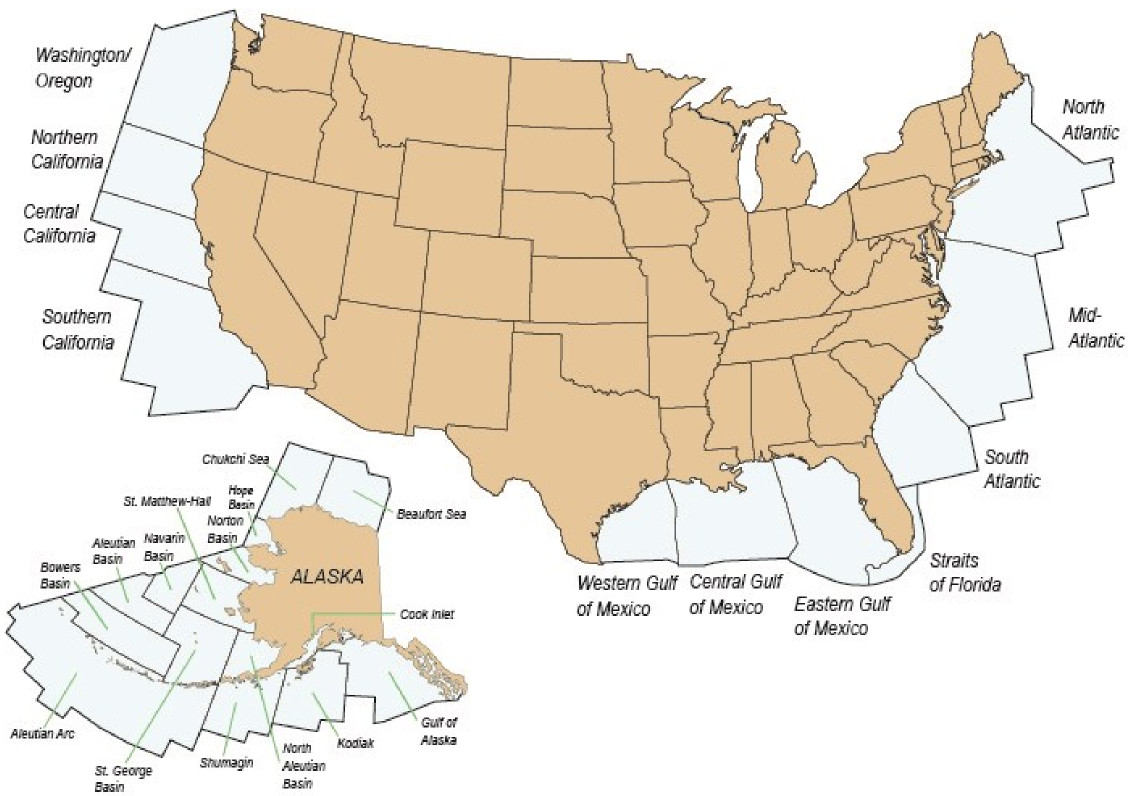
OCS Report
BOEM 2017-085

2016a National Assessment of Undiscovered Oil and Gas Resources of the U.S. Outer Continental Shelf



U.S. Department of the Interior
Bureau of Ocean Energy Management
Resource Evaluation Division

BOEM
Bureau of Ocean Energy Management

OCS REPORT
BOEM 2017-085

2016a National Assessment of Undiscovered Oil and Gas Resources of the U.S. Outer Continental Shelf

January 2018

Prepared by:
Bureau of Ocean Energy Management
Resource Evaluation Division
45600 Woodland Road
Sterling, VA 20166

REPORT AVAILABILITY

To download a PDF version of this document, go to https://www.boem.gov/Oil-and-Gas-Energy-Program/Resource-Evaluation/Resource-Assessment/Index.aspx and click on 2016 National Assessment of Undiscovered Oil and Gas Resources of the U.S. Outer Continental Shelf.

CITATION

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

ACKNOWLEDGMENTS

The following BOEM offices or programs contributed to this document: Alaska OCS Region Office of Resource Evaluation, Gulf of Mexico OCS Region Office of Resource Evaluation, and Pacific OCS Region Lease Management Section.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF TERMS

analogous reservoirs: as used in resource assessments, reservoirs with similar rock and fluid properties, conditions (depth, temperature, and pressure), and drive mechanisms; typically are at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery

British thermal unit: amount of heat required to raise the temperature of one pound (0.454 kg) of liquid water by one degree Fahrenheit at a constant pressure of one atmosphere

conventionally recoverable: producible by natural pressure, pumping, or secondary recovery methods, such as gas or water injection

cumulative production: sum of all produced volumes of oil and gas prior to a specified point in time

field: area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same general geologic structural feature and/or stratigraphic trapping condition; two or more reservoirs in a field may be separated vertically by impervious strata, laterally by local geologic barriers, or by both

pool: discovered or undiscovered accumulation of hydrocarbons, typically within a single stratigraphic interval

play: group of pools that share a common history of hydrocarbon generation, migration, reservoir development, and entrapment

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

reserves: quantities of hydrocarbon resources anticipated to be recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty

reserves appreciation: observed incremental increase through time in the estimates of reserves (proved and unproved) of an oil and/or natural gas field as a consequence of extension, revision, improved recovery, and the addition of new reservoirs

resources: concentrations in the earth's crust of naturally occurring liquid or gaseous hydrocarbons that can conceivably be discovered and recovered

total endowment: all technically recoverable hydrocarbon resources of an area; estimates of total endowment equal the sum of undiscovered technically recoverable resources, cumulative production, proved reserves, unproved reserves, and reserves appreciation

undiscovered resources: resources postulated, on the basis of geologic knowledge and theory, to exist outside of known fields or accumulations

undiscovered technically recoverable resources (UTRR): oil and gas that may be produced as a consequence of natural pressure, artificial lift, pressure maintenance, or other secondary recovery methods, but without any consideration of economic viability; primarily located outside of known fields

undiscovered economically recoverable resources (UERR): portion of undiscovered technically recoverable resources that is economically recoverable under imposed economic and technologic conditions

ACRONYMS AND ABBREVIATIONS

2D	two dimensional
3D	three dimensional
AGF	annual growth factor
AU	assessment unit
Bbl	barrels
Bbo	billion barrels of oil
BBOE	billion barrels of oil equivalent
BCFG	billion cubic feet of gas
BOE	barrels of oil equivalent
BOEM	Bureau of Ocean Energy Management
cf	cubic feet
cfg	cubic feet of gas
COST	Continental Offshore Stratigraphic Tests
DOI	Department of the Interior
FLNG	floating liquefied natural gas
FPSO	floating production storage and offloading
ft	feet
GOM	Gulf of Mexico
HC	Hudson Canyon
km	kilometers
LNG	liquid natural gas
NPRA	National petroleum reserves-Alaska
m	meters
Ma	million years ago
Mcf	thousand cubic feet
mi	miles
OCS	Outer Continental Shelf
TAPS	Trans-Alaska pipeline system
Tcf	trillion cubic feet
Tcfg	trillion cubic feet of gas
UERR	undiscovered economically recoverable resources
U.S.	United States
UTRR	undiscovered technically recoverable resources

2016a National Assessment of Undiscovered Oil and Gas Resources of the United States Outer Continental Shelf

EXECUTIVE SUMMARY

The U.S. Bureau of Ocean Energy Management (BOEM) manages oil and natural gas resources on the U.S. Outer Continental Shelf (OCS). The OCS comprises the portions of submerged seabed that are under Federal jurisdiction. BOEM periodically performs an OCS-wide assessment of undiscovered oil and gas resources, typically in five-year intervals, to inform the scoping and development of the National OCS Oil and Gas Leasing Program. The National OCS Oil and Gas Leasing Program is an important component of a comprehensive energy strategy to allow for safe and responsible domestic oil and natural gas production as a means to enhance energy security and support economic growth and job creation. This report provides a summary of the methods and results from the 2016a National Assessment of Undiscovered Oil and Gas Resources. The 2016a Assessment is a comprehensive appraisal that considers relevant data and information available as of January 1, 2014[1]. View a summary factsheet of assessment results (BOEM, 2016a) at http://www.boem.gov/2016a-National-Assessment-Fact-Sheet/.

Oil and natural gas resources on the OCS are a critical component of the U.S. energy portfolio. Petroleum resources are considered finite, because they do not renew at a rate remotely approaching their rate of consumption. Petroleum is an important driver of the Nation's economy, and there is considerable interest in determining the magnitude of this domestic resource base. Resource assessments are a critical component of energy policy analysis and provide important information about the relative potential of U.S. offshore areas as sources of oil and natural gas.

Individually, geologic plays and assessment units (AUs) represent a group of geologically related hydrocarbon accumulations that share a common history of hydrocarbon generation, accumulation, and entrapment. BOEM uses a modeling approach to estimate the undiscovered oil and gas resource potential of an area through the assessment of unique geologic plays and AUs. Geologic play and AU results are then aggregated to the 26 OCS Planning Areas, the four OCS Regions, and the national level.

Results from this analysis are presented as undiscovered technically recoverable resources (UTRR) and undiscovered economically recoverable resources (UERR). UTRR are hydrocarbons potentially recoverable by conventional production methods regardless of the size, accessibility, and economics of the accumulations assessed. UERR are a subset of the UTRR and only include the resources that are economically recoverable at a given price for oil and gas. To facilitate UERR calculation, BOEM applies

[1] This publication includes updates to two geologic plays in the Beaufort Sea of the Alaska OCS effective December, 2017.

engineering and economic parameters that allow for full cycle modeling of the undiscovered oil and gas fields included in the UTRR. For the 2016 Assessment, BOEM used pricing parameters that range from $30/barrel of oil to $220/barrel of oil.

BOEM accounts for the inherent uncertainty involved with assessing an unknown quantity by introducing modeling parameters that incorporate distributions or ranges of values and using a Monte Carlo sampling approach to allow for input of 10,000 model trials. In general, risk 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, and the degree of uncertainty in possible outcomes narrows considerably. With the uncertainties appropriately captured and characterized, resource assessments are valuable inputs to developing and planning energy policy.

Nationally, BOEM assesses mean values of UTRR at 90.55 billion barrels of oil and 327.58 trillion cubic feet of gas. To capture a reasonable range of uncertainty, BOEM also reports a 95 percent chance for UTRR values of at least 76.69 billion barrels of oil and 284.41 trillion cubic feet of gas and a 5 percent chance of more than 105.59 billion barrels of oil and 375.87 trillion cubic feet of gas.

1 INTRODUCTION

Resource assessments are a critical component of energy policy analysis and provide important information about the relative potential of U.S. Outer Continental Shelf (OCS) areas as sources of oil and natural gas. The OCS comprises the portion of the submerged seabed whose mineral estate is subject to Federal jurisdiction. For planning purposes, BOEM divides the OCS into 26 OCS planning areas (**Figure 1**). This report summarizes the results of the Bureau of Ocean Energy Management's (BOEM's) 2016 Assessment of the undiscovered technically and economically recoverable oil and gas resources of the OCS. Undiscovered technically recoverable resources (UTRR) are hydrocarbons recoverable by current technologies, regardless of the size, accessibility, and economics of the accumulations. Undiscovered economically recoverable resources (UERR) represent the portion of the UTRR that are economically recoverable under imposed economic and technologic conditions. The 2016 Assessment represents a comprehensive resource appraisal that considers relevant data and information available as of January 1, 2014. No government-sponsored geological or geophysical data acquisition projects were conducted for this assessment.

This report provides an estimate of the undiscovered technically and economically recoverable oil and natural gas resources located outside of known oil and gas fields on the OCS. It also provides an overview of the recent physical, geological, technological, and economic information incorporated into the methodologies used to generate these estimates. The 2016 Assessment utilizes a probabilistic play-based approach to estimate the UTRR of oil and gas for individual geologic plays and assessment units (AUs). This methodology is suitable for both conceptual plays where there is little or no specific information available and for developed or mature plays where there are discovered oil and gas fields that provide a considerable amount of relevant empirical information. Individual play and assessment unit (AU) results are aggregated to larger areas such as basins, planning areas, and regions. Where applicable, estimates of the quantities of historical production, reserves, and future reserves appreciation are presented to provide a frame of reference.

This national report draws extensively from information and data presented in detailed reports that support the regional assessments in the Alaska OCS (BOEM 2018-001), Atlantic OCS (BOEM 2016-071), Gulf of Mexico OCS (BOEM 2017-005), and Pacific OCS (BOEM 2014-667, BOEM 2017-053). These reports and additional detailed information about the regional geology, assessment methodology, and economic assumptions as applied to specific regions can be found at: http://www.boem.gov/National-Assessment-2016.

1.1 Commodities Assessed

Hydrocarbon resources are naturally occurring liquid, gaseous, or solid compounds of predominantly hydrogen and carbon that exist in the subsurface as crude oil and natural gas. The commodities of hydrocarbon resources that are assessed for this project are described below.

Oil is a liquid hydrocarbon resource and may include crude oil and/or condensate. Crude oil exists in a liquid state in the subsurface and at the surface. Condensate (natural gas liquids) may exist in a dissolved gaseous state in the subsurface and liquefy at the surface.

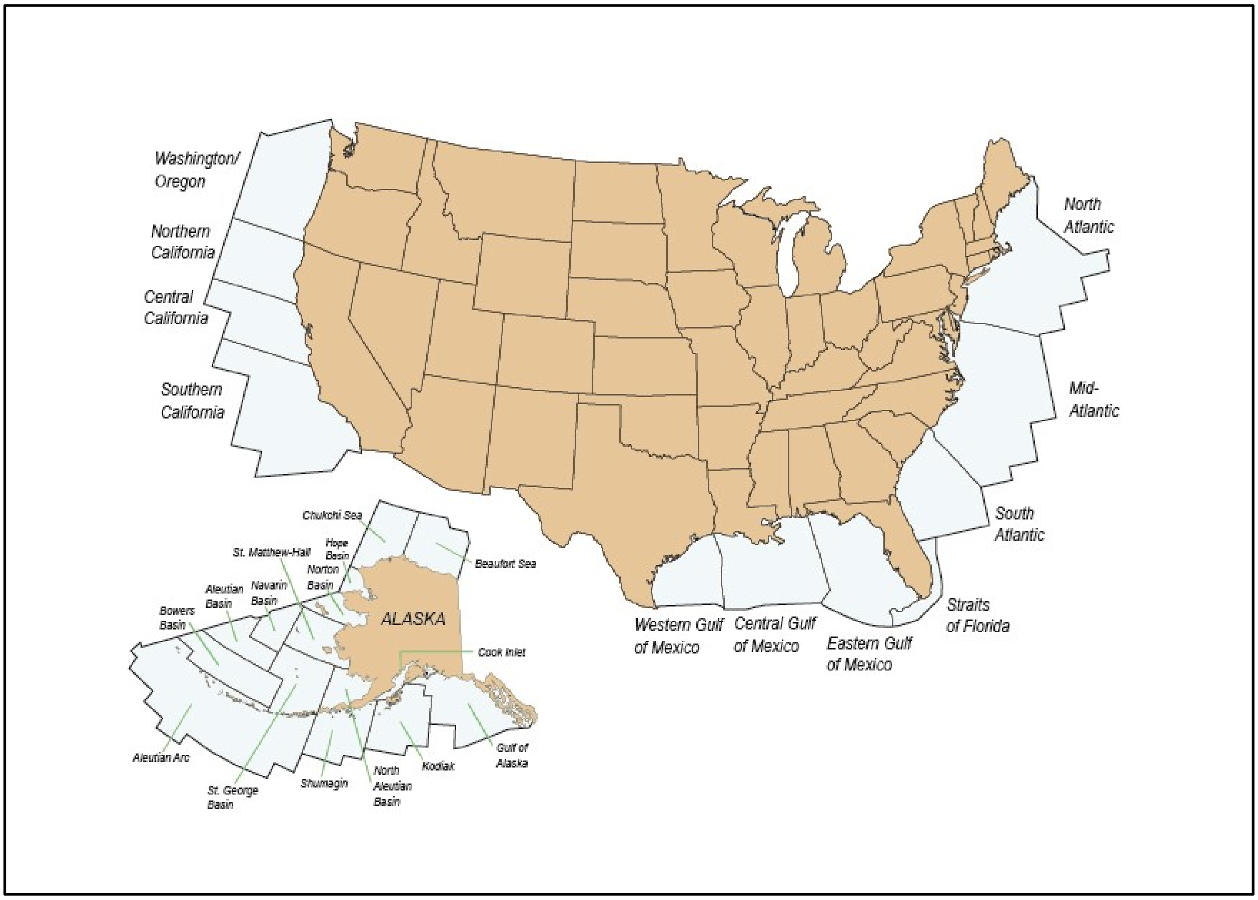


Figure 1. Map of the U.S. Outer Continental Shelf highlighting the 26 OCS planning areas.

Condensate that can be produced from the subsurface with conventional extraction techniques have been assessed for this project. The volumetric estimates of oil resources from this assessment represent combined volumes of crude oil and condensate and are reported as standard stock tank barrels (hereafter "barrels" or "Bbl").

Natural gas is a gaseous hydrocarbon resource and may include associated and/or nonassociated gas; the terms natural gas and gas are used interchangeably in this report. Associated gas exists in spatial association with crude oil; it may exist in the subsurface as free (undissolved) gas within a "gas cap" or as gas that is dissolved in crude oil ("solution gas"). Nonassociated gas (dry 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 project; other gas resources (for example, shale gas and gas hydrates) have not been assessed. The volumetric estimates of gas resources from this assessment represent aggregate volumes of associated and nonassociated gas and are reported as standard cubic feet of gas (hereafter "cubic feet" or "cfg").

Oil-equivalent gas is a volume of gas (associated and/or nonassociated) expressed in terms of its energy equivalence to oil (5,620 cubic feet of gas per barrel of oil) and is reported as barrels. The combined volume of oil and oil-equivalent gas resources is referred to as combined oil-equivalent resources or BOE (barrels of oil equivalent) and is reported as barrels.

1.2 Resource Categories

Hydrocarbon resources are generally categorized by their discovery status and commerciality or economic viability. For this assessment, we focus on undiscovered resources. Discovered resources are not uniquely assessed in this report; however, we utilized knowledge of their location and volume in our assessment of undiscovered resources and estimation of total resource endowments. We provide the following definitions to ensure proper understanding of the assessed resource categories.

1.2.1 Discovered Resources

Discovered resources are hydrocarbons whose location and volume are known or estimated using specific geologic evidence. Discovered resources include cumulative production, remaining reserves, and contingent resources (**Figure 2**).

Original recoverable reserves are the total amount of discovered resources that are estimated to be economically recoverable; they include cumulative production, remaining reserves, and contingent resources.

Cumulative production is the total amount of discovered resources that have been extracted from an area prior to a specified date.

Reserves are discovered resources that remain in an area; they must be discovered, recoverable, commercial, and remaining.

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 situations when evaluation of the accumulation is insufficient to clearly assess commerciality.

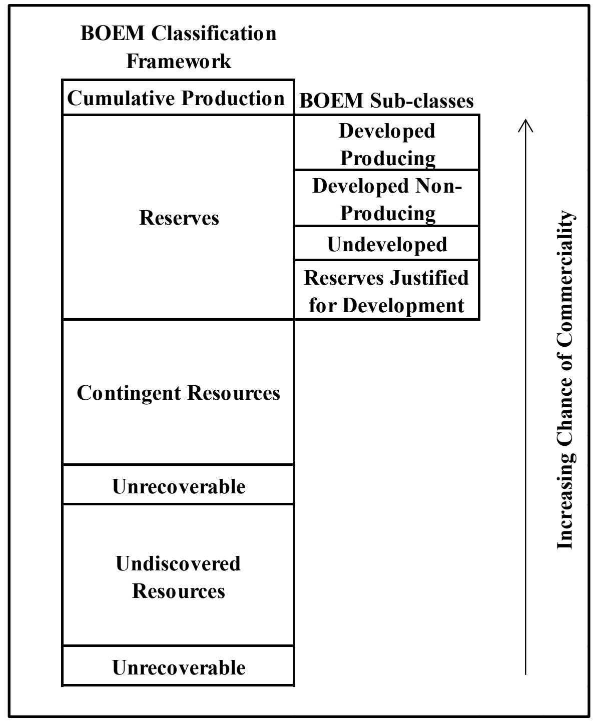


Figure 2. BOEM Resource Classification framework.

Reserves appreciation (reserves growth) is the amount of resources in known accumulations that is expected to augment proved reserves as a consequence of the extension of known pools or fields, discovery of new pools within existing fields, or the application of improved extraction techniques. Prediction of reserves appreciation is generally based on statistical analysis of historical field data. For the 2016 Assessment, reserves appreciation is only applied to the Gulf of Mexico OCS Region.

For more information on discovered resources and reserves inventory, regional reserves reports can be found at: http://www.boem.gov/Reserves-Inventory-Program/.

1.2.2 Undiscovered Resources

Undiscovered resources are resources postulated on the basis of geologic knowledge and theory, to exist outside of known fields or accumulations. Included resources are also from undiscovered pools within known fields to the extent that they occur within separate geologic plays or AUs.

Technically recoverable resources are resources that may be produced as a consequence of natural pressure, artificial lift, pressure maintenance, or other secondary recovery methods, but without any consideration of economic viability. They are primarily located outside of known fields and can be removed from the subsurface with conventional extraction techniques (that is, technology whose usage is considered common practice as of this assessment); they include moderate- to high-gravity crude oil, condensate, and gas but do not include low-gravity "heavy" oil, oil shale, shale gas, and gas hydrates.

Following the assessment of UTRR, an economic evaluation was performed for each region to estimate the portion of those resources that could be extracted profitably over a range of commodity prices, at the present level of technology, and including the effects of current and expected future economic factors. Those factors include costs for exploration, development, and production of resources; market prices of the various hydrocarbon commodities; and other economic conditions.

Economically recoverable resources are technically recoverable resources that can be economically recoverable under imposed economic and technologic conditions.

1.2.3 Total Resource Endowment

Total resource endowment—comprising the sum of UTRR, cumulative production, remaining reserves, contingent resources, and reserves appreciation—is uniquely estimated for areas where resources have been discovered. In U.S. Federal waters, this includes the Alaska, Gulf of Mexico (GOM), and Pacific OCS. In the Atlantic OCS, we recognize no discovered resources, and the total resource endowment consists only of UTRR. The estimation of total resource endowment is based on previous assessments of discovered resources and this assessment of undiscovered resources.

1.3 Assessment Areas and Entities

Management of the oil and gas resources in these OCS Regions is governed by the OCS Lands Act (43 U.S. Code [U.S.C.] 1331 et seq.), which sets forth procedures for leasing, exploration, and development and production of those resources. Section 18 of the OCS Lands Act calls for the preparation of a nationwide offshore oil and gas leasing program, setting forth a five-year schedule of lease sales designed to best meet the nation's energy needs. Analytical work for Section 18 is done at the OCS planning area level. Thus, although the underlying geologic framework of the OCS forms the basis for the delineation of assessment areas and the assessment of oil and gas resources, this report aggregates estimates of undiscovered resources first to the 26 OCS planning areas and then to the regional level for the four OCS regions: the Atlantic OCS Region, Gulf of Mexico OCS Region, Pacific OCS Region, and Alaska OCS Region. The undiscovered resources from the four OCS Regions are then aggregated to provide a national-level assessment. The following definitions are provided for assessment areas and entities cited in this report.

1.3.1 Provinces and Basins

A **province** is an area of petroleum geologic homogeneity, which may include one or more geologic basins or geologic areas; the terms province and assessment province are used interchangeably in this report. A **basin** is a depressed and geographically confined area of the earth's crust in which sediments have accumulated and hydrocarbons may have formed; the terms basin and geologic basin are used interchangeably in this report.

1.3.2 Geologic Plays and Assessment Units

The assessment of UTRR within geologic basins and areas is performed at the **geologic play** or AU level. These units represent a group of geologically related hydrocarbon accumulations that share a common history of hydrocarbon generation, accumulation, and entrapment; the terms geologic play and petroleum geologic play are used interchangeably in this report.

Plays and AUs are classified according to their exploration and discovery status to qualitatively express the probability that hydrocarbon accumulations exist. In established plays and AUs, hydrocarbons have been discovered, and a petroleum system has been proven. Conceptual plays and AUs do not have proven hydrocarbon accumulations, but data suggests that hydrocarbon accumulations may exist.

Plays are also classified according to their expected predominant hydrocarbon type. An oil play contains predominantly crude oil and associated gas. A gas play contains predominantly nonassociated gas and may contain condensate. A mixed play contains crude oil, associated gas, and nonassociated gas, and may contain condensate.

Detailed descriptions of the location, definition, classification, petroleum geologic characteristics, and resource assessment of each geologic play and AU are provided in the individual regional reports.

1.4 Hydrocarbon Accumulations

The terms prospect, pool, and field describe potential and proven hydrocarbon accumulations within plays. A **prospect** is an untested geologic feature having the potential for trapping and accumulating hydrocarbons. A **pool** is a discrete accumulation (discovered or undiscovered) of hydrocarbon resources that are hydraulically separated from any other hydrocarbon accumulation; it is typically related to a single stratigraphic interval or structural feature. A **field** is a single- or multiple-pool accumulation of hydrocarbon resources that has been discovered. An oil field contains predominantly crude oil and associated gas; a gas field contains predominantly nonassociated gas and may contain condensate.

There are numerous uncertainties regarding an area's geologic framework, petroleum geologic characteristics, and location and volume of its undiscovered oil and gas resources. Some of these uncertainties include the presence and quality of petroleum source rocks, reservoir rocks, and traps; the timing of hydrocarbon generation, migration, and entrapment; and the location, number, and size of accumulations. The value and uncertainty regarding these petroleum geologic factors can be qualitatively expressed (for example, "there is a high probability that the quality of petroleum source rocks is good"). However, in order to develop volumetric resource estimates, the value and uncertainty regarding some factors must be quantitatively expressed (for example, "there is a 95 percent probability that reservoir rocks will have porosities of 10 percent or more"). Each of these factors—and the volumetric resource estimate derived from them—is expressed as a range of values with each value having a corresponding probability of occurrence. We provide the following definitions to ensure proper understanding of the probabilistic nature of this assessment and the resource estimates presented in this report.

Probability (chance) is the predicted likelihood that an event, condition, or entity exists; it is expressed in terms of success (the chance of existence) or risk (the chance of nonexistence). **Petroleum geologic probability** is the chance that an event (for example, generation of hydrocarbons), property (permeability of reservoir rocks), or condition (presence of traps) necessary for the accumulation of hydrocarbons exists. The criteria, analysis, and use of petroleum geologic probability in this assessment vary slightly between regions, and full documentation of these influences can be found in the regional reports.

A **probability distribution** is a range of predicted values with corresponding probabilities of occurrence; the terms probability distribution and distribution are used interchangeably in this report. The estimates of UTRR from this assessment are developed as cumulative probability distributions in which a specified volume or more of resources corresponds to a probability of occurrence. We report these estimates as a range of values from each cumulative probability distribution. The range includes a low estimate, corresponding to the 95^{th} percentile value of the distribution (that is, the probability of existence of the estimated volume or more is 95 in 100); a mean (or expected) estimate corresponding to the statistical average of all values in the distribution; and a high estimate corresponding to the 5^{th} percentile value of the distribution (that is, the probability of existence of the estimated volume or more is 5 in 100).

Conditional estimates are estimates of the volume of hydrocarbon resources in an area, given the assumption (condition) that hydrocarbons actually exist; they do not incorporate the probability (risk) that hydrocarbons do not exist. No conditional estimates have been developed for this assessment. **Risked (unconditional) estimates** are estimates of the volume of hydrocarbon resources in a play or AU, including the probability (risk) that hydrocarbons do not actually exist in that play. All estimates presented in this report are risked estimates.

2 METHODOLOGY

BOEM uses a geologic play-based (or equivalent AU-based) approach for identification and estimation of resource parameters, and employs a statistical methodology to develop resource estimates based on these parameters. The following sections describe the process used to analyze the geologic data, identify and evaluate the resource parameters, and develop resource estimates.

The principal procedural components of the process include petroleum geological analysis, AU and play definition and analysis, and resource estimation. Petroleum geological analysis provides the geological and geophysical information that is the basis for all other components of the assessment. Play definition and analysis involves identifying and quantifying the necessary elements for the estimation of resources in geologic plays and AUs. The resource estimation process uses a set of computer programming tools developed for the statistical analysis of play data. The results of that statistical analysis are estimates of the UTRR of geologic plays and AUs. The resource estimates are further subjected to a separate statistical analysis that incorporates economic and engineering parameters to estimate the UERR for the assessment areas. For those areas with existing production, estimates of discovered resources are added to estimates of UTRR to obtain a measure of total resource endowment.

Due to the national scope of this document, we provide a review of the general assessment methodology in this section. For details specific to individual regions, we refer the reader to region-specific sections in this publication as well as to stand-alone regional reports.

2.1 Petroleum Geological Analysis

Petroleum geological analysis involves analysis of the geologic and geophysical data to identify areas of hydrocarbon potential and ascertain the areal and stratigraphic extent of potential petroleum systems within these areas. The information obtained through this process is the basis for the definition of geologic plays and AUs, and the quantification of parameters in the play definition and analysis component.

We compile published and proprietary information to understand the depositional and tectonic history of each province, as well as identify the areas of hydrocarbon potential and establish the petroleum geologic framework on which the plays and AUs are defined. The scope of the information ranges from studies of the regional geology and tectonics of an area to detailed geochemical and well log analyses from exploratory wells and core holes. Exploratory well information and interpretations of seismic-reflection profiles help identify the stratigraphic intervals within the assessment areas. We use paleontological and lithological analyses to determine the age and environment of deposition of stratigraphic units.

Potential petroleum source rocks are identified by accessing published and proprietary geochemical studies and data from exploratory and development drilling. Hydrocarbon indications from exploratory and production wells are used along with analyses of well data to identify potential petroleum source rocks and to estimate source rock properties. We integrate geophysical well information with interpretations of seismic-reflection profiles to estimate generative areas within those source rock units.

We identify potential hydrocarbon reservoirs and likely migration pathways from source to reservoir primarily through exploratory well data and interpretations of seismic-reflection profiles. Reservoir rock properties and the presence of trapping mechanisms are estimated by using information from well log analysis and from analogous stratigraphic units in producing areas. Geophysical interpretations of seismic-reflection profiles are used to infer migration pathways and to estimate the extent of stratigraphic intervals in which reservoir-quality rocks are expected.

Identification of potential structural traps (prospects) is based primarily on existing proprietary interpretation and subsurface mapping of seismic-reflection data. Where feasible and appropriate, the interpretations are modified to include new data and ideas. In some areas, interpretations are based on sparse seismic-reflection data, and although those interpretations can be used to identify depositional and structural trends, they cannot be used to identify individual prospects. In such cases, and for assessment areas which are outside of areas with existing data or interpretations, estimates of the number and areal size of prospects are based on interpretations from geologically analogous areas.

2.2 Play Definition and Analysis

Play definition involves the identification, delineation, and qualitative description of a body of rocks that potentially contain geologically related hydrocarbon accumulations. When properly defined, a geologic play or AU comprises a group of hydrocarbon accumulations that can be considered as a single entity for statistical evaluation. Plays and AUs are defined based on the determination of source rock, reservoir rock, and trap characteristics of stratigraphic units. Many plays are defined on the basis of reservoir rock stratigraphy and are delineated by the extent of the reservoir rocks. Other plays and AUs are defined on the basis of structural characteristics of prospective traps. Plays may overlap aerially and may, in some cases, also occupy the same stratigraphic interval.

Play analysis involves the quantitative description of parameters relating to the volumetric hydrocarbon potential of the play. The presence of necessary conditions for the generation, migration, and entrapment of hydrocarbons is unknown, but probabilities for their existence and quantification are estimated, and these can then be used in the resource estimation process to develop probability distributions for quantities of hydrocarbon resources. Play analysis provides the necessary quantitative information in the form of play-specific probability distributions; these distributions reflect the uncertainty about the values of the parameters and are used as the basis for the statistical resource estimation process.

Each play and AU is characterized by parameters that, in combination, describe the volumetric resource potential of the play, assuming that the play does contain hydrocarbon accumulations. We assign a range of values to each parameter based on information obtained through the petroleum geological analysis component. Some of these values (for example, areas of mapped prospects and thicknesses of expected reservoir rock units) are based on geophysical mapping. Others (for example, rock and hydrocarbon properties) are based on exploratory well information. Certain rock and hydrocarbon properties (for example, net pay, reservoir rock porosity and permeability, and oil viscosity) are unknown in the absence of exploratory drilling; in such cases, values are based on known properties in areas that are expected to be similar. Where data are insufficient or unavailable, scientifically based subjective judgments are made regarding appropriate geologic analog data which are also used for modeling purposes.

In addition, plays are assigned success probabilities based on discovery status and on subjective evaluation. The probabilities (chances) of success of individual components are combined to yield the probability of success for the play or AU as a whole (play chance) and the probability of success for individual prospects within the play (conditional prospect chance). **Play chance** is the probability that at least one accumulation of technically recoverable resources exists in a play. **Conditional prospect chance** is the probability that technically recoverable resources exist within an individual prospect in the play, given the conditional assumption that the play is successful. Combination of the play chance and conditional prospect chance yields the average prospect chance (including the chance that the play may not be successful).

For play analysis in ultra-mature petroleum provinces (particularly the shallow water AUs in the GOM), we place significant importance on data and information derived from the rich empirical framework of existing data. By utilizing the information from over 30,000 reservoir completions, we are able to characterize the range of expected play components within the context of measured parameters that are captured in the BOEM corporate database. Some specific examples include reservoir thickness, reservoir areal extent, recovery factors, and oil and gas proportions.

2.3 Resource Estimation

Volumetric estimates of UTRR and UERR are based on the geologic and petroleum engineering information developed through petroleum geological analysis and quantified through play analysis. These estimates are developed in two stages. First, UTRR are assessed for each play with no explicit consideration of resource commodity prices or costs (although there is recognition that current technology is affected by costs and profitability). Second, economic and petroleum engineering factors are introduced for each play and AU, using a separate methodology, to estimate the portion of these resources that are economically recoverable over a broad range of commodity prices.

Prospect sizes within plays with sufficient data coverage, discovered field sizes within mature basins (those with extensive exploration and production histories), and many other geologic properties have distributions that approximate a statistical pattern called **lognormality**. In a lognormal distribution, a plot of the frequency of occurrence of a property against the logarithm of its value will yield a normal or bell-shaped plot. The BOEM assessment of the volume of UTRR is based on the assumption that, within a properly defined play, the size distribution of the entire population of accumulations (which includes discovered and undiscovered accumulations) will also be lognormal.

To estimate the portion of UTRR that can be profitably extracted given particular economic constraints, BOEM uses Monte Carlo methodology to simulate the exploration, development, production, and delivery of the estimated resources in each play. The Monte Carlo method is a multiple-trial procedure in which, for each trial, values for constituent parameters are selected at random from their distributions and combined to provide a single result for that trial. The results of the overall distribution comprise many trials.

The ranked distributions (**Figure 3**) are sampled along with probability distributions for costs, production properties (for example, gas-to-oil proportion, production rates, and decline rates), and other engineering and economic factors. The program simulates exploration, delineation, installation of production and delivery facilities, and drilling of development wells. Costs, production, and revenues are scheduled over the lifetime of each field assumed to exist in the play. The program develops a risk-weighted discounted cash flow and calculates a present economic value for the field. The economic resources by field are combined with additional costs specific to the assessment area to determine its economic resources. Costs for equipment and infrastructure are included at the field level (for example, platform, subsea, and other production well costs) or assessment area level (for example, trunk pipeline), as appropriate. This procedure is performed iteratively for varying oil and gas prices to develop a probability distribution of the UERR. The oil price represents the world oil price as defined by the Department of Energy and is equivalent to the average refiner's acquisition cost of domestic oil. We account for local market price variations (for example, the varying quality of crude oil or cost of transportation) at the assessment area level.

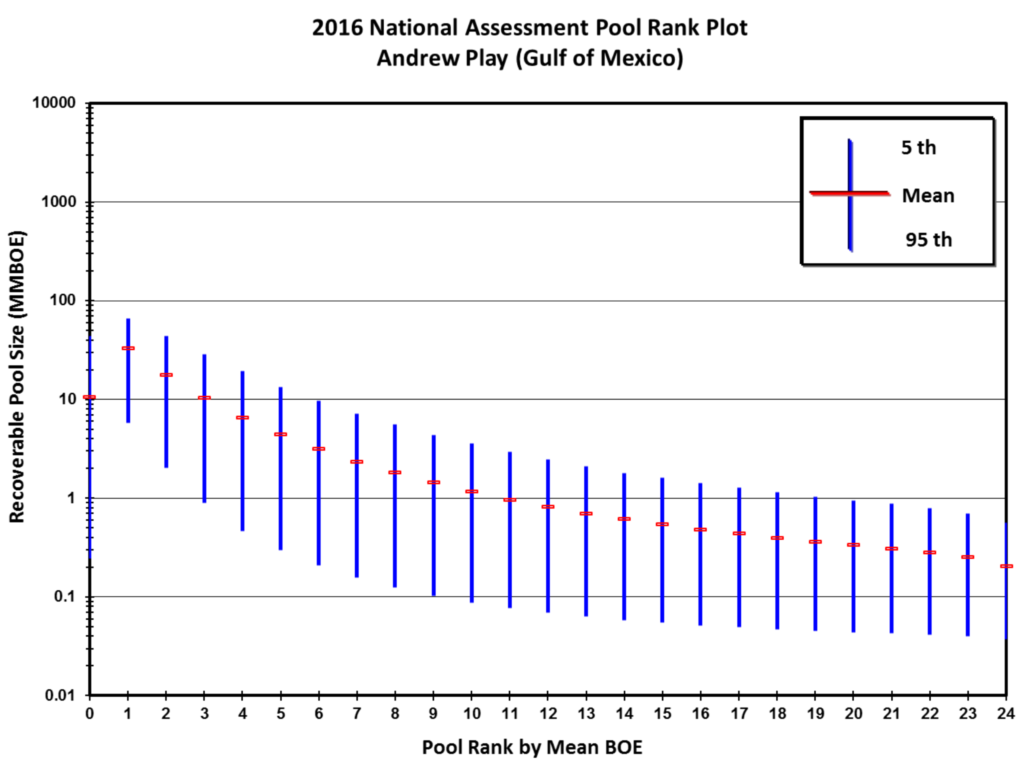


Figure 3. Sample lognormal field size distribution ranked by mean pool size.

2.4 Assessment of Undiscovered Technically Recoverable Resources

For the 2016 Assessment, all OCS Regions use a play-based subjective methodology. Our subjective methodology, when condensed to its core components, includes a six step method for assessing both the technically and economically recoverable resources within a play (**Figure 4**). Early in the process, we generate a lognormal distribution of potential pool sizes that can exist within the boundaries of the play (**Figure 3**). This distribution is largely built from existing data that allows us to understand the petroleum geology of the play area. Parameters such as thickness of reservoir, average area of a pool, percentage of the rock that is oil bearing vs. gas bearing, etc., are compiled to help inform the pool size distributions. In more mature areas, such as the GOM, the data and information are compiled from past discoveries within the basin. As more discoveries are made, we are able to update our data distributions and increase the accuracy of our estimations of undiscovered pools and resources. For more frontier areas like the Atlantic and Alaska OCS Regions, data are obtained from exploration and production in geologically analogous areas to generate a distribution of potential pool sizes. Once we have established an undiscovered pool size distribution, the pools are subjected to risking parameters based on quality of the reservoir rock and maturity of the play to provide a distribution of prospects. The prospects are ranked by size and aggregated independently to provide an estimate of UTRR within the play.

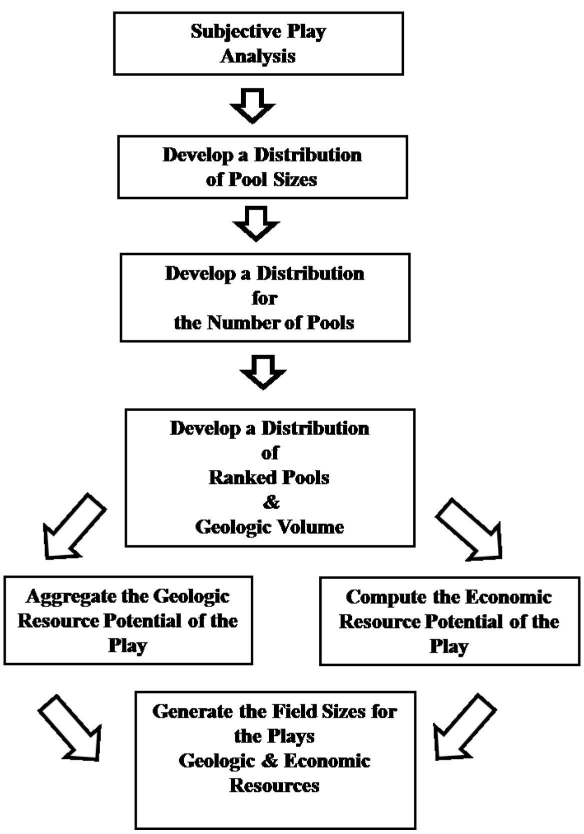


Figure 4. Six step method for assessing resources within a play.

2.5 Assessment of Undiscovered Economically Recoverable Resources

Following the assessment of UTRR, we perform an economic evaluation for each geologic play and AU to estimate the portion of those resources that can be extracted profitably over a range of commodity prices and at the present level of technology, including the effects of current and expected economic factors. These factors include costs for exploration, development, and production of resources; market prices of the various hydrocarbon commodities; and other economic conditions (for example, interest rates, which affect the cost of capital, and revenues that could alternatively be gained by investing capital elsewhere).

This assessment allows for uncertainty in oil and gas prices by developing a continuous series of resource estimates over a wide range of prices, highlighting the occurrence where oil and gas can be profitably developed as a function of price. Oil and gas are linked in our model; that is, the supply value of both commodities must be determined together at a given oil price and its corresponding gas price. We use this linked approach because the economic viability of an individual field is calculated assuming the presence of both oil and gas together at a fixed ratio for any given field. Because of this linkage, the oil and gas supply estimates do not reflect relative market-demand effects between the two commodities (that is, a relative increase or decrease in the market value of gas relative to that of oil is not accounted for in the model). For tabulated results, the gas price is set relative to the oil price at 30, 40, 60, and 100 percent of the oil price for equivalent energy content. For example, an oil price of $60.00 per Bbl corresponds to a gas price of $3.20 per Mcf at 30 percent of the equivalent oil energy content. For the 2016 Assessment, the primary reporting is done using a gas adjustment equivalency that is set at 30% of the oil price. **Figure 5** illustrates the range of gas prices relative to oil prices through time.

2.6 Estimation of Total Resource Endowment

The **total resource endowment** is the sum of the discovered resources (originally recoverable reserves and contingent resources), appreciation and growth of discovered reserves, and UTRR. For mature regions such as the GOM, where there is extensive historical exploration and production, the total resource endowment includes a significant component of discovered reserves and reserves appreciation. For frontier areas where there has been little to no exploration and production, such as the Atlantic OCS, the resource endowment is based entirely on the UTRR in that region.

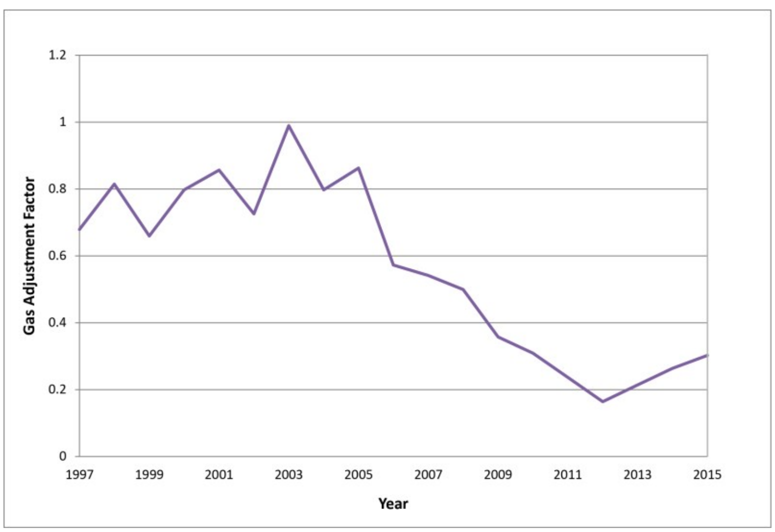


Figure 5. Gas price adjustment factors from 1997–2015 illustrating fluctuations in the price of gas relative to a barrel of oil.

