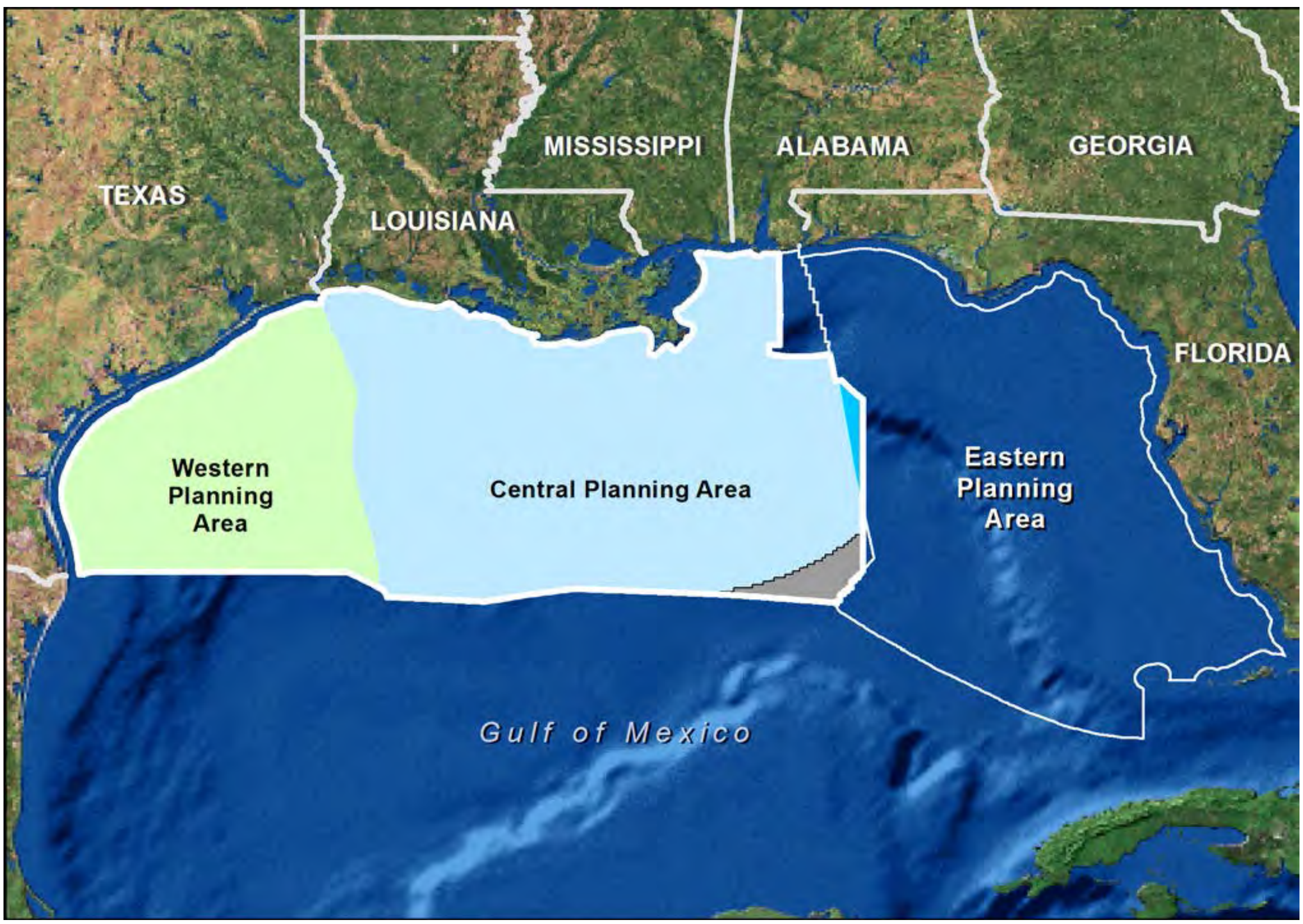
OCS EIS/EA
BOEM 2017-009

Gulf of Mexico OCS Oil and Gas Lease Sales: 2017-2022

Gulf of Mexico Lease Sales 249, 250, 251, 252, 253, 254, 256, 257, 259, and 261

Final Multisale Environmental Impact Statement

Volume I: Chapters 1-3



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

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Author

Bureau of Ocean Energy Management
Gulf of Mexico OCS Region

Published by

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

New Orleans
March 2017

REGIONAL DIRECTOR'S NOTE

In the *2017-2022 Outer Continental Shelf Oil and Gas Leasing: Proposed Final Program* (Five-Year Program), 10 regionwide lease sales (encompassing the Western Planning Area, Central Planning Area, and the portion of the Eastern Planning Area not subject to Congressional moratorium) are scheduled for the Gulf of Mexico region. Federal regulations allow for several related or similar proposals to be analyzed in one environmental impact statement (EIS) (40 CFR § 1502.4). Since each lease sale proposal and projected activities are very similar for each proposed lease sale area, the Bureau of Ocean Energy Management (BOEM) has prepared a single programmatic EIS for the 10 proposed lease sales: *Gulf of Mexico OCS Oil and Gas Lease Sales: 2017-2022; Gulf of Mexico Lease Sales 249, 250, 251, 252, 253, 254, 256, 257, 259, and 261; Final Multisale Environmental Impact Statement* (2017-2022 GOM Multisale EIS).

This Final Multisale EIS analyzes the potential impacts of the proposed actions on the marine, coastal, and human environments. It is important to note that this Final Multisale EIS was prepared using the best information that was publicly available at the time the document was prepared. This Multisale EIS's analysis focuses on identifying the baseline conditions and potential environmental effects of oil and natural gas leasing, exploration, development, and production in the GOM. This Multisale EIS will also assist decisionmakers in making informed, future decisions regarding the approval of operations, as well as leasing. At the completion of this Multisale EIS, a decision will be made only for proposed Lease Sale 249. Supplemental National Environmental Policy Act (NEPA) reviews, including opportunities for public involvement, will be conducted annually for the remaining proposed lease sales.

BOEM's Gulf of Mexico OCS Region and its predecessors have been conducting environmental analyses of the effects of Outer Continental Shelf (OCS) oil and gas development since the inception of the National Environmental Policy Act of 1969. We have prepared and published more than 70 draft and 70 final EISs. Our goal has always been to provide factual, reliable, and clear analytical statements in order to inform decisionmakers and the public about the environmental effects of proposed OCS oil- and gas-related activities and their alternatives. We view the EIS process as providing a balanced forum for early identification, avoidance, and resolution of potential conflicts. It is in this spirit that we welcome comments on this process and future supplemental NEPA reviews from all concerned parties.

Michael A. Celata

Michael A. Celata
Regional Director
Bureau of Ocean Energy Management
Gulf of Mexico OCS Region

COVER SHEET

Gulf of Mexico Multisale Environmental Impact Statement
for
Proposed Gulf of Mexico OCS Oil and Gas
Lease Sales 249, 250, 251, 252, 253, 254, 256, 257, 259, and 261

	Draft ( )	**Final (x)**
Type of Action:	Administrative (x)	Legislative ( )

Area of Potential Impact: Offshore Marine Environment and Coastal Counties/Parishes of Texas, Louisiana, Mississippi, Alabama, and northwestern Florida

Agency	Headquarters' Contact	Region Contacts
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ABSTRACT

This Final Multisale Environmental Impact Statement (EIS) covers the proposed 2017-2022 Gulf of Mexico's Outer Continental Shelf (OCS) oil and gas lease sales as scheduled in the *2017-2022 Outer Continental Shelf Oil and Gas Leasing: Proposed Final Program* (Five-Year Program). The 10 proposed regionwide lease sales are Lease Sale 249 in 2017, Lease Sales 250 and 251 in 2018, Lease Sales 252 and 253 in 2019, Lease Sales 254 and 256 in 2020, Lease Sales 257 and 259 in 2021, and Lease Sale 261 in 2022.

The proposed actions are Federal actions requiring an environmental review. This document provides the following information in accordance with the National Environmental Policy Act and its implementing regulations, and it will be used in making decisions on the proposals. This document includes the purpose and background of the proposed actions, identification of the alternatives, description of the affected environment, and an analysis of the potential environmental impacts of the proposed actions, alternatives, and associated activities, including proposed mitigating measures and their potential effects. Potential contributions to cumulative impacts resulting from activities associated with the proposed actions are also analyzed.

Hypothetical scenarios were developed on the levels of activities, accidental events (such as oil spills), and potential impacts that might result if the proposed actions are adopted. Activities and disturbances associated with the proposed actions on biological, physical, and socioeconomic resources are considered in the analyses.

This Final Multisale EIS analyzes the potential impacts of the proposed actions on air and water quality, coastal habitats, deepwater benthic communities, *Sargassum*, live bottom habitats, fishes and invertebrates, birds, protected species, commercial and recreational fisheries, recreational resources, archaeological resources, human resources, and land use. It is important to note that this Final Multisale EIS was prepared using the best information that was publicly available at the time the document was prepared. Where relevant information on reasonably foreseeable significant adverse impacts is incomplete or unavailable, the need for the information was evaluated to determine if it was essential to a reasoned choice among the alternatives and if so, was either acquired or in the event it was impossible or exorbitant to acquire the information, accepted scientific methodologies were applied in its place.

Additional copies of this Final Multisale EIS and the other referenced publications may be obtained from the Bureau of Ocean Energy Management, Gulf of Mexico OCS Region, Public Information Office (GM 335A), 1201 Elmwood Park Boulevard, New Orleans, Louisiana 70123-2394, by telephone at 504-736-2519 or 1-800-200-GULF, or on the Internet at http://www.boem.gov/nepaprocess/.

EXECUTIVE SUMMARY

PURPOSE OF AND NEED FOR THE PROPOSED ACTIONS

2017-2022 Schedule of Proposed Gulf of Mexico OCS Region Lease Sales	
Lease Sale Number	Year
249	2017
250 and 251	2018
252 and 253	2019
254 and 256	2020
257 and 259	2021
261	2022

The Bureau of Ocean Energy Management (BOEM) has issued the *2017-2022 Outer Continental Shelf Oil and Gas Leasing: Final Proposed Program:* (Five-Year Program; USDOI, BOEM, 2016a). The Five-Year Program schedules 10 regionwide Gulf of Mexico (GOM) oil and gas lease sales. Five regionwide lease sales are tentatively scheduled in August of each year from 2017 through 2021 and five regionwide lease sales are tentatively scheduled in March of each year from 2018 through 2022. The lease sales proposed in the GOM in the Five-Year Program are regionwide lease sales comprised of the Western, Central, and a small portion of the Eastern Planning Areas (WPA, CPA, and EPA, respectively) not subject to Congressional moratorium (**Figure 1**).

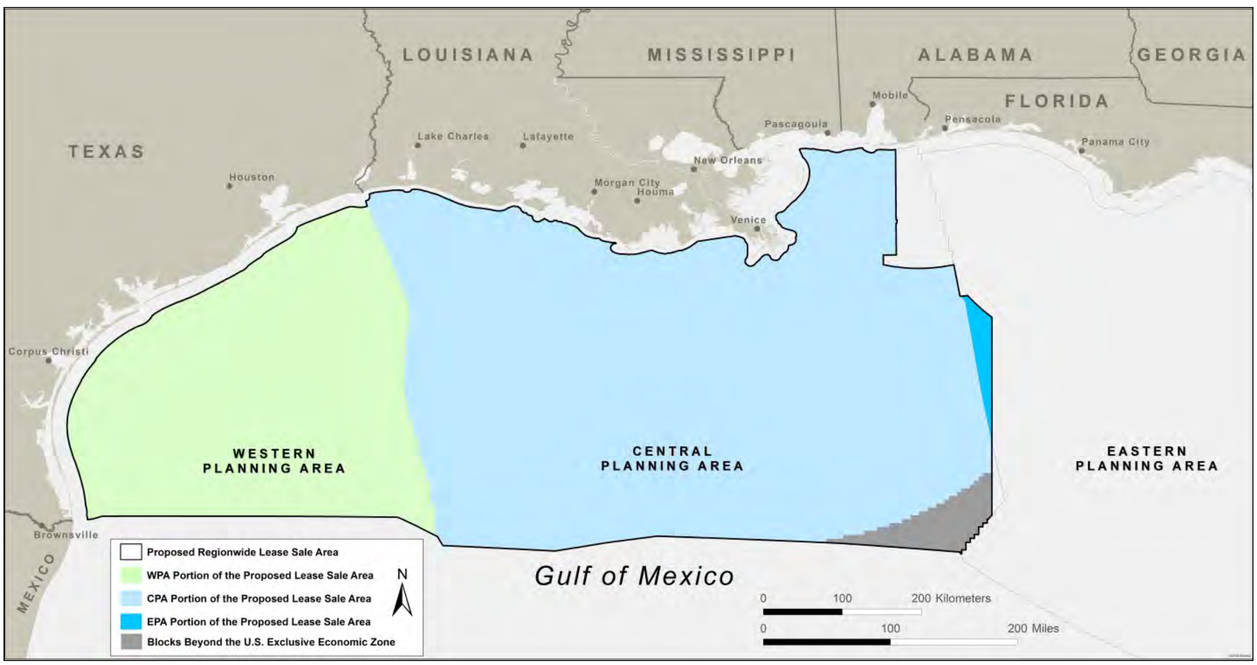

Figure 1. Proposed Regionwide Lease Sale Area Combining the Western, Central, and Eastern Planning Areas.

The development of the Five-Year Program also triggers region-specific National Environmental Policy Act (NEPA) reviews for the proposed lease sales. Region-specific reviews are conducted by Program Area (e.g., the Gulf of Mexico and Alaska OCS Regions) prior to lease sale decisions for those areas that are included in the Five-Year Program. Even though the Five-Year Program includes regionwide lease sales, any individual lease sale could still be scaled back during the prelease sale process to conform more closely to the separate planning area model used in the

Proposed Final Outer Continental Shelf Oil & Gas Leasing Program: *2012-2017* (2012-2017 Five-Year Program; USDOI, BOEM, 2012a), should circumstances warrant.

Purpose of the Proposed Actions

The Outer Continental Shelf Lands Act of 1953, as amended (43 U.S.C. §§ 1331 *et seq*. [1988]), hereafter referred to as the OCSLA, establishes the Nation's policy for managing the vital energy and mineral resources of the Outer Continental Shelf (OCS). Section 18 of the OCSLA requires the Secretary of the Interior to prepare and maintain a schedule of proposed OCS oil and gas lease sales determined to "best meet national energy needs for the 5-year period following its approval or reapproval" (43 U.S.C. § 1344). The Five-Year Program establishes a schedule that the U.S. Department of the Interior (USDOI or DOI) will use as a basis for considering where and when leasing might be appropriate over a 5-year period.

> *"It is hereby declared to be the policy of the United States that . . . the Outer Continental Shelf is a vital national resource held by the Federal Government for the public, which should be made available for expeditious and orderly development, subject to environmental safeguards, in a manner which is consistent with the maintenance of competition and other national needs."*
>
> OCSLA, 43 U.S.C. §§ 1331 *et seq.*

The purpose of the proposed Federal actions in this 2017-2022 Gulf of Mexico Multisale Environmental Impact Statement (Multisale EIS) is to offer for lease those areas that may contain economically recoverable oil and gas resources in accordance with the OCSLA, which specifically states "should be made available for expeditious and orderly development, subject to environmental safeguards" (OCSLA, 43 U.S.C. §§ 1331 *et seq*.). The proposed lease sales would provide qualified bidders the opportunity to bid upon and lease acreage in the Gulf of Mexico OCS in order to explore, develop, and produce oil and natural gas.

Need for the Proposed Actions

The need for the proposed actions is to further the orderly development of OCS resources in an environmentally and economically responsible manner. Oil serves as the feedstock for liquid hydrocarbon products, including gasoline, aviation and diesel fuel, and various petrochemicals. Oil from the Gulf of Mexico OCS contributes to meeting domestic demand and enhances national economic security.

THE DECISION TO BE MADE

BOEM will make an individual decision on whether and how to proceed with each proposed lease sale in the Five-Year Program. After completion of this Multisale EIS, BOEM will make a decision on proposed Lease Sale 249 (i.e., prepare a Record of Decision for Lease Sale 249 only). As discussed in **Chapter 1.3.1**, individual decisions will be made on each subsequent lease sale after completion of the appropriate supplemental NEPA documents.

PUBLIC INVOLVEMENT

BOEM conducted a public scoping process that extended from April 29 to June 1, 2015. Public scoping meetings were held in five cities (New Orleans, Louisiana; Houston, Texas; Panama City, Florida; Mobile, Alabama; and Gulfport, Mississippi). In addition to accepting oral and written comments at each public meeting, BOEM accepted written comments by mail, email, and through the regulations.gov web portal (http://www.regulations.gov). BOEM received a total of 10 comments in response to the Notice of Intent to Prepare an EIS. Many of the comments cited broad environmental concerns or specific concern about impacts on marine wildlife in general or on protected species such as marine mammals and sea turtles. Others cited concerns about impacts to critical habitats, fish and fisheries, sensitive benthic communities, and pelagic resources. Several of the comments had concerns with the effects of oil spills and the safety of offshore operations. Within the broad category of socioeconomics, comments focused on impacts on fisheries, recreation, tourism, and local jobs. Some of the comments provided recommendations for inclusion of particular alternatives or mitigation in this Multisale EIS analysis. Some comments recommended the implementation of specific analysis methodologies, while others recommended that recent industry technology and safety advances be taken into consideration.

Pursuant to the OCSLA, the Bureau of Ocean Energy Management published a Call for Information (Call) to request and gather information to determine the Area Identification (Area ID) for each lease sale. The Call was published in the *Federal Register* (2015a) on September 4, 2015. The Call invited potential bidders to nominate areas of interest within the program area(s) included in the *2017-2022 Outer Continental Shelf Oil and Gas Leasing: Draft Proposed Program* (Draft Proposed Program). The Call was also an opportunity for the public to provide information on environmental, socioeconomic, and other considerations relevant to determining the Area ID. The comment period for the Call closed on October 5, 2015. BOEM received one comment letter in response to the Call from the Louisiana Department of Natural Resources. The Louisiana Office of Coastal Management requested that BOEM consider secondary and cumulative impacts of OCS lease sales on coastal environments as well as identify, quantify, and mitigate (e.g., compensatory mitigation) secondary and cumulative harm that occurs to Louisiana's coastal wetlands, and implement plans for validating predictions of social and environmental effects on coastal resources. Using information provided in response to the Call and from scoping comments, BOEM then developed an Area ID recommendation memorandum. The Area ID is an administrative prelease step that describes the geographic area for environmental analysis and consideration for leasing. On November 20, 2015, the Area ID decision was made. One Area ID was prepared for all proposed lease sales. The Area ID memorandum recommended keeping the entire regionwide area of the GOM included in the Draft Proposed Program for consideration in this Multisale EIS. The area identified for lease includes all of the available unleased blocks in the GOM not subject to Congressional moratorium pursuant to the Gulf of Mexico Energy Security Act of 2006.

A Notice of Availablity (NOA) of the Draft Multisale EIS was published in the *Federal Register* on April 22, 2016, initiating a solicitation of public comments on the Draft Multisale EIS (*Federal Register*, 2016a). The 45-day comment period ended on June 7, 2016. In accordance with

30 CFR § 556.26, BOEM scheduled public meetings soliciting comments on the Draft Multisale EIS. Ninety-three individuals attended five public meetings, which were held in Beaumont, Texas; New Orleans, Louisiana; Panama City, Florida; Mobile, Alabama; and Gulfport, Mississippi. BOEM received over 1,300 comments in response to the Draft Multisale EIS via letter, email, written and verbal comments at public meetings, and the regulations.gov website. A large majority of the comments was a form letter from the "No New Leases" organization. As requested by the Director of the Mississippi Coalition for Vietnamese-American Fisher Folks and Families (MSCVAFF) during the comment period, BOEM had select portions of the Multisale EIS (the summary, fish and invertebrates, and commercial fishing sections, as well as meeting handouts) translated into the Vietnamese language. Once completed, these documents were made available to the MSCVAFF for review and comment through August 31, 2016. BOEM did not receive any additional comments.

ALTERNATIVES

BOEM has identified four action alternatives, and the no action alternative, to be analyzed in this Multisale EIS. These alternatives are briefly described below. The mitigating measures (pre- and postlease), including the proposed stipulations, are fully described in **Chapter 2 and Appendices B and D**, as are the deferred alternatives not analyzed in detail.

Alternative A—Regionwide OCS Lease Sale (The Preferred Alternative)

Alternative A would allow for a proposed regionwide lease sale encompassing all three planning areas within the U.S. portion of the Gulf of Mexico OCS for any given lease sale in the Five-Year Program. This is BOEM's preferred alternative. This alternative would offer for lease all available unleased blocks within the WPA, CPA, and EPA portions of the proposed lease sale area for oil and gas operations (**Figure 2**), with the following exceptions:

(1) whole and portions of blocks deferred by the Gulf of Mexico Energy Security Act of 2006 (discussed in the *OCS Regulatory Framework* white paper [Cameron and Matthews, 2016]);

(2) blocks that are adjacent to or beyond the United States' Exclusive Economic Zone in the area known as the northern portion of the Eastern Gap; and

(3) whole and partial blocks within the current boundary of the Flower Garden Banks National Marine Sanctuary.

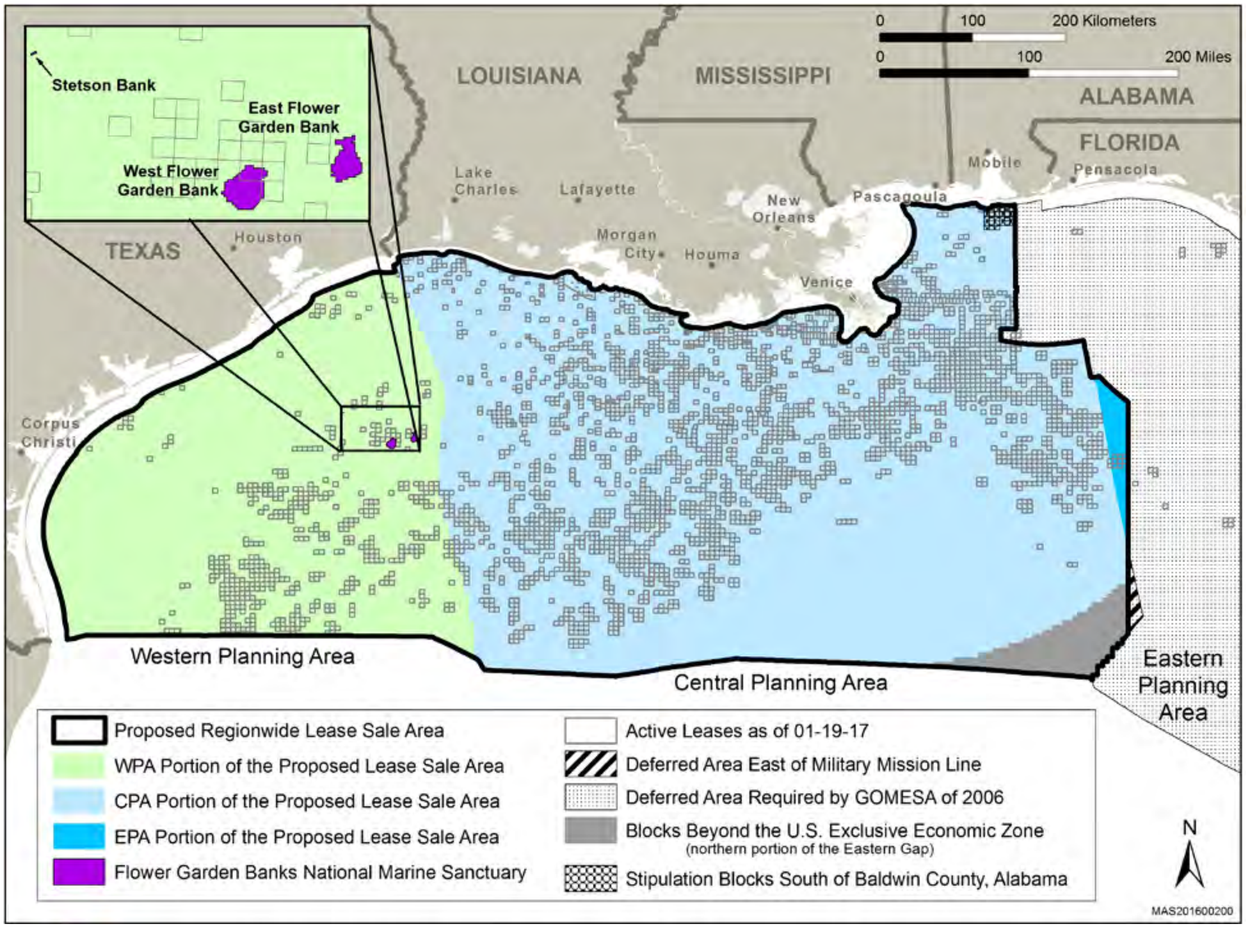

Figure 2. Proposed Regionwide Lease Sale Area, Encompassing the Available Unleased Blocks within All Three Planning Areas (approximately 91.93 million acres with approximately 75.4 million acres available for lease as of January 2017).

Alternative B—Regionwide OCS Lease Sale Excluding Available Unleased Blocks in the WPA Portion of the Proposed Lease Sale Area

Alternative B would allow for a proposed lease sale encompassing the CPA and EPA within the U.S. portion of the Gulf of Mexico OCS (**Figure 3**). Available blocks within the WPA would ***not*** be considered under this alternative. This alternative would offer for lease all available unleased blocks within the CPA and EPA portions of the proposed lease sale area as those planning area portions described in Alternative A for oil and gas operations, with the following exceptions:

(1) whole and portions of blocks deferred by the Gulf of Mexico Energy Security Act of 2006 (discussed in the *OCS Regulatory Framework* white paper [Cameron and Matthews, 2016]); and

(2) blocks that are adjacent to or beyond the United States' Exclusive Economic Zone in the area known as the northern portion of the Eastern Gap.

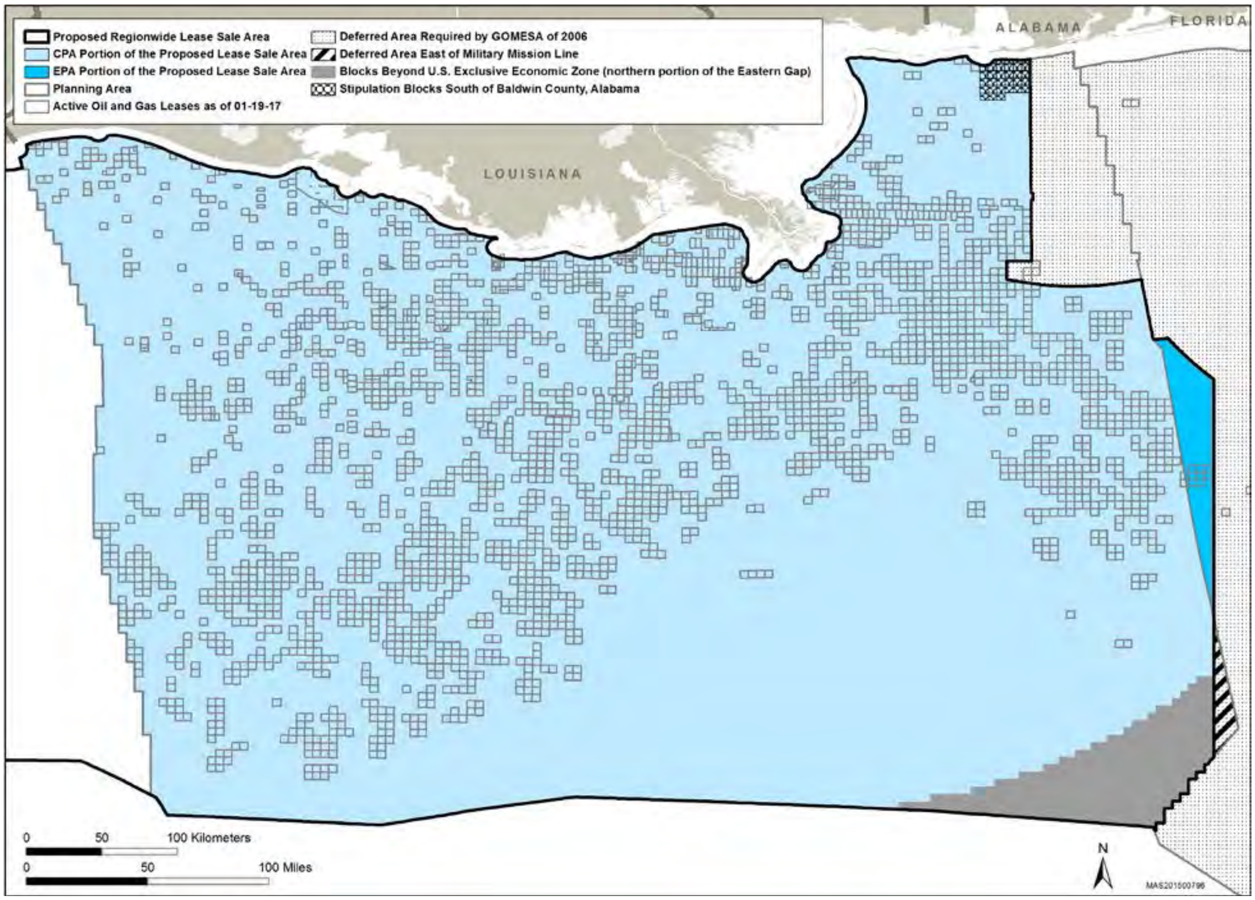

Figure 3. Proposed Lease Sale Area for Alternative B, Excluding the Available Unleased Blocks in the WPA (approximately 63.35 million acres with approximately 49.6 million acres available for lease as of January 2017).

Alternative C—Regionwide OCS Lease Sale Excluding Available Unleased Blocks in the CPA/EPA Portions of the Proposed Lease Sale Area

Alternative C would allow for a proposed lease sale encompassing the WPA within the U.S. portion of the Gulf of Mexico OCS (**Figure 4**). Available blocks within the CPA and EPA would ***not*** be considered under this alternative. This alternative would offer for lease all available unleased blocks within the WPA portion of the proposed lease sale area for oil and gas operations, with the following exception:

(1) whole and partial blocks within the current boundary of the Flower Garden Banks National Marine Sanctuary.

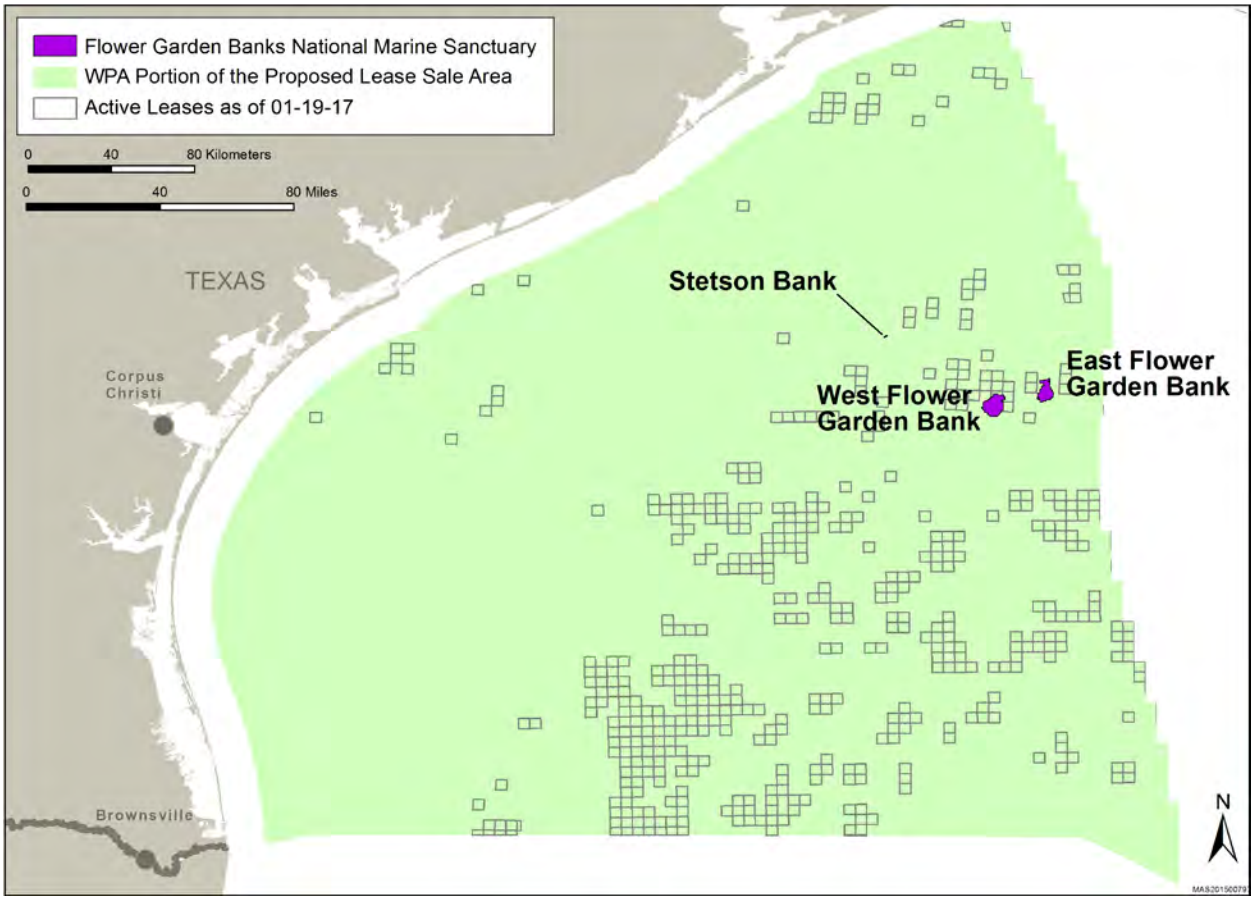

Figure 4. Proposed Lease Sale Area for Alternative C, Excluding the Available Unleased Blocks in the CPA and EPA (approximately 28.58 million acres with approximately 25.8 million acres available for lease as of January 2017).

Alternative D—Alternative A, B, or C, with the Option to Exclude Available Unleased Blocks Subject to the Topographic Features, Live Bottom (Pinnacle Trend), and/or Blocks South of Baldwin County, Alabama, Stipulations

Alternative D could be combined with any of the action alternatives above (A, B, or C) and would allow the flexibility to offer leases under any alternative with additional exclusions. Under Alternative D, the decisionmaker could exclude from leasing any available unleased blocks subject to any one and/or combination of the following stipulations:

- Topographic Features Stipulation;
- Live Bottom (Pinnacle Trend) Stipulation; and
- Blocks South of Baldwin County, Alabama, Stipulation (not applicable to Alternative C).

This alternative considered blocks subject to these stipulations because these areas have been emphasized in scoping, can be geographically defined, and adequate information exists regarding their ecological importance and sensitivity to OCS oil- and gas-related activities, as shown in **Figure 5**. All of the assumptions (including the other potential mitigating measures) and estimates would remain the same as described for any given alternative.

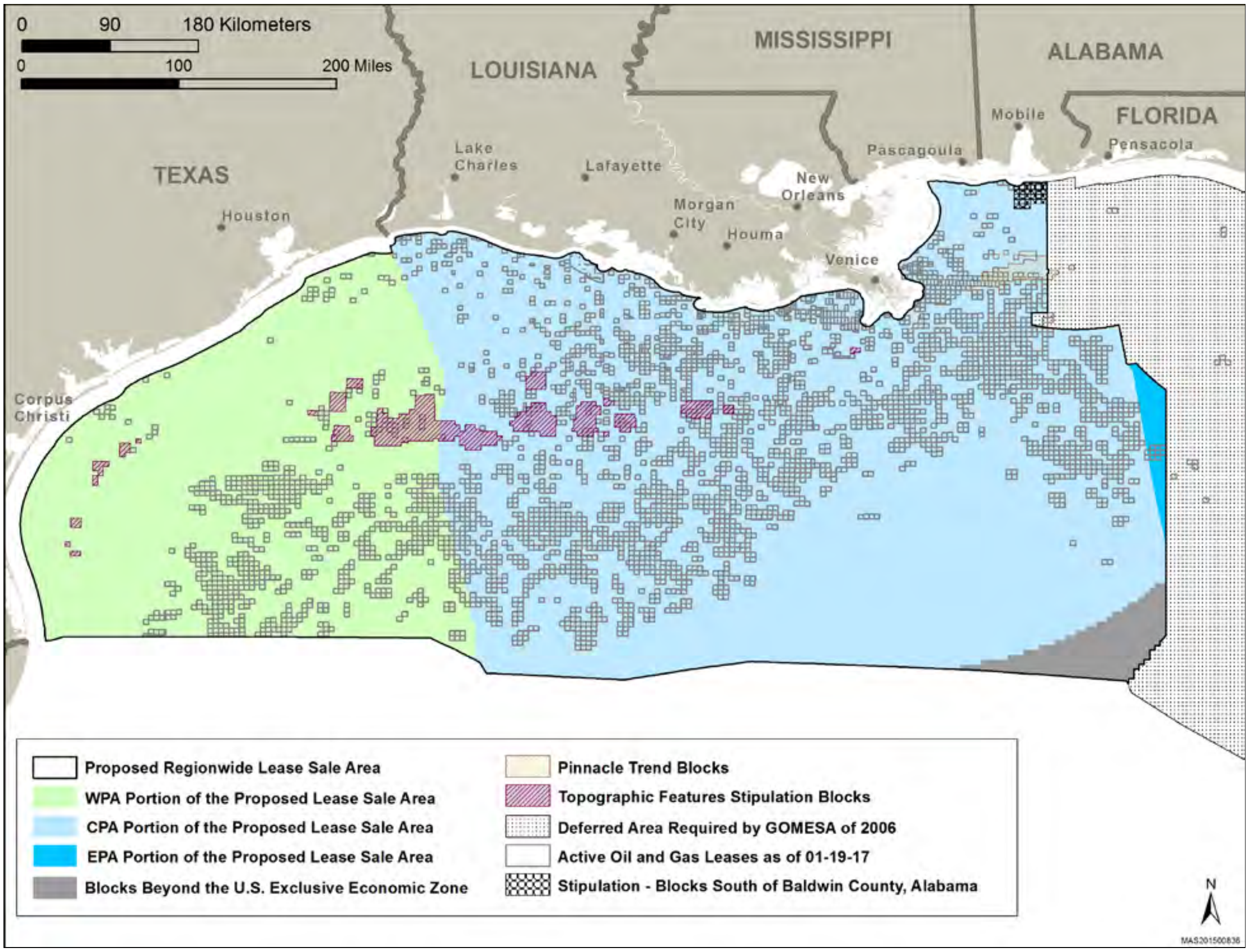

Figure 5. Identified Topographic Features, Pinnacle Trend, and Baldwin County Stipulation Blocks in the Gulf of Mexico.

Alternative E—No Action

Alternative E is the cancellation of a single proposed lease sale. The opportunity for development of the estimated oil and gas that could have resulted from a proposed action (i.e., a single proposed lease sale) or alternative to a proposed action, as described above, would be precluded or postponed to a future lease sale. Any potential environmental impacts resulting from a proposed lease sale would not occur. Activities related to previously issued leases and permits (as well as those that may be issued in the future under a separate decision) related to the OCS oil and gas program would continue. If a lease sale were to be cancelled, the resulting development of oil and gas would most likely be postponed to a future lease sale; therefore, the overall level of OCS oil- and gas-related activity would only be reduced by a small percentage, if any.

MITIGATING MEASURES

Proposed lease stipulations and other mitigating measures designed to reduce or eliminate environmental risks and/or potential multiple-use conflicts between OCS operations and U.S. Department of Defense activities may be applied to the chosen alternative. Mitigating measures in the form of lease stipulations are added to the lease terms and are therefore enforceable as part of the lease. The 10 lease stipulations being considered are the Topographic Features Stipulation; Live Bottom (Pinnacle Trend) Stipulation; Military Areas Stipulation; Evacuation Stipulation; Coordination Stipulation; Blocks South of Baldwin County, Alabama, Stipulation; Protected Species Stipulation; United Nations Convention on the Law of the Sea Royalty Payment Stipulation; Below Seabed Operations Stipulation; and the Stipulation on the Agreement between the United States of America and the United Mexican States Concerning Transboundary Hydrocarbon Reservoirs in the Gulf of Mexico (Transboundary Stipulation). The United Nations Convention on the Law of the Sea Royalty Payment Stipulation is applicable to a proposed lease sale even though it is not an environmental or military stipulation. The Topographic Features and Live Bottom (Pinnacle Trend) Stipulations have been applied as programmatic mitigation in the Five-Year Program EIS (USDOI, BOEM, 2016b) and, therefore, would apply to all leases issued under the Five-Year Program in the designated lease blocks. **Chapter 2.2.4** provides a brief description of each stipulation and the potential benefits associated with its use. **Appendix D** provides a more detailed analysis of the 10 lease stipulations and their effectiveness.

Application of lease stipulations will be considered by the Assistant Secretary of the Interior for Land and Minerals Management (ASLM). The inclusion of the stipulations as part of the analysis of the proposed actions does not ensure that the ASLM will make a decision to apply the stipulations to leases that may result from a proposed lease sale, nor does it preclude minor modifications in wording during subsequent steps in the prelease process if comments indicate changes are necessary or if conditions warrant. Any lease stipulations or mitigating measures to be included in a lease sale will be described in the Final Notice of Sale. In addition, mitigations may be added to plan and/or permits for OCS oil- and gas-related activities (**Chapter 2.2.4.3**). For more information on mitigating measures that are added at the postlease stage, refer to **Appendix B** ("Commonly Applied Mitigating Measures").

DIRECT AND INDIRECT ACTIONS ASSOCIATED WITH A PROPOSED LEASE SALE

BOEM describes the potentially occurring actions associated with a single proposed lease sale and the cumulative activities that provide a framework for a detailed analysis of the potential environmental impacts. Exploration and development scenarios describe the infrastructure and activities that could potentially affect the biological, physical, and socioeconomic resources in the GOM. They also include a set of ranges for resource estimates, projected exploration and development activities, and impact-producing factors.

Offshore activities are described in the context of scenarios for a proposed action (**Chapter 3.1**) and for the OCS Program (**Chapter 3.3**). BOEM's Gulf of Mexico OCS Region developed these scenarios to provide a framework for detailed analyses of potential impacts of a proposed lease sale. The scenarios are presented as ranges of the amounts of undiscovered, unleased hydrocarbon resources estimated to be leased and discovered as a result of a proposed action. The analyses are based on a traditionally employed range of activities (e.g., the installation of platforms, wells, and pipelines, and the number of helicopter operations and service-vessel trips) that would be needed to develop and produce the amount of resources estimated to be leased.

Within each resource section in **Chapter 4**, the cumulative analysis considers environmental and socioeconomic impacts that may result from the incremental impact of a proposed action when added to all past, present, and reasonably foreseeable future activities, including non-OCS oil- and gas-related activities such as import tankering and commercial fishing, as well as all OCS oil- and gas-related activities (OCS Program). This includes projected activity from lease sales that have been held but for which exploration or development has not yet begun or is continuing. In addition, impacts from natural occurrences, such as hurricanes, are analyzed.

ENVIRONMENTAL IMPACTS

The affected environment and the potential impacts of a single proposed lease sale and each alternative have been described and analyzed by resource. Analysis of the alternatives include routine activities, accidental events, cumulative impact analysis, incomplete or unavailable information, and conclusions for each resource. This Multisale EIS also considers baseline data in the assessment of impacts from a proposed action on the resources and the environment (**Chapter 4**).

The major issues that frame the environmental analyses in this Multisale EIS are the result of concerns raised during years of scoping for the Gulf of Mexico OCS Program. Issues related to OCS oil and gas exploration, development, production, and transportation activities include the potential for oil spills, wetlands loss, air emissions, wastewater discharges and water quality degradation, marine trash and debris, structure and pipeline emplacement activities, platform removal, vessel and helicopter traffic, multiple-use conflicts, support services, population fluctuations, land-use planning, impacts to recreation and beaches, aesthetic interference, environmental justice, and conflicts with State coastal zone management programs. Environmental resources and activities identified during the scoping process that warrant an environmental analysis include air quality, water quality, coastal habitats (including wetlands and seagrasses), barrier beaches and associated dunes, live bottom habitats (including topographic features and pinnacle trends), *Sargassum* and associated communities, deepwater benthic communities, marine mammals, sea turtles, birds, fishes and invertebrate resources, commercial fisheries, recreational fishing, recreational resources, archaeological resources, and socioeconomic factors (including environmental justice), and within the CPA only, beach mice.

Other relevant issues include impacts from the *Deepwater Horizon* explosion, oil spill, and response; impacts from past and future hurricanes on environmental and socioeconomic resources; and impacts on coastal and offshore infrastructure. During the past several years, the Gulf Coast States and Gulf of Mexico oil and gas activities have been impacted by major hurricanes. The description of the affected environment includes impacts from these relevant issues on the physical environment, biological environment, and socioeconomic activities, and on OCS oil- and gas-related infrastructure.

Impact Conclusions

The full analyses of the potential impacts of routine activities and accidental events associated with a proposed action and a proposed action's incremental contribution to the cumulative impacts are described in the individual resource discussions in **Chapter 4**. A summary of the potential impacts from a proposed action on each environmental and socioeconomic resource and the conclusions of the analyses can be found in the following discussions. **Table 1** provides a comparison of the expected impact levels by alternative and is derived from the analysis of each resource in **Chapter 4**. The impact level ratings have been specifically tailored and defined for each resource within the **Chapter 4** impact analysis. Cumulative impacts of current and past activities would continue to occur under Alternative E.

Table 1. Alternative Comparison Matrix.

Impact Level Key[1]					
Beneficial[2]	Negligible	Minor	Moderate	Major	
	Alternative				
Resource	A	B	C	D	E
Air Quality	Minor	Minor	Minor	Minor	None
Water Quality	Negligible	Negligible	Negligible	Negligible	None
Coastal Habitats					
Estuarine Systems	Moderate	Moderate	Minor	Moderate	Negligible
Coastal Barrier Beaches and Associated Dunes	Minor	Minor	Negligible to Minor	Negligible to Minor	Negligible
Deepwater Benthic Communities	Negligible	Negligible	Negligible	Negligible	None
Sargassum and Associated Communities	Negligible	Negligible	Negligible	Negligible	None
Live Bottoms					
Topographic Features	Negligible	Negligible	Negligible	Negligible	None
Pinnacles and Low-Relief Features	Negligible to Minor	Negligible to Minor	Negligible	Negligible	None
Fishes and Invertebrate Resources	Minor	Minor	Minor	Minor	None
Birds	Moderate	Moderate	Moderate	Moderate	None

Impact Level Key[1]					
Beneficial[2]	Negligible	Minor	Moderate	Major	
	Alternative				
Resource	A	B	C	D	E
Protected Species					
Marine Mammals	Negligible	Negligible	Negligible	Negligible	None
Sea Turtles	Negligible	Negligible	Negligible	Negligible	None
Beach Mice	Negligible	Negligible	Negligible	Negligible	None
Protected Birds	Negligible	Negligible	Negligible	Negligible	None
Protected Corals	Negligible	Negligible	Negligible	Negligible	None
Commercial Fisheries	Beneficial to Minor	Beneficial to Minor	Beneficial to Minor	Beneficial to Minor	Negligible
Recreational Fishing	Beneficial to Minor	Beneficial to Minor	Beneficial to Minor	Beneficial to Minor	Negligible
Recreational Resources	Beneficial to Minor	Beneficial to Minor	Beneficial to Minor	Beneficial to Minor	Negligible
Archaeological Resources	Negligible[3]	Negligible[3]	Negligible[3]	Negligible[3]	None
Human Resources and Land Use					
Land Use and Coastal Infrastructure	Minor	Minor	Minor	Minor	None
Economic Factors	Beneficial to Minor	Beneficial to Minor	Beneficial to Minor	Beneficial to Minor	Negligible to Minor
Social Factors (including Environmental Justice)	Minor	Minor	Minor	Minor	None

Note: Some resources have a range for the impact levels to account for certain variables such as the uncertainty of non-OCS oil- or gas-related activities, the level and magnitude of potential accidental events, and the minimization of the OCS oil- or gas-related impacts through lease stipulations, mitigations, and/or regulations. The impact level ratings have been specifically tailored and defined for each resource within the **Chapter 4** impact analysis.

[1] The findings for Alternatives A-D would be the incremental contribution of a proposed action to what would be expected to occur under the No Action Alternative (i.e., no lease sale). Therefore, each impact determination under Alternatives A-D assumes that the conditions and impacts (i.e., past, present, and future activities) under the No Action Alternative would be present.

[2] The level of beneficial impacts is specified in the analysis, which could range from low, medium, or high.

[3] The level of impacts for archaeological resources ranges between negligible to major and is dependent upon whether survey is performed, mitigation is imposed, mitigation is followed, or a site is identified prior to the activity.

Air Quality

Air quality is the degree at which the ambient air is free of pollution; it is assessed by measuring the pollutants in the air. To protect public health and welfare, the Clean Air Act established National Ambient Air Quality Standards (NAAQS) for certain common and widespread pollutants. The six common "criteria pollutants" are particle pollution (also known as particulate matter, $PM_{2.5}$ and PM_{10}), carbon monoxide (CO); nitrogen dioxide (NO_2); sulfur dioxide (SO_2); lead (Pb); and ozone (O_3). Air emissions from OCS oil and gas development in the Gulf of Mexico would arise from emission sources related to drilling and production with associated vessel support, flaring and venting, decommissioning, fugitive emissions, and oil spills. Associated activities that take place as a result of a proposed action support and maintain the OCS oil and gas platform sources. Air emissions from non-OCS oil- and gas-related emissions in the Gulf of Mexico would arise from emission sources related to State oil and gas programs, onshore industrial and transportation sources, and natural events. Since the primary National Ambient Air Quality Standards are designed to protect human health, BOEM focuses on the impact of these activities on the States, where there are permanent human populations.

In the "Air Quality Modeling in the Gulf of Mexico Region" study (**Appendices F-H**), photochemical grid modeling was conducted to assess the impacts to nearby states of existing and proposed future OCS oil and gas exploration, development, and production. This draft interim assessment is being used to disclose potential cumulative and incremental air quality impacts of the proposed lease sales; the final results are expected in fall 2017. The air quality modeling study examines the potential impacts of the proposed lease sales with respect to the NAAQS for the criteria pollutants O_3, NO_2, SO_2, CO, $PM_{2.5}$, PM_{10}; the air quality-related values (AQRVs), including visibility and acid deposition (sulfur and nitrogen) in nearby Class I and sensitive Class II areas; and the incremental impacts of Prevention of Significant Deterioration (PSD) pollutants (NO_2, PM_{10}, $PM_{2.5}$) with respect to PSD Class I and Class II increments. (*Note: This analysis does not constitute a regulatory PSD increment consumption analysis as would be required for major sources subject to the New Source Review program requirements of the Clean Air Act*). An assessment of the final study results will be discussed in future NEPA documents.

A regionwide lease sale has not previously been analyzed and historic trend data are limited. In the scenario in **Chapter 3.1**, the projected activities of a single regionwide lease sale is based on a range of historic observations and provides a reasonable expectation of oil and gas production anticipated from a single proposed lease sale. The projected activities of 10 proposed regionwide lease sales' mid-case scenario, which was used in the model, falls within the range of a single proposed lease sale. To understand how these results would apply to a single proposed lease sale, the level of projected activity was compared between the modeled highest year of the 10 proposed lease sales to a single proposed lease sale. This is conservative because the current price of oil equals the low range of the scenario. Using these assumptions, the potential impacts of a single proposed lease sale would be **minor**. More specifically, the potential impacts of a single proposed lease sale to the Breton Wilderness Area would be **moderate**, whereas the overall potential impacts of a single proposed lease sale would be **minor** for all other areas. However, since these potential impacts are conservative given the current prices of oil and gas, BOEM anticipates future modeling. A full analysis of air quality can be found in **Chapter 4.1**.

The incremental contribution of a proposed lease sale to the cumulative impacts would most likely have a minor effect on coastal nonattainment areas because most impacts on the affected resource could be avoided with proper mitigation. Portions of the Gulf Coast onshore areas have ozone levels that exceed the Federal air quality standard, but the incremental contribution from a proposed lease sale would be very small and would not on their own cause an exceedance.

As previously stated, BOEM contracted an air quality modeling study in the GOM region to assess the impacts of OCS oil- and gas-related development to nearby States, as required under the OCSLA. The data from forecasted emissions resulting from the 10 proposed lease sales was annualized using BOEM's Resource Evaluation's mid-case scenario. These results are presented in **Appendices F-H**. The cumulative impacts from all 10 proposed lease sales would be **minor** to **moderate**. More specifically, the cumulative impacts of 10 proposed lease sales to the Breton Wilderness Area and Gulf Islands National Seashore would be **moderate**, whereas the overall cumulative impacts of 10 proposed lease sales would be **minor** to **moderate**.

The cumulative impacts, in addition to the past, present, and future activities, of 10 proposed lease sales would most likely have a **moderate** effect on coastal nonattainment areas for certain pollutants. Portions of the Gulf Coast onshore areas have ozone levels that exceed the Federal air quality standard, but the cumulative impacts from 10 proposed lease sales do not on their own cause an exceedance. A full analysis of air quality can be found in **Chapter 4.1**.

Water Quality

Water quality is a term used to describe the condition or environmental health of a waterbody or resource, reflecting its particular biological, chemical, and physical characteristics and the ability of the waterbody to maintain the ecosystems it supports and influences. It is an important measure for both ecological and human health. The impacts of OCS Program-related drilling operational discharges (**Chapter 3.1.5.1**) on water quality are short term and localized. The potential impact from the discharge of produced water is considered **negligible** (beyond 1,000 m [3,281 ft]) to **moderate** (within 1,000 m [3,281 ft]). The potential impacts from OCS Program-related oil spills on water quality after mitigation are also short term and are considered **moderate**, even with the implementation of mitigating measures. This is because, after removal of most free product, the residual oil dissipates quickly through dispersion and weathering; however, secondary impacts to water quality may occur, such as the introduction of additional hydrocarbon into the dissolved phase through the use of dispersants and the sinking of hydrocarbon residuals from burning. The impacts from a proposed action are a small addition to the cumulative impacts on water quality when compared with inputs from hypoxia, potentially leaking shipwrecks, chemical weapon and industrial waste dumpsites, natural oil seeps, and natural turbidity. The incremental contribution of the routine activities and accidental events associated with a proposed action to the cumulative impacts on water quality is not expected to be significant. For Alternative E, the cancellation of a proposed lease sale would result in no new activities associated with a proposed lease sale; therefore, the incremental impacts would be **none**. A full analysis of water quality can be found in **Chapter 4.2**.

Coastal Habitats

Estuarine Systems (Wetlands and Seagrasses/Submerged Vegetation)

The estuarine system is the transition zone between freshwater and marine environments. It can consist of many habitats, including wetlands and submerged vegetation. The impacts to these habitats from routine activities associated with a proposed action are expected to be **minor** to **moderate**. **Minor** impacts would be due to the projected low probability for any new pipeline landfalls (0-1 projected), the minimal contribution to the need for maintenance dredging, and the mitigating measures expected to be used to further reduce or avoid these impacts (e.g., use of modern techniques such as directional drilling). However, impacts caused by vessel operation related to the proposed action over a 50-year period would be **moderate** considering the permanent loss of hundreds of acres of wetlands. Overall, impacts to estuarine habitats from oil spills associated with activities related to a proposed action would be expected to be **minor** because of the distance of most postlease activities from the coast, the expected weathering of spilled oil, the projected low probability of large spills near the coast, the resiliency of wetland vegetation, and the available cleanup techniques.

Cumulative impacts to estuarine habitats are caused by a variety of factors, including the OCS oil- and gas-related and non-OCS oil- and gas-related activities outlined in **Chapter 4.3.1** and the human and natural impacts. Development pressures in the coastal regions of the GOM have been largely the result of tourism and residential beach-side development, and this trend is expected to continue. Storms would continue to impact the coastal habitats and have differing impacts. The incremental contribution of a proposed action to the cumulative impacts on estuarine habitats is expected to be **minor** to **moderate** depending on the selected alternative. For Alternative E, the cancellation of a proposed lease sale would result in no new activities associated with a proposed lease sale. There could, however, be some incremental increase in impacts caused by a compensatory increase in imported oil and gas to offset reduced OCS production, but it would likely be **negligible**. A full analysis of estuarine habitats can be found in **Chapter 4.3.1**.

Coastal Barrier Beaches and Associated Dunes

The coastal barrier beaches and associated dunes are those beaches and dunes that line the coast of the northern GOM, including both barrier islands and beaches on the mainland. The impacts to coastal barrier beaches and dunes from routine activities associated with a proposed action are expected to be **minor** due to the minimal number of projected onshore pipelines, the minimal contribution to vessel traffic and the need for maintenance dredging, and the mitigating measures that would be used to further reduce or avoid these impacts. The greater threat from an oil spill to coastal beaches is from a coastal spill as a result of a nearshore vessel accident or pipeline rupture and from cleanup activities. Overall, impacts to coastal barrier beaches and dunes from oil spills associated with OCS oil- and gas-related activities related to a proposed action would be expected to be **minor** because of the distance of most of the resulting activities from the coast, expected weathering of spilled oil, projected low probability of large spills near the coast, and available cleanup techniques. Cumulative impacts to coastal barrier beaches and dunes are caused by a variety of factors, including the OCS oil- and gas-related and non-OCS oil- and gas-related activities outlined in **Chapter 4.3.2** and the other human and natural impacts. Development pressures in the coastal regions of the GOM have been largely the result of tourism and residential beach-side development, and this trend is expected to continue. Efforts to stabilize the GOM shoreline can deprive natural restoration of the barrier beaches through sediment nourishment and sediment transport, which has adversely impacted coastal beach landscapes. Storms will continue to impact the coastal habitats and have differing impacts. The incremental contribution of a proposed action to the cumulative impacts on coastal barrier beaches and dunes is expected to be **minor**. Under Alternative E, the cancellation of a proposed lease sale, the resulting additional impacts to coastal barrier beaches and dunes would be **negligible**; however, cumulative impacts from all sources, including OCS and non-OCS sources, would be the same as Alternative A. A full analysis of coastal barrier beaches and associated dunes can be found in **Chapter 4.3.2**.

Deepwater Benthic Communities

BOEM defines "deepwater benthic communities" as including both chemosynthetic communities (chemosynthetic organisms plus seep-associated fauna) and deepwater coral communities (deepwater coral plus associated fauna). These communities are typically found in water depths of 984 feet (ft) (300 meters [m]) or deeper throughout the GOM, although deepwater benthic habitats are relatively rare compared with ubiquitous soft bottom habitats.

The OCS oil- and gas-related impact-producing factors for deepwater benthic communities can be grouped into three main categories: (1) bottom-disturbing activities; (2) drilling-related sediment and waste discharges; and (3) noncatastrophic oil spills. These impact-producing factors have the potential to damage individual deepwater habitats and disrupt associated benthic communities if insufficiently distanced or otherwise mitigated. However, impacts from individual routine activities and accidental events are usually temporary, highly localized, and expected to impact only small numbers of organisms and substrates at a time. Moreover, use of the expected site-specific plan reviews/mitigations will distance activities from deepwater benthic communities, greatly diminishing the potential effects. Therefore, at the regional, population-level scope of this analysis and assuming adherence to all expected regulations and mitigations, the incremental contribution would be expected to be **negligible** to **minor**. Proposed OCS oil- and gas-related activities would also contribute incrementally to the overall OCS and non-OCS cumulative effects experienced by deepwater benthic communities and habitats. The OCS oil- and gas-related cumulative impacts to deepwater benthic communities are estimated to be **negligible** to **minor**. Under Alternative E, the potential for impacts would be **none** because new impacts to deepwater benthic communities related to a cancelled lease sale would be avoided entirely. A full analysis of deepwater benthic communities can be found in **Chapter 4.4**.

***Sargassum* and Associated Communities**

Sargassum in the GOM is comprised of *S. natans* and *S. fluitans*, and is characterized by a brushy, highly branched thallus with numerous leaf-like blades and berrylike pneumatocysts. The *Sargassum* cycle is truly expansive, encompassing most of the western Atlantic Ocean and the Gulf of Mexico with the growth, death, and decay of these plant and epiphytic communities, which may play a substantial role in the global carbon cycle. Several impacting factors can affect *Sargassum*, including vessel-related operations, oil and gas drilling discharges, operational discharges, accidental spills, non-OCS oil- and gas-related vessel activity, and coastal water quality. Routine vessel operations and accidental events that occur during drilling operations or vessel operations, and oiling due to an oil spill were the impact-producing factors that could be reasonably expected to impact *Sargassum* populations in the GOM. All of these impact-producing factors would result in the death or injury to the *Sargassum* plants or to the organisms that live within or around the plant matrix. However, the unique and transient characteristics of the life history of *Sargassum* and the globally widespread nature of the plants and animals that use the plant matrix buffer against impacts that could be at any given location. Impacts to the overall population of the *Sargassum* community are therefore expected to be **negligible** from either routine activities or reasonably foreseeable accidental events. The incremental impact of a proposed action on the population of *Sargassum* would be **negligible** when considered in the context of cumulative impacts to the population. Under Alternative E, a proposed lease sale would be cancelled and the potential for impacts from routine activities and accidental events would be **none**. Impacts from changing water quality would be much more influential on *Sargassum* than OCS development and would still occur without the presence of OCS oil- and gas-related activities. A full analysis of *Sargassum* and associated communities can be found in **Chapter 4.5**.

Live Bottoms

Topographic Features

Defined topographic features (**Chapter 4.6.1**) are a subset of GOM live bottom habitats that are large enough to have an especially important ecological role, with specific protections defined in the proposed Topographic Features Stipulation. Within the Gulf of Mexico, BOEM has identified 37 topographic features where some degree of protection from oil and gas development may be warranted based on geography and ecology. Of all the possible impact-producing factors, it was determined that bottom-disturbing activities associated with drilling, exploration, and vessel operations were the only impact-producing factors from routine activities that could be reasonably expected to substantially impact topographic features. The impact-producing factors resulting from accidental events include bottom-disturbing activities from drilling, exploration, and vessel operations, as well as the release of sediments and toxins during drilling operations. Oil-spill response activities were also considered to be a source of potential impacts to topographic features.

Adherence to the Topographic Features Stipulation, which is analyzed in each action alternative (detailed in **Appendix D**), would assist in preventing most of the potential impacts on topographic feature communities by increasing the distance of OCS oil- and gas-related activities. Should this stipulation be applied to any future lease sale, as it has been historically, impacts of a proposed action to topographic features from routine activities and accidental events or the cumulative impact of a proposed action in the GOM are expected to be **negligible**. The incremental contribution of a proposed action to the cumulative impacts on topographic features is also expected to be **negligible** assuming adherence to the proposed Topographic Features Stipulation. Under

Alternative E, the potential for new incremental impacts to topographic features from a cancelled lease sale would be **none** because they would be avoided entirely. Impacts ranging from **negligible** to **moderate** may still be expected from non-OCS oil- and gas-related activities depending on factors such as fishing and pollution; however, the incremental impact of the proposed activities should not result in an augmentation of the expected impacts. A full analysis of topographic features can be found in **Chapter 4.6.1**.

Pinnacles and Low-Relief Features

The Pinnacle Trend is an approximately 64 x 16 mile (103 x 26 kilometer) high-relief area in water depths ranging from approximately 200-650 ft (60-200 m). It is in the northeastern portion of the CPA at the outer edge of the Mississippi-Alabama shelf between the Mississippi River and De Soto Canyon (**Figures 2-4 and 4-16**). Outside of the Pinnacle Trend area, low-relief live bottom epibenthic communities occur in isolated locations in shallow waters (<984 ft; 300 m) throughout the GOM, wherever there exists suitable hard substrate and other physical conditions (e.g., depth, turbidity, etc.) allowing for community development. Hard bottom habitats occur throughout the GOM but are relatively rare compared with ubiquitous soft bottoms.

The impact-producing factors for pinnacles and low-relief live bottom features can be grouped into three main categories: (1) bottom-disturbing activities; (2) drilling-related sediment and waste discharges; and (3) oil spills. These impact-producing factors have the potential to damage individual live bottom habitats and disrupt associated benthic communities if insufficiently distanced or otherwise mitigated. At the broad geographic and temporal scope of this analysis, and assuming adherence to all expected lease stipulations and typically applied regulations and mitigations, routine activities are expected to have largely localized and temporary effects. Although accidental events have the potential to cause severe damage to specific live bottom communities, the number of such events is expected to be very small. Therefore, at the regional, population-level scope of this analysis, the incremental contribution of impacts from reasonably foreseeable routine activities and accidental events to the overall cumulative impacts is expected to be **negligible** to **minor**. Proposed OCS oil- and gas-related activities would also contribute incrementally to the overall OCS and non-OCS cumulative impacts experienced by live bottom habitats. Under Alternative E, the potential for impacts to pinnacle and low-relief feature communities related to a cancelled lease sale would be **none** because new impacts would be avoided entirely. The OCS oil- and gas-related cumulative impacts to live bottom communities are estimated to be **negligible**. A full analysis of pinnacles and low-relief features can be found in **Chapter 4.6.2**.

Fish and Invertebrate Resources

The distribution of fishes and invertebrates varies widely, and species may be associated with different habitats at various life stages, which is discussed further in **Chapter 4.7**. The impact-producing factors affecting these resources are anthropogenic sound, bottom-disturbing activities, habitat modification, and accidental oil spills. The impacts from routine activities, excluding infrastructure emplacement, would be expected to be **negligible** or **minor** due to short-term localized effects. The installation of OCS oil- and gas-related infrastructure constitutes a long-term modification of the local habitat and is hypothesized to have resulted over the life of the program in **moderate** changes in the distribution of some species. Although this effect is not necessarily adverse and infrastructure is expected to be decommissioned and sites restored to natural habitat, the cumulative impact over the life of the OCS Program extensively pertains to time and space. Accidental spills have been historically low-probability events and are typically small in size. The expected impact to fishes and invertebrate resources from accidental oil spills is **negligible**. Commercial and recreational fishing are expected to have the greatest direct effect on fishes and invertebrate resources, resulting in impact levels ranging from **negligible** for most species to potentially **moderate** for some targeted species (e.g., hogfish spp., gray triggerfish [*Balistes capriscus*], and greater amber jack [*Seriola dumerili*]). The analysis of routine activities and accidental events indicates that the incremental contribution to the overall cumulative impacts on fishes and invertebrate resources as a result of a single proposed lease sale would be **minor**. Under Alternative E, the expected impacts on fish and invertebrate resources would be **none**. A full analysis of fish and invertebrate resources can be found in **Chapter 4.7**.

Birds

The affected birds include both terrestrial songbirds and many groups of waterbirds. Routine impacts to coastal, marine, and migratory birds that were considered include routine discharges and wastes, noise, platform severance with explosives (barotrauma), geophysical surveys with airguns (barotrauma), platform presence and lighting, and pipeline landfalls. The impacts to birds from OCS oil-and gas-related routine activities are similar wherever they may occur in the GOM, and all are considered **negligible** to **minor**. Negligible to minor impacts would not affect a substantial number of birds. Any impacts would be acute and reversible. As used here, acute means *short-term,* as it does in the context of short-term toxicity exposure and tests. Further, no injury to or mortality of a small number of individuals or a small flock would occur. Accidental impacts to birds are caused by oil spills, spill cleanup activities, and emergency air emissions. Seabirds may not always experience the greatest impacts from a spill but it may take longer for populations to recover because of their unique population ecology (demography). Some species, such as gulls, have larger clutches (laughing gulls usually have three eggs per clutch except in the tropics) and may recover quite quickly. However, many species of seabirds can have a clutch size of just one egg, and they have relatively long life spans and often have delayed age at first breeding. Because of the latter case, impacts for overall accidental events would be expected to be moderate. Impacts from overall accidental events on other waterbirds farther inshore would also be expected to be moderate because of the extensive overlap of their distributions with oiled inshore areas and shorelines expected from a large oil spill (≥1,000 bbl). Moderate impacts would affect a substantial abundance of birds.

The incremental contribution of a proposed action to the overall cumulative impacts is considered **moderate**, but only because of the potential impacts that could result from a large oil spill (≥1,000 bbl). This conclusion is based on the incremental contribution of a proposed action to the cumulative OCS oil- and gas-related and non-OCS oil- and gas-related impacts. Alternative E would offer no new lease blocks for exploration and development; therefore, incremental impacts to birds would be **none**. However, there would be continuing impacts associated with the existing oil and gas activities from previously permitted activities and previous lease sales. A full analysis of birds can be found in **Chapter 4.8**.

Protected Species

Marine Mammals

The Gulf of Mexico marine mammal community is diverse and distributed throughout the GOM, with the greatest abundances and diversity of species inhabiting oceanic and OCS waters. The major potential impact-producing factors affecting marine mammals in the GOM as a result of cumulative past, present, and reasonably foreseeable OCS energy-related activities are decommissioning activities, operational discharges, G&G activities, noise, transportation, marine debris, and accidental oil spill and spill-response activities. Accidental events that involve large spills, particularly those continuing to flow fresh hydrocarbons into oceanic and/or outer shelf waters for extended periods (i.e., days, weeks, or months), pose an increased likelihood of impacting marine mammal populations inhabiting GOM waters. While accidental events have the potential to impact marine mammal species, the number of such events is expected to be very small.

Proposed OCS oil- and gas-related activities would also contribute incrementally to the overall OCS and non-OCS cumulative effects experienced by marine mammal populations. At the regional, population-level scope of this analysis, impacts from reasonably foreseeable routine activities and accidental events could be **negligible** to **moderate** for any of the action alternatives. However, the incremental contribution of a proposed action to cumulative impacts to marine mammal populations, depending upon the affected species and their respective population estimate, even when taking into consideration the potential impacts of the *Deepwater Horizon* explosion, oil spill, and response; non-OCS oil- or gas-related factors; and the minimization of the OCS oil- or gas-related impacts through lease stipulations and regulations, would be expected to be **negligible**. Under Alternative E, the cancellation of a proposed lease sale, impacts on marine mammals within the Gulf of Mexico would be **none**. However, cumulative impacts would be unchanged from the conclusions reached for the other alternatives. A full analysis of marine mammals can be found in **Chapter 4.9.1**.

Sea Turtles

Five sea turtle species have been ESA-listed and are present throughout the northern GOM; however, only Kemp's ridley and loggerhead sea turtles commonly nest on beaches in the GOM. Because of expected mitigations (e.g., BOEM and the Bureau of Safety and Environmental Enforcement [BSEE] proposed compliance with Notices to Lessees and Operators [NTLs] under the proposed Protected Species Stipulation and conditions of approval on postlease activities), the routine activities (e.g., noise or transportation) and accidental events (e.g., oil spills) related to a proposed action are not expected to have long-term adverse effects on the size and productivity of any sea turtle species or populations in the northern GOM. Lethal effects could occur from chance collisions with OCS oil- and gas-related service vessels or ingestion of accidentally released plastic materials from OCS oil- and gas-related vessels and facilities. However, there have been no reports to date on such incidences. Most routine activities and accidental events are therefore expected to have **negligible** to **moderate** impacts. For example, a minor impact might be a behavioral change in response to noise while a moderate impact might be a spill contacting an individual and causing injury or mortality.

Historically, intense harvesting of eggs, loss of suitable nesting beaches, and fishery-related mortality have led to the rapid decline of sea turtle populations. Anthropogenic actions continue to pose the greatest threat to sea turtles since their listing under the Endangered Species Act (ESA), as well as different natural threats including climate change and natural disasters. The incremental contribution of a proposed action to the cumulative impacts to sea turtles would be expected to be **negligible** as a result of a proposed action. Population-level impacts are not anticipated. Under Alternative E, the cancellation of a proposed lease sale, impacts on sea turtles within the Gulf of Mexico would be **none**. However, cumulative impacts would be unchanged from the conclusions reached for the other alternatives. A full analysis of sea turtles can be found in **Chapter 4.9.2**.

Beach Mice

The four subspecies of beach mouse (*Peromyscus polionotus* ssp.) are small coastal rodents that are only found along beaches in parts of Alabama and northwest Florida and are federally listed as endangered. Beach mice rely on dune systems as favorable habitat for foraging and maintaining burrows. Due to the distance between beach mouse habitat and OCS oil- and gas-related activities, routine impacts are not likely to affect beach mouse habitat except under very limited situations. Pipeline emplacement or construction, for example, could cause temporary degradation of beach mouse habitat; however, these activities are not expected to occur in areas of designated critical habitat. Accidental oil spills and associated spill-response efforts are not likely to impact beach mice or their critical habitat because the species live above the intertidal zone where contact is less likely. Habitat loss from non-OCS oil- and gas-related activities (e.g., beachfront development) and predation have the greatest impacts to beach mice. Overall, the incremental contribution of impacts from reasonably foreseeable routine activities and accidental events to the overall cumulative impacts on beach mice is expected to be **negligible**. Under Alternative E, the cancellation of a proposed lease sale, impacts on beach mice would be **none**. However, cumulative impacts would be unchanged from the conclusions reached for the other alternatives. A full analysis of beach mice can be found in **Chapter 4.9.3**.

Protected Birds

Protected birds are those species or subspecies listed under the ESA by the U.S. Fish and Wildlife Service (FWS) as threatened or endangered due to the decrease in their population sizes or loss of habitat; therefore, a proposed action could have a greater impact. BOEM is undergoing consultation with FWS to minimize the potential impacts to ESA-listed species. Impacts from routine activities, which include discharges and wastes affecting air and water quality, noise, and possibly artificial lighting, would be **negligible** to protected birds. The listed bird species considered are typically coastal birds and would not be exposed to much of the oil- and gas-related activities.

Waste discharges to air or water produced as a result of routine activities are regulated by the U.S. Environmental Protection Agency and BOEM, and these discharges are subject to limits to reduce potential impacts; therefore, due to precautionary requirements and monitoring, the impacts to protected birds would be **negligible**. The major impact-producing factors resulting from accidental events associated with a proposed action that may affect protected birds include accidental oil spills and response efforts and marine debris. In the case of an accidental oil spill, impacts would be **negligible** to **moderate** depending on the magnitude and time and place of such an event. Major impacts could occur if a large oil spill occurred with direct contact to a protected bird species or if the habitat became contaminated resulting in mortality of a listed species. Marine debris produced by OCS oil- and gas-related activities as a result of accidental disposal into the water may affect protected birds by entanglement or ingestion. Due to the regulations prohibiting the intentional disposal of items, impacts would be expected to be **negligible**; however, impacts may scale up to **moderate** if the accidental release of marine debris caused mortality of a listed bird.

Overall, BOEM would expect **negligible** to **moderate** impacts to protected birds considering routine activities, accidental events, and cumulative impacts. Due to the precautionary requirements and monitoring discussed above, the incremental impacts to protected birds would be **negligible** for any of the action alternatives (i.e., Alternatives A-D). Under Alternative E, the additional incremental impacts to ESA-protected birds or their habitats would be **none**. A full analysis of protected birds can be found in **Chapter 4.9.4**.

Protected Corals

Elkhorn, staghorn, boulder star, lobed star, and mountainous star corals are listed by the National Marine Fisheries Service as threatened due to the decrease in their population sizes; therefore, the relative impacts from a proposed action could be disproportionate to those experienced by other coral species. BOEM understands this and is undergoing consultation for these species to minimize the potential impacts. Though the listed species are given ESA status, they could be affected by the same types of impact-producing factors from a proposed action as other coral species that are not ESA-listed. Assuming adherence to all expected lease stipulations and other postlease, protective restrictions and mitigations, the routine activities related to a proposed action are expected to have mostly localized and temporary effects because the site-specific survey information and distancing requirements described in NTL 2009-G39 will allow BOEM to identify and protect live bottom features (where protected corals may be found) from harm by proposed OCS oil- and gas-related activities during postlease reviews. While accidental events have the potential to cause severe damage to specific coral communities, the number of such events is expected to be small. Further, many of the protected corals occur in the Flower Garden Banks National Marine Sanctuary, which under the current boundaries is not proposed for future leasing under any of the alternatives in this Multisale EIS. Therefore, the incremental contribution of activities resulting from a proposed action to the overall cumulative impacts on protected corals is expected to be **negligible**. Proposed OCS oil- and gas-related activities would contribute incrementally to the overall OCS and non-OCS cumulative impacts experienced by corals. Under Alternative E, the cancellation of the proposed action, impacts to protected corals would be **none**.

However, cumulative impacts would be unchanged from the conclusions reached for the other alternatives. A full analysis of protected corals can be found in **Chapter 4.9.5**.

Commercial Fisheries

A proposed action could affect commercial fisheries by affecting fish populations or by affecting the socioeconomic aspects of commercial fishing. The impacts of a proposed action on fish populations are presented in **Chapter 4.7**. Routine activities such as seismic surveys, drilling activities, and service-vessel traffic can cause space-use conflicts with fishermen. Structure emplacement could have positive or negative impacts depending on the location and species. For example, structure emplacement prevents trawling in the associated area and, thus, could impact the shrimp fishery. On the other hand, production platforms can facilitate fishing for reef fish such as red snapper and groupers. Accidental events, such as oil spills, could cause fishing closures and have other impacts on the supply and demand for seafood. However, accidental events that could arise from a proposed action would likely be small and localized. A proposed action would be relatively small when compared with the overall OCS Program, State oil and gas activities, overall vessel traffic, hurricanes, economic factors, Federal and State fisheries management strategies, and other non-OCS oil- and gas-related factors. Therefore, the incremental contribution of a proposed action to the cumulative impacts to commercial fisheries would range from minor **beneficial** to **minor** adverse effects. The exact impacts would depend on the locations of activities, the species affected, the intensity of commercial fishing activity in the affected area, and the substitutability of any lost fishing access. Alternative E would prevent these impacts from occurring, although commercial fisheries would still be subject to the impacts from the OCS Program, as well as the impacts from non-OCS sources. A full analysis of commercial fisheries can be found in **Chapter 4.10**.

Recreational Fishing

The Gulf of Mexico's extensive estuarine habitats (**Chapter 4.3.1**), live bottom habitats (**Chapter 4.6**), and artificial substrates (including artificial reefs, shipwrecks, and oil and gas platforms) support several valuable recreational fisheries. Alternatives A-D can affect recreational fishing by affecting fish populations or by affecting the socioeconomic aspects of recreational fishing. The impacts of Alternatives A-D on fish populations are presented in **Chapter 4.7**. Vessel traffic can cause space-use conflicts with anglers. Structure emplacement generally enhances recreational fishing, although this positive effect will be offset during decommissioning unless a structure were maintained as an artificial reef. Accidental events, such as oil spills, can cause fishing closures and can affect the aesthetics of fishing in an area. However, accidental events that could arise would likely be small and localized. Alternatives A-D should also be viewed in light of overall trends in OCS platform decommissioning, State oil and gas activities, overall vessel traffic, hurricanes, economic factors, and Federal and State fisheries management strategies. The incremental impacts of Alternatives A-D on recreational fisheries are expected to be **beneficial** (low) to **minor**. Alternative E would cause some economic adjustments (refer to **Chapter 4.14.2**.), which could cause **negligible** impacts to recreational fishing activities. A full analysis of recreational fishing can be found in **Chapter 4.11**.

Recreational Resources

Alternatives A-D would contribute to the negligible to minor aesthetic impacts and space-use conflicts that arise due to the broader OCS Program. These conflicts arise due to marine debris, the visibility of platforms, and vessel traffic. Structure emplacements can have positive impacts on recreational fishing and diving because platforms often act as artificial reefs. Oil spills can negatively affect beaches and other coastal recreational resources. Alternatives A-D should also be viewed in light of economic trends, as well as various non-OCS oil- and gas-related factors that can cause space-use conflicts and aesthetic impacts, such as commercial and military activities. Because of the relatively small contribution of any given lease sale under any of the proposed action alternatives to the overall OCS Program, in addition to other non-OCS oil- and gas-related activities, the incremental impacts are expected to be minor **beneficial** (low) to **minor** adverse effects. There could be **negligible** impacts to recreational resources due to the small economic adjustments that would occur in light of Alternative E. A full analysis of recreational resources can be found in **Chapter 4.12**.

Archaeological Resources

Archaeological resources are any material remains of human life or activities that are at least 50 years of age and that are capable of providing scientific or humanistic understanding of past human behavior, cultural adaptation, and related topics through the application of scientific or scholarly techniques, such as controlled observation, contextual measurement, controlled collection, analysis, interpretation, and explanation (30 CFR § 250.105). Archaeological resources are primarily impacted by any activity that directly disturbs or has the potential to disturb the seafloor. For the OCS Program, this includes the placement of drilling rigs and production systems on the seafloor; pile driving associated with platform emplacement; pipeline placement and installation; the use of seismic receiver nodes and cables; the dredging of new channels, as well as maintenance dredging of existing channels; anchoring activities; post-decommissioning activities, including trawling clearance; and the masking of archaeological resources from industry-related infrastructure and debris.

Regardless of which planning area a proposed lease sale is held, the greatest potential impact to an archaeological resource as a result of a proposed action under any of the action alternatives is site-specific and would result from direct contact between an offshore activity or accidental event and a site. Archaeological surveys, where required prior to an operator beginning OCS oil- and gas-related activities on a lease, are expected to be effective at identifying possible archaeological sites. **Major** impacts could potentially occur if the mitigations (e.g., archaeological surveys) were not applied to postlease activities. With identification, evaluation, and avoidance or mitigation of archaeological resources, the incremental contribution of a proposed action is expected to result in **negligible**, long-term cumulative impacts to archaeological resources; however, if an archaeological site were to be impacted, impacts to that specific site may range from **negligible** to **major**. Under Alternative E, the impact-producing factors described in **Chapter 4.13** would not take place for that proposed lease sale; therefore, the impacts would be **none**. A full analysis of archaeological resources can be found in **Chapter 4.13**.

Human Resources and Land Use (Including Environmental Justice)

Land Use and Coastal Infrastructure

Oil and gas exploration, production, and development activities on the OCS are supported by an expansive onshore network of coastal infrastructure that includes hundreds of large and small companies. Because OCS oil- and gas-related activities are supported by this long-lived, expansive onshore network, the potential impacts of a proposed lease sale are not expected to produce any major impacts to land use and coastal infrastructure. The impact of routine operations would range from **beneficial** to **moderate**. The impacts of reasonably foreseeable accidental events such as oil spills, chemical and drilling fluid spills, and vessel collisions are not likely to last long enough to adversely affect overall land use or coastal infrastructure in the analysis area and would therefore be **negligible** to **moderate**. In the cumulative analysis, activities relating to all past, present, and future OCS oil- and gas-related activities and State oil and gas production are expected to minimally affect the current land use of the analysis area because most subareas have strong industrial bases and designated industrial parks. Non-OCS oil- and gas-related factors contribute substantially to the cumulative impacts on land use and coastal infrastructure, while there is only a **minor** incremental contribution of a proposed lease sale.

For any of the action alternatives, the cumulative impacts on land use and coastal infrastructure could range from **beneficial** to **moderate** for OCS oil- and gas-related activities and **beneficial** to **major** for non-OCS oil- and gas-related activities, depending on the specifics of each situation, whether the impacts are measurable, how long the impacts would last, and the size of the affected geographic area as defined in **Chapter 4.14.1**. Alternative E would result in no lease sale and, thus, the direct impacts as a result of a proposed lease sale would be **none**, and would result in no incremental contribution of impacts to land use and coastal infrastructure beyond a temporary negative economic impact for the oil and gas industry and coastal states (such as Louisiana) that are more dependent on oil and gas revenues. A full analysis of land use and coastal infrastructure can be found in **Chapter 4.14.1**.

Economic Factors

A proposed lease sale would lead to **beneficial** (low) impacts arising from industry expenditures, government revenues, corporate profits, and other market impacts. Some of these impacts would be concentrated along the Gulf Coast, while others would be widely distributed. A proposed lease sale would also lead to negative economic impacts arising from accidental events and other sources. There would be some differences in economic impacts among Alternatives A-D, corresponding to the differences in the scales and distributions of likely activities. Alternatives A-D should be viewed in light of the OCS Program, as well the numerous forces that can affect energy markets and the overall economy. Most of the incremental economic impacts of a proposed action are forecast to be **beneficial**, although there would be some **minor** adverse impacts due to oil spills and to the effects on industries that compete with the offshore oil and gas industry for resources. Alternative E, the cancellation of a proposed lease sale, would negatively impact firms and employees that depend on recurring leases; therefore, the impacts of Alternative E would be

negligible to **minor**, with some partially offsetting **beneficial** impacts. A full analysis of economic factors can be found in **Chapter 4.14.2**.

Social Factors (Including Environmental Justice)

Potential social impacts resulting from a proposed action would occur within the larger socioeconomic context of the GOM region. The affected environment of the analysis area is quite large geographically and in terms of population (133 counties and parishes with over 22.7 million residents). The impacts from routine activities related to a proposed action are expected to be **negligible** to **moderate**, widely distributed, and to have little impact because of the existing extensive and widespread support system for the petroleum industry and its associated labor force. Outside of a low-probability catastrophic oil spill, which is not reasonably foreseeable and not part of a proposed action, any potential accidental events are not likely to be of sufficient scale or duration to have adverse and disproportionate long-term impacts for people and communities in the analysis area and would therefore range from **negligible** to **moderate**. In the cumulative analysis, impacts from OCS oil- and gas-related activities would range from **beneficial** to **moderate**. Non-OCS oil- and gas-related factors, which include all human activities, natural events, and processes, actually contribute more to cumulative impacts than do factors related to OCS oil- and gas-related activities alone, and result in **beneficial** to **major** adverse impacts. The incremental contribution to cumulative impacts of a proposed action would be **minor**. Alternative E would result in no lease sale and, thus, overall incremental impacts as a result of alternative E would be **none**. A full analysis of social factors can be found in **Chapter 4.14.3**.

Environmental Justice Determination: The oil and gas industry in the GOM region is expansive and long-lived over several decades with substantial infrastructure in place to support both onshore and offshore activities. BOEM's scenario estimates call for 0-1 new gas processing plant and 0-1 new pipeline landfall over the 50-year life of a single proposed action. Impacts to GOM populations from a proposed action would be immeasurable for environmental justice since these low-income and minority communities are located onshore, distant from Federal OCS oil- and gas-related activities. Also, since these vulnerable populations are located within the larger context of onshore and State-regulated nearshore oil and gas activities that are connected to downstream infrastructure over which BOEM has no regulatory authority, BOEM has determined that a proposed action would not produce environmental justice impacts in the GOM region. A full analysis of social factors and an environmental justice determination can be found in **Chapter 4.14.3**.

APPENDICES

To improve the readability of this Multisale EIS, more detailed supporting information has been placed in the appendices, which include postlease processes, commonly applied mitigating measures, a Memorandum of Agreement between BOEM and the U.S. Environmental Protection Agency, prelease stipulations, OSRA figures, species not considered further, and State Coastal Management Programs.

Appendix A describes postlease approval activities, including the following: geological and geophysical surveys; exploration and development plans; permits and applications; inspection and enforcement; pollution prevention, oil-spill response plans, and financial responsibility; air emissions; flaring and venting; hydrogen sulfide contingency plans; archaeological resources regulation; coastal zone management consistency review and appeals for postlease activities; best available and safest technologies, including at production facilities; personnel training and education; structure removal and site clearance; marine protected species NTLs; and the Rigs-to-Reefs program.

Appendix B describes commonly applied mitigations that were developed as a result the continuing OCS Program in the Gulf of Mexico. These are mitigations that BOEM and BSEE could apply to permits and approvals. These mitigating measures address concerns such as endangered and threatened species, geologic and manmade hazards, military warning and ordnance disposal areas, archaeological sites, air quality, oil-spill response planning, chemosynthetic communities, artificial reefs, operations in hydrogen sulfide-prone areas, and shunting of drill effluents in the vicinity of biologically sensitive features. Operational compliance of the mitigating measures is enforced through BSEE's onsite inspection program.

Appendix C is the Memorandum of Agreement between BOEM and the USEPA; it outlines the roles and responsibilities for both agencies during the preparation of this Multisale EIS.

Appendix D describes the potential lease stipulations that were developed as a result of numerous scoping efforts for the continuing OCS Program in the Gulf of Mexico. The lease stipulations being considered are the Topographic Features Stipulation; Live Bottom (Pinnacle Trend) Stipulation; Military Areas Stipulation; Evacuation Stipulation; Coordination Stipulation; Blocks South of Baldwin County, Alabama, Stipulation; Protected Species Stipulation; United Nations Convention on the Law of the Sea Royalty Payment Stipulation; Below Seabed Operations Stipulation; and the Stipulation on the Agreement between the United States of America and the United Mexican States Concerning Transboundary Hydrocarbon Reservoirs in the Gulf of Mexico (Transboundary Stipulation). The United Nations Convention on the Law of the Sea Royalty Payment Stipulation is applicable to a proposed lease sale even though it is not an environmental or military stipulation.

Appendix E provides the combined probabilities for an offshore oil spill ≥1,000 barrels occurring and contacting coastal and offshore areas for each of the proposed actions.

Appendix F details the meteorological information used for the air quality modeling described in **Chapter 4.1**. Parameters such as wind speed, wind direction, air temperature, and humidity are required by models to determine the rate that pollutants disperse and react in the atmosphere. This appendix details the modeling performance evaluation of a Weather and Research Forecast model for 2012 used in conducting the air quality modeling summarized in **Chapter 4.1**.

Appendix G describes how the emissions were generated for the Cumulative and Visibility Impact Analysis Emissions Inventory used in conducting the air quality modeling summarized in **Chapter 4.1**.

Appendix H provides the photochemical modeling, the evaluation of the modeling, and the results of the the air quality modeling summarized in **Chapter 4.1**.

Appendix I is a listing of species not considered further in this Multisale EIS because these species are not generally found in the area of activity and/or impact. Therefore, it is not reasonably foreseeable that these species would have population effects from a proposed action.

Appendix J describes State Coastal Management Programs (CMPs). Each State's CMP is a comprehensive statement setting forth objectives, enforceable policies or guidelines, and standards for public and private use of land and water resources and uses in that State's coastal zone. The programs provide for direct State land and water use planning and regulations. The programs also include a definition of what constitutes permissible land uses and water uses. To ensure conformance with State CMP policies or guidelines and local land use plans, BOEM prepares a Federal consistency determination for each proposed OCS lease sale. Federal consistency is the Coastal Zone Management Act requirement where Federal agency activities that have reasonably foreseeable effects on any land or water use or natural resource of the coastal zone must be consistent to the maximum extent practicable with the enforceable policies or guidelines of a coastal State's federally approved CMP.

Appendix K provides consultation correspondence with Federal and State agencies.

Appendix L provides detailed responses to comments received on the Draft Multisale EIS. The comments and responses are presented in a matrix organized by the topics of the comments. All substantive comment letters, emails, and public meeting transcripts, along with their respective unique identifiers, are reproduced in their entirety following the matrix and references.

TABLE OF CONTENTS

Volume I

Page

Volume II

Volume III

Page

LIST OF FIGURES

Page

LIST OF TABLES

Page

ABBREVIATIONS AND ACRONYMS

°C	degree Celsius
°F	degree Fahrenheit
µg	microgram
µg/g	micrograms/gram
µm	micrometer
2012-2017 Five-Year Program	*Proposed Final Outer Continental Shelf Oil & Gas Leasing Program: 2012-2017*
2D	two dimensional
3D	three dimensional
4D	four dimensional
ac	acre
Agreement	Agreement between the United States of America and the United Mexican States Concerning Transboundary Hydrocarbon Reservoirs in the Gulf of Mexico
AL	Alabama
API	American Petroleum Institute
Area ID	Area Identification
AQRV	air quality-related value
ASLM	Assistant Secretary of the Interior for Land and Minerals
bbl	barrel
Bbbl	billion barrels
Bcf	billion cubic feet
BBO	billion barrels of oil
BOEM	Bureau of Ocean Energy Management
BOEMRE	Bureau of Ocean Energy Management, Regulation and Enforcement
BOP	blowout preventer
BP	Before Present
BSEE	Bureau of Safety and Environmental Enforcement
BTEX	benzene, toluene, ethylbenzene, and xylene
Call	Call for Information
CAMx	Comprehensive Air-quality Model with extensions
Cd	cadmium
CD	Consistency Determination
CEI	Coastal Environments, Inc.
CEQ	Council on Environmental Quality
CEWAF	chemically enhanced (dispersed) water-accommodated fractions
CFR	Code of Federal Regulations
CG	Coast Guard (also: USCG)
CH_4	methane
CIAP	Coastal Impact Assistance Program
CMP	Coastal Management Program
CO	carbon monoxide

CO_2	carbon dioxide
CO_2-e	CO_2-equivalent
COE	Corps of Engineers (U.S. Army)
CPA	Central Planning Area
CPRA	Coastal Protection and Restoration Authority
Cu	copper
CSA	Continental Shelf Associates
CYP1A	cytochrome P-4501A
CWPPRA	Coastal Wetlands Planning, Protection and Restoration Act
CZMA	Coastal Zone Management Act
dB	decibel
dB re: 1μPa	decibels referenced 1 microPascal
DOI	Department of the Interior (U.S.) (also: USDOI)
DOT	Department of Transportation (U.S.) (also: USDOT)
DMR	discharge monitoring report
DPP	development and production plan
Draft Proposed Program	*2017-2022 OCS Oil and Gas Leasing: Draft Proposed Program*
EFH	essential fish habitat
e.g.	for example
EIA	Economic Impact Area
EIS	environmental impact statement
EPA	Eastern Planning Area
EPAct	Energy Policy Act of 2005
ERMA	Environmental Response Management Application
ESA	Endangered Species Act of 1973
ESI	Environmental Sensitivity Index
et al.	and others
et seq.	and the following
FERC	Federal Energy Regulatory Commission
Five-Year Program	*2017-2022 Outer Continental Shelf Oil and Gas Leasing: Proposed Final Program* (also: 2017-2022 Five-Year Program)
Five-Year Program EIS	*Outer Continental Shelf Oil and Gas Leasing Program: 2017-2022, Final Programmatic Environmental Impact Statement*
FL	Florida
FGBNMS	Flower Garden Banks National Marine Sanctuary
FPSO	floating production, storage, and offloading system
FR	*Federal Register*
ft	feet
FWS	Fish and Wildlife Service
G&G	geological and geophysical
g	gram
GAP	General Activities Plan
GIS	Geographic Information System
GIWW	Gulf Intracoastal Waterway

GMFMC	Gulf of Mexico Fishery Management Council
GOM	Gulf of Mexico
GPS	global positioning system
GUIS	Gulf Islands National Seashore
GWEI	Gulfwide Emissions Inventory
H_2S	hydrogen sulfide
ha	hectare
HAPC	habitat area of particular concern
Hg	mercury
HRG	high-resolution geophysical
Hz	Hertz
i.e.	that is
km	kilometer
IPCC	Intergovernmental Panel on Climate Change
ITL	Information to Lessees and Operators
LA	Louisiana
lb	pound
LCA	Louisiana Coastal Area
LNG	liquefied natural gas
LOOP	Louisiana Offshore Oil Port
m	meter
MAG-PLAN	MMS Alaska-GOM Model Using IMPLAN
MARAD	Maritime Administration (U.S. Department of Transportation)
MATS	Modeled Attainment Test Software
Mcf	thousand cubic feet
MCV	modular capture vessel
mg/L	milligrams/liter
mi	mile
mm	millimeter
MMbbl	million barrels
MMcf	million cubic feet
MMPA	Marine Mammal Protection Act
MMS	Minerals Management Service
MODU	mobile offshore drilling unit
MOU	Memorandum of Understanding
MS	Mississippi
MSCVAFF	Mississippi Coalition for Vietnamese-American Fisher Folks and Families
MWCC	Marine Well Containment Company
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NASA	National Aeronautics and Space Administration
NAZ	narrow azimuth
NCP	National Oil and Hazardous Substances Pollution Contingency Plan

NEPA	National Environmental Policy Act
NGL	natural gas liquids
NHPA	National Historic Preservation Act
NMFS	National Marine Fisheries Service
nmi	nautical-mile
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NOA	Notice of Availability
NOAA	National Oceanic and Atmospheric Administration
NOI	Notice of Intent to Prepare an EIS
NOS	National Ocean Service
NPDES	National Pollutant Discharge Elimination System
NPS	National Park Service
NRC	National Research Council
NRDA	Natural Resource Damage Assessment
NTL	Notice to Lessees and Operators
O_3	ozone
OBF	oil-based fluid
OCD	Offshore and Coastal Dispersion
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
ODMDS	ocean dredged-material disposal site
ONRR	Office of Natural Resources Revenue
OSAT	Operational Science Advisory Team
OSHA	Occupational Safety and Health Administration
OSRA	Oil Spill Risk Analysis
OSRP	oil-spill response plan
OSV	offshore supply/service vessel
P.L.	Public Law
PAH	polycyclic aromatic hydrocarbons
Pb	lead
PBR	Potential Biological Removal
PDARP/PEIS	*Programmatic Damage Assessment and Restoration Plan and Final Programmatic Environmental Impact Statement*
pH	potential of hydrogen
PM	particulate matter
$PM_{2.5}$	particulate matter less than or equal to 2.5 μm
PM_{10}	particulate matter less than or equal to 10 μm
ppb	parts per billion
ppm	parts per million
PSD	Prevention of Significant Deterioration
psi	pounds per square inch
RESTORE Act	Resources and Ecosystems Sustainability, Tourist Opportunities, and Revived Economies of the Gulf Coast States Act

ROD	Record of Decision
RSDFO	Regional Supervisor for District Field Operations
SAP	Site Assessment Plan
SBF	synthetic-based fluid
SBM	synthetic-based mud
Secretary	Secretary of the Interior
SEL	sound exposure level
SMART	Special Monitoring of Applied Response Technologies
SO_2	sulphur dioxide
SO_x	sulphur oxides
Stat.	Statute
SURF	subsea umbilical, risers, and flowlines
sVGP	Small Vessel General Permit
Tcf	trillion cubic feet
TLP	tension-leg platform
Trustee Council	Natural Resource Damage Assessment Trustee Council
TX	Texas
U.S.	United States
U.S.C.	United States Code
UME	unusual mortality event
UNCLOS	United Nations Convention on the Law of the Sea
USCG	U.S. Coast Guard (also: CG)
USDHS	U.S. Department of Homeland Security
USDOC	U.S. Department of Commerce
USDOE	U.S. Department of Energy
USDOI	U.S. Department of the Interior (also: DOI)
USDOT	U.S. Department of Transportation (also: DOT)
USEPA	U.S. Environmental Protection Agency
USGS	U.S. Geological Survey
VGP	Vessel General Permit
VOC	volatile organic compound
VSP	vertical seismic profiling
W.	west
WAF	water-accommodated fraction
WAZ	wide azimuth
WBF	water-based fluid
WRF	Weather and Research Forecasting
WPA	Western Planning Area
WTCW	well treatment fluids, completion fluids, and workover
yd	yard
Zn	zinc

CONVERSION CHART

To convert from	To	Multiply by
centimeter (cm)	inch (in)	0.3937
millimeter (mm)	inch (in)	0.03937
meter (m)	foot (ft)	3.281
meter^2 (m^2)	foot^2 (ft^2)	10.76
meter^2 (m^2)	yard^2 (yd^2)	1.196
meter^2 (m^2)	acre (ac)	0.0002471
meter^3 (m^3)	foot^3 (ft^3)	35.31
meter^3 (m^3)	yard^3 (yd^3)	1.308
kilometer (km)	mile (mi)	0.6214
kilometer^2 (km^2)	mile^2 (mi^2)	0.3861
hectare (ha)	acre (ac)	2.47
liter (L)	gallons (gal)	0.2642
degree Celsius (°C)	degree Fahrenheit (°F)	°F = (1.8 x °C) + 32
1 barrel (bbl) = 42 gal = 158.9 L = approximately 0.1428 metric tons 1 nautical mile (nmi) = 1.15 mi (1.85 km) or 6,076 ft (1,852 m) tonnes = 1 long ton or 2,240 pounds (lb)		

CHAPTER 1

THE PROPOSED ACTIONS

What's in This Chapter?

- The Bureau of Ocean Energy Management (BOEM) has issued the *2017-2022 Outer Continental Shelf Oil and Gas Leasing: Proposed Final Program* (Five-Year Program). It sets forth a schedule for 10 proposed regionwide Gulf of Mexico (GOM) lease sales spaced evenly throughout the 5-year period.
- The purpose of a proposed action (i.e., a proposed lease sale) in this 2017-2022 Gulf of Mexico Multisale Environmental Impact Statement (Multisale EIS) is to offer for lease those areas in the GOM that may contain economically recoverable oil and gas resources in accordance with the Outer Continental Shelf Lands Act of 1953 (OCSLA), subject to environmental safeguards.
- The need for a proposed action is to manage the development of Outer Continental Shelf (OCS) energy resources in an environmentally and economically responsible manner. Oil from the Gulf of Mexico OCS would contribute to meeting domestic demand and enhance national economic security.
- Pursuant to the OCSLA's staged leasing process, for each lease sale proposed in the Five-Year Program, individual decisions are made on whether and how to proceed with each proposed lease sale. Therefore, this Multisale EIS is a programmatic EIS that will provide the environmental review foundation for all 10 proposed GOM lease sales in the Five-Year Program schedule.
- Following an established, robust decisionmaking process that invites input from numerous interested parties and the general public, BOEM produced this Multisale EIS to inform decisionmaking for the first proposed lease sale (i.e., Lease Sale 249) and for supplemental National Environmental Policy Act (NEPA) reviews for the subsequent proposed GOM lease sales in the Five-Year Program.
- This Multisale EIS explains the environmental considerations used to assess the potential environmental consequences of the proposed actions and alternatives, as well as the potential mitigations that could minimize or avoid those consequences.

1 PURPOSE OF AND NEED FOR THE PROPOSED ACTIONS

1.0 INTRODUCTION

2017-2022 Schedule of Proposed Gulf of Mexico OCS Region Lease Sales	
Lease Sale Number	Year
249	2017
250 and 251	2018
252 and 253	2019
254 and 256	2020
257 and 259	2021
261	2022

The Bureau of Ocean Energy Management (BOEM) has issued the *2017-2022 Outer Continental Shelf Oil and Gas Leasing: Proposed Final Program* (Five-Year Program; USDOI, BOEM, 2016a). The Five-Year Program schedules 10 regionwide Gulf of Mexico (GOM) oil and gas lease sales. Five regionwide lease sales are tentatively scheduled in August of each year from 2017 through 2021 and five regionwide lease sales are tentatively scheduled in March of each year from 2018 through 2022. The lease sales proposed in the GOM in the Five-Year Program are regionwide lease sales comprised of the Western, Central, and a small portion of the Eastern Planning Areas (WPA, CPA, and EPA, respectively) not subject to Congressional moratorium. These planning areas are located off the States of Texas, Louisiana, Mississippi, Alabama, and Florida (**Figure 1-1**).

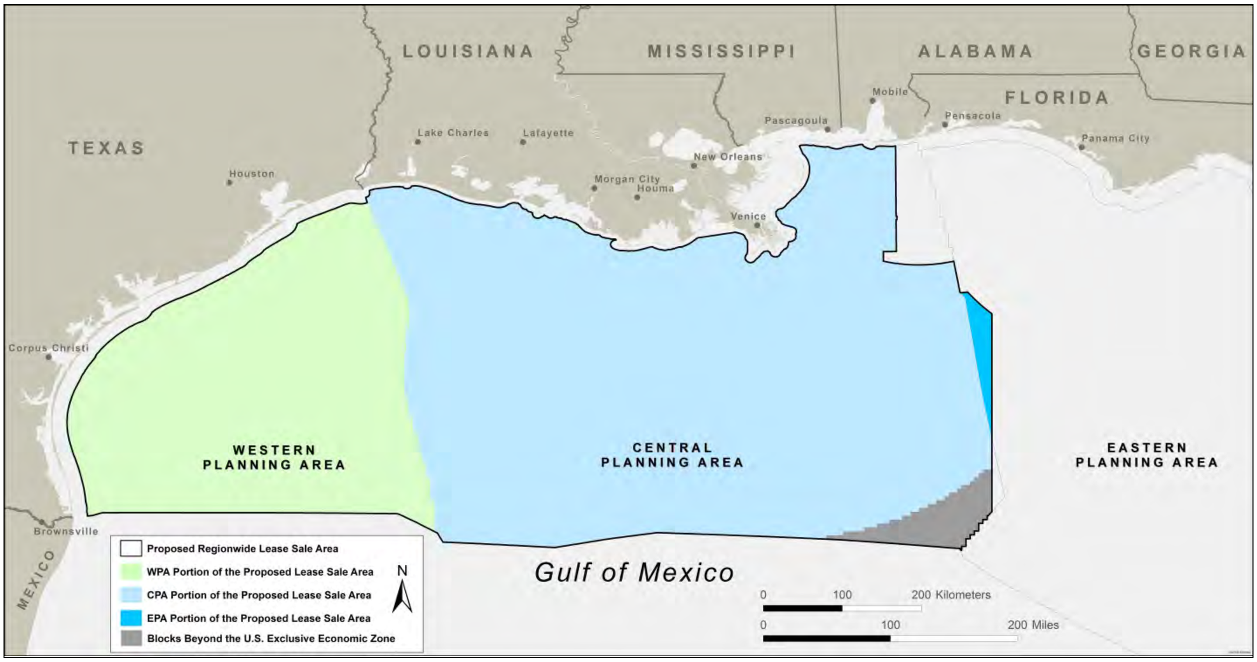

Figure 1-1. Proposed Regionwide Lease Sale Area Combining the Western, Central, and Eastern Planning Areas.

The development of the Five-Year Program triggers region-specific NEPA reviews for each of the proposed lease sales. Region-specific reviews are conducted by Program Area (i.e., the Gulf of Mexico and Alaska OCS Regions) prior to individual lease sale decisions for those areas that are included in the Five-Year Program. Even though the Five-Year Program includes regionwide lease sales, any individual lease sale could still be scaled back during the prelease sale process, including, for example, to employ the separate planning area model used in the *Proposed Final Outer Continental Shelf Oil & Gas Leasing Program*: *2012-2017* (2012-2017 Five-Year Program; USDOI, BOEM, 2012a), should circumstances warrant.

The proposed action is to hold a lease sale in the GOM according to the schedule of proposed lease sales set forth by the Five-Year Program. Since each of the 10 proposed lease sales in the GOM are very similar and occur in close timeframes, BOEM has decided to prepare this programmatic EIS to support the individual decisions for each proposed lease sale. Pursuant to the OCSLA's staged leasing process, BOEM must make an individual decision on whether and how to proceed with each proposed lease sale. Therefore, in order to make an informed decision on a single proposed lease sale, the analyses contained in this Multisale EIS examine the impacts from a single proposed lease sale. This analysis will be used to support each of the 10 proposed lease sale decisions.

The Secretary of the Interior (Secretary) has designated BOEM as the administrative agency responsible for the leasing of submerged Outer Continental Shelf (OCS) lands for oil and gas production and for the supervision of certain offshore operations after lease issuance. BOEM is responsible for managing development of the Nation's offshore resources in an environmentally and economically responsible way. The functions of BOEM include the following: OCS oil and gas leasing; oversight of exploration and development; plan administration; environmental studies; resource evaluation and economic analyses; the use of OCS sand, gravel, and shell resources; and the OCS renewable energy program. The Bureau of Safety and Environmental Enforcement (BSEE) is responsible for enforcing safety and environmental regulations related to energy activities on the OCS. The functions of BSEE include oversight of all field operations, such as permitting for drilling and decommissioning, research, inspections, offshore regulatory programs, oil-spill response, and training and environmental compliance functions.

1.1 PURPOSE OF THE PROPOSED ACTIONS

> *"It is hereby declared to be the policy of the United States that ... the Outer Continental Shelf is a vital national resource held by the Federal Government for the public, which should be made available for expeditious and orderly development, subject to environmental safeguards, in a manner which is consistent with the maintenance of competition and other national needs."*
>
> OCSLA, 43 U.S.C. §§ 1331 *et seq*.

The Outer Continental Shelf Lands Act of 1953, as amended (43 U.S.C. §§ 1331 *et seq*.), hereafter referred to as OCSLA, establishes the Nation's policy for managing the vital energy and mineral resources of the OCS. Section 18 of OCSLA requires the Secretary to prepare and maintain a schedule of proposed OCS oil and gas lease sales determined to "best meet national energy needs for the 5-year period following its approval or reapproval" (43 U.S.C. § 1344). The Five-Year Program establishes a schedule that the U.S. Department of the Interior (USDOI or DOI) will use as a basis for considering where and when leasing might be appropriate over a 5-year period.

The purpose of the proposed Federal actions in this Multisale EIS (i.e., each of the 10 proposed lease sales) is to offer for lease those areas that may contain economically recoverable oil and gas resources in accordance with OCSLA, which specifically states that these areas "should be made available for expeditious and orderly development, subject to environmental safeguards" (OCSLA, 43 U.S.C. §§ 1331 *et seq*.). Each individual proposed lease sale would provide qualified bidders the opportunity to bid upon and lease acreage in the Gulf of Mexico OCS in order to explore, develop, and produce oil and natural gas.

1.2 NEED FOR THE PROPOSED ACTIONS

The need for the proposed actions (i.e., each of the 10 proposed lease sales) is to manage the development of the OCS energy resources in an environmentally and economically responsible manner. Oil serves as the feedstock for liquid hydrocarbon products, including gasoline, aviation and diesel fuel, and various petrochemicals. Oil from the Gulf of Mexico OCS contributes to meeting domestic demand and enhances national economic security.

