4. ENVIRONMENTAL AND SOCIOECONOMIC CONSEQUENCES

4.1. IMPACT-PRODUCING FACTORS AND SCENARIO – ROUTINE OPERATIONS

4.1.1. Offshore Impact-Producing Factors and Scenario

This section describes the offshore infrastructure and activities (IPF's) associated with a proposed action that could potentially affect the biological, physical, and socioeconomic resources of the GOM. When appropriate, offshore IPF's associated with the Gulfwide OCS Program are discussed because some proposed action, IPF's (i.e., infrastructure) affect resources that are geographically Gulfwide and, therefore, are necessary for the cumulative analysis. The Gulfwide OCS Program is composed of the Eastern, Central, and Western Planning Areas. Offshore is defined here as the OCS portion of the GOM that begins 10 mi offshore Florida; 3 mi offshore Louisiana, Mississippi, and Alabama; and 3 leagues offshore Texas; and it extends seaward to the limits of the EEZ (**Figure 1-1**). Coastal infrastructure and activities associated with a proposed action and the Gulfwide OCS Program are described in **Chapter 4.1.2.**, Coastal Impact-Producing Factors and Scenario.

Offshore activities are described in the context of scenarios for a proposed action and for the Gulfwide OCS Program. The MMS's GOM OCS Region developed these scenarios to provide a framework for detailed analyses of potential impacts of the proposed lease sales. Each scenario 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. A proposed action is represented by a set of ranges for resource estimates, projected exploration and development activities, and impact producing factors. Each of the proposed sales is expected to be within the scenario ranges; therefore, a proposed action is representative of either proposed Lease Sale 189 or Lease Sale 197. 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. 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 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 an MMS 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.

The assumed life of the leases resulting from a proposed lease sale does not exceed 40 years. This is based on averages for time required for exploration, development, production life, and abandonment for leases in the GOM. For the cumulative analysis, the Gulfwide OCS Program is discussed in terms of current activities, current trends, and projections of these trends into the reasonably foreseeable future. For modeling purposes and quantified Gulfwide OCS Program activities, a 40-year analysis period (year of the first lease sale (2003) through 38 years after the second lease sale (2005) as proposed in the 5-Year Program for 2002-2007) is used. Activity projections become increasingly uncertain as the length of time for projections are made increases and the number of influencing factors increases. The projections used to develop a proposed action and Gulfwide OCS Program scenarios are based on resource and reserves estimates as presented in the *2000 Assessment of Conventionally Recoverable Hydrocarbon Resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 1999* (Lore et al., 2001), current industry information, and historical trends.

The statistics used for these historic trends exhibit a lag time of about two years; therefore, the models using the trends also reflect two-year-old statistics. In addition, the overall trends average out the "boom and bust" nature of GOM OCS operations. The models cannot fully adjust for short-term changes in the rates of activities. In fact, these short-term changes should not be projected into the long term. An example of a short-term change was the surge in deepwater activities in the mid-1990's as a result of technological advancements in seismic surveying and development options, as well as a reflection of deepwater royalty relief. This short-term effect was greater than the activity level predicted by the resources and socioeconomic models. The MMS believes that the models, with continuing adjustments and refinements, adequately project GOM OCS activities in the long term for the EIS analyses.

The proposed action and the Gulfwide OCS Program scenarios are based on the following factors:

- recent trends in the amount and location of leasing, exploration, and development activity;
- estimates of undiscovered, unleased, conventionally recoverable oil and gas resources in the planning area;
- existing offshore and onshore oil and/or gas infrastructure;
- industry information; and
- oil and gas technologies, and the economic considerations and environmental constraints of these technologies.

The proposed actions are Lease Sales 189 and 197, as scheduled in the *Outer Continental Shelf Oil and Gas Leasing Program: 2002-2007*. In general, a proposed lease sale represents 15-19 percent of the OCS Program in the EPA based on barrels of oil equivalent (BOE) resource estimates. Activities associated with a proposed lease sale in the EPA are assumed to represent 15-19 percent of OCS Program activities in the EPA unless otherwise indicated. In general, a proposed lease sale represents less than 1 percent of the Gulfwide OCS Program based on BOE resource estimates. Activities associated with a proposed action are assumed to represent less than 1 percent of Gulfwide OCS Program activities and impacts unless otherwise indicated.

Specific projections for activities associated with a proposed action are discussed in the following scenario sections. The potential impacts of the activities associated with a proposed action are considered in the environmental analysis sections (**Chapters 4.2.1. and 4.4.**).

The Gulfwide OCS Program scenario includes all activities that are projected to occur from past, proposed, and future lease sales during the analysis period. Activities that take place beyond the analysis timeframe as a result of future lease sales are not included in this analysis. The impacts of activities associated with the Gulfwide OCS Program on biological, physical, and socioeconomic resources are analyzed in the cumulative environmental analysis section (**Chapter 4.5.**).

4.1.1.1. Resource Estimates and Timetables

4.1.1.1.1. Proposed Action

A proposed action's scenarios are used to assess the potential impacts of a proposed lease sale. The resource estimates for a proposed action 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) estimates of the portion or percentage of these resources assumed to be leased, discovered, developed, and produced as a result of a proposed action. The estimates of undiscovered, unleased, conventionally recoverable oil and gas resources are based upon a comprehensive appraisal of the conventionally recoverable petroleum resources of the Nation as of January 1, 1999. Due to the inherent uncertainties associated with an assessment of undiscovered resources, probabilistic techniques were employed and the results were reported as a range of values corresponding to different probabilities of occurrence. A thorough discussion of the methodologies employed and the results obtained in the assessment are presented in the MMS report *2000 Assessment of Conventionally Recoverable Hydrocarbon Resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 1999* (Lore et al., 2001). The estimates of the portion of the resources assumed to be leased, discovered, developed, and produced as a result of a proposed action are based upon logical sequences of events that incorporate past experience, current conditions, and foreseeable development strategies. A profusion of historical databases and information derived from oil and gas exploration and development activities are available to MMS and were used extensively. The undiscovered, unleased, conventionally recoverable resource estimates for a proposed action are expressed as ranges, from low to high. The range reflects a range of projected economic valuations of the produced oil and gas. The "low" end of the range is based on an economic case of $18 per barrel of oil and $2.11 per thousand cubic feet (Mcf) for gas. The "high" estimate is based on an economic case of $30 per barrel of oil and $3.52 per Mcf for gas.

Table 4-1 presents the projected oil and gas production for a proposed action and for the Gulfwide OCS Program. **Table 4-2** provides a summary of the major scenario elements of a proposed action and some of the related impact producing factors. To analyze impact producing factors for a proposed action and the Gulfwide OCS Program, the proposed lease sale area was divided into two offshore subareas based upon ranges in water depth (1,600-2,400 m and >2,400 m). **Figure 3-10** depicts the location of the offshore subareas. The water-depth ranges reflect the technological requirements and 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. Estimates of resources and facilities are distributed into each of the subareas.

The estimated amounts of resources projected to be leased, discovered, developed, and produced as a result of a proposed lease sale are 0.065-0.085 BBO and 0.265-0.340 Tcf of gas. The number of exploration and delineation wells, production platforms, and development wells projected to develop and produce the estimated resources for a proposed action is given in **Table 4-2**. The table shows the distribution of these factors by offshore subareas in the proposed lease sale area. **Table 4-2** also includes estimates of the major impact producing factors related to the projected levels of exploration, development, and production activity.

For purposes of analysis, the life of the leases resulting from a proposed action is assumed to not exceed 40 years. Exploratory drilling activity takes place over a 16-year period, beginning in one year after the lease sale. Development activity takes place over an 18-year period, beginning with the installation of the first production platform and ending with the drilling of the last development wells. Production of oil and gas begins by the fourth year after the lease sale and continues through the 35th year. Final abandonment and removal activities occur in the 37th year.

4.1.1.1.2. Gulfwide OCS Program

Gulfwide OCS Program: Projected reserve/resource production for the Gulfwide OCS Program (15.49-22.42 BBO and 153.42-207.98 Tcf of gas) represents anticipated production from lands currently under lease plus anticipated production from future lease sales over the 40-year analysis period. **Table 4-3** presents projections of the major activities and impact producing factors related to future Gulfwide OCS Program activities.

Eastern Planning Area: Projected reserve/resource production for the OCS Program in the EPA (0.14-0.37 BBO and 2.49-3.54 Tcf of gas) represents anticipated production from lands currently under lease in the EPA plus anticipated production from future EPA lease sales over the 40-year analysis period. Projected production represents less than 1-2 percent of the oil and approximately 2 percent of the gas of the total Gulfwide OCS Program. **Table 4-4** presents projections of the major activities and impact producing factors related to future operations in the EPA.

Central Planning Area: Projected reserve/resource production for the OCS Program in the CPA (12.00-16.52 BBO and 108.27-146.27 Tcf of gas) represents anticipated production from lands currently under lease in the CPA, plus anticipated production from future CPA lease sales over the 40-year analysis period. Projected production represents approximately 74-78 percent of the oil and 70 percent of the gas of the total Gulfwide OCS Program. **Table 4-5** presents projections of the major activities and impact producing factors related to future operations in the CPA.

Western Planning Area: Projected reserve/resource production for the OCS Program in the WPA (3.35-5.53 BBO and 42.66-58.17 Tcf of gas) represents anticipated production from lands currently under lease in the WPA plus anticipated production from future WPA lease sales over the 40-year analysis period. Projected production represents approximately 22-25 percent of the oil and 28 percent of the gas of the total Gulfwide OCS Program. **Table 4-6** presents projections of the major activities and impact producing factors related to future operations in the WPA.

4.1.1.2. Exploration and Delineation

Prelease exploration activity centers on prospecting for promising accumulations of oil and gas on unleased OCS blocks. “Prospecting” in deep water, like the proposed lease sale area, necessarily involves analyzing data collected by an array of tools that remotely sense the geology below the sea bottom, and skilled explorationists (i.e., geologists, geophysicists, and engineers) conceptualizing where oil and gas might be found. Prior to a lease sale, oil and gas operators evaluate available G&G data in order to decide upon lease prospects. Geophysical data used in exploration focuses on seismic surveys that record the speed at which compressional waves move through sediment, rocks, and fluids they contain. A variety of data sources are accessed in this evaluation: in-house operator, operator consortia, purchased from vendors, university consortia, and open literature. Lease prospects are ranked by operators using G&G data, proprietary methodologies, and economic criteria to determine a dollar amount for lease sale bidding.

When an operator successfully acquires an OCS lease, a period of postlease prospect maturation begins. Maturation refers to a suite of concurrent activities whereby data and analyses are assembled to a state of completeness or sophistication that permits management to decide whether or not to invest in an exploration program. During prospect maturation, explorationists apply various techniques and tools to examine specific G&G qualities, perform special processing on the seismic data, and/or apply software to manipulate large datasets. Previous assumptions and conclusions about the lease's prospects are revisited and new ideas are tested. Operators usually rank mature prospects again using proprietary economic models, an internal risk evaluation team, various kinds of decision trees, and/or structured scenarios. The process is designed to increase the likelihood that the drilled prospect is a discovery and a dry hole is averted.

Operators use drilling terms that characterize stages in the discovery and production of hydrocarbon resources. An exploration well generally refers to the first well drilled on a unproven or semi-proven basin or territory to determine if a resource exists. If the geologic area, basin, or "play" has not been tested before, the term wildcat exploration well is sometimes used. If a resource is discovered or if the operator is uncertain whether or not an economic discovery has been made, a delineation well may be drilled. Delineation wells help define how big a structure might be, the geographic extent of the reservoir rock, the amount of resource in the discovery "pay zones," and the ease that a formation can be produced (i.e., porosity and permeability). A delineation well can be a separate well or a "sidetrack." The operator uses the initial exploration well to drill a sidetrack well. The bit drills through the sidewall of the existing well bore at an angle (deviation) to test a different layer or structure. A sidetrack well can test for the same data at lower cost because a drill rig does not need to be de-mobilized, moved, and re-mobilized at a different location.

In 2002, MMS analyzed success rates of exploration wells for the 1995-2000 period. For water depths greater than 200 m, the geologic success rate for exploration wells has been between 30 and 40 percent. Conversely, approximately 60-70 percent of these wells were dry holes. Geologic success is distinguished from economic success because a geologically successful well may not be economic to produce. A deepwater exploration well is a very expensive investment; therefore, operators are highly motivated to engage the best technology available so that the chance for a discovery and economic return is increased.

4.1.1.2.1. Seismic Surveying Operations

Geophysical seismic surveys are performed to obtain information on surface and near-surface geology and on subsurface geologic formations. The MMS is currently completing a programmatic EA on G&G permitted activities in the GOM (USDOI, MMS, in preparation), which includes a detailed description of seismic surveying technologies and operations. It is incorporated here by reference and summarized below. High-resolution surveys done in support of lease operations are authorized under the terms and conditions of the lease agreement, and are referred to as postlease surveys. Prelease surveys take into account similar seismic work performed off-lease and collectively authorized under MMS's G&G permitting process.

High-resolution seismic surveys collect data on surficial geology used to identify potential shallow geologic hazards for engineering and site planning for bottom-founded structures. They are also used to identify environmental resources such as chemosynthetic community habitat. Deep-penetration, CDP seismic surveys obtain data about geologic formations greater than 10,000 m (32,800 ft) below the seafloor. High-energy, marine seismic surveys include both 2D and 3D surveys. Data from 2D/3D surveys are used to map structural features of stratigraphically important horizons in order to identify potential hydrocarbon traps. They can also be used to identify and map habitats for chemosynthetic communities.

Prior to 1989, explosives (dynamite) were used in certain limited areas to generate seismic pulses needed for the surveys. However, the damaging environmental impacts associated with explosives' acoustical energy (high velocity and high peak pressure) led the seismic industry to replace the explosives with seismic airguns. Considered nonexplosive, the piston-type airguns use compressed air to create impulses with superior acoustic signals without generating the environmental impacts of explosives. Due to the decreased impacts, ease of deployment, and reduced regulatory timeframes that come with using airguns, it is assumed that no explosives would be used in future seismic surveys.

Typical seismic surveying operations tow an array of airguns and a streamer (signal receiver cable) behind the vessel 5-10 m below the sea surface. The airgun array produces a burst of underwater sound by releasing compressed air into the water column that creates an acoustical energy pulse. Depending on survey type and depth to the target formations, the release of compressed air every couple of seconds creates a regular series of strong acoustic impulses separated by silent periods lasting 7-16 seconds. Airgun arrays are designed to focus the sound energy downward. Acoustic (sound) signals are reflected off the subsurface sedimentary layers and recorded near the water surface by hydrophones spaced within streamer cables. These streamer cables are often 3 mi or greater in length. Vessel speed is typically 4.5-6 knots (about 4-8 mph) with gear deployed.

The 3D seismic surveying enables a more accurate assessment of potential hydrocarbon reservoirs to optimally locate exploration or development wells and minimize the number of wells required to develop a field. State-of-the-art computers have the power to manipulate and process large tracks of 3D seismic data. The 3D surveys carried out by seismic vendors can consist of several hundred OCS blocks. Multiple-source and multiple-streamer technologies are used for 3D seismic surveys. A typical 3D survey might employ a dual array of 18 guns per array. Each array might emit a 3,000-in^3 burst of compressed air at 2,000 pounds per square inch (psi), generating approximately 4,500 kilojoule (kJ) of acoustic energy for each burst. At 10 m from the source, the pressure experienced is approximately ambient pressure plus 1 atmosphere (atm). The streamer array might consist of 6-8 parallel cables, each 6,000-8,000 m long, spaced 75 m apart. A series of 3D surveys collected over time, commonly referred to as a four-dimensional, 4D, or time-lapse survey, is used for reservoir management (to monitor how a reservoir is draining to optimize the amount of hydrocarbon that is produced).

Multicomponent data, sometimes referred to as 4C data, is a product of an emerging technology that incorporates recording the traditional seismic compressional (P) waves with a full complement of other wave types, but predominantly shear (S) waves. The 4C technology provides a second independent image of a geologic section as well as improves the lithology picture in structurally complex areas. It can also aid in reservoir fluid prediction. The 4C data may be 2D or 3D in nature and procedurally involves draped or towed ocean-bottom receiver cable(s) for acquisition. The 4C data can be used as a defining prelease tool or a postlease aid for reservoir prediction.

Postlease seismic surveying may include high-resolution, 2D, 3D, or 4D surveying. In addition, multicomponent data (2D-4C and 3D-4C data) may be collected to improve lithology and reservoir prediction. High-resolution surveying is done on a site-specific or lease-specific basis or along a proposed pipeline route. These surveys are used to identify potential shallow, geologic hazards for engineering and site planning for bottom-founded structures. They are also used to identify environmental resources such as hard-bottom areas, topographic features, potential chemosynthetic community habitat, or historical archaeological resources. New technology has allowed for 3D acquisition and for deeper focusing of high-resolution data. It is assumed at least one postlease, high-resolution seismic survey would be conducted for each lease.

Deeper penetration seismic surveying (2D, 3D, or 4D) may also be done postlease for more accurate identification of potential reservoirs, increasing success rates for exploratory drilling and aiding in the identification of additional reservoirs in “known” fields. The 3D technology can be used in developed areas to identify bypassed hydrocarbon-bearing zones in currently producing formations and new productive horizons near or below currently producing formations. It can also be used in developed areas for reservoir monitoring and field management. The 4D seismic surveying is used for reservoir monitoring and management, as well as in identifying bypassed “pay zones.” Through time-lapsed surveys, the movement of oil, gas, and water in reservoirs can be observed over time. Postlease, deep seismic surveys may occur periodically throughout the productive life of a lease.

From 1996 to 2001, the number of prelease geophysical permits Gulfwide has been consistently high, averaging over 100 permits a year. The majority of these permits are related to the cyclic nature (7-9 years) of seismic surveys; more state-of-the-art 2D and 3D seismic surveys would be run in mature regions of the CPA and WPA where inadequate and dated seismic coverage currently exists. Due to the smaller size of the proposed lease sale area and the recent completion of available surveys (1999 and 2000), prelease surveys for a proposed action are projected to be random and limited. The MMS estimates that only one or two prelease seismic surveys per year may be applied for and permitted as a result of a proposed action. For OCS Program activities in the EPA for the years 2003-2042, 40-80 prelease seismic surveys may be permitted, with the majority occurring during years 2009-2010, 2019-2020, and 2029-2030.

Developing technologies may provide additional detail on the geology and fluids beneath the seafloor that can have applications for the deepwater areas of the GOM. These technologies include vertical cables, marine vibrators, and combinations of multiple vessels, source arrays, and streamers.

4.1.1.2.2. Exploration and Delineation Drilling Plans

An EP must be submitted to MMS for review and approval before any on-site exploration activities can begin on a leased block. Two versions of the EP are produced by the operator for MMS. One version is a proprietary copy that remains on file with MMS. It contains information such as the operator's structure maps, interpreted seismic and structural cross sections showing the operator's evaluation of the prospective structure. The second version is for public access and contains everything that the proprietary version contains except the competitive data noted above. An EP can include exploration programs with multiple wells. Such an approach gives the operator greater flexibility in planning for mechanical problems and provides alternatives and contingencies.

The required contents of an EP include descriptions of the following: (1) the location(s) of the exploration well(s) on the lease block; (2) the drill rig or ship expected to be used; (3) the geologic horizon(s) and age of the prospect; (4) the bathymetric maps, geologic structure maps, seismic velocity data, and interpreted seismic and structural cross sections; (5) a description and schedule of exploration activities; and (6) the environmental monitoring plans and compliance certifications. Upon receipt of an operator's complete EP, MMS reviews it for compliance with all applicable laws and regulations and provides a response and finding within 30 days. The MMS performs technical and environmental reviews for shallow geologic hazards (unstable sea bottom or surface-breaking faults) and manmade hazards (such as existing pipelines), archaeological resources, endangered species, H_2S, sensitive biological features (chemosynthetic communities), water and air quality, oil-spill response, socioeconomic issues, and other competing OCS uses (e.g., military operations). Review of the EP may result in a CER or an EA and/or EIS that must be prepared in support of the NEPA environmental review. The CER, EA, and/or EIS are based on available information. Guidelines and environmental information requirements for lessees and operators submitting an EP are addressed in 30 CFR 250.203 and further explained in NTL 2002-G08. Additional information required includes (1) a geophysical report (for determining the potential for the presence of deepwater benthic communities), (2) an archaeological report, (3) air emissions data, (4) a live-bottom survey and report, (5) a biological monitoring plan, and (6) recommendations by the affected State(s), DOD, FWS, NOAA Fisheries, and/or internal MMS offices. As part of the review process, EP's and supporting environmental information are sent to the affected State(s) for consistency certification review and determination under each State's approved CZM program.

After EP approval and prior to conducting drilling operations, the operator is required to submit and obtain approval for an APD. The APD requires additional equipment and hardware specifications, rig certifications, and data beyond that contained in the EP (i.e., the mud weight and casing program for control of the well).

4.1.1.2.3. Exploration and Delineation Drilling

Exploration and delineation wells in the proposed lease sale area are assumed to be drilled with MODU's. Those capable of being deployed in the proposed lease sale area's water depths (1,600-3,000 m or 5,250-9,850 ft) include (1) conventionally-moored semisubmersibles (semis) (those anchored to the bottom with a chain catenary or tension moorings), (2) DP semisubmersibles (semi), (3) conventionally-moored drillships, and (4) DP drillships (**Figure 4-1**).

The water depth limit for conventionally-moored semis is approximately 2,500 m (8,550 ft). Most of the proposed lease sale area, therefore, is within the capability of this class of MODU's, but not the entire area. In March 2002, Shell set an ultra-deepwater world record in the GOM for a non-DP, conventionally-moored semi of 2,775 m (9,100 ft) (depth of deepest anchor) (Offshore-Technology website; www.offshore-technology.com).

Dynamic positioning refers to the system of propeller jets that gyroscopically accommodate for movement of the ship in winds and currents to keep the drill rig assembly stable and in the same location.

DP semis can operate in water depths up to approximately 3,000 m (RigZone website; http://www.rigzone.com). The DP semis have a depth of operation about 500 m greater than conventionally-moored semis and have the advantage that they do not disturb the sea bottom with anchors. The DP drillships have about the same or a slightly deeper capability than DP semis, depending on the technology deployed. Drillships are constructed to, or adapted to, integrate a drill rig assembly and its support facilities into a floating hull. Because of their size, DP drillships are used in the deepest water (>3,000 m; >9,800 ft). The practical ultra-deepwater drilling depth limits are currently around 3,050 m (10,000 ft). The RigZone website shows that very few rigs built for deepwater exploration have drilling capability beyond 10,000 ft, and those that do are DP drillships.

Day rates for deepwater MODU's fluctuate significantly depending on industry activity levels. In May 2002 day rates for DP drillships were reported as $149,000 (RigZone website; http://www.rigzone.com). Day rates for semisubmersibles were $86,000-$94,000 for 2nd and 3rd generation rigs, with a marketed utilization rate of 75 percent. RigZone's semisubmersible categorization of 1st through 5th generation makes it difficult to correlate a semis generation to a depth range or DP capability. In July 2000 RigZone reported day rates for semisubmersibles as $27,500-$139,000, with a marketed utilization rate of 100 percent.

The type of rig chosen to drill a prospect depends primarily on water depth. Most operators in the GOM OCS refer to deepwater as depths beyond 300 m (1,000 ft), while the term ultra-deep refers to depths beyond 1,000 m (3,280 ft). Since the water-depth ranges for each type of drilling rig overlap, other factors such as availability and day rates are also considered when deciding upon the type of rig to use. The table below indicates the depth ranges used in this analysis for GOM MODU's.

Drilling Rig Type	Water-Depth Range
Conventionally-Moored Semisubmersible	>600 m, <2,600 m
DP Semisubmersible	>600 m, <3,000 m
Drillship	>600 m

The Gulfwide OCS Program scenario projects 6 weeks (42 days) as the average duration for an exploration well to reach total depth; however, the range (30-100 days) can be great. Longer times on station can occur when problems with the equipment, weather or currents, or the geology are encountered. Other variables that influence the duration of an exploration well include (1) the depth of the prospect's potential target zone, (2) the complexity of the well design, and (3) the directional offset (deviation) of the wellbore needed to reach a particular zone.

Figure 4-2 represents a generic well schematic for an exploration well in the proposed lease sale area. The generic well design was derived from actual well-casing programs from nearby projects in the Mississippi Canyon and DeSoto Canyon OCS areas and from internal MMS data. A generic well configuration cannot capture all of the possible configurations that might impact the well design that are caused by (1) unique geologic conditions at a specific well location, (2) directional drilling requirements, (3) potential sidetrack(s), or (4) company preferences. For exploratory wells, contingencies (such as anticipated water-flow zones in the formation) must also be considered in the casing program.

The drilling of a deepwater exploration well begins with setting the first of many sections, or strings, of casing (steel tube). Each casing section is narrower than the preceding one, and each change in casing diameter is separated by a "shoe" (**Figure 4-2**). The drillstring (pipe and bit) drills the wellbore inside the casing. The first casing set at the sea bottom (or mudline) can be large, approximately 30-40 in (75-100 cm) in diameter, especially when drilling through salt to reach subsalt objectives. The first string is emplaced by "jetting" out the unconsolidated sediment with a water jet as the largest casing pipe is set in place. The casing is cemented to the formation by forcing cement downhole to squeeze up and around the outside of the pipe and the wall of the geologic formation. This seal is tested with a pressure test. Because the shallow sediments are soft and unconsolidated, the next casing intervals (a thousand feet or more below mudline) are commonly drilled with treated seawater without a riser (a steel-jacketed tube that connects the well head to the drill rig and within which the drilling mud and cuttings circulate). Drilling mud is generally not used when a riser is not used, and the formation cuttings are discharged from the wellbore directly to the sea bottom. After the blowout preventer (BOP) is installed, commonly at the sea bottom, the riser is connected and circulation for drilling muds and cuttings between the well bit and the surface rig is established.

Next, a repetitive procedure takes place until the well reaches its planned total depth: (1) drill to next casing point, (2) install the casing, (3) cement the casing, (4) test 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. The casing points are determined by downhole formation pressure that is predicted before drilling with seismic wave velocities. As the well deepens, extra lengths of pipe (each about 100 ft long) are screwed onto the drillstring at the surface to extend length to the cutting bit. The downtime needed to install extra lengths of drill pipe is referred to as “tripping” into or out of the hole. The bottom of a well is commonly open and uncased before the well is completed.

The MMS mandates that operators conduct their offshore operations in a safe manner. Subpart D of MMS's operating regulations (30 CFR 250) provides guidance to operators on drilling activities. For example, operators are required by 30 CFR 250.400 to take necessary precautions to keep their wells under control at all times using the best available and safest drilling technology (NTL 99-G01). Deepwater areas pose some unique concerns regarding well control. In 1998, the International Association of Drilling Contractors (IADC) published deepwater well-control guidelines (IADC, 1998) to assist operators in this requirement. These guidelines address well planning, well-control procedures, equipment, emergency response, and training.

As exploration drilling occurs in progressively deeper waters, operators may consider using MODU’s 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 and later transported to shore for processing. Operators may also consider barging hydrocarbons from test wells 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 MMS to flare test hydrocarbons.

Between 1992 and 2001, the average number of rigs drilling in GOM deepwater (>305 m or 1,000 ft) jumped dramatically from 3 to 43 rigs (Baud et al., 2002). Competition for deepwater drilling rigs in the GOM may limit the availability of these MODU’s to drill deepwater prospects. Drilling activities may also be constrained by the availability of rig crews, risers, and other equipment.

Proposed Action Scenario: **Table 4-2** shows the range of exploration and delineation wells by water depth subarea. It is estimated that 11-13 exploration and delineation wells would be drilled as a result of a proposed action. These wells are projected to be drilled over a 16-year period beginning two years after a proposed lease sale, with a maximum of three drilled during one year. The exploration and delineation scenario assumes 42 days to reach total depth.

Gulfwide OCS Program Scenario: It is estimated that 8,996-11,333 exploration and delineation wells would be drilled Gulfwide as a result of the OCS Program. **Table 4-3** shows the estimated range of exploration and delineation wells by water depth subarea. Of these wells, approximately 0.5-0.7 percent would be in the EPA, 76-79 percent in the CPA, and 20-24 percent in the WPA. Activity is projected to be relatively stable for the first 10 years of the analysis period, followed by a steady reduction in the annual rate of exploration and delineation wells.

4.1.1.3. Development and Production

According to 30 CFR 250.105, exploration means the commercial search for oil, gas, or sulfur. Delineation is any additional well needed by the lessee to decide whether to proceed with development and production. Development means those activities that take place following the discovery of minerals in paying quantities. Production means those activities that take place after the successful completion of any means for the removal of minerals.

4.1.1.3.1. Development and Production Plans

In 1992, MMS formed an internal Deepwater Task Force to address technical issues and regulatory concerns relating to deepwater (greater than 1,000 ft or 305 m) operations and projects utilizing subsea technology. Based on the Deepwater Task Force's recommendation, an NTL was developed, which required operators to submit a DWOP for all operations in deep water and all projects using subsea technology (currently NTL 2000-N06). A DWOP is intended to explain an operator's conceptual design for a production program while plans are in a formative and flexible stage that can adapt to changes before capital expenditures for equipment are finalized. The DWOP step was established to address regulatory issues and concerns that were not addressed in the existing MMS regulatory framework, and it is intended to initiate an early dialogue between MMS and industry before major capital expenditures on deepwater and subsea projects are committed. Deepwater technology has been evolving faster than MMS's ability to revise OCS regulations; the DWOP was established through the NTL process, which provides for a more timely and flexible approach to keep pace with the expanding deepwater operations and subsea technology. The DWOP requirements are being incorporated into MMS operating regulations via the proposed rulemaking for revisions to 30 CFR 250 Subpart B.

The DWOP is intended to address the different functional requirements of production equipment in deepwater, particularly the technological requirements associated with subsea production systems and the complexity of deepwater production facilities. The DWOP provides MMS with information specific to deepwater equipment issues to demonstrate that a deepwater project is being developed in an acceptable manner as mandated in the OCSLA, as amended, and MMS operating regulations at 30 CFR 250. The MMS reviews deepwater development activities from a total system perspective, emphasizing operational safety, environmental protection, and conservation of natural resources. The DWOP process is a phased approach that parallels the operator's state of knowledge about how a field would be developed. A DWOP outlines the design, fabrication, and installation of the proposed development/production system and its components. A DWOP includes structural aspects of the facility (fixed, floating, subsea); anchoring and mooring system; wellbore, completion, and riser systems; safety systems; offtake; and hazards and operability of the production system. The DWOP provides MMS with the information to determine if the operator has designed and built sufficient safeguards into the production system to prevent the occurrence of significant safety or environmental incidents. The DWOP, in conjunction with other permit applications, provides MMS the opportunity to assure that the production system is suitable for the conditions in which it would operate.

The MMS recently completed a review of several industry-developed, recommended practices that address the mooring and risers for floating production facilities. The recommended practices address such things as riser design, mooring system design (stationkeeping), and hazard analysis. The MMS is in the process of incorporating these recommended practices into the existing regulations. Hazard analyses allow MMS to be assured that the operator has anticipated emergencies and is prepared to address them, either through their design or the operation of the equipment in question.

One of MMS's primary responsibilities is to ensure development of economically producible reservoirs according to sound conservation, engineering, and economic practices as cited in 30 CFR 250.202(a), 250.203(b)(21), 250.204(b)(17), and 250.1101(a). The MMS has established requirements for the submission of conservation information (NTL 2000-N05) for production activities. Operators should submit the necessary information as part of their Supplemental POE and Initial and Supplemental DOCD. Conservation reviews are performed to ensure that economic reserves are fully developed and produced.

A DOCD must be submitted to MMS for review and decision before any development operations can begin on a lease. A DOCD is analogous to an Exploration Plan, but applicable to the development phase of postlease activity. The boundary between activities governed by an EP and a DOCD are transitional in the same way that postlease phases of exploration and development are transitional.

A DOCD describes the proposed development activities, drilling activities, structure facilities, production operations, environmental monitoring plans, and other relevant information. It also includes a schedule of development and production activities. Requirements for lessees and operators submitting a DOCD are addressed in 30 CFR 250.204. Information guidelines for DOCD's are given in NTL 2002-G08.

After receiving a complete DOCD, MMS performs technical and environmental reviews for compliance with all applicable laws and regulations. The MMS evaluates the proposed activity for potential impacts relative to shallow geologic hazards and manmade hazards (including existing pipelines), archaeological resources, endangered species, sensitive biological features, water and air quality, H_2S, oil-spill response, socioeconomic issues, and other competing OCS uses (e.g., military operations).

A CER, EA, and/or EIS are prepared in support of the NEPA environmental review of a DOCD. The CER, EA, and/or EIS is based on available information, which may include (1) a geophysical report (for determining the potential for the presence of deepwater benthic communities, (2) an archaeological report, (3) air emissions data, (4) a live-bottom survey and report, (5) a biological monitoring plan, and (6) recommendations by the affected State(s), DOD, FWS (for selected plans under provisions of a DOI agreement), NOAA Fisheries, and/or internal MMS offices. As part of the review process, the DOCD and supporting environmental information may be sent to the affected State(s) for consistency certification review and determination under each State's approved CZM program. The OCSLA (43 U.S.C. 1345(a) through (d) and 43 U.S.C. 1351(a)(3)) provides for the coordination and consultation with the affected State and local governments concerning a DOCD.

4.1.1.3.2. Development and Production Drilling

A development or production well is designed to produce a known hydrocarbon reservoir. Multiple wells are commonly drilled from the same structure. The number of wells per structure varies according to the type of structure used, the prospect size, the drilling/production strategy employed for the development drilling program, and the requirements for resource conservation (avoidance of overproduction and reservoir damage). When an exploration well discovers a hydrocarbon resource, the operator must decide whether or not to complete the well without delay, to delay completion with the rig on station (i.e., conducting additional tests), or to temporarily abandon the well and move the rig offsite. If a decision is made to complete the well, a new stage of activity commences. Completing a well involves the treatment of the formation by fracking, adding stimulating chemicals or agents, and installing the downhole equipment that would allow testing of the formation so that flow rates and parameters can be evaluated over a period of days to weeks. Finally the well is ready to go online and produce the oil or gas resources from the reservoir.

A development or production well is designed to extract a known hydrocarbon reservoir. When an exploration well discovers a hydrocarbon accumulation, 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. If an exploration well is clearly a dry hole, the operator usually abandons the well without delay.

Completion is the conversion of an exploratory or development well to a producing well. The process begins with installing the downhole equipment to allow testing of the formation and production of oil or gas from the reservoir. Examples of completion activities include setting and cementing the casing, perforating the casing and surrounding cement, installing production tubing and packers, and gravel-packing the well. Completed wells may be put into production if the operator determines the reservoir economics warrant it and if a pipeline is at hand to transport the resource. Alternatively, the well could be "shut in" to await the development of a pipeline or other distribution system. Well treatments are commonly done as part of the completion process to improve well productivity. Acidizing a reservoir to dissolve cementing agents and improve fluid flow is the most common well treatment in the GOM.

4.1.1.3.3. Production Structures

The MMS has described and characterized suitable deepwater production structures in its deepwater reference document (Regg et al., 2000). It is assumed that some variety or combination of floating and/or subsea production facility would be used for producing hydrocarbon resources in the proposed lease sale area. Production systems suitable for the proposed lease sale area include systems that can be deployed in water depths greater than 1,600 m (5,250 ft), automatically removing from consideration structures that are fixed to the seafloor (**Figure 4-1**).

Suitable proposed lease-sale area structures include the following: (1) floating production systems that are moored to the seafloor, such as tension-leg platforms (TLP), semis, and spars; (2) subsea systems that have all the necessary components to produce and control the well on the seafloor; and (3) floating production, storage and offloading systems (FPSO) that consist of a large drillship and shuttle tankers. In the proposed lease sale area, spars, semisubmersibes, and subsea structures would be installed in both water depths. The TLP's, while suitable to the proposed lease sale area's shallower water depth, are not economically feasible. The FPSO's, while suitable for both water depths in the proposed lease sale area, have not been authorized by MMS for use in the EPA. Those production systems that are suitable to the proposed lease sale area are discussed below.

4.1.1.3.3.1. Types of Production Structures

Semisubmersible

A TLP has a hull with pontoons held in place by tensioned tendons connected to a foundation on the seafloor that is secured by piles driven into the seabed. The tensioned tendons provide a broad depth range of utilization and also limit the TLP's vertical motion and, to a degree, its horizontal motion. At present, TLP's can be used in water depths up to approximately 2,100 m (6,900 ft).

Semisubmersible production structures resemble their drilling rig counterparts and are characterized by a floating hull with pontoons below the waterline and vertical columns to the hull box/deck. The structures keep on station with conventional catenary chains or semi-taut line mooring systems connected to anchors in the seabed. Semisubmersibles having dynamic positioning capability would probably deploy catenary or tensioned mooring lines anchored to the seafloor.

A spar structure is a deep-draft, floating caisson that consists of a large-diameter (27.4 to 36.6 m) cylinder or a cylinder with a lower tubular steel trellis-type component (truss spar) that supports a conventional production deck. 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 (2,950 ft) and may be used in water depths as great as 3,000 m (9,850 ft) (Regg et al., 2000).

Subsea Production

For some development programs, especially those in deep water, an operator may choose to use a subsea production system (Regg et al., 2000) instead of a floating production structure. A subsea production system comprises various components including templates, production tree (well head), "jumper" pipe connections, manifolds, pipelines, control equipment, and umbilicals. A subsea production system can range from a single-well template with production going to a nearby structure to multiple-well templates producing through a manifold to a pipeline and then to a riser system at a distant production facility, possibly in shallower waters.

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. Unlike wells from conventional fixed structures, subsea wells do not have surface facilities directly supporting them during their production phases. A drilling rig must 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 well control.

Although the use of subsea systems has recently increased as development has moved into deeper water, subsea systems are not new to the GOM. The first subsea production wells in the GOM were installed in the early 1960's. Subsea systems in the GOM are currently used in water depths up to 2,400 m. Operators are contemplating their use out to 3,000 m and beyond.

4.1.1.3.3.2. Bottom Area Disturbance

Structures constructed, emplaced, or anchored on the OCS to facilitate oil and gas exploration, development, and production include drilling rigs (jack-ups, semis, and drillships), production platforms, subsea systems, and pipelines. The emplacement of these structures disturbs some area of the sea bottom (benthos) beneath the structure. If anchors are employed, there are some benthic areas around the structure that are also disturbed. This disturbance includes both physical compaction beneath the structure and the resuspension and settlement of sediments. Jack-up rigs and semisubmersibles are assumed to be used in water depths less than 750 m and would potentially disturb about 1.5 ha (3.7 ac) each. In water depths greater than 750 m, dynamically positioned drillships would be used, with negligible benthic disturbance (except a very small area where the well is drilled). Conventional, fixed platforms installed in water depths less than about 400 m have a predicted disturbance of about 2 ha. At water depths exceeding 400 m, compliant towers, TLP's, spars, and floating production systems (FPS) would be used (**Figure 4-1**). A compliant tower consists of a narrow flexible tower and a piled formation that supports a conventional deck. A compliant tower would disturb the same bottom area—about 2 ha—as a conventional, fixed platform. A TLP consists of a floating structure held in place by tensioned tendons connected to the seafloor by templates secured with piles. A TLP would disturb about 5 ha of bottom area. A spar platform consists of a large-diameter cylinder supporting a conventional deck, three types of risers (production, drilling, and export), and a hull that is moored via a taut catenary system of 6-20 lines anchored to the seafloor. The bottom area disturbed by a spar is dependent on the anchor configuration and could be about 5 ha. A FPS consists of a semisubmersible vessel anchored in place with wire rope and chain. A FPS could disturb about 1.5 ha of sea bottom. Subsea systems, located on the ocean floor, are connected to the surface deck via production risers and would disturb less than 1 ha each. Emplacement of pipelines disturbs about 0.32 ha of seafloor per kilometer of pipeline.

Impacts from bottom disturbance are of concern near sensitive areas such as topographic features; pinnacles; low-relief, live-bottom features; chemosynthetic communities; high-density biological communities in water 400 m or greater; and archaeological sites. Regulations and mitigating measures protect known and unknown, newly discovered sensitive areas from potential impacts resulting from bottom disturbance.

4.1.1.3.3.3. Sediment Displacement

Trenching for pipeline burial affects the seafloor by displacing and/or resuspending seafloor sediments. The MMS's regulations (30 CFR 250.1003(a)(1)) require that pipelines installed in water depths <61 m (<200 ft) be buried to a depth of at least 3 ft below the mudline. Pipeline burial reduces pipeline movement by high currents and storms, protects the pipeline from external damage that could result from anchors and fishing gear, reduces the risk of fishing gear entanglement, as well as minimizing interference with the operations of other users of the OCS. It is predicted that 5,000 m^3 of sediment would be resuspended for each kilometer of pipeline trenched. In addition, pipelines crossing fairways must be buried to a depth of at least 10 ft and to 16 ft if crossing an anchorage area. Pipelines constructed as a result of a proposed action are not projected to be constructed in <61 m (<200 ft) or cross a fairway or anchorage area; therefore, no pipeline burials are projected as a result of a proposed action.

Sediment displacement also occurs as a result of the removal of pipelines. It is projected that the number of pipeline removals (or relocations) would increase Gulfwide as the existing pipeline infrastructure ages. For each kilometer of pipeline removed in water depths <61 m (<200 ft), approximately 5,000 m^3 of sediment could be resuspended.

Pipelines projected to be installed as a result of a proposed action would be in water depths >500 m, where DP lay barges would be used. Anchoring would not be required.

Displaced sediments are those that have been physically moved "in bulk." Displaced sediments would cover or bury an area of the seafloor, while resuspended sediments would 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.

Proposed Action Scenario: It is expected that pipelines from proposed action facilities would connect to existing or proposed pipelines near the proposed lease sale area. Because of the projected water depth in which the proposed pipelines would be installed, the scenario assumes no anchoring due to DP lay barges, and no burying.

Gulfwide OCS Program Scenario: From 2003 to 2042, 9,800-24,374 km of pipeline are projected to be constructed in <61 m (<200 ft) as a result of the Gulfwide OCS Program (**Table 4-3**).

4.1.1.3.4. Infrastructure Presence

Hydrocarbon resources cannot be located or developed without physically encountering and penetrating the formations that hold the resource. A drill bit must penetrate structures and rocks that hold promise for containing resources of oil and gas. Drilling rigs, vessels, platforms, machinery, and equipment are necessary to drill to great depths, and to lift, process and transport resource. For this activity to occur, the presence of these facilities hardware in the OCS environment is required. There are limited opportunities to mitigate or modify the presence of these surface and subsurface structures and still have them carry out their designed functions.

4.1.1.3.4.1. Anchoring

In the proposed lease sale area, drilling activities may or may not require anchoring, while production structures would be anchored to the seafloor. In contrast to shallower water, pipeline lay barges and service vessels would not anchor.

Semisubmersibles and/or drillships may be used to drill the 30-40 exploration and delineation wells projected as a result of a proposed action. To remain in place, semisubmersibles would either be anchored or DP. Even some DP semis may anchor. Drillships would use DP systems to remain in place and not anchor.

Anchored drilling activities or production structures (2 projected as a result of a proposed action) would require anchor-handling vessels. These vessels would position and emplace each anchor.

Anchoring systems can be catenary, semi-taut, or taut. The scope of traditional, catenary anchors is 5-7 times the water depth. Taut leg-mooring systems have begun to be used in deep water and reduce the anchor footprint on the seafloor. Regardless of the anchoring system used, a site-specific, environmental assessment of impacts from anchoring would be conducted by MMS for each exploration and development plan received.

Pipelines, projected to be installed as a result of a proposed action, would be in water depths greater than 500 m, where DP lay barges would be used rather than anchoring. In the deeper waters of the proposed lease sale area, service vessels would likely be DP vessels. However, in the shallower waters of the proposed lease sale area, mooring buoys may be used.

4.1.1.3.4.2. Space-Use Conflicts

During OCS operations, the areas occupied by seismic vessels, structures, anchor cables, and safety zones are unavailable to commercial fishermen. Usually, fishermen are precluded from a very small area for several days during active seismic surveying. Virtually all commercial trawl fishing in the GOM is performed in water depth less than 200 m (Louisiana Dept. of Wildlife and Fisheries, 1992). None of the blocks in the proposed action area are in water depths shallower than 1,600 m.

Longline fishing is performed in water depths greater than 100 m and usually beyond 300 m. All surface longlining is prohibited in the northern DeSoto Canyon area (designated as a swordfish nursery area by NOAA Fisheries). In the EPA, the closure area encompasses 160 blocks within the proposed lease sale area. Longline fishing would also probably be precluded from blocks for miles around the closure area because of the great length of typical longline sets and time required for their retrieval.

The scenario assumes exploratory drilling rigs spend 42 days on-site, which would be a short-term interference to commercial fishing. The proposed lease sale area ranges in depth from 1,600 to 3,000 m. This is beyond the range of typical commercial trawling. Even though production structures in deeper water are larger and individually would take up more space, there would be fewer of them compared to the great numbers of bottom-founded platforms in shallower water depths in other parts of the GOM. Factoring in navigational safety zones, deepwater structures would require 7-20 ha of space. Factoring in various configurations of navigational safety zones, deepwater facilities may request up to a 500-m radius safety zone or approximately 95 ha of space depending on the size of the surface structure (USCG regulations, 33 CFR 1, Part 147.15). However, existing Coast Guard-administered 500-m safety zones do not apply to vessels under 100 ft in length and would therefore have no impact on the vast majority of commercial or recreational fishing vessels. The issue of security zones, which could be implemented to protect significant manned structures from a directed threat, is under review but can be imposed at any time by Executive Order under the Ports and Waterways Safety Act for Antiterrorism. Production structures in all water depths have a life expectancy of 20-30 years. The MMS data indicate that the total area lost to commercial fishing due to the presence of production platforms has historically been and would continue to be less than 1 percent of the total area available.

Proposed Action Scenario: Only 40 ha (2 structures @ up to 20 ha) would be lost to commercial fishing as a result of a proposed action. This is approximately 0.00002 percent of the total area available in the proposed lease sale area (about 600,000 ha). Considering that virtually all trawling occurs in water depths of less than 200 m, essentially no trawling area would be lost due to a proposed action. Longlining is only permitted by Federal regulation in 96 blocks south of 28 °N. latitude and would be further limited due to the proximity of the closed area.

Gulfwide OCS Program Scenario: Total OCS EPA production structure installation has been estimated through the year 2042. Total activity in the EPA is estimated as 5-9 installed production structures between 2003 and 2042. As identified oil and gas fields are developed and fewer new reservoirs are located, the overall annual rate of platform and structure installation would decrease. Platform removal rates are assumed to increase as mature fields are depleted. The trend of increased area lost to commercial fishing would be reversed over time as the rate of platform removal exceeds the rate of platform installation. It is assumed that the total area lost to commercial fishing due to the presence of OCS production platforms in the EPA would continue to be less than 0.1 percent of the total area available to commercial fishing with little or no impact to trawling or longlining activities because of water depth and other Federal commercial fishing restrictions.

4.1.1.3.4.3. Aesthetic Interference

The factors that could adversely affect the aesthetics of the coastline are oil spills and residue, tarballs, trash and debris, noise, pollution, increased vessel and air traffic, and the presence of drilling and production platforms visible from land. Oil spills, oil residue from tankers cleaning their holding tanks, and tarballs could affect beaches, wetlands, and coastal residences. Increased vessel and air traffic may result in additional noise or in oil and chemical pollution of water in port and out to sea. The potential visibility of fixed structures in local GOM waters is worrisome for local chambers of commerce and tourist organizations. In a study conducted by the Geological Survey of Alabama (GSA) in 1998, several facets of the visibility of offshore structures were analyzed. The GSA earth scientists found that visibility is dictated not only by size and location of the structures and curvature of the Earth but also by atmospheric conditions. Social scientists added factors, such as the viewer's elevation (ground level, in a 2-story house, or in a 30-story condominium) and the viewer's expectations and perceptions. The size of an offshore structure depends on the reservoir being tapped, characteristics of the well-stream fluid, and the type of processing needed to treat the hydrocarbons. Location reflects the geology of the reservoir. Optimal location of structures means at or near the surface of the reservoir (GSA, 1998). Atmosphere refers to conditions of weather, air quality, and the presence or absence of fog, rain, smog, and/or winds. The height of the viewer affects their ability to see and distinguish objects several yards or miles away. Perceptions often dictate what people expect to see and, hence, what they do see.

To test visibility in as scientific a way as possible, GSA staff worked with members of the Offshore Operators Committee. They took a series of photographs on one day in October 1997, from a helicopter hovering at 300 ft. They used the same camera, lens, shutter speed, and f-stop setting. The subjects of the photos were four different types of structures usually found in both State and Federal waters offshore Alabama. The structures ranged in height from 60 to 70 ft; they varied in size from 120 ft by 205 ft to 40 ft by 90 ft with the smallest being 50 ft by 80 ft. The tallest and widest structures, i.e., those showing the most surface in the viewscape, were visible at up to 5 mi from shore. The shorter and the smaller the structure, the less visible at 5 mi; the smallest could barely be seen at 3 mi from shore. According to this study, no structure located more than 10 mi offshore would be visible (GSA, 1998). The proposed lease sale area is 70 mi from Louisiana, 98 mi from Mississippi, 93 mi from Alabama, and 100 mi from Florida.

Additional impact producing factors associated with offshore oil and gas activities are oil spills and trash and debris. These are the 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. The effects of an oil spill on the aesthetics of the coastline depend on factors such as season, extent of pollution, beach type and location, condition and type of oil washing ashore, tidal action, and cleanup methods (if any).

4.1.1.3.4.4. Bottom Debris

Bottom debris is defined as material resting on the seabed (such as cable, tools, pipe, drums, anchors, and structural parts of platforms, as well as objects made of plastic, aluminum, wood, etc.) that are accidentally lost (e.g., during hurricanes) or tossed overboard from facilities. The maximum quantity of bottom debris per operation is estimated to be several tons. **Chapter 4.1.1.11.** describes the requirements and guidelines for removing bottom debris and gear after structure decommissioning and removal operations. Up to a several tons of bottom debris are expected to result from activities associated with a proposed action.

4.1.1.3.5. Workovers and Abandonments

Completed and producing wells 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, or to permanently abandon 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 a few days to several months to complete, with an average of about 5-15 days. Historical data suggest that each producing well averages one workover or other well operation/treatment about every 4 years (USEPA, 1993a and b). Current oil-field practices include preemptive procedