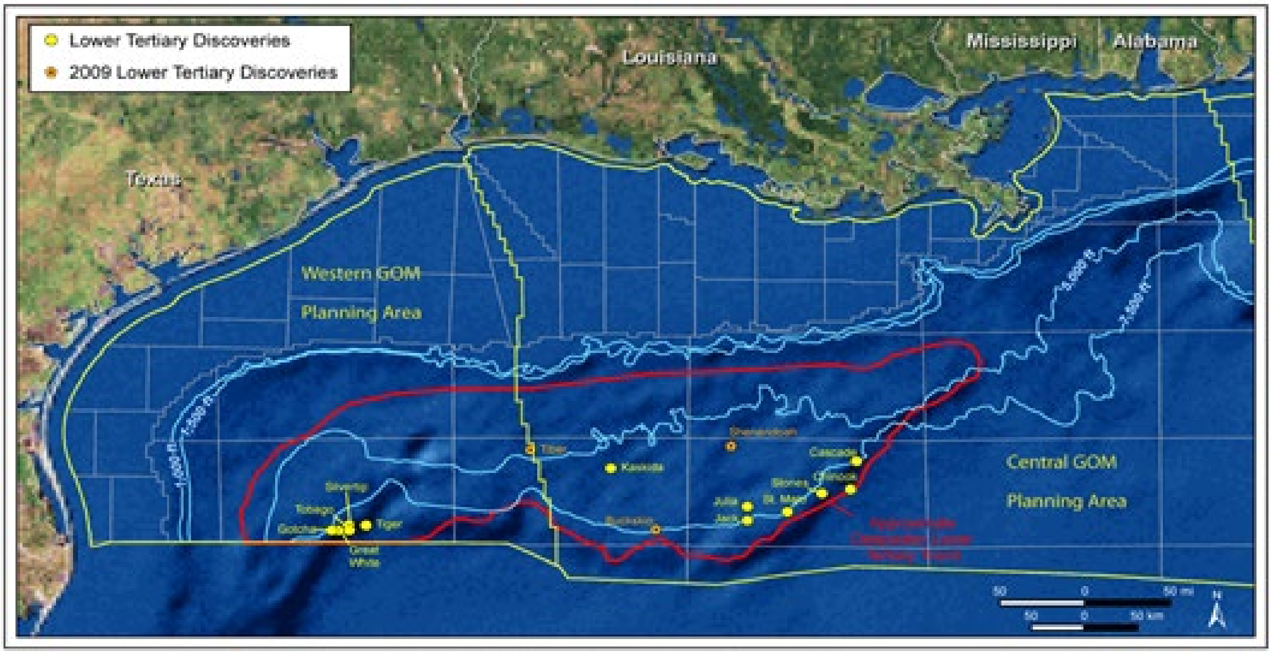
In summary, the CORE felt that significant progress was made on the 2011 methodology since the 2006 Assessment. The overall 2011 Assessment methodology review was endorsed by the AAPG Executive Committee in May 2011.

For the 2011 Assessment, the estimate of UTRR for the total OCS ranged from 65.2 to 121.7 with a mean of 89.9 Bbo, and from 307.9 to 556.5 with a mean of 404.5 Tcfg. For the total OCS, the mean values of the undiscovered technically recoverable oil increased by approximately 5%, while gas decreased by 4% compared to the 2006 Assessment. Based on the BOE mean UTRR values, the GOM was estimated to have about 54%, followed by Alaska with 31%, Pacific with 8%, and Atlantic with 7%. The total OCS endowment was estimated to be 129.5 Bbo for oil and 661.1 Tcfg for gas, which was an increase of about 12% for oil and 4% for gas when compared to the previous assessment of 2006.

During the period assessed, the GOM region continued to add significant new reserves for the OCS. From 2004 to 2009, more than 75 new deepwater discoveries were made in the GOM OCS. The Lower Tertiary geologic trend (see **Figure 15**) accounted for most of these new discoveries, namely: Gotcha, Tobago, Silvertip, Great White, Tiger, and Tiber in the Western GOM Planning Area; and Kaskida, Buckskin, Jack, Julia, St. Malo, Stones, Chinook, Cascade, and Shenandoah in the Central GOM Planning Area. The Lower Tertiary geologic trend (also referred to as the Wilcox play) stretches from west to east over 450 miles and reaches more than 100 miles from north to south. The trend could cover more than 30,000 square miles at an average depth of 27,500 feet subsea.

Wells that were drilled on this trend during this time targeted reservoir rocks of Paleocene to Eocene age and confirmed the presence of a regionally continuous Lower Tertiary sediment delivery system. The deepwater GOM was estimated to provide 70% of the oil and 36% of the gas in the GOM. For the Cenozoic plays, the majority of the undiscovered resources were believed to be located on the slope, while nearly three-fourths of the existing reserves were on the shelf because of the long period of extensive exploration efforts.

Figure 15. Lower Tertiary Trend in the Gulf of Mexico Prior to the 2011 Assessment



At the time of the 2011 Assessment, the bulk of the projected increase in U.S. offshore oil and gas production was expected to come from the new discoveries in deep and ultra-deepwater regions of the GOM. According to the Petroleum Economist (June 10th 2010 edition), "Lower Tertiary trend continues to reveal big discoveries. Significant finds have been made both in the trend's shallow and deepwaters, which could hold as much as 15 billion barrels of oil, in high-pressure, high-temperature sub-salt formations at least 25,000 feet below the sea floor." The Lower Tertiary is recognized as a huge resource with the potential for long-life projects of up to 30 to 40 years. The growing number of Lower Tertiary developments in the GOM has also demonstrated that the technical challenges associated with HPHT environments are being overcome and could allow for increased oil and gas production.

In Alaska, Lease Sale 193 in 2008 in the Chukchi Sea Planning Area offered evidence of the interest the oil and gas industry had in the area, and by proxy, evidence of potential oil and gas resources. Lease Sale 193 generated approximately $2.7 billion in high bonus bids and a total amount exposed of around $3.4 billion. Approximately 2.8 million acres on 487 tracts were leased out of the 29.4 million acres offered for the lease sale.

The 2011 Assessment of the Atlantic OCS incorporated and applied modern exploration concepts and key new learnings from offshore Nova Scotia, conjugate northwestern Africa, and the African Transform Margin. Existing BOEM Atlantic region data sets were enhanced, and new gravity and magnetic data were acquired and interpreted. Also, the methodology for play and prospect level risk used by BOEM for the Atlantic OCS was updated and modified from those previously used (Lore et al., 2001). The new methodology retained the strengths of a comprehensive play-based approach. Conceptual plays were developed based on geophysical data, regional geologic data and knowledge of the region, consideration of productive analogs in similar tectonic/structural location, the style of analog oil and gas traps, reservoir depositional environment and lithology, reservoir age, and petroleum system analysis of existing drilling in the analog. Thus, within the

Atlantic OCS, nine conceptual plays and one established high-risk play were identified and their resources inventoried.