3 NATIONAL ASSESSMENT RESULTS

Results from the 2016 Assessment represent a multi-year effort that includes data and information available as of January 1, 2014. Aggregated estimates of UTRR oil for the entire OCS range from 76.69 Bbo at the 95th percentile (i.e., there is a 95 percent chance of at least 76.69 Bbo) to 105.59 Bbo at the 5th percentile, with a mean of 90.55 Bbo. Similarly, gas estimates range from 284.41 Tcfg at the 95th percentile to 375.87 Tcfg at the 5th percentile with a mean of 327.58 Tcfg (**Table 1)**. Mean aggregated UTRR values for the OCS are shown by type and region (**Figure 6**). On a BOE basis that includes both oil and gas, approximately 50 percent of the potential resources are located within the Gulf of Mexico OCS Region, and the Alaska OCS Region ranks second with 34 percent. The Pacific OCS Region is third among the regions in terms of oil potential and fourth with respect to gas. The Atlantic OCS Region ranks third when considering gas potential and fourth in terms of oil.

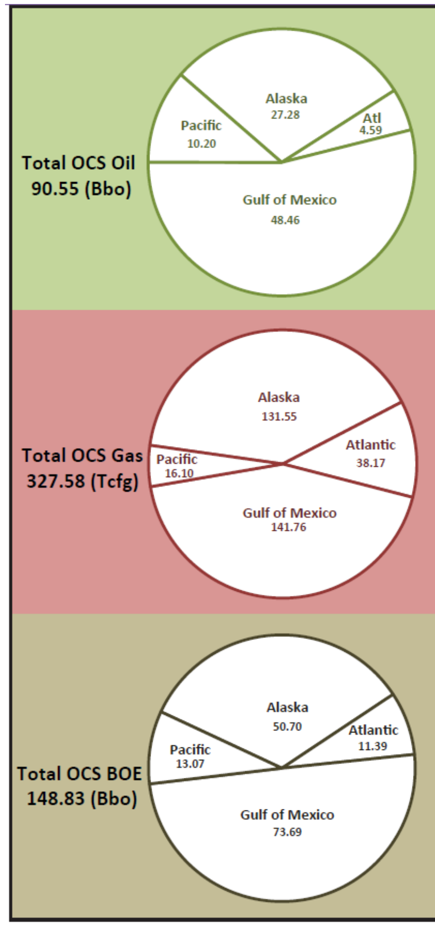


Figure 6. Mean UTRR by type and OCS Region.

We report aggregated estimates of UERR using assumed price parameters that range from \$30/Bbl and \$1.60/Mcf to \$160/Bbl and \$8.54/

Table 1. Risked UTRR of the entire United States OCS by Region.

Region	Risked Undiscovered Technically Recoverable Oil and Gas Resources (UTRR)								
	Oil (Bbo)			Gas (Tcfg)			BOE (Bbo)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Alaska OCS	19.09	27.28	37.43	96.76	131.55	167.98	36.3	50.70	67.32
Atlantic OCS	1.15	4.59	9.19	12.8	38.17	68.71	3.43	11.39	21.41
Gulf of Mexico OCS	39.48	48.46	58.53	124.01	141.76	159.63	61.55	73.69	86.93
Pacific OCS	6.96	10.2	14.03	10.52	16.1	23.92	8.83	13.07	18.28
Total U.S. OCS	76.69	90.55	105.59	284.41	327.58	375.87	129.29	148.83	172.47

Note: Resource values are in billion barrels of oil (Bbo), trillion cubic feet of gas (Tcfg) and barrel of oil equivalents (BOE). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding.

Mcf. The UERR for the entire OCS includes 39.20 Bbo and 53.67 Tcfg at the low end of price assumption, and 78.81 Bbo and 191.46 Tcfg at the high price assumption (**Table 2**).

We use price-supply curves (**Figure 7**) to show the relationship of oil and gas prices to economically recoverable resource volumes (i.e., a horizontal line from the price axis to the curve yields the quantity of economically recoverable resources at the selected price). The price-supply charts contain two curves and two price scales, one for oil and one for gas. The curves represent mean values at any specific price. The two vertical lines indicate the mean estimates of UTRR oil and gas resources for the specific area or region (for **Figure 7**, the vertical lines represent UTRR for the entire U.S. OCS). At high prices, UERR volumes approach the UTRR volumes.

Price-supply curves (APPENDIX 1) represent resources available given sufficient exploration and development efforts and do not imply an immediate response to price changes. The oil and gas price-supply curves are not independent of each other; that is, one specific price cannot be used to obtain an oil resource while a separate unrelated gas price is used to obtain a gas resource. Gas price is dependent on oil price and must be used in conjunction with the oil price on the opposite axis of the chart to calculate resources. Price coupling is necessary in our model, because oil and gas frequently occur together and individual pool economics are calculated using the coupled pricing. **Table 2** presents specific price pairs associated with a 30 percent economic value of gas relative to oil. Estimates of the total endowment of hydrocarbons on the OCS are presented in **Table 3**. The total endowment comprises the sum of historic production, remaining reserves, future reserves appreciation, contingent resources, and UTRR. Mean estimates of the total endowment for the entire OCS are 128 Bbo and 577 Tcfg, or 231 BBOE (**Table 3**).

Table 2. Risked mean-level UERR of the entire United States OCS by Region.

Region	Risked Undiscovered Economically Recoverable Oil and Gas Resources (UERR)											
	$30/Bbl $1.60/Mcf		$40/Bbl $2.14/Mcf		$60/Bbl $3.20/Mcf		$100/Bbl $5.34/Mcf		$110/Bbl $5.87/Mcf		$160/Bbl $8.54/Mcf	
	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas
Alaska OCS	0.68	0.26	2.12	1.16	8.38	9.36	17.29	33.59	18.57	38.59	22.00	60.43
Atlantic OCS	3.21	3.64	3.47	5.06	3.76	8.41	4.00	13.00	4.03	13.81	4.15	17.22
Gulf of Mexico OCS	31.31	44.48	35.01	56.09	39.55	74.67	42.88	92.04	43.31	94.51	44.77	103.47
Pacific OCS	4.00	5.30	5.10	6.61	6.45	8.29	7.30	9.43	7.43	9.62	7.89	10.35
Total U.S. OCS	39.20	53.67	45.70	68.93	58.15	100.73	71.47	148.05	73.35	156.53	78.81	191.46

Note: Resource values are in billion barrels of oil (Bbo) and trillion cubic feet of gas (Tcfg). Some total mean values may not equal the sum of the component values due to independent rounding. Prices are in dollars per barrel($/Bbl) for oil, and dollars per thousand cubic feet ($/Mcf) for gas. This table represents a gas price adjustment of 0.3.

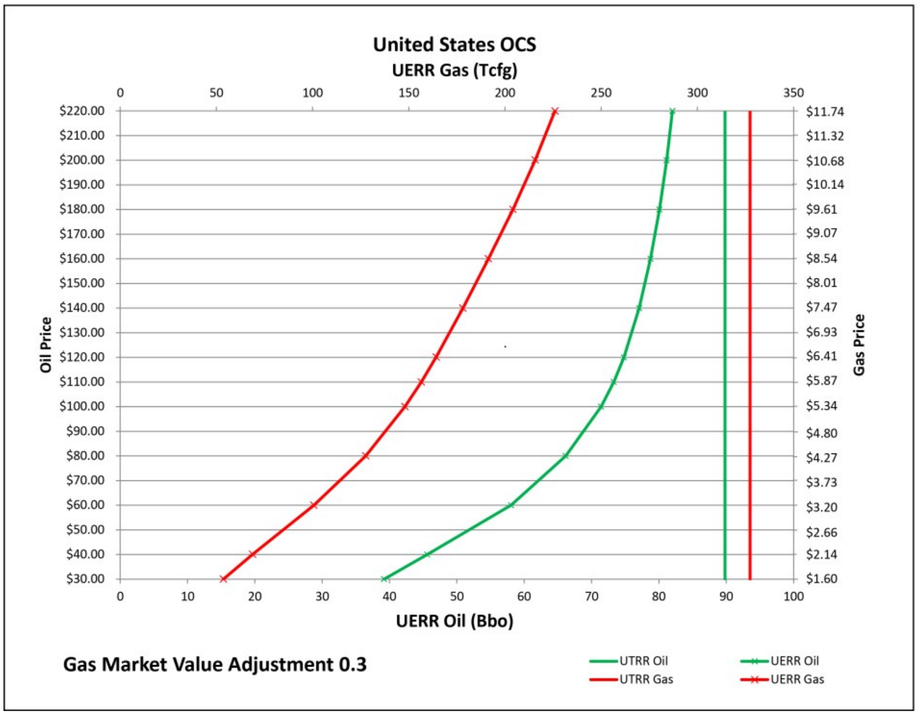


Figure 7. Price-supply curve of the entire United States OCS.

Table 3. Distribution of total hydrocarbon endowment by type, region, and resource category.

Resource Category		Endowment for the U.S. OCS				
		Alaska	Atlantic	Gulf of Mexico	Pacific	Total OCS
Cumulative Production	Oil (Bbo)	0.03	-	18.52	1.31	19.86
	Gas (Tcf)	0.00	-	184	1.8	185.80
	BOE (Bbo)	0.03	-	51.25	1.63	52.91
Remaining Reserves	Oil (Bbo)	0.01	-	3.67	0.29	3.97
	Gas (Tcf)	0.00	-	9	0.58	9.58
	BOE (Bbo)	0.01	-	5.28	0.39	5.68
Contingent Resources	Oil (Bbo)		-	3.29	1.31	4.60
	Gas (Tcf)		-	11.3	0.93	12.23
	BOE (Bbo)		-	5.31	1.47	6.78
Reserves Appreciation	Oil (Bbo)	-	-	8.94	-	8.94
	Gas (Tcf)	-	-	41.31	-	41.31
	BOE (Bbo)	-	-	16.29	-	16.29
UTRR (Mean)	Oil (Bbo)	27.28	4.59	48.46	10.20	90.55
	Gas (Tcf)	131.55	38.17	141.76	16.10	327.58
	BOE (Bbo)	50.70	11.39	73.69	13.07	148.83
Total Endowment	Oil (Bbo)	27.32	4.59	82.88	13.11	127.89
	Gas (Tcf)	131.55	38.17	387.37	19.41	576.50
	BOE (Bbo)	50.74	11.39	151.82	16.56	230.51

Note: Some total mean values may not equal the sum of the component values due to independent rounding. Values for cumulative production, remaining reserves, and contingent resources are based on data available as of January 1, 2014.

4 ALASKA OUTER CONTINENTAL SHELF REGION

A full and complete description of the 2016 Alaska OCS assessment of undiscovered resources is available in OCS Report BOEM 2018-001 (Lasco, 2018) and Beaufort Sea Update (BOEM Fact Sheet RED-2017-12b). Additionally, a comprehensive background is provided in the summary of the 1995 resource assessment in Alaska (OCS Report MMS 96-0033; Sherwood et al., 1998). The discussion below, at times, provides a summary of the more detailed information found in Sherwood et al. (1996), Sherwood et al. (1998), and Lasco (2017).

4.1 Location and Geologic Setting

The Alaska OCS comprises submerged lands that extend from the U.S.-Canadian maritime boundary in southeastern Alaska, west and north to the U.S.-Russia maritime boundary in the Bering Sea, and northeast to the U.S.-Canada maritime boundary in the Beaufort Sea (**Figure 8**). The area of Federal jurisdiction in these waters begins at the seaward limit of State of Alaska waters, which is located 3 miles offshore. Submerged Federal lands include all of the continental shelves as well as large areas of the continental slopes and deep abyssal plains of the north Pacific Ocean and the Bering, Chukchi, and Beaufort Seas. The Alaska OCS includes 15 formally defined planning areas.

Of the four U.S. OCS Regions, the Alaska OCS is the geographically largest and the most geologically diverse. The Alaska OCS includes more than one billion acres and more than 6,000 miles of coastline—more coastline than in the entire rest of the United States. Though the Alaska OCS includes deepwater areas in the Beaufort and Bering Seas and in the Gulf of Alaska, most geologic plays included in this assessment are in water depths less than 700 feet. Extreme weather and ice conditions severely limit the ability to conduct exploration and development operations in water depths exceeding 700 ft resulting in minimal data for an assessment.

The Alaska OCS includes 79 assessed geologic plays within 11 different planning areas, spread out over three general geographic provinces. The majority of the plays reside within the Beaufort and Chukchi planning areas, where we assess 43 different geologic plays.

4.1.1 Geologic Setting

Offshore southern Alaska, the oceanic crust of the Pacific plate moves northward and is subducted beneath the Aleutian volcanic arc and the Shumagin, Kodiak, and Gulf of Alaska continental shelves. The compression and uplift resulting from the convergence of plates along this zone largely controls the geological development of the Pacific Margin of Alaska. The Tertiary age Aleutian volcanic arc is constructed entirely upon oceanic crust and extends from the Bering Sea continental margin westward to Russian waters. From the Bering shelf margin northeast to the interior of southern Alaska, the modern volcanic arc is superposed upon older volcanic arc systems ranging up to Jurassic (145 to 200 million years ago (Ma)) in age (Reed and Lanphere, 1973). East of Cook Inlet, the volcanic arc and convergent margin tectonics gradually give way to the strike-slip fault tectonics that dominate the eastern Gulf of Alaska, where the Pacific plate moves northwest and laterally past the North American continental plate. Most of the undiscovered oil and gas resources along the Pacific margin of Alaska are associated with forearc basins and

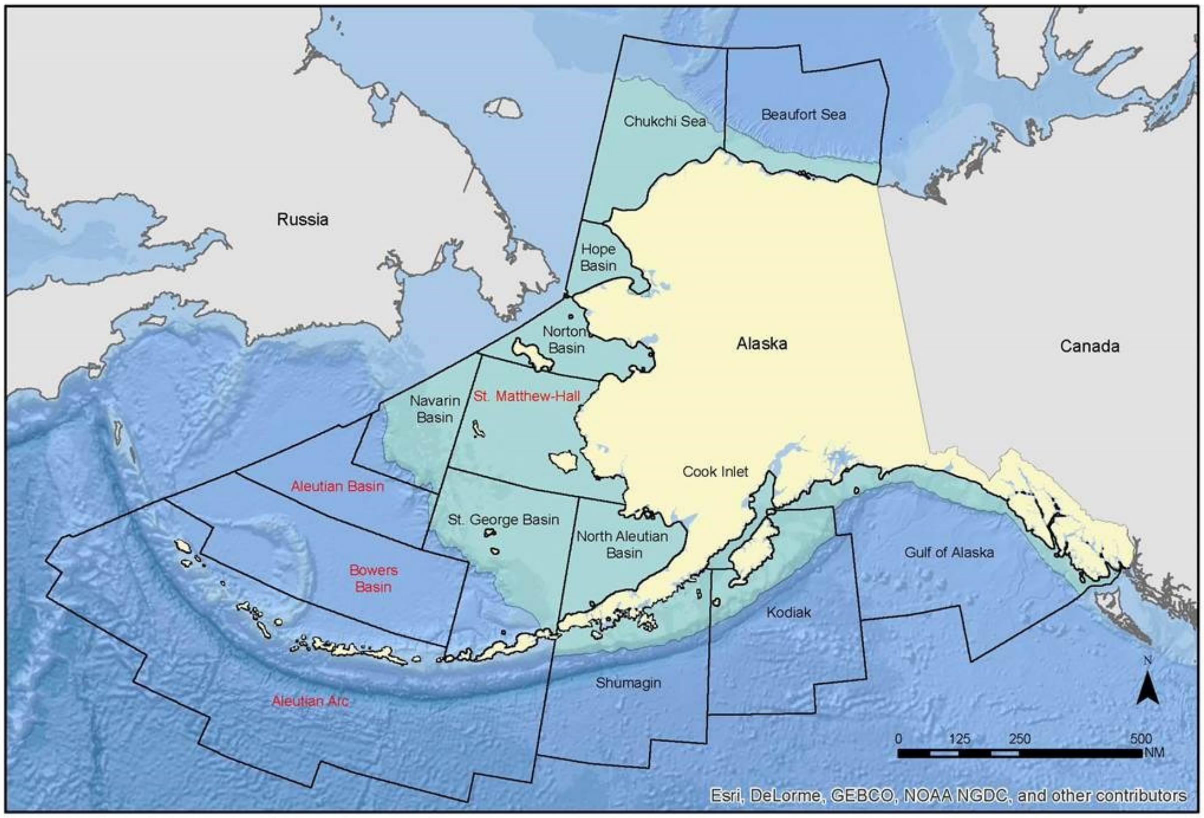


Figure 8. Map of Alaska OCS Region planning areas.
The portion of the Alaskan OCS that are assessed in this report are shown in green. Planning areas shown in red were not evaluated in this study as their petroleum potential is negligible.

shelf-margin wedges of Tertiary age (66 Ma and younger). Except in Cook Inlet, these Tertiary rocks are superposed on a deformed “basement” consisting of older volcanic arc complexes and accretionary terranes that generally offer negligible hydrocarbon resource potential.

Western offshore Alaska is dominated by the extensive (350-mile wide) Bering Sea continental shelf. From Jurassic to earliest Tertiary time, the Bering shelf hosted one segment of a larger system of volcanic arcs extending from southeast Alaska to the Russian Sea of Okhotsk. This volcanic arc system marked the northward descent of a southern oceanic (proto-Pacific) plate encroaching from the south. Continental fragments and volcanic arcs borne along with the southern oceanic plate collided with both Russian and Alaskan elements of the volcanic arc system in earliest Tertiary time (Worrall, 1991). The collision(s) strongly deformed the rocks of most parts of the Bering shelf segment and other parts of the volcanic arc system. Rocks deformed by these collisions, typically Cretaceous age or older, offer only negligible potential for undiscovered oil and gas resources.

The Aleutian arc was also established as a new plate boundary at this time, trapping fragments of an old volcanic arc and oceanic crust that formerly were part of the southern oceanic plate as defined by Marlow et al. (1982). Subduction of a spreading ridge that lay within the southern oceanic plate reorganized plate interactions in the north Pacific and caused strike-slip faulting throughout southern Alaska in Early Tertiary and later time (Atwater, 1970). Most of the Bering shelf basins (Norton, St. Matthew-Hall, Navarin, St. George, and North Aleutian Basins) began to subside at this time as pull-aparts or related features along strike-slip fault systems passing through the Bering shelf. Most of the undiscovered oil and gas resources offshore western Alaska are associated with Tertiary rocks deposited in the Bering shelf basins formed during this period of strike-slip faulting.

Offshore areas north and northwest of Alaska are dominated by the broad (250-mile) continental shelf of the Chukchi Sea and the relatively narrow (50-mile wide) shelf of the Beaufort Sea. In Paleozoic and Mesozoic time, these shelf areas and onshore Arctic Alaska shared petroleum-rich geologic basins that were later broken up or restructured in Early Cretaceous time by rifting along the Beaufort shelf margin and the rise of the Brooks Range (Craig et al., 1985; Moore et al., 1992; Warren et al., 1995). These uplifts and fragmentation of the crust in northern Alaska gave rise to several new basins that received many thousands of meters of sediments during Cretaceous and Tertiary times (115 Ma to present). These events also created the geologic structures that later trapped the vast oil reserves found in the Prudhoe Bay area of Arctic Alaska.

4.2 Methodology

The BOEM resource assessment methodology for the Alaska OCS Region utilizes the practices described in Chapter 2 (METHODOLOGY) and includes a full petroleum systems analysis of geological and geophysical data available to BOEM. These data include a robust reflection seismic database, gravity and magnetics, subsurface well information from existing wells supplemented with geochemical data from well samples, well log analysis, tectonic analysis, and paleontological and lithologic data.

Most of the data utilized in the Alaska resource assessment is based on data collected through the development of oil and gas fields within the region. However, there are some areas within the Alaska OCS where there are not enough data collected locally, and BOEM relies on the use of data from fields in analogous onshore plays to help assess these areas.

4.3 Planning Areas and Subregions

Due to the high number of plays assessed in the Alaska Region as well as the nature of the application of engineering assumptions, discussions about the Alaska OCS Region will be focused at the planning area level. Included in this section is an overview of the geology and economic factors influencing the Alaska OCS Region by planning areas, which are grouped informally into three subregions. The Arctic Subregion of northern Alaska includes the Beaufort Sea, Chukchi Sea, and Hope Basin Planning Areas. The western Alaska Bering Shelf Subregion includes the Norton Basin, Navarin Basin, North Aleutian Basin, and St. George Basin Planning Areas. The Pacific Margin Subregion is located in southern Alaska and includes the Shumigan, Kodiak, Cook Inlet, and Gulf of Alaska Planning Areas.

4.3.1 Beaufort Sea Planning Area

The Beaufort Sea Planning Area (**Figure 9**) contains the Beaufort shelf, essentially a direct geological extension of (onshore) northern Alaska. It comprises a series of basins and intervening highs formed during a complex history of rifting and continental break up north of Alaska and folding and thrusting on the south and east. The 14 geologic plays in the Beaufort Sea extend from the 3-mile limit of State of Alaska waters northward to the approximate shelf/slope break.

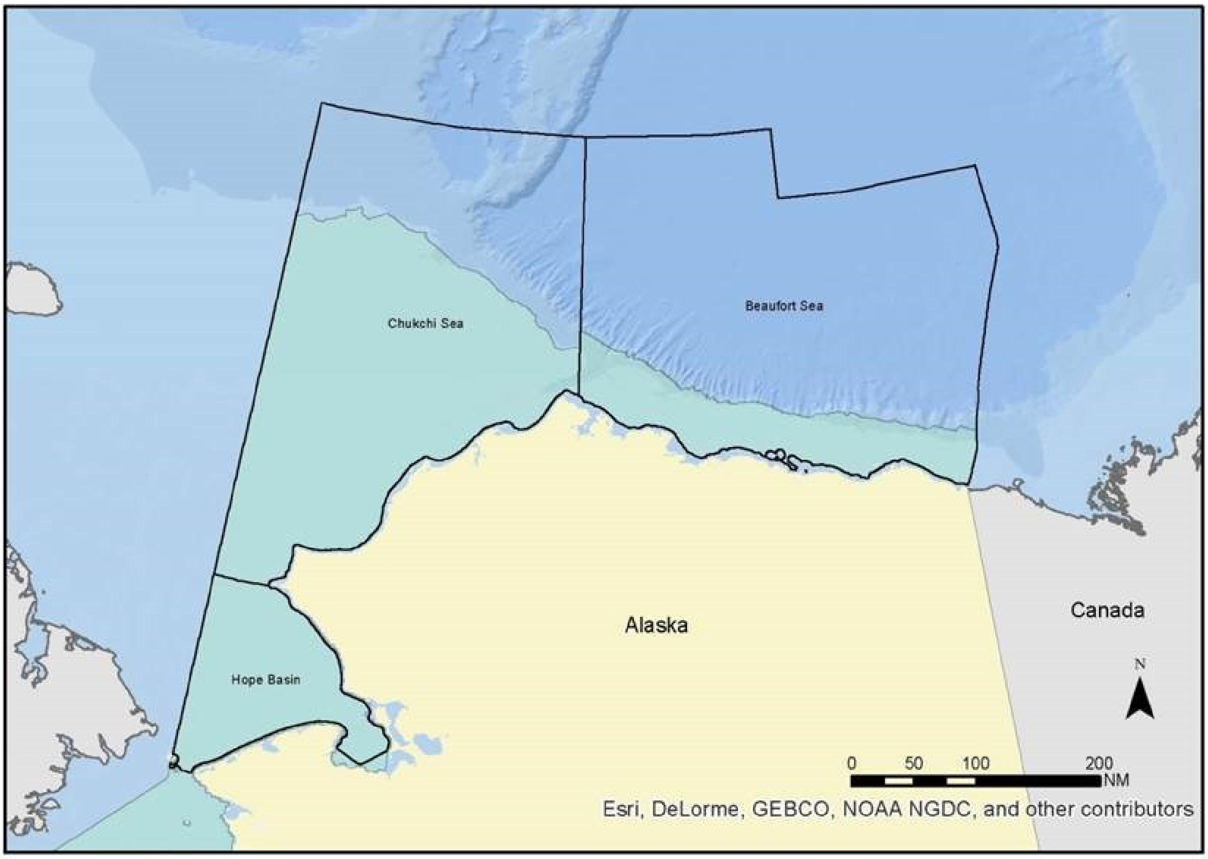


Figure 9. Map of the northern Alaska Arctic Subregion showing the Beaufort Sea, Chukchi Sea, and Hope Basin planning areas.
The portion of the Alaskan OCS that are assessed in this report are shown in green.

Northern Alaska's discovered resources are scattered among more than 30 oil and gas fields, but most resources occur in the several large oil fields in the Prudhoe Bay area. Many, but not all, of the key oil-source and reservoir sequences of northern Alaska extend directly into offshore planning areas. For this reason, and because of the abundance of untested potential traps in the offshore, the Beaufort and adjacent Chukchi Sea areas are considered high potential areas.

A total of 36 wells have been drilled on Beaufort Sea OCS leases. These wells led to a number of OCS oil discoveries, including Tern Island (Liberty field), where oil was discovered in the Mississippian Kekiktuk formation of the Endicott group, and at Seal Island (Northstar field), where oil was discovered in the Triassic Ivishak Formation. The Hammerhead and Kuvlum wells discovered oil in Cenozoic Brookian clastics. Two wells at the Sandpiper prospect encountered significant quantities of gas and a relatively thin liquid leg under the gas in Sadlerochit sands. The Phoenix and Antares wells encountered minor amounts of oil in the Sag River Formation. Mukluk and Mars wells encountered minor amounts of oil in the Sadlerochit Group. The Galahad well encountered minor amounts of gas and an oil show in numerous Cenozoic sands, and the McCovey well showed oil in core samples from the Brookian turbidite sequence.

4.3.1.1 Economic Factors

For the foreseeable future, development in the Beaufort Sea will likely be restricted to relatively shallow water depths (< 600 feet) on the continental shelf. Production platform designs vary with water depths. Artificial gravel islands are the preferred platforms in shallow areas (< 50 feet depths), bottom-founded (gravity) structures are the likely design in moderate depths (50–250 feet), and either armored steel platforms or subsea well systems will be employed on the outer shelf (> 150 feet). Exploration wells are likely to employ similar platform types.

The maximum number of wells that can be contained on a production platform varies with platform type. We assume that space and topside weight are not limiting factors for artificial islands, so up to 90 well slots could be installed on these types of platforms. For mobile gravity platforms, topside space is a limiting factor, so a maximum of 60 well slots is assumed. For floating conical platforms, both topside weight and space are limiting factors, so a maximum of 48 well slots is assumed.

4.3.2 Chukchi Sea Planning Area

The Chukchi Sea Planning Area (**Figure 9**) is located on the northwestern margin of the Alaska OCS within the Arctic Subregion. Water depths across most of the Chukchi shelf are typically about 160 feet, except in the Barrow and Hanna submarine canyons, where water depths range from 165–660 feet. The northern parts of the planning area extend over the deep Canada basin-Beaufort slope and the deep basins and submarine ridges of the Chukchi borderland. The Chukchi Sea Planning Area contains 29 geologic plays considered for assessment in the 2016 Assessment. Two plays assessed contain negligible oil and gas resources.

The Chukchi Sea Planning Area is underlain by five distinct geologic basins that are deformed by listric faults, transtensional faults, rift-extension faults, and a fold and thrust belt. This complexity has produced a large number of petroleum prospects that are mapped in conventional two-dimensional seismic data. The current BOEM inventory contains 856 mapped prospects (generally anticlines, fault traps, or stratigraphic wedge-outs) in the Chukchi Sea Planning Area, and an additional five mapped structures were tested by five exploration wells. These prospects range from hundreds of acres to hundreds of thousands of acres, with nearly a dozen larger than the major oil fields of the Alaska North Slope.

Industry investigations of the U.S. Chukchi shelf resulted in the collection of 100,000 line miles of high quality seismic-reflection data. In addition, comprehensive gravimetric, magnetic, thermal, and geochemical surveys were also conducted on the U.S. Chukchi shelf. A total of five exploratory wells were drilled on Chukchi shelf from 1989 to 1991. Three wells were drilled over two open-water seasons. Four of the wells encountered pooled hydrocarbons.

4.3.2.1 Economic Factors

Pipeline systems are designed to collect oil production from the widely scattered plays in the Chukchi Sea. The trunkline system comprises both offshore and onshore segments. For purposes of our analysis, offshore trunklines are assumed to run from two centrally located offshore facilities to landfalls on the Chukchi coast. Overland trunklines are assumed to run from these coastal landfalls to the Trans-Alaska Pipeline System (TAPS). We choose a southerly overland route across the National Petroleum Reserves in Alaska (NPRA) (approximately 250–300 miles) to avoid the poorly-drained tundra and inlets of the northern Alaska coastal plain. Similar to the Beaufort, offshore gathering systems are modeled as serving several developments with pipeline costs prorated by mileage. Because the Chukchi plays cover wide areas, play pipeline lengths vary between 12–90 miles. Prospects within play areas are also quite widespread, so flowline lengths vary between 10–40 miles.

Development of the Chukchi Sea could take many decades, during which time oil production from this area would be entirely dependent on continued operation of North Slope infrastructure, particularly TAPS. The export scenario for Arctic Alaska gas assumes an in-state pipeline delivering gas to an liquefied natural gas (LNG) conversion plant located in southcentral Alaska (Nikiski) for delivery to an assumed market in East Asia.

4.3.3 Hope Basin Planning Area

The Hope Basin Planning Area lies in the southern Chukchi Sea of the Arctic Subregion, south of Point Hope between the northwest coast of Alaska and the U.S.-Russia maritime boundary (**Figure 9**). It includes portions of both the Hope and Kotzebue Basins and is separated within the planning area by Kotzebue arch. The Hope Basin extends 300 miles west into Russian waters, and the Kotzebue Basin extends eastward beneath the State of Alaska.

Exploratory drilling within the Hope and Kotzebue basins consists of two onshore wells drilled on State of Alaska lands on the south and north flanks, respectively, of the Kotzebue Basin in 1975. These wells penetrated Tertiary sediments with no oil or gas shows. Additionally, seismic data have been collected over most of the Hope Basin Planning Area. Seismic sequences analogous to the major stratigraphic sequences penetrated by the Kotzebue Basin wells were correlated across Kotzebue arch and into Hope Basin on the basis of seismic character and position. Our model for the age, lithology, and hydrocarbon potential of the Hope Basin is therefore drawn from correlations through seismic data to the Kotzebue Basin wells. We have also utilized stratigraphic information from drilling in the entirely separate but analogous Norton Basin 200 miles to the south.

The 2016 oil and gas assessment of Hope Basin identifies four geologic plays. Three plays were quantitatively assessed while the fourth play was assessed as offering negligible potential based on high risk and small prospect numbers. The three quantified plays in Hope Basin are estimated to contain a maximum of 169 pools, which include predominantly gas pools with a minority fraction of mixed (oil and gas) and oil (no gas cap) pools.

4.3.3.1 Economic Factors

The Hope Basin was modeled for the production of gas and oil, although natural gas will primarily support initial development. Crude oil could be recovered if satellite oil pools are reachable from gas production platforms. Condensate recovered as a byproduct of gas production could share crude oil transportation systems. At the present time, there are no petroleum operations in this remote area off northwestern Alaska.

Environmental conditions in the southern section of the Arctic Subregion are considerably less severe than in the more northern Chukchi and Beaufort Seas. Sea ice forms in the fall and covers the area for over half of the year. However, while incursion of the multi-year Arctic ice pack does not occur in this region, sea ice movement is both rapid and erratic, requiring special design considerations for permanent platforms. Water depths in the Hope Basin are moderate, ranging from 50–180 feet.

In mobile sea ice conditions, large bottom-founded concrete platforms are the preferred design for production. However, considering the platform size required for these water depths, ice-reinforced floating production platforms supplemented with subsea wells and tiebacks are likely to be favored. Exploration drilling would be conducted using drillships with icebreaker support vessels during the short open-water season. Offshore platforms will require extensive gas handling equipment, but fewer well slots are needed, because subsurface drainage areas are generally larger for gas reservoirs. Also, fewer service wells are needed for gas fields.

4.3.4 Norton Basin Planning Area

The Norton Basin Planning Area (**Figure 10**) is located off the coast of west-central Alaska, approximately coincident with Norton Sound in the northern Bering Sea. Norton Sound is bounded by the Seward Peninsula on the north, and the Yukon Delta and St. Lawrence Island on the south. The United States-Russia Convention Line of 1867 defines the western boundary of the Norton Planning Area. The geologic basin and is approximately 125 miles long and ranges from 30 to 60 miles in width.

Four geologic plays are assessed in the Norton Basin Planning Area, including the Upper Tertiary Basin Fill Play, the Mid-Tertiary East and Mid-Tertiary West Subbasin Fill Plays, and the Lower Tertiary Subbasin Fill Play. The quantified plays in the Norton Basin are estimated to contain a maximum of 77 pools, all of which are gas pools with a minority fraction of associated condensate. A fifth play in the rocks of the acoustic basement was identified but was not assessed due in part to poor data quality. Two stratigraphic test wells or

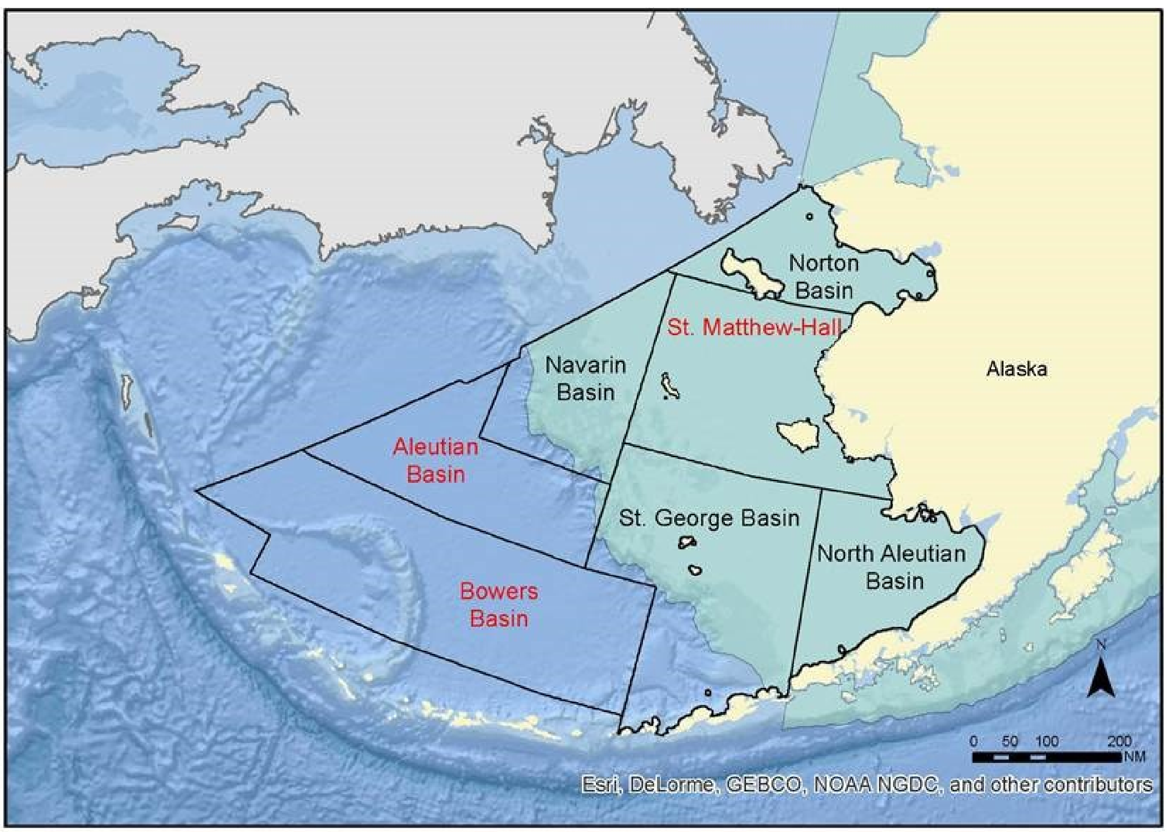


Figure 10. Map of the western Alaska Bearing Shelf Subregion showing the location of the Norton Basin, Navarin Basin, North Aleutian Basin, and St. George Basin Planning Areas.
The portion of the Alaskan OCS that are assessed in this report are shown in green. Planning areas shown in red were not evaluated in this study as their petroleum potential is negligible.

Continental Offshore Stratigraphic Tests (COST) wells are located in the Norton Basin. Twenty-one oil companies participated in financing these wells. Over the course of ten years, nearly 50,000 line miles of common depth point (CDP) seismic data in Norton Basin were acquired. Varying amounts of high-resolution seismic data and gravity/magnetic data have also been collected in the Norton Basin Planning Area Six exploration wells were drilled on leases following a 1983 lease sale.

4.3.4.1 Economic Factors

Currently, there is no petroleum-related infrastructure in the Norton Basin. Any new infrastructure, including an LNG facility and marine loading terminal, is likely to be located in the vicinity of Nome with its existing airport and port facilities. The primary constraints to year-round operations of a marine terminal are sea ice (November–May) and the shallow water of Norton Sound. With that in mind, this planning area was modeled utilizing Floating Liquefied Natural Gas (FLNG) vessels as the preferred field production platform.

Exploration drilling would be conducted using jack-up rigs during the summer open-water season. The development scenario assumes that gas would be recovered by concrete production platforms resting on prepared seafloor berms. Artificial gravel islands or a steel reinforced bottom-founded vessel could be utilized as production platforms in very shallow water (< 50 feet). Gas production would be transported by trenched subsea pipelines to a central gathering platform and transported by a 65-mile trunkline to shore-based facilities constructed near Nome. Subsea pipeline gathering systems are relatively short (10–60 miles) because the province is small and the plays/prospects generally overlap.

One FLNG ship would operate in the planning area during open-water seasons and, over several years, produce an individual field to depletion before moving to another field in the region. Gas production would be converted to LNG onboard the FLNG vessels and then shipped by marine carriers to East Asia. Ice-reinforced tankers would shuttle hydrocarbon liquids (condensate and natural gas liquids) to a terminal in Nikiski, Alaska, for processing and local consumption or to Valdez, Alaska, where it would be commingled with North Slope crude oil and shipped to the U.S. West Coast.

4.3.5 Navarin Basin Planning Area

The Navarin Basin Planning Area includes a prospective area of approximately 100 miles by 240 miles in the western Alaska Bering Shelf Subregion (**Figure 10**). Water depths range from 200 feet on the OCS to over 4,000 feet on the continental slope. The average water depth for this broad distribution is 480 feet. In some areas, the Navarin Basin is filled with up to 36,000 feet of sedimentary rocks of Tertiary age.

Five plays based on the facies-cycle wedge model by White (1980) are assessed. In this facies-cycle wedge model, the base of a wedge is made up of a succession of facies deposited during a marine transgression. The middle of the wedge represents the peak of the transgression, and the top of the wedge represents a subsequent marine regression.

The five plays assessed for the Navarin Basin include the: 1) Miocene Basin Sag Play, 2) Late Oligocene Basin Shelf Play, 3) Oligocene Rift Subbasin Neritic Fill Play, 4) Oligocene Rift Subbasin Bathyal Fill Play, and 5) Early Rift Onset Play.

4.3.5.1 Economic Factors

The Navarin Basin area is covered by variable concentrations of sea ice from January to June, with frequent changes in concentration and movement driven by strong currents. The province was modeled as a gas-prone producing province with some associated light oil and/or gas condensate. Due to the remoteness of the planning area, the production of the Navarin Basin was modeled on the use of FLNG vessels as the preferred production platform.

Exploration drilling would be conducted in the open-water season by semisubmersible drill rigs constructed for harsh environments. Production platforms could be either large and costly 32-slot monotowers or potentially less expensive FLNG vessels. Additional wells could be installed in subsea templates. Small satellite fields could be developed entirely with subsea systems with flowlines to nearby FLNG vessels or production platforms.

Based upon the resource volumes anticipated in this region, conventional onshore-based facilities supporting offshore platforms operations may only be economically feasible assuming development in surrounding basins. Recent advances in floating LNG developments appeared to be a more likely technical and economic scenario, especially as a stand-alone project. For this assessment, economic costs were based using an FLNG development scenario where production platforms are tied to an FLNG facility. Shuttle tankers supported by seasonal icebreaker support vessels would transport LNG to an East Asia market.

Crude oil and gas-condensates produced in the Navarin province would be gathered to a centrally located offshore storage and loading terminal. Ice-reinforced shuttle tankers would transport oil and condensate to Nikiski for processing and local consumption or to Valdez for transportation to the U.S. West Coast.

4.3.6 St. George Basin Planning Area

The St. George Basin Planning Area is located offshore western Alaska (**Figure 10**). The assessment area is on the outer Bering Sea shelf in water depths of ~700 feet and less. The eastern boundary is the North Aleutian Basin Planning Area and the western boundary adjoins the Navarin Basin Planning Area.

Ten exploratory wells, including one sidetrack, were drilled from 1984 to 1985 with no discoveries reported. Subsequent scheduled lease sales were cancelled due to lack of interest during the industry downturn in the late 1980s. There are no currently active leases or lease sales scheduled in the planning area.

The St. George Basin Planning Area contains two main Cenozoic depocenters, the St. George Graben and the Pribilof Basin, that contain as much as 40,000 feet and 20,000 feet of Cenozoic sediments, respectively. Four geologic plays in the St. George Basin Planning Area with geophysically mapped prospects are the: (1) St. George Graben Play, (2) South Platform Play, (3) North Platform Play, and (4) Pribilof Basin Play. The quantified plays in the St. George Basin are estimated to contain a maximum of 75 pools, which include predominantly gas pools with a minority fraction of mixed (oil and gas) pools.

4.3.6.1 Economic Factors

The St. George Basin economic development scenario assumes a similar development scenario as the Navarin province. Traditional onshore infrastructure for converting natural gas to LNG for transport is replaced with an FLNG ship anchored offshore to provide processing and marine loading functions. There will be a local subsea pipeline network to support production platforms in this province. An extended gas pipeline to the Alaska Peninsula is not needed in this development scenario. Small volumes of crude and condensate collected on the FLNG ship would be loaded on shuttle tankers and transported to Nikiski or Valdez.

Exploration drilling would be conducted in the open-water season by semisubmersible drill rigs constructed for harsh environments. Small satellite fields could be developed with subsea systems with flowlines to nearby production platforms.

4.3.7 North Aleutian Basin Planning Area

The North Aleutian Basin is about 17,500 square miles in area and underlies the northern coastal plain of the Alaska Peninsula and the waters of Bristol Bay (Figure 10). North Aleutian Basin is also referred to as the "Bristol Bay" basin. Water depths range from 15 to 700 feet, with the most prospective areas located in approximately 300 feet of water.

The prospects in the central part of the North Aleutian Basin have long been the focus of exploration interest in North Aleutian Basin. In this assessment, as well as in past assessments, most of the undiscovered oil and gas resources of the North Aleutian Basin OCS Planning Area are associated with the prospects in the central part of the basin.

Seismic data in the North Aleutian Basin Planning Area comprises 61,438 line miles of conventional, two-dimensional, common-depth-point data and 3,234 line miles of shallow-penetrating, high-resolution data. Airborne magnetic data in the area covers 9,596 line miles and airborne gravity data covers 6,400 line miles. Most two-dimensional seismic data were acquired in the period from 1975 to 1988.

We identify six geologic plays in the North Aleutian Basin Planning Area and formally assess five of the plays. The sixth play is not included in part due to lack of resources. These include the Bear Lake/Stepovak Play, Tolstoi Formation Play, Black Hills Uplift-Amak Basin Play, Mesozoic-Deformed Sedimentary Rocks Play, and Mesozoic Basement-Buried "Granite Hills" Play. The five quantified plays in the North Aleutian Planning Area are estimated to contain a maximum of 119 pools.

4.3.7.1 Economic Factors

Exploration drilling is likely to utilize jack-up rigs in shallow sites (< 150 feet) and semisubmersibles for deeper sites (> 150 feet). The North Aleutian Basin Planning Area was modeled for the production of both oil and gas, although this is predominantly a gas-prone province. Condensate will be recovered by producing wet gas reservoirs, and small crude oil pools could be produced as satellites. Because this province has a relatively high gas resource potential (8.6 BCFG mean) and is relatively close to land, BOEM initially assumed that an onshore LNG facility and marine terminal would be constructed on the Alaska Peninsula. The high cost for LNG facilities, marine loading terminals, and LNG ships would typically require a minimum reserve base of approximately 5 Tcf with co-produced liquids.