In 2015, the United States (U.S.) consumed 7.08 billion barrels of petroleum products, an average of about 19.4 million barrels per day (USDOE, Energy Information Administration, 2016a) and 27.47 trillion cubic feet (Tcf) of natural gas per day (USDOE, Energy Information Administration, 2016b). Over the next 20 years, the Energy Information Administration expects the U.S. to rely on more oil and natural gas to meet its energy demands, even as alternative sources of energy provide an increasing share of U.S. energy needs. The Energy Information Administration projects that consumption of liquid fuels will decrease slightly through 2040, but consumption of natural gas would increase by a greater amount over the same period (**Figure 1-2**). For the purposes of this Multisale EIS, it is assumed that both future energy demand and supply would mirror historical trends and, at this time, it does not consider any possible climate change policy interventions, which could potentially implicate demand or supply, price, or modes of domestic or global energy substitution.

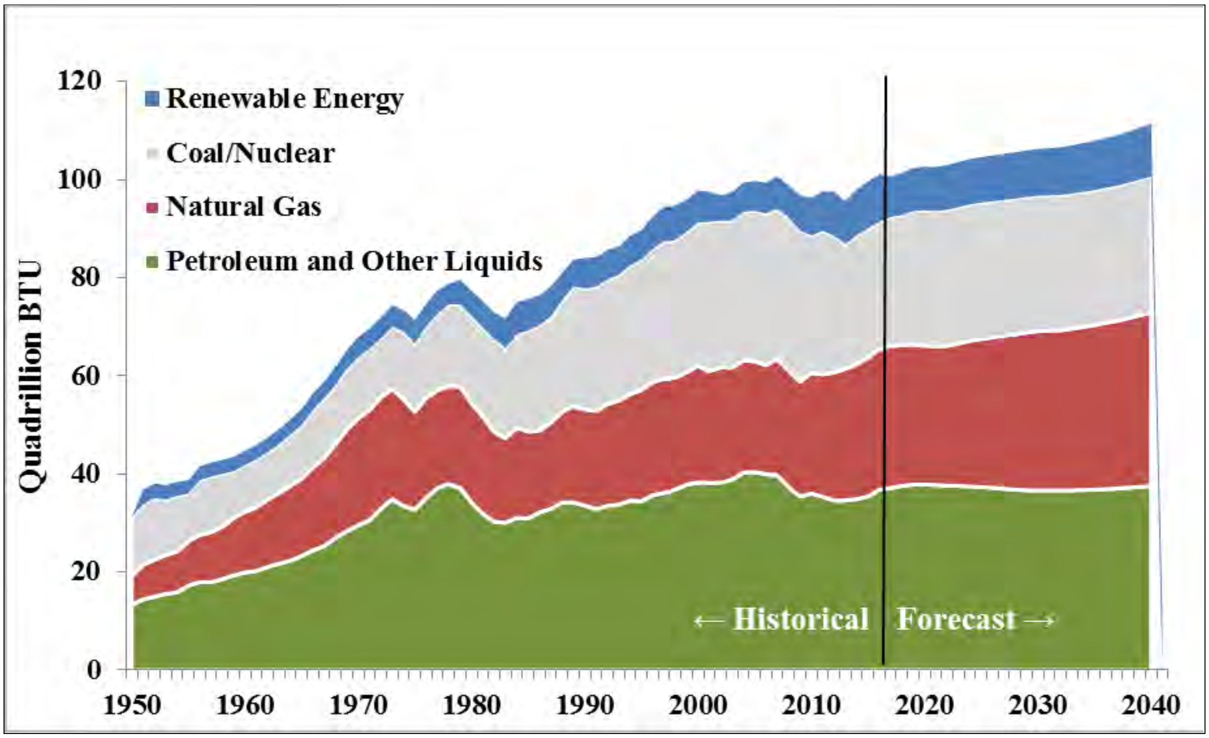

Figure 1-2. Energy Use in the United States (Sources: USDOE, Energy Information Administration, 2016c and 2016d).

Since the U.S. is expected to continue to rely on oil and natural gas to meet its energy needs, the proposed actions would contribute to meeting domestic demand and reduce the need for imports of these resources (USDOI, BOEM, 2016a). The Gulf of Mexico OCS region has the greatest resource potential for being a major long-term supplier of crude oil and natural gas of the four OCS regions in the United States. In 2015, the Gulf of Mexico OCS as a whole was responsible for 16 percent of domestic oil production and 5 percent of domestic natural gas production. Crude oil recovered from the OCS is of high importance to U.S refineries, especially along the Gulf Coast. The GOM production is expected to account for 18 percent and 21 percent of total forecast U.S. crude oil production in 2016 and 2017, respectively. For more details on national energy markets, refer to Chapter 1.2 of the Five Year Program) (USDOI, BOEM, 2016a).

1.3 OCS Oil and Gas Program Planning and Decision Process

BOEM produces NEPA documents for each of the major stages of energy development planning. From the overarching *Outer Continental Shelf Oil and Gas Leasing Program: 2017-2022; Final Programmatic Environmental Impact Statement* (Five-Year Program EIS) (USDOI, BOEM, 2016b), through each of the NEPA documents for the individual decisions on oil and gas lease sales, and followed by more site-specific reviews for the approval of exploration, development and production, and decommissioning plans (**Figure 1-3**).

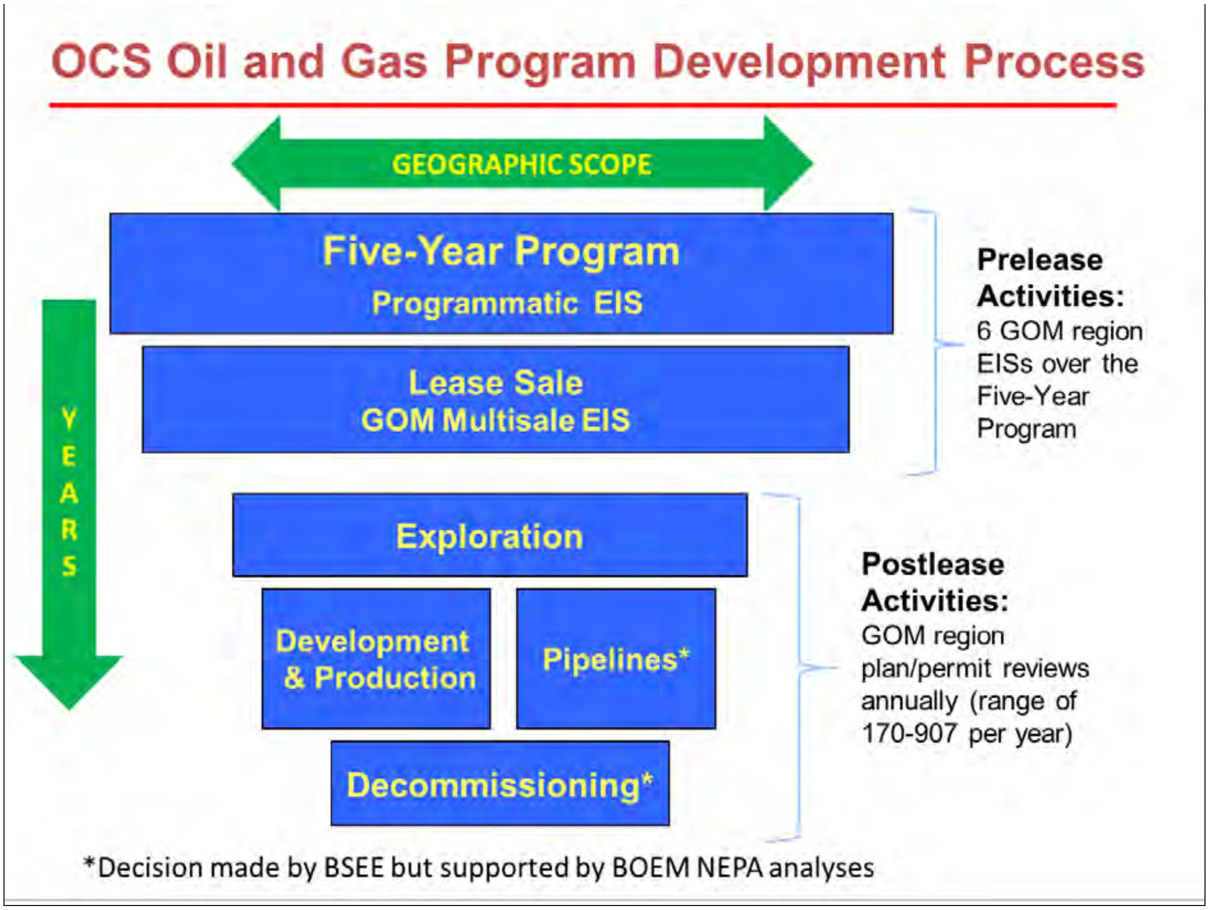

Figure 1-3. OCS Oil and Gas Program Development Process.

1.3.1 Prelease Process

BOEM has a two-stage Federal offshore prelease sale planning process:

(1) develop a Five-Year Program of proposed offshore lease sales for the OCS Program; and

(2) conduct an individual lease sale consultation and decision process for each lease sale scheduled in the approved Five-Year Program.

Due to the staged decisionmaking process in OCSLA, BOEM does a staged or tiered process in which NEPA documents are prepared that cover potential impacts associated with the various stages of the OCSLA process. This includes analyses at the Five-Year Program stage, proposed lease sale stage, exploration or development and production plan stage, and various permitting stages, including, but not limited to, drilling and decommissioning. At the lease sale stage, this is typically done through an EIS, which analyzes the potential impacts of postlease activities. However, at the lease issuance stage, no activities beyond certain ancillary activities are actually authorized by the lease; therefore, there are few environmental impacts reasonably expected from the lease sale itself. The U.S. Court of Appeals for the District of Columbia has ruled that the obligation to fully comply with NEPA does not mature until leases are issued (Center for Biological Diversity v. U.S. Department of the Interior, 2009; Center for Sustainable Economy v. Sally Jewell, 2015). BOEM has chosen at its discretion to prepare an EIS at this stage to analyze the potential environmental impacts that could result if exploration, development, production, and decommissioning activities eventually occur, in order to provide the context and setting of future proposed actions and to better understand the potential impacts associated with these types of activities as well as the cumulative impacts on GOM resources. This allows more time to include public involvement and to evaluate the potential impacts, and it provides for a more informed lease sale decision, which in turn allows for future site-specific reviews to tier to and be more streamlined.

1.3.1.1 Five-Year Program of Proposed OCS Lease Sales

As required by the OCSLA, a new oil and gas leasing program—to cover the years 2017-2022—has been developed. There are multiple stages to developing the Five-Year Program. Following issuing a request for information, the *2017-2022 Outer Continental Shelf Oil and Gas Leasing: Draft Proposed Program* (Draft Proposed Program) (USDOI, BOEM, 2015a) was the first proposal in the staged preparation process of the new Five-Year Program, which is a nationwide schedule of proposed lease sales. The Draft Proposed Program proposed a schedule of 14 potential lease sales in eight OCS planning areas: 10 lease sales in the three GOM planning areas; 1 lease sale each in the Chukchi Sea, Beaufort Sea, and Cook Inlet Planning Areas, offshore Alaska; and 1 lease sale in a portion of the combined Mid-Atlantic and South Atlantic Planning Areas. BOEM received hundreds of thousands of comments in response to the publication of the Draft Proposed Program and analyzed the comments as appropriate for the second proposal in the staged preparation process—the Proposed Program.

The Proposed Program, which was released for public comment in March 2016 (USDOI, BOEM, 2016c), removed the proposed Atlantic planning areas from further consideration for the 5-year period and proposed a schedule of 13 lease sales in seven OCS Planning areas: 10 lease sales in the three GOM planning areas; and 1 lease sale each in the Chukchi Sea, Beaufort Sea, and Cook Inlet Planning Areas, offshore Alaska.

On November 18, 2016, the final proposal, the Proposed Final Program (also known as the Five-Year Program), was published, which removed the proposed lease sales in the Chukchi Sea and Beaufort Sea from further consideration for the 5-year period (USDOI, BOEM, 2016a). The

Proposed Final Program schedules 11 proposed lease sales in two program areas in all or parts of four OCS planning areas: 10 proposed lease sales in the regionwide Gulf of Mexico (GOM) Program Area; and 1 proposed lease sale in the Cook Inlet Program Area offshore Alaska. No lease sales are scheduled for the Pacific or Atlantic OCS.

In accordance with Section 18(c)(2) of the OCSLA, the Secretary will not approve the Proposed Final Program until at least 60 days after sending it to the President and Congress. On January 17, 2017, the Secretary's decision was described in the Record of Decision and a signed program decision memorandum was made publicly available (USDOI, 2017).

The Five-Year Program EIS (USDOI, BOEM, 2016b) analyzed as its proposed action in the Draft Five-Year Program EIS the schedule of leases put forward in the Draft Proposed Program. The Final Five-Year Program EIS includes an analysis of the potential environmental impacts of the lease sale schedule put forward in the Proposed Program, including the 10 proposed GOM lease sales. It also analyzes reasonable alternatives to the proposed lease sale schedule and the mitigating measures that may reduce or eliminate any potential impacts. On January, 29, 2015, BOEM released a Notice of Intent (NOI) to prepare the Five-Year Program EIS in conjunction with the release of the Draft Proposed Program (*Federal Register*, 2015b). As a part of the NOI, BOEM solicited public input on the scope of the environmental analysis and on the alternatives and mitigating measures to be analyzed. BOEM received thousands of comments and analyzed and incorporated these as appropriate into the Five-Year Program EIS. The Draft Five-Year Program EIS was released for public comment in March 2016 (**Figure 1-4**). The Final Five-Year Program EIS was made available on November 18, 2016, and the Record of Decision was made available on January 18, 2017.

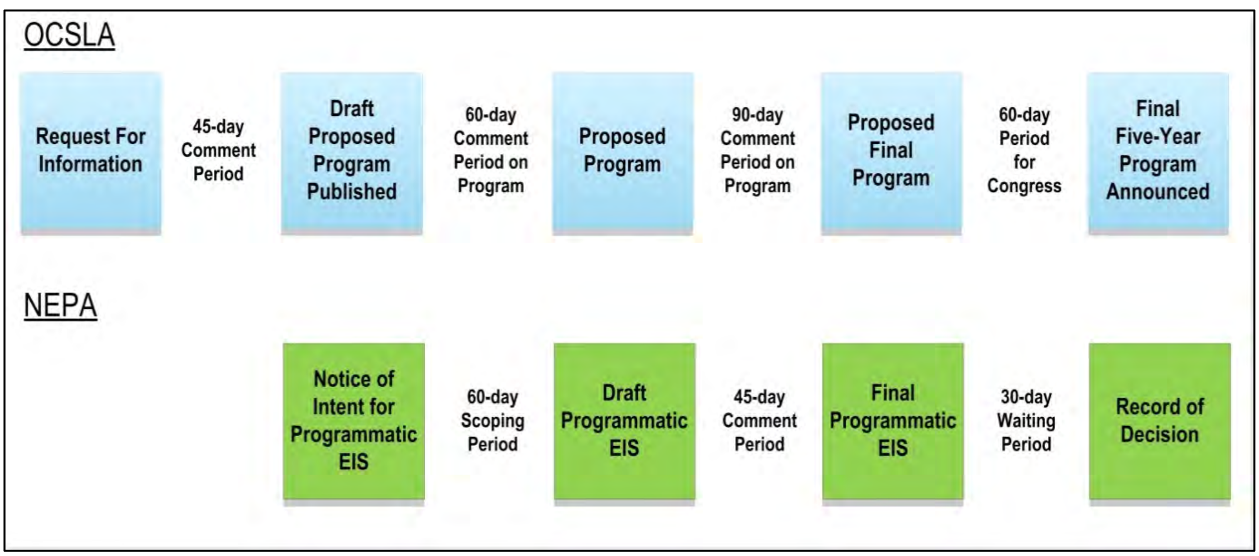

Figure 1-4. Planning for the Five-Year Program.

1.3.1.2 Individual Lease Sale Consultation and Decision Process

As noted earlier, the development of the Five-Year Program also triggers region-specific NEPA reviews for the individual proposed lease sales (refer to **Figure 1-5**). Region-specific reviews are conducted by Program Area (i.e., the Gulf of Mexico and Alaska OCS Regions) prior to lease sale decisions for those areas that are included in the Program. No lease sales have been scheduled for the Pacific or Atlantic OCS Regions in the Five-Year Program.

This Multisale EIS tiers from the Five-Year Program EIS. In January 2017, the Secretary selected Alternative A, which includes a schedule for 10 proposed regionwide lease sales in the GOM.

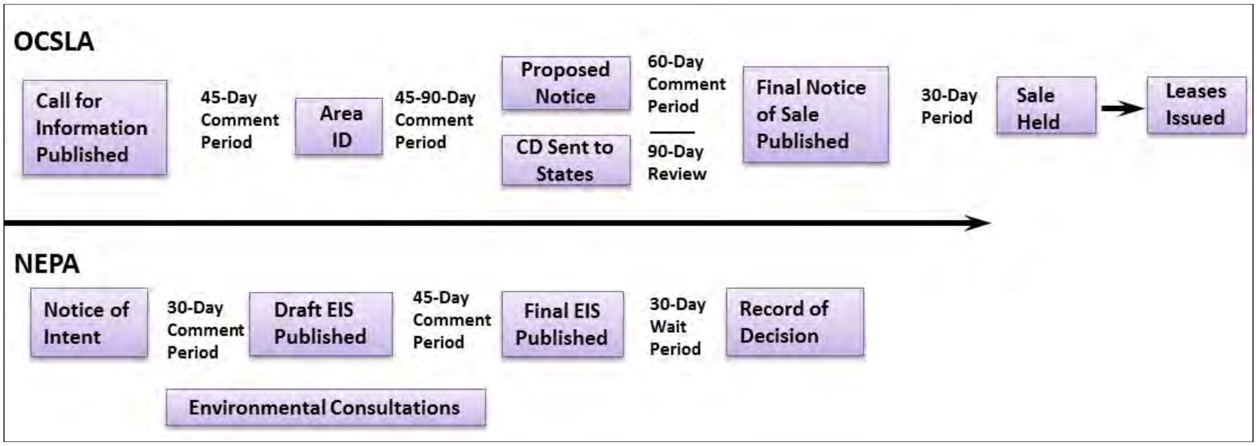

Figure 1-5. Typical Planning Timeline for Regional OCS Oil and Gas Lease Sales.

Pursuant to the OCSLA staged leasing process, for each lease sale proposed in the Five-Year Program, BOEM makes individual decisions on whether and how to proceed with a proposed lease sale. Federal regulations allow for several related or similar proposals to be analyzed in one EIS (40 CFR § 1502.4). Since each proposed lease sale and the projected activities related to such a lease sale are very similar and would occur in close timeframes, BOEM has decided to prepare a single programmatic EIS to support the 10 proposed GOM lease sales scheduled in the Five-Year Program. However, as previously noted, OCSLA requires individual decisions to be made for each lease sale. Therefore, in order to make an informed decision on a single proposed lease sale, the analyses contained in this Multisale EIS examine impacts from a single proposed lease sale. A lease sale scenario, described in **Chapter 3**, includes all of the activities that could occur over a 50-year analysis period. The findings of these analyses can be applied individually to each of the subsequent proposed lease sales.

The analyses contained in this Multisale EIS examines the impacts of a single proposed lease sale, which would apply to any of the 10 proposed GOM lease sales.

BOEM plans to supplement this Multisale EIS on a regular basis to provide for more consistency and for planning purposes. Unless circumstances or information warrants an earlier Supplemental EIS, BOEM expects to issue a Supplemental EIS once a calendar year. An additional NEPA review (e.g., a Determination of NEPA Adequacy, an environmental assessment [EA] or, if determined necessary, a Supplemental EIS) will be conducted prior to the decision on an individual proposed GOM lease sale to address any relevant new information. Each subsequent supplemental review tiers from the previous NEPA documents in this series of reviews as illustrated in **Figure 1-6**. Informal and formal consultation with other Federal agencies, federally recognized Indian Tribes, the affected States, and stakeholders would also be carried out as appropriate. This Multisale EIS would also assist decisionmakers in making informed, future decisions regarding the approval of operations, as well as the individual proposed lease sale decisions.

Also, as described in the Five-Year Program, any individual lease sale could be scaled back during the prelease sale process to offer a smaller area should circumstances warrant. For example, an individual lease sale could offer an area that conforms more closely to the separate planning area model used in the 2012-2017 Five-Year Program. Therefore, the analyses in this Multisale EIS also include alternatives similar to past WPA, CPA, and EPA lease sale environmental reviews.

This Multisale EIS is the NEPA document prepared for proposed Lease Sale 249. Subsequently, BOEM plans to prepare supplemental EISs on a calendar year basis as illustrated in **Figure 1-6**. Respective NEPA documents will be completed before decisions are made on the subsequent lease sales. This Multisale EIS approach allows for subsequent NEPA analyses to focus on the potential changes in each of the proposed lease sales and on any new issues and information that may have become available since the publication of the previous NEPA document.

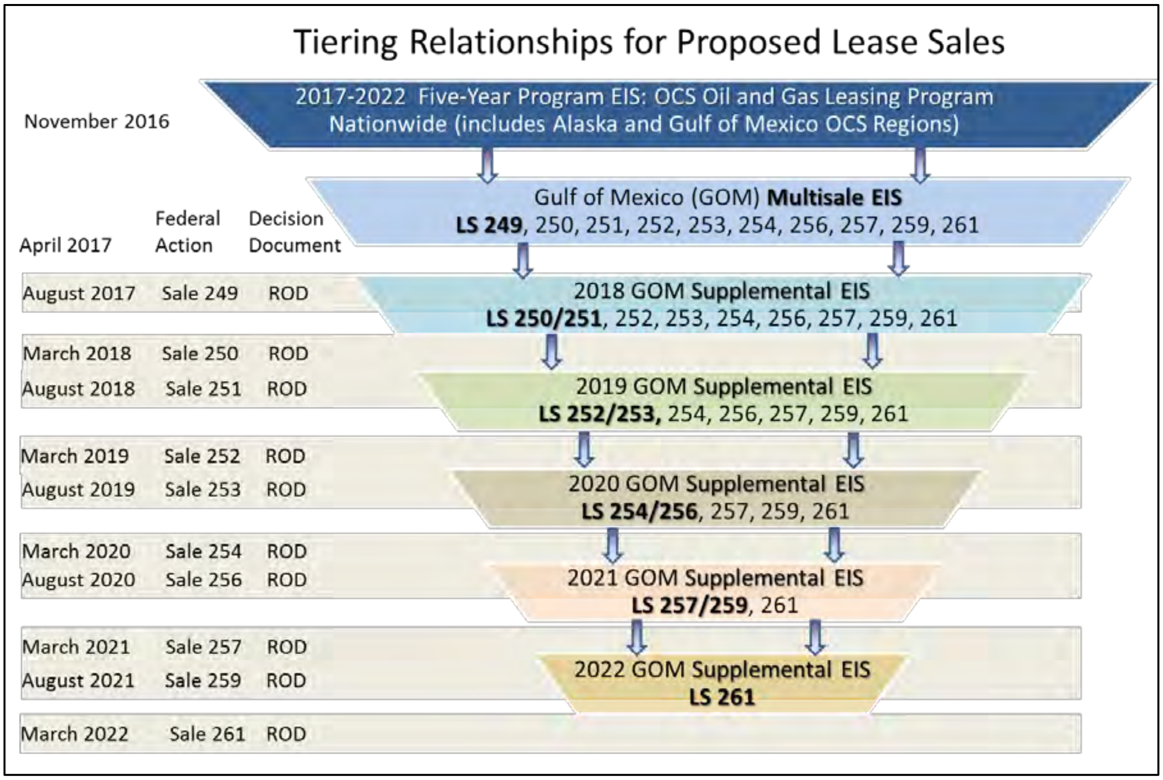

Figure 1-6. Supplemental Approach Showing the Tiering Relationships for Proposed Gulf of Mexico Lease Sales.

1.3.2 Gulf of Mexico Postlease Activities

BOEM and BSEE are responsible for managing, regulating, and monitoring oil and natural gas exploration, development, and production operations on the Federal OCS to promote the orderly development of mineral resources in a safe and environmentally sound manner. BOEM's regulations for oil, gas, and sulphur lease operations are specified in 30 CFR parts 550, 551, 554, and 556. The BSEE regulations for oil, gas, and sulphur operations are specified in 30 CFR parts 250 and 254. Refer to **Appendix A** for descriptions of postlease activities, including the following: geological and geophysical (G&G) surveys; exploration and development plans; permits and applications; inspection and enforcement; pollution prevention, oil-spill response plans, and financial responsibility; air emissions; flaring and venting; hydrogen sulfide contingency plans; archaeological resources regulation; coastal zone management consistency review and appeals for postlease activities; best available and safest technologies, including at production facilities; personnel training and education; structure removal and site clearance; marine protected species Notices to Lessees and Operators (NTLs); and the Rigs-to-Reefs program.

All plans for OCS oil- and gas-related activities (e.g., exploration and development plans) go through rigorous BOEM review and approval to ensure compliance with established laws and regulations before any project-specific activities can begin on a lease. Mitigating measures are incorporated and documented in plans submitted to BOEM. These measures may be implemented through, among other things, lease stipulations and project-specific requirements or conditions of approval. Conditions of approval are based on BOEM's and BSEE's technical and environmental evaluations of the proposed operations. Conditions may be applied to any OCS plan, permit, right-of-use and easement, or pipeline right-of-way grant.

Mitigating measures address concerns such as endangered and threatened species, geologic and manmade hazards, military warning and ordnance disposal areas, archaeological sites, air quality, oil-spill response planning, chemosynthetic communities, artificial reefs, operations in hydrogen sulfide (H_2S)-prone areas, and shunting of drill effluents in the vicinity of biologically sensitive features. Refer to **Appendix B** ("Commonly Applied Mitigating Measures") for more information on the mitigations that BOEM and BSEE often apply to permits and approvals. Operational compliance of the mitigating measures is enforced through BSEE's onsite inspection program.

BOEM and BSEE issue NTLs to provide clarification, description, or interpretation of a regulation; guidelines on the implementation of a special lease stipulation or regional requirement; or administrative information. A detailed listing of the current Gulf of Mexico OCS Region's NTLs is available through BOEM's Gulf of Mexico OCS Region's website at http://boem.gov/Regulations/Notices-Letters-and-Information-to-Lessees-and-Operators.aspx or through the Region's Public Information Office at 504-736-2519 or 1-800-200-GULF. A detailed listing of BSEE's Gulf of Mexico OCS Region's current NTLs is available through BSEE's Gulf of Mexico OCS Region's website at https://www.bsee.gov/guidance-and-regulations/guidance/notice-to-lessees.

1.4 The Decision To Be Made

A decision will be made on whether and how to proceed with each proposed lease sale in the Five-Year Program. After completion of this Multisale EIS, a decision will be made on proposed Lease Sale 249 (i.e., prepare a Record of Decision for Lease Sale 249 only). As discussed in **Chapter 1.3.1**, individual decisions will be made on each subsequent lease sale after completion of the appropriate NEPA documents.

1.5 Regulatory Framework

Federal laws mandate the OCS leasing program (i.e., OCSLA) and the environmental review process (e.g., NEPA). These regulations are intended to encourage orderly, safe, and environmentally responsible development of oil, natural gas, alternative energy sources, and other mineral resources on the OCS. BOEM consults with numerous federally recognized Indian Tribes and Federal and State departments and agencies that have authority to govern and maintain ocean resources pursuant to other Federal laws. As illustrated in **Figure 1-7**, BOEM's consultation partners for specific Federal regulations, several Federal regulations establish specific consultation and coordination processes with federally recognized Indian Tribes and Federal, State, and local agencies.

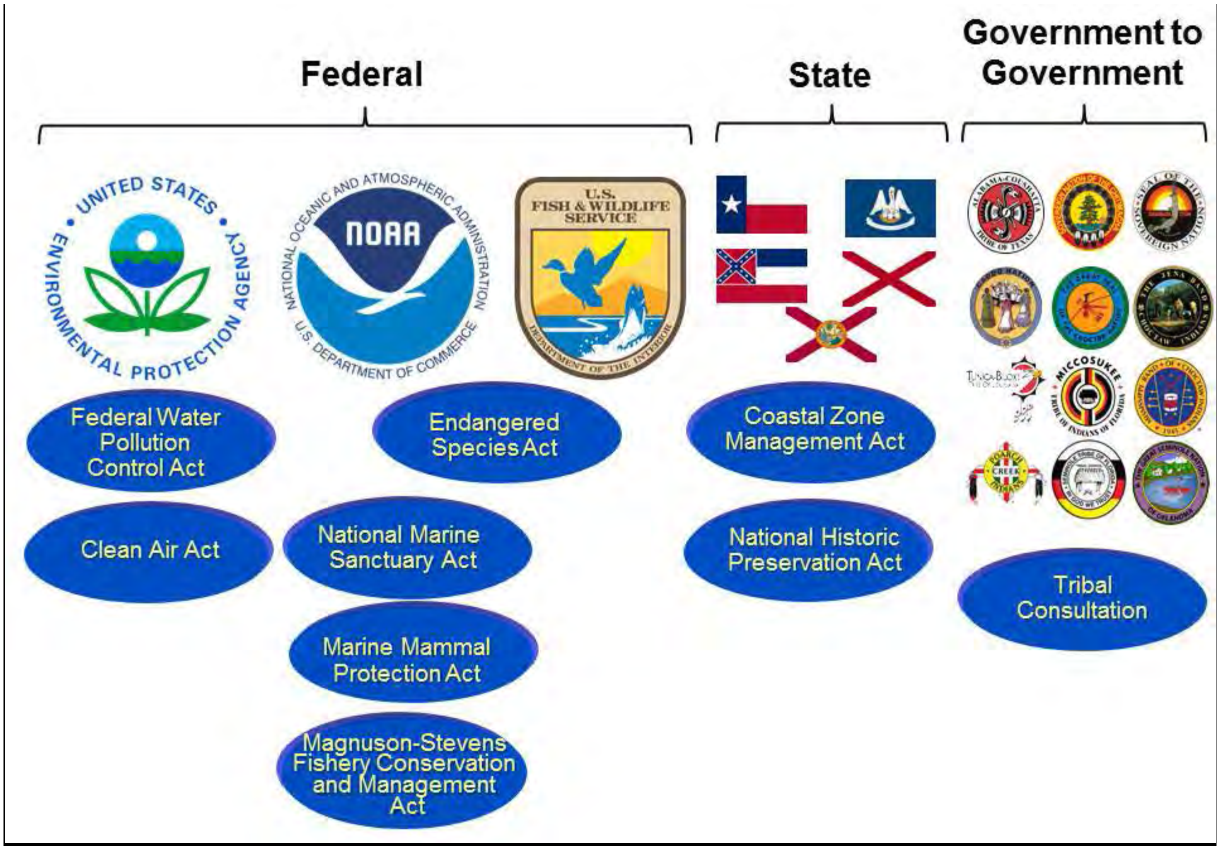

Figure 1-7. BOEM's Consultation Partners for Specific Federal Statutes and Regulations.

Among these Federal entities are the U.S. Environmental Protection Agency (USEPA), U.S. Fish and Wildlife Service (FWS), and the National Oceanic and Atmospheric Administration (NOAA) through the National Marine Fisheries Service (NMFS). In addition to coordinating with Federal Government entities, BOEM coordinates and consults with any State governor or local government executives that may be affected by a particular lease, easement, or right-of-way. Each state, with the exception of Alaska, has developed and implemented a federally approved coastal management program pursuant to the Coastal Zone Management Act (16 U.S.C. §§ 1451 *et seq*.). The boundaries of each State's coastal zone are available at https://coast.noaa.gov/czm/media/StateCZBoundaries.pdf. A detailed description of major Federal laws and Executive Orders that are relevant to the OCS leasing process is provided in the *OCS Regulatory Framework* white paper, which can be found on BOEM's website (Cameron and Matthews, 2016). Chapter 3 of BOEM's *OCS Regulatory Framework* white paper identifies 43 major Federal laws and Executive Orders that are relevant to the OCS leasing process (Cameron and Matthews, 2016). During the planning process, federally recognized Indian Tribes are informed of the potential activities on the OCS and are asked if they are interested in entering into a meaningful consultation with BOEM's leadership to discuss the activities.

1.6 OTHER OCS OIL- AND GAS-RELATED ACTIVITIES

BOEM and BSEE have programs and activities that are OCS-related but not specific to the oil and gas leasing process or to the management of exploration, development, and production activities. These programs include environmental and technical studies, cooperative agreements with other Federal and State agencies for NEPA work, joint jurisdiction over cooperative efforts, inspection activities, and regulatory enforcement. BOEM also participates in industry research efforts and forums. The information collected through these efforts is used in support of the BOEM NEPA documents that inform Agency decisions.

Environmental Studies Program

BOEM promotes energy independence, environmental protection, and economic development through responsible management of OCS resources based on the best available science. To support this work and inform bureau policy decisions, BOEM's Environmental Studies Program develops, conducts, and oversees world-class scientific research specifically to inform policy decisions regarding development of OCS energy and mineral resources.

Through the Environmental Studies Program, BOEM is a leading contributor to the growing body of scientific knowledge about the marine and coastal environment. The Environmental Studies Program obtains information needed for NEPA assessment and the management of environmental and socioeconomic impacts on the human, marine, and coastal environments that may be affected by OCS oil and gas development. Research covers a broad range of disciplines, including physical oceanography, atmospheric sciences, biology, protected species, social sciences, economics, submerged cultural resources, and the environmental impacts of energy development. BOEM (and its predecessors) has funded more than $1 billion in research since the studies program was established in 1973 in accordance with Section 20 of the OCSLA. Technical summaries of more than 1,200 BOEM-sponsored environmental research projects and more than 3,400 research reports are publicly available online through the Environmental Studies Program Information System (ESPIS). For the latest information on BOEM's ongoing environmental studies work, go to http://www.boem.gov/studies. In the Gulf of Mexico OCS Region, over 350 studies for approximately $250 million have been completed and more than 900 reports and scientific papers have been produced. A complete list of all ongoing Gulf of Mexico OCS Region studies is available on the BOEM website. Each listing not only describes the research being conducted but also shows the institution performing the work, the cost of the effort, timeframe, and any associated publications, presentations, or affiliated websites.

BOEM incorporates findings from the studies program into its environmental reviews and NEPA documents, which are used to avoid, mitigate, or monitor the impact of energy and mineral resource development on the OCS. The BOEM's Gulf of Mexico OCS Region analysts use the ESP studies to prepare this document. While not all of the Gulf of Mexico OCS Region's studies are specifically referenced in this Multisale EIS, analysts used those that are relevant. Decisionmakers also use the information in ESP studies in managing and regulating exploration, development, and production activities on the OCS. This integrated approach of incorporating applied science to inform decisionmakers is illustrated in **Figure 1-8**.

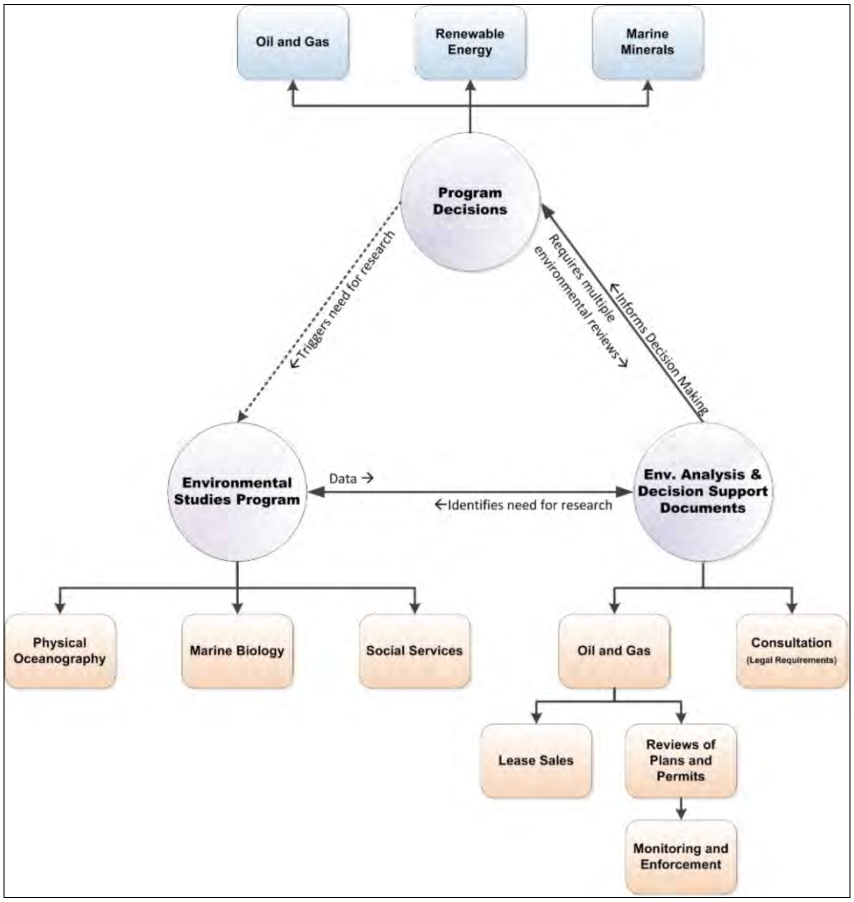

Figure 1-8. BOEM's Integrated Approach for Incorporating Applied Science into Decisionmaking.

Technology Assessment Program

The BSEE's Technology Assessment Program supports research associated with operational safety and pollution prevention. The Technology Assessment Program is comprised of two functional research activities: (1) operational safety and engineering research (topics such as air quality, decommissioning, and mooring and anchoring); and (2) other research (topics such as renewable energy and alternate use; Hurricanes Andrew, Ivan, Katrina, Rita, and Lili; and international activities). The Technology Assessment Program has four primary objectives:

- Technical Support—Providing engineering support in evaluating industry operational proposals and related technical issues and in ensuring that these proposals comply with applicable regulations, rules, and operational guidelines and standards.

- Technology Assessment—Investigating and assessing industry applications of technological innovations and promoting the use of the best available and safest technologies in Bureau regulations, rules, and operational guidelines.
- Research Catalyst—Promoting leadership in the fields of operational safety and pollution prevention in offshore energy extraction activities.
- International Regulations—Providing international cooperation for research and development initiatives to enhance the safety of offshore energy extraction activities and the development of appropriate regulatory program elements worldwide.

Oil-Spill Response Research

For more than 25 years, BSEE (and its predecessors) have aggressively maintained a comprehensive, long-term research program dedicated to improving oil-spill response options. The major focus of the program is to improve the methods and technologies used for oil-spill detection, containment, treatment, recovery, and cleanup. The Oil-Spill Response Research Program is a cooperative effort bringing together funding and expertise from research partners in government agencies, industry, and the international community.

The Program also manages Ohmsett, the National Oil Spill Response Research Test Facility, located in Leonardo, New Jersey. Ohmsett is the largest outdoor saltwater wave/tow tank facility in North America. Ohmsett allows full-scale, oil-spill response testing, training, and research with oil in a realistic marine environment.

Interagency Agreements

Memoranda of Understanding under NEPA

The Council on Environmental Quality's (CEQ) implementing regulations (40 CFR § 1500.5(b)) encourages agency cooperation early in the NEPA process. A Federal agency can be a lead, joint lead, or cooperating agency. A lead agency manages the NEPA process and is responsible for the preparation of an EIS; a joint lead agency shares these responsibilities; and a cooperating agency that has jurisdiction by law and has special expertise with respect to any environmental issue shall participate in the NEPA process upon the request of the lead agency.

When an agency becomes a cooperating agency, the cooperating and lead agencies usually enter into a Memorandum of Understanding (MOU), previously called a Cooperating Agency Agreement. The MOU details the responsibilities of each participating agency. BOEM, as lead agency, has previously requested other Federal agencies to become cooperating agencies while other agencies have requested BOEM to become a cooperating agency (e.g., the Ocean Express Pipeline project). Some projects, such as major gas pipelines across Federal waters and projects under the Deepwater Port Act of 1974, can require cooperative efforts by multiple Federal and State agencies.

The NOI for this Multisale EIS included an invitation to other Federal agencies and State, Tribal, and local governments to consider becoming cooperating agencies in the preparation of this EIS. Consultation and coordination activities for this Multisale EIS are described in **Chapter 5**. In a letter dated September 8, 2015, the U.S. Environmental Protection Agency's (USEPA) Regions 4 and 6 requested cooperating agency status for the 2017-2022 Multisale EIS. On December 16, 2015, a Memorandum of Agreement between BOEM's Gulf of Mexico OCS Region and USEPA Regions 4 and 6 was initiated; this Memorandum of Agreement defines the roles and responsibilities for each agency (**Appendix C**).

Memorandum of Understanding and Memoranda of Agreement between BSEE and USCG

Since BSEE and USCG have closely related jurisdiction over different aspects of safety and operations on the OCS, the agencies have established a formal MOU that delineates lead responsibilities for managing OCS activities in accordance with the OCSLA, as amended, and the Oil Pollution Act of 1990. The latest MOU, dated November 27, 2012, supersedes the September 2004, December 1998, and August 1989 versions of the interagency agreement. The MOU is designed to minimize duplication and promote consistent regulation of facilities under the jurisdiction of both agencies.

Generally, the MOU identifies BSEE as the lead agency for matters concerning the equipment and operations directly involved in the production of oil and gas. These include, among others, design and operation of risers, permanent mooring foundations of the facility, drilling and well production and services, inspection and testing of all drilling-related equipment, and platform decommissioning. Issues regarding certain aspects of safe operation of the facility, its systems, and equipment generally fall under the jurisdiction of USCG. These include, among others, design of vessels, their sea-keeping characteristics, propulsion and dynamic positioning systems, supply and lightering procedures and equipment, utility systems, safety equipment and procedures, and pollution prevention and response procedures.

Memorandum of Agreement between BOEM and BSEE – Environmental and NEPA

The BOEM/BSEE Memorandum of Agreement establishes the working relationship between BOEM and BSEE for environmental review and enforcement for activities on the OCS. It is intended to minimize duplication of efforts, promote consistency in procedures and regulations, and resolve disputes. Under this Memorandum of Agreement, BSEE will serve as a cooperating agency on BOEM's NEPA documents and may adopt NEPA analyses prepared by BOEM.

1.7 Other Pertinent Environmental Reviews or Documentation

BOEM is aware of other environmental reviews and studies relevant to the resources under consideration in this Multisale EIS. Notices of Intent were published in the *Federal Register* for the following reviews:

- *BOEM's Gulf of Mexico Geological and Geophysical Activities Programmatic Draft EIS.* BOEM, with the National Oceanic and Atmospheric Administration's NMFS and BSEE as cooperating agencies, prepared a Programmatic EIS to evaluate the potential environmental impacts of multiple G&G activities within Federal waters of the Gulf of Mexico's OCS and adjacent State waters. BOEM and NMFS intend for that Programmatic EIS to provide the necessary documentation and analyses to support informed decisions regarding future OCSLA permit and Marine Mammal Protection Act (MMPA) authorization actions related to G&G activities on the OCS. In addition, the preparation of this Programmatic EIS will help to ensure compliance with other applicable laws and statutes such as the Endangered Species Act (ESA), Magnuson-Stevens Fishery Conservation and Management Act, Coastal Zone Management Act (CZMA), and the National Historic Preservation Act (NHPA). The G&G Programmatic EIS establishes a framework for subsequent NEPA analyses for site-specific actions while identifying and analyzing appropriate mitigating measures to be used during future G&G activities on the OCS in support of the oil and gas, renewable energy, and marine mineral resource programs. The impacts of future site-specific actions will be addressed in subsequent NEPA evaluations, per the Council on Environmental Quality's regulations (40 CFR § 1502.20), by tiering from this programmatic evaluation. Public scoping for the G&G Programmatic EIS was held from May 10-July 9, 2013, and the Draft G&G Programmatic EIS was available for public review and comment from September 29, 2016 until November 28, 2106. BOEM anticipates the release of the Final G&G Programmatic EIS in August 2017.

- *NOAA's Flower Garden Banks National Marine Sanctuary Expansion EIS*. In February 2015, NOAA's Office of National Marine Sanctuaries announced its intent to prepare a Draft EIS to consider possible expansion of the Flower Garden Banks National Marine Sanctuary. When the Flower Garden Banks National Marine Sanctuary was designated in 1992, the boundaries were established based on best available information regarding biologically sensitive habitats. Subsequent exploration in the northwestern Gulf of Mexico has identified other reefs, banks, and associated features that may be ecologically linked to the Flower Garden Banks National Marine Sanctuary. Although many of these areas have some level of protection through other designations, inclusion in the sanctuary would provide a comprehensive management framework to fill in the existing regulatory gaps and provide necessary protection to these critical habitats. In June 2016, NOAA issued a Draft EIS that considers five alternatives. BOEM, among other agencies, is a Cooperating Agency in the preparation of this EIS. Refer to **Chapter 2.2.3** for more information as this relates to the alternatives considered in this Multisale EIS.

- *Deepwater Horizon Natural Resource Trustees' Natural Resource Damage Assessment Final Programmatic EIS (*Deepwater Horizon Natural Resource

Damage Assessment Trustees, 2016). In February 2016, the Federal and State natural resource trustee agencies (Trustees) issued the *Deepwater Horizon Oil Spill: Final Programmatic Damage Assessment and Restoration Plan and Final Programmatic Environmental Impact Statement* (PDARP/PEIS) for public review. The PDARP/PEIS considers programmatic alternatives to restore natural resources, ecological services, and recreational use services injured or lost as a result of the *Deepwater Horizon* oil spill. The *Deepwater Horizon* oil spill's natural resource Trustees have developed restoration alternatives, comprised of various restoration types, to address injuries to natural resources and resource services resulting from the *Deepwater Horizon* oil spill. Criteria and evaluation standards under the Oil Pollution Act of 1990's natural resource damage assessment regulations guided the Trustees' consideration of programmatic restoration alternatives. The PDARP/PEIS also evaluates the environmental consequences of the restoration alternatives under NEPA.

Supporting technical information in previous NEPA reviews have been developed as standalone technical reports and are summarized and incorporated by reference as appropriate. These include the OCS regulatory framework and improvements since the *Deepwater Horizon* explosion, oil spill, and response; the catastrophic spill event analysis; and the essential fish habitat assessment. Subsequent updates to this information have been minimal and, therefore, BOEM has prepared separate technical reports, which will be updated as needed. This approach would be conducive to reducing the size of this Multisale EIS and future NEPA documents.

- *OCS Regulatory Framework* White Paper. Federal laws mandate the OCS leasing program (i.e., the OCSLA) and the environmental review process (i.e., the NEPA). In implementing its responsibilities under the OCSLA, BOEM and BSEE must consult with numerous Federal departments and agencies that have authority to govern and maintain ocean resources pursuant to other Federal laws. Among these Federal entities are the USCG, USEPA, COE, FWS, and NOAA through NMFS. Several Federal regulations establish specific consultation and coordination processes with Federal, State, and local agencies (i.e., the Coastal Zone Management Act of 1972 [CZMA], the Endangered Species Act of 1973 [ESA], the Magnuson-Stevens Fishery Conservation and Management Act, and the Marine Mammal Protection Act [MMPA]). These regulations have been discussed in past NEPA documents for oil and natural gas lease sales, such as the *Gulf of Mexico OCS Oil and Gas Lease Sales: 2012-2017; Western Planning Area Lease Sales 229, 233, 238, 246, and 248; Central Planning Area Lease Sales 227, 231, 235, 241, and 247, Final Environmental Impact Statement* (2012-2017 WPA/CPA Multisale EIS) (USDOI, BOEM, 2012b). This report is available on BOEM's website (Cameron and Matthews, 2016).

- *Catastrophic Spill Event Analysis* White Paper. The August 16, 2010, CEQ report, prepared following the *Deepwater Horizon* explosion, oil spill, and response in the GOM, recommended that BOEM, formerly the Minerals Management Service (MMS) and Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), should "[e]nsure that NEPA [National Environmental Policy Act] documents provide decisionmakers with a robust analysis of reasonably foreseeable impacts, including an analysis of reasonably foreseeable impacts associated with low probability catastrophic spills for oil and gas activities on the Outer Continental Shelf" (CEQ, 2010). BOEM prepared a "Catastrophic Spill Event Analysis," which was included as Appendix B in the 2012-2017 WPA/CPA Multisale EIS. This analysis has been reviewed and updated, as appropriate, during each Supplemental EIS for the remaining proposed GOM lease sales through 2017. These subsequent updates have been minimal and, therefore, BOEM has prepared a separate technical report, which will be updated as needed. This evaluation is a robust analysis of the impacts from low-probability catastrophic spills and will be made available to all applicable decisionmakers including, but not limited to, the Secretary of the Department of the Interior for the Five-Year Program, the Assistant Secretary of Land and Minerals Management for an oil and gas lease sale, and the Regional Supervisors of the Gulf of Mexico OCS Region's Office of Environment and Office of Leasing and Plans. This report is also available on BOEM's website (USDOI, BOEM, 2017).

- *Essential Fish Habitat Assessment* White Paper. The 2017-2022 Programmatic EFH Assessment for the Gulf of Mexico ("EFH Assessment") is a stand-alone analysis that addresses BOEM's obligation under Section 305(b) of the Magnuson-Stevens Fishery Conservation and Management Act (16 U.S.C. § 1855(b)) to consult with the U.S. Department of Commerce regarding actions that may adversely affect essential fish habitat. The EFH Assessment also informs many of the analyses documented in this Multisale EIS. The Federal actions addressed in the EFH Assessment are the individual proposed Gulf of Mexico Lease Sales 249-254, 256, 257, 259, and 261 and related activities, such as G&G activities and decommissioning operations. Individual lease sales would offer for lease some or all unleased blocks in the WPA, CPA, and EPA proposed lease sale areas for oil and gas exploration and recovery operations. A proposed action would provide for the issuance of permits to conduct G&G survey activities between the coastline and the seaward extent of the Exclusive Economic Zone of the GOM. Decommissioning operations encompass many component activities: (1) equipment and vessel mobilization and target preparation; (2) underwater structural-member severance (nonexplosive and explosive methods); (3) post-severance salvage; and (4) final site-clearance verification. These types of activities all have the potential to impact fish and EFH. The EFH Assessment serves as the initiation of a Programmatic Consultation by BOEM's Gulf of

Mexico OCS Region with the U.S. Department of Commerce on OCS oil- and gas-related activities for 2017-2022. Based on the most recent and best available information, BOEM will also continue to evaluate and assess risks to managed species and identified EFH in upcoming environmental compliance documentation under NEPA and other statutes. Information relevant to EFHs is incorporated and analyzed in this Multisale EIS in **Chapter 4.2** (Water Quality), **Chapter 4.3** (Coastal Habitats), **Chapter 4.4** (Deepwater Benthic Communities), **Chapter 4.5** (*Sargassum* and Associated Communities), and **Chapter 4.6** (Live Bottom Habitats). This report is also available on BOEM's website (USDOI, BOEM, 2016d).

1.8 Format and Organization of the Multisale EIS

In an effort to thoroughly explain all the environmental considerations and mitigations that are involved in BOEM's assessment of the potential environmental consequences of OCS oil- and gas-related activities, BOEM recognizes that past NEPA reviews have become encyclopedic in nature. To more closely align with CEQ's guidance regarding EIS format, a major goal in preparing this Multisale EIS includes increasing the readability of the document for decisionmakers and the public, and shortening the document by providing relevant and appropriate information needed to assess the effects of the proposed actions and alternatives. A major focus for preparing this Multisale EIS has been on clear and concise writing, using graphics to emphasize major concepts where appropriate, and placing more detailed and technical supporting information in the appendices and incorporating it by reference. The remaining chapters in this Multisale EIS are described below.

- **Chapter 2** describes the potential lease sale options and the alternatives, including the proposed action, being analyzed in this Multisale EIS; discusses the potential mitigating measures (pre- and postlease), including the proposed stipulations, and the issues considered and not considered in the analysis; and discusses the deferred alternatives and provides a broad comparison of impacts by alternative.
- **Chapter 3** describes all the potentially occurring actions associated with a single lease for the Five-Year Program and the cumulative activities that provide a framework for detailed analyses of the potential impacts analyzed in **Chapter 4**. Exploration and development scenarios describe the infrastructure and activities that could potentially affect the biological, physical, and socioeconomic resources in the GOM. It is a hypothetical framework of assumptions based on estimated amounts, timing, and general locations of OCS exploration, development, and production activities and facilities, both offshore and onshore. It also includes a set of ranges for resource estimates, projected exploration and development activities, and impact-producing factors.
- **Chapter 4** describes the affected environment and the potential impacts of a single proposed lease sale and each alternative by resource. Analysis of the

alternatives includes routine activities, accidental events, cumulative impact analysis, incomplete or unavailable information, and conclusions for each resource.

- **Chapter 5** describes the consultation and coordination efforts used in preparing this Multisale EIS. This includes a description of the scoping process, activities, and results; cooperating agencies; distribution of the EIS; consultations with Federal and State agencies under the Coastal Zone Management Act, Endangered Species Act, the Magnuson-Stevens Fishery Conservation and Management Act, and the National Historic Preservation Act; and government-to-government consultation and coordination. **Chapter 5** also includes comments received on the Draft Multisale EIS and BOEM's responses.
- **Chapter 6** includes all of the citations referenced throughout this Multisale EIS.
- **Chapter 7** is a list of all the preparers of this Multisale EIS.
- **Chapter 8** is a glossary of terms used in this Multisale EIS.
- Finally, to improve the readability of this Multisale EIS, more detailed supporting information has been placed in the **Appendices**.

CHAPTER 2

ALTERNATIVES INCLUDING THE PROPOSED ACTIONS

What's In This Chapter?

- This Multisale EIS is the NEPA document used to support a decision on proposed Lease Sale 249.
- The analyses in this Multisale EIS are also relevant to proposed Lease Sales 250-254, 256, 257, 259, and 261.
- Alternative A: A single proposed lease sale offering all available unleased blocks within the WPA, CPA, and EPA portions of the proposed lease sale area with exceptions as outlined in **Chapter 2.2.2**.
- Alternative B: A single proposed lease sale offering all available unleased blocks within the CPA and EPA but not within the WPA portion of the proposed lease sale area with exceptions.
- Alternative C: A single proposed lease sale offering all available unleased blocks within the WPA but not within the CPA/EPA portions of the proposed lease sale area with one exception.
- Alternative D: Alternative A, B, or C with the option to exclude any available unleased blocks subject to the Topographic Features Stipulation, Live Bottom (Pinnacle Trend) Stipulation, and/or Blocks South of Baldwin County, Alabama, Stipulation.
- Alternative E: Cancellation of a single proposed lease sale.
- Alternatives not analyzed include the following:
  - follow the 2012-2017 Five-Year Program leasing schedule, including separate lease sales for the EPA;
  - exclude blocks that would be subject to any future expansion of the Flower Garden Banks National Marine Sanctuary;
  - add additional buffer zones to further protect sensitive environments, species, or the view from shores;
  - exclude the WPA and CPA;
  - add more measures to reduce the potential impacts to sperm whale high-use areas;
  - exclude blocks within the De Soto Canyon area;
  - exclude areas that have been designated as loggerhead sea turtle critical habitat by NOAA; and
  - delay the proposed lease sales until the state of recovery of the GOM following the *Deepwater Horizon* explosion, oil spill, and response is known.
- The issues that most impact the decision to lease are reviewed in this Multisale EIS, including impacts to air and water quality, biological resources, recreation, land use, economics, and environmental justice.
- A comparison of alternatives and impact summaries is presented.

2 ALTERNATIVES INCLUDING THE PROPOSED ACTIONS

2.0 Introduction

As stated in **Chapter 1.0**, the proposed action is to hold a lease sale in the GOM according to the schedule of proposed lease sales set forth in the 2017-2022 Five-Year Program. Since each of the 10 proposed lease sales in the GOM region are very similar and occur in close timeframes, BOEM has decided to prepare this multisale analysis as described in **Chapter 2.1**. Four action alternatives and a No Action Alternative (Alternative E) are described, including a comparison of impacts by alternative.

2.1 MULTISALE NEPA ANALYSIS

As authorized under 40 CFR § 1502.4, one EIS is allowed to analyze related or similar proposals. This Multisale EIS addresses 10 proposed regionwide oil and gas lease sales encompassing all three planning areas in the U.S. portion of the Gulf of Mexico OCS (**Figure 1-1**), as scheduled in the Five-Year Program (USDOI, BOEM, 2016a). However, as previously noted in **Chapter 1.3.1.2**, the OCSLA requires individual decisions to be made for each lease sale. Therefore, in order to make an informed decision on a single proposed lease sale, the analyses contained in this Multisale EIS examine impacts from a single proposed regionwide lease sale (i.e., proposed Lease Sale 249).

For analysis purposes, a proposed action is presented as a set of ranges of resource extraction estimates, projected exploration and development activities, and impact-producing factors for the proposed lease sale area. Each of the proposed lease sales is expected to have oil and gas production within the scenario ranges for the proposed lease sale area analyzed in this Multisale EIS; therefore, a proposed action is also representative of proposed Lease Sales 249-254, 256, 257, 259, and 261. Each proposed action includes existing regulations and lease stipulations. This EIS will be the only NEPA document prepared for proposed Lease Sale 249. An additional NEPA review (a Determination of NEPA Adequacy, an EA or, if determined necessary, a Supplemental EIS) will be conducted prior to each of the remaining proposed lease sales to address any relevant new information available since this Final Multisale EIS Informal and formal consultations with other Federal agencies, the affected States, federally recognized Indian Tribes, and the public will be carried out to assist in the determination of whether or not the information and analyses in this Multisale EIS are still valid. Specifically, information requests such as NOIs and request for public comment will be issued soliciting input on subsequent proposed lease sales as appropriate (refer to **Chapter 1.3.1.2**).

The supplemental approach for regional lease sales is intended to focus the NEPA/EIS process on updating subsequent lease sale NEPA reviews to address any relevant significant new information and/or issues since publication of the previous lease sale NEPA document from which it tiers (**Figure 1-6**) This tiering approach also lessens duplication and saves resources. The scoping process for this document is described in **Chapter 5**. As mandated by NEPA, this Multisale EIS analyzes the potential impacts of the proposed actions on the marine, coastal, and human environment.

> *Agencies are encouraged to tier their environmental impact statements to eliminate repetitive discussions of the same issues and to focus on the actual issues ripe for decision at each level of environmental review.*

Any subsequent NEPA reviews will tier from this Multisale EIS and will summarize and incorporate the material by reference. Because any subsequent reviews will be prepared for a proposed action that "is, or is closely similar to, one which normally requires the preparation of an EIS" (40 CFR § 1501.4(e)(2)), the review documents will be made publicly available.

If a Supplemental EIS is necessary (40 CFR § 1502.9), it will tier from this Multisale EIS, summarize and incorporate the material by reference, and focus on addressing any new information, issue(s) and/or concern(s). The Supplemental EIS will include a discussion of the purpose of the Supplemental EIS, a description of the proposed action(s) and alternatives, a comparison of the proposed alternatives, a description of the affected environment, potentially affected resources, an analysis of new impacts, and new information not addressed in this Multisale EIS. The Supplemental EIS will also include an updated discussion of associated BOEM coordination and consultations. As discussed further in **Chapter 1.7**, an analysis of the impacts of low-probability catastrophic spills has been prepared as a BOEM white paper and is incorporated by reference (*Catastrophic Spill Event Analysis* white paper; USDOI, BOEM, 2017).

2.2 Alternatives, Mitigating Measures, and Issues

Below is a description of the 2017-2022 proposed Gulf of Mexico OCS Region's lease sale schedule per the Five-Year Program followed by a reasonable range of alternatives to the proposed action that can be considered for selection to avoid or minimize impacts throughout the 2017-2022 Five-Year Program.

2.2.1 What is the 2017-2022 Proposed Lease Sale Schedule?

A total of 10 proposed regionwide lease sales has been identified in BOEM's 2017-2022 Five-Year Program, with 1 lease sale in 2017; 2 lease sales each year in 2018, 2019, 2020, and 2021; and 1 lease sale in 2022 offering all available unleased blocks not subject to Congressional moratorium in the combined WPA, CPA, and EPA in each proposed lease sale. The alternatives below are being considered in order to ensure that BOEM has considered a reasonable range of alternatives to the proposed actions within the framework of the Five-Year Program.

2017-2022 Schedule of Proposed Gulf of Mexico OCS Region Lease Sales	
Lease Sale Number	Year
249	2017
250 and 251	2018
252 and 253	2019
254 and 256	2020
257 and 259	2021
261	2022

The regionwide lease sale approach provides greater flexibility, including responding to changing conditions (including Mexico's new plan offering offshore licenses every September); a better workload balance within BOEM; and allowing for more frequent opportunities to bid on rejected, relinquished, or expired blocks. Also, any individual lease sale could still be scaled back to offer a smaller area, if conditions warrant. In addition, regionwide leasing could facilitate better planning to explore pools that may straddle the U.S.-Mexico boundary. More frequent lease sales in the planning areas (through regionwide leasing) may expedite and increase the present value of leasing and tax revenues. More frequent lease sales for the available unleased blocks, however, could reduce the time available for companies to update their information and develop improved value estimates for the remaining available unleased blocks.

2.2.2 What are the Alternatives that BOEM is Considering for Each Proposed Lease Sale?

The discussions below outline the alternatives that are considered for this environmental analysis. To make an informed decision on a single proposed lease sale, the alternatives and analyses contained in this Multisale EIS examine impacts from a single proposed lease sale and can be applied individually to each of the subsequent proposed lease sales. Additional alternatives could also be considered in subsequent NEPA reviews should new information or circumstances warrant.

The analyses of impacts summarized below in **Chapter 2.3** and described in detail in **Chapter 4** for each resource are based on the development scenario, which is a set of assumptions and estimates on the amounts, locations, and timing for OCS exploration, development, and production operations and facilities, both offshore and onshore, related to a single proposed lease sale. A detailed discussion of the development scenario and major related impact-producing factors is included in **Chapter 3**. A proposed lease sale includes proposed lease stipulations designed to reduce environmental risks; these stipulations are discussed in **Chapter 2.2.4.1**.

2.2.2.1 Alternative A—Regionwide OCS Lease Sale (The Preferred Alternative)

Alternative A would allow for a proposed regionwide lease sale encompassing all three planning areas within the U.S. portion of the Gulf of Mexico OCS for any given lease sale in the Five-Year Program. This is BOEM's preferred alternative. This alternative would offer for lease all available unleased blocks within the WPA, CPA, and EPA portions of the proposed lease sale area for oil and gas operations (**Figure 2-1**), with the following exceptions:

(1) whole and portions of blocks deferred by the Gulf of Mexico Energy Security Act of 2006 (discussed in the *OCS Regulatory Framework* white paper [Cameron and Matthews, 2016]);

(2) blocks that are adjacent to or beyond the United States' Exclusive Economic Zone in the area known as the northern portion of the Eastern Gap; and

(3) whole and partial blocks within the current boundary of the Flower Garden Banks National Marine Sanctuary.

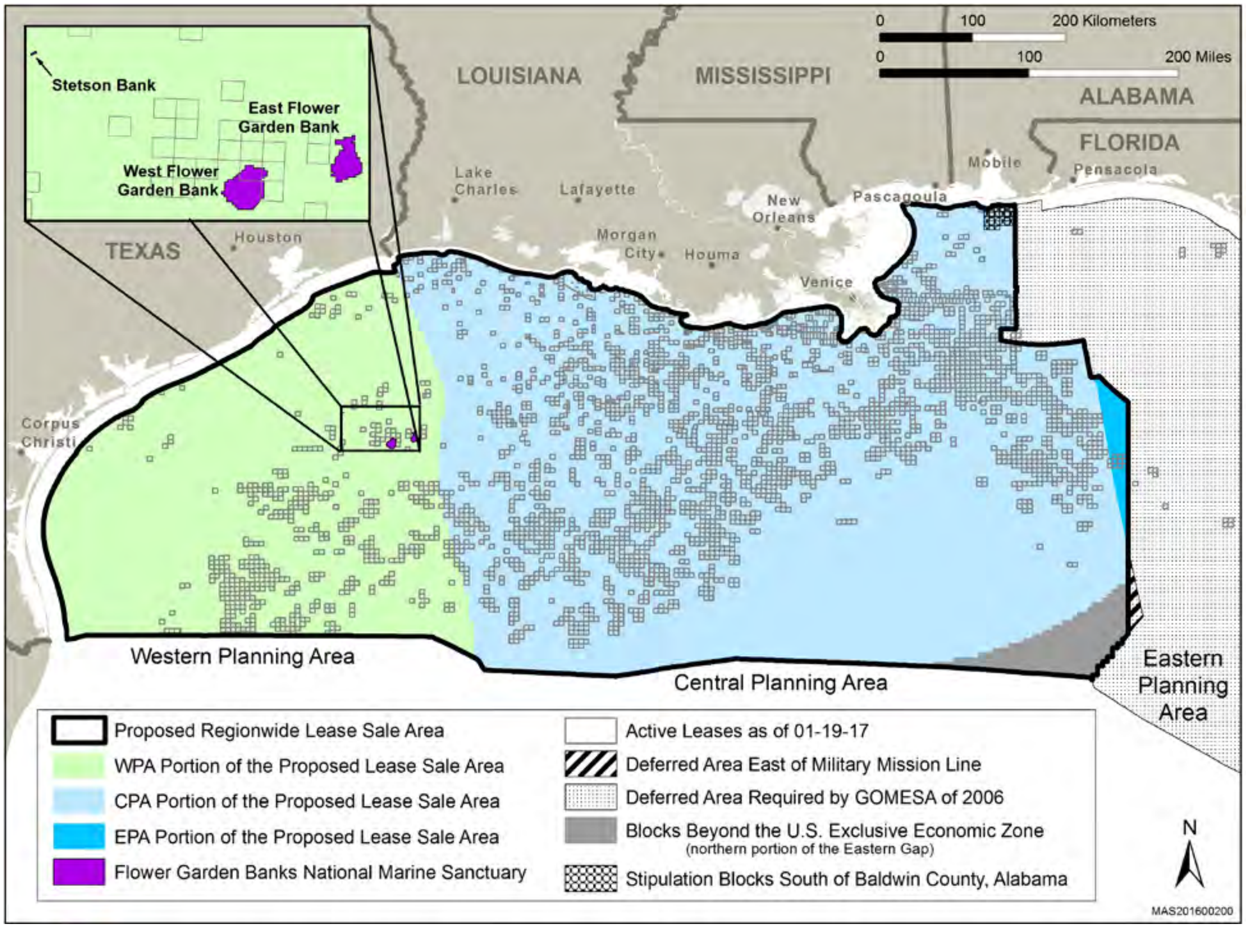

Figure 2-1. Proposed Regionwide Lease Sale Area, Encompassing the Available Unleased Blocks within All Three Planning Areas (a total of approximately 91.93 million acres with approximately 75.4 million acres available for lease as of January 2017).

The WPA begins 3 marine leagues (9 nautical miles [nmi]; 10.36 miles [mi]; 16.67 kilometers [km]) offshore Texas and extends seaward to the limits of the United States' jurisdiction over the continental shelf (often referred to as the Exclusive Economic Zone) in water depths up to approximately 3,346 m (m) (10,978 feet [ft]). The proposed WPA portion of the lease sale area encompasses about 28.58 million ac. As of January 2017, approximately 25.8 million ac of the proposed WPA lease sale area are currently unleased.

The CPA begins 3 nmi (3.5 mi; 5.6 km) offshore Louisiana, Mississippi, and Alabama, and extends seaward to the limits of the United States' jurisdiction over the continental shelf (often referred to as the Exclusive Economic Zone) in water depths up to approximately 3,346 m (10,978 ft). The proposed CPA portion of the lease sale area encompasses about 63 million ac of the total CPA area of 66.45 million ac. As of January 2017, approximately 49.0 million ac of the proposed CPA lease sale area are currently unleased.

The proposed EPA portion of the lease sale area covers approximately 657,905 ac and includes those blocks previously included in the EPA Lease Sales 225 and 226 areas, which is bordered by the CPA boundary on the west and the Military Mission Line (86º41' W. longitude) on the east. The portion of the EPA available for leasing is south of eastern Alabama and western Florida; the nearest point of land is 125 mi (201 km) northwest in Louisiana. As of January 2017, approximately 606,995 ac of the proposed EPA lease sale area are currently unleased.

In general, a regionwide lease sale, which would include all available unleased blocks in all three planning areas, would represent 1.2-4.2 percent of the total OCS Program production in the GOM based on barrels of oil equivalent resource estimates. The estimated amounts of resources projected to be leased, discovered, developed, and produced as a result of a typical proposed regionwide lease sale are 0.211-1.118 billion barrels of oil (BBO) and 0.547-4.424 trillion cubic feet (Tcf) of gas (refer to **Table 3-1**). A regionwide lease sale would offer approximately 91.93 million ac, with approximately 75.4 million ac available for lease as of January 2017. Leasing information related to all three planning areas is updated monthly and can be found on BOEM's website at http://www.boem.gov/Gulf-of-Mexico-Region-Lease-Map/.

2.2.2.2 Alternative B—Regionwide OCS Lease Sale Excluding Available Unleased Blocks in the WPA Portion of the Proposed Lease Sale Area

*A*lternative B would allow for a proposed lease sale encompassing the CPA and EPA within the U.S. portion of the Gulf of Mexico OCS (**Figure 2-2**). Available blocks within the WPA would ***not*** be considered under this alternative. This alternative would offer for lease all available unleased blocks within the CPA and EPA portions of the proposed lease sale area as those planning area portions are described in Alternative A for oil and gas operations, with the following exceptions:

(1) whole and portions of blocks deferred by the Gulf of Mexico Energy Security Act of 2006 (discussed in the *OCS Regulatory Framework* white paper [Cameron and Matthews, 2016]); and

(2) blocks that are adjacent to or beyond the United States' Exclusive Economic Zone in the area known as the northern portion of the Eastern Gap.

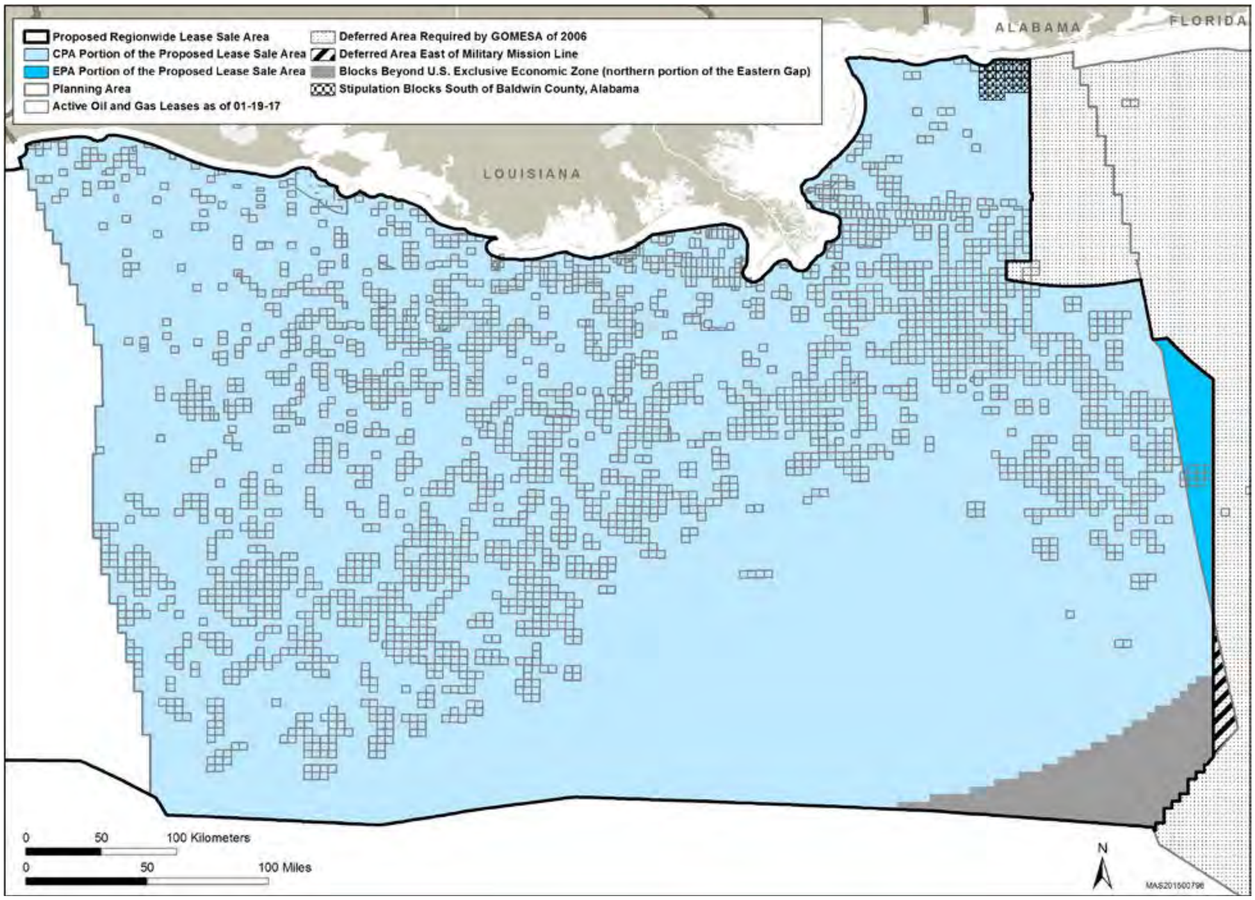

Figure 2-2. Proposed Lease Sale Area for Alternative B, Excluding the Available Unleased Blocks in the WPA (approximately 63.35 million acres with approximately 49.6 million acres available for lease as of January 2017).

In general, a lease sale that would include all available unleased blocks in the CPA and EPA would represent approximately 1.0-3.6 percent of the total OCS Program production in the GOM based on barrels of oil equivalent resource estimates. The estimated amounts of resources projected to be leased, discovered, developed, and produced as a result of a proposed lease sale under Alternative B are 0.185-0.970 BBO and 0.44-3.672 Tcf of gas (refer to **Table 3-1**).

2.2.2.3 Alternative C—Regionwide OCS Lease Sale Excluding Available Unleased Blocks in the CPA/EPA Portions of the Proposed Lease Sale Area

Alternative C would allow for a proposed lease sale encompassing the WPA within the U.S. portion of the Gulf of Mexico OCS (**Figure 2-3**). Available blocks within the CPA and EPA would ***not*** be considered under this alternative. This alternative would offer for lease all available unleased blocks within the WPA portion of the proposed lease sale area for oil and gas operations, with the following exception:

(1) whole and partial blocks within the current boundary of the Flower Garden Banks National Marine Sanctuary.

The proposed Alternative C lease sale area encompasses virtually all of the WPA's approximately 28.58 million ac as that planning area is described as a subset of Alternative A. In general, a lease sale that would include all available unleased blocks in the WPA would represent approximately 0.2-0.6 percent of the total OCS Program production in the GOM based on barrels of oil equivalent resource estimates. The estimated amounts of resources projected to be leased, discovered, developed, and produced as a result of a proposed lease sale offering only WPA available unleased blocks are 0.026-0.148 BBO and 0.106-0.752 Tcf of gas (refer to **Table 3-1**).

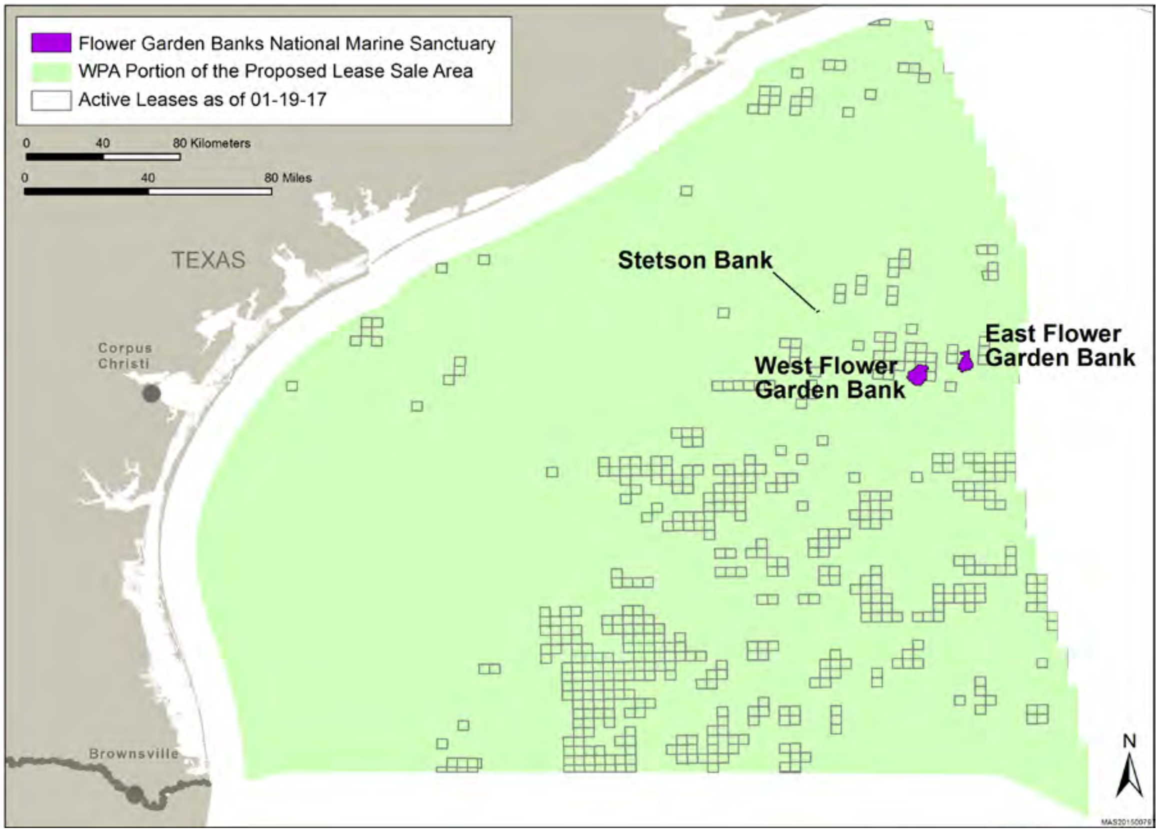

Figure 2-3. Proposed Lease Sale Area for Alternative C, Excluding the Available Unleased Blocks in the CPA and EPA (approximately 28.58 million acres with approximately 25.8 million acres available for lease as of January 2017).

2.2.2.4 Alternative D—Alternative A, B, or C, with the Option to Exclude Available Unleased Blocks Subject to the Topographic Features, Live Bottom (Pinnacle Trend), and/or Blocks South of Baldwin County, Alabama, Stipulations

Alternative D could be combined with any of the Action alternatives above (i.e., Alternatives A, B, or C) and would allow the flexibility to offer leases under any alternative with additional exclusions. Under Alternative D, the decisionmaker could exclude from leasing any available unleased blocks subject to any one and/or a combination of the following stipulations:

- Topographic Features Stipulation;
- Live Bottom (Pinnacle Trend) Stipulation; and

– Blocks South of Baldwin County, Alabama, Stipulation (not applicable to Alternative C).

This alternative considered blocks subject to these stipulations because these areas have been emphasized in scoping, can be geographically defined, and adequate information exists regarding their ecological importance and sensitivity to OCS oil- and gas-related activities.

A total of 207 blocks within the CPA and 160 blocks in the WPA are affected by the Topographic Features Stipulation (**Figure 2-4**). There are currently no identified topographic features protected under this stipulation in the EPA. The Live Bottom Stipulation covers the pinnacle trend area of the CPA, affecting a total of 74 blocks (**Figure 2-4**). More details on the blocks affected by the Topographic Features Stipulation and the Pinnacle Trend blocks subject to the Live Bottom Stipulation can be found at http://www.boem.gov/Biologically-Sensitive-Areas-List/. Maps indicating the areas affected by the Topographic Features Stipulation can be found at http://www.boem.gov/Topographic-Features-Stipulation-Map-Package/.

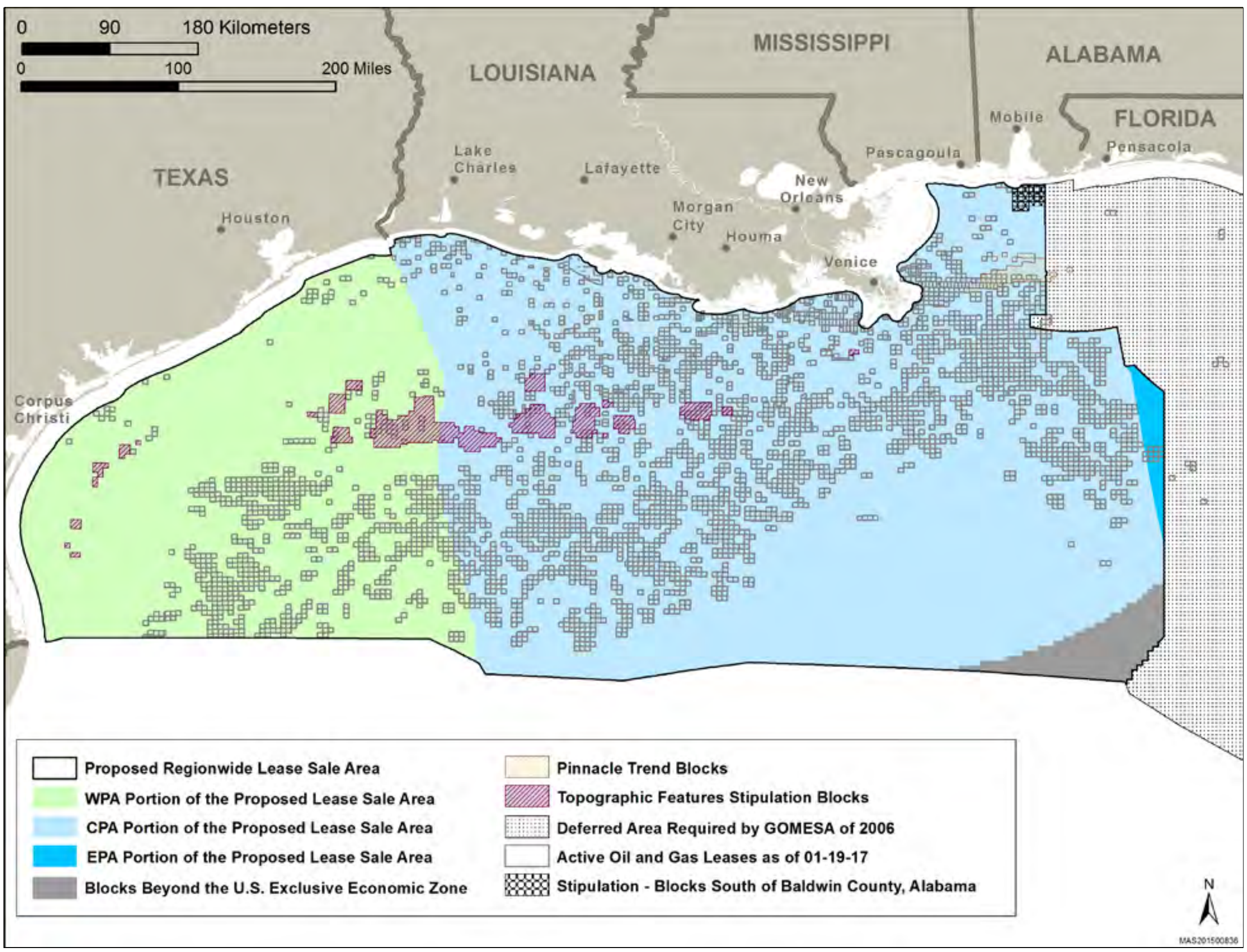

Figure 2-4. Identified Topographic Features, Pinnacle Trend, and Blocks South of Baldwin County, Alabama, Stipulation Blocks in the Gulf of Mexico.

Figure 2-5 illustrates one example of the blocks that would be excluded under this alternative (shaded in blue). For this example, under Alternative D, there would be 15 blocks eliminated from the proposed lease sale area. Any production that could potentially result from these blocks would not be realized. Should the decisionmaker decide instead to adopt Alternatives A, B, or C, which apply the Topographic Features Stipulation, the 15 blocks (that would have been eliminated from potential exploration and development under Alternative D) would still be made available but with mitigations applied to avoid or minimize impacts to the features.

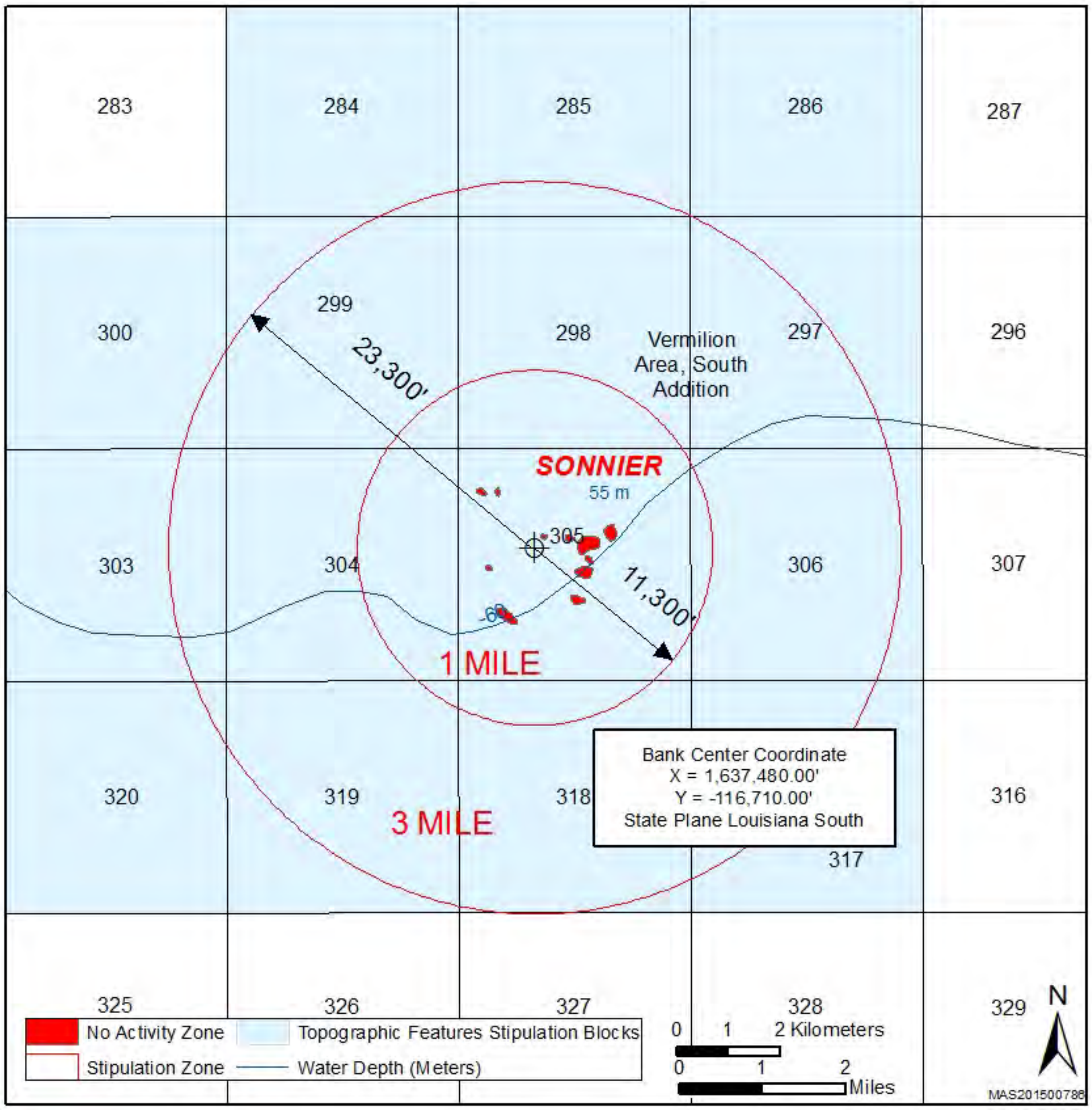

Figure 2-5. Example of Excluded Blocks under Alternative D.

As of the publication of this Multisale EIS, the Blocks South of Baldwin County, Alabama, Stipulation (herein referred to as the Baldwin County Stipulation Blocks) applies to a total of 32 blocks (Mobile 826-830, 869-874, 913-918, 957-962, 1001-1006, and Viosca Knoll 33-35) within 15-mi (24 km) of Baldwin County, Alabama (representing less than 1% of the total number of blocks to be offered under Alternative A or B). The intent of a proposal excluding these blocks would be to mitigate the visual impacts of concern raised by the Governor of Alabama on previous EISs, as well as on the 2017-2022 Five-Year Program from which this Multisale EIS tiers. The stipulation, however, has been continually adopted in annual CPA lease sales since 1999 and has effectively mitigated visual impacts. The stipulation specifies requirements for consultation that lessees must follow when developing plans for fixed structures (refer to **Appendix D**) while still allowing leasing and OCS oil- and gas-related operations in the area, which could not occur with the no-leasing buffer. If any of the action alternatives are selected, BOEM expects this stipulation to be analyzed and decided on during each individual lease sale stage in the Five-Year Program; therefore, no visual impacts would be expected to occur should the stipulation be applied.

Alternative D, if adopted, would prevent any OCS oil- and gas-related activity whatsoever in the affected blocks; thus, it would eliminate any potential direct impacts to the biota of those blocks from OCS oil- and gas-related activities, which otherwise could be conducted within the blocks. Under Alternative D, the number of blocks that would become unavailable for lease represents only a small percentage of the total number of blocks to be offered under Alternative A, B, or C (<4%, even if blocks subject to all three stipulations were excluded). Therefore, Alternative D could reduce offshore infrastructure and activities, but Alternative D may (and BOEM believes more reasonable to expect) only shift the location of offshore infrastructure and activities farther from these sensitive zones and not lead to a reduction in overall offshore infrastructure and activities. The regional impact levels for all resources, except for the topographic features and live bottoms, would be similar to those described under Alternative A, B, or C. All of the assumptions (including the other potential mitigating measures) and estimates would remain the same as described for Alternatives A, B, C. The exclusion of this small subset of available unleased blocks could reduce exploration, development, and production flexibility and, therefore, could result in adverse economic effects (e.g., reduced royalties). A detailed discussion of the development scenario and major related impact-producing factors is included in **Chapter 3**. A proposed lease sale includes proposed lease stipulations designed to reduce environmental risks; these stipulations are discussed in **Chapter 2.2.4.1**.

2.2.2.5 Alternative E—No Action

Alternative E is the cancellation of a single proposed lease sale. The opportunity for development of the estimated oil and gas that could have resulted from a proposed action (i.e., a single proposed lease sale) or alternative to the proposed action, as described above, would be precluded or postponed to a future lease sale. Any potential environmental impacts resulting from a proposed lease sale would not occur. Activities related to previously issued leases and permits (as well as those that may be issued in the future under a separate decision) related to the OCS oil and gas program would continue. If a lease sale were to be cancelled, the resulting development of oil and gas would most likely be postponed to a future lease sale; therefore, the overall level of OCS oil- and gas-related activity would only be reduced by a small percentage, if any. Therefore, the cancellation of a proposed lease sale would not significantly change the environmental impacts of overall OCS oil- and gas-related activity. However, the cancellation of a proposed lease sale may result in direct economic impacts to the individual companies, and the revenues collected by the

Federal Government (and thus revenue disbursements to the States) could also be adversely affected. If future lease sales were to occur, the impacts from the cancellation of a single lease sale to individual companies and Federal revenues would likely be minor. The Five-Year Program discusses the impacts of cancelling all proposed GOM lease sales included in the Five-Year Program.

2.2.3 What Other Alternatives and Deferrals have BOEM Considered but Not Analyzed in Detail?

BOEM evaluated a range of alternatives to ensure that a reasonable range of alternatives have been considered in this Multisale EIS. Below are the alternatives that have been considered but eliminated from detailed study with a brief discussion of the reasons for eliminating them.

Previous Multisale Schedule

This alternative would maintain the approach taken in the 2012-2017 Five-Year Program, which consisted of 12 lease sales in total, including 5 annual lease sales beginning in 2017 in the WPA offering all available unleased blocks, 5 annual lease sales beginning in 2018 in the CPA offering all available unleased blocks, and 2 lease sales in the EPA in 2014 and 2016 offering all available unleased blocks. No CPA or EPA blocks that are subject to Congressional moratorium pursuant to GOMESA would be included for leasing consideration.

While lease sales in the GOM have historically been separate annual lease sales in the CPA and WPA and periodic lease sales in the EPA as appropriate, significant recent energy reforms in Mexico have the potential to meaningfully change how exploration and development decisions are made in the GOM. The Transboundary Agreement reached with Mexico (refer to **Chapter 2.2.4.1**) allows leaseholders on the U.S. side of the boundary and Pemex to explore and exploit a transboundary reservoir as a "unit," just as leaseholders are permitted to do on reservoirs on the U.S. side of the boundary. By scheduling lease sales offering all available unleased blocks in the GOM, BOEM is providing more frequent opportunities to bid on rejected, relinquished, or expired OCS lease blocks, as well as facilitating better planning to explore resources that may straddle the U.S.-Mexico boundary. Furthermore, any individual lease sale could be scaled back to conform more closely to the traditional separate planning area model should circumstances warrant.

This Multisale EIS considers Alternatives B and C, which were similar to the previous lease sale approach of having lease sales for each planning area. Alternative B is fundamentally equivalent to a CPA lease sale in the 2012-2017 Five-Year Program, differing in that the EPA would be combined with the CPA into a single proposed lease sale (similar to how the two EPA lease sales in the 2012-2017 Five-Year Program were held concurrently with CPA lease sales). Alternative C is fundamentally equivalent to a WPA lease sale in the 2012-2017 Five-Year Program. Because this alternative (i.e., the 2012-2017 Five-Year Program lease sale schedule) is a decision made at the programmatic level under the Five-Year Program, this alternative was not considered for further analysis.

Exclude Blocks Subject to the Flower Garden Banks National Marine Sanctuary Expansion

BOEM is aware of NOAA's proposal to expand the boundaries of the Flower Garden Banks National Marine Sanctuary (FGBNMS) and has considered analyzing a separate alternative that would exclude all blocks subject to that expansion from oil and gas leasing. The NOAA published a Draft EIS for the proposed expansion on June 7, 2016, and BOEM is a cooperating agency on that EIS. The NOAA's Draft EIS has five alternatives for expansion. In their preferred alternative (Alternative C), the sanctuary would expand to 383 square miles (mi^2) (992 square kilometers [km^2]) and would include 15 additional reefs and banks. This alternative includes a total of 18 nationally significant natural features within 11 discrete proposed boundary areas. Refer to **Chapter 1.7** for further discussion on NOAA's Flower Garden Banks National Marine Sanctuary Expansion EIS.

BOEM has existing protective measures in the Topographic Features Stipulation that currently protect topographic features from oil and gas activities, including some features outside of the current FGBNMS boundaries, which are proposed for inclusion in NOAA's new proposed expansion. In addition, BOEM protects topographic features and other surrounding habitats by conducting site-specific, case-by-case reviews of plans and permit applications in order to distance bottom-disturbing activities from sensitive habitat. Should NOAA decide in the future to expand the boundaries of the FGBNMS, the potential environmental effects from OCS oil- and gas-related activities would likely be further reduced from those impacts already considered. However, there could be adverse economic impacts by the removal of potential blocks of interest. Because of the protective measures already in place, as well as the flexibility to adjust the current set of alternatives to encompass any future FGBNMS expansion, BOEM believes that the effects of a potential expansion are appropriately accounted for within the existing alternatives in this Multisale EIS.

Additional Buffers

BOEM has considered a suite of alternatives that would implement additional buffer zones around potential areas of concern. Each of these is briefly discussed below, including the reasons why these additional buffer area alternatives have not been carried forward for full analysis.

- During scoping, the Save the Manatee Club requested an alternative that would impose a buffer around those blocks in the EPA that are subject to Congressional moratorium pursuant to GOMESA. The Save the Manatee Club noted that, even though leasing is not allowed in these areas of the EPA, previous experiences such as the *Deepwater Horizon* explosion, oil spill, and response demonstrate that these areas are still at risk to potential impacts. The GOMESA includes a moratorium on oil and gas leasing within 125 mi (201 km) of the Florida coastline in the EPA and in a portion of the CPA until 2022. For an analysis of a low-probability catastrophic spill, such as the *Deepwater Horizon* explosion and oil spill, refer to the *Catastrophic Spill Event Analysis* white paper (USDOI, BOEM, 2017). Such an event, however, is not considered reasonably foreseeable as a result of a proposed action. Additionally, the comments did not offer any well-defined buffer areas and/or reasoning to support such a buffer.

A key component to managing risk is to implement a rigorous regulatory regime to ensure that postlease drilling activities are conducted in a safe manner. It is at this stage that detailed information regarding a specific proposed action is available for review, including reservoir characteristics, infrastructure designs, and features to ensure safety and reduce environmental risk. BOEM has implemented a suite of regulatory changes following the *Deepwater Horizon* explosion, oil spill, and response. These are discussed in detail in **Chapter 3.2 and Appendix A**. For these reasons, BOEM concluded that an alternative including an additional buffer around the EPA was not warranted for detailed analysis.

- The National Park Service (NPS) requested an alternative that considered a no-leasing buffer within 15 mi (24 km) of the Gulf Islands National Seashore (GUIS). As noted in **Chapter 1.1**, the purpose of the proposed Federal actions is to offer for lease those areas that may contain economically recoverable oil and gas resources in accordance with the OCSLA (67 Stat. 462), as amended (43 U.S.C. §§ 1331 *et seq*.). Over time, using adaptive management practices, BOEM and its predecessors have proactively developed a suite of mitigating measures that are applied at the prelease or postlease phases of the oil and gas program to avoid and protect fixed biologically and culturally sensitive features, which includes the GUIS (Gulf Islands National Seashore Information to Lessees and Operators [ITL]). This ITL ensures that postlease plans submitted by lessees of whole and partial lease blocks within the first 12 mi (19 km) of Federal waters near the GUIS are reviewed by BOEM in order to minimize visual impacts from development operations on these blocks. The lease blocks that would be subject to the Gulf Islands National Seashore ITL are illustrated in **Figure 2-6**. This is consistent with NPS' proposed management strategy for maintaining optimal night sky viewing conditions, which include cooperating with partners to minimize intrusion of artificial light into the night scene in the national seashore and evaluating the impacts on the night sky caused by national seashore facilities (USDOI, NPS, 2011).

  Based on historical leasing patterns, the proposed actions would likely only minimally contribute to the existing disturbances from OCS and non-OCS sources. Numerous OCS structures and wells have existed within 15 mi (24 km) of the GUIS over the years, many of which have been removed. Some OCS platforms are visible on the horizon (**Figure 2-7**).

  Section 8(g) of the OCSLA, as amended, requires a "fair and equitable" distribution of revenues between the Federal Government and a coastal state for Federal lease blocks within 3 mi (5 km) of the seaward boundary of the State that may contain oil and gas reservoirs underlying both OCS and submerged State tidelands. Due to the location of the GUIS, the proposed buffer area includes blocks off the coasts of Louisiana, Mississippi, and Alabama, and could result in reduced revenue sharing for those States as a result of the alternative being chosen. Consultation with the Governor of each State is required at the time of soliciting nominations for the leasing of OCS lands wholly or partially within the 3 mi (5 km) mentioned above. The GOMESA enhances the revenue sharing provisions for the four Gulf oil- and gas-producing States of Alabama, Louisiana, Mississippi, and Texas, and their coastal political subdivisions, which are to be used for coastal conservation, restoration, and hurricane protection.

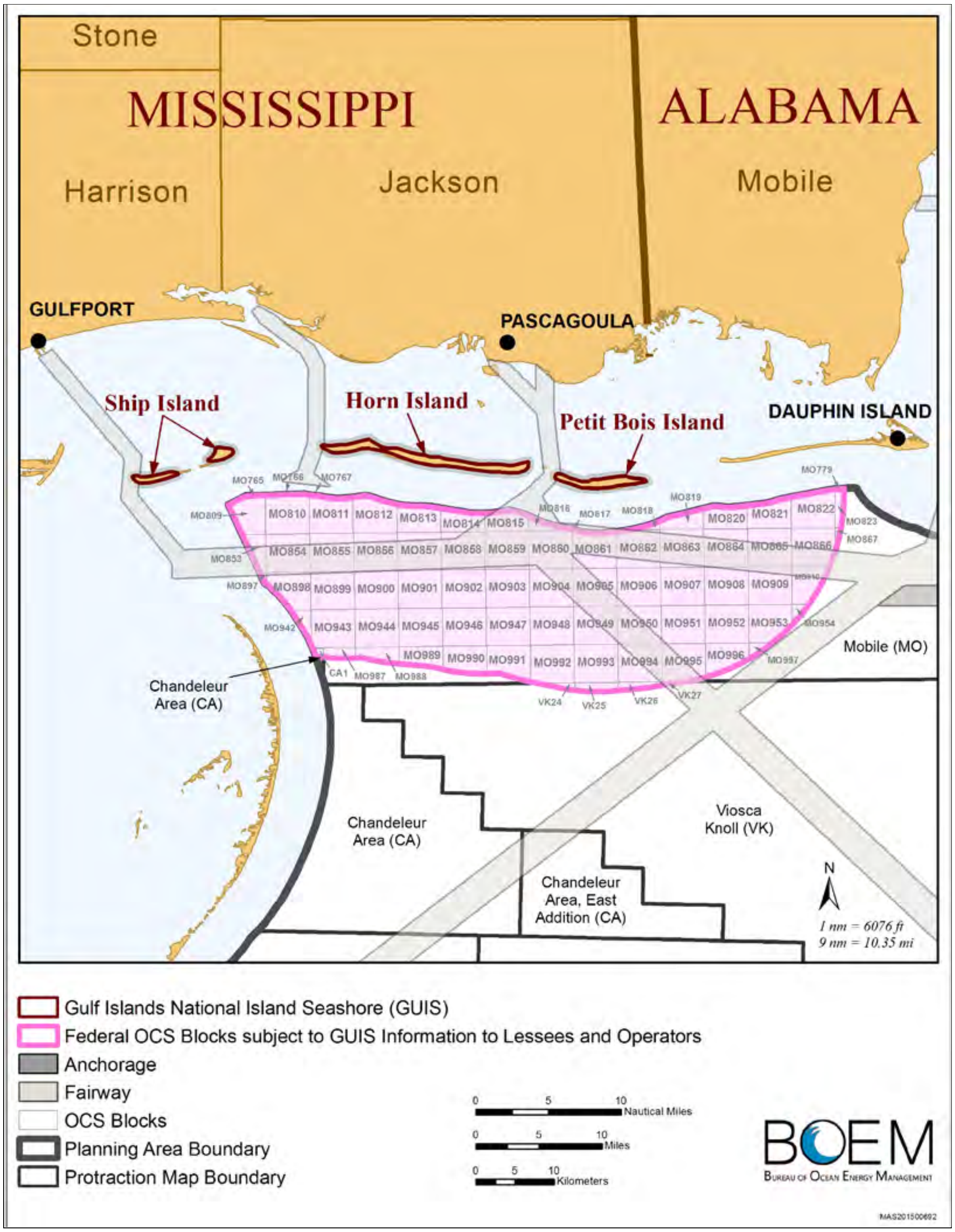

Figure 2-6. Federal OCS Blocks Subject to the Gulf Islands National Seashore's Information to Lessees and Operators.

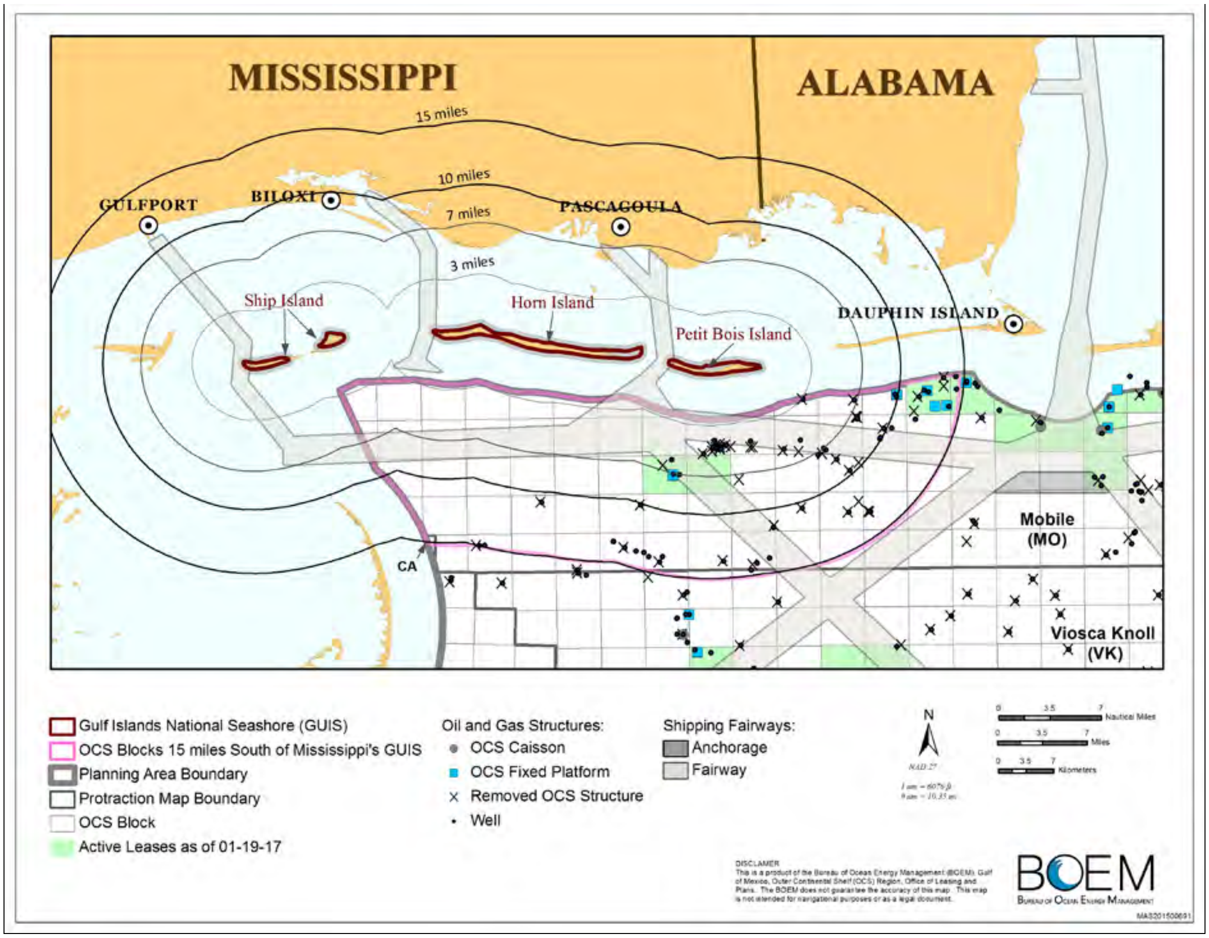

Figure 2-7. Historical Structure Locations near Horn and Petit Bois Islands.

> Even without the presence of oil and gas activities in State waters and on the Federal OCS, there is substantial vessel traffic in this area due to the presence of federally designated shipping safety fairways and anchorage areas to provide unobstructed approaches for vessels using U.S. ports (33 CFR part 166). These visual impacts would remain ongoing and unaffected by the proposed actions; therefore, altering a proposed action would not alleviate visual impacts to the GUIS. Because of the environmental protection measures already implemented by BOEM and BSEE through the established ITL for the subject area, this alternative was not analyzed in detail in this Multisale EIS.

To exclude the additional buffer areas proposed above from potential oil and gas exploration and development would not achieve the desired goal of reducing risk from OCS oil- and gas-related activities. The Gulf of Mexico OCS has a mature oil and gas program. Over time, using adaptive management practices, BOEM has proactively developed a suite of mitigating measures that are applied at the prelease or postlease phases of the oil and gas program. These measures serve to avoid and protect potential areas of concern, such as topographic features, pinnacles, live bottoms, chemosynthetic communities, deepwater corals, and historic shipwrecks (e.g., Topographic Features Stipulation, Live Bottom (Pinnacle Trend) Stipulation, NTL 2009-G39, NTL 2009-G40, and

NTL 2005-G07). Protective measures are also in place to mitigate potential impacts from seismic activities, marine debris, vessel traffic, structure-removal activities, and vessel traffic to mobile resources such as marine mammals and sea turtles (e.g., NTL 2016-G02, NTL 2012-G01, and NTL 2010-G05).

Lease Sale Offering Only EPA Available Unleased Blocks

This alternative would allow for a proposed lease sale encompassing the EPA within the U.S. portion of the Gulf of Mexico OCS. Available unleased blocks within the CPA and WPA would ***not*** be considered under this alternative. This alternative would offer for lease all available unleased blocks within the EPA portion of the proposed lease sale area for oil and gas operations with the exception of whole and portions of blocks deferred by the Gulf of Mexico Energy Security Act of 2006. During scoping, the Save the Manatee Club requested NEPA analysis of the EPA in a separate process. The Save the Manatee Club noted that the EPA has unique environmental and cultural resources, and has heretofore only been minimally impacted by drilling operations in the Gulf of Mexico. Any potential impacts to resources exclusive or more prevalent to the EPA (e.g., manatees and Gulf sturgeon) have been considered in the alternatives analyses.