The 2014 Atlantic Assessment update (BOEM, 2014) incorporated important new information from recent oil and gas discoveries considered analogous to selected geologic plays in the Atlantic OCS. Since the 2011 Assessment, the number of analogous discoveries that were appropriate for use in developing the field size distributions for two of the conceptual plays in the Atlantic OCS had increased nearly three-fold. All of the analogous new field discoveries were offshore East Africa and West Africa. They display similar geologic settings and petroleum system elements to what is observed in the Atlantic OCS.

Progress in drilling technology has enabled the exploration for hydrocarbons in water depths of up to 12,000 feet and 40,000 feet total depth. Recent technological advancements, such as horizontal wells and multi-lateral completions, enabled the recovery of a higher percentage of the in-place resources from a field. Also, the introduction of drill ships and semi-submersibles capable of drilling in up to 12,000 feet of water depth, coupled with dual gradient drilling techniques, expanded the envelope of producible oil and gas resources in very challenging environments.

J. BOEM 2016 Assessment (BOEM, 2016)

Results from the 2016 Assessment represented a multi-year effort that included data and information available as of January 1, 2014. Aggregated estimates of UTRR oil for the entire OCS ranged from 76.46 Bbo at the 95th percentile to 104.02 Bbo at the 5th percentile, with a mean of 89.87 Bbo. Similarly, gas estimates ranged from 282.74 Tcfg to 377.62 Tcfg with a mean of 327.49 Tcfg. On a BOE basis that includes both oil and gas, approximately 50% of the potential resources were within the GOM, and the Alaska OCS ranked second with 34%. The Pacific was third among the regions in terms of oil potential and fourth with respect to gas. The Atlantic region ranked third when considering gas potential and fourth in terms of oil.

In the GOM, the UTRR mean estimate for oil remained statistically unchanged, increasing 0.1% while the estimates for gas decreased by 77 Tcfg, or about 35%. The decrease in UTRR gas was attributed to a refinement of field size distributions for geologic plays primarily in shallow water. The refined field size distributions better represented recent exploratory well results, the size of recently discovered gas fields, and the range of prospect sizes that received bids in recent GOM lease sales. For example, the play with the largest decrease in the GOM was the Lower Tertiary play, in which the mean UTRR gas decreased from approximately 45 Tcf in 2011 to 25 Tcf in 2016. This accounted for about a quarter of the total decrease in the region. In total, five out of the seven plays with the greatest reduction in mean UTRR gas from 2011 to 2016 were shallow water shelf plays.

UTRR estimates on the Atlantic OCS were updated in 2014, yielding mean values of 4.72 Bbo and 37.51 Tcfg. The off-cycle update in 2014 was due in large part to the availability of significant new information derived from global analog plays. For the 2016 Assessment, only minor revisions were incorporated, resulting in a slight decrease to mean oil volume and slight increase to mean gas volume, to 4.59 Bbo and 38.17 Tcfg, respectively. This represented a decrease of approximately 3% for oil and an increase of 2% for gas.

Prior to the data cutoff date of January 1, 2014, BOEM recognized effectively no significant new geologic data gathered on the Alaska OCS. Additionally, no OCS leases acquired since the

2011 Assessment had been tested. Thus, the 2016 mean estimates of UTRR for the Alaska OCS (26.61 Bbo and 131.45 Tcfg) remained unchanged in comparison to the 2011 Assessment. The geologic information acquired in the 2015 drilling season in the Chukchi Sea was to be incorporated into a future BOEM assessment of the Alaska OCS UTRR.

Similar to the Alaska OCS, no significant new geologic information was available in the Pacific OCS since the previous assessment. In addition, there was no new leasing or exploratory efforts on unleased lands. The only new activities occurring in the region since the previous assessment were in the existing producing fields in the Southern California Planning Area. As a result, the 2016 mean UTRR of 10.20 Bbo and 16.10 Tcfg were unchanged from the results presented in 2011.

K. BOEM 2021 Assessment (BOEM, 2021a)

The 2021 Assessment represented a multi-year effort that included data and information available as of January 1, 2019. For the 2021 Assessment, BOEM developed and incorporated a new, standardized methodology for estimating the chance of success for both geologic plays and individual prospects. BOEM also developed a new workflow that quantifies the probability of three major petroleum system elements and applies the chance of success (i.e., the chance hydrocarbons are discovered) of a geologic play or prospect based on the quality of data associated with those elements. The new methods and workflow were applied to all OCS regions.

UTRR oil estimates for the entire OCS ranged from 57.32 Bbo at the 95th percentile to 81.75 Bbo at the 5th percentile, with a mean of 68.79 Bbo. Gas estimates ranged from 183.46 Tcfg to 278.22 Tcfg with a mean of 229.03 Tcfg. On a BOE basis, 43% of the UTRR was within the Alaska OCS. The GOM OCS ranked second with 36% of the resources. The Pacific was third among the regions in terms of oil potential and fourth with respect to gas. The Atlantic OCS ranked third when considering gas potential and fourth in terms of oil. After more than 60 years of OCS exploration and development, BOEM estimated that greater than 60% of OCS resources remained undiscovered. Approximately 33% had been produced, with 3% remaining as discovered reserves.

In the GOM, when compared with the estimates included in the previous assessment, the UTRR mean estimate for oil dropped 38% from 48.46 Bbo to 29.59 Bbo, while the estimate for gas decreased 61% from 141.76 Tcfg to 54.84 Tcfg. The overall decrease in UTRR in the GOM was due in part to the refinement of field size distributions and the estimated number of prospects for some mature geologic plays, particularly on the shallow water shelf. Several geologic plays in the Mesozoic section were reported with a modest increase in mean UTRR. In total, 30 geologic plays were assessed in the GOM OCS.

The Atlantic OCS mean estimates of UTRR decreased to 4.31 Bbo and 34.09 Tcfg (10.38 BBOE) when compared to the previous assessment, due in large part to the availability of new information derived from global analog plays and adjustments to play and prospect risk profiles. This represented a slight decrease in both oil and gas volumes, leading to an overall decrease of 1.01 BBOE from 2016 (a 10% decrease). A total of 10 geologic plays were assessed in the Atlantic OCS.

Mean UTRR for the Alaska OCS decreased by 3.95 BBOE compared to BOEM's 2016 Assessment, with the bulk of the reduction due to the reassessment of risk profiles in the

Beaufort Sea Planning Area. The Chukchi Sea mean UTRR increased slightly, while the remaining nine Alaska planning areas with resources remained relatively flat. A total of 73 geologic plays were assessed on the Alaska OCS.

The Pacific OCS mean UTRR estimates of 10.20 Bbo and 16.07 Tcfg remained relatively unchanged for both oil and natural gas, respectively, when compared to the previous assessment. A total of 43 geologic plays were assessed on the Pacific OCS.