Given the long distances to potential gas markets in East Asia and the environmental sensitivity of the Bristol Bay region, BOEM modeled a development scenario employing FLNG as a more economical alternative to traditional shore-based facilities with potentially less environmental impacts. LNG would be delivered by larger ships to receiving terminals in East Asia. Relatively small volumes of light crude oil and condensate would be loaded on tankers and transported to Nikiski for processing and local consumption or to Valdez for transportation to the U.S. West Coast.

4.3.8 Shumagin Planning Area

The Shumagin Planning Area (**Figure 11**) lies offshore of south central Alaska and is located in the Pacific Margin Subregion. The planning area comprises the Federal offshore lands area on the continental shelf and slope on the Pacific side of the Alaska Peninsula south of Kodiak archipelago, landward of the Aleutian trench. The shoreward (northwestern) boundary is the Federal/State water boundary, and the southeastern boundary is loosely set at water depths of roughly 6,500 feet. The southwestern end of the planning area extends just past the Sanak Islands, near the end of the Alaska Peninsula. The Shumagin Planning Area is approximately 330 miles in length measuring northeast to southwest and extends southeastward to about 85 miles offshore. The 2016 Assessment of the Shumagin Planning Area identifies only a single play, the Neogene Structural Play.

There have been no lease sales held or OCS tracts leased in the Shumagin Planning Area. Consequently, there have been no exploratory oil and gas wells drilled.

4.3.8.1 Economic Factors

The resource potential of the Shumagin Planning Area is dominated by gas, so the infrastructure model was formulated for gas production with hydrocarbon liquids (gas condensate) recovered as a byproduct. The geologic assessment forecasts zero crude oil resources. Considering the long distances to natural gas markets, LNG would be the most efficient transportation strategy. FLNG ships will operate in the province and, over several years, produce an individual field to depletion before moving on to another field in the province. LNG would be transported by LNG carriers directly to East Asia. Any light crude oil and condensate produced would be loaded on tankers and transported to Nikiski for processing and local consumption or to Valdez for transportation to the U.S. West Coast.

4.3.9 Kodiak Planning Area

The Kodiak Planning Area (**Figure 11**) lies offshore of south central Alaska. The planning area comprises the Federal offshore lands area on the continental shelf, slope, and abyssal plain flanking the Pacific coastline of the Kodiak archipelago. The part of the planning area that is prospective for hydrocarbons lies landward of the Aleutian trench. The shoreward (northwestern) boundary is the 3-mile limit, and the southeastern boundary of the planning area extends into water depths of 6,500 feet. The northeastern boundary of the planning area adjoins the Gulf of Alaska Planning Area. It extends north from the 6,500-foot water depth line to the edge of the Amatuli trough, a sea valley that transects the continental shelf seaward of the Kenai Peninsula, and then swings west into the gap between the Kenai Peninsula and the Kodiak Island group. The Kodiak Planning Area averages about 425 miles in length measuring northeast to southwest, and extends about 75 miles offshore to the southeast from Kodiak Island.

There have been no lease sales held or OCS tracts leased in the Kodiak Planning Area and consequently no exploratory oil and gas wells have been drilled. However, there have been six stratigraphic test wells drilled. Because of the sparseness of data, only one geologic play within the Kodiak Shelf Planning Area is recognized, the Neogene Structural Play. This play is estimated to contain a maximum of 50 pools which are predicted to be entirely gas pools.

4.3.9.1 Economic Factors

The Kodiak Planning Area was modeled for the production of both oil and gas, although this is

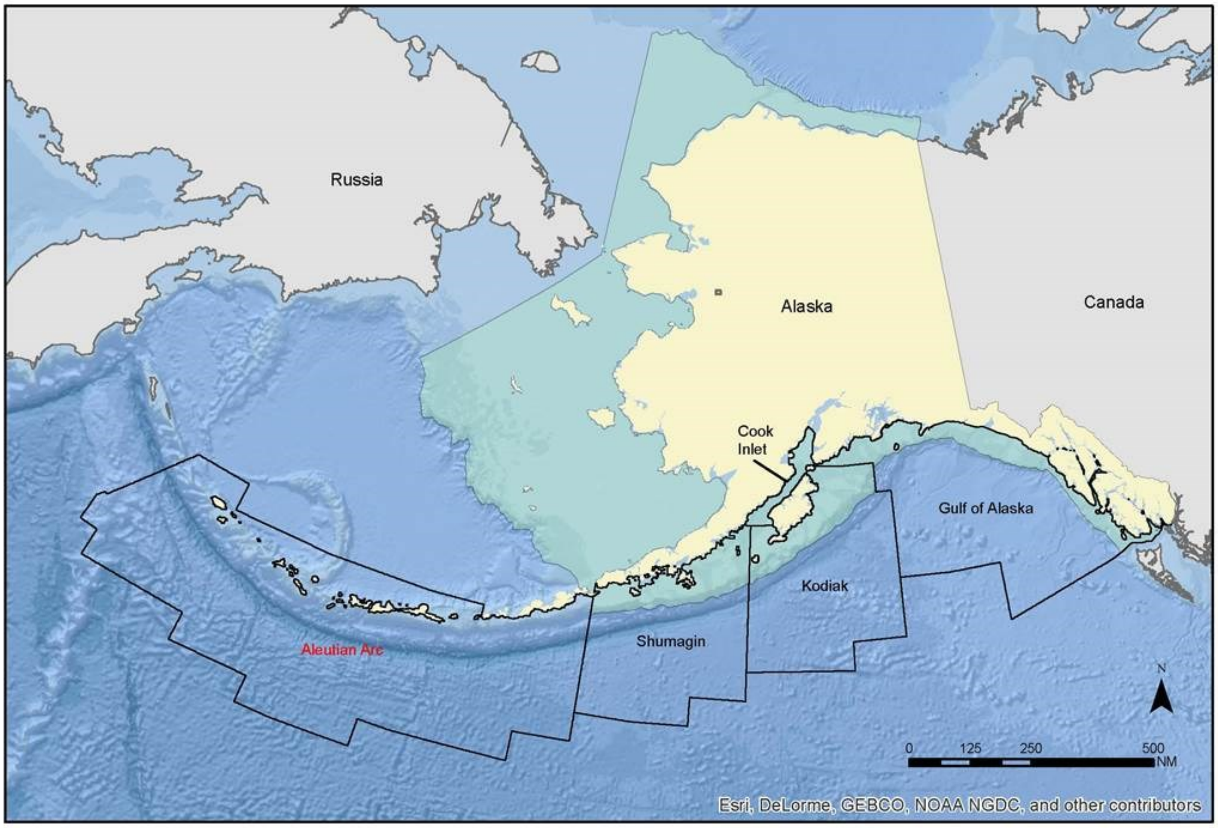


Figure 11. Map of the south Alaska Pacific Margin Subregion showing the Shumagin, Kodiak, Cook Inlet, and Gulf of Alaska Planning Areas.
The portion of the Alaskan OCS that are assessed in this report are shown in green. The Aleutian Arc Planning Area was not evaluated in this study as its petroleum potential is negligible.

predominantly a gas-prone province. Considering the long distances to natural gas markets, LNG would be the most efficient transportation strategy. One FLNG ship will operate in the province and, over several years, produce an individual field to depletion before moving to another field in the province. LNG would be transported by LNG carriers directly to East Asia. Relatively small volumes of light crude oil and condensate would be loaded on tankers and transported Nikiski for processing and local consumption or to Valdez for transportation to the U.S. West Coast.

4.3.10 Cook Inlet Planning Area

The Cook Inlet Planning Area is located in offshore southcentral Alaska and is part of the Pacific Margin Subregion (**Figure 11**). The waters of Cook Inlet and Shelikof Strait overlie a large forearc basin situated between the Aleutian trench and the active volcanic arc on the Alaska Peninsula. The Cook Inlet Planning Area overlies the forearc basin and extends from the vicinity of Redoubt volcano and Kalgin Island on the north to the southwestern reaches of Kodiak Island on the south.

The Cook Inlet Planning Area extends for nearly 300 miles along inner coast of the Gulf of Alaska. It includes the Cook Inlet itself as well as the Shelikof Straits between the Alaska Peninsula and Kodiak Island. This planning area is located adjacent to the largest population center in the State of Alaska, with its associated roads, airports, and marine harbors. The industrial center for the oil industry is on the northern Kenai Peninsula in Kenai/Nikiski.

Exploration in the Cook Inlet region began around the turn of the century on the Alaska Peninsula and continues to the present day. Oil production in the Cook Inlet region began in 1958 with the onshore Swanson River Field. From 1964–1968, 14 offshore platforms were installed in the Upper Cook Inlet, and production from State submerged lands began in 1967 (Sherwood et al., 1998).

Natural gas was first recovered as a byproduct of oil production at Swanson River Field and has been reinjected into oil reservoirs for pressure maintenance. Gas production from nonassociated gas fields began in the late 1960s. LNG was first exported to Japan from the Phillips-Marathon LNG plant in 1969. No LNG was exported in 2016. Gas infrastructure now includes: offshore and onshore pipeline networks; a (presently idled) ammonia-urea plant; electric power generation plants; and gas transmission pipelines to consumers in Anchorage and surrounding areas.

We identify four geologic plays in the Cook Inlet Planning Area, including the: Tertiary Oil Play, Tertiary Gas Play, Mesozoic Structural Play, and Mesozoic Stratigraphic Play. The quantified plays in the Federal OCS of Cook Inlet are estimated to contain a maximum of 91 pools, which include predominantly oil pools (no gas cap) with a small minority being mixed (oil and gas).

4.3.10.1 Economic Models

Exploration and development activities will take place in shallower water depths (< 600 feet) and less severe sea conditions as compared to more exposed areas facing the Pacific Ocean. In addition to the hazards associated with active volcanism and seismicity, other environmental factors are unique to the Cook Inlet province, including the strong currents associated with a large tidal flux. Tidal ranges vary from over 30 feet in the Upper Cook Inlet to 7 feet in the Shelikof Straits causing tidal currents that range up to 8 miles per hour. Special methods of anchoring and corrosion protection are required for platform legs and subsea pipelines (Visser, 1992).

Exploration drilling could be conducted year-round in the Lower Cook Inlet, as seasonal sea ice is generally confined to the Upper Cook Inlet. Drilling rig types would depend primarily on water depths. In shallow water (< 150 feet), jack-up rigs would likely be selected. For deeper waters, semisubmersible rigs are likely to be employed.

Production platforms in shallow water (< 150 feet) will likely be steel jacket or monotower designs, similar to those in Upper Cook Inlet. For deeper water sites (150–600 feet), various types of floating platforms or tension-leg structures could be used. These platforms are likely to contain storage tanks and have offshore loading capabilities at isolated fields. It is possible that heavy-duty semisubmersibles could be used as production platforms. Subsea templates connected by flowlines to nearby production platforms may be used to develop small satellite fields. A 125-mile subsea trunkline was used to gather oil from scattered prospects to existing facilities on the Kenai Peninsula. We assume that pipelines will not be trenched but would be coated and weighted to counteract corrosion and strong bottom currents.

Declining oil and gas production from existing Cook Inlet fields, combined with an increasing consumer market, suggest that future production from this province will be utilized by the local Alaska market. Local marketing could improve the viability of both gas and oil development by eliminating higher transportation costs to distant outside markets. However, the market price for oil in the Cook Inlet will continue to be largely regulated by the price for North Slope crude.

4.3.11 Gulf of Alaska Planning Area

The Gulf of Alaska Planning Area includes an 850-mile long segment of the Alaska continental margin from near the southwest tip of the Kenai Peninsula on the west to Dixon Entrance at the U.S.-Canadian border on the southeast (**Figure 11**). It extends from the 3-mile limit seaward to approximately the areas where water depths reach 3,300 feet. The continental shelf ranges in width from less than 15 miles adjacent to Baranof Island in the southeast to more than 60 miles near Middleton Island in the west.

Exploration in the uplands near the Gulf of Alaska began northwest of Kayak Island in 1901, with 44 wells drilled in the Katalla oil field and nearby areas by 1932. The shallow wells were drilled around surface oil seeps. They produced high quality oil at low flow rates from a fractured-rock reservoir. Production in the Katalla district yielded only about 154,000 Bbo before production stopped in 1933. Over the next 30 years, 23 additional exploratory wells were drilled onshore in the area extending from north of Kayak Island to about 60 miles southeast of Yakutat Bay. None yielded producible quantities of hydrocarbons.

Twelve exploratory wells were drilled in Federal waters following OCS lease sales. Eleven of the wells were completed between Kayak Island and Icy Bay in 1977 and 1978. Exploration of the Gulf of Alaska shelf finally concluded with the drilling of the ARCO Y-0211 Yakutat No.1 well offshore south of Yakutat Bay in 1983. None of the offshore wells encountered significant quantities of pooled hydrocarbons.

The Gulf of Alaska Planning Area includes five assessed geologic plays that reflect the tectonic and stratigraphic histories of the diverse terranes that underlie the Gulf of Alaska shelf. These plays are the: Middleton Fold and Thrust Belt Play; Yakataga Fold and Thrust Belt Play; Yakutat Shelf-Basal Yakataga Formation Play; Yakutat Shelf-Kulthieth Sands Play; and Subducting Terrane Play. The five quantified plays in the Gulf of Alaska are estimated to contain a maximum of 139 pools which include predominantly mixed pools (oil and gas) with a minority fraction of gas pools.

4.3.11.1 Economic Factors

The Gulf of Alaska province was modeled for the production of both gas and oil, and although no production infrastructure exists in the Gulf of Alaska, oil will drive initial development. Subsea pipelines would connect offshore platforms to onshore facilities constructed near Yakutat, although floating production storage and offloading (FPSO) vessels may be a more economical option to produce remote oil fields in the province. Crude oil and condensate from gas would be loaded on tankers and transported to refineries in the U.S. West Coast. Considering the long distance to natural gas markets, LNG would be the most efficient gas transportation strategy. It may be more economically viable to produce the more remote gas fields with a FLNG vessel.

Environmental hazards can be grouped into two categories: one related to oceanography (violent storms, high waves, freezing spray, strong currents) and the other related to tectonic activity (seismicity, volcanism, tsunamis). Exploration drilling could be conducted year-round, but rig towing during fall and winter months would be avoided. Production platform types will largely depend on water depth, with gravity-based structures in shallow water (< 300 feet) and floating platforms (buoy-shaped, tension-leg, or moored semisubmersibles) in deeper water. Subsea templates are likely to be installed for production, with subsea flowlines connected to platforms in shallower water.

4.4 Assessment Results

Estimates of the total volume of UTRR and of the portion of those resources that may be economically recoverable under various economic scenarios are developed in the Alaskan OCS at the play level (**Table 4**) and aggregated to the planning area (**Table 5**), OCS region, and national level. Based on this assessment, the total volume of UTRR oil on the Alaska OCS is estimated to range from 19.09 to 37.43Bbo with a mean estimate of 27.28 Bbo (**Table 5**). The total volume of UTRR gas is estimated to range from 96.76 Tcf to 167.98 Tcf with a mean estimate of 131.55 Tcf. The mean volume of UTRR on a combined basis (oil and gas, equivalent energy) in the Alaskan OCS is 50.70 BBOE.

The fraction of UTRR that is estimated to comprise UERR varies based on several assumptions beyond those implicit in the calculation of geologic resources, including commodity price environment, cost environment, and relationship of gas price to oil price. In general, larger volumes of resources are estimated to be economically recoverable under more favorable economic conditions. **Table 6** provides UERR for the 11 different planning areas of the Alaska OCS over a price spectrum that ranges from \$30/barrel to \$160/barrel and assumes a 30 percent value of gas price to oil. The price-supply curve in **Figure 12** graphically shows the modeled increase in UERR oil and gas as commodity price increases.

Table 4. Risked UTRR for the Alaksa OCS Region by play.

Planning Area	Region / Play	Oil (Bbo) 95%	Oil (Bbo) Mean	Oil (Bbo) 5%	Gas (Tcf) 95%	Gas (Tcf) Mean	Gas (Tcf) 5%	BOE (Bbo) 95%	BOE (Bbo) Mean	BOE (Bbo) 5%
	Alaska (OCS)	**19.09**	**27.28**	**37.43**	**96.76**	**131.55**	**167.98**	**36.30**	**50.70**	**67.32**
Beaufort Shelf	Undeformed Pre-Miss. Basement	0.00	0.02	0.06	0.00	0.08	0.32	0.00	0.03	0.12
	Endicott	0.03	0.26	0.80	0.07	0.52	1.57	0.05	0.35	1.08
	Lisburne	0.00	0.14	0.69	0.00	0.22	0.98	0.00	0.18	0.86
	Upper Ellesmerian	0.27	1.25	2.93	0.51	2.28	5.40	0.37	1.66	3.89
	Rift	0.00	0.80	2.44	0.00	2.00	4.80	0.00	1.16	3.30
	Brookian Faulted Western Topset	0.00	0.24	0.98	0.00	2.09	7.03	0.00	0.61	2.23
	Nanushuk Topset Clinothem	0.01	1.08	4.33	0.18	0.68	1.89	0.04	1.21	4.67
	Brookian Faulted Western Turbidite	0.00	0.06	0.20	0.00	0.97	3.46	0.00	0.23	0.81
	Torok Turbidite Clinothem	0.00	0.15	0.52	0.00	0.21	0.63	0.00	0.18	0.63
	Brookian Faulted Eastern Topset	0.00	1.05	3.05	0.00	9.99	22.86	0.00	2.83	7.11
	Brookian Unstructured Eastern Topset	0.10	0.58	1.44	0.07	0.34	0.76	0.12	0.64	1.58
	Brookian Faulted Eastern Turbidite	0.00	0.24	0.58	0.00	3.94	9.96	0.00	0.94	2.35
	Brookian Unstructured Eastern Turbidite	0.00	0.12	0.39	0.00	0.25	0.79	0.00	0.17	0.53
	Brookian Foldbelt	0.00	2.90	7.63	0.00	4.16	11.35	0.00	3.65	9.65
Cook Inlet	Tertiary - Oil	0.00	0.34	0.97	0.00	0.13	0.38	0.00	0.36	1.03
	Mesozoic - Stratigraphic	0.00	0.35	1.11	0.00	0.16	0.51	0.00	0.38	1.20
	Mesozoic - Structural	0.06	0.33	0.77	0.03	0.15	0.35	0.06	0.35	0.83
	Tertiary - Gas	0.00	0.00	0.00	0.00	0.77	2.25	0.00	0.14	0.40
Chukchi Sea	Endicott - Chukchi Platform	0.00	2.63	6.22	0.00	12.35	26.35	0.00	4.83	10.91
	Endicott - Arctic Platform	0.00	0.03	0.15	0.00	0.49	2.07	0.00	0.12	0.52
	Lisburne	0.00	0.12	0.52	0.00	0.54	2.34	0.00	0.21	0.93
	Ellesmerian - Deep Gas	0.00	0.02	0.09	0.00	0.98	3.54	0.00	0.20	0.72
	Sadlerochit - Chukchi Platform	0.17	0.60	1.25	1.08	4.34	9.18	0.36	1.38	2.88
	Sadlerochit - Arctic Platform	0.00	0.74	2.19	0.00	4.67	15.41	0.00	1.57	4.93
	Rift - Active Margin	1.21	3.89	7.97	4.15	13.24	27.71	1.95	6.25	12.90
	Rift - Stable Shelf	0.27	2.01	5.74	1.42	9.99	28.68	0.52	3.79	10.84
	Rift - Deep Gas	0.00	0.01	0.03	0.00	0.24	1.17	0.00	0.05	0.24
	L. Brookian Foldbelt	0.62	1.46	2.63	3.46	7.85	13.73	1.24	2.85	5.08
	L. Brookian Wrench Zone - Torok Turbidites	0.03	0.23	0.60	0.14	1.50	4.22	0.05	0.50	1.35
	L. Brookian Wrench Zone - Nanushuk Topset	0.00	0.16	0.65	0.00	0.91	3.56	0.00	0.32	1.28
	Brookian North Chukchi High - Sand Apron	0.00	0.66	2.45	0.00	4.47	16.06	0.00	1.46	5.31
	L. Brookian N Chukchi Basin - Topset	0.00	0.14	0.42	0.00	1.57	5.26	0.00	0.41	1.36
	Brookian - Deep Gas	0.00	0.01	0.07	0.00	0.46	2.62	0.00	0.09	0.53
	L. Brookian - Torok-Arctic Platform	0.00	0.08	0.19	0.00	0.34	0.85	0.00	0.14	0.34
	L. Brookian - Nanushuk Arctic Platform	0.02	0.38	1.07	0.06	0.75	2.07	0.03	0.51	1.44
	U. Brookian - Sag Phase-North Chukchi Basin	0.00	0.01	0.07	0.00	0.06	0.38	0.00	0.02	0.13
	U. Brookian - Tertiary Turbidites-North Chukchi Basin	0.00	0.02	0.10	0.00	0.27	1.09	0.00	0.07	0.29
	U. Brookian - Tertiary Fluvial Valleys	0.00	1.01	3.55	0.00	3.39	11.15	0.00	1.61	5.53
	U. Brookian - Intervalley Ridges	0.00	0.32	0.92	0.00	0.52	1.16	0.00	0.41	1.13
	Franklinian-Northeast Chukchi Basin	0.00	0.11	0.46	0.00	1.28	5.08	0.00	0.33	1.36
	L. Brookian - Nuwuk Basin	0.00	0.23	0.90	0.00	1.90	7.55	0.00	0.57	2.25
	U.Brookian - Nuwuk Basin	0.00	0.44	1.57	0.00	3.13	11.64	0.00	1.00	3.64
	Hope - Late Sequence (HB Play 1)	0.00	0.03	0.13	0.00	0.60	2.73	0.00	0.13	0.62
	Hope - Early Sequence (HB Play 2)	0.00	0.02	0.10	0.00	0.59	2.55	0.00	0.13	0.56
	Hope - Shallow Basal Sands (HB Play 3)	0.00	0.01	0.05	0.00	0.34	1.39	0.00	0.07	0.30
Gulf of Alaska	Middleton Fold and Thrust Belt	0.00	0.01	0.06	0.00	0.41	1.75	0.00	0.09	0.37
	Yakataga Fold and Thrust Belt	0.00	0.12	0.45	0.00	0.76	2.89	0.00	0.26	0.96
	Yakutat Shelf- Basal Yakataga Formation	0.00	0.11	0.38	0.00	0.61	2.10	0.00	0.22	0.75
	Yakutat Shelf - Kulthieth Sands	0.00	0.30	0.88	0.00	1.94	6.03	0.00	0.65	1.96
	Subducting Terrane	0.00	0.08	0.28	0.00	0.32	1.10	0.00	0.13	0.47

Alaska Undiscovered Technically Recoverable Oil and Gas Resources

Table 4. Continued

Planning Area	Region / Play	Alaska Undiscovered Technically Recoverable Oil and Gas Resources								
		Oil (Bbo)			Gas (Tcf)			BOE (Bbo)		
		95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Hope Basin	Late Tertiary Sequence	0.00	0.09	0.34	0.00	2.07	7.99	0.00	0.46	1.76
	Early Tertiary Sequence	0.00	0.03	0.12	0.00	0.77	3.33	0.00	0.17	0.71
	Shallow Basal Sands	0.00	0.03	0.14	0.00	0.92	3.66	0.00	0.20	0.79
Navarin Basin	Miocene Basin Sag	0.00	0.03	0.14	0.00	0.16	0.80	0.00	0.06	0.28
	Late Oligocene Basin Shelf	0.00	0.08	0.34	0.00	0.60	2.45	0.00	0.19	0.77
	Oligocene Rift Subbasin Neritic Fill	0.00	0.01	0.05	0.00	0.07	0.38	0.00	0.02	0.12
	Oligocene Rift Subbasin Bathyal Fill	0.00	0.01	0.07	0.00	0.21	1.21	0.00	0.05	0.28
	Eocene Rift Onset	0.00	0.01	0.03	0.00	0.17	0.95	0.00	0.04	0.20
North Aleutian Basin	Bear Lake/Stepovak (Miocene/Oligocene)	0.00	0.41	1.18	0.00	5.59	14.46	0.00	1.40	3.75
	Tolstoi Fm. (Eocene/Paleocene)	0.02	0.12	0.28	0.40	2.50	5.69	0.09	0.57	1.29
	Black Hills Uplift - Amak Basin	0.00	0.15	0.74	0.00	0.31	1.88	0.00	0.21	1.08
	Mesozoic - Deformed Sedimentary Rocks	0.00	0.04	0.18	0.00	0.02	0.08	0.00	0.04	0.20
	Mesozoic Basement - Buried 'Granite Hills'	0.00	0.03	0.12	0.00	0.21	1.17	0.00	0.07	0.33
Norton Basin	Upper Tertiary Basin Fill	0.00	0.01	0.06	0.00	0.71	3.19	0.00	0.14	0.63
	Mid-Tertiary East Subbasin Fill	0.00	0.01	0.03	0.00	0.33	1.79	0.00	0.07	0.35
	Mid-Tertiary West Subbasin Fill	0.00	0.04	0.15	0.00	1.94	7.90	0.00	0.38	1.55
	Lower Tertiary Subbasin Fill	0.00	<0.01	0.01	0.00	0.07	0.39	0.00	0.01	0.08
St. George Basin	Graben	0.00	0.08	0.23	0.00	0.86	2.64	0.00	0.23	0.70
	South Platform	0.00	0.04	0.14	0.00	0.88	4.09	0.00	0.19	0.87
	North Platform	0.00	0.04	0.18	0.00	0.60	2.63	0.00	0.15	0.65
	Pribilof Basin	0.00	0.06	0.23	0.00	0.45	1.78	0.00	0.14	0.55
Shumagin	Neogene Structural Play (Shumagin)	0.00	0.01	0.05	0.00	0.49	2.04	0.00	0.10	0.42
Kodiak	Neogene Structural Play (Kodiak)	0.00	0.05	0.20	0.00	1.84	7.62	0.00	0.38	1.55

Note: Resource values are in billion barrels of oil (Bbo), trillion cubic feet of gas (Tcfg) and barrel of oil equivalents (BOE). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding.

Table 5. Risked UTRR of the Alaska OCS Region by planning area.

Region / Planning Area	Risked Undiscovered Technically Recoverable Oil and Gas Resources (UTRR)								
	Oil (Bbo)			Gas (Tcfg)			BOE (Bbo)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Alaska OCS*	**19.09**	**27.28**	**37.43**	**96.76**	**131.55**	**167.98**	**36.30**	**50.70**	**67.32**
Chukchi Sea	9.30	15.38	23.08	48.88	76.77	111.44	17.99	29.04	42.91
Beaufort Sea	4.11	8.90	13.72	13.92	27.74	43.78	6.59	13.84	21.51
Hope Basin	0.00	0.15	0.45	0.00	3.77	10.40	0.00	0.82	2.30
Navarin Basin	0.00	0.13	0.42	0.00	1.22	3.67	0.00	0.35	1.07
North Aleutian Basin	0.12	0.75	1.82	1.47	8.62	17.37	0.38	2.29	4.91
St. George Basin	0.00	0.21	0.57	0.00	2.80	6.69	0.00	0.71	1.76
Norton Basin	0.00	0.06	0.17	0.00	3.06	9.65	0.00	0.60	1.89
Cook Inlet	0.25	1.01	2.01	0.50	1.20	1.97	0.34	1.23	2.36
Gulf of Alaska	0.13	0.63	1.45	0.71	4.04	9.23	0.25	1.34	3.09
Shumagin	0.00	0.01	0.05	0.00	0.49	2.04	0.00	0.10	0.42
Kodiak	0.00	0.05	0.20	0.00	1.84	7.62	0.00	0.38	1.55

*The Aleutian Arc, Aleutian Basin, Bowers Basin, and St. Matthew-Hall planning areas of the Alaska OCS region were not evaluated in this study as their petroleum potential is negligible.

Note: Resource values are in billion barrels of oil (Bbo), trillion cubic feet of gas (Tcfg) and barrel of oil equivalents (BOE). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding.

Table 6. Risked mean-level UERR of the Alaska OCS Region by planning area.

Region / Planning Area	Risked Undiscovered Economically Recoverable Oil and Gas Resources (UERR)											
	$30/Bbl		$40/Bbl		$60/Bbl		$100/Bbl		$110/Bbl		$160/Bbl	
	$1.60/Mcf		$2.14/Mcf		$3.20/Mcf		$5.34/Mcf		$5.87/Mcf		$8.54/Mcf	
	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas
Alaska OCS*	**0.68**	**0.26**	**2.12**	**1.16**	**8.38**	**9.36**	**17.29**	**33.59**	**18.57**	**38.59**	**22.00**	**60.43**
Chukchi Sea	0.00	0.00	0.07	0.06	2.87	4.25	9.25	22.58	10.20	26.36	12.61	40.63
Beaufort Sea	0.07	0.03	1.02	0.66	4.01	4.15	6.08	8.09	6.33	8.80	7.09	12.64
Hope Basin	0.00	0.00	0.01	0.02	0.04	0.08	0.06	0.17	0.06	0.20	0.08	0.90
Navarin Basin	0.00	0.00	0.00	0.00	0.02	0.03	0.05	0.12	0.05	0.16	0.07	0.30
North Aleutian Basin	0.14	0.05	0.33	0.13	0.46	0.22	0.51	0.34	0.52	0.38	0.55	0.86
St. George Basin	0.00	0.00	0.02	0.02	0.07	0.07	0.10	0.15	0.11	0.17	0.13	0.66
Norton Basin	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.40
Cook Inlet	0.62	0.25	0.81	0.33	0.94	0.40	0.98	0.77	0.99	0.84	1.00	1.03
Gulf of Alaska	0.00	0.00	0.00	0.01	0.07	0.20	0.31	1.62	0.36	1.93	0.47	2.73
Shumagin	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
Kodiak	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.05	0.02	0.54

Note: Resource values are in billion barrels of oil (Bbo) and trillion cubic feet of gas (Tcfg). Some total mean values may not equal the sum of the component values due to independent rounding. Prices are in dollars per barrel($/Bbl) for oil, and dollars per thousand cubic feet ($/Mcf) for gas. This table represents a gas price adjustment of 0.3.

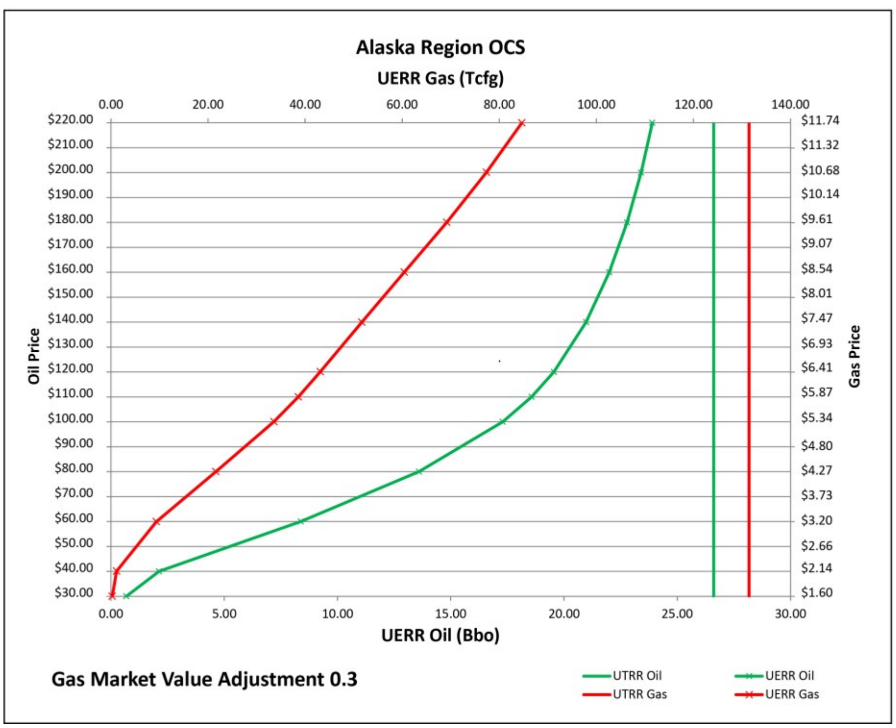


Figure 12. Price-supply curve for the Alaska OCS Region.

5 ATLANTIC OUTER CONTINENTAL SHELF REGION

A full and complete description of the 2016 Atlantic OCS assessment of undiscovered resources is available in OCS Report BOEM 2016-071 (Post et al., 2016). The discussion below, at times, provides a summary of the more detailed information found in Post et al. (2016).

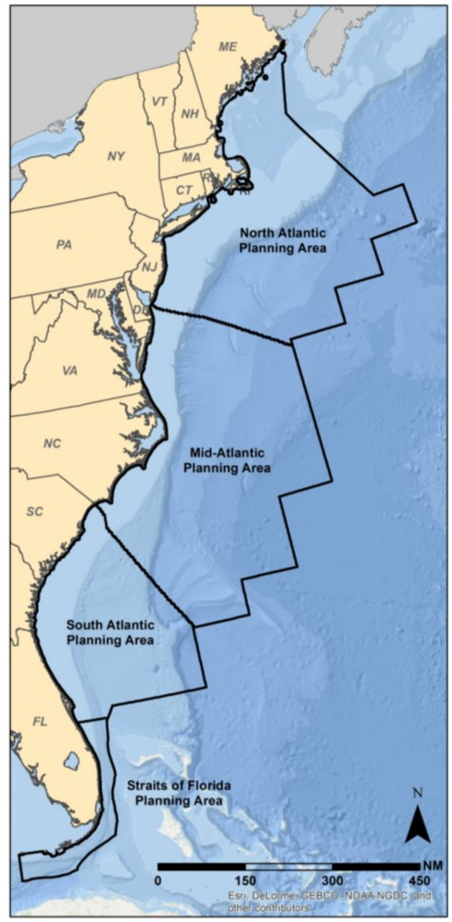


Figure 13. Planning areas for the Atlantic OCS Region.

5.1 Location and Geologic Setting

The Atlantic OCS Region is located on the eastern margin of the U.S (**Figure 13**). It extends from the Canadian province of Nova Scotia (northeast) to The Bahamas (southwest), a distance of approximately 1,150 miles. The Atlantic OCS Region is divided into four planning areas: North Atlantic, Mid-Atlantic, South Atlantic, and the Straits of Florida. For the 2016 Assessment, the Straits of Florida Planning Area is considered to be in the GOM regional summary as Gulf of Mexico-based geologic plays extend into that Planning Area. Water depths on the Atlantic OCS range from less than 30 feet to greater than 15,000 feet.

The Atlantic OCS Region began to form during the Late Triassic breakup of western Pangea, which was characterized by widespread continental rifting throughout the region (Iturralde-Vinent, 2003; Withjack and Schlische, 2005). Subsequent drifting apart of the North American and African conjugate margins resulted in the sea floor spreading and opening of the current Atlantic Ocean. The geology and resource assessments of the region reflect the geometry and transition from the early, complex rift system to the present-day passive margin (Withjack and Schlische, 2005; Sheridan, 1987). A series of post-rift sedimentary depocenters of Early Jurassic-recent age developed along the region. From northeast to southwest these are the Georges Bank Basin, Baltimore Canyon Trough, Carolina Trough, and Blake Plateau Basin. The depocenters and their sedimentary sections vary in size, shape, and thickness.

5.2 Exploration and Discovery Status

As of December 2016, there had been no commercial hydrocarbon production from the waters of the U.S. Atlantic OCS. Significant oil and gas exploration activity occurred from the late 1960s to the mid-late 1980s, when approximately 239,000 line miles of 2D seismic data were acquired, processed, and interpreted. In 1982, a "pseudo" 3D survey was acquired over a four-block area centered on the Hudson Canyon (HC) Block 598 area in the Baltimore Canyon Trough. The BOEM seismic data set in the Atlantic OCS consists of approximately 170,000 line miles of 2D data, approximately 12,400 line miles of reprocessed reflection seismic data, and approximately 185,000 line miles of depth-converted, time-migrated data.

On the U.S. Atlantic OCS, excluding the Straits of Florida Planning Area, nine lease sales were held from 1976–1983 where 410 leases covering 2,334,198 acres were acquired. Fifty-one (51) wells were drilled, including five COST wells drilled between 1975 and 1979 and 46 industry wells drilled between 1978 and 1984.

A single gas discovery was made in the HC Block 598 area (comprising blocks HC 598, HC 599, HC 642, and HC 643). All eight wells drilled in this four OCS block area had hydrocarbon shows; six were successfully drillstem tested and flowed gas. The discovery was made in approximately 450 feet of water off the coast of New Jersey in the Baltimore Canyon Trough. The trapping mechanism is a seismically defined anticlinal structure bounded on its updip side by a listric down-to-the-basin fault. Because most of the drillstem test rates were variable, often declining over time, and test interpretation indicated reservoir compartmentalization, the leases were relinquished prior to attempting any commercialization of the area.

5.3 Engineering and Technology

There are no apparent engineering or technology issues that would limit exploration and production in the Atlantic OCS Region. Current drillship capabilities allow drilling in 12,000 feet of water to subsea depths of 40,000 feet. Production technology has been proven in extreme water depths in the GOM, where the Perdido Spar facility is moored in approximately 8,000 feet of water and an FPSO system is used at the Stones field in approximately 9,500 feet of water. Also in the GOM, deepwater subsea completion technology has been proven in over 9,000 feet of water. All of these technologies are fully transferrable to the potential oil and gas provinces of the Atlantic OCS, and their use is incorporated in this assessment. As there is currently no hydrocarbon production in the onshore Atlantic coastal region or offshore, the Atlantic OCS would require new construction of pipelines and processing facilities.

5.4 Methodology

The BOEM resource assessment methodology for the Atlantic OCS follows the approach described in the Chapter 2 (METHODOLOGY) and includes a full petroleum systems analysis of geological and geophysical data available to BOEM. These data include a robust seismic reflection database, gravity and magnetics data, subsurface well information from existing U.S. and Nova Scotian drilling, and geochemical data and sea surface slicks identified on satellite synthetic aperture radar data. Unlike other U.S. OCS Regions, the Atlantic OCS does not have any commercial oil or gas production, and we recognize the subjectivity of assessing undiscovered resources in this region by developing "conceptual" AUs. Local data are supplemented by information derived from a database of global analogs that provide appropriate guidance for potential field sizes and hydrocarbon volumes.

AUs can be proven or conceptual based on the documented occurrence or postulation of the petroleum system. When properly defined, all discovered and undiscovered accumulations in an AU represent a statistically coherent population that can be assigned common probabilities of occurrence for each petroleum system element and process.

In the Atlantic OCS, we identify and assess a total of ten AUs. Nine of the AUs are conceptual in nature and include some chance of petroleum system failure. One of the AUs is considered to be proven based on the gas encountered and tested by wells in the HC 598 area.

5.5 Analogs

Due to the lack of oil and gas field data on the Atlantic OCS margin, the BOEM assessment of undiscovered resources relies on information derived from accumulations found in analogs around the world. Analogs considered appropriate for this U.S. Atlantic resource inventory are selected based on similar or equivalent tectonic or structural setting with comparable petroleum system elements, including source, reservoir, seal, environment of deposition, lithology, depth of burial, diagenetic history, porosity and permeability, and trap type. The geologic age of the target reservoir in the Atlantic AUs is not always the same as the analog reservoir age.

Though regional plate tectonic restorations focus the analog investigation on conjugate Northwest Africa, our analysis identifies other areas with comparable geological setting and evolution (though not necessarily the age of the formations) to the U.S. Atlantic margin. Analogs used for this assessment are built from geologic and petroleum system analyses of areas including the conjugate Northwest African Margin, South Viking Graben of the U.K. North Sea, West African Margin and its conjugate South American Transform Margin, and the East African Transform Margin. In nearly all cases, the primary source of information is literature-based research that enables a working characterization of the analog AU petroleum system elements and processes, as well as a quantification of any associated discovered reserves and resources.

Since 2007, giant oil and gas fields in our analog database with reserves and resources of 500 MMBOE and greater have been discovered. The number of discoveries, and the large associated volumes in those discoveries, increased the reserves and resources in these analogs from an estimated 4.5 BBOE in 2007 to over 36 BBOE at the January 1, 2014 cutoff date for this resource inventory.

5.6 Risk

The BOEM assessment model allows for the introduction of geologic risk at two levels. At the highest level, we assign a petroleum system risk on conceptual AUs to account for the possibility that some or all of the petroleum system elements or processes may fail. Consequently, we quantitatively assess the probability of occurrence of petroleum system elements (source, reservoir, seal, and overburden rocks) and processes (trap formation, the generation-expulsion-migration-accumulation of petroleum, and preservation). The presence and/or occurrence of petroleum system elements and processes are determined, and their probability of occurrence constrained, by regional geological and geophysical data.

For the petroleum systems analysis of AUs in the Atlantic, BOEM employs a risking methodology that allows only three probabilities to be assigned based on “definitely exists (high)” or 1.0; “probably exists (medium)” equivalent to 0.75; and “may or may not exist (low)” or 0.50. There are a total of seven petroleum system elements and processes. For the single proven AU in the Atlantic OCS, we assign a petroleum system probability of 1.0, meaning that no risk is associated with the occurrence of the petroleum system.

The second component of geologic risk is applied at the prospect level. Prospect risk addresses risk scenarios applicable to the probabilities of success on an individual prospect, including hydrocarbon fill, reservoir, and trap components. Prospect risk is applied to all prospects in all AUs, regardless of any risks/probabilities associated with petroleum system elements and processes. For the prospect risk of each AU, we round the quantitative assessment to values of either 0.10, 0.20, or 0.30. This represents a probability of success of 10%, 20%, and 30%, respectively.

By risking conceptual AUs with petroleum system and prospect probabilities of occurrence, we acknowledge the multiple risks on both. However, if the petroleum system in a conceptual BOEM AU becomes proven (with or without commercial success), the petroleum system risk in that AU would be eliminated, as is the case in the single proven AU, the Cretaceous & Jurassic Interior Shelf Structure AU. This would result in a significant increase in assessed undiscovered resources; these potentially higher values are not reflected in this assessment.

5.7 Field Size Distribution

For every AU, we introduce into the BOEM assessment model a distribution that includes the expected number of undiscovered pools and a distribution that identifies the possible size of those accumulations.

The number of undiscovered pools in each AU is based on information assembled from the analysis of the analogs. A density of undrilled prospects for each AU is established based on the exploration history and results (number of new field wildcat wells, areal size, and number of discoveries, etc.) in each analog area. The maturity of the analog is taken into consideration, and adjustments are made to the undiscovered pool density of the Atlantic AUs when the analog is considered immature.

The BOEM assessment methodology incorporates a lognormal distribution assumption to generate the field/pool size distribution for each AU. The lognormal distribution is constrained by two single value parameters, the mean and the variance. The mean is a statistical measure of central tendency of the field/pool sizes in which the logarithms of the variables are normally distributed. The variance is a measure of the amount of spread in the data. Because the theoretical limit of the lognormal distribution is infinite in both directions, we truncate the distribution to represent a realistic state of nature. The lognormal distribution is restricted by geologic constraints and interpretations that are applied to each AU to create a reasonable high and low boundary for the field/pool sizes predicted in the modeling process. The smallest field/pool size considered for this assessment is 1.0 MMBOE. All smaller fields/pools are removed from the distribution. The largest field/pool size in the distribution of inventoried resources in the AU is truncated at the largest field/pool size in the analog distribution.

Field size distributions for AUs in the Atlantic are developed using all available information related to the relevant analog fields and basins. We use available publications, including company or analyst presentations, to estimate the areal extent of each analog discovery and, where possible, the size of each prospect tested and found to be dry, non-productive, or not commercially viable.

5.8 Assessment Units

Within the Atlantic Region, nine conceptual AUs and one established AU have been identified and their resources inventoried. Water and drilling depths in these plays range from less than 100 feet to greater than 10,000 feet and from 7,000 feet to more than 30,000 feet, respectively.

5.8.1 Cretaceous & Jurassic Marginal Fault Belt

The undrilled Cretaceous & Jurassic Marginal Fault Belt conceptual AU is confined to the Mid-Atlantic Planning Area occurring in a seismically defined area of ~8,500 square miles. The AU is in the updip region of the Carolina Trough, where water depths range from approximately 1,000–4,000 feet. Anticipated reservoirs are siliciclastics and carbonates in rollover structures, fault traps, or combination structural-stratigraphic traps. Productive analogs similar to seismically identified features in the AU are located in the updip areas of the onshore GOM Mesozoic basins of East Texas, South Arkansas, and Mississippi-Alabama-Florida.

5.8.2 Cenozoic–Cretaceous & Jurassic Carolina Trough Salt Basin

The conceptual Cenozoic–Cretaceous & Jurassic Carolina Trough Salt Basin AU is located downdip (basinward) from the Cretaceous & Jurassic Marginal Fault Belt AU. This AU is undrilled and covers an area of approximately 5,700 square miles that is entirely within the Mid-Atlantic Planning Area. Present-day water depths in this AU range from approximately 8,000 feet to greater than 9,000 feet. Siliciclastic reservoirs are interpreted to be the primary targets, although carbonates deposited in high-energy environments may also occur. We interpret vertical salt movement to provide cross-stratal migration conduits connecting deeper, mature oil and gas source rocks with younger reservoirs.