The proposed EPA portion of the lease sale area covers approximately 657,905 ac and includes those blocks previously included in the EPA Lease Sales 225 and 226 areas, which is bordered by the CPA boundary on the west and the Military Mission Line (86º41′ W. longitude) on the east. The area is south of eastern Alabama and western Florida; the nearest point of land is 125 mi (201 km) northwest in Louisiana. As of March 2016 January 2017, approximately 606,995 ac (70%) and 175 lease blocks of the proposed EPA lease sale area are currently unleased.

Although the majority of the EPA is unavailable for leasing through June 30, 2022, under GOMESA, there are existing leases in the planning area. Thirteen lease sales have been held in this planning area as it has been configured over the years, and 105 wells have been drilled, with significant discoveries of natural gas. However, there has been no production from the wells in the planning area currently available for leasing. Lease Sale 224 in March 2008 resulted in leases being awarded on 36 OCS blocks with bonuses totaling $64.7 million in the small area available for leasing consideration. For the most recent lease sales held in the same small area (i.e., Lease Sales 225 and 226), no bids were received.

From a leasing perspective, it is less practical to conduct separate lease sales for the EPA due to its size (i.e., the number of blocks available for lease) and considering the leasing history in this area. Although recent leasing in the EPA has been minimal, providing these blocks more frequently through a regionwide approach would more effectively balance Bureau workload and provide greater flexibility to industry, including the ability to respond to the significant recent energy reforms in Mexico that have the potential to meaningfully change how exploration and development decisions are made in the GOM.

Regionwide OCS Lease Sale with Additional Mitigating Measures for Sperm Whale High-Use Areas

Sperm whales, protected under the ESA, often concentrate in the deepwater area offshore the Mississippi River delta, especially in the vicinity of the Mississippi Canyon area and adjacent continental slope (Davis and Fargion, 1996). Some commenters have requested special consideration of the Mississippi Canyon area to protect potentially important sperm whale habitat and have suggested that a ban on new leasing in the Mississippi Canyon area would help protect sperm whales from further disruption caused by new offshore oil- and gas-related activities. They also provided literature (Wise et al., 2014) regarding potential water quality effects to the Mississippi Canyon area following the *Deepwater Horizon* oil spill and how the persistence of oil and contaminants following the *Deepwater Horizon* oil spill might be affecting marine species in the Mississippi Canyon area.

Wise et al. (2014) found nickel and chromium in skin cells from sampled animals in the Mississippi Canyon and in adjacent areas; however, it is important to note that sperm whales in the GOM are using the entire GOM, not just the Mississippi Canyon area. There are substantially less OCS oil and gas structures in the Mississippi Canyon and De Soto Canyon areas compared with the entire Gulf of Mexico. Limiting leasing in such a relatively small area would not limit the exposure of sperm whales and Bryde's whales to chemicals because chemicals may still enter these areas via the Mississippi River. Various chemicals and heavy metals, including nickel and chromium, accumulate in soils near urban, industrial, and agricultural areas and are washed into the Mississippi River during heavy rainfall events (Mielke et al., 2000). Furthermore, high concentrations of trace metals (including nickel and chromium) have been observed in some core sediment samples that were taken in the central Gulf of Mexico at various depths across the shelf, slope, and abyssal plain and at least 3,000 m (9,843 ft) away from offshore platforms more than 7 years before the *Deepwater Horizon* oil spill (Wade et al., 2008). Wade et al. (2008) stated that the concentrations of trace metals from these particular samples were likely due to complex natural transport and biogeochemical processes and not to anthropogenic resources.

Although Wise et al. (2014) detected the presence of nickel and chromium in oil sampled during the *Deepwater Horizon* oil spill, it was stated that their data could not directly show that the nickel and chromium found in the whales they sampled were from the *Deepwater Horizon* oil spill and that other sources could be industry-related waste or boat paint from various marine vessels containing chromium as an antifouling agent. Some data suggest that sperm whale skin cells are more resistant to the cytotoxic and genotoxic effects of chromium than human skin cells and that sperm whale skin cells have evolved cellular mechanisms to protect them against the genotoxicity of environmental agents such as chromium (Chen et al., 2012).

Although it can be speculated that excluding the Mississippi Canyon area could result in less projected OCS oil- and gas-related activity, thus decreasing the likelihood of OCS oil- and gas-related activities impacting sperm whales, there are not enough conclusive data on their density and distribution in the GOM throughout the year to conclude that speculation. Therefore, because of sperm whale diversity and wide distribution throughout the GOM, the overall level of impacts would not be expected to change by excluding the Mississippi Canyon area from a proposed lease sale. BOEM believes that current long-term biological data do not support additional mitigating measures or exclusion of this area beyond the long-standing mitigation practices already in place to minimize impacts on this species. A full analysis of marine mammals, including sperm whales, can be found in **Chapter 4.9.1**.

Regionwide OCS Lease Sale Excluding Blocks within the De Soto Canyon Area

Some commenters have requested special consideration of the De Soto Canyon area to protect potentially important Bryde's whale habitat. Bryde's whales in the De Soto Canyon area are of particular concern considering that the available information suggests a very small and genetically distinct population within a limited range, making the population vulnerable to anthropogenic impacts. Large baleen whales are particularly vulnerable to vessel strikes because most are slow moving and may not be able to evade an oncoming vessel (Laist et al., 2001).

However, there is currently very limited oil- and gas-related activity in the De Soto Canyon area. Furthermore, BOEM and BSEE provide guidance on vessel strike avoidance measures and protected species reporting, marine trash and debris awareness and elimination, and seismic survey mitigating measures and Protected Species Observer Reports to all operators via NTLs. Adherence to these NTLs is expected to effectively reduce potential impacts to protected species without having to exclude these areas all together. Limiting leasing even further in the De Soto Canyon area would not limit other anthropogenic impacts, such as vessel strikes from marine transportation, to Bryde's whales. Additionally, biologically important areas for marine mammals in the GOM were identified based on both scientific information and expert elicitation and developed to inform regulatory and management decisions (Ferguson et al., 2015). The biologically important area identified in the GOM for Bryde's whale includes slope waters off the coast of Florida, primarily between 100 and 300 m (328 and 984 ft) deep (LaBrecque et al., 2016). For these reasons, this alternative was not carried through for detailed analysis. A full analysis of marine mammals can be found in **Chapter 4.9.1**.

Regionwide OCS Lease Sale Excluding Blocks within Loggerhead Sea Turtle Critical Habitat

Some commenters have requested special consideration of loggerhead sea turtle critical habitat (as designated by NMFS) to protect potentially important habitat for the Northwest Atlantic loggerhead sea turtle distinct population segment. **Chapter 4.9.2** analyzed loggerhead sea turtles, including a discussion of loggerhead sea turtles' critical habitat and threats. According to **Chapter 4.9.2.2.1**, the incremental contribution to cumulative impacts on sea turtles would be expected to be **negligible** as a result of a proposed action, and population-level impacts to sea turtles are not anticipated. The NMFS designated marine critical habitats in its Final Rule in July 2014. Within the GOM, the only NMFS-designated offshore marine critical habitat for Northwest Atlantic loggerhead sea turtle is *Sargassum*. A full analysis of *Sargassum* can be found in **Chapter 4.5**, where BOEM concluded **negligible** impacts to this habitat as a result of a proposed action.

As noted in NMFS' Final Rule, it is challenging to identify specific areas where these *Sargassum* concentrations are likely to form consistently, given its dynamic nature. Estimates suggest that between 0.6 and 6 million metric tons of *Sargassum* are present annually in the GOM, with an additional 100 million metric tons exported to the Atlantic basin (Gower and King, 2008 and 2011; Gower et al., 2013). Due to the expansive areal extent of loggerhead sea turtle critical habitat (i.e., *Sargassum*) in the GOM, excluding all such areas is effectively considered under the No Action Alternative. Furthermore, *Sargassum* has a yearly cycle that promotes quick recovery from impacts. Routine activities and accidental events would only impact a small portion of this habitat and be limited in size and scope as new plants rapidly replace the impacted plants, therefore, BOEM does not believe it is necessary to include an alternative excluding these areas.

Delay Leasing Until the State of the Gulf of Mexico Environmental Baseline is Known

This suggested alternative would address comments raised that the state of recovery of the Gulf of Mexico environmental baseline following the *Deepwater Horizon* explosion, oil spill, and response has not yet been fully determined and that BOEM should delay leasing until missing information is known, or at least for several years. The basis for this alternative is the concern that additional leasing could contribute to an incremental increase in the chance of another low-probability catastrophic oil spill or that cumulative impacts could have devastating environmental effects on an ecosystem that is still recovering from a previous event. It should be noted that, because of the dynamic nature of the Gulf of Mexico, the environmental baseline is not static and is constantly changing due to a variety of natural and anthropogenic factors. This would be true even if the *Deepwater Horizon* explosion, oil spill, and response had not occurred. This Multisale EIS has taken into account that there remains incomplete information and that an Agency will likely never have complete and perfect information available to it at the time of a decision. Throughout this Multisale EIS, BOEM has complied with the analytical requirements of 40 CFR § 1502.22 of the CEQ regulations, which allow an agency to evaluate the information that is available, disclose what information is incomplete or unavailable, and evaluate its relevance and importance to the underlying analysis. Thereafter, a Federal agency may proceed with a decision in light of the information that is available and applied using accepted methodologies. It should also be noted that this option of delaying leasing is already incorporated into the No Action Alternative that is analyzed in this Multisale EIS. At the time of the lease-sale decision, the Assistant Secretary for Land and Minerals Management can choose the No Action Alternative for any of the lease sales covered in this Multisale EIS. This would result in a delay of leasing, potentially until the next scheduled lease sale in the current Five-Year Program or beyond, where again the Assistant Secretary for Land and Minerals Management can choose the No Action Alternative.

In addition, credible scientific data regarding the potential short-term and long-term impacts of the *Deepwater Horizon* explosion, oil spill, and response on Gulf of Mexico resources has become available through issuance of the PDARP/PEIS, but there remains information being developed through the Natural Resource Damage Assessment (NRDA) process and other sources. New information would include evaluation of restoration techniques to see if adjustments would be needed and BOEM's Environmental Studies Program, as well as numerous studies by other Federal and State agencies and academia. Nonetheless, the subject-matter experts that prepared this Multisale EIS acquired and used new scientifically credible information that was publicly available, determined that additional information was not available absent exorbitant expenditures or could not be obtained regardless of cost in a timely manner, and where gaps remained, exercised their best professional judgment to extrapolate baseline conditions and impact analyses using accepted methodologies based on credible information. This approach complies with the requirements of 40 CFR § 1502.22 of the CEQ regulations regarding how agencies should address incomplete or unavailable information.

The references for **Chapters 1-5** are dominated by scientific research. In the vast majority of these references, the methods used to conduct the research are spelled out. These references are publicly available and the "scientific methodologies of research and modeling" would be too extensive to detail in an EIS. However, in numerous places in this Multisale EIS, where it was considered important, specific methodologies were summarized. For example, the use of *in-situ* fluorescence and oxygen measurements as proxies for oil concentration and biodegradation to track the subsurface plume of oil from the *Deepwater Horizon* explosion and oil spill was included in this Multisale EIS where appropriate.

In addition, BOEM's catastrophic analysis, the *Catastrophic Spill Event Analysis* white paper, provides more information about general impacts of a low-probability catastrophic oil spill (USDOI, BOEM, 2017). A low-probability catastrophic oil spill is not reasonably foreseeable and not part of a proposed action; however, it should be noted that the catastrophic analysis is intended to be a general overview of the potential effects of a catastrophic spill and to complement the substantive analyses of reasonably foreseeable smaller accidental events (noncatastrophic) presented in the main body of the EIS. As such, the *Catastrophic Spill Event Analysis* white paper should be read with the understanding that further detail about oil impacts from more reasonably foreseeable accidents on a particular resource can be found in the main body of this Multisale EIS or previous relevant NEPA documents. Given the above, BOEM has determined that this suggested alternative does not require additional analysis in this Multisale EIS, distinct and apart from the No Action Alternative already considered.

2.2.4 What Types of Mitigating Measures Does BOEM Apply?

The NEPA process is intended to help public officials make decisions that are based on an understanding of environmental consequences and to take actions that protect, restore, and enhance the environment. Agencies are required to identify and include in an EIS those appropriate mitigating measures not already included in the proposed action or alternatives. The CEQ regulations (40 CFR § 1508.20) define mitigation as follows:

Mitigating measures considered in this NEPA document rely primarily on avoiding an impact altogether by not allowing certain actions or parts of an action.

- Avoidance—Avoiding an impact altogether by not taking a certain action or part of an action.
- Minimization—Minimizing impacts by limiting the intensity or magnitude of the action and its implementation.
- Restoration—Rectifying the impact by repairing, rehabilitating, or restoring the affected environment.
- Maintenance—Reducing or eliminating the impact over time by preservation and maintenance operations during the life of the action.
- Compensation—Compensating for the impact by replacing or providing substitute resources or environments.

BOEM considers the use of mitigation at all phases of energy development and planning, from the overarching Five-Year Program EIS, through each of the NEPA documents for the lease sales, and followed by more site-specific reviews for exploration, development and production, and platform removal plans (**Figure 1-2**). Mitigations can be applied at the prelease stage, typically through applying lease stipulations or at the postlease stage by applying site-specific mitigating measures to plans, permits, and/or authorizations (refer to **Chapter 2.2.4.3**). Through this approach, BOEM is able to analyze impacts and mitigations that are appropriate for consideration at the appropriate time.

2.2.4.1 Proposed Lease Mitigating Measures (Stipulations)

The potential lease stipulations and mitigating measures included for analysis in this Multisale EIS were developed as a result of numerous scoping efforts for the continuing OCS Program in the Gulf of Mexico. The 10 lease stipulations described below would be considered at the prelease stage, as applicable, to any proposed lease sale. These measures will be considered for adoption by the ASLM under authority delegated by the Secretary of the Interior. The Topographic Features and Live Bottom (Pinnacle Trend) Stipulations have been adopted as programmatic mitigation in the 2017-2022 Five-Year Program EIS (USDOI, BOEM, 2016b) and, therefore, would apply to all leases issued under the 2017-2022 Five-Year Program in designated lease blocks. The analysis of the other eight stipulations for any particular alternative does not ensure that the ASLM will make a decision to apply the stipulations to leases that may result from any proposed lease sale nor does it preclude minor modifications in wording during subsequent steps in the prelease process if comments indicate changes are necessary or if conditions change. Any stipulations or mitigation requirements to be included in a proposed lease sale will be described in the Record of Decision for that proposed lease sale. **Appendix D** provides a more detailed analysis of the 10 lease stipulations and their effectiveness.

Topographic Features Stipulation

> *This stipulation has been adopted as programmatic mitigation in the 2017-2022 Five-Year Program EIS and would apply to all leases issued under the 2017-2022 Five-Year Program*

The topographic features located in the WPA and CPA provide habitat for coral-reef-community organisms (**Chapter 4.1.1.6**). There are currently no identified topographic features protected under this stipulation in the EPA. The OCS oil- and gas-related activities resulting from a proposed action could have potentially major impacts on or near these communities if the Topographic Features Stipulation is not adopted and such activities are not otherwise mitigated. The blocks affected by the Topographic Features Stipulation are shown in **Figure 2-4**.

The stipulation establishes No Activity Zones at the topographic features. Outside the No Activity Zones, additional restrictive zones are established where oil and gas operations could occur, but where drilling discharges would be shunted. Monitoring studies have demonstrated that the shunting requirements of the stipulations are effective in preventing the muds and cuttings from impacting the biota of the banks. The stipulation would prevent or minimize damage to the biota of the banks from routine OCS oil- and gas-related activities resulting from a proposed action, while allowing the development of nearby oil and gas resources, specifically as discussed in **Appendix D**.

Live Bottom (Pinnacle Trend) Stipulation

> *This stipulation has been adopted as programmatic mitigation in the 2017-2022 Five-Year Program EIS and would apply to all leases issued under the 2017-2022 Five-Year Program*

For the purpose of this stipulation, “live bottom areas” are defined as seagrass communities or those areas that contain biological assemblages consisting of sessile invertebrates such as sea fans, sea whips, hydroids, anemones, ascidians, sponges, bryozoans, or corals living upon and attached to naturally occurring hard or rocky formations with rough, broken, or smooth topography; or areas whose lithotope favors the accumulation of turtles, fishes, and other fauna. Live bottom features may include pinnacle trend features, low-relief features, or potentially sensitive biological features. This stipulation would be applied to protect pinnacle trend features (i.e., Live Bottom [Pinnacle Trend] Stipulation). The Live Bottom (Pinnacle Trend) Stipulation protects pinnacle trend features from routine OCS oil- and gas-related activity by distancing bottom-disturbing activity (e.g., anchors, chains, cables, and wire ropes) 30 m (100 ft) from hard bottoms/pinnacles. The Live Bottom (Pinnacle Trend) Stipulation is intended to protect live bottom features (Pinnacle Trend features) from damage and, at the same time, provide for the recovery of potential oil and gas resources. It is noted that blocks potentially subject to the Live Bottom (Low Relief) Stipulation are not included as part of the proposed action for this Multisale EIS; however, should any such blocks become available, the Live Bottom (Low Relief) Stipulation could be applied to protect these features.

Military Areas Stipulation

BOEM has effectively managed and avoided space-use conflicts with military activities in the Gulf of Mexico since the early 1970s.

The Military Areas Stipulation has been applied to all blocks leased in military areas since 1977 and reduces potential impacts, particularly in regards to safety, but it does not reduce or eliminate the actual physical presence of OCS oil- and gas-related operations in areas where military operations are conducted. The stipulation contains a "hold harmless" clause (holding the U.S. Government harmless in case of an accident involving military operations) and requires lessees to coordinate their activities with appropriate local military contacts. **Figure 2-8** shows the military warning areas in the Gulf of Mexico.

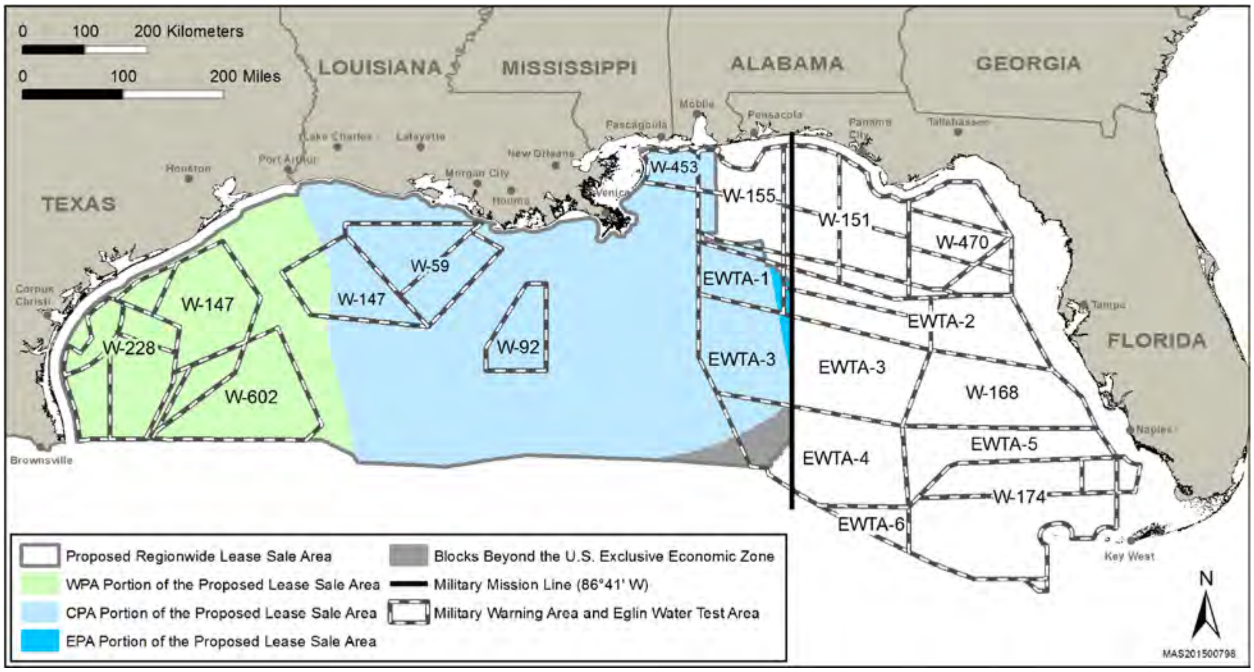

Figure 2-8. Military Warning Areas and Eglin Water Test Areas in the Gulf of Mexico.

Evacuation Stipulation

This stipulation would be a part of any lease in the easternmost portion of the CPA and all blocks leased in the EPA portion of the proposed lease sale area resulting from a proposed action. An evacuation stipulation has been applied to all blocks leased in these areas since 2001. The Evacuation Stipulation is designed to protect the lives and welfare of offshore oil and gas personnel. The OCS oil- and gas-related activities have the potential to occasionally interfere with specific requirements and operating parameters for the lessee's activities in accordance with the military stipulation clauses contained herein. If it is determined that the operations will result in interference with scheduled military missions in such a manner as to possibly jeopardize the national defense or to pose unacceptable risks to life and property, then a temporary suspension of operations and the evacuation of personnel may be necessary.

Coordination Stipulation

This stipulation would be a part of any lease in the easternmost portion of the CPA and all blocks leased in the EPA portion of the proposed lease sale area resulting from a proposed action. A coordination stipulation has been applied to all blocks leased in these areas since 2001. The Coordination Stipulation is designed to increase communication and cooperation between military authorities and offshore oil and gas operators. Specific requirements and operating parameters are established for the lessee's activities in accordance with the military stipulation clauses. For instance, if it is determined that the operations will result in interference with scheduled military missions in such a manner as to possibly jeopardize the national defense or to pose unacceptable risks to life and property, then certain measures become activated and the OCS oil- and gas-related operations may be curtailed in the interest of national defense.

Blocks South of Baldwin County, Alabama, Stipulation

This stipulation would be included only on leases on blocks south of and within 15 mi (24 km) of Baldwin County, Alabama. The stipulation specifies requirements for consultation that lessees must follow when developing plans for fixed structures, with the goal of reducing potential visual impacts The stipulation has been continually adopted in annual CPA lease sales since 1999 and has effectively mitigated visual impacts.

Protected Species Stipulation

The Protected Species Stipulation has been applied to all blocks leased in the GOM since December 2001. This stipulation was developed in consultation with the U.S. Department of Commerce, National Oceanic and Atmospheric Administration, NMFS and the U.S. Department of the Interior, FWS in accordance with Section 7 of the Endangered Species Act, and it is designed to minimize or avoid potential adverse impacts to federally protected species.

United Nations Convention on the Law of the Sea Royalty Payment Stipulation

Consistent with Article 82 of the 1982 United Nations Convention on the Law of the Sea (UNCLOS), there are 12 royalty payment lease provisions that would apply to applicable leases should the United States becomes a party to the UNCLOS. These provisions would apply prior to or during the life of any lease issued by the United States on a block or portion of a block located beyond its Exclusive Economic Zone as defined in UNCLOS and subject to such conditions that the Senate may impose through its constitutional role of advice and consent.

Below Seabed Operations Stipulation

The Below Seabed Operations Stipulation language is intended to be lease sale-specific language and would incorporate maps of the potentially affected blocks containing rights-of-use and easements. This stipulation is designed to minimize or avoid potential space-use conflicts with moored and/or floating production facilities that have already been granted rights-of-use and easements in particular OCS blocks.

Stipulation on the Agreement Between the United States of America and the United Mexican States Concerning Transboundary Hydrocarbon Reservoirs in the Gulf of Mexico (Transboundary Stipulation)

The "Agreement between the United States of America and the United Mexican States Concerning Transboundary Hydrocarbon Reservoirs in the Gulf of Mexico" (Agreement) was signed on February 20, 2012, and entered into force on July 18, 2014. The stipulation has been applied to blocks or portions of blocks located wholly or partially within the 3 statute miles (4.8 km) of the maritime or continental shelf boundary with Mexico. The stipulation incorporates by reference the Agreement and notifies lessees that, among other things, activities in this boundary area will be subject to the Agreement and that approval of plans, permits, and unitization agreements will be conditioned upon compliance with the terms of the Agreement. A copy of the Agreement can be found on BOEM's website at http://www.boem.gov/BOEM-Newsroom/Library/Boundaries-Mexico.aspx.

Summary

These measures would be considered for adoption by the ASLM at the prelease stage, as applicable, under authority delegated by the Secretary of the Interior. The analysis of any stipulations for any particular alternative does not ensure that the ASLM will make a decision to apply the stipulations to leases that may result from any proposed lease sale nor does it preclude minor modifications in wording during subsequent steps in the prelease process if comments indicate changes are necessary or if conditions change.

Any stipulations or mitigation requirements to be included in a lease sale will be described in the Record of Decision for that lease sale. Mitigating measures in the form of lease stipulations are added to the lease terms and are therefore enforceable as part of the lease. In addition, each exploration and development plan, as well as any permits and pipeline applications related to leases issued as a result of a lease sale, will undergo a NEPA review, and additional project-specific mitigations applied as conditions of plan or permit approval at the postlease stage. The BSEE has the authority to monitor and enforce these conditions under 30 CFR part 250 subpart N and may seek remedies and penalties from any operator that fails to comply with those conditions, stipulations, and mitigating measures.

2.2.4.2 Prelease Mitigating Measures (Stipulations) by Alternative

Table 2-1 indicates what stipulations could be applied for each alternative. Alternative D would consider the same stipulations as Alternative A, B, or C, as applicable, with the exception of removing the Topographic Features and Live Bottoms (Pinnacle Trend) Stipulations since all blocks subject to these stipulations would not be made available. Since Alternative E is the cancellation of a proposed lease sale, no stipulations would apply.

Table 2-1. Applicable Stipulations by Alternative. (Stipulations that would apply to specific lease blocks under any given alternative are marked with an X. Stipulations that would not apply are marked "–". Because Alternative E would cancel a proposed lease sale, no leasing activities would occur and, therefore, no stipulations would apply.)

Stipulation	Alternative A	Alternative B	Alternative C	Alternative D	Alternative E
Topographic Features	X	X	X	–	–
Live Bottoms	X	X	–	–	–
Military Areas	X	X	X	X	–
Evacuation	X	X	–	See A, B, or C	–
Coordination	X	X	–	See A, B, or C	–
Blocks South of Baldwin County, Alabama	X	X	–	See A, B, or C	–
Protected Species	X	X	X	X	–
United Nations Convention on the Law of the Sea Royalty Payment	X	X	X	X	–
Below Seabed Operations	X	X	–	See A, B, or C	–
Transboundary	X	X	X	X	–

2.2.4.3 Postlease Mitigating Measures

Mitigating measures are a standard part of BOEM's program to ensure that operations are always conducted in an environmentally sound manner.

Postlease mitigating measures have been implemented for over 40 years in the Gulf of Mexico region, as they relate to OCS plans and pipeline applications. Following a lease sale, an applicant seeks approvals to develop their lease by preparing and submitting OCS plans. The OCS plans are reviewed by BOEM and, depending on what is proposed to take place in a specific place, BOEM may assign conditions of approval on the plan. The conditions of approval become part of the approved postlease authorization and include environmental protections, requirements that maintain conformance with law, requirements of other agencies having jurisdiction, or safety precautions. Mitigating measures are an integral part of BOEM's program to ensure that postlease operations are conducted in an environmentally sound manner (with an emphasis on minimizing any adverse impact of routine operations on the environment). For example, certain measures ensure site clearance, and survey procedures are carried out to determine potential snags to commercial fishing and avoidance of archaeological sites and biologically sensitive areas such as pinnacles, topographic features, and chemosynthetic communities.

BOEM analyzes impacts on a finer geographic scale and mitigations that are appropriate for consideration through site-specific environmental reviews. This chapter discusses mitigating measures that could be applied by BOEM during site-specific plan and/or permit reviews. **Appendix A** discusses BOEM's rigorous postlease processes and **Appendix B** describes over 120 standard mitigations that may be required by BOEM or BSEE as a result of plan and permit review processes for the Gulf of Mexico OCS Region.

Mitigating measures have been proposed, identified, evaluated, or developed through previous BOEM lease sale and site-specific NEPA reviews and analyses. Many of these mitigating measures have been adopted and incorporated into regulations and/or as guidelines governing OCS exploration, development, and production activities. All plans for OCS oil- and gas-related activities (e.g., exploration and development plans, pipeline applications, and structure-removal applications) go through rigorous BOEM review and approval to ensure compliance with established laws and regulations. Existing mitigating measures must be incorporated and documented in plans submitted to BOEM. Operational compliance of the mitigating measures is enforced through BSEE's onsite inspection program.

Some BOEM-identified mitigating measures are incorporated into OCS oil- and gas-related operations through cooperative agreements or efforts with industry and State and Federal agencies. These mitigating measures include NMFS' Observer Program to protect marine mammals and sea turtles during explosive removals, labeling operational supplies to track possible sources of debris or equipment loss, development of methods of pipeline landfall to eliminate impacts to beaches or wetlands, and beach cleanup events.

Site-specific mitigating measures are also applied by BOEM during plan and permit reviews. BOEM realized that many of these site-specific mitigations were recurring and developed a list of commonly applied "standard" mitigations. There are currently over 120 standard mitigations. The wording of a standard mitigation is developed by BOEM in advance and may be applied whenever conditions warrant. Standard mitigation text is revised as often as is necessary (e.g., to reflect changes in regulatory citations, agency/personnel contact numbers, and internal policy). Categories of site-specific mitigations include the following: air quality; archaeological resources; artificial reef material; chemosynthetic communities; Flower Garden Banks; topographic features; hard bottoms/pinnacles/potentially sensitive biological features; military warning areas and Eglin Water Test Areas; hydrogen sulfide; drilling hazards; remotely operated vehicle surveys; geophysical survey reviews; and general safety concerns. Site-specific mitigation "types" include the following: advisories; conditions of approval; hazard survey reviews; inspection requirements; notifications; post-approval submittals; and safety precautions. In addition to standard mitigations, BOEM may also apply nonrecurring mitigating measures that are developed on a case-by-case basis. Refer to **Appendix B** ("Commonly Applied Mitigating Measures") for more information on the mitigations that BOEM and BSEE typically apply to plans and/or permits.

BOEM is continually revising applicable mitigations to allow the Gulf of Mexico OCS Region to more easily and routinely track mitigation compliance and effectiveness. A primary focus of this effort is requiring post-approval submittal of information within a specified timeframe or after a triggering event (e.g., end of operations reports for plans, construction reports for pipelines, and removal reports for structure removals).

2.2.5 What are the Primary Topics and Resources Being Evaluated?

Issues are defined by CEQ to represent those principal "effects" that an EIS should evaluate in-depth. Scoping identifies specific environmental resources and/or activities rather than "causes" as significant issues (CEQ, 1981). The analysis in the EIS can then show the degree of change from the present conditions for each issue to the actions related to a proposed action.

Selection of environmental and socioeconomic issues to be analyzed was based on the following criteria:

- issue is identified in CEQ regulations as subject to evaluation;
- the relevant resource/activity was identified through agency expertise, through the scoping process, or from comments on past EISs;
- the resource/activity may be vulnerable to one or more of the impact-producing factors associated with the OCS Program;
- a reasonable probability of an interaction between the resource/activity and impact-producing factor should exist; or
- information that indicates a need to evaluate the potential impacts to a resource/activity has become available.

2.2.5.1 Issues to be Analyzed

The following issues relate to potential impact-producing factors and the resources and activities that could be affected by OCS exploration, development, production, and transportation activities.

Accidental Events: Concerns were raised related to the potential impact of oil spills, including the *Deepwater Horizon* explosion, oil spill, and response, on the marine and coastal environments, specifically regarding the potential effects of oil spills on tourism, emergency response capabilities, spill prevention, effect of winds and currents on the transport of oil spills, accidental discharges from both deepwater losses of well control and pipeline ruptures, and oil spills resulting from past and future hurricanes. Other concerns raised over the years of scoping were the fate and behavior of oil spills, availability and adequacy of oil-spill containment and cleanup technologies, oil-spill cleanup strategies, impacts of various oil-spill cleanup methods, effects of weathering on oil spills, toxicological effects of fresh and weathered oil, air pollution associated with spilled oil, and short-term and long-term impacts of oil on wetlands.

After the *Deepwater Horizon* explosion, oil spill, and response, BOEM prepared a "Catastrophic Spill Event Analysis," which was previously included as an appendix to the 2012-2017

WPA/CPA Multisale EIS and the subsequent Supplemental EISs. This analysis has since been published as an independent white paper and can be found on BOEM's website (USDOI, BOEM, 2017). The purpose of this technical analysis is to assist BOEM in the preparation of robust environmental analyses of the proposed actions. The CEQ guidance addresses impacts with catastrophic consequences in the context of evaluating reasonably foreseeable significant adverse effects in an EIS when they address the issue of incomplete or unavailable information (40 CFR § 1502.22). "'Reasonably foreseeable' impacts include impacts which have catastrophic consequences even if their probability of occurrence is low, provided that the analysis of the impacts is supported by credible scientific evidence, is not based on pure conjecture, and is within the rule of reason" (40 CFR § 1502.22(b)(4)). Therefore, this analysis, which is based on credible scientific evidence, identifies the most likely and most significant impacts from a high-volume blowout and oil spill that continues for an extended period of time. Such a catastrophic event is not reasonably foreseeable and not part of a proposed action; but, in line with CEQ guidance (CEQ, 2010), the reasonably foreseeable impacts that could result in the exceedingly unlikely event that such a spill were to occur are analyzed in the *Catastrophic Spill Event Analysis* white paper (USDOI, BOEM, 2017). The scenario and impacts discussed in this analysis should not be confused with the scenario and impacts anticipated to result from routine activities or more reasonably foreseeable smaller accidental events of a proposed action.

Drilling Fluids and Cuttings: Specific concerns related to drilling fluids include impacts on water quality from the presence of mercury, synthetic-based drilling fluids (SBFs) and large volumes of industrial chemicals necessary for deepwater drilling operations, and potential for persistence of drilling muds and cuttings. Other concerns raised over the years of scoping were potential smothering of benthic communities by offshore disposal of drilling fluids and cuttings, the use and disposal of drilling fluids including potential spills of oil-based drilling fluids (OBFs), onshore disposal of OBFs, the fate and effects of SBFs in the marine environment, and the potential toxic effects or bioaccumulation of trace metals in drilling fluids discharged into the marine environment.

Visual and Aesthetic Interference: Lighting was raised as a specific concern. Concerns raised over the years of scoping were the potential effects of the presence of drilling rigs and platforms, service vessels, helicopters, trash and debris, and flaring on visual aesthetics.

Air Emissions: The potential effects of emissions of combustion gases from platforms, drill rigs, service vessels, and helicopters have been raised as an issue over the years of scoping. Also under consideration are the flaring of produced gases during extended well testing and the potential impacts of the transport of production with associated hydrogen sulfide (H_2S).

Water Quality Degradation: Issues related to water quality degradation raised over the years of scoping most often were associated with operational discharges of drilling muds and cuttings, produced waters, and domestic wastes. Water quality issues also included concerns related to impacts from sediment disturbance, petroleum spills and blowouts, and discharges from service vessels.

Other Wastes: Other concerns raised over the years of scoping include storage and disposal of trash and debris, and trash and debris on recreational beaches.

Structure and Pipeline Emplacement: Some of the issues raised over the years of scoping related to structure and pipeline emplacement are bottom area disturbances from bottom-founded structures or anchoring, sediment displacement related to pipeline burial, space-use conflicts, and the vulnerability of offshore pipelines to damage that could result in hydrocarbon spills or H_2S leaks.

Platform Removals: Concerns were raised over the years of scoping about the abandonment of operations include how a platform is removed, the potential impacts of explosive severance and removals on marine organisms, the remaining operational debris snagging fishing nets, and site-clearance procedures.

OCS Oil- and Gas-Related Support Services, Activities, and Infrastructure: Specific issues were damage to coastal infrastructure by past hurricane activity and the vulnerability of coastal infrastructure to damage from future hurricanes. Concerns raised over the years of scoping include activities related to the shore-based support of the development and production plan include vessel and helicopter traffic and emissions, construction or expansion of navigation channels or onshore infrastructure, maintenance and use of navigation channels and ports, and deepening of ports.

Sociocultural and Socioeconomic: Many concerns have focused on the potential impacts to coastal communities, including demands on public services and tourism. Issues raised from years of scoping include impacts on employment, population fluctuations, effects on land-use impacts to low-income or minority populations, and cultural impacts.

Geological and Geophysical Activities: Specific issues were noise impacts related to seismic airgun surveys on marine mammals, sea turtles, fisheries, and other resources. Other concerns include vessel strikes with marine mammals and sea turtles, as well as concerns regarding potential space-use conflicts.

Other Issues: Many other issues have been identified. Several of these issues are subsets or variations of the issues listed above. All are taken under advisement and are considered in the analyses, if appropriate. Additional issues raised during scoping are consideration of the extensive safety improvements implemented since the *Deepwater Horizon* explosion, oil spill, and response; noise from platforms, vessels, and helicopters; turbidity as a result of seafloor disturbance or discharges; and damage to biota and habitats.

Resource Topics Analyzed in This Multisale EIS: The analyses in **Chapters 4.1-4.5** address the issues and concerns identified above under the following resource topics:

- Air Quality
- Water Quality (Coastal and Offshore)
- Coastal Habitats (Estuarine Systems and Coastal Barrier Beaches and Associated Dunes)
- Deepwater Benthic Communities (Chemosynthetic and Deepwater Coral)
- *Sargassum* and Associated Communities
- Live Bottoms (Topographic Features, Pinnacles, and Low-Relief Features)
- Fishes and Invertebrate Resources
- Birds
- Protected Species (ESA Listed Marine Mammals, Sea Turtles, Beach Mice, Protected Birds, and Protected Corals)
- Commercial Fisheries
- Recreational Fishing
- Recreational Resources
- Archaeological Resources (Historic and Prehistoric)
- Human Resources and Land Use (Land Use and Coastal Infrastructure, Economic Factors, and Social Factors, Including Environmental Justice)

2.2.5.2 Issues Considered but Not Analyzed

As previously noted, the CEQ regulations for implementing NEPA instruct agencies to adopt an early process (termed "scoping") for determining the scope of issues to be addressed and for identifying significant issues related to a proposed action. As part of this scoping process, agencies shall identify and eliminate from detailed study the issues that are not significant to the proposed action or have been covered by prior environmental review.

Through our scoping efforts, numerous issues and topics were identified for consideration in this Multisale EIS. The following categories were considered not to be significant issues related to a proposed action or have been covered by prior environmental review.

Program and Policy Issues

Comments and concerns that relate to program and policy are issues under the direction of the U.S. Department of the Interior and/or BOEM's guiding regulations, statutes, and laws. The comments and concerns related to program and policy issues are not considered to be specifically related to the proposed actions. For example, the Louisiana Department of Natural Resources, Office of Coastal Management requested that this Multisale EIS make provisions for compensatory mitigation for all lease sale impacts. Such comments are forwarded to the appropriate program offices for their consideration. Programmatic issues including expansion of the proposed lease sale area, administrative boundaries, and royalty relief have been considered in the preparation of the Five-Year Program EIS (USDOI, BOEM, 2016b).

Revenue Sharing

A number of comments were received on previous EISs from State and local governments, interest groups, and the general public stating that locally affected communities should receive an increased share of revenues generated by the OCS oil and gas leasing program. In particular to the GOM, Louisiana reiterated continued concerns that Louisiana's coastal wetlands are disproportionately bearing the impacts from OCS oil- and gas-related activities and that BOEM should make provisions for appropriate compensatory mitigation related to OCS lease sale activities.

Comments and concerns that relate to the use and distribution of revenues are issues under the direction of the U.S. Congress or the Department of the Interior and their guiding regulations, statutes, and laws.

On October 1, 2010, the revenue collection function of the Minerals Management Service (BOEM's predecessor) became the independent Office of Natural Resource Revenue. The Office of Natural Resource Revenue distributes revenues collected from Federal mineral leases to special-purpose funds administered by Federal agencies, to States, and to the General Fund of the U.S. Department of the Treasury. Legislation and regulations provide formulas for the disbursement of these revenues. With the enactment of GOMESA, the Gulf producing States (i.e., Texas, Louisiana, Mississippi, and Alabama) and their coastal political subdivisions (CPSs) were granted an increased share of offshore oil and gas revenue. Beginning in FY 2007, and thereafter, Gulf producing States and their CPSs received 37.5 percent of the qualified OCS revenue from new leases, including bonus bids, rentals, and production royalty, issued in the 181 Area in the EPA and in the 181 South Area, which is located from 100 mi (161 km) offshore from the Alabama-Florida State line and over 285 mi (459 km) from Tampa, Florida. Beginning in FY 2017 and through 2055, GOM producing States and their CPSs will receive 37.5 percent and the Land and Water Conservation Fund will receive 12.5 percent of qualified OCS revenue from new leases in the existing areas available for leasing, subject to a $500 million cap. The remaining 50 percent of qualified OCS revenues and revenues exceeding the $500 million cap will be distributed to the U.S. Treasury.

The socioeconomic benefits and impacts to local communities are analyzed in **Chapter 4.1.1.23.3.**

2.3 COMPARISON OF IMPACTS BY ALTERNATIVE

The full analyses of the potential impacts of routine activities and accidental events associated with a proposed action and a proposed action's incremental contribution to the cumulative impacts are described in the individual resource discussions in **Chapter 4**. **Table 2-2** provides a comparison of expected impact levels by alternative and is derived from the analysis of each resource in **Chapter 4**. The impact level ratings have been specifically tailored and defined for each resource within the **Chapter 4** impact analysis. Cumulative impacts of current and past activities, however, would continue to occur under Alternative E.

Table 2-2. Alternative Comparison Matrix.

Impact Level Key[1]				
Beneficial[2]	Negligible	Minor	Moderate	Major

	Alternative				
Resource	A	B	C	D	E
Air Quality	Minor	Minor	Minor	Minor	None
Water Quality	Negligible	Negligible	Negligible	Negligible	None
Coastal Habitats					
Estuarine Systems	Moderate	Moderate	Minor	Moderate	Negligible
Coastal Barrier Beaches and Associated Dunes	Minor	Minor	Negligible to Minor	Negligible to Minor	Negligible
Deepwater Benthic Communities	Negligible	Negligible	Negligible	Negligible	None
Sargassum and Associated Communities	Negligible	Negligible	Negligible	Negligible	None
Live Bottoms					
Topographic Features	Negligible	Negligible	Negligible	Negligible	None
Pinnacles and Low-Relief Features	Negligible to Minor	Negligible to Minor	Negligible	Negligible	None
Fishes and Invertebrate Resources	Minor	Minor	Minor	Minor	None
Birds	Moderate	Moderate	Moderate	Moderate	None
Protected Species					
Marine Mammals	Negligible	Negligible	Negligible	Negligible	None
Sea Turtles	Negligible	Negligible	Negligible	Negligible	None
Beach Mice	Negligible	Negligible	Negligible	Negligible	None
Protected Birds	Negligible	Negligible	Negligible	Negligible	None
Protected Corals	Negligible	Negligible	Negligible	Negligible	None
Commercial Fisheries	Beneficial to Minor	Beneficial to Minor	Beneficial to Minor	Beneficial to Minor	Negligible
Recreational Fishing	Beneficial to Minor	Beneficial to Minor	Beneficial to Minor	Beneficial to Minor	Negligible
Recreational Resources	Beneficial to Minor	Beneficial to Minor	Beneficial to Minor	Beneficial to Minor	Negligible
Archaeological Resources	Negligible[3]	Negligible[3]	Negligible[3]	Negligible[3]	None

Impact Level Key[1]				
Beneficial[2]	Negligible	Minor	Moderate	Major

	Alternative				
Resource	A	B	C	D	E
Human Resources and Land Use					
Land Use and Coastal Infrastructure	Minor	Minor	Minor	Minor	None
Economic Factors	Beneficial to Minor	Beneficial to Minor	Beneficial to Minor	Beneficial to Minor	Negligible to Minor
Social Factors (including Environmental Justice)	Minor	Minor	Minor	Minor	None

Note: Some resources have a range for the impact levels to account for certain variables such as the uncertainty of non-OCS oil- or gas-related activities, the level and magnitude of potential accidental events, and the minimization of the OCS oil- or gas-related impacts through lease stipulations, mitigations, and/or regulations. The impact level ratings have been specifically tailored and defined for each resource within the **Chapter 4** impact analysis.

1 The findings for Alternatives A-D would be the incremental contribution of a proposed action to what would be expected to occur under the No Action Alternative (i.e., no lease sale). Therefore, each impact determination under Alternatives A-D assumes that the conditions and impacts (i.e., past, present, and future activities) under the No Action Alternative would be present.

2 The level of beneficial impacts is specified in the analysis, which could range from low, medium, or high.

3 The level of impacts for archaeological resources ranges between negligible to major and is dependent upon whether survey is performed, mitigation is imposed, mitigation is followed, or a site is identified prior to the activity.

2.4 Summary of Impacts

Presented here is an overall summary of impacts for each resource. A more detailed analysis of impacts for each resource from a proposed action is presented in **Chapter 4**.

2.4.1 Air Quality

Air quality is the degree at which the ambient air is free of pollution; it is assessed by measuring the pollutants in the air. To protect public health and welfare, the Clean Air Act established National Ambient Air Quality Standards (NAAQS) for certain common and widespread pollutants. The six common "criteria pollutants" are particle pollution (also known as particulate matter, $PM_{2.5}$ and PM_{10}), carbon monoxide (CO); nitrogen dioxide (NO_2); sulfur dioxide (SO_2); lead (Pb); and ozone (O_3). Air emissions from OCS oil and gas development in the Gulf of Mexico would arise from emission sources related to drilling and production with associated vessel support, flaring and venting, decommissioning, fugitive emissions, and oil spills. Associated activities that take place as a result of a proposed action support and maintain the OCS oil and gas platform sources. Air emissions from non-OCS oil- and gas-related emissions in the Gulf of Mexico would arise from emission sources related to State oil and gas programs, onshore industrial and transportation sources, and natural events. Since the primary National Ambient Air Quality Standards are designed to protect human health, BOEM focuses on the impact of these activities on the States, where there are permanent human populations.

In the "Air Quality Modeling in the Gulf of Mexico Region" study (**Appendices F-H**), photochemical grid modeling was conducted to assess the impacts to nearby states of existing and proposed future OCS oil and gas exploration, development, and production. This draft interim assessment is being used to disclose potential cumulative and incremental air quality impacts of the proposed lease sales; the final results are expected in fall 2017. The air quality modeling study examines the potential impacts of the proposed lease sales with respect to the NAAQS for the criteria pollutants O_3, NO_2, SO_2, CO, $PM_{2.5}$, PM_{10}; the air quality-related values (AQRVs), including visibility and acid deposition (sulfur and nitrogen) in nearby Class I and sensitive Class II areas; and the incremental impacts of Prevention of Significant Deterioration (PSD) pollutants (NO_2, PM_{10}, $PM_{2.5}$) with respect to PSD Class I and Class II increments. (*Note: This analysis does not constitute a regulatory PSD increment consumption analysis as would be required for major sources subject to the New Source Review program requirements of the Clean Air Act*). An assessment of the final study results will be discussed in future NEPA documents.

A regionwide lease sale has not previously been analyzed and historic trend data are limited. In the scenario in **Chapter 3.1**, the projected activities of a single regionwide lease sale is based on a range of historic observations and provides a reasonable expectation of oil and gas production anticipated from a single proposed lease sale. The projected activities of 10 proposed regionwide lease sales' mid-case scenario, which was used in the model, falls within the range of a single proposed lease sale. To understand how these results would apply to a single proposed lease sale, the level of projected activity was compared between the modeled highest year of the 10 proposed lease sales to a single proposed lease sale. This is conservative because the current price of oil equals the low range of the scenario. Using these assumptions, the potential impacts of a single proposed lease sale would be **minor**. More specifically, the potential impacts of a single proposed lease sale to the Breton Wilderness Area would be **moderate**, whereas the overall potential impacts of a single proposed lease sale would be **minor** for all other areas. However, since these potential impacts are conservative given the current prices of oil and gas, BOEM anticipates future modeling. A full analysis of air quality can be found in **Chapter 4.1**.

The incremental contribution of a proposed lease sale to the cumulative impacts would most likely have a minor effect on coastal nonattainment areas because most impacts on the affected resource could be avoided with proper mitigation. Portions of the Gulf Coast onshore areas have ozone levels that exceed the Federal air quality standard, but the incremental contribution from a proposed lease sale would be very small and would not on their own cause an exceedance.

As previously stated, BOEM contracted an air quality modeling study in the GOM region to assess the impacts of OCS oil- and gas-related development to nearby States, as required under the OCSLA. The data from forecasted emissions resulting from the 10 proposed lease sales was annualized using BOEM's Resource Evaluation's mid-case scenario. These results are presented in

Appendices F-H. The cumulative impacts from all 10 proposed lease sales would be **minor** to **moderate**. More specifically, the cumulative impacts of 10 proposed lease sales to the Breton Wilderness Area and Gulf Islands National Seashore would be **moderate**, whereas the overall cumulative impacts of 10 proposed lease sales would be **minor** to **moderate**.

The cumulative impacts, in addition to the past, present, and future activities, of 10 proposed lease sales would most likely have a **moderate** effect on coastal nonattainment areas for certain pollutants. Portions of the Gulf Coast onshore areas have ozone levels that exceed the Federal air quality standard, but the cumulative impacts from 10 proposed lease sales do not on their own cause an exceedance. A full analysis of air quality can be found in **Chapter 4.1**.

2.4.2 Water Quality

Water quality is a term used to describe the condition or environmental health of a waterbody or resource, reflecting its particular biological, chemical, and physical characteristics and the ability of the waterbody to maintain the ecosystems it supports and influences. It is an important measure for both ecological and human health. The impacts of OCS Program-related routine operational discharges (**Chapter 3.1.5.1**) on water quality are considered **negligible** (beyond 1,000 m [3,281 ft]) to **moderate** (within 1,000 m [3,281 ft]) of the source. The potential impacts from OCS Program-related oil spills on water quality are considered **moderate**, even with the implementation of mitigating measures. This is because activities to address oil spills may cause secondary impacts to water quality, such as the introduction of additional hydrocarbons into the dissolved phase through the use of dispersants and the sinking of hydrocarbon residuals from burning. The impacts from a proposed action are a small addition to the cumulative impacts on water quality when compared with inputs from hypoxia, potentially leaking shipwrecks, chemical weapon dumpsites, natural oil seeps, and natural turbidity. The incremental contribution of the routine activities and accidental events associated with a proposed action to the cumulative impacts on water quality is expected to be **negligible** for any of the action alternatives. For Alternative E, the cancellation of a proposed lease sale would result in no new activities associated with a proposed lease sale; therefore, the incremental impacts would be **none**. A full analysis of water quality can be found in **Chapter 4.2**.

2.4.3 Coastal Habitats

2.4.3.1 Estuarine Systems (Wetlands and Seagrasses/Submerged Vegetation)

The estuarine system is the transition zone between freshwater and marine environments. It can consist of many habitats, including wetlands and submerged vegetation. The impacts to these habitats from routine activities associated with a proposed action are expected to be **minor** to **moderate**. **Minor** impacts would be due to the projected low probability for any new pipeline landfalls (0-1 projected), the minimal contribution to the need for maintenance dredging, and the mitigating measures expected to be used to further reduce or avoid these impacts (e.g., the use of modern techniques such as directional drilling). However, impacts caused by vessel operations related to a proposed action over 50 years would be **moderate** considering the permanent loss of hundreds of acres of wetlands. Overall, impacts to estuarine habitats from oil spills associated with activities related to a proposed action would be expected to be **minor** because of the distance of most postlease activities from the coast, the expected weathering of spilled oil over that distance, the projected low probability of large spills near the coast, the resiliency of wetland vegetation, and the available cleanup techniques.

Cumulative impacts to estuarine habitats are caused by a variety of factors, including the OCS oil- and gas-related and non-OCS oil- and gas-related activities outlined in **Chapter 4.3.1** and human and natural impacts. Development pressures in the coastal regions of the GOM have been largely the result of tourism and residential beach-side development, and this trend is expected to continue. Storms will continue to impact the coastal habitats and have differing impacts. The incremental contribution of a proposed action to the cumulative impacts on estuarine habitats is expected to be **minor** to **moderate** depending on the selected alternative. For Alternative E, the cancellation of a proposed lease sale would result in no new activities associated with a proposed lease sale. There could, however, be some incremental increase in impacts caused by a compensatory increase in imported oil and gas to offset reduced OCS production, but it would likely be **negligible**. A full analysis of estuarine habitats can be found in **Chapter 4.3.1**.

2.4.3.2 Coastal Barrier Beaches and Associated Dunes

The coastal barrier beaches and associated dunes are those beaches and dunes that line the coast of the northern GOM, including both barrier islands and beaches on the mainland. The impacts to coastal barrier beaches and dunes from routine activities associated with a proposed action are expected to be **minor** due to the minimal number of projected onshore pipelines, the minimal contribution to vessel traffic and to the need for maintenance dredging, and the mitigating measures that would be used to further reduce or avoid these impacts. The greater threat from an oil spill to coastal beaches is from a coastal spill as a result of a nearshore vessel accident or pipeline rupture, and cleanup activities. Overall, impacts to coastal barrier beaches and dunes from oil spills associated with OCS oil- and gas-related activities related to a proposed action would be expected to be **minor** because of the distance of most of the resulting activities from the coast, expected weathering of spilled oil, projected low probability of large spills near the coast, and available cleanup techniques. Cumulative impacts to coastal barrier beaches and dunes are caused by a variety of factors, including the OCS oil- and gas-related and non-OCS oil- and gas-related activities outlined in **Chapter 4.3.2** and other human and natural impacts. Development pressures in the coastal regions of the GOM have been largely the result of tourism and residential beach-side development, and this trend is expected to continue. Efforts to stabilize the GOM shoreline can deprive natural restoration of the barrier beaches through sediment nourishment and sediment transport, which have adversely impacted coastal beach landscapes. Storms will continue to impact the coastal habitats and have differing impacts. The incremental contribution of a proposed action to the cumulative impacts on coastal barrier beaches and dunes is expected to be **minor**. Under Alternative E, the cancellation of a proposed lease sale, the resulting additional impacts to coastal barrier beaches and dunes would be **negligible**; however, cumulative impacts from all sources, including OCS and non-OCS sources, would be the same as Alternative A. A full analysis of coastal barrier beaches and associated dunes can be found in **Chapter 4.3.2**.

2.4.4 Deepwater Benthic Communities

BOEM defines "deepwater benthic communities" as including both chemosynthetic communities (chemosynthetic organisms plus seep-associated fauna) and deepwater coral communities (deepwater coral plus associated fauna). These communities are typically found in water depths of 984 ft (300 m) or deeper throughout the GOM. Deepwater benthic habitats are relatively rare compared with ubiquitous soft bottom habitats.

The OCS oil- and gas-related, impact-producing factors for deepwater benthic communities can be grouped into three main categories: (1) bottom-disturbing activities; (2) drilling-related sediment and waste discharges; and (3) noncatastrophic oil spills. These impact-producing factors have the potential to damage individual deepwater habitats and disrupt associated benthic communities if insufficiently distanced or otherwise mitigated. However, impacts from individual routine activities and accidental events are usually temporary, highly localized, and expected to impact only small numbers of organisms and substrates at a time. Moreover, use of the expected site-specific plan reviews/mitigations will distance activities from deepwater benthic communities, greatly diminishing the potential effects. Therefore, at the regional, population-level scope of this analysis and assuming adherence to all expected regulations and mitigations, the incremental contribution would be expected to be **negligible** for any of the action alternatives. Proposed OCS oil- and gas-related activities would also contribute incrementally to the overall OCS and non-OCS cumulative effects experienced by deepwater benthic communities and habitats. The OCS oil- and gas-related cumulative impacts to deepwater benthic communities are estimated to be **negligible** to **minor**. Under Alternative E, the potential for impacts would be **none** because new impacts to deepwater benthic communities related to a cancelled lease sale would be avoided entirely. A full analysis of deepwater benthic communities can be found in **Chapter 4.4**.

2.4.5 *Sargassum* and Associated Communities

Sargassum in the GOM is comprised of *S. natans* and *S. fluitans* (Lee and Moser, 1998; Stoner, 1983; Littler and Littler, 2000) and is characterized by a brushy, highly branched thallus with numerous leaf-like blades and berrylike pneumatocysts (Coston-Clements et al., 1991; Lee and Moser, 1998; Littler and Littler, 2000). The *Sargassum* cycle is expansive, encompassing most of the western Atlantic Ocean and the Gulf of Mexico with the growth, death, and decay of these plant and epiphytic communities, which may play a substantial role in the global carbon cycle (Gower and King, 2008). Several impacting factors can affect *Sargassum*, including vessel-related operations, oil and gas drilling discharges, operational discharges, accidental spills, non-OCS oil- and gas-related vessel activity, and coastal water quality. Routine vessel operations and accidental events that occur during drilling operations or vessel operations, and oiling due to an oil spill were the impact-producing factors that could be reasonably expected to impact *Sargassum* populations in the GOM. All of these impact-producing factors would result in the death or injury to the *Sargassum* plants or to the organisms that live within or around the plant matrix. However, the unique and transient characteristics of the life history of *Sargassum* and the globally widespread nature of the plants and animals that use the plant matrix buffer against impacts that could occur at any given location. Impacts to the overall population of the *Sargassum* community are therefore expected to be **negligible** from either routine activities or reasonably foreseeable accidental events for any of the action alternatives. The incremental impact of the proposed action on the population of *Sargassum* would be **negligible** when considered in the context of cumulative impacts to the population. Under Alternative E, a proposed lease sale would be cancelled and the potential for impacts from routine activities and accidental events would be **none**. Impacts from changing water quality would be much more influential on *Sargassum* than OCS development and would still occur without the presence of OCS oil- and gas-related activities. A full analysis of *Sargassum* and associated communities can be found in **Chapter 4.5**.

2.4.6 Live Bottoms

2.4.6.1 Topographic Features

Defined topographic features (**Chapter 4.6.1**) are a subset of GOM live bottom habitats that are large enough to have an especially important ecological role, with specific protections defined in the proposed Topographic Features Stipulation. Within the Gulf of Mexico, BOEM has identified 37 topographic features where some degree of protection from oil and gas development may be warranted based on geography and ecology. Of all the possible impact-producing factors, it was determined that bottom-disturbing activities associated with drilling, exploration, and vessel operations were the only impact-producing factors from routine activities that could be reasonably expected to substantially impact topographic features. The impact-producing factors resulting from accidental events include bottom-disturbing activities from drilling, exploration, and vessel operations as well as the release of sediments and toxins during drilling operations. Oil-spill response-related activities were also considered to be a source of potential impacts to topographic features.

Adherence to the Topographic Features Stipulation, which is analyzed in each action alternative and which is detailed in **Appendix D**, would assist in preventing most of the potential impacts on topographic feature communities by increasing the distance of OCS oil- and gas-related activities. Should this stipulation be applied to any future lease sale, as it has been historically, the impacts of a proposed action to topographic features from routine activities and accidental events would be **negligible**. The incremental contribution of a proposed action to the cumulative impacts on topographic features is also expected to be **negligible**, assuming adherence to the proposed Topographic Features Stipulation. Under Alternative E, the potential for new incremental impacts to topographic features from a cancelled lease sale would be **none** because they would be avoided entirely. Impacts ranging from **negligible** to **moderate** may still be expected from non-OCS oil- and gas-related activities depending on factors such as fishing and pollution; however, the incremental impact of the proposed activities should not result in an augmentation of the expected impacts. A full analysis of topographic features can be found in **Chapter 4.6.1**.

2.4.6.2 Pinnacles and Low-Relief Features

The Pinnacle Trend is an approximately 64 x 16 mi (103 x 26 km) high-relief area in water depths ranging from approximately 200 to 650 ft (60 to 200 m). It is in the northeastern portion of the CPA at the outer edge of the Mississippi-Alabama shelf between the Mississippi River and

De Soto Canyon (**Figures 2-4 and 4-18**). Outside of the Pinnacle Trend area, low-relief, live bottom epibenthic communities occur in isolated locations in shallow waters (<984 ft; 300 m) throughout the GOM wherever there exists suitable hard substrate and other physical conditions (e.g., depth, turbidity, etc.) allowing for community development. Hard bottom habitats occur throughout the GOM, but are relatively rare compared with ubiquitous soft bottoms.

The impact-producing factors for pinnacles and low-relief live bottom features can be grouped into three main categories: (1) bottom-disturbing activities; (2) drilling-related sediment and waste discharges; and (3) oil spills. These impact-producing factors have the potential to damage individual live bottom habitats and disrupt associated benthic communities if insufficiently distanced or otherwise mitigated. At the broad geographic and temporal scope of this analysis, and assuming adherence to all expected lease stipulations and typically applied regulations and mitigations, routine activities are expected to have largely localized and temporary effects. Although accidental events have the potential to cause severe damage to specific live bottom communities, the number of such events is expected to be very small. Therefore, at the regional, population-level scope of this analysis, the incremental contribution of impacts from reasonably foreseeable routine activities and accidental activities to the overall cumulative impacts is expected to be **negligible** to **minor**. Proposed OCS oil- and gas-related activities would also contribute incrementally to the overall OCS and non-OCS cumulative effects experienced by live bottom habitats. Under Alternative E, the potential for impacts to pinnacle and low-relief feature communities related to the cancelled lease sale would be **none** because new impacts would be avoided entirely. The OCS oil- and gas-related cumulative impacts to live bottom communities are estimated to be **negligible.** A full analysis of pinnacles and low-relief features can be found in **Chapter 4.6.2**.

2.4.7 Fish and Invertebrate Resources

The distribution of fishes and invertebrates varies widely and species may be associated with different habitats at various life stages, as discussed further in **Chapter 4.7**. The impact-producing factors affecting these resources are anthropogenic sound, bottom-disturbing activities, habitat modification, and accidental oil spills. The impacts from routine activities, excluding infrastructure emplacement, would be expected to be **negligible** or **minor** due to short-term localized effects. The installation of OCS oil- and gas-related infrastructure constitutes a long-term modification of the local habitat and is hypothesized to have resulted over the life of the program in **moderate** changes in the distribution of some species. Although this effect is not necessarily adverse and infrastructure is expected to be decommissioned and sites restored to natural habitat, the cumulative impact over the life of the OCS Program is spatiotemporally extensive. Accidental spills have been historically low-probability events and are typically small in size. The expected impact to fishes and invertebrate resources from accidental oil spills is **negligible**. Commercial and recreational fishing are expected to have the greatest direct effect on fishes and invertebrate resources, resulting in impact levels ranging from **negligible** for most species to potentially **moderate** for some targeted species (e.g., hogfish spp., gray triggerfish [*Balistes capriscus*], and greater amber jack [*Seriola dumerili*]). The analysis of routine activities and accidental events indicates that the incremental contribution to the overall cumulative impacts on fishes and invertebrate resources as a result of a single proposed lease sale would be **minor**. Under Alternative E, the expected impacts on fish and invertebrate resources would be **none**. A full analysis of fish and invertebrate resources can be found in **Chapter 4.7**.

2.4.8 Birds

The affected birds include both terrestrial songbirds and many groups of waterbirds. Routine impacts to coastal, marine, and migratory birds that were considered include routine discharges and wastes, noise, platform severance with explosives (barotrauma), geophysical surveys with airguns (barotrauma), platform presence and lighting, and pipeline landfalls. The impacts to birds from OCS oil-and gas-related routine activities are similar wherever they may occur in the GOM, and all are considered negligible to minor. Negligible to minor impacts would not affect a substantial number of birds. Any impacts would be acute and reversible. As used here, acute means *short-term,* as it does in the context of short-term toxicity exposure and tests. Further, no injury to or mortality of a small number of individuals or a small flock would occur. Accidental impacts to birds are caused by oil spills, spill cleanup activities, and emergency air emissions. Seabirds may not always experience the greatest impacts from a spill but may take longer for populations to recover because of their unique population ecology (demography). Some species of seabirds, such as gulls, have larger clutches (laughing gulls usually have 3 eggs per clutch except in the tropics) and may recover quite quickly. However, many species of seabirds can have a clutch size of just one egg, and they have relatively long life spans and often have delayed age at first breeding. Because of the latter case, impacts on seabirds from overall accidental events would be expected to be moderate. Impacts from overall accidental events on other waterbirds farther inshore would also be expected to be moderate because of the extensive overlap of their distributions with oiled inshore areas and shorelines expected from a large oil spill (≥1,000 bbl). Moderate impacts would affect a substantial abundance of birds.

The incremental contribution of a proposed action to the overall cumulative impacts is considered **moderate**, but only because of the potential impacts that could result from a large oil spill (≥1,000 bbl). This conclusion is based on the incremental contribution of a proposed action to the cumulative OCS oil- and gas-related and non-OCS oil- and gas-related impacts. Alternative E would offer no new lease blocks for exploration and development; therefore, incremental impacts to birds would be **none**. However, there would be continuing impacts associated with the existing oil and gas activities from previously permitted activities and previous lease sales. A full analysis of coastal and migratory birds can be found in **Chapter 4.8**.

2.4.9 Protected Species

2.4.9.1 Marine Mammals

The Gulf of Mexico marine mammal community is diverse and distributed throughout the GOM, with the greatest abundances and diversity of species inhabiting oceanic and OCS waters. The major potential impact-producing factors affecting marine mammals in the GOM as a result of cumulative past, present, and reasonably foreseeable OCS energy-related activities are decommissioning activities, operational discharges, G&G activities, noise, transportation, marine debris, and accidental oil-spill and spill-response activities. Accidental events involving large spills, particularly those continuing to flow fresh hydrocarbons into oceanic and/or outer shelf waters for extended periods (i.e., days, weeks, or months), pose an increased likelihood of impacting marine mammal populations inhabiting GOM waters. While accidental events have the potential to impact marine mammal species, the number of such events is expected to be very small.

Proposed OCS oil- and gas-related activities would also contribute incrementally to the overall OCS and non-OCS cumulative effects experienced by marine mammal populations. At the regional, population-level scope of this analysis, impacts from reasonably foreseeable routine activities and accidental events could be **negligible** to **moderate** for any of the action alternatives. However, the incremental contribution of a proposed action to the cumulative impacts to marine mammal populations, depending upon the affected species and their respective population estimate, even when taking into consideration the potential impacts of the *Deepwater Horizon* explosion, oil spill, and response; non-OCS oil- or gas-related factors; and the minimization of the OCS oil- or gas-related impacts through lease stipulations and regulations, would be expected to be **negligible**. Under Alternative E, the cancellation of a proposed lease sale, impacts on marine mammals within the Gulf of Mexico would be **none**. However, cumulative impacts would be unchanged from the conclusions reached for the other alternatives. A full analysis of marine mammals can be found in **Chapter 4.9.1**.

2.4.9.2 Sea Turtles

Five sea turtle species have been ESA-listed and are present throughout the northern GOM; however, only Kemp's ridley and loggerhead sea turtles commonly nest on beaches in the GOM. Because of expected mitigations (e.g., BOEM and BSEE proposed compliance with NTLs under the proposed Protected Species Stipulation and conditions of approval on postlease activities), routine activities (e.g., noise or transportation) and accidental events (e.g., oil spills) related to a proposed action are not expected to have long- term adverse effects on the size and productivity of any sea turtle species or populations in the northern GOM. Lethal effects could occur from chance collisions with OCS oil- and gas-related service vessels or ingestion of accidentally released plastic materials from OCS oil- and gas-related vessels and facilities. However, there have been no reports to date on such incidences. Most routine activities and accidental events as a result of a proposed action are therefore expected to have **negligible** to **moderate** impacts. For example, a minor impact might be a behavioral change in response to noise while a moderate impact might be a spill contacting an individual and causing injury or mortality.

Historically, intense harvesting of eggs, loss of suitable nesting beaches, and fishery-related mortality have led to the rapid decline of sea turtle populations. Anthropogenic actions continue to pose the greatest threat to sea turtles since their listing under the ESA, as well as different natural threats including climate change and natural disasters. The incremental contribution of a proposed action to the cumulative impacts to sea turtles would be expected to be **negligible** as a result of a proposed action. Population-level impacts are not anticipated. Under Alternative E, the cancellation of a proposed lease sale, impacts on sea turtles within the Gulf of Mexico would be **none**. However, cumulative impacts would be unchanged from the conclusions reached for the other alternatives. A full analysis of sea turtles can be found in **Chapter 4.9.2**.

2.4.9.3 Beach Mice

The four subspecies of beach mouse (*Peromyscus polionotus* ssp.) are small coastal rodents that are only found along beaches in parts of Alabama and northwest Florida, and they are federally listed as endangered. Beach mice rely on dune systems as favorable habitat for foraging and maintaining burrows. Due to the distance between beach mouse habitat and OCS oil- and gas-related activities, routine impacts are not likely to affect beach mouse habitat except under very limited situations. Pipeline emplacement or construction, for example, could cause temporary degradation of beach mouse habitat; however, these activities are not expected to occur in areas of designated critical habitat. Accidental oil spills and associated spill-response efforts are not likely to impact beach mice or their critical habitat because the species live above the intertidal zone where contact is less likely. Habitat loss from non-OCS oil- and gas-related activities (e.g., beachfront development) and predation have the greatest impacts to beach mice. Overall, the incremental contribution of impacts from reasonably foreseeable routine activities and accidental activities to the overall cumulative impacts on beach mice is expected to be **negligible**. Under Alternative E, the cancellation of a proposed lease sale, impacts on beach mice would be **none**. However, cumulative impacts would be unchanged from the conclusions reached for the other alternatives. A full analysis of beach mice can be found in **Chapter 4.9.3**.

2.4.9.4 Protected Birds

Protected birds are species or subspecies ESA-listed by FWS as threatened or endangered due to the decrease in their population sizes or loss of habitat; therefore, a proposed action could have a greater impact. BOEM is undergoing consultation with FWS to minimize the potential impacts to ESA-listed species. Impacts from routine activities, which include discharges and wastes affecting air and water quality, noise, and possibly artificial lighting, would be **negligible** to protected birds. The listed bird species considered are typically coastal birds and would not be exposed to much of the oil and gas activities. Waste discharges to air or water produced as a result of routine activities are regulated by the USEPA and BOEM and are subject to limits to reduce potential impacts; therefore, due to precautionary requirements and monitoring, the impacts to protected birds would be **negligible** for any of the action alternatives. The major impact-producing factors resulting from accidental events associated with a proposed action that may affect protected birds include accidental oil spills and response efforts and marine debris. In the case of an accidental oil spill, impacts would be **negligible** to **moderate** depending on the magnitude and spatiotemporal proximity of such an event. Major impacts could occur if a large oil spill occurred with direct contact to a protected bird species or if the habitat became contaminated resulting in mortality of a listed species. Marine debris produced by OCS oil- and gas-related activities as a result of accidental disposal into the water may affect protected birds by entanglement or ingestion. Due to the regulations prohibiting the intentional disposal of items, impacts would be expected to be **negligible**;

however, impacts may scale up to **moderate** if the accidental release of marine debris caused mortality of a listed bird.

Overall, BOEM would expect **negligible** to **moderate** impacts to protected birds considering routine activities, accidental events, and cumulative impacts. Due to the precautionary requirements and monitoring discussed above, the incremental impacts to protected birds would be **negligible** for any of the action alternatives (i.e., Alternatives A-D). Under Alternative E, the additional incremental impacts to ESA-protected birds or their habitats would be **none**. A full analysis of protected birds can be found in **Chapter 4.9.4**.

2.4.9.5 Protected Corals

Elkhorn, staghorn, boulder star, lobed star, and mountainous star corals are listed by NMFS as threatened due to the decrease in their population sizes; therefore, the relative impacts from a proposed action could be disproportionate to those experienced by other coral species. BOEM understands this and is undergoing consultation for these species to minimize the potential impacts. Though the listed species are given ESA status, they could be affected by the same types of impact-producing factors from a proposed action as other coral species that are not ESA listed. Assuming adherence to all expected lease stipulations and other postlease, protective restrictions and mitigations, the routine activities related to a proposed action are expected to have mostly localized and temporary effects because the site-specific survey information and distancing requirements described in NTL 2009-G39 will allow BOEM to identify and protect live bottom features (where protected corals may be found) from harm by proposed OCS oil- and gas-related activities during postlease reviews. While accidental events have the potential to cause severe damage to specific coral communities, the number of such events is expected to be small. Further, many of the protected corals occur in the Flower Garden Banks National Marine Sanctuary, which, under the current boundaries, is not proposed for future leasing under any of the alternatives in this Multisale EIS. Therefore, the incremental contribution of activities resulting from a proposed action to the overall cumulative impacts to protected corals is expected to be **negligible** for any of the action alternatives. Proposed OCS oil- and gas-related activities would contribute incrementally to the overall OCS and non-OCS cumulative impacts experienced by corals. Under Alternative E, the cancellation of a proposed lease sale, impacts on protected corals would be **none**. However, cumulative impacts would be unchanged from the conclusions reached for the other alternatives. A full analysis of protected corals can be found in **Chapter 4.9.5**.

2.4.10 Commercial Fisheries

A proposed action could affect commercial fisheries by affecting fish populations or by affecting the socioeconomic aspects of commercial fishing. The impacts of a proposed action on fish populations are presented in **Chapter 4.7**. Routine activities such as seismic surveys, drilling activities, and service-vessel traffic can cause space-use conflicts with fishermen. Structure emplacement could have positive or negative impacts, depending on the location and species. For example, structure emplacement prevents trawling in the associated area and, thus, could impact the shrimp fishery. On the other hand, production platforms can facilitate fishing for reef fish such as red snapper and groupers. Accidental events, such as oil spills, could cause fishing closures and have other impacts on the supply and demand for seafood. However, accidental events that could arise from a proposed action would likely be small and localized. A proposed action would be relatively small when compared with the overall OCS Program, State oil and gas activities, overall vessel traffic, hurricanes, economic factors, Federal and State fisheries management strategies, and other non-OCS oil- and gas-related factors. Therefore, the incremental contribution of a proposed action to the cumulative impacts to commercial fisheries would range from minor **beneficial** to **minor** adverse effects for any of the action alternatives. The exact impacts would depend on the locations of activities, the species affected, the intensity of commercial fishing activity in the affected area, and the substitutability of any lost fishing access. Alternative E would prevent these impacts from occurring, although commercial fisheries would still be subject to the impacts from the OCS Program, as well as the impacts from non-OCS sources. A full analysis of commercial fisheries can be found in **Chapter 4.10**.

2.4.11 Recreational Fishing

The Gulf of Mexico's extensive estuarine habitats (**Chapter 4.3.1**), live bottom habitats (**Chapter 4.6**), and artificial substrates (including artificial reefs, shipwrecks, and oil and gas platforms) support several valuable recreational fisheries. Alternatives A-D can affect recreational fishing by affecting fish populations or by affecting the socioeconomic aspects of recreational fishing. The impacts of Alternatives A-D on fish populations are presented in **Chapter 4.7**. Vessel traffic can cause space-use conflicts with anglers. Structure emplacement generally enhances recreational fishing, although this positive effect will be offset during decommissioning unless a structure were maintained as an artificial reef. Accidental events, such as oil spills, can cause fishing closures and can affect the aesthetics of fishing in an area. However, accidental events that could arise would likely be small and localized. Alternatives A-D should also be viewed in light of overall trends in OCS platform decommissioning, State oil and gas activities, overall vessel traffic, hurricanes, economic factors, and Federal and State fisheries management strategies. The incremental impacts of Alternatives A-D on recreational fisheries are expected to be **beneficial** (low) to **minor**. Alternative E would cause some economic adjustments (refer to **Chapter 4.14.2**), which could cause **negligible** impacts to recreational fishing activities. A full analysis of recreational fishing can be found in **Chapter 4.11**.

2.4.12 Recreational Resources

Alternatives A-D would contribute to the negligible to minor aesthetic impacts and space-use conflicts that arise due to the broader OCS Program. These conflicts arise due to marine debris, the visibility of platforms, and vessel traffic. Structure emplacements can have positive impacts on recreational fishing and diving because platforms often act as artificial reefs. Oil spills can negatively affect beaches and other coastal recreational resources. Alternatives A-D should also be viewed in light of economic trends, as well as various non-OCS oil- and gas-related factors that can cause space-use conflicts and aesthetic impacts, such as commercial and military activities. Because of the relatively small contribution of any given lease sale under any of the proposed action alternatives to the overall OCS Program, in addition to other non-OCS oil- and gas-related activities, the incremental impacts are expected to be **beneficial** (low) to **minor** adverse effects. There could be **negligible** impacts to recreational resources due to the small economic adjustments that would occur as a result of Alternative E. A full analysis of recreational resources can be found in **Chapter 4.12**.

2.4.13 Archaeological Resources

Archaeological resources are any material remains of human life or activities that are at least 50 years of age and that are capable of providing scientific or humanistic understanding of past human behavior, cultural adaptation, and related topics through the application of scientific or scholarly techniques, such as controlled observation, contextual measurement, controlled collection, analysis, interpretation, and explanation (30 CFR § 250.105). Archaeological resources are primarily impacted by any activity that directly disturbs or has the potential to disturb the seafloor. For the OCS Program, this includes the placement of drilling rigs and production systems on the seafloor; pile driving associated with platform emplacement; pipeline placement and installation; the use of seismic receiver nodes and cables; the dredging of new channels, as well as maintenance dredging of existing channels; anchoring activities; post-decommissioning activities including trawling clearance; and the masking of archaeological resources from industry-related infrastructure and debris.

Regardless of which planning area a proposed lease sale is held, the greatest potential impact to an archaeological resource as a result of a proposed action under any of the action alternatives is site-specific and would result from direct contact between an offshore activity or accidental event and a site. Archaeological surveys, where required prior to an operator beginning OCS oil- and gas-related activities on a lease, are expected to be effective at identifying possible archaeological sites. A proposed action's postlease activities, including the drilling of wells and installation of platforms, installation of pipelines, anchoring, and removal of platforms and other structures installed on the seafloor and site clearance activities, as well as accidental events such as loss of debris, may result in **negligible** to **major** impacts to archaeological sites. **Major** impacts could potentially occur if the mitigations described above were not applied to postlease activities.

With identification, evaluation, and avoidance or mitigation of archeological resources, the incremental contribution of a proposed action is expected to result in **negligible**, long-term cumulative impacts to archeological resources; however, if an archaeological site were to be impacted, impacts to that specific site may range from **negligible** to **major**. Alternative E would result in BOEM cancelling a proposed lease sale; therefore, the impact-producing factors mentioned above would not take place for that proposed lease sale, and any impact that these actions could cause would not occur. A full analysis of archaeological resources can be found in **Chapter 4.13**.

2.4.14 Human Resources and Land Use (Including Environmental Justice)

2.4.14.1 Land Use and Coastal Infrastructure

Oil and gas exploration, production, and development activities on the OCS are supported by an expansive onshore network of coastal infrastructure that includes hundreds of large and small companies. Because OCS oil- and gas-related activities are supported by this long-lived, expansive onshore network, a proposed action is not expected to produce any major impacts to land use and coastal infrastructure. The impact of routine operations would range from **negligible** to **moderate**. The impacts of reasonably foreseeable accidental events such as oil spills, chemical and drilling fluid spills, and vessel collisions are not likely to last long enough to adversely affect overall land use or coastal infrastructure in the analysis area and would therefore be **negligible** to **moderate**. In the cumulative analysis, activities relating to all past, present, and future OCS oil- and gas-related activities and State oil and gas production are expected to minimally affect the current land use of the analysis area because most subareas have strong industrial bases and designated industrial parks. Non-OCS oil- and gas-related factors contribute substantially to the cumulative impacts on land use and coastal infrastructure, while there is only a **minor** incremental contribution of a proposed lease sale.

The cumulative impacts on land use and coastal infrastructure could range from **beneficial** to **moderate** for OCS oil- and gas-related activities and **beneficial** to **major** for non-OCS oil- and gas-related activities depending on the specifics of each situation, whether the impacts are measurable, how long the impacts would last, and the size of the affected geographic area as defined in **Chapter 4.14.1**. Alternative E would result in no lease sale and, thus, the direct impacts as a result of a proposed lease sale would be **none** and no incremental contribution of impacts to land use and coastal infrastructure beyond a temporary negative economic impact for the oil and gas industry and coastal states, such as Louisiana, that are more dependent on oil and gas revenues. A full analysis of land use and coastal infrastructure can be found in **Chapter 4.14.1**.

2.4.14.2 Economic Factors

A proposed action would lead to **beneficial** (low) impacts arising from industry expenditures, government revenues, corporate profits, and other market impacts. Some of these impacts would be concentrated along the Gulf Coast, while others would be widely distributed. A proposed action would also lead to negative economic impacts arising from accidental events and other sources. There would be some differences in economic impacts among Alternatives A-D, corresponding to the differences in the scales and distributions of likely activities. Alternatives A-D should be viewed in light of the OCS Program, as well the numerous forces that can affect energy markets and the overall economy. Most of the incremental economic impacts of a proposed action are forecast to be **beneficial**, although there would be some **minor** adverse impacts. Alternative E, the cancellation of a proposed lease sale, would negatively impact firms and employees that depend on recurring leases; therefore, the impacts of Alternative E would be **negligible** to **minor**, with some partially offsetting **beneficial** impacts. A full analysis of economic factors can be found in **Chapter 4.14.2**.

2.4.14.3 Social Factors (Including Environmental Justice)

Potential social impacts resulting from a proposed action would occur within the larger socioeconomic context of the GOM region. The affected environment of the analysis area is quite large geographically and in terms of population (133 counties and parishes with over 22.7 million residents). The impacts from routine activities related to a proposed action are expected to be **negligible** to **moderate**, widely distributed, and to have little impact because of the existing extensive and widespread support system for the petroleum industry and its associated labor force. Outside of a low-probability catastrophic oil spill, which is not reasonably foreseeable and not part of a proposed action, any potential accidental events are not likely to be of sufficient scale or duration to have adverse and disproportionate long-term impacts for people and communities in the analysis area and would therefore range from **negligible** to **moderate**. In the cumulative analysis, impacts from OCS oil- and gas-related activities would range from **beneficial** to **moderate**. Non-OCS oil- and gas-related activities, which include all human activities, natural events, and processes, actually contribute more to cumulative impacts than do factors related to OCS oil- and gas-related activities alone and result in **beneficial** to **major** impacts. The incremental contribution to cumulative impacts of a proposed action would be **minor**. Alternative E would result in no lease sale and, thus, overall incremental impacts as a result of alternative E would be **none**. A full analysis of social factors can be found in **Chapter 4.14.3**.

Environmental Justice Determination: The oil and gas industry in the GOM region is expansive and long-lived over several decades with substantial infrastructure in place to support both onshore and offshore activities. BOEM's scenario estimates call for 0-1 new gas processing plant and 0-1 new pipeline landfall over the 50-year life of a single proposed action. Impacts to GOM populations from a proposed action would be immeasurable for environmental justice since these low-income and minority communities are located onshore, distant from Federal OCS oil- and gas-related activities. Also, since these vulnerable populations are located within the larger context of onshore and State-regulated nearshore oil and gas activities that are connected to downstream infrastructure over which BOEM has no regulatory authority, BOEM has determined that a proposed action would not produce environmental justice impacts in the GOM region. A full analysis of social factors and an environmental justice determination can be found in **Chapter 4.14.3**.

CHAPTER 3

IMPACT-PRODUCING FACTORS AND SCENARIO

What's in This Chapter?

BOEM develops scenarios that describe OCS oil- and gas-related routine activities and accidental events from a single proposed lease sale, the OCS oil and gas cumulative activities of multiple lease sales, and the non-OCS oil- and gas-related activities and/or events.

- Routine activities for a single proposed lease sale include the following:
  - Exploration and Delineation – geological and geophysical surveys, and drilling exploration and delineation wells.
  - Offshore Development and Production – drilling production wells, infrastructure emplacement, and work-overs and abandonment of wells.
  - Transport – resource transportation (e.g., pipelines and tankers) as well as service transportation (e.g., service vessels and helicopters).
  - Discharges and Wastes – includes operational wastes produced by facilities and vessels, and the disposal of wastes.
  - Decommissioning and Removal Operations – the removal and/or abandonment of platforms and pipelines.
  - Coastal Infrastructure – information on all the types of infrastructure that supports the offshore oil and gas industry (e.g., construction, transport, and processing facilities).
  - Air Emissions – the types of emissions that can be expected.
  - Noise – the types of noise routinely produced during a lease.
  - New and Unusual Technology – the technologies that have evolved to meet the technical, environmental, and economic challenges of deepwater development.
- Accidental events for a single proposed lease sale could include the following (analyses based on historical data and trends):
  - Oil Spills – information on coastal and offshore spills.
  - Losses of Well Control – the process of a loss of well control event.
  - Accidental Air Emissions – instances that might result in accidental air emissions, including hydrogen sulfide (H_2S).
  - Pipeline Failures – instances that might result in a pipeline failure).
  - Vessel and Helicopter Collisions – instances that might result in a vessel or helicopter collision and the history of these incidences.
  - Chemical and Drilling-Fluid Spills – instances that might result in a chemical or drilling-fluid spill.
  - Spill Response – the spill-response requirements and initiatives, offshore response, and the activities involved in an onshore response and cleanup.
- Cumulative activities include the following:
  - Cumulative OCS Oil and Gas Program – all activities (i.e., the routine activities projected to occur and the accidental events that could occur, as listed above) from past, proposed, and future lease sales.
  - Non-OCS Oil- and Gas-Related Activities – impact-producing factors from the broad range of other activities taking place within the proposed lease sale area.

3 IMPACT-PRODUCING FACTORS AND SCENARIO

3.0 INTRODUCTION

This chapter describes the offshore infrastructure and activities (impact-producing factors) associated with Alternative A or a regionwide proposed action (i.e., a typical lease sale that would result from a proposed action), which would encompass all acreage available for lease within the WPA, CPA, and EPA (not under moratorium) that could potentially affect the biological, physical, and socioeconomic resources of the Gulf of Mexico. This chapter also describes the offshore infrastructure and activities associated with two alternatives that would offer proposed lease sales by individual planning area, which would consist of a single proposed lease sale for all acreage available for lease and not under moratorium either within the CPA and EPA combined (Alternative B) or the WPA (Alternative C). Under Alternative D, the number of blocks that would become unavailable for lease represents only a small percentage (<4%) of the total number of blocks to be offered under Alternative A, B, or C. Therefore, Alternative D could reduce or delay offshore infrastructure and activities but may only shift the location of offshore infrastructure and activities farther from sensitive topographic zones and not lead to a reduction in offshore infrastructure and activities. Since the ranges given for Alternatives A, B, and C are broad and represent the low and high levels of forecasted activity, any reduction of activity from choosing Alternative D is still expected to fall within those ranges; therefore, the scenarios do not change when considering Alternative D. The potential impacts associated with selecting Alternative D are discussed in **Chapter 4** under each resource. Refer to **Chapter 2.2.2.4** for more information on Alternative D. In addition, **Chapter 3.3.1** describes the Cumulative OCS Oil and Gas Program scenario or activity resulting from past and future lease sales in the GOM that could potentially affect the biological, physical, and socioeconomic resources of the GOM within the WPA, CPA, and EPA.

What is an Impact-Producing Factor?

An impact-producing factor is an activity or process, as a result of a proposed lease sale, that could cause impacts on the environmental or socioeconomic setting. The impact analyses determine the context and intensity of effects caused by any source on environmental resources (**Chapter 4**) including OCS oil- and gas- related activity and other ecological, economic, or social effects. Each phase of oil- and gas-related operation would have a set of impact-producing factors that may affect physical or environmental conditions and/or may affect one or more natural, cultural, or socioeconomic resources.

How are the Impact-Producing Factors Categorized?

Routine Activities. These activities generally occur on a regular basis during the lifetime of a lease. The operations are broken down by phase and include exploration, development, oil or gas production and transport, and decommissioning. Examples of routine activity include drilling wells, installing production structures, and decommissioning, etc. Routine operations are discussed in **Chapter 3.1**.

Accidental Events. Though not planned or intended, BOEM recognizes that there is potential for accidental releases, based on historical trends. Types of accidental events include releases into the environment (e.g., oil spills, loss of well control, accidental air emissions, pipeline failures, chemical and drilling fluid spills, and trash and debris), collisions (e.g., helicopters, service vessels, and platforms), and spill-response activities. Reasonably foreseeable accidental events are discussed in **Chapter 3.2**.

Cumulative Impacts. The impact-producing factors considered in this chapter are defined as other past, present, and reasonably foreseeable future activities occurring within the same geographic range and within the same timeframes as the aforementioned projected routine activities and potential accidental events, including BOEM's Cumulative OCS Oil and Gas Program. Cumulative activities are discussed in **Chapter 3.3**.

What is a Scenario?

> *Scenario development is the process of analyzing and projecting future activities that could occur as a result of each action alternative (i.e., Alternative A, B, C, or D).*

A scenario describes the offshore activities that could occur for a single proposed lease sale under each alternative. BOEM's Gulf of Mexico OCS Region developed these scenarios to support the detailed analyses of the proposed lease sales' potential impacts whether regionwide or for individual planning areas, as defined in the alternatives in **Chapter 2.2.2**. Each scenario is a hypothetical framework of assumptions based on estimated amounts, timing, and general locations of OCS exploration, development, and production for offshore and onshore activities and facilities. The scenario for each alternative is defined as a set of ranges for resource estimates, projected exploration and development activities, and impact-producing factors.

The scenarios do not predict future oil and gas activities with absolute certainty, even though they were formulated using historical information and current trends in the oil and gas industry. These scenarios are only approximate since future factors such as the economic climate, the future availability of support facilities, and future pipeline capacities are all unknown. The scenarios used in this Multisale EIS represent the best assumptions and estimates of a set of future conditions that are considered reasonably foreseeable and suitable for presale impact analyses. The development scenarios do not represent a BOEM recommendation, preference, or endorsement of any level of leasing or offshore operations or of the types, numbers, and/or locations of any onshore operations or facilities.

How are the Scenarios Developed?

> ***How are ranges determined?*** *The low and high production scenarios, and the factors that influence them, are used to create the range in anticipated oil and gas activity.*

BOEM uses a series of spreadsheet-based data analyses tools to develop the forecasts of the oil and gas exploration, discovery, development, and production activity scenario for each action alternative presented in this Multisale EIS. The activity level associated with a proposed lease sale could vary based on a number of factors, including the price of oil, hydrocarbon resource potential, cost of development, and resource availability (e.g., drilling rig availability) among other things. The scenario information presented takes into account historical oil and gas prices, price trends, oil and gas supply and demand, and related factors that influence oil and gas product-price and price volatility. The analyses are compared with actual historical activity and infrastructure data to ensure that historical precedent, as well as recent trends, are reflected in each activity forecast. Due to the inherent uncertainties associated with an assessment of undiscovered resources, probabilistic techniques were employed to develop the scenario and the results are reported as a range of values corresponding to probabilities of occurrence.

> ***What does a range of activity mean?*** *A meaningful range provides a reasonable expectation of the lowest to highest oil and gas production and associated activity anticipated from a single proposed lease sale.*

BOEM used these analyses to develop a reasonable low-activity scenario and a reasonable high-activity scenario for each alternative. BOEM does not expect every lease sale to reach the highest high or lowest low of the forecasted scenario ranges, but every proposed lease sale would fall within the ranges. The range of volumes described by these scenarios represents BOEM's best estimate of the range of possible production volumes and associated activity that can reasonably be expected from the acreage leased during a single proposed lease sale. These scenarios are developed to provide the environmental impact analyses in **Chapter 4** the flexibility to develop impact metrics for the full range of potential impacts that could be possible from a single proposed lease sale. BOEM is confident that the analysis methodology, with adjustments and refinements based on recent activity levels and industry information, adequately project Gulf of Mexico OCS oil- and gas-related activities in both the short term and the long term for the Multisale EIS analyses.

3.1 Impact -Producing Factors and Scenario—Routine Operations

3.1.1 Resource Estimates and Timetables

A single proposed lease sale scenario was developed for each alternative and is used to assess the potential impacts of a proposed lease sale within the geographic ranges of each alternative. The resource estimates for each alternative are based on two factors: (1) the conditional estimates of undiscovered, unleased, conventionally recoverable oil and gas resources in the proposed lease sale areas; and (2) the estimates of the portion or percentage of these resources assumed to be leased, discovered, developed, and produced as a result of a proposed action and each alternative.

What is the Total Production Estimate for Each Alternative?

Table 3-1 and Figure 3-1 present the projected oil and gas production for a single proposed lease sale under each alternative and for the Cumulative OCS Oil and Gas Program (2017-2086). As stated above, the number of blocks that would become unavailable for lease under Alternative D represents only a small percentage (<4%) of the total number of blocks to be offered under Alternative A, B, or C. Therefore, Alternative D could reduce offshore infrastructure and activities;

however, it would likely only shift the location of offshore infrastructure and activities to be farther removed from sensitive topographic zones. Refer to **Chapter 2.2.2.4** for more information on Alternative D.

Table 3-1. Projected Oil and Gas in the Gulf of Mexico OCS.

Reserve/Resource Production	Lease Sale (2017-2066)	OCS Cumulative (2017-2086)
Alternative A: Proposed Regionwide OCS Lease Sale		
Oil (BBO)	0.211-1.118	15.482-25.806
Gas (Tcf)	0.547-4.424	57.875-108.513
Alternative B: Proposed Regionwide OCS Lease Sale Excluding Available Unleased Blocks in the WPA Portion of the Proposed Lease Sale Area (Proposed Lease Sale in the CPA/EPA Portion of the Proposed Lease Sale Area)		
Oil (BBO)	0.185-0.970	13.707-22.152
Gas (Tcf)	0.441-3.672	46.328-84.009
Alternative C: Proposed Regionwide OCS Lease Sale Excluding Available Unleased Blocks in the CPA/EPA Portions of the Proposed Lease Sale Area (Proposed Lease Sale in the WPA Portion of the Proposed Lease Sale Area)		
Oil (BBO)	0.026-0.148	1.775-3.654
Gas (Tcf)	0.106-0.752	11.547-24.504

BBO = billion barrels of oil.
Tcf = trillion cubic feet.

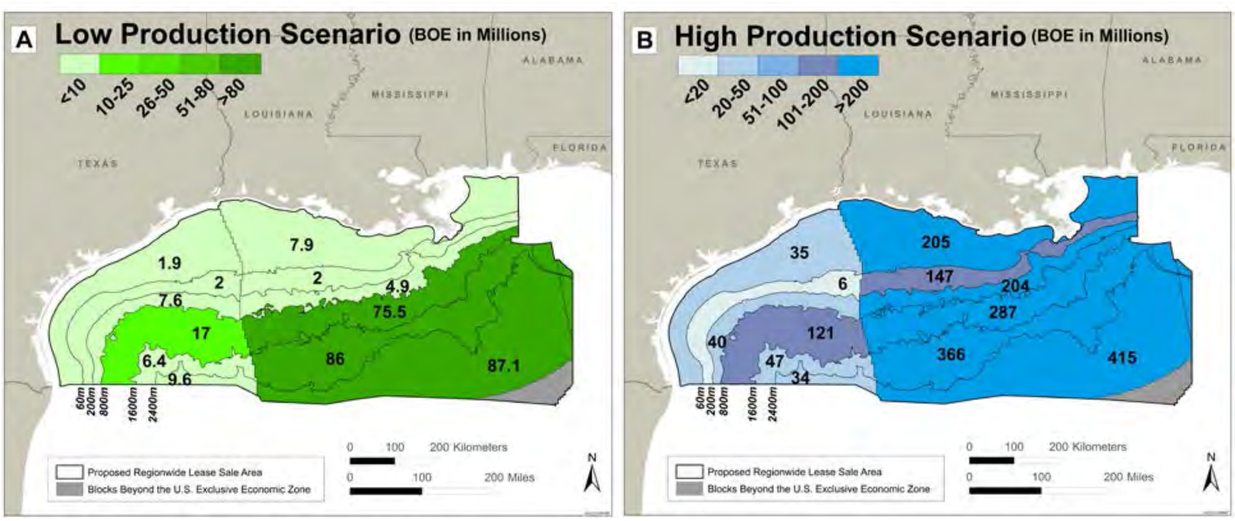

Figure 3-1. Total Oil and Gas Production (BOE) in the Gulf of Mexico in the Low and High Production Scenario by Water Depth for a Single Proposed Lease Sale (2017-2066).

How Much and Where is Activity Expected to Occur for Each Alternative?

To analyze the estimated hydrocarbon resources and associated activities and infrastructure (including the number of exploration and delineation wells, production platforms, and development wells) and resulting impact-producing factors for each alternative, the geographic ranges of each alternative were divided into offshore subareas based upon ranges in water depth. **Figure 3-2** depicts the location of the offshore subareas or water-depth ranges. The water-depth ranges were developed to reflect the technological requirements, related physical and economic impacts as a consequence of the oil and gas potential, exploration and development activities, and lease terms unique to each water-depth range.

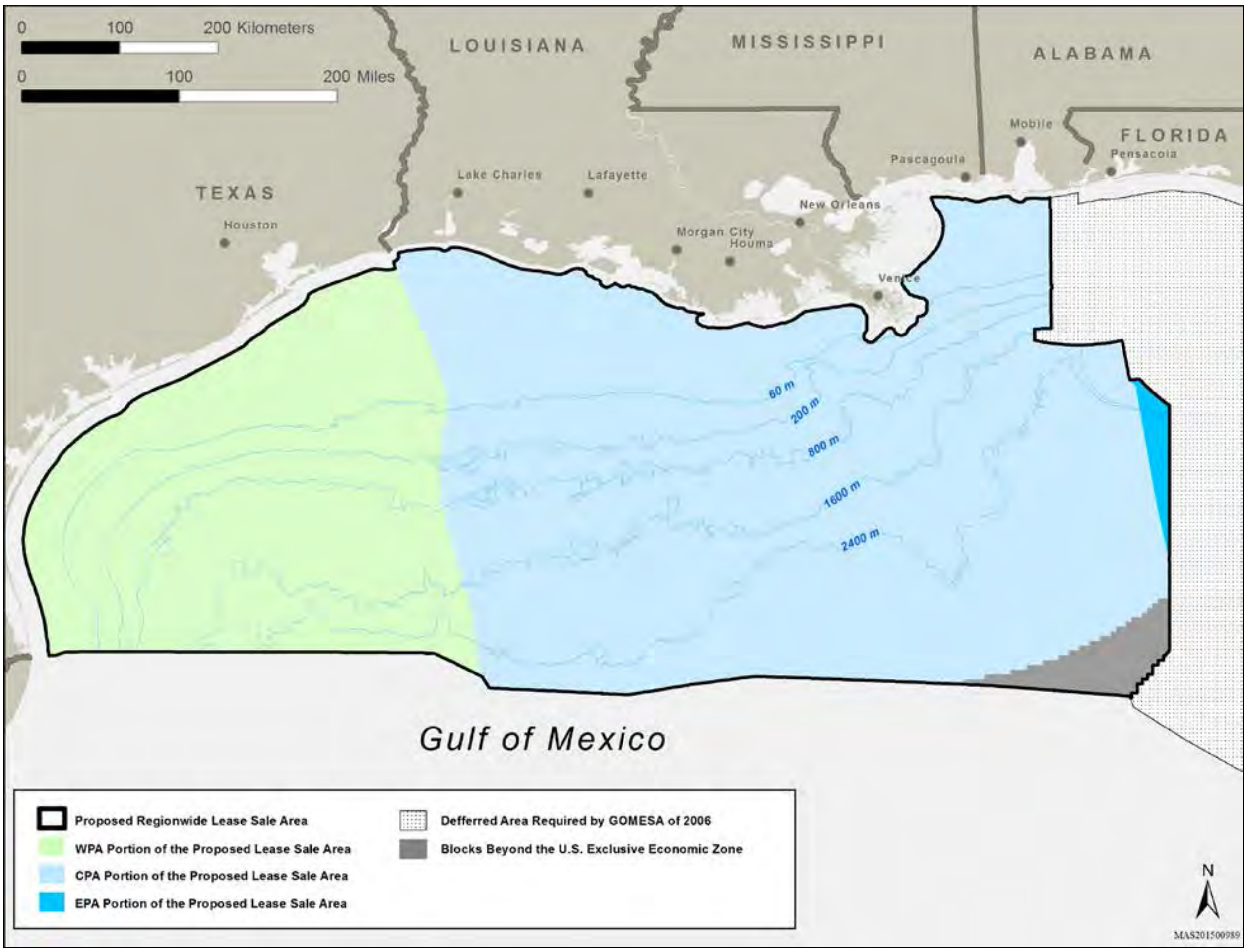

Figure 3-2. Offshore Subareas in the Gulf of Mexico.

Estimates of associated activities and infrastructure or the major impact-producing factors related to the projected levels of exploration, development, and production activity were developed for each of the subareas (water-depth ranges) for Alternatives A, B, and C, and are presented in **Table 3-2**.

Table 3-2. Offshore Scenario Activities and Impact-Producing Factors Related to a Single Proposed Lease Sale for Alternative A, B, or C from 2017 through 2066.

Activity	Alternative[1]	Offshore Subareas (m)[2]						Totals[3]
		0-60	60-200	200-800	800-1,600	1,600-2,400	>2,400	
Exploration and Delineation Wells	A	24-634	8-300	5-11	6-15	5-8	5-16	53-984
	B	20-570	5-293	2-8	2-10	2-2	2-10	33-893
	C	4-64	2-7	2-3	3-5	3-6	3-6	17-91
Development and Production Wells[4]	A Total	14-326	7-220	7-95	13-51	10-37	10-38	61-767
	B Total	10-282	4-211	4-78	10-35	9-31	9-34	46-671
	C Total	4-44	4-9	4-17	4-16	3-6	3-4	22-96
	A Oil	1-35	0-23	3-46	6-22	5-19	4-19	19-164
	B Oil	1-32	0-23	2-38	5-18	4-16	4-17	16-144
	C Oil	0-5	0-1	2-9	1-5	1-4	1-3	5-27
	A Gas	1-35	0-23	3-46	6-22	5-19	4-19	19-164
	B Gas	5-169	2-120	0-17	1-7	1-6	1-7	10-326
	C Gas	2-27	2-6	0-4	1-7	0-1	0-1	5-46
Installed Production Structures	A	8-183	4-85	1-4	1-3	1-2	1-3	16-280
	B	7-158	3-81	1-3	1-2	1	1-2	14-247
	C	3-25	2-4	1	1	1	1	9-33
Production Structures Removed Using Explosives	A	6-130	3-63	0	0	0	0	9-193
	B	5-112	2-60	0	0	0	0	7-172
	C	2-18	2-3	0	0	0	0	4-21
Total Production Structures Removed	A	8-183	4-85	1-4	1-3	1-2	1-3	16-280
	B	7-158	3-81	1-3	1-2	1	1-2	14-247
	C	3-25	2-4	1	1	1	1	9-33
Length of Installed Pipelines (km)[5]	A	59-527	53-417	53-327	78-358	59-275	53-240	355-2,144
	B	40-395	34-336	33-240	55-233	50-227	42-210	254-1,641
	C	20-132	20-81	20-88	24-125	10-48	11-31	105-505
Service-Vessel Trips (1,000's round trips)	A	9-265	4-126	6-51	7-38	7-26	7-36	43-541
	B	8-229	3-120	6-39	6-26	6-15	6-25	38-452
	C	3-36	2-6	6-13	6-13	6-12	6-11	30-89
Helicopter Operations (1,000's round trips)	A	52-2,131	34-1,409	8-71	8-53	8-36	8-53	122-3,750
	B	43-1,848	26-1,426	8-53	8-36	8-18	8-36	105-3,415
	C	17-299	17-71	8-18	8-18	8-18	8-18	70-440

[1] Alternative D could reduce activity values of the combined Alternative A, B, or C, but it may only shift the location of offshore infrastructure and activities farther from sensitive topographic zones. Refer to **Chapter 2.2.2.4** for more information. Alternative A would a regionwide lease sale, Alternative B would be the CPA/EPA portions of the lease sale area, and Alternative C would be the WPA portion of the lease sale area.

[2] Refer to **Figure 3-1**.

[3] Subareas totals may not add up to the planning area total because of rounding.

[4] Development and Production Wells includes some exploration wells that were re-entered and completed. These wells were removed from the Exploration and Delineation well count.

[5] Projected length of pipelines does not include length in State waters.

When analyzing hydrocarbon resources and associated activities and infrastructure by planning area across the GOM, regardless of the alternative, the majority are located within the boundaries of the CPA. Therefore, for a proposed action under Alternative A, which would encompass all acreage available for lease within the WPA, CPA, and EPA, the majority of the activity would still be located in the CPA. An analysis of the scenario forecast for Alternative A suggests that a maximum of 88 percent of the oil production and associated activity and 83 percent of the gas production and associated activity is forecasted to occur within the CPA/EPA. A maximum of 13 percent of the oil production and associated activity and 19 percent of the gas production and associated activity from Alternative A is forecasted to occur within the WPA.

Finally, it is important to note that a single proposed lease sale, no matter which alternative is selected, would represent only a small proportion and small contribution to past, present, and future activity as a result of the overall forecasted Cumulative OCS Oil and Gas Program scenario or activity forecasted to occur between 2017 and 2086. This is represented in the table below.

Single Proposed Lease Sale (2017-2066)	Percent of Production of a Single Proposed Lease Sale in Relation to		
	Cumulative Production Regionwide (2017-2086)	Cumulative Production in the CPA/EPA (2017-2086)	Cumulative Production in the WPA (2017-2086)
Alternative A	1.2-4.2%	–	–
Alternative B	1.0-3.6%	1.2-4.4%	–
Alternative C	0.2-0.6%	–	1.2-3.5%

Note: Alternative D could reduce production values of the combined Alternative A, B, or C, but it may only shift the location of offshore infrastructure and activities farther from sensitive topographic zones. Refer to **Chapter 2.2.2.4** for more information.

Additional detailed information for activities or major impact-producing factors associated with a single proposed lease sale under each alternative are discussed in the following sections.

What is the Typical Timeline of a Lease?

The OCS oil- and gas-related activities generally occur in four phases: (1) exploration to locate viable oil or natural gas deposits; (2) development well drilling, platform construction, and pipeline infrastructure placement; (3) operation (oil or gas production and transport); and (4) decommissioning of facilities once a reservoir is no longer productive or profitable (**Figure 3-3**). Under the proposed action, most activities would occur on OCS leases only after a lease sale is held in the GOM. The two-dimensional (2D) and three-dimensional (3D) seismic surveying may occur on a lease to inform bidding prior to a lease sale (**Chapter 3.1.2.1**). A lease may range in length depending on hydrocarbon production on the lease; however, BOEM projects that the overwhelming majority of the oil and natural gas fields discovered as a result of each alternative would reach the end of their economic life within a time span of 50 years following a lease sale. Exploration and development activity forecasts become increasingly more uncertain as the length of time of the forecast increases due to an increasing number of influencing factors, and unusual cases may exist where activity on a lease may continue beyond 50 years.

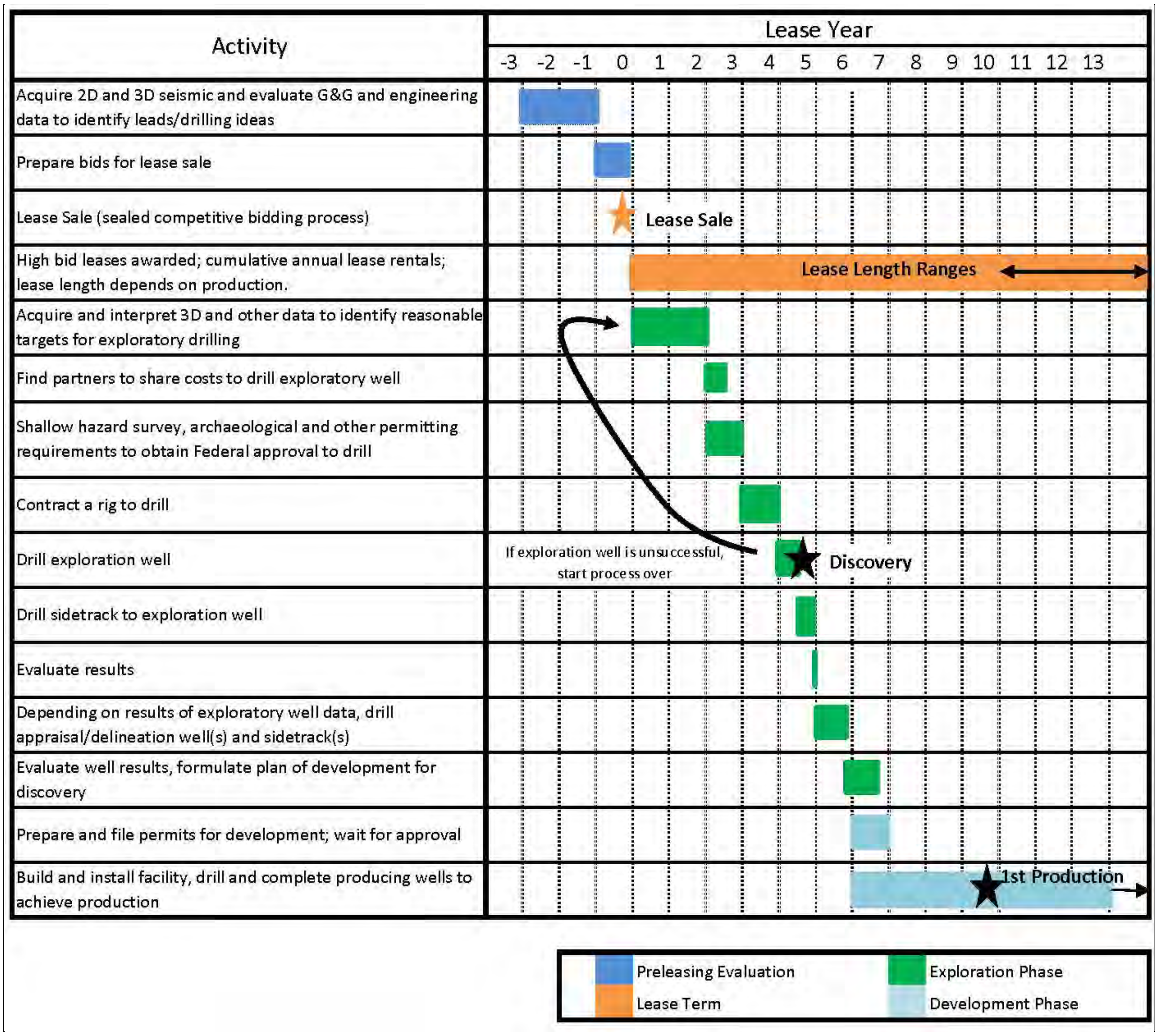

Figure 3-3. *Typical Timeline for Offshore Oil and Gas Drilling.*

3.1.2 Exploration and Delineation

The timeline for exploration and delineation activities during the life of a "typical" lease are shown in **Figure 3-3**. Exploration includes both geological and geophysical surveys and exploration drilling activities.