The period prior to the 2021 Assessment saw several HPHT projects at different stages of development in the GOM (BOEM, 2020b). Unique engineering challenges exist for HPHT projects because special subsea equipment must be fabricated to withstand high pressures (typically greater than 15,000 pounds per square inch) and high temperatures (greater than 350°F). There are also significant additional costs associated with HPHT projects due to research and development and design requirements for the equipment and technology to perform in these extreme environments.

Reservoirs with HPHT properties have been discovered in many areas of the GOM, but they are most prevalent in the Lower Tertiary and the Jurassic Norphlet Formations (BOEM, 2020b). Shell's Appomattox project in the GOM was the first high temperature project to gain BSEE approval and begin production using new BSEE HPHT guidance. The Appomattox project achieved first production in 2019 with expected production of 175,000 BOE per day. The platform is in 7,400 feet of water and the subsea wells have equipment rated for 15,000 psi and 400°F.

L. Summary

DOI has completed 11 comprehensive resource assessments since 1975. Resource estimates are a product of the knowledge base existing at the point in time in which they are developed. As such, resource assessments reflect the results from a complex interaction of many factors—available G&G data and information, working geologic models and play concepts, exploration and production technology and activities, cost-price relationships, and assessment techniques—which make it difficult to attribute changes in estimates to a single factor.

Since 1975, geologic information available to assessors changed dramatically. For example, at the time of the initial assessment, there was only a single deep stratigraphic test well drilled anywhere on the Atlantic and Alaska OCS. Marine 2-D seismic data were primitive by today's standards and there were no 3-D seismic data available. The ability to drill horizontal and extended reach wells or use multi-lateral completions was non-existent 35 years ago and subsea completion technology was in its infancy. By the 1990s, information technology had significantly improved, serving as the catalyst to transform the geosciences and the petroleum industry. Since 1975, industry has drilled more than 55,000[4] wells and collected greater than 3.4 million line-miles of 2-D and nearly 380,000 OCS blocks of 3-D seismic data (BOEM, 2023). Additionally, more than 1,100 oil and gas fields have been discovered and technological advances have expanded deepwater drilling capabilities from a little over 1,000 feet of water to 12,000 feet and greater.

It is important to note that although data acquisition has increased knowledge regarding the resource potential of the OCS, much of these data exist for the central and western GOM and

[4] Source: BOEM and BSEE Technical Information Management System database

Southern California, and the information that has been acquired in most of the other areas is now 25 to 45 years old, resulting in considerable uncertainty concerning the resource potential of many of these frontier areas.

It is challenging to draw broad general conclusions concerning the impact of new data and information on the DOI resource assessments. The additional data and information that become available to assessors between assessments are frequently mixed in terms of having a positive or negative effect on the perception of the overall hydrocarbon potential of the OCS. With each successive oil and natural gas resource assessment, DOI assessors strive to incorporate the most current information related to G&G and engineering data, economics and market forces, and industry's exploration and production capabilities. Simultaneously, DOI assessors advance the science of resource assessment by continuously updating and revising assessment techniques, models, and approaches.

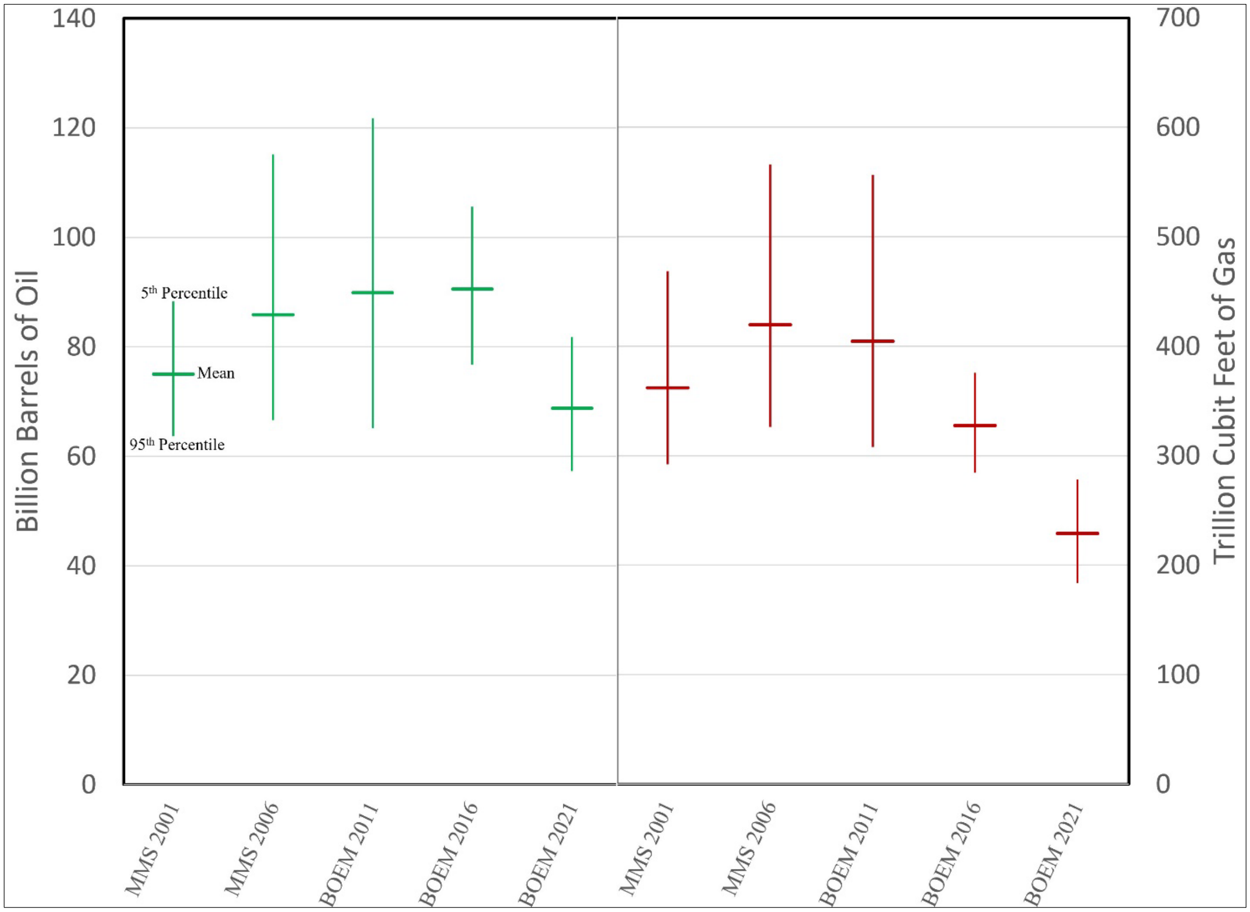
Early DOI resource assessments (1975–1995) focused on reporting UERR estimates during a period that was characterized by volatile oil and gas prices. It was also during this period that the oil and gas industry's technology capabilities expanded immensely. During this timeframe, industry exploration in frontier OCS basins in the Atlantic, in the Bering Sea, offshore southern Alaska, and in portions of the area offshore Southern California yielded non-commercial results. At the same time, production in the Central and Western GOM and the Santa Barbara Channel expanded greatly and production was established in the Santa Maria Basin off California. Assessment techniques became more sophisticated during this period, evolving from Delphi subjective judgment approaches to detailed stochastic hydrocarbon play evaluations (PRESTO III and GRASP).