5.8.3 Late Jurassic–Early Cretaceous Carbonate Margin

In the U.S. Atlantic OCS, seismic data and a limited number of wells suggest that the conceptual Late Jurassic–Early Cretaceous Carbonate Margin AU (a continuation of a prospective area offshore Nova Scotia) is a geographically narrow band that typically averages less than 10 miles wide. This AU covers an area of ~12,000 square miles in water depths from ~3,500–6,500 feet. The primary analog field for this AU is Deep Panuke, a 1999 natural gas discovery on the shallow water shelf offshore Nova Scotia. Wells in the Deep Panuke reservoir contain 33–330 feet of dry gas pay, with resources estimated to range between ~400 BCFG and 1.4 TCFG. Limited exploration for equivalent carbonates has also taken place offshore Morocco and resulted in a single oil discovery.

5.8.4 Cenozoic–Cretaceous & Jurassic Paleo-Slope Siliciclastic Core and Extension

The Cenozoic–Cretaceous & Jurassic Paleo-Slope Siliciclastic Core AU is located in the North and Mid-Atlantic Planning Areas. The more distal Cenozoic–Cretaceous & Jurassic Paleo-Slope Siliciclastic Extension AU is recognized in the North, Mid-, and South Atlantic Planning Areas. Both AUs are conceptual in nature, and both represent siliciclastic depositional systems downdip of their youngest equivalent carbonate margin. These are the most basinward AUs of the U.S. Atlantic OCS. Present-day water depths for these AUs range from approximately 4,500–8,000 feet (core) to approximately 8,500–10,500 feet (extension). Reservoir facies are interpreted to comprise coarse-grained lithofacies of siliciclastic turbidites and mass flow deposits on the paleo-slope and basin floor.

Analogs for the Core AU include Jurassic age siliciclastic reservoirs of the South Viking Graben of the U.K. North Sea, Cretaceous age reservoirs of deepwater fields of the Tano basin (offshore Ghana and Côte d'Ivoire) and the Sierra-Leone-Liberian basin (offshore Sierra Leone & Liberia), and the Woodbine fields of the southern part of the onshore East Texas basin. Analog fields for the Extension AU are found in the South Viking Graben, the West African, South American, and East African Transform Margin, and the onshore Texas downdip Woodbine. The analog fields for the Core and Extension AUs have a combined reserve/resource volume that exceeds 30 BBOE.

5.8.5 Cretaceous & Jurassic Blake Plateau Basin

The conceptual Cretaceous & Jurassic Blake Plateau Basin AU comprises the undrilled Blake Plateau basin downdip from the Southeast Georgia Embayment, an area of approximately 38,000 square miles. Water depths over this AU range between 2,000 and 3,600 feet. Global analog fields include the South Florida Basin onshore Florida and the Paris basin, though exploration success rates and reserves per discovery are low in both analog basins. Importantly, we believe that the hydrocarbon source rocks in the Blake Plateau basin are more likely to be oil-prone than many other areas of the Atlantic OCS based on analog source rocks in similar depositional environments.

5.8.6 Jurassic Shelf Stratigraphic

The conceptual Jurassic Shelf Stratigraphic AU is updip from the Late Jurassic–Early Cretaceous Carbonate Margin AU, and covers an area of approximately 10,000 mi² in approximately 200–2,600 feet of water. The Jurassic Shelf Stratigraphic AU is divided into two areas separated along strike by the structures of the Cretaceous & Jurassic Interior Shelf Structure AU. No wells on the OCS have been drilled to specifically target the Jurassic Shelf Stratigraphic AU.

The AU reservoirs likely comprise limestones and/or dolomites and are expected to be similar to the onshore GOM analog fields, including Walker Creek (Arkansas), Oaks (Louisiana), and Little Cedar Creek (Alabama). The hydrocarbon source component in this AU is considered probable, but is unproven as wells drilled along trend often lack hydrocarbon shows.

5.8.7 Cretaceous & Jurassic Interior Shelf Structure

The Cretaceous & Jurassic Interior Shelf Structure AU occurs over an area of approximately 3,400 mi² in the Baltimore Canyon Trough in water depths ranging from 150 to 3,000 feet. This is the only proven or established AU (one in which the petroleum system is confirmed) in the U.S. Atlantic OCS. It is confined to an area of generally listric, down-to-the-basin faulting and associated compensating faults of the "Gemini Fault System" (Poag, 1987).

These faults provide migration conduits that facilitate the movement of hydrocarbons generated and expelled from mature older Jurassic age source rocks into siliciclastic reservoirs of younger Jurassic and Cretaceous age and that form structural traps for these hydrocarbons (Prather, 1991; Sassen and Post, 2008; Sassen, 2010). This AU was targeted by 14 wildcat wells drilled between 1978 and 1981, resulting in a single gas condensate discovery in the HC 598 area.

5.8.8 Triassic–Jurassic Rift Basin

The conceptual Triassic–Jurassic Rift Basin AU comprises an area of ~4,500 square miles adjacent to the Georges Bank basin in the North Atlantic Planning Area. Water depths over this AU range from ~150 to 800 feet.

At least 30, and possibly as many as 50, analogous Triassic–Jurassic rift basins are documented in the onshore eastern U.S. Between 1890 and 1998, 80 wells were drilled for oil and gas exploration in these basins with some type of reported oil and/or gas show reported in 27 (34%) of the wells. However, no economic conventional oil and gas or coalbed methane accumulations have been found (Coleman et al., 2015; Post and Coleman, 2015). Productive analogs are found in the Vulcan Graben of offshore NW Australia, where Triassic and Jurassic siliciclastic reservoirs contain resources estimated to range between ~2 and 300 MMBOE per field/discovery.

5.8.9 Cretaceous & Jurassic Hydrothermal Dolomite

The conceptual Cretaceous & Jurassic Hydrothermal Dolomite AU is located in the northern part of the Georges Bank basin in the North Atlantic Planning Area. The AU is interpreted to occur over an area of ~1,500 square miles, in water depths that range from ~100 to 1,100 feet. This AU is associated with the crest and northwest flank of the Yarmouth Arch geological feature. Because the AU is undrilled, the petroleum system elements and processes are interpretive and speculative. Although source rocks have not been directly confirmed, satellite-identified sea surface slicks suggest source rocks exist, and that generation-expulsion-migration have occurred or are occurring. Cretaceous & Jurassic Hydrothermal Dolomite AU reservoirs include hydrothermal dolomitization associated with the upward circulation of deeper, hotter fluids along fault systems. Albian-Scipio, the largest oil field in the Michigan basin, and similar fields in the Michigan and Appalachian basin, are considered analogs for this AU. Reserves for analog fields for this AU range from less than 1 MMBOE to 500 MMBOE.

5.9 Assessment Results

Estimates of the total volume of UTRR, and of the portion of those resources that may be economically recoverable under various economic scenarios, are developed at the AU level (**Table 7**) and aggregated to the planning area (**Table 8**), OCS Region, and national level. For summary reporting in the OCS-wide National Assessment report (all regions), results are tabulated for the planning areas, so that they may be used for planning needs in developing the National OCS Oil and Gas Leasing Program. Based on this assessment, the total volume of UTRR oil is estimated to range from 1.15 to 9.19 Bbo with a mean estimate of 4.59 Bbo. The total volume of UTRR gas is estimated to range from 12.80 Tcf to 68.71 Tcf with a mean estimate of 38.17 Tcf. On a combined basis, the mean volume of UTRR oil and gas resources in the Atlantic OCS is 11.39 BBOE.

The total volume of UTRR that are estimated to be UERR varies based on several assumptions, including commodity price environment, cost environment, and relationship of gas price to oil price.

Larger volumes of resources are estimated to be economically recoverable under more favorable economic conditions. **Table 9** provides UERR for the North, Mid-, and South Atlantic OCS Planning areas over a price spectrum that ranges from \$30/barrel to \$160/barrel and assumes a 30 percent value of gas price to oil price.

Estimates of UERR are presented as price-supply curves for the Atlantic OCS Region in **Figure 14**. A price-supply curve shows the relationship of price to economically recoverable resource volumes (i.e., a horizontal line from the price axis to the curve yields the quantity of economically recoverable resources at the selected price). The price-supply charts contain two curves and two price scales, one for oil (green) and one for gas (red); the curves represent mean values at any specific price.

Table 7. Risked UTRR for assessment units in the Atlantic OCS Region.

Region	2016 Atlantic Undiscovered Technically Recoverable Oil and Gas Resources (UTRR)								
	Oil (Bbo)			Gas (Tcf)			BOE (Bbo)		
Assessment Unit	0.95	Mean	0.05	0.95	Mean	0.05	0.95	Mean	0.05
Atlantic OCS	**1.15**	**4.59**	**9.19**	**12.80**	**38.17**	**68.71**	**3.43**	**11.39**	**21.41**
Late Jurassic - Early Cretaceous Atlantic Carbonate Margin	0.00	0.23	0.97	0.00	5.21	22.57	0.00	1.15	4.98
Cretaceous & Jurassic Atlantic Marginal Fault Belt	0.00	0.24	0.75	0.00	5.44	15.31	0.00	1.21	3.48
Cenozoic - Cretaceous & Jurassic Carolina Trough Salt Basin	0.00	0.61	1.72	0.00	7.94	21.31	0.00	2.02	5.51
Jurassic Shelf Stratigraphic	0.00	0.07	0.29	0.00	1.55	6.68	0.00	0.34	1.47
Cretaceous & Jurassic Interior Shelf Structure	0.02	0.06	0.10	0.47	1.29	2.30	0.11	0.29	0.51
Cretaceous & Jurassic Blake Plateau Basin	0.00	0.33	0.87	0.00	0.46	1.21	0.00	0.41	1.09
Triassic - Jurassic Rift Basin	0.00	0.20	0.92	0.00	0.28	1.30	0.00	0.25	1.15
Cretaceous & Jurassic Hydrothermal Dolomite	0.00	0.10	0.52	0.00	0.15	0.90	0.00	0.12	0.68
Cenozoic - Cretaceous & Jurassic Paleo Slope Siliciclastic (core)	0.00	1.86	8.11	0.00	10.62	46.63	0.00	3.75	16.41
Cenozoic - Cretaceous & Jurassic Paleo Slope Siliciclastic (extension)	0.00	0.90	4.12	0.00	5.23	24.33	0.00	1.83	8.45

Note: Resource values are in billion barrels of oil (Bbo) and trillion cubic of gas (Tcfg). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding.

Table 8. Risked UTRR of Atlantic OCS Planning Areas.

Region	Risked Undiscovered Technically Recoverable Oil and Gas Resources (UTRR)								
	Oil (Bbo)			Gas (Tcfg)			BOE (Bbo)		
Planning Area	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Atlantic OCS	**1.15**	**4.59**	**9.19**	**12.80**	**38.17**	**68.71**	**3.43**	**11.39**	**21.41**
North Atlantic	0.06	1.77	5.11	1.08	11.76	32.74	0.25	3.86	10.94
Mid-Atlantic	0.10	2.41	5.54	2.13	24.63	50.03	0.48	6.79	14.44
South Atlantic	0.00	0.41	0.90	0.00	1.78	5.00	0.00	0.73	1.79

Note: Resource values are in billion barrels of oil (Bbo) and trillion cubic of gas (Tcfg). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding.

Table 9. Risked mean-level UERR for the Atlantic OCS Region by planning area.

Region / Planning Area	Risked Undiscovered Economically Recoverable Oil and Gas Resources (UERR)											
	$30/Bbl $1.60/Mcf		$40/Bbl $2.14/Mcf		$60/Bbl $3.20/Mcf		$100/Bbl $5.34/Mcf		$110/Bbl $5.87/Mcf		$160/Bbl $8.54/Mcf	
	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas
Atlantic OCS	3.21	3.64	3.47	5.06	3.76	8.41	4.00	13.00	4.03	13.81	4.15	17.22
North Atlantic	1.40	1.82	1.48	2.45	1.58	3.69	1.64	5.05	1.65	5.28	1.68	6.24
Mid-Atlantic	1.74	1.68	1.89	2.41	2.06	4.38	2.18	7.42	2.19	7.97	2.25	10.29
South Atlantic	0.08	0.14	0.09	0.20	0.12	0.35	0.18	0.52	0.19	0.56	0.22	0.69

Note: Resource values are in billion barrels of oil (Bbo) and trillion cubic feet of gas (Tcfg). Some total mean values may not equal the sum of the component values due to independent rounding. Prices are in dollars per barrel($/Bbl) for oil, and dollars per thousand cubic feet ($/Mcf) for gas. This table represents a gas price adjustment factor of 0.3.

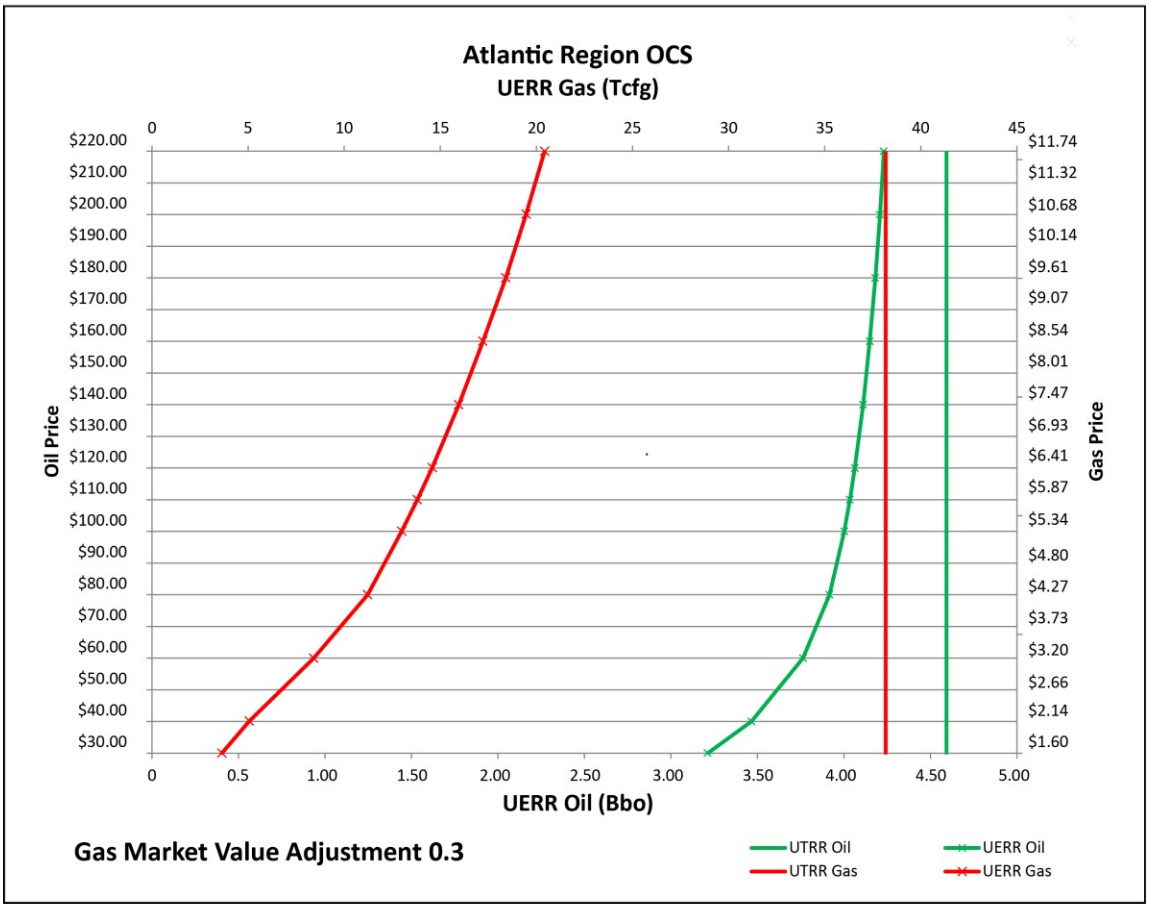


Figure 14. Price-supply curve for the Atlantic OCS Region.

6 GULF OF MEXICO OUTER CONTINENTAL SHELF REGION

A full and complete description of the 2016 Gulf of Mexico OCS assessment of undiscovered resources is available in OCS Report BOEM 2017-005. The discussion below, at times, provides a summary of the more detailed information found in OCS Report BOEM 2017-005.

6.1 Location and Geologic Setting

For the purpose of oil and gas resource assessment, the Gulf of Mexico OCS includes the Western, Central, and Eastern GOM Planning Areas and the Straits of Florida Planning Area[2]. The area extends from the U.S.-Mexico border to the narrow waters between the east coast of Florida and the Bahamian mainland. The GOM OCS shares a common maritime boundary with territorial waters of the countries of Mexico, Cuba, and the Bahamas.

The GOM Basin formed beginning in the Late Triassic to Early Jurassic Periods when Africa and South America separated from North America during the breakup of the Pangaean supercontinent (Martin, 1978; Salvador, 1987). After the initiation of rifting, a series of shallow seas formed that were periodically separated from open ocean waters. Cyclical seawater influx and evaporation precipitated thick halite accumulations known as the Louann Salt. During the Late Jurassic, the basin was permanently exposed to the open sea, changing the depositional environment to shallow marine. In these shallow seas, broad carbonate banks grew around the margins of the basin during the Cretaceous Period. Uplift of the North American continent and the ensuing Laramide Orogeny in the Late Cretaceous provided the source for large amounts of siliciclastic sand and mud that were transported to the Texas and Louisiana coastal areas by the Mississippi, Rio Grande, and other river systems throughout the Cenozoic Era. The depocenters of these rivers generally shifted from west to east and prograded north to south through time. Deposition of these gulfward prograding depocenters was interrupted repeatedly by eustatically driven marine transgressions that were accompanied by the deposition of marine shales. After these flooding events when relative sea level dropped, progradation resulted in deposition of progressively more sand-rich sediments, including thick sequences of deepwater turbidites. Late in the Cenozoic, episodes of continental glaciation provided an increased clastic sediment load to the basin, resulting in the modern Texas and Louisiana shelf and slope that are characterized by massive amounts of clastic materials. This loading and subsequent deformation of the Louann Salt throughout time created many of the regional structures that are favorable for the entrapment of hydrocarbons.

6.2 Methodology

The BOEM resource assessment methodology for the GOM OCS follows the approach described in Chapter 2(METHODOLOGY) and incorporates the analysis of geological, geophysical, engineering, and production data available to BOEM. The assessment utilizes a play-based approach, which is suitable for both conceptual plays where there is little or no

[2] For administrative purposes under the Oil and Gas Leasing Program, the Straits of Florida Planning Area is included in the Atlantic OCS Region.

specific information available and for established plays with discovered oil and gas fields and for which considerable empirical data are available. This method utilizes a strong correlation between the geologic model developed by the assessment team and information derived from oil and gas exploration activities. The assessment methodology includes developing play models, delineating the geographic limits of each play, and compiling data on critical geologic and reservoir engineering parameters. These parameters are critical inputs in the determination of the total quantities of recoverable resources in each play. In the case of Cenozoic-aged plays in the GOM, we further aggregate into AUs for modeling purposes.

BOEM maintains an inventory of over 30,000 discovered oil and gas reservoirs in the GOM that in aggregate comprise over 1,300 unique BOEM-designated oil and gas fields. The GOM reservoirs are aggregated to over 13,000 unique sands, where each sand represents the aggregation of all fault-block portions (reservoirs) of an originally continuous sandstone body. Each sand in the GOM is aggregated to the pool level; as utilized in this report, a pool is the aggregation of all sands within a field that occur in a single stratigraphic interval and in the same play. Reserves appreciation is then applied to these pool-level hydrocarbon volumes to account for growth that is expected to occur.

6.2.1 Reserves Appreciation

Estimates of the quantity of proved oil and gas reserves in a field typically increase as the field is developed and produced. This is known as reserves appreciation or reserves growth and was first reported by Arrington (1960). Root and Attanasi (1993) estimated that the growth of known fields from 1978 to 1990 in the United States accounted for 90 percent of the annual additions to domestic reserves. BOEM data for GOM OCS fields reveal that, since 1981, increases in proved reserves through appreciation have greatly exceeded new field discoveries and comprise approximately two-thirds of the total increase. Characteristically, the relative magnitude of this growth is proportionally larger in the years immediately following field discovery.

The objective of the reserves appreciation effort in this resource assessment is to incorporate field growth in the measure of past performance, forming the basis for projecting future discoveries within defined geologic plays. We use growth functions to estimate a field's size at a future date. In modeling reserves growth, the age of the field is typically used as a surrogate for the degree of field development.

Root and Attanasi (1993) reviewed the history and basic approaches traditionally employed to model reserves appreciation. The approach employed in this study was to calculate annual growth factor (AGFs) as first implemented by Arrington (1960). This technique utilizes the age of the field, as measured in years after discovery, as the variable to represent the degree of field maturity. The AGFs are calculated from the BOEM database of OCS fields with proved reserves. Several assumptions are central to this approach, including assumptions that the amount of growth in any year is proportional to the size of the field, and that the proportionality varies inversely with the age of the field. Additionally, we assume that the factors causing future appreciation will result in patterns and magnitudes of growth similar to those observed in the past.

6.3 Assessment Units and Geologic Plays

The 2016 Assessment in the GOM includes an analysis of 12 AUs of Cenozoic age and 19 geologic plays[3] of Mesozoic age. AUs include all reservoirs of a specific geologic age in a specified geographic area, whereas geologic plays are 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.

6.3.1 Cenozoic Assessment Units

For this inventory of undiscovered resources in the Cenozoic sediments of the U.S. Gulf of Mexico OCS, the geologic analyses inherent in resource assessments occur at the play level. As with past GOM assessments, each discovered reservoir in a BOEM-designated field is evaluated and assigned to a distinctive play that shares common geologic factors which influence the accumulation of hydrocarbons. The reservoirs are then aggregated to the sand level, and subsequently each sand is aggregated to the pool level. Reserves appreciation is then applied to these pool-level hydrocarbon volumes. Herein, a pool is the aggregation of all sands within a single field that occur in the same play. These Cenozoic Plays are then aggregated into AUs for modeling purposes based on geographic setting (modern shelf or modern slope; Figure 15) and geologic age. We use six major age assignments for the Cenozoic AUs: Pleistocene, Pliocene, Upper Miocene, Middle Miocene, Lower Miocene, and Lower Tertiary. The combination of geography and age results in 12 Cenozoic AUs, six on the modern shelf (shallow water) and six on the modern slope (deepwater) (**Table 10**).

Table 10. Cenozoic assessment units for the Gulf of Mexico OCS Region.

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

Aggregated AUs provide a larger population of data, which reduces uncertainty and improves forecasting. Within these AUs, hydrocarbon volumes of the specific ages that are associated with a particular oil and/or gas field are aggregated. For example, all reservoirs within a single field located on the slope that are of Middle Miocene age are combined together into a single volume, or pool. These pools are identified by the field from which they are derived (e.g., Mississippi Canyon 778—Thunder Horse). Note that a single BOEM-designated field may contain more than one pool. For this Cenozoic assessment, we utilize data from 1,755 pools on the shelf and 387 pools on the slope.

[3] Although 19 Mesozoic plays were identified for this study, the UTRR reported herein includes contributions from only 15 of those plays; the four non-assessed plays were either early stage concepts or assessed as insignificant resource volumes.

6.3.2 Cenozoic Assessment Units—Modern Shelf

The assessed subsurface area of the shelf occurs between the Federal/State boundary and the modern shelf edge (**Figure 15**). The geology of the shelf varies from west to east, as well as from near shore to the distal edge of the shelf. The offshore Texas area is characterized by a series of large, down-to-the-basin, expansion fault systems that trend parallel to the Texas coastline. The fault systems are progressively younger basinward, with successively younger strata involved in the expansion. These fault systems developed when progradational deltaic wedges and associated strandplain and barrier island sediments differentially loaded overpressured shale or salt. This loading mobilized the incompetent shale or salt into downdip shale- or salt-cored anticlines, causing extension taken up by the fault systems. The shallow sections of these fault systems have been thoroughly explored, and rollover anticlines located on the downthrown sides of the faults have been prolific gas producers from Miocene reservoirs for decades. Overall, the Texas shelf is a gas-prone province.

Farther east, the Louisiana shelf is characterized by a series of down-to-the-basin, listric, normal fault-related trends that generally become younger basinward. For example, the inner shelf is dominated by Miocene sediment, the middle shelf is dominated by Pliocene sediment, and the outer shelf is dominated by Pleistocene sediment. The complexity and abundance of salt structures generally increase to the south and include diapirs, salt stock canopies, welds, autochthonous salt ridges and anticlines, and associated counter-regional faults. Examples of reservoir sand depositional environments of the modern shelf include: (1) fluvial environments such as channels and point bars; (2) lower delta plain environments such as distributary channels, distributary-mouth bars, and bays; and (3) deep-sea fan environments such as channels, channel levees and overbank, and lobes.

The shallow sections of the Louisiana, Mississippi, and Alabama shelf have been extensively explored, with reservoir sands trapped by stratigraphy, faulted anticlines, normal faults, and salt bodies. Exploration and production of oil and gas from the Cenozoic AUs on the modern shelf has been ongoing for

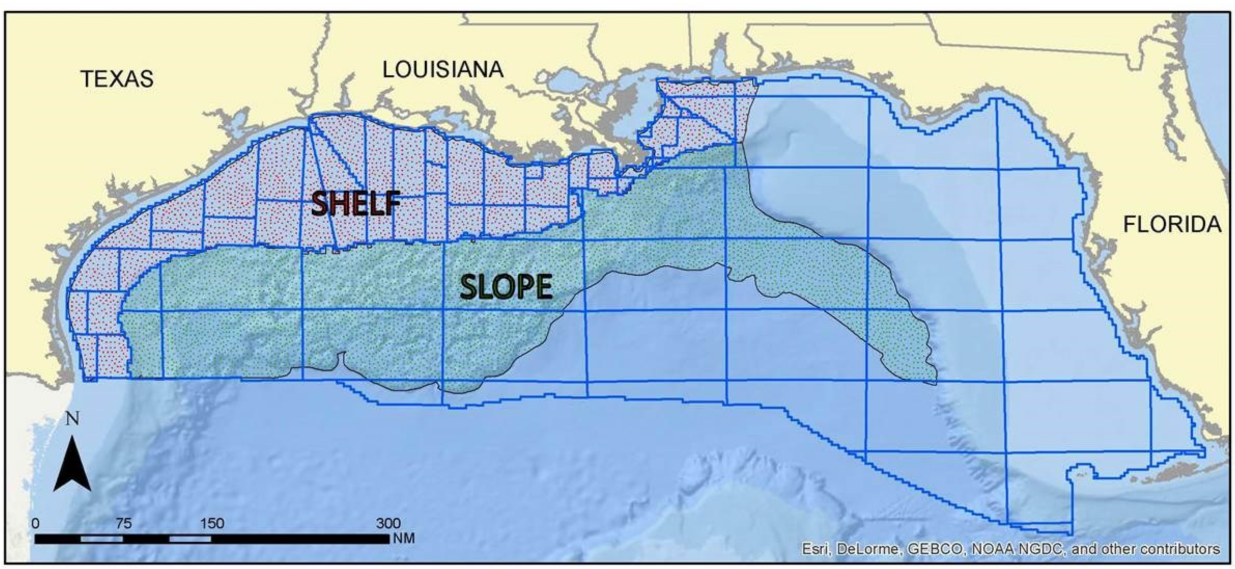


Figure 15. Location of shelf and slope assessment units in the Gulf of Mexico OCS Region.

over 50 years.

The Pleistocene Shelf AU represents the youngest unit included in the GOM assessment. Information from 373 discovered oil and gas pools is utilized to predict the undiscovered resources within the Pleistocene Shelf. Discovered Pleistocene Shelf pools are largely concentrated in the Central GOM in the South Extensions of the shelf protraction areas. Additionally, several discovered Pleistocene Shelf pools are located in the South Padre Island Protraction Area on the southern Texas shelf. We expect approximately 80% of the undiscovered resource (on a BBOE basis) in the Pleistocene Shelf AU to be gas.

The discovered pools in the Pliocene Shelf AUs are focused in the Central Planning Area and the eastern part of the Western Planning Areas on the GOM shelf. Unlike the Pleistocene pools, the Pliocene pools are more uniformly distributed between the modern coastline and the modern shelf edge. The Pliocene Shelf is considered one of the more mature units in the GOM, with information from 506 discovered oil and gas pools available to inform the assessment of undiscovered resources. We expect approximately 70% of the undiscovered resource (on a BBOE basis) in the Pliocene Shelf AU to be gas.

The discovered pools within the Upper Miocene Shelf AU are distributed across the entire GOM shelf, with an area of concentration proximal to the modern shoreline both east and west of the Mississippi River delta in the Central GOM Planning Area. The Upper Miocene Shelf also comprises one of the more mature plays in the GOM, with 470 discovered pools. The Upper Miocene Shelf AU is projected to be the most oil-rich (relative to gas) of the six Shelf AUs; based largely on information from the existing pools, we project that nearly 50% of the undiscovered resources in the Upper Miocene Shelf AU will be oil.

The existing oil and gas pools in the Middle Miocene Shelf AU are bi-modally distributed across the GOM shelf. Of the 245 discovered pools comprising this AU, we recognize a relatively continuous distribution along the Texas shelf in the Western GOM Planning Area and into the western half of the Central GOM Planning Area. Additionally, a group of discovered Middle Miocene pools are located on the shelf east of the Mississippi River delta. We project that approximately 85% of the undiscovered resources in the Middle Miocene Shelf will be gas-prone.

The discovered pools in the Lower Miocene Shelf AU are located very near the modern coastline in a continuous band across the Western GOM Planning Area and the western part of the Central GOM Planning Area. The 158 discovered pools in this AU provide empirical information that indicates a very large part (~90%) of the yet-to-find resources will be gas-prone.

The oldest unit assessed on the GOM shelf is the Lower Tertiary Shelf AU. While this unit is considered to be a “discovered” unit for the purpose of assigning geologic risk, it remains relatively immature with respect to the other five Cenozoic Shelf units. For this assessment, we recognize only three discovered pools that are characterized as Lower Tertiary Shelf. Also, due largely to the anticipated high temperatures and pressures that are expected at the deep drilling depths required to access Lower Tertiary reservoirs on the shelf, we project that over 95% of the undiscovered resources in the Lower Tertiary Shelf will be gas.

6.3.2.1 Cenozoic Assessment Units—Modern Slope

The six Cenozoic Slope AUs occur between the modern shelf edge (approximately coincident with the 200 meter isobath) and the Sigsbee Escarpment, which represents the southernmost extent of large allochthonous salt bodies that override the sediments of the abyssal plain. We also include the large compressional structures in front of the Sigsbee Escarpment and the area that includes the depositional limit of Louann Salt. The slope contains a wide variety of salt-related features including displaced salt sheets (allochthons), with a gradual transition from small, isolated salt bodies (e.g., stocks, tongues, walls) in the upper slope to large, contiguous salt canopies in the lower slope. Basically, as a result of load-induced evacuation, flowing Jurassic Louann Salt has climbed the Mesozoic and Cenozoic stratigraphy as allochthonous tiers and glaciers in a prograding extensional setting with a compressional toe-of-slope.

In areas of focused salt withdrawal, topographic lows formed on the seafloor providing a focus for additional sediment deposition. With time, these topographic lows became salt-withdrawal basins ("minibasins") which in many cases accumulated very thick sections of younger sediments. Some of the larger discoveries in the GOM, such as Mars-Ursa (Mississippi Canyon 807) and Auger (Garden Banks 426), are closely associated with the development of these minibasins. Where the salt was entirely evacuated from its source, the synclinal flanks of the minibasins collapsed, leaving an inverted sediment pile anticline, or "turtle" structure. An example of a turtle structure is Thunder Horse (Mississippi Canyon 778), one of the largest discoveries in the GOM.

The entire process of salt evacuation, mini-basin formation, and allochthon emplacement can repeat through time. In fact, an extensive paleo-salt canopy covered much of the shelf and slope during the Upper Miocene. Subsequently, renewed sediment loading during the Pliocene and Pleistocene created even younger minibasins where this paleo-canopy was located, squeezing the salt upward along a new series of counter-regional faults to form the modern Sigsbee Salt Canopy.

Exploration plays on the slope include Miocene and older objectives in subsalt structures associated with large compressional folds, turtle structures, and the younger Pliocene and Pleistocene minibasins situated above and between tabular salt bodies. In the southern portions of the Keathley Canyon and Walker Ridge protraction areas, the modern salt canopy may override Pliocene and Pleistocene sands to form subsalt reservoirs. Reservoir sands of the modern slope were deposited as deep-sea fans in channels, channel-levee complexes, and sheet-sand lobes.

In the southeastern extension of the slope AU area (**Figure 15**) along the Florida Escarpment (**Figure 16**), salt structure growth occurs throughout the Upper Jurassic through Pleistocene stratigraphic section. Cenozoic age deepwater fans may occur in hydrocarbon traps consisting of high-relief, autochthonous (in place) salt swells and vertical welds/pinnacle salt structures. These structures formed when updip extension and associated gravity gliding continued into the Cenozoic, and adequate salt volumes existed to provide salt to core them.

The Pleistocene Slope AU represents one of the more mature deepwater plays in the GOM. The average (1993) and median (1992) discovery year of the 76 discovered pools that we use to help assess this unit represent the oldest of the six Slope AUs in the GOM. The Pleistocene Slope Play is also by far the most gas-prone of the six deepwater plays; we project that nearly 65% of the undiscovered resource will be gas.

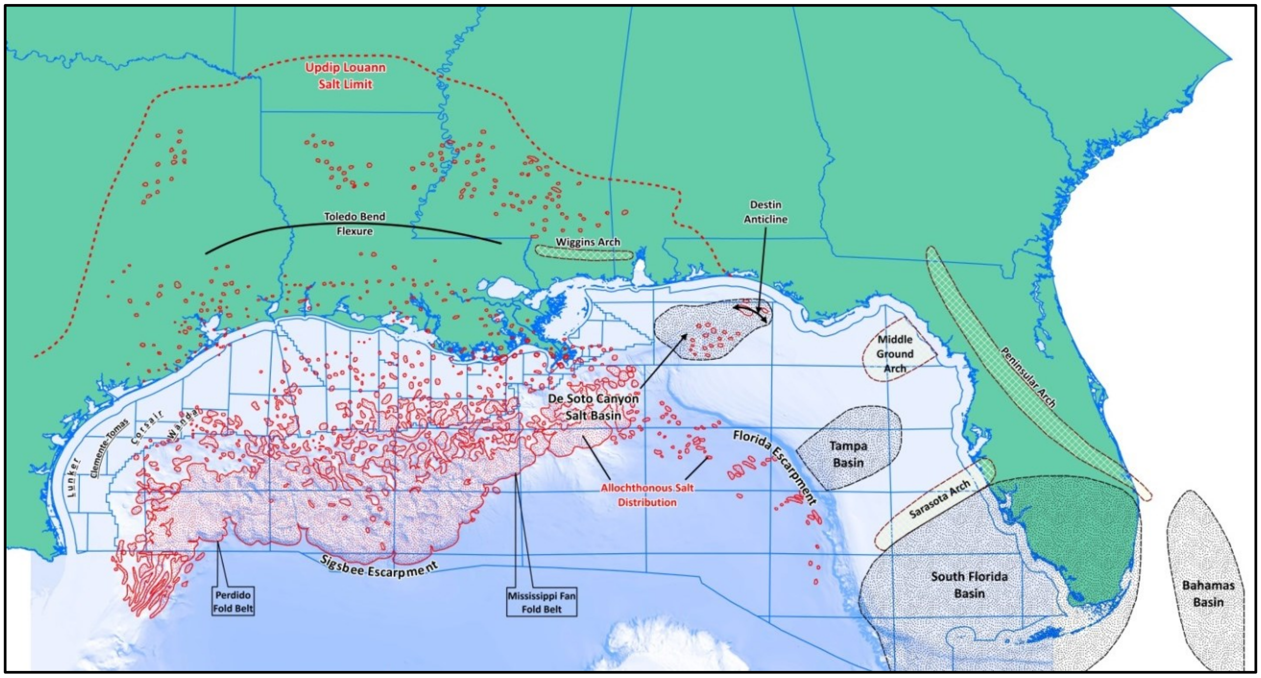


Figure 16. Generalized physiographic map of the Gulf of Mexico OCS Region. Salt distribution after Muehlberger (1992), Simmons (1992), and Lopez (1995).

Spatially, the existing Pleistocene Slope discoveries are located in the upper slope near the modern shelf break. Most Pleistocene Slope discoveries are in mini-basin settings in the Garden Banks and Green Canyon Protraction Areas.

The Pliocene Slope AU is also a relatively mature deepwater play, with an average discovery year of 1994 for the 121 discovered pools in the BOEM database. The existing discoveries are widely distributed across the salt mini-basin province of the Slope AU area. Nearly 65% of the predicted undiscovered resources are projected to be oil.

The 86 discovered pools associated with the Upper Miocene Slope AU are concentrated in the eastern part of the GOM Central Planning Area, in and around the Mississippi Canyon Protraction Area. Average water depth of the discovered fields exceeds 4,000 feet. Based on the information in the existing pools, nearly 65% of the predicted undiscovered resources are projected to be oil.

The discovered pools in the Middle Miocene Slope AU are distributed in a manner similar to the Upper Miocene Slope with the exception that the trend is further south from the modern shelf edge. The 72 discovered pools are generally located in the Vioska Knoll, Mississippi Canyon, and southeast corner of Green Canyon Protraction Areas in the Central GOM Planning Area. Additionally, three discovered pools are located in the far western part of the Slope province.

The Lower Miocene Slope AU includes nine discovered pools, including several located in compressional foldbelt features at and near the distal end of the Sigsbee Escarpment. Several of these discoveries are large, oil-prone reservoirs at drill depths greater than 20,000 feet and in water depths greater than 5,000 feet. Based on our learnings from the nine discovered pools, we project that undiscovered resources in this AU will be overwhelmingly oil rich.

The Lower Tertiary Slope AU represents the most immature of the Cenozoic Slope AUs, where the average discovery date of the 23 known pools is 2005. The Lower Tertiary discoveries thus far have been in an average water depth that exceeds 7,000 feet at locations that are typically associated with the southern or distal margin of the Slope province. All but one of the existing Lower Tertiary pools used in this assessment are oil reservoirs (with solution gas, in some cases), and our expectation is that over 90% of the undiscovered resource in this Unit will be oil.

6.3.3 Mesozoic Geologic Plays

Unlike the aggregated AUs of the Cenozoic sediments, for this inventory of undiscovered resources in the Mesozoic sediments of the U.S. GOM OCS, most Mesozoic sediments were differentiated by specific rock units or plays. Specifically, Mesozoic sediments were divided into 19 plays, 15 of which are assessed in this study. The four non-assessed plays are either early-stage concepts or believed to contribute insignificant volumes of resources to the GOM Basin. As of this study's cutoff date, we have identified only three established Mesozoic plays (Andrew, James, and Norphlet), with a combined total of 32 discovered pools. The assessment of the remaining 12 Mesozoic plays with no discoveries in OCS waters heavily relies upon analog data from onshore Gulf Coast plays for modeling. **Figure 17** illustrates generalized stratigraphy of Mesozoic rock groups and formations in the northeastern coastal region of the GOM and the South Florida Basin area of Florida. Parts of the stratigraphic columns are modeled after onshore sections; rock units listed, therefore, may or may not be present throughout the entire northeastern GOM or Florida offshore area.

Mesozoic sediments initially formed during the Late Triassic to Early Jurassic rifting episode that created the GOM Basin. This breakup event formed a series of northeast-southwest-trending rifts offset by northwest-southeast-trending transfer faults/zones. The Wiggins Arch and parts of the Sarasota Arch represent Paleozoic Era remnants left behind during the rifting stage. The rift grabens were active depocenters receiving lacustrine and alluvial deposits, resulting in the Eagle Mills Formation. During the Middle Jurassic, marine water sporadically entered the incipient GOM Basin, resulting in the deposition of thick evaporative deposits of the Werner Anhydrite and Louann Salt. Aeolian environments In the Late Jurassic resulted in the sand dunes of the Norphlet Formation, which were later capped by a widespread, marine-transgressive, organic-rich, carbonate mudstone (the Smackover Formation) and became a major hydrocarbon source rock for the GOM. A minor regression resulted in the evaporites and red beds of the Buckner Formation and the terrigenous clastics of the Haynesville Formation that overlie the Smackover Formation, completing the ancestral GOM Basin stratigraphic sequence. Contemporaneous with carbonate-evaporite depositional sequences south of the Sarasota Arch (e.g., Bone Island and Pumpkin Bay Formations) were the first major influxes of terrigenous classic materials into the northern GOM, represented by the Late Jurassic to Early Cretaceous Cotton Valley Group and Hosston Formation. Subsequent repeated transgressions and regressions led to the deposition of high-energy siliciclastics (e.g., Paluxy, Dantzler, and Tuscaloosa Formations) and carbonates during the Cretaceous Period, which caused progradation of the shelf edge, where thick reef complexes developed (e.g., Sligo, James, Sunniland, and Andrew Limestones).

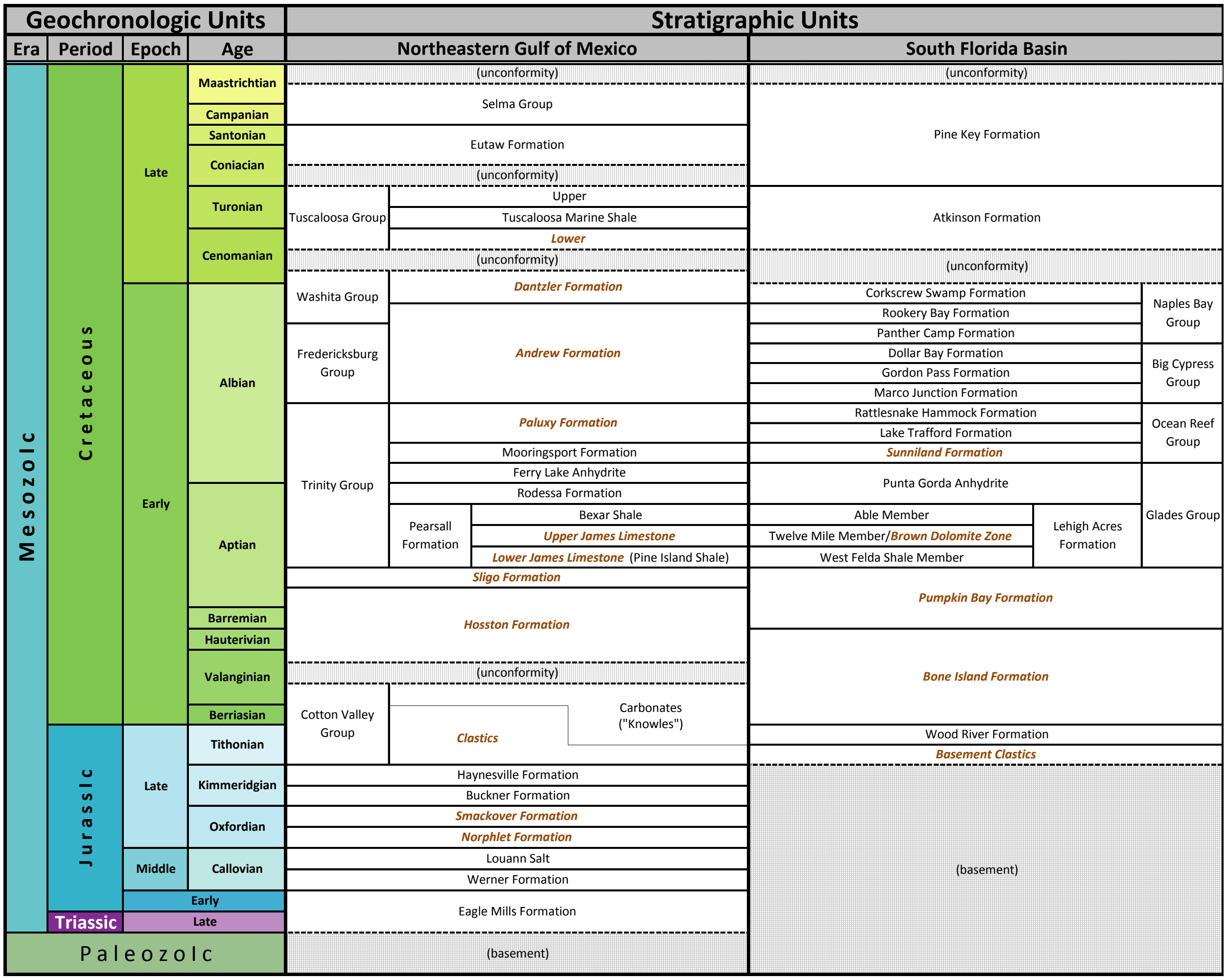


Figure 17. Rock units in the northeastern Gulf of Mexico and South Florida Basin.
Rock units assessed in this report are highlighted. Modified from Faulkner and Applegate (1986), Gohrbandt (2002), Petty (2008), and Dubiel et al. (2010).

The individual play descriptions that follow pertain specifically to the OCS waters of the GOM Basin. They are not meant to provide a comprehensive review of updip, onshore-equivalent plays.

6.3.3.1 Established Mesozoic Plays

6.3.3.1.1 Andrew

The “Andrew Limestone” is a term used by drilling operators to describe undifferentiated carbonates of Lower Cretaceous Washita-Fredericksburg age. Generally for the Lower Cretaceous, a well-defined rudist reef crests the shelf edge and foreslope leading into open marine environments (Yurewicz et al., 1993). The established Andrew Play (Albian age) is defined by this narrow shelf-edge reef facies that extends from the Chandeleur through the northern Vernon Basin Areas. Flanking the rudist reefs are oolitic packstones and shelf grainstones adjacent and trending subparallel to shelf-edge boundstones and packstones. Updip to the northeast are lagoonal, nonporous wackestones and mudstones interbedded with basin-wide shales representing transgressive units (Yurewicz et al., 1993; Petty, 1999). Downdip to the southwest, the play is bound by a forereef facies of dark shales and carbonate muds. Beyond the defined play to the southeast along strike, stratigraphic equivalents begin in the Sunniland/South Florida Basin Play.

Two BOEM-designated fields have been declared in the Andrew Play. However, hydrocarbons have been encountered within several biostrome shoals that have come in contact with hydrocarbon migration routes from Lower Cretaceous source beds (Wagner et al., 1994). Reservoir porosity and permeability are controlled by a combination of primary fabric, digenetic leaching, and dolomitization. Hydrocarbons are trapped in small anticlines located within the porous and permeable facies. Marine shales, micrites, and anhydrites provide seals for the play. For a detailed discussion, see Petty (1999) and Bascle et al. (2001).

6.3.3.1.2 James

The established Lower Cretaceous James Limestone Play extends from the Mobile Area southeastward along the Lower Cretaceous shelf edge through the northern Viosca Knoll, Destin Dome, De Soto Canyon, Florida Middle Ground, The Elbow, and northern Vernon Basin Areas. Farther to the southeast, this carbonate trend ends where along strike, stratigraphic equivalents begin in the Sunniland/South Florida Basin Play. Updip to the northeast, the play is limited by backreef lagoonal carbonate muds, while downdip to the southwest, the play grades into a forereef facies of dark shales and carbonate muds. The play contains ten discovered pools which are located in the northwest part of the play area.

Carbonate depositional environments were widespread throughout the Lower Cretaceous in the eastern GOM. Although barrier reef complexes are important stratigraphic features along the shelf edge, more prolific oil and gas fields have been discovered in patch reefs and debris mounds behind the shelf-edge reef trend and, therefore, are more attractive targets for hydrocarbon exploration (Sams, 1982). The James Play is defined by such a patch-reef trend in a backreef environment. The ten pools in the play are part of a patch-reef trend oriented northwest to southeast. The patch reefs favor preexisting structural highs and are typically elliptical, with 3- to 5-mile long axes oriented perpendicularly to the basin. The reefs comprise a central core of rudist boundstone surrounded by concentric deposits of grainstone and packstone bioclastic debris. Payzone thicknesses in the ten pools range from about 10 to 100 feet.

6.3.3.1.3 Norphlet

The Norphlet and Salt Roller/High-Relief Salt Structure Plays have been combined based on the identification of Norphlet reservoirs in the previously undrilled deepwater area of the Salt Roller/High-Relief Salt Structure Play. The north/northeast and south/southwest play boundaries generally coincide with the depositional limit of the Jurassic Louann Salt. To the west, the occurrence of high-relief salt-cored structures (salt canopies, salt domes, salt diapirs, salt-floored minibasins, and salt-cored compressional folds) defines the play limits. The established Norphlet Play has evolved from onshore Mississippi, Alabama, and Florida into Alabama State waters, shallow waters of the OCS shelf, and recently into OCS deepwater areas.

The Smackover-Norphlet is a closed petroleum system. Laminated, algal-rich lime mudstones of the overlying lower Smackover Formation (Late Jurassic, Oxfordian) are geochemically typed as the source rocks for the Norphlet (Sassen, 1990) and also provide the overlying top seal for Norphlet reservoirs (Mankiewicz et al., 2009). With the exception of a few onshore fields, the Norphlet is only productive where there is no porosity in the Upper Smackover. Where there is porosity in the Upper Smackover, the Norphlet only contains commercial volumes of hydrocarbons after all available Smackover porosity has been filled with hydrocarbon.

The Norphlet reservoirs in the GOM consist of aeolian dunes. Sand-thickness isopachs show Norphlet dune fields in that area comprise northwest to southeast oriented, subparallel, elongate sand bodies up to 800 feet thick (Ajdukiewicz et al., 2010).

The primary hydrocarbons associated with the Norphlet Play change over the play area, where gas with associated liquids in the shallow waters of the northern part of the play changes to oil with associated gas in the deeper water to the south. The Norphlet Play in OCS waters contains 20 discovered pools. Sixteen are associated with the shallow water, gas-prone portion of the play, and four are in deepwater, with oil as the primary hydrocarbon. Discoveries in the deepwater oil portion of the play include Appomattox (MC 392) and Vicksburg "B" (DC 353).

Within the deepwater area, primary play risks include the presence of a reservoir, reservoir quality, and hydrocarbon properties including the presence of asphaltenes, which can restrict hydrocarbon flow. Additional risks include timing (trap creation relative to hydrocarbon creation and expulsion) and trap seal (vertical and horizontal) for hydrocarbon preservation.

6.3.3.2 Conceptual Mesozoic Plays

6.3.3.2.1 Mesozoic Deep Shelf

The conceptual Mesozoic Deep Shelf Play is defined by a series of large, four-way dipping structural closures on the Louisiana shelf and source, reservoir, and seal lithologies that comprise seismically correlated units of Upper Jurassic through Upper Cretaceous age. The play is located in relatively shallow water on the Texas-Louisiana shelf and extends from High Island East Addition to Grand Isle South Addition, a distance of approximately 225 miles. At its widest, the play is approximately 65 miles. These dimensions provide a play area of roughly 10,233 square miles (6.5 million acres). Aeromagnetics and deep-penetrating seismic data delineate a series of rift-formed horst blocks that subsequently develop four-way dipping structures; these form the primary targets in the play.

Drilling targets are located below salt welds and salt décollements and drilling depths range from 30,000 to 35,000 feet below sea level. High-energy carbonate grainstones, reefs, and carbonate detrital talus/breccias are the most likely reservoir facies and are similar to those found in the Golden Lane and Poza Rica Fields in Mexico.

There have been no discoveries in the play prior to this study's cutoff date. The play is considered immature, with primary risks being related to the presence of reservoir-quality rocks in the objective section.

6.3.3.2.2 Mesozoic Slope

The conceptual Mesozoic Slope Play is defined by reservoirs associated with seismically delineated structures of the Perdido and Mississippi Fan Fold Belt Plays in the deepwater GOM. The Perdido Fold Belt is located in the Alaminos Canyon and southwestern Keathley Canyon Areas, and the Mississippi Fan Fold Belt occurs primarily in the east-central Keathley Canyon, Walker Ridge, Green Canyon, Atwater Valley, and southern Mississippi Canyon Areas. Significant parts of each play are beneath salt canopies. Though prolific Cenozoic production has been established from structures in both fold belts, commercial production has not been established from Mesozoic reservoirs. Despite the absence of commercial discoveries in the Mesozoic sediments of the fold belts, the presence of hydrocarbon shows indicates a working petroleum system. Primary risks are the presence and quality of reservoir in the carbonate and siliciclastic rocks of the Mesozoic and the occurrence of effective top seals.

6.3.3.2.3 Buried Hill

The three conceptual Buried Hill Plays (Buried Hill Structural, Buried Hill Stratigraphic, and Buried Hill Drape) are related to a series of paleo-topographic structural features delineated by seismic and potential field data in the deepwater GOM beyond the Sigsbee Escarpment. Buried hills formed during the Late Triassic to Early Jurassic rifting episode(s) that created the GOM Basin. The Marton and Buffler (1993) simple-shear model for GOM opening provides an explanation for the distribution of buried hills, suggesting that they represent a series of continental fragments "calved" from the Yucatan block as this upper plate (hanging wall) rotated/translated southeastward above a low angle detachment (Roberts et al., 2005). A variety of Jurassic, Cretaceous, and Paleogene reservoir objectives could be associated with these features, the largest of which covers approximately 250,000 acres (391 square miles) and has approximately 5,000 feet of vertical relief.

In the Buried Hill Structural Play, the buried hill itself is the reservoir target. Enhanced reservoir porosity and permeability in the "granitic" core of the buried hill results from weathering, fracturing, and possibly karstification. Source rocks for the Buried Hill Structural Play are always younger than the buried hill and are either laterally adjacent to the buried hill reservoir or onlap and seal it. Primary risks for the Buried Hill Structural Play are developing and maintaining reservoir-quality porosity and permeability in the core of the buried hill, the presence of source rocks that have generated and expelled hydrocarbons, and the preservation of those hydrocarbons in the relatively unconventional reservoir of the buried hill.

The Buried Hill Stratigraphic Play comprises Jurassic and Cretaceous age siliciclastic and carbonate reservoirs either on or adjacent to the buried hill or in nearby grabens. Locally derived clastics deposited as alluvial deltas, barrier island-beach systems, fluvial deltas, or fans are potential reservoirs in siliciclastic-dominated sequences, whereas high-energy carbonate grainstones, reefs, and carbonate detrital talus/breccias are the most likely reservoirs in the carbonate-dominated facies. The Buried Hill Stratigraphic Play has risks associated with the reservoirs that are seismically interpreted as siliciclastic and carbonate facies. Source rock presence, generation and expulsion history, and the preservation of hydrocarbons in the traps are also risks.

The Buried Hill Drape Play is defined by compaction of sediments over buried hill features. Depending on the relief of individual buried hills, potential reservoirs primarily in overlying Cretaceous and Paleogene age sediments may be present as turbidite deposits in relatively low-relief structural closures developed by differential compaction over the more rigid, less compacting, buried hills. Depending on location and paleo-topographic relief, Jurassic sediments could also provide reservoir objectives. Risks in the Buried Hill Drape Play are related to the presence of and the porosity/permeability characteristics of interpreted reservoir facies. Source rock presence, maturity, etc., are also risks as is the presence of migration conduits connecting possible Paleogene reservoirs and Jurassic source rocks.

No wells have been drilled in any of these plays prior to this study's cutoff date. The various Buried Hill Play types represent prolific, productive plays in Southeast and East Asia, North and South America, Africa, Europe, and Australasia. A number of references were used to develop the analog in this play. Among these are: Landes et al. (1960), P'an (1982), Zhai and Zhai (1982), Zheng (1988), Yu and Li (1989), Horn (1990), Tong and Zuan (1991), Areshev et al. (1992), Tran et al. (1994), Blanche and Blanche (1997), and Sladen (1997).

6.3.3.2.4 Lower Tuscaloosa

The Upper Cretaceous Tuscaloosa Group (Cenomanian and Turonian ages) is subdivided into Upper (sands and shales), Middle ("Tuscaloosa Marine Shale"), and Lower (sands and shales) sections. The conceptual Lower Tuscaloosa Play represents the oldest Upper Cretaceous, fluvial-deltaic complex encountered in the Alabama/Mississippi/Louisiana area. The OCS portion of the play extends from the Mobile and Viosca Knoll Areas offshore Mississippi and Alabama to the Pensacola and Destin Dome Areas offshore Florida. Updip onshore, the play is productive, while downdip the play's boundary occurs where Upper Cretaceous sands interfinger with prodelta shales. No significant accumulations of hydrocarbons have been encountered in the numerous OCS wells that have penetrated the play.

The productive onshore Lower Tuscaloosa consists of progradational deltaic sands, aggradational stacked barrier bar and channel sands, and reworked retrogradational sands. In the OCS, however, the Lower Tuscaloosa has a more distal depositional setting, and sands tend to be of lower reservoir quality. Significant structural features in the play are anticlines and faults, both related to salt movement. Potential source rocks are laminated carbonate mudstones in the basal portion of the Oxfordian Smackover Formation. Potential seals are created by the juxtaposition of reservoir sands with shales and salt, both structurally and stratigraphically. For a detailed discussion, see Petty (1997).

6.3.3.2.5 Lower Cretaceous Clastic

The conceptual Lower Cretaceous Clastic Play is defined by siliciclastic sedimentation in barrier bar and channel facies of the Hosston, Paluxy, and Dantzler Formations (**Figure 17**). The play extends south from Mississippi, Alabama, and Florida into the northern portions of the Viosca Knoll, Destin Dome, Apalachicola, and Gainesville Protraction Areas. The downdip limit is located where Lower Cretaceous clastic sands interfinger with prodelta shales. Of the OCS wells that penetrated this play, all were dry; however, this play does not appear to be the primary exploration target for these wells.

The Hosston Formation has a gross interval thickness of 2,000 feet in the Mobile Area and 2,700 feet in the Destin Dome Area. The Paluxy Formation is widespread offshore and locally has high porosity in barrier bars and stream channels, with gross interval thicknesses ranging from 900 feet in the Mobile Area to over 2,200 feet in the Destin Dome Area. The Dantzler Formation is thickest over the Destin Anticline but thins to the south away from its source area. Structural traps in the play are related to salt tectonics and faulting, while stratigraphic traps are related to facies changes. The Upper Jurassic Smackover Formation is the main source rock for the play, while Lower Cretaceous marine shales provide seals.

6.3.3.2.6 Sligo

Similar to the younger James Play, the Lower Cretaceous Carbonate Sligo Formation Play is defined by reefs and reef talus. The play's exploration potential and limiting factors are also similar to the James Limestone Play. To the southeast, the Sligo carbonate trend ends where along strike, stratigraphic equivalents begin in the Sunniland/South Florida Basin Play. Updip to the northeast, the play is limited by backreef lagoonal wackestones and mudstones interbedded with regional transgressive marine shales (Yurewicz et al., 1993). Downdip to the southwest, the play grades into a forereef facies of dark shales and carbonate muds. The conceptual play contains no discovered fields in OCS waters.

6.3.3.2.7 Sunniland/South Florida Basin

The conceptual Lower Cretaceous Sunniland/South Florida Basin Play is located in the South Florida Basin area. Ranging in age from Berriasian to Albian, the play consists of rudist reefs and reef debris haloes along the shelf edge, and interior platform grainstones, patch reefs, and debris haloes in backreef areas associated with the Bone Island, Pumpkin Bay, Lehigh Acres (Brown Dolomite Zone), and Sunniland Formations. The play is limited to the north by a facies change from carbonates to siliciclastics. Forereef facies of dark shales and carbonate muds bound the play to the south and west. To the east, the play interval continues onshore into Florida, including the producing Sunniland Trend. There are no discovered oil or gas pools in this play on the OCS.

Potential reservoirs in the play primarily are patch reefs built up on local basement highs, but also may include platform grainstones and reef talus reservoirs. Structural closures over reefal buildups are possible, but traps are mainly stratigraphic. Potential source rocks are thought to exist in Lower Cretaceous, locally-occurring, organic-rich lagoonal carbonates, marine limestones, or shales, depending on where the potential reservoirs are within the reef system in the South Florida Basin.

6.3.3.2.8 Florida Basement Clastic

The conceptual Jurassic age Florida Basement Clastic Play is defined by siliciclastics eroded from weathered basement rocks exposed from Middle to Late Jurassic time associated with the South Florida Basin area. The play may also extend into the Tampa Basin, across the Peninsular Arch into the Bahamas Basin, and northward into the Atlantic Region along the east coast of Florida. There are no discovered pools in this play in OCS waters. Potential reservoirs were likely deposited as alluvial fans, barrier island/beach systems, and fluvial deltas immediately overlying the basement rocks. Basement clastic sands penetrated to date have been less than 150 feet thick and are rich in mica and feldspar. The biggest risk is poor quality of the potential reservoir sands.

6.3.3.2.9 Cotton Valley Clastic

The Upper Jurassic (Tithonian) to Lower Cretaceous (Valanginian) Cotton Valley Group consists of sandstone, shale, and limestone and underlies much of the northern coastal plain of the GOM from east Texas to Alabama. On the OCS, Cotton Valley sediments extend as far south as the Sarasota Arch. To the north the play extends onshore, and to the east sediments terminate on the Middle Ground Arch.

The clastic sediments of the Cotton Valley Group include sands, shales, and siltstones that were deposited, from landward to basinward, in delta plain, prodelta, restricted lagoonal, barrier island, and open- to marginal-marine conditions. The conceptual Cotton Valley Clastic Play, as assessed herein, is defined by Tithonian to Berriasian, fine-grained sandstones and siltstones contained in stacked coastal barrier islands in the Mobile, Viosca Knoll, and Destin Dome Areas. These clastics are found below the non-assessed, Valaginian platforms of the Knowles Carbonate Play and overlie the lithologically similar clastics of the Haynesville Formation.

Though the Cotton Valley Clastic Play has been penetrated by a number of OCS wells (MP 154 #001, DD 529 #001, VK 251 #001, and VK 117 #001), no discoveries have been made in Federal waters. The Cotton Valley Group produces from several onshore fields along the Gulf Coast, with the nearest onshore production to the offshore Cotton Valley from the Catahoula Creek Field in Hancock County, Mississippi.

6.3.3.2.10 Smackover

The Upper Jurassic Smackover Formation is a carbonate unit deposited during a major marine transgression and highstand across the northern rim of the GOM. In Federal waters, the formation is located primarily in the Pensacola, Apalachicola, De Soto Canyon, Florida Middle Ground, and The Elbow Areas. To the north, the Smackover extends onshore where it is productive, while to the south, the play grades into nonporous carbonate mudstones and shales. No oil or gas fields on the OCS have been associated with the conceptual Smackover Play.

The Upper Smackover section consists of inner ramp, high-energy, oolitic grainstones alternating with carbonate mudstones. Localized thrombolitic reefs and grainstone shoals developed over (1) basement highs, (2) salt pillow structures, and (3) topographic highs related to large sand dunes of the underlying Norphlet Formation. The downdip and lower Smackover section consists of laminated lime mudstones, wackestones, some porous packstones, siliciclastic siltstones, and shales. The Smackover is self-sourcing, with hydrocarbons being derived from the low-energy, algal-rich, laminated carbonate mudstones located near the base of the section. For a detailed discussion, see Petty (2010).

6.4 Assessment Results

Estimates of the total volume of UTRR are developed at the geologic play and AU level (**Table 11**) and aggregated to the planning area (**Table 12**), OCS Region, and national level. For summary reporting in the OCS-wide National Assessment report (all regions) results are tabulated for the planning areas, so that they may be used for planning needs in developing the National OCS Oil and Gas Leasing Program. Based on this assessment, the total volume of UTRR oil is estimated to range from 39.48 to 58.53 Bbo with a mean estimate of 48.46 Bbo. The total volume of UTRR gas is estimated to range from 124.01 Tcf to 159.63 Tcf with a mean estimate of 141.76 Tcf. On a combined basis, the mean volume of UTRR oil and gas resource in the GOM OCS is 73.69 BBOE. By way of comparison, the discovered resources in the GOM at the time of this report (reserves, cumulative production, and contingent resources) are estimated at 26.69 Bbo and 204.75 Tcf of gas (total of 63.12 BBOE).

Figure 18 ranks the assessed assessment units/plays in the GOM based on mean-level UTRR in BBOE. Relative to the thoroughly explored, mature plays on the modern shelf, plays on the modern slope and abyssal plain are estimated to have the most undiscovered resources, with Lower Tertiary plays containing the highest potential for future discoveries. Of the Mesozoic-aged plays, Norphlet dunes are estimated to have the greatest potential for future undiscovered resources, mainly in the immature portion located in the eastern GOM in ultra-deepwater (≥ 2,400 m).

The fraction of the total volume of UTRR that are estimated to be UERR varies based on several assumptions, including commodity price environment, cost environment, and relationship of gas price to oil price. Larger volumes of

Table 11. Risked UTRR for the Gulf of Mexico Region by assessment unit/play.

Region / Play/Assessment Unit	2016 Gulf of Mexico Undiscovered Technically Recoverable Oil and Gas Resources (UTRR)								
	Oil (Bbo)			Gas (Tcf)			BOE (Bbo)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Gulf of Mexico OCS	**39.48**	**48.46**	**58.53**	**124.01**	**141.77**	**159.63**	**61.55**	**73.69**	**86.93**
Pleistocene Shelf	0.03	0.10	0.25	0.65	2.32	5.41	0.15	0.52	1.21
Pleistocene Slope	0.23	0.51	0.80	2.36	5.11	8.22	0.65	1.42	2.26
Pliocene Shelf	0.08	0.24	0.71	1.00	3.13	8.14	0.25	0.79	2.15
Pliocene Slope	0.75	3.58	6.93	2.36	11.37	21.68	1.17	5.61	10.79
Upper Miocene Shelf	0.45	0.85	1.44	3.14	5.98	10.89	1.01	1.92	3.37
Upper Miocene Slope	3.12	5.27	7.64	9.56	16.64	24.36	4.82	8.23	11.97
Middle Miocene Shelf	0.05	0.28	0.56	1.52	8.91	18.52	0.32	1.86	3.85
Middle Miocene Slope	4.40	7.39	11.27	7.71	13.15	20.23	5.77	9.73	14.87
Lower Miocene Shelf	0.01	0.13	0.33	0.38	6.62	16.53	0.07	1.31	3.28
Lower Miocene Slope	1.76	7.26	13.25	0.96	3.59	6.31	1.94	7.90	14.37
Lower Tertiary Shelf	0.12	0.24	0.34	13.35	25.84	40.96	2.50	4.84	7.62
Lower Tertiary Slope	6.80	15.63	26.98	2.84	6.38	10.48	7.31	16.76	28.84
Mesozoic Deep Shelf	0.00	0.00	0.00	0.00	4.34	18.62	0.00	0.77	3.32
Mesozoic Slope	0.70	1.64	2.85	2.55	5.83	10.20	1.15	2.68	4.67
Lower Tuscaloosa	0.00	0.04	0.16	0.00	0.24	0.75	0.00	0.09	0.30
Andrew	0.00	0.05	0.11	0.01	0.12	0.29	0.00	0.07	0.16
James	0.02	0.05	0.09	0.50	1.15	1.94	0.11	0.26	0.43
Sligo	0.00	0.04	0.11	0.00	0.21	0.69	0.00	0.07	0.23
Lower Cretaceous Clastic	0.00	0.01	0.02	0.00	0.04	0.14	0.00	0.01	0.05
Florida Basement Clastic	0.00	<0.01	0.01	0.00	0.08	0.25	0.00	0.02	0.06
Buried Hill Stratigraphic	0.00	0.49	2.15	0.00	1.46	6.50	0.00	0.75	3.31
Buried Hill Structural	0.00	1.23	5.33	0.00	2.07	8.69	0.00	1.60	6.88
Buried Hill Drape	0.00	0.54	2.38	0.00	2.47	10.16	0.00	0.98	4.19
Smackover	0.02	0.04	0.06	0.06	0.13	0.22	0.03	0.06	0.10
Cotton Valley Clastic	0.01	0.03	0.08	0.03	0.18	0.41	0.01	0.06	0.15
Sunniland/South Florida Basin	0.13	0.25	0.40	0.12	0.24	0.37	0.15	0.29	0.47
Norphlet	1.00	2.58	4.45	6.81	14.17	23.61	2.21	5.10	8.65

Note: Resource values are in billion barrels of oil (Bbo) and trillion cubic of gas (Tcfg). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding.

Table 12. Risked UTRR for the Gulf of Mexico OCS Region by planning area.

Region / Planning Area	Risked Undiscovered Technically Recoverable Oil and Gas Resources (UTRR)								
	Oil (Bbo)			Gas (Tcfg)			BOE (Bbo)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Gulf of Mexico OCS	39.48	48.46	58.53	124.01	141.76	159.63	61.55	73.69	86.93
Western Gulf of Mexico	8.20	11.57	15.56	32.09	38.99	45.65	13.91	18.50	23.68
Central Gulf of Mexico	24.67	33.25	42.74	77.72	91.27	105.65	38.50	49.49	61.53
Eastern Gulf of Mexico	2.35	3.63	5.28	7.15	11.49	16.20	3.62	5.68	8.16
Straits of Florida	0.01	0.01	0.02	0.01	0.02	0.02	0.01	0.02	0.02

Note: Resource values are in billion barrels of oil (Bbo) and trillion cubic of gas (Tcfg). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding.

resources are estimated to be economically recoverable under more favorable economic conditions. **Table 13** provides UERR for the four GOM OCS planning areas over a price spectrum that ranges from $30/barrel to $160/barrel and assumes a 30 percent value of gas price to oil price. Estimates of UERR are presented as price-supply curves for the GOM OCS in **Figure 19**. A price-supply curve shows the relationship of price to economically recoverable resource volumes (i.e., a horizontal line from the price axis to the curve yields the quantity of economically recoverable resources at the selected price). The price-supply charts contain two curves and two price scales, one for oil (green) and one for gas (red); the curves represent mean values at any specific price.

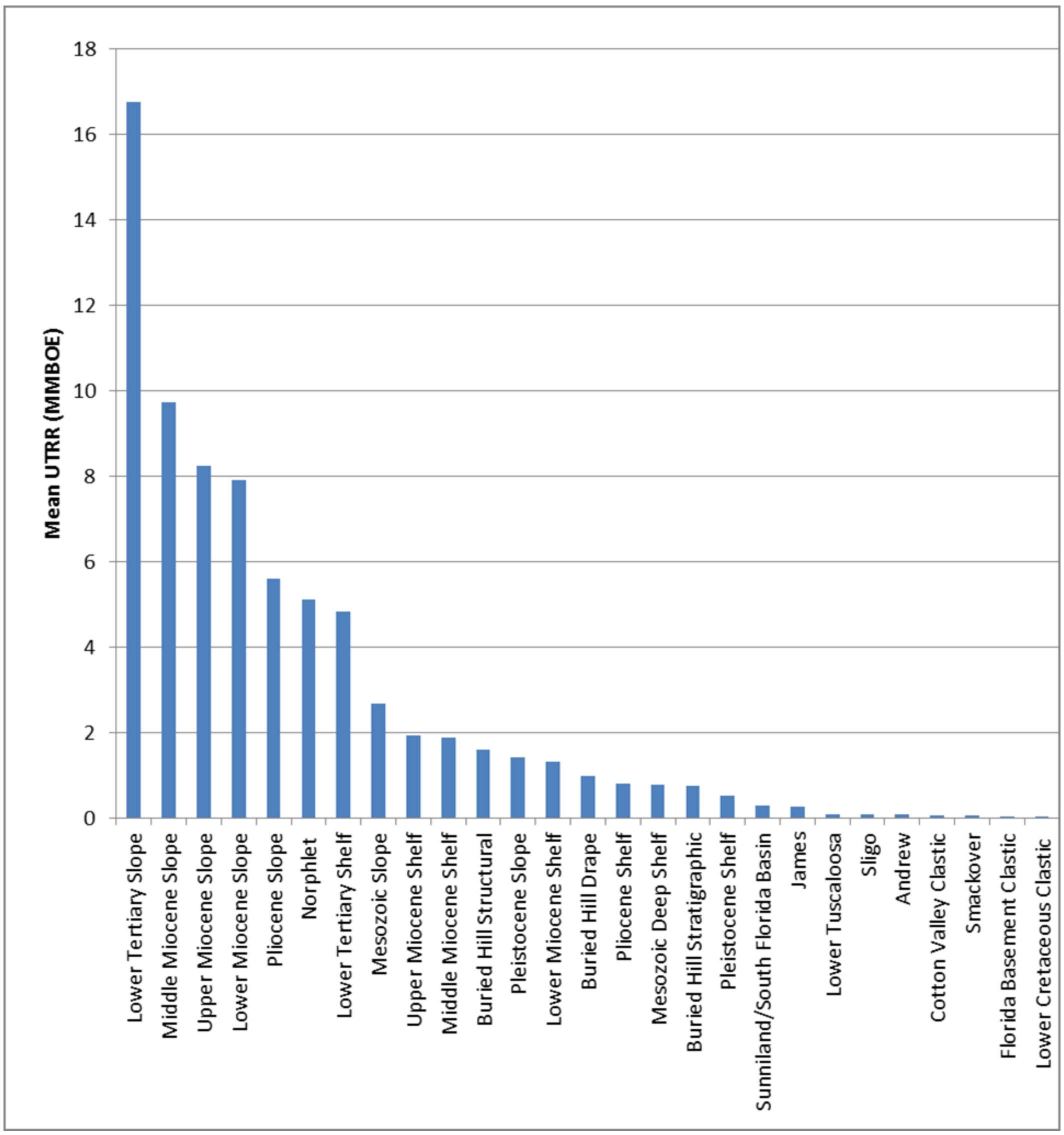


Figure 18. Gulf of Mexico assessment units/plays ranked by mean UTRR.

Table 13. Risked mean-level UERR for the Gulf of Mexico OCS Region by planning area.

Region Planning Area	Risked Undiscovered Economically Recoverable Oil and Gas Resources (UERR)											
	$30/Bbl $1.60/Mcf		$40/Bbl $2.14/Mcf		$60/Bbl $3.20/Mcf		$100/Bbl $5.34/Mcf		$110/Bbl $5.87/Mcf		$160/Bbl $8.54/Mcf	
	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas
Gulf of Mexico OCS	31.31	44.48	35.01	56.09	39.55	74.67	42.88	92.04	43.31	94.51	44.77	103.47
Western Gulf of Mexico	7.28	12.03	8.21	15.88	9.36	21.84	10.20	27.23	10.31	27.98	10.68	30.53
Central Gulf of Mexico	21.69	27.82	24.22	35.02	27.31	46.74	29.56	57.83	29.85	59.41	30.84	65.21
Eastern Gulf of Mexico	2.34	4.62	2.58	5.18	2.88	6.08	3.10	6.97	3.13	7.12	3.24	7.72
Straits of Florida	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01

Note: Resource values are in billion barrels of oil (Bbo) and trillion cubic of gas (Tcfg). Some total mean values may not equal the sum of the component values due to independent rounding. Prices are in dollars per barrel($/Bbl) for oil, and dollars per thousand cubic feet ($/Mcf) for gas. This table represents a gas price adjustment factor of 0.3.

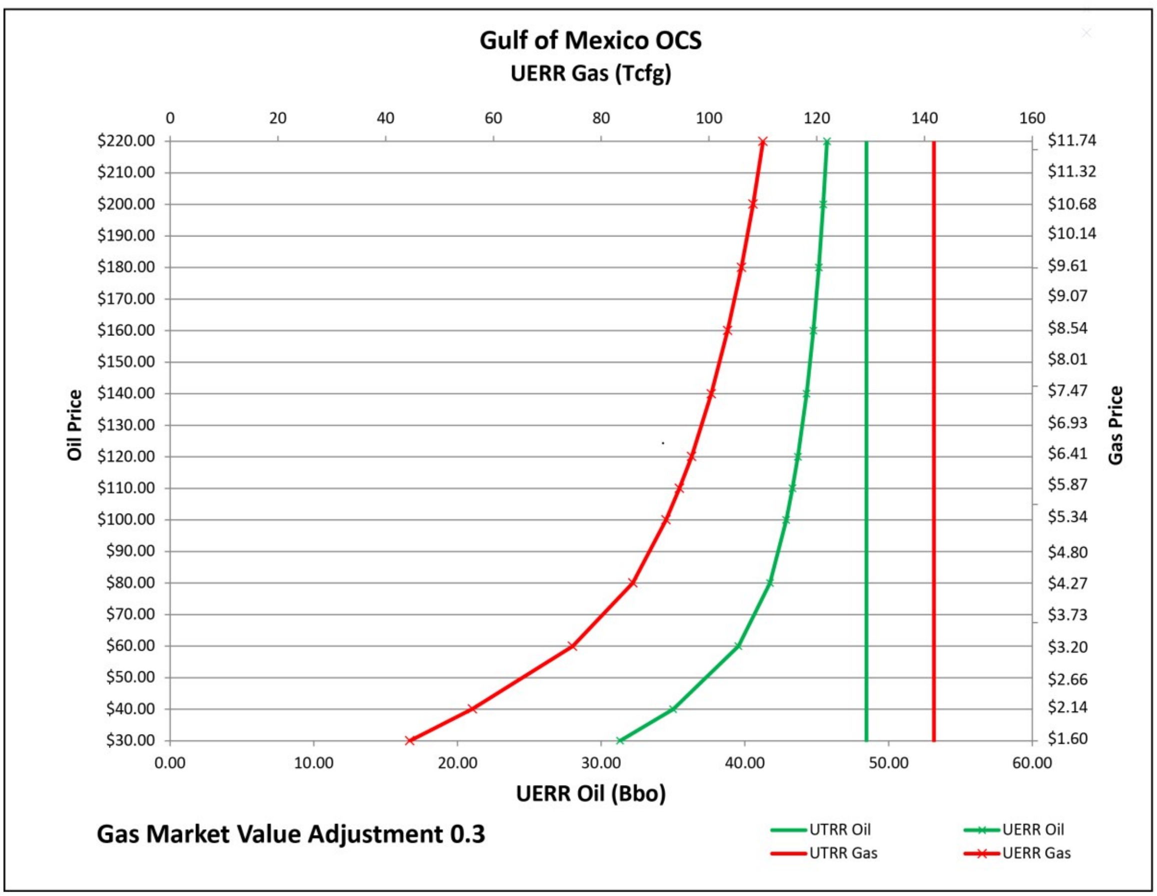


Figure 19. Price-supply curve for the Gulf of Mexico OCS Region.

7 PACIFIC OUTER CONTINENTAL SHELF REGION

A full and complete description of the 2016 Pacific OCS assessment of undiscovered resources is available in OCS Report BOEM 2017-053 (Ojukwu and Smith, 2017). Additionally, a comprehensive background is provided in the 2011 Pacific resource assessment (OCS Report BOEM 2014-667; Piper et al., 2014). The discussion below, at times, provides a summary of the more detailed information found in Ojukwu and Smith (2017) and Piper et al. (2014).

7.1 Location and Geologic Setting

The Pacific OCS Region extends from the U.S.-Canada boundary to the U.S.-Mexico boundary and includes submerged Federal lands off the states of Washington, Oregon, and California. The region encompasses an area of complex geology along a tectonically active crustal margin. Much of the Cenozoic age sedimentary deposition, volcanism, folding, and faulting within this region has created a number of environments favorable for the generation, accumulation, and entrapment of hydrocarbons. Numerous geologic basins and areas exist along the continental shelf and slope within the OCS Region. Some of these are geological extensions of onshore basins with proven hydrocarbon accumulations; several other areas are sparsely explored but are expected to have considerable petroleum potential.

The geologic history of the Pacific Margin has been dominated by the interaction of oceanic and continental crustal plates. In the offshore area north of Cape Mendocino, CA, both active seafloor spreading and the Cascadia subduction zone convergent margin have been active throughout the Cenozoic Era. The Cascadia subduction zone trends roughly north/south along the modern shelf edge and is formed by the eastward subduction of the Juan De Fuca and Gorda Plates under the North American Plate. South of Cape Mendocino, the dominant tectonic feature of Middle to Late Cenozoic age is the right-lateral San Andreas transform fault. The San Andreas Fault forms the border between the Pacific Plate and the North American Plate. In southern California, this boundary has been complicated by the approximately 120 degrees clockwise rotation of the western Transverse Ranges. To the south of this, the Southern California Continental Borderland is a region of extension and northwest-trending right-lateral translation that has occurred concurrently with the rotation.

7.2 Methodology

The BOEM resource assessment methodology for the Pacific OCS utilizes the approach described in Chapter 2 (METHODOLOGY) and includes a full petroleum system analysis of geological and geophysical data available to BOEM. These data include a robust reflection seismic database, gravity and magnetics, subsurface well information from existing U.S. drilling, supplemented with geochemical data from well log analysis, tectonic analysis found in regional geologic reports, paleontological and lithographic data for identification of stratigraphic units.

Most of the data collected for the Pacific resource assessment is based on proprietary data collected through the development of oil and gas fields within the region. However, there are some areas within the Pacific Region where there is not enough data collected locally, and BOEM relies on the use of analogous data to help assess these areas. The unique geologic setting in the Pacific OCS allows for the introduction of an intermediate assessment entity—the geologic basin—that is not used in the other three OCS Regions. The geologic basin often contains one or more geologic plays and can span one or more OCS planning area. Geologic basins provide a unit that can apply a wider range of engineering assumptions across the plays of the Pacific OCS. Due to the contrast of a geologic unit like a basin with a jurisdictional unit like a planning area, some partial aggregations of basins up to the planning area level are necessary to account for the area of basins that may cross planning area boundaries.

For the current assessment, the Pacific OCS is subdivided into five assessment provinces (**Figure 20**): Pacific Northwest, Central California, Santa Barbara-Ventura Basin, Inner Borderland, and Outer Borderland. Within the five provinces, we identify 20 geologic basins and areas in which sediments accumulated and hydrocarbons may have formed. Forty-five petroleum geological plays have been defined and described in 12 basins and areas, and we formally assess 43 of these plays.

7.3 Planning Areas

For consistent reporting of undiscovered resources between the four OCS Regions, and in support of the development of the National OCS Oil and Gas Leasing Program, we aggregate all resource reporting to the OCS planning area level. The interplay of assessed geologic entities and the four Pacific OCS planning areas are described below.

The Washington-Oregon OCS Planning Area includes resource estimates from two Pacific basins: the Washington-Oregon area and the northern most portion of the Eel River Basin. The Washington-Oregon Planning Area contains resources from eight different geologic plays.

The Northern California OCS Planning Area includes resources assessed in two geologic basins—the Eel River Basin and the Point Arena Basin. Within the Northern California Planning Area, seven geologic plays are assessed.

The Central California OCS Planning Area includes resource estimates from the Bodega-La Honda Basin, the Año Nuevo Basin, and a northern section of the Santa Maria-Partington Basin. The Central California Planning Area includes resources from ten of the Pacific geologic plays.

The Southern California OCS Planning Area includes the majority of Pacific OCS resources. We assess resources from seven geologic basins, including the southern portion of the Santa Maria-Partington Basin, Santa Barbara-Ventura Basin, Los Angeles Basin, Oceanside-Capistrano Basin, Santa Cruz-Santa Rosa Area, San Nicolas Basin, and Cortes-Velero-Long Area. Within these seven basins, 26 of the Pacific geologic plays have assessed resources.

Because the planning area boundaries divide basins and plays that form the basis for the technical evaluation, these estimates have the additional subjective element of basin resources being apportioned to the planning areas.

7.4 Discussion of Geologic Provinces and Basins

A brief description of the 12 geologic basins that contribute undiscovered oil and gas resources to this study are included below.

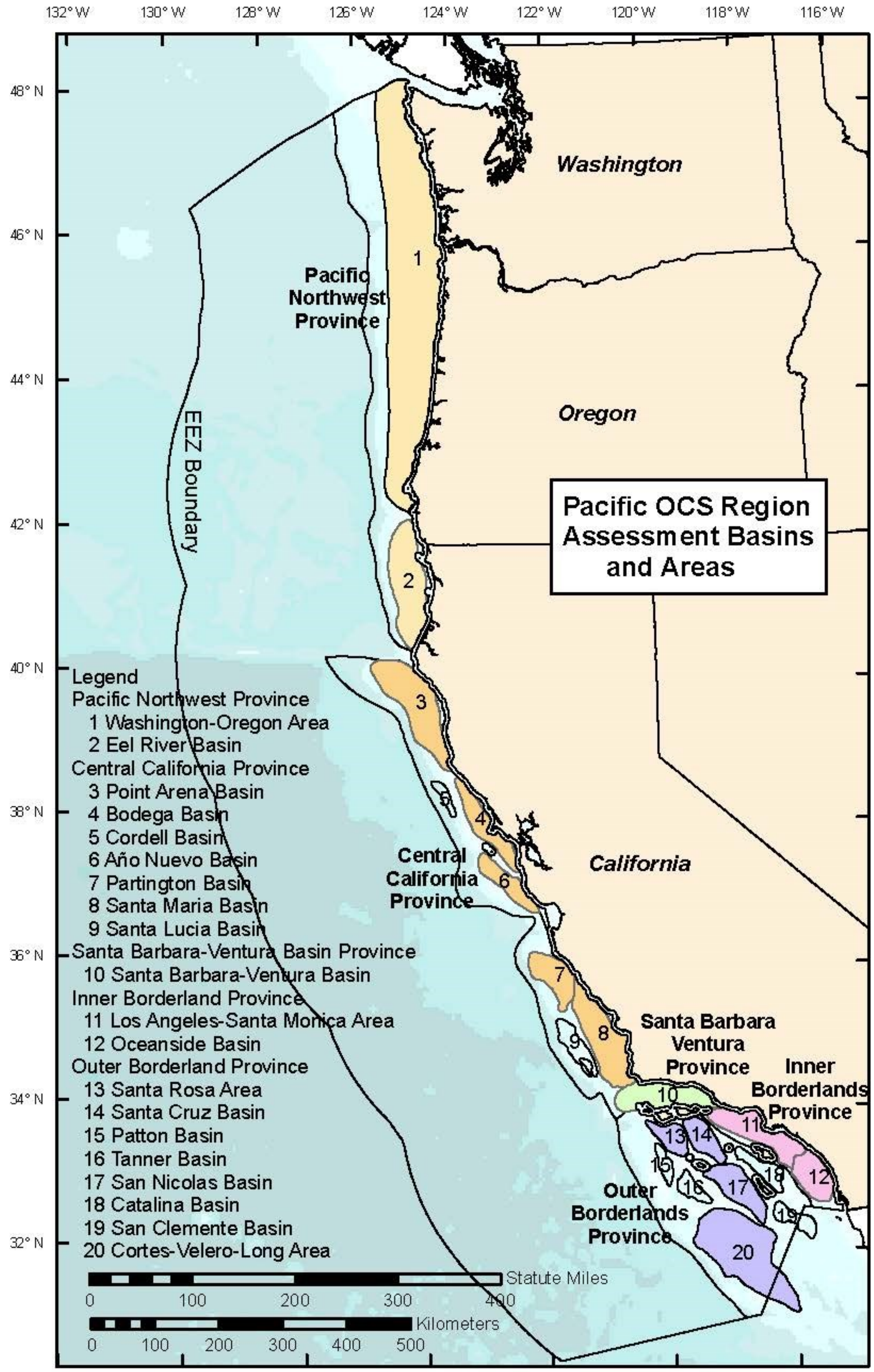


Figure 20. Map of the Pacific OCS Region showing assessment provinces, geologic basins and areas, and assessed areas.
This figure was modified from a figure in OCS Report BOEM 2014-667.

7.4.1 Washington-Oregon Basin

Washington-Oregon geologic basin is the northernmost basin in the Pacific OCS and is entirely within the Washington-Oregon Planning Area. The Washington-Oregon Basin is the largest basin in the Pacific Northwest Province (**Figure 21**). It extends a distance of about 400 miles and has a width of about 30 to 50 miles wide, encompassing roughly 18,000 square

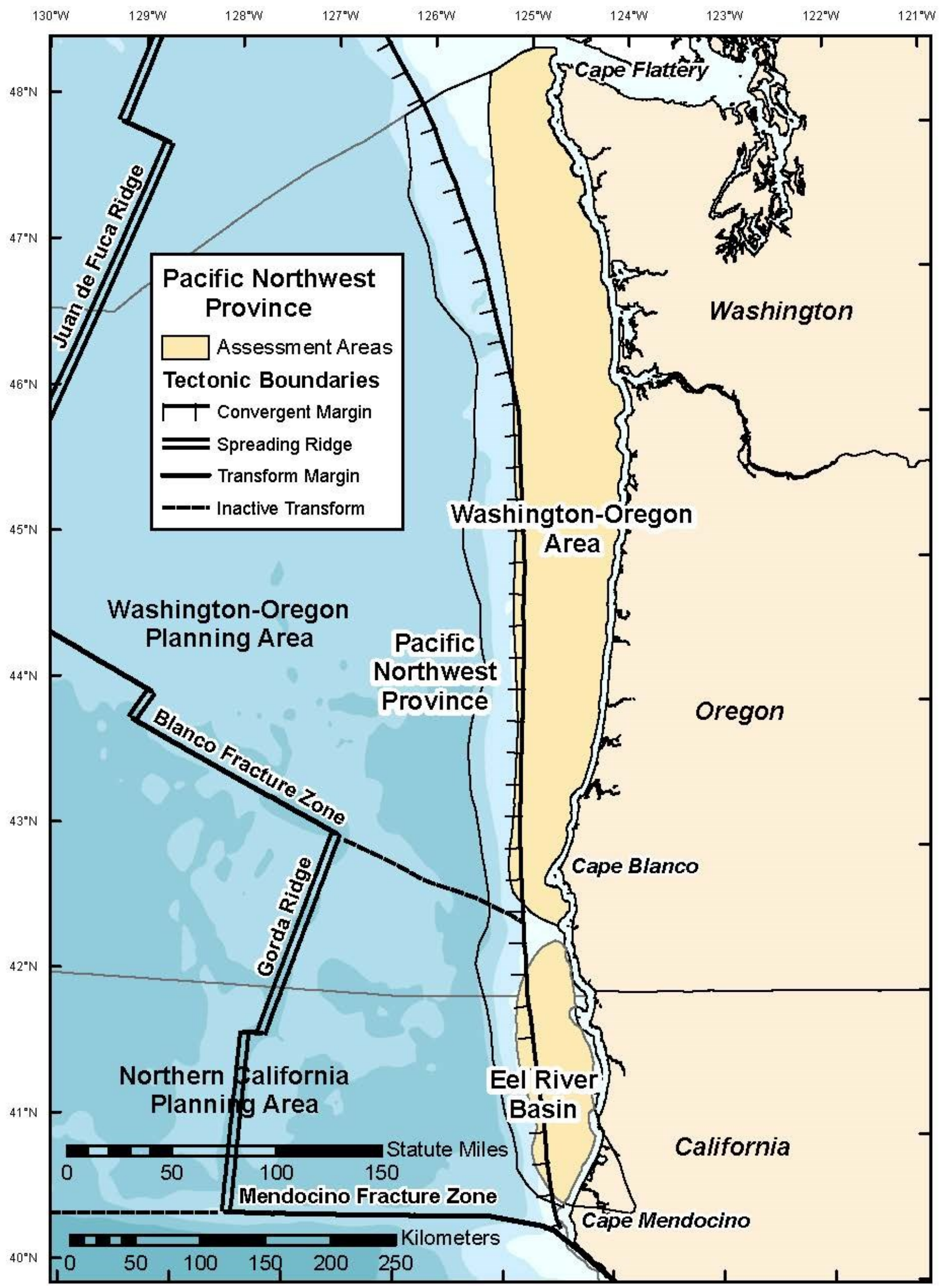


Figure 21. Map of the Pacific Northwest province showing assessment areas and planning area boundaries.
This figure was modified from a figure in OCS Report BOEM 2014-667.

miles. Water depths in the area range from about 100 feet to about 1,200 feet locally along the shelf-slope boundary.

Twelve exploratory wells were drilled within the province at ten sites in the 1960s. Eight of the wells encountered hydrocarbon shows. One well off central Washington and one off southern Oregon were tested and yielded gas at about 10 to 70 Mcf per day; two other wells offshore southern Washington had oil shows indicating the presence of high-gravity oil. Additional data that inform the current analysis include stratigraphic and paleontologic data from the offshore wells and a relatively sparse grid of 2D seismic data obtained in the 1970s and 1980s.

We have identified six Neogene-age plays based on the interpretation of the seismic-reflection profiles and the borehole data. The deepest rocks penetrated by offshore wells include sediment mixtures ranging between the Paleocene and Miocene epochs. Plays within the Washington-Oregon basin include the Neogene Fan Sandstone Play, Neogene Shelf Sandstone Play, Paleogene Sandstone Play, and Mélange Play.

7.4.1.1 Economic Factors

There is little oil and gas infrastructure on the coastline in the Washington-Oregon Area, and no large coastal cities. We assume development scenarios that include shared pipelines among multiple platforms and subsea completions, tied to shore at one or more of several coastal harbor towns.

7.4.2 Eel River Basin

The Eel River Basin is just north of Cape Mendocino and landward of the Cascadia subduction zone. The basin spans the border between the Washington-Oregon Planning Area and the Northern California Planning Area and is in the Pacific Northwest Province (**Figure 21**). The basin measures approximately 125 miles long and 30 miles wide and continues onshore in the southeast for about 25 miles in the vicinity of Eureka, California. The Eel River Basin assessment area encompasses about 3,500 square miles. Water depths in the assessment area range from about 200 feet to nearly 4,000 feet locally along the western limit of the basin.

Four exploratory wells were drilled in the central part of offshore Eel River Basin in the 1960s. All were drilled on structurally high targets. The only indication of hydrocarbons encountered in the offshore wells is veins of gilsonite (an asphalt) in a core from the bottom of well OCS-Petty P 0019 #1. Abundant gas seeps have been mapped in the southern part of the offshore basin, and extensive bottom simulating reflectors, likely indicating the presence of gas hydrate, are mapped throughout the western margin of the basin (Field and Kvenvolden, 1985).

The offshore geology has been extrapolated from the offshore well data and onshore geologic information and interpreted using a moderate to dense grid of seismic-reflection data. Prospect mapping is the basis for parameters relating to prospects in plays of this basin and for analogous plays in the Washington-Oregon assessment area.

The Eel River Basin includes four of the 43 geologic plays within the Pacific OCS Region the Neogene Fan Sandstone Play, Neogene Shelf Sandstone Play, Paleogene Sandstone Play, and Mélange Play. The Neogene Fan Sandstone Play is the only play in the basin that does not extend from the Northern California Planning Area into the Washington-Oregon Planning Area.

7.4.2.1 Economic Factors

There is little oil and gas infrastructure on the coastline in the Eel River Area, and no large coastal cities. Development scenarios built around local consumption assume offshore pipelines are tied into the existing onshore infrastructure of the onshore gas fields.

7.4.3 Point Arena Basin

The Point Arena Basin is situated just south of Cape Mendocino and located entirely in the Northern California Planning Area. It is the northernmost basin in the Central California Province (**Figure 22**). It extends a distance of about 100 miles lengthwise, has a width of about 30 miles, and encompasses an area of about 3,000 square miles. A small part of the basin extends into State waters and onshore at Point Delgada and Point Arena. Water depths in the basin range from about 200 feet at the 3-mile line to about 5,000 feet along the western margin.

During the 1960s, three offshore exploratory wells were drilled in the Point Arena Basin. Oil shows were encountered in all three of these wells and in two onshore wells. The offshore area has been studied using a moderately dense to dense grid of seismic-reflection profiles. Silica diagenetic reflectors are seen on the seismic data in the southern part of the basin; their presence suggests that oil generation may have occurred as shallow as 3,000 feet below the seafloor, and that fractured reservoirs are likely present in that part of the basin.

Plays within the Point Arena Basin include the Neogene Sandstone Play, Monterey Fractured Play, and Pre-Monterey Sandstone Play. All three plays trend towards the southernmost part of the basin.

7.4.3.1 Economic Factors

There is little oil and gas infrastructure on the coastline north of the San Francisco Bay, and there are no large coastal cities. Development scenarios assume pipelines are shared among multiple platforms or subsea completions and tied to shore at either Eureka to the north or San Francisco Bay.

7.4.4 Bodega Basin

The Bodega Basin of the Central California Province is located between the Point Arena and Año Nuevo Basins and extends from just south of Point Arena to Half Moon Bay on the west side of the San Francisco Peninsula (**Figure 22**). Total area of the basis is approximately 1,700 square miles. Some parts of the basin extend into State waters, including that part exposed onshore at the Point Reyes Peninsula. The continental shelf is wider here than in Point Arena Basin; water depths within the basin range from about 30 feet on the Federal/State boundary to 1,000 feet near the shelf-slope break.

Subsurface data are available from ten offshore exploratory wells drilled from nine sites in the northern and central portions of the basin and from a moderately dense grid of seismic-reflection profiles. The petroleum potential of the offshore portion of the basin may be most prospective in the vicinity of the Point Reyes fault, where large vertical displacement has created an anomalously thick section of Monterey Formation strata and a number of potential structural traps. However, the absence of significant shows in the offshore wells (many of which were drilled near the fault) suggests that this vertically continuous fault may have been a barrier to migrating hydrocarbons.

Plays within the Bodega Basin include the Neogene Sandstone Play, Monterey Fractured Play, and Pre-Monterey Sandstone Play. The extent of each play spans the entire extent of the basin and continues onshore to the San Andreas fault zone.

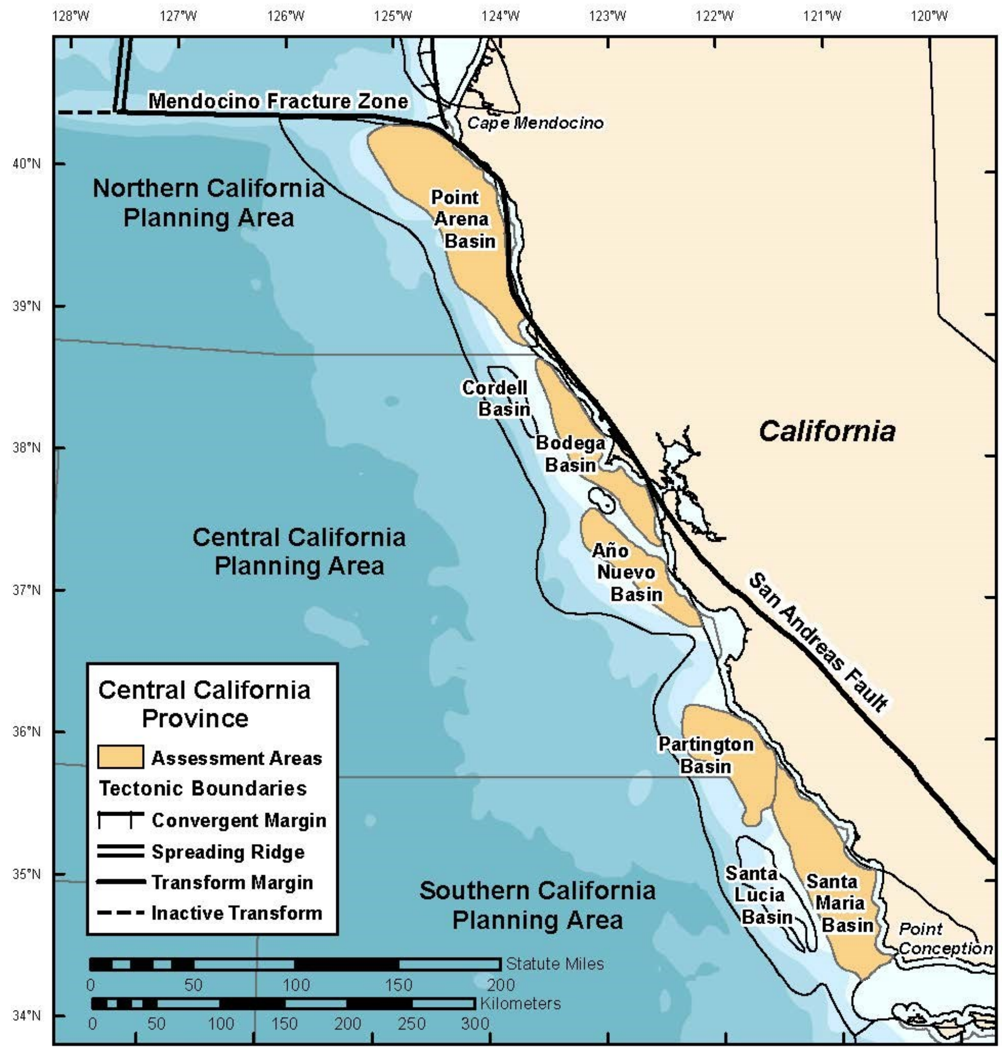


Figure 22. Map of the Central California province showing assessment areas and planning area boundaries.

7.4.4.1 Economic Factors

There is little oil and gas infrastructure on the coastline north of the San Francisco Bay, and there are no large coastal cities. Scenarios regarding development of hydrocarbons within the basin assume pipelines could be shared among multiple platforms or subsea completions and tied to shore at San Francisco Bay. The southern two-thirds of the basin lies within the Cordell Bank, Gulf of the Farallones, and Monterey Bay marine sanctuaries.

7.4.5 Año Nuevo Basin

The Año Nuevo Basin is located between the Bodega and Partington basins in the Central California Province (**Figure 22**). The Año Nuevo Basin is located entirely within the Central California Planning Area. This elongated, northwest-trending basin extends approximately 80 miles, is approximately 15 miles wide, and occupies an area of approximately 1,000 square miles. A small portion of the basin lies in State waters and is exposed onshore at Point Año Nuevo. Water depths in the assessment area range from approximately 200 feet at the 3-mile line near Point Año Nuevo to more than 4,000 feet on the continental slope south and west of the Farallon Islands.

Data and information are available from two offshore exploratory wells, a moderately dense grid of high quality, seismic-reflection profiles, data from onshore wells and outcrops, and published sources. The primary petroleum source rocks for all plays in the basin are interpreted to be rocks of the Miocene Monterey Formation, by analogy with several California coastal basins. Although organic geochemical data are lacking for Monterey rocks in the Año Nuevo Basin, the presence of organic-rich, thermally mature source rocks is strongly indicated by shows in Monterey and other strata in the basin.

Abundant oil shows in the offshore wells and subsurface seismic amplitude anomalies indicate that oil and gas have generated and migrated within the Año Nuevo Basin. The petroleum potential of the basin may be most prospective in the southeast portion, where vertically continuous faults may have created migration pathways through potentially mature Monterey rocks, and where numerous structural traps exist.

The three plays assessed within the Año Nuevo Basin include the Neogene Sandstone Play, Fractured Monterey Play, and Pre-Monterey Sandstone Play. Areally, all three plays stack upon one another and extend to near the boundaries of the basin.

7.4.5.1 Economic Factors

Oil and gas production development scenarios assume that both subsea and multi-platform production of hydrocarbons would occur in the Año Nuevo Basin. Pipelines installed would be shared among platforms and would tie together and make landfall near Santa Cruz, CA.

7.4.6 Santa Maria-Partington Basin

The Santa Maria-Partington Basin is approximately 165 miles long and 25 mile wide and occupies an area of approximately 3,800 square miles (**Figure 22**). Water depths range from 300 feet near Point Sal to 8,000 feet at the northwest extent of the basin. The basin itself straddles the boundary line delineating the Central and Southern California Planning Areas. The majority of the Partington portion of the basin lies within the Central California Planning Area, while the rest of the basin lies within the Southern California Planning Area.

More than 50 exploratory wells have been drilled in the southern and central portions of the offshore Santa Maria Basin; the northern portion of the basin and the entire Partington Basin remain undrilled. The Monterey Formation has been the primary exploration target in the basin since the discovery well at the Point Arguello field was drilled in 1980. Seventy-eight OCS blocks have been leased, and 13 fields have been discovered. Three fields in the offshore Santa Maria Basin (Point Arguello, Point Pedernales, and Rocky Point fields) are producing hydrocarbons at the time of this assessment.

Seismic-reflection data coverage in the offshore Santa Maria and Partington Basins is dense; the average trackline spacing in southern and central offshore Santa Maria Basin is less than one-half mile. Towards the west and north into Partington Basin, the coverage includes approximately 1-mile spacing. For this assessment, a seismic data set of multiple surveys with a grid density of approximately 1-mile spacing was interpreted.

For this assessment, we recognize four geologic plays. The Fractured Monterey Play is areally extensive and is interpreted to exist across the full extent of the basin. The Basal Sisquoc Sandstone Play, the Paleogene Sandstone Play, and the Breccia Play are all aerially discontinuous and are not projected to be found across all parts of the basin.

7.4.6.1 Economic Factors

The existing development and infrastructure are all located in the southern part of the basin in an area proximal to the coastline. In this vicinity, we assume use of existing infrastructure for future development, including opportunities for utilizing pipelines and onshore facilities. For development further north, we assume pipelines shared among multiple platforms and subsea completions and tied to existing infrastructure onshore near Santa Maria.

7.4.7 Santa Barbara-Ventura Basin

The Santa Barbara-Ventura Basin is the only basin in the Santa Barbara-Ventura Basin Province (**Figure 23**). Though only the Federal portion of the basin (generally called the Santa Barbara Channel) is included in the offshore assessment province, the basin itself includes an onshore area that is about equal in size to the offshore portion. The province as defined is about 1,800 square miles in area, and water depths range from about 100 to 1,800 feet.

The present-day north-south compressional regime has uplifted and tilted rocks on the north and south sides of the basin. This feature, and associated faulting, has created numerous geologic traps for hydrocarbons. On the west end of the Santa Barbara Channel, the most important oil-producing formation is the organic-rich Monterey Formation. The Monterey is less productive to the east where Eocene through Pliocene sandstones are the major petroleum producers in the eastern half of the offshore basin.

The Santa Barbara-Ventura Basin includes four assessed geologic plays. The Pico-Repetto Sandstone Play comprises oil and gas accumulations in Pliocene and Early Pleistocene turbidite sandstones. The Fractured Monterey Play exists throughout the basin and consists of Middle to Late Miocene siliceous fractured shale reservoirs of the Monterey Formation. The Rincon-Monterey-Topanga Sandstone Play and the Sespe-Alegria-Vaqueros Sandstone Play are assessed as a single play, based primarily on the stratigraphic proximity and occurrence of hydrocarbons in the corresponding formations. The Rincon-Monterey-Topanga Sandstone Play is limited to two isolated areas within the basin, whereas the Sespe-Alegria-Vaqueros Sandstone Play is basin-wide. The Gaviota-Sacate-Matilija (GSM) Play includes known and prospective accumulations of oil and associated gas in Eocene to Early Oligocene sandstones of various depositional environments, including deepwater turbidites, slope to shelf fans and channels, nearshore bars, and continental and deltaic deposits.

Nearly three-quarters of Pacific OCS regional production is from the Santa Barbara-Ventura Basin; when onshore fields are included, this trend has produced over 2 Bbo and is likely to ultimately produce over 3 Bbo. Stratigraphic and paleontologic data from onshore and offshore wells and a dense grid of 2D seismic data obtained in the 1970s and 1980s are the bases for interpretation of the offshore geology.

7.4.7.1 Economic Factors

Santa Barbara Channel has the most oil and gas development and infrastructure of the Pacific OCS. Future development would likely be required to tie in to existing pipelines. The number of platforms would be minimized by the use of extended-reach drilling. In Santa Barbara Channel, the longest extended-reach wells reach nearly 7 miles from the production platform.

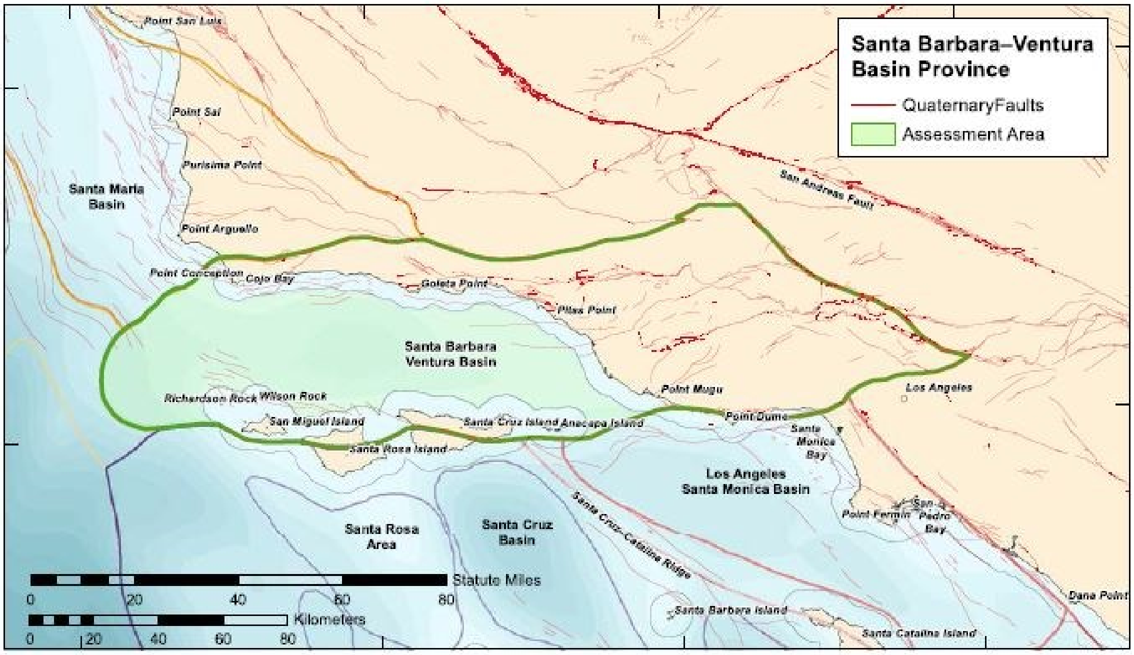


Figure 23. Map of the Santa Barbara-Ventura Basin province showing assessed area.

7.4.8 Los Angeles-Santa Monica-San Pedro Basins

The Los Angeles-Santa Monica-San Pedro Basins (LA-SM-SP) of the Inner Borderlands Province are located off the coast of southern California (**Figure 24**). The assessed basins are bounded on the north by the Malibu Coast-Santa Monica fault zone, and extend westward to the Santa Cruz-Catalina Ridge and southeastward to Dana Point. The Los Angeles Basin comprises a thick accumulation of sediments (over 30,000 feet) which are related to the tectonic rotation of the western Transverse Ranges. The combined area of the three basins is approximately 1,600 square miles, with water depth ranging from 100 feet to over 3,000 feet.

The onshore Los Angeles Basin is one of the most prolific oil provinces in the world on a per-square mile basis, with cumulative oil production exceeding 9 Bbo. There are two major trends (each with about 3 Bbo of originally recoverable oil) in the southern part of the onshore basin that trend into the offshore area. Two fields (Beta and Beta NW) have been discovered in the southern Federal offshore area of the LA-SM-SP area. Most exploratory wells have not tapped the thickest parts of the basins.

We assess five geologic plays in the LA-SM-SP Basin. The Puente Fan Play includes Middle Miocene to Lower Pliocene fan sandstones of the Puente and Repetto Formations and represents the only established play in the area. The Upper Miocene Sandstone Play is defined as a frontier play that includes accumulations of oil and associated gas in distal Puente Fan sandstones on the San Pedro shelf. The Modelo Play is a conceptual play, defined to include accumulations of oil and associated gas in structural and fault traps of the Modelo Formation. The Modelo Formation is stratigraphically equivalent to the Monterey Formation of central California and the western Santa Barbara-Ventura basin. The Dume Thrust Fault Play is a frontier play that includes oil and associated gas in fault traps along the Dume and

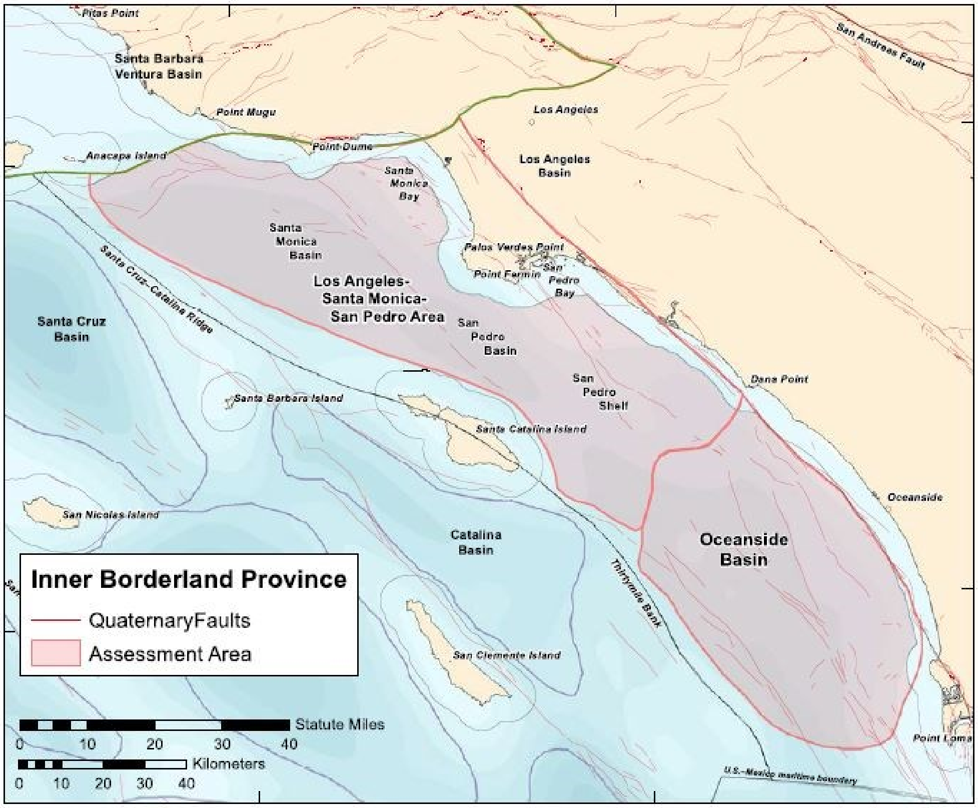


Figure 24. Map of the Inner Borderland Province showing the Los Angeles-Santa Monica-San Pedro Area and the Oceanside Basin.
This figure was modified from a figure in OCS Report BOEM 2014-667.

Malibu Coast faults. The Sano Onofre Breccia Play is a frontier play that includes oil and associated gas in stratigraphic and structural traps of the fractured Catalina Schist, the schist-derived San Onofre Breccia, and the overlying nodular shale. Four of the geologic plays (San Onofre Breccia, Modelo, Upper Miocene Sandstone, and Puente Fan Sandstone) are defined on the basis of reservoir rock stratigraphy while the Dume Thrust Fault Play is defined based on expected fault trapping style. All of the plays are Miocene in age or younger.

Stratigraphic and paleontologic data from the offshore wells and a moderate to dense grid of 2D seismic data obtained in the 1970s and 1980s are the bases for interpretation of the offshore geology.

7.4.8.1 Economic Factors

The Los Angeles Basin has the largest concentration of onshore facilities on the West Coast, and there are multiple coastal access points in the LA-SM-SP area. The number of potential future platforms would be minimized by the use of extended-reach drilling.

7.4.9 Oceanside-Capistrano Basin

The Oceanside Basin of the Inner Borderlands Province (**Figure 24**) is bounded on the northwest by the Dana Point sill and extends south approximately 50 miles to the vicinity of La Jolla, CA; it is bounded on the west by the Thirty Mile Bank. The entire basin is about 50 miles long, averages 30 miles in width, and occupies an area of about 1,500 square miles.

Water depth in the basin ranges from 300 to about 3,000 feet.

Three conceptual plays, all based on reservoir rock stratigraphy, are defined in the Oceanside-Capistrano Basin. The Upper Miocene Sandstone Play is a conceptual play comprising oil and associated gas in Upper Miocene sandstones of the Capistrano Formation. The Fractured Monterey Play is a conceptual play comprising Middle to Upper Miocene fractured rocks of the Monterey Formation. The Monterey Formation is considered to be both source rock and reservoir rock for this play. The Lower Miocene Sandstone Play is a conceptual play comprising Lower to Middle Miocene clastic rocks of the San Onofre Breccia, Topanga Formation, and Vaqueros Formation.

While no deep exploratory wells have been drilled in the offshore basin, several high quality seismic-reflection surveys have been recorded. Onshore, more than 60 exploratory wells have been drilled from the early 1950s to 1984. Two fields—the San Clemente and Cristianitos Creek fields—have been discovered. Collectively, these fields produced a very small quantity (less than 5 Mbbl) of high-gravity oil from the Upper Cretaceous Williams Formation in the late 1950s. Both fields were considered to be subcommercial and have been abandoned.

7.4.9.1 Economic Factors

There are no developed fields in the Oceanside basin; however there are multiple viable coastal access points. Any future development would likely be required to share pipelines and other facilities. The number of platforms could be minimized by the use of extended-reach drilling.

7.4.10 Santa Cruz-Santa Rosa Basins

The Santa Cruz-Santa Rosa Basins are adjacent but separate geologic basins in the Outer Borderland assessment province. The basins are located south of the Channel Islands and west of the Santa Cruz−Catalina ridge (**Figure 25**). Individually the basins trend roughly NW/SE and are separated by an un-named margin that trends NNW/SSE. Collectively the basins cover an area of approximately 2,000 square miles where water depths in the center of the basins exceed 3,000 feet.

We assess three geologic plays in the Santa Cruz-Santa Rosa area that are defined by reservoir rock stratigraphy. The Fractured Monterey Play is a conceptual play comprising oil and associated gas in Middle Miocene fractured siliceous rocks of the Monterey Formation. The Lower Miocene Sandstone Play is a conceptual play consisting of oil and associated gas in Lower Miocene clastic rocks. The Paleogene-Cretaceous Sandstone Play of the Santa Cruz-Santa Rosa assessment area is a conceptual play comprising oil and associated gas in Upper Cretaceous and Paleogene clastic rocks. The Fractured Monterey and Lower Miocene Sandstone Plays are confined to the Santa Cruz basin proper and the Santa Rosa area proper and have been assessed separately in each area. The Paleogene-Cretaceous Sandstone Play exists within and between both areas and has been assessed for both areas together.

No exploratory wells have been drilled within the Santa Cruz-Santa Rosa Basin assessment area; one well was drilled across a fault immediately east of the Santa Cruz Basin, and another well was drilled across a fault immediately north of the Santa Rosa Area. The adjacent wells penetrated Lower Miocene, Paleogene, and Cretaceous strata. Most Middle Miocene and younger strata have been eroded from the uplifted areas in which the wells were drilled. No appreciable shows of oil or gas were encountered in either of the adjacent wells. In addition, a number of moderate to high quality

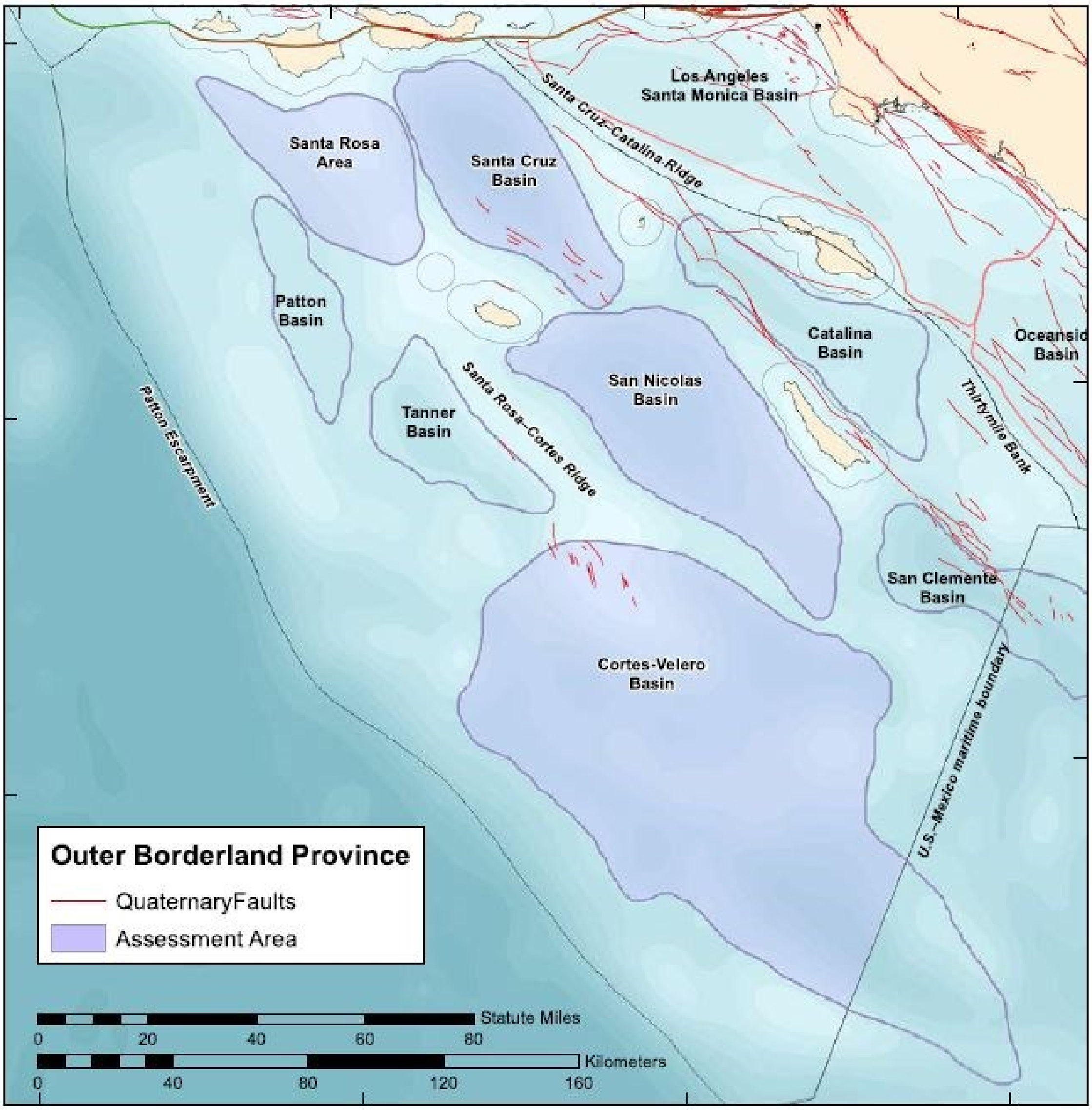


Figure 25. Outer Borderland Province basins and areas.
Assessed basins are colored purple. This figure was modified from a figure in OCS Report BOEM 2014-667.

seismic-reflection surveys have been recorded in both areas.

7.4.10.1 Economic Factors

There is no existing oil and gas infrastructure within the Outer Borderland Province, and the distance from shore (~ 50 miles) may require that any future development utilize an FPSO facility from which tankers could transport production. Should there be multiple platforms or subsea completions in a given area, these facilities could be shared. The number of platforms would be minimized by use of extended-reach drilling technology.

7.4.11 San Nicolas Basin

The San Nicolas Basin assessment area is located immediately southeast of San Nicolas Island in the Outer Borderland Province (**Figure 25**). The basin is bounded on the east by the San Clemente ridge and on the west by the Santa Rosa-Cortes ridge. The basin is about 70 miles long by 10 to 30 miles wide and encompasses an area of approximately 1,300 square miles. The water depth within the basin ranges from 3,000 to 5,000 feet and averages 3,500 feet.

We identify four petroleum geologic plays in the San Nicolas Basin on the basis of reservoir rock stratigraphy. The Upper Miocene Sandstone Play is a conceptual play where we project oil and associated gas in Upper Miocene sandstones. The Fractured Monterey Play is a conceptual play comprising oil and associated gas in Middle Miocene fractured rocks of the Monterey Formation. The Monterey Formation is considered to be both petroleum source rock and reservoir rock for this play by analogy with Monterey rocks in the offshore Santa Barbara-Ventura and Santa Maria basins and the onshore San Joaquin basin. The Lower Miocene Sandstone Play is a conceptual play comprising oil and associated gas opportunities in Lower Miocene sandstones. The Paleogene-Cretaceous Sandstone Play is a conceptual play which includes Upper Cretaceous and Paleogene-aged sandstones. The primary petroleum source rocks for this play are believed to be Paleogene mudstones and shales similar to the Oligocene and Eocene section of adequate to excellent source rock quality that were penetrated by the deep stratigraphic test well OCS-CAL 75-70 No. 1 on Cortes bank. All of the plays in the basin are considered to be conceptual plays based on the absence of directly detected hydrocarbons within the play areas.

No industry exploratory wells have been drilled within the San Nicolas Basin; however, a number of high quality seismic-reflection surveys have been recorded. Eight wells were drilled immediately west of the basin on the southern end of the Santa Rosa-Cortes ridge.

7.4.11.1 Economic Factors

There is no existing oil and gas infrastructure within the Outer Borderland Province, and the distance from shore (~ 50 miles) to the middle of the San Nicolas Basin may require that any future development utilize a FPSO facility from which tankers could transport production. Should there be multiple platforms or subsea completions in a given area, these facilities could be shared. The number of platforms would be minimized by use of extended-reach drilling technology.

7.4.12 Cortes-Velero-Long

The Cortes-Velero-Long assessment area is located in the southern part of the Outer Borderland Province (Figure 25). This NW/SE trending assessment area is approximately bounded by the Santo Tomas and Blake knolls to the east, the Patton escarpment to the west, the Northeast and Tanner banks to the north, and the U.S.-Mexico maritime boundary to the south. It is approximately 95 miles long, ranges from 30 to 60 miles wide, and encompasses approximately 4,800 square miles. The water depth within the area ranges from 4,500 to 6,000 feet.

This composite assessment area comprises the U.S. Federal portion of four geologic subareas: the West Cortes, East Cortes, Velero, and Long Basins. These subareas have been combined as a single assessment area due to the nearly continuous extent of Paleogene strata and lack of definitive basin boundaries. The southern part of the Velero Basin extends beyond the U.S.-Mexico maritime boundary; it is not included in the assessment area and has not been assessed.

We assess undiscovered resources in two petroleum geologic plays in the Cortes-Velero-Long assessment area. The plays are defined on the basis of reservoir rock stratigraphy. The plays (and corresponding reservoir rocks) include the Lower Miocene Sandstone Play and the Paleogene-Cretaceous Sandstone Play. Both are considered to be conceptual plays based on the absence of directly detected hydrocarbons within the play areas.

No exploratory wells have been drilled within the basinal areas of the Cortes-Velero-Long assessment area; however, a number of high quality seismic-reflection surveys have been recorded. Eight wells were drilled on the southern end of the Santa Rosa-Cortes ridge. These wells penetrated Lower Miocene, Paleogene, and Cretaceous strata. No appreciable shows of oil or gas were encountered in the wells; however, weak indications of hydrocarbons (oil staining, minor fluorescence, and weak gas shows) were encountered in some of the wells.

7.4.12.1 Economic Factors

There is no oil and gas infrastructure within the Cortes-Velero-Long assessment area, nor is there any proximal to the Outer Borderland Province. Future development in the relatively remote area would likely utilize a FPSO facility from which tankers could offload production. Should there be multiple platforms or subsea completions in a given area, these facilities could be shared. The number of platforms would be minimized by use of extended-reach drilling technology

7.5 Assessment Results

Estimates of the total volume of UTRR, and of the portion of those resources that may be economically recoverable under various economic scenarios, are developed in the Pacific OCS at the play level (**Table 14**) and aggregated to the Geologic Basin and Province (**Table 5**), Planning Area (**Table 16**), OCS Region, and national level.

The total volume of UTRR that are estimated to be UERR varies based on several assumptions beyond those implicit in the calculation of geologic resources, including commodity price environment, cost environment, and relationship of gas price to oil price. In general, larger volumes of resources are estimated to be economically recoverable under more favorable economic conditions. **Table 17** provides UERR for the Washington-Oregon, Northern California, Central California, and Southern California Planning Areas over a price spectrum that ranges from $30/barrel to $160/barrel and assumes a 30 percent value of gas price to oil. Estimates of UERR are presented as price-supply curves for the Pacific OCS in **Figure 26**. A price-supply curve shows the relationship of price to economically recoverable resource volumes (i.e., a horizontal line from the price axis to the curve yields the quantity of economically recoverable resources at the selected price). The price-supply charts contain two curves and two price scales, one for oil (green) and one for gas (red); the curves represent mean values at any specific price. The two vertical lines indicate the mean estimates of UTRR oil and gas resources for the Pacific OCS Region. At high prices, the economically recoverable resource volumes approach the technically recoverable volumes. The oil and gas price-supply curves are not independent of each other; that is, one specific oil price cannot be used to obtain an oil resource while a separate unrelated gas price is used to obtain a gas resource. The gas price is dependent on the oil price and must be used in conjunction with the oil price on the opposite axis of the chart to calculate resources, as oil and gas frequently occur together and individual pool economics are calculated using the coupled pricing. Due to fluctuations in the economic value of gas relative to oil, four different BTU-based price pairings for oil and gas are analyzed. Figure 26 presents specific price pairs associated with a 30 percent economic value of gas relative to oil.

7.6 Discussion

Based on the limited development and expansion of existing oil and gas fields, the absence of recent exploratory drilling efforts to find new fields, and the paucity of newly-acquired exploration seismic data on the Pacific OCS, there have been no changes to mean UTRR oil and gas estimates for the Pacific OCS in the time since the last national assessment of undiscovered resources. Additionally, we have made no substantive change to the assumptions and underlying development methodologies that are utilized to calculate UERR. For reporting purposes, the presentation of UERR using a 30 percent gas price adjustment represents a change from the 2011 reporting assumption of 40 percent.

The Pacific OCS continues to be an area of the OCS that we view as largely oil-prone, with nearly 80 percent of the UTRR assessed as oil. Further, over 50 percent of the undiscovered technically recoverable oil resource is located in the Central California Province, where the Monterey Formation fractured siliceous reservoir rocks and associated plays are most commonly found. Eighty-eight percent of the oil resource in the Central California Province is located in Monterey plays.

Table 14. Risked UTRR for the Pacific OCS Region by province and area/basin.

Basin	Region / Play	2016 Pacific UTRR Oil and Gas Resources								
		Oil (Bbo)			Gas (Tcf)			BOE (Bbo)		
	Play	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
	Pacific OCS	**6.96**	**10.20**	**14.03**	**10.52**	**16.10**	**23.92**	**8.83**	**13.07**	**18.28**
Washington-Oregon Area	Growth Fault	0.00	0.13	0.42	0.00	0.45	1.42	0.00	0.21	0.67
	Neogene Channel/Fan Sandstone	0.00	0.11	0.29	0.00	0.85	2.15	0.00	0.26	0.67
	Neogene Shelf Sandstone	0.00	0.15	0.39	0.00	0.58	1.34	0.00	0.25	0.63
	Paleogene Sandstone	0.00	0.01	0.03	0.00	0.36	0.94	0.00	0.07	0.19
Eel River Basin	Neogene Channel/Fan Sandstone	0.01	0.03	0.08	0.28	0.60	0.96	0.06	0.13	0.25
	Neogene Shelf Sandstone	0.00	0.04	0.06	0.00	0.90	1.58	0.00	0.20	0.34
	Paleogene Sandstone	0.00	0.01	0.03	0.00	0.03	0.09	0.00	0.01	0.04
Ano Nuevo Basin	Neogene Sandstone	0.00	0.08	0.18	0.00	0.09	0.21	0.00	0.09	0.22
	Monterey Fractured	0.23	0.58	1.10	0.19	0.59	1.23	0.26	0.68	1.32
	Pre-Monterey Sandstone	0.00	0.05	0.15	0.00	0.07	0.25	0.00	0.07	0.19
Bodega-La Honda Basin	Neogene Sandstone	0.00	0.05	0.17	0.00	0.06	0.18	0.00	0.06	0.20
	Monterey Fractured	0.49	1.09	1.87	0.54	1.10	2.17	0.58	1.28	2.26
	Pre-Monterey Sandstone	0.00	0.27	0.59	0.00	0.36	0.86	0.00	0.33	0.74
Cortez-Velero-Long	Lower Miocene Sandstone	0.00	0.18	0.56	0.00	0.44	2.20	0.00	0.26	0.95
	Paleogene-Cretaceous Sandstone	0.00	0.13	0.56	0.00	0.32	1.82	0.00	0.19	0.89
Oceanside-Capistrano	Upper Miocene Sandstone	0.00	0.50	1.31	0.00	0.26	0.67	0.00	0.55	1.43
	Monterey Fractured	0.00	0.39	1.01	0.00	0.44	1.01	0.00	0.47	1.19
	Lower Miocene Sandstone	0.00	0.17	0.67	0.00	0.42	1.48	0.00	0.25	0.94
Point Arena Basin	Neogene Sandstone	0.00	0.08	0.22	0.00	0.09	0.40	0.00	0.10	0.29
	Monterey Fractured	1.03	1.77	2.82	0.84	1.78	3.38	1.18	2.08	3.42
	Pre-Monterey Sandstone	0.00	0.16	0.32	0.00	0.22	0.66	0.00	0.20	0.43
San Nicolas Basin	Upper Miocene Sandstone	0.00	0.07	0.29	0.00	0.04	0.19	0.00	0.08	0.32
	Monterey Fractured	0.00	0.20	0.68	0.00	0.23	0.72	0.00	0.24	0.80
	Lower Miocene Sandstone	0.00	0.12	0.51	0.00	0.30	1.08	0.00	0.18	0.70
	Paleogene-Cretaceous Sandstone	0.00	0.09	0.44	0.00	0.23	0.75	0.00	0.13	0.57
Santa Barbara-Ventura	Pico-Repetto Sandstone	0.00	0.19	0.85	0.02	0.39	1.62	0.01	0.26	1.13
	Monterey Fractured	0.28	0.76	1.68	0.29	0.70	1.05	0.33	0.89	1.87
	Rincon-Monterey-Topanga Ss	0.02	0.28	0.34	0.36	1.21	4.76	0.09	0.49	1.19
	Gaviota-Sacate-Matilija Ss	0.00	0.11	0.31	0.04	0.45	1.34	0.01	0.19	0.55
Santa Maria-Partington	Basal Sisquoc Sandstone	0.03	0.08	0.15	0.03	0.08	0.12	0.04	0.09	0.17
	Paleogene Sandstone	0.00	0.01	0.04	0.00	0.02	0.12	0.00	0.01	0.06
	Breccia	0.00	0.01	0.06	0.00	0.01	0.05	0.00	0.01	0.07
	Monterey Frac Subjective	0.37	1.02	2.11	0.30	0.74	1.45	0.43	1.15	2.37
Los Angeles- Santa Monica-San Pedro	Puente Fan Ss	0.09	0.30	0.64	0.11	0.33	0.55	0.11	0.35	0.74
	Upper Miocene Ss	0.00	0.04	0.09	0.00	0.02	0.04	0.00	0.04	0.10
	Modelo	0.00	0.15	0.44	0.00	0.21	0.40	0.00	0.18	0.52
	Dume Thrust Fault	0.00	0.34	0.78	0.00	0.45	1.74	0.00	0.42	1.09
	San Onofre Breccia	0.00	0.07	0.16	0.00	0.03	0.08	0.00	0.08	0.17
Santa Cruz - Santa Rosa	Paleogene-Cretaceous Ss	0.00	0.07	0.28	0.00	0.18	1.23	0.00	0.11	0.50
	SCruz Monterey Frac	0.00	0.20	0.52	0.00	0.22	0.88	0.00	0.24	0.67
	SCruz L Mio Ss	0.00	0.08	0.24	0.00	0.19	0.70	0.00	0.11	0.36
	SRosa L Mio Ss	0.00	0.02	0.12	0.00	0.06	0.40	0.00	0.04	0.19
	SRosa Monterey Frac	0.00	0.03	0.13	0.00	0.04	0.21	0.00	0.04	0.16

Note: Resource values are in billion barrels of oil (Bbo) and trillion cubic of gas (Tcfg). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding.