3.1.2.1 Geological and Geophysical Surveys

Geological and geophysical (G&G) surveys conducted as a result of a lease sale typically collect data on surficial or near-surface geology used to identify on-lease potential shallow geologic hazards for engineering and site planning for bottom-founded structures. The G&G regulations and processes are discussed in **Appendix A.1**. The G&G activities for oil and gas exploration are authorized on the basis of whether or not the proposed activities occur (1) before leasing takes place (prelease) and authorized by permits or (2) on an existing lease (postlease or ancillary) and authorized by OCS plan approvals, plan revisions, or by a requirement for notification of BOEM before certain on-lease activities are undertaken. BOEM's resource evaluation program oversees G&G data acquisition and permitting activities pursuant to regulations at 30 CFR parts 550 and 551. There are a variety of G&G activities that are conducted for oil and gas exploration and development as on-lease activities:

- various types of deep-penetration seismic airguns used almost exclusively for oil and gas exploration;
- electromagnetic surveys, deep stratigraphic and shallow test drilling, and various remote-sensing methods in support of oil and gas exploration;
- high-resolution geophysical (HRG) surveys (airgun and non-airgun) used to detect and monitor geohazards, archaeological resources, and certain types of benthic communities; and
- geological and geotechnical bottom sampling used to assess the suitability of seafloor sediments for supporting structures (e.g., platforms, pipelines, and cables), as well as to identify environmental resources such as chemosynthetic communities, gas hydrates, buried channels and faults, and archaeological resources.

Airgun Surveys

Shallow-penetration airgun (HRG airgun) seismic surveys image shallow depths, typically 1,000 m (3,280 ft) or less below the seafloor to produce high-resolution images. Shallow-penetration surveys, also commonly known as shallow hazard surveys, are conducted to investigate the shallow subsurface for geohazards and soil conditions and to identify potential benthic biological communities (or habitats) and archaeological resources. The shallow hazards survey is also used to identify and map geologic features in the vicinity of proposed wells, platforms, anchors and anchor chains, mounds or knolls, acoustic void zones, gas- or oil-charged sediments, or seeps associated with surface faulting that may be indicative of ocean-bottom chemosynthetic communities.

What is a shallow hazard? *A shallow hazard is a buried channel up to 4,000 ft (1,219 m) below the seafloor filled with permeable sediment that presents hazards to drilling operations. Drilling through these channels may result in water flowing up and around the well casing, may deposit sand or silt on the seafloor within a few hundred feet of the wellhead, and could result in hydrate formation if gas is present. Unanticipated shallow hazards can lead to downhole pressure kicks that range from minor and controllable to significant and uncontrollable, and up to and including a serious blowout condition.*

Deep-penetration airgun seismic surveys are conducted to obtain data on geological formations as deep as 40,000 ft (12,192 m) below the seafloor. Further detailed information on airgun surveys may be found in BOEM's *Atlantic OCS Proposed Geological and Geophysical Activities: Mid-Atlantic and South Atlantic Planning Areas, Final Programmatic Environmental Impact Statement* (Atlantic G&G Activities Programmatic EIS) (USDOI, BOEM, 2014a). A G&G Programmatic EIS is currently being developed for the GOM (refer to **Chapter 1.7**). Data from these surveys can be used to assess potential hydrocarbon structural and stratigraphic traps and reservoirs, and also help to optimally locate exploration, development, and production wells, thus maximizing extraction and production from a reservoir. BOEM's resource evaluation staff uses deep 2D and 3D seismic data for resource estimation and bid evaluation to ensure that the Government receives a fair market value for lease blocks offered.

The vast majority of the underwater sound generated during an airgun survey is attributable to the airgun or airgun arrays, survey vessel towing the airgun(s), and additional equipment such as electromechanical (HRG non-airgun) tools. An airgun or airgun array releases compressed air into the water, creating a sound energy pulse that can penetrate deep beneath the seafloor.

Airgun arrays are broadband sound sources that project energy over a wide range of frequencies, from less than 10 Hertz (Hz) to more than 2,000 Hz (2 kilohertz [kHz]). Most of the usable energy, however, is concentrated in the frequency range below 200 Hz. The energy level produced by an airgun array depends primarily on three factors:

- the firing pressure in pounds per square inch (psi) of the guns (2,000 psi for most of the surveys currently being conducted);
- the number of airguns in the array (generally between 20 and 80); and
- the total volume in cubic inches of the array (generally between 1,500 and 8,640 cubic inches).

The output of an airgun array is directly related to the firing pressure and to the number of guns and is only proportional to the cube root of the volume. The airguns in the array are arranged to project the maximum amount of seismic energy vertically into the seafloor. Nonetheless, a significant portion of the sound energy from the array is emitted at off-vertical angles and spreads into the surrounding environment. Most of the sound energy is directed downward. The frequency spectrum of the sound spreading near-horizontally can differ markedly from that of the sound directed downward. There also can be substantial differences in the intensity and frequency spectrum of sound spreading in different horizontal directions.

Data acquisition generally takes place day and night and, depending on the size of the survey area, may continue for days, weeks, or months. A typical deep-penetration seismic airgun survey may experience approximately 20-30 percent of non-operational downtime due to a variety of factors, including technical or mechanical problems, standby for weather or other interferences, and performance of mitigating measures (e.g., ramp-up, pre-survey visual observation periods, and shutdowns).

There are several different types/methods of performing airgun surveys dependent upon the data needs. These range from 2D, 3D, and 4D techniques more commonly used in the prelease phase to various vertical seismic profiling (VSP) techniques (e.g., zero-offset, multiple-offset, walk-away, and checkshot surveys), as well as HRG airgun surveys more commonly used during postlease operations.

Checkshot surveys are similar to zero-offset VSP but (1) are less complex and require less time to conduct, (2) produce less information, (3) are cheaper, (4) use a less sophisticated borehole seismic sensor, and (5) acquire shorter data records at fewer depths. During a checkshot survey, a seismic sensor is sequentially placed at a few depths (<20) in a well, and a seismic source (almost always an airgun) is hung from the side of the well platform. Only the first energy arriving at the sensor from the seismic source is permanently recorded. No reflection events are recorded and no sophisticated data processing like that for VSP surveys are required. The purpose of a checkshot survey is to estimate the velocity of sound in rocks penetrated by the well. Typically, the depths at which the sensors are placed are at, or near, the boundaries of prominent lithologic features. Checkshot surveys can be conducted much quicker than other VSP surveys, but they produce much less information. Because checkshot surveys are much less expensive and do not use the wellbore and the drilling rig as long, they are much more common than other VSP surveys. In most checkshot surveys, the seismic source is hung from the platform in a fixed location within the water column, so a surface vessel is not needed. Because reflection energy does not need to be acquired, the seismic source usually is smaller than those used for other VSP surveys. Detailed descriptions of other VSP survey methods are summarized in BOEM's Atlantic G&G Activities Programmatic EIS (USDOI, BOEM, 2014a).

Both 2D and 3D towed-streamer seismic exploration surveys are conducted off-lease by geophysical contractors either on a proprietary or nonexclusive (multiclient) basis. Proprietary surveys usually cover only a few blocks for an individual client who will then own the data and therefore will have exclusive use of it. In contrast, nonexclusive (multiclient or speculative) survey data are owned by the contractor, are generally collected over large multi-block areas, and are licensed to as many clients as possible to recover costs and produce profits for the contractor.

Newer acquisition technology involves multiple vessels towing airgun arrays with additional vessels towing streamers. These 3D WAZ surveys increase the illumination of many subsurface areas, particularly areas that are overlain with salt, and eliminate unwanted noise attenuation. The 3D coil surveys are a navigational variation of WAZ surveys and are acquired in a spiral fashion that allows for a longer acoustical distance between source and receivers for a better illumination of the acquired data and do not involve vessel turning and repositioning associated with linear acquisition. Detailed descriptions of the different airgun survey methods are summarized in BOEM's Atlantic G&G Activities Programmatic EIS (USDOI, BOEM, 2014a).

Electromechanical/HRG Non-airgun Surveys

Electromechanical (also referred to as HRG non-airgun surveys) surveys use a higher frequency, low-energy sound signal that is emitted and reflected back to the source. The survey equipment is either mounted to the ship or remotely operated vehicle (ROV), conducted using an autonomous underwater vehicle, or towed behind a survey vessel. The sound source and receiver can be located in a single piece of equipment or the sound source is collected by towed hydrophones. When conducted for oil and gas exploration and development, these seafloor- to shallow-focused subbottom penetration surveys are used to identify benthic/biological communities/habitats, archaeological resources, seafloor bathymetry, geological hazards, and seafloor engineering.

There are several different types of HRG non-airgun (electromechanical) equipment used to meet the data needs and different sound levels (frequencies) used for different mapping resolutions. The specific frequency used would depend on the manufacturer, water depth, purpose of the survey, and seabed characteristics in the area of interest. Detailed descriptions of the different electromechanical/HRG non-airgun survey methods are provided in BOEM's Atlantic G&G Activities Programmatic EIS (USDOI, BOEM, 2014a). A G&G Programmatic EIS is currently being developed for the GOM (refer to **Chapter 1.7**).

Gravity and Electromagnetic Surveys

Measurements of the earth's gravity and magnetic fields are useful in helping to determine geologic structures in the subsurface. Such data are useful in frontier exploration areas and as a complement to seismic data in well-explored areas. Gravity and magnetic surveys are conducted from ships, in conjunction with airgun and electromechanical surveys, aircraft, or, very rarely, are conducted using an autonomous underwater vehicle. The types of surveys that help map oil and gas resources by measuring earth's magnetic and gravity fields are summarized in BOEM's Atlantic G&G Activities Programmatic EIS (USDOI, BOEM, 2014a).

Geological Surveys

Geological surveys are conducted to obtain information about surface and subsurface geological and geotechnical characteristics. For oil and gas purposes, this information is used to aid in the following:

- siting, design, construction, and operation of production facilities;
- assessment of sediment, stratigraphy, and geology (i.e., potential hydrocarbon source rock) characteristics; and
- evaluation of subsurface properties, such as the presence of gas hydrates or hazards to drilling and/or physical structures.

There are several different types of survey methods used to obtain geological/geotechnical information, including grab and box sampling, geologic coring, and shallow test drilling. Detailed descriptions of the different geological surveys are summarized in BOEM's Atlantic G&G Activities Programmatic EIS (USDOI, BOEM, 2014a). As noted earlier, a G&G Programmatic EIS is currently being developed for the GOM (refer to **Chapter 1.7**).

How Much G&G Surveying Activity Could Occur?

Due to the cyclic nature in the acquisition of seismic surveys, a prelease seismic survey would be attributable to lease sales held up to several years after the survey. In preparing the G&G activity forecast, BOEM began with a short-term forecast of 2D and 3D G&G activities based on historical relationships. Between 1968 and 2014 about 1,860,000 line miles of 2D data were acquired. Between 1993 and 2014 about 250,000 OCS blocks of 3D data were acquired. In constructing the current forecast, BOEM projected the number of narrow azimuth (NAZ) and wide azimuth (WAZ) 3D survey blocks for each planning area. The NAZ and WAZ 3D survey blocks were then added to generate a baseline forecast which was then anchored to the level of exploratory well drilling activities. This process defined a level of exploration effort per block of 3D seismic acquired. This forecast was then compared with historical 2D line miles and 3D blocks actually acquired in the GOM since 1968 (1993 for 3D) to ensure that the long-term projections were within the range of historical values. For 2D line mile projections, the number of permits forecasted was then derived through the average number of miles per permit issued using historical data, exploration well drilling effort from the exploration and development scenarios, and data from currently pending applications. BOEM conservatively assumed that one HRG survey would occur for every block leased (estimated by the number of production structures predicted) and that one HRG survey would occur for every 5 km (3 mi) of pipeline laid (the average length of a pipeline permit). To estimate VSP surveys, BOEM conservatively assumed that a VSP survey would be conducted on 15 percent of all exploration and development wells drilled. **Table 3-3** reflects a reasonable level of G&G surveying activities that could be expected to occur leading up to and following scheduled lease sales in the Gulf of Mexico single proposed lease sale areas (2017-2066).

Table 3-3. Estimated Exploration and Seismic Survey Activity Leading Up To and Following a Proposed Lease Sale in the Gulf of Mexico.

Survey Area	2D Surveys (mi)	2D Permits	3D Lease Blocks	3D Permits	Ancillary Permits	HRG Surveys	VSP Surveys
Regionwide	48,000-650,000	31-310	13,400-185,000	25-128	19-214	87-709	17-263
CPA/EPA	47,000-603,000	27-283	18,900-171,300	20-108	16-198	64-576	11-234
WPA	900-4,100	4-9	5,500-25,100	6-21	3-26	30-134	5-29

2D = two-dimensional; 3D = three-dimensional; HRG = high-resolution geophysical; VSP = vertical seismic profiling.

If any action is proposed in an area of archaeological concern, BOEM or BSEE's Regional Directors may also require the preparation of an archaeological report (which may include a site-specific survey) to accompany the exploration (EP), development operations and coordination document (DOCD), or development and production plan (DPP) under 30 CFR § 250.194(c) and 30 CFR § 550.194(c). Refer to **Chapter 4.1.3** for information on archaeological requirements and impacts to archaeological resources.

*Alternative A, B, or C**: For each alternative, seismic surveys are projected to follow the same trend as exploration drilling activities, which would peak in 2030-2040 and decline until 2060, with regards to a particular lease sale. Geophysical surveys generally would be the first activities to occur within the Gulf of Mexico. The HRG surveys generally occur before exploratory drilling, but they can also occur before development drilling, platform and pipeline installation, and decommissioning activities. It is important to note that the cycling of G&G data acquisition is not driven by the 50-year life cycle of a single productive lease but instead would tend to respond to new production or potential new production driven by new technology. Consequently, some areas would be resurveyed in 2-year cycles, while other areas, considered nonproductive, may not be surveyed for 20 years or more. The above estimates far exceed the number of blocks available for leasing in the entire Gulf of Mexico OCS. Data collection may be repeated on any one block as technology advances, or multiple surveys may be conducted over the same OCS blocks for different purposes (e.g., prelease exploratory surveys and shallow hazard surveys).

*Alternative D could reduce activity values of the combined Alternative A, B, or C, but it may only shift the location of offshore infrastructure and activities farther from sensitive topographic zones. Since the ranges given for Alternatives A, B, and C are broad and represent the low and high levels of forecasted activity, any reduction of activity from choosing Alternative D is expected to still fall within those ranges; therefore, the scenarios do not change when considering Alternative D. The potential impacts associated with selecting Alternative D are discussed in **Chapter 4** under each resource. Refer to **Chapter 2.2.2.4** for more information.

3.1.2.2 Exploration and Delineation Plans and Drilling

The term exploration well generally refers to the first well drilled on a prospective geologic structure to confirm that a resource exists and to validate how much resource can be expected.

Oil and gas operators use drilling terms that represent stages in the discovery and development of hydrocarbon resources. If a resource is discovered during the drilling of an exploration well in quantities appearing to be economically viable, one or more follow-up delineation wells are drilled. Refer to **Figure 3-3** above for a typical exploration and production timeline of an oil or gas lease. Delineation wells are drilled to specific subsurface targets in order to obtain information about the reservoir that can be used by the operator to identify the lateral and vertical extent of a hydrocarbon accumulation. Following a discovery, an operator often temporarily plugs and abandons the well to allow time for a development plan to be generated and submitted for approval and for equipment to be built or procured.

In the GOM, exploration and delineation wells are typically drilled with mobile offshore drilling units (MODUs) (i.e., jack-up rigs, semisubmersible rigs, submersible rigs, platform rigs, or drill ships). Non-MODUs, such as inland barges, are also used. The type of rig chosen to drill a prospect depends primarily on water depth, though the water-depth ranges for each type of drilling rig do overlap to a degree. Other factors such as availability and daily rates also play a large role when an operator decides upon the type of drilling rig to contract. The water-depth ranges for drilling rigs used in this analysis are listed below:

MODU or Drilling Rig Type	Water-Depth Range
Jack-up, submersible, and inland barges	≤100 m (≤328 ft)
Semisubmersible and platform rig	100-3,000 m (328-9,843 ft)
Drillship	≥600 m (≥1,969 ft)

Historically, drilling rig availability has been a limiting factor for activity in the GOM and is assumed to be a limiting factor for activity projected as a result of a proposed lease sale. Drilling activities may also be constrained by the availability of rig crews, shore-based facilities, risers, and other equipment.

The scenario for each alternative assumes that an average exploration well would require 6-10 weeks to drill per well, and more than one well can be drilled at a location. The actual time required for each well depends on a variety of factors, including the depth of the prospect's potential target zone, the complexity of the well design, and the directional offset of the wellbore needed to reach a particular zone. This scenario assumes that the average exploration or delineation well depth would be approximately 4,210-8,080 m (13,800-26,500 ft) below the mudline.

Some delineation wells may be drilled using a sidetrack technique. In sidetracking a well, a portion of the existing wellbore is plugged back to a specific depth, directional drilling equipment is installed, and a new wellbore is drilled to a different geologic location. The lessee may use this technology to better understand their prospect and to plan future wells. Use of this technology may also reduce the time and exploration expenditures needed to help evaluate the prospective horizons on a new prospect.

The cost of an average exploration well can be $40-$150 million or more, without certainty that objectives can be reached. Some recent ultra-deepwater exploration wells (>6,000-ft [1,829-m] water depth) in the GOM have been reported to cost upwards of $200 million. The actual cost for each well depends on a variety of factors, including the depth of the prospect's potential target zone, the complexity of the well design, and the directional offset of the wellbore needed to reach a particular zone.

Figure 3-4 represents a generic well schematic for a relatively shallow exploration well in the deepwater GOM. This well design was abstracted from actual well-casing programs from projects in the Mississippi Canyon and De Soto Canyon Areas and from internal BOEM data. A generic well configuration cannot capture all of the possible influences that impact how a well is designed. These influences include (1) unique geologic conditions at a specific well location, (2) directional drilling requirements, (3) potential sidetrack(s), or (4) company preferences. For exploration wells, contingencies (such as anticipated water-flow zones in the formation) must also be considered in the casing program.

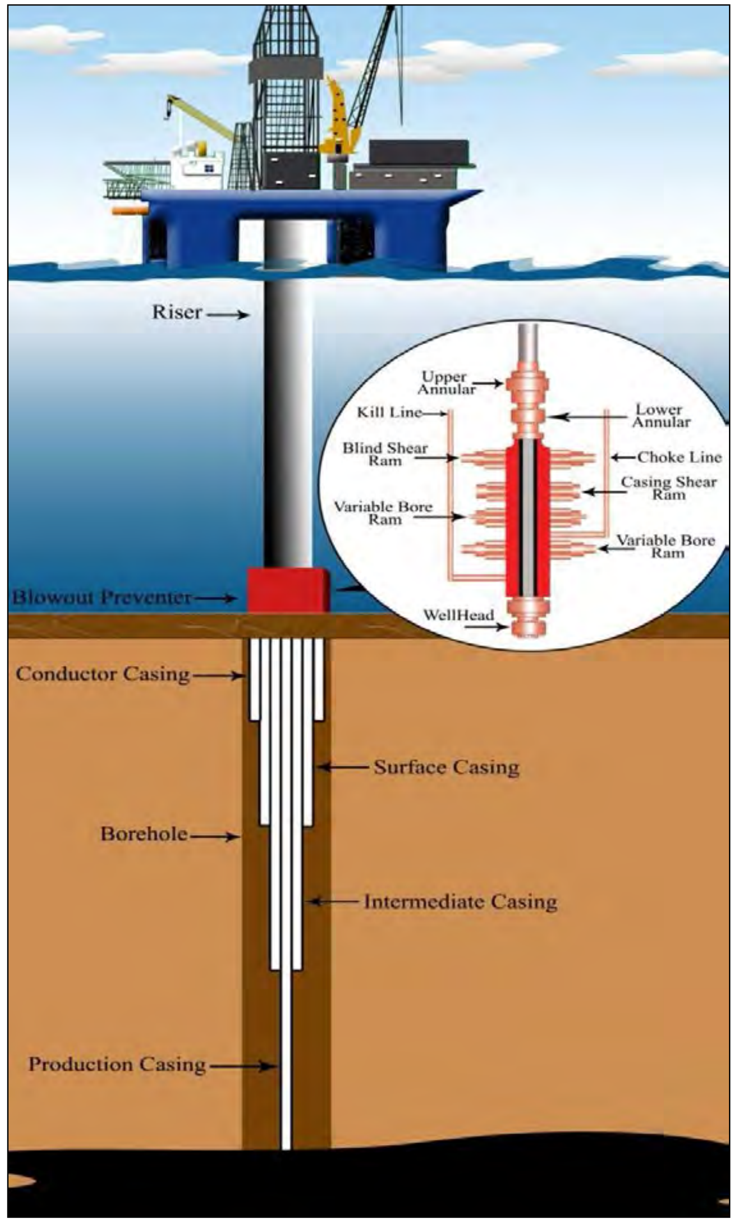

Figure 3-4. General Well Schematic (USDOI, 2010) (not to scale).

For exploration and development, deep water is defined as water ≥1,000 ft (≥305 m) deep and ultra-deepwater is defined as water ≥5,000 ft (≥1,524 m) deep. The drilling (spudding) of a deepwater exploration well begins with setting the conductor casing, one of the many sections or strings of casing (steel tube) installed in the wellbore. The first casing set in the sea bottom (or mudline) can be large, approximately 30-40 in (75-100 cm) in diameter. The larger diameter pipe may be necessary when drilling through salt to reach subsalt objectives because more casing strings may be needed to reach the well's objective. The first string is emplaced by drilling or "jetting" out the unconsolidated sediment with a water jet as the largest casing pipe is set in place. The casing is cemented to the sea bottom and tested. Because the shallow sediments are frequently soft and unconsolidated, the next casing interval (1,000 ft [305 m] or more below mudline) is commonly drilled with treated seawater and without a riser (a steel-jacketed tube that connects the wellhead to the drill rig and within which the drilling mud and cuttings circulate). Because a riser is not used, the formation cuttings are typically discharged from the wellbore directly to the sea bottom unless the location is near sensitive bottom areas (NTL 2009-G40). Muds and cuttings are discussed further in **Chapter 3.1.5.1.1**. After the conductor casing is set, a blowout preventer (BOP) would be installed, commonly at the sea bottom, the riser connected, and circulation for drilling muds and cuttings between the well bit and the surface rig established.

Next, a repetitive procedure would take place until the well reaches its planned total depth: (1) drill to the next casing point; (2) install the casing; (3) cement the casing; (4) test the integrity of the seal; and (5) drill through the cement shoe and downhole until the next casing point is reached and a narrower casing string is then set.

As drilling activities occur in progressively deeper waters, operators may consider using MODUs that have onboard hydrocarbon storage capabilities. This option may be exercised if a well requires extended flow testing (1-2 weeks or longer) in order to fully evaluate potential producible zones and to justify the higher costs of deepwater development activities. The liquid hydrocarbons resulting from an extended well test could be stored onboard a rig and later transported to shore for processing. Operators may also consider barge shuttling hydrocarbons from test well(s) to shore. There are some dangers inherit with barging operations if adverse weather conditions develop during testing. If operators do not choose to store produced liquid hydrocarbons during the well testing, they must request and receive approval from BSEE to burn test hydrocarbons. The BSEE would only grant permission to flare or vent associated natural gas during well cleanup and for well-testing procedures for a limited period of time.

The regulation at 30 CFR part 550 subpart B specifies the requirements for the exploration plans (EPs) that operators must submit to BOEM for approval prior to deploying an exploration program. Refer to **Appendix A.2** for a detailed discussion of regulations, processes, and environmental information requirements for lessees and operators related to EPs, operation plans, and DOCDs. Refer to **Chapters 1.3.1 and 3.1.10**, which provide a summary of new safety requirements.

How Much Exploratory Drilling Activity Would Likely Occur?

Following a lease sale, exploratory drilling activity would likely occur over the course of each lease but could begin within 1 year. The majority of the exploratory drilling for all blocks leased would likely occur early and would generally be complete by the 25th year. Refer to **Figure 3-5(A)** below. **Table 3-2 and Figure 3-5(B, C)** show the estimated range of exploration and delineation wells by water-depth range. Regardless of the production scenario or alternative, most exploration drilling activity is expected to be on the continental shelf (0-200 m [0-656 ft] water depth).

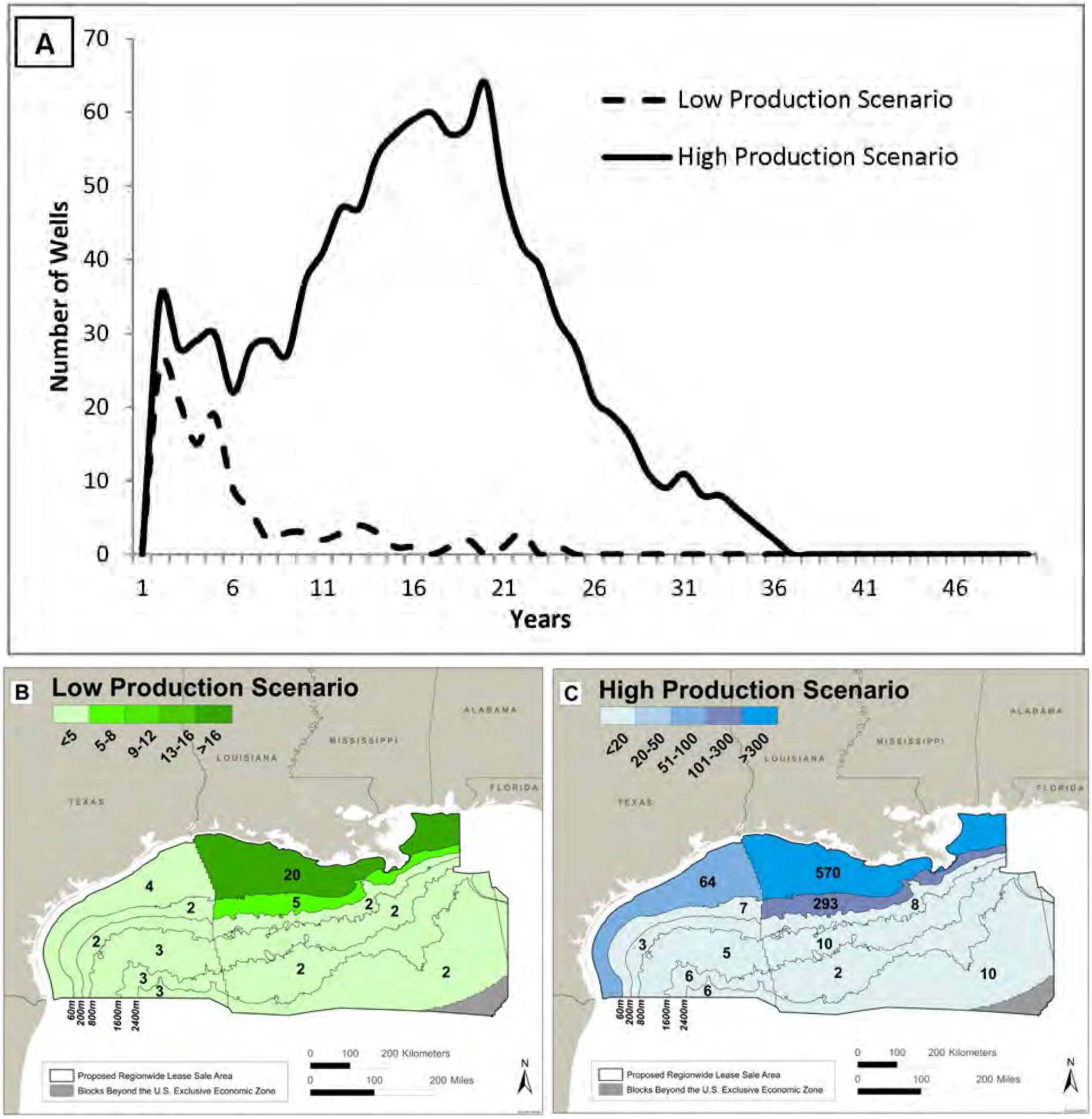

Figure 3-5. (A) Number of Exploration and Delineation Wells Drilled over the Course of a Proposed Action under Alternative A for 50 Years. (B, C) Location of Exploration Wells Drilled during the Entire 50-Year Period. (Note: This drilling activity spans 40 years. These wells are not all drilled during the same time period. The most wells drilled in a given year is 64, and the most wells drilled in any given 5-year span is 298.)

Alternative A:* BOEM estimates that 53-984 exploration and delineation wells would be drilled as a result of forecasted activity associated with Alternative A.

Alternative B:* BOEM estimates that 33-893 exploration and delineation wells would be drilled as a result of forecasted activity associated with Alternative B.

Alternative C:* BOEM estimates that 17-91 exploration and delineation wells would be drilled as a result of forecasted activity associated with Alternative C.

*Alternative D could reduce activity values of the combined Alternative A, B, or C, but it may only shift the location of offshore infrastructure and activities farther from sensitive topographic zones. Since the ranges given for Alternative A, B, and C are broad and represent the low and high levels of forecasted activity, any reduction of activity from choosing Alternative D would still fall within those ranges; therefore, the scenarios do not change when considering Alternative D. The potential impacts associated with selecting Alternative D are discussed in **Chapter 4** under each resource. Refer to **Chapter 2.2.2.4** for more information.

3.1.3 Offshore Development and Production

3.1.3.1 Development and Production Drilling

A development well is drilled to extract resources from a known hydrocarbon reservoir.

Delineation and production wells are sometimes collectively termed development wells. After a development well is drilled, the operator must decide whether or not to complete the well without delay, to delay completion with the rig on station so that additional tests may be conducted, or to temporarily abandon the well site and move the rig off station to a new location and drill another well. Sometimes an operator may decide to drill a series of development wells, move off location, and then return with a rig to complete all the wells at one time. If an exploration well is clearly a dry hole, the operator would typically permanently abandon the well without delay, but could convert the well into an injection well. An injection well is typically used to store CO_2, dispose of produced water, or enhance oil production.

Depending on the information obtained from delineation well drilling, these wells can be completed and prepared to serve as production wells. Production wells are wells that are drilled following the delineation stage of the development program. The production well would be drilled specifically for the purpose of extracting hydrocarbons from the subsurface and therefore positioned within the reservoir in locations where the greatest volume of production can be realized. Wells initially drilled as delineation wells that are later converted to production wells and wells drilled as production wells are sometimes collectively referred to as development wells.

Following the drilling of development wells, the operator of a field may decide to remain on location and immediately begin the next stage of the field development program, i.e., preparing the development wells for production. However, there are a number of reasons that the operator may decide to move off location and delay the work required to prepare the wells for production; for example, additional well tests may be required or the drilling rig may be committed to another location. When a decision to delay the work is chosen, each development well would be temporarily abandoned before the drilling rig can be moved to another location. It is also common for an operator to drill the required number of development wells in stages, leaving some time between the well drilling stages to evaluate the information obtained from the wells and, if necessary, use this information to modify the development program.

What is the Well Completion Process?

Should the operator decide to move forward with developing a well, completion operations must be undertaken. If it is decided that the well will not be completed, then it will be plugged and abandoned (**Chapter 3.1.3.5**). When the decision is made to perform a well completion, a new stage of activity begins to convert an individual borehole into an operational system for controlled recovery of underground hydrocarbon resources. Those activities include installation of the final well casings that isolate fluid migrations along the borehole length while also establishing perforated sections where needed to capture the hydrocarbons from the geologic reservoir into the production casing (National Petroleum Council, 2011).

Different geologic and reservoir properties will affect the completion process. The primary drivers of offshore completions in the GOM are sand control and formation stimulation with an extensive history of successful application. As described below, there is a wide range of variability in the particular activities that might be used in the completion process, depending on the specific characteristics of the well. Many of the terms used to describe these activities (e.g., fracking and acidization) do not have precise, fixed definitions in all contexts. Accordingly, two very different processes with different potential environmental impacts may both be called by the same name. For these reasons, the description of these activities in this chapter is meant to be a general description of the range of activities that may be involved in well completion. BOEM estimates that approximately 63-70 percent of wells drilled as development wells become producing wells. The majority of these production wells are anticipated to undergo some form of well stimulation during their production life, with many (>65% [Sanchez and Tibbles]) being frac-pack completions. Implementation of the well stimulation activities included in a proposed action would largely use existing infrastructure and would not result in bottom-disturbing activities, except potentially the drilling of new injection wells.

There is a wide variety of well completion techniques performed in the Gulf of Mexico, and the type of well completion used to prepare a drill well for production is based on the rock properties of the reservoir as well as the properties of the reservoir fluid. However, for the vast majority of well completions, the typical process includes installing or “running” the production casing, cementing the casing, perforating the casing and surrounding cement, injecting water, brine, or gelled brine as carrier fluid for a “frac pack”/sand proppant pack and gravel pack; treating/acidizing the reservoir formation near the wellbore; installing production screens; running production tubing; and installing a production tree. Cement is pumped into the well both to displace drilling fluids that remain in the well and also to fill in the space that exists between the casing and the face of the rock formations in the wellbore. The casing and cement would be perforated adjacent to the reservoir to allow the reservoir fluids to enter the wellbore.

A gravel pack (a non-fracturing treatment) is a filtration system in which a metal screen is placed in the wellbore and the surrounding annulus is packed with prepared gravel of a size designed to provide a barrier preventing formation sand from entering the well with the hydrocarbons. The main objective of gravel packs is to stabilize the formation while causing minimal impairment to well productivity. The term “frac pack” has become an industry-recognized term for the completion process of fracturing and gravel packing and is the most widely used completion technique for sand control in the Gulf of Mexico. The “frac pack” process, which has been used in the Gulf of Mexico for more than 25 years, combines the production improvement from hydraulic fracturing (see below) with the sand control provided by gravel packing. Typically, about 30-35 percent of the oil present in the reservoir at the start of production is recovered during primary recovery (Hyne, 2012). The use of well stimulation treatments supports the continued recovery of oil as primary recovery of an oil and/or gas reservoir declines. These activities are covered by a permit known as an Application for Permit to Modify. All Applications for Permit to Modify are reviewed and approved by BSEE. BOEM carries forward any established mitigating measures based upon lease stipulations/terms, regulatory requirements, etc., to the individual plan actions.

Well treatment, such as acidizing, is used to improve the flow of reservoir fluids into the wellbore by cleaning out and/or dissolving debris that accumulates in the wellbore and near-wellbore reservoir formation as a result of the drilling process. For moderate to high permeability reservoirs, today’s most technologically advanced well treatment and stimulation processes are designed not only to mitigate flow restrictions caused by a reduction in permeability in the near-wellbore region (also known as formation “damage”) but also to serve as another mechanism to help control the flow of sand into the wellbore and to enhance the flow rate of the well. Production tubing is run inside the casing. Production tubing protects the casing from wear and corrosion, and it provides a continuous conduit for the reservoir fluid to flow from the reservoir to the wellhead. The production tree is a wellhead device that is used to control, measure, and monitor the conditions of the reservoir and the well from the surface.

The term hydraulic fracturing covers a broad range of techniques used to stimulate and improve production from a well. Fracture fluid is injected into a wellbore at high pressure to break open the rock to create/improve the flow path for hydrocarbon to flow in to the well. The pressurized high-density, gelatin-like fluid also serves as the carrier agent for the mechanical agent or proppant that is mixed with the completion fluids. The mechanical agents, typically sand, manmade ceramics, or small microspheres (tiny glass beads), are injected into the small fractures and remain lodged in the fractures when the process is completed. The proppant serves to hold the fractures open, allowing them to perform as conduits to assist the flow of hydrocarbons from the reservoir formation to the wellbore. Well-treatment chemicals are also commonly used to improve well productivity. For example, acidizing is a common well-treatment procedure in the GOM as well.

In contrast to the large-scale, induced hydraulic fracturing procedures, commonly referred to as “fracking,” used in onshore oil and gas operations for low-permeability “tight gas,” “tight oil,” and “shale gas” reservoirs, the vast majority of hydraulic fracturing treatments carried out on the OCS in the GOM are fracture packs, which are small scale by comparison and most commonly used for high-permeability formations to reduce the concentration of sand and silt in the produced fluids and to maintain high flow rates. The fracture pack or “frac-pack” completion process uses pressurized fluids, typically seawater, brine, or gelled brine, to create small fractures in the reservoir rock within a zone near the wellbore where the reservoir’s permeability was damaged by the drilling process. Since formation “damage” caused by drilling operations does not extend for large distances away from the reservoir-borehole interface, the fracturing induced by the procedure is also designed to remain in close proximity to the borehole, extending distances of typically 15-30 m (49-98 ft) from the borehole (Ali et al., 2002; Sanchez and Tibbles, 2007) to prevent the production of formation fines and sand.

Additives used in fracture-pack operations are often similar, if not identical, to those used for shale or tight sand development in other regions and are used for similar purposes. The concentrations of some of these additives are typically different due to the GOM’s very different geologic characteristics of the producing formation. The most significant difference is that the GOM typically has much higher formation permeability and lower amounts of clay/shale in typical formations (API, 2015). Another factor that can substantially influence additive selection and use in offshore operations is the ability to discharge treated wastewaters that meet applicable regulatory requirements (API, 2015).

Boehm et al. (2001) notes 22 functional categories of additives and 2 categories of proppants used offshore in the GOM for fracturing activities:

—water-based polymers
—defoamers
—friction reducers
—oil gelling additives
—fluid loss additives
—biocides
—breakers
—acid-based gel systems
—emulsifiers
—water-based systems
—clay stabilizers
—cross-linked gel systems
—surfactants
—alcohol/water systems
—non-emulsifiers
—oil-based systems
—pH control additives
—polymer plugs
—crosslinkers
—continuous mix gel concentrates
—foamers
—resin-coated proppants
—gel stabilizers
—intermediate-to-high strength ceramic proppants

Each of these is described in greater detail in the Boehm et al. (2001) study, along with other treatment and completion chemicals. The appendix to the study offers a chemical inventory with example products and Material Safety Data Sheets for those products. In general, discharges of any fluids, including those associated with well completion, are subject to the terms of National Pollution Discharge Elimination System (NPDES) permits issued by the USEPA under the Clean Water Act. These permits place limitations on the toxicity of selected effluents, as well as other requirements for monitoring and reporting. Wastes and discharges generated from OCS oil- and gas-related activities, including produced water and well completion fluids, are addressed in **Chapter 3.1.5**.

During a “frac pack,” the pumping equipment, sand (proppant), and additives are carried, mixed, and pumped from a specialized stimulation and treatment vessel. The base fluid that is used for the frac-pack operation would typically be treated seawater, although other brines may be used if conditions dictate (API, 2015). BOEM considers these large special purpose vessels (supporting fracturing operations) as offshore supply/service vessels (OSVs). In **Table 3-2**, the number of OSV trips is estimated by subareas (range of water depths) in the GOM. Potential impacts associated with OSVs are described in various chapters throughout this Multisale EIS; these impacts include operational wastes, noise, and air emissions related to vessel movement throughout the GOM.

What is explained above is a general procedure for “frac-pack” operation, but every fracturing job is case specific. In general, the fracturing process remains the same but chemical formulations, fluid and proppant volumes, pump time, and pressure will vary based on the depth and engineering/geologic parameters for a particular well completion. After a production test determines the desired production rate to avoid damaging the reservoir, the well is ready to go online and produce.

A deepwater operations plan is required for all deepwater development projects in water depths ≥1,000 ft (305 m) and for all projects proposing subsea production technology. A deepwater operations plan is required initially and is usually followed by a DOCD. The DOCD is the chief planning document that lays out an operator’s specific intentions for development. Refer to **Appendix A.2** for a detailed discussion on regulations, processes, and environmental information requirements for lessees and operators related to EP’s, deepwater operations plans, and DOCDs.

How Much Development Activity Would Likely Occur?

Development activity during a proposed action usually takes place over a 49-year period, beginning with the installation of a production platform on the first lease and ending with the drilling of the last development wells. The majority of development well drilling would likely occur in the first 25 years of each lease. Production of oil and gas could begin by the third year after the lease sale and generally would conclude by the 50th year; refer to **Figure 3-6(A)** below. **Table 3-2 and Figure 3-6(B, C)** show the estimated range of development and production wells by water-depth range. In the low production scenario, development and production activity is expected to occur fairly evenly spread between the continental shelf (0- to 200-m [0- to 656-ft] water depth) and deeper water depths (200-1,600 m; 656-5,249 ft) with a majority of activity in the CPA; however, for the high production scenario, most development and production drilling activity is expected to occur on the continental shelf (0- to 200-m [0- to 656-ft] water depth).

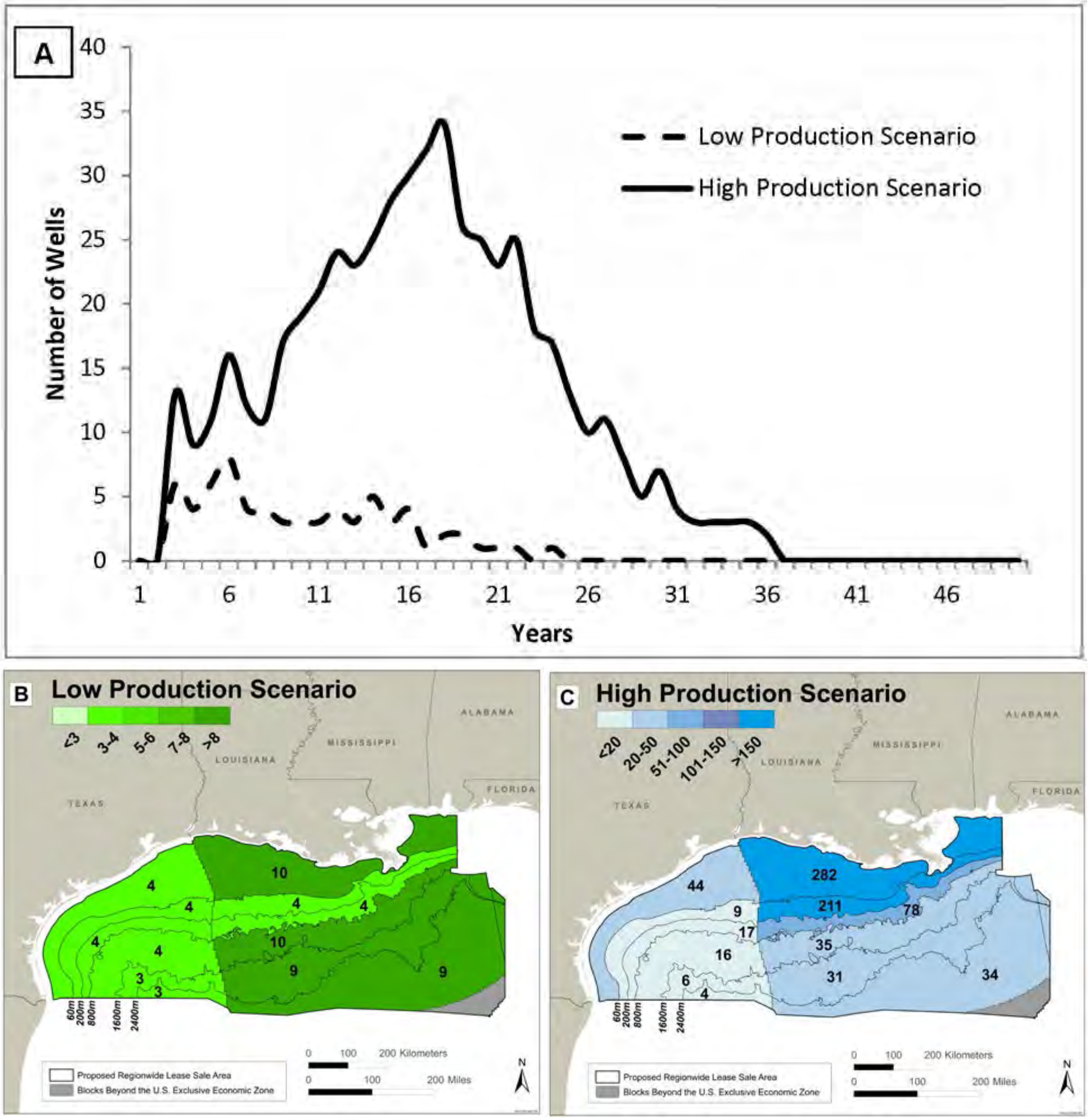

Figure 3-6. (A) Number of Production Wells Drilled over the Course of a Proposed Action under Alternative A for 50 Years. (B, C) Total Number of Development and Production Wells Drilled in the Low and High Production Scenario by Water Depth for Alternative A. (Note: This drilling activity spans 40 years. Multiple wells can be drilled from a single structure. These wells are not all drilled during the same time period. The most wells drilled in a given year is 35, and the most wells drilled in any given 5 year span is 150.)

Alternative A:* It is estimated that 61-767 development and production wells would be drilled as a result of forecasted activity associated with Alternative A. **Table 3-2** shows the estimated range of development wells by water depth.

Alternative B*: BOEM estimates that 46-671 development and production wells would be drilled as a result of Alternative B.

Alternative C*: BOEM estimates that 22-96 development and production wells would be drilled as a result of Alternative C. **Table 3-2** shows the estimated range of development and production wells by water-depth subarea.

*Alternative D could reduce activity values of the combined Alternative A, B, or C, but it may only shift the location of offshore infrastructure and activities farther from sensitive topographic zones. Since the ranges given for Alternatives A, B, and C are broad and represent the low and high levels of forecasted activity, any reduction of activity from choosing Alternative D would still fall within those ranges; therefore, the scenarios do not change when considering Alternative D. The potential impacts associated with selecting Alternative D are discussed in **Chapter 4** under each resource. Refer to **Chapter 2.2.2.4** for more information.

3.1.3.2 Offshore Production Systems

After the approval of an EP or DOCD, the operator submits applications for specific activities, including production systems, to BOEM for approval. Refer to **Appendix A.3** for more information on permits and applications related to offshore production systems.

Development wells may be drilled from movable structures, such as jack-up rigs, fixed bottom-supported structures, floating vertically moored structures, floating production facilities, and drillships (either anchored or dynamically positioned drilling vessels) (**Figure 3-7**). The spectrum of these production systems is discussed in **Chapter 3.1.3.2** below.

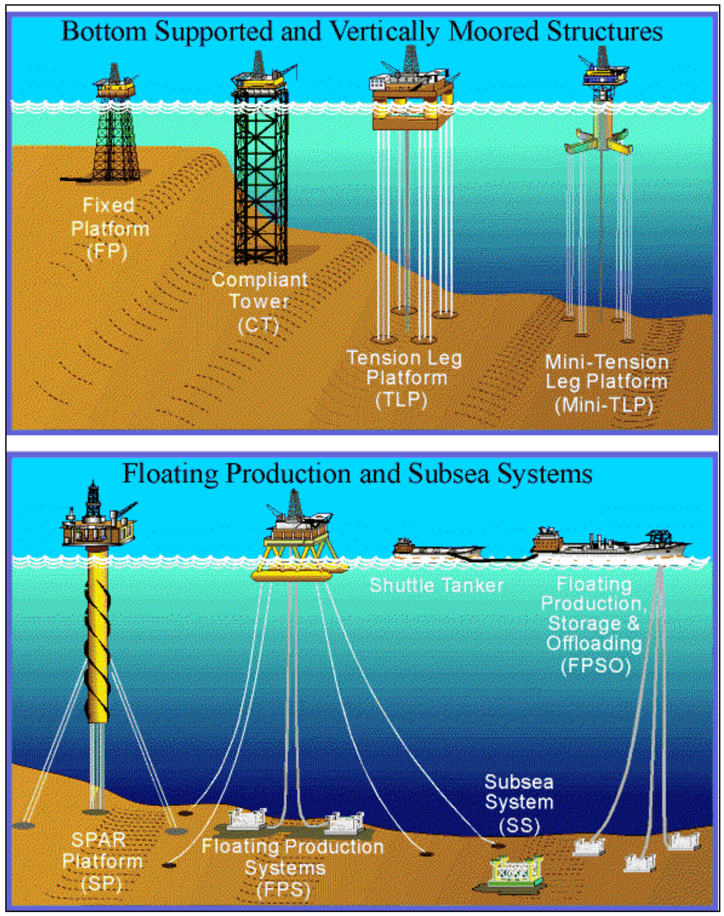

Figure 3-7. Offshore Production Systems.

The type of production structure installed at a site depends mainly on water depth, but the total facility lifecycle, type and quantity of hydrocarbon production expected, number of wells to be drilled, and number of anticipated tie backs from other fields can also influence an operator's procurement decision. The number of wells per structure varies according to the type of production structure used, the prospect size, and the drilling/production strategy deployed for the drilling program and for resource conservation. Production systems can be fixed, floating, or, increasingly in deep water, subsea. Advances in the composition of drilling fluids and drilling technology are likely to provide operators with the means to reduce rig costs in the deepwater OCS program.

Until recently, there had been a gradual increase of drilling depth (as measured in true vertical depth). Beginning in 1996, the maximum drilling depth increased rapidly, reaching depths below 30,000 ft (9,144 m) in 2002. In 2013, Cobalt International Energy drilled the Ardennes #1 exploration well (Green Canyon Block 896), reaching a true vertical depth of 36,552 ft (11,141 m). The recent dramatic increase in true vertical depth may be attributed to several factors, including enhanced rig capabilities, deeper exploration targets, royalty relief for shallow water, deep gas prospects, and the general trend toward greater water depths.

BOEM has described and characterized production structures in its deepwater reference document (USDOI, MMS, 2000a). These descriptions are summarized below and were used in preparing the scenario for this Multisale EIS. In water depths of up to 400 m (1,312 ft), the scenarios assume that conventional, fixed platforms that are rigidly attached to the seafloor would be the type of structure preferred by operators. In water depths of <200 m (656 ft), 20 percent of the platforms are expected to be manned (defined as having sleeping quarters on the structure). In depths between 200 and 400 m (656 and 1,312 ft), all structures are assumed to be manned. It is also assumed that helipads would be located on 66 percent of the structures in water depths <60 m (197 ft), on 94 percent of structures in water depths between 60 and 200 m (656 ft), and on 100 percent of the structures in water depths >200 m (656 ft). At water depths >400 m (1,312 ft), platform designs based on rigid attachment to the seafloor are not expected to be used. The 400-m (1,312-ft) isobath appears to be the current economic limit for this type of structure.

Fixed Platforms

A fixed platform consists of a welded tubular steel jacket, deck, and surface facility. The jacket and deck make up the foundation for the surface facilities. Piles driven into the seafloor secure the jacket. The water depth at the intended location dictates the height of the platform. Once the jacket is secured and the deck is installed, additional modules are added for drilling, production, and crew operations. Large, barge-mounted cranes position and secure the jacket prior to the installation of the topsides modules. While the base dimensions are typically around 200,000 ft^2 (18,581 m^2), the topside modules is typically only 40,000 ft^2 (3,716 m^2). Economic considerations limit development of fixed (rigid) platforms to water depths no greater than 1,500 ft (457 m) (USDOI, MMS, 2000a).

A caisson is a fixed platform that consists of a single vertical column that rises from the seabed and supports a small surface facility above the water. This is termed a free-standing caisson. A braced caisson has the same general structure, but the column is laterally supported by one or more inclined braces. Caissons are not generally designed to be manned.

Compliant Towers

Compliant towers are similar to fixed platforms in that they have a steel tubular jacket that is used to support the surface facilities. Unlike fixed platforms, compliant towers yield to the water and wind movements in a manner similar to floating structures. Like fixed platforms, they are secured to the seafloor with piles. The jacket of a compliant tower has smaller dimensions than those of a fixed platform and may consist of two or more sections. It can also have buoyant sections in the upper jacket with mooring lines from jacket to seafloor (guyed-tower designs) or a combination of the two. The water depth at the intended location dictates platform height. Once the lower jacket is secured to the seafloor, it acts as a base (compliant tower) for the upper jacket and surface facilities. Large barge-mounted cranes position and secure the jacket and install the surface facility modules. These differences allow the use of compliant towers in water depths ranging up to 3,000 ft (914 m). The base dimensions of a compliant tower are typically smaller than a fixed platform and is only around 90,000 ft^2 (8,361 m^2), and the topside modules are typically only 40,000 ft^2 (3,716 m^2). This range is generally considered to be beyond the economic limit for fixed jacket-type platforms (USDOI, MMS, 2000a).

Spar

A spar is a deep-draft floating caisson, which is a hollow cylindrical structure approximately 90-120 ft (27-36 m) in diameter similar to a very large buoy. Its four major systems are hull, moorings, topsides, and risers. The spar relies on a traditional mooring system (i.e., anchor-spread mooring) to maintain its position. About 90 percent of the structure is underwater and supports a conventional production deck (USDOI, MMS, 2000a). A third generation of spar design is the cell spar. The cell spar's hull is composed of several identically sized cylinders surrounding a center cylinder. The cylinder or hull may be moored via a chain catenary or semi-taut line system connected to 6-20 anchors on the seafloor. Spars are now used in water depths up to 900 m (2,953 ft) and may be used in water depths of 3,000 m (9,843 ft) or deeper (NaturalGas.org, 2010; USDOI, MMS, 2006; Oynes, 2006).

Tension-Leg Platform

A tension-leg platform (TLP) is a buoyant platform held in place by a mooring system. The TLPs are similar to conventional fixed platforms except that the platform is maintained on location through the use of moorings held in tension by the buoyancy of the hull. The mooring system is a set of tension legs or tendons attached to the platform and connected to a template or foundation on the seafloor. Tendons are typically steel tubes with dimensions of 2-3 ft (0.6-0.9 m) in diameter with up to 3 in (8 cm) of wall thickness, with the length depending on water depth. A typical TLP would be installed with as many as 16 tendons. The template is held in place by piles driven into the seafloor. This method dampens the vertical motions of the platform but allows for horizontal movements. The topside facilities (i.e., processing facilities, pipelines, and surface trees) of the TLP and most of the daily operations are the same as for a conventional platform (USDOI, MMS, 2000a).

Semisubmersible Production Structures

Semisubmersible production structures (semisubmersibles) resemble their drilling rig counterparts and are the most common type of offshore drilling rig (NaturalGas.org, 2010). Semisubmersibles are partially submerged with pontoons that provide buoyancy. Their hull contains pontoons below the waterline and vertical columns that connect to the hull box/deck. The structures keep on station with conventional, catenary, or semi-taut line mooring systems connected to anchors in the seabed. Semisubmersibles can be operated in a wide range of water depths. Floating production systems are suited for deepwater production in depths up to 8,000 ft (26,437 m) (NaturalGas.org, 2010; USDOI, MMS, 2006; Oynes, 2006).

Subsea Production Systems

For some development programs, especially those in deep and ultra-deepwater, an operator may choose to use a subsea production system instead of a floating production structure. Although the use of subsea systems has recently increased as development has moved into deeper water, subsea systems are not new to the GOM and they are not used exclusively for deepwater development. Unlike wells from conventional fixed structures, subsea wells do not have surface facilities directly supporting them during their production phases. A subsea production system has various bottom-founded components. Among them are well templates, well heads, "jumper" connections between well heads, flow control manifolds, in-field pipelines and their termination sleds, and umbilicals and their termination assemblies. A subsea production system can range from a single-well template connected to a nearby manifold or pipeline to a riser system at a distant production facility or a series of wells that are tied into the system. Subsea systems rely on a "host" facility for support and well control. Centralized or "host" production facilities in deep water or on the shelf may support several satellite subsea developments. A drilling rig would be brought on location to provide surface support to reenter a well for workovers and other types of well maintenance activities. In addition, should the production/safety system fail and a blowout result, surface support must be brought on location to regain control of the well.

Floating Production, Storage, and Offloading Systems

The category of floating production systems referred to as floating production, storage, and offloading systems (FPSOs) can normally be characterized as ship-shape vessels (tankers) that have been retrofitted (conversions) or purpose built (new built) for this application (USDOI, MMS, 2000a). Floating systems are differentiated as follows:

- FPSO — floating production, storage, and offloading system; offloading of the crude oil to a shuttle tanker; these are typically converted or newly built tankers that produce and store hydrocarbons, which are subsequently transported by other vessels to terminals or deepwater ports.
- FPS — floating production system; universal term to refer to all production facilities that float rather than are structurally supported by the seafloor; included would be TLPs, spars, semisubmersibles, shipshape vessels, etc. The term is also frequently used to describe the general category of floating production facilities that do not have onsite storage. The term is also used by the American Bureau of Shipping to describe a classification of floating production facilities that do not have storage capability.
- FSO — floating storage and offloading system; like the FPSO, these are typically converted or newly built tankers. They differ from the FPSO by not incorporating the processing equipment for production; the liquids are stored for shipment to another location for processing.

BOEM's predecessor, MMS, prepared an EIS on the potential use of FPSOs on the Gulf of Mexico OCS (USDOI, MMS, 2001). In accordance with the scenario provided by industry, the FPSO environmental impact statement addresses the proposed use of FPSOs in the deepwater areas of the CPA and WPA only. In January 2002, this Agency announced its decision to accept applications for FPSOs after a rigorous environmental and safety review. Petrobras Americas Inc. developed the first FPSO to come online in the GOM and began production in June 2012 from two prospects. The Cascade Prospect (Walker Ridge Block 206 Unit) is located approximately 250 mi (402 km) south of New Orleans, Louisiana, and about 150 mi (241 km) from the Louisiana coastline in approximately 8,200 ft (2,499 m) of water. The Chinook Prospect (Walker Ridge Block 425 Unit) is located about 16 mi (26 km) south of the Cascade Prospect. A second FPSO, Shell Stones, began production in 2016.

3.1.3.3 Infrastructure Emplacement/Structure Installation and Commissioning Activities

Structures described in **Chapter 3.1.3.2** may be placed over development wells to facilitate production from a prospect. These structures provide the means to access and control wells. They serve as a staging area to process and treat produced hydrocarbons from wells, initiate export of produced hydrocarbons, conduct additional drilling or reservoir stimulation, conduct workover activities, and carry out eventual abandonment procedures. There is a range of offshore infrastructure installed for hydrocarbon production. Among these are pipelines, fixed and floating platforms, caissons, well protectors, casing, wellheads, and conductors.

Subsea wells may also be completed to produce hydrocarbons from on the shelf and in the deepwater portions of the GOM. The subsea completions would require a host structure to control their flow and to process their well stream. Control of the subsea well is accomplished via an umbilical from the host.

Pipelines are the primary means of transporting produced hydrocarbons from offshore oil and gas fields to distribution centers or onshore processing points. Pipelines range from small-diameter (generally 4-12 in; 10-30 cm) gathering lines, sometimes called flowlines, that link individual wells and production facilities to large-diameter (as large as 36 in; 91 cm) lines, sometimes called trunk lines, for transport to shore. Pipelines would typically be installed by lay barges that are either anchored or dynamically positioned while the pipeline is laid. Pipeline sections may be welded together on a conventional lay barge as it moves forward on its route or they may be welded together at a fabrication site onshore and wound onto a large-diameter spool or reel. Once the reel barge is on location, the pipeline is straightened and lowered to the seafloor on its intended route. Both types of lay barge use a stinger to support the pipeline as it enters the water. The stinger helps to prevent undesirable bending or kinking of the pipeline as it is installed. In some cases, pipelines or segments of pipelines are welded together onshore or along a beach front area and then towed offshore to their location for installation. In a typical offshore operation, a lay barge would move one pipe length every 15 minutes, while third-generation barges may achieve rates of a mile per day (Wolbers and Hovinga, 2003). The rate of progress depends on the lay barge type, crew experience, and weather. Additional information on pipeline installation can be found in **Chapter 3.1.3.3.1** below.

Fixed, jacketed platforms are the most common surface structures of the GOM (refer to **Chapter 3.1.3.2**) and account for about 60 percent of all bottom-founded surface structures on the shallow continental shelf. Fixed platforms are brought on location as a complete unit or in sections on an installation barge towed by powerful tug boats. If the structure is fabricated in sections, it is generally composed of two segments: the jacket and the deck. Accidents have occurred during the vulnerable period when heavy equipment is held only by cranes. In December 1998, the 3,600-ton topside structure for the Petronius compliant tower was lost in 1,750 ft (533 m) of water as it was being lifted into place by the lift barge in Viosca Knoll Block 892.

The platform's tubular-steel jacket would then be launched from the barge, upended, and lowered into position by a derrick barge with a large crane. The jacket is anchored to the seafloor by piles driven through the legs. The deck section with one or more levels is then lifted atop the jacket and welded to the foundation. The platform may have a helipad installed on its deck section. Platforms may or may not be manned continuously. The different types of floating platforms are discussed in **Chapter 3.1.3.2**.

Caissons are the second most numerous and account for about 30 percent of bottom-founded, surface structures in the GOM. Caissons are typically located primarily on the shallow continental shelf. Simpler in design and fabrication than traditional jacketed platforms, most caissons consist of a steel pipe that generally ranges from 36 to 96 in (91 to 2.44 cm) in diameter. The caisson pipe is driven over existing well(s) to a depth that allows for shoring against varying sea states. Though primarily installed for well protection, some caissons may also be used as foundations for equipment and termination or relay points for pipeline operations.

Well protectors account for about 10 percent of all bottom-founded surface structures in the GOM. Well protectors are used primarily to safeguard producing wells and their production trees from boat damage and from battering by floating debris and storms. Similar to fixed platforms, well protectors consist of small piled jackets with three or four legs generally less than 36 in (91 cm) in diameter, which may or may not support a deck section.

In shallow-water installations, jackets, piles, and topsides are fabricated onshore and transported to the site on a cargo barge, and installation times usually range from 2-4 weeks. For most deepwater systems, installation activities would extend over a period of 2 or 3 months or more, and if a number of wells are subsea, drilling and completion activities may extend over several years. The time required to complete the myriad of operations to start production at a structure is dependent on the complexity of its facilities.

To keep floating structures on station, a mooring system would be designed and installed. Lines to anchors or piling arrays attach the floating components of the structure. With a TLP, tendons stem from a base plate on the sea bottom to the floating portion of the structure. Commissioning activities involve the emplacement, connecting, and testing of the structure's modular components that are assembled onsite.

How Much Offshore Support Infrastructure Could Be Developed?

Following a lease sale, support infrastructure installation would likely occur over the course of each lease but could begin within 1 year. The majority of platforms installed in early years would be caissons and small fixed platforms in shallow water. Floating structures installed in deeper water would take several years to construct and install. The highest number of platforms operating as a result of a lease sale would peak before year 10 in the low production scenario and around year 25 for the high production scenario; refer to **Figure 3-8(A)** below. **Table 3-2 and Figure 3-8(B, C)** show the estimated range installed production structures by water-depth range. Regardless of the production scenario or alternative, most support structure installation is expected to be on the continental shelf (0- to 200-m [0- to 656-ft] water depth).

Alternative A:* It is estimated that 16-280 production structures would be installed as a result of a lease sale under Alternative A.

*Alternative B**: It is estimated that 14-247 production structures would be installed as a result of a lease sale under Alternative B.

*Alternative C**: It is estimated that 17-91 production structures would be installed as a result of a lease sale under Alternative C.

*Alternative D could reduce activity values of the combined Alternative A, B, or C, but it may only shift the location of offshore infrastructure and activities farther from sensitive topographic zones. Since the ranges given for Alternatives A, B, and C are broad and represent the low and high levels of forecasted activity, any reduction of activity from choosing Alternative D would still fall within those ranges; therefore, the scenarios do not change when considering Alternative D. The potential impacts associated with selecting Alternative D are discussed in **Chapter 4** under each resource. Refer to **Chapter 2.2.2.4** for more information.

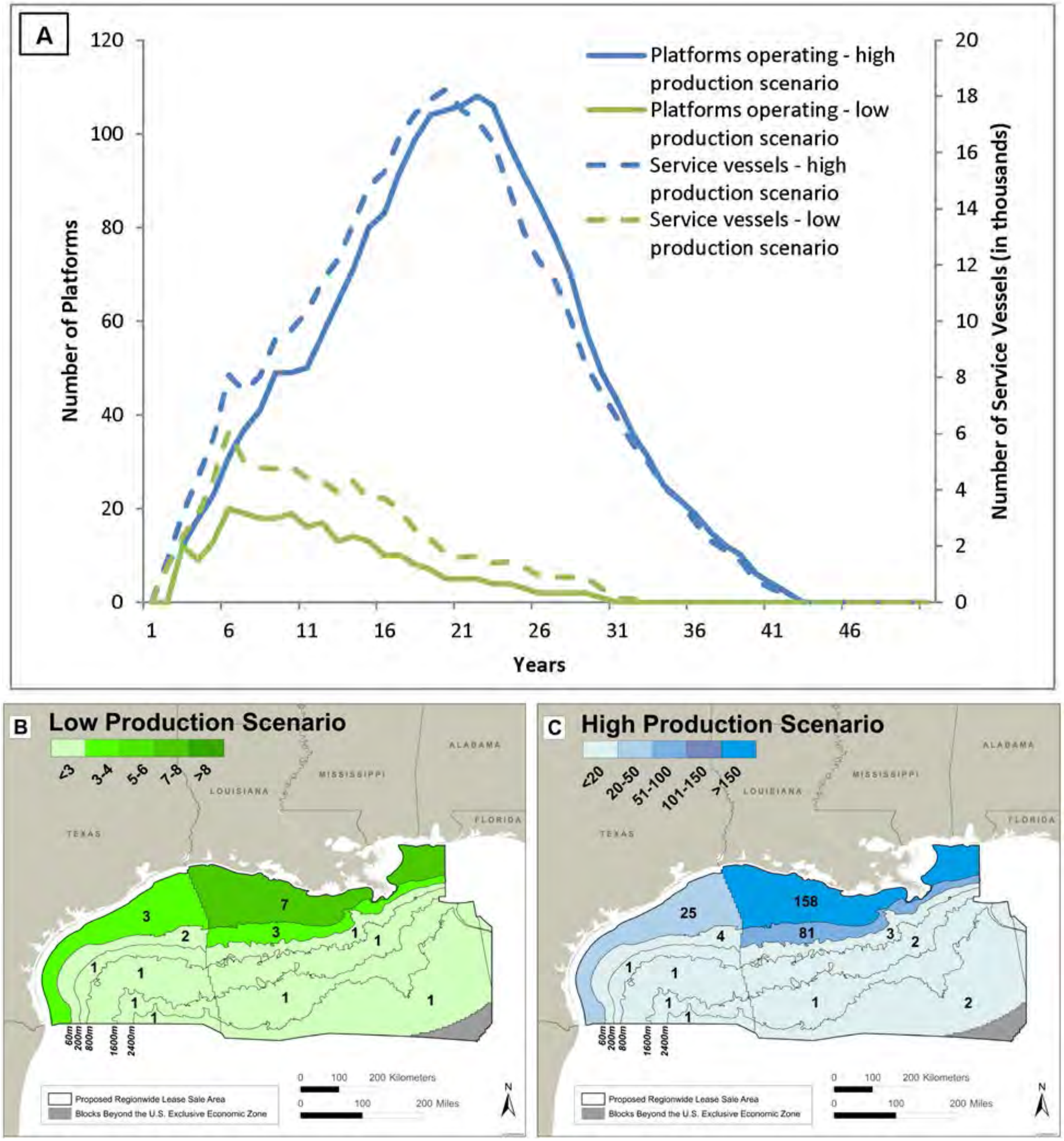

Figure 3-8. Number of Production Structures and Service Vessels Operating over the Course of a Proposed Action under Alternative A for 50 Years. (B, C) Total Number of Platforms Installed in the Low and High Production Scenario by Water Depth.

3.1.3.3.1 Pipelines

Pipelines are the primary method used to transport a variety of liquid and gaseous products between OCS production sites and onshore facilities around the GOM (**Table 3-4**). A mature pipeline network exists in the GOM to transport oil and gas production from the OCS to shore. There are currently 144 pipeline landfalls (pipelines that have at one time carried hydrocarbon product) in the Louisiana Coastal Area (LCA) (Smith, official communication, 2015). Included in this number of pipeline landfalls is a subset of 121 pipeline systems under the U.S. Department of Transportation's (DOT) jurisdiction originating in Federal waters and terminating onshore or in Louisiana State waters (Smith, official communication, 2015; **Table 3-5**). There are 14 OCS oil- and gas-related pipelines that transition into Texas State lands or that make landfall onshore, many of which switch back across this boundary. The BSEE and DOT share responsibility for pipeline regulation on the OCS in the transition between Federal and State waters. For more information on the regulation and permitting of pipelines, refer to **Appendix A.3**.

Table 3-4. Oil Transportation Scenario under Alternatives A, B, and C.

Activity	Alternative[1]	Offshore Subareas (m)[2]						Totals[3]
		0-60	60-200	200-800	800-1,600	1,600-2,400	>2,400	
Percent Oil Piped[4]	A	72-94%	100%	100%	100%	100%	100-66%	99.8-90.0%
	B	70-94%	100%	100%	100%	100%	100-50%	98.8-84.6%
	C	100%	100%	100%	100%	100%	100%	100%
Percent Oil Barged	A	28-6%	0%	0%	0%	0%	0%	0.2%
	B	30-6%	0%	0%	0%	0%	0%	0.2%
	C	0%	0%	0%	0%	0%	0%	0%
Percent Tankered[5]	A	0%	0%	0%	0%	0%	0-34%	0-9.8%
	B	0%	0%	0%	0%	0%	0-50%	0-15.2%
	C	0%	0%	0%	0%	0%	0%	0%

[1] Alternative D could reduce activity values of the combined Alternative A, B, or C. Refer to **Chapter 2.2.2.4** for more information. Percentage values indicated here would not change.
[2] Refer to **Figure 3-2**. Ranges are reported from the low production scenario to the high production scenario.
[3] Subareas totals may not add up to the planning area total because of rounding.
[4] 100% of gas is assumed to be piped.
[5] Tankering is forecasted to occur only in water depths >1,600 m (5,249 ft).

Table 3-5. Existing Coastal Infrastructure Related to OCS Oil- and Gas-Related Activities in the Gulf of Mexico.

Infrastructure	Texas	Louisiana	Mississippi	Alabama	Florida	Total
Pipeline Landfalls[1]	14	122	3	5	0	144
Platform Fabrication Yards[2]	12	37	4	1	0	54
Shipyards[2]	32	64	9	18	14	137
Pipe Coating Facilities[2]	9	6	0	2	2	19
Supply Bases[2]	32	55	2	7	0	96
Ports[2]	11	14	3	1	5	34
Waste Disposal Facilities[2]	16	29	3	3	2	53
Natural Gas Storage Facilities[2]	13	8	0	1	0	22
Helicopter Hubs[2]	118	115	4	4	0	241
Pipeline Shore Facilities[2]	13	40	0	0	0	53
Barge Terminals[2]	110	122	6	6	8	252
Tanker Ports[2]	4	6	0	0	0	10
Gas Processing Plants[2]	39	44	1	13	1	98
Refineries[3]	20	16	3	3	0	42
Petrochemical Plants[2]	126	66	2	9	13	216

[1] Source: Smith, 2015.
[2] Source: Dismukes, 2011.
[3] Source: USDOE, Energy Information Administration, 2015a.

Newer installation methods have allowed the pipeline infrastructure to extend farther into deep water. The gas pipeline supporting the Shell Stones FPSO is expected to be the deepest pipeline in the GOM at 2,900 m (9,500 ft). More than 500 pipelines reach water depths of 400 m (1,312 ft) or more, and over 400 of those pipelines reach water depths of 800 m (2,625 ft) or more. These technical challenges are described in more detail in *Deepwater Gulf of Mexico 2006: America's Expanding Frontier* (USDOI, MMS, 2006).

Pipeline Installation and Maintenance

> *30 CFR § 250.1003*
>
> *Pipelines greater than 8 5/8 inches in diameter and installed in water depths of less than 200 feet shall be buried to a depth of at least 3 feet unless they are located in pipeline congested areas or seismically active areas as determined by the Regional Supervisor.*

Pipelines constructed in water depths <200 ft (61 m) are potential snags for anchors and trawls and must be buried according to BSEE's regulations. These pipelines account for 56 percent of the total pipeline length in Federal waters. The regulations also provide for the burial of any pipeline, regardless of size, if BSEE determines that the pipeline may constitute a hazard to other uses of the OCS; in the Gulf of Mexico, BSEE has determined that all pipelines installed in water depths <60 m (197 ft) must be buried. The purpose of these requirements is to reduce the movement of pipelines by high currents and storms, protect the pipeline from the external damage that could result from anchors and fishing gear, reduce the risk of fishing gear becoming snagged, and minimize interference with the operations of other users of the OCS. For pipelines >$8^5/_8$ in (22.9 cm), a waiver of the burial requirement may be requested and may be approved if the line is to be laid in an area where the character of the seafloor would allow the weight of the line to cause it to sink into the sediments (self-burial). For a pipeline that crosses a fairway or anchorage in Federal waters in depths ≤60 m (197 ft), any length of pipeline must be buried to a minimum depth of 10 ft (3 m) below mudline across a fairway and a minimum depth of 16 ft (5 m) below mudline across an anchorage area. Some operators voluntarily bury these pipelines deeper than the minimum.

Where pipeline burial is necessary, a jetting sled would be used. Such sleds are mounted with high-pressure water jets and pulled along the seafloor behind the pipe-laying barge. The water jets are directed downward to dig a trench; the sled guides the pipeline into the trench. Such an apparatus can jet pipe at an average of 1.6 km/day (1.0 mi/day). The cross section of a typical jetted trench for the flowline bundles would be about 4 m^2 (43 ft^2); for deeper burial when crossing a fairway, the cross section would be about 13 m^2 (140 ft^2). The cross section of a typical jetted trench for the export and interconnecting export pipelines would be about 5 m^2 (54 ft^2); for a pipeline trench crossing a fairway, the cross section would be about 15 m^2 (161 ft^2).

Jetting disperses sediments over the otherwise undisturbed water bottom that flanks the jetted trench. The area covered by settled sediment and the thickness of the settled sediment depends upon variations in bottom topography, sediment density, and currents. Newer installation methods have allowed the pipeline infrastructure to extend to deeper water.

The following information is discussed more thoroughly in this Agency's *Deepwater Gulf of Mexico 2006: America's Expanding Frontier* (USDOI, MMS, 2006). Pipeline installation activities in deepwater areas can be difficult both in terms of route selection and construction. Depending on the location, the sea-bottom surface can be extremely irregular and present engineering challenges (e.g., high hydrostatic pressure, cold temperatures, and darkness, as well as varying subsurface and bottom current velocities and directions). Rugged seafloor may cause terrain-induced pressures within the pipe that can be operationally problematic, as the oil must be pumped up and down steep slopes. An uneven seafloor could result in unacceptably long lengths of unsupported pipeline, referred to as "spanning," which in turn could lead to pipe failure from bending stress early in the life of the line. It is important to identify areas where substantial lengths of pipeline may go unsupported. Accurate, high-resolution geophysical surveying becomes increasingly important in areas with irregular seafloor. Recent advances in surveying techniques have significantly improved the capabilities for accurately defining seafloor conditions, providing the resolution needed to determine areas where pipeline spans may occur. After analyzing survey data, the operator chooses a route that minimizes pipeline length and avoids areas of seafloor geologic structures and obstructions that might cause excessive pipe spanning, unstable seafloor, and potential benthic communities.

The BSEE's minimum cathodic protection design criteria for pipeline external corrosion protection is 20 years. For the most part, pipelines have a designed life span greater than 20 years and, if needed, can be retrofitted to increase the life span (**Chapter 3.1.6.1**). Should a pipeline need to be replaced because of integrity issues, a replacement pipeline is installed or alternate routes are used to transport the products, or a combination of the two. Besides replacement because of integrity issues, a pipeline may also be required to be replaced as a result of storm or other damages. The BSEE estimates that the overall pipeline replacement over the past few years is about 1 percent of the total installed.

The greater pressures and colder temperatures in deep water present difficulties with respect to maintaining the flow of crude oil and gas through pipelines. Under these conditions, the physical and chemical characteristics of the produced hydrocarbons can lead to the accumulation of gas hydrate, paraffin, and other substances within the pipeline. These accumulations can restrict and eventually block flow if not successfully prevented and/or abated. There are physical (including "pigging" devices) and chemical techniques (e.g., methanol or ethylene glycol) that can be applied to manage these potential accumulations. Companies are continuously looking for and developing new technologies, such as electrically and water-heated pipelines and burial of pipelines in deepwater for insulation purposes.

Long-distance transport of multiphase well-stream fluids can be achieved with an effectively insulated pipeline. There are several methods to achieve pipeline insulation: pipe-in-pipe systems, which included electrically and water-heated pipelines; pipe with insulating wrap material; and as previously mentioned, buried pipelines where the soils act as an insulator. The design of all of these systems seeks a balance between the high cost of the insulation, the intended operability of the system, and the acceptable risk level.

Clearance of pipeline interiors is carried out by "pigs." Pigging is a term used to describe a mechanical method of displacing a liquid in a pipeline or to clean accumulated paraffin (a waxy buildup) from the interior of the pipeline by using a mechanized plunger or pig. Paraffin deposits will form inside pipelines that transport liquid hydrocarbons and, if some remedial action such as pigging is not taken, the deposited paraffin will eventually completely block all fluid flow through the line. The frequency of pigging could range from several times a week to monthly or longer, depending on the nature of the produced fluid. In cases where paraffin accumulation cannot be mitigated, extreme measures can be taken in some cases such as coil tubing entry into a pipeline to allow washing (dissolving) of paraffin plugs. If that fails, then it could result in having to replace a pipeline.

Leaks in pipelines are detected through a series of pressure gauges mandated in 30 CFR 250.1004. Additionally, each DOI pipeline route in the GOM is inspected at least monthly for an indication of pipeline leakage. These inspections are made by using a helicopter, marine vessel, or other approved means (USDOI, MMS, 1991). Refer to **Chapter 3.2.1** for more information on oil spills.

How Much Pipeline Infrastructure Would Likely Be Developed?

BOEM projects that the majority of new pipelines constructed as a result of a proposed action would connect to the existing pipeline infrastructure. In the rare instance that a new pipeline to shore would need to be constructed, it would likely be because there are no existing pipelines reasonably close and because constructing a pipeline to shore is considered more cost effective, although it is highly unlikely for an operator to choose this contingency (Dismukes, official communication, 2011a). BOEM anticipates that pipelines from most of the new offshore production facilities would tie-in to the existing pipeline infrastructure offshore or in State waters, which would result in few new pipeline landfalls. Pipeline emplacement resulting from a proposed action would increase the capacity and potentially the maximum extraction rate of oil and gas.

The length of new pipelines was estimated using the amount of production, the number of structures projected as a result of each alternative, and the location of the existing pipelines. The range in length of pipelines projected is because of the uncertainty of the location of new structures, which existing or proposed pipelines would be used, and where they tie-in to existing lines. Many factors would affect the actual transport system, including company affiliations, amount of production, product type, and system capacity.

Alternative A:* BOEM projects 355-2,144 km (220-1,332 mi) of new pipelines under Alternative A (**Table 3-2**). About 16-25 percent of the new pipeline length would be in water depths <60 m (197 ft), requiring burial.

Alternative B:* BOEM projects 254-1,641 km (157-1,020 mi) of new pipelines under Alternative B (**Table 3-2**). About 15-24 percent of the new pipeline length would be in water depths <60 m (197 ft), requiring burial.

Alternative C:* BOEM projects 105-505 km (65-314 mi) of new pipelines under Alternative C (**Table 3-2**). About 19-26 percent of the new pipeline length would be in water depths <60 m (197 ft), requiring burial.

*Alternative D could reduce activity values of the combined Alternative A, B, or C, but it may only shift the location of offshore infrastructure and activities farther from sensitive topographic zones. Since the ranges given for Alternatives A, B, and C are broad and represent the low and high levels of forecasted activity, any reduction of activity from choosing Alternative D would still fall within those ranges; therefore, the scenarios do not change when considering Alternative D. The potential impacts associated with selecting Alternative D are discussed in **Chapter 4** under each resource. Refer to **Chapter 2.2.2.4** for more information.

Pipeline Landfalls

The OCS oil- and gas-related pipelines nearshore and onshore may join pipelines carrying production from State waters or territories for transport to processing facilities or to distribution pipelines located farther inland. Oil and gas companies have a strong financial incentive to reduce costs by utilizing, to the fullest extent possible, the mature pipeline network that already exists in the GOM. Economies of scale are a factor in pipeline transportation; maximizing the amount of product moved through an already existing pipeline decreases the long-term average cost of production.

Additional considerations include mitigation costs for any new wetland and environmental impacts and various landowner issues at the landfall point. Because of these strong incentives to move new production into existing systems and to avoid creating new landfalls, the 5-year moving average of new OCS pipeline landfalls has been below two per year since 1986. Over the last 15 years (1999-2014), there has been an average of slightly over one new OCS pipeline landfall every 2 years (0.53 per year). **Table 3-6** lists the OCS pipeline landfalls that have been installed since 1996. While no new pipelines landfalls have been installed in the last 5 years, pipeline landfalls have been approved during that time. To project the likely number of new OCS pipeline landfalls, BOEM examined the historical relationships between new pipeline landfalls and a variety of factors including platforms installed, oil and gas production, and the total number of new pipelines. Based on this examination, BOEM assumes that the majority of new Federal OCS oil and gas pipelines would connect to the existing pipelines in Federal and State waters and that very few would result in new pipeline landfalls.

Table 3-6. OCS Pipeline Landfalls Installed from 1996 to 2014.

Segment Number	Year of Installation*	Product Type	Size (in)	Company	State
10631	1996	Oil	24	Equilon Pipeline Company LLC	LA
12470	1996	Oil	24	Manta Ray Gathering Company LLC	LA
11217	1997	Gas	30	Enbridge Offshore	LA
11496	1997	Oil	12	ExxonMobil Pipeline Company	LA
11952	2000	Oil	18-20	ExxonMobil Pipeline Company	TX
14470	2004	Oil	10	Chevron USA Inc.	LA
13972	2004	Oil	24	Manta Ray Gathering Company LLC	TX
13987	2004	Oil	24	Manta Ray Gathering Company LLC	TX
13534	2005	Oil	30	BP Pipelines (North America)	LA
13534	2005	Oil	30	Mardi Gras Endymion Oil Pipeline Co.	LA
17108	2007	Gas/Condensate	16	Stone Energy Corporation	LA
17691	2009	Gas/Oil	8	Stone Energy Corporation	LA

*Year when the initial hydrostatic test occurred.

Source: Smith, official communication, 2015.

Alternative A, B, or C:* Up to one (i.e., 0-1) new pipeline landfall could result under Alternative A, B, or C.

*Alternative D is not expected to affect pipeline landfalls. Refer to **Chapter 2.2.2.4** for more information.

3.1.3.3.2 Bottom-Area Disturbance

Structures emplaced or anchored on the OCS to facilitate oil and gas exploration and production include drilling rigs or MODUs (i.e., jack-ups, semisubmersibles, and drillships), pipelines, and fixed surface, floating, and subsea production systems; these structures are discussed in **Chapters 3.1.3.2** above. The emplacement or removal of these structures disturbs small areas of the sea bottom beneath or adjacent to the structure. If mooring lines of steel, chain, or synthetic polymer are anchored to the sea bottom, areas around the structure could also be directly affected by their emplacement. This disturbance includes physical compaction or crushing beneath the structure or mooring lines and the resuspension and settlement of sediment caused by the activities of emplacement. Movement of floating types of facilities would also cause the movement of the mooring lines in its array. Small areas of the sea bottom would be affected by this kind of movement.

Wells drilled in shallow water create a splay of drilling muds and cuttings that spread 250 m (820 ft) from the well, and in deepwater (over 300-m [984-ft] water depth) the coverage area would be approximately 500 m (1,640 ft) from the well. Muds and cuttings are discussed further in **Chapter 3.1.5.1.1**. There are numerous studies about splays from various areas of the GOM and other locations around the world (Neff et al., 2000; USEPA, 2000a; International Association of Oil and Gas Producers, 2003). These splays on the seafloor vary from one location to the next and vary by well depth, which controls the total volume of cuttings available for disbursement. Variation in splay size are caused by water depth, well depth, drilling fluid type (cuttings from oil-based or synthetic mud are taken to shore for disposal), and currents. A typical splay is not in a uniform circular shape but rather in the shape of a fan that is influenced by prevailing currents and the fall rate of drill cuttings; however, for this calculation, disturbance is considered a possibility in all directions from a well. The model used here is an oversimplification in order to obtain a conservative estimate of disturbance per offshore production system. Given that a splay from a well generally overlays the footprint of an offshore production system and creates a larger surface area of disturbance, only bottom disturbance from the splay is considered when evaluating overall bottom disturbance.

Subsea production systems located on the ocean floor are connected to surface topsides by a variety of components. These bottom-founded components are an integrated system of flowlines, manifolds, flowline termination sleds, umbilicals, umbilical sleds, blowout preventers, well trees, and production risers. Richardson et al. (2008) indicated that all currently operating subsea systems are tied to an offshore production system.

Emplacement of flowlines and export pipelines that cross a fairway disturb between 0.5 and 1.0 ha (1.2 and 2.5 ac) of seafloor per kilometer of pipeline (Cranswick, 2001). Pipe-laying vessels operating in the deepwater Gulf of Mexico rely on dynamic positioning rather than conventional anchors to maintain their position during operations and do not require trenching, so deepwater pipe-laying is assumed to disturb 0.32 ha (0.79 ac). The variation lies in BSEE's requirement to bury pipelines in water depths <200 ft (61 m) to a depth of 3 ft (1 m). Burial is typically done by water jetting a trench followed by placing the pipeline into it.

Alternative A:* Bottom-area disturbance is calculated as a relationship between the structures projected (i.e., platforms, wells, subsea structures, and pipeline miles installed [**Chapter 3.1.3.3.1**]) and the associated disturbance of each. Under Alternative A, between 1,226 and 21,158 ha (3,029 and 52,282 ac) of sea bottom is projected to be disturbed. This is <0.01-0.05 percent of the total area of the Gulf of Mexico.

*Alternative B**: Under Alternative B, between 1,056 and 18,648 ha (2,609 and 46,080 ac) of sea bottom is projected to be disturbed in the CPA/EPA. This is <0.01-0.03 percent of the total area of the Gulf of Mexico.

*Alternative C**: Under Alternative C, between 693 and 2,525 ha (1,712 and 6,239 ac) of sea bottom is projected to be disturbed in the WPA. This is <0.001-0.01 percent of the total area of the Gulf of Mexico.

*Alternative D could reduce activity values of the combined Alternative A, B, or C, but it may only shift the location of offshore infrastructure and activities farther from sensitive topographic zones. Since the ranges given for Alternatives A, B, and C are broad and represent the low and high levels of forecasted activity, any reduction of activity from choosing Alternative D would still fall within those ranges; therefore, the scenarios do not change when considering Alternative D. The potential impacts associated with selecting Alternative D are discussed in **Chapter 4** under each resource. Refer to **Chapter 2.2.2.4** for more information.

3.1.3.3.3 Sediment Displacement

Displaced sediments are those that have been physically moved “in bulk.” Displaced sediments cover or bury an area of the seafloor, while resuspended sediments cause an increase in turbidity of the adjacent water column. Resuspended sediments eventually settle, covering the surrounding seafloor. Resuspended sediments may include entrained heavy metals or hydrocarbons.

The chief means for sediment displacement is the overboard discharge of drill cuttings carried to the surface by drilling mud. Cuttings that outfall from surface platforms settle to the sea bottom as a mound or plume if influenced by the prevailing currents. Sediment displacement can also take place when anchored exploration rigs and production structures are subject to high current energy, such as GOM loop currents or hurricane sea states. Mooring lines in contact with the sea bottom can scrape sediment into heaps and mounds as the surface facility moves in response to currents.

Trenching for pipeline burial causes displacement or resuspension of seafloor sediments. Sediment displacement also occurs as a result of the removal of pipelines. It is projected that the number of pipeline decommissionings (or re-routings) would increase regionwide as the existing pipeline infrastructure ages (refer to **Chapter 3.1.6.1**). For each kilometer of pipeline removed in water depths <200 ft (61 m), approximately 5,000 m^3 (176,573 ft^3) of sediment would be displaced and resuspended (Cranswick, 2001).

3.1.3.3.4 Navigation Channels

BOEM conservatively estimates that there are approximately 4,850 km (3,013 mi) of Federal navigation channels, bayous, and rivers potentially exposed to OCS traffic regionwide (**Table 3-7; Figure 3-9**) and that the average canal is widening at a rate of 0.99 m/yr (3.25 ft/yr) (Thatcher et al., 2011). This would result in a total (OCS and non-OCS oil- and gas-related) annual land loss of approximately 831 ac/yr (336 ha/yr). Total land loss in these areas can be caused by multiple factors, including saltwater intrusion, hurricanes, and vessel traffic (refer to **Chapter 3.3.2.8** below). Assuming that vessel traffic alone was the sole source of erosion, the rate of land loss would be related to the usage of those canals by both OCS Program-related vessels and other vessel traffic. Using the estimated proportion of OCS Program vessel traffic as a measurement of erosion, the numbers above are considered conservative because open waterways were included in the total length of Federal navigation channels, vessel size was not taken into consideration, and there are sources of erosion to navigation canals other than vessel traffic alone.

Table 3-7. Waterway Length, Depth, Traffic, and Number of Trips for 2012.

Waterway	Canal Length (km)	Maintained Depth (ft)	Traffic (1,000 short tons)	Number of Trips	
				Foreign	Domestic
Gulf Intracoastal Waterway (GIWW)					
Apalachee Bay to Panama City, FL	217	12	607	0	329
Panama City to Pensacola Bay, FL	177	12	1,610	0	1,114
Pensacola Bay, FL to Mobile Bay, AL	74	12	3,962	0	3,646
Mobile Bay, AL to New Orleans, LA	215	12, 14	18,209	0	13,585
Mississippi River, LA to Sabine River, TX	428	12, 10	63,911	0	52,435
Sabine River to Galveston, TX	135	12	59,577	0	33,113
Galveston to Corpus Christi, TX	305	11, 11, 10.2	29,314	0	21,178
Corpus Christi, TX to Mexican Border	214	10, 12, 7	1,920	0	1,483
Morgan City – Port Allen Route, LA	103	10	18,832	0	9,463
Florida Harbors, Channels, and Waterways					
Escambia and Conecuh Rivers, FL and AL; Escambia Bay, FL	12	10	1,664	0	1,930
La Grange Bayou, FL	3	9	219	0	70
Panama City Harbor, FL	9	34, 32, 10	2,326	308	674
Pensacola Harbor, FL	21	35, 33, 15, 14	879	471	435
St. Marks River, FL	61	9	72	0	36
Tampa Harbor, FL	141	45, 43, 34, 12, 9	31,650	834	1,459
Port Manatee, FL	5	40	3,397	219	30

Waterway	Canal Length (km)	Maintained Depth (ft)	Traffic (1,000 short tons)	Number of Trips	
				Foreign	Domestic
Alabama Harbors, Channels, and Waterways					
Mobile Harbor, AL	71	47, 45, 40, 13-39	54,888	1,338	17,965
Theodore Ship Channel, AL	13	40	4,646	212	1,357
Mississippi Harbors, Channels, and Waterways					
Biloxi Harbor, MS	39	12, 10, 12	1,047	0	1,106
Gulfport Harbor, MS	34	30, 32, 8	1,888	200	406
Pascagoula Harbor, MS	18	40, 38, 38, 22, 12	33,785	601	3,110
Bayou Casotte, MS	2	38	33,467	518	2,837
Louisiana Harbors, Channels, and Waterways					
Atchafalaya River (Lower), LA	62	20	983	332	11,050
Barataria Bay Waterway, LA	66	17, 10	288	13	5,146
Bayou Lafourche and Bayou Lafourche-Jump Waterway	80	28, 27, 27, 9	6,092	2,342	16,463
Bayou Little Caillou, LA	56	12	68	0	305
Bayou Teche, LA	171	3,3,4,7	474	0	321
Bayou Teche and Vermilion River, LA	83	8,11,9,8,5	601	17	1,541
Bayou Terrebonne, LA	61	10	134	0	692
Calcasieu River and Pass, LA	176	42, 42, 41-42, 36, 12, 7	54,382	1,318	32,207
Freshwater Bayou, LA	34	12	493	57	4,989
Houma Navigation Canal, LA	59	16, 15, 16	473	30	1,812
Mermentau River, LA	131	4, 7, 12, 10, 10, 9, 11, 6, 8, 4, 4, 7	311	0	1,802
Mermentau River, Bayou Nezpique, and Des Cannes, LA	122	9, 14, 10	443	0	649
Mississippi River, Baton Rouge LA to the Mouth of Passes	437	45, 13	456,551	5,635	216,588
Port of New Orleans, LA	83	45, 30, 32, 36, 37, 12	79,342	1,852	26,820
Port of Baton Rouge, LA	144	45, 40, 9, 12	59,993	664	47,602
Port of South Louisiana	86	45	252,069	2,451	67,601
Port of Plaquemines, LA	131	45	58,280	654	74,951
Passes of the Mississippi River, LA	57	13, 45	230,048	5,635	3,707
Mississippi River Gulf Outlet via Venice Vicinity Consolidation	22	16, 14, 14	1,585	13	6,276
Petit Anse, Tigre, and Carlin Bayous	28	6, 9, 5, 7	1,563	0	1,243
Port of Iberia	14	13	~2,200	NA	NA
Port of Morgan City, LA	–	12	1,771	202	12,474

Waterway	Canal Length (km)	Maintained Depth (ft)	Traffic (1,000 short tons)	Number of Trips	
				Foreign	Domestic
Waterway from Empire, LA to the Gulf of Mexico	17	6,9,14	1,044	0	7,292
Waterway from Intracoastal Waterway to Bayou Dulac, LA	61	14	145	0	1,271
Texas Harbors, Channels and Waterways					
Brazos Island Harbor, TX	47	36.5, 38, 31, 38, 12, 14, 7	5,614	251	1,155
Cedar Bayou, TX	22	11	1,349	0	1,222
Channel to Aransas Pass, TX	11	14	782	20	749
Channel to Port Bolivar, TX	17	12	0	0	56,583
Corpus Christi Ship Channel, TX	64	47, 45, 46, 47, 14, 9	69,001	1,349	102,837
Dickenson Bayou, TX	34	9	47	0	25
Freeport Harbor, TX	14	44, 37, 18, 40	22,085	716	3,207
Galveston Channel, TX	6	41	11,618	2,843	61,016
Houston Ship Channel, TX	112	45, 40, 32-39, 9, 7, 35-37, 7, 40, 12	238,186	6,262	81,048
Matagorda Ship Channel, TX	91	35, 9.8, 10, 12.8, 2	9,333	329	1,847
Sabine-Neches Waterway, TX	160	40, 37, 39, 32, 27, 20, 9, 8	137,218	1,908	31,828
Texas City Channel, TX	14	43, 41, 42, 42	57,758	776	6,625

Source: U.S. Dept. of the Army, COE, 2012.

While a proposed lease sale under Alternative A, B, or C would contribute to the continued need for maintenance dredging of existing navigation channels, a mature network of navigation channels already exists in the analysis area; therefore, no new navigation channel construction would be expected as a direct result of a proposed lease sale under Alternative A, B, C, or D.

Alternative A:* Assuming that vessel traffic alone was the sole source of erosion, there would be an average annual loss of 0.40-5.02 ha (0.99-12.40 ac) for Alternative A. All service vessels associated with EPA blocks are assumed to use CPA navigational canals while inland and constitute less than 1 percent of the total vessel traffic. Service vessels associated with CPA leases are assumed to use CPA navigational canals and constitutes less than 2 percent of the total traffic. Service vessels associated with WPA leases are assumed to use WPA navigational canals and constitute less than 1 percent of the total traffic in the GOM.

*Alternative B**: Assuming that vessel traffic alone was the sole source of erosion, there would be an annual loss of 0.46-5.53 ha (1.15-13.66 ac) for Alternative B.

*Alternative C**: Assuming that vessel traffic alone was the sole source of erosion, there would be an annual loss of 0.18-0.54 ha (0.45-1.34 ac) for Alternative C.

*Alternative D could reduce activity values of the combined Alternative A, B, or C, but it may only shift the location of offshore infrastructure and activities farther from sensitive topographic zones. Since the ranges given for Alternatives A, B, and C are broad and represent the low and high levels of forecasted activity, any reduction of activity from choosing Alternative D would still fall within those ranges; therefore, the scenarios do not change when considering Alternative D. The potential impacts associated with selecting Alternative D are discussed in **Chapter 4** under each resource. Refer to **Chapter 2.2.2.4** for more information.

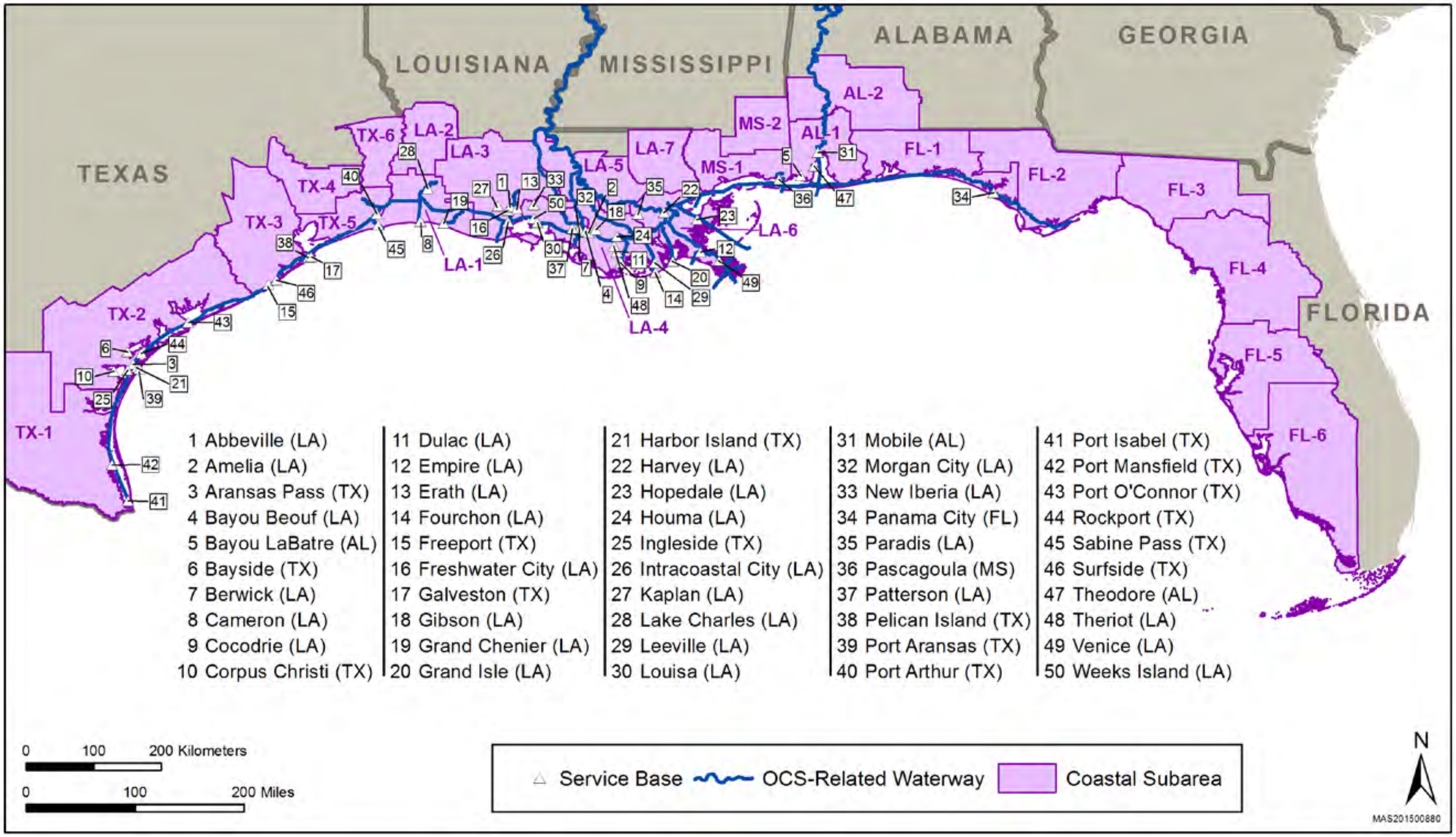

Figure 3-9. Gulfwide OCS Oil- and Gas-Related Service Bases and Major Waterways.

3.1.3.4 Infrastructure Presence

3.1.3.4.1 Anchoring

Most exploration drilling, platform, and pipeline emplacement operations on the OCS require anchors to hold the rig, topside structures, or support vessels in place. Anchors disturb the seafloor and sediments in the area where dropped or emplaced. Anchoring can cause physical compaction beneath the anchor and chains or lines, as well as resuspended sediment. A disturbed area on the sea bottom forms by the swing arc formed by anchor lines scraping across bottom within the range of the anchoring system configuration. Dynamically positioned rigs, production structures, and vessels are held in position by four or more propeller jets and do not cause anchoring impacts. Conventional pipe-laying barges use an array of eight 9,000-kg (19,842-lb) anchors to position the barge and to move it forward along the pipeline route. These anchors are continually moved as the pipe-laying operation proceeds. The area actually affected by these anchors depends on water depth, wind, currents, chain length, and the size of the anchor and chain. Mooring buoys may be placed near drilling rigs or platforms so that service vessels need not anchor or for when they cannot anchor (in deeper water). The temporarily installed anchors for these buoys would most likely be smaller and lighter than those used for vessel anchoring and, thus, would have less impact on the sea bottom. Moreover, installing one buoy would preclude the need for numerous individual vessel-anchoring occasions. Service-vessel anchoring is assumed not to occur in water depths >150 m (492 ft) and only occasionally in shallower waters (vessels would always tie up to a platform or buoy in water depths >150 m [492 ft]). Barges are assumed to tie up to a production system rather than anchor. Barges and other vessels are also used for both installing and removing structures. Barge vessels use anchors placed away from their location of work.

3.1.3.4.2 Space-Use Requirements

Leasing on the OCS results in operations that temporarily occupy sea bottom and water surface area for dedicated uses. The OCS oil- and gas-related operations include the deployment of seismic vessels, bottom surveys, and the installation of surface or subsurface bottom-founded production structures with anchor cables and safety zones. While in use, these areas would become unavailable to commercial fishermen, sand borrowing, or any other competing use.

> *BOEM’s data indicate that the total area lost due to the presence of production platforms has historically been and would continue to be less than 1 percent of the total surface area available.*

The G&G surveys can occur in both shallow and deepwater areas. Usually, fishermen are precluded from a very small area for several days during active G&G surveying. Exploratory drilling rigs spend approximately 40-150 days onsite and are a short-term interference to commercial fishing. A major bottom-founded production platform in water depths less than 450 m (1,476 ft), with a surrounding 100-m (328-ft) navigational safety zone, requires approximately 6 ha (15 ac) of space. A bunkhouse structure needs about 4 ha (9 ac) and a satellite structure needs about 1.5 ha (3.7 ac) of space.

In water depths greater than 450 m (1,476 ft), production platforms would be compliant towers, floating production structures (such as TLPs and spars), and FPSOs. Even though production structures in deeper water are larger and individually would take up more space, there would be fewer of them compared with the great numbers of bottom-founded platforms in shallower water depths. Factoring in various configurations of navigational safety zones, deepwater facilities may require up to a 500-m (1,640-ft) radius safety zone or 78 ha (193 ac) of space (33 CFR § 147.15). Production structures in all water depths have a life expectancy of 20-30 years.

Alternative A:* A maximum of 648 ha (1,598 ac) could be lost to other uses under Alternative A. This number is based on a high of 108 production structures of approximately 6 ha (15 ac) of surface area operating simultaneously during the life of a proposed action. This is approximately 0.001 percent of the surface area of the Gulf of Mexico.

Alternative B:* A maximum of 546 ha (1,347 ac) could be lost to other uses under Alternative B. This number is based on a high of 91 production structures of approximately 6 ha (15 ac) of surface area operating simultaneously during the life of Alternative B. This is approximately 0.0008 percent of the surface area of the Gulf of Mexico.

Alternative C:* A maximum of 120 ha (296 ac) could be lost to other uses under Alternative C. This number is based on a high of 20 production structures of approximately 6 ha (15 ac) of surface area operating simultaneously during the life of Alternative C. This is approximately 0.0002 percent of the surface area of the Gulf of Mexico.

*Alternative D could reduce activity values of the combined Alternative A, B, or C, but it may only shift the location of offshore infrastructure and activities farther from sensitive topographic zones. Since the ranges given for Alternatives A, B, and C are broad and represent the low and high levels of forecasted activity, any reduction of activity from choosing Alternative D would still fall within those ranges; therefore, the scenarios do not change when considering Alternative D. The potential impacts associated with selecting Alternative D are discussed in **Chapter 4** under each resource. Refer to **Chapter 2.2.2.4** for more information.

3.1.3.4.3 Structure Lighting

The OCS oil- and gas-related structures in the GOM are illuminated from incandescent lights and from the glow of burning or flaring natural gas that cannot be stored or transported to shore. The U.S. Coast Guard (USCG) regulates workplace health and safety and maritime safety items, including lights illuminating working enviroments and navigational warning lights, on OCS platforms according to 33 CFR § 143.15. To assist in nighttime operations and aid navigation, manned platforms are generally well illuminated by exterior floodlights. Platforms generally have two varieties of floodlights: high-pressure sodium or mercury vapor. High-pressure sodium lights emit yellow-orange light, whereas mercury vapor lights emit a perceptually blue-white light. Some initiative has been taken to move toward downward facing lighting and green light. Although there are differences between platforms, floodlights located between 20 and 40 m (66 and 132 ft) above the water surface illuminate the structure and the surrounding water to a depth of at least 100-200 m (328-656 ft) and can often be observed several miles away from the platform (Keenan et al., 2007). Unmanned structures usually have minimal aid-to-navigation lights.

In addition to offshore lighting, coastal support infrastructure is also illuminated. Coastal infrastructure lighting may be specifically designed to emit horizontal or vertical light. Horizontal and near-horizontal light emittance increases the visibility of light sources from a distance and significantly increases the illuminated area, but it can also cause the encroachment of light into adjacent unlit areas. Light emitted horizontally or near-horizontally produces more sky glow than that emitted upward, and much more than light emitted downward (Gaston et al., 2012).

3.1.3.5 Workovers and Abandonments

Completed and producing wells may require periodic reentry that is designed to maintain or restore a desired flow rate. These procedures are referred to as a well "workover." Workover operations are also carried out to evaluate or reevaluate a geologic formation or reservoir (including recompletion to another strata) or to permanently abandon a part or all of a well. Examples of workover operations are acidizing the perforated interval in the casing, plugging back, squeezing cement, milling out cement, jetting the well in with coiled tubing and nitrogen, and setting positive plugs to isolate hydrocarbon zones. Workovers on subsea completions require that a rig be moved on location to provide surface support. Workovers can take from 1 day to several months to complete depending on the complexity of the operations, with a median of 7 days. Current oil-field practices include preemptive procedures or treatments that reduce the number of workovers required for each well. On the basis of historical data, BOEM projects a producing well may expect to have seven workovers or other well activities during its lifetime. Workover fluids are discussed in **Chapter 3.1.5.1.3** below.

There are two types of well abandonment operations—temporary and permanent. An operator may temporarily abandon a well to (1) allow detailed analyses or additional delineation wells while deciding if a discovery is economically viable, (2) save the wellbore for a future sidetrack to a new geologic bottom-hole location, or (3) wait on design or construction of special production equipment or facilities. The operator must meet specific requirements to temporarily abandon a well. Permanent abandonment operations are undertaken when a wellbore is of no further use to the operator (i.e., the well is a dry hole or the well's producible hydrocarbon resources have been depleted). During permanent abandonment operations, equipment is removed from the well, and specific intervals in the well that contain hydrocarbons are plugged with cement. A cement surface plug is also required for the abandoned wells. This serves as the final isolation component between the wellbore and the environment.

3.1.4 Transport

3.1.4.1 Barges

The capacity of oil barges used offshore can range from 5,000 to 80,000 bbl. Barges transporting oil may remain offshore for as long as 1 week while collecting oil; each round trip is assumed to be 5 days.

How Much Barging Activity Would Likely Occur?

Historically, barging in the GOM has remained less than 1 percent. In 2005, barging activity temporarily rose to 1.29 percent while pipelines that were damaged from hurricanes were repaired. In 2014, 0.08 percent of the total volume was transported by barge as compared with 0.13 percent in 2010. The average amount of oil barged between 2010 and 2014 was 0.12 percent annually. The number of active barging systems has been reduced over time from approximately eight systems in 2005 to four systems in 2010 and has remained constant since then. It is assumed that barging would continue to account for <1 percent of the oil transported for the entire OCS Program and for any single alternative. **Table 3-4** provides the percentages of oil barged to shore by subarea for each alternative.

In 2013, all "active" offshore barging locations were located in the CPA. The locations east of the Mississippi River accounted for roughly 78 percent of the total barged volume. Likewise, the locations located west of the Mississippi River accounted for the remaining 22 percent.

3.1.4.2 Oil Tankers

The FPSOs store crude oil in tanks in the hull of the vessel and periodically offload the crude to shuttle tankers or oceangoing barges for transport to shore. The FPSOs are used to develop marginal oil fields or are used in areas remote from the existing OCS pipeline infrastructure, especially development in the Lower Eocene Wilcox trend (Walker Ridge leasing area) that is far from most existing pipeline networks. The FPSO systems are suitable for the light and intermediate oils of the GOM, as well as heavier oil, such as the heavy oil Brazil plans to produce offshore in deep water. The use of FPSOs is only projected in water depths >1,600 m (5,250 ft). Shuttle tankers are used to transport crude oil from FPSO production systems to Gulf Coast refinery ports or to offshore deepwater ports such as the Louisiana Offshore Oil Port. Shuttle tanker design and systems are in compliance with USCG regulations, the Jones Act, and OPA requirements. As such, shuttle tankers are required to be double hulled. In the Gulf, the maximum size of shuttle tankers is limited primarily by the 34- to 47-ft (10- to 14-m) water depths. Because of these depth limitations, shuttle tankers are likely to be 500,000-550,000 bbl in cargo capacity.

Offloading operations involve the arrival, positioning, and hook-up of a shuttle tanker to the FPSO. Shuttle tankers can maintain their station during FPSO offloading operations using techniques that generally do not require anchoring. Offloading could occur at an average rate of 50,000 bbl per hour. During the FPSO offloading procedure, the shuttle tanker would continue to operate its engines in an idle mode so that any necessary maneuvers of the vessel could be promptly executed. Safety features, such as marine break-away offloading hoses and emergency shut-off valves, would be incorporated in order to minimize the potential for, and size of, an oil spill. In addition, weather and sea-state limitations would be established to further ensure that hook-up and disconnect operations would not lead to accidental oil release. A vapor recovery system between the FPSO and shuttle tanker would be employed to minimize the release of fugitive emissions from cargo tanks during offloading operations.

Tankering related to FPSO systems in the GOM began in 2012 at the Cascade Chinook Project. For additional information on FPSOs, refer to **Chapter 3.1.3.2**. The production transported by shuttle tankers related to this FPSO system accounted for 2.2 percent of the total volume produced in the GOM during 2014. Forecasted tankering operations are presented in **Table 3-4**. During the production ramp up interval (the first 2 years of production operations), 8 offloads were made during the first 6 months followed by 15 offloads over the next year. During the 2nd full year of operation, 46 offloads were made. In the subsequent years of production, two shuttle tankers on a staggered schedule were predicted to perform one offload every week (52 trips a year). A second FPSO (Stones Project) in the GOM area (Walker Ridge) began production in 2016. This facility is also scheduled to transport the produced liquid hydrocarbons by shuttle tankers.

How Much Tankering Activity Would Likely Occur?

To develop a scenario for analytical purposes, the following assumptions are made regarding future OCS oil transportation by shuttle tanker:

- advances in pipe-laying technology would keep pace with the expansion of the oil industry into the deeper waters of the Gulf beyond the continental slope;
- all produced gas would be piped;
- tankering would not occur from operations on the continental shelf;
- tankering would only take place from marginal fields or fields in areas remote from the existing OCS pipeline infrastructure; and
- maximum offloading frequency for an FPSO could be once every 3 days during peak production.

Alternative A:* BOEM projects 0-1 FPSO systems could result under Alternative A. The number of shuttle tanker trips to port in a given year is primarily a function of the FPSO production rate, the number of wells drilled, and the capacity of supporting shuttle tankers. Considering an FPSO operating at a peak production rate of 150,000 bbl/day, supported by shuttle tankers of 500,000-bbl capacity, maximum offloading could occur once every 3.3 days. This would equate to a 54.75-MMbbl production with 110 offloading events and shuttle tanker transits to GOM coastal or offshore ports annually per FPSO.

*Alternative B**: BOEM projects 0-1 FPSO systems would result under Alternative B. Because the FPSO projections are expected to occur in the CPA, a similar number of tanker trips would occur from an FPSO under Alternative B as would under Alternative A.

*Alternative C**: BOEM projects no FPSO systems would result under Alternative C because no FPSO activity is expected to occur in the WPA; thus, no tankering is projected to occur under Alternative C.

*Because FPSOs are not expected to occur in the same area as the sensitive topographic features, Alternative D is not expected to affect FPSO system development. Refer to **Chapter 2.2.2.4** for more information.

3.1.4.3 Service Vessels

Service vessels are one of the primary modes of transporting personnel between service bases and offshore platforms, drilling rigs, derrick barges, and pipeline construction barges. In addition to offshore personnel, service vessels carry cargo (i.e., freshwater, fuel, cement, barite, liquid drilling fluids, tubulars, equipment, and food) offshore.

How Much Service Vessel Activity Would Likely Occur?

Service vessels were evaluated for the following categories: wells (exploration and development drilling); plug and abandonment of wells; platform installation; platform operation; platform decommissioning; subsea installation; subsea removal; and pipeline installation. Other vessel operations, including G&G activity associated with a leasing event, is assumed to be covered in these estimates. Based on the model provided by Kaiser (2010), there were an average of 4.46 supply vessels needed per week during exploration and development drilling in shallow water and 6.4 supply vessels needed per week during exploration and development drilling in deep water. Drilling operations in shallow water takes less time (5.9 weeks) when compared with deepwater drilling (10 weeks). A platform in shallow water (<800 m; 2,624 ft) is estimated to require one vessel trip every 3.1 days over the production life. A platform in deep water (≥800 m; 2,624 ft) is estimated to require one vessel trip every 1.2 days over the production life. All trips are assumed to originate from the designated service base to an offshore site and back. The duration vessels service an operational platform was considered to be between 11 and 31 years (low to high). Service-vessel operations are most closely tied to actual production activities. Visual representation of this can be seen in **Figure 3-8**.

Alternative A:* Alternative A is estimated to generate 43,000-541,000 service-vessel trips over the 50-year period (**Table 3-2**) or 860-10,820 trips annually. **Table 3-7** indicates that over 875,000 service-vessel trips occurred on Federal navigation channels, ports, and OCS-related waterways in 2012. The number of service-vessel trips projected annually for Alternative A would represent <2 percent of the total annual traffic on these OCS-related waterways.

*Alternative B**: Alternative B is estimated to generate 38,000-452,000 service-vessel trips over the 50-year period (**Table 3-2**) or 760-9,040 trips annually. **Table 3-7** indicates that over 875,000 service-vessel trips occurred on Federal navigation channels, ports, and OCS-related waterways in 2012. The number of service-vessel trips projected annually for Alternative B would represent <2 percent of the total annual traffic on these OCS-related waterways.

*Alternative C**: Alternative C is estimated to generate 30,000-88,500 service-vessel trips over the 50-year period (**Table 3-2**) or 600-1,770 trips annually. **Table 3-7** indicates that over 875,000 service-vessel trips occurred on Federal navigation channels, ports, and OCS-related waterways in 2012. The number of service-vessel trips projected annually for Alternative C would represent <1 percent of the total annual traffic on these OCS-related waterways.

*Alternative D could reduce activity values of the combined Alternative A, B, or C, but it may only shift the location of offshore infrastructure and activities farther from sensitive topographic zones. Since the ranges given for AlternativeS A, B, and C are broad and represent the low and high levels of forecasted activity, any reduction of activity from choosing Alternative D would still fall within those ranges; therefore, the scenarios do not change when considering Alternative D. The potential impacts associated with selecting Alternative D are discussed in **Chapter 4** under each resource. Refer to **Chapter 2.2.2.4** for more information.

3.1.4.4 Helicopters

Helicopters are one of the primary modes of transporting personnel between service bases and offshore platforms, drilling rigs, derrick barges, and pipeline construction barges. Helicopters are routinely used for normal crew changes and at other times to transport management and special service personnel to offshore exploration and production sites. In addition, equipment and supplies are sometimes transported. An operation is considered a roundtrip and includes takeoff and landing.

Deepwater operations require helicopters that travel farther and faster, carry more personnel, are all-weather capable, and have lower operating costs. Helicopter trips have been declining over the last 15 years. There are several issues that could be contributing to this decline, including competition with increasingly faster boats and the development of new technology such as subsea systems. These systems decrease the number of platforms and personnel needed offshore, therefore reducing the amount of transportation needed. Additionally, oil and gas companies are increasingly subcontracting all helicopter support to independent contractors who may use one fleet to service multiple oil and gas companies. The number of helicopters operating in the GOM is expected to decrease in the future, and helicopters that do operate are expected to be larger and faster.

The Federal Aviation Administration (FAA) regulates helicopter flight patterns. Because of noise concerns, FAA Circular 91-36C encourages pilots to maintain higher than minimum altitudes near noise sensitive areas. The Helicopter Safety Advisory Conference recommended practice states that helicopters should maintain a minimum altitude of 750 ft (229 m) while in transit offshore and a maximum of 500 ft (152 m) while working between platforms and drilling rigs (Helicopter Safety Advisory Conference, 2010). When flying over land, the specified minimum altitude is 1,000 ft (305 m) over unpopulated areas and coastlines, and 2,000 ft (610 m) over populated areas and sensitive areas including national parks, recreational seashores, and wildlife refuges. In addition, guidelines and regulations issued by NMFS under the authority of the Marine Mammal Protection Act include provisions specifying helicopter pilots to maintain an altitude of 1,000 ft (305 m) within 100 yd (91 m) of marine mammals.

How Much Helicopter Activity Would Likely Occur?

The scenarios for each alternative and the Cumulative OCS Oil and Gas Program scenarios (**Chapter 3.3.1.7**) below use the current level of activity as a basis for projecting future helicopter operations in relation to the production activity forecasted. According to the Helicopter Safety Advisory Conference (2015), from 1996 to 2014, helicopter operations (take offs and landings) in support of regionwide OCS operations have averaged, annually, about 1.2 million operations, 2.7 million passengers, and 386,000 flight hours. There has been a decline in helicopter operations from 1,668,401 in 1996 to 741,201 in 2014 (Helicopter Safety Advisory Conference, 2015). Future projections are based on a high equal to the average number of flights over the last 15 years and a low equal to a continuing forecast of the current decline. A trip is considered the transportation from a service base to an offshore site and back, similar to service vessels.

Alternative A:* There are 122,000-3,750,000 helicopter trips projected over the 50-year period for Alternative A (**Table 3-2**), or 2,440-75,000 trips annually.

*Alternative B**: There are 105,000-3,415,000 helicopter trips projected over the 50-year period for Alternative B (**Table 3-2**), or 2,100-68,300 trips annually.

*Alternative C**: There are 70,000-440,000 helicopter trips projected over the 50-year period for Alternative C (**Table 3-2**), or 1,400-8,800 trips annually.

*Alternative D could reduce activity values of the combined Alternative A, B, or C, but it may only shift the location of offshore infrastructure and activities farther from sensitive topographic zones. Since the ranges given for AlternativeS A, B, and C are broad and represent the low and high levels of forecasted activity, any reduction of activity from choosing Alternative D would still fall within those ranges; therefore, the scenarios do not change when considering Alternative D. The potential impacts associated with selecting Alternative D are discussed in **Chapter 4** under each resource. Refer to **Chapter 2.2.2.4** for more information.

3.1.5 Discharges and and Wastes

3.1.5.1 Operational Wastes and Discharges Generated by OCS Oil- and Gas-Related Facilities

The primary operational wastes and discharges generated during offshore oil and gas exploration and development are drilling fluids, drill cuttings, various waters (e.g., bilge, ballast, fire, and cooling), deck drainage, sanitary wastes, and domestic wastes. During production activities, additional waste streams include produced water, produced sand, and well-treatment, workover, and completion fluids. Minor additional discharges occur from numerous sources. These discharges may include desalination unit discharges, blowout preventer fluids, boiler blowdown discharges, excess cement slurry, several fluids used in subsea production, and uncontaminated freshwater and saltwater.

What Regulations Govern Operational Wastes and Discharges from OCS Oil- and Gas-Related Facilities and How Are Those Regulations Managed?

The Clean Water Act (CWA) establishes conditions and permitting for discharges of pollutants into the waters of the United States under the NPDES and gives the USEPA the authority to implement pollution control programs such as setting wastewater standards for industry and to set water quality standards for all contaminants in surface waters. Accordingly, the USEPA regulates all waste streams generated from OCS oil- and gas-related activities through permits issued by the USEPA Region that has jurisdictional oversight.

The USEPA Region 4 has jurisdiction over the eastern portion of the Gulf of Mexico OCS, including all of the EPA and a portion of the CPA off the coasts of Alabama and Mississippi (**Figure 3-10**). The USEPA Region 6 has jurisdiction over the rest of the CPA and all of the WPA. Each region issues general permits but can require an operator to apply for an individual permit. Each USEPA Region has promulgated general permits for discharges that incorporate the 1993 and 2000 effluent guidelines (USEPA, 1993a and 2000b) for synthetic-based fluid (SBF)-wetted cuttings as a minimum. The permits are valid for 5 years.

The current USEPA Region 4 general permit (GEG460000) was issued on March 15, 2010; became effective on April 1, 2010; and expired on March 31, 2015 (USEPA, 2010a). The renewal of the permit is being administratively continued for those operators who are already covered under the permit and request an extension. However, no new general permits will be granted until the permit is renewed. Operators may apply for an individual permit. The draft proposed permit was released on August 18, 2016. It includes the following changes: (1) new electronic reporting requirements; (2) new whole effluent toxicity testing sampling and reporting requirements for well treatment, completion, and workover fluids not discharged with produced wastewaters; (3) requirements to submit additional information pertaining to the chemicals and additives used in well treatment, completion and workover operations; and (4) clarification regarding types of operators (*Federal Register*, 2016b). In the preliminary Ocean Discharge Criteria Evaluation for the permit, the USEPA Region 4 reached a determination of no unreasonable degradation (USEPA, 2016a). The preliminary determination was made after reviewing the available data and incorporating a variety of technology-based, water quality-based, and Section 403-based requirements in the permit to ensure compliance with Section 403 of the Clean Water Act (USEPA, 2016b). The current USEPA Region 6 permit (GMG290000) was reissued with an effective date of October 1, 2012, expiring at midnight on. September 30, 2017 (USEPA, 2012a).

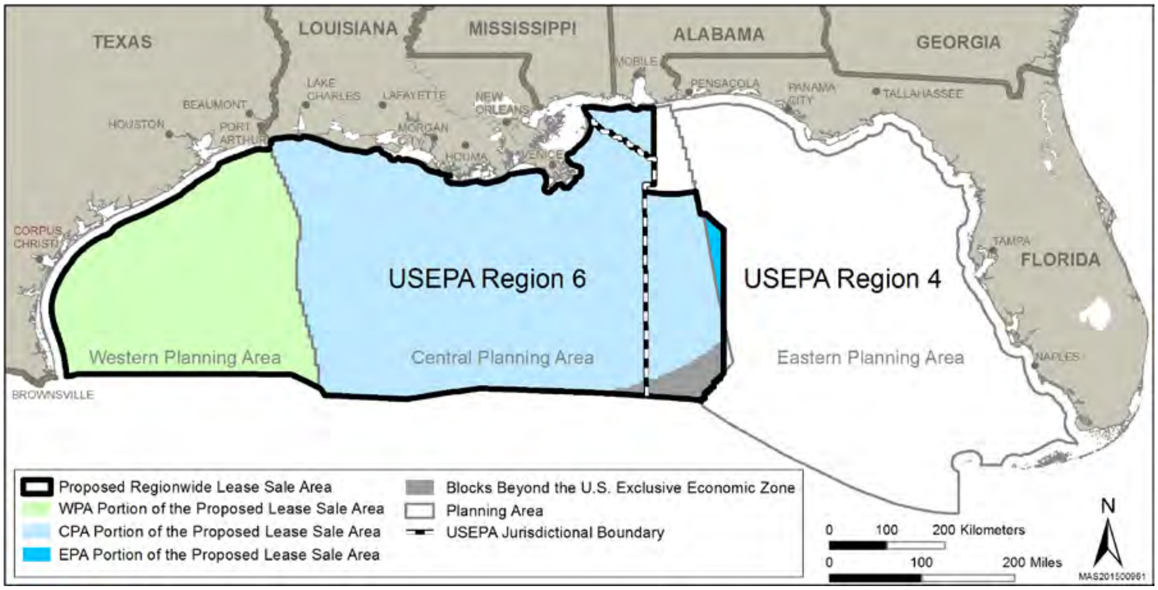

Figure 3-10. Boundaries for USEPA Regions 4 and 6.

Permits issued under Section 402 (NPDES) of the CWA for offshore activities must comply with any applicable water quality standards and/or Federal water quality criteria, as well as Section 403 (Ocean Discharge Criteria) of the CWA. Water quality standards consist of the waterbody's designated uses, water quality criteria to protect those uses and to determine if they are being attained, and antidegradation policies to help protect high-quality waterbodies (refer to **Chapter 4.2**). Discharges from offshore activities near State water boundaries must comply with all applicable State water quality standards.

Section 403 of the CWA requires that NPDES permits for discharges to the territorial seas (baseline to 3 mi [5 km]), contiguous zone, and ocean be issued in compliance with USEPA's regulations for preventing unreasonable degradation of the receiving waters. Prior to permit issuance, ocean discharges must be evaluated against the USEPA's published criteria for determination of unreasonable degradation. Unreasonable degradation is defined in the NPDES regulations (40 CFR § 125.1211e) as the following:

- significant adverse changes in ecosystem diversity, productivity, and stability of the biological community within the area of discharge and surrounding biological communities;
- threat to human health through direct exposure to pollutants or through consumption of exposed aquatic organisms; and

- loss of aesthetic, recreational, scientific, or economic values, which is unreasonable in relation to the benefit derived from the discharge.

Role of the U.S. Environmental Protection Agency in Adminstering NPDES Permits

In order for a facility to be covered by a general NPDES permit, the operator must submit a notice of intent (NOI) to be covered by the general permit. Region 6 developed an "electronic NOI (eNOI)" system so that coverage is immediate (USEPA, 2015a). The USEPA evaluates NOIs on a case-by-case basis and reserves the right to deny coverage if it is determined the facility is ineligible or has falsified information. The NPDES permit sets minimum requirements that every allowable discharge must meet. If a waste does not meet the requirements of the permit, the permit would be considered violated and the USEPA could take an enforcement action. Discharges are monitored and the data are reported to the USEPA through discharge monitoring reports (DMRs). These reports must be turned in quarterly and contain all of the information required by the permit for that discharge. Region 6 now has an electronic Discharge Monitoring Report (DMR) system known as "NetDMR," which is now required for all facilities covered by their general permit (USEPA, 2015b). Failure to submit any information or monitoring results required by the permit is considered a violation. Data from submitted NetDMRs populate the USEPA's national Integrated Compliance Information System database. Region 6 reviews the Integrated Compliance Information System's data to identify facilities violating the permit conditions or reporting requirements. Violations are reviewed and enforcement actions are taken as deemed appropriate, particularly for serious single event violations, an ongoing pattern of noncompliance, or significant noncompliance (noncompliance for two running quarters or more). Depending on the type of violation, severity, length of violation, environmental damage, or illegal activity, the USEPA may request more information, issue a warning letter or order corrective actions, assess a penalty, or refer it to the U.S. Department of Justice or Criminal Investigation Division. The USEPA may use information, pictures, and other documentation from BSEE, BOEM, or USCG to support its enforcement cases. The public may view violations and enforcement actions in the Enforcement and Compliance History Online database (USEPA, 2015c), which is updated every 30 days from the Integrated Compliance Information System's database.

Role of the Bureau of Safety and Environmental Enforcement

In addition to facilities' inspections in Federal waters in the Gulf of Mexico (refer to **Chapter 1.3.2**), BSEE performs NPDES inspections on behalf of the USEPA Region 6 for production platforms and drilling rigs through a 1984 Memorandum of Understanding between the U.S. Department of the Interior, the USEPA, and the U.S. Department of Transportation (USDOI, MMS, 1983) and a 1989 Memorandum of Agreement between between MMS (BOEM and BSEE's predecessor) and the USEPA Region 6 (USDOI, MMS, 1989). According to the Memorandum of Agreement, BSEE inspects a maximum of 50 OCS facilities per year for compliance with NPDES permit provisions. The Region 6 NPDES inspection responsibility officially transitioned from BSEE's Districts to BSEE's Environmental Enforcement Branch, Environmental Inspection and Enforcement Unit on September 18, 2014, in preparation for the 2015 inspection cycle (Sanders, official communication, 2015). The scope of those inspections does not include sampling. Coordination of a potential Memorandum of Agreement between BSEE and USEPA Region 4 concerning NPDES inspection needs is ongoing.

Facility inspections are chosen on a variety of parameters such as pollution history, the USEPA's reporting anomalies and errors, and general frequency for a lack of past inspection visits, among others. An inspection or audit may also be triggered by a major pollution release event triggering a rapid visit turnaround. The BSEE utilizes the U.S. Environmental Protection Agency's ICIS database where DMRs are reported for the permitted features specific to the facility, and deviations and violations are noted. A thorough review of these data is included and evaluated for every inspection. When completed, an inspection report is prepared and sent to the USEPA where the noncompliances observed during the inspection are summarized and formally referred to them for support of potential further enforcement action. If violations or concerns are observed during the inspection, as per any of BSEE regulations from 30 CFR parts 200-699, then BSEE-driven incidents of noncompliance are prepared and sent directly to the offending facility, and the USEPA is copied as a courtesy.

Pollution-related incidents of noncompliance are shown in **Table 3-8**. The BSEE posts some incidents of noncompliance on its website (USDOI, BSEE, 2015a), but as BSEE is working to improve its website postings, additional information can be requested through BSEE's Freedom of Information Act office. Over 700 NPDES inspections were performed between 1999 and 2016 (**Table 3-9**).

Table 3-8. Pollution-Related Incidents of Noncompliance (INCs) Issued Since 1986.

INC Number	INC Description	Approximate Number of INCs Issued
E-100	The operator failed to prevent unauthorized discharge of pollutants into offshore waters.	2,035
E-101	The lessee failed to dispose of drill cuttings, sand, and other well solids as approved.	18
E-102	Facility is not equipped with curbs, gutters, drip pans, and drains necessary to collect all contaminants not authorized for discharge.	1,331
E-103	The sump system does not automatically maintain the oil at a level sufficient to prevent discharge of oil into offshore waters.	1,054
E-104	All hydrocarbon handling equipment for testing and production is not designed, installed, and operated to prevent pollution.	43
E-105	All gravity drains are not equipped with a water trap or other means to prevent gas in the sump system from escaping through the drains.	194
E-106	Sump piles are used as processing devices.	48

E-107	The lessee failed to adhere to the prohibition on the addition of petroleum-based substances to the mud system without prior approval of the district manager.	2
E-108	The lessee failed to prevent the disposal of equipment, cables, chains, containers, or other materials into offshore waters.	49

Source: USDOI, BSEE, 2011.

Table 3-9. National Pollutant Discharge Elimination System Inspections from 1999 through 2016.

Calendar Year	Number of Platforms Inspected	Number of Rigs Inspected	Annual Totals
1999	34	16	50
2000	76	15	91
2001	40	12	52
2002	39	18	57
2003	30	10	40
2004	16	7	23
2005	22	11	33
2006	20	12	32
2007	25	4	29
2008	30	20	50
2009	26	23	49
2010	17	12	29
2011	18	21	39
2012	30	24	54
2013	37	32	69
2014	16	14	30
2015	38	1	39
2016	24	1	25
Total	538	253	791

(1) Data as of November 10, 2016.

(2) Inspections performed by the Minerals Management Service; Bureau of Ocean Energy Management, Regulation and Enforcement; and Bureau of Safety and Environmental Enforcement.

Sources: Sanders, official communication, 2015 and 2016.

3.1.5.1.1 Drilling Muds and Cuttings

Why Are Drilling Fluids or Drilling Muds Used?

Drilling fluids (also known as drilling muds) and cuttings represent a large quantity of the discharge generated by drilling operations. Drilling fluids are used in rotary drilling to remove cuttings from beneath the bit, to control well pressure, to cool and lubricate the drill string and its bit, and to seal the well. Drill cuttings are the fragments of rock generated during drilling and carried to the surface with the drilling fluid. Drilling discharges of muds and cuttings are regulated by the USEPA through the NPDES permitting process.

What are the Different Types of Drilling Muds and Can They be Discharged to the OCS?

Drilling fluids used on the OCS are divided into two categories: water-based fluids (WBFs) and nonaqueous-based fluids (OBFs or SBFs).

The composition of drilling fluids is complex. Drill cuttings are a different grain size and composition from the existing surface sediments. Drilling fluids used on the OCS are divided into two categories: water based and nonaqueous based. Water-based fluids (WBFs) have a water soluble continuous phase while nonaqueous-based fluids have a continuous phase that is not soluble in water. The base fluid can be freshwater or saltwater in WBFs, mineral or diesel oil-based fluids (OBFs), or synthetic-based fluids (SBFs). Thus, both OBFs and SBFs are nonaqueous-based fluids. Clays, barite, and other chemicals are added to the base fluid to improve the performance of the drilling fluid (Boehm et al., 2001).

On the OCS, the WBFs have been used for decades in drilling. In the GOM, they are the most commonly used drilling fluids for exploration and production wells. The discharge of WBFs and cuttings associated with WBFs is allowed on the OCS under the general NPDES permits issued by USEPA Regions 4 and 6, as long as the discharge meets the conditions required in the permit. Discharge of WBFs results in increased turbidity in the water column, alteration of sediment characteristics because of coarse material in cuttings, and the input of trace metal into the environment. Occasionally, formation oil may be discharged with the cuttings, adding hydrocarbons to the discharge. However, as noted in the NPDES permits, no free oil shall be discharged; static sheen tests must be performed once per week when discharging. In shallow environments, WBFs are rapidly dispersed in the water column immediately after discharge and rapidly descend to the seafloor (Neff, 1987). In deep waters, fluids dispersed near the water surface would disperse over a wider area than fluids dispersed in shallow waters.

The early nonaqueous drilling fluids, termed oil-based drilling fluids (OBF), were occasionally used for directional drilling and in drill-bore sections where additional lubricity was needed. Crude, diesel, and mineral oil were used. Diesel OBFs contains light aromatics such as benzene, toluene, and xylene. Mineral oil is advantageous over diesel because it is less toxic. Hydrocarbon concentration and impacts to benthic community diversity and abundance have been observed within 200 m (656 ft) of the drill site with diminishing impacts measured to a distance of 2,000 m (6,562 ft) (Neff, 1987). All OBFs and associated cuttings must be transported to shore for recycling or disposal unless reinjected. Due to the environmental concerns of OBFs, SBFs were created in the 1990s (Bakhtyar and Gagnon, 2012). The OBFs are rarely used because of the many advantages of SBFs. The SBFs are manufactured hydrocarbons. The SBF mud system also contains additives such as emulsifiers, clays, wetting agents, thinners, and barite. Since the SBFs are not petroleum based, they do not contain the aromatic hydrocarbons and polycyclic aromatic hydrocarbons (PAH) that contributed to OBF toxicity and persistence on the seafloor (Bakhtyar and

Gagnon, 2012). In fact, SBFs have several additional advantages over OBFs, which include that they are well characterized, have lower toxicity and bioaccumulation potentials, and biodegrade faster. Since 1992, SBFs have been increasingly used, especially in deep water, because they perform better than WBFs and OBFs. The SBFs reduce drilling times and costs incurred from expensive drilling rigs. By 1999, about 75 percent of all wells drilled in waters deeper than 305 m (1,000 ft) were drilled with SBFs in the Gulf of Mexico (CSA, 2004a). Although there are many types of SBFs, esters, internal olefins, and linear alpha olefins are most commonly used in the GOM.

A literature review (Neff et al., 2000) discussed knowledge about the fate and effects of SBFs discharges on the seabed. Like OBFs, the SBFs are hydrophobic, meaning they are not soluble in the water column and therefore are not expected to adversely affect water quality. The SBF-wetted cuttings settle close to the discharge point and affect the local sediments. Cuttings piles with a maximum depth of 8-10 in (20-25 cm) were noted in a seabed study of shelf and slope locations where cuttings drilled with SBF were discharged. The SBF discharge can alter sediment grain size and add organic matter, which can result in localized anoxia while SBF degrades (Melton et al., 2004). Different formulations of SBFs use base fluids that degrade at different rates, thus affecting the duration of the impact. Esters and olefins are the most rapidly biodegraded SBFs. Ongoing research is aimed at understanding the relationships between the chemical structure in SBFs and the environmental fates and effects, which would provide the design basis for fluids with better environmental performance. For example, recent testing showed that less branching of alpha and internal olefins positively impacted both sediment toxicity and anaerobic biodegradation (Dorn et al., 2011).

Bioaccumulation tests indicate that SBFs and their degradation products should not bioaccumulate (Neff et al., 2000). In a study to measure degradation rates of SBFs on the seafloor, biodegradation proceeded after a lag period of up to 28 weeks, which was influenced by both the SBF type and prior exposure of the sediments to SBFs (Roberts and Nguyen, 2006). Sediment sulfate depletion due to microbial activity coincided with SBF degradation. Decreased SBF concentrations indicated that recovery in sediments occurred in the year between sample collections. Deposited cuttings and measurable sediment effects indicative of organic enrichment were concentrated within a distance of 250 m (820 ft) in both shelf and slope sites (CSA, 2004a).

The discharge of the base SBF drilling fluid is prohibited. The SBFs and cuttings must meet environmental requirements. Both USEPA Regions 4 and 6 permit the discharge of cuttings wetted with SBF as long as the retained SBF amount is below a prescribed percent, meets biodegradation and toxicity requirements, and is not contaminated with the formation oil or PAH.

Typically, the upper portion of the well is drilled with WBF and the remainder is drilled with SBF. The upper sections would be drilled with a large diameter bit; progressively smaller drill bits are used with increasing depth. Therefore, the volume of cuttings per interval (length of wellbore) in the upper section of the well would be greater than the volume generated in the deeper sections.

What is Barite and What Does It Have to do with Drilling Muds?

Barite, a barium sulfate ($BaSO_4$) mineral, is used as a weighting agent to increase the hydrostatic pressure of drilling muds in order to control high-pressure zones encountered during drilling. Because barite is also soft, it does not erode equipment but instead acts essentially as a lubricant (Mills, 2006). Additionally, barite is inert and does not react with other additives in the drilling fluid. Because of barite's useful qualities, barite is a major component of all types of drilling fluid, but its use has somewhat declined due to advances in synthetic-based mud formulations and drilling technology. A study of 81 wells noted that, from 1998 to 2002, the quantity of barite discharged for a shallow well (2,936 m; 9,634 ft average) to a deep well (5,140 m; 16,864 ft average) is 110 tons barite per well and 586 tons barite per well, respectively (Candler and Primeaux, 2003).

Since barite is a natural mineral, it can have natural impurities associated with it. The impurities of concern in barite are trace metals such as mercury (Hg), cadmium (Cd), copper (Cu), zinc (Zn), and lead (Pb) that are often found in other mineral phases that were formed on or in the barite mineral deposit (Crecelius et al., 2007). However, the American Petroleum Institute (API) has set specifications for the barite used in the oil industry, which includes that the amount of water-soluble alkaline earth metals must be below 250 milligrams/kilogram (parts per million [ppm]) (Mills, 2006). More importantly, since 1993, the USEPA has required the concentrations of Hg and Cd to be less than or equal to 1 ppm and 3 ppm, respectively, in the stock barite used to make up drilling muds (USEPA, 1993a and 2000b). Through Hg and Cd regulation, the USEPA can also control levels of other trace metals in barite. This reduces the addition of Hg to sediments to values similar to the concentration of Hg found in marine sediments throughout the GOM (Neff, 2002). Furthermore, barite is nearly insoluble in seawater, which means that it remains in the solid form where it is not readily available to biota unless the mineral particles themselves are directly digested.

Despite atmospheric Hg deposition being considered the main source of anthropogenic Hg inputs into the marine environment, the availability of Hg in barite was studied to confirm that barite in drilling muds was not a significant or available source of Hg in the marine environment. Crecelius et al. (2007) studied the solubility of barite and the rate at which it dissolves (and thereby releases associated metals such as Hg from the solid phase into the aqueous phase), the amount of metals released from barite, and the rate of dissolution of barite and release of metals after burial under simulated seafloor conditions. The research used three grades of barite: one commercially available barite ore used in drilling fluids, which meets the USEPA's trace metal criteria; and two grades of barite to represent those used in the GOM prior to the 1993 USEPA regulation enacted to reduce the concentrations of Hg and Cd in drilling fluid. During a 1-week exposure of barite in seawater, in the pH range of 7.3 to 8.3, <1 percent of the Hg dissolved from the barite. The studies conducted at varying pH levels to mimic digestive tract conditions showed that very little (<0.1%) of the Hg in barite became available within 48 hours. When barite is added to anoxic sediments, the concentrations of methylmercury (methyl-Hg) and Hg were not elevated as compared with the same anoxic sediment without the addition of barite.

Crecelius et al. (2007) confirmed that trace metal contaminants in barite were in sulfide mineral inclusions dispersed within the barite matrix. In seawater with a pH of 7.3 to 8.3 over the period of 1 week, <1 percent of the Cu and Pb, 3 percent of the Zn, and 15 percent of the Cd dissolved from the inclusions within the barite. Thus, a small amount of these metals are soluble in seawater at this pH range. Since low-metal barite (barite that meets current USEPA standards) releases little of these metals to seawater, low-metal barite is not likely to cause environmental effects to organisms living in the water column. However, in acidic conditions simulating the gut of deposit-feeding benthic animals, a major portion of the Cd, Cu, Pb, and Zn are soluble, and <1 percent of the barium (Ba) are soluble in 48 hours.

In addition to laboratory studies, field studies have also been conducted to examine the role that barite plays in sediment Hg levels. Concentrations of total mercury in uncontaminated estuarine and marine sediments generally are 0.2 micrograms/gram (μg/g) dry weight or lower. Surface sediments collected 20-2,000 m (66-6,562 ft) away from four oil production platforms in the northwestern GOM contained 0.044-0.12 μg/g total mercury. These amounts are essentially background concentrations for mercury in surficial sediments on the Gulf of Mexico OCS (Neff, 2002). A comparative study of surface and subsurface sediment samples from six offshore drill locations showed higher levels of total mercury found in the sediments closest to the drilling sites as compared with the sites greater than 3 km (1.9 mi) distant. Higher total mercury concentrations corresponded to higher barium concentrations also present. Higher total mercury levels in nearfield sediments did not translate to higher methyl-Hg concentration in those sediments, with a few exceptions (Trefry et al., 2007). Sediment redox conditions and organic content influence methylmercury formation. For more information on sediment and water quality, refer to **Chapter 4.2**.

3.1.5.1.2 Produced Waters

What is Produced Water?

Produced water is brought up from the hydrocarbon-bearing strata along with produced oil and gas. This waste stream can include formation water; injection water; well-treatment, completion, and workover compounds added downhole (including flowback water); and compounds used during the oil and water separation process. Formation water (brine) originates in the permeable sedimentary rock strata and is brought up to the surface commingled with the oil and gas. Injection water is water that was injected to enhance oil production and is used in secondary oil recovery. Flowback fluid (or water) is fluid that has been returned uphole after being injected into the formation for stimulation purposes. This includes water and chemicals used for hydraulic fracturing practices, as that would be considered a stimulation practice; fracture pack or “frac packs” are often used in the Gulf of Mexico during the completion process to clean and stimulate the area around the wellbore as well as for sand control (refer to **Chapter 3.1.3.1** for more information on hydraulic fracturing processes used offshore in the Gulf of Mexico).

In addition to the added chemical products, produced water contains chemicals that have dissolved into the water from the geological formation where the water was stored. The amount of dissolved solids can be more concentrated than is found in seawater. Produced water contains inorganic and organic chemicals and radionuclides (226Ra and 228Ra). The composition of the discharge can vary greatly in the amounts of organic and inorganic compounds.

Can Produced Water be Discharged to the OCS?

Both USEPA Region 4 and Region 6 general permits allow the discharge of produced water on the OCS provided that they meet discharge criteria. The produced water is treated to separate free oil from the water. Since the oil and water separation process does not completely separate all of the oil, some hydrocarbons remain with the produced water and often the water is treated to prevent the formation of sheen. Produced water may be discharged if the oil and grease concentration does not exceed 42 milligrams per liter (mg/L) daily maximum or 29 mg/L monthly average. The discharge must also be tested for toxicity; the toxicity test is primarily for chronic exposure, but it can include acute exposure. Both USEPA Region 4 and Region 6 permits require no discharge within 1,000 m (3,281 ft) of an area of biological concern (areas of biological concern are identified by USEPA in consultation with DOI). Region 4 also requires no discharge within 1,000 m (3,281 ft) of any federally designated dredged material ocean disposal site.

As noted above, completion fluids, including fluids from fracture packs or “frac-packs,” not returned to the deck of the platform during the completion job may be co-mingled and discharged with produced water if they meet the conditions of the appropriate NPDES permit. However, if the fluid composition is not compatible with the production system, the operator may decide to separate the returning well fluids from the production fluids and treat the fluids in temporary treatment systems or collect the fluids for onshore disposal depending upon logistics (e.g., treatability of well fluid, volume of fluid, personnel limitations, treatment unit capacity, space on deck, weather, etc.).

How Much Nitrogen and Phosphorus does Produced Water Contain?

The USEPA Region 6 NPDES permit required participation in the Produced Water Hypoxia Study, in which produced water was collected from 50 platforms that discharge into the hypoxic zone and analyzed for oxygen-demanding characteristics (Veil et al., 2005; Rabalais, 2005). In comparison to loadings from the Mississippi and Atchafalaya Rivers, the total nitrogen loading from produced water is about 0.16 percent and total phosphorus loading is about 0.013 percent of the nutrient loading coming from the rivers. For more information on hypoxia and water quality in the Gulf of Mexico, refer to **Chapters 3.3.2.12 and 4.2**.

How Much Produced Water may be Generated?

Estimates of the volume of produced water generated per well vary because the percent of water is related to well age and hydrocarbon type. Usually, produced-water volumes are small during the initial production phase and increases over time as the formation approaches hydrocarbon depletion. Produced-water volumes range from 2 to 150,000 bbl/day (USEPA, 1993a). In some cases, a centralized platform is used to process water from several surrounding platforms. Some of the produced water may be reinjected into the well. Reinjection occurs when the produced water does not meet discharge criteria or when the water is used as part of operations. However, the vast majority of produced water is discharged per the conditions of the relevant U.S. Environmental Protection Agency NPDES permit. For example, in 2007, 48,673,102 bbl were used for enhanced recovery purposes, 1,298,417 bbl of produced water were reinjected, and 537,352,846 bbl were discharged after treatment (Clark and Veil, 2009). In 2012, of a total produced-water volume of 509,159,846 bbl, 52,043,434 bbl were injected while an estimate of 457,116,412 bbl were discharged (Veil, 2015).

BOEM maintains records of the volume of water produced from each block on the OCS and its disposition—injected on lease, injected off lease, transferred off lease, or discharged overboard. The amount discharged overboard for the years 2000-2014 is summarized by water depth in **Table 3-10**. The total volume for all water depths during this 15-year period ranged from 485.6 to 648.2 MMbbl, with the largest contribution (68-88%) coming from operations on the shelf. The total volume of produced water generally decreased after 2004, reflecting an overall decrease in contributions from operations on the shelf. The contribution of produced water from operations in deep water (>400-m [1,312-ft] water depth) and ultra-deepwater (>1,600-m [5,249-ft] water depth) production has been increasing. From 2000 to 2014, the contribution from these operations (deep and ultra-deepwater together) increased from 6 percent (37.8 MMbbl) to 31 percent (150.0 MMbbl) of the total produced-water volume (calculated from data in **Table 3-10**). The low-temperature and high-pressure conditions found in deeper water can result in flow problems such as hydrate formation in the lines. Additional quantities of chemicals are used to assure production, and even with recovery systems, some of these chemicals will be present in produced water (USDOI, MMS, 2000a). For deepwater operations, new technologies are being developed that may discharge or reinject produced water at the seafloor or at “minimal surface structures” before the production stream is transported by pipeline to the host production facility.

Table 3-10. Annual Volume of Produced Water Discharged by Depth (millions of bbl).

Year	Shelf 0-60 m	Shelf 60-200 m	Slope 200-400 m	Deepwater 400-800 m	Deepwater 800-1,600 m	Ultra-Deepwater 1,601-2,400 m	Ultra-Deepwater >2,400 m	Total
2000	370.6	193.1	35.5	25.6	12.2	0.0	0.0	637.0
2001	364.2	185.2	35.0	32.0	16.6	0.0	0.0	633.0
2002	344.6	180.4	32.5	35.2	21.4	0.0	0.0	614.1
2003	359.4	182.9	31.2	39.0	35.5	0.2	0.0	648.2
2004	346.7	160.5	29.3	36.9	39.2	1.8	0.0	614.4
2005	270.0	113.5	23.1	33.5	43.0	5.8	0.0	488.9
2006	260.3	99.6	20.6	35.0	61.6	12.4	0.0	489.5
2007	307.0	139. 3	22.2	40.0	70.6	15.5	0.1	594.7
2008	252.7	118.6	15.9	32.7	60.2	16.1	0.1	496.3
2009	265.2	109.2	19.9	39.2	65.6	25.0	0.1	524.2
2010	278.4	115.7	20.9	40.7	56.8	32.5	0.1	545.1
2011	273.7	117.0	20.7	39.7	67.7	32.2	0.1	551.1
2012	240.8	108.9	20.8	35.0	71. 5	32.3	0.1	509.4
2013	248.8	104.2	20.0	33.1	76.0	36.9	0.3	519.3
2014	248.7	97.2	18.5	35.7	79.3	50	1.0	530.4
2015	243.9	102.1	15.0	40.8	83.3	50.6	1.3	537.0

Source: Gonzales, official communication, 2015.

3.1.5.1.3 Well-Treatment, Workover, and Completion Fluids

What are Completion Fluids?

Wells are drilled using a base fluid and a combination of other chemicals to aid in the drilling process. Fluids (drilling muds) present in the borehole can damage the geologic formation in the producing zone. Completion fluids are used to displace the drilling fluid and protect formation permeability. “Clear” fluids consist of brines made from seawater mixed with calcium chloride, calcium bromide, and/or zinc bromide. These salts can be adjusted to increase or decrease the density of the brine to hold back-pressure on the formation. Additives, such as defoamers and corrosion inhibitors, are used to reduce problems associated with the completion fluids. Recovered completion fluids can be recycled for reuse.

What are Workover Fluids?

Workover fluids are used to maintain or improve existing well conditions and production rates on wells that have been in production. Workover operations include casing and subsurface equipment repairs, re-perforation, acidizing, and stimulating via hydraulic fracturing. In the Gulf of Mexico, the type of hydraulic fracturing commonly used are fracture-pack or “frac packs” (refer to **Chapter 3.1.3.1** for more information on these processes). During some of the workover operations, the producing formation may be exposed, in which case fluids like the aforementioned completion fluids are used. In other cases, such as acidizing and hydraulic fracturing, including “frac-packs” (also considered stimulation or well treatment), hydrochloric and other acids are used. Both procedures are used to increase the permeability of the formation. The acids dissolve limestone, sandstone, and other deposits. Because of the corrosive nature of acids, particularly when hot, corrosion inhibitors are added. Since the fluids are altered with use, they are not recovered and recycled; however, these products may be mixed with the produced water and disposed of as described in **Chapter 3.1.5.1.2** above.

What are Well Treatment Fluids?

Production treatment fluids are chemicals applied during the oil and gas extraction process. Production chemicals are used to dehydrate produced oil or treat the associated produced water for reuse or disposal. A wide variety of chemicals are used, including corrosion and scale inhibitors, bactericides, paraffin solvents, demulsifiers, foamers, defoamers, and water treatment chemicals (Boehm et al., 2001). Some of the production chemicals mix with the production stream and are transported to shore with the product. Other chemicals mix with the produced water. Most produced water cannot be discharged without some chemical treatment. Even water that is reinjected downhole must be cleaned to protect equipment. The types and volumes of chemicals that are used changes during the life of the well. In the early stages, defoamers are used. In the later stages, when more water than oil is produced, demulsifiers and water-treatment chemicals are used more extensively.

Boehm et al. (2001) discusses completion, stimulation, and workover chemicals that are used in the Gulf of Mexico. These same chemicals are used for fracturing, including “frac packs,” gravel packs, and acidizing processes. The report lists and defines the types of chemicals used as well as providing examples for each category of chemical (Boehm et al. (2001), Table 3). BOEM has included an update to this study in their 2015-2017 Studies Development Plan (http://www.boem.gov/Environmental-Studies-Planning/). After the fluids used for fracturing have performed their desired function, they are disposed of in the same manner as completion fluids or may be combined with the produced water. If the fluids return topside as a part of the completion job, they are considered waste completion fluids and would be disposed of as such. After the completion job is finished, the fluid is removed from the tubing in the well in order to begin producing hydrocarbons; this fluid may be comingled with the produced water and discharged per the requirements for produced water.

Can Well Treatment, Completion, and Workover Fluids be Discharged?

Both USEPA Regions 4 and 6 allow the discharge of well-treatment, completion, and workover fluids if they meet the condition of the NPDES permits. Both USEPA Regions 4 and 6 prohibit the discharge of well-treatment, completion, and workover fluid with additives containing priority pollutants (e.g., benzene, toluene, lead, and mercury; the full list of priority pollutants can be found in Appendix A of 40 CFR part 423). Additives containing priority pollutants must be monitored. Some well-treatment, workover, and completion chemicals are discharged with the drilling muds and cuttings or with the produced-water streams. These discharges must meet the general toxicity limits in the NPDES general permit. Discharge and monitoring records must be kept.

As part of the NPDES general permit renewal process, USEPA Region 4 released a Draft Ocean Discharge Criteria Evaluation. Considering well treatment, completion, and workover fluids, the USEPA Region 4 concluded in the Draft Ocean Discharge Criteria Evaluation that the volume and constituents of the discharged material are not considered sufficient to pose a potential problem through bioaccumulation or persistence (USEPA, 2016a). However, to confirm the USEPA's decision and as a precaution against any changes in operational practices that could change the USEPA's assumptions, the discharged volumes of well treatment, completion, and workover fluids must be recorded monthly and reported once each year on the compliance monitoring report as a condition of the draft permit.

3.1.5.1.4 Production Solids and Equipment

As defined by the USEPA in the discharge guidelines (*Federal Register*, 1993), produced sands are slurried particles, which surface from hydraulic fracturing, and the accumulated formation sands and other particles including scale, which is generated during production. This waste stream also includes sludges generated in the produced-water treatment system, such as tank bottoms from oil/water separators and solids removed in filtration. The guidelines do not permit the discharge of produced sand, which must be transported to shore and disposed of as nonhazardous oil-field waste according to State regulations. Estimates of total produced sand expected from a platform are from 0 to 35 bbl/day according to the USEPA (1993a). A variety of solid wastes are generated, including construction/demolition debris, garbage, and industrial solid waste. No equipment or solid waste from a facility may be disposed of in marine waters.

3.1.5.1.5 Bilge, Ballast, and Fire Water

Bilge, ballast, and fire water all constitute minor discharges generated by offshore oil and gas production activities, which are allowed to be discharged to the ocean, as long as the USEPA's guidelines are followed. Ballast water is untreated seawater that is taken on board a vessel to maintain stability. Ballast water contained in segregated ballast tanks never comes into contact with either cargo oil or fuel oil. Newly designed and constructed floating storage platforms use permanent ballast tanks, in which the ballast in those tanks rarely becomes contaminated. Bilge water is seawater that becomes contaminated with oil and grease and with solids such as rust when it collects at low points in the facility. Uncontaminated bilge and ballast water are included in the miscellaneous discharges category of the USEPA Region 4 and Region 6 general permits (USEPA, 2010a and 2012a). With the right equipment on board, dirty bilge and ballast water can be processed in a way that separates most of the oil from the water before it is discharged into the sea (USEPA, 1993a). The discharge of any oil or oily mixtures is prohibited under 33 CFR § 151.10. The USEPA requires monitoring for visual sheen related to miscellaneous discharges, such as bilge and ballast water.

Offshore drilling rigs and the offshore production facilities used to process oil have special fire protection requirements. Fire water is defined in the USEPA Region 4 and Region 6 general permits as excess seawater or freshwater that permits the continuous operation of fire control pumps, as well as water released during training of personnel in fire protection. Fire control system test water is seawater, sometimes treated with a biocide that is used as test water for the fire control system on offshore platforms. This test water is discharged directly to the sea as a separate waste stream (USEPA, 1993a). As well, fire protection can also include a barrier of water that is sometimes used during flaring to provide protection between flaring systems and personnel, equipment, and facilities. The USEPA Region 4 and Region 6 general permits allow for the discharge of fire water that meets their specified limitations. The requirements include regulations and monitoring for treatment chemicals, discharge rate, free oil, and toxicity.

3.1.5.1.6 Cooling Water

Cooling water is defined as water used for contact or noncontact cooling, including water used for equipment cooling, evaporative cooling tower makeup, and dilution of effluent heat content. Seawater is drawn through an intake structure on the drilling rig, ship, or platform to cool power generators and other machinery, and produced oil or water. Drillship cooling water structures have been noted to intake 16-20 million gallons/day while semisubmersibles have been noted to intake 2 to over 10 million gallons/day from a water depth >400 ft (122 m) from the water's surface (USEPA, 2006). However, newer semisubmersible units were noted to have an intake capacity of 35 million gallons per day. Not all intake water is necessarily used as cooling water; some may be use for ballast water, cleaning, firewater, and testing. Organisms may be killed through impingement or entrainment. When fish and other aquatic life become trapped against the screen at the entrance to the cooling water intake structure through the force of the water being drawn through the intake structure, it is termed impingement. When eggs and larvae are sucked into the heat exchanger and eventually discharged from the facility, it is termed entrainment (**Chapter 4.7**; *Federal Register*, 2006a).

The Clean Water Act, Section 316(b) Phase III, established categorical regulations for offshore oil and gas cooling water intake structures. The NPDES permit began incorporating these regulations in NPDES General Permit GMG290000 for the USEPA Region 6 in 2007 and General Permit GEG460000 for the USEPA Region 4 in 2010 for new facilities that began construction after July 17, 2006, and that take in more than 2 million gallons per day of seawater, of which more than 25 percent is used for cooling (USEPA, 2010a and 2012a). The requirements have several tracks depending on whether the facility is a fixed or nonfixed facility and whether it has a sea chest intake or not. Some of the requirements include cooling water intake structure design requirements to meet a velocity of <0.5 ft (0.2 m) per second, construction to minimize impingement and/or entrainment, entrainment monitoring, recordkeeping, and completion of a source water biological study. Alteration to a sea chest intake structure on a mobile facility could render the facility less seaworthy, so it is not required. The requirements include a baseline study that characterizes the biological community in the vicinity of the structure or monitoring. A Joint Industry Biological Baseline Study was completed for USEPA Region 6 in June 2009 (LGL Ecological Research Associates, Inc., 2009), and an industry-wide cooling water intake structure entrainment monitoring study, approved by USEPA Region 6, was completed in 2014 (CSA and LGL Ecological Research Associates, Inc., 2014). For more information on the specifics regarding potential impacts to fisheries, refer to **Chapter 4.7**.

3.1.5.1.7 Deck Drainage

Deck drainage includes all wastewater resulting from platform washings, deck washings, rainwater, and runoff from curbs, gutters, and drains, including drip pans and work areas. The USEPA's general guidelines for deck drainage require that no free oil be discharged, as determined by visual sheen.

The quantities of deck drainage vary greatly depending on the size and location of the facility. An analysis of 950 GOM platforms during 1982-1983 determined that deck drainage averaged 50 bbl/day/platform (USEPA, 1993a). The deck drainage is collected, the oil is separated, and the water is discharged to the sea.

3.1.5.1.8 Treated Domestic and Sanitary Wastes

Domestic wastes originate from sinks, showers, laundries, and galleys. Sanitary wastes originate from toilets. For domestic waste, no solids or foam may be discharged. In addition, the discharge of all food waste within 12 nmi (14 mi; 22 km) from the nearest land is prohibited. In sanitary waste, floating solids are prohibited. Facilities with 10 or more people must meet the requirement of total residual chlorine greater than 1 mg/L and maintained as close to this concentration as possible. There is an exception in both general permits for the use of marine sanitation devices.

In general, a typical manned platform would discharge 35 gallons/person/day of treated sanitary wastes and 50-100 gallons/person/day of domestic wastes (USEPA, 1993a). It is assumed that these discharges are rapidly diluted and dispersed.

3.1.5.1.9 Minor/Miscellaneous Discharges

Minor and miscellaneous discharges include all other discharges not already discussed that may result during oil and gas operations. Minor or miscellaneous wastes may include desalination unit discharge, blowout preventer fluid, boiler blowdown, excess cement slurry, uncontaminated freshwater and saltwater, and miscellaneous discharges at the seafloor, such as subsea wellhead preservation and production control fluid, umbilical steel tube storage fluid, leak tracer fluid, and riser tensioner fluids. These discharges are regulated by the USEPA Region 4 and Region 6 NPDES permits. In all cases, no free oil shall be discharged with the waste. Unmanned facilities may discharge uncontaminated water through an automatic purge system without monitoring for free oil. The discharge of freshwater or seawater that has been treated with chemicals is permitted providing that the prescribed discharge criteria are met.

3.1.5.2 Operational Wastes and Discharges Generated by Service Vessels

Service vessels are discussed in **Chapter 3.1.4.3**. Discharges from supply/service vessels equal to or greater than 79 ft (24 m) in length are regulated by the U.S. Environmental Protection Agency's NPDES under the Vessel General Permit (VGP). The Final 2013 VGP was issued on March 28, 2013, became effective on December 19, 2013, and expires on December 19, 2018

(USEPA, 2013a). The Final 2013 VGP regulates 26 specific discharge categories, including numeric ballast-water discharge limits for most vessels, and ensures that ballast-water treatment systems are functioning correctly.

Discharges incidental to the normal operation of nonmilitary, nonrecreational vessels less than 79 ft (24 m) (i.e., "small vessels"), operating in a capacity as a means of transportation, are regulated under the Small Vessel General Permit (sVGP). The Final 2014 sVGP was issued on September 10, 2014, became effective on December 19, 2014, and will expire on December 18, 2019 (USEPA, 2014a). The USEPA issued the sVGP in anticipation of the December 18, 2014, expiration date of the then-existing moratorium on permitting small vessels, which specified that neither the USEPA nor the States may require NPDES permits, other than for ballast water, for incidental discharges from these small vessels. However, on December 18, 2014, President Obama signed into law the Howard Coble Coast Guard and Maritime Transportation Act of 2014, which extended that moratorium until December 18, 2017. Ballast-water discharges from small vessels still require NPDES permit coverage under the sVGP.

Operational wastes generated from supply/service vessels that support OCS oil- and gas-related operations include bilge and ballast waters (**Chapter 3.1.5.1.5**), trash and debris (**Chapter 3.2.7**), and sanitary and domestic wastes (**Chapter 3.1.5.1.8**).

Bilge water is water that collects in the lower part of a ship. The bilge water is often contaminated by oil that leaks from the machinery within the vessel. The discharge of any oil or oily mixtures is prohibited under 33 CFR § 151.10; however, discharges may occur in waters greater than 12 nmi (14 mi; 22 km) from land if the oil concentration is less than 100 ppm. Discharges may occur within 12 nmi (14 mi; 22.5 km) of land if the concentration is less than 15 ppm.

Ballast water is used to maintain stability of the vessel and may be pumped from coastal or marine waters. Generally, the ballast water is pumped into and out of separate compartments and is not usually contaminated with oil; however, the same discharge criteria apply as for bilge water (33 CFR § 151.10). Ballast water discharged from ships is one of the pathways for the introduction and spread of aquatic nuisance species. To address this issue, USCG's ballast-water discharge standard final rule, which was published on March 23, 2012 (*Federal Register*, 2012) and became effective on June 21, 2012, established a standard for the allowable concentration of living organisms in ballast water discharged from ships in U.S. waters.

The discharge of trash and debris is prohibited (33 CFR §§ 151.51-151.77) unless it is passed through a comminutor and can pass through a 25-millimeter (mm) (1-in) mesh screen. All other trash and debris must be returned to shore for proper disposal with municipal and solid waste.

All vessels with toilet facilities must have a marine sanitation device that complies with 40 CFR part 140 and 33 CFR part 159. Vessels complying with 33 CFR part 159 are not subject to State and local marine sanitation device requirements. However, a State may prohibit the discharge of all sewage within any or all of its waters. Domestic waste consists of all types of wastes generated in the living spaces on board a ship, including gray water that is generated from dishwasher, shower, laundry, bath, and washbasin drains. Gray water from vessels is not regulated under the NPDES in the Gulf of Mexico. Gray water should not be processed through the marine sanitation device, which is specifically designed to handle sewage.

3.1.5.3 Onshore Disposal of Waste and Discharge Generated Offshore or Onshore

3.1.5.3.1 Onshore Disposal of Wastes Generated from OCS Oil- and Gas-Related Facilities

Most wastes, other than produced water and water-based drilling muds and cuttings, are regulated by the USEPA and must be transported to shore or reinjected downhole. Additionally, wastes may be disposed of onshore because they do not meet permit requirements or because onshore disposal is economically advantageous. Wastes that are typically transported to shore include produced sand, aqueous fluids such as wash water from drilling and production operations, naturally occurring radioactive materials such as tank bottoms and pipe scale, industrial wastes, municipal wastes, and other exploration and production wastes (Dismukes, 2010). Most OBF muds and some SBF muds are recycled. If the physical and chemical properties of muds degrade, they may be disposed of or treated and reused for purposes other than drilling, instead of being recycled. Different reuses of treated muds include, among others, fill material, daily cover material at landfills, aggregate or filler in concrete, and brick or block manufacturing. The OBF cuttings are disposed of onshore or are injected onsite (USEPA, 1999). Both USEPA Regions 4 and 6 permit the discharge of SBF-wetted cuttings, provided the cuttings meet the criteria with regard to percent SBF retained, PAH content, biodegradability, and sediment toxicity. The SBF is either recycled or transferred to shore for regeneration and reuse or disposal. For information on OBF or SBF, refer to **Chapter 3.1.5.1.1**. Drill cuttings contaminated with hydrocarbons from the reservoir fluid must be disposed of onshore or reinjected.

The USEPA allows treatment, workover, and completion fluids to be commingled with the produced-water stream if the combined produced-water/ treatment, workover, and completion discharges pass the toxicity test requirements of the NPDES permit. Facilities with less than 10 producing wells may not have enough produced water to be able to effectively commingle the treatment, workover, and completion fluids with the produced-water stream to meet NPDES requirements (USEPA, 1993b). Spent treatment, workover, and completion fluid is stored in tanks on tending workboats or is stored on platforms and later transported to shore on supply boats or workboats. Once onshore, the treatment, workover, and completion wastes are transferred to commercial waste-treatment facilities and disposed of in commercial disposal wells. Offshore wells are projected to generate an average volume of 200 bbl from either a well treatment or workover job every 4 years. Each new well completion would generate about 150 bbl of completion fluid.

Operators are prohibited in the GOM from discharging any produced sands offshore. Cutting boxes (15- to 25-bbl capacities), 55-gallon steel drums, and cone-bottom portable tanks are used to transport the solids to shore via offshore service vessels. Total produced sand from a typical platform is estimated to be 0-35 bbl/day (USEPA, 1993b). Refer to **Chapter 3.1.5.1.4** for more information on produced sands. Both Texas and Louisiana have State oversight of exploration and production waste-management facilities (Veil, 1999).

3.1.5.3.2 Onshore Disposal and Storage Facilities Supporting OCS-Generated Operational Wastes

BOEM-funded research by Dismukes et al. (2007) further supports past conclusions that existing solid-waste disposal infrastructure is adequate to support both existing and projected offshore oil and gas drilling and production needs. Recently, there is a trend toward incorporating more innovative methods for waste handling in an attempt to reduce the chance of adverse environmental impacts. Some of these innovative methods include hydrocarbon recovery/recycling programs, slurry fracture injection, treating wastes for reuse as road base or levee fill, and segregating waste streams to reduce treatment time and improve oil recovery (Dismukes, official communication, 2011b). Research shows that the volume of OCS-generated waste is closely correlated with the level of offshore drilling and production activity. For each alternative (A, B, C, or D), existing onshore facilities would continue to be used to dispose of wastes generated offshore. However, no new disposal facilities are expected to be licensed as a direct result of Alternative A, B, C, or D. There is no current expectation for new onshore waste disposal facilities to be authorized and constructed during the 2017-2066 period as a direct result of each alternative (A, B, C, or D). If needed, existing facilities may undergo expansion, but no new disposal facilities are expected.

3.1.5.3.3 Discharges from Onshore Support Facilities

The primary onshore facilities that support offshore oil- and gas-related activities include service bases, helicopter hubs at local ports/service bases, construction facilities (i.e., platform fabrication yards, pipeyards, and shipyards), processing facilities (i.e., refineries, gas processing plants, and petrochemical plants), and terminals (i.e., pipeline shore facilities, barge terminals, and tanker port areas). Water discharges from these facilities are from either point sources, such as a pipe outfall, or nonpoint sources, such as rainfall run-off from paved surfaces. The USEPA or the USEPA-authorized State program regulates point-source discharges as part of the NPDES. Facilities are issued general or individual permits that limit discharges specific to the facility type and the waterbody receiving the discharge. Other wastes generated at these facilities are handled by local municipal and solid-waste facilities, which are also regulated by the USEPA or an USEPA-authorized State program.

3.1.6 Decommissioning and Removal Operations

During exploration, development, and production operations, the seafloor around activity sites within a proposed lease sale area becomes the repository of temporary and permanent equipment and structures. Regulations and processes related to structure and site clearance are discussed in **Appendix A.13**. The structures are generally grouped into two main categories depending upon their relationship to the platform/facilities (i.e., piles, jackets, caissons, templates, mooring devises, etc.) or the well (i.e., wellheads, casings, casing stubs, etc.).

A varied assortment of severing devices and methodologies has been designed to cut structural targets during the course of decommissioning activities. These devices are generally grouped and classified as either nonexplosive or explosive, and they can be deployed and operated by divers, ROVs, or from the surface. Which severing tool the operators and contractors use takes into consideration the target size and type, water depth, economics, environmental concerns, tool availability, and weather conditions.

Nonexplosive severing tools are used on the OCS for a wide array of structure and well decommissioning targets in all water depths. Based on 10 years of historical data (1994-2003), nonexplosive severing is employed exclusively on about 58 (~37%) removals per year (USDOI, MMS, 2005). Since many decommissionings use both explosive and nonexplosive technologies (prearranged or as a backup method), the number of instances may be much greater. Common nonexplosive severing tools consist of abrasive cutters (e.g., sand cutters and abrasive water jets), mechanical (carbide) cutters, diver cutting (e.g., underwater arc cutters and the oxyacetylene/oxy-hydrogen torches), and diamond wire cutters.

With the exception of minor air and water quality concerns (i.e., exhaust from support equipment and toxicity of abrasive materials), nonexplosive severing tools generally cause little to no environmental impacts; therefore, there are very few regulations regarding their use. However, the use of nonexplosive cutters leads to greater human health and safety concerns, primarily because (1) divers are often required in the methodology (e.g., torch/underwater arc cutting and external tool installation and monitoring), (2) more personnel are required to operate them (increasing their risks of injury in the offshore environment), (3) lower success rates require that additional cutting attempts be made, and (4) the cutters can only sever one target at a time, taking on average 30 minutes to several hours for a complete cut (USDOI, MMS, 2005). The last two items are often hard to quantify and to assign risks to the cutters, but the main principle is that there is a linear relationship between the length of time any offshore operation is staged and on-site (exposure time) and the potential for an accident to occur (Twachtman, Snyder, & Byrd, Inc. and Louisiana State University, Center for Energy Studies, 2004). Therefore, even if there are no direct injuries or incidents involving a diver or severing technicians, the increased “exposure time” needed to successfully sever all necessary targets could result in unrelated accidents involving other barge/vessel personnel.

Explosive severance tools can be deployed on almost all structural and well targets in all water depths. Historically, explosive charges are used in about 98 (~63%) decommissioning operations annually (USDOI, MMS, 2005), often as a back-up cutter when other methodologies prove unsuccessful. Explosives work to sever their targets by using (1) mechanical distortion (ripping), (2) high-velocity jet cutting, and (3) fracturing or “spalling.”

Mechanical distortion is best exhibited with the use of explosives such as standard and configured bulk charges. If the situation calls for minimal distortion and an extremely clean severing, then most contractors rely upon the jet-cutting capabilities of shaped charges. In order to “cut” with these explosives, the specialized charges are designed to use the high-velocity forces released at detonation to transform a metal liner (often copper) into a thin jet that slices through its target. The least used method of severing currently in use on the Gulf of Mexico OCS is fracturing, which uses a specialized charge to focus pressure waves into the target wall and use refraction forces to spall or fracture the steel on the opposing side (NRC, 1996).

In water depths >800 m (2,625 ft), OCS regulations offer the lessees the option to avoid the jetting by requesting alternate removal depths for well abandonments (30 CFR § 250.1716(b)(3)) and facilities (30 CFR § 250.1728(b)(3)). Above mudline cuts would be allowed for depths >800 m (2,625 ft), with reporting requirements on the remnant's description and height off of the seafloor to BOEM; this is data necessary for subsequent reporting to the U.S. Navy. With the exception of several dynamically positioned vessels, deepwater drilling operations most often use moored semisubmersibles. Coupled with the growing number of TLPs, spars, and MODUs, operators and contractors have to contend with new demands for quick-disconnect and line severing tools that may be necessary during emergencies and decommissioning operations when the anchor cannot be retrieved.

Some of the mooring systems used in deepwater operations have quick-disconnect technology built into their designs. Using several varieties of exploding bolts, electromechanical couplings, and/or hydraulic-actuated connections, these release mechanisms can be controlled from the vessel and triggered on short notice. In situations where the mooring system disconnects were not employed or become disabled, severing contractors have several mechanical and explosive cutting tools at their disposal for shearing cables, lines, and chains from their moorings. Mechanical cutters such as wheel and guillotine saws, hydraulic shears, and diamond wire cutters can be deployed using ROVs, allowing the cuts to be performed as close to the anchors as possible. In much the same way, small explosive shaped-charge devices can be positioned onto the mooring targets by ROVs. These external cutters are generally designed with hydraulic/electric actuators and hinge systems that allow the shaped charge to be "clamped" over the target and then detonated after the ROV is removed to a safe distance. Together, these effective severing methods and the deep-diving capabilities of the ROVs allow for full recovery of the lines/cables/chains, which could present a future hazard to commercial fishing gear and navigation.

After bottom-founded objects are severed and the structures are removed, operators are required to use trawling or sonar searches to verify that the site is clear of any obstructions that may conflict with other uses. Refer to **Appendix A.13** for a more detailed discussion of site-clearance processes.

*Alternative A**: **Table 3-2** shows platform removals by water-depth subarea as a result of Alternative A. Of the 16-280 production structures estimated to be removed as a result of a proposed action under Alternative A, 9-193 production structures (installed landward of the 800-m [2,625-ft] isobath) could likely be removed using explosives. While production structures are removed, it is anticipated that multiple appurtenances or types of equipment (e.g., subsea systems, pipelines, umbilical lines, etc.) would not be removed from the seafloor if placed in waters exceeding 800 m (2,625 ft) as allowed under certain conditions in 30 CFR § 250. An estimate of the well stubs and other various subsea structures that may be removed using explosives is not possible at this time. For the purposes of impact assessment, the prudent assumption should be that charges used for well severance behave in the same manner and produce parameters of the same magnitude as do charges detonated on the bottom in open water.

Alternative B*: **Table 3-2** shows platform removals by water-depth subarea as a result of Alternative B. Of the 14-247 production structures estimated to be removed as a result of Alternative B, 7-172 production structures (installed landward of the 800-m [2,625-ft] isobath) could likely be removed using explosives. It is anticipated that multiple appurtenances would not be removed from the seafloor if placed in waters exceeding 800 m (2,625 ft).

*Alternative C**: **Table 3-2** shows platform removals by water-depth subarea as a result of Alternative C. Of the 9-33 production structures estimated to be removed as a result of Alternative C, 4-21 production structures (installed landward of the 800-m [2,625-ft] isobath) could likely be removed using explosives. It is anticipated that multiple appurtenances would not be removed from the seafloor if placed in waters exceeding 800 m (2,625 ft).

*Alternative D could reduce activity values of the combined Alternative A, B, or C, but it may only shift the location of offshore infrastructure and activities farther from sensitive topographic zones. Since the ranges given for Alternatives A, B, and C are broad and represent the low and high levels of forecasted activity, any reduction of activity from choosing Alternative D would still fall within those ranges; therefore, the scenarios do not change when considering Alternative D. The potential impacts associated with selecting Alternative D are discussed in **Chapter 4** under each resource. Refer to **Chapter 2.2.2.4** for more information.

3.1.6.1 Structure Age and Idle Iron

The Bureau of Ocean Energy Management, Regulation and Enforcement issued NTL 2010-G05 to establish guidelines for decommissioning structures within the timeframes established by regulations, conditions of approval, and lease instruments.

Federal regulations require that offshore leases be cleared of all structures within 1 year after production on the lease ceases, but a producing lease can hold infrastructure idle for as long as the lease is producing (30 CFR § 250.112). Refer to **Chapter 3.1.6 and Appendix A.13** for more information on decommissioning. As of 2015, the average age of all removed offshore structures was 19 years. Simpler structures like caissons had an average lifespan of 17 years when decommissioned, and more complex structures like fixed platforms had an average lifespan of 20 years. The average age of all active platforms is 29 years, with some platforms from previous lease sales still in production after 60 years (Casselman, 2010). For this proposed action, no platforms are expected to be in operation beyond the 50-year analysis period (refer to **Figure 3.8**). Although accidents, storm damage, and unforeseen geological problems may cause platforms to be removed early, the discrepancy between the assumed and actual life of platforms is probably explained by the end of economic production from the field rather than by design or engineering factors unique to each platform. Most of the hurricane-related spills resulted from storm damage to older pipelines and other aging infrastructure. Past studies have shown that there is a direct relationship between older offshore production facilities and the potential for accidents and spills (Pulsipher et al., 1998). It is expected that, in the future, more of these facilities would be taken out of production or be replaced as new infrastructure is brought on line. With the placement of new infrastructure, combined with the continual updating of safety regulations and programs, it is expected future spills would be greatly reduced. More complex operations such as mooring, station keeping, riser management, and deepwater well control may complicate operations and increase the number of procedures prone to errors and equipment prone to failure. The newest platforms incorporate advanced technology about which few data on long-term success or incidents have been gathered (USDOI, GS, 2011). Refer to **Chapter 3.2** for other accidental events. Any infrastructure that is decommissioned and no longer "economically viable," severely damaged, or idle on active leases is considered "idle iron" according to NTL 2010-G05, "Decommissioning Guidance for Wells and Platforms."

The BSEE's idle iron policy keeps inactive facilities and structures from littering the Gulf of Mexico by requiring companies to dismantle and responsibly dispose of infrastructure after they plug nonproducing wells. BSEE enforces these lease agreements primarily for two reasons beyond the CFR requirement:

- Environmental Effects – Toppled structures pose a potential environmental hazard due to the topsides and the associated equipment, electronics, wiring, piping, tanks, etc., that are left on the bottom of the Gulf of Mexico. These items pose a financial, safety, and environmental burden, and must be removed from the bottom.
- Safety – Severe weather such as hurricanes have toppled, severely damaged, or destroyed the structures associated with oil and gas production. While any structure could be destroyed during a hurricane, idle facilities pose an unnecessary risk of leaks from wells into the environment and potential damage to the ecosystem, passing ships, and commercial fishermen.

The typical life span of a pipeline has been estimated to be 20-40 years, but with current corrosion management, that lifetime has been substantially increased. One technique for extending the life of a gas pipeline is to coat the inside of the pipe periodically with a corrosion-inhibiting substance. The coating may be applied as either an aerosol pumped in with the production stream or as a liquid “slug” pushed through the pipe with a pig. The slug treatment provides greater protection (Cranswick, 2001). Corrosion can lead to major accidents on platforms. In 2011, a platform owned by Mariner Energy, about 100 mi (161 km) off the Louisiana shore, was using a piece of steel heating equipment that had corroded over its 30-year life, causing it to leak hydrocarbons that ignited the platform (Sebastian, 2011).

Subsea wells, in which the wellhead, Christmas tree, and production-control equipment are all located on the seafloor, were introduced in the 1970’s and started to grow especially popular in the 1980’s and 1990’s. Older generations of subsea wells had a designed life of 15-20 years, and many of those devices are reaching the end of that time span (Holeywell, 2014).

3.1.6.2 Artificial Reefs

Although BSEE supports and encourages the reuse of obsolete oil and gas structures as artificial reefs and is a cooperating agency in implementing the National Artificial Reef Plan, specific requirements must be met for a departure to be granted. More information on these regulations and processes can be found in **Appendix A.15**. Structure-removal permit applications requesting a departure under the Rigs-to-Reefs Policy undergo technical and environmental reviews. The policy document details the minimum engineering and environmental standards that operators/lessees must meet to be granted approval to deploy a structure as an artificial reef. Conditions of approval are applied as necessary to minimize the potential for adverse effects to sensitive habitat and communities in the vicinity of the structure and proposed artificial reef site. Additionally, structures deployed as artificial reefs must not threaten nearby structures or prevent access to oil and gas, marine mineral, or renewable energy resources.

Routine activities include the decommissioning of structures, but redeployment and reefing is considered a State activity. Refer to **Chapter 3.3.2.1.2** for more information on artificial reefs.

3.1.7 Coastal Infrastructure

The following chapters discuss coastal impact-producing factors and provide scenario projections for onshore coastal infrastructure that may potentially result from a proposed lease sale under Alternative A, B, or C in the 2017-2022 Five-Year Program. Under Alternative D, the number of blocks that would become unavailable for lease represents only a small percentage (<4%) of the total number of blocks to be offered under Alternative A, B, or C. Therefore, Alternative D could reduce offshore infrastructure and activities, but it could only shift the location of offshore infrastructure and activities farther from sensitive topographic zones and not lead to a reduction in offshore infrastructure and activities. Refer to **Chapter 2.2.2.4** for more information on Alternative D. This discussion describes the potential need for new facility construction and for expansions at existing facilities. A detailed description of the baseline affected environment for land use and coastal infrastructure in the GOM can be found in **Chapter 4.14.1.1**.

Oil and gas exploration, production, and development activities on the OCS are supported by an expansive onshore infrastructure industry that includes large and small companies providing an array of services from construction facilities, service bases, and waste disposal facilities to crew, supply, and product transportation, as well as processing facilities. It is an extensive and mature system providing support for both offshore and onshore oil and gas activities in the GOM region (**Figure 3-11**). The extensive presence of this coastal infrastructure is not subject to rapid fluctuations and results from long-term industry trends. Existing oil and gas infrastructure is expected to be sufficient to handle development associated with a proposed action. Should there be some expansion at current facilities, the land in the analysis area is sufficient to handle such development.

Impact-producing factors associated with coastal infrastructure include service bases, gas processing plants, pipeline landfalls, navigation channels, and waste disposal facilities. **Chapter 3.1.5.1.3** addresses onshore waste disposal. **Chapter 3.1.3.3.1** discusses pipeline landfalls. While no single proposed lease sale under Alternative A, B, or C is projected to substantially change existing OCS-related service bases or require any additional service bases, it would contribute to the use of existing service bases. Sufficient land exists to construct a new gas processing plant in the unlikely event that one should be needed. However, because the current spare capacity at existing facilities should be sufficient to satisfy new gas production, the need to construct a new facility would possibly materialize only toward the end of the life of a proposed action. Therefore, BOEM projects 0-1 new gas processing plants to result from a proposed lease sale under Alternative A, B, or C. While a proposed action would contribute to the continued need for maintenance dredging of existing navigation channels, a mature network of navigation channels already exists in the analysis area; therefore, no new navigation channel construction would be expected as a direct result of a proposed lease sale under Alternative A, B, or C (Dismukes, official communication, 2015).

BOEM continuously collects new data and monitors changes in infrastructure demands in order to support scenario projections that reflect current and future industry conditions. The scenario projections outlined below reflect the already well-established industrial infrastructure network in the GOM region and fluctuations in OCS oil- and gas-related activity levels. To prevent underestimating potential effects, BOEM makes conservative infrastructure scenario estimates; therefore, a projection of between 0 and 1 is more likely to be 0 than 1.

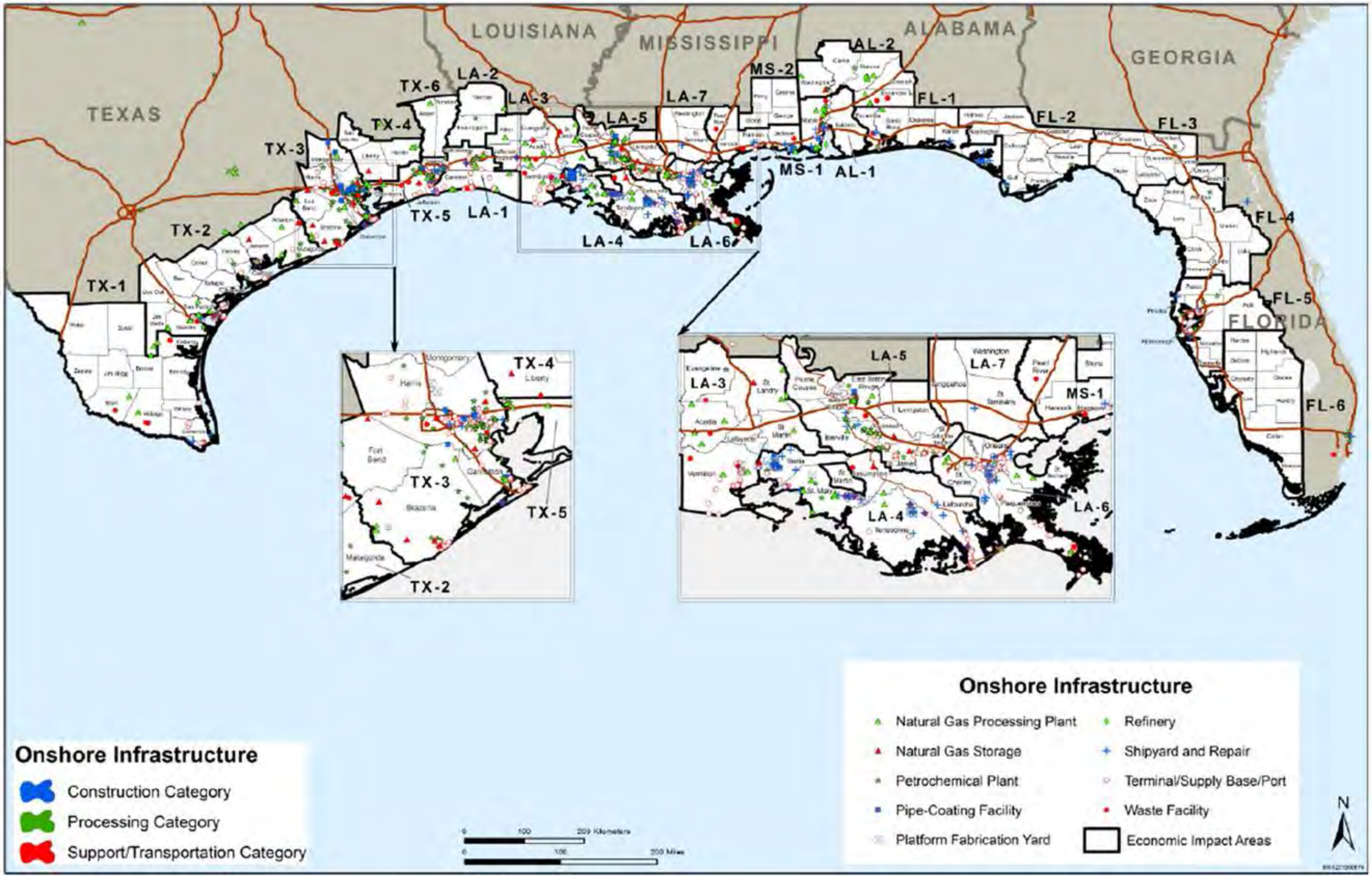

Figure 3-11. Onshore Infrastructure.

The following chapters provide the current trends, or outlook scenario projections, for the varied infrastructure categories. The primary sources for all of the information on coastal infrastructure and activities presented here are BOEM's Gulf of Mexico OCS Region's fact books: (1) *OCS-Related Infrastructure in the Gulf of Mexico Fact Book* (The Louis Berger Group, Inc., 2004); (2) *Fact Book: Offshore Oil and Gas Industry Support Sectors* (Dismukes, 2010); and (3) *OCS-Related Infrastructure Fact Book; Volume I: Post-Hurricane Impact Assessment* and *Volume II: Communities in the Gulf of Mexico* (Dismukes, 2011).

3.1.7.1 Construction Facilities

3.1.7.1.1 Platform Fabrication Yards

Facilities where platforms (and drilling rigs) are fabricated are called platform fabrication yards. Most platforms are fabricated onshore and then towed to an offshore location for installation. When an oil and/or gas discovery occurs, an exploratory drilling rig would be either replaced with, or converted to, a production platform assembled at the site using a barge equipped with heavy lift cranes. Platform fabrication is highly dependent on the structural nature of the oil and gas industry. As oil prices fluctuate, platform fabrication yards adjust accordingly. When oil prices are low, they diversify their operations into other marine-related activities or scale back on the overall scope of their operations. The variety of diversification strategies may include drilling rig maintenance and re-builds, barge or vessel fabrication, dry-docking, or equipment survey.

The existing fabrication yards do not operate as "stand alone" businesses; rather, they rely heavily on a dense network of suppliers of products and services. Also, since such a network has been historically evolving in the GOM region for many decades, existing fabrication yards possess a compelling force of economic concentration to prevent the emergence of new fabrication yards. There are 54 platform fabrication yards in the analysis area, with the highest concentration in Louisiana at 37 and followed by Texas at 12 (**Table 3-5**). Given the large size of offshore platforms, fabrication yards necessarily span several hundred acres. The location of platform fabrication yards is tied to the availability of a navigable channel sufficiently large enough to allow the towing of bulky and long structures, such as offshore drilling and production platforms. Thus, platform fabrication yards are located either directly along the Gulf Coast or inland along large navigable channels, such as the Intracoastal Waterway.

Alternative A, B, C, or D: No new facilities are expected to be constructed as a result of Alternative A, B, C, or D. The potential exists for some current yards to close, be bought out, or merge over the 50-year analysis period (2017-2066), resulting in fewer active yards in the analysis area.

3.1.7.1.2 Shipbuilding and Shipyards

There are several kinds of shipyards throughout the Gulf Coast region that build and repair all manner of vessels, many of which are not related to OCS oil- and gas-related activities. These marine vessels are perhaps the most important means of transporting equipment and personnel from onshore bases and ports to offshore drilling and production structures. The shipbuilding and repair industry has struggled over the last few decades. Since the mid-1990's, there has been some industry stabilization, but the outlook for shipbuilding and shipyards is uncertain. The industry is overly dependent on military contracts and faces numerous economic challenges, such as the lack of international competitiveness, workforce development challenges, availability of capital, and the lack of research and development funding. In the GOM region, there is a direct correlation between OCS oil- and gas-related activities and the demand or opportunities for expanding shipbuilding and offshore support vessels. There are 137 shipyards located within the analysis areas (**Table 3-5**). To a great extent, growth would be based on a successful resolution of several pertinent issues that have affected and continue to affect shipbuilding in the U.S. and particularly in the analysis area: maritime policy; declining military budget; foreign subsidies; USCG regulations; Oil Pollution Act of 1990; financing; and an aging fleet. Generally, as oil and gas drilling and production increase, the demand for an expanded shipbuilding effort also increases. However, despite the drop in oil and gas prices at the end of 2014 and beginning of 2015, Louisiana-based Bollinger Shipyards began construction on four massive dry docks able to service 300-ft (91-m) or larger vessels (Jervis, 2015).

Alternative A, B, C, or D: No new facilities are expected to be constructed as a result of Alternative A, B, C, or D. There is more than an adequate supply of shipyard resources in the GOM region. Some shipyards may close, be bought out, or merge over the 50-year analysis period (2017-2066), resulting in fewer active yards in the analysis area.

3.1.7.1.3 Pipe-Coating Facilities and Yards

Pipe-coating plants generally receive manufactured pipe by rail or water at either their plant or pipeyard depending on their inventory capabilities. At the plant, pipes that transport oil and gas are coated on the interior and exterior to protect from corrosion and abrasion. There are 19 pipe-coating plants in the analysis areas (**Table 3-5**). Pipe-coating facilities receive manufactured pipe, which they then coat the surfaces of with metallic, inorganic, and organic materials to protect from corrosion and abrasion and to add weight to counteract the water's buoyancy. Two to four sections of pipe are then welded at the plant into 40-ft (12-m) segments. The coated pipe is stored (stacked) at the pipe yard until it is needed offshore.

To meet deepwater demand, pipe-coating companies were expanding capacity or building new plants before the *Deepwater Horizon* explosion, oil spill, and response; afterwards, activity levels dropped temporarily, then rebounded until the oil price drop and economic downturn of late 2014/early 2015, resulting in a decrease in OCS activity levels and less demand for pipe-coating services. As activity levels fluctuate in the GOM, the demands for pipe-coating services fluctuate accordingly.

Alternative A, B, C, or D: No new facilities are expected to be constructed as a result of Alternative A, B, C, or D. Current capacity, supplemented by expansions at already existing facilities, is anticipated to meet OCS Program demand.

3.1.7.2 Support Facilities and Transportation

3.1.7.2.1 Service Bases and Ports

A service base is a community of businesses that load, store, and supply equipment, supplies, and personnel needed at offshore work sites. A service base may also be referred to as a supply base or terminal and may be associated with a port. A proposed lease sale under Alternative A, B, or C is expected to utilize only those ports that currently have facilities used by the oil and gas industry as offshore service bases. Although a service base may primarily serve the adjacent OCS planning area and Economic Impact Areas (EIAs) in which it is located, it may also provide substantial services for the other OCS planning areas and EIAs. **Table 3-11** shows the 50 services bases organized by EIA, and **Figure 3-9** shows the geographic location of the service bases.

Table 3-11. OCS Oil- and Gas-Related Service Bases.

State	EIA	County/Parish		
Texas	TX-1	Port Isabel (Cameron)	Port Mansfield (Willacy)	
	TX-2	Aransas Pass (Nueces) Bayside (Aransas) Corpus Christi (Nueces)	Harbor Island (Nueces) Ingleside (San Patricio) Port Aransas (Nueces)	Port O'Connor (Calhoun) Rockport (Aransas)
	TX-3	Freeport (Brazoria) Galveston (Galveston)	Pelican Island (Galveston)	Surfside (Harris)
	TX-5	Port Arthur (Jefferson) Sabine Pass (Jefferson)		
Louisiana	LA-1	Cameron (Cameron)	Grand Chenier (Cameron)	Lake Charles (Calcasieu)
	LA-3	Amelia (St. Mary) Bayou Boeuf (St Mary)	Berwick (St. Mary)	Cocodrie (Terrebonne)
	LA-4	Amelia (St. Mary) Bayou Boeuf (St. Mary) Berwick (St. Mary) Cocodrie (Terrebonne) Dulac (Terrebonne)	Fourchon (Lafourche) Gibson (Terrebonne) Houma (Terrebonne) Leeville (Lafourche) Louisa (St. Mary)	Morgan City (St. Mary) New Iberia (Iberia) Patterson (St. Mary) Theriot (Terrebonne) Weeks Island (Iberia)
	LA-6	Empire (Plaquemines) Grand Isle (Jefferson)	Harvey (Jefferson) Hopedale (St. Bernard)	Paradis (St. Charles) Venice (Plaquemines)
Mississippi	MS-1	Pascagoula (Jackson)		
Alabama	AL-1	Bayou LaBatre (Mobile)	Mobile (Mobile)	Theodore (Mobile)
Florida	FL-1	Panama City (Bay)		

EIA = Economic Impact Area.

As the industry continues to evolve, so do the requirements of the onshore support network. With advancements in technology, the shore-side supply network would continue to be challenged to meet the needs and requirements. The intermodal nature of oil and gas operations gives ports (which traditionally have water, rail, and highway access) a natural advantage as ideal locations for onshore activities and intermodal transfers (**Figure 3-12**). Therefore, ports would continue to be a vital factor in the total process and must incorporate the needs of the offshore oil and gas industry into their planning and development efforts, particularly with regard to determining their future investment needs. In this manner, both technical and economic determinants influence the dynamics of port development.

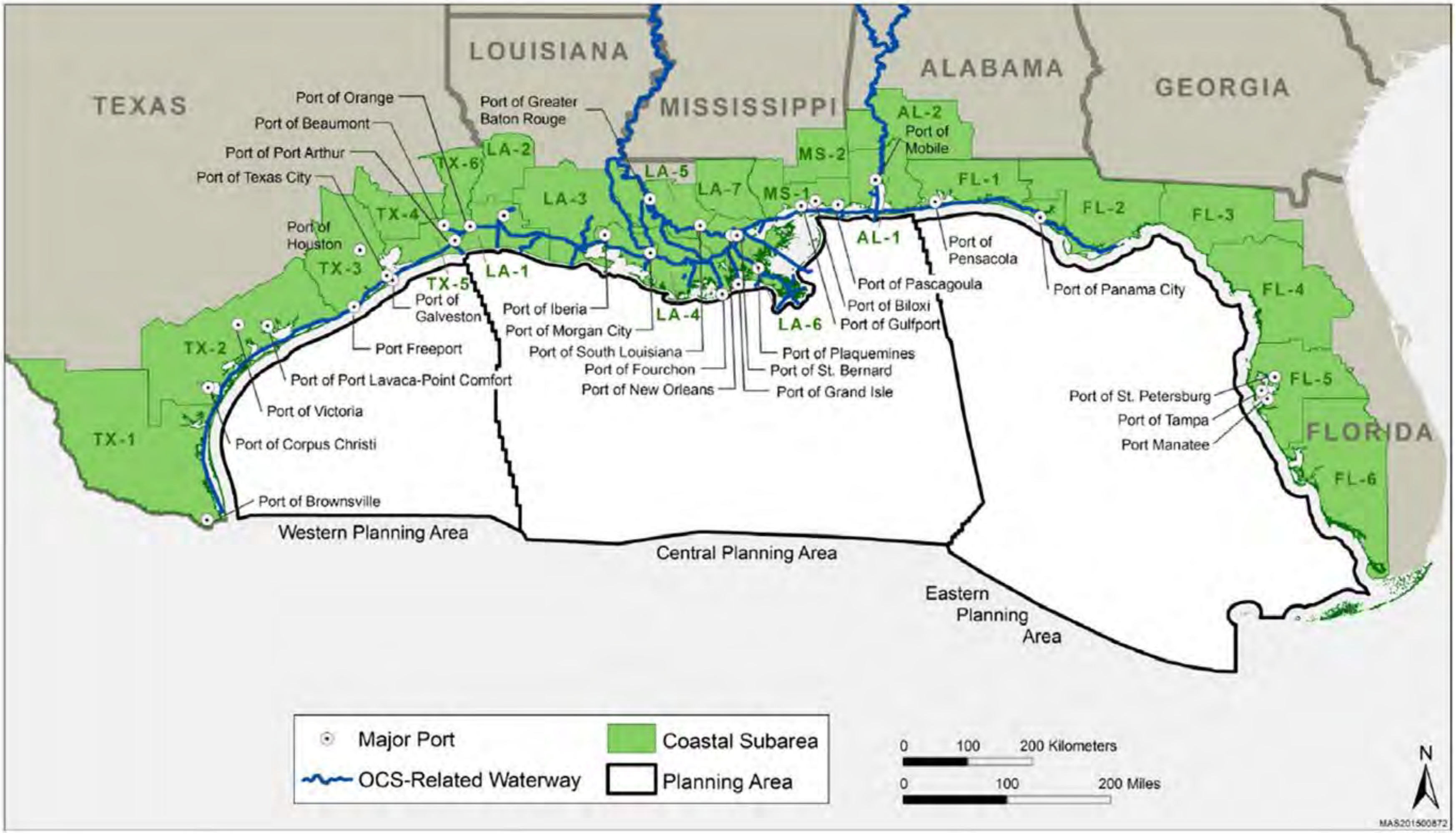

Figure 3-12. OCS-Related Ports and Waterways in the Gulf of Mexico.

Expansion of some existing service bases is expected to occur to capture and accommodate the current and future oil and gas business that is generated by development on the OCS. In early 2015, for example, Louisiana-based Bollinger Shipyards was constructing four massive dry docks able to service 300-plus-foot (91-plus-meter) vessels at Port Fourchon while Schlumberger was expanding its Port Fourchon operations (Jervis, 2015). Some channels in and around the service bases would need to be deepened and expanded in support of deeper draft vessels and other port activities, some of which would be OCS related. Channel depths at most major U.S. ports typically range from 35 to 45 ft (11 to 14 m). The current generation of new large ships that service the offshore industry requires channels from 45 to 53 ft (14 to 16 m).

Alternative A, B, C, or D: Alternative A, B, C, or D would not change identified service bases or require any additional service bases. The OCS oil- and gas-related activities over the course of the 50-year analysis period (2017-2067) would continue to contribute to the ongoing trend of consolidating activities at specific ports, especially with respect to deepwater activities (i.e., Port Fourchon and Galveston).

3.1.7.2.2 Helicopter Hubs

There are 241 identified heliports within the GOM region that support OCS oil- and gas-related activities; 118 are located in Texas, 115 in Louisiana, 0 in Florida, 4 in Mississippi, and 4 in Alabama (**Table 3-5**). **Chapter 3.1.4.4** provides information on helicopter operation projections.

Alternative A, B, C, or D: No new helicopter hubs are projected as a result of a proposed lease sale or the OCS Program; however, if activity levels increase, they may expand at current locations.

3.1.7.2.3 Tanker Port Areas

The transport of OCS-produced oil from FPSO operations to inside or shore-side facilities would be accomplished with shuttle tankers rather than oil pipelines. The following tanker ports were identified as destinations for shuttle tankers transporting crude oil from FPSO operations in the GOM: Houston or the Louisiana Offshore Oil Port are most likely candidates, followed by possibly Corpus Christi, Freeport, and Port Arthur/Beaumont, Texas, although it would be most likely for oil to be transported to Port Arthur/Beaumont via pipeline (Dismukes, official communication, 2011a). Tankers that offloaded oil from Petrobras' Cascade Chinook delivered to the following areas: Nederland, Texas; Pascagoula, Mississippi; Mobile, Alabama; Port Arthur, Texas; Garyville, Louisiana; Houston, Texas; Lake Charles, Louisiana; Saint Rose, Louisiana; Galveston Bar, Texas; Texas City, Texas; Corpus Christi, Texas; Baton Rouge, Louisiana; the Louisiana Offshore Oil Port; and Yabucoa, Puerto Rico. **Chapter 3.1.4.2** provides BOEM's current tankering projections.

Alternative A, B, C, or D: Tanker trips associated with Alternative A, B, C, or D would represent a small percentage of annual tanker trips into identified tanker ports. Therefore, no new tanker port facilities are projected to result from Alternative A, B, C, or D.

3.1.7.2.4 Barge Terminals

The OCS oil barged from offshore platforms to onshore barge terminals represents a small portion of the total amount of oil barged in coastal waters. While there is a tremendous amount of barging that occurs in the coastal State waters of the GOM, no estimates exist of the volume of this barging that is directly attributable to the OCS industry. Secondary barging of OCS oil often occurs between terminals or from terminals to refineries. Oil that is piped to shore facilities and terminals is often subsequently transported by barge up rivers, through the Gulf Intracoastal Waterway, or along the coast. **Chapter 3.1.4.1** provides BOEM's current barging projections.

Alternative A, B, C, or D: Barging of OCS production is expected to remain stable. No major modifications or new barge terminals are expected to be constructed as a direct result of a proposed lease sale or OCS Program operations.

3.1.7.2.5 Pipeline Shore Facilities

The term "pipeline shore facility" is a broad term describing the onshore location where the first stage of processing occurs for OCS pipelines carrying different combinations of oil, condensate, gas, and produced water. Some processing may occur offshore at the platform; only onshore facilities are addressed in this discussion. Pipelines carrying only dry gas do not require pipeline shore facilities; the dry gas is piped directly to the gas processing plant. Therefore, new pipeline shore facilities are projected to only result from oil pipeline landfalls. A pipeline shore facility may support one or several pipelines; therefore, new pipeline shore facilities are projected to only result from larger pipelines (>12 in; 30 cm). Although older facilities may be located in wetlands, current permitting programs prohibit or discourage companies from constructing any new facilities in wetlands. Also, it is more cost effective for companies to tie into the existing offshore pipeline network. **Chapter 3.1.3.3.1** provides BOEM's current pipeline landfall projections.

Alternative A, B, C, or D: No new pipeline shore facilities are projected as a result of Alternative A, B, C, or D, which would represent a small percent of the resources handled by existing shore facilities.

3.1.7.2.6 Waste Disposal Facilities

A variety of different types of wastes are generated by offshore oil and gas exploration and production activities along the GOM. Some wastes are common to any manufacturing or industrial operation (e.g., garbage, sanitary waste [toilets], and domestic waste [sinks and showers]) while others are unique to the oil and gas industry (e.g., drill fluids and produced water). Most waste must be transported to shore-based facilities for storage and disposal. In the analysis area, there are 16 waste disposal facilities in Texas, 29 in Louisiana, 3 each in Mississippi and Alabama, and 2 in Florida. Refer to **Chapter 3.1.5.3** for more information.

> *Alternative A, B, C, or D:* No new waste disposal facilities are expected to be constructed as a result of Alternative A, B, C, or D. **Chapter 3.1.5.3** provides BOEM's current scenario analysis for waste disposal facilities.

3.1.7.2.7 Natural Gas Storage Facilities

Most of the natural gas storage facilities in the GOM region are salt caverns. The overwhelming majority of all salt cavern storage facilities operating in the U.S. are located along the GOM. Gulf Coast salt caverns account for only 4.2 percent of total U.S. working gas capacity and 15.5 percent of total U.S. deliverability. In the GOM, Texas has 14 salt cavern sites with 78 billion cubic feet per day (Bcf/day) of working gas capacity and Louisiana has 7 sites with 48 Bcf/day of working gas capacity, Mississippi has 3 sites with 32 Bcf/day of working gas capacity, and Alabama has 1 site with 7 Bcf/day of working gas capacity (USDOE, Energy Information Administration, 2007). Not all of these facilities are located within the BOEM-defined EIAs. More specifically, there are 22 underground natural gas storage facilities in the BOEM-defined EIAs. These facilities total 165 Bcf/day of working gas capacity.

> *Alternative A, B, C, or D:* No new natural gas storage facilities are projected as a result of Alternative A, B, C, or D. Any expansions or new facilities would be the result of onshore rather than offshore production.

3.1.7.3 Processing Facilities

The following chapters discuss various processing facilities, i.e., gas processing facilities, refineries, and LNG facilities. These are included as the final endpoint for OCS oil and gas; however, at the time that OCS product reaches these facilities, it has already been joined with non-OCS product from State waters and onshore activities. The percentage of oil and gas product processed by these facilities that actually originated from OCS waters has not been determined and is not likely to ever be possible to discover since it is due to a number of factors unrelated to the delivery of OCS product, such as downstream demand. Therefore, in contrast to most other infrastructure types, scenario projections for processing facilities are inherently limited with no direct correlation to OCS oil- and gas-related activities.

> *Alternative A, B, C, or D:* It is most likely that existing facilities would experience equipment switch-outs, upgrades, or expansions to meet increases in demand. The OCS oil- and gas-related activities that result from Alternative A, B, C, or D would contribute to the likelihood of 0-1 new gas processing facilities.

3.1.7.3.1 Gas Processing Plants

All natural gas is processed in some manner to remove unwanted water vapor, solids, and/or other contaminants that would interfere with pipeline transportation or marketing of the gas. After processing, gas is then moved into a pipeline system for transportation to an area where it is sold.

More than half (54%) of the natural gas processing plant capacity in the U.S. is located along the Gulf Coast and is available for supporting Federal offshore production (USDOE, Energy Information Administration, 2011). In the GOM region, the majority of gas processing plants are located in Louisiana (44) and Texas (39), followed by Alabama (13), Mississippi (1), and Florida (1) (**Table 3-5**). While natural gas production on the OCS shelf (shallow water) has been declining, deepwater gas production has been increasing, but not at the same pace. Overall, the combined trends of increasing onshore shale gas development, declining offshore gas production, and increasing efficiency and capacity of existing gas processing facilities have lowered demands for new gas processing facilities along the Gulf Coast. Spare capacity at existing facilities should be sufficient to satisfy new gas production for many years, although there remains a slim chance that a new gas processing facility may be needed by the end of the 50-year life of a proposed lease sale. Expectations for new gas processing facilities being built during the analysis period (2017-2066) are dependent on long-term market trends that are not easily predicable over the next 50 years (Dismukes, official communication, 2015).

Alternative A, B, C, or D: It is most likely that existing facilities would experience equipment switch-outs, upgrades, or expansions to meet increases in demand. The OCS oil- and gas-related activities that result from Alternative A, B, C, or D would contribute to the likelihood of 0-1 new gas processing facilities.

3.1.7.3.2 Refineries

The U.S. Department of Energy's Energy Information Administration updates national energy projections annually, including refinery capacity. Most of the GOM region's refineries are located in Texas and Louisiana (**Table 3-5**). Texas EIAs contain 20 operable refineries, with an operating capacity of over 4.5 MMbbl/day, which is over 25 percent of the total U.S. capacity. Louisiana EIAs contain 16 operable refineries, with an operational capacity of over 3.2 MMbbl/day, which is over 18 percent of the total U.S. capacity (USDOE, Energy Information Administration, 2015c). There has been a trend toward constructing simple refineries instead of complex refineries. In the United States, the last complex refinery started operating in 1977 in Garyville, Louisiana. In the GOM analysis area, a new simple refinery was constructed in 2014 in Galena Park, Texas (USDOE, Energy Information Administration, 2015d).

Alternative A, B, C, or D: No new facilities are expected to be constructed as a direct result of Alternative A, B, C, or D.

3.1.7.3.3 Onshore Liquefied Natural Gas Facilities

The wide variety of pipeline systems and delivery markets makes the GOM attractive for LNG developers. Onshore natural gas production has increased to the extent that LNG facilities along the GOM are seeking and receiving approval to export natural gas to foreign countries. There are six existing LNG import/export terminals in the GOM region—two in Texas, three in Louisiana, and one in Mississippi (USDOE, Federal Energy Regulatory Commission, 2015a). There are

16 proposed LNG export terminals in the GOM region—8 in Texas, 7 in Louisiana, and 1 in Mississippi (USDOE, Federal Energy Regulatory Commission, 2015a). Facilities with export approval that are under construction are located in Sabine and Hackberry, Louisiana; and Freeport and Corpus Christi, Texas. Also approved for export but not yet under construction is Sabine Pass Liquefaction in Sabine Pass, Louisiana (USDOE, Federal Energy Regulatory Commission, 2015a). In 2014, New Orleans-based Harvey Gulf International Marine began construction of an LNG bunkering facility at Port Fourchon, Louisiana. The first of its kind in the United States, the LNG facility will provide LNG fuel to the growing supply of LNG-operated vessels servicing the OCS, as well as over-the-road vehicles fueled by LNG (Schuler, 2014).

Alternative A, B, C, or D: BOEM projects that expansions at existing facilities and construction of new facilities would not occur as a direct result of Alternative A, B, C, or D. Any expansions or new facilities would be the result of onshore rather than offshore production.

3.1.7.3.4 Petrochemical Plants

Petrochemical plants are usually located in areas with close proximity to the raw material supply (petroleum-based) and multiple transportation routes, including rail, road, and water. Texas, New Jersey, Louisiana, North Carolina, and Illinois are the top domestic chemical producing states. However, most of the basic chemical production is concentrated along the Gulf Coast where petroleum and natural gas feedstock are available from refineries. Of the top 10 production complexes in the world, 5 are located in Texas and 1 is located in Louisiana.

Along the Gulf Coast, the petrochemical industry is heavily concentrated in coastal Texas and south Louisiana and in various counties along the Alabama, Mississippi, and Florida coasts. The vast majority of petrochemical plants in the Gulf region are located along coastal Texas (126) and south Louisiana (66). **Table 3-5** provides the numerical distribution for each state in the analysis area, and **Figure 3-11** illustrates the geographical distribution of petrochemical facilities across the 133 Gulf counties and parishes within analysis area.

Alternative A, B, C, or D: No new facilities are expected to be constructed as a direct result of Alternative A, B, C, or D.

3.1.8 Air Emissions

Section 328(a) of the 1990 Clean Air Act Amendments gives the USEPA air quality responsibility for the OCS area in the Gulf of Mexico east of 87.5° W. longitude, and BOEM retains air quality jurisdiction for OCS operations west of the same longitude in the Gulf of Mexico. In addition, Section 328(b) of the Clean Air Act Amendments requires BOEM to assure coordination of air-pollution control regulations between emissions in the Gulf of Mexico OCS and emissions in adjacent onshore areas. The Clean Air Act Amendments requires the USEPA to set the NAAQS and to periodically review and update the standards, as necessary, to ensure they provide adequate health and environmental protection. Consequently, there would be a continuing need for emission inventories and modeling to ensure that the NAAQS are being met, as well as for Coastal Zone Management Act and State Implementation Plans planning requirements.

The Outer Continental Shelf Lands Act (43 U.S.C. § 1334(a)(8)) tasks the U.S. Department of the Interior to assure that air pollutant emissions from offshore oil and gas exploration, development, and production sources do not significantly affect the air quality of any state. In particular, BOEM is responsible for determining if air pollutant emissions from offshore oil and gas activities in the Gulf of Mexico influence the NAAQS compliance status of Texas, Louisiana, Mississippi, Alabama, and Florida. BOEM's air quality regulations in 30 CFR §§ 550.302, 550.303, and 550.304 were promulgated as mandated by Section 5(a)8 of the OCSLA. As previously mentioned, Section 328(a) of the Clean Air Act Amendments splits air quality jurisdicition in the GOM between BOEM and USEPA, while Section 328(b) of the Clean Air Act Amendments requires BOEM to assure coordination of air-pollution control regulations between emissions in the Gulf of Mexico and emissions in adjacent onshore areas. To.assess offshore oil- and gas-related activities and their associated emissions, BOEM conducted a series of studies. BOEM has published the following study documents: in 1995, the *Gulf of Mexico Air Quality Study* (System Applications International et al., 1995); in 2004, the *Gulfwide Emission Inventory Study for the Regional Haze and Ozone Modeling Effort* (Wilson et al., 2004) and the *Data Quality Control and Emissions Inventories of OCS Oil and Gas Production Activities in the Breton Area of the Gulf of Mexico* (Billings and Wilson, 2004); in 2007, the *Year 2005 Gulfwide Emission Inventory Study* (Wilson et al., 2007); and in 2010, the *Year 2008 Gulfwide Emission Inventory Study* (Wilson et al., 2010). Due to new and updated NAAQS, drilling in deep water, and offshore sources changing because of new technology, BOEM continues to update the emissions inventories every 3 years to coincide with the USEPA and State agency inventory process. Since the emission inventories also include greenhouse gas emissions, OCS operators can use the data to report their greenhouse gas emissions to the USEPA.

To build on the previously conducted studies, BOEM completed the *Year 2011 Gulfwide Emission Inventory Study* (Wilson et al., 2014) with a goal of having a calendar year 2011 inventory air pollution emissions for all OCS oil and gas production-related sources in the Gulf of Mexico. Pollutants covered in this inventory are the criteria pollutants such as carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM), and sulfur dioxide (SO_2); and volatile organic compounds (VOCs), as well as major greenhouse gases such as carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). Ozone (O_3), a criteria pollutant, is formed by photochemical reactions of NO_x and VOC in the atmosphere. Although ozone is not covered in this inventory, ozone precursors (NO_x and VOCs) are covered. Lead (Pb), another criteria pollutant, is not covered in this inventory due to the lack of credible emission factors for this pollutant. Benzene, toluene, ethylbenzene, and xylene (BTEX) is a category of VOCs that occur naturally in crude oil, as well as during the process of making gasoline and other fuels from crude oil. Although BTEX is not individually addressed in this inventory, VOCs are covered.

The *Year 2011 Gulfwide Emission Inventory Study* presents a full description of monthly activity data from platform and non-platform sources, and it additionally updates those procedures used in previous inventories by taking the most recent emission factors from the USEPA and the

Emission Inventory Improvement Program to develop a comprehensive criteria pollutant and greenhouse gas emissions inventory. A Year 2014 Gulfwide Emission Inventory Study, which is currently in progress, is built upon previous studies to develop a base year 2014 air pollution emissions inventory for all OCS oil and gas production-related sources in GOM. Furthermore, the study will cover well stimulation vessels and develop hazard air pollutant emission estimates for select oil and natural gas production platform emission sources. Refer to **Chapter 4.1** for more information.

A Fugitive Emissions Update study, which is in the process of being awarded, would update fugitive emission factors, component counts and stream compositions for both shallow water and deepwater oil and gas facilities in the Gulf of Mexico Region OCS. Specifically, the objectives are to update the calculation of fugitive emissions in the OCS emissions inventories by updating the default component count to include larger deepwater platforms, to update the default speciation weight fractions for total hydrocarbon (THC) emissions by stream type, and to quantify the expected methane emissions reductions that would result from replacement of high bleed pneumatic controllers with low bleed pneumatic controllers. This study is expected to be complete by 2019.

3.1.8.1 Drilling

Refer to **Chapter 3.1.3.1** for the description of drilling operations and activities. Refer to **Chapter 4.1.2** and **Figures 4-9** and **4-10** for emissions in tons per year for criteria pollutants and greenhouse gases from these activities. Emissions associated with drilling from OCS oil- and gas-related activities are attributed to gasoline, diesel, and natural gas fuel usage in engines such as propulsion engines, prime engines, mud pumps, draw works, and emergency power. Pollutants emitted during drilling activities include combustion gases (i.e., CO, NO_x, PM, SO_2, CO_2, CH_4, and N_2O), as well as noncombustion sources (i.e., VOCs, PM, and CH_4). To understand further how emissions criteria pollutants are estimated, refer to NTL 2008-G04, “Information Requirements for Exploration Plans and Development Operations Coordination Documents.”

3.1.8.2 Production

Refer to **Chapter 3.1.3.1** for the description of production operations and activities. Emissions associated with production from OCS oil- and gas-related activities are attributed to boilers, diesel engines, combustion flares, fugitives, glycol dehydrators, natural gas engines, turbines, pneumatic pumps, pressure/level controllers, storage tanks, cold vents, and others. Pollutants emitted during production activities include CO, NO_x, PM, SO_2, VOCs, CO_2, CH_4, and N_2O.

3.1.8.3 Vessel Support Operations and Activities during Offshore Oil and Gas Activities

Refer to **Chapter 3.1.4** for the description of vessel support operations and activities during OCS oil- and gas-related activities. Emissions associated with support vessels from OCS oil- and gas-related activities are attributed to the operations of the primary diesel engine used for propulsion and other smaller diesel engines that are used to run generators or small cranes and winches for loading and unloading the vessels. Pollutants emitted during drilling activities include combustion gases (i.e., CO, NO_x, PM, SO_2, CO_2, CH_4, and N_2O) and VOCs.

3.1.8.4 Flaring and Venting

The availability of a flare or vent is essential in oil and gas operations, primarily for safety reasons. It ensures that associated natural gas can be safely disposed of in emergency and shutdown situations.

Flaring is the controlled burning of natural gas and is a common practice in oil and gas exploration, production, and processing operations. The burning occurs at the end of a stack or boom. Flares generate heat and noise. Pollutants emitted during flaring include CO, NO_x, PM, SO_2, VOCs, CO_2, CH_4, and N_2O.

Venting is the controlled release of unburned gases into the atmosphere in the course of oil and gas production operations. In venting, the natural gases associated with oil production are released directly into the atmosphere and not burned. Vents produce less noise and are less visible. Pollutants emitted during venting include VOCs, CO_2, and CH_4.

Flaring and venting can have environmental impacts. Flaring may involve the disposal of sweet gas or sour gas. Sweet gas is natural gas that does not contain hydrogen sulfide (H_2S) while sour gas is natural gas that does contain H_2S. Flaring produces predominantly CO_2 emissions, while venting produces predominantly CH_4 emissions. Both carbon dioxide and methane are known as greenhouse gases associated with concerns about global warming. The global warming potential of a kilogram of methane is estimated to be 21 times that of a kilogram of carbon dioxide when effects are considered over 100 years. Therefore, flaring is often considered to be the preferred method to dispose of natural gas in oil and gas operations. Although the global warming potential of methane when compared with carbon dioxide usually suggests that flaring is a more environmentally attractive option than venting, neighbors of onshore oil and gas developments prefer venting because it is less visible and produces less noise. Flaring and venting systems are used to burn off waste gas and surplus gases, and they are also a safety means to protect process equipment, the system's processes, and the environment. Therefore, the activities can be divided into routing flaring and venting, and nonroutine (emergency) flaring and venting. Flares usually operate continuously; however, some are used only for process upsets. Natural gas discharges via venting can be due to routine or emergency releases.

Routine Flaring and Venting

Routine flaring occurs on a regular basis due to the normal operations of a facility. Flares can be used routinely to control emissions from storage tanks, loading operations, glycol dehydration units, vent collection system, and amine units. Natural gas discharges via venting can be due to routine or emergency releases. Vents receive exhaust streams from miscellaneous sources, as well as manifold exhaust streams from other equipment on the same platform such as amine units, glycol dehydrators, loading operations, and storage tanks.

3.1.8.5 Fugitive Emissions

Fugitive emissions are leaks from sealed surfaces associated with process equipment. Leaks can occur from operating conditions (pressure, temperature, etc.), aging, deterioration of sealing devices, and equipment solidity. Specific fugitive source types include cold vents; hydrocarbon loading and unloading operations; and equipment components such as valves, flanges, connectors, pump seals, compressor seals, and open-ended lines. Pollutants emitted from fugitive emissions include VOCs and CH_4.

3.1.8.6 Greenhouse Gases

The gases that keep the solar heat budget in the lower atmosphere are called greenhouse gases. Naturally, the atmospheric layer close to the Earth surface partially captures the long wave radiation from the Sun and keeps the planet habitable. These gases include CO_2, CH_4, N_2O, and a variety of manufactured chemicals. Greenhouse gases can be emitted from natural sources; others are anthropogenic, resulting from human activities.

In response to the FY 2008 Consolidated Appropriations Act, the USEPA issued 40 CFR part 98, which requires reporting of greenhouse gas emissions. Subpart C of the Green House Gas Reporting Rule requires operators to report greenhouse gas emissions from general stationary fuel combustion sources to the USEPA. Subpart W of the Greenhouse Gas Reporting Rule requires petroleum and natural gas facilities that emit 25,000 metric tons or more of CO_2 equivalents (CO_2e) per year to report emissions from equipment leaks and venting. Emissions associated with greenhouse gases from OCS oil- and gas-related activities are attributed to the combustion of fossil fuel, production and transportation of oil and natural gas, and equipment leaks. Pollutants emitted during these activities include CO_2, CH_4, N_2O, and CO_2e.

3.1.8.7 Decommissioning

Refer to **Chapter 3.1.6** for the description of decommissioning operations and activities. Emissions associated with decommissioning from OCS oil- and gas-related activities are attributed to the exhaust of diesel engines from the vessels including mobile offshore work-over rigs and lift vessels involved in the removal of pipelines and field facilities. Pollutants emitted during decommissioning include combustion gases (CO_2, NO_x, CO, PM, SO_2, CH_4 and VOCs).

3.1.9 Noise

Noise associated with OCS oil- and gas-related exploration and development results from seismic surveys, the installation of structures, the operation of fixed structures such as offshore platforms and drilling rigs, the decommissioning and explosive severance of structures, and helicopter and service-vessel traffic. Acoustic sources can be described by their sound characteristics. For the regulatory process, they are generally divided into two categories: impulsive noise and nonimpulsive noise.

Impulsive Noise

Impulsive noises (e.g., explosives, airguns, and impact pile drivers) are generally considered powerful sounds with relatively short durations, broadband frequency content, and rapid rise times to peak levels.

Airguns produce an intense but highly localized sound energy that propagates throughout the water column, and they represent a noise source of acoustic concern. BOEM completed the Atlantic G&G Activities Programmatic EIS, which includes a detailed description of the seismic surveying technologies, energy output, and operations and which has appendices that provide details on marine mammal, sea turtle, and fish hearing (USDOI, BOEM, 2014a); these descriptions are hereby incorporated by reference.

Deepwater marine seismic surveys (refer to **Chapter 3.1.2.1**) direct low-frequency energy waves (generated by an airgun array) into the ocean floor and record the response of the reflected energy waves' response from the subsurface. The firing times of the guns are staggered by milliseconds in an effort to make the farfield noise pulse as coherent as possible. In short, the intent of the airgun array is to have it emit a very symmetric packet of energy in a very short amount of time and with a frequency content that penetrates well into the earth at a particular location (Caldwell, 2001). In some airgun surveys (including WAZ), these sources are activated in sequence between source vessels. The noise generated by airguns is intermittent, with pulses generally less than 1 second in duration. Airgun arrays produce noise pulses with very high peak levels. The pulses are a fraction of a second long and repeat every 10-15 seconds (this range is for all airgun arrays). In other words, while airgun arrays are by far the strongest sources of underwater noise associated with OCS oil- and gas-related activities, because of the short duration of the pulses, the total energy is limited (Gordon and Moscrop, 1996). Acoustic calibration for the National Science Foundation's *R/V Marcus Langseth* and its seismic array, conducted work by Tolstoy et al. (2009) in the GOM, suggests that, for deep water (~5,249 ft; 1,600 m), the 180-decibel (dB) radius would occur at less than 0.6 mi (1 km) from the source, while in shallow waters (~164 ft; 50 m), the 180-dB radius would be considerably larger (e.g., ~0.7 mi; 1.1 km).

Nonimpulsive Noise

Nonimpulsive noise generally includes all other noise (e.g., sonars and vibratory pile drivers) and includes continuous anthropogenic noise (e.g., vessel noise).

Ambient noise is an important aspect to the marine habitat and is an efficient way to transmit energy through the ocean; therefore, many marine organisms have evolved to utilize this. It is also the sound field against which animal signals must be detected and is a result of both natural and anthropogenic noise sources. Anthropogenic noise is generally low-frequency (10 to 500 Hz), sea-surface agitation falls within the medium-frequency range (500 Hz to 25 kHz), and high-frequency noise (>25 kHz) can be from thermal noise (Hildebrand, 2009). Anthropogenic noise is generated by many different activities, including shipping, fishing, boating, research, and activities related to oil and gas exploration, development, and production. The activities encompass areas that represent important marine habitat (Hildebrand, 2009). The OCS oil- and gas-related noise generated from these activities can be transmitted through both air and water, and may be long- or short-lived in time, distance, and sound level. The intensity level and frequency of the noise emissions are highly variable, both between and among the various types of sound sources. Noise from proposed OCS oil- and gas-related activities may affect resources near the activities.

It is generally recognized that commercial shipping is a dominant component of the ambient, low- and medium-frequency background noise in modern world oceans (Gordon and Moscrop, 1996) and that OCS oil- and gas-related, service-vessel traffic would contribute to this. Another sound source more specific to OCS operations originates from seismic operations.

Information on drilling noise in the GOM is unavailable to date. From studies mostly in Alaskan waters, drilling operations (these can include pile driving, generators, pumps, etc.) often produce noise that includes strong tonal components at low frequencies, including infrasonic frequencies in at least some cases. Drillships are noisier than semisubmersibles (Richardson et al., 1995). Sound and vibration paths to the water are through either the air or the risers, in contrast to the direct paths through the hull of a drillship. This sound difference is due to the dynamic positioning systems on the drillships as compared with anchored MODUs. Richardson et al. (1995) stated that sound was measured at three ring-caisson sites in the Arctic. Sound was measured from the 20- to 1,000-Hz band levels at a range of 1.8 km (1.1 mi) at levels of 113-126 dB re: 1μPa (decibels referenced 1 microPascal). The received sound levels varied based on the activity of the support vessels. These estimated levels were higher than drilling activities on an artificial island but lower than on drillships (Richardson et al., 1995).

Machinery noise generated during the operation of fixed structures can be continuous or transient, and variable in intensity. Underwater noise from fixed structures ranges from about 20 to 40 dB above background levels within a frequency spectrum of 30-300 Hz at a distance of 30 m (98 ft) from the source (Gales, 1982). These levels vary with type of platform and water depth. Underwater noise from platforms standing on metal legs would be expected to be relatively weak because of the small surface area in contact with the water and the placement of machinery on decks well above the water.

Aircraft and vessel support may further contribute to acoustic pollution around a production facility, as well as the transit area. Noise generated from helicopter and service-vessel traffic is transient in nature and extremely variable in intensity. Helicopter sounds contain dominant tones (resulting from rotors) generally below 500 Hz (Richardson et al., 1995). For example, a Bell 212 helicopter may operate at a 22-Hz tone and have an estimated received level of 149 dB re: 1μPa (Richardson et al., 1995). Differences in the density sound speed of air and water reduce the sound that propagates into the water column from the air and generally restrict it to entry angles that are within about 11 degrees of perpendicular to the water's surface. Helicopters often radiate more sound forward than backward; thus, underwater noise is generally brief in duration, compared with the duration of audibility in the air. In addition to the altitude of the helicopter, water depth and bottom conditions strongly influence propagation and levels of underwater noise from passing aircraft. Lateral propagation of sound is greater in shallow water than in deep water. Helicopters, while flying offshore, generally maintain altitudes above 700 ft (213 m) during transit to and from the working area and an altitude of about 500 ft (152 m) while between platforms.

Service vessels transmit noise through both air and water. The primary sources of vessel noise are propeller cavitation, propeller singing, and rotating machinery; other sources include auxiliaries, flow noise from water dragging along the hull, and bubbles breaking in the wake (Richardson et al., 1995). Propeller cavitation is usually the dominant noise source (broad band but with peak energy in low frequency). The intensity of noise from service vessels is roughly related to ship size, laden or not, and speed. Large ships tend to be noisier than small ones, and ships underway with a full load (or towing or pushing a load) produce more noise than empty vessels. For example, a 16-m (52-ft) crewboat may have a 90-Hz tone with a source level of 156 dB re: 1μPa, and a small ship may have a broadband source level of 170-180 dB re: 1μPa (Richardson et al., 1995). For a given vessel, relative noise also tends to increase with increased speed. Commercial vessel noise is a dominant component of manmade ambient noise in the ocean (Jasny, 1999).

Information on the acoustic environment and marine sound can also be found in Chapter 4.2.2 of the Five-Year Program EIS.

3.1.10 New and Unusual Technology

Technologies continue to evolve to meet the technical, environmental, and economic challenges of deepwater development. BOEM's predecessor prepared a Programmatic EA to evaluate the potential effects of deepwater technologies and operations (USDOI, MMS, 2000b). As a supplement to the EA, BOEM's predecessor prepared a series of reference document that provides a profile of the different types of development and production structures that may be employed in the GOM deep water (USDOI, MMS, 2000a). The Programmatic EA and technical papers were used in the preparation of this Multisale EIS. Additional technologies introduced since the publication of the EA in 2000 include WAZ (**Chapter 3.1.2.1**) and duel-gradient drilling. Duel-gradient drilling uses seawater-density fluid in place of the mud that would normally flow through a well and uses dense mud at the bottom of the well to maintain bottom-hole pressure. This technology allows operators to reach reservoirs 40,000 ft (12,192 m) below the seafloor, a depth that is otherwise affected by water depth.

The operator must identify new or unusual technology, as defined in 30 CFR § 550.200, in exploration and development plans. Some of the technologies proposed for use by the operators are actually extended applications of existing technologies and interface with the environment in essentially the same way as well-known or conventional technologies. These technologies are reviewed by BOEM for alternative compliance or departures that may trigger additional environmental review. Some examples of new technologies that do not affect the environment differently and that are being deployed in the regionwide OCS Program are synthetic mooring lines, subsurface safety devices, and multiplex subsea controls.

Some new technologies differ in how they function or interface with the environment. These include equipment or procedures that have not been installed or used in Gulf of Mexico OCS waters. Having no operational history, they have not been assessed by BOEM through technical and environmental reviews. New technologies may be outside the framework established by BOEM's regulations and, thus, their performance (i.e., safety, environmental protection, efficiency, etc.) has not been studied by BOEM. The degree to which these new technologies interface with the environment and the potential impacts that may result are considered in determining the level of NEPA review that would be initiated if an operator wishes to deploy it.

BOEM has developed a new and unusual technologies' matrix to help facilitate decisions on the appropriate level of engineering and environmental review needed for a proposed technology. All projects in the GOM using nonconventional production or completion technology require a deepwater operations plan and a review by BSEE. Technologies will be added to the new and unusual technologies' matrix as they emerge, and technologies will be removed as sufficient experience is gained in their implementation. From an environmental perspective, the matrix characterizes new technologies into three components: technologies that may affect the environment; technologies that do not interact with the environment any differently than "conventional" technologies; and technologies for which BOEM does not have sufficient information to determine its potential impacts to the environment. In this latter case, BOEM would seek to gain the necessary information from operators or manufacturers regarding the technologies in order to make an appropriate determination on its potential effects on the environment.

Alternative Compliance and Departures: When an OCS operator proposes the use of technology or procedures not specifically addressed in established BOEM regulations, the operations are evaluated for alternative compliance or departure determination. BOEM, in coordination with BSEE's Technical Assessment Section, conducts a project-specific engineering safety review to ensure that equipment proposed for use is designed to withstand the operational and environmental condition in which it would operate. Any new technologies or equipment that represent an alternative compliance or departure from existing BOEM regulation must be fully described and justified before it would be approved for use. For BOEM to grant alternative compliance or departure approval, the operator must demonstrate an equivalent or improved degree of protection as specified in 30 CFR § 550.141. Comparative analysis with other approved systems, equipment, and procedures is one tool that BOEM uses to assess the adequacy of protection provided by alternative technology or operations. Actual operational experience is necessary with alternative compliance measures before BOEM/BSEE would consider them as proven technology.

In addition to new and unusual technology for drilling, as a result of the *Deepwater Horizon* explosion, oil spill, and response, many technologies or applications were developed in an attempt to stop the spill and cap the well in any future accidents. The NTL 2010-N10, "Statement of Compliance with Applicable Regulations and Evaluation of Information Demonstrating Adequate Spill Response and Well Containment Resources," applies to operators conducting operations using subsea BOPs or surface BOPs on floating facilities. BOEM would assess whether each lessee has submitted adequate information demonstrating that it has access to and can deploy surface and subsurface containment resources that would be adequate to promptly respond to a blowout or other loss of well control. Containment resources could consist of, but are not limited to, subsea containment and capture equipment including containment domes and capping stacks, subsea utility equipment including hydraulic power, hydrate control, and dispersion injection equipment.

3.2 IMPACT-PRODUCING FACTORS AND SCENARIO—ACCIDENTAL EVENTS

3.2.1 Oil Spills

As a consequence of activities related to the exploration, development, production, and transportation of oil and gas, the potential for accidental releases exists. Input through public scoping meetings, Federal and State agency consultation and coordination, and industry and nongovernmental organizations' comments indicate that stakeholders continue to have concerns about oil spills and the threat they pose to the environment. Although oil-spill occurrence cannot be predicted, an estimate of its likelihood can be quantified using spill rates derived from historical data and projected volumes of oil production and transportation. The following chapters discuss the history of oil spills in the GOM, the processes that affect spilled oil, and a risk analysis for spills that may be reasonably foreseeable as a result of Alternative A, B, C, or D, as well as information on the number and size of spills from non-OCS oil- and gas-related sources. Under Alternative D, the number of blocks that would become unavailable for lease represents only a small percentage (<4%) of the total number of blocks to be offered under Alternative A, B, or C. Therefore, Alternative D could reduce offshore infrastructure when chosen in conjunction with Alternative A, B, or C, but it could only shift the location of offshore infrastructure and activities farther from sensitive topographic zones and not lead to a reduction in offshore infrastructure and activities. Refer to **Chapter 2.2.2.4** for more information on Alternative D. For an analysis of a low-probability catastrophic spill, which is not reasonably foreseeable as a result of a proposed action or the alternatives, refer to the *Catastrophic Spill Event Analysis* white paper (USDOI, BOEM, 2017) and Chapter 3.4 of the Five-Year Program EIS.

3.2.1.1 Past OCS Spills

3.2.1.1.1. Trends in Reported Spill Volumes and Numbers

A summary of reported spill incidents is available from USCG in a report entitled *Polluting Incidents In and Around U.S. Waters, A Spill/Release Compendium: 1969-2011* (USDHS, CG, 2012). The data include reports of all releases involving oil and hazardous substances from various sources, including barges, tanks, pipelines, and waterfront facilities. A review of the information shows that the majority of spills are ≤1 bbl. While all spills must be reported to USCG through the National Response Center, BSEE's regulations require that all OCS spills ≥1 bbl from an operator's facility must also notify the Regional Supervisor (30 CFR § 254.46). In addition, all spills ≥50 have additional reporting requirements and in some cases are followed up by incident investigations. A recent report prepared by ABS Consulting, Inc. (2016) examined the occurrence rates for offshore oil spills and gathered data from a variety of sources including BSEE, USCG, and DOT's Pipeline and

Hazardous Material Safety Administration. The report focused on all spills ≥1 bbl from offshore platforms, offshore pipelines, tankers, and barges. **Figure 3-13** shows the number of oil spills ≥1 bbl that have occurred in the GOM and **Figure 3-14** shows the total volume (bbl) of oil spilled for spills ≥1 bbl in the GOM for the period 2001 through 2015.

The study examined a number of causal factors including equipment failure, human error, weather/natural causes, and other/external factors. Spills from offshore production platforms and drilling rigs revealed two notable trends. First, hurricanes have had a substantial impact on the total number and volume of spills, as can be seen in **Figures 3-13 and 3-14**. Second, the dominant driver of reduced spill rates is likely a reduction in equipment failures as the number of events has steadily decreased since 1975, suggesting that technology advancements have played a large role in the improving spill rates. The analysis also examined additional causal factors related to pipeline spills, including corrosion and vessel/anchor/trawl damage. The analysis reveals that, like platform spills, hurricanes have had a substantial impact on spill frequency and spill volume. The results also showed that the number of operational spills per year appears to follow a downward trend as the majority of pipeline spills in the last 15 years were caused by hurricanes (ABS Consulting, Inc., 2016). **Figures 3-15 and 3-16** show the relative contribution from offshore platforms versus offshore pipelines.

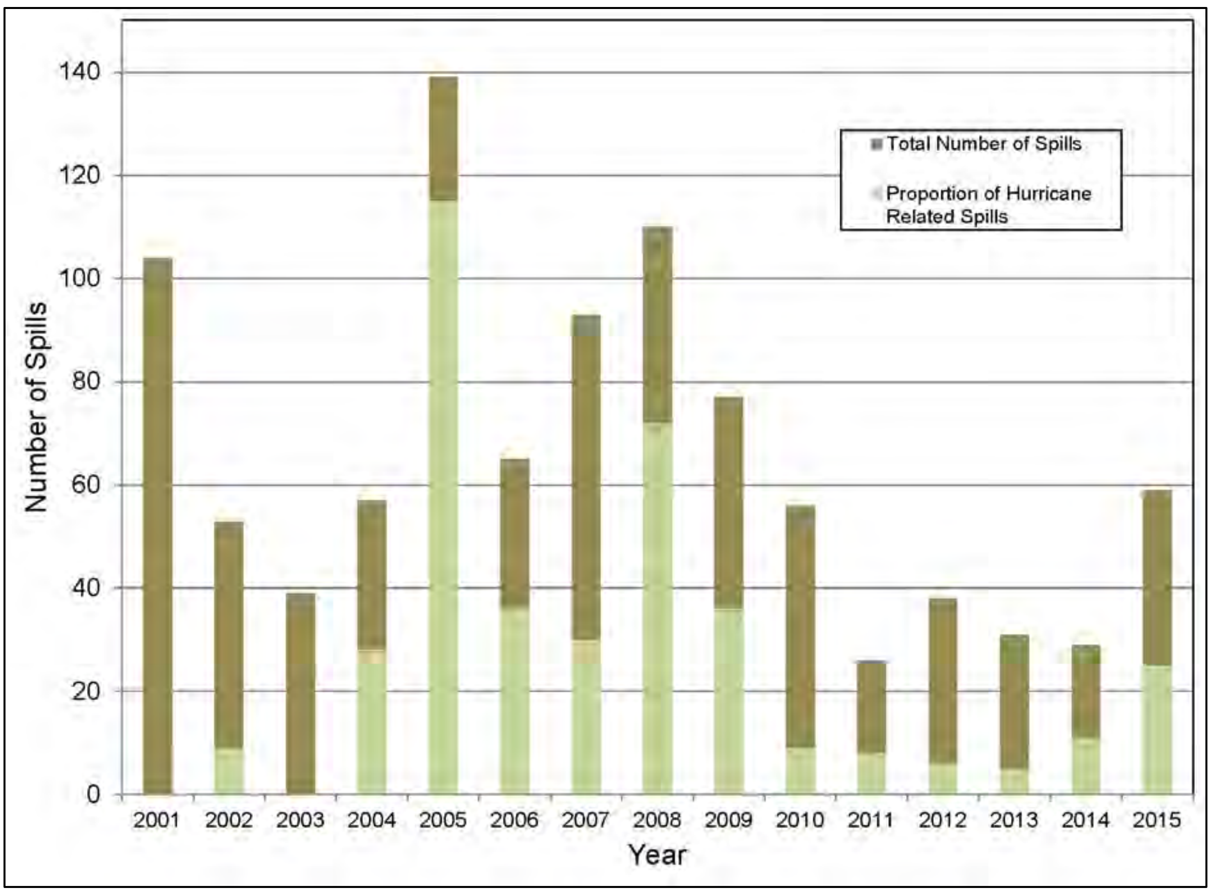

Figure 3-13. Number of Oil Spills ≥1 bbl That Have Occurred in the Gulf of Mexico for the Period 2001 through 2015.

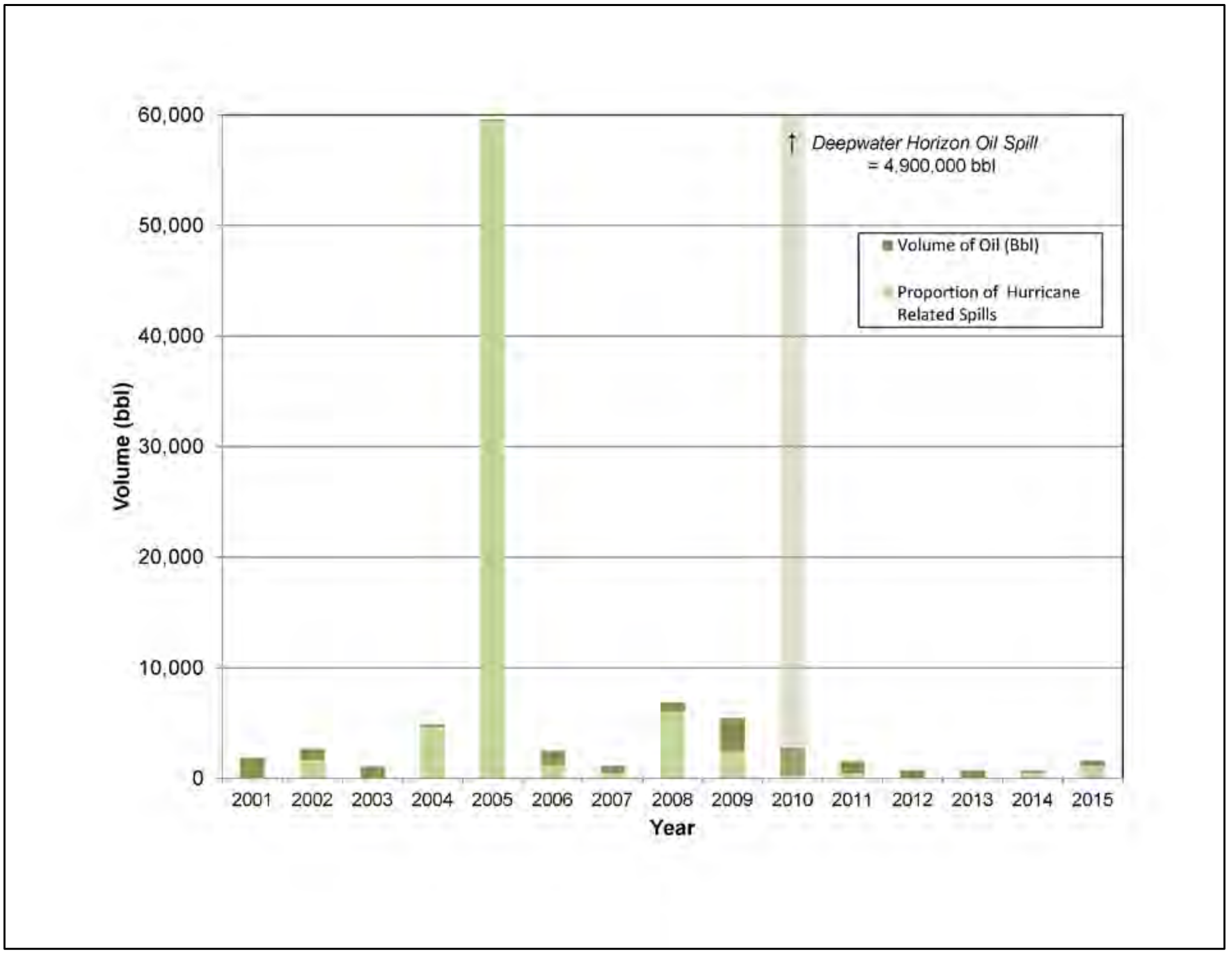

Figure 3-14. Total Volume (bbl) of Oil Spilled in Gulf of Mexico Waters for Spills ≥1 bbl for the Period 2001 through 2015. (Notes: In 2005, the integrated tug-barge unit comprised of the tugboat Rebel *and the double-hull tank barge* DBL 152 *struck the submerged remains of a pipeline service platform that previously collapsed during Hurricane Rita, releasing an estimated 45,846 bbl (1,925,532 gallons) of oil. In 2010, the* Deepwater Horizon *explosion and oil spill released approximately 4,900,000 bbl (205,800,000 gallons) of oil over 87 days.)*

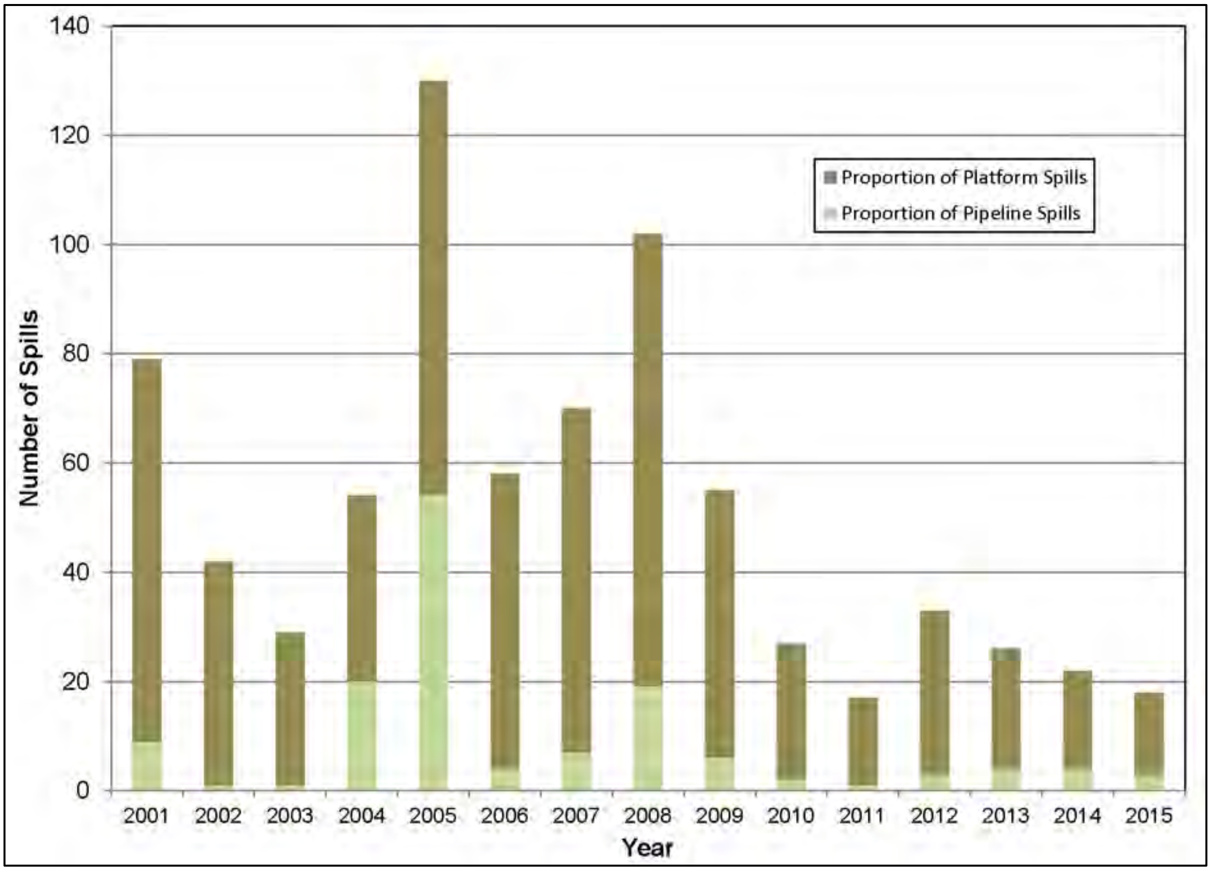

Figure 3-15. Number of Platform and Pipeline-Related Oil Spills ≥1 bbl That Have Occurred in the Gulf of Mexico for the Period 2001 through 2015.

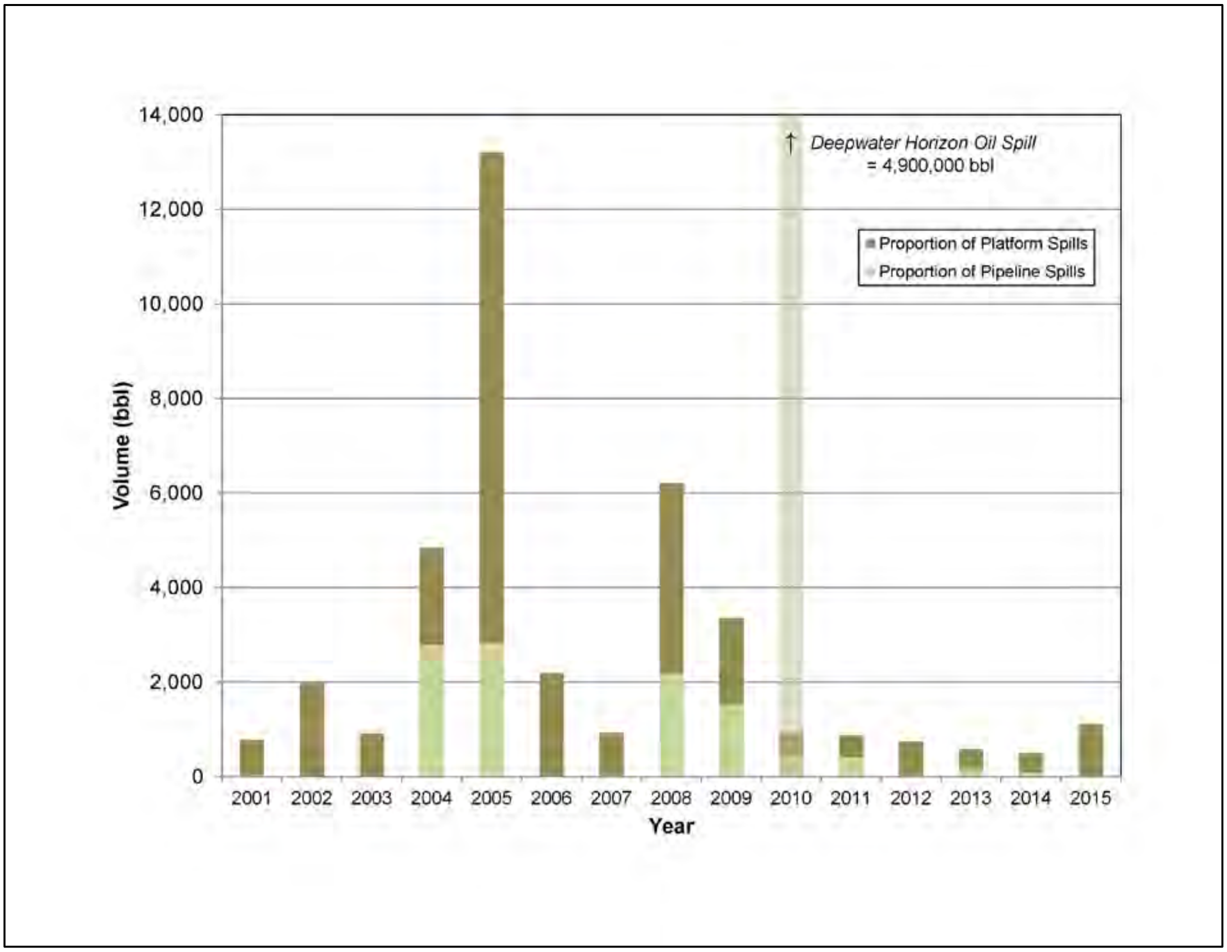

Figure 3-16. Total Volume of Spilled Oil for Platform and Pipeline-Related Oil Spills ≥1 bbl That Have Occurred in the Gulf of Mexico for the Period 2001 through 2015.

In response to the damages sustained to oil and gas infrastructure as a result of hurricanes, the MMS (now BOEM and BSEE) imposed more stringent design and assessment criteria for both new and existing structures in the GOM. The rule incorporates three API bulletins to help increase survivability during hurricane conditions and reduce the number of damaged platforms, including (1) guidance for design and operation of MODU mooring systems; (2) recommendations to siting jackup MODUs and to recommend certain operational procedures to enhance jackup survivability and stationkeeping during drilling, workover, and while stacked (idled) at a non-sheltered location; and (3) guidance to improve tie-down performance.

Oil-Spill Occurrence Rates

Previous work by Anderson and LaBelle (1990, 1994, and 2000) provided estimates of oil-spill occurrence rates expressed and normalized in terms of the number of spills per volume of crude oil handled. This work was updated in Anderson et al. (2012) and utilized United States' OCS platform and pipeline spill data from 1964 through 2010. Platform and pipeline spills included both crude oil and condensate, but platform spills may also include refined products such as diesel fuel. The report utilized the spill record from 1964 through 2010 but also examined shorter intervals to identify trends and also to show how the *Deepwater Horizon* explosion, oil spill, and response influenced the spill statistics. The report notes several additional factors that have influenced spill rates, including six highly destructive hurricanes between 2002 and 2008 that destroyed or extensively damaged 305 platforms, 76 drilling rigs, and over 1,200 pipeline segments, and the inclusion of “passive spills” or petroleum missing based on pre-storm platform inventories.

Recently, BSEE contracted ABS Consulting, Inc. (2016) to update the occurrence rates for offshore oil spills based on the previous work by Anderson and LaBelle (1990, 1994, and 2000) and Anderson et al. (2012) (**Table 3-12**). The report uses the most recent available data since the prior report to calculate rates consistent with current trends. When comparing the most recent 15 years of data (2001 through 2015) to the 1996 through 2010 rates in Anderson et al. (2012), platform spill rates remained at 0.25 spills per Bbbl for spills ≥1,000 bbl and 0.13 spills per Bbbl for spills ≥10,000 bbl. Spill rates for OCS pipelines dropped from 0.88 to 0.38 spills per Bbbl for spills ≥1,000 bbl and from 0.18 to 0.07 spills per Bbbl for spills ≥10,000 bbl.

Table 3-12. Spill Rates for Petroleum Spills ≥1,000 Barrels from OCS Platforms and Pipelines, 1964 through 2010.

Spill Size and Source	Previous Rate, 1964-2010[1]			Revised Rate, 1996-2010[1]			Current Rate, 2001-2015[2]		
	Volume Handled (Bbbl)	Number of Spills	Spill Rate	Volume Handled (Bbbl)	Number of Spills	Spill Rate	Volume Handled (Bbbl)	Number of Spills	Spill Rate
≥1,000 bbl									
Platforms	15.8 of 18.1	5 of 13	0.32	8.0	2	0.25	8.0	2	0.25
Pipelines	9.6 of 18.1	9 of 20	0.94	8.0	7	0.88	8.0	3	0.38
≥10,000 bbl									
Platforms	15.8 of 18.1	1 of 5	0.06	8.0	1	0.13	8.0	1	0.13
Pipelines	9.6 of 18.1	–	0.19	8.0	–	0.18	8.0	–	0.07

[1]Anderson et al., 2012.
[2]ABS Consulting, Inc., 2016.

3.2.1.1.2 Coastal Spills

Coastal spills are defined here as spills in State offshore waters from barges and pipelines carrying OCS-produced oil. These spills may occur at shoreline storage, processing, and transport facilities supporting the OCS oil and gas industry and could be spills of crude oil or spills of fuel oil used in vessels. Many reports of spills cannot be traced back to the source or type of oil and are recorded as unknown. Similarly, for these small spills of unknown oil, the volume is also likely to be an estimate. Records of spills in coastal waters or State offshore waters are maintained by USCG (USDHS, CG, 2016). The source may be recorded, for example, as an offshore pipeline, but the database does not identify the source of the oil in the pipeline (OCS versus non-OCS domestic). A pipeline carrying oil from a shore base to a refinery may be carrying oil from both State and OCS production; imported oil might also be commingled in the pipeline. The USCG also records the type of oil spilled and whether it is crude oil, a refined product such diesel fuel or heavy fuel oil, or a type of commodity in transport, such as vegetable oil. The USCG data have some shortcomings that should be noted. For spills of unknown source, the caller may guess as to what type of oil, crude, or fuel was released. The database includes a latitude and longitude GPS (global positioning system) position for each spill, as well as a verbal description of location. The verbal description may not match the position. For example, the verbal description could be Mississippi Sound, but the GPS position is actually on the OCS. For this report, the GPS position was used, not the verbal description of the location.

BOEM pays special attention to spills related to exploration and production that occur on Federal leases in OCS waters, i.e., the submerged lands, subsoil, and seabed lying between the seaward extent of the State's jurisdiction and the seaward extent of Federal jurisdiction. BOEM does not maintain comprehensive data on spills that have occurred in the State's jurisdiction. Although BSEE has occasionally collected information on State pollution incidents, there is no database available that contains only past spills that have occurred in State offshore or coastal waters solely and directly as a result of OCS oil and gas development.

Therefore, coastal spill data from all potential spillage sources were searched using USCG's database for the most recent 13 years, January 2002-April 2015 (USDHS, CG, 2016) in order to obtain information on spills that have occurred in State offshore or coastal waters, most probably as a result of oil and gas development. In order to search the data, USCG's data were examined using the latitude and longitude provided in the spill report, which resulted in some of the reported locations that fell inland or outside of the GOM being omitted. Some broad assumptions were made in the use of these data. State offshore waters and coastal waters are defined here as the portion of the GOM under State jurisdiction that begins at the coastline and ends at the Federal/State boundary 9 nmi (10.36 mi; 16.67 km) offshore Texas; 3 nmi (3.5 mi; 5.6 km) offshore Louisiana, Mississippi, and Alabama; and 9 nmi (10.36 mi; 16.67 km) offshore Florida. The number of GOM coastal spills from five sources associated with State or Federal offshore production and international importation was determined from the data (**Table 3-13**). Louisiana and Texas have extensive oil and gas activity occurring in their territorial seas, as well as in Federal waters on the OCS. The sources that were counted are fixed platforms, MODUs, OSVs, offshore pipelines, and tank ships or barges. Although counts for tank ships and barges are shown as sources, the amount of barged and tankered GOM oil production is limited; therefore, these numbers are conservatively high as they include all of the oil tankered or barged. BOEM shows that 96 percent of OCS oil- and gas-related activity spills are <1 bbl, with an average size of 0.05 bbl, and that 4 percent of OCS oil- and gas-related activity spills are < 999 bbl, with an average size of 77 bbl (Anderson et al., 2012).

Table 3-13. Historic Spill Source, Location, and Characteristics of a Maximum Spill for Coastal Waters[1] (data extracted from USDHS, CG records, 2002-July 2015)[2].

Source	Number of Spills			Maximum Volume of a Single Incident	
	Total Number of Spill Events	Number of Spills (<1,000 bbl)	Number of Spills (≥1,000 bbl)	Volume (bbl) of Maximum Spill from the Source	Maximum Spill Amount Product/Year
Western Planning Area (WPA)[2]					
Fixed Platform	147	147	0	7.62	Crude/2005
Pipeline	0	0	0	N/A	N/A
MODU	2	2	0	4	Crude/2002
OSV	1	1	0	0.05	Crude/2014
Tank Ship or Barge	5	5	0	23.8	Crude/2009
Total	155	155	0	–	–
Central Planning Area (CPA)[2]					
Fixed Platform	2,398	2,398	0	300	Crude/2004
Pipeline	4	4	0	5	Crude/2002
MODU	28	27	1	4,928,100	Crude/2010
OSV	7	7	0	0.07	Crude 2014
Tank Ship or Barge	6	6	0	2	Crude/2013
Total	2,443	2,442	1	–	–
Eastern Planning Area (EPA)[2]					
Fixed Platform	0	0	0	N/A	N/A
Pipeline	0	0	0	N/A	N/A
MODU	0	0	0	N/A	N/A
OSV	0	0	0	N/A	N/A
Tank Ship or Barge	0	0	0	N/A	N/A
Total	0	0	0	–	–
Coastal Waters: Texas					
Fixed Platform	67	67	0	20	Crude/2002
Pipeline	14	14	0	10	Crude/2005
MODU	5	5	0	0.48	Crude/2002
OSV	2	2	0	0.05	Crude/2003
Tank Ship or Barge	3	3	0	0.36	Crude/2009
Total	91	91	0	–	–

Source	Number of Spills			Maximum Volume of a Single Incident	
	Total Number of Spill Events	Number of Spills (<1,000 bbl)	Number of Spills (≥1,000 bbl)	Volume (bbl) of Maximum Spill from the Source	Maximum Spill Amount Product/Year
Coastal Waters: Louisiana					
Fixed Platform	2,022	2,021	1	1,200	Crude/2008
Pipeline	98	97	1	7,000	Crude/2008
MODU	4	4	0	0.24	Crude/ 2013
OSV	17	17	0	3	Crude/2013
Tank Ship or Barge	2	2	0	50	Crude/2002
Total	2,143	2,141	2	–	–
Coastal Waters: Mississippi					
Fixed Platform	1	1	0	0.001	Crude/2008
Pipeline	0	0	0	N/A	NA
MODU	0	0	0	N/A	N/A
OSV	0	0	0	N/A	N/A
Tank Ship or Barge	1	1	0	0.05	Crude/2002
Total	2	2	0	–	–
Coastal Waters: Alabama					
Fixed Platform	2	2	0	0.024	Crude/2007
Pipeline	0	0	0	N/A	N/A
MODU	0	0	0	N/A	N/A
OSV	0	0	0	N/A	N/A
Tank Ship or Barge	0	0	0	N/A	N/A
Total	2	2	0	–	–
Coastal Waters: Florida					
Fixed Platform	0	0	0	N/A	N/A
Pipeline	0	0	0	N/A	N/A
MODU	0	0	0	N/A	N/A
OSV	0	0	0	N/A	N/A
Tank Ship or Barge	0	0	0	N/A	N/A
Total	0	0	0	–	–

Source	Number of Spills			Maximum Volume of a Single Incident	
	Total Number of Spill Events	Number of Spills (<1,000 bbl)	Number of Spills (≥1,000 bbl)	Volume (bbl) of Maximum Spill from the Source	Maximum Spill Amount Product/Year

bbl = barrel; MODU = mobile offshore drilling unit; N/A = not applicable; OSV = offshore support vessel.

Note: The reader should note that the spills are reported to USCG by responsible parties, other private parties, and government personnel. The USCG does not verify the source or volume of every report.

[1]Coastal Waters – The portion of the Gulf of Mexico under State jurisdiction that begins at the coastline and ends at the Federal/State boundary 9 nmi (10.36 mi; 16.67 km) offshore Texas; 3 nmi (3.5 mi; 5.6 km) offshore Louisiana, Mississippi, and Alabama; and 9 nmi (10.36 mi; 16.67 km) offshore Florida.

[2]The data included represents spill events from January 2002 until July 2015.

3.2.1.1.3 Offshore Spills

Petroleum spills from OCS oil- and gas- related activities include crude oil, condensate, and refined products such as diesel, hydraulic oil, lube oil and mineral oil. For spills of synthetic oil products, drilling muds, or chemicals, refer to **Chapter 3.2.6**. Spills from facilities include spills from drilling rigs, drillships, and storage, processing, or production platforms that occurred during OCS drilling, development, and production operations. Spills from pipeline operations are those that have occurred on the OCS and are directly attributable to the transportation of OCS oil. Oil-spill information comes from a variety of sources. The BSEE requires operators to report any spill ≥1 bbl occurring on the OCS and maintains a database for all reported incidents. Not included in BSEE's data records are spills <1 bbl. Spills of any size and composition are required to be reported to USCG's National Response Center and are further documented in USCG's Marine Information for Safety and Law Enforcement (2001-present) database and its predecessors. Also not included in BSEE's database are spills that have occurred in Federal waters from OCS barging operations and from other service vessels that support the OCS oil and gas industry. These data are included in USCG's record of all spills; however, USCG's database does not include the source of oil (OCS versus non-OCS) or in the case of spills from vessels, the type of vessel operations; such information is needed to determine if a particular spill occurred as a result of OCS operations. Spills from vessels are provided for tankers in worldwide waters and tankers and barges in U.S. coastal and offshore waters. The latter is a subset of the spills included in the worldwide tanker spill data. These data identify whether the spill occurred "at sea" or "in port' as they can occur due to mishaps during loading, unloading, and taking on fuel oil, and from groundings, hull failures, and explosions. As mentioned previously, a recent report prepared by ABS Consulting, Inc. (2016) examined the occurrence rates for offshore oil spills gathering data from a variety of sources including BSEE, USCG, and DOT's Pipeline and Hazardous Material Safety Administration. **Tables 3-14 and 3-15** provide information on OCS spills ≥1,000 bbl that have occurred offshore in the GOM for the period from 1964 through July 2016.

Table 3-14. Petroleum[1] Spills ≥1,000 Barrels from United States OCS[2] Platforms, 1964-July 2016.

Date	Leasing Area[3] and Block Number	Water Depth (ft)	Distance to Shore (mi)	Volume Spilled (bbl)	Operator	Facility or Structure and Cause of Spill
4/08/1964	EI 208	94	48	2,559	Continental Oil	Freighter struck Platform A: fire, platform and freighter damaged
10/03/1964	Hurricane Hilda			11,869[4]	Event Total	5 platforms destroyed during Hurricane Hilda
	EI 208	94	48	5,180	Continental Oil	Platforms A, C, and D destroyed: blowouts (several days)
	SS 149	55	33	5,100	Signal O & G	Platform B destroyed: blowout (17 days)
	SS 199	102	44	1,589	Tenneco Oil	Platform A destroyed: lost storage tank
7/19/1965	SS 29	15	7	1,688[5]	PanAmerican	Well #7 drilling: blowout (8 days), minimal damage
1/28/1969	6B 5165 Santa Barbara Channel, California	190	6	80,000	Union Oil	Well A-21 drilling: blowout (10 days), 50,000 bbl during blowout phase, subsequent seepage of 30,000 bbl (over decades), 4,000 birds killed, considerable oil on beaches, platform destroyed
3/16/1969	SS 72	30	6	2,500	Mobil Oil	Submersible rig *Rimtide* drilling in heavy seas bumped by supply vessel
2/10/1970	MP 41	39	14	65,000[6]	Chevron Oil	Platform C: rig shifted and sheared wellhead, blowout (3-4 days), fire of unknown origin, blowout 12 wells (49 days), lost platform, minor amounts of oil on beaches
12/1/1970	ST 26	60	8	53,000	Shell Oil	Platform B: wireline work, gas explosion, fire, blowout (138 days), lost platform and 2 drilling rigs, 4 fatalities, 36 injuries, minor amounts of oil on beaches
1/09/1973	WD 79	110	17	9,935	Signal O & G	Platform A: oil storage tank structural failure
1/26/1973	PL 23	61	15	7,000	Chevron Oil	Platform CA: storage barge sank in heavy seas
11/23/1979	MP 151	280	10	1,500[7]	Texoma Production	MODU Pacesetter III: diesel tank holed, workboat contact in heavy seas

Date	Leasing Area[3] and Block Number	Water Depth (ft)	Distance to Shore (mi)	Volume Spilled (bbl)	Operator	Facility or Structure and Cause of Spill
11/14/1980	HI 206	60	27	1,456	Texaco Oil	Platform A: storage tank overflow during Hurricane Jeanne evacuation
9/24/2005	Hurricane Rita			5,066[8]	Event Total	1 platform and 2 rigs destroyed by Hurricane Rita
	EI 314	230	78	2,000[5]	Forest Oil	Platform J: destroyed, lost oil on board and in riser
	SM 146	238	78	1,494[9]	Hunt Petroleum	Jack-up Rig Rowan Fort Worth: swept away, never found
	SS 250	182	69	1,572[9]	Remington O & G	Jack-up Rig Rowan Odessa: legs collapsed
04/20/2010	MC 252	4,992	53	4.9 million[10]	BP E & P	*Deepwater Horizon* Rig: gas explosion, blowout (86 days to cap well), fire, drilling rig sank, 11 fatalities, multiple injuries, considerable oil on beaches, wildlife affected, temporary closure of area fisheries

Notes: barrel (bbl) = 42 gallons, billion = 109, MODU = mobile offshore drilling unit
Between 1964 and 2009, over 17.5 billion bbl of oil and 176.1 Mcf of natural gas were produced on the OCS.

[1]Crude oil release unless otherwise noted; no spill contacts to land unless otherwise noted.

[2]Outer Continental Shelf (OCS) – submerged lands, subsoil, and seabed administered by the U.S. Federal Government (http://www.boem.gov/Governing-Statutes/).

[3]Gulf of Mexico leasing area unless otherwise noted (official protraction diagrams, http://www.boem.gov/Official-Protraction-Diagrams/l): EI = Eugene Island, HI = High Island, MC = Mississippi Canyon, MP = Main Pass, PL = South Pelto, SS = Ship Shoal, SM = South Marsh Island, ST = South Timbalier, and WD = West Delta.

[4]Hurricane Hilda, 10/3/1964: platform spills ≥1,000 bbl at 3 facilities totaled 11,869 bbl; treated as 1 spill event.

[5]Condensate – a liquid product of natural gas production.

[6]Spill volume estimate between 30,000 and 65,000 bbl, previously reported as 30,000 bbl.

[7]Diesel fuel.

[8]Hurricane Rita, 9/24/2010: platform and 2 rig losses ≥1,000 bbl at 3 locations totaled to 5,066 bbl; treated as 1 spill event. The 5,066-bbl spill was a “passive” spill based on unrecovered pre-storm inventories from the platform and 2 rigs; no spill observed; no response required.

[9]Diesel fuel and other refined petroleum products stored on rig.

[10]The Federal Interagency Solutions Group, 2010.

Sources: Anderson et al., 2012; ABS Consulting, Inc., 2016.

Table 3-15. Petroleum[1] Spills ≥1,000 Barrels from United States OCS[2] Pipelines, 1964-July 2016.

Date	Leasing Area[3] and Block Number	Water Depth (ft)	Distance to Shore (mi)	Volume Spilled (bbl)	Operator	Pipeline Segment (pipeline authority[4]) Cause/Consequences of Spill
10/15/1967	WD 73	168	22	160,638	Humble Pipeline	12" oil pipeline, Segment #7791 (DOT): anchor kinked, corrosion, leak
3/12/1968	ST 131	160	28	6,000	Gulf Oil	18" oil pipeline, Segment #3573 (DOT): barge anchor damage
2/11/1969	MP 299	210	17	7,532	Chevron Oil	4" gas pipeline, Segment #3469 (DOT): anchor damage
5/12/1973	WD 73	168	22	5,000	Exxon Pipeline	16" gas & oil pipeline, Segment #807 (DOT): internal corrosion, leak
4/17/1974	EI 317	240	75	19,833	Pennzoil	14" oil Bonita pipeline, Segment #1128 (DOI): anchor damage
9/11/1974	MP 73	141	9	3,500	Shell Oil	8" oil pipeline, Segment #36 (DOI): Hurricane Carmen broke tie-in to 12" pipeline, minor contacts to shoreline, brief cleanup response in Chandeleur Area
12/18/1976	EI 297	210	17	4,000	Placid Oil	10" oil pipeline, Segment #1184 (DOI): trawl damage to tie-in to 14" pipeline
12/11/1981	SP 60	190	4	5,100	Atlantic Richfield	8" oil pipeline, Segment #4715 (DOT): workboat anchor damage
2/07/1988	GA A002	75	34	15,576	Amoco Pipeline	14" oil pipeline, Segment #4879 (DOT): damage from illegally anchored vessel
1/24/1990	SS 281	197	60	14,423[5]	Shell Offshore	4" condensate pipeline, Segment #8324 (DOI): anchor damage to subsea tie-in
5/06/1990	EI 314	230	78	4,569	Exxon	8" oil pipeline, Segment #4030 (DOI): trawl damage
8/31/1992	PL 8	30	6	2,000	Texaco	20" oil pipeline, Segment #4006 (DOT): Hurricane Andrew, loose rig Treasure 75, anchor damage, minor contacts to shoreline, brief cleanup response
11/16/1994	SS 281	197	60	4,533[5]	Shell Offshore	4" condensate pipeline, Segment #8324 (DOI): trawl damage to subsea tie-in
1/26/1998	EC 334	264	105	1,211[5]	Pennzoil E & P	16" gas & condensate pipeline, Segment #11007 (DOT): anchor damage to tie-in to 30" pipeline, anchor dragged by vessel in man-overboard response
9/29/1998	SP 38	108	6	8,212	Chevron Pipe Line	10" gas & oil pipeline, Segment #5625 (DOT): Hurricane Georges, mudslide damage, small amount of oil contacted shoreline
7/23/1999	SS 241	133	50	3,200	Seashell Pipeline	12" oil pipeline, Segment #6462 & Segment #6463 (DOT): "Loop Davis" jack-up rig, barge crushed pipeline when sat down on it
1/21/2000	SS 332	435	75	2,240	Equilon Pipeline	24" oil pipeline, Segment #10903 (DOT): anchor damage from MODU under tow

Date	Leasing Area[3] and Block Number	Water Depth (ft)	Distance to Shore (mi)	Volume Spilled (bbl)	Operator	Pipeline Segment (pipeline authority[4]) Cause/Consequences of Spill
9/15/2004	MC 20	479	19	1,720[6]	Taylor Energy	6" oil pipeline, Segment #7296 (DOI): Hurricane Ivan, mudslide damage
9/13/2008	HI A264	150	73	1,316[7]	HI Offshore System	42" gas pipeline, Segment #7364 (DOT): Hurricane Ike, anchor damage parted line
7/25/2009	SS 142	60	30	1,500	Shell Pipe Line	20" oil pipeline, Segment #4006 (DOT): micro-fractures from chronic contacts at pipeline crossing caused failure (separators between pipelines missing)
5/11/2016[8]	GC 248	3,500	97	2,100	Shell Offshore	6" oil pipeline, Segment #14371 (DOI): cracked collar on jumper line connecting well head to pipeline network

Notes: barrel (bbl) = 42 gallons, billion = 10^9, MODU = mobile offshore drilling unit.
Between 1964 and 2009, over 17.5 billion bbl of oil and 176.1 Mcf of natural gas were produced on the OCS.

[1]Crude oil release unless otherwise noted; no spill contacts to land unless otherwise noted.

[2]Outer Continental Shelf (OCS) – submerged lands, subsoil, and seabed administered by the U.S. Federal Government (http://www.boem.gov/Governing-Statutes/).

[3]Gulf of Mexico leasing area unless otherwise noted (official protraction diagrams, http://www.boem.gov/Official-Protraction-Diagrams/l): EC = East Cameron, EI = Eugene Island, GA = Galveston, HI = High Island, MC = Mississippi Canyon, MP = Main Pass, PL = South Pelto, SS = Ship Shoal, SP = South Pass, ST = South Timbalier, and WD = West Delta.

[4]Pipeline authority: DOI = Department of the Interior, Bureau of Ocean Energy Management, Regulation and Enforcement; DOT = Department of Transportation, Pipeline and Hazardous Materials Safety Administration.

[5]Condensate – a liquid product of natural gas production.

[6]The 1,720-bbl spill was a “passive” spill based on unrecovered pre-storm inventory trapped in the segment by a mudslide; no spill observed, no response required.

[7]The 1,316-bbl spill was a “passive” spill based on unrecovered pre-storm inventory in the segment parted by storm; no spill observed, no response required.

[8]This incident is still under investigation and the information provided here should be considered preliminary.

Sources: Anderson et al., 2012; ABS Consulting, Inc., 2016.

Taylor Energy Oil Discharge at Mississippi Canyon Block 20 Site and Ongoing Response Efforts

The BSEE and BOEM have worked with USCG under a Unified Command to monitor and respond to discharges from Taylor Energy's Mississippi Canyon Block 20 (MC-20) site since the oil production platform and 25 of 28 connected wells were impacted and damaged during Hurricane Ivan in 2004. The multi-agency effort has worked continuously to prevent and control the oil discharge, improve the effectiveness of containment around the source of the oil discharge, and mitigate environmental impacts.

The BSEE and USCG have also worked closely with representatives of Taylor Energy to mitigate the impacts of the discharge associated with the felled platform. Collaborative efforts have resulted in removal of the platform deck, removal of subsea debris, decommissioning of the oil pipeline, and efforts to plug 9 of the 25 impacted wells. Despite these efforts, there is an ongoing oil discharge from Taylor Energy's MC-20 site.

Based on data collected from nearly daily overflights since September 2014, oil sheens have been observed and reported by Taylor Energy to be as large as 1.5 mi (2.4 km) wide and 14 mi (23 km) long, with an average of 1 mi (2 km) wide and 5.5 mi (8.9 km) long, covering an average area of 8 mi^2 (21 km^2). Over this period, the daily volume of oil discharging from the MC-20 site has fluctuated between a low of ≤1 bbl to a high of 55 bbl (2,329 gallons). The average reported daily oil volume on the sea surface over a 7-month period was over 2 bbl; the volume over 75 days was >1 bbl, including 23 days of volume >3.8 bbl and 4 days >35 bbl. These spill size and volume estimates are based on reports submitted by Taylor Energy's contractors to the National Response Center. The BSEE's current estimate is that the oil discharge from the site, if left unchecked, could continue for 100 years or more.

The specific source(s) of discharge at the MC-20 site are not fully known. However, because the discharge volume is greater than can reasonably be accounted for by oil released from sediment only, oil is most likely emanating from one or more of the 25 wells (USDOI, BSEE, 2015).

Taylor Energy had originally been ordered by MMS in October 2007 to permanently plug and abandon all of the wells by June 2008. In November 2007, MMS issued Taylor Energy an order to provide supplemental bonding to guarantee performance of Taylor Energy's decommissioning obligations at the site. In December 2007, MMS ordered Taylor Energy to prevent any further hydrocarbon seepage from the MC-20 site. In February 2008, MMS sent Taylor Energy a Notice of Incident of Noncompliance for failure to provide the required supplemental bonding.

The DOI and Taylor Energy entered into a Trust Agreement in 2008 wherein Taylor Energy committed funds to fulfill obligations under the OCSLA regarding the MC-20 site. By entering into the Agreement, Taylor Energy fulfilled its supplemental bonding obligations and resolved the pending administrative citation with respect to those obligations. Decommissioning of the wells at the site, required under the regulations and the 2008 Trust Agreement, has not yet been completed.

For example, not all of the wells have been permanently plugged and abandoned. Future work to be performed under the Trust Agreement will be determined based on site conditions and the availability of applicable technology.

In addition to its obligations under the OCSLA, pursuant to the Oil Pollution Act (OPA) and BOEM regulations, Taylor Energy is required to provide evidence of financial responsibility (e.g., bond and insurance) demonstrating that it can fulfill its OPA obligations (e.g., removal and compensation for damages) for oil spills from the MC-20 site.

Shell Offshore Pipeline Spill at Green Canyon Block 248

On May 12, 2016, USCG responded to an offshore oil spill that reportedly discharged from a Shell subsea well-head flow line, approximately 90 mi (145 km) south of Timbalier Island, Louisiana, at Green Canyon Block 248. The release came from the Glider subsea system, which ties back to the Brutus platform at Green Canyon Block 158. The volume of the release was estimated at 2,100 bbl. Response efforts included on-water recovery vessels and skimming operations. There have been no reported impacts to wildlife or fisheries, and the sheen did not make contact with the shoreline. This information is preliminary and BSEE personnel are leading an investigation to determine the cause of the release and the effectiveness of the on-water response. Due to the timing of this event, this spill was not included in the ABS Consulting Inc.'s (2016) *Update of Occurrence Rates for Offshore Oil Spills*.

3.2.1.2 Characteristics of OCS Oil

Crude oils are a natural mixture of hundreds of different compounds, with liquid hydrocarbons accounting for up to 98 percent of the total composition. The chemical composition of crude oil can vary significantly from different producing areas; thus, the exact composition of oil being produced in OCS waters varies throughout the GOM. Extensive laboratory testing has been performed on various oils from the GOM to determine their physical and chemical characteristics. For example, numerous oils collected from the GOM (U.S. waters) are included in Environment Canada's (2013) oil properties database. The database provides details of an oil's chemical composition, including hydrocarbon groups (i.e., saturates, aromatics, resins, and asphaltenes), VOCs (such as benzene, toluene, ethylbenzene, and xylene), sulfur content, biomarkers, and metals. The database also includes API gravities, of which GOM oils are in the range of 15° to 60°. The American Petroleum Institute gravity is a common measure of the relative density of crude oil and is expressed in degrees (°API) with water having a value of 10° API. Crude oils with lower densities and viscosities usually contain higher levels of naphtha with predominantly volatile paraffinic hydrocarbons (**Table 3-16**). Light crude oils are easier to process, while heavy crude oils are more difficult. The sulfur content (sweet vs. sour) of crude oil also determines the amount of processing required. Light sweet crude oil is preferred by refineries because of its low sulfur content (typically less than 0.5%) (API, 2011).

Data have been collected from approximately 450 deepwater EPs and DOCDs that were submitted to BOEM/BSEE. These data are available through BOEM's Exploration and Development

Plans Online Query (USDOI, BOEM, 2014b). Statistics on these API gravities show a similar range of 16° to 58° as those reported in the Environment Canada database. The mean value for all oils examined was 36°.

Table 3-16. Properties and Persistence by Oil Component Group.

Properties and Persistence	Light Weight	Medium Weight	Heavy Weight
Hydrocarbon Compounds	Up to 10 carbon atoms	10-22 carbon atoms	>20 carbon atoms
API º	>31.1º	31.1º-22.3º	<22.3º
Evaporation Rate	Rapid (within 1 day) and complete	Up to several days; not complete at ambient temperatures	Negligible
Solubility in Water	High	Low (at most a few mg/L)	Negligible
Acute Toxicity	High due to monoaromatic hydrocarbons (BTEX)	Moderate due to diaromatic hydrocarbons (naphthalenes – 2 ring PAHs)	Low, except due to smothering (i.e., heavier oils may sink)
Chronic Toxicity	None, does not persist due to evaporation	PAH components (e.g., naphthalenes – 2 ring PAHs)	PAH components (e.g., phenanthrene, anthracene – 3 ring PAHs)
Bioaccumulation Potential	None, does not persist due to evaporation	Moderate	Low, may bioaccumulate through sediment sorption
Compositional Majority	Alkanes and cycloalkanes	Alkanes that are readily degraded	Waxes, asphaltenes, and polar compounds (not significantly bioavailable or toxic)
Persistence	Low due to evaporation	Alkanes readily degrade, but the diaromatic hydrocarbons are more persistent	High; very low degradation rates and can persist in sediments as tarballs or asphalt pavements

Notes: API = American Petroleum Institute; BTEX = benzene, toluene, ethylbenzene, and xylene; mg/L = milligram per liter; PAH = polycyclic aromatic hydrocarbons.
Sources: Michel, 1992; Lee et al., 2015.

3.2.1.3 Transport and Fate of Offshore Spills

The physical and chemical properties of oil greatly affect its transport and fate in the environment. Once spilled, oil is subject to a number of physical, chemical, and biological processes that alter its composition and can determine environmental impacts. Horizontal transport of oil is accomplished through spreading, advection, dispersion, and entrainment, whereas vertical transport involves dispersion, entrainment, Langmuir circulation (a series of shallow, slow, counter-rotating vortices at the ocean's surface aligned with the wind developed when wind blows steadily over the sea surface), sinking, overwashing, partitioning, and sedimentation. Following a spill, the composition of the released oil can change substantially due to weathering processes such as evaporation, emulsification, dissolution, and oxidation. The ultimate fate of oil in the environment and its impacts are influenced not only by the magnitude, spatial extent, and duration of the event but also by the response methods that may be employed (**Chapter 3.2.8**). More details on the properties and persistence of different types of oils are provided in **Table 3-16**.

Spreading

It is expected that some portion of spilled oil would rise in the water column and/or remain on the sea surface, depending on the depth of the spill and whether a subsurface plume forms. Gulf of Mexico oils, having an average API gravity of 36°, have a tendency to float. Once on the sea surface, oil rapidly spreads out, forming a slick that is initially a few millimeters (mm) in thickness in the center and much thinner around the edges. The rate of spreading depends upon the viscosity of the spilled oil, whether or not the oil is released at the water surface or subsurface, and whether the spill is instantaneous or continuous for some period. The spilled oil would continue to spread until its thickest part is about 0.1 mm. Once it spreads thinner than 0.1 mm, the slick would begin to break up into small patches, forming a number of elongated slicks, with an even thinner sheen trailing behind each patch of oil. Oil becomes diluted as it physically mixes with the surrounding water and moves into the water column, and the physical mixing zone of surface oil is generally limited to approximately 33 ft (20 m) (Lange, 1985; McAuliffe et al., 1975 and 1981a; Tkalich and Chan, 2002; Thompson et al., 1999; Schroeder, 2000). However, under turbulent mixing conditions oil can be transported deeper into the water column. In one extraordinary circumstance, a tropical storm forced a large volume of dispersant/oil mixture as deep as 246 ft (75 m) (Silva et al., 2015).

Weathering

Immediately upon being spilled, oil begins reacting with the environment. This process is called weathering. A number of processes alter the chemical and physical characteristics of the original hydrocarbon mixture, which reduces the oil mass over time. Weathering processes include evaporation of volatile hydrocarbons into the atmosphere, dissolution of soluble components, dispersion of oil droplets into the water column, emulsification and spreading of the slick on the surface of the water, chemo- or photo-oxidation of specific compounds (creating new components that are often more soluble), and biodegradation. Weathering and the existing meteorological and oceanographic conditions determine the time that the oil remains on the surface of the water, and the characteristics of the oil at the time of contact with a particular resource also influence the persistence time of an oil slick. Oil-spill cleanup timing and effectiveness would also be determining factors.

Chemical, physical, and biological processes operate on spilled oil to change its hydrocarbon compounds, reducing many of the components until the slick can no longer continue as a cohesive mass floating on the surface of the water. By spreading out, the oil's more volatile components are exposed to the atmosphere and within a few days following a spill, light crude oils can lose up to 75 percent of their initial volume and medium crude oils can lose up to 40 percent (NRC, 2003). Some crude oils mix with water to form an emulsion that is much thicker and stickier than the original oil (USDOC, NOAA, 2010a). Winds and waves continue to stretch and tear the oil patches into smaller pieces, or tarballs. Oil at a "light" API gravity would have few asphaltenes, would not emulsify, and would not form tarballs. Oil at a "heavy" API gravity, or enriched in heavy components after weathering, would more likely emulsify and form tarballs. While some tarballs may be as large as pancakes, most are coin-sized. Tarballs are very persistent in the marine environment and can travel hundreds of miles. It is expected that oil spilled as a result of an accident associated with a regionwide proposed action would be within the range of 30°-35° API. BOEM used the SINTEF Oil Weathering Model to numerically model weathering processes to (1) estimate the likely amount of oil remaining on the ocean surface as a function of time and (2) predict the composition of any remaining oil (USDOI, MMS, 2007a). The results of BOEM's weathering analyses were as follows. By 10 days after a spill event of 1,000 bbl, approximately 32-74 percent of the slick would have dissipated by natural weathering, with between 30 and 32 percent lost to the atmosphere via evaporation and between 2 and 42 percent lost into the water column via natural dispersion. The volume of the slick would be further reduced by spill-response efforts (**Chapter 3.2.8**). However, other fates would likely be appropriate to a catastrophic spill event, especially in deep waters. For example, Ryerson et al. (2011) estimated that the total hydrocarbon mass for the *Deepwater Horizon* oil spill (including gas fraction) was partitioned among the following fates: ~36 percent to the deep subsurface plume; ~21 percent recovered by surface ships; ~10 percent to a surface slick; ~6 percent flared at the surface; and ~4 percent evaporated at the surface, which leaves ~23 percent unaccounted for based on available chemical data.

Persistence

The persistence of an offshore oil slick is strongly influenced by how rapidly it spreads and weathers and by the effectiveness of oil-spill response in removing the oil from the water surface. Hypothetical analyses were performed for a simulated pipeline break. Based on several scenarios implemented in the weathering model (e.g., variable season, oil type, and emulsification), BOEM estimated that the spill would dissipate from the water surface in approximately 2-10 days. Similarly, an OCS pipeline spill of 8,212 bbl on September 29, 1998, for which a panel investigation report was available, contained overflight information of the oil spill that showed the spill persisted for 5 days on the surface (USDOI, MMS, 1999).

Subsurface Release

The behavior of a spill depends on many factors, including the characteristics of the oil being spilled as well as oceanographic and meteorological conditions. Previously, an experiment in the North Sea indicated that the majority of oil released during a deepwater blowout would quickly rise to the surface and form a slick (Johansen et al., 2001). In such a case, impacts from a deepwater oil spill would occur at the surface where the oil is likely to be mixed into the water and dispersed by wind and waves. The oil would undergo natural physical, chemical, and biological degradation processes including weathering. However, data and observations from the *Deepwater Horizon* explosion, oil spill, and response challenged the previously prevailing thought that most oil from a deepwater blowout would quickly rise to the surface. Due in part to the application of subsea dispersants, measurable amounts of hydrocarbons (dispersed or otherwise) were detected in the water column as subsurface plumes and on the seafloor in the vicinity of the release (e.g., Diercks et al., 2010; OSAT, 2010). Subsurface plume formation is based on numerous factors, including the level of subsea dispersant injection, the amount of natural dispersion related to blowout properties, and oceanographic conditions such as water column stratification and cross currents. After the *Ixtoc* blowout in 1979, located 50 mi (80 km) offshore in the Bay of Campeche, Mexico, some subsurface oil also was observed dispersed within the water column (Boehm and Fiest, 1982); however, the scientific investigations were limited (Reible, 2010). The water quality of marine waters would be affected by the dissolved components and oil droplets that are small enough that they do not rise to the surface or are mixed down by surface turbulence. In the case of subsurface oil plumes, it is important to remember that these plumes would be affected by subsurface currents and could be diluted over time. Even in the subsurface, oil would undergo natural physical, chemical, and biological degradation processes including weathering.

3.2.1.4 Analysis of Offshore Spills ≥1,000 bbl

3.2.1.4.1 Overview of Spill Risk Analysis

The BOEM conducts an oil-spill risk analysis prior to conducting lease sales in OCS areas (refer to **Figure 3-17**). The analysis is conducted in three parts:

(1) the trajectories of oil spills from hypothetical spill locations, which are simulated using the Oil Spill Risk Analysis (OSRA) Model (Smith et al., 1982);

(2) the probability of oil-spill occurrence, which is based on spill rates derived from historical data (Anderson et al., 2012) and on estimated volumes of oil produced and transported; and

(3) the combination of results of the first two to estimate the overall oil-spill risk if there is oil development.

In the GOM, the Cumulative OCS Oil and Gas Program scenario comprises all future operations that would occur over a 70-year time period (2017-2086) from proposed, existing, and future leases regionwide. The analysis uses data on past OCS production and spills, along with estimates of future activities, to evaluate the risk of future spills.

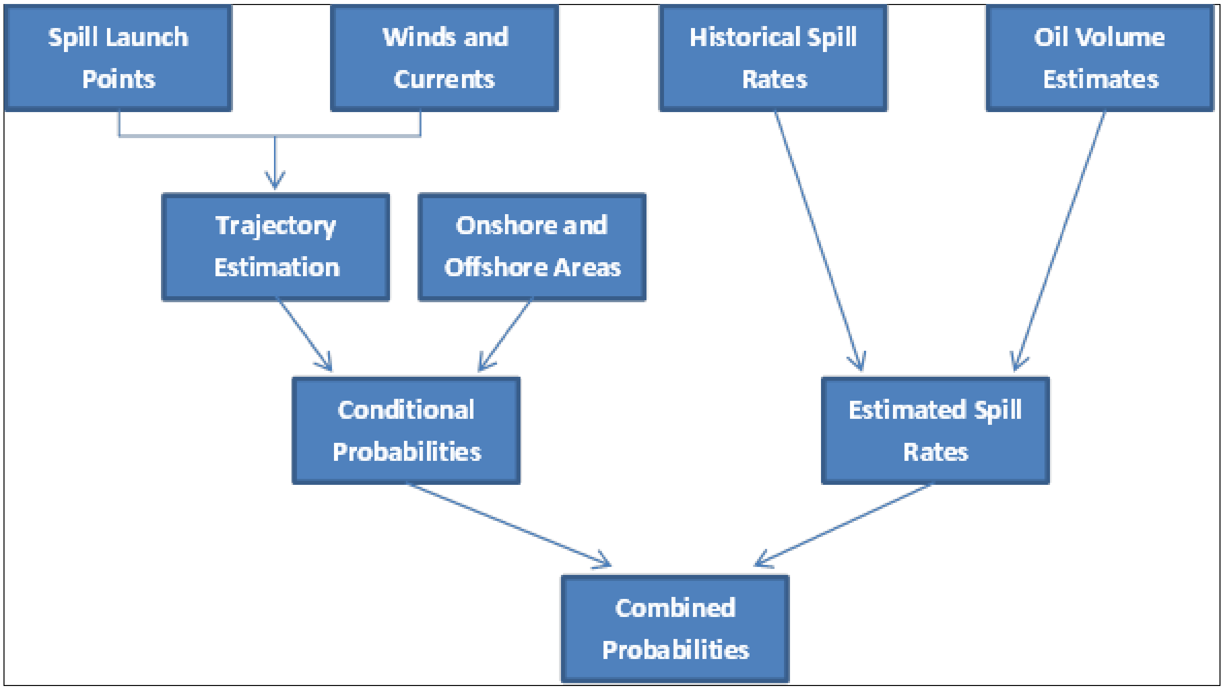

Figure 3-17. The Oil Spill Risk Analysis Model Process.

3.2.1.4.2 Trajectory Modeling for Offshore Spills ≥1,000 bbl

The OSRA model simulates the trajectory of thousands of spills throughout the Gulf of Mexico OCS and calculates the probability of these spills being transported and contacting specified geographic areas and features. Using the OSRA model, BOEM estimates the likely trajectories of hypothetical offshore spills ≥1,000 bbl. Only spills ≥1,000 bbl are addressed because smaller spills may not persist long enough to be simulated by trajectory modeling. For this analysis, the OSRA model was run for Alternatives A, B, and C (**Tables 3-2 and 3-4**) and the Cumulative OCS Oil and Gas Program (2017-2086).

The OSRA model uses hypothetical spill locations called launch points and simulates the trajectory of a spill's movement on the surface of the water using modeled ocean currents and winds. The model can simulate a large number of hypothetical trajectories from each launch point. Spill trajectories are initiated once per day from each launch point and are time stepped every hour until a statistically valid number of simulations have been run to characterize the risk of contact. The simulated oil spills originate from approximately 6,000 points uniformly distributed 6-7 mi (10-11 km) apart within the Gulf of Mexico OCS. This spacing between launch points is sufficient to provide a resolution that creates a statistically valid characterization of the entire area (Price et al., 2001).

The model tabulates the number of times each trajectory moves across or touches a location (contact) occupied by polygons mapped on the gridded area. These polygons represent specified geographic areas and features. The OSRA model compiles the number of contacts to each feature that results from all of the modeled trajectory simulations from all of the launch points for a specific area. Contact occurs for offshore features if the trajectory simulation passes through the polygon.

Contact occurs for land-based features if the trajectory simulation touches the border of the feature. The simulation stops when the trajectory contacts the lines representing the land/water boundary or the borders of the domain. The probability of contact to a defined feature is calculated by dividing the number of contacts by the number of trajectories started at various launch locations in the gridded area.

The output from this component of the OSRA model provides information on the likely trajectory of a spill by wind and current transport, should one occur and persist for the time modeled in the simulations; the calculations for this EIS were modeled for 10 and 30 days. All contacts that occurred during these periods were tabulated for Alternatives A, B, and C (**Table 3-17**).

Table 3-17. Probability (percent chance) of a Particular Number of Offshore Spills ≥1,000 Barrels Occurring as a Result of Either Facility or Pipeline Operations Related to Alternative A, B, or C.

	Facility Spills (%)		Pipeline Spills (%)		Total Spills (%)	
Alternative A[1]						
Number of Spills	Low	High	Low	High	Low	High
1	5	21	15	37	19	36
2	<0.5	3	1	18	2	23
3	<0.5	<0.5	<0.5	6	<0.5	10
4	<0.5	<0.5	<0.5	1	<0.5	3
5	<0.5	<0.5	<0.5	<0.5	<0.5	1
Alternative B[2]						
Number of Spills	Low	High	Low	High	Low	High
1	4	19	14	36	17	37
2	<0.5	2	1	16	2	20
3	<0.5	<0.5	<0.5	4	<0.5	7
4	<0.5	<0.5	<0.5	1	<0.5	2
5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5
Alternative C[3]						
Number of Spills	Low	High	Low	High	Low	High
1	1	4	2	11	3	14
2	<0.5	<0.5	<0.5	1	<0.5	1
3	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5
4	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5
5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5

Note: The columns under each spill category refer to the low and high resource estimates. Refer to **Table 3-1** for more information on resource estimates.

[1]Proposed regionwide lease sale.

[2]Proposed regionwide lease sale excluding blocks in the WPA.

[3]Proposed regionwide lease sale excluding blocks in the CPA/EPA.

3.2.1.4.3 Estimated Number of Offshore Spills ≥1,000 bbl and Probability of Occurrence

The mean number of spills ≥1,000 bbl estimated to occur as a result of each alternative is provided in **Table 3-18**. The range of the mean number of spills reflects the range of oil production volume estimated as a result of each alternative. The mean number of future spills ≥1,000 bbl is calculated by multiplying the spill rate (1.13 spills/BBO) by the volume of oil estimated to be produced as a result of each alternative. Spill rates were calculated based on the assumption that spills occur in direct proportion to the volume of oil handled and are expressed as number of spills per billion barrels of oil handled (spills/BBO).

Table 3-18. Mean Number and Sizes of Spills Estimated to Occur in OCS Offshore Waters from an Accident Related to Rig/Platform and Pipeline Activities Supporting Each Alternative Over a 50-Year Time Period.

Spill Size Group	Spill Rate (spills/BBO)[1]	Number of Spills Estimated			Estimated Median Spill Size (bbl)[1]
		Alternative A	Alternative B	Alternative C	
0-1.0 bbl	2,020	424-2,258	374-1,959	51-290	<1
1.1-9.9 bbl	57.4	12-64	11-56	2-9	3
10.0-49.9 bbl	17.4	4-20	3-17	1-3	
50.0-499.9 bbl	11.3	2-13	2-11	<1-2	126
500.0-999.9 bbl	1.63	<1-2	<1-2	<1	
Platforms					
≥1,000-9,999 bbl	0.25	<1	<1	<1	5,066
≥10,000 bbl	0.13	<1	<1	<1	–[2]
Pipelines					
≥1,000-9,999 bbl	0.88	<1-1	<1	<1	1,720
≥10,000 bbl	0.18	<1	<1	<1	–[2]

Notes: The number of spills estimated is derived by application of the historical rate of spills (1996-2010) per volume of crude oil handled based on the projected production for each alternative (**Table 3-2**). The actual number of spills that may occur in the future could vary from the estimated number.

[1]The spill rates presented are a sum of rates for United States OCS platforms/rigs and pipelines. The average (vs. the median) spill sizes for a larger number of spill size categories can also be found in the original source (Anderson et al., 2012).

[2]During the last 15 years, the only ≥10,000-bbl spill was the *Deepwater Horizon*. However, this spill is considered to be a low-probability catastrophic event, which is not reasonably foreseeable and is therefore not included.

The probabilities for oil spill occurrence resulting from each alternative (2017-2066) and the Cumulative OCS Oil and Gas Program (2017-2086) for offshore spills ≥1,000 bbl can be found in **Table 3-19** and for spills ≥10,000 bbl in **Table 3-20**. The OSRA model estimates the chance of oil spills occurring during the production and transportation of a specific volume of oil over the lifetime of the scenario being analyzed. The estimation process uses a spill rate constant, based on historical accidental spills ≥1,000 bbl, expressed as a mean number of spills per billion barrels of oil handled. For this analysis, the low estimate and high estimate of projected oil production for a single proposed lease sale for each alternative and for the Cumulative OCS Oil and Gas Program (2017-2086) are used. For more information on OCS spill-rate methodologies and trends, refer to Anderson et al. (2012). A discussion of how the range of resource estimates was developed is provided in **Chapter 3.1.1 and Table 3-1**.

Table 3-19. Oil-Spill Occurrence Probability Estimates for Offshore Spills ≥1,000 Barrels Resulting from Each Alternative (2017-2066) and the Cumulative OCS Oil and Gas Program (2017-2086).

	Forecasted Oil Production (Bbbl)[1]	Mean Number of Spills Estimated to Occur				Estimates of Probability (% chance) of One or More Spills			
		Platforms	Pipelines	Tankers	Total	Platforms	Pipelines	Tankers	Total
Single Proposed Lease Sale Alternatives									
Alternative A[2]	0.210	0.05	0.19	0	0.24	5	17	<0.5	21
	1.118	0.28	0.98	0.01	1.27	24	63	<0.5	72
Alternative B[3]	0.185	0.05	0.16	0	0.21	5	15	<0.5	19
	0.970	0.24	0.85	0	1.10	22	57	<0.5	67
Alternative C[4]	0.026	0.01	0.02	0	0.03	1	2	<0.5	3
	0.148	0.04	0.13	0	0.17	4	12	<0.5	15
Cumulative OCS Oil and Gas Program									
Regionwide	15.482	3.87	13.62	0.08	17.57	98	>99.5	7	>99.5
	25.806	6.45	22.71	0.13	29.29	>99.5	>99.5	12	>99.5
CPA/EPA	13.590	3.40	11.96	0.07	15.42	97	>99.5	7	>99.5
	22.381	5.60	19.70	0.11	25.40	>99.5	>99.5	11	>99.5
WPA	1.892	0.47	1.66	0	2.14	38	81	<0.5	88
	3.425	0.86	3.01	0	3.87	58	95	<0.5	98

Notes: Bbbl = billion barrels.
"Platforms" refers to facilities used in exploration, development, or production.
[1]Values represent the low and high resource estimates. Refer to **Table 3-1** for more information on resource estimates.
[2]Proposed regionwide lease sale.
[3]Proposed regionwide lease sale excluding blocks in the WPA.
[4]Proposed regionwide lease sale excluding blocks in the CPA/EPA.

Source: Ji, official communication, 2015.

Table 3-20. Oil-Spill Occurrence Probability Estimates for Offshore Spills ≥10,000 Barrels Resulting from Each Alternative (2017-2066) and the Cumulative OCS Oil and Gas Program (2017-2086).

	Forecasted Oil Production (Bbbl)[1]	Mean Number of Spills Estimated to Occur				Estimates of Probability (% chance) of One or More Spills			
		Platforms	Pipelines	Tankers	Total	Platforms	Pipelines	Tankers	Total
Single Sale Alternatives									
Alternative A[2]	0.210	0.03	0.04	0	0.07	3	4	<0.5	6
	1.118	0.15	0.20	0	0.35	14	18	<0.5	29
Alternative B[3]	0.185	0.02	0.03	0	0.06	2	3	<0.5	6
	0.970	0.13	0.17	0	0.30	12	13	<0.5	26
Alternative C[4]	0.026	0	0	0	0.01	<0.5	<0.5	<0.5	1
	0.148	0.02	0.03	0	0.05	2	3	<0.5	4

	Forecasted Oil Production (Bbbl)[1]	Mean Number of Spills Estimated to Occur				Estimates of Probability (% chance) of One or More Spills			
		Platforms	Pipelines	Tankers	Total	Platforms	Pipelines	Tankers	Total
Cumulative OCS Oil and Gas Program									
Regionwide	15.482	2.01	2.79	0.02	4.82	87	94	2	99
	25.806	3.35	4.65	0.04	8.04	97	99	4	>99.5
CPA/EPA	13.590	1.77	2.45	0.02	4.23	83	91	2	99
	22.381	2.91	4.03	0.04	6.97	95	98	4	>99.5
WPA	1.892	0.25	0.34	0	0.59	22	29	<0.5	44
	3.425	0.45	0.62	0	1.06	36	46	<0.5	65

Notes: Bbbl = billion barrels.
"Platforms" refers to facilities used in exploration, development, or production.
[1]Values represent the low and high resource estimates. Refer to **Table 3-1** for more information on resource estimates.
[2]Proposed regionwide lease sale.
[3]Proposed regionwide lease sale excluding blocks in the WPA.
[4]Proposed regionwide lease sale excluding blocks in the CPA/EPA.

Source: Ji, official communication, 2015.

3.2.1.4.4 Most Likely Source of Offshore Spills ≥1,000 bbl

Table 3-17 indicates the probabilities of one or more spills ≥1,000 bbl occurring from OCS facility or pipeline operations related to each alternative. The most likely cause of a spill ≥1,000 bbl is a pipeline break at the seafloor (Anderson et al., 2012). The various circumstances responsible for pipeline breaks included during the 1996-2010 analysis period were damage by an anchor, mudslide damage during a hurricane, a jack-up rig barge crushing the pipeline when it sat down on it, and microfractures from chronic contacts at a pipeline crossing where separators between the pipelines were missing.

3.2.1.4.5 Most Likely Size of an Offshore Spill ≥1,000 bbl

The estimated size of an offshore spill utilizes the median spill size from the trend analysis found in Anderson et al. (2012) for accidents occurring from drilling rig, platform, or pipeline activities. Extreme events such as the *Deepwater Horizon* oil spill skew the average and, as such, does not provide a useful statistical measure. The median size of spills ≥1,000 bbl that occurred during 1996-2010 is 2,240 bbl. This size was calculated based on the nine spills (both platforms/rigs and pipelines) that occurred during this timeframe and included the *Deepwater Horizon* oil spill. For information on the mean number and size of spills estimated to occur for each alternative, refer to **Table 3-18**.

3.2.1.4.6 Length of Coastline Affected by Offshore Spills ≥1,000 bbl

The BOEM has previously estimated the length of shoreline that could be contacted if a spill ≥1,000 bbl occurred as a result of an accident associated with each alternative (USDOI, MMS, 2007a). The length of shoreline contacted is dependent upon the original spill size and the volume of oil removed by natural weathering and offshore cleanup operations prior to the slick making shoreline contact. The shoreline length contacted is a simple arithmetic calculation based on the area of the remaining slick. The calculation assumes that the slick will be carried 30 m (98 ft) inshore of the shoreline, either onto the beachfront up from the water's edge or into the bays and estuaries, and will be spread out at uniform thickness of 1 mm; this assumes that no oil-spill boom is used. The maximum length of shoreline affected by a spill of 4,600 bbl was estimated to be 30-50 km (19-31 mi) of shoreline, assuming such a spill were to reach land within 12 hours. Some redistribution of the oil due to longshore currents and further smearing of the slick from its original landfall could also occur.

3.2.1.4.7 Risk Analysis by Resource

The BOEM analyzes risk to resources from oil spills and oil slicks that could occur as a result of each alternative. The results are based on BOEM's estimates of likely spill locations, sources, sizes, frequency of occurrence, the physical fate of different types of oil slicks, and the probable transport that are described in more detail in the preceding spill scenarios. For offshore spills, combined probabilities were calculated using the OSRA model, which includes both the likelihood of a spill from each alternative occurring and the likelihood of the oil slick reaching areas where known resources exist.

The environmental, social and economic resources utilizing the OSRA modeling results were selected by BOEM analysts. Details on the individual resource categories, as well as a detailed analysis of the impacts to each resource from oil spills, are provided under each resource category in **Chapter 4**.

3.2.1.4.8 Likelihood of an Offshore Spill ≥1,000 bbl Occurring and Contacting Coastal and Offshore Areas

A more complete measure of spill risk was calculated by multiplying the probability of contact generated by the OSRA model by the probability of occurrence of one or more spills 1,000 bbl as a result of each alternative. This provides a risk factor that represents the probability of a spill occurring as a result of each alternative and contacting a specified geographic area or feature. These are referred to as "combined probabilities" because they combine the risk of occurrence of a spill from OCS sources and the risk of such a spill contacting areas of sensitive environmental, social and economic resources. The combined probabilities for an offshore spill ≥1,000 bbl occurring and contacting coastal and offshore areas for each for each alternative can be found in the figures in **Appendix E**.

To better reflect the geologic distribution of oil and gas resources and natural variances of meteorological and oceanographic conditions in the computation of combined probabilities, BOEM also generated combined probabilities for smaller areas within the GOM. A cluster analysis was used to analyze the contact probabilities generated for each of the 6,000 launch points. For this analysis, similar trajectories and contact to 10-mi (16-km) shoreline segments were tabulated to identify offshore cluster areas. The estimated oil production from each alternative was proportionally distributed to the cluster areas and the likelihood of spill occurrence was calculated for each cluster area. The probability of spill occurrence was combined with probabilities of contact from the trajectory modeling to estimate the combined risk of spills occurring and contacting specific areas from spills in each cluster area. To account for the risk of spills occurring from the transportation of oil to shore, generalized pipeline corridors originating within each of the offshore cluster areas and terminating at major oil pipeline landfall areas were developed. The oil volume estimated to be produced as a result of each alternative within each cluster area was proportioned among the pipeline corridors. The mean number of spills and the probability of contact of spills from each pipeline corridor were then calculated and combined with the risk of spills occurring and contacting resources from OCS facility development and production operations to complete the analysis.

3.2.1.5 Analysis of Offshore Spills <1,000 bbl

3.2.1.5.1 Estimated Number of Offshore Spills <1,000 bbl and Total Volume of Oil Spilled

The number of spills <1,000 bbl estimated to occur over the next 50 years as a result of each alternative is provided in **Table 3-18**. The number of spills is estimated by multiplying the oil-spill rate for each of the different spill size groups by the projected oil production as a result of each alternative (**Tables 3-2 and 3-4**). As spill size increases, the occurrence rate decreases and so the number of spills estimated to occur decreases.

3.2.1.5.2 Most Likely Source and Type of Offshore Spills <1,000 bbl

Most spills <1,000 bbl on the OCS would likely occur from a mishap on a production facility, most likely related to a failure related to the storage of oil. From 1995 to 2009, there were 14,191 spills <1,000 bbl on platforms, rigs, or vessels and 1,139 spills from pipelines (Anderson et al., 2012). Spills on platforms and rigs could be crude or refined (diesel, hydraulic) oil. Reported pipeline spills are likely to be crude oil, and vessel spills are likely to be refined oil. For spills <1,000 bbl, a total of 19,050 bbl were released to OCS waters from platforms, rigs, or vessels, and 8,002 bbl were released from pipelines.

3.2.1.5.3 Most Likely Size of Offshore Spills <1,000 bbl

Table 3-12 provides the most likely volume of oil estimated to be spilled for each of the spill-size groups. As stated previously, the estimated size of an offshore spill utilizes the median spill size from the trend analysis in Anderson et al. (2012) for all spill-size classes During the 50-year analysis period, 96 percent of all spills estimated to occur as a result of each alternative would be small spills <1 bbl (Anderson et al., 2012).

3.2.1.5.4 Likelihood of an Offshore Spill <1,000 bbl Occurring and Contacting Coastal and Offshore Areas

Because spills <1,000 bbl are not expected to persist as a slick on the surface of the water beyond a few days and because spills on the OCS would occur at least 3-10 nmi (3.5-11.5 mi; 5.6-18.5 km) from shore, it is unlikely that any spills would make landfall prior to breaking up. For an offshore spill <1,000 bbl to make landfall, the spill would have to occur proximate to State waters (defined as 3-12 mi [5-19 km] from shore). If a spill were to occur proximate to State waters, only a spill >50 bbl would be expected to have a chance of persisting long enough to reach land. Spills

>50 and <1,000 bbl are infrequent. Should such a spill occur, the volume that would make landfall would be expected to be extremely small (a few barrels).

3.2.1.6 Analysis of Coastal Spills

Coastal spills occur in coastal waters, which are defined here as State offshore waters and spills in navigation channels, rivers, and bays from barges and pipelines carrying OCS-produced oil. These spills occur at shoreline storage, processing, and transport facilities supporting the OCS oil and gas industry. BOEM projects that most (>90%) oil produced as a result of a proposed action under Alternative A would be brought ashore via pipelines to oil pipeline shore bases, stored at these facilities, and eventually transferred via pipeline or barge to GOM coastal refineries. Because oil is commingled at shore bases and cannot be directly attributed to a particular lease sale, this analysis of coastal spills addresses spills that could occur prior to the oil arriving at the initial shoreline facility. It is also possible that non-OCS oil may be commingled with OCS oil at these facilities or during subsequent secondary transport.

3.2.1.6.1 Estimated Number and Most Likely Sizes of Coastal Spills

According to USCG's database for the most recent 13 years, January 2002-July 2015, (USDHS, CG, 2016) (**Table 3-13**), in the waters 0-9 nmi (0-10.36 mi; 16.67 km) off the Texas coast, there were a total of 91 spills reported from 2002 to 2015 or about 7 spills <1,000 bbl/yr. In the waters 0-3 nmi (0-3.45 mi; 5.56 km) off the Louisiana coast, there were a total of more than 2,143 spills reported from 2002-2015, or about 165 spills <1,000 bbl/yr. In the waters 0-3 mi (0-5 km) off the Mississippi coast, there were a total of 2 spills reported from all sources, or about 0.2 spills <1,000 bbl/yr. In the waters 0-3 nmi (0-3.45 mi; 5.56 km) off the Alabama coast, there were a total 2 spills reported from all sources from 2002-2015, or about 0.2 spills <1,000 bbl/yr. In the waters 0-9 nmi (0-10.36 mi; 16.67 km) off the Florida coast, there were a total 0 spills reported from all sources from 2002-2015,. When limited to just oil- and gas-related spill sources such as platforms, pipelines, MODU's, and support vessels, the number and most likely spill sizes to occur in coastal waters in the future are expected to resemble the patterns that have occurred in the past as long as the level of energy-related commercial and recreational activities remain the same. The coastal waters of Louisiana, Texas, Mississippi, Alabama, and Florida have had a total of 165, 7, 0.2, 0.2, and 0 spills <1,000 bbl/yr, respectively. Assuming future trends would reflect past historical records, it is also predicted that Louisiana will be the state most likely to have a spill ≥1,000 bbl occur in water 0-3 mi (0-5 km) offshore.

3.2.1.6.2 Likelihood of Coastal Spill Contact

Estimates of future coastal spills are based on historical spills reported to USCG. Based upon historical data, offshore Louisiana is the most likely location for the occurrence of a coastal spill. A spill that occurs in Federal waters could also be transported to State waters.

3.2.2 Losses of Well Control

All losses of well control are required to be reported to BSEE. In 2006, BOEM and BSEE's predecessor (the Minerals Management Service), revised the regulations for loss of well control incident reporting, which were further clarified in NTL 2010-N05, "Increased Safety Measures for Energy Development on the OCS." Operators are required to document any loss of well control event, even if temporary, and the cause of the event by mail or email to the addressee indicated in the NTL. The operator does not have to include kicks that were controlled but should include the release of fluids through a flow diverter (a conduit used to direct fluid flowing from a well away from the drilling rig). The current definition for loss of well control is as follows:

- uncontrolled flow of formation or other fluids (the flow may be to an exposed formation [an underground blowout] or at the surface [a surface blowout]);
- uncontrolled flow through a diverter; and/or
- uncontrolled flow resulting from a failure of surface equipment or procedures.

Not all loss of well control events would result in a blowout as defined above, but it is most commonly thought of as a release to the human environment. A loss of well control can occur during any phase of development, i.e., exploratory drilling, development drilling, well completion, production, or workover operations. A loss of well control can occur when improperly balanced well pressure results in sudden, uncontrolled releases of fluids from a wellhead or wellbore (PCCI Marine and Environmental Engineering, 1999; Neal Adams Firefighters, Inc., 1991).

Of the 48 loss of well control events reported in the GOM from 2007 to 2015, 26 (54%) resulted in loss of fluids at the surface or underground (USDOI, BSEE, 2016a).

The BSEE reports that they have had 288 unique loss of well control incidents captured in their database from 1956 to 2010 (Herbst, 2014), with an additional 22 incidents documented from 2010 through August 2015. A synopsis conducted by BSEE of the 288 well incidents that occurred from 1956 through 2010 shows the following:

- 69 of the 288 incidents had duration greater than or equal to 5 days (24%);
- 55 of the 69 incidents occurred in water depths <300 ft (91 m) (80%);
- 42 of the 69 incidents occurred within 50 mi (80 km) of shore (61%);
- a total of 31 fatalities occurred in 5 of the 69 incidents;
- a total of 84 injuries occurred in 7 of the 69 incidents; and
- 8 of the 69 incidents were oil blowouts (12%).

In contrast, the *Deepwater Horizon* oil spill continued uncontained for 87 days, between April 20 and July 15, 2010. The *Deepwater Horizon* blowout in Mississippi Canyon Block 252 resulted in the release of 4.9 MMbbl of oil and large quantities of gas (McNutt et al., 2011). For purposes of calculating the maximum possible civil penalty under the CWA, a January 2015 judgement used a quantity of 4.0 MMbbl of oil for total discharged and 3.19 MMbbl of oil as the actual amount that was released into environment (Barbier and Shushan, 2015). As shown by the *Deepwater Horizon* explosion and oil spill, the loss of well control in deep water presents obstacles and challenges that differ from a loss of well control in shallow waters. Although many of the same techniques used for wild well control efforts in shallow water were used to attempt to control the *Macondo* well, these well control efforts were hindered by water depth, which required reliance solely upon the use of ROVs for all well intervention efforts. This is a concern in deep water because the inability to quickly regain control of a well increases the size of a spill.

There are several options that can be attempted to control a well blowout. Common kill techniques include (1) bridging, (2) capping/shut-in, (3) capping/diverting, (4) surface stinger, (5) vertical intervention, (6) offset kill, and (7) relief wells (Neal Adams Firefighters, Inc. 1991). Although much has been learned about well control as a result of the *Deepwater Horizon* explosion, oil spill, and response, if a deepwater subsea blowout occurs in the future, it is still likely that an operator would be required to immediately begin to drill one or more relief wells to gain control of the well. This may be required whether or not this is the first choice for well control because a relief well is typically considered the ultimate final solution for regaining well control in such circumstances. Although it can take months, the actual amount of time required to drill the relief well depends upon the following: (1) the depth of the formation below the mudline; (2) the complexity of the intervention; (3) the location of a suitable rig; (4) the type of operation that must be terminated in order to release the rig (e.g., may need to complete a casing program before releasing the rig); and (5) any problems mobilizing personnel and equipment to the location.

The major difference between a blowout during the drilling phase versus the completion or workover phases is the tendency for a drilling well to “bridge off.” Bridging is a phenomenon that occurs when severe pressure differentials are imposed at the well/reservoir interface and the formation around the wellbore collapses and seals the well. Deepwater reservoirs are susceptible to collapse under “high draw down” conditions. However, a completed well may not have the same tendency to passively bridge off as would a drilling well involving an uncased hole. Bridging would have a beneficial effect for spill control by slowing or stopping the flow of oil from the well (PCCI Marine and Environmental Engineering, 1999). There is a difference of opinion among blowout specialists regarding the likelihood of deepwater wells bridging naturally in a short period of time. Completed wells, or those in production, have more severe consequences in the event of a blowout due to the hole being fully cased down to the producing formation, which lowers the probability of bridging (PCCI Marine and Environmental Engineering, 1999). Therefore, the potential for a well to bridge is greatly influenced by the phase of a well. Refer to **Chapter 3.2.8** for a discussion of planned well-source containment options that were designed to address an ongoing loss of well control event.

Blowout Preventers

A blowout preventer (BOP) is a device with a complex of choke lines and hydraulic rams mounted atop a wellhead designed to close the wellbore with a sharp horizontal motion that can cut through or pinch shut well casing and sever tool strings. The BOPs were invented in the early 1920's and have been instrumental in ending dangerous, costly, and environmentally damaging oil gushers on land and in water. The BOPs have been required for OCS oil and gas operations from the time offshore drilling began in the late 1940's.

The BOPs are actuated as a last resort upon imminent threat to the integrity of the well or the surface rig. For cased wells, in a normal situation, the hydraulic ram may be closed if oil or gas from an underground zone enters the wellbore and destabilizes it. By closing a BOP, usually by redundant surface-operated and hydraulic actuators, the drilling crew can prevent explosive pressure release and allow control of the well to be regained by balancing the pressure exerted by a column of drilling mud with formation fluids or gases from below.

Because BOPs are important for the safety of the drilling crew, as well as the rig and the wellbore itself, BOPs are regularly inspected, tested, and refurbished. The post-*Deepwater Horizon* explosion, oil spill, and response regulations and inspection program required for BOPs is discussed in **Appendix A.5**.

Finalization of the Well Control Rule on April 29, 2016, resulted in reforms that establish (phased in over time) the following items: (1) incorporation of the latest industry standards that establish minimum baseline requirements for the design, manufacture, repair, and maintenance of blowout preventers; (2) additional controls over the maintenance and repair of BOPs; (3) use of dual shear rams in deepwater BOPs (API Standard 53); (4) requirement that BOP systems include a technology that allows the drill pipe to be centered during shearing operations; (5) more rigorous third-party certification of the shearing capability of BOPs; (6) expanded accumulator capacity and operational capabilities for increased functionality; (7) real-time monitoring capability for deepwater and high-temperature/high- pressure drilling activities; (8) establishment by regulation of criteria for the testing and inspection of subsea well containment equipment; (9) increased reporting of BOP failure data to BSEE and the Original Equipment Manufacturers (OEMs); (10) expectations set for what constitutes a safe drilling margin and allows for alternative safe drilling margins when justified, (11) requirement for the use of accepted engineering principles and establishment of general performance criteria for drilling and completion equipment; (12) establishment of additional requirements for using remotely operated vehicles (ROVs) to function certain components on the BOP stack; (13) requirement for adequate centralization of the casing during cementing; and (14) makes the testing frequency of BOPs used on workover and decommissioning operations the same as drilling operations. Additonal information regarding the Well Control Rule can be found on BSEE's website at https://www.bsee.gov/guidance-and-regulations/regulations/well-control-rule.

In addition, the Technology Assessment Program, a research element within BOEM's regulatory program, supports research associated with operational safety and pollution prevention.

Since the *Deepwater Horizon* explosion, oil spill, and response, several well control-related studies have been funded through this program and the details of this research can be found on BSEE's website at http://www.bsee.gov/Technology-and-Research/Technology-Assessment-Programs/index/.

3.2.3 Accidental Air Emissions

Accidental events associated with offshore oil and gas activities can result in the emission of air pollutants. These OCS oil- and gas-related accidental events could include the release of oil, condensate, or natural gas; chemicals used offshore; pollutants from the burning of these products; fire; or H_2S release. The air pollutants could include NAAQS criteria pollutants, volatile and semi-volatile organic compounds, hydrogen sulfide, and methane. Emissions sources related to accidents from OCS operations can include well blowouts, oil spills, pipeline breaks, tanker accidents, and tanker explosions.

If a fire was associated with an accidental event, it could produce a broad array of pollutants including VOCs, NAAQS primary pollutants, and greenhouse gases. Although temporary in nature, response activities could impact air quality. These response activities could include *in-situ* burning, the use of flares to burn gas and oil, and the use of dispersants applied from aircraft. *In-situ* burning could impact air quality due to the possible release of toxic gases, and dispersants could impact air quality by possibly releasing toxic aromatics into the atmosphere. Atmospheric pollutants emitted from the *Deepwater Horizon* oil spill included plumes of organic aerosol particles and VOCs. In these plumes, the highly volatile species evaporated on time scales of <10 hours, while intermediate volatility evaporated between 10 and 1,000 hours. After the highly volatile species surfaced, they spread to a larger area due to surface currents and contributed to a wide spectrum of vapors (Bahreini et al., 2012). Additionally, in the presence of evaporating hydrocarbons from the oil spill, NO_x emissions from the recovery and cleanup activities produced ozone (Middlebrook et al., 2012).

The presence of H_2S within formation fluids occurs sporadically in the Gulf of Mexico OCS and may be released during an accident. Accidents involving the release of H_2S could result in irritation, injury, and lethality from leaks; exposure to sulfur oxides produced by flaring; equipment and pipeline corrosion; and outgassing and volatilization from spilled oil. Regulations and NTLs include safeguards and protective measures, which are in place to protect workers from H_2S releases.

3.2.3.1 Hydrogen Sulfide and Sulfurous Petroleum

Sulfur may be present in oil as elemental sulfur, within gas as H_2S, or within organic molecules, all three of which vary in concentration independently. Safety and infrastructure concerns include the following: irritation, injury, and even lethality to workers who are exposed to H_2S from leaks; exposure to sulfur oxides produced by flaring; equipment and pipeline corrosion; and outgassing and volatilization from spilled oil.

Sour oil and gas occur sporadically throughout the Gulf of Mexico OCS, primarily off the Louisiana, Mississippi, and Alabama coasts. Sour hydrocarbon tends to originate in carbonate source or reservoir rocks that may not have abundant clay minerals that serve as a binder for elemental sulfur. If not bound in clay minerals, it remains free and can become a part of any hydrocarbon produced or sourced from that rock.

Deep gas reservoirs on the GOM continental shelf are likely to have high corrosive content, including H_2S. There is some evidence that petroleum from deepwater areas may be sulfurous, but exploration wells have not identified deepwater areas that are extraordinarily high in H_2S concentration.

BOEM reviews all exploration and development plans in the Gulf of Mexico OCS for the possible presence of H_2S in the area(s) identified for exploration and development activities. Activities determined to be associated with a presence of H_2S are subjected to further review and requirements. Federal regulations at 30 CFR § 250.490(c) require all lessees, prior to beginning exploration or development operations, to request a classification of the potential for encountering H_2S. The classification is based on previous drilling and production experience in the areas surrounding the proposed operations, as well as other factors.

According to BSEE's regulations at 30 CFR § 250.490(f), all operators on the OCS involved in production of sour gas or oil (i.e., >20 ppm) are also required to file an H_2S Contingency Plan. This plan lays out procedures to ensure the safety of the workers on the production facility. In addition, all operators are required under 30 CFR § 250.107 to adhere to the National Association of Corrosion Engineers' (NACE) *Standard Material Requirements—Methods for Sulfide Stress Cracking and Stress Corrosion Cracking Resistance in Sour Oilfield Environments* (NACE MR0175-2003) (NACE, 2003) as best available and safest technology. The NACE standards that relate to an H_2S partial pressure of 0.05 pounds per square inch absolute primarily address stress cracking and stress corrosion resistance, while BSEE's definition of "H_2S present" addresses human safety and protecting the environment for H_2S concentrations equal to or exceeding 20 ppm. The BSEE is concerned if either threshold is crossed (NTL 2009-G31). These engineering standards preserve the integrity of infrastructure through specifying equipment to be constructed of materials with metallurgical properties that resist or prevent sulfide stress cracking and stress corrosion cracking in the presence of sour gas. The BSEE issued a final rule (30 CFR § 250.490; *Federal Register*, 1997) governing requirements for preventing H_2S releases, detecting and monitoring H_2S and sulfur dioxide, protecting personnel, providing warning systems and signage, and establishing requirements for H_2S flaring and venting. The NTL 2009-G31 establishes Standard Material Requirements, Materials for Sulfide Stress Cracking and Stress Corrosion Cracking Resistance in Sour Oilfield Environments (NACE Standard MR0175-2003) as best available and safest technology, provides further guidance on classifying an area for the presence of H_2S, includes guidance on H_2S detection, updates regulatory citations, and includes a guidance document statement. Hydrogen sulfide contingency plans are discussed in **Appendix A.8**.

3.2.4 Pipeline Failures

Significant sources of damages to OCS pipeline infrastructure can be caused by corrosion (**Chapters 3.1.3.3.1 and 3.1.6.1**), physical pipeline stress due to location, mass sediment movements and mudslides that can exhume or push the pipelines into another location, and accidents due to weather or impacts from anchor drops or boat collisions.

Long unsupported pipelines subjected to strong bottom currents will experience vortex-induced vibrations, which significantly increase pipeline fatigue. Two potential causes for pipeline failure are regional-scale hydrodynamic forces and vortex-induced vibrations. Hydrodynamic forces are of most concern to pipelines with multiple unsupported spans. In conjunction with strong episodic events, these pipelines may experience lateral instability and movement. Although the effects of hydrodynamic forces warrant attention, vortex-induced vibrations are perhaps of greatest concern.

Following the 2004, 2005, and 2008 hurricane seasons, BOEM commissioned studies to examine the failure mechanisms of offshore pipelines (Atkins et al., 2006 and 2007; Energo Engineering, 2010). Numerous pipelines were damaged after the 2004-2008 hurricanes passing through the CPA and WPA. Much of the reported damage was riser or platform-associated damage, which typically occurs when a platform is toppled or otherwise damaged. While many pipelines were damaged, few resulted in a spill >50 bbl. The total pipeline damage reports and number of spills are listed by hurricane below.

Hurricane	Total Pipeline Damage Reports	Number of Spills >50 bbl
Ivan	168	8
Katrina	299	5
Rita	243	5
Gustav and Ike	314	6

The largest spills are typically due to pipeline movements, mudslides, anchor drops, and collisions of one type or another. Most pipeline damage occurs in shallow water (<200 ft; 61 m) because of the potential for increasing impacts of the storm on the seabed in shallow water, the relative density of pipelines, or the age and design standards of the pipeline or the platforms to which the pipelines are connected. The future impact of hurricanes on damage to pipelines is uncertain. As oil production shifts from shallow to deeper water, there may be a consolidation of pipeline utilization.

The uncertain location of pipelines (both active and abandoned in place) is an ongoing safety and environmental hazard. On October 23, 1996, in Tiger Pass, a channel through the Mississippi River Delta into the Gulf of Mexico near Venice, Louisiana, the crew of the Bean Horizon Corporation dredge *Dave Blackburn* dropped a stern spud (a large steel shaft that is dropped into the river bottom to serve as an anchor and a pivot during dredging operations) into the bottom of the channel in preparation for continued dredging operations. The spud struck and ruptured a 12-in

(30-cm) diameter, submerged natural gas steel pipeline. Within seconds of reaching the surface, the natural gas ignited, destroying the dredge and the tug (USDOT, National Transportation Safety Board, 1998). Lack of awareness of the precise location of the pipeline was a major contributing factor to this accident (USDOT, National Transportation Safety Board, 1998). On December 5, 2003, this Agency received an incident report that a cutterhead dredge barge ruptured a 20-in (51-cm) diameter condensate pipeline in Eugene Island Block 39. Lack of awareness of the precise location of the pipeline was the major contributing factor to this accident as well. An OCS-related spill ≥1,000 bbl would likely be from a pipeline accident; the median spill size is estimated to be 2,200 bbl for rig/platform and pipeline activities supporting each alternative (**Tables 3-14 and 3-15**). For Alternative A, B, or C, up to one spill of this size is estimated to occur.

3.2.5 Vessel and Helicopter Collisions

BOEM's data show that, from 2007 to 2014, there were 137 OCS oil- and gas-related vessel collisions (USDOI, BSEE, 2015c). Most collision mishaps are the result of service vessels colliding with platforms or vessel collisions with pipeline risers. Fires resulted from hydrocarbon releases in several of the collision incidents. Diesel fuel is the product most frequently spilled, while oil, natural gas, corrosion inhibitor, hydraulic fluid, and lube oil have also been released as the result of a vessel collision. Approximately 10 percent of vessel collisions with platforms in the OCS caused diesel spills. To date, the largest diesel spill associated with a collision occurred in 1979 when an anchor-handling boat collided with a drilling platform in the Main Pass leasing area, spilling approximately 1,500 bbl. Human error accounts for approximately half of all reported vessel collisions from 2006 to 2010. Safety fairways, traffic separation schemes, and anchorages are the most effective means of preventing vessel collisions with OCS structures. In 2014, an approximated 3,571 bbl of bunker fuel spilled into the Houston Ship Channel after a collision between a barge and a ship.

In general, fixed structures such as platforms and drilling rigs are prohibited in fairways. Temporary underwater obstacles, such as anchors and attendant cables or chains attached to floating or semisubmersible drilling rigs, may be placed in a fairway under certain conditions. A limited number of fixed structures may be placed at designated anchorages. The USCG's requirements for indicating the location of fixed structures on nautical charts and for lights, sound-producing devices, and radar reflectors to mark fixed structures and moored objects also help minimize the risk of collisions. To prevent any further incidents in regard to collisions with submerged or destroyed platforms following Hurricanes Katrina and Rita, in December 2005, the Bureau of Ocean Energy Management, Regulation and Enforcement published a safety alert that provided the location of all facilities that were destroyed during the storms. In addition, USCG's 8th District's Local Notice to Mariners (monthly editions and weekly supplements) informs GOM users about the addition or removal of drilling rigs and platforms, locations of aids to navigation, and defense operations involving temporary moorings. Marked platforms often become aids to navigation for vessels (particularly fishing boats and vessels supporting offshore oil and gas operations) that operate in areas with high densities of fixed structures.

The National Offshore Safety Advisory Committee (NOSAC, 1999) examined collision avoidance measures between a generic deepwater structure and marine vessels in the GOM. The NOSAC offered three sets of recommendations: (1) voluntary initiatives for offshore operators; (2) joint government/industry cooperation or study; and (3) new or continued USCG action. The NOSAC (1999) proposes that oil and gas facilities be used as aids-to-navigation because of their proximity to fairways, fixed nature, well-lighted decks, and inclusion on navigational charts. Mariners intentionally set and maintain course toward these facilities, essentially maintaining a collision course. Unfortunately, most deepwater facilities do not install collision avoidance radar systems to alert offshore facility personnel of a potentially dangerous situation. The NOSAC estimates that 7,300 large vessels (tankers, freight ships, passenger ships, and military vessels) pass within 35 mi (56 km) of a typical deepwater facility each year. This estimate resulted in approximately 20 transits per day for the 13 deepwater production structures existing in 1999. The NOSAC found the total collision frequency to be approximately one collision per 250 facility-years (3.6×10^{-3} per year). The NOSAC estimated that, if the number of deepwater facilities increases to 25, the estimated total collision frequency would increase to one collision in 10 years. A cost-benefit analysis within the report did not support the use of a dedicated standby vessel for the generic facility; however, the analysis did support the use of a radar system on deepwater facilities if the annual costs of the system were less than or equal to $124,500.

The OCS oil- and gas-related vessels could strike marine mammals, sea turtles, and other marine animals during transit. To limit or prevent such strikes, NMFS provides all boat operators with whale-watching guidelines, which is derived from the Marine Mammal Protection Act. These guidelines suggest safe navigational practices based on speed and distance limitations when encountering marine mammals. The frequency of vessel strikes with marine mammals, sea turtles, or other marine animals probably varies as a function of spatial and temporal distribution patterns of the living resources, as the pathways of maritime traffic (coastal traffic is more predictable than offshore traffic), and as a function of vessel speed, the number of vessel trips, and the navigational visibility.

The average number of helicopter accidents per year in the GOM since 1984 has been 7.9 per year, with the last 10 years averaging 4.7 per year and with only two in 2014. The 2014 GOM oil industry helicopter accident rate per 100,000 flight hours was 0.68, with a total of two accidents compared with a 31-year annual average accident rate of 1.74. The fatal accident rate per 100,000 flight hours during 2014 was 0.34 compared with a 31-year average of 0.44 (Heliport Safety Advisory Conference, 2015).

Since 1999, there have been 23 accidents of which only 5 were fatal; this resulted in 13 fatalities and 15 injuries. The leading causes, not all inclusive, of the accidents since 1999 were engine related, loss of control or improper procedures, helideck obstacle strikes, controlled flight into terrain, and other technical failures (Helicopter Safety Advisory Conference, 2015).

3.2.6 Chemical and Drilling-Fluid Spills

Chemicals and synthetic-based drilling fluids are used in offshore oil and gas drilling and production activities, and may be spilled to the environment due to equipment failure, weather (i.e., wind, waves, and lightning), accidental collision, and human error.

Chemicals are stored and used to condition drill muds during production and in well completions, stimulation, and workover procedures. The relative quantity of their use is reflected in the largest volumes spilled. Well completion, workover, and treatment fluids, including calcium chloride brine and zinc bromide, are the largest quantity used and are typically the largest accidental releases. Zinc bromide is of particular concern because it is persistent (nondegradable) and is comparatively toxic. A study of chemical spills from OCS oil- and gas-related activities determined that only two chemicals could potentially impact the marine environment—zinc bromide and ammonium chloride (Boehm et al., 2001). Other common chemicals spilled include methanol and ethylene glycol, which are used in deepwater operations where gas hydrates tend to form due to cold temperatures. These alcohol-based chemicals are nonpersistent (degradable) and exhibit comparatively low toxicity.

The SBF has typically been used since the mid-1990s for the deeper well sections because SBF has superior performance properties. The synthetic oil used in SBF is relatively nontoxic to the marine environment and has the potential to biodegrade. However, SBF is considered more toxic than water-based fluid, and spills of SBF are categorized separately from water-based fluid releases. Accidental riser disconnections result in the release of large quantities of drilling fluid.

Refer to **Table 3-21** for information on spill statistics for chemicals and SBFs for 2007-2012 (USDOI, BSEE, 2015c). The BSEE reports spills in categories of 10-49 bbl (small spills) and >50 bbl (large spills). **Table 3-21** shows the total annual spill volumes in barrels of product lost for SBFs and chemicals in both spill size categories. The number of spill incidents per year are listed with the average spill volume in barrels for a given year.

Table 3-21. Number and Volume of Chemical and Synthetic-Based Fluid Spills for 10-49 Barrels and >50 Barrels in the Gulf of Mexico from 2007 through 2014.

Year	Product Lost (bbl)		Number of Spills		Average Spill Volume (bbl)	
	SBF	Chemical	SBF	Chemical	SBF	Chemical
A. Spills 10-49 bbl						
2007	110	17	6	1	18	17
2008	73	102	2	6	37	17
2009	38	24	1	2	38	12
2010	54	51	3	3	18	17
2011	73	0	2	0	37	0
2012	88	12	4	1	22	12
2013	51	20	2	1	26	20

Year	Product Lost (bbl)		Number of Spills		Average Spill Volume (bbl)	
	SBF	Chemical	SBF	Chemical	SBF	Chemical
A. Spills 10-49 bbl						
2014	0	0	0	0	0	0
Average Value	61	28	3	2	24	12
B. Spills Greater Than 50 bbl						
Year	Product Lost (bbl)		Number of Spills		Average Spill Volume (bbl)	
	SBF	Chemical	SBF	Chemical	SBF	Chemical
2007	1,518	550	2	1	759	550
2008	1,849	3,229	2	16	925	202
2009	602	500	4	3	151	167
2010	131	123	2	1	66	123
2011	252	0	2	0	126	0
2012	158	1,595	3	5	53	319
2013	0	0	0	0	0	0
2014	323	66	3	1	108	66
Average Value	604	758	2	3	273	178

SBF = synthetic-based fluid.

During the period of 2007 to 2014, small SBF spills occurred at an average annual volume of 61 bbl, while large spills occurred at an annual average volume of 601 bbl. During the same period, small chemical spills occurred at an average annual volume of 28 bbl, while large chemical spills occurred at an average annual volume of 758 bbl. Small SBF spills averaged 24 bbl per spill, while large SBF spills averaged 178 bbl per spill. A spike in the volume of large chemical spills in 2008 is attributed to Hurricane Ike, which occurred on September 13, 2008.

3.2.7 Trash and Debris

The discharge of marine debris by the offshore oil and gas industry and supporting activities is subject to a number of laws and treaties. These include the Marine Debris Research, Prevention, and Reduction Act; the Marine Plastic Pollution Research and Control Act; and the MARPOL-Annex V treaty. Regulation and enforcement of these laws is conducted by a number of agencies such as USEPA, NOAA, and USCG. The BSEE policy regarding marine debris prevention is outlined in NTL 2015-BSEE-G03, “Marine Trash and Debris Awareness and Elimination.” This NTL instructs OCS operators to post informational placards that outline the legal consequences and potential ecological harms of discharging marine debris. This NTL also states that OCS workers should complete annual marine debris prevention training; operators are also instructed to develop a certification process for the completion of this training by their workers. These various laws, regulations, and NTL would likely minimize the discharge of marine debris from OCS operations.

Occasionally during construction or operation, equipment may be dropped to the seafloor. If this happens within the planned construction site, the bottom-disturbing impacts are conservatively considered as part of the routine impacts; however, accidental drops may occur during transport.

3.2.8 Spill Response

3.2.8.1 BSEE Spill-Response Requirements and Initiatives

3.2.8.1.1 Spill-Response Requirements

As a result of the Oil Pollution Act of 1990 and the reorganization of the Bureau of Ocean Energy Management, Regulation and Enforcement into BOEM and BSEE, BSEE was tasked with a number of oil-spill response duties and planning requirements. Within BSEE, the Oil Spill Preparedness Division addresses all aspects of offshore oil-spill planning, preparedness, and response. Additional information about the Oil Spill Preparedness Division can be found on BSEE's website at http://www.bsee.gov/About-BSEE/Divisions/OSPD/index/.

The BSEE implements the following regulations according to 30 CFR parts 250 and 254:

- requires immediate notification for spills >1 bbl—all spills require notification to USCG, and BSEE receives notification from USCG of all spills ≥1 bbl;
- conducts investigations to determine the cause of a spill;
- assesses civil and criminal penalties, if needed;
- oversees spill source control and abatement operations by industry;
- sets requirements and reviews and approves OSRPs for offshore facilities (More information on oil-spill response plan regulations and processes can be found in **Appendix A.5**.);
- conducts unannounced drills to ensure compliance with OSRPs;
- requires operators to ensure that their spill-response operating and management teams receive appropriate spill-response training;
- conducts inspections of oil-spill response equipment;
- requires industry to show financial responsibility to respond to possible spills; and
- provides research leadership to improve the capabilities for detecting and responding to an oil spill in the marine environment.

BOEM receives and reviews the worst-case discharge information submitted for EPs, DPPs, and DOCDs on the OCS. BOEM also has regulatory requirements addressing site-specific OSRPs and spill-response information. As required by BOEM at 30 CFR §§ 550.219 and 550.250, operators are required to provide BOEM with an OSRP that is prepared in accordance with 30 CFR part 254 subpart B with their proposed exploration, development, or production plan for the facilities that they will use to conduct their activities; or to alternatively reference their approved regional OSRP by providing the following information:

- a discussion of the approved regional OSRP;
- the location of the primary oil-spill equipment base and staging area;
- the name of the oil-spill equipment removal organization(s) for both equipment and personnel;
- the calculated volume of the worst-case discharge in accordance with 30 CFR § 254.26(a) and a comparison of the worst-case discharge in the approved regional OSRP with the worst-case discharge calculated for the proposed activities; and
- a description of the worst-case discharge response scenario to include the trajectory information, potentially impacted resources, and a detailed discussion of the spill response proposed to the worst-case discharge in accordance with 30 CFR §§ 254(b)-(e).

All OSRPs are reviewed and approved by BSEE, whether submitted with a BOEM-associated plan or directly to BSEE in accordance with 30 CFR part 254. Hence, BOEM relies heavily upon BSEE's expertise to ensure that the OSRP complies with all pertinent laws and regulations, and demonstrates the ability of an operator to respond to a worst-case discharge. BOEM's regulations require that an operator must have an approved OSRP prior to BOEM's approval of an operator-submitted exploration, development, or production plan.

The operator is also required to carry out the training, equipment testing, and periodic drills described in the OSRP. In addition, since 1989, BSEE has conducted government-initiated unannounced exercises. In any given year, BSEE will hold both table-top, unannounced exercises and a limited number of response equipment deployment unannounced exercises. Equipment deployment exercises are held when BSEE elects to conduct an exercise of an operator's procurement, loading, and deployment of certain pieces of oil-spill response equipment that are cited within an operator's OSRP. The BSEE equipment deployment exercises are designed most often to take place in open water in waterways adjacent to where the equipment is stored in order to test the equipment that is proposed to be utilized offshore during the response, but the exercise may be moved to an alternate location if BSEE's exercise parameters require it. In addition, BSEE can also require that the nearshore and onshore equipment be deployed if a BSEE-developed drill scenario requires it. Drills testing the nearshore and onshore equipment would typically take place in an onshore or nearshore environment within the vicinity of a staging or storage area.

Any dispersant application included as part of the drill scenario always simulates the actual application of dispersant during BSEE's drills. No actual dispersants are ever utilized during the drills. Likewise, the oil spill itself is only simulated during any of BSEE's unannounced drills. Typical

BSEE unannounced deployment exercises last only a few hours and rarely take longer than a day. Multi-day scenarios only occur when a more complicated drill scenario is developed by BSEE to test an operator's ability to adequately respond. Several NTLs and guidance documents have been issued by BOEM and BSEE that clarify oil-spill requirements since the occurrence of the *Deepwater Horizon* explosion, oil spill, and response. More information on these NTLs and guidance documents can be found in **Appendix A.5**.

3.2.8.1.2 Spill-Response Initiatives

For more than 25 years, BSEE and its predecessors have maintained a comprehensive long-term research program to improve oil-spill response knowledge and technologies. The major focus of the program is to improve the methods and technologies used for oil-spill detection, containment, treatment, recovery, and cleanup. The BSEE Oil Spill Response Research program is a cooperative effort bringing together funding and expertise from research partners in State and Federal government agencies, industry, academia, and the international community. The funded projects cover numerous spill-response-related issues such as chemical treating agents; *in-situ* burning of oil; research conducted at BSEE's Oil Spill Response Test Facility (Ohmsett) located in Leonardo, New Jersey; behavior of oil; decisionmaking support tools; mechanical containment; and remote sensing.

The BSEE's recently awarded research contracts that highlight the varied types of research projects can be found on BSEE's website at http://www.bsee.gov/Technology-and-Research/Oil-Spill-Response-Research/index/.

3.2.8.2 Offshore Response, Containment, and Cleanup Technology

In the event of a spill, particularly a loss of well control, there is no single method of containment and removal that would be 100 percent effective. Spill cleanup is a complex and evolving technology. There are many situations and environmental conditions that necessitate different approaches. New technologies constantly evolve, but they provide only incremental benefits. Each new tool then becomes part of the spill-response tool kit. Each spill-response technique/tool has its specific uses and benefits (Fingas, 1995). Offshore removal and spill-containment efforts to respond to an ongoing spill offshore would likely require multiple technologies, including source containment, mechanical spill containment and cleanup, *in-situ* burning of the slick, and the use of chemical dispersants. Even with the deployment of all of these spill-response technologies, it is likely that, with the operating limitations of today's spill-response technology, not all of the oil can be contained and removed offshore.

Because no single spill-response method is 100 percent effective, it is likely that larger spills under the right conditions would require the simultaneous use of all available cleanup methods (i.e., source containment, mechanical spill containment and cleanup, dispersant application, and *in-situ* burning). Accordingly, the response to the *Deepwater Horizon* explosion, oil spill, and response employed all of these options simultaneously. The cleanup technique chosen for a spill response would vary depending upon the unique aspects of each situation. The selected mix of countermeasures would depend upon the shoreline and natural resources that may be impacted; the size, location, and type of oil spilled; weather; and other variables. The overall objective of on-water recovery is to minimize the risk of impact by preventing the spread of free-floating oil. The physical and chemical properties of crude oil can greatly affect the effectiveness of containment and recovery equipment, dispersant application, and *in-situ* burning. It is expected that oil found in the majority of the proposed lease sale area could range from medium weight oil to condensate. The variety of standard cleanup protocols that were used for removing *Deepwater Horizon* oil from beaches, shorelines, and offshore water are identified in **Table 3-22**.

Table 3-22. Primary Cleanup Options Used during the *Deepwater Horizon* Response.

	Fresh Oil	Sheens	Mousse	Tarballs	Burn Residue
On-Water Response	Disperse, skim, burn	Light sheens very difficult to recover, heavier sheens picked up with sorbent boom or sorbent pads	Skim	Snare boom	Manual removal
On-Land Response	Sorbent pads, manual recovery, flushing with water, possible use of chemical shoreline cleaning agents	Light sheens very difficult to recover, heavier sheens picked up with sorbent boom or sorbent pads	Sorbent pads, manual recovery	Snare boom, manual removal, beach cleaning machinery	Manual removal

Source: USDOC, NOAA, 2010a.

Most oil-spill response strategies and equipment are based upon the simple principle that oil floats. However, as evident during the *Deepwater Horizon* explosion, oil spill, and response, this is not always true. Sometimes it floats and sometimes it suspends within the water column or sinks to the seafloor (refer to **Chapter 3.2.1.3**). Oil suspended in the water column and moving with the currents is difficult to track and recover using standard visual survey methods (Coastal Response Research Center, 2007).

Source Containment

The NTL 2010-N10 states that offshore operators address containment system expectations to be able to rapidly contain a spill as a result of a loss of well control from a subsea well. This resulted in the development of rapid response containment systems that are available through either the Marine Well Containment Company (MWCC) or Helix Well Ops in the Gulf of Mexico. In addition, industry has a multitude of vendors available within the GOM region that can provide the services and supplies necessary for debris removal capability, dispersant injection capability, and top-hat deployment capability. Many of these vendors are already cited for use by MWCC and Helix Well Ops. The BSEE does not allow an operator to begin drilling operations until adequate subsea containment and collection equipment, as well as subsea dispersant capability, is determined by BSEE to be available to the operator and is sufficient for use in response to a potential incident from the proposed well(s).

Marine Well Containment Company

The Marine Well Containment Company's (MWCC's) Containment System includes two modular capture vessels (MCVs); enhanced subsea umbilical, risers, and flowlines (SURF) equipment; three capping stacks; and additional ancillary equipment. The capping stack is uniquely designed to shut off the flow of fluid from the well or by providing a conduit to safely flow well fluids to the two MCVs. The processing equipment on the MCVs can separate sand and process liquids and gases flowed from a damaged subsea well. The MWCC Containment System is built for use in the deepwater Gulf of Mexico, defined as water depths from 500 to 10,000 ft (1,524-3,048 m), in temperatures up to 350 °F (177 °C), and under pressure up to 15,000 psi. The MWCC's suite of containment equipment enables the company to mobilize and deploy the most appropriate well containment technology based upon the unique well control incident and equipment requirements. The system has the capacity to contain up to 100,000 bbl of liquid per day (4.2 million gallons/day) and handle up to 200 million standard cubic feet of gas per day. It is envisioned that this system could be fully operational within days to weeks after a spill event occurs (Marine Spill Response Corporation, 2015a).

The Marine Well Containment Company's SURF equipment, which is used to flow fluid from the capping stack to the MCVs as well as to provide dispersant and hydrate mitigation injection, is staged in Theodore, Alabama. The MWCC houses, stores, and tests the processing equipment for the two MCVs as well as its capping stacks in Ingleside, Texas. The companies that originated this system have formed a nonprofit organization, the Marine Well Containment Company, to operate and maintain the system (Marine Spill Response Corporation, 2015a). The MWCC would provide fully trained crews to operate the system, ensure the equipment is operational and ready for rapid response, and conduct research on new containment technologies (Marine Spill Response Corporation, 2015a).

In the summer of 2012, a full-scale deployment of MWCC's critical well-control equipment to exercise the oil and gas industry's response to a potential subsea blowout in the deep water of the Gulf of Mexico was conducted by BSEE. The MWCC's 15,000-psi capping stack system, a 30-ft (9-m) tall, 100-ton piece of equipment similar to the one that stopped the flow of oil from the *Macondo* well following the *Deepwater Horizon* explosion in 2010, was successfully tested during this deployment drill. During this exercise, the capping stack was deployed from its storage location in Ingleside, Texas, to an area in the Gulf of Mexico nearly 200 mi (322 km) from shore. Once on site, the system was lowered to a simulated wellhead (a pre-set parking pile) on the ocean floor in nearly 7,000 ft (2,134 m) of water, connected to the wellhead, and then pressurized to 10,000 psi.

Helix Well Ops

Another option for source control and containment in the Gulf of Mexico is through Helix Well Ops. Helix Well Ops contracted the equipment that it found useful in the *Deepwater Horizon* explosion, oil spill, and response and offered it to oil and gas producers for use beginning January 1, 2011. This system focused on the utilization of the *Helix Producer I* and the *Q4000* vessels. Each of these vessels played a role in the *Deepwater Horizon* explosion, oil spill, and response explosion, oil spill, and was continually working in the Gulf of Mexico. Helix Well Ops' system, which is referred to as the Helix Fast Response System today, has the ability to fully operate in up to 10,000 ft (3,048 m) of water and has intervention equipment to cap and contain a well with the mechanical integrity to be shut-in. The Helix Fast Response System also has the ability to capture and process 57,000 bbl of oil per day, 72,000 bbl of liquid per day, and 120 million standard cubic feet per day at 10,000 psi (Helix Well Containment Group, 2015).

In April-May 2013, a full-scale deployment of Helix Well Ops' critical well-control equipment to exercise the oil and gas industry's response to a potential subsea blowout in the deep water of the Gulf of Mexico was conducted by BSEE. Helix Well Ops' capping stack system is a 20-ft (6-m) tall, 146,000-pound piece of equipment similar to the one that stopped the flow of oil from the *Macondo* well following the *Deepwater Horizon* explosion in 2010. It was successfully tested during this unannounced deployment drill. The capping stack was deployed from its storage location and once onsite, the system was lowered to a simulated wellhead (a pre-set parking pile) on the ocean floor in nearly 5,000 ft (1,524 m) of water, connected to the wellhead, and then pressurized to 8,400 psi.

3.2.8.2.1 Mechanical Cleanup

Generally, mechanical containment and recovery is the primary oil-spill response method used (33 CFR § 153.305(a)). Mechanical recovery is the process of using booms and skimmers to remove oil from the water surface. Booms are used to enclose oil and prevent it from spreading; to protect harbors, bays, and biologically sensitive areas; to divert oil to areas where it can be recovered or treated; and to concentrate oil and maintain an even thickness so that skimmers can be used; or other cleanup techniques, such as *in-situ* burning, can be applied. Sorbent booms are specialized containment and recovery devices made of porous sorbent material such as woven or fabric polypropylene, which absorbs oil while it is being contained. Sorbent booms are used when the oil slick is relatively thin for final polishing of an oil spill, to remove small traces of oil or sheen, or as a backup to other booms. Skimmers are mechanical devices designed to remove oil from the water surface. Skimmers are classified according to their basic operating principles: oleophilic surface skimmers; weir skimmers; suction skimmers or vacuum devices; elevating skimmers; and submersion skimmers (Fingas, 2013).

It is expected that the oil-spill response equipment needed to respond to an offshore spill in the proposed sale area could be called out from one or more of the following oil-spill equipment base locations: New Iberia, Belle Chasse, Baton Rouge, Sulphur, Morgan City, Port Fourchon, Harvey, Houma, Galliano, New Iberia, Leeville, Fort Jackson, Venice, Grand Isle, or Lake Charles, Louisiana; Corpus Christi, Port Arthur, Aransas Pass, Ingleside, Galveston, or Houston, Texas; Pascagoula or Kiln, Mississippi; Mobile or Bayou La Batre, Alabama; and/or Panama City, Pensacola, Tampa, and/or Miami, Florida (Clean Gulf Associates, 2015; Marine Spill Response Corporation, 2015b; National Response Corporation, 2015). Response times for any of this equipment would vary, depending on the location of the equipment, the staging area, and the spill site; and on the transport requirements for the type of equipment procured. It is anticipated that equipment would be procured from the closest available oil-spill staging areas.

As indicated in **Chapter 3.2.8.1 and Appendix A.5**, BSEE oversees a research program to improve the capabilities for detecting and responding to an oil spill in the marine environment. One of BSEE's recently completed research projects suggested an alternative to improve the present regulatory requirements at 30 CFR § 254.44 for determining the effective daily recovery capacity of spill-response skimming equipment. This suggested alternative would consider the encounter rate of a skimming system with spilled oil instead of the presently used de-rated pump capacity of a skimmer. This project was undertaken because the *Deepwater Horizon* oil-spill response highlighted that the existing regulation may not be an effective or accurate planning standard and predictor of oil-spill response equipment recovery capacity. The project was completed in 2012 and the National Academy of Sciences completed a peer review in 2013. The USCG has indicated that the guidance generated by this research is applicable for offshore use but that a separate standard would still need to be developed for nearshore response capability determinations.

If an oil spill occurs during a storm, spill response from shore may be delayed to after the storm. Spill response would not be possible while storm conditions continued, given the sea-state limitations for skimming vessels and containment boom deployment. However, oil released onto the ocean surface during a storm event would be subject to accelerated rates of weathering and dissolution (i.e., oil and water would be agitated, forcing oil into smaller droplets and facilitating dissolution of the high end aromatic compounds present).

In rough seas, a large spill of low viscosity oil, such as a light or medium crude oil, can be scattered over many square kilometers within just a few hours. Oil recovery systems typically have swath widths of only a few meters and move at slow speeds while recovering oil. Therefore, even if this equipment can become operational within a few hours, it would not be feasible for them to encounter more than a fraction of a widely spread slick (International Tanker Owners Pollution Federation Limited, 2010). For this reason, it is assumed that a maximum of 10-30 percent of an oil spill in an offshore environment can be mechanically removed from the water prior to the spill making landfall (U.S. Congress, Office of Technology Assessment, 1990). Some newer oil skimming equipment procured internationally displayed faster recovery speed during the response to the *Deepwater Horizon* oil spill, and some changes were also made in the logistics of how skimmers and booms were positioned offshore during this response that increased the equipment's swath width. However, for the *Deepwater Horizon* response, it was estimated that only 3 percent of the total oil spilled was picked up by mechanical equipment offshore (Lubchenco et al., 2010).

A common difficulty when deploying booms and skimmers to recover oil is coordinating vessel activities to work the thickest areas of oil (International Tanker Owners Pollution Federation Limited, 2010). It is a rule of thumb that 90 percent of the oil is in 10 percent of the area. The 10 percent of the oil that makes up 90 percent of a slick is typically sheen. For this reason, containment and recovery operations on water require extensive logistical support to direct the response effort. Additionally, the limitations that poor weather and rough seas impose on spill-response operations offshore are seldom fully appreciated. Handling wet, oily, slippery equipment on vessels that are pitching and rolling is difficult and can raise safety considerations. Winds, wave action, and currents can drastically reduce the ability of a boom to contain and a skimmer to recover oil. It is important to select equipment for a response that is suitable for the type of oil and the prevailing weather and sea conditions for a region. Efforts should generally be made to target the heaviest oil concentrations and areas where collection and removal of the oil would reduce the likelihood of oil reaching sensitive resources and shorelines. As oil weathers and increases in viscosity, cleanup techniques and equipment should be reevaluated and modified (International Tanker Owners Pollution Federation Limited, 2010).

Practical limitations of strength, water drag, and weight mean that generally only relatively short lengths of boom (tens to a few hundred meters) can be deployed and maintained in a working configuration. Towing booms at sea (e.g., in U or J configurations, which increase a skimmer's swath width) is a difficult task requiring specialized vessels and trained personnel (International Tanker Owners Pollution Federation Limited, 2010). Additional boom limitations are discussed in **Chapter 3.2.8.3**. Because skimmers float on the water surface, they experience many of the operational difficulties that apply to booms, particularly those posed by wind, waves, and currents (International Tanker Owners Pollution Federation Limited, 2010). The effectiveness of any skimmer depends upon a number of factors, in addition to the ambient weather and sea conditions, including the type of oil, the thickness of the oil, the presence of debris in the oil or in the water, the extent of weathering and emulsification of the oil, and the location of the spill (Fingas, 2013). Even moderate wave motion can greatly reduce the effectiveness of most skimmer designs (International Tanker Owners Pollution Federation Limited, 2010). In high sea-state conditions, many skimmers, especially weir and suction skimmers, take up more water than oil (Fingas, 2013). Because of the various constraints placed upon skimmers in the field, their design capacities are rarely realized. Experience from numerous spills has consistently shown that skimmer recovery rates reported under test conditions cannot be sustained during a spill response (International Tanker Owners Pollution Federation Limited, 2010). The availability of sufficient oil-storage facilities is necessary to ensure continuous oil-spill recovery. This storage needs to be easy to handle and easy to empty once full so that it can be used repeatedly with the least interruption in recovery activity (International Tanker Owners Pollution Federation Limited, 2010).

There are no proven methods for the containment of submerged oil, and methods for recovery of submerged oils have limited effectiveness. Efforts to mechanically contain and/or recover suspended oil have focused on different types of nets, either the ad hoc use of fishing nets or specially designed trawl nets. There has been some research conducted on the design of trawl nets for the recovery of emulsified fuels. However, the overall effectiveness for large spills is expected to be very low. The suspended oil can occur as liquid droplets or semisolid masses in sizes ranging from millimeters to meters in diameter (Coastal Response Research Center, 2007). At spills where oil has been suspended in the water column, responders have devised low technology methods for tracking the presence and spread of oil over space and time. For suspended oil, these methods include stationary systems such as snare sentinels, which can consist of any combination of the following: a single length of white absorbent pom-poms (snare) on a rope attached to a float and an anchor; one or more crab traps on the bottom that are stuffed with snare; and minnow or other type of traps that are stuffed with snare and deployed at various water depths. The configuration would depend upon the water depth where the oil is located within the water column.

At present, it is not possible to determine the particle size, number of particles, or percent oil cover in the water column based upon the visual observations of oil on these systems (Coastal Response Research Center, 2007).

Spills involving submerged oil trigger the need for real-time data on current profiles (surface to bottom), wave energy, suspended sediment concentrations, detailed bathymetry, seafloor sediment characteristics, and sediment transport patterns and rates. These data are needed to validate or calibrate models (both computer and conceptual), direct sampling efforts, and predict the behavior and fate of the submerged oil. This information might be obtained through the use of acoustic Doppler current profilers, dye tracer studies, rapid seafloor mapping systems, and underwater camera or video systems that can record episodic events (Coastal Response Research Center, 2007). During the *Deepwater Horizon* response, fluorimeters were used successfully to detect the presence of submerged oil.

3.2.8.2.2 Spill Treating Agents

Treating oil with specially prepared chemicals is another option for responding to oil spills. An assortment of chemical spill treating agents is available to assist in cleaning up oil. However, approval must be obtained in accordance with the provisions of the National Oil and Hazardous Substances Pollution Contingency Plan (NCP) before these chemical agents can be used.

The USEPA has recently issued a proposed rule to amend the requirements in Subpart J of the NCP that governs the use of dispersants, other chemical and biological agents, and other spill mitigating substances when responding to oil discharges into waters of the United States. The proposed rule addresses the efficacy, toxicity, environmental monitoring of dispersants, and other chemical and biological agents, as well as public, State, local and Federal officials' concerns regarding their use (*Federal Register*, 2015c). The USEPA also updated the NCP product schedule in 2014. The 2014 NCP Product Schedule lists the following types of products that are authorized for use on oil discharges:

- dispersants;
- surface washing agents;
- surface collecting agents;
- bioremediation agents; and
- miscellaneous oil-spill control agents.

In February 2014, the USEPA also published an NCP Product Schedule Notebook that presents manufacturers' summary information that describes (1) the conditions under which each of the products is recommended for use, (2) handling and worker precautions, (3) storage information, (4) recommended application procedures, (5) physical properties, (6) toxicity information, and (7) effectiveness information (USEPA, 2014b).

Dispersants

When dispersants are applied to spilled crude oil, the surface tension of the oil is reduced, allowing wind and wave action to break the oil into tiny droplets that are dispersed into the upper portion of the water column. Oil that is chemically dispersed at the surface move into the top 20 ft (6 m) of the water column where it mixes with surrounding waters and begins to biodegrade (U.S. Congress, Office of Technology Assessment, 1990). Dispersant use, in combination with natural processes, breaks up oil into smaller components that allows them to dissipate into the water and degrade more rapidly (Nalco, 2010). Dispersant use must be in accordance with a Regional Response Team's (RRT) Preapproved Dispersant Use Manual and with any conditions outlined within a RRT's site-specific, dispersant approval given after a spill event. Consequently, dispersant use must be in accordance with the restrictions for specific water depths, distances from shore, and monitoring requirements. At this time, neither the Region IV nor the Region VI RRT dispersant use manuals, which cover the GOM region, give preapproval for the application of dispersant use subsea. However, the USEPA is presently revisiting these RRT preapprovals in light of the dispersant issues, such as subsea application, that arose during the *Deepwater Horizon* response. The USEPA issued a letter dated December 2, 2010, that provided interim guidance on the use of dispersants for major spills that are continuous and uncontrollable for periods greater than 7 days and for expedited approval of subsurface applications. This letter outlined the following exceptions to the current preapprovals until they are updated:

- dispersants may not be applied to major spills that are continuous in nature and uncontrollable for a period greater than 7 days;
- additional dispersant monitoring protocols and sampling plans may be developed that meet the unique needs of the incident; and
- subsurface dispersants may be approved on an incident-specific basis as requested by USCG's On-Scene Coordinator.

In addition, this letter indicated that more robust documentation may be required. This documentation would include daily reports that contain the products used, specific time and locations of application, equipment used for each application, spotter aircraft reports, photographs, vessel data, and analytical data.

Additionally, in light of the dispersant issues that arose during the *Deepwater Horizon* response, the State of Florida's Department of Environmental Protection submitted a letter dated May 5, 2011, to the USEPA Region IV RRT in which the State of Florida withdrew all State waters (9 nmi [10.36 mi; 16.67 km] off the coast of Florida in the Gulf of Mexico) from the Green Zone (or approved area) for dispersant preapproval as outlined within the *Use of Dispersants in Region IV* document (USEPA, Region IV Regional Response Team, 1996). The State indicated in the letter that this change was requested due to the enormous changes that have occurred in communication and response technologies since the preapproval was first agreed to in 1996. The State indicated that they felt that the *Use of Dispersants in Region IV* document needed to be updated to reflect technological advances and lessons learned during the response to the *Deepwater Horizon* oil spill (State of Florida, Dept. of Environmental Protection, 2011).

For a deepwater (>1,000-ft [305-m] water depth) spill ≥1,000 bbl, dispersant application may be a preferred response in the open-water environment to prevent oil from reaching a coastal area, in addition to mechanical response. However, the window of opportunity for successful dispersant application may be somewhat narrower for some deepwater locations that are dependent upon the physical and chemical properties of oil, which tend to be somewhat heavier than those found closer to shore. A significant reduction in the window of opportunity for dispersant application may render this response option ineffective.

Due to the unprecedented volume of dispersants applied for an extended period of time in situations not previously envisioned or incorporated in existing dispersant use plans (i.e., during the *Deepwater Horizon* oil-spill response), the National Response Team has developed guidance for monitoring atypical dispersant operations. The guidance document, which was approved on May 30, 2013, is titled *Environmental Monitoring for Atypical Dispersant Operations: Including Guidance for Subsea Application and Prolonged Surface Application*. The subsea guidance generally applies to the subsurface ocean environment and focuses on operations in water depths below 300 m (984 ft) and below the pycnocline or in the interface between an upper mixed density gradients and a lower stable density gradient. The surface application guidance supplements and complements the existing protocols as outlined within the existing Special Monitoring of Applied Response Technologies monitoring program where the duration of the application of dispersants on discharged oil extends beyond 96 hours from the time of the first application (U.S. National Response Team, 2013). This guidance is provided to the Regional Response Teams by the National Response Team to enhance existing Special Monitoring of Applied Response Technologies protocols and to ensure that their planning and response activities are consistent with national policy.

The most popular application method for dispersants in the offshore GOM is from small and large fixed-wing aircraft. Based on the present location of dispersant stockpiles and dispersant application equipment available to the Oil Spill Removal Organizations used by offshore operators in the GOM, it is expected that the dispersant application aircraft called out for an oil-spill response to an offshore spill in the proposed lease sale area would come from Houma, Louisiana; Kiln, Mississippi; Mesa, Arizona; Concord, California; and/or Salisbury, Maryland. Stockpiles of dispersants are located at each of the designated staging airports. Response times for this equipment would vary, depending on the spill site and on the transport time for additional supplies of dispersants to arrive at a staging location. Based on historic information, this Multisale EIS assumes that dispersant application applied to the water surface would be effective on 20-50 percent (S.L. Ross Environmental Research Ltd., 2000) of the treated oil.

If an oil spill occurs during a storm, the dispersant application would occur following the storm. Aerial and vessel dispersant application would not be possible while storm conditions continued. However, oil released onto the ocean surface during a storm event would be subject to accelerated rates of weathering and dissolution (i.e., oil and water would be agitated, forcing oil into smaller droplets and facilitating dissolution of the high-end aromatic compounds present).

Other Spill Treating Agents

Surface washing agents, emulsion breakers and inhibitors, recovery enhancers, solidifiers, and sinking agents are other types of chemical treatment agents that are available, if approval is obtained, for treating oil spills. The use of these chemical products is subject to approval in the same manner as dispersants. The use of bioremediation agents also requires approval in the same manner as dispersants. The U.S. Environmental Protection Agency's NCP Product Schedule Notebook presents manufacturers' summary information that describes (1) the conditions under which each of the products is recommended for use, (2) handling and worker precautions, (3) storage information, (4) recommended application procedures, (5) physical properties, (6) toxicity information, and (7) effectiveness information (USEPA, 2014b).

3.2.8.2.3 In-situ Burning

In-situ burning is an oil-spill cleanup technique that involves the controlled burning of the oil at or near a spill site. The use of this spill-response technique can provide the potential for the removal of large amounts of oil over an extensive area in less time than other techniques. In ideal circumstances, *in-situ* burning requires less equipment and much less labor than other cleanup techniques (Fingas, 2013). *In-situ* burning involves the same oil collection process used in mechanical recovery, except instead of going into a skimmer, the oil is funneled into a fire boom, which is a specialized boom that has been constructed to withstand the high temperatures from burning oil. While *in-situ* burning is another method for disposing of oil that has been collected in a boom, this method is typically more effective than skimmers when the oil is highly concentrated. There were 411 *in-situ* burn operations conducted during the course of the *Deepwater Horizon* oil-spill response, successfully eliminating between 220,000 and 300,000 bbl of oil from the water surface (Allen, 2010), approximately 5 percent of the *Macondo* oil spilled (Lubchenco et al., 2010).

Because of the successful use of this technology during the *Deepwater Horizon* oil-spill response, the Gulf of Mexico's Oil Spill Removal Organizations have procured fire boom, which they have strategically stockpiled throughout the GOM region. Response times for bringing a fire-resistant boom onsite would vary, depending on the location of the equipment, the staging area, and the spill site. If an oil spill occurs during a storm, *in-situ* burning would occur following the storm. *In-situ* burning would not be possible while storm conditions continued.

3.2.8.2.4 Natural Dispersion

Depending upon environmental conditions and spill size, the best response to a spill may be to allow the natural dispersion of a slick to occur. Natural dispersion may be a preferred option for smaller spills of lighter nonpersistent oils and condensates that form slicks that are too thin to be removed by conventional methods and that are expected to dissipate rapidly, particularly if there are no identified potential impacts to offshore resources and a potential for shoreline impact is not indicated. In addition, natural dispersion may also be a preferred option in some nearshore environments, such as a marsh habitat, when the potential damage caused by a cleanup effort could cause more damage than the spill itself. For more information on the transport and fate of oil spills, refer to **Chapter 3.2.1.3**.

3.2.8.3 Onshore Response and Cleanup

Offshore response and cleanup is preferable to shoreline cleanup; however, if an oil slick reaches the coastline, it is expected that the specific shoreline cleanup countermeasures identified and prioritized in the appropriate Area Contingency Plans (ACPs) for various habitat types would be used. The sensitivity of the contaminated shoreline is the most important factor in the development of cleanup recommendations. Shorelines of low productivity and biomass can withstand more intrusive cleanup methods such as pressure washing. Shorelines of high productivity and biomass are very sensitive to intrusive cleanup methods and, in many cases, the cleanup is more damaging than allowing natural recovery.

Oil-spill response planning in the U.S. is accomplished through a mandated set of interrelated plans. The ACPs cover subregional geographic areas and represent the third tier of the National Response Planning System mandated by the Oil Pollution Act of 1990. The ACPs are a focal point of response planning, providing detailed information on response procedures, priorities, and appropriate countermeasures. The USCG has worked diligently to improve coastal oil-spill response since the *Deepwater Horizon* oil spill by improving the ACPs for each coastal USCG sector. The GOM coastal area that falls within USCG's 8th District is covered by ACPs for areas covered by USCG Sector Corpus Christi, Sector Houston/Galveston, Sector Port Arthur, Sector Morgan City, Sector New Orleans, and Sector Mobile. The ACPs from USCG's 7th District cover the remaining GOM coastal area. The Gulf of Mexico OCS Region's ACPs also include separate Geographic Response Plans (GRP), which are developed jointly with local, State, and other Federal entities to better focus spill-response tactics and priorities. These GRPs contain the resources initially identified for protection during a spill, response priorities, procedures, and appropriate spill-response countermeasures. The ACPs are written and maintained by Area Committees assembled from Federal, State, and local government agencies that have pollution-response authority; nongovernmental participants may attend meetings and provide input. The coastal Area Committees are chaired by respective Federal On-Scene Coordinators from the appropriate USCG Office and are comprised of members from local or area-specific jurisdictions. Response procedures identified within an ACP or its GRP(s) reflect the priorities and procedures agreed to by members of the Area Committees.

If an oil slick reaches the coastline, the responsible party should be prepared to deploy any of the shoreline cleanup countermeasures that were specified for the protection of the prioritized sensitive areas that are identified within the appropriate GRPs that cover these areas. The single, most-frequently recommended, spill-response strategy for the areas identified for protection in all of the applicable ACPs or its GRPs is the use of a shoreline boom to deflect oil away from coastal resources such as seagrass beds, marinas, resting areas for migratory birds, bird and turtle nesting areas, etc. Since oil spilled at sea tends to move and spread rapidly into very thin layers, boom is deployed to corral the oil on the water to enhance recovery effectiveness of skimmers and other response technologies. Boom is also used to protect shoreline areas and to minimize the consequences of an oil spill reaching shore. There are tradeoffs in deciding where and when to place boom because, once deployed, boom is time consuming to tend and to relocate. For example, booming operations are sensitive to wind, wave, and currents and need to be tethered and secured to keep the boom from moving. Rough seas can tear, capsize, or shred boom. Currents over 1.5 knots (1.7 miles per hour) or even a wake from a boat can send oil over or under a boom. Untended boom can become a barricade to wildlife and ship traffic. Boom anchors can damage some habitats (Gulf Coast Incident Management Team, 2011). During the *Deepwater Horizon* response, it was discovered that hard boom often did more damage in the marsh it was intended to protect than anticipated after weather conditions ended up stranding the boom back into the marsh.

If a shoreline is oiled, the selection of the type of shoreline remediation to be used would depend on the following: (1) the type and amount of oil on the shore; (2) the nature of the affected coastline; (3) the depth of oil penetration into the sediments; (4) the accessibility and the ability of vehicles to travel along the shoreline; (5) the possible ecological damage of the treatment to the shoreline environment; (6) weather conditions; (7) the current state of the oil; and (8) jurisdictional considerations. To determine which cleanup method is most appropriate during a spill response, decision-makers must assess the severity and nature of the injury using Shoreline Cleanup and Assessment Team (SCAT) survey observations. These onsite decisionmakers must also estimate the time it would take for an area to recover in the absence of cleanup (typically considering short term to be 1-3 years, medium term to be 3-5 years, and long term greater than 5 years) (U.S. National Response Team, 2010). The variety of standard cleanup protocols that were used for removing *Macondo* oil from beaches, shorelines, and offshore water are identified in **Table 3-22**.

During the *Deepwater Horizon* shoreline response, oiling conditions generally included surface and buried oil layers, surface and buried oil/sand balls, stained sand, and sunken oil in the adjacent subtidal waters. Since waste minimization was a core principle considered when cleaning sand beaches, efforts were made to remove as little sediment as practical from the shore zone during cleaning operations. Treatment methods for sand beaches comprised manual and mechanical removal, an on-site treatment plant, and sediment relocation. Mechanical removal involved a range of commercial self-propelled or towed machines designed primarily to sieve debris and litter on recreational beaches. Field trials were conducted to evaluate which specific mechanisms were more appropriate for the different oiling conditions. The beach cleaners were used as scrapers on the more heavily oiled beaches in Louisiana, whereas the sieving function was more appropriate to recover oil particles on the beaches of Mississippi, Alabama, and Florida. Oiled wetlands included *Spartina* salt marshes and *Phragmites* (“roseau cane”) brackish-freshwater wetlands in the Mississippi Delta. Because previous spills in this region provided an understanding of the recovery potential for the oiled wetlands, natural recovery was the preferred strategy in most cases based on the generally light oiling conditions. Natural attenuation was relatively rapid if an area was only lightly oiled, as the *Macondo* well oil type had an API gravity of 35˚. A guiding principle for wetland treatment was to minimize physical intrusion and work from floating platforms, skiffs, or shallow-draft barges, whenever possible. Floating mechanical flushing machines, using concrete pump arms, were used on a limited scale to reach into oiled fringe wetlands to wash and recover mobile oil. Oiled rip rap, breakwaters, and groins and jetties were treated through manual removal of bulk oil and were washed using a range of temperatures and pressures depending on the character of the oil (Owens et al., 2011).

Shoreline Cleanup Countermeasures

When spilled oil contaminates shoreline habitats, responders should survey the affected areas to determine appropriate response. Although general approvals or decision tools for using shoreline cleanup methods can be developed during pre-spill planning stages, responders' specific treatment recommendations should integrate gathered, filed, and documented data on shoreline habitats, oil type, the degree of shoreline contamination, spill-specific physical processes, and ecological and cultural resource issues. Cleanup endpoints should be established early so that appropriate cleanup methods can be selected to meet the cleanup objectives. Shoreline surveys, as part of the SCAT program, should be conducted systematically because they are imperative to the cleanup decisions. Also, repeated surveys are needed to monitor the effectiveness of the ongoing treatment methods so that the need for changes in methodology, additional treatment, or constraints can be evaluated (USDOC, NOAA, 2013a).

The following assumptions and guidance regarding the cleanup of spills that contact coastal resources are identified in NOAA's *Characteristic Coastal Habitats: Choosing Spill Response Alternatives* job aid, which provides general guidance adopted in the Gulf of Mexico OCS Region's ACPs (USDOC, NOAA, 2010b). The ACPs applicable to the GOM coastal region encompass a vast geographical area. The differences in the response priorities and procedures among the various ACPs or the GRPs reflect the differences in the identified resources needing spill protection.

Sand Beaches

Predicted Oil Behavior

Light oil accumulations would be deposited as oily swashes or bands along the upper intertidal zone of sand beaches. Heavy oil accumulations would cover the entire beach surface. Oil would be lifted off of the lower beach with the rising tide. The maximum penetration of oil into fine-to-medium-grained sand is about 10-15 cm (4-6 in) and up to 25 cm (10 in) in coarse-grained sand. Burial of oiled layers by clean sand can be rapid (within 1 day), and burial to depths as much as 1 m (3 ft) is possible if the oil comes ashore at the beginning of a depositional period. Organisms living in the beach sediment may be killed by smothering or lethal oil concentrations in the interstitial water. Biological impacts include temporary declines in infauna, which can affect important shorebird foraging areas.

Response Considerations

Sand beaches are one of the easiest shoreline types to clean. Cleanup would concentrate on removing oil and oily debris from the upper swash zone once most of the oil has come ashore.

Manual cleanup, rather than road graders and front end loaders, is advised to minimize the volume of sand removed from the shore and requiring disposal. All efforts should focus on preventing vehicular and foot traffic from mixing oil deeper into the sediments. Mechanical reworking of lightly oiled sediments from the high-tide line to the middle intertidal zone can be effective along exposed beaches.

Salt to Brackish Marshes

Predicted Oil Behavior

Oil adheres readily to intertidal vegetation in salt and brackish marshes. The band of coating would vary widely depending upon the water level at the time of oiling. Large slicks would persist through multiple tidal cycles and will coat the entire stem from the high-tide line to the base. Heavy oil coating would be restricted to the outer fringe of thick vegetation, although lighter oils can penetrate deeper, to the limit of tidal influence. Medium to heavy oils do not readily adhere to or penetrate the fine sediments but can pool on the surface or in animal burrows and root cavities. Light oils can penetrate the top few centimeters of sediment and, under some circumstances, oil can penetrate burrows and cracks up to 1 m (3 ft).

Response Considerations

Under light oiling, the best practice is to let the area recover naturally. Natural removal processes and rates should be evaluated before conducting cleanup. Heavily pooled oil can be removed by vacuum, sorbents, or low-pressure flushing. During flushing, care should be taken to prevent transporting oil to sensitive areas down slope or along shore. Cleanup activities should be carefully supervised to avoid damaging vegetation. Any cleanup activity should not mix the oil deeper into the sediments, trampling of the plants and disturbance of soft sediments should be minimized. Lastly, aggressive cleanup methods should only be considered when other resources (e.g., migratory birds and endangered species) are at greater risk from oiled vegetation left in place. Under heavy oiling that requires more aggressive cleanup, replanting can reduce further shoreline erosion and accelerate vegetation recovery (Zengel et al., 2015)

Sand and Gravel Beaches

Predicted Oil Behavior

During small spills, oil could be deposited along and above the high-tide swash on sand and gravel beaches. Large spills would likely spread across the entire intertidal area. Oil penetration into the beach sediments may be up to 50 cm (20 in); however, the sand fraction can be quite mobile and oil behavior is much like on a sand beach if the sand fraction exceeded about 40 percent. The burial of oil may be deep at and above the high-tide line where oil tends to persist, particularly where beaches are only intermittently exposed to waves. In sheltered pockets on the beach, pavements of asphalted sediments can form if oil accumulations are not removed because most of the oil remains on the surface.

Response Considerations

First, heavy accumulations of pooled oil from the upper beach face should be removed. All oiled debris should be removed, but sediment removal should be limited as much as possible. Low-pressure flushing can be used to float oil away from the sediments for recovery by skimmers or sorbents. High-pressure spraying should be avoided because of the potential for transporting contaminated finer sediments (sand) to the lower intertidal or subtidal zones; mechanical reworking of oiled sediments from the high-tide zone to the middle intertidal zone can be effective in areas regularly exposed to wave activity; however, oiled sediments should not be relocated below the mid-tide zone. Lastly, in-place tilling may be used to reach deeply buried oil layers in the mid-tide zone on exposed beaches.

Exposed or Sheltered Tidal Flats

Predicted Oil Behavior

Oil does not usually adhere to the surface of sheltered or exposed tidal flats but instead moves across the flat and accumulates at the high-tide line. Deposition of oil on the sheltered or exposed flat may occur on a falling tide if concentrations are heavy. Oil would not penetrate water-saturated sediments but could penetrate burrows and desecration cracks or other crevices in muddy sediments in sheltered flats or coarse-grained sand in exposed flats. In areas of high suspended-sediment concentrations, the oil and sediments could mix, resulting in the deposition of contaminated sediments on the flats. Biological impacts could be severe.

Response Considerations

Sheltered tidal flats are high-priority areas for protection since cleanup options are limited. Cleanup of the sheltered tidal flat surface would be very difficult because of the soft substrate, and many methods may be restricted. Low-pressure flushing, vacuuming, and deployment of sorbents from shallow-water draft boats may be used on sheltered tidal flats. Currents and waves on exposed tidal flats can be effective in the natural removal of oil. Cleanup can only be done during low tide on exposed flats, thereby providing a narrow window of opportunity for response. The use of heavy machinery should be restricted on exposed tidal flats to prevent oil mixing into the sediments. Manual methods are preferred on exposed tidal flats.

Exposed, Solid Manmade Structures Such as Seawall/Piers

Predicted Oil Behavior

Oil is held offshore by waves reflecting off of the steep hard surfaces of exposed, solid manmade structures such as seawall/piers. Oil would readily adhere to the dry rough surfaces but it would not adhere to wet substrates. The most resistant oil would remain as a patchy band at or above the high-tide line.

Response Considerations

Cleanup is usually not required, and high-pressure water spraying may be conducted to remove risks of contamination of people or vessels or to improve aesthetics.

Mangroves

Predicted Oil Behavior

Oil can wash through mangroves if oil comes ashore at high tide. If a berm or shoreline is present, oil tends to concentrate and penetrate into the berm sediments or accumulated wrack/litter. Heavy and emulsified oil can be trapped in thickets of red mangrove prop roots or dense young trees. Oil readily adheres to prop roots and tree trunks. Re-oiling from resuspended or released oil residues may cause additional injury over time. Oiled trees start to show evidence of effects (leaf yellowing) weeks after oiling, and tree mortality may take months, especially for heavy oils.

Response Considerations

Oiled wrack can be removed once the threat of oiling has passed as wrack can actually protect the trees from direct oil contact. Sorbent boom can be placed in front of oiled forests to recover oil released naturally and, in most cases, no other cleanup activities are recommended. Where thick oil accumulations are not being naturally removed, low-pressure flushing or vacuum may be attempted at the outer fringe. No attempt should be made to clean interior mangroves except where access to the oil is possible from terrestrial areas, and it is extremely important that cleanup activities be conducted by boat so that disturbance of the substrate by foot traffic be prevented.

Seagrasses

Predicted Oil Behavior

Oil would usually pass over subtidal seagrass beds, with no direct contamination. Floating oil stranded on adjacent beaches can pick up sediment and then get eroded and deposited in adjacent seagrass beds.

Response Considerations

Care should be taken when deploying and anchoring booms to prevent physical damage to seagrass beds and to prevent sediment suspension and mixing with the oil and disturbance of roots and vegetation by foot traffic and boat activity. Seagrasses should not be cut unless species like sea turtles, manatees, or waterfowl are at substantial risk of contacting or ingesting oil. Also, dispersant use directly over subtidal seagrass beds may impact the highly sensitive communities. However, the use of booms or dispersants in offshore areas can reduce impacts to highly sensitive intertidal environments, as well as prevent shoreline stranding in mangroves that can be a chronic source of re-oiling of adjacent seagrass beds. Lastly, *in-situ* burning should only be considered outside the immediate vicinity of seagrass beds to protect sensitive intertidal environments because burn residues can sink and the potential effects of the residue would depend on the composition and amount of the oil to be burned and the location where it would sink.

Bays and Estuaries

Predicted Oil Behavior

Oil can impact bottom habitats (benthic organisms) when water is shallow. Stranded oil on nearby shorelines can become a prolonged source for oil re-released to the water column, and tides and freshwater can substantially influence spilled oil movement.

Response Considerations

Reducing impacts to organisms that live on or in the sea surface is often a high priority, reducing the extent of impacts to sensitive nearshore subtidal or intertidal habitats should be considered. Spill response is not conducted from a shoreline but from water-based vessels or aircraft. The use of certain response options is seasonally limited to protect species with sensitive life histories. Lastly, adverse effects to birds would be greatest during migration and overwintering when birds form large flocks.

3.3 CUMULATIVE IMPACTS

3.3.1 Cumulative OCS Oil and Gas Program Scenario

The Cumulative OCS Oil and Gas Program scenario includes all activities (i.e., routine activities projected to occur and accidental events that could occur) from past, proposed, and future lease sales. This includes projected activity from (1) past lease sales, including lease sales still scheduled for the 2012-2017 Five-Year Program but for which exploration or development has either not yet begun or is continuing; (2) lease sales that would be held in this Five-Year Program; and (3) future lease sales that would be held as a result of future Five-Year Programs (four additional programs are included in this cumulative analysis). Activities that take place beyond the analysis timeframe as a result of future lease sales are not included in this analysis. **Tables 3-23 and 3-25** present projections of the major activities and impact-producing factors related to future Cumulative OCS Oil and Gas Program activities. **Table 3-25** can be found in **Chapter 3.3.1.7** below.

Table 3-23. Future Activity Projections Associated with the Cumulative OCS Oil and Gas Program (2017-2086), Including All Future Activities that are Projected to Occur from Past, Proposed, and Future Lease Sales.

Activity	Planning Area		Offshore Subareas (m)[1] 0-60	60-200	200-800	800-1,600	1,600-2,400	>2,400	Totals[2]
Exploration and Delineation Wells	GOM		939-2,562	253-1,166	110-170	153-240	97-278	119-301	1,671-4,717
	CPA/EPA		775-1,999	202-1,007	83-142	88-184	70-142	99-211	1,317-3,685
	WPA		164-563	51-159	27-28	65-56	27-136	20-90	354-1,032
Development and Production Wells[3]	GOM	Total	4,050-9,225	1,570-4,324	912-2,034	617-1,127	446-723	633-985	8,238-18,418
		Oil	438-987	164-453	446-993	280-487	230-372	310-482	1,868-3,774
		Gas	2,440-5,566	894-2,457	186-415	149-288	79-126	126-194	3,874-9,046
	CPA/EPA	Total	3,170-6,634	1,139-3,558	676-1,557	490-779	405-623	595-899	6,475-14,050
		Oil	354-740	122-379	326-750	240-385	207-319	289-437	1,538-3,010
		Gas	1,898-3,972	645-2,015	142-327	95-152	72-110	119-179	2,971-6,755
	WPA	Total	880-2,591	431-766	236-477	137-348	41-100	38-86	1,763-4,368
		Oil	84-247	42-74	120-243	40-102	23-53	21-45	330-764
		Gas	542-1,594	249-442	44-88	54-136	7-16	7-15	903-2,291
Installed Production Structures	GOM		2,168-5,121	558-1,638	36-71	26-38	16-38	23-42	2,827-6,948
	CPA/EPA		1,760-3,682	432-1,347	23-54	17-26	14-21	20-30	2,266-5,160
	WPA		408-1,439	126-291	13-17	9-12	2-17	3-12	561-1,788
Production Structures Removed Using Explosives	GOM		2,435-4,388	568-1,310	0	0	0	0	3,003-5,698
	CPA/EPA		2,051-3,315	440-1,065	0-0	0-0	0-0	0-0	2,491-4,380
	WPA		384-1,073	128-245	0-0	0-0	0-0	0-0	512-1,318
Total Production Structures Removed	GOM		3,381-6,148	784-1,796	39-69	36-44	20-33	21-31	4,281-8,121
	CPA/EPA		2,847-4,639	608-1,459	26-54	25-31	17-22	18-24	3,541-6,229
	WPA		534-1,509	176-337	13-15	11-13	3-11	3-7	740-1,892
Length of Installed Pipelines (km)[4]	GOM		2,181-15,822	1,432-10,511	1,078-8,037	1,268-8,265	700-7,001	704-7,359	7,363-56,995
	CPA/EPA		586-11,799	388-8,355	328-6,390	385-6,381	364-6,168	405-6,750	2,456-45,843
	WPA		1,595-4,023	1,044-2,156	750-1,647	883-1,884	336-833	299-609	4,907-11,152
Service-Vessel Trips (1,000's round trips)	GOM		2,443-6,998	645-2,300	284-942	213-556	134-498	187-577	3,909-11,873
	CPA/EPA		1,978-5,037	496-1,892	186-722	140-389	115-306	163-440	3,079-8,788
	WPA		465-1,960	150-408	98-221	72-167	19-192	23-137	830-3,085
Helicopter Operations (1,000's round trips)	GOM		11,714-55,063	4,511-25,155	270-1,162	183-651	139-422	183-546	17,000-83,000
	CPA/EPA		9,614-40,734	3,544-21,159	191-898	148-440	121-352	165-475	13,786-64,059
	WPA		2,098-14,329	966-3,996	78-264	34-211	17-70	17-70	3,214-18,941

[1]Refer to **Table 3-2**.
[2]Subareas totals may not add up to the planning area total because of rounding.
[3]Development and Production Wells includes some exploration wells that were re-entered and completed. These wells were removed from the Exploration and Delineation well count.
[4]Projected length of pipelines does not include length in State waters.

It is reasonably foreseeable to assume that lease sales would continue to be proposed for many years to come in the Gulf of Mexico region, based on resource availability, existing infrastructure, and projected time lapses required for any other major energy sources to come online. However, the level of activities (exploration wells, production wells, and pipelines) becomes more speculative as time is projected into the future. The causes for this are uncertainty in oil prices, resource potential, cost of development, and drill rig availability, versus the amount of acreage leased from a lease sale.

Therefore, these scenarios do not predict future OCS oil- and gas-related activities with absolute certainty, even though they were formulated using historical information and current trends in the oil and gas industry. Indeed, these scenarios are only approximate since future factors such as the contemporary economic marketplace, the availability of support facilities, and pipeline capacities are all unknowns. Notwithstanding these unpredictable factors, the scenarios used in this Multisale EIS represent the best assumptions and estimates of a set of future conditions that are considered reasonably foreseeable and suitable for presale impact analyses. The development scenarios do not represent a BOEM recommendation, preference, or endorsement of any level of leasing or offshore operations, or of the types, numbers, and/or locations of any onshore operations or facilities. Methodologies for the Cumulative OCS Oil and Gas Program scenario are similar to those for a regionwide or individual planning area typical lease sale scenario analysis and are described in detail in **Chapter 3** above.

3.3.1.1 Cumulative OCS Oil and Gas Program Projected Production

As of 2014, 19.02 BBO of oil and 185.2Tcf of gas had been produced in the GOM (USDOI, BOEM, 2013; USDOI, BSEE, 2015d). While offshore oil production has remained fairly constant over the last 10 years, gas production rates offshore have declined due to availability from onshore production (**Figure 3-18**). Projected future reserve/resource production estimates for the Cumulative OCS Oil and Gas Program scenario regionwide are 15.482-25.806 BBO and 57.875-108.513 Tcf of gas. These estimates represent all anticipated production from lands currently under lease plus all anticipated production from future lease sales over the 70-year analysis period (**Table 3-1**). **Table 3-23** presents all anticipated activity associated with production from lands currently under lease in regionwide plus all anticipated activity associated with production from future total OCS Program (WPA, CPA, and EPA) lease sales over the 70-year analysis period.

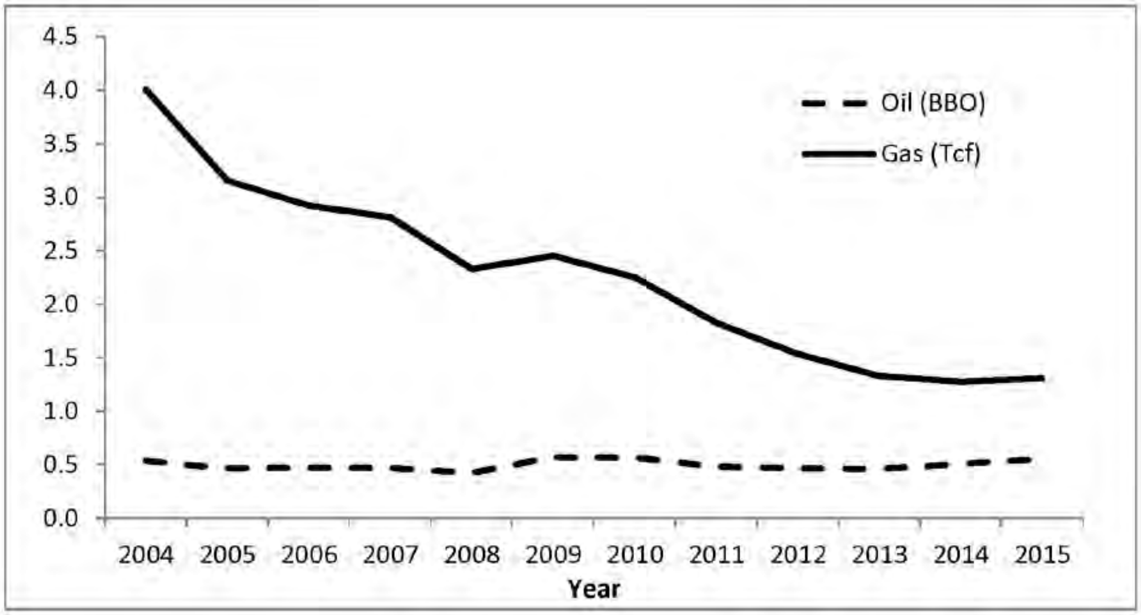

Figure 3-18. OCS Oil and Gas Production Between 2004 and 2015 (USDOI, BSEE, 2016b).

Projected future reserve/resource production estimates for the Cumulative OCS Oil and Gas Program scenario in the CPA and EPA are 13.707-22.152 BBO and 46.328-84.009 Tcf of gas. These estimates represent all anticipated production from lands currently under lease in the CPA and EPA plus all anticipated production from future leased lands in the CPA and EPA over the 70-year analysis period (**Table 3-1**). Projected production estimates in the CPA and EPA represents approximately 88.5-85.8 percent of the oil and 80-77.4 percent of the gas of the cumulative OCS Oil and Gas Program regionwide. **Table 3-23** presents all anticipated activity associated with production from lands currently under lease in the CPA and EPA plus all anticipated activity associated with production from future leased lands in the CPA and EPA over the 70-year analysis period.

Projected future reserve/resource production estimates for the Cumulative OCS Oil and Gas Program scenario in the WPA are 1.775-6.654 BBO and 11.547-24.504 Tcf of gas. These estimates represent all anticipated production from lands currently under lease in the WPA plus all anticipated production from future leased lands in the WPA over the 70-year analysis period (**Table 3-1**). Projected production estimates in the WPA represent approximately 11.5-14.2 percent of the oil and 20-22.5 percent of the gas of the cumulative OCS Oil and Gas Program regionwide. **Table 3-23** presents all anticipated activity associated with production from lands currently under lease in the WPA plus all anticipated activity associated with production from future leased lands in the WPA over the 70-year analysis period.

3.3.1.2 Cumulative Geological and Geophysical Surveys

Chapter 3.1.2.1 discusses OCS oil- and gas- related G&G survey activities. In order to forecast future programs as required in the cumulative case analysis, the baseline projection was scaled relative to the forecast of exploration wells drilled as defined by the cumulative case scenarios to obtain a longer term outlook. Cumulatively, G&G surveys are projected to follow the same trend as cumulative exploration drilling activities, which would peak in 2030-2040 and decline until 2060, and remain relatively low throughout the last quarter of the 70-year analysis period. It is important to note that the cycling of G&G data acquisition is not driven by the 50-year life cycle of a single productive lease but instead would tend to respond to new production or potential new production driven by new technology. Consequently, some areas would be resurveyed in 2-year cycles, while other areas, considered nonproductive, may not be surveyed for 20 years or more. Conservatively, BOEM assumes that, as a result of the Cumulative OCS Oil and Gas Program, one HRG survey would occur for every block leased (estimated by the number of platforms predicted), one HRG survey would occur for every 5 km (3 mi) of pipeline laid (the average length of a pipeline permit), and one VSP survey would be conducted on 15 percent of all exploration and development wells drilled. **Table 3-24** below reflects a reasonable level of cumulative G&G surveying activities that could be expected to occur in the Gulf of Mexico (2017-2086).

Table 3-24. Cumulative G&G Surveying Activities Expected in the Gulf of Mexico (2017-2086).

Survey Area	2D Surveys (mi)	2D Permits	3D Lease Blocks	3D Permits	Ancillary Permits	HRG Surveys	VSP Surveys
Regionwide	365,800-1,036,700	183-506	126,800-358,400	90-235	2,261-5,559	4,300-18,347	1,486-3,470
CPA/EPA	362,000-1,026,100	171-482	104,100-292,100	69-186	1,813-4,128	2,757-14,329	1,168-2,660
WPA	3,700-10,600	12-23	22,700-66,300	21-48	449-1,430	1,542-4,019	317-810

3.3.1.3 Cumulative Exploration and Delineation Plans and Drilling

Chapter 3.1.2.2 describes in detail exploration and delineation activities. Since the 1950's, approximately 18,954 exploratory wells have been drilled, of which 12,516 have been permanently abandoned (Marine Cadastre, 2015). The future projected exploration and delineation well estimate for the Cumulative OCS Oil and Gas Program scenario regionwide during the 70-year analysis period is 1,671-4,717 exploration and delineation wells drilled. Of these, 1,317-3,685 wells would be in the CPA/EPA and 354-1,032 wells would be in the WPA. **Table 3-23** shows the estimated range of exploration and delineation wells by water-depth range for the Cumulative OCS Oil and Gas Program scenario for each planning area of the GOM. Of the wells projected under the Cumulative OCS Oil and Gas Program Scenario, 71-79 percent are expected to be on the continental shelf (0-200 m [0-656 ft] water depth) and 29-21 percent are expected in water-depth ranges >200 m (656 ft).

3.3.1.4 Cumulative Development and Production Drilling

Chapter 3.1.3.1 describes in detail development and production activities. Since the 1950s, approximately 35,029 development wells have been drilled, of which, 13,941 have been permanently abandoned (Marine Cadastre, 2015). The future projected development and production well estimate for the Cumulative OCS Oil and Gas Program Scenario regionwide is

8,238-18,418 development and production wells drilled. Of these, 6,475-14,050 wells would be in the CPA/EPA and 1,763-4,368 wells would be in the WPA. **Table 3-23** shows the estimated range of development and production wells by water-depth range for the Cumulative OCS Oil and Gas Program scenario for each planning area of the GOM. Of the wells projected under the Cumulative OCS Oil and Gas Program scenario, 68-73.5 percent are expected to be on the continental shelf (0-200 m [0-656 ft] water depth) and 32-26.5 percent are expected in water-depth ranges >200 m (656 ft).

3.3.1.5 Infrastructure Emplacement/Structure Installation and Decommissioning Activities

As of 2013, 7,020 platforms had been installed regionwide in the OCS; however, active platforms were estimated at only approximately 2,634 (USDOI, BSEE, 2015e; **Figure 3-19**). **Chapter 3.1.3.2** describes in detail infrastructure emplacement and structure installation and commissioning activities. The projected estimate of additional production structures expected to be installed for the Cumulative OCS Oil and Gas Program scenario in the WPA, CPA, and EPA during the 70-year analysis period is 2,827-6,948 production structures. Of these, 2,266-5,160 structures would be in the CPA/EPA and 561-1,788 structures would be in the WPA. **Table 3-23** shows the estimated range of production structure installation range by water-depth range for the Cumulative OCS Oil and Gas Program scenario for each planning area of the GOM. Of the platforms projected under the Cumulative OCS Oil and Gas Program scenario, about 97 percent are expected to be on the continental shelf (0-200 m [0-656 ft] water depth) and 3 percent are expected in water-depth ranges >200 m (656 ft).

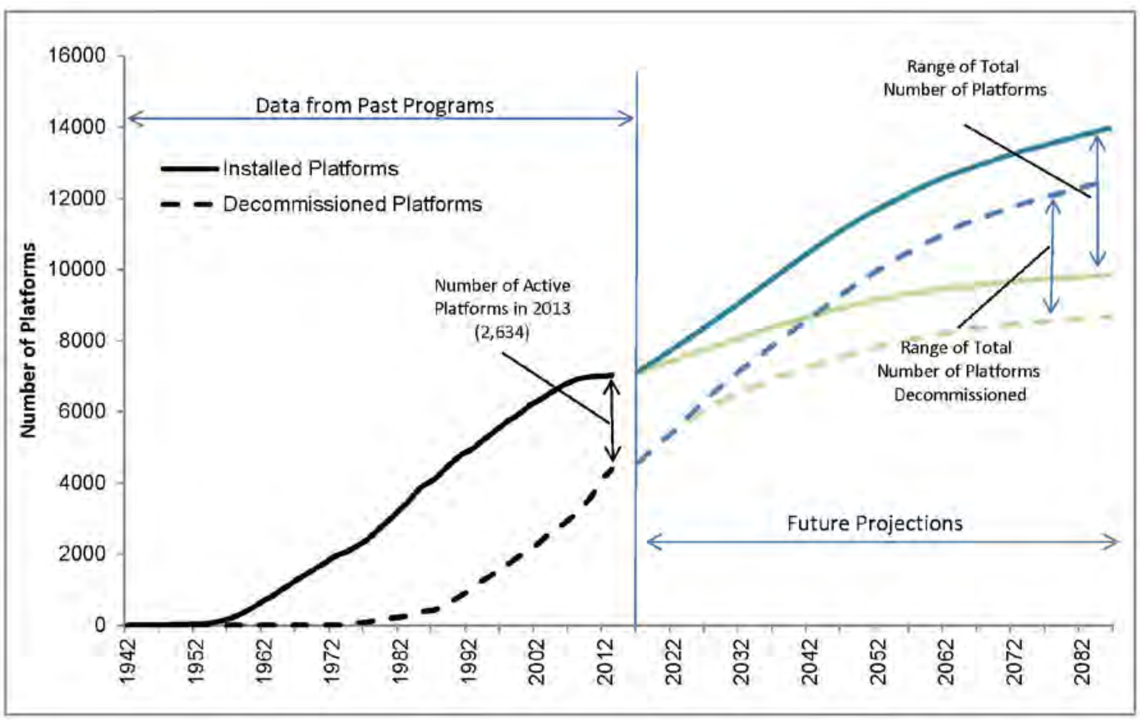

Figure 3-19. Number of Production Structures Installed and Decommissioned in Past Programs and the Range of Future Projections that May Occur as a Result of All Past, Present, and Future Actions (USDOI, BSEE, 2015e).

Pipelines: **Chapter 3.1.3.3.1** describes in detail activities associated with oil and gas transportation via pipelines. BOEM estimates 10,789-35,415 mi (7,363-56,995 km) of pipeline would be installed regionwide as a result of the activities associated with the Cumulative OCS Oil and Gas Program scenario (**Tables 3-23 and 3-25**). About 30-27 percent of the new pipeline length would be in water depths <60 m (197 ft) and would require burial. As of 2015, 144 pipeline landfalls currently exist in coastal areas of the OCS (Smith, official communication, 2015).

Bottom-Area Disturbance: **Chapter 3.1.3.3.2** describes in detail infrastructure emplacement and structure installation and commissioning activities. Bottom area disturbance is calculated as a relationship between the structures projected (i.e., platforms, wells, subsea structures, and pipeline miles installed) and the associated disturbance of each. For the Cumulative OCS Oil and Gas Program scenario, between 294,821 and 605,178 ha (728,518-1,495,427 ac) of sea bottom is projected to be disturbed. Future activity is expected to disturb >1 percent of the seafloor regionwide. Of this, 241,116-460,238 ha (595,810-1,137,272 ac) of the disturbance is expected in the CPA/EPA and 53,705-144,939 ha (132,707-358,152 ac) of the disturbance is expected in the WPA.

Navigation Channels: BOEM conservatively estimates that there are approximately 4,850 km (3,013 mi) of Federal navigation channels, bayous, and rivers potentially exposed to OCS traffic regionwide (**Table 3-7 and Figure 3-9**). No new navigation canals are expected to be created; however, erosion of existing channels may occur. **Chapter 3.1.3.3.4** describes in detail activities associated with navigation channels. Using the estimated proportion of vessel traffic associated with the Cumulative OCS Oil and Gas Program scenario as a measurement of erosion, BOEM conservatively estimates the OCS Oil and Gas Program's contribution to bank erosion over the 70-year cumulative scenario to be 3,135-9,524 ac (1,269-3,854 ha). This number is considered conservative because open waterways were included in the total length of Federal navigation channels, bank armoring rates may increase, vessel size was not taken into consideration, and there are sources of erosion to navigation canals other than vessel traffic alone.

3.3.1.6 Infrastructure Presence

Chapter 3.1.3.4 describes in detail activities associated with infrastructure presence. The maximum number of production structures operating simultaneously in the Cumulative OCS Oil and Gas Program scenario in the WPA, CPA, and EPA is 1,367 structures, including all depth ranges. Therefore, a maximum of 8,202 ha (20,268 ac) or approximately 6 ha (15 ac) of surface area would be temporarily unavailable to other activities in the OCS. To put this in perspective, <1 percent of the surface area of the GOM would be temporarily lost to the Cumulative OCS Oil and Gas Program. Additional impact-producing factors associated with offshore oil and gas infrastructure are oil spills and trash and debris. These are the factors most widely recognized as major threats to the aesthetics of coastal lands, especially recreational beaches. These factors, individually or collectively, may adversely affect the fishing industry, resort use, and the number and value of recreational beach visits.

3.3.1.7 Transport

Barging: **Chapter 3.1.4.1** describes in detail activities associated with barging. Barging is projected to continue to account for <1 percent of the oil transported (**Table 3-25**).

Table 3-25. Future Oil Transportation Projections Associated with the Cumulative OCS Oil and Gas Program (2017-2086), Including All Future Transportation that is Projected to Occur from Past, Proposed, and Future Lease Sales.

Activity	Region	Offshore Subareas (m)[1]						Totals[2]
		0-60	60-200	200-800	800-1,600	1,600-2,400	>2,400	
Percent Oil Piped[3]	GOM	94-95%	100%	100%	100%	89.6-87.4%	87.4-85.7%	91.6-90.6%
	CPA/EPA	94-95%	100%	100%	100%	97.8-96.3%	94.9-95.3%	90.8-91.0%
	WPA	100%	100%	100%	100%	100-89%	100-86.4%	100-95.1%
Percent Oil Barged	GOM	6-5%	0%	0%	0%	0%	0%	0.2%
	CPA/EPA	6-5%	0%	0%	0%	0%	0%	0.2%
	WPA	0%	0%	0%	0%	0%	0%	0%
Percent Tankered[4]	GOM	0%	0%	0%	0%	10.4-12.6%	12.6-14.3%	8-9%
	CPA/EPA	0%	0%	0%	0%	12.2-13.7%	5.1-4.7%	9-8.75%
	WPA	0%	0%	0%	0%	0-11%	0-13.6%	0-4.85%

[1]Refer to **Figure 3-2**. Ranges are reported from the low production scenario to the high production scenario.
[2]Subareas totals may not add up to the planning area total because of rounding.
[3]100% of gas is assumed to be piped.
[4]Tankering is forecasted to occur only in water depths >1,600 m (5,249 ft).

Tankering: The OCS oil- and gas-related tankering began in 2012. Since 2012, tankering has increased to account for about 2 percent of the yearly production of oil. **Chapter 3.1.4.2** describes in detail activities associated with tankering. BOEM estimates that 5-14 FPSO systems could be installed regionwide (a maximum of 2 per decade) as a result of the Cumulative OCS Oil and Gas Program scenario. Zero to five systems are projected within the WPA and 5-9 systems are projected within the CPA/EPA. As a result of these additional systems, up to 9 percent of the oil during any given year may be tankered to a processing facility (**Table 3-25**).

Service Vessels: **Chapter 3.1.4.3** describes in detail activities associated with service vessels. The Cumulative OCS Oil and Gas Program scenario estimates that 3,909,000-11,873,000 service-vessel trips would occur regionwide over the 70-year analysis period (**Table 3-23**) or 55,842-169,614 trips annually. **Table 3-7** indicates 875,000 vessel trips occurred on Federal navigation channels, ports, and OCS oil- and gas-related waterways in 2012. Annual OCS oil- and gas-related vessel traffic due to cumulative OCS oil- and gas-related activity represents between 6 and 19 percent of the total traffic in the GOM.

Helicopters: **Chapter 3.1.4.4** describes in detail activities associated with helicopters. The Cumulative OCS Oil and Gas Program scenario estimates that 17-83 million helicopter trips would occur regionwide over the 70-year analysis period (**Table 3-23**). This equates to an average rate of 240,000-1,190,000 operations annually.

3.3.1.8 Discharges and Wastes

Detailed descriptions of discharges and wastes associated with the OCS Oil and Gas Program activity can be found in **Chapter 3.1.5**. Various laws, regulations, and NTLs would likely minimize the discharges and wastes from OCS oil- and gas-related activities in association with the Cumulative OCS Oil and Gas Program scenario. Cumulative effects of discharges and wastes are discussed in **Chapter 4.2**.

3.3.1.9 Decommissioning and Removal Operations

As of 2013, approximately 62.5 percent of structures had been decommissioned and removed (USDOI, BSEE, 2015e; **Figure 3-19**. **Chapter 3.1.6** describes in detail decommissioning and removal operations. **Table 3-23** shows the forecasted platform removals by water-depth range for the Cumulative OCS Oil and Gas Program scenario for each planning area of the GOM. Of the 4,281-8121 production structures estimated to be removed from the GOM in the Cumulative Oil and Gas Program scenario, 3,003-5,698 production structures (installed landward of the 800-m [2,625-ft] isobath) would likely to be removed using explosives.

3.3.1.10 Coastal Infrastructure

Refer to **Table 3-5** for information on existing coastal infrastructure that services the OCS Oil and Gas Program. **Chapter 3.1.7** describes coastal infrastructure in detail. The Cumulative OCS Oil and Gas Program scenario estimates no additional: service bases, heliports, platform fabrication yards, shipyards, or pipe-coating facilities and yards.

Expectations for new gas processing facilities being built (as a direct result of the Cumulative OCS Oil and Gas Program) are dependent on long-term market trends that are not easily predicable over the next 70 years. Existing facilities would likely experience equipment switch-outs or upgrades during this time. BOEM projects that expansions at existing LNG facilities and the construction of new facilities would not occur as a direct result of the cumulative OCS Oil and Gas Program. New refineries may be built, but there has been a trend toward constructing simple refineries instead of complex refineries.

3.3.1.11 Air Emissions

Chapter 3.1.8 describes in detail activities associated with the production of air emissions. BOEM is responsible for determining if air pollutant emissions from offshore oil and gas activities in the Gulf of Mexico influence the NAAQS' compliance status of Texas, Louisiana, Mississippi, Alabama, and Florida. As such, BOEM would continue to inventory emissions and model emissions whenever the USEPA updates the NAAQS. Effects to air quality from the Cumulative OCS Oil and Gas Program are discussed in **Chapter 4.1**.

3.3.2 Non-OCS Oil- and Gas-Related Impact-Producing Factors

The impact-producing factors considered in this chapter are defined as other past, present, and reasonably foreseeable future activities occurring within the same geographic range and within the same timeframes as the aforementioned projected routine activities and potential accidental events, but they are not related to the Cumulative OCS Oil and Gas Program. This chapter describes other impact-producing factors that could potentially affect an environmental or socioeconomic resource in addition to OCS oil- and gas-related activity.

While the scenario developed for the Cumulative OCS Oil and Gas Program scenario forecasts 70 years of activities, the scenarios developed as part of this chapter vary in the length of time projected depending on what would be considered reasonably foreseeable by impact-producing factors based on the data available and the ability to predict future actions without being speculative.

3.3.2.1 State Oil and Gas Activity

All of the five Gulf Coast States have had some historical oil and gas exploration activity and, with the exception of Florida and Mississippi, all currently produce oil and gas in State waters. The coastal infrastructure that supports the OCS Program also supports State oil and gas activities.

State oil and gas infrastructure consists of the wells that extract hydrocarbon resources, facilities that produce and treat the raw product, pipelines that transport the product to refineries and gas plants for further processing, and additional pipelines that transport finished product to points of storage and final consumption. The type and size of infrastructure that supports production depends upon the size, type, and location of the producing field, the time of development, and the life cycle stage of operations.

Texas

According to the Railroad Commission of Texas, since June 2015 cumulative total State offshore production of oil was reported at over 42 million bbl and offshore gas production totals were reported at over 4.1 billion Mcf (Railroad Commission of Texas, 2015). Texas was the leading crude-oil producing state in the Nation in 2013 and exceeded production levels even from the Federal offshore areas (USDOE, Energy Information Administration, 2014a).

The Lands and Minerals Division of the Texas General Land Office holds lease sales for oil and gas on State lands, and the Texas General Land Office manages Texas State resources for the benefit of public education. The Texas General Land Office generally holds lease sales every 4 months in January, April, July, and October. The Texas General Land Office's Mineral Leasing Division uses a sealed bid process for the leasing of State lands. BOEM expects that Texas would conduct regular oil and gas lease sales in State waters during the next 70 years, although the lease sales' regularity could differ from current practices.

Louisiana

Louisiana has been the second most important oil- and gas-producing state after Alaska. Oil production in Louisiana began in 1902, with the first oil production in the coastal zone in 1926. Southern Louisiana produces mostly oil and northern Louisiana produces mostly gas. Over the last 60 years, Louisiana averaged around 27 MMbbl of oil and 12 Tcf of gas per year (State of Louisiana, Dept. of Natural Resources, 2015a and 2015b).

Louisiana's leasing procedure is carried out by the Petroleum Lands Division of the Office of Mineral Resources within the Louisiana Department of Natural Resources (State of Louisiana, Dept. of Natural Resources, 2015c). BOEM expects that Louisiana would conduct regular oil and gas lease sales in State waters during the next 70 years.

Mississippi

At present, Mississippi only has an onshore oil and gas leasing program; however, it is expected that the State would start issuing leases for offshore activity in State waters in the near future. In 2004, the Mississippi Legislature limited offshore natural oil and gas exploration to areas located predominantly south of the barrier islands. On December 19, 2011, the Mississippi Development Authority published draft regulations; the public comment period closed on January 20, 2012 (Mississippi Development Authority, 2011). However, recent efforts to open Mississippi State waters for G&G and leasing activities have been challenged in court (Davis, 2014).

Development of an offshore oil and gas leasing program in Mississippi State waters during the next 70 years is reasonably foreseeable.

Alabama

The State Oil and Gas Board of Alabama is the regulatory agency of the State of Alabama with statutory charge of oil and gas development. From 1989 to 2014, a total of 8,278,884 MMcf of gas has been produced in State waters, averaging approximately 331,155 MMcf of gas production per year. From 1989 to 2012, a total of 293,730,516 bbl of oil were produced, averaging approximately 12,770,892 bbl/yr (State of Alabama, Oil and Gas Board, 2015).

Alabama has no established schedule of lease sales. The limited number of tracts in State waters has resulted in the State not holding regularly scheduled lease sales. The last lease sale was held in 1997. BOEM does not expect Alabama to institute a lease sale program in the near future, although there is at least a possibility of a lease sale in State waters during the next 70 years.

Florida

The Florida Department of Environmental Protection's Mining Mitigation and Delineation Program is the permitting authority for the exploration and production of oil and gas in Florida.

A total of 19 wells were drilled in Florida State waters from 1947 to 1983 (State of Florida, Dept. of Natural Resources, 1991). Offshore exploratory drilling in Federal waters of the EPA included six wells completed in 1988 and 1989; one of these was the discovery in the Destin Dome Area and was classified by the Federal Government as a producible field (State of Florida, Dept. of Natural Resources, 1991). In July 1990, all offshore drilling activity in Florida State waters was prohibited and the State's policy on offshore oil and gas drilling changed. Since 1989, the Florida State Congress has prohibited new leasing off Florida in the EPA.

With current State policy and regulations prohibiting oil and gas exploration and development in State waters, BOEM does not expect Florida to institute a lease sale program in the near future. If State policy and regulations change and the moratorium is allowed to expire, the potential for a lease sale in State waters could be a possibility during the next 70 years.

3.3.2.1.1 State Pipeline Infrastructure

The existing pipeline network in the Gulf Coast States is the most extensive in the world and has unused capacity (Cranswick, 2001). The network carries oil and gas onshore and inland to refineries and terminals, and a network of pipelines distributes finished products such as diesel fuel or gasoline to and between refineries and processing facilities onshore (Peele et al., 2002, Figure 4.1). Expansion of this network is projected to be primarily small-diameter pipelines to increase the interconnectivity of the existing network and a few major interstate pipeline expansions. However, as discussed in **Chapter 3.1.3.3.1**, there is spare capacity in the existing pipeline infrastructure to move oil and gas to market, and deepwater ports can serve onshore facilities, including intrastate as well as interstate pipelines. Refer to **Table 3-6** for a list of current pipeline landfalls.

3.3.2.1.2 Artificial Reefs

Use of artificial reefs to enhance fisheries along the U.S. coastline was documented as early as the mid-19th century (Stone, 1974; McGurrin et al., 1989; Christian et al., 1998). For nearly 200 years, purpose-built structures (e.g., wooden huts, cinder block reefs, and concrete pyramids) and obsolete materials (e.g., decommissioned vessels and damaged concrete pipe) have been intentionally deposited in estuarine and marine environments to add bottom relief, attract fishes, and improve angler access and success. As a result of research into the potential benefits and adverse impacts resulting from specific artificial reef designs, materials, and siting, the National Artificial Reef Plan and subsequent revision in 2007 were developed to provide guidance to artificial reef coordinators, fisheries managers, and other parties on recommended siting, construction, management, and monitoring of artificial reefs. The Secretary of the Army, through the COE, is responsible for the artificial reef permitting process and for coordination of the appropriate State and Federal agencies (USDOC, NOAA, 2007). The Wallop-Breaux Amendment provided increased Federal funding to State agencies for sport fish restoration, contributing to the National Fisheries Enhancement Act's objectives through support of habitat enhancement projects, research, and monitoring (Christian et al., 1998).

Offshore oil and gas platforms have been contributing hard substrate to the GOM since the 1930's, and fishermen quickly found fishing success was enhanced in the vicinity of OCS oil- and gas-related structures (State of Louisiana, Dept. of Wildlife and Fisheries, 1987). By the late-1970's some artificial reef advocates and recreational fishermen had begun viewing the decommissioning and removal of OCS oil- and gas-related structures as a lost opportunity. The increased interest and participation in fishing at offshore oil and gas platforms and national support for effective artificial reef development coincided with research and fisheries management efforts, which led to passage of the National Fishing Enhancement Act of 1984 and the development of the first National Artificial Reef Plan. In 1987, Louisiana published a State artificial reef plan that specifically addressed the need to support public interest through development of artificial reef planning areas and the addition of decommissioned OCS platforms as artificial reef substrate (State of Louisiana, Dept. of Wildlife and Fisheries, 1987). Texas' Artificial Reef Act of 1989 explicitly identified decommissioned platforms as the preferred substrate for the construction of artificial reefs (State of Texas, Parks and Wildlife Dept., 1990). Currently, all five Gulf Coast States have active artificial reef programs, which develop and manage artificial reefs on the Federal OCS.

The OCSLA and implementing regulations establish decommissioning obligations for lessees, including the removal of platforms. The Rigs-to-Reefs Policy provides a means by which lessees may request a waiver to the removal requirement. For additional information, refer to **Chapter 3.1.6.2**. Since the first Rigs-to-Reefs conversion, approximately 11 percent of the platforms decommissioned from the Gulf of Mexico OCS have been redeployed within designated State artificial reefs. Scientific and public interest in the ecology of offshore structures and the potential benefits of contributing hard substrate to a predominantly soft bottom environment have led to increased emphasis on the development of artificial reefs. The current paradigm posits oil and gas structures act as both fish-attracting and production-enhancing devices, depending upon the species (Carr and Hixon, 1997; Gallaway et al., 2009; Shipp and Bortone, 2009; and Dance et al., 2011). However, determination of specific and cumulative impacts resulting from construction of artificial reefs within permitted areas is very difficult. As recommended by the National Artificial Reef Plan (USDOC, NOAA, 2007), well-defined objectives, clear management strategies, and long-term monitoring are critical elements of an artificial reef program and are necessary if managers intend to use artificial reefs as a fisheries management tool.

3.3.2.2 Marine Vessel Activity

Under current conditions, freight and cruise ship passenger marine transportation within the analysis area should continue to grow at a modest rate or remain relatively unchanged based on historical freight and cruise traffic statistics. In 2013, the Sabine-Neches Waterway had the highest vessel capacity, followed by the Port of New Orleans in terms of tonnage handled. The Port of Houston was the third largest port in the United States (USDOT, MARAD, 2015a). Tankers carrying mostly petrochemicals account for about 60 percent of the vessel calls in the Gulf of Mexico. Dry-bulk vessels, including bulk vessels, bulk containerships, cement carriers, ore carriers, and wood-chip carriers, account for another 17 percent of the vessel calls. The GOM also supports a popular cruise industry. In 2011, there were 149 cruise ship departures from Galveston, 139 cruise ship departures from New Orleans, and 199 cruise ship departures from Tampa (USDOT, MARAD, 2012).

Total port calls, or vessel stops at a port, in the U.S. is increasing as a whole, and total port calls within the GOM is also increasing. Gulf of Mexico port calls represent approximately 33 percent of total U.S. port calls. Trends for GOM port calls relative to total U.S. port calls shows an approximate 3 percent average increase of GOM port calls between 2003 and 2012, from 18,034 to 24,730 port calls (USDOT, MARAD, 2015a) (**Table 3-26**).

Table 3-26. Number of Vessel Calls at U.S. Gulf Ports Between 2002 and 2011[1].

Vessel Type	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012[11]
Tanker-Product[2,3]	5,143	5,764	6,171	6,594	6,784	6,597	6,451	7,000	8,413	15,032
Tanker-Crude[2,4]	4,227	4,361	4,303	4,343	4,614	4,574	4,502	5,150	5,626	
Container[5]	1,263	1,284	1,378	1,354	1,306	1,372	1,641	1,934	2,338	2,047
Dry Bulk[6]	4,837	4,959	4,575	5,289	4,988	4,563	4,021	3,475	3,917	4,888
RO-RO (Roll-on Roll-off)[7]	398	370	337	423	386	374	491	549	566	547
Gas[8]	624	548	558	622	628	462	441	500	604	612
Combo[9]	375	258	201	155	135	116	102	94	66	NA
General[10]	1,167	1,141	1,160	1,246	1,362	1,363	1,300	1,387	1,459	1,604
All Types	18,034	18,685	18,683	20,026	20,203	19,421	18,949	20,089	22,989	24,730

[1]The data in this report are only for oceangoing self-propelled vessels of 10,000 deadweight (DWT) capacity or greater. In 2005, these vessels accounted for 98 percent of the capacity calling at U.S. ports.
[2]Petroleum tankers and chemical tankers.
[3]10,000-69,999 DWT.
[4]>70,000 DWT.
[5]Container carriers, refrigerated container carriers.
[6]Bulk vessels, bulk containerships, cement carriers, ore carriers, wood-chip carriers.
[7]RO/RO vessels, RO/RO containerships, vehicle carriers.
[8]Liquefied natural gas carriers, liquefied natural gas/liquefied petroleum gas carriers, liquefied petroleum carriers.
[9]Ore/bulk/oil carriers, bulk/oil carriers.
[10]General cargo carriers, partial containerships, refrigerated ships, barge carriers, livestock carriers.
[11]In 2012, product and crude tankers were not distinguished.

Source: USDOT, MARAD, 2015a.

It is expected that the usage of GOM ports would continue to increase by approximately 3 percent annually over the next 50 years. As such, it is anticipated that port calls by all ship types would be bounded annually by a lower limit of current use and an upper limit of approximately 99,417 vessel port calls per year.

Non-OCS oil- and gas-related tankering includes ships carrying crude or ships carrying product. Overall, tankering (including U.S. ships and foreign ships) in the U.S. increased by

28 percent between 2003 and 2011 (USDOT, MARAD, 2013). While U.S. tankering port of calls declined between 2003 and 2011, foreign ship tankering port of calls increased, as listed below.

Ship Origin	2003	2011
U.S. Tankers	3,759	2,956
Foreign Tankers	14,744	20,722

Source: USDOT, MARAD, 2013.

Due to the double-hulled ships' ability to reduce or prevent oil spills, double-hulled ships have replaced almost all single-hulled ships. In 2003, 60-70 percent of all tankers were double hulled, but by 2011, 97-100 percent of all tankers were double hulled.

Non-OCS oil- and gas-related vessels other than those listed above utilize the GOM. These ships include research vessels, recreational vessels and commercial vessels. Commercial and recreational fishing in the Gulf of Mexico are regulated by NMFS. For more information on recreational fishing vessels, refer to **Chapter 4.11**. For more information on commercial fishing vessels, refer to **Chapter 4.10**. Research activities, including surveys, genetic research, capture, relocation, or telemetric monitoring, may affect organisms or ecosystems in the GOM. If any of these activities could involve the take of an endangered species, the activity is required to obtain a permit through NMFS. Vessels involved in the photography of marine mammals may also require a permit through NMFS.

Any of the non-OCS oil- and gas-related vessels could affect marine and archaeological resources by anchoring. Effects would be similar to those discussed in the OCS oil- and gas-related anchoring **Chapter 3.1.3.4.1**.

3.3.2.3 Non-OCS Oil- and Gas-Related Wastes and Discharges

Current and historic marine activities, unrelated to the OCS oil and gas program, are considered in the cumulative scenario for water quality in the GOM. These include regulated effluents from State oil and gas activities and the discharge of bilge, ballast water, and sanitary wastes from commercial shipping, similar to OCS oil- and gas-related service vessels (**Chapter 3.1.5**). Other non-OCS oil- and gas-related wastes are associated with dredged material disposal, potentially polluting shipwrecks, military activities, disposal of military chemical weapons and industrial wastes, land-based discharges, and non-OCS oil- and gas-related sources of trash and debris.

3.3.2.3.1 Potentially Polluting Shipwrecks

There are thousands of shipwrecks in U.S. waters. Some of the vessels involved in those wrecks are likely to contain oil, as fuel and possibly cargo, and may eventually result in pollution to the marine environment. Warships and cargo vessels sunk in wartime may also contain munitions, including explosives and chemical warfare agents, which may pose a continued threat because of their chemical composition. The NOAA maintains a large database of shipwrecks, dumpsites, navigational obstructions, underwater archaeological sites, and other underwater cultural resources (USDOC, NOAA, 2013b). This internal database, Resources and Undersea Threats, includes approximately 20,000 shipwrecks in U.S. waters. Shipwrecks in the Resources and Undersea Threats database were ranked to identify the most ecologically and economically significant, potentially polluting wrecks in U.S. waters for inclusion in the Remediation of Underwater Legacy Environmental Threats Program. Under this Program, wrecks are ranked based on age, size, hull material, type, location, historical information on the vessel, engineering analysis, archaeological site formation, whether they are currently leaking, and modeling of the trajectory, fate, and consequences of an oil release from a shipwreck. The NOAA identified 87 priority wrecks on the 2012 Remediation of Underwater Legacy Environmental Threats Program (those with the highest probability of discharge). Of these, 53 sank during an act of war and 34 sank as a result of collision, fire, grounding, storms, or other causes. Priority wrecks located in the Gulf of Mexico include *R.W. Gallagher*, which contains 80,855 bbl of Bunker C fuel oil, located about 40 mi (64 km) south of Terrebonne Parish, Louisiana, and *Joseph M. Cudahy*, which contains 77,444 bbl of crude and lubricating oil, located about 65 mi (105 km) northwest of Key West, Florida. The NOAA Wreck Oil Removal Program provides for the removal of oil from priority wrecks, where feasible.

Another shipwreck of note is *Tank Barge DBL 152*, which, on November 11, 2005, struck the submerged remains of a pipeline service platform in West Cameron Block 229 (about 50 mi [80 km] southeast of Sabine Pass, Texas). The platform had previously collapsed during Hurricane Rita. The barge was carrying a cargo of approximately 119,793 bbl of a blended mixture of low-API gravity oil (i.e., heavy oil, likely to sink). A portion of the oil was released at the point of impact, which sank to the seafloor. The barge was towed toward shallow water to facilitate salvage; however, it grounded and capsized approximately 12 mi (19 km) to the west-northwest, releasing additional oil to the seafloor. An estimated 45,846 bbl of oil were released during the incident, of which about 2,355 bbl were recovered by divers. In January 2006, recovery of additional oil was deemed infeasible and cleanup operations were discontinued, leaving approximately 43,491 bbl of oil unrecovered on the seafloor (USDOC, NOAA, 2013c).

3.3.2.3.2 Discharges Associated with Military Activities

A full description of military activities is discussed in **Chapter 3.3.2.6.1** below. Military operations within military warning areas (MWAs) and Eglin Water Test Areas (EWTAs) vary in types of missions performed and their frequency of use. Such missions may include carrier maneuvers, missile testing, rocket firing, pilot training, air-to-air gunnery, air-to-surface gunnery, minesweeping operations, submarine operations, air combat maneuvers, aerobatic training, and instrument training. To eliminate potential impacts from multiple-use conflicts related to the warning and test areas, a standard Military Areas Stipulation is routinely applied to all GOM leases (example in **Appendix D.3**).

Between the years of 1995 through 1999, Eglin Air Force Base in Florida conducted nearly 39,000 training sorties per year in the eastern Gulf. Potential impacts from these activities are discussed in the *Eglin Gulf Test and Training Range, Final Programmatic Environmental*

Assessment (Air Force Air Armament Center, 2002). These military activities may result in marine impacts from chaff, fuel releases, flares, chemical materials, and debris.

Chaff, which is composed of short aluminum fibers similar in appearance to human hair, metalized glass fiber, or plastic, is dispensed by military aircraft as a countermeasure to distract radar-guided missiles from their targets. The Air Force Air Armament Center identified a remote potential that chaff could be mistaken as a food source and be ingested by aquatic organisms; however, the quantity of chaff used was not stated (Air Force Air Armament Center, 2002, page 4-18).

During in-flight emergencies, fuel may be released in the air or a fuel tank may be jettisoned and impact the surface. Drones may also be shot down and release fuel upon surface impact. The type of fuel used, JP-8, is very volatile and, when released at altitude, evaporates quickly. The Air Force Air Armament Center concluded that temporary localized effects to air and water quality may result from fuel releases; however, the frequency of fuel releases is extremely low (Air Force Air Armament Center, 2002, pages ES-1 and ES-2).

Flares may be ejected from aircraft to confuse and divert enemy heat-seeking or heat-sensitive missiles, and may also be used to illuminate surface areas during nighttime operations. Flares are composed primarily of aluminum, magnesium, and Teflon™. Upon burning, the magnesium (as magnesium oxide) in the flare may be deposited on the water surface. The Air Force Air Armament Center characterizes the impact to water from flares to be less than the natural concentrations of magnesium found in the Gulf (Air Force Air Armament Center, 2002, pages 4-20 and 4-21).

The Air Force Air Armament Center stated that chemical materials are introduced into the marine environment through drones, gun ammunition, missiles, chaff, flares, smokes and obscurants. The Air Force Armament Center concluded that potential chemical contamination concentrations were extremely low and not likely to impact marine species.

Debris may be released into the GOM as a result of military activities, including ordnance and shrapnel deposits from bombs and missiles, drones, chaff and flare cartridges, and intact inert bombs. This debris generally falls into the major categories of aluminum, steel, plastic, concrete, and other components (i.e., copper and lead) and originates largely from inert bombs, missiles, and downed drones (Air Force Armament Center, 2002, page 2-21).

3.3.2.3.3 Historical Chemical Weapon Disposal Areas

After World War I, chemical weapons were routinely disposed of in the world's oceans, including the GOM. In some instances, conventional explosives and radiological wastes were dumped along with chemical weapons. Army records document several instances of mustard and phosgene bombs being disposed of in the Gulf of Mexico, originating from New Orleans, Louisiana, and Mobile, Alabama. Chemical weapons disposed of in other locations, and potentially in the Gulf of Mexico, contained hydrogen cyanide, arsenic trichloride, cyanogen chloride, lewisite, tabun, sarin, and VX, as reported in a Report to Congress (Bearden, 2007).

Six former explosives dumping areas are noted on NOAA's chart of the Gulf of Mexico (USDOC, NOAA, 2015a) and likely contain disposed chemical weapons. These include two areas offshore Texas (about 65 nmi [75 mi; 120 km] southeast of Aransas Pass and about 100 nmi [115 mi;185 km] south of Galveston); two areas offshore Louisiana (both about 35-40 nmi [42-46 mi;65-74 km] south of the mouth of the Mississippi River); one area offshore Alabama (about 70 nmi [81 mi; 130 km] southeast of Mobile Bay); and one offshore Florida (about 130 nmi [150 mi; 241 km] west of Tampa Bay).

The Marine Protection, Research, and Sanctuaries Act of 1972, also known as the Ocean Dumping Act, was promulgated to regulate ocean dumping and to set aside certain areas as national marine sanctuaries. Section 101 of the Act (33 U.S.C. § 1411) prohibits ocean dumping, except as authorized by permit issued by the USEPA pursuant to Section 102 (33 U.S.C. § 1412). Section 102 specifically states that radiological, chemical, and biological warfare agents, high-level radioactive waste, and medical waste would not be permitted for ocean disposal after 1972.

3.3.2.3.4 Historical Industrial Waste Dumping Areas

Between 1940 and 1970, certain offshore locations of the United States were used for the disposal of various industrial wastes and low-level radioactive wastes, these activities being large, unrecorded, and unregulated (USDOC, NOAA, 2015b).

Section 102 of the Ocean Dumping Act (33 U.S.C. § 1412) authorizes the issuance of permits for ocean disposal of certain waste streams and requires that the USEPA determine that such dumping will not unreasonably degrade or endanger human health, welfare, or amenities, or the marine environment, ecological systems, or economic potentialities.

In 1973, the USEPA permitted two interim industrial waste disposal sites in the Gulf of Mexico pursuant to Section 102 of the Marine Protection, Research, and Sanctuaries Act, the charting of which has been maintained by NOAA. Disposal Site A, located within the WPA, is situated on the upper part of the Texas-Louisiana continental shelf, about 125 nmi (144 mi; 232 km) south of Galveston, Texas. Disposal Site B is located in the CPA off the western side of the Mississippi Delta about 60 nmi (75 mi; 120 km) south of the mouth of the Mississippi River. The National Academy of Sciences' report, *Assessing Potential Ocean Pollutants* (National Academy of Sciences, 1975), provides additional information about these sites.

3.3.2.3.5 Dredged Material Disposal

Dredged material is described in 33 CFR part 324 as any material excavated or dredged from navigable waters of the United States. Materials from maintenance dredging are primarily disposed of offshore on existing dredged-material disposal areas and in ocean dredged-material disposal sites (ODMDSs). Additional dredged-material disposal areas for maintenance or new-project dredging are developed as needed and must be evaluated and permitted by COE and relevant State agencies prior to construction. The ODMDSs are regulated by the USEPA under the Clean Water Act and the Marine Protection, Research, and Sanctuaries Act.

If funds are available, the COE uses dredge materials beneficially for restoring and creating habitat, for beach nourishment projects, and for industrial and commercial development (**Chapter 3.3.2.8.3**). The applicant would need funds to cover the excess cost over the least cost environmentally acceptable alternative (the Federal Standard). The material must also be suitable for the particular beneficial use. Virtually all ocean dumping that occurs today is maintenance dredging of sediments from the bottom of channels and bodies of water in order to maintain adequate channel depth for navigation and berthing. There are four authorized open-water disposal areas in Louisiana and Mississippi along stretches of the main Gulf Intracoastal Waterway (GIWW) between Louisiana and Mississippi: in Louisiana, Disposal Area 66 (1,593 ac; 645 ha); and in Mississippi, Disposal Area 65A (1,962 ac; 794 ha), Disposal Area 65B (815 ac; 330 ha), and Disposal Area 65C (176 ac; 71 ha) (U.S. Dept. of the Army, COE, 2008, Table 1). Dredged materials from the GIWW are disposed of at these locations. The ODMDSs utilized by the COE are located in the cumulative activities area and can be found on the Ocean Disposal Database website (U.S. Dept. of the Army, COE, 2015a).

There are two primary Federal environmental statutes governing dredge material disposal. The Marine Protection, Research, and Sanctuaries Act (also called the Ocean Dumping Act) govern transportation for the purpose of disposal into ocean waters. Section 404 of the Clean Water Act governs the discharge of dredged or fill material into U.S. coastal and inland waters. The USEPA and COE are jointly responsible for the management and monitoring of ocean disposal sites. The responsibilities are divided as follows: (1) the COE issues permits under the Clean Water Act and the Marine Protection, Research, and Sanctuaries Act; (2) the USEPA has lead for establishing environmental guidelines/criteria that must be met to receive a permit under either statute; (3) permits for ODMDS disposal are subject to USEPA review and concurrence; and (4) the USEPA is responsible for designating ODMDSs.

The COE's Ocean Disposal Database reports the amount of dredged material disposed in ODMDSs by district (U.S. Dept. of the Army, COE, 2015a). **Table 3-27** shows the quantities of dredged materials disposed of in ODMDSs between 2004 and 2013 by the Galveston, New Orleans, and Mobile Districts.

Table 3-27. Quantities of Dredged Materials Disposed of in Ocean Dredged-Material Disposal Sites Between 2004 and 2013.

Year	New Orleans District		Galveston District		Mobile District	
	yd^3	m^3	yd^3	m^3	yd^3	m^3
2004	21,156,300	16,175,160	4,078,900	3,118,544	9,902,000	7,570,626
2005	21,403,200	16,363,928	1,250,900	956,382	3,796,900	2,902,940
2006	13,493,400	10,316,449	9,182,200	7,020,299	3,219,100	2,461,180
2007	17,550,700	13,418,479	6,361,200	4,863,489	1,952,800	1,493,023
2008	16,800,900	12,845,216	5,664,800	4,331,052	3,725,093	2,848,039
2009	7,618,900	5,825,070	16,295,000	12,458,427	10,351,223	7,914,082
2010	15,386,100	11,763,523	6,226,300	4,760,350	4,361,670	3,334,738
2011	15,613,143	11,937,110	3,502,600	2,677,931	3,749,570	2,866,753
2012	14,680,727	11,224,226	10,875,772	8,315,128	1,592,204	1,217,328
2013	3,669,836	2,805,792	4,452,299	3,404,028	3,473,019	2,655,315
Average	14,737,321	11,267,495	6,788,997	5,190,563	4,612,358	3,526,402

Source: U.S. Dept. of the Army, COE, 2015a.

The New Orleans District dredges an average annual 14.7 million yd^3 (11.3 million m^3). Current figures estimate that approximately 38 percent of that average is available for the beneficial use of dredge materials program (U.S. Dept. of the Army, COE, 2013). The remaining 62 percent of the total material dredged yearly by the COE's New Orleans District is disposed of at placement areas regulated under Section 404 of the Clean Water Act, at ODMDSs, or is stored in temporary staging areas located inland (e.g., the Pass a Loutre Hopper Dredge Disposal Site at the head of the Mississippi River's main "birdfoot" distributary channel system).

Evaluation of dredged material for ocean disposal under the Marine Protection, Research, and Sanctuaries Act relies largely on biological (bioassay) tests. The ocean testing manual, commonly referred to as the Green Book (USEPA, 1991), provides national guidance for determining the suitability of dredged material for ocean disposal. Benthic and water-column impacts of dredged material disposal are evaluated prior to disposal through analysis of representative samples of the material to be disposed, unless the sand source is previously characterized. Sample evaluation may include physical analysis (i.e., grain size, total solids, and specific gravity) and chemical analysis for priority pollutants (i.e., metals, semivolatile and volatile organic compounds, PCBs, and pesticides).

BOEM anticipates that, over the next 70 years, the amount of dredged material disposed of at ODMDSs would fluctuate generally within the trends established by the COE district offices. Between 2004 and 2013, the New Orleans District has averaged about 14.7 million yd^3 (11.2 million m^3) of material dredged per year disposed of at ODMDSs, while the Mobile District is about one-quarter of that quantity, or 4.6 million yd^3 (3.5 million m^3). Quantities disposed of at ODMDSs may decrease as more beneficial uses of dredged material onshore are identified and evaluated.

3.3.2.3.6 Land-Based Discharges

As authorized by the Clean Water Act, the NPDES permit program controls water pollution by regulating point sources on land that discharge pollutants into waters of the United States. Point sources are discrete conveyances (outfalls) such as pipes or manmade ditches that may contain process water flows and/or precipitation from impervious surfaces. Industrial, municipal, and other facilities must obtain permits if their discharges go directly to surface waters. In most cases, the NPDES permit program is administered by authorized states (USEPA, 2015a).

The NPDES program includes periodic characterization of outfall flow to limit pollutants entering surface water. The Mississippi River basin drains 41 percent of the 48 contiguous states of the United States. The basin covers more than 1,245,000 mi^2 (3,224,535 km^2) and includes all or parts of 31 states and two Canadian provinces (U.S. Dept. of the Army, COE, 2015b). Nonpoint-source contributions to the Mississippi River from erosion, uncontained runoff, and groundwater discharge are primary sources of freshwater, sediment, suspended solids, organic matter, and pollutants (including nutrients, heavy metals, pesticides, oil and grease, and pathogens). As a result, water quality in coastal waters of the northern GOM is highly influenced by seasonal variation in river flow. The Mississippi River introduces approximately 3,680,938 bbl of oil and grease per year from land-based sources (NRC, 2003, Table I-9, page 242; **Chapter 3.3.2.4**) into the waters of the Gulf. Nutrients carried in waters of the Louisiana and Texas rivers contribute to seasonal formation of hypoxic zones (**Chapter 3.3.2.12**) on the Louisiana and Texas shelf. Additional information regarding water quality in the northern GOM can be found in **Chapter 4.2**.

3.3.2.3.7 Trash and Debris

Marine debris originates from both land-based and ocean-based sources. Forty-nine percent of marine debris originates from land-based sources, 18 percent originates from ocean-based sources, and 33 percent originates from general sources (sources that are a combination of land-based and sea-based activities) (USEPA, 2009a). Some of the sources of land-based marine debris are beachgoers, storm-water runoff, landfills, solid waste, rivers, floating structures, and ill-maintained garbage bins. Marine debris also comes from combined sewer overflows and typically includes medical waste, street litter, and sewage. Ocean-based sources of marine debris include galley waste and other trash from ships, recreational boaters, fishermen, and offshore oil and gas exploration and production facilities. Commercial and recreational fishers produce trash and debris by discarding plastics (e.g., ropes, buoys, fishing line and nets, strapping bands, and sheeting), wood, and metal traps. Some trash items, such as glass, pieces of steel, and drums with chemical or chemical residues, can be a health threat to local water supplies and as a result to biological, physical, and socioeconomic resources, to beachfront residents, and to users of recreational beaches. To compound this problem, there is population influx along the coastal shorelines. These factors, combined with the growing demand for manufactured and packaged goods, have led to an increase in nonbiodegradable solid wastes in our waterways.

3.3.2.4 Non-OCS Oil- and Gas-Related Spills

The NRC (2003) computed petroleum hydrocarbon inputs into North American marine waters for several major categories. The results show that three activities – extraction, transportation, and consumption – are the main sources of anthropogenic petroleum hydrocarbon pollution in the sea.

Non-OCS oil- and gas-related spills include the loss of petroleum products as a result of the extraction-, transportation-, and refinery-related activities from State oil and gas leases offshore Louisiana and Texas. The major sources of petroleum hydrocarbon discharges into the marine waters by transportation activities, including non-OCS oil- and gas-related sources, are tank vessel spills, operational discharges from cargo washings, coastal facilities spills, and gross atmospheric deposition of VOC releases from tankers. Non-OCS oil- and gas-related offshore spills are possible during the extensive maritime barging and tankering operations that occur in offshore waters of the GOM. Spills from transportation activities include a wide variety of petroleum products (not just crude oil), each of which behaves differently in the environment and may contain different concentrations of toxic compounds.

Consumption-related sources of petroleum releases to the marine environment include land-based sources (i.e., river discharge and runoff), two-stroke vessel discharge, non-tank vessel spills, operational discharges, gross atmospheric deposition, and aircraft dumping. Releases that occur during the consumption of petroleum, whether by individual car and boat owners, non-tank vessels, or run-off from increasingly paved urban areas, contribute the vast majority of petroleum introduced to the environment through human activity. Nearly 85 percent of the 29 million gallons of petroleum that enter North American ocean waters each year as a result of human activities comes from land-based runoff, polluted rivers, and aircraft. Land runoff and two-stroke engines account for nearly three quarters of the petroleum introduced to North American waters from activities associated with petroleum consumption, activities almost exclusively restricted to coastal waters. Unlike other sources, inputs from consumption occur almost exclusively as slow chronic releases. The estimates for land-based sources of petroleum are the most poorly documented and the uncertainty associated with the estimates range over several orders of magnitude. On occasion, aircraft carry more fuel than they can safely land with so fuel is jettisoned into offshore marine waters. The amount of 1,120 bbl (160 tonnes) of jettisoned fuel per year was estimated for the GOM.

Tables 3-28 and 3-29 provide the NRC (2003) estimates of hydrocarbon inputs into marine waters. In general, response activities to non-OCS oil- and gas-related spills would be similar to those described for an OCS oil- and gas-related spill (**Chapter 3.2.8**).

Table 3-28. Average Annual Inputs of Petroleum Hydrocarbons to Coastal Waters of the Gulf of Mexico, 1990-1999.

Inputs	Western Gulf of Mexico		Eastern Gulf of Mexico	
	(tonnes)	(bbl)	(tonnes)	(bbl)
Extraction of Petroleum				
Platforms Spills	90	630	trace[1]	trace
Atmospheric Releases (VOCs)	trace	trace	trace	trace
Permitted Produced-Water Discharges	590	4,130	trace	trace
Sum of Extraction Inputs	680	4,760	trace	trace
Transportation of Petroleum				
Pipeline Spills	890	6,230	trace	trace
Tank Vessel Spills	770	5,390	140	980
Coastal Facilities Spills[2]	740	5,180	10	70
Atmospheric Releases (VOCs)[3]	trace	trace	trace	trace
Sum of Transportation Inputs[4]	2,400	16,800	160	1,120
Consumption of Petroleum				
Land-Based Sources[5]	11,000	77,000	1,600	11,200
Recreational Vessels	770	5,390	770	5,390
Vessel >100 GT (spills)	100	700	30	210
Vessel >100 GT (operational discharges)	trace	trace	trace	trace
Vessel <100 GT (operational discharges)	trace	trace	trace	trace
Deposition of Atmospheric Releases (VOCs)	90	630	60	420
Aircraft Jettison of Fuel	N/A	N/A	N/A	N/A
Sum of Consumption	12,000	84,000	2,500	17,500

[1]Trace indicates <70 bbl (10 tonnes).

[2]Coastal facility spills do not include spills in coastal waters related to exploration and production spills or spills from vessels. The category "Coastal Facilities" includes aircraft, airport, refined product in coastal pipeline, industrial facilities, marinas, marine terminals, military facilities, municipal facilities, reception facilities, refineries, shipyards, and storage tanks.

[3]Volatization of light hydrocarbons during tank vessel loading, washing, and voyage.

[4]Sums may not match.

[5]Inputs from land-based sources during consumption of petroleum are the sum of diverse sources. Three categories of wastewater discharge are summed: municipal; industrial (not related to petroleum refining); and petroleum refinery wastewater. Urban runoff is included. It results from oil droplets from vehicles washing into waterways from parking lots and roads, and the improper disposal of oil containing consumer products.

GT = gross tons.

N/A = not available.

VOCs = volatile organic compounds.

Source: NRC, 2003.

Table 3-29. Average Annual Inputs of Petroleum Hydrocarbons to Offshore Waters of the Gulf of Mexico, 1990-1999.

Inputs	Western Gulf of Mexico		Eastern Gulf of Mexico	
	(tonnes)	(bbl)	(tonnes)	(bbl)
Natural Sources				
Seeps	70,000	490,000	70,000	490,000
Extraction of Petroleum				
Platform Spills	50	350	trace[1]	trace
Atmospheric Releases (VOCs)	60	420	trace	trace
Permitted Produced-Water Discharges	1,700	11,900	trace	trace
Sum of Extraction	1,800	12,600	trace	trace
Transportation of Petroleum				
Pipelines Spills	60	420	trace	trace
Tank Vessels Spills	1,500	10,500	10	70
Atmospheric Releases (VOCs)	trace	trace	trace	trace
Sum of Transportation	1,600	11,200	10	70
Consumption of Petroleum				
Land-Based Consumption[2]	N/A	N/A	N/A	N/A
Recreational Vessel Consumption[3]	N/A	N/A	N/A	N/A
Vessel >100 GT (spill)	120	840	70	490
Vessel >100 GT (operational discharges)	25	175	trace	trace
Vessel <100 GT (operational discharges)	trace	trace	trace	trace
Deposition of Atmospheric Releases (VOCs)	1,200	8,400	1,600	11,200
Aircraft Jettison of Fuel	80	560	80	560
Sum of Consumption[4]	1,400	9,800	1,800	12,600

[1]Trace indicates <70 bbl (10 tonnes).
[2]Limited to coastal zone.
[3]Limited to within 3 mi (5 km) of the coast.
[4]Sums may not match.
GT = gross tons.
N/A = not available.
VOCs = volatile organic compounds.

Source: NRC, 2003.

3.3.2.5 Non-OCS Oil- and Gas- Related Air Emissions

There are many air emissions sources related to non-OCS oil- and gas-related activities. Air emissions are caused by non-OCS onshore oil and gas activities and offshore State oil and gas activities, including combustion sources from power and heat generation, and the use of compressors, pumps, and reciprocating engines (i.e., boilers, turbines, and other engines); emissions resulting from flaring and venting of gas; and fugitive emissions. For instance, at the northern border between Texas and Louisiana (Haynesville Shale), there is a very large reserve of recoverable natural gas with recent extensive leasing and exploration activities. The economic impact is important in the region; however, it also generates significant amounts of ozone precursors as revealed by air quality modeling scenarios ranging from limited, moderate, and aggressive development reported in Kemball-Cook et al. (2010). Such precursors, nitrogen oxides and VOCs, are emitted during drilling, subsequent rock fracturing, venting, well completion, dehydration of natural gas, and fugitive emissions from compressor engines, wells, and pipeline components. The principal pollutants from these air emissions could also include NO_x, SO_x, CO, PM_{10}, $PM_{2.5}$, H_2S, VOC, benzene, ethylbenzene, toluene, xylene, glycols, and polycyclic aromatic hydrocarbons (PAHs).

Non-OCS oil- and gas-related activities can also include emissions from commercial and home heating, naturally occurring forest fires, motor vehicles, industrial activities in territorial seas and coastal waters, and industrial and transportation activities onshore. These activities can range from large, highly regulated industrialized sources such as electric utilities that burn fuel down to individual human sources such as outdoor grilling, jet skis, or using gasoline-powered equipment. In addition, sand borrowing and transportation in State territorial waters also generate emissions that can affect air quality. The principal pollutants from these air emissions sources include NO_x, SO_x, CO, PM_{10}, $PM_{2.5}$, and VOC. For more information on sources of air quality issues, refer to **Chapter 4.1.2**.

3.3.2.6 Other Non-OCS Oil- and Gas-Related Activities

3.3.2.6.1 Military Warning and Water Test Areas

The Gulf of Mexico (GOMEX) Range Complex contains four separate operating areas: Panama City and Pensacola, Florida; New Orleans, Louisiana, and Corpus Christi, Texas. The operating areas within the GOMEX Range Complex are not contiguous but are scattered throughout the GOM. The GOMEX Range Complex includes special-use airspace with associated warning areas and restricted airspace, and surface and subsurface sea space of the four operating areas. The air space over the GOM is used by the DOD for conducting various military operations. Twelve MWAs and six EWTAs are located within the GOM (**Figure 3-8**). These MWAs and EWTAs are multiple-use areas where military operations and oil and gas development have coexisted without conflict for many years. Several military stipulations are planned for leases issued within identified military areas.

To eliminate potential impacts from multiple-use conflicts on the aforementioned area and on blocks that the Navy has identified as needed for testing equipment and for training mine warfare personnel, a standard Military Areas Stipulation is routinely applied to all GOM leases (**Appendix D.3**).

In addition, BOEM's Gulf of Mexico OCS Region issued NTL 2014-BOEM-G04, which provides links to the addresses and telephone numbers of the individual command headquarters for the military warning and water test areas in the GOM. The NTL 2014-BOEM-G04 can be found on BOEM's website at http://www.boem.gov/Notices-to-Lessees-and-Operators/.

BOEM anticipates that, over the next 50 years, the military use areas currently designated regionwide would remain the same and that none of them would be released for nonmilitary use. Over the cumulative activities scenario, BOEM expects to continue to require military coordination stipulations in these areas. The intensity of the military's use of these areas, or the type of activities conducted in them, is anticipated to fluctuate with military mission needs.

3.3.2.6.2 Offshore Deepwater Ports and Nearshore Liquefied Natural Gas Terminals

Deepwater ports are designed to provide access for tankers and LNG carriers to offshore offloading facilities for hydrocarbon products, i.e., crude oil and natural gas. Crude oil passing through an offshore port may be temporarily stored and then transported to shore via pipeline. The term "deepwater port" includes all associated components and equipment, including pipelines, pumping stations, service platforms, mooring buoys, and similar features or equipment to the extent that they are located seaward of the high water mark (USDOT, MARAD, 2015b).

The Deepwater Port Act of 1974, as amended by the Maritime Transportation Security Act of 2002, establishes a licensing system for ownership, construction, operation and decommissioning of deepwater port structures located beyond the U.S. territorial sea. The Deepwater Port Act sets out conditions that deepwater port license applicants must meet, including the minimization of adverse impacts on the marine environment and submission of detailed plans for construction, operation, and decommissioning of deepwater ports. The Deepwater Port Act also sets out detailed procedures for the issuance of licenses by the Secretary of Transportation and prohibits the issuance of a license without the approval of the Governors of the adjacent coastal states (USDOT, MARAD, 2015b). Since early 2015, 20 deepwater port license applications have been filed with the Maritime Administration (MARAD) for approval (18 applications for licenses to import LNG and 2 applications filed for licenses to import oil).

Gulf of Mexico Offshore Deepwater Ports

Currently in the U.S., there is one offshore deepwater port in operation in the GOM, i.e., the Louisiana Offshore Oil Port (LOOP). The LOOP has received and transferred over 11 Bbbl of crude oil since its inception (LOOP, LLC, 2015).The offloaded crude oil is transported to shore via 48-in (123-cm) diameter pipeline. The LOOP receives and temporarily stores crude oil supplies from three sources, including the following:

- tankers carrying foreign (imported oil from Arabian Gulf, Russia, West Africa, North Sea, Mexico, and South America) and domestic crude oil from FPSOs;
- domestic crude oil produced in the Gulf of Mexico (Mars and Thunder Horse platforms); and
- movement of domestic crude oil via the Houston to Houma (Ho-Ho) pipeline.

Another LNG deepwater port (Port Dolphin) has been proposed in the Gulf of Mexico, and it has been approved by MARAD and USCG. Port Dolphin is in development and is obtaining the necessary permits for construction; in addition, Höegh LNG is currently evaluating the market potential that may affect the status of the project (Castro, official communication, 2015). Port Dolphin has approval from the Federal Energy Regulatory Commission (FERC) and MARAD for completion of construction of the deepwater port and pipeline until December 2018. Gulf Gateway Energy Bridge was an LNG deepwater port in the Gulf of Mexico, and it was decommissioned in 2013. Additional information on the licenses and applications of deepwater ports and LNG facilities specific to the Gulf of Mexico can be found on MARAD's website (USDOT, MARAD, 2015b).

In 2015, Delfin LNG proposed an offshore floating LNG project in the U.S. which would be located approximately 45 mi (72 km) offshore of Cameron, Louisiana (*Federal Register,* 2015d). The proposed project schedule is to receive Federal approvals and the Deepwater Port Act license in 2016, to have offshore and onshore construction in 2017 to 2018, and to commence operations in 2019.

Gulf Gateway Energy Bridge, LLC (Gulf Gateway) operated in the Gulf of Mexico off the coast of Louisiana from 2005 to 2012. The decision to decommission the facility was due to irreparable hurricane damage to pipelines (Hurricane Ike in 2008) interconnecting with the deepwater port and a changing natural gas market, which impacted the operator's ability to receive consistent shipments (USDOT, MARAD, 2015b).

Nearshore Liquefied Natural Gas (LNG)

The FERC is responsible for authorizing the siting and construction of onshore and nearshore (State waters) LNG import or export facilities under Section 3 of the Natural Gas Act. The FERC, under Section 7 of the Natural Gas Act, also issues certificates of public convenience and necessity for LNG facilities engaged in interstate natural gas transportation by pipeline. There are more than 110 LNG facilities operating in the U.S. performing a variety of services. The LNG terminal means all natural gas facilities located onshore or nearshore (in State waters) that are used to receive, unload, load, store, transport, gasify, liquefy, or process natural gas that is

- imported to the U.S. from a foreign country,
- exported to a foreign country from the U.S., or
- transported in interstate commerce by a waterborne vessel.

Some facilities export natural gas from the U.S., some provide natural gas supply to the interstate pipeline system or local distribution companies, while others are used to store natural gas for periods of peak demand. There are also facilities that produce LNG for vehicle fuel or for industrial use. Depending on location and use, an LNG facility may be regulated by several Federal agencies and by State utility regulatory agencies. Projects that are approved and built are subject to FERC's oversight for as long as the facility is in operation. The FERC currently regulates 24 operational LNG facilities (USDOE, FERC, 2015b). In the Gulf of Mexico State waters (nearshore), there are currently five LNG terminals, of which all five are currently in operation and planned for expansion of the facilities to export of natural gas to foreign markets:

- Freeport LNG Import/Export Terminal (Freeport, Texas);
- Golden Pass LNG Import/Export Terminal (Sabine Pass, Texas);
- Sabine Pass LNG Import/Export Terminal (Sabine Pass, Texas);
- Cameron LNG Import/Export Terminal (Formerly Hackberry LNG) (Cameron, Louisiana); and
- Lake Charles LNG Import/Export Terminal (Lake Charles, Louisiana).

The Corpus Christi LNG import/export terminal (Corpus Christi, Texas) was recently reviewed and approved by FERC and DOE, and they subsequently began construction in May 2015 (Cheniere Energy, 2015).

While interest in deepwater port development peaked in the 2000-2010 period, economic conditions for LNG have changed since 2010. BOEM notes that interest in LNG offshore terminal projects is expected to diminish over at least the next decade, with potential and subsequent stabilization in the LNG market. It is possible that LNG facilities in the Gulf of Mexico, or elsewhere, presently in the permitting process or in early construction phases could be withdrawn from consideration, cancelled, or deferred until LNG economics improve or until facilities under construction for importing LNG could be modified for exporting LNG. BOEM anticipates that, over the next 50 years, two additional LNG facilities in the CPA would be licensed and operating. It is unclear as to whether these LNG facilities will occur during the period of a proposed action, although trends evident in the submittal, approval, and withdrawal of recent applications suggest that such development is unlikely. Additional information on LNG terminal applications, application review determinations, and operational status for the Gulf of Mexico offshore LNG facilities can be found on MARAD's website at http://www.marad.dot.gov/ports/.

3.3.2.6.3 Development of Gas Hydrates

Methane hydrates (or gas hydrates) are cage-like lattices of water molecules containing methane, the chief constituent of natural gas found under arctic permafrost, as well as beneath the ocean floor. These may represent one of the world's largest reservoirs of carbon-based fuel. However, with abundant availability of natural gas from conventional and shale resources, there is no economic incentive to develop gas hydrate resources, and no commercial-scale technologies to exploit them have been demonstrated (USDOE, Energy Information Administration, 2012).

In the Gulf of Mexico, a Joint Industry Project was formed to carry out an assessment of gas hydrates in deep water of the GOM and to better understand the impact of hydrates on safety and seafloor stability, climate change, and assessment of the feasibility of marine hydrate as a potential future energy source. The findings of the 13-year (2001-2014) study concluded that hydrates are a readily managed, shallow drilling hazard and that hazard mitigation can be accomplished using existing protocols; field data indicate the occurrence of high-saturation hydrate accumulations in the GOM; methods employed to locate and predict hydrates were effective and accurate; and development of prototype tools and methods to collect hydrate pressure cores were developed.

BOEM released the results of a systematic geological and statistical assessment of gas hydrates resources in the GOM (USDOI, MMS, 2008a). This assessment incorporates the latest science with regard to the geological and geochemical controls on gas hydrate occurrence. It indicated that a mean volume of 607 trillion m^3 (21,444 Tcf) of methane was in-place in hydrate form. The assessment has determined that a mean of 190 trillion m^3 (6,710 Tcf) of this resource occurs as relatively high-concentration accumulations within sand reservoirs that may someday be produced. The remainder occurs within clay-dominated sediments from which methane probably would never be economically or technically recoverable.

BOEM anticipates that, over the next 40 years, the Joint Industry Project would complete the third leg of its characterization project for GOM gas hydrates in the cumulative impacts area. Within 40 years, it is likely that the first U.S. domestic production from hydrates may occur in Alaska, where gas obtained from onshore hydrates would either support local oil and gas field operations or be available for commercial sale if and when a gas pipeline is constructed to the lower 48 states. However, it is not possible to discount the possibility that first U.S. domestic production of gas hydrates could occur in the GOM (Moridis et al., 2008). Despite the substantially increased complexity and cost of offshore operations, there is a mature network of available pipeline capacity and easier access to markets in the GOM.

3.3.2.6.4 Renewable Energy and Alternative Use

On August 8, 2005, President George W. Bush signed the Energy Policy Act of 2005 into law. Section 388 (a) of the Energy Policy Act amended Section 8 of the OCSLA (43 U.S.C. § 1337) to authorize DOI to grant leases, easements, or rights-of-way on the OCS for the development and support of energy resources other than oil and gas and to allow for alternate uses of existing structures on OCS lands.

A final programmatic EIS for the OCS renewable energy program was published by this Agency in October 2007 (USDOI, MMS, 2007b) and a Record of Decision was published in the *Federal Register* on January 10, 2008 (*Federal Register*, 2008a). The Act authorized this Agency to develop a comprehensive program and regulations to implement the new authority. Final rules for

BOEM's renewable energy program were published on April 29, 2009, as 30 CFR part 285 (*Federal Registe*r, 2009).

The two primary categories of renewable energy that have the potential for development in the coastal and OCS waters of the U.S. are wind turbines and marine hydrokinetic systems. The first and most technologically mature renewable energy is wind energy, a popular source of clean and renewable energy that has been in use for centuries. The DOE released a strategic plan for creating an offshore wind industry in the U.S. (USDOE, 2011). In this plan, DOE determined that offshore wind energy can help the Nation reduce its greenhouse gas emissions, diversify its energy supply, provide cost-competitive electricity to key coastal regions, and stimulate economic revitalization of key sectors of the economy. However, if the Nation is to realize these benefits, key barriers to the development and deployment of offshore wind technology must be overcome, including the relatively high cost of energy, technical challenges surrounding installation and grid interconnection, and the permitting processes governing deployment in both Federal and State waters. There are two critical objectives to realize the strategic plan's goals: (1) reduce the cost of offshore wind energy; and (2) reduce the timeline for deploying offshore wind energy (USDOE, 2011, page 2). Since April 29, 2009, when the regulations governing renewable energy on the OCS were publicized, no wind park developments have been proposed in OCS waters of the GOM; however, there have been proposals in Texas coastal waters.

In Fiscal Year 2010, the DOE instituted the Offshore Wind Innovation and Demonstration initiative to consolidate and expand its efforts to promote and accelerate responsible commercial offshore wind development in the United States. In 2012, the DOE's Wind Program announced Federal funding nationwide in three major categories: technology development; market acceleration; and advanced technology demonstration. The Wind Program is working with BOEM to advance a national strategy for offshore wind research and development (Navigant Consulting, Inc., 2013). According to the Navigant Consulting, Inc. report, there is a potential of 594 gigawatts of potential wind energy available in the GOM. Offshore wind could create approximately 20.7 direct jobs per annual megawatt (or 20,700 jobs per annual gigawatt) installed in U.S. waters. Baryonyx Rio Grande Wind Farms received $4 million to produce three demonstration turbines in State waters (refer to "Renewable Energy Projects in Texas State Waters" below).

The second category of potential offshore renewable energy technologies is marine hydrokinetic systems, which are in a more developmental stage relative to wind turbines. The marine hydrokinetic systems consist of devices capable of capturing energy from ocean waves and currents. There has been no interest expressed in wave or current technologies in the GOM because the conditions necessary for their deployment are not suitable to the Gulf of Mexico. The marine hydrokinetic current technologies are actively being considered for the east coast of Florida where the Gulf Stream would provide a strong and continuous source of energy to turn underwater turbines.

The Energy Policy Act clarifies the Secretary's authority to allow the existing oil and gas structures on OCS lands to remain in place after production activities have ceased and to transfer liability and extend the life of these facilities for non-oil and gas purposes, such as research, renewable energy production, aquaculture, etc., before being removed. With many bottom-founded platform structures located along the nearshore border of OCS waters, the GOM would seem to have some potential for the reuse of these facilities.

BOEM expects that, over the next 40 years, a limited number of alternative use projects would be proposed in the WPA. It is also likely that these alternative use projects would consist of wind energy projects based on the current development of that technology. BOEM's expectation is based on the fact that known projects are being proposed in Texas State waters. Likewise, the potential alternative use projects could consist of a combination of integrated existing GOM infrastructure with new-built facilities.

Renewable Energy Projects in Texas State Waters

On October 24, 2005, the Texas General Land Office announced authorization for the first offshore wind energy project in the United States to be built in State waters off the Texas coast. An 11,355-ac (4,595-ha) lease was awarded to Galveston-Offshore Wind, L.L.C., a subsidiary of Louisiana-based Wind Energy Systems Technologies (now Coastal Point Energy LLC), where 50 wind turbines would be placed for the 150-megawatt development. The lease area is located approximately 7 mi (11 km) southeast of Galveston Island. Wind Energy Systems Technologies (now Coastal Point Energy LLC) was awarded the rights for additional leases south of the Galveston-Offshore Wind, L.L.C. project area, which would be developed after the Galveston project. The target completetion date is 2018. The Texas General Land Office leased acreage to Baryonyx Corporation to build additional offshore wind projects; however, while Baryonyx Corporation received money during the first phase of the Offshore Wind and Innovation Demonstration initiative, which was led by the U.S. Department of Energy, they did not receive funding to continue into the second phase (USDOE, Office of Energy Efficiency and Renewable Energy, 2015). Baryonyx Corporation ultimately abandonded the project.

3.3.2.6.5 Aquaculture

Offshore aquaculture is the rearing of aquatic animals in controlled environments (e.g., cages or net pens) in Federal waters. The NOAA has published the rule to implement a Fishery Management Plan for regulating offshore aquaculture in the Gulf of Mexico (*Federal Register*, 2016c). The rule establishes a comprehensive regulatory program for managing the development of an aquaculture industry in Federal waters of the Gulf of Mexico. An interagency group has been established and is working on the permitting process for future proposed aquaculture activities. This group consists of the three permitting agencies, i.e., NOAA, USEPA, and USACE, and other agencies with an interest or expertise on the OCS, including USCG, FWS, BOEM, and BSEE. This group will continue to coordinate the permitting process.

3.3.2.6.6 OCS Sand Borrowing

If OCS sand is desired for coastal restoration or beach nourishment, BOEM uses the following two types of lease conveyances: a noncompetitive negotiated agreement (NNA) that can only be used for obtaining sand and gravel for public works projects funded in part or whole by a Federal, State, or local government agency; and a competitive lease sale in which any qualified person may submit a bid. BOEM has issued 51 noncompetitive negotiated agreements but has never had a competitive lease sale for OCS sand and gravel resources. BOEM's Marine Minerals Program continues to focus on identifying sand resources for coastal restoration, investigating the environmental implications of using those resources, and processing noncompetitive use requests.

Since 2003, BOEM has participated in the multiagency Louisiana Sand Management Working Group to identify, prioritize, and define a pathway for accessing sand resources in the near-offshore OCS of Louisiana, an area where competitive space use mainly involves OCS oil- and gas-related infrastructure such as wells, platforms, and pipelines. **Table 3-30** shows the projected approximate volume of OCS sand uses for coastal restoration projects over the next 5 years. Approximately 76 million yd^3 (58 million m^3) are expected to be needed for coastal restoration projects, as reported by the Gulf of Mexico OCS Region's Marine Minerals Program. To visualize such a dimension, this volume of sand could fill the Louisiana Superdome stadium 16.5 times.

In 2005, BOEM began to conduct offshore sand studies to investigate available sources of OCS sand for restoring coastal areas in Louisiana, Texas, Alabama, and Mississippi that were damaged by Hurricanes Katrina and Rita. Sand sources identified through BOEM's cooperative effort with Louisiana would likely serve as the major source of material for the restoration of the barrier islands planned as part of the Louisiana Coastal Area ecosystem restoration study (U.S. Dept. of the Army, COE, 2004) and for projects identified in the Louisiana 2012 and 2017 Master Plans (State of Louisiana, Coastal Protection and Restoration Authority, 2012 and 2015), projects developed under the *Deepwater Horizon* Natural Resource Damage Assessment (NRDA); Coastal Wetlands Planning, Protection and Restoration Act; Coastal Impact Assessment Program; National Fish and Wildlife Foundation's Gulf Environmental Benefit Fund; and the 2012 Resources and Ecosystems Sustainability, Tourist Opportunities and Revived Economies of the Gulf Coast States Act (RESTORE Act) barrier island restoration efforts.

Table 3-30. Projected OCS Sand Resource Needs for Planned Restoration Projects.

Restoration Project	Maximum Sand (yd^3)	OCS Lease Area and Block Number (if known)
NRDA Breton Island	~6,000,000	Breton Sound 42-44; Main Pass 42-44 and 53-55
NRDA Caillou Lake Headlands (Whiskey)	13,400,000	Ship Shoal 88
Mississippi Coastal Improvement Program (MsCIP)	23,000,000	Mobile 817-819 and 861-864
Southwest Louisiana	~15,000,000	N/A
Raccoon Island	~1,100,000	Ship Shoal 88 and 89; South Pelto 12-14
Trinity and East Islands	~16,260,000	Ship Shoal 88 and 89; South Pelto 12-14
Timbalier Island	~10,700,000	Ship Shoal 88 and 89; South Pelto 12-14
East Timbalier Island Restoration	~11,230,000	South Pelto 12-14
Caminada Headland (I and II)	~11,300,000	South Pelto 12-14
Total	~108,490,000	

N/A = not available.
~ = approximately.

Since the dredging of OCS sand and the associated activities of oceangoing dredge vessels could present some use conflicts on blocks also leased for oil and gas extraction, BOEM initiated a regional offshore sand management program in Louisiana in 2003, which, over the course of 10 years and several meetings, has developed options and recommendations for an orderly process to manage the competing use of OCS sand resources in areas of existing OCS infrastructure. With input from the Sand Management Working Group, BOEM has developed guidelines for sand resource allocations, maintaining a master schedule of potential sand dredging projects, developing procedures for accessing sand under emergency conditions, and establishing environmental requirements for the use of offshore borrow areas.

Noncompetitive negotiated agreements have been issued in the following locations. No sand noncompetitive negotiated agreements have ever been issued for OCS sand in the WPA. The EPA has three noncompetitive negotiated agreements:

- Pinellas County, Florida;
- Longboat Key, Town of Longboat Key, Florida; and
- Collier County, Florida.

The following 11 noncompetitive negotiated agreements for OCS sand have been issued in the CPA:

- Holly Beach, Cameron Parish, Louisiana;
- South Pelto test area, Terrebonne Parish, Louisiana;
- Pelican Island shoreline restoration, Plaquemines Parish, Louisiana;
- Raccoon Island marsh creation, Terrebonne Parish, Louisiana;
- St. Bernard Shoals, St. Bernard and Plaquemines Parishes, Louisiana;
- Ship Shoal in South Pelto Area for Caminada Headland restoration, Lafourche and Jefferson Parishes, Louisiana;
- Sabine Bank, Cameron Parish, Louisiana;
- Caminada II, Lafourche and Jefferson Parishes, Louisiana;
- NRDA Whiskey Island, Terrebonne Parish, Louisiana;
- North Breton Island, Breton Island National Wildlife Refuge, Louisiana; and
- Mississippi Coastal Improvements Program, Gulf Island National Seashore, Mississippi.

In 2013, BOEM began working with the U.S. Dept. of the Interior, Geological Survey (USGS) and FWS on a North Breton Island Restoration Project work plan, which is included in the NRDA early restoration plan, Phase III (USDOC, NOAA, 2015c). The North Breton Island Restoration Project (Louisiana) would use sand from the Breton Sound Area to restore shorebird and brown pelican nesting habitat in the Breton National Wildlife Refuge. It is anticipated that the noncompetitive negotiated agreement would be signed in 2017, with dredging for the North Breton Island Restoration Project beginning in late 2017. BOEM issued two noncompetitive negotiated agreements in Louisiana in 2015: the first was for the *Deepwater Horizon* NRDA Whiskey Island Restoration Project in Terrebonne Parish using sand from Ship Shoal Block 88; and the second was for Phase Two of the Caminada Headland Restoration Project in Lafourche and Jefferson Parishes using sand from South Pelto Blocks 13 and 14. Dredging for Caminada II began in 2015 and is anticipated to be complete in 2017. Whiskey island is anticipated to begin construction in Winter 2016/2017 with completion in 2018. Another project site, East Timbalier Island, has been severely degraded due to the impacts of several strong storms, subsidence, and other factors. Historically, the island served to define the seaward boundary of the eastern Terrebonne Basin estuary, reducing the transmission of GOM waves into Terrebonne Bay. The noncompetitive negotiated agreement is expected to be signed in 2017 using proposed borrow areas from Ship Shoal in South Pelto Blocks 12, 13, and 14. BOEM is also working with the COE's Mobile District and the National Park Service on the Mississippi Coastal Improvements Program, which would use OCS sand from the Mobile Area for barrier island restoration projects along East and West Ship Islands in the Gulf Islands National Seashore. The noncompetitive negotiated agreement Record of Decision was signed in 2016 and will utilize OCS sand from Mobile Blocks 817-819 and 861-864. Dredging associated with the Mississippi Coastal Improvements Program is expected to begin in 2017 and is expected to continue until 2019.

BOEM is authorized by 30 CFR § 550.101 to ensure that operations conform to sound conservation practice to preserve, protect, and develop mineral resources of the OCS and to minimize or eliminate conflicts between the exploration, development, and production of oil and natural gas and the recovery of other resources. BOEM's responsibility as steward of significant sand resources on the OCS is outlined in NTL 2009-G04. This NTL provides guidance for the avoidance and protection of significant OCS sediment resources essential to coastal restoration initiatives in BOEM's Gulf of Mexico OCS Region. The use of OCS sediment resources is authorized by BOEM through its Marine Minerals Program. Additional measures have been implemented and continue to be developed to help safeguard the most significant OCS sediment resources, reduce multiple use conflicts, and minimize interference with oil and gas operations under existing leases or pipeline rights-of-way. Mitigating measures ensure activities (including surface or near-surface emplacement of platforms, wells, drilling rigs, pipelines, umbilicals, and cables) avoid or are removed from, to the maximum extent practicable, significant OCS sediment resources.

Over the next 50 years, increased use of OCS sand for restoration projects in states that fall within the CPA are likely. Currently, no WPA restoration projects have been specifically identified. The boundary between the OCS and Texas State waters (9 nmi [10 mi; 16 km]) allows that some offshore sand is within the jurisdiction of the State; however, the easternmost portion of the shelf in Texas State waters is relatively devoid of beach-quality sand deposits. The Texas General Land Office, in cooperation with BOEM and the Texas Bureau of Economic Geology, has investigated the potential for use of Heald and Sabine Banks and confirmed substantial reserves of restoration quality sand. However, the State of Texas has yet to identify specific projects. The COE has intermittently used OCS sand reserves, and it is expected that this trend would continue. With respect to Louisiana, some uncertainty exists as to the amount of offshore OCS sand that would eventually be sought for coastal restoration projects. The Louisiana Coastal Area Ecosystem Restoration Plan potentially may use up to 60 million yd^3 (46 million m^3) (U.S. Dept. of the Army, COE, 2009a). Recently, there has been an increase in requests from Louisiana for State-funded OCS sand resources projects. BOEM anticipates that this growing trend of State-led projects would continue into the future as restoration funding is made available directly to the State through the Coastal Impact Assistance Program, the Gulf of Mexico RESTORE Act, Coastal Wetlands Planning, Protection and Restoration Act, National Fish and Wildlife Foundation: Gulf Environmental Benefit Fund, the *Deepwater Horizon* NRDA restoration, and GOMESA. These programs are outlined in more detail in **Chapter 3.3.2.8.3**.

3.3.2.7 Noise from Non-OCS Oil- and Gas-Related Sources

Other noise sources in the GOM are from non-OCS oil- and gas-related activities: vessel propeller cavitation from commercial shipping vessels, research vessels, tourism vessels, and commercial and recreational fishing vessels; sources from other equipment used on vessels (e.g., pingers used in fisheries to prevent animals getting caught in nets); State drilling operations; aircraft; military operations; coastal infrastructure construction (e.g., pile driving); underwater explosions; and natural phenomena such as wind, large storms, or lightning strikes. It is not under BOEM's authority to regulate any of these non-OCS oil- and gas-related noise sources, although some do occur on the

OCS. Refer to **Chapter 3.1.9** for general information on OCS oil- and gas-related sources of noise in the GOM.

Non-OCS Oil- and Gas-Related Geological and Geophysical Surveys

The G&G surveys are conducted to (1) obtain data for hydrocarbon and mineral exploration and production in Federal or State waters; (2) aid in siting renewable energy structures and facilities, and pipelines; (3) locate and monitor the use of potential sand and gravel resources for development; (4) identify possible seafloor or shallow-depth geologic hazards; and (5) locate potential archaeological resources and benthic habitats that should be avoided (**Chapters 4.4 and 4.13**, Deepwater Benthic Communities and Archaeological Resources, respectively).

Detailed descriptions of G&G activities are provided in more detail in the Atlantic G&G Activities Programmatic EIS (USDOI, BOEM, 2014a). A Programmatic EIS is currently being developed for the GOM (refer to **Chapter 1.7**). The selection of a specific technique or suite of techniques is driven by data needs and the target of interest. These activities include the following:

- various types of deep-penetration seismic airgun surveys used for State oil and gas exploration and development;
- other types of surveys and sampling activities used only in support of State oil and gas exploration and development, including electromagnetic surveys, deep stratigraphic and shallow test drilling, and various remote-sensing methods;
- HRG surveys used in all three program areas to detect shallow geohazards and marine minerals, archaeological resources, and certain types of benthic communities; and
- geological and geotechnical bottom sampling used in all three program areas to assess the suitability of seafloor sediments for supporting structures (e.g., platforms, pipelines, cables, renewable energy facilities such as wind turbines) or to evaluate the quantity and quality of marine minerals and sand for beach nourishment or other potential marine mineral extraction projects.

Deep-penetration seismic surveys, in which survey vessels tow an airgun or an array of airguns that emit acoustic energy pulses through the overlying water then into the seafloor over long durations and over large areas, are the most extensive G&G activities that would be conducted. These surveys would occur almost exclusively in support of oil and gas exploration and development and could be conducted in State waters. The G&G activities in support of renewable energy development would consist mainly of HRG and geotechnical surveys in Federal and State waters less than 40 m (131 ft) deep (USDOI, MMS, 2007b); this area represents approximately 25.9 percent of the GOM. The G&G activities in support of marine mineral uses (e.g., sand and gravel mining) would consist mainly of HRG and geotechnical surveys in Federal and State waters greater than 30 m (98 ft) deep; this area represents approximately 19.5 percent of the GOM. The G&G activities beyond the outer boundary of the planning areas have not been determined but could include geophysical surveys in support of the U.S. Extended Continental Shelf Project, which aims to establish the full extent of the continental shelf of the U.S., consistent with international law.

3.3.2.8 Coastal Environments

3.3.2.8.1 Sea-Level Rise and Subsidence

As part of the Mississippi River's delta system, both the Delta Plain and the Chenier Plain of the Louisiana Coastal Area (LCA) are experiencing relatively high rates of subsidence. All coastlines of the world have been experiencing a gradual absolute rise of sea level that is based on measurements across the globe and that extends across the influence of a single sedimentary basin. There are two aspects of sea-level rise during the past 10,000 years (Holocene Epoch): absolute sea-level rise and relative sea-level rise. Absolute sea-level rise refers to a net increase in the volume of water in the world's oceans. Relative sea-level rise refers to the appearance of sea-level rise, a circumstance where subsidence of the land is taking place at the same time that an absolute sea-level change may be occurring. Geologists tend to consider all sea-level rises as relative because the influence of one or the other is difficult to separate over geologic timeframes.

An absolute sea-level rise would be caused by the following two main contributors to the volume of ocean water on the Earth's surface: (1) change in the volume of ocean water based on temperature; and (2) change in the amount of ice locked in glaciers, mountain ice caps, and the polar ice sheets. For the period 1961-2003, thermal expansion of the oceans accounts for only 23 ± 9 percent of the observed rate of sea-level rise (Bindoff et al., 2007); the remainder is water added to the oceans by melting glaciers, ice caps, and the polar ice sheets. The measurement of sea-level rise over the last century is based on tidal gauges and, more recently, satellite observations, which are not model dependent. Projections for future sea-level rise are dependent on temperature. As determined by an analysis of air bubbles trapped in Antarctic ice cores, today's atmospheric concentration of CO_2 is the highest it has ever been over the last 2.1 million years (Karl et al., 2009; Luthi et al., 2008; Hönisch et al., 2009). Although the measured data for atmospheric CO_2 concentration or temperatures measurements since the Industrial Revolution are generally not in dispute, proxy data for climates of the geologic past are a source of debate, and the models constructed to make projections for how climate may change remain controversial. Climate models are very sophisticated, but they may not account for all variables that are important or may not assign variables the weight of their true influence.

> *Although absolute sea-level rise is a contributor to the total amount of sea-level rise along the Gulf Coast, subsidence is the most important contributor to the total.*

The Intergovernmental Panel on Climate Change (IPCC) reported that, since 1961, global average sea level (mean sea level) has risen at an average rate of 1.8 millimeter/year (mm/yr) (0.07 in/yr) and, since 1993, at 3.1 mm/yr (0.12 in/yr) (Bindoff et al., 2007). With updated satellite data to 2010, Church and White (2011) show that satellite-measured sea levels continue to rise at a rate close to that of the upper range of the IPCC projections (IPCC, 2012). It is unclear whether the faster rate for 1993-2010 reflects decadal variability or an increase in the longer-term trend. In the structured context used by the IPCC, there is high confidence that the observed sea-level rise rate increased from the 19th to the 20th century. Over the period 1901 to 2010, global mean sea level rose by 0.19 m (0.62 ft) (with a range of 0.17-0.21 m [56-69 ft]). The rate of sea-level rise since the mid-19th century has been larger than the mean rate during the previous two millennia (IPCC, 2014). The U.S. Global Change Research Program reported that, over the last 50 years, sea level has risen up to 8 in (203 mm) along parts of the Atlantic and Gulf Coasts, which included Louisiana and Texas (Karl et al., 2009), and that global sea level is currently rising at an increasing rate.

In comparison to other areas along the Gulf Coast, Louisiana's Mississippi Delta and Chenier Plains are built of young sediments deposited over the last 7,000 years. These deltaic sediments have been undergoing compaction and subsidence since they were deposited. The land is sinking at the same time that sea level is rising, contributing to high rates of relative sea-level rise along the Louisiana coast. Blum and Roberts (2009) posited four scenarios for subsidence and sea-level rise, and they concluded sediment starvation alone would cause approximately 2,286 mi^2 (592,071 ha) of the modern delta plain to submerge by 2100, without any other impacting factors (including sea-level rise) contributing to land loss.

A general value of approximately 6 mm/yr (0.23 in/yr) of subsidence from sediment compaction, dewatering, and oxidation of organic matter (Meckel et al., 2006; Dokka, 2006) is a reasonable rate to attribute to the Louisiana coastal area, with the understanding that subsidence rates along the Louisiana coast are spatially variable and influenced by subsurface structure and the timing and manner that the delta was deposited.

Stephens (2009 and 2010) reported that the influence of subsurface structure has not been taken into account in subsidence assessments in the LCA and along the Gulf Coast (Stephens, 2009, page 747). Most workers studying the effects of subsidence along the LCA have focused on surficial or near-surface geologic data sources and have made no attempt to integrate basin analysis into planning for coastal restoration or flood control project planning.

Results from the National Assessment of Coastal Vulnerability to Sea Level Rise estimate the rate of sea-level rise in the GOM, in particular the areas around Eugene Island, Louisiana, to be the highest (9.65 mm/yr; 3.17 ft/century) in the United States (USDOC, NOAA, 2015d). This classification is based upon variables such as coastal geomorphology, regional coastal slope, rate of sea-level rise, wave and tide characteristics, and historical shoreline change rates. As much as 88 percent of the northern GOM falls within the high vulnerability category. Areas ranked as the very low vulnerability category still have some sea-level rise. The lowest rate of rise is found in Panama City, Florida, with a rate of 1.6 mm/yr or 0.53 ft/century. Given this range, BOEM anticipates that, over the next 50 years, the northern GOM would likely experience a minimum relative sea-level rise of 80.7 mm (3.18 in) and a maximum relative sea-level rise of 482.6 mm (19.0 in). Sea-level rise and subsidence together have the potential to affect many important areas, including the OCS oil and gas industry, waterborne commerce, commercial fishery landings, and important habitat for biological resources (State of Louisiana, Coastal Protection and Restoration Authority, 2012). Oil and gas infrastructure located within 15 in (381 mm) of the highest high tide in coastal areas along the Gulf of Mexico could potentially be affected by sea-level rise during this program. Programmatic aspects of climate change relative to the environmental baseline for the GOM are discussed in Chapter 4.2.1 of the Five-Year Program EIS.

Formation Extraction and Subsidence

Extracting fluids and gas from geologic formations can lead to localized subsidence at the surface. The Texas coast is experiencing high (5-11 mm/yr) (0.19-0.43 in) rates of relative sea-level rise that are the sum of subsidence and eustatic sea-level rise (Sharp and Hill, 1995). Even higher rates are associated with areas of groundwater pumping from confined aquifers. Berman (2005, Figure 3) reported that 2 m (6 ft) of subsidence had occurred in the vicinity of the Houston Ship Channel by the mid-1970's as a result of groundwater withdrawal.

Morton et al. (2005) examined localized areas or "hot spots" corresponding to fields in the LCA where oil, gas, and brine were extracted at known rates. Morton et al. (2005, Figure 26) shows measured subsidence along transects across these fields that range from 18 to 4 mm/yr (0.7 to 0.15 in), with the greatest rates tending to coincide with the surface footprints of oil or gas fields. Mallman and Zoback (2007) interpreted downhole pressure data in several Louisiana oil fields in Terrebonne Parish and found localized subsidence over the fields; however, they could not link these localized rates to the subsidence measured and observed on a regional scale.

Down-to-the-basin faulting, also called listric or growth faulting, is a long recognized fault style along deltaic coastlines, and the Mississippi Delta is no exception (Dokka, 2006; Gagliano, 2005a). There is currently disagreement in the literature regarding the primary cause of modern fault movement in the Mississippi Delta region, and the degree to which it is driven by fluid withdrawal or sediment compaction resulting from the sedimentary pile pressing down on soft, unconsolidated sediments that causes downward and toward the basin movement along surfaces of detachment in the shallow and deep subsurface. Berman (2005) discussed the conclusions of Morton et al. (2005) and believed that they failed to make the case that hydrocarbon extraction caused substantial subsidence over the broader area of coastal Louisiana, a conclusion also reached by Gagliano (2005b).

Oil production on the LCA peaked at 513 MMbbl in 1970 and gas production peaked at 7.8 MMcf in 1969 (Ko and Day, 2004). Between 2003 and 2012, oil production from Federal Gulf of Mexico waters has continued to decline (USDOE, Energy Information Administration, 2014b). From the peak, the level of production activity is slowly decreasing. The magnitude of subsidence caused by formation extraction is a function of how pervasive the activity is across the LCA. The oil and gas field maps in Turner and Cahoon (1987, Figure 4) and Ko and Day (2004, Figure 1) seem an adequate basis to estimate the LCA's oil- and gas-field footprint at ~20 percent of the land area. The amount of subsidence from formation extraction is also occurring on a delta platform that is experiencing natural subsidence and sea-level rise. Fluid and gas extraction may lead to high local subsidence on the scale of individual oil and gas fields but not as a pervasive contributor to regional subsidence across the LCA.

3.3.2.8.2 Erosion

BOEM conservatively estimates that there are approximately 4,850 km (3,013 mi) of Federal navigation channels, bayous, and rivers potentially exposed to OCS traffic regionwide (**Table 3-7**) and that the average canal is widening at a rate of 0.99 m/year (3.25 ft/year). Regionwide, this results in a total annual land loss of approximately 480 ac/yr (1,186 ha/yr).

In the Louisiana Coastal Master Plan (State of Louisiana, Coastal Protection and Restoration Authority, 2012), it is estimated that up to 1,750 mi^2 (4,500 km^2) of land would be lost in the next 50 years. Using BOEM's conservative estimate of approximately 4,850 km (3,014 mi) of Federal navigation channels, bayous, and rivers potentially exposed to OCS traffic in the LCA (**Table 3-7**) and the average canal widening rate of -0.99 m/yr (-3.25 ft/yr) (Thatcher et al., 2011), a total land loss of approximately 83,053 ac (33,611 ha) in navigation canals may be estimated over the next 70 years. Using this estimate and comparing it with the total expected land loss in coastal Louisiana over the next 50 years, BOEM estimates that approximately 2 percent of the total land loss in Louisiana would occur due to salt intrusion, hurricanes, and vessel traffic (OCS Program-related and non-OCS Program-related) in navigation canals. Because OCS Program-related vessel traffic constitutes such a small percentage (<1%) of the contributing factor to erosion in navigation canals, greater than 99 percent of the land loss in coastal Louisiana in the next 70 years can be attributed to non-OCS sources.

Net landloss due to navigation canals alone can be calculated by comparing erosion rates with beneficial activities such as land gained through the use of dredged sands. BOEM anticipates that, over the next 40 years, if current trends in the beneficial use of dredged sand and sediment are simply projected based on past land additions (U.S. Dept. of the Army, COE, 2009b), approximately 50,000 ac (20,234 ha) may be created or protected in the LCA through dredged materials programs.

3.3.2.8.3 Coastal Restoration Programs

The Mississippi Delta sits atop a pile of Mesozoic and Tertiary-aged sediments up to 7.5 mi (12.2 km) thick at the coast and it may be as much as 60,000 ft (18,288 m) or 11.4 mi (18.3 km) thick offshore (Gagliano, 1999). Five major lobes are generally recognized within about the uppermost 50 m (164 ft) of sediments (Britsch and Dunbar, 1993; Frazier, 1967, Figure 1). The oldest lobe contains peat deposits dated as 7,240 years old (Frazier, 1967). The youngest delta lobe of the Mississippi Delta is the Plaquemines-Balize lobe that has been active since the St. Bernard lobe was abandoned about 1,000 years ago. The lower Mississippi River has shifted its course to the Gulf of Mexico every thousand years or so, seeking the most direct path to the sea while building a new deltaic lobe. Older lobes were abandoned to erosion and subsidence as the sediment supply was shut off. Because of the dynamics of delta building and abandonment, the Louisiana coastal area (U.S. Dept. of the Army, COE, 2004) experiences relatively high rates of subsidence relative to more stable coastal areas eastward and westward. Coastal Louisiana wetlands make up the seventh largest delta on Earth and undergo about 90 percent of the total coastal wetland loss in the continental United States. In fact, from 1932 to 2010, coastal Louisiana has undergone a net change in land area of about 1.2 million ac (0.48 million ha). Trend analyses conducted from 1985 to 2010 show that the coastal Louisiana wetland loss rate is 16.57 mi^2 (42.92 km^2) per year. If this loss were to occur at a constant rate, it would equate to Louisiana losing an area the size of one football field per hour (Couvillion et al., 2011).

In recognition of these ongoing impacts, several programs have been for the conservation, protection, and preservation of coastal areas, including wetlands along the Gulf Coast. In recent years, Louisiana has received over $1 billion in offshore 8(g) revenues, over half a billion dollars in Coastal Impact Assistance Program funds, and stands to receive many more billions in offshore revenue shares in coming years. These programs are described below.

Coastal Wetlands Planning, Protection and Restoration Act

The first systematic program authorized for coastal restoration in the LCA was the Federal 1990 Coastal Wetlands Planning, Protection and Restoration Act (CWPPRA), otherwise known as the "Breaux Act." Individual CWPPRA projects are designed to protect and restore between 10 and 10,000 ac (4 and 4,047 ha), require an average of 5 years to transition from approval to construction, and are funded to operate for 20 years (U.S. Government Accountability Office, 2007), which is a typical expectation for project effectiveness (Campbell et al., 2005).

The 1990 CWPPRA introduced an ongoing program of relatively small projects to partially restore the coastal ecosystem. As the magnitude of Louisiana's coastal land losses and ecosystem degradation became more apparent, it was identified that a more systematic approach to integrate smaller projects with larger projects to restore natural geomorphic structures and processes was needed. Projects have ranged from small demonstration projects to projects that cost over $50 million. The Coast 2050 report (State of Louisiana, Dept. of Natural Resources, 1998) combined previous restoration planning efforts with new initiatives from private citizens, local governments, State and Federal agency personnel, and the scientific community to converge on a shared vision to sustain the coastal ecosystem. The LCA Ecosystem Restoration Study (U.S. Dept. of the Army, COE, 2004) built upon the Coast 2050 Report. The LCA's restoration strategies generally fell into one of the following categories: (1) freshwater diversion; (2) marsh management; (3) hydrologic restoration; (4) sediment diversion; (5) vegetative planting; (6) beneficial use of dredge material; (7) barrier island restoration; (8) sediment/nutrient trapping; and (9) shoreline protection, as well as other types of projects (Louisiana Coastal Wetlands Conservation and Restoration Task Force, 2006, Table 1).

As of August 2016, 210 authorized CWPPRA projects were approved, 103 of which have been constructed. Over 83,000 "anticipated total acres" have been projected from completed projects, and 102 projects that were not yet completed as of mid-2016 are reported to result in greater than 54,000 anticipated total acres (LaCoast.gov, 2016). Of the 103 completed projects listed on LaCoast.gov (2016), more than half were one of three categories types: shoreline protection projects (30 projects); hydrologic restoration projects (24 projects); and marsh creation projects (22 projects).

Following Hurricanes Katrina and Rita in 2005, an earlier emphasis on coastal or ecosystem restoration of the LCA was reordered to add an equal emphasis on hurricane flood protection. The Department of Defense Appropriations Act of 2006 required Louisiana to create a State organization to sponsor the hurricane protection and restoration projects that resulted. The State legislature established the Coastal Protection and Restoration Authority (CPRA) and charged it with coordinating the efforts of local, State, and Federal agencies to achieve long-term, integrated flood control and wetland restoration. The CPRA has since produced comprehensive master plans for a sustainable coast (State of Louisiana, Coastal Protection and Restoration Authority, 2007 and 2012) as their vision of an integrated program that identified 109 high-performing projects that could substantially increase flood protection for communities and create a sustainable coast (State of Louisiana, Coastal Protection and Restoration Authority, 2012).

Anticipating which projects are undertaken for COE's comprehensive range of flood control, coastal restoration, and hurricane protection measures for the LCA would feed into the CPRA's Annual Plan for authorization and which ones would ultimately be completed is challenging. Past completed projects have the potential of protecting up to 100,000 ac (40,469 ha) of Louisiana's wetlands (State of Louisiana, Coastal Protection and Restoration Authority, 2014). Because CWPPRA projects compete for annual Federal appropriations, there is no simple way to establish projections for land added or preserved over the cumulative activities scenario period (2017-2086) and the potential protection those projects would provide. Nor is there a way to anticipate which projects under the protection of the State's CPRA are admitted to its Annual Plan and completed.

Louisiana Coastal Master Plan

Since 2007, the CPRA has built or improved 159 mi (256 km) of levees, benefited 19,405 ac (7,853 ha) of coastal habitat, secured $17 billion in State and Federal funding, moved over 150 projects into design and construction, and constructed 32 mi (51 km) of barrier islands/berms (State of Louisiana, Coastal Protection and Restoration Authority, 2012). The projects included in the Louisiana Coastal Master Plan have the potential to build between 580 and 800 mi^2 (1,502 and 2,072 km^2) of land over the next 50 years, depending on future coastal conditions.

In 2012, Louisiana's CPRA released a Final Coastal Master Plan, which expanded upon the 2007 Master Plan. The objectives of the 2012 Master Plan focused on: flood protection, harnessing natural processes, supporting coastal habitats, sustaining cultural heritage, and promoting a working coast (State of Louisiana, Coastal Protection and Restoration Authority, 2012). The 2012 Louisiana Coastal Master Plan was based on a $50 billion budget and targeted use of these funds allows for improved protection for communities and could (with additional funding and depending how future coastal conditions change) turn the tide of land loss in Louisiana for the first time in a century. The $50 billion budget was determined by an estimate of money that Louisiana could receive in the next 50 years for coastal protection and restoration from sources such as the Gulf of Mexico Energy

Security Act, Energy and Water Act, Coastal Wetlands Planning and Restoration Act, *Deepwater Horizon* Natural Resources Damage Assessment, *Deepwater Horizon* Clean Water Act penalties, carbon and nutrient credits, future State funding, and Louisiana's Coastal Protection and Restoration Fund.

The CPRA is actively working on the 2017 Coastal Master Plan, which would carry the 2007 and 2012 Master Plans forward while improving methods, ensuring that projects are completed efficiently and effectively while maintaining the vision of the future and adapting to future conditions (State of Louisiana, Coastal Protection and Restoration Authority, 2015). In order to develop the list of candidate projects for inclusion, the CPRA solicited proposals for new projects to be evaluated. Two solicitation periods occurred, one closing on August 21, 2014, and the second closing on October 31, 2014. A variety of project ideas were submitted, including bank stabilization, diversions, hydrologic restoration, marsh creation, oyster barrier reef restoration, ridge restoration, shoreline protection, and structural protection. Project sponsors included agencies, parishes, elected officials, nongovernment organizations, and private landowners.

As funding becomes available, the CPRA's Annual Plan is the vehicle for outlining how projects are prioritized and implemented. Each Annual Plan would provide project and funding details for the current year as well as 2 years into the future. The Annual Plan would provide an easy way for citizens and legislators to track progress of the 2012 and 2017 Coastal Master Plans.

Coastal Impact Assistance Program

The Energy Policy Act of 2005 was signed into law by President George W. Bush on August 8, 2005. Section 384 of Energy Policy Act amended Section 31 of the OCSLA (43 U.S.C. § 1356(a)) to establish the Coastal Impact Assistance Program (CIAP). The authority and responsibility for the management of CIAP is vested in the Secretary of the Interior; the Secretary delegated this authority and responsibility to BOEM until September 30, 2011. Under Section 384, Congress directed the Secretary to disburse $250 million for each of the fiscal years 2007 through 2010 to eligible OCS oil- and gas-producing States and coastal political subdivisions.

On October 1, 2011, FWS took over administration of CIAP as directed by the Secretary because the program aligned with FWS's conservation mission and similar grant programs run by FWS. The eligibility requirements for States, coastal political subdivisions, and fundable projects remained largely the same after the transfer.

The CIAP provides Federal grant funds derived from Federal offshore lease revenues to oil-producing states for conservation, protection, or restoration of coastal areas. The funds can be directed to a number of different projects, including restoration of wetlands; mitigation of damage to fish, wildlife, or natural resources; planning assistance and payment of the administrative costs of complying with these objectives; implementation of a federally approved marine, coastal, or comprehensive conservation management plan; and mitigation of the impacts of OCS oil- and gas-related activities through the funding of onshore infrastructure projects and public service needs.

Eligible CIAP States	Eligible CIAP Coastal Political Subdivisions
Alabama	Baldwin and Mobile Counties
Alaska	Municipality of Anchorage and Bristol Bay, Kenai Peninsula, Kodiak Island, Lake and Peninsula, Matanuska-Susitna, North Slope, and Northwest Arctic Boroughs
California	Alameda, Contra Costa, Los Angeles, Marin, Monterey, Napa, Orange, San Diego, San Francisco, San Luis Obispo, San Mateo, Santa Barbara, Santa Clara, Santa Cruz, Solano, Sonoma, and Ventura Counties
Louisiana	Assumption, Calcasieu, Cameron, Iberia, Jefferson, Lafourche, Livingston, Orleans, Plaquemines, St. Bernard, St. Charles, St. James, St. John the Baptist, St. Martin, St. Mary, St. Tammany, Tangipahoa, Terrebonne, and Vermilion Parishes
Mississippi	Hancock, Harrison, and Jackson Counties
Texas	Aransas, Brazoria, Calhoun, Cameron, Chambers, Galveston, Harris, Jackson, Jefferson, Kennedy, Kleberg, Matagorda, Nueces, Orange, Refugio, San Patricio, Victoria, and Willacy Counties

CIAP = Coastal Impact Assistance Program.

Natural Resource Damage Assessment

The Oil Pollution Act of 1990, as provided in 33 U.S.C. § 2706, allowed the designation of the Natural Resource Damage Assessment Trustee Council (Trustee Council), which included certain Federal agencies, States, and federally recognized Indian Tribes. Executive Order 13554, which was signed on October 5, 2010, recognized the role of the Trustee Council under the Oil Pollution Act and "designated trustees as provided in 33 U.S.C. 2706, with trusteeship over those natural resources injured, lost, or destroyed as a result of the *Deepwater Horizon* oil spill." Specifically, Executive Order 13554 recognized the importance of carefully coordinating the work of the Gulf Coast Ecosystem Task Force with the Trustee Council, "whose members have statutory responsibility to assess natural resource damages from the *Deepwater Horizon* oil spill, to restore trust resources, and seek compensation for lost use of those trust resources" (The White House, 2012). The Task Force, on the other hand, was charged with creating a plan to improve the overall health of the Gulf of Mexico area and has focused on a number of stressors to the Gulf Coast ecosystem beyond those caused by the *Deepwater Horizon* explosion, oil spill, and response. While the work of the Task Force has been independent from the work of the Trustees, the valuable information gathered by the Task Force will be useful to the Trustees in their restoration planning efforts (USDOC, NOAA, 2015e).

The NRDA activities for the BP oil spill have been divided into the categories below and focus on specific species, habitats, or uses (USDOC, NOAA, 2015f):

- marine mammals and sea turtles;
- fish and shellfish;
- birds;
- deepwater habitat (e.g., deepwater coral);

- nearshore habitats (including seagrasses, mud flats, and coral reefs);
- shoreline habitats (including salt marsh, beaches, and mangroves);
- land-based wildlife and habitat; and
- public uses of natural resources (including recreational fishing, boating, beach closures).

The Trustee Council is currently in Phase III of early restoration, and the data collection, analysis, and restoration are ongoing (Deepwater Horizon Natural Resource Damage Assessment Trustees, 2016). The final Phase III plan proposes $627 million for 44 new early restoration projects across the Gulf Coast States. It also includes plans to prepare a programmatic EIS and programmatic restoration plan for early restoration (USDOC, NOAA, 2015g).

Resources and Ecosystems Sustainability, Tourist Opportunities, and Revived Economies of the Gulf Coast States Act

In July 2012, in response to the *Deepwater Horizon* explosion, oil spill, and response and other environmental challenges in the Gulf Coast region, Congress passed the Resources and Ecosystems Sustainability, Tourist Opportunities, and Revived Economies of the Gulf Coast States Act or the RESTORE Act, (Gulf Coast Ecosystem Restoration Council, 2015). In September 2012, an Executive Order was released affirming the Federal Government's Gulf Coast ecosystem restoration efforts in light of the recent passage of the RESTORE Act, which created a Gulf Coast Restoration Trust Fund (Trust Fund), outlined a structure for allocating the Trust Fund, and established the Gulf Coast Ecosystem Restoration Council (Council) (The White House, 2012). The Council is comprised of governors from the five affected Gulf Coast States, the Secretaries from the U.S. Departments of the Interior, Commerce, Agriculture, and Homeland Security, as well as the Secretary of the Army and the Administrator of the U.S. Environmental Protection Agency. The Gulf Coast States recommended and President Obama appointed the Secretary of Commerce as the Council's Chair. As an independent entity, the Council has responsibilities with respect to 60 percent of the funds made available from a Gulf Coast Restoration Trust Fund and is charged with developing a comprehensive plan for ecosystem restoration on the Gulf Coast (Comprehensive Plan), as well as any future revisions to the Comprehensive Plan (Gulf Coast Ecosystem Restoration Council, 2014).

The Initial Comprehensive Plan, approved in August 2013, establishes the Council's goals defined as: (1) restore and conserve habitat; (2) restore water quality; (3) replenish and protect living coastal and marine resources; (4) enhance community resilience; and (5) restore and revitalize the GOM economy (The White House, 2012). In July 2014, the Council approved a proposal submission and evaluation process to select projects for inclusion on the draft Funded Priorities List, which will be included as an addendum to the Initial Comprehensive Plan. This first Funded Priorities List addendum would contain projects and programs that will be funded with available Transocean Deepwater Inc. funds. Future amendments to this Funded Priorities List and the process by which projects are selected for inclusion would evolve over time as new information becomes available, adaptive management activities occur, and as funding uncertainties are resolved (Gulf Coast Ecosystem Restoration Council, 2014). As a result of the settlement of Clean Water Act civil claims against Transocean Deepwater Inc. and related entities, a total of approximately $800 million, plus interest, was deposited in the Trust Fund between 2013 and 2015. Thus, based upon the RESTORE Act and the payment schedule agreed to by the court for the Transocean settlement, by February 20, 2015, 30 percent of that total amount (i.e., $240 million plus interest) was deposited in the Trust Fund for allocation by the Council under the Council-Selected Restoration Component (Gulf Coast Ecosystem Restoration Council, 2013).

Among its other duties, the Council is tasked with establishing additional advisory committees as may be necessary to assist the Council, including a scientific advisory committee and a committee to advise the Council on public policy issues; gathering information relevant to Gulf Coast restoration, including thorough research, modeling, and monitoring; and providing an annual report to Congress on implementation progress (The White House, 2012).

As outlined in the RESTORE Act, the Council submitted a 2014 Annual Report to Congress on the implementation progress (Gulf Coast Ecosystem Restoration Council, 2014). In 2015, the Council proposed regulation that would establish the formula allocating funds made available from the Gulf Coast Restoration Trust Fund among the Gulf Coast States of Alabama, Florida, Louisiana, Mississippi and Texas (*Federal Register*, 2015e). The Council also released a draft initial-funded priorities list (Gulf Coast Ecosystem Restoration Council, 2015).

National Fish and Wildlife Foundation: Gulf Environmental Benefit Fund

In early 2013, a U.S. District Court approved two plea agreements resolving certain criminal cases against BP and Transocean, cases which arose from the 2010 *Deepwater Horizon* explosion, oil spill, and response. The agreements direct a total of $2.544 billion to the National Fish and Wildlife Foundation to fund projects benefiting the natural resources of the Gulf Coast that were impacted by the spill.

Between 2013 and 2018, the National Fish and Wildlife Foundation's newly established Gulf Environmental Benefit Fund will receive a total of $1.272 billion for barrier island and river diversion projects in Louisiana; $356 million each for natural resource projects in Alabama, Florida, and Mississippi; and $203 million for similar projects in Texas. Funding priorities include projects that

- restore and maintain the ecological functions of landscape-scale coastal habitats, including barrier islands, beaches, and coastal marshes, and ensure their viability and resilience against existing and future threats, such as sea-level rise;
- restore and maintain the ecological integrity of priority coastal bays and estuaries; and

- replenish and protect living resources including oysters, red snapper and other reef fish, Gulf Coast bird populations, sea turtles, and marine mammals (National Fish and Wildlife Foundation, 2015).

As of 2016, the Gulf Environmental Benefit Fund has supported 75 projects worth nearly $500 million. In making the awards, the National Fish and Wildlife Foundation has worked closely with key State and Federal resource agencies to select projects that remedy harm and eliminate or reduce the risk of future harm to Gulf Coast natural resources. For example, funding was awarded from the Gulf Environmental Benefit Fund for engineering and construction of both Caminada Beach and Dune Increment II and East Timbalier Island, both involving the use of OCS sediment resources (National Fish and Wildlife Foundation, 2016).

3.3.2.8.4 Saltwater Intrusion

Saltwater intrusion is one of many factors that impact coastal environments, contributing to coastal land loss. Such impacts can be natural, as when storm surge brings GOM water inland, or anthropogenic, as when navigation or pipeline canals allow tides to introduce high salinity water to interior marshes. In addition, produced water from oil wells in the coastal zones can be a source of water of extreme high salinity, well over 100 parts per thousand. Produced water, which is regulated, often contains pollutants such as heavy metals and hydrocarbons, as well.

Marsh plants are exposed to salinity stress when higher salinity GOM waters reach interior marshes, exposing plants to salinities above their tolerance levels. This can result in decreased plant growth and/or mortality depending on the tolerance of the plant species and the amount, rate, and duration of salinity increase (Mendelssohn and McKee, 1987). Plant dieback can be followed by subsequent erosion of the marsh substrate and eventual land loss (Ko and Day, 2004; Boesch et al., 1994).

The freshwater-adapted habitats (i.e., fresh or intermediate marsh and forested wetlands) are more sensitive to saltwater intrusion than the other more salt-tolerant habitats, such as brackish and saline marsh. Saltwater intrusion can result in conversion of freshwater to saline habitats or can simply kill fresh or intermediate marshes, thus converting them to open water (Johnston et al., 2009).

The leveeing of the Mississippi River and the construction of numerous water control structures are generally thought to have accelerated coastal land loss by isolating coastal wetlands from the freshwater, sediment, and nutrients of the Mississippi River, which previously served to nourish and sustain these wetlands. Among other impacts, this isolation effect results in the loss or reduction in freshwater flow, and thus a greater marine influence on the coastal wetlands, which in turn results in saltwater intrusion (Johnston et al., 2009).

Saltwater intrusion into coastal environments can also impact estuarine species distribution, shifting patterns of habitat usage. Marine species penetrate farther inland when salinities are within their tolerance, and less salt-tolerant species are restricted to the fresher areas. This can also lead to a shift in the pattern of availability of preferred fish species to fishermen.

3.3.2.8.5 Maintenance Dredging and Federal Channels

Along the Texas Coast there are eight federally maintained navigation channels in addition to the GIWW. Most of the dredged materials from the Texas channels have high concentrations of silt and clay. Beneficial uses of dredged material include beach nourishment for the more sandy materials and storm reduction projects or ocean disposal for much of the finer-gained material. Ocean disposal locations along the Texas coast are situated so that materials are placed on the down drift side of the channel (U.S. Dept. of the Army, COE, 1992,).

There are 10 Federal navigation channels in the LCA, ranging in depth from 4 to 14 m (12 to 45 ft) and in width from 38 to 300 m (125 to 1,000 ft), that were constructed as public works projects beginning in the 1800's (Good et al., 1995, Table 1). The combined length of the Federal channels in Good et al. was reported as 2,575 mi (1,600 km), with three canals considered deep-draft and seven considered shallow (Good et al., 1995, page 9). The Federal navigation channels in Louisiana identified by Good et al. (1995, Table 1) are as follows: (1) GIWW East of Mississippi River; (2) Mississippi River Gulf Outlet; (3) GIWW between the Atchafalaya and Mississippi Rivers; (4) GIWW West of Atchafalaya River; (5) Barataria Bay Waterway; (6) Bayou Lafourche; (7) Houma Navigation Canal; (8) Mermentau Navigation Channel; (9) Freshwater Bayou; and (10) Calcasieu River Ship Channel. The Mississippi River Gulf Outlet has been decommissioned and sealed with a rock barrier as of July 2009 (Shaffer et al., 2009, page 218).

The GIWW is a Federal, shallow-draft navigation channel constructed to provide a domestic connection between GOM ports after the discovery of oil in East Texas in the early 1900's, as well as to provide a pathway to support the growing need for interstate transport of steel and other manufacturing materials in the early 20th century. It extends approximately 1,400 mi (2,253 km) along the Gulf Coast from St. Marks in northwestern Florida to Brownsville, Texas, with the Louisiana part reported to be 994 mi (1,600 km) in length (Good et al., 1995). With the exception of the east-west GIWW in Louisiana, Federal channels are approximately north-south in orientation, making them vulnerable to saltwater intrusion during storms (refer to **Chapter 3.3.2.8.3** above).

Cumulative impacts include the displacement of wetlands by original channel excavation and disposal of the dredged material. Turner and Cahoon (1987, Table 4-5) estimated that immediate impacts from the construction of navigation channels were between 58,000 and 96,000 ac (23,472 and 38,850 ha). Indirect cumulative land losses resulted from hydrologic modifications, saltwater intrusion, or bank erosion from vessel wakes (Wang, 1988). Once cut, navigation canals tend to widen as banks erode and subside, depending on the amount of traffic using the channel. Good et al. (1995, Table 1) estimated indirect impacts on wetland loss from bank erosion at 35,000 ac (14,164 ha).

The COE reported that the New Orleans District has the largest channel maintenance dredging program in the U.S., with an annual average of 70 million yd^3 (53.5 million m^3) of material dredged (U.S. Dept. of the Army, COE, 2009a). Maintenance dredging activity from 2004 through 2013 for Federal channels by COE's Galveston District, New Orleans District, and Mobile District are reported in COE's Ocean Disposal Database (U.S. Dept. of the Army, COE, 2015a) (**Table 3-27**). The average amount of material disposed of in the 10-year period is highest for the New Orleans District (14,737,321 yd^3 [11,267,495 m^3]), followed by the Galveston District (6,788,997 yd^3 [5,190,563 m^3]) and the Mobile District (4,612,358 yd^3 [3,526,402 m^3]). Federal channels and canals are maintained throughout the onshore cumulative impact area by the COE, State, county, commercial, and private interests. Proposals for new and maintenance dredging projects are reviewed by Federal, State, and local agencies as well as by private and commercial interests to identify and mitigate adverse impacts upon social, economic, and environmental resources.

Maintenance dredging is performed on an as-needed basis. Typically, the COE schedules surveys every 2 years on each navigation channel under its responsibility to determine the need for maintenance dredging. Dredging cycles may be from 1 to as many as 11 years from channel to channel and from channel segment to channel segment. The COE is charged with maintaining all larger navigation channels in the cumulative activities area. The COE dredges millions of cubic meters of material per year in the cumulative activities area, most of which is under the responsibility of the New Orleans District. Some shallower port-access channels may be deepened over the next 10 years to accommodate deeper draft vessels. Vessels that support deepwater OCS oil- and gas-related activities may include those with drafts to about 7 m (23 ft).

Construction and maintenance dredging of rivers and navigation channels can furnish sediment for a beneficial purpose, a practice the COE calls beneficial use of dredge materials program. Drilling, production activity, and maintenance at most coastal well sites in Louisiana require service access canals that undergo some degree of aperiodic maintenance dredging to maintain channel depth, although oil and gas production on State lands peaked in 1969-1970 (Ko and Day, 2004, page 398). In recent years, dredged materials have been sidecast to form new wetlands using the beneficial use of dredge materials program. Potential areas suited for beneficial use of dredged material are considered most feasible within a 10-mi (16-km) boundary around authorized navigation channels in the New Orleans District, but the potential for future long-distance pipelines for disposal of dredged material could increase the potential area available for the beneficial use of dredge materials program considerably (U.S. Dept. of the Army, COE, 2009a, page 27).

As discussed in **Chapter 3.3.2.8.5**, the New Orleans District dredges an average annual 14.7 million yd^3 (11.3 million m^3) of material. Current figures estimate that approximately 38 percent of that average is available for the beneficial use of the dredge materials program (U.S. Dept. of the Army, COE, 2013). The COE reported that, over the last 20 years, approximately 12,545 ha (31,000 ac) of wetlands have been created with dredged materials, most of which are located on the LCA delta plain (U.S. Dept. of the Army, COE, 2013).

3.3.2.9 Natural Events and Processes

3.3.2.9.1 Physical Oceanography

Physical oceanographic processes in the GOM include the Loop Current, Loop Current eddies, and whirlpool-like features that appear underneath the Loop Current and Loop Current eddies that interact with the bottom. Infrequently observed processes include a limited number of high-speed current events, at times approaching 100 cm/s (39 in/s). These events were observed at depths exceeding 1,500 m (4,921 ft) in the northern GOM (Hamilton and Lugo-Fernandez, 2001; Hamilton et al., 2003) and as very high-speed currents in the upper portions of the water column observed in deep water by several oil and gas operators.

Caribbean Sea waters colliding with the Yucatan Peninsula turn northward and enter the Yucatan Channel as a strong flow called the Yucatan Current. This current exhibits two basic arrangements inside the Gulf of Mexico. First, the Yucatan Current enters the GOM and turns immediately eastward, exiting the GOM towards the Atlantic Ocean via the Florida Straits to become the Gulf Stream. The second arrangement consists of a northward penetration of the Yucatan Current into the Gulf of Mexico reaching to 26º-28º N. latitudes, then curls clockwise turning south, and exiting via the Florida Straits into the Atlantic Ocean to become, again, the Gulf Stream. This circulation inside the GOM is called the Loop Current. The Loop Current transports warm and salty water year round into the GOM at a rate of 25-30 million cubic meters per second, and it is the main energy source for oceanographic processes inside the Gulf of Mexico. At its climatic northern position, the Loop Current becomes unstable, breaks, and sheds a large (200- to 400-km diameter [124- to 248-mi diameter]) clockwise whirlpool that travels southwestwards at speeds of 4-8 km/day (2-5 mi/day). The southwest trip of Loop Current eddies continues until colliding with the Texas and Mexico continental slope in the western GOM, where they disintegrate. This sequence connects the eastern with the western Gulf, which otherwise appear disconnected.

Mean seasonal circulation patterns of inner-shelf and outer-shelf currents on the Louisiana-Texas continental shelf, the northeastern GOM shelf, and the West Florida shelf are primarily wind driven and are also influenced by riverine outflow. Cold water from deeper off-shelf regions moves onto and off the continental shelf by cross-shelf flow associated with upwelling and downwelling processes in some locations (Collard and Lugo-Fernandez, 1999). There are also a number of secondary whirlpools with smaller diameters (50-100 km; 31-62 mi) that affect the exchange between the shelf and deepwater, and these smaller whirlpools interact with the larger Loop Current eddies (Donohue et al., 2008). Additionally, wind events such as tropical cyclones (especially hurricanes), extratropical cyclones, and cold-air outbreaks can result in extreme waves and cause currents with speeds of 100-150 cm/s (39-59 in/s) over continental shelves.

Deepwater currents of the GOM can be approximated as a two-layer system with an upper layer about 800-1,000 m (2,625-3,281 ft) deep that is dominated by the Loop Current and associated clockwise whirlpools and a lower layer below ~1,000 m (3,281 ft) that has near uniform currents (Cox et al., 2010; Welsh et al., 2009; Inoue et al., 2008). The coupling between these two layers is generally absent, but it appears that motions at the layer interface are needed to transmit the energy from the Loop Current and eddies downward (Cox et al., 2010; Welsh et al., 2009; Inoue et al., 2008, Donohue et al., 2008). Mean deep flow around the edges of the GOM circulates in a counterclockwise direction, as observed at ~2,000 m (6,562 ft) (Sturges et al., 2004) and at ~900 m (2,953 ft) (Weatherly, 2004), with current speeds generally decreasing with depth.

3.3.2.9.2 Natural Seeps

“Natural seeps” is used here to mean the naturally occurring seepage of crude oil and tar into the GOM. These seeps are geographically common and have likely been active throughout history. Natural seeps account for approximately 47 percent of the crude oil entering the marine environment (Kvenvolden and Cooper, 2003). Mitchell et al. (1999) estimated a range of 280,000-700,000 bbl per year (40,000-100,000 tonnes per year), with an average of 490,000 bbl (70,000 tonnes) for the northern GOM, excluding the Bay of Campeche. Using this estimate and assuming seep scales are proportional to surface area, the NRC (2003) estimated annual seepage for the entire GOM at ~980,000 bbl (140,000 tonnes) per year, or about 3 times the estimated amount of oil spilled by the 1989 *Exxon Valdez* event (~270,000 bbl) (Steyn, 2010) or a quarter of the amount released into the environment by the *Deepwater Horizon* explosion and oil spill (4.1 MMbbl of oil) (Lubchenco et al., 2010). As seepage is a natural occurrence, the rate of ~980,000 bbl (140,000 tonnes) per year is expected to remain unchanged throughout the cumulative analysis period. Refer to **Chapter 4.4** for more information on natural seeps.

3.3.2.9.3 Hurricanes

Climatic cycles in tropical latitudes typically last 20-30 years or even longer (USDOC, NOAA, 2005). As a result, the North Atlantic experiences alternating periods of above-normal or below-normal hurricane seasons. There is a two- to three-fold increase in hurricane activity during eras of above-normal activity. The hurricane activity from 1995 to 2007 is representative of an era of above-normal hurricane activity (Elsner et al., 2008, page 1,210).

Twenty-one hurricanes made landfall in the WPA, CPA and EPA during the 1995-2015 hurricane seasons, disrupting OCS oil- and gas-related activity in the GOM (**Table 3-31**). Half of these hurricanes reached a maximum strength of Category 1 or 2 while in the CPA or WPA, while the other half were powerful hurricanes reaching maximum strengths of Category 4 or 5. The current era of heightened Atlantic hurricane activity began in 1995; therefore, the Gulf of Mexico could expect below average hurricanes in the GOM in the near term due to a strong El Nino. Increased hurricanes may occur if El Nino wanes during the first half of the 50-year analysis period and levels return to below-normal activity during the remaining half to three-quarters of the 50-year analysis period.

Table 3-31. Hurricane Landfalls in the Northern Gulf of Mexico from 1995 through 2016.

Event	Year	Affected State	Storm Name	Intensity at Landfall
1	1995	AL, FL	Opal	Hurricane Category 3
2	1995	FL	Erin	Hurricane Category 2
3	1997	LA, AL	Danny	Hurricane Category 1
4	1998	FL	Earl	Hurricane Category 1
5	1998	MS, AL	Georges	Hurricane Category 2
6	1999	TX	Bret	Hurricane Category 3
7	2002	LA	Lili	Hurricane Category 1
8	2003	TX	Claudette	Hurricane Category 1
9	2004	FL	Charley	Hurricane Category 4
10	2004	FL	Frances	Hurricane Category 2
11	2004	MS, AL	Ivan	Hurricane Category 3
12	2005	LA, MS	Cindy	Hurricane Category 1
13	2005	FL, AL	Dennis	Hurricane Category 3
14	2005	LA, MS	Katrina	Hurricane Category 5
15	2005	TX, LA	Rita	Hurricane Category 3
16	2005	FL	Wilma	Hurricane Category 3
17	2007	TX, LA	Humberto	Hurricane Category 1
18	2008	LA	Gustav	Hurricane Category 2
19	2008	TX, LA	Ike	Hurricane Category 4
20	2008	TX	Dolly	Hurricane Category 1
21	2012	LA	Isaac	Hurricane Category 1

Note: There were no hurricane landfalls in the northern Gulf of Mexico in 2009-2011 and 2013-2016.

Source: USDOC, NOAA, 2016a.

Hurricanes Ivan, Katrina, Rita, Gustav, and Ike entered the GOM and destroyed 181 structures and 1,673 wells on the OCS (Kaiser, 2015a). In general, they caused extensive damage to OCS platforms, topside facilities, and pipeline systems (**Table 3-32**). During Hurricanes Ivan, Katrina, and Rita, 9 jack-up rigs and 19 moored rigs were either toppled or torn from their mooring systems. Sixty platforms were destroyed as a result of Hurricanes Gustav and Ike in 2008, 31 platforms had extensive damage, and 93 platforms had moderate damage (USDOI, MMS, 2008b). The number of destroyed platforms by Hurricanes Gustav and Ike exceeds the number destroyed by Hurricane Katrina. Hurricane Isaac made landfall near the mouth of the Mississippi River on August 28, 2012, as a Category 1 hurricane, which only caused very minor damage to the offshore oil or gas infrastructure in the GOM. However, after Hurricane Isaac, tarballs and tar mat fragments were found along Alabama’s shoreline (Auburn University, Samuel Ginn College of Engineering, 2012). It was also observed that Hurricane Isaac resulted in the suspension of small amounts of tarballs and some oil from sediments (Mulagabal et al., 2013). Refer to **Chapters 3.2.1.1.1 and 3.2.4** for additional details for pipeline failures caused by hurricanes.

Table 3-32. Oil Spilled from Pipelines on the Federal OCS, 2002-2009.

Regulator	Area	Total Oil Spilled (bbl)	Oil Spilled due to Hurricanes (bbl)	Proportion of Total Oil Spilled due to Hurricanes (%)
BOEM	Federal OCS	5,522	5,179	94
DOT	Federal OCS	5,667	3,272	58
DOT	State Waters	9,903	9,622	97

Source: USDOI, BOEMRE, 2011c.

3.3.2.9.4 Climate Change

Issues related to climate change, including global warming, sea-level rise, and programmatic aspects of climate change relative to the environmental baseline for the GOM are discussed in Chapter 4.2.1 of the Five-Year Program EIS.

3.3.2.10 Mississippi River Hydromodification

The Mississippi River has been anchored in place by engineered structures built in the 20th century and has been hydrologically isolated from the delta it built. The natural processes that allowed the river to flood and distribute alluvial sediments across the delta platform and channels to meander have been shut down. Hydromodifying interventions include construction of (1) levees along the river and distributary channel systems, (2) upstream dams and flood control structures that impound sediment and meter the river flow rate, and (3) channelized channels with earthen or armored banks. Once the natural processes that act to add sediment to the delta platform to keep it emergent are shut down, subsidence begins to outpace deposition of sediment.

Of total upstream-to-downstream flow, the Old River Control Structure (built 1963) diverts 70 percent of flow down the levee-confined channels of the Mississippi River and 30 percent down the unconfined Atchafalaya River, which has been actively aggrading its delta plain since 1973 (*LaCoast.gov*, 2011). Blum and Roberts reported that the time-averaged sediment load carried by the Mississippi and Atchafalaya Rivers before installation of the Old River Control Structure was ~400-500 million tons per year and that the average suspended load available to either river after construction of the Old River Control Structure was ~205 million tons per year (Blum and Roberts, 2009, Figure 2). Modern sediment loads are, therefore, less than half that is required to build and maintain the modern delta plain, a figure largely in agreement with previous work reporting decreases in suspended sediment load of nearly 60 percent since the 1950's (Turner and Cahoon, 1987; Tuttle and Combe, 1981).

Blum and Roberts (2009, Figure 3b) posited three scenarios for subsidence and sea-level rise, and concluded that sediment starvation alone would cause ~2,286 mi^2 (592,071 ha) of the modern delta plain to submerge by 2050 without any other impacting factors contributing to land loss. The use of sediment budget modeling, a relatively new tool for land loss assessment, appears to indicate that hydrographic modification of the Mississippi River has been the most profound man-caused influence on land loss in the LCA. Sediment starvation of the deltaic system is allowing rising sea level and subsidence to outpace the constructive processes building and maintaining the delta.

BOEM anticipates that, over the next 50 years, there might be minor sediment additions resulting from new and continuing freshwater diversion projects managed by the COE. Refer to **Chapter 3.3.2.8.3** for more information on coastal restoration.

3.3.2.11 Mississippi River Eutrophication

The Mississippi River Basin drains 41 percent of the contiguous United States. The basin covers more than 1,245,000 mi^2 (3,224,535 km^2) and includes all or parts of 31 states and 2 Canadian provinces (U.S. Dept. of the Army, COE, 2015b). Dissolved pollutants, including nutrients, enter surface water within the Mississippi River Basin via uncontained runoff and groundwater discharge (nonpoint sources).

The sources of nutrients in surface waters can be broadly divided as natural and anthropogenic. Natural sources are generally ubiquitous; however, their contribution is usually low because, over the course of time, natural systems have established balances between the production and consumption of nutrients. Anthropogenic sources arise from many activities. In the agricultural setting of the Mississippi River drainage basin, farmers increase the productivity and yield of their crops by use of chemical fertilizers. If more fertilizers are applied than are used by the crops, they can move into ground and surface waters and become a major source of nutrients in rivers. Additionally, fertilizer that is bound to soil or “loose” fertilizer may be subject to erosion by wind or water and affect surface waters. Information regarding nutrient management can be found on the U.S. Department of Agriculture’s Natural Resources Conservation Service website (USDA, NRCS, 2015). Other major sources of nutrients in surface waters are domestic and animal wastes. Although municipal wastewater is treated, only a fraction of the nutrients is removed. In addition to the nutrients derived from human sewage, municipal wastewater also contains nutrients from such things as lawn fertilizers, household cleaners, and detergents. Other anthropogenic sources of nutrients are industrial, either from the manufacture of fertilizers or as by-products of other manufacturing processes (Antweiler et al., 1995).

The most significant inorganic forms of two elements, nitrogen and phosphorus, include four nutrient compounds: nitrate (NO_3^-); nitrite (NO_2^-); ammonium (NH_4^+); and orthophosphate (PO_4^{-3}). Of these four major nutrient compounds, only nitrate is found in concentrations approaching the USEPA’s maximum contaminant level of 10 mg/L. Orthophosphate usually is present in low concentrations, and concentrations of ammonium and nitrite usually are insignificant (USDOI, GS, 1995).

Nutrient enrichment results in eutrophication, causing growth of algae (algal bloom) and other aquatic plants. A second effect of eutrophication is the increased uptake of dissolved oxygen by bacteria in response to higher concentrations of organic matter. If oxygen is taken up by decaying organic matter faster than it is imported from the atmosphere or produced by photosynthesis, it becomes depleted, and the aquatic species that require it are adversely affected. Furthermore, oxygen depletion causes basic changes in the chemical environment (i.e., a reduced environment) that allow materials (including many metals) that were formerly associated with the solid phase sediments (e.g., sorbed) to become soluble and, therefore, more mobile in the aqueous phase (USDOI, GS, 1995).

On October 21, 2014, the U.S. Department of the Interior and the U.S. Department of Agriculture announced a new partnership to strengthen the effectiveness of State and Federal nutrient-reduction strategies (USDOI, GS, 2014). As a result of this and other efforts, states are beginning to impose Best Management Practices on growers within the Mississippi River Basin to develop nutrient management plans, including fertilizer applicator certification programs, and monitoring to minimize excess nutrients from washing into waterways.

3.3.2.12 Hypoxia

The Gulf of Mexico hypoxic zone is a band of oxygen-stratified water that stretches along the Texas-Louisiana shelf each summer where the dissolved oxygen concentrations are less than 2 mg/L (USEPA, 2015d). Other small hypoxic areas infrequently form at the discharge of smaller rivers along the Gulf Coast; however, in the Gulf of Mexico, the hypoxic zone resulting from the Mississippi and Atchafalaya Rivers is by far the predominant feature. The hypoxic zone is the result of excess nutrients, primarily nitrogen, carried downstream by rivers to discharge to coastal waters. Density stratification results where the less dense, nutrient-rich freshwater spreads on top of the denser seawater and prevents oxygen from replenishing the bottom waters. The excess nutrients cause phytoplankton blooms that eventually die and sink to the bottom, where bacterial decomposition consumes dissolved oxygen. The oxygen-depleted bottom waters occur seasonally and are affected by the timing of the Mississippi and Atchafalaya Rivers' discharges carrying nutrients and freshwater to shelf surface waters. Hypoxic zones are sometimes called "dead zones" because of the absence of commercial quantities of shrimp and fish in the bottom layer.

The hypoxic zone on the Louisiana-Texas shelf is the largest such zone in the United States and the entire western Atlantic Ocean (Turner et al., 2005). The Louisiana Universities Marine Consortium generally forecasts the seasonal maximum size of the Louisiana-Texas hypoxic zone based on nitrogen loading in the Mississippi River (as measured in May of each year), and the actual size reported is based on cruise data collected by the Louisiana Universities Marine Consortium in July of each year. Recent estimates of the area of low oxygen by NOAA (USDOC, NOAA, 2015h) as of August 3, 2015, measured 6,474 mi^2 (16,700 km^2) (**Figure 3-20**), an increase from the size measured in 2014 (5,052 mi^2) and larger than the estimated size (5,838 mi^2) forecast by the Louisiana Universities Marine Consortium (2015) in June 2015 and three times larger than the Action Plan Goal of 5,000 km^2 or 1,991 mi^2 (Louisiana Universities Marine Consortium, 2014). The hypoxic zone extends up to 60-70 km (37-43 mi) from the shoreline, well into OCS waters.

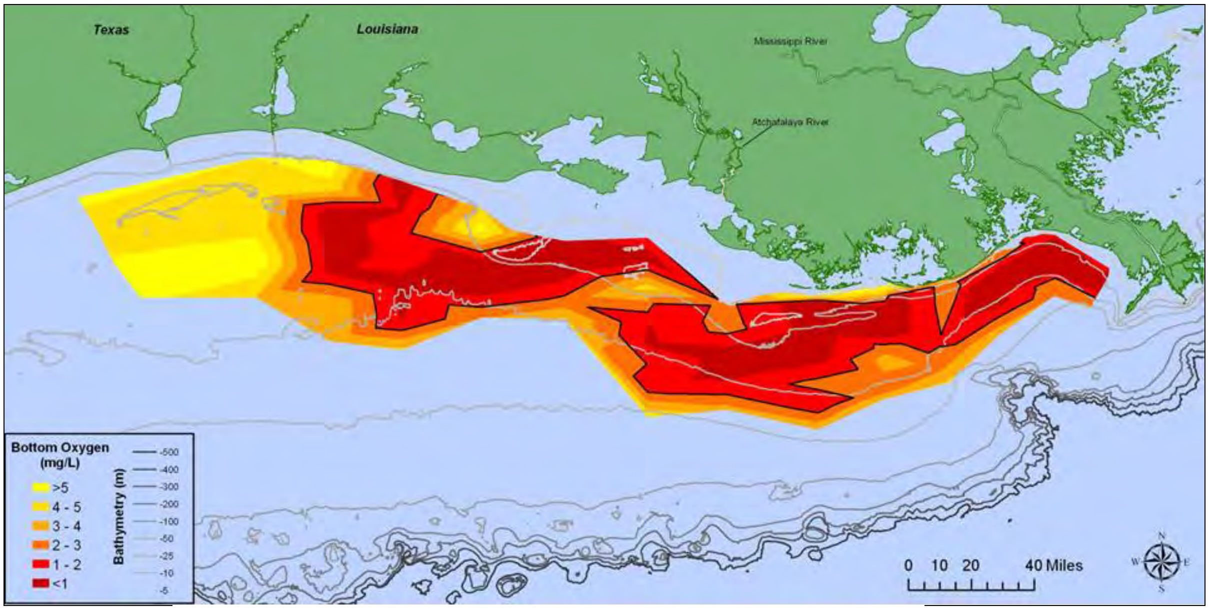

Figure 3-20. 2015 Gulf of Mexico Hypoxic Zone (USDOC, NOAA, 2015h).

Rabalais (2005) and Bierman et al. (2008) evaluated the potential contributions of carbon and nitrogen in discharged produced waters on the hypoxic zone. Both studies found that the effects due to produced water were minimal compared with those of the Mississippi River. As such, the Louisiana-Texas hypoxic zone is considered to be unrelated to OCS oil- and gas-related activities but is discussed here as a potential cumulative effect.

3.3.2.13 Sedimentation

The lower Mississippi River, from Cairo, Illinois, to the Gulf of Mexico, transported an average of 150 million tons (with a range of 70-230 million tons) of sediment annually between 1963 and 2005. Historically, the quantity of sediment derived from catchment erosion has been affected by changes in land use and river management, increasing in the 19th and early 20th centuries before decreasing due to soil conservation and improved land management. Seasonal analysis shows that, in the spring, the median load is approximately four times the median total load in the fall. The median sediment size is mostly silt, but it coarsens during the winter and spring when 10 percent of the sediment load is coarser than fine sand (U.S. Dept. of the Army, European Research Office, 2008).

Suspended sediment and bed load enter the GOM from the outlets of the Mississippi and Atchafalaya Rivers. Suspended sediment is circulated along the Louisiana-Texas continental shelf where it settles out and may later become resuspended during storms. Bed-load sediment discharge builds the Mississippi and Atchafalaya River deltas and may be redistributed on the continental shelf by currents and wave action. Sediment on the continental shelf may ultimately be intercepted by the Mississippi Canyon where it is transported downslope to the Mississippi Fan in deep water.

Since the marine environment is a dynamic system, sediment quality and water quality can affect each other. For example, a contaminant may react with the mineral particles in the sediment and be removed from the water column (e.g., adsorption). Thus, under appropriate conditions, sediments can serve as sinks for contaminants such as metals, nutrients, or organic compounds. However, if sediments are resuspended (e.g., due to dredging or a storm event), the resuspension can lead to a temporary redox flux, including a localized and temporal release of any formally sorbed metals as well as nutrient recycling. Resuspension events are less likely in deepwater environments (Caetano et al., 2003; Fanning et al., 1982).

Several studies have addressed offshore water and sediment quality in deep waters. Water at depths >1,400 m (4,593 ft) is relatively homogeneous with respect to temperature, salinity, and oxygen (Nowlin,1972; Pequegnat, 1983; Gallaway et al., 1988; Jochens et al., 2005). Limited analyses of trace metals and hydrocarbons for the water column and sediments exist (Trefry, 1981; Gallaway et al., 1988). Continental Shelf Associates, Inc. completed an Agency-funded field study of four drilling sites located in water depths of 1,033-1,125 m (3,389-3,691 ft) (CSA, 2006). The sampling design called for before and after exploratory or development drilling and captured the drilling-related changes that occur in sediments and sediment pore water. Chemical impacts of drilling were detected at all four sites. Impacts noted within the near-field zone included elevated barium, synthetic-based fluids, total organic carbon concentrations, and low sediment oxygen levels. One of the study locations was Viosca Knoll Block 916, which was considered to be relatively pristine prior to drilling. No drilling had ever been performed at Viosca Knoll Block 916, and the closest drilling activity had occurred 1.4 mi (2.3 km) north-northwest 2 years prior to the study. The site was located at a water depth of 1,125 m (3,691 ft) and 70 mi (120 km) from the mouth of the Mississippi River. At this relatively pristine location, mean concentrations of sediment barium increased by approximately 30-fold at near-field stations following exploratory drilling (from 0.108% to 3.32%). As well, mean concentrations of sediment mercury and total PAHs increased in the near-field. At this site, sediment cadmium concentrations did not change substantially following exploratory drilling.

Several studies have assessed the occurrence and distribution of hydrocarbons in sediments since the *Deepwater Horizon* explosion, oil spill, and spill response in 2010 from Mississippi Canyon Block 252. Montagna et al. (2013) reported results of monitoring cruises conducted in the fall of 2010 to measure potential impacts on two soft bottom benthic invertebrate groups, i.e., macrofauna and meiofauna. The most severe relative reduction of faunal abundance and diversity extended to 3 km (2 mi) from the wellhead in all directions, covering an area of 24 km^2 (9 mi^2). Moderate impacts were observed up to 17 km (11 mi) toward the southwest and 8.5 km (5.3 mi) toward the northeast of the wellhead, covering an area of 148 km^2 (57 mi^2). Benthic effects were correlated to hydrocarbon concentrations and distance from the wellhead but not distance to natural hydrocarbon seeps.

A study by Valentine et al. (2014) used the concentration of the marker compound hopane in more than 3,000 sediment samples from 534 locations to evaluate the extent of oil on the seafloor. The pattern of contamination was described as similar to a “bathtub ring” formed from an oil-rich layer of water impinging laterally on the continental slope at a depth of about 900-1,300 m (2,953-4,265 ft). A secondary “fallout plume” from the oil-rich layer was reported to impact a zone of sediments at a depth of about 1,300-1,700 m (4,265-5,577 ft). The combined areas of impact were estimated to span 3,200 km^2 (1,236 mi^2). Based on the horizontal and vertical distribution of hopane in the sediments, the authors concluded that the contamination was consistent with the recent *Deepwater Horizon* explosion and oil spill as the source and not natural ongoing seeps. Calculations presented in the study indicate that oil in the “bathtub ring” represents 4-31 percent of the approximately 2 MMbbl of oil estimated to be sequestered in the oil-rich layer of water at depths of 1,000-1,300 m (3,287-4,265 ft).

Sammarco et al. (2013) conducted a regional study using approximately 70 sediment samples in coastal waters from Galveston, Texas, to the Florida Keys. Sediment total petroleum hydrocarbon and total PAH concentrations peaked in samples near Pensacola, Florida, and Galveston, Texas.

The Department of the Interior Mission

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The Bureau of Ocean Energy Management Mission

The Bureau of Ocean Energy Management (BOEM) is responsible for managing development of U.S. Outer Continental Shelf energy and mineral resources in an environmentally and economically responsible way.