Beginning with the fourth resource assessment in 1990, UTRR estimates were introduced. As the UTRR estimates are not calculated directly with respect to price volatility, they allow for a more meaningful comparison among different vintages of resource assessments.

The 1996 Assessment represented a watershed event in the agency's resource assessments, as it incorporated major changes in the basic underlying approach to resource assessment and shifted the principal focus from assessing UERR to UTRR. This transition implemented NAS recommendations upon their review of the preceding resource assessment's methodologies and results, resulting in a more expansive interpretation of OCS UTRR potential and significant increases of the estimates when compared to the previous assessment.

Figure 16 compares the results from the 2001 Assessment through the 2021 Assessment for UTRR. Overall, between the 2001 and 2021 Assessments, the mean UTRR of oil decreased by approximately 8% (75.0 to 68.8 Bbo) and the mean UTRR of gas declined by approximately 37% (362.2 to 229.0 Tcfg). The mean total endowment of oil increased by 8% (100.5 to 108.3 Bbo) and the total endowment of gas decreased by 30% (601.0 to 461.2 Tcfg) over the same time period.

Figure 16. Comparison of 2001–2021 UTRR Estimates



Notes: The green bars represent oil with values noted on the left vertical axis, and the red bars represent gas with values noted on the right vertical axis.

V. Interpreting Resource Estimates and Possible Effects of Understated Inventories on Domestic Investment

A. Background

Section 357(a)(4) of the EPAct directed the Secretary of the Interior to "...estimate the effect that understated oil and gas resource inventories have on domestic energy investments."

When describing oil and natural gas, the term "inventory" could have different connotations depending on the context when used. For example, certain stakeholders might think of oil and natural gas inventories as physical stockpiles of the resources. To others, such as the investment community, these inventories might represent estimated quantities of already discovered reserves reflected on the books of individual oil and gas companies. In this section, the use of the term "inventories" is meant to describe the quantities of oil and natural gas yet to be discovered.

The wording of this directive—to estimate the effects of "understated" resource inventories—suggests that there is a perception that government assessments are too conservative, particularly when viewed over time and in hindsight following actual discoveries in some OCS areas. However, each assessment reflects a snapshot in time that should not be viewed as either understated or overstated when compared to later assessments, which reflect changed circumstances and knowledge. True knowledge of the extent of oil and natural gas resources can only occur through the actual drilling of wells.

Estimating undiscovered resources, no matter how sophisticated the models and statistical techniques employed, is an inherently uncertain exercise that is based on hypotheses and assumptions, with the results limited by the quality of the underlying geologic data. Results incorporate perceived levels of risk and are expressed in ranges of estimates to reflect the uncertainty. Nevertheless, resource assessments are a component of energy policy analysis, and provide the industry and public with information about the relative potential of U.S. offshore areas as sources of oil and natural gas.

The main objective of the government's assessment of undiscovered resources is to develop a set of scientifically based estimates concerning the potential quantities of oil and natural gas that could exist on the OCS. BOEM assessments of OCS resources typically provide aggregate oil and gas resource estimates for all of the OCS planning areas in the GOM, Atlantic, Pacific, and Alaska. These assessments represent the government scientists' best estimate of what quantities of oil and natural gas remain undiscovered given the current state of geologic knowledge and reasonably foreseeable technology. Both BOEM and the Department of Energy use these assessments for planning, forecasting, and policy analyses. The oil and gas industry and private investors use this information generally to guide investment decisions and their search for new resources. BOEM resource assessments are also used by Congress and other agencies to support energy policy analyses and decision making.

BOEM resource assessments also provide detailed information about specific geologic plays associated with the aggregate estimates for OCS planning areas. Although this play information can provide industry with some new perspectives on an area, it is unlikely that this information alone or the aggregate resource assessments for OCS planning areas have any direct material effect on the oil and gas industry's domestic investment in exploration and development as a whole. Industry and private investors, when considering alternative investment opportunities, often conduct independent assessments, employing their own models and techniques for evaluating and interpreting the data. The same factors that serve to moderate the government's assessment of certain areas (e.g., lack of data, uncertainty) could also influence industry's own assessments and conclusions, and ultimately its willingness or ability to invest in those areas.

The OCSLA requires the Secretary of the Interior to develop OCS oil and gas leasing programs that set out the schedule and location of lease sales based on consideration and balancing of a number of factors (OCSLA Section 18(a)(2)), one of which is the geologic characteristics of the oil- and natural gas-bearing physiographic regions of the OCS. BOEM national assessments of undiscovered oil and gas resources on the OCS are conducted at least every 5 years and are timed in part to support the Section 18(a)(2) requirements. For the development of a National OCS Program, these assessments serve to indicate the relative potential of various petroleum provinces and planning areas and provide BOEM with the basis for considering possible effects of future oil and gas related activities from the OCS.

Areas included in a National OCS Program are the only areas available for leasing in a 5-year period unless the Secretary cancels a lease sale or there is Congressional action to add or cancel sales. Industry and others are afforded a number of opportunities to provide input on those areas of interest to them, and to comment on the proposed lease sale schedule.

B. Inventories of Undiscovered Resources Over Time

Each assessment is at best a snapshot in time that reflects the most current data, exploration, and development technologies, and existing knowledge about the resource potential for each OCS area. The analytical search process continually adds prospects to the inventory as they are identified, drops them as they are leased or eliminated by further seismic evaluation or drilling, and re-characterizes their resource potential and costs. Thus, the actual knowledge of oil and natural gas resources on which leasing and planning decisions are based is never final or definitive.

Changes occur with time in technology, G&G data available to assessors, and geologic interpretations and models that can lead to higher or lower estimates as assessments are updated in later years. For this reason, specific assessments of undiscovered oil and gas resources need not decline systematically over relatively short time periods.

BOEM routinely updates and revises its resource estimates to reflect changing conditions and knowledge. For the 2016 Assessment, mean estimates for oil decreased less than 1% and mean estimates for natural gas decreased by 19% when compared to the 2011 Assessment. For the 2021 Assessment, mean UTRR for oil decreased by 23% while gas decreased by 30% when compared to the 2016 Assessment. As discussed previously, these decreases are due to an improvement in the UTRR methodology used in the 2021 Assessment and in the refinement of field size distributions.