Table 15. Risked UTRR for the Pacific OCS Region by province and area/basin.

Province	Pacific UTRR Oil and Gas Resources		
	Oil (Bbo)	Gas (Tcf)	BOE (Bbo)
Area/Basin	Mean	Mean	Mean
Pacific Northwest Province			
Washington-Oregon Area	0.40	2.23	0.80
Eel River Basin	0.07	1.52	0.34
Total Province	**0.47**	**3.75**	**1.14**
Central California Province			
Ano Nuevo Basin	0.71	0.75	0.84
Bodega-La Honda Basin	1.40	1.52	1.68
Point Arena Basin	2.01	2.10	2.38
Santa Maria-Partington Basin	1.11	0.84	1.26
Total Province	**5.23**	**5.21**	**6.16**
Santa Barbara-Ventura Basin Province			
Santa Barbara-Ventura Basin	1.34	2.74	1.83
Total Province	**1.34**	**2.74**	**1.83**
Inner Borderland Province			
Oceanside-Capistano Basin	1.06	1.12	1.26
Los Angeles-Santa Monica-San Pedro Basin	0.89	1.03	1.08
Total Province	**1.95**	**2.15**	**2.34**
Outer Borderland Province			
Cortez-Valero-Long	0.31	0.76	0.45
San Nicholas Basin	0.49	0.79	0.63
Santa Cruz-Santa Rosa	0.40	0.69	0.52
Total Province	**1.20**	**2.24**	**1.60**

Table 16. Risked UTRR for the Pacific OCS Region by planning area.

Region	Risked Undiscovered Technically Recoverable Oil and Gas Resources (UTRR)								
	Oil (Bbo)			Gas (Tcfg)			BOE (Bbo)		
Planning Area	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Pacific OCS	**6.96**	**10.20**	**14.03**	**10.52**	**16.10**	**23.92**	**8.83**	**13.07**	**18.28**
Washington/Oregon	0.00	0.40	1.14	0.03	2.28	5.80	0.01	0.81	2.18
Northern California	1.07	2.08	3.55	2.14	3.58	5.35	1.45	2.71	4.50
Central California	1.22	2.40	3.87	1.16	2.49	4.19	1.42	2.84	4.61
Southern California	2.82	5.32	8.70	3.58	7.76	13.60	3.46	6.70	11.12

Note: Resource values are in billion barrels of oil (Bbo) and trillion cubic of gas (Tcfg). 95% indicates a 95 percent chance of at least the amount listed; 5% indicates a 5 percent chance of at least the amount listed. Only mean values are additive. Some total mean values may not equal the sum of the component values due to independent rounding.

Table 17. Risked UERR for the Pacific OCS Region by planning area.

Region / Planning Area	Risked Undiscovered Economically Recoverable Oil and Gas Resources (UERR)											
	$30/Bbl $1.60/Mcf		$40/Bbl $2.14/Mcf		$60/Bbl $3.20/Mcf		$100/Bbl $5.34/Mcf		$110/Bbl $5.87/Mcf		$160/Bbl $8.54/Mcf	
	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas
Pacific OCS	4.00	5.30	5.10	6.61	6.45	8.29	7.30	9.43	7.43	9.62	7.89	10.35
Washington/Oregon	0.09	0.32	0.14	0.46	0.20	0.65	0.23	0.79	0.24	0.81	0.26	0.93
Northern California	0.60	0.65	0.83	0.91	1.13	1.25	1.34	1.52	1.37	1.57	1.50	1.77
Central California	1.35	1.42	1.63	1.71	1.91	2.00	2.08	2.17	2.11	2.20	2.18	2.27
Southern California	1.96	2.91	2.50	3.54	3.21	4.39	3.65	4.94	3.72	5.03	3.95	5.37

Note: Resource values are in billion barrels of oil (Bbo) and trillion cubic feet of gas (Tcfg). Some total mean values may not equal the sum of the component values due to independent rounding. Prices are in dollars per barrel($/Bbl) for oil, and dollars per thousand cubic feet ($/Mcf) for gas. This table represents a gas price adjustment of 0.3.

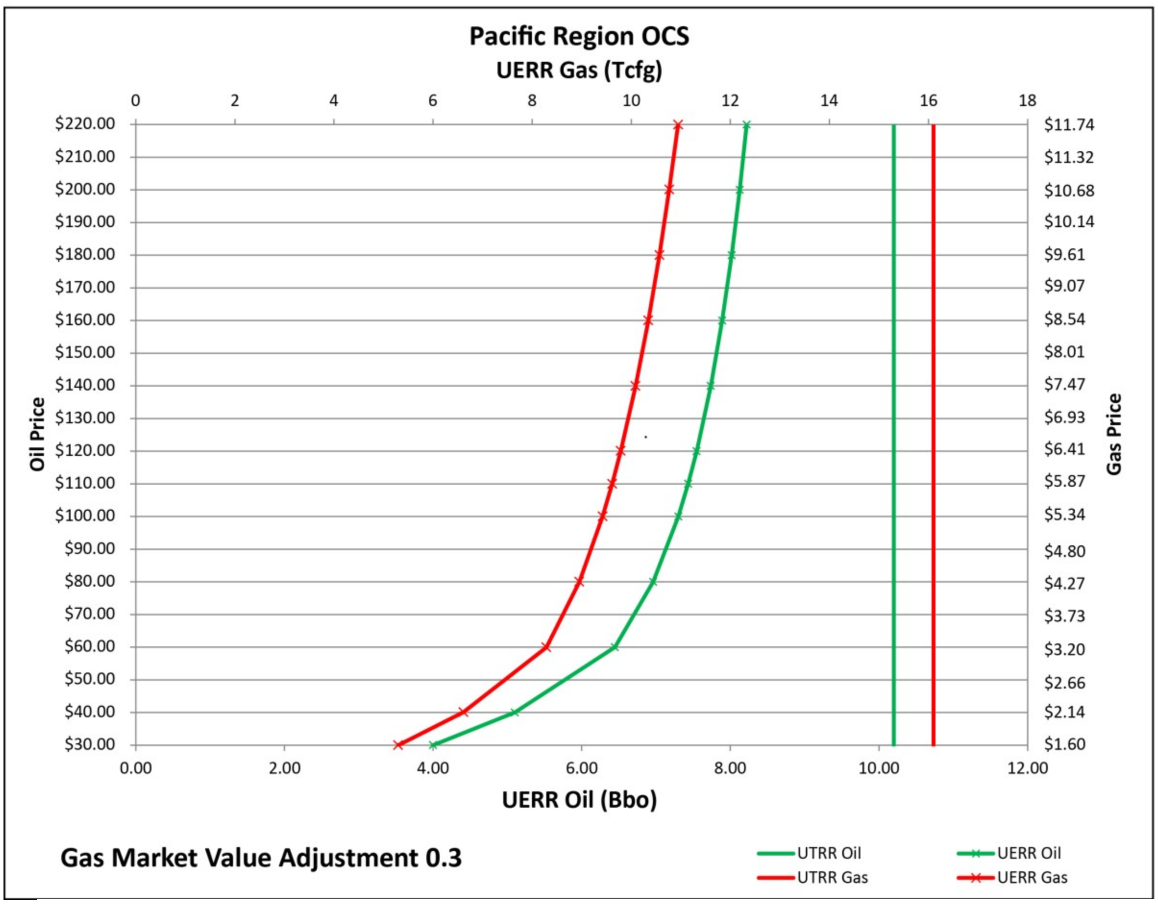


Figure 26. Price-supply curve for the Pacific OCS region.

8 COMPARISON OF THE BOEM 2016 ASSESSMENT WITH THE BOEM 2011 ASSESSMENT

Though the BOEM regional Offices of Resource Evaluation continuously maintain an inventory of both discovered and undiscovered oil and gas resources for their respective OCS areas, the assessment and formal aggregation of undiscovered technically and economically recoverable resources to a national level takes place approximately every five years[4]. In this section, we compare the results of the current (2016) assessment effort with those published as part of the 2011 National Assessment.

8.1 UTRR

The calculation of the UTRR for each OCS Region captures our current understanding of the overall petroleum system(s) in the area, as well as our most recent interpretation of the many components that comprise the individual number, size, and distribution of oil and gas prospects. For mature geologic plays and provinces, such as the Gulf of Mexico, the rich empirical data allow for a careful re-examination of yet-to-find resources on a nearly continuous basis. For less active areas, such as the Alaska OCS, the year-after-year assessment of undiscovered resources changes very little. A summary of each of the four OCS Regions and a comparison to the 2011 National Assessment UTRR are provided below.

In the GOM, the UTRR mean estimate for oil remained statistically unchanged, increasing 0.1 percent to 48.46 Bbo, while the mean estimate for gas decreased 35 percent from 219.46 to 141.76 Tcfg. The decrease in UTRR gas is attributed to a refinement of field size distributions for geologic plays in shallow water that better represent our 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.

Estimates of UTRR on the Atlantic OCS were updated in 2014, where we reported a mean of 4.72 Bbo and 37.51 Tcfg. Compared to the 2011 assessment, these values represented a 43 percent increase in oil resources and a 20 percent increase in gas resources. 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 have been incorporated resulting in a slight decrease to mean oil volume and slight increase to mean gas volume, now 4.59 Bbo and 38.17 Tcfg, respectively.

Prior to the data cutoff date of January 1, 2014, we recognize effectively no significant new geologic data gathered on the Alaskan OCS. Additionally, no OCS leases acquired since the 2011 assessment had been tested. However, this assessment does include revisions to two geologic plays in the Beaufort Sea in December, 2017, that are based in part on new information from industry wells in the NPRA. Thus, our 2016 mean estimates of UTRR for the Alaska OCS (27.28 Bbo and 131.55 Tcfg) is only slightly changed in comparison to the 2011 assessment. The geologic information acquired in the 2015 drilling season in the Chukchi Sea will be incorporated into a future BOEM assessment of the Alaska OCS UTRR.

---

[4] Atlantic OCS UTRR and UERR were assessed in 2014 through publications BOEM Fact Sheet RED-2014-01 and BOEM Fact Sheet RED-2014-01c.

Similar to the Alaska OCS, where we recognize no significant new geologic information since the previous assessment, the Pacific OCS has had no new leasing or exploratory efforts on unleased lands. The only new activities occurring in the region since the last assessment are 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 are unchanged from the results presented in 2011.

In addition to the mean UTRR estimate by region, we offer a comparison of the aggregation to the national level that includes the 5th and 95th percentile from the 2011 and 2016 resource assessments (**Figure 27**). For the entire OCS, mean estimates for oil decreased from 90.02 Bbo in 2011 to 90.55 in 2016 (approximately 1 percent) and gas decreased from 404.60 Tcfg to 327.58 Tcfg (roughly 18 percent). Additionally, the range between the 5th and 95th percentile is reduced from the 2011 to 2016 assessment. The reduction is due both to overall changes in assessed oil and gas volumes and to a change in the aggregation approach in the Alaska OCS region.

8.2 UERR

For the 2016 National Assessment, we report UERR using a gas price adjustment factor of 0.3 to account for the current relative value of gas compared to a barrel of crude oil. When we last reported UERR in 2011, we did so using a 0.4 gas price adjustment factor. In practical terms, in 2011 for a $60/Bbl oil price we used a corresponding gas price of $4.27/Mcf. In 2016, for the same $60/Bbl oil price, we use a $3.20/Mcf gas price. As a result, UERR values for all OCS Regions would decrease on this phenomenon alone. In addition, the 2016 UERR reflect changes to a number of development scenarios and engineering and economic assumptions.

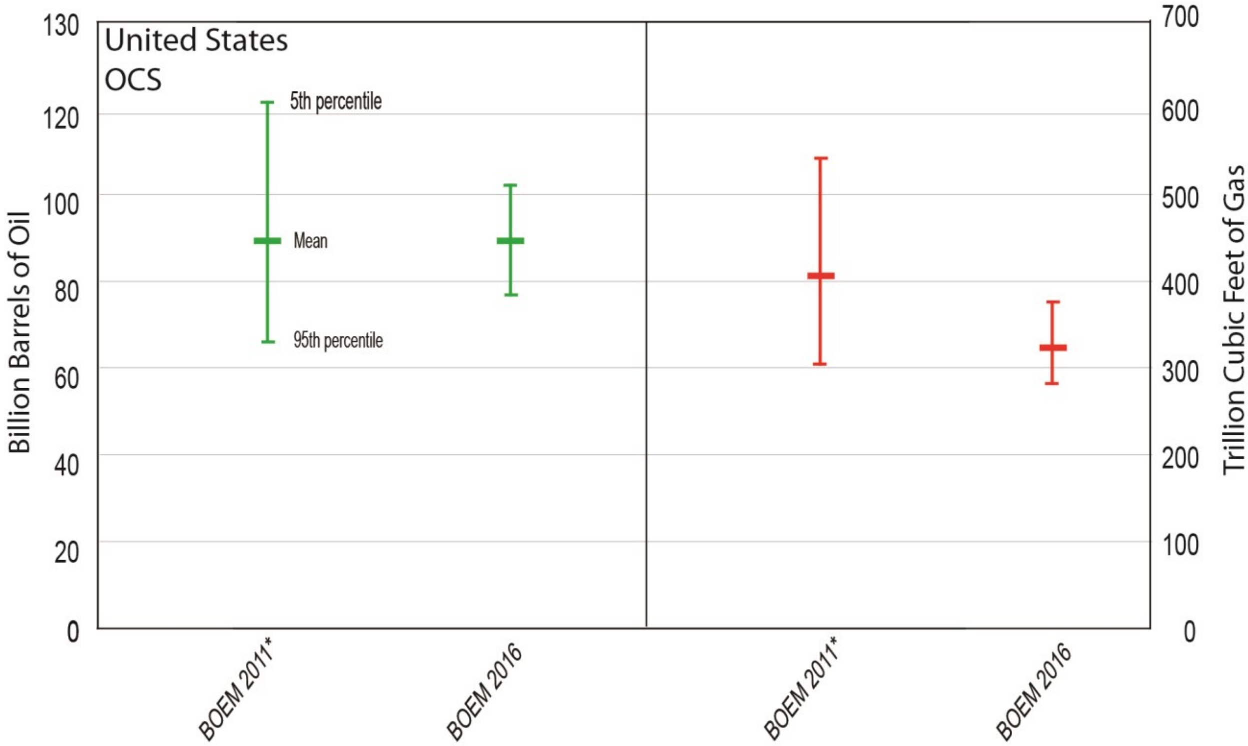


Figure 27. Risked UTRR from the 2011 and 2016 National Assessments. (*2014 Atlantic update included in 2011 assessment values)

For the entire OCS in 2016, the \$60/Bbl and \$3.20/Mcf case yields mean UERR volumes of 58.15 Bbo and 100.73 Tcfg. Both of these numbers are lower (6% and 54%, respectively) than the 2011 UERR volumes at \$60/Bbl of 61.80 Bbo and 217.81 Tcfg.

Specifically, UERR gas resources in Alaska have declined since 2011 due to the implementation of an increased tariff required by changes in the presumed delivery of gas via LNG tanker systems. In the Atlantic OCS, UERR gas volumes are down slightly from 2011 due largely to an improved understanding of potential reservoir performance. In the GOM, the decline in UERR gas resources is more a reflection of changes to the UTRR gas volumes, rather than specific changes to development scenarios or anticipated reservoir performance.

9 REFERENCES

Ajdukiewicz, J. M., P. H. Nicholson, and W. L. Esch, 2010, Prediction of deep reservoir quality using early diagenetic process models in the Jurassic Norphlet Formation, Gulf of Mexico: American Association of Petroleum Geologists Bulletin, v. 94, p. 1189-1227.

Areshev, E. G., T. L. Dong, N. T. San, and O. A. Shnip, 1992, Reservoirs in fractured basement on the continental shelf of southern Vietnam: Journal of Petroleum Geology, v. 15, p. 451-464.

Arrington, J. R. 1960, Size of crude reserves is key to evaluating exploration programs: Oil and Gas Journal, v. 58, no. 9, p. 130-134.

Atwater, T., 1970, Implications of plate tectonics for the Cenozoic tectonic evolution of western North America: Geological Society of America Bulletin, v. 8 1, p. 3513-3536.

Bascle, B. J., L. D. Nixon, and K. M. Ross, 2001, Atlas of Gulf of Mexico gas and oil reservoirs as of January 1, 1999: Minerals Management Service OCS Report 2001-086, CD-ROM.

Blanche, J. B., and J. D. Blanche, 1997, An overview of the hydrocarbon potential of the Spratly Islands archipelago and its implications for regional development, *in* S. J. Matthews and R. W. Murphy, eds., Petroleum geology of southeast Asia: Geological Society Special Publication, no. 126, p. 293-310.

BOEM (Bureau of Ocean Energy Management), 2014a, Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Atlantic Outer Continental Shelf, 2014 Update: BOEM RED 2014-01, 3 pp. http://www.boem.gov/Assessment-of-Oil-and-Gas-Resources-2014-Update/

BOEM 2014b, Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, 2011 (Includes 2014 Atlantic Update), BOEM RED-2014-01c, 8 pp.

BOEM 2014, 2011 National Assessment of oil and gas resources: assessment of the Pacific Outer Continental Shelf Region: BOEM OCS Report 2014-667, 244 pp.

BOEM, 2016, Assessment of undiscovered oil and gas resources of the Nations's Outer Continental Shelf, 2016a: BOEM Fact Sheet RED-2017-012, 8 pp.

BOEM, 2017a, Assessment of technically and economically recoverable hydrocarbon resources of the Gulf of Mexico Outer Continental Shelf as of January 1, 2014: BOEM OCS Report 2017-005, 50 pp.

BOEM, 2017b, 2017 Assessment of undiscovered oil and gas resources in the western Beaufort Sea OCS Planning Area: BOEM Fact Sheet RED-2017-12b, 5 pp.

Craig, J. D., K. W. Sherwood, and P. P. Johnson, 1985, Geologic report for the Beaufort Sea Planning Area (Alaska): U.S. Minerals Management Service, OCS Report MMS 85-0111, 192 pp.

Coleman, J.L., Jr., R.C. Milici, and P.J. Post, 2015, Assessment of the Oil and Natural Gas Potential of the East Coast Mesozoic Synrift Basins, Onshore and State Waters of the United States: *in* P.J. Post, et al., eds., Petroleum Systems in Rift Basins, GCSSEPM Foundation 34th Annual Perkins-Rosen Research Conference, p. 96–194.

Dubiel, R. F., P. D. Warwick, L. R. H. Biewick, L. Burke, J. L. Coleman, K. O. Dennen, C. Doolan, C. B. Enomoto, P. C. Hackley, A. W. Karlsen, M. D. Merrill, K. Pearson, O. N. Pearson, J. K. Pitman, R. M. Pollastro, E. L. Rowan, S. M. Swanson, and B. J. Valentine, 2010, Geology and assessment of undiscovered oil and gas resources in Mesozoic (Jurassic and Cretaceous) rocks of the onshore and

State waters of the Gulf of Mexico Region, USA: Gulf Coast Association of Geological Societies Transactions, v. 60, p. 207-216.

Faulkner, B. M., and A. V. Applegate, 1986, Hydrocarbon exploration evaluation of Pulley Ridge Area, offshore South Florida Basin: Gulf Coast Association of Geological Societies Transactions, v. 36, p. 83-95.

Field, M.E., and K.A. Kvenvolden, 1985, Gas hydrates on the northern California continental margin: Geology, v. 13, no. 7, p. 517-520.

Gohrbandt, K. H., 2002, Eastern Gulf of Mexico-1: a look at regional deposition under W. Florida shelf, slope: Oil & Gas Journal, v. 3, p. 26-30.

Horn, M. K., 1990, Renqiu Field, *in* E. A. Beaumont and N.H. Foster, eds., Treatise of petroleum geology, atlas of oil and gas fields: structural traps II, traps associated with tectonic faulting, p. 227-252.

Iturralde-Vinent, M. A., 2003, The conflicting paleontologic versus stratigraphic record of the formation of the Caribbean seaway, *in* C. Bartolini, R. T. Buffler, and J. Blickwede, eds., The Circum-Gulf of Mexico and the Caribbean: hydrocarbon habitats, basin formation, and plate tectonics: American Association of Petroleum Geologists Memoir 79, p. 75-88.

Lasco, D., 2018, 2016a Assessment of Oil and Gas Resources: Alaska Outer Continental Shelf Region: BOEM OCS Report 2018-001, 14 pp.

Landes, K. K., J. J. Amoruso, L. J. Charlesworth Jr., F. Heany, and P. J. Lesperance, 1960, Petroleum resources in basement rocks: American Association of Petroleum Geologists Bulletin, v. 44, p. 1682-1691.

Lopez, J. A., 1995, Salt tectonism of the Gulf Coast Basin, map, 1:1,560,000: New Orleans Geological Society, New Orleans, Louisiana.

Mankiewicz, P. J., R. J. Pottorf, M. G. Kozar, and P. Vrolijk, 2009, Gas geochemistry of the Mobile Bay Jurassic Norphlet Formation: thermal controls and implications for reservoir connectivity: American Association of Petroleum Geologists Bulletin, v. 93, p. 1319-1346.

Marlow, M.S., A. K. Cooper, D. W. Scholl, and H. McLean, 1982, Ancient plate boundaries in the Bering Sea region: *in* J. H. Leggett, ed., Trench-Forearc geology; sedimentation and tectonics on modern and active plate margins: Geological Society of London, p. 202-212.

Martin, R. G., 1978, Northern and eastern Gulf of Mexico continental margin stratigraphic and structural framework, in A. H. Bouma, G. T. Moore, and J. M. Coleman, eds., Framework, facies, and oil-trapping characteristics of the upper continental margin: American Association of Petroleum Geologists Studies in Geology, no. 7, p. 21–42.

Marton, G., and R. T. Buffler, 1993, Application of simple-shear model to the evolution of passive continental margins of the Gulf of Mexico Basin: Geology, v. 21, p. 495-498.

Moore, T. E., W. K. Wallace, K. J. Bird, S. M. Karl, C. G. Mull, and J. T. Dillon, 1992, Stratigraphy, structure, and geologic synthesis of Northern Alaska: U. S. Geological Survey Open File Report OF 92-330, 183 pp.

Muehlberger, W. R., 1992, Tectonic map of North America, southeast and southwest sheets, 1:5,000,000: American Association of Petroleum Geologists, Tulsa, Oklahoma.

Ojukwu, C.O., and K. Smith, 2016 Assessment of oil and gas resources: Assessment of the Pacific Outer Continental Shelf Region: BOEM 2016-053, 33 pp.

P'an, C.-H., 1982, Petroleum in basement rocks: American Association of Petroleum Geologists Bulletin, v. 66, p. 1597-1643.

Petty, A. J., 1997, Lower Tuscaloosa clastic facies distribution (Upper Cretaceous), Federal and State waters, eastern Gulf of Mexico: Gulf Coast Association of Geological Societies Transactions, v. 37, p. 453-462.

Petty, A. J., 1999, Petroleum exploration and stratigraphy of the Lower Cretaceous James Limestone (Aptian) and Andrew Formation (Albian): Main Pass, Viosca Knoll, and Mobile Areas, northeastern Gulf of Mexico: Gulf Coast Association of Geological Societies Transactions, v. 39, p. 440-450.

Petty, A. J., 2010, Stratigraphy and petroleum exploration history of the Smackover Formation (Oxfordian), northeastern Gulf of Mexico: Gulf Coast Association of Geological Societies, v. 50. p. 583-596.

Petty, A. J., 2008, Stratigraphy and petroleum exploration history of the Cotton Valley Group (Lower Cretaceous to Upper Jurassic) and Haynesville Group (Upper Jurassic), offshore northeastern Gulf of Mexico: Gulf Coast Association of Geological Societies Transactions, v. 58, p. 713-728.

Poag, C. W., 1987, The New Jersey transect: Stratigraphic framework and depositional history of a sediment-rich passive margin, *in* C. W. Poag, A. B. Watts, et al., eds., Initial reports of the Deep Sea Drilling Project, Volume 95: Washington, D.C., U.S. Government Printing Office, p. 763-817.

Post, P.J., and J.L. Coleman Jr., 2015, Mesozoic rift basins of the U.S. central Atlantic offshore: comparisons with onshore basins, analysis, and potential petroleum prospectivity: in P.J. Post et al., eds., Petroleum Systems in Rift Basins, GCSSEPM Foundation 34th Annual Perkins-Rosen Research Conference, p. 1–93.

Post, P. J., R. J. Klazynski, E. S. Klocek, T. J. Riches, and K. Li, 2016, Inventory of technically and economically recoverable hydrocarbon resources of the Atlantic Outer Continental Shelf as of January 1, 2014: BOEM 2016-071, 58 pp.

Prather, B. E., 1991, Petroleum geology of the Upper Jurassic and Lower Cretaceous, Baltimore Canyon Trough, western North Atlantic Ocean: American Association of Petroleum Geologists Bulletin, v. 75, p. 258-277.

Reed, B. L., and M. A. Lanphere, 1973, Alaska-Aleutian Range batholith; geochronology, chemistry, and relation to Circum-Pacific plutonism: Geological Society of America Bulletin, v. 84, no. 8 p. 2853-2610.

Roberts, M., C. Hollister, H. Yarger, and R. Welch, 2005, Regional geologic and geophysical observations basinward of the Sigsbee Escarpment and Mississippi Fan Fold Belt, central deepwater Gulf of Mexico: hydrocarbon prospectivity and play types, *in* P. Post, et al., eds., Petroleum systems of divergent continental margin basins: 25th Bob F. Perkins Research Conference, Gulf Coast Section of the Society of Economic Paleontologists and Mineralogists, p. 1190-1199.

Root, D. H., and E. D. Attanasi, 1993, Small fields in the oil and gas assessment: Bulletin of the American Association of Petroleum Geologists, v. 77, no. 3, p 485-490.

Salvador, A., 1987, Late Triassic-Jurassic paleogeography and origin of Gulf of Mexico Basin: American Association of Petroleum Geologists Bulletin, v. 11, p. 1-14.

Sams, R. H., 1982, Gulf Coast stratigraphic traps in the Lower Cretaceous carbonates: Oil & Gas Journal, v. 80, p. 177-187.

Sassen, R., 1990, Geochemistry of carbonate source rocks and crude oils in Jurassic salt basins of the Gulf Coast: Gulf Coast Section of the Society of Economic Paleontologists and Mineralogists Foundation Ninth Annual Research Conference Proceedings, 1990, p. 11-22.

Sassen, R., 2010, Jurassic condensate of the Hudson Canyon area, U.S. Atlantic: Insight to Deep Sources: http://www.searchanddiscovery.com/documents/2010/50278sassen/ndx_sassen.pdf (accessed 26-Apr-2017).

Sassen, R., P. J. and Post, 2008, Enrichment of diamondoids and 13C in condensate from Hudson Canyon, US Atlantic: Organic Geochemistry, 39, p. 147-151.

Simmons, G. R., 1992, The regional distribution of salt in the northwestern Gulf of Mexico: styles of emplacement and implications for early tectonic history [Ph. D. thesis]: Texas A&M University, Department of Oceanography, College Station, Texas, 180 pp.

Sheridan, R. E., 1987, The passive margin of the U.S.A.: Episodes, v. 10, p. 254-258.

Sherwood, K.W., J.D. Craig, and L.W. Cooke, 1996, Endowments of Undiscovered conventionally recoverable and economically recoverable oil and gas in the Alaska Federal Offshore: OCS Report MMS 96-0033, 23 pp.

Sherwood, K.W., J.D. Craig, L.W. Cooke, R.T. Lothamer, P.P Johnson, S.A. Zerwick, J. Scherr, B. Herman, D. McLean, S. Haley, J. Larson, J. Parker, R. Newman, C.D. Comer, S.M. Banet, S.B. Hulburt, P. Sloan, G. Martin, and W.L. Horowitz, 1998, Undiscovered oil and gas resources, Alaska Federal Offshore: OCS Report MMS 98-0054, 511p.

Sladen, C., 1997, Exploring the lake basins of south and southeast Asia, *in* S. J. Matthews and R. W. Murphy, eds., Petroleum geology of southeast Asia: Geological Society Special Publication, no. 126, p. 49-76.

Tong, X., and H. Zuan, 1991, Buried-hill discoveries of the Damintun depression in north China: American Association of Petroleum Geologists Bulletin, v. 75, p. 780-794.

Tran C., D. V. Ha, H. Carstens, and S. Berstad, 1994, Vietnam – attractive plays in a new geological province: Oil and Gas Journal, v. 92, No. 11, p. 78-83.

Visser, R. C., 1992, A retrospective of platform development in Cook Inlet, Alaska: Journal of Petroleum Technology, Feb. 1992.

Wagner, B. E., Z. Sofer, and B. L. Claxton, 1994, Source rock in the Lower Cretaceous, deepwater Gulf of Mexico: Gulf Coast Association of Geological Societies Transactions, v. 44, p. 729-736.

Warren, T., K. W. Sherwood, D. K. Thurston, V. F. Kruglyak, S. A. Zerwick, O. V. Shcherban, and A. V. Grevtsev, 1995, Petroleum exploration opportunities on the U.S.-Russia Chukchi Sea continental shelf, *in* Proceedings of the Fifth (1995) International Offshore and Polar Engineering Conference, International Society of Offshore and Polar Engineers, The Hague, The Netherlands, 1995, v. 11, p. 493-500.

White, D. A., 1980, Assessing oil and gas plays in facies-cycle wedges: American Association of Petroleum Geologists Bulletin, v. 64, no. 8, p. 1158-1178.

Withjack, M. O., and R. W. Schlische, 2005, A review of tectonic events on the passive margin of Eastern North America, *in* P. J. Post, N. C. Rosen, D. L. Olson, S. L. Palmes, K. L. Lyons, and G. B. Newton, eds., Petroleum Systems of Divergent Continental Margin Basins, 25th Annual Meeting Gulf Coast Section SEPM Foundation Bob F. Perkins Research Conference, p. 203-235.

Worrall, D. M., 1991, Tectonic history of the Bering Sea and the Evolution of Tertiary Strike-Slip Basins of the Bering Shelf Geological Society of America Special Paper 257, 120 pp.

Yu Z., and G. Li, 1989, Development of Renqiu fractured carbonate oil pools by water injection, *in* J. F. Masin and P. A. Dickey, eds., Oil field development techniques: Proceedings of the Daqing international meeting, 1982: American Association of Petroleum Geologists Studies in Geology, p. 175-191.

Yurewicz, D. A., T. B. Marler, K. A. Meyerholtz, and F. X. Siroky, 1993, Early Cretaceous carbonate platform, north rim of the Gulf of Mexico, Mississippi and Louisiana, *in* J. A. Toni Simo, R.W. Scott, and J.-P. Masse, eds., Cretaceous carbonate platforms: American Association of Petroleum Geologists Memoir 56, p. 81-96.

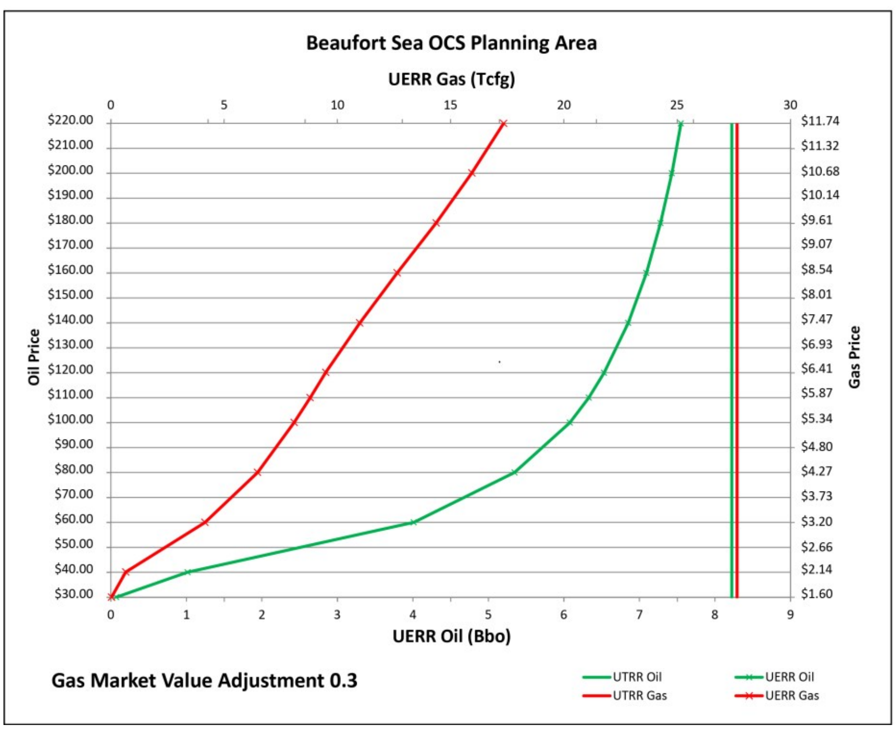
Zhai G., and Z. Quanheng, 1982, Buried hill oil and gas pools in the North China Basin, *in* M. T. Halbouty, ed., The deliberate search for the subtle trap: American Association of Petroleum Geologists Memoir 32, p. 317-335.

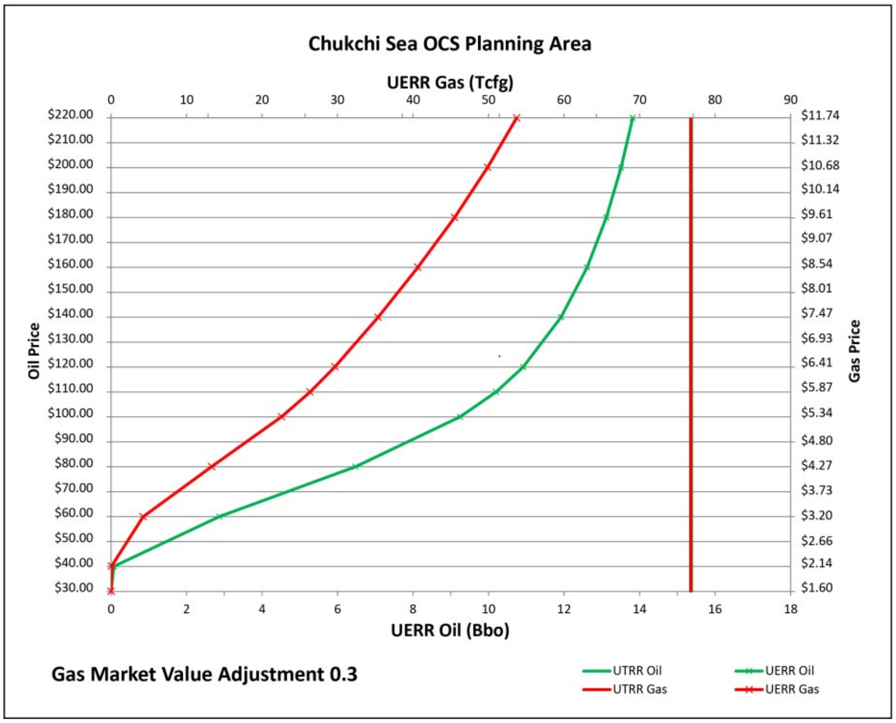
Zheng C., 1988, A new exploration method for buried-hill oil fields, the Liahoe depression, China, in H. C. Wagner, L. C. Wagner, F. F. Wang, and F. L. Wong, eds., Petroleum resources of China and related subjects: Houston, Texas, Circum-Pacific Council for Energy and Mineral Resources Earth Science Series, v. 10, p. 251-262.

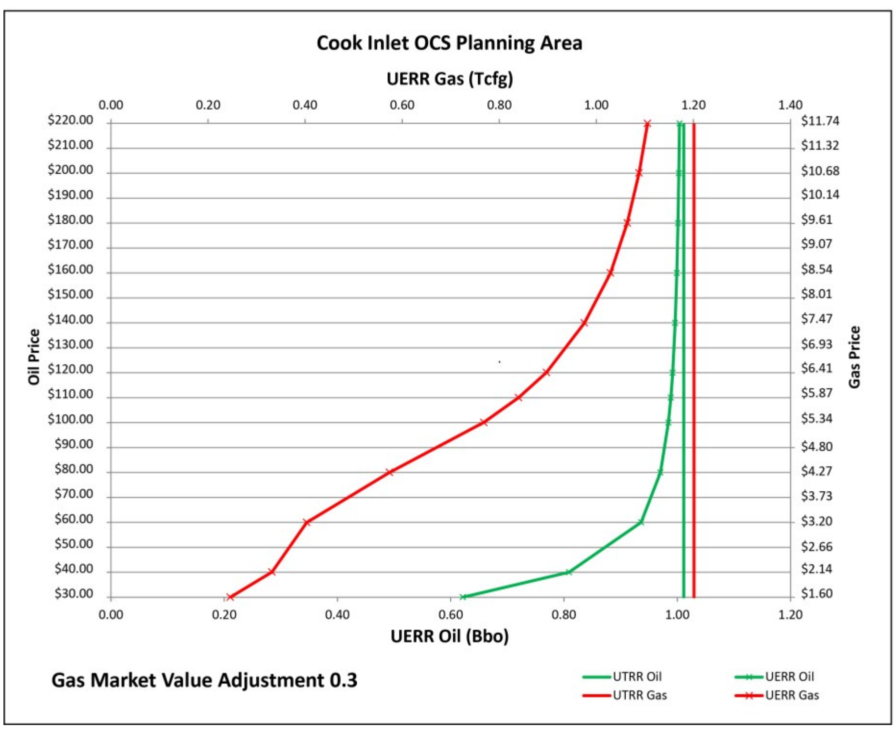
10 APPENDIX 1

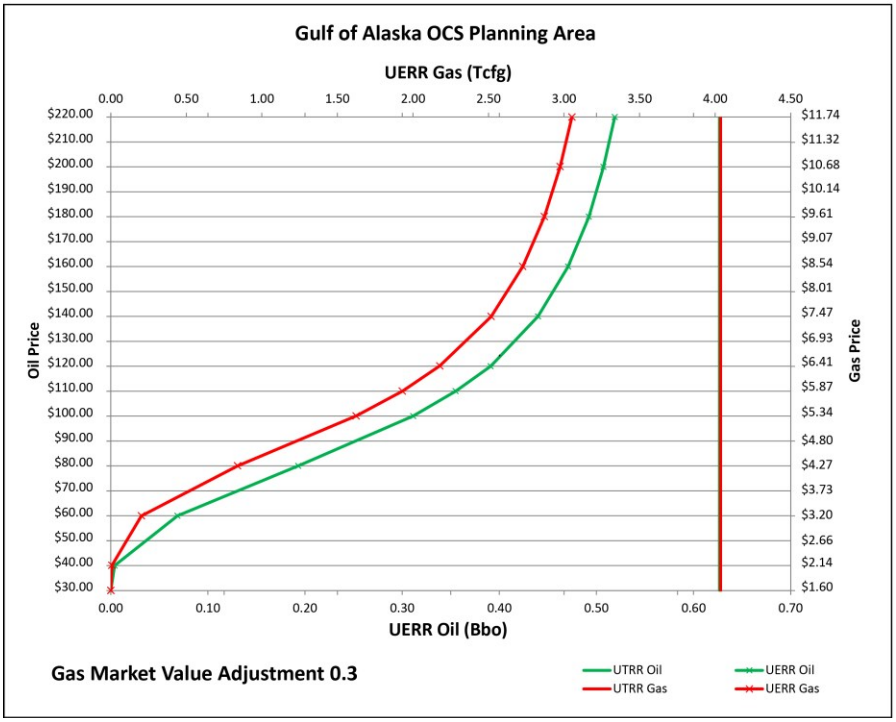
Price-supply curves for all OCS planning areas. Price-supply curves are presented using a 0.3 gas market adjustment factor to account for the relative value of gas compared to a barrel of crude oil at the time of the assessment. Price-supply curves for all regions are provided at 0.4, 0.6, and 1.0 gas market adjustment factors relative to oil. These price-supply curves can be found at the following location: www.boem.gov. Price-supply curves for the Alaska OCS Region are provided for the following OCS planning areas: Beaufort Sea, Chukchi Sea, Cook Inlet, Gulf of Alaska, Hope Basin, Kodiak Shelf, Navarin Basin, North Aleutian, Norton Basin, Shumagin Shelf, and St. George Basin. Price-supply curves for the Atlantic OCS Region are provided for the following planning areas: North Atlantic, Mid-Atlantic, and South Atlantic. Price-supply curves for the Gulf of Mexico OCS Region are provided for the following planning areas: Eastern GOM, Central GOM, Western GOM, and Straits of Florida. Price-supply curves for the Pacific OCS Region are provided for the following planning areas: Washington-Oregon, Northern California, Central California, and Southern California.

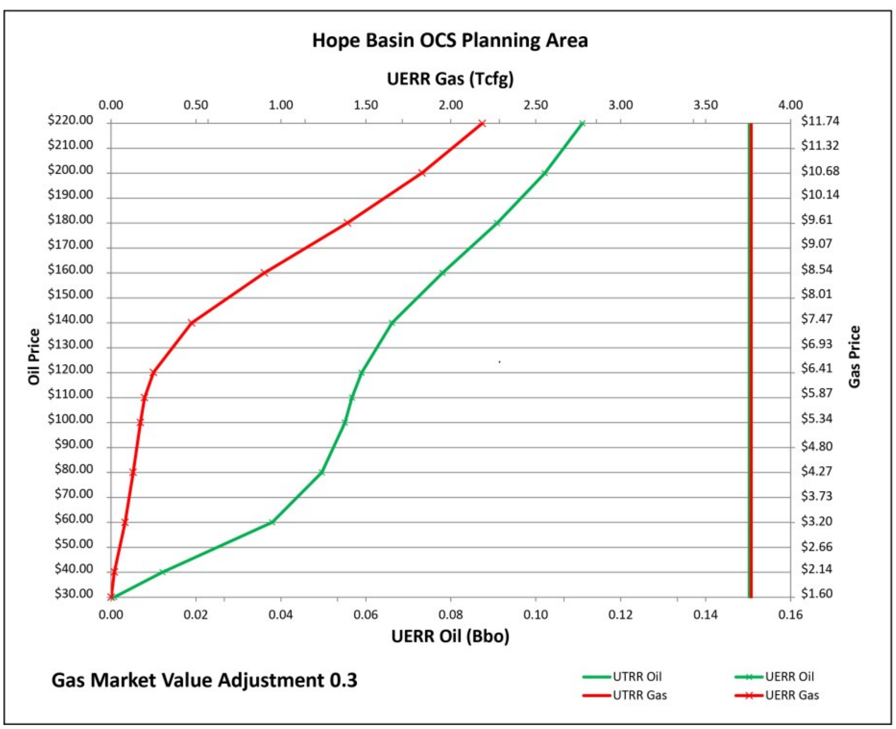
10.1 Alaska OCS Region

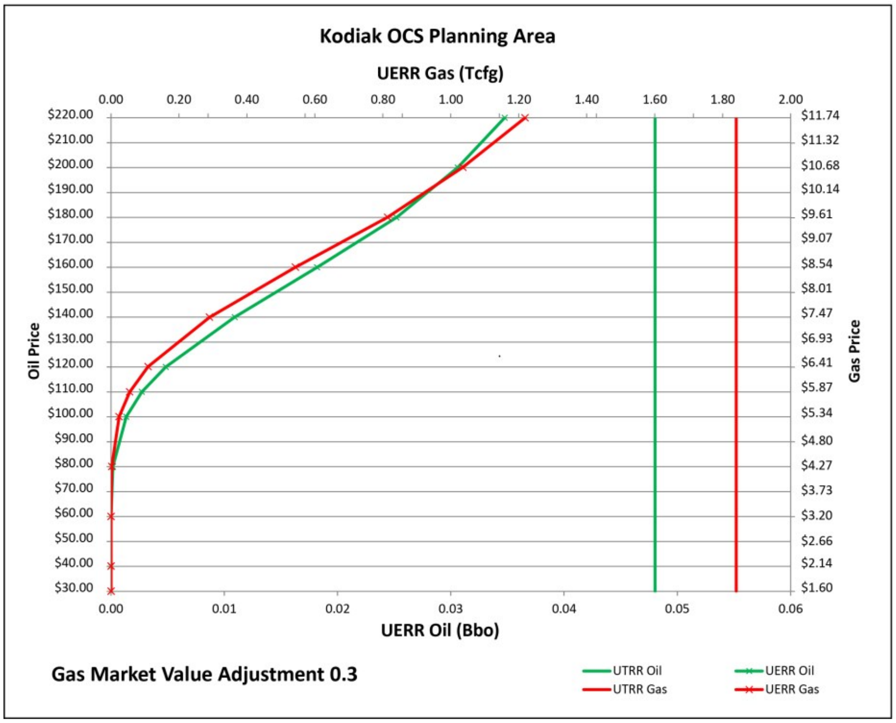


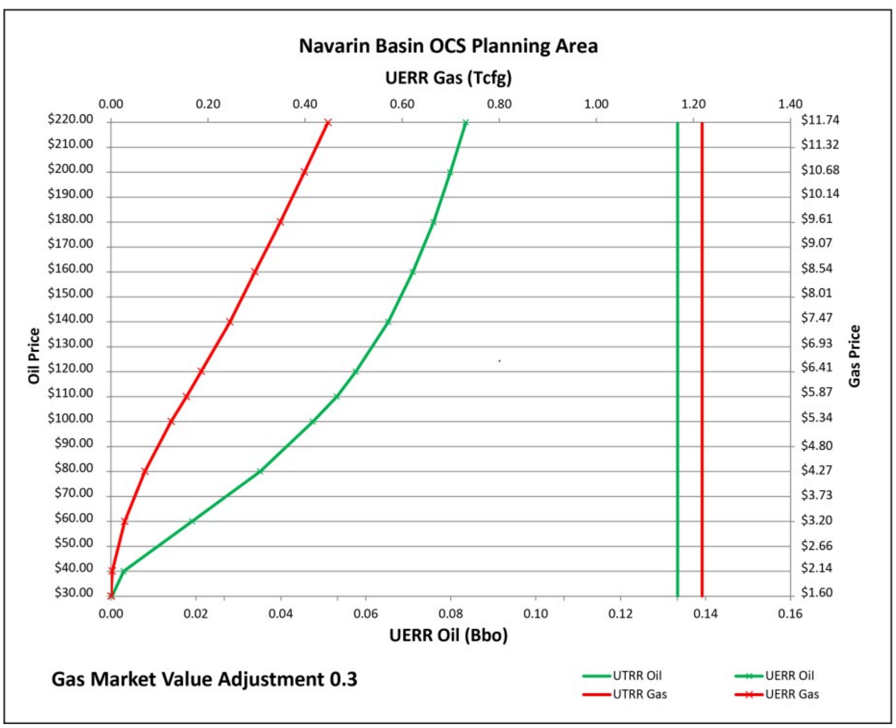

Chukchi Sea OCS Planning Area
UERR Gas (Tcfg)
Oil Price
Gas Price
UERR Oil (Bbo)
Gas Market Value Adjustment 0.3
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas

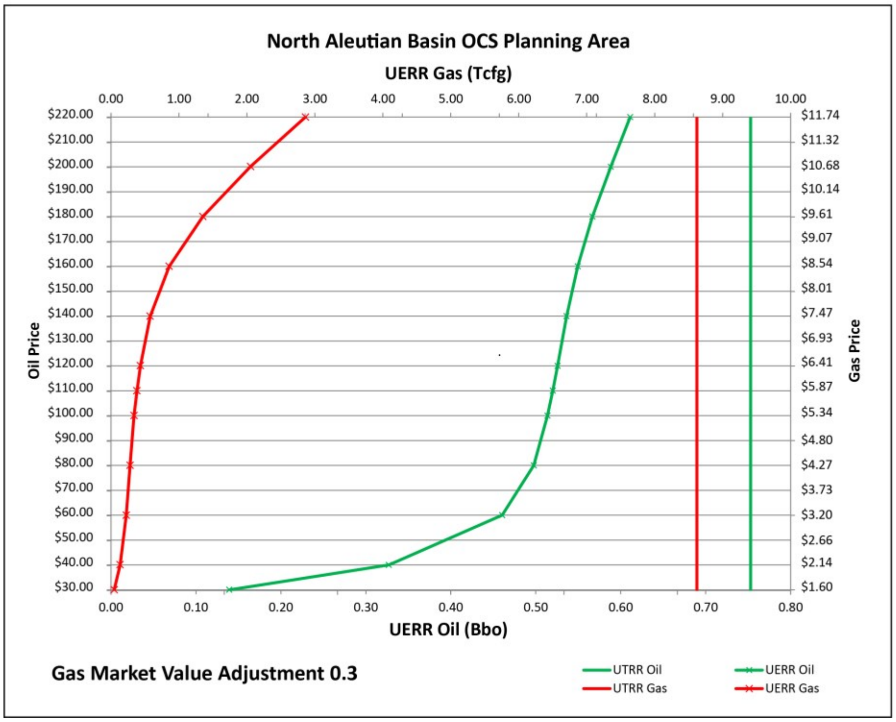

Cook Inlet OCS Planning Area
UERR Gas (Tcfg)
Oil Price
Gas Price
UERR Oil (Bbo)
Gas Market Value Adjustment 0.3
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas

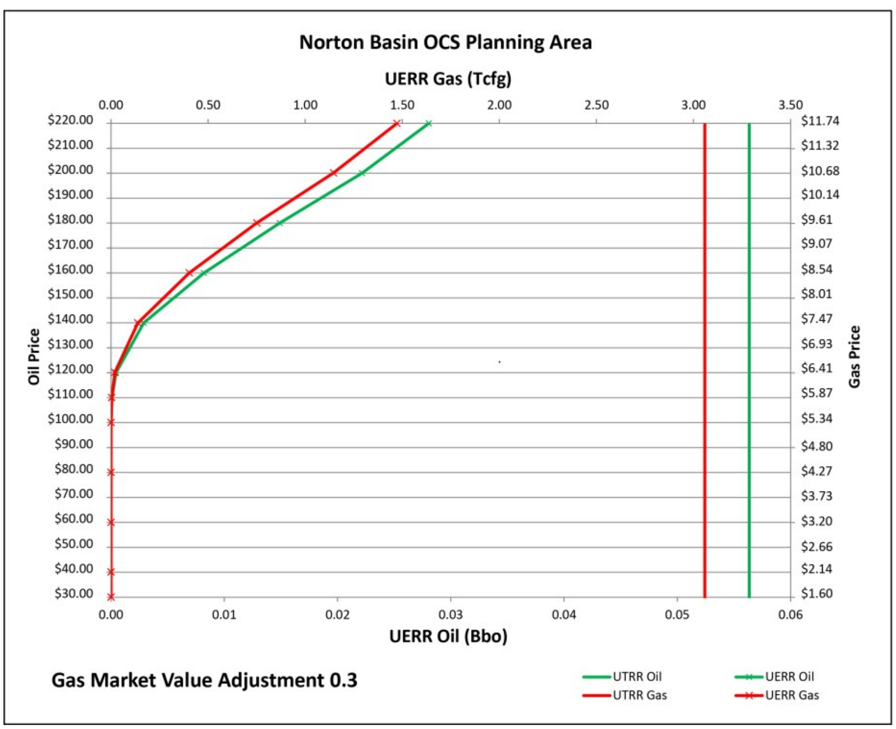

Gulf of Alaska OCS Planning Area
UERR Gas (Tcfg)
0.00 0.50 1.00 1.50 2.00 2.50 3.00 3.50 4.00 4.50
Oil Price
$220.00 $210.00 $200.00 $190.00 $180.00 $170.00 $160.00 $150.00 $140.00 $130.00 $120.00 $110.00 $100.00 $90.00 $80.00 $70.00 $60.00 $50.00 $40.00 $30.00
Gas Price
$11.74 $11.32 $10.68 $10.14 $9.61 $9.07 $8.54 $8.01 $7.47 $6.93 $6.41 $5.87 $5.34 $4.80 $4.27 $3.73 $3.20 $2.66 $2.14 $1.60
0.00 0.10 0.20 0.30 0.40 0.50 0.60 0.70
UERR Oil (Bbo)
Gas Market Value Adjustment 0.3
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas

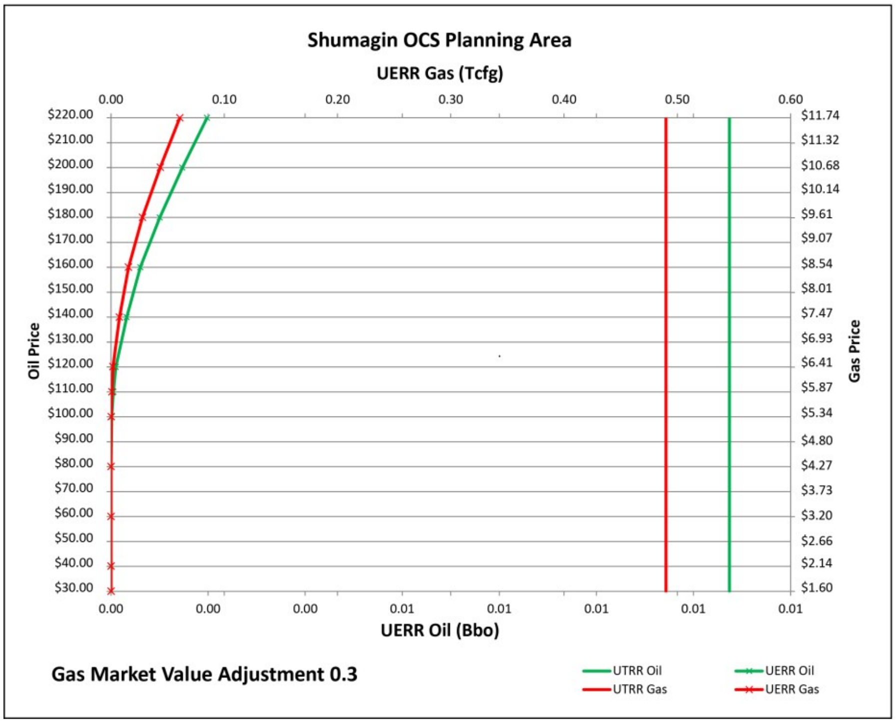

Hope Basin OCS Planning Area
UERR Gas (Tcfg)
0.00 0.50 1.00 1.50 2.00 2.50 3.00 3.50 4.00
Oil Price
$220.00 $210.00 $200.00 $190.00 $180.00 $170.00 $160.00 $150.00 $140.00 $130.00 $120.00 $110.00 $100.00 $90.00 $80.00 $70.00 $60.00 $50.00 $40.00 $30.00
Gas Price
$11.74 $11.32 $10.68 $10.14 $9.61 $9.07 $8.54 $8.01 $7.47 $6.93 $6.41 $5.87 $5.34 $4.80 $4.27 $3.73 $3.20 $2.66 $2.14 $1.60
0.00 0.02 0.04 0.06 0.08 0.10 0.12 0.14 0.16
UERR Oil (Bbo)
Gas Market Value Adjustment 0.3
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas

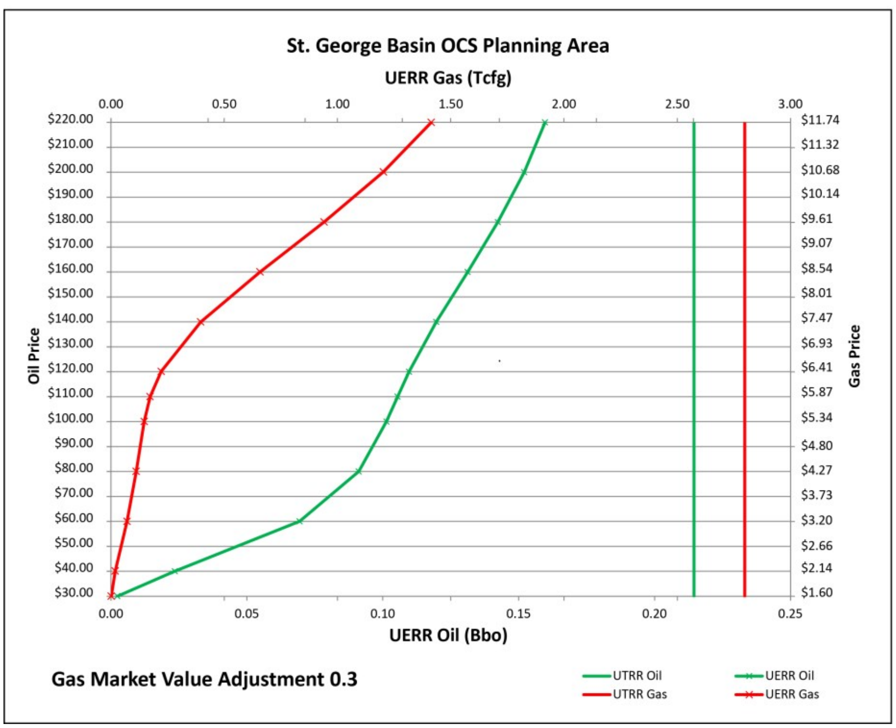

Kodiak OCS Planning Area
UERR Gas (Tcfg)
0.00
0.20
0.40
0.60
0.80
1.00
1.20
1.40
1.60
1.80
2.00
$220.00
$210.00
$200.00
$190.00
$180.00
$170.00
$160.00
$150.00
$140.00
$130.00
$120.00
$110.00
$100.00
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
Oil Price
$11.74
$11.32
$10.68
$10.14
$9.61
$9.07
$8.54
$8.01
$7.47
$6.93
$6.41
$5.87
$5.34
$4.80
$4.27
$3.73
$3.20
$2.66
$2.14
$1.60
Gas Price
0.00
0.01
0.02
0.03
0.04
0.05
0.06
UERR Oil (Bbo)
Gas Market Value Adjustment 0.3
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas


Navarin Basin OCS Planning Area
UERR Gas (Tcfg)
0.00
0.20
0.40
0.60
0.80
1.00
1.20
1.40
$220.00
$210.00
$200.00
$190.00
$180.00
$170.00
$160.00
$150.00
$140.00
$130.00
$120.00
$110.00
$100.00
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
Oil Price
$11.74
$11.32
$10.68
$10.14
$9.61
$9.07
$8.54
$8.01
$7.47
$6.93
$6.41
$5.87
$5.34
$4.80
$4.27
$3.73
$3.20
$2.66
$2.14
$1.60
Gas Price
0.00
0.02
0.04
0.06
0.08
0.10
0.12
0.14
0.16
UERR Oil (Bbo)
Gas Market Value Adjustment 0.3
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas

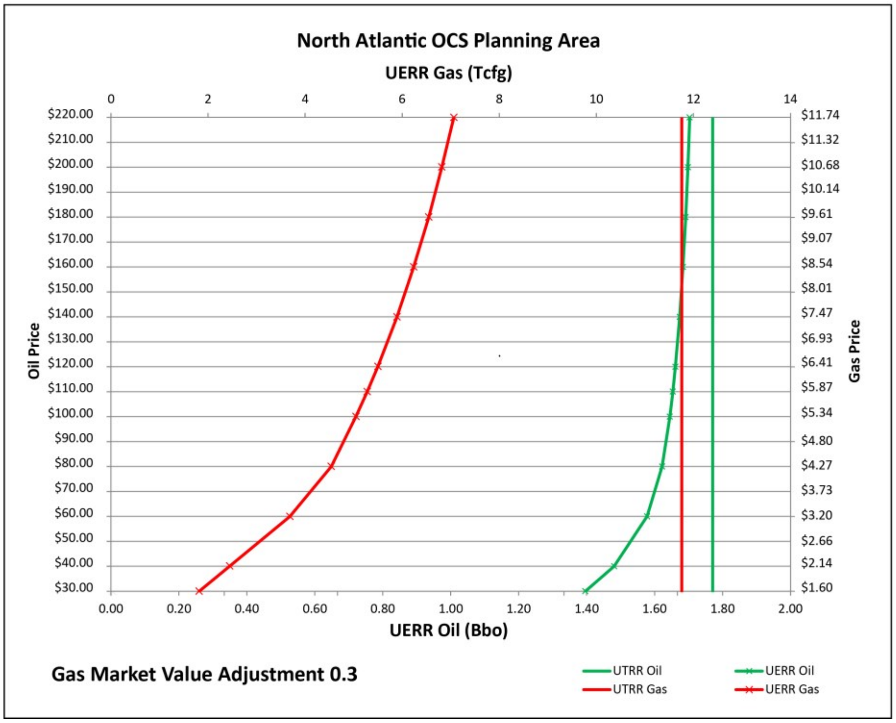

North Aleutian Basin OCS Planning Area
UERR Gas (Tcfg)
0.00 1.00 2.00 3.00 4.00 5.00 6.00 7.00 8.00 9.00 10.00
$220.00 $210.00 $200.00 $190.00 $180.00 $170.00 $160.00 $150.00 $140.00 $130.00 $120.00 $110.00 $100.00 $90.00 $80.00 $70.00 $60.00 $50.00 $40.00 $30.00
Oil Price
$11.74 $11.32 $10.68 $10.14 $9.61 $9.07 $8.54 $8.01 $7.47 $6.93 $6.41 $5.87 $5.34 $4.80 $4.27 $3.73 $3.20 $2.66 $2.14 $1.60
Gas Price
0.00 0.10 0.20 0.30 0.40 0.50 0.60 0.70 0.80
UERR Oil (Bbo)
Gas Market Value Adjustment 0.3
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas

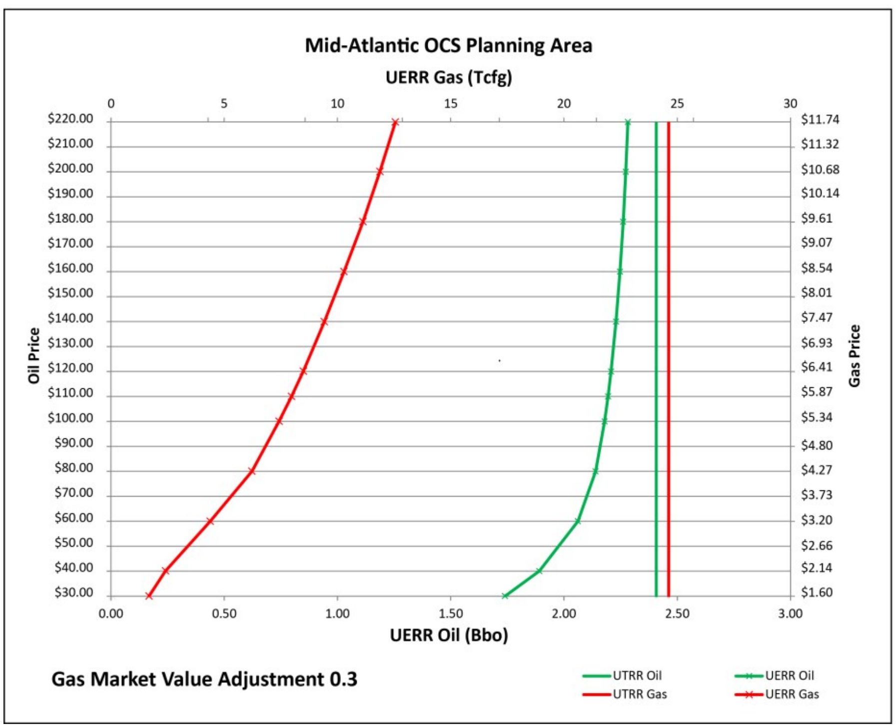

Norton Basin OCS Planning Area
UERR Gas (Tcfg)
0.00 0.50 1.00 1.50 2.00 2.50 3.00 3.50
$220.00 $210.00 $200.00 $190.00 $180.00 $170.00 $160.00 $150.00 $140.00 $130.00 $120.00 $110.00 $100.00 $90.00 $80.00 $70.00 $60.00 $50.00 $40.00 $30.00
Oil Price
$11.74 $11.32 $10.68 $10.14 $9.61 $9.07 $8.54 $8.01 $7.47 $6.93 $6.41 $5.87 $5.34 $4.80 $4.27 $3.73 $3.20 $2.66 $2.14 $1.60
Gas Price
0.00 0.01 0.02 0.03 0.04 0.05 0.06
UERR Oil (Bbo)
Gas Market Value Adjustment 0.3
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas

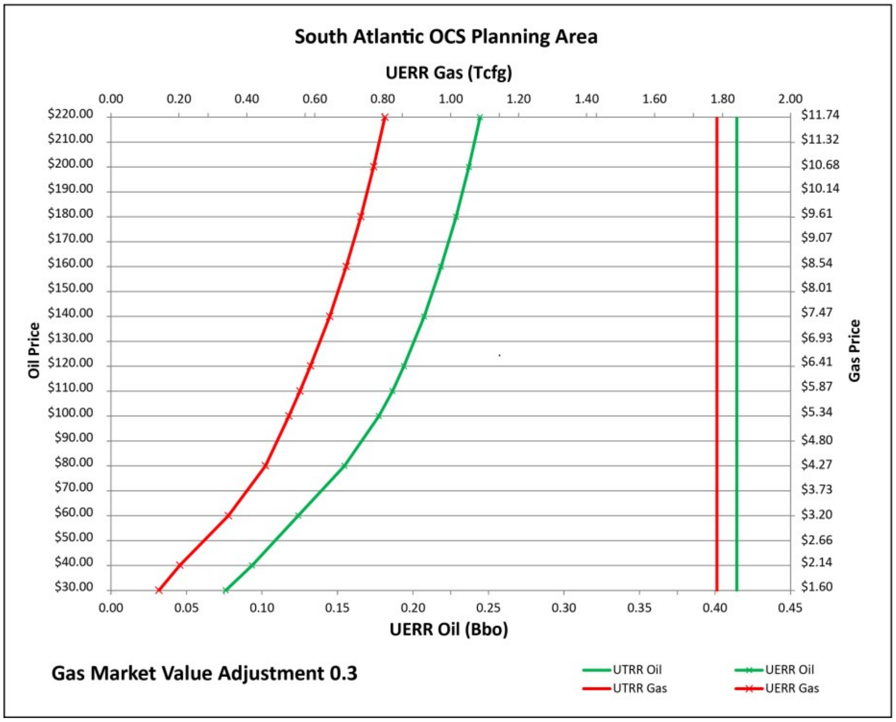

Shumagin OCS Planning Area
UERR Gas (Tcfg)
0.00
0.10
0.20
0.30
0.40
0.50
0.60
Oil Price
$220.00
$210.00
$200.00
$190.00
$180.00
$170.00
$160.00
$150.00
$140.00
$130.00
$120.00
$110.00
$100.00
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
Gas Price
$11.74
$11.32
$10.68
$10.14
$9.61
$9.07
$8.54
$8.01
$7.47
$6.93
$6.41
$5.87
$5.34
$4.80
$4.27
$3.73
$3.20
$2.66
$2.14
$1.60
0.00
0.00
0.00
0.01
0.01
0.01
0.01
0.01
UERR Oil (Bbo)
Gas Market Value Adjustment 0.3
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas


St. George Basin OCS Planning Area
UERR Gas (Tcfg)
0.00
0.50
1.00
1.50
2.00
2.50
3.00
Oil Price
$220.00
$210.00
$200.00
$190.00
$180.00
$170.00
$160.00
$150.00
$140.00
$130.00
$120.00
$110.00
$100.00
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
Gas Price
$11.74
$11.32
$10.68
$10.14
$9.61
$9.07
$8.54
$8.01
$7.47
$6.93
$6.41
$5.87
$5.34
$4.80
$4.27
$3.73
$3.20
$2.66
$2.14
$1.60
0.00
0.05
0.10
0.15
0.20
0.25
UERR Oil (Bbo)
Gas Market Value Adjustment 0.3
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas

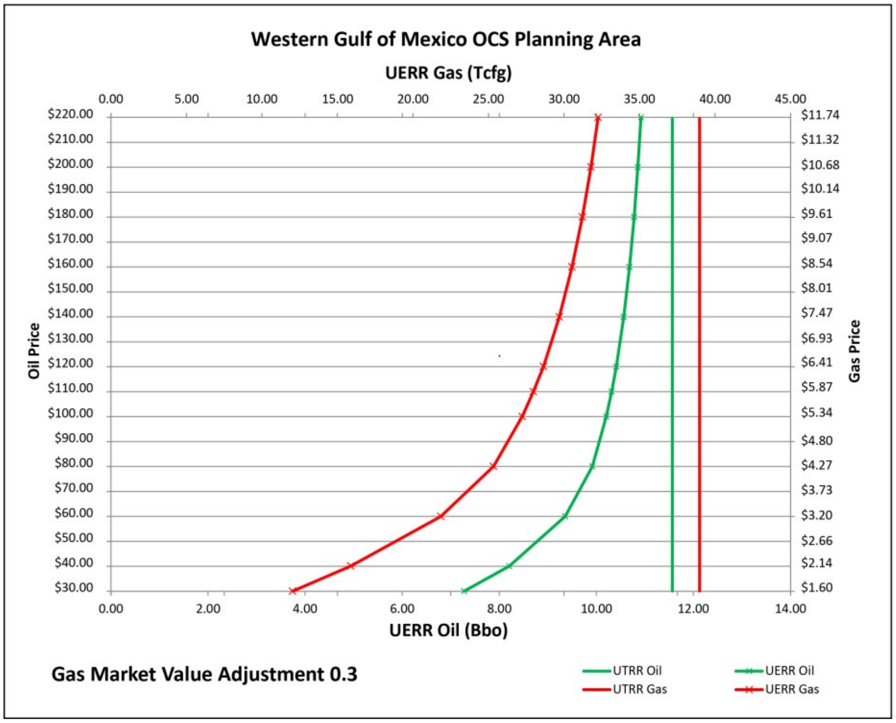
10.2 Atlantic OCS Region

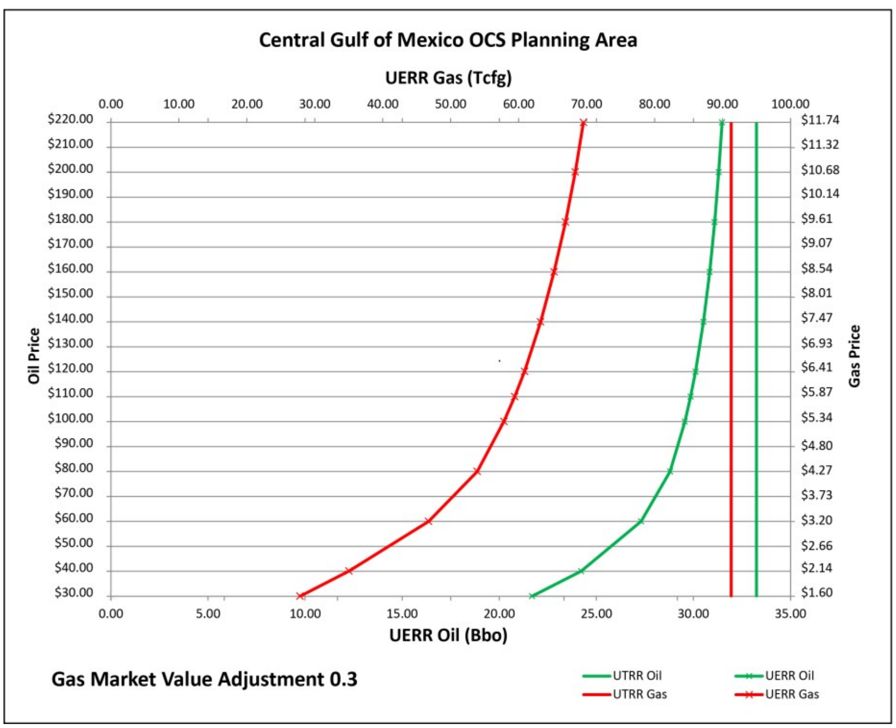


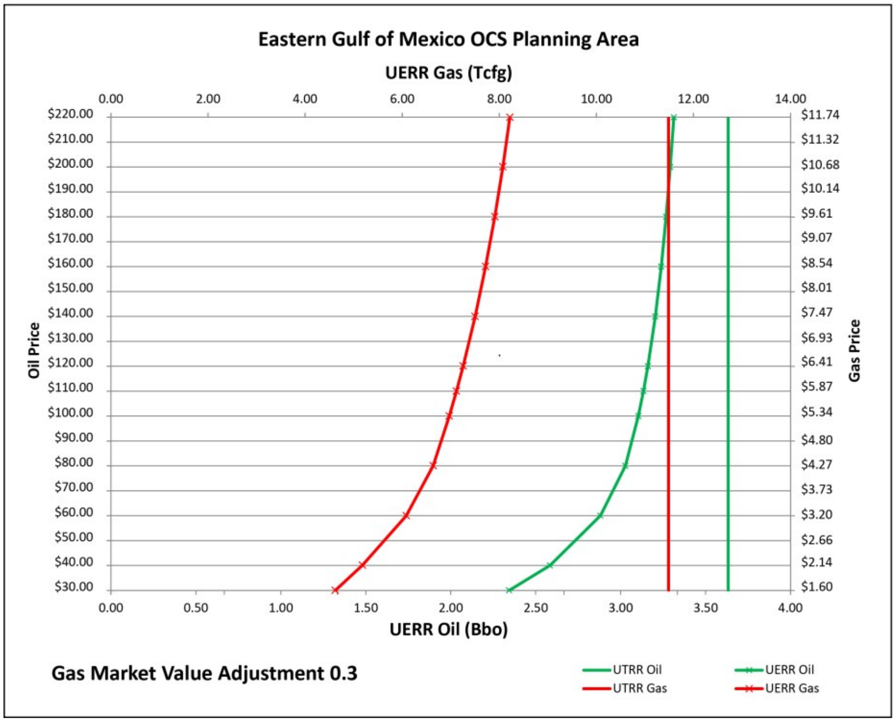


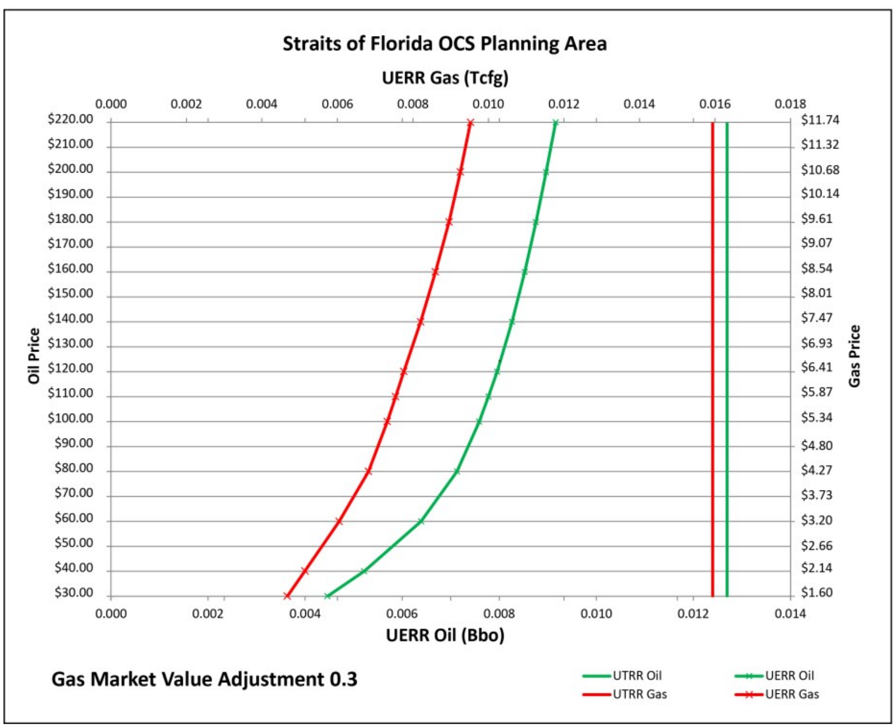

South Atlantic OCS Planning Area
UERR Gas (Tcfg)
0.00
0.20
0.40
0.60
0.80
1.00
1.20
1.40
1.60
1.80
2.00
Oil Price
$220.00
$210.00
$200.00
$190.00
$180.00
$170.00
$160.00
$150.00
$140.00
$130.00
$120.00
$110.00
$100.00
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
Gas Price
$11.74
$11.32
$10.68
$10.14
$9.61
$9.07
$8.54
$8.01
$7.47
$6.93
$6.41
$5.87
$5.34
$4.80
$4.27
$3.73
$3.20
$2.66
$2.14
$1.60
0.00
0.05
0.10
0.15
0.20
0.25
0.30
0.35
0.40
0.45
UERR Oil (Bbo)
Gas Market Value Adjustment 0.3
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas

10.3 Gulf of Mexico OCS Region

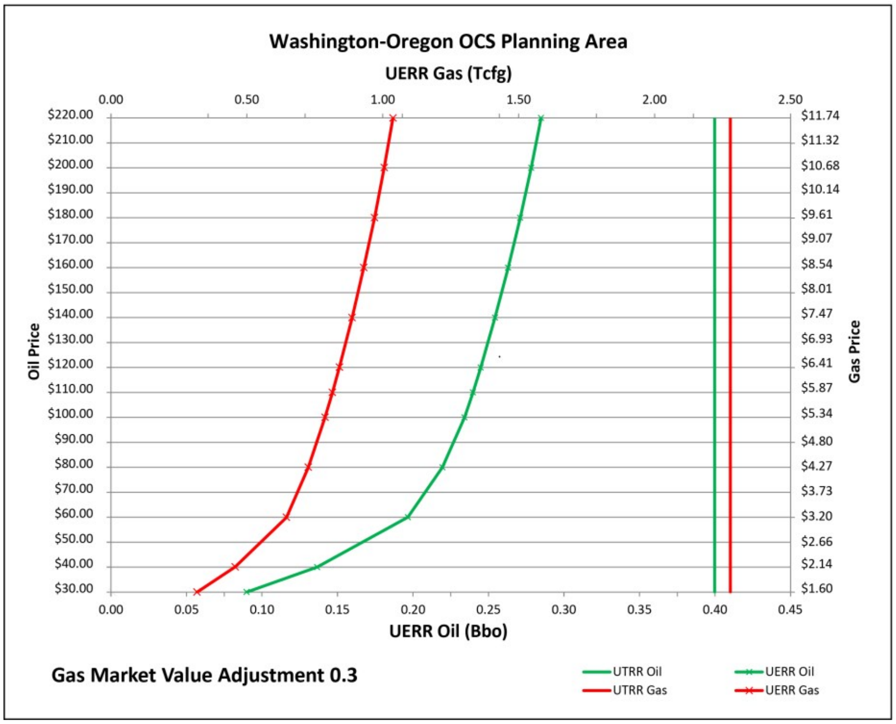


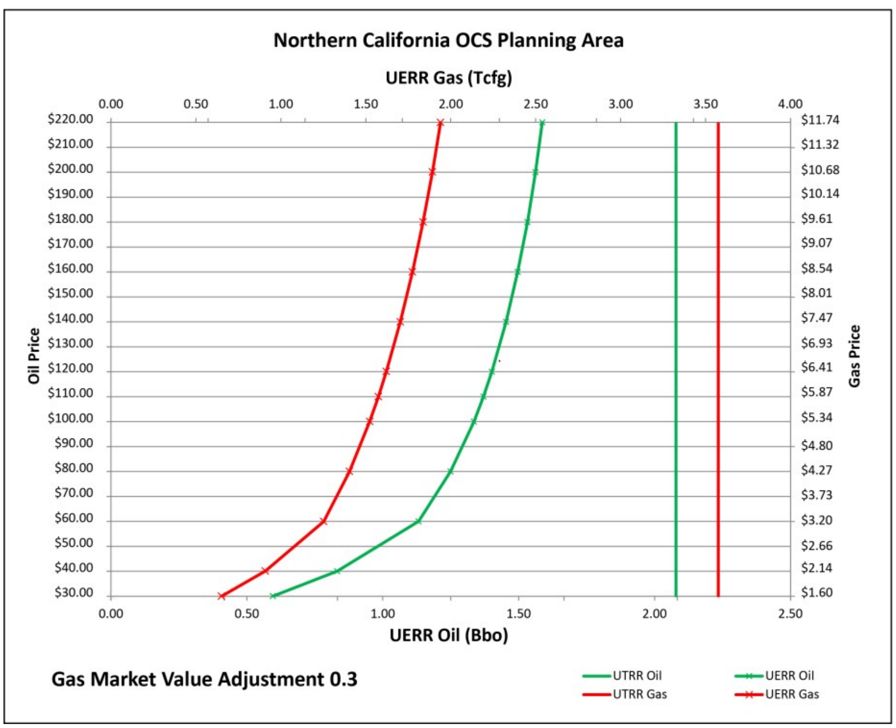


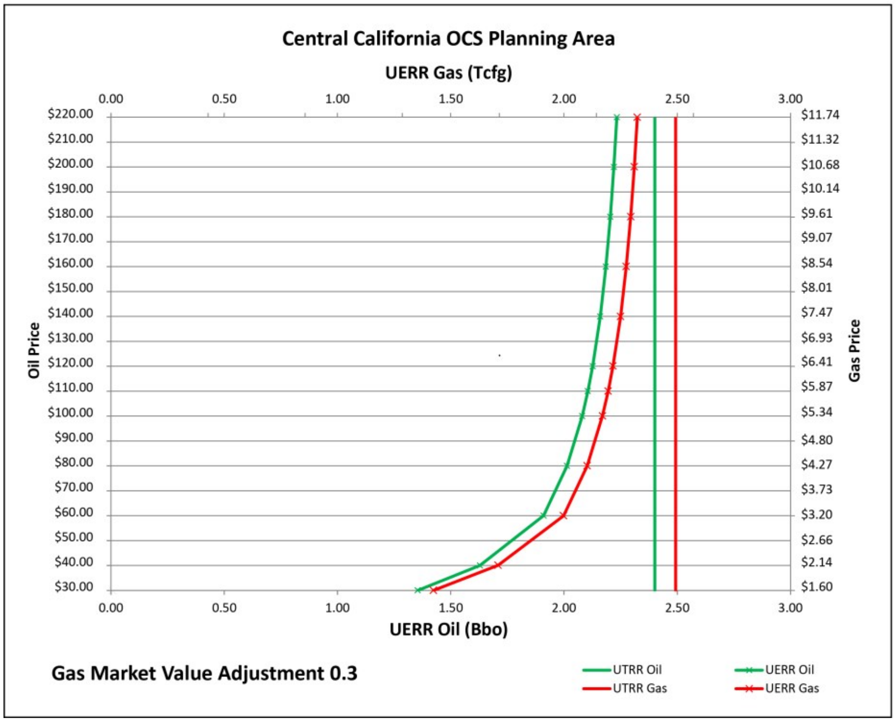

Eastern Gulf of Mexico OCS Planning Area
UERR Gas (Tcfg)
UERR Oil (Bbo)
Oil Price
Gas Price
Gas Market Value Adjustment 0.3
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas

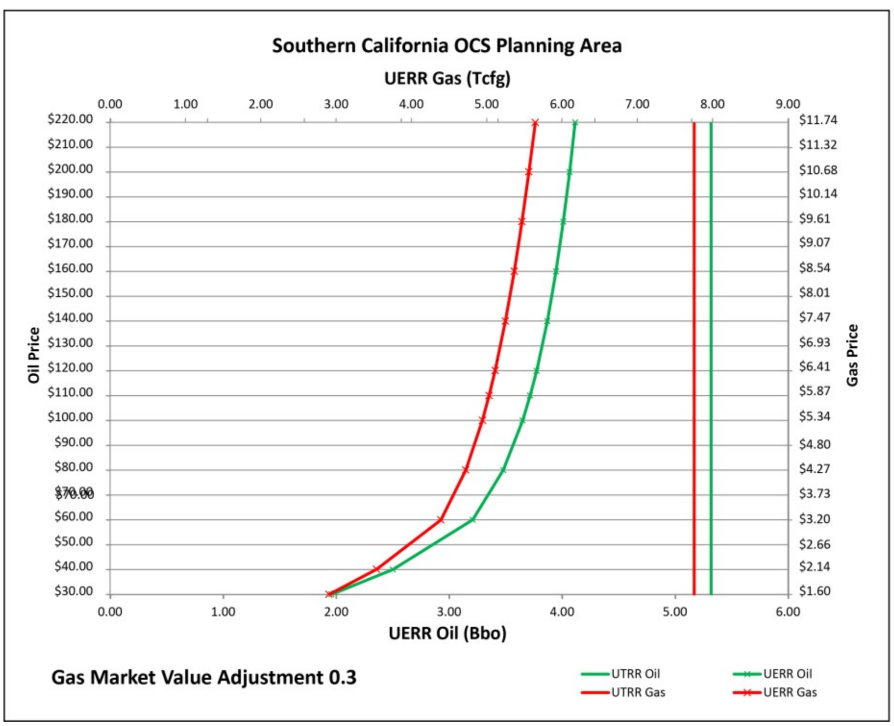

Straits of Florida OCS Planning Area
UERR Gas (Tcfg)
UERR Oil (Bbo)
Oil Price
Gas Price
Gas Market Value Adjustment 0.3
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas

10.4 Pacific OCS Region






Central California OCS Planning Area
UERR Gas (Tcfg)
0.00
0.50
1.00
1.50
2.00
2.50
3.00
Oil Price
$220.00
$210.00
$200.00
$190.00
$180.00
$170.00
$160.00
$150.00
$140.00
$130.00
$120.00
$110.00
$100.00
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
Gas Price
$11.74
$11.32
$10.68
$10.14
$9.61
$9.07
$8.54
$8.01
$7.47
$6.93
$6.41
$5.87
$5.34
$4.80
$4.27
$3.73
$3.20
$2.66
$2.14
$1.60
UERR Oil (Bbo)
Gas Market Value Adjustment 0.3
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas


Southern California OCS Planning Area
UERR Gas (Tcfg)
0.00
1.00
2.00
3.00
4.00
5.00
6.00
7.00
8.00
9.00
Oil Price
$220.00
$210.00
$200.00
$190.00
$180.00
$170.00
$160.00
$150.00
$140.00
$130.00
$120.00
$110.00
$100.00
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
Gas Price
$11.74
$11.32
$10.68
$10.14
$9.61
$9.07
$8.54
$8.01
$7.47
$6.93
$6.41
$5.87
$5.34
$4.80
$4.27
$3.73
$3.20
$2.66
$2.14
$1.60
UERR Oil (Bbo)
Gas Market Value Adjustment 0.3
UTRR Oil
UERR Oil
UTRR Gas
UERR Gas

Department of the Interior (DOI)

The Department of the Interior protects and manages the Nation's natural resources and cultural heritage; provides scientific and other information about those resources; and honors the Nation's trust responsibilities or special commitments to American Indians, Alaska Natives, and affiliated island communities.

Bureau of Ocean Energy Management (BOEM)

The mission of the Bureau of Ocean Energy Management is to manage development of U.S. Outer Continental Shelf energy and mineral resources in an environmentally and economically responsible way.