C. Utility of Resource Assessments

Government resource assessments are used for programmatic planning, like development of the National OCS Program, analyses of proposed legislation, and estimating effects on investment and revenues from various leasing and regulatory policies. To inform these efforts and ensure meaningful policy analyses, government decision-makers need to consider projections of potential undiscovered accumulations of oil and natural gas from comprehensive assessments of resource potential. The government's resource assessments typically focus on large areas, examining the interplay of prospective geologic plays to estimate the potential sizes of yet-to-be discovered accumulations of oil and gas, and typically do not attempt to locate, identify, or delineate specific oil or gas fields or prospects.

Industry's investment decisions include a variety of considerations and are based largely on comparative evaluations of the profitability of specific investment alternatives, including international opportunities in some cases. The decisions on where to drill for oil and natural gas rely on a number of factors related to expected financial returns, market position, and perceived geological and geopolitical risk. These investment decisions occur in a staged manner over time.

On the OCS, exploration and development costs are relatively high; the costs associated with seismic surveys, drilling, platform installation and maintenance, and decommissioning can be substantial, especially in frontier areas. Based on their assessments, many companies acquire, via competitive bidding, an inventory of promising acreage before undertaking costly seismic acquisition or exploratory drilling programs. The expected profitability of specific projects is affected by a company's perception of risk—geologic and economic—which are lower in areas with proven resource potential and where oil and gas development is more mature. Companies only invest in domestic oil and gas exploration and development when they have reasonable certainty of realizing a sufficient return on that investment. In those OCS areas that are currently unavailable for leasing, companies are disinclined to expend capital or time attempting to evaluate the hydrocarbon potential.

D. Effects of Risk on Resource Assessments

Assessments of undiscovered resources are associated with significant uncertainty and geologic risk, therefore estimates should only be used as broad indicators rather than exact volume forecasts. In order to quantify these risks and uncertainties, seismic surveys are used to reveal possible oil and gas accumulations that serve to focus exploration drilling efforts. Actual deposits can only be discovered through drilling costly exploratory wells. Exploration investment can often fail to yield discoveries of oil and gas, and when prospects are identified, on closer evaluation, some do not warrant further investment with exploratory drilling. Many prospects turn out to contain no oil and gas; others are found to contain oil or gas but are not economically viable because of the size of the deposit or other factors that add development costs.

Estimating resource potential is not an exact science, and different technical experts and companies could have widely different views on appropriate methodologies and the interpretation of data. While the government has much of the same basic G&G data on unleased OCS oil and natural gas prospects as do private companies, interpretations of those data and perceptions of an area's hydrocarbon potential vary. Both groups, however, evaluate the resource potential by explicitly incorporating geologic risk and uncertainty into the resource assessments to account for the absence of a strong relationship between the geologic variables and the presence of specific amounts of hydrocarbon resources, as well as the lack of geologic information for many of the OCS areas.

Government assessments of oil and gas resource potential rely on risk-based methodologies to statistically reflect different chances for drilling success in different areas. As described in Section III, the resource assessment models explicitly account for differences in geologic risk among oil and gas provinces and planning areas. As a result, the risk-based estimates in frontier areas could ultimately be seen as far too conservative if later exploration demonstrates that the area is hydrocarbon-prone, and will have overstated resources in those areas that ultimately prove unsuccessful. BOEM attempts to mitigate this problem by conducting periodic assessments that incorporate new data from drilling and new seismic surveys. New knowledge could lead to increases or decreases in estimates of undiscovered resources, but generally leads to a reduction of uncertainty.

VI. Impediments and Restrictions Affecting OCS Oil and Gas Activities

Section 357(a)(5) of the EPAct calls, in part, for DOI to provide analysis to "identify and explain how legislative, regulatory, and administrative programs or processes restrict or impede the development of identified resources…" Impediments to leasing and development, ranging from restrictions on access to certain Federal lands by the legislative and executive branches to legal, regulatory, and administrative requirements relating to leasing and development, can restrict or delay development activities. Restrictions on exploration and development, or delays in governmental review and approval processes, can raise project costs and risks, affecting if and when resources are developed relative to alternative industry investment opportunities. Section II describes in detail the OCS areas currently under withdrawal or unavailable for leasing.

There are long lead times needed for exploration and development of OCS oil and gas resources, especially in frontier areas where risks and costs are high. Preparing to offer oil and gas leases entails years of planning and consultation under OCSLA Sections 18 and 19. Once a lease sale is held, it could take 5 to 10 years for drilling on those leases to commence. Production could take another 5 years or more after a discovery (BOEM, 2022).

Under Section 18 of OCSLA, BOEM prepares a National OCS Program that includes a 5-year schedule of proposed OCS oil and gas lease sales that are designed to best meet national energy needs. OCSLA subsections 18(c) and (d) prescribe a detailed process of consultation and analysis for the development of a National OCS Program. BOEM's preparation of a National OCS Program typically takes multiple years and includes robust public involvement throughout the process.

On January 27, 2021, E.O. 14008 directed DOI to launch a comprehensive review of leasing and permitting practices. The next lease sale was GOM Lease Sale 257, held on November 17, 2021. This sale was vacated by the U.S District Court for the District of Columbia; however, as directed by the Inflation Reduction Act of 2022 (IRA; P.L. 117-169), BOEM accepted 307 high bids for Lease Sale 257 and issued leases on September 14, 2022.[8] BOEM held Cook Inlet Lease Sale 258 on December 30, 2022, also directed by the IRA. Only one bid was received, and the lease was issued in March 2023. The final two GOM lease sales scheduled in the 2017–2022 National OCS Program, Lease Sales 259 and 261, were the subject of Congressional directives in the IRA. BOEM held GOM Lease Sale 259 in March 2023, and pursuant to the IRA and in accordance with direction from the U.S. Court of Appeals for the Fifth Circuit, BOEM held GOM Lease Sale 261 on December 20, 2023.

A Request for Information (RFI) for a potential 2019-2024 Program was published in the Federal Register on July 3, 2017, which was followed by a Draft Proposed Program published on January 8, 2018, containing 47 lease sales in all planning areas of the OCS other than the North Aleutian Basin. The previous administration never released a Proposed Program; the current administration

[8] On January 27, 2022, the U.S. District Court for the District of Columbia vacated Lease Sale 257 because the Court found a deficiency in the NEPA documentation for the lease sale. *Friends of the Earth v. Haaland*, 583 F.Supp.3d 113, 162 (D.D.C. 2022). On April 28, 2023, the U.S. Circuit Court for the District of Columbia Circuit vacated the decision of the District Court as moot given passage of the IRA requiring DOI to issue the Lease Sale 257 leases. *Friends of the Earth v. Haaland*, Op. No. 22-5036 (D.C. Cir. Apr. 28, 2023).

published the Proposed Program and Draft Programmatic EIS in July 2022. On September 29, 2023, DOI announced in the Federal Register the availability of the PFP and Final Programmatic EIS for the 2024–2029 National OCS Program. The PFP proposes a schedule of oil and gas lease sales for the 2024–2029 period, including three lease sales in the GOM. BOEM submitted the PFP to the President and Congress, along with the Final Programmatic EIS. BOEM also provided copies of all incoming comments received on the previous assessment, the Proposed Program, and responses to comments on the Proposed Program received from state and local governments and Federal agencies. The Secretary approved the 2024-2029 National OCS Program on December 14, 2023, after the required 60 day waiting period following the transmittal to the President and Congress.

The inclusion of an area in an approved National OCS Program, however, does not necessarily mean that a lease sale will be held in that area. Each lease sale that is scheduled in the approved 2024–2029 Program will be subject to a separate pre-lease sale decision making process that includes the necessary environmental review and analysis.

OCS oil and gas activity must comply with a variety of Federal and state statutes, regulations, and orders, including NEPA, CZMA, ESA, MMPA, CAA, and CWA, which are designed to provide for safe and responsible resource development and environmental protection. Many of the ocean's energy resources are in environmentally sensitive areas and the development of those resources must be balanced against potential environmental impacts. BOEM and BSEE are the primary regulatory and permitting agencies for OCS oil and gas activities. However, other agencies, such as the U.S. Coast Guard (USCG), Environmental Protection Agency, Department of Transportation (Office of Pipeline Safety), U.S. Army Corps of Engineers, U.S. Fish and Wildlife Service, and the National Marine Fisheries Service have independent regulatory authority and processes for certain aspects of these activities. BOEM also coordinates closely with the Department of Defense regarding multiple use conflicts and competing uses of the OCS. Additionally, coastal states potentially affected by any proposed OCS leasing or development activity are afforded numerous opportunities to have their concerns addressed through the consultative processes outlined in the OCSLA, NEPA, and CZMA.[9]

Under E.O. 13175 and DOI Policy on consultation with Indian Tribes, BOEM is obligated to engage in government-to-government consultations with Tribes on any Departmental action with Tribal implications. This includes federally recognized Tribes with current and historic interests in coastal areas of Alaska, the Pacific, the GOM, and the Atlantic. In Alaska, BOEM additionally consults with Alaska Native Claims Settlement Act (ANCSA) Corporations. These consultations are conducted on additional approvals (e.g., plans and permits) as appropriate throughout the life of an OCS oil and gas lease.

BOEM is committed to maintaining open and transparent communications with Tribal governments, Alaska Native organizations, and other indigenous communities. BOEM's approach emphasizes continuing or establishing relationships that are built and maintained with trust, respect, and shared responsibility as part of a deliberative process for effective collaboration and informed decision making.

[9] Under the CZMA specifically, affected states review certain proposed OCS activities for consistency with their coastal zone management plans. If a state finds the activity to be inconsistent, the activity cannot proceed unless the Secretary of Commerce overrules the state after a company appeal. This process can stop or delay OCS activities.

Required environmental reviews and consultations generally result in the development of lease terms and conditions that place certain restrictions on the development of the oil and natural gas resources on the lease area. These can include requirements that affect surface occupancy and timing of development. These terms and conditions help ensure safety and protect sensitive environmental resources and other uses of the OCS, and BOEM does not consider existing lease stipulations and approval conditions to be an undue impediment to OCS oil and gas development.

Although any unnecessary delays and uncertainties associated with approval processes can impede energy exploration and development, BOEM and BSEE regularly collaborate to identify and implement process efficiencies to improve coordination among government agencies, with Tribal communities and local stakeholders, and with industry to help ensure that the agencies' permitting and administrative processes do not result in unnecessary impediments to OCS activities.

APPENDICES

APPENDIX A: GLOSSARY

The glossary defines relevant terms in a general rather than a strictly technical manner.

API gravity: An arbitrary scale expressing the gravity or density of liquid petroleum products. The measuring scale is calibrated in terms of "degrees API." The higher the API gravity, the lighter the fluid.

Appreciation: Analogous to reserves appreciation. See "reserves."

Assessment: The estimation of potential amounts of hydrocarbon resources.

Associated gas: See "gas, natural."

Barrel: A volumetric unit of measure for crude oil equivalent to 42 U.S. gallons.

Barrel of oil-equivalent (BOE): The sum of gas resources, expressed in terms of their energy equivalence to oil, plus the oil volume. The conversion factor of 5,620 standard cubic feet of gas equals 1 BOE is based on the average heating values of domestic hydrocarbons.

Chance: See "probability" or "risk."

Condensate: Hydrocarbons associated with saturated gas that are present in the gaseous state at reservoir conditions but produced as liquids at the surface.

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

Continental margin: The composite continental rise, continental slope, and continental shelf as a single entity. The term, as used in this report, applies only to the portion of the margin whose mineral estate is under Federal jurisdiction; geographically synonymous with Outer Continental Shelf (OCS).

> Continental shelf: The shallow, gradually sloping zone extending from the shoreline to a depth at which there is a marked steep descent to the ocean bottom.
>
> Continental slope: The portion of the continental margin extending seaward from the continental shelf to the continental rise or ocean floor.

Conventionally recoverable: Producible by natural pressure, pumping, or secondary recovery methods, such as gas or water injection.

Cumulative probability distributions: A distribution showing the probability of a given amount or more occurring. These distributions include the values for the resource estimates presented throughout this report: a low estimate having a 95% probability (19 in 20 chance) of at least that amount (F_{95}), a high estimate having a 5% probability (one in 20 chance) of at least that amount (F_5), and a mean estimate representing the average of all possible values. These distributions are often referred to as S-curves.

Cumulative production: The sum of all produced volumes of hydrocarbons prior to a specified point in time.

Deterministic: A process in which future states can be forecast exactly from knowledge of the present state and rules governing the process. It contains no random or uncertain components.

Development: Activities following exploration, including the installation of production facilities and the drilling and completion of wells for production.

Development systems: Basic options used in constructing OCS permanent production facilities. Examples of development systems include:

> Compliant tower: An offshore facility consisting of a narrow, flexible tower and a piled foundation that can support a conventional deck for drilling and production operations. Unlike a fixed platform, the compliant tower withstands large lateral forces by sustaining significant lateral deflections and is usually used in water depths between 1,500 and 3,000 feet.
>
> Fixed platform: An offshore facility consisting of a jacket (a tall vertical section made of tubular steel members supported by piles driven into the seabed) with a deck placed on top, providing space for crew quarters, drilling rigs, and production facilities. The fixed platform is economically feasible for installation in water depths up to about 1,650 feet.
>
> Floating production system (FPS): An offshore facility consisting of a semi-submersible platform that is equipped with drilling and production equipment. It is anchored in place with wire rope and chain or can be dynamically positioned using rotating thrusters. Wellheads are on the ocean floor and are connected to the surface deck with production risers designed to accommodate platform motion. FPSs can be used in water depths ranging from 600 to 6,000 feet.
>
> Mini-tension leg platform (mini-TLP): An offshore facility consisting of a floating mini-tension leg platform of relatively low cost developed for production of smaller deepwater reserves that would be uneconomic to produce using more conventional deepwater production systems. It can also be used as a utility, satellite, or early production platform for larger deepwater discoveries. Mini-TLPs can be used in water depths ranging from 600 to 3,500 feet.
>
> SPAR: An offshore facility consisting of a large diameter vertical cylinder supporting a deck. It has a typical fixed platform topside (surface deck with drilling and production equipment), three types of risers (drilling, production, and export), and a hull, which is moored using a taut catenary system of six to 20 lines anchored into the sea floor. SPARs are presently used in water depths up to 3,000 feet, although existing technology can extend this to about 10,000 feet.
>
> Tension leg platform (TLP): An offshore facility consisting of a floating structure held in place by vertical, tensioned tendons connected to the sea floor by pile-secured templates. Tensioned tendons provide for use of the tension leg platform in a broad water depth range and for limited vertical motion. Tension leg platforms can be used in water depths up to about 6,000 feet.

Dissolved gas: See "gas, natural."

Economic analysis: An assessment performed in order to estimate the portion of the undiscovered conventionally recoverable resources in an area that is expected to be commercially viable in the long term under a specific set of economic conditions.

Economic risk: See "risk."

Economically recoverable resources: See "resources."

Estimated ultimate recovery (EUR): All hydrocarbon resources within known fields that can be profitably produced using current technology under existing economic conditions. Estimates of ultimate recovery equal the sum of cumulative production, remaining reserves, contingent resources, and reserves appreciation.

Exploration: The process of searching for minerals prior to development. Exploration activities include geophysical surveys, drilling to locate hydrocarbon reservoirs, and the drilling of delineation wells to determine the extent and quality of an existing discovery prior to a development decision.

Field: A producible accumulation of hydrocarbons consisting of a single pool or multiple pools related to the same geologic structure and/or stratigraphic condition. In general usage this term refers to a commercial accumulation.

Fixed platform: See "development systems."

Floating production system: See "development systems."

Frequency: The number of times an indicated event occurs within a specified interval.

Gas, natural: A mixture of gaseous hydrocarbons (typically methane with lesser amounts of ethane, propane, butane, pentane, and possibly some nonhydrocarbon gases).

> Associated gas: Natural gas that occurs in crude oil reservoirs as free gas (gas cap).
>
> Dissolved gas: Natural gas that occurs as gas in solution within crude oil reservoirs.
>
> Non-associated gas: Natural gas that occurs in reservoirs not in contact with significant quantities of crude oil.

Geologic risk: See "risk."

Growth factor: A function used to calculate an estimate of a field's size at a future date. Growth factors reflect technology, market, and economic conditions existing over the period spanned by the estimates.

> Annual growth factor: The function representing the ratio of the size of a field of a specific age as estimated in a subsequent year.
>
> Cumulative growth factor: The function representing the ratio of the size of a field a specific number of years after discovery to the initial estimate of its size in the year of discovery.

Hydrocarbon maturation: The process by which organic material trapped in source rocks is transformed naturally by heat and pressure through time and depth of burial into oil and/or gas.

Hydrocarbons: Any of a large class of organic compounds containing primarily carbon and hydrogen. Hydrocarbons include crude oil and natural gas. As used in this report the term is synonymous with petroleum.

Marginal probability of hydrocarbons (MP_{hc}): An estimate, expressed as a decimal fraction, of the chance that an oil or natural gas accumulation containing technically recoverable quantities of hydrocarbons exists in the area under consideration. The area under consideration is typically a geologic entity, such as a reservoir, prospect, play, basin, or province; or a large geographic area such as a planning area or region. All estimates presented in this report reflect the probability that an area may be devoid of technically recoverable hydrocarbons.

Mean: A statistical measure of central tendency; the arithmetic average or expected value, calculated by summing all values and dividing by the number of values

Model: A geologic hypothesis expressed in mathematical form.

Minimum economic field size (MEFS): The smallest field size that will generate income sufficient to cover expenses and yield a prescribed minimum rate-of-return.

Monte Carlo simulation: A method of approximating solutions of problems by iterative sampling from simulated random or pseudo-random processes.

Non-associated gas: See "gas, natural."

Oil, crude: A mixture of hydrocarbons that exists naturally in the liquid phase in subsurface reservoirs.

Outer Continental Shelf (OCS): The continental margin, including the shelf, slope, and rise, beyond the line that marks the boundary of state ownership; that part of the seabed under Federal jurisdiction.

Petroleum: A collective term for oil, gas, and condensate.

Planning area: A subdivision of an offshore area used as the initial basis for considering blocks to be offered for lease in the Department of the Interior's OCS oil and gas leasing program.

Play: A group of known and/or postulated pools that share common geologic, geographic, and temporal properties, such as history of hydrocarbon generation, migration, reservoir development, and entrapment.

Probability: A means of expressing an outcome on a numerical scale that ranges from impossibility to absolute certainty; the chance that a specified event will occur.

Prospect: A geologic feature having the potential for trapping and accumulating hydrocarbons; a pool or potential field.

Proved reserves: See "reserves."

Recoverable resources: See "resources."

Region: A very large expanse of acreage usually characterized or set apart by some aspect such as a political division or area of similar geography. In this report, the regions are groupings of planning areas.

Reserves: The quantities of hydrocarbons estimated with reasonable certainty to be commercially recoverable from known accumulations and under current economic conditions, operating methods, and government regulations. Current economic conditions include prices and costs prevailing at the time of the estimate. Estimates of reserves do not include reserves appreciation. All reserve estimates involve some degree of uncertainty.

> Undeveloped reserves: Undeveloped reserves are those reserves that are expected to be recovered from future wells and facilities, including future improved recovery projects that are anticipated with a high degree of certainty in reservoirs that have previously shown favorable response to improved recovery projects.
>
> Developed reserves: Developed reserves are those reserves that 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 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.
>
> Reserves appreciation: The observed incremental increase through time in the estimates of reserves of an oil and/or natural gas field as a consequence of extension, revision, improved recovery, and the addition of new reservoirs.

Reservoir: A subsurface, porous, permeable rock body in which an isolated accumulation of oil and/or gas is stored.

Resource assessment: The estimation of potential amounts of recoverable resources. The focus is normally on conventionally or technically recoverable hydrocarbons.

Resources: Concentrations in the earth's crust of naturally occurring liquid or gaseous hydrocarbons that can conceivably be discovered and recovered. Normal use encompasses both discovered and undiscovered resources.

> Contingent Resources: Are discovered resources estimated to be potentially recoverable from known accumulations but are not available for commercial development due to one or more contingencies. Examples of contingencies include resources on relinquished leases, lack of viable markets, commercial recovery dependent on technology under development, and where evaluation of the accumulation is insufficient to clearly assess commerciality.
>
> Recoverable resources: The volume of hydrocarbons that is potentially recoverable, regardless of the size, accessibility, recovery technique, or economics of the postulated accumulations.

Technically recoverable resources: The volume of hydrocarbons that could be produced from a wellbore as a consequence of natural pressure, artificial lift, pressure maintenance (gas or water injection), or other secondary recovery methods. They do not include quantities of hydrocarbon resources that could be recovered by enhanced recovery techniques, gas in geopressured brines, natural gas hydrates, or oil and gas that may be present in insufficient quantities or quality (low-permeability, "tight" reservoirs) to be produced via conventional recovery techniques.

Economically recoverable resources: The volume of technically recoverable resources that is potentially recoverable at a profit after considering the costs of production and the product prices.

Discovered resources: Hydrocarbons whose location and quantity are known or estimated from specific geologic evidence.

Known resources: Hydrocarbons associated with reservoirs penetrated by one or more wells that are not currently qualified under existing regulations as capable of producing in paying quantities pursuant to 30 CFR 550.116 are known resources. Known resources can exist on active, relinquished, or expired leases and fields. Superseded by the definition for Contingent Resources.

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.

Undiscovered technically recoverable resources (UTRR): Resources in undiscovered accumulations analogous to those in existing fields producible with current recovery technology and efficiency, but without any consideration of economic viability. These accumulations are of sufficient size and quality to be amenable to conventional primary and secondary recovery techniques. Undiscovered conventionally recoverable resources are primarily located outside of known fields.

Undiscovered economically recoverable resources (UERR): The portion of the undiscovered conventionally recoverable resources that is economically recoverable under imposed economic and technologic conditions.

Risk: The chance or probability that a particular event will not occur; the complement (1.00 - MP_{hc}) of marginal probability or success.

Economic risk: The chance that no commercial accumulation of hydrocarbons will exist in the area under consideration (e.g., prospect, play, or area). The chance that an area may not contain hydrocarbons or the volume present may be noncommercial is incorporated in the economic risk.

Geologic risk: The chance that technically recoverable volumes of hydrocarbons will not exist in the area under consideration (e.g., prospect, play, basin, or area). The commercial viability of an accumulation is not a consideration.

Risked (unconditional) estimates: Resource volumes that are estimated to exist, incorporating the possibility that the area may be devoid of technically recoverable volumes of oil or natural gas.

Statistically, the risked mean value may be determined through multiplication of the mean of a conditional distribution by the related marginal probability of occurrence.

Seal: Impervious rocks that form a barrier to migrating hydrocarbons above, below, and/or lateral to the reservoir rock.

Source rock: A sedimentary rock, commonly a shale or carbonate, whose organic matter has been transformed naturally by heat and pressure through time and depth of burial into oil and/or gas. This transformation is referred to as generation or maturation.

SPAR: See "Development Systems."

Stochastic: A process in which each observation possesses a random variable.

Subjective judgment: A technique utilized to assign probabilities of occurrence to possible events when all of the possible outcomes of an event are not known and when the frequency of recognized outcomes cannot be estimated with certainty; often referred as expert opinion.

Tension leg platform: See "Development Systems."

Total endowment: All conventionally recoverable hydrocarbon resources of an area. Estimates of total endowment equal the sum of undiscovered technically recoverable resources, cumulative production, remaining reserves, contingent resources, and reserves appreciation.

Trap: A barrier to hydrocarbon migration that allows oil and gas to accumulate in a reservoir.

Stratigraphic trap: A trap that results from changes in the lithologic character of a rock.

Structural trap: A trap that results from folding, faulting, or other deformation of a rock.

Uncertainty: Imprecision in estimating the value (or range of values) for a variable.

Undiscovered economically recoverable resources (UERR): See "Resources."

Undiscovered resources: See "Resources."

Undiscovered technically recoverable resources (UTRR): See "Resources."

APPENDIX B: ACRONYMS

°F	degree Fahrenheit
2-D	two-dimensional
3-D	three-dimensional
AAPG	American Association of Petroleum Geologists
AASG	Association of American State Geologists
ANCSA	Alaska Native Claims Settlement Act
API	American Petroleum Institute
BOEM	Bureau of Ocean Energy Management
BSEE	Bureau of Safety and Environmental Enforcement
CAA	Clean Air Act
CFR	Code of Federal Regulations
CORE	Committee on Resource Evaluation
CWA	Clean Water Act
CZMA	Coastal Zone Management Act
DOI	Department of the Interior
E.O.	Executive Order
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
EPAct	Energy Policy Act
ESA	Endangered Species Act
EUR	Estimated Ultimate Recovery
FPS	floating production system
G&G	geological and geophysical
GOM	Gulf of Mexico
GOMESA	Gulf of Mexico Energy Security Act
GRASP	Geologic Resource Assessment Program
HPHT	high pressure and/or high temperature
IRA	Inflation Reduction Act
MEFS	minimum economic field size
MMPA	Marine Mammal Protection Act
MMS	Minerals Management Service
MNM	Marine National Monuments
MP_{hc}	marginal probability of hydrocarbons
MPP	massively parallel processor
NAS	National Academy of Sciences
NEPA	National Environmental Policy Act
NMS	Natural Marine Sanctuaries
NMSA	Natural Marine Sanctuaries Act

NOAA	National Oceanic and Atmospheric Administration
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
OGOR	Oil and Gas Operations Reports
ONRR	Office of Natural Resources Revenue
P.L.	Public Law
PETRIMES	Petroleum Resources Information Management and Evaluation System
PRESTO	Probabilistic Resource Estimates Offshore
PRMS	Petroleum Resources Management System
RFI	Request for Information
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
TLP	Tension leg platform
UERR	undiscovered economically recoverable resources
UTRR	undiscovered technically recoverable resources
U.S.	United States
U.S.C.	United States Code
USGS	U.S. Geological Survey

Appendix C: Units

bbl	barrel
Bbo	billion barrels of oil
BBOE	billion barrels of oil-equivalent
Bcf	billion cubic feet
BOE	barrels of oil-equivalent
F_5	5th percentile, a 5% probability (a one in 20 chance) of there being more than that amount
F_{95}	95th percentile, a 95% probability (a 19 in 20 chance) of there being more than that amount
Mcf	thousand cubic feet
MMcf	million cubic feet
psi	pounds per square inch
Tcf	trillion cubic feet
Tcfg	trillion cubic feet of gas

APPENDIX D: REFERENCES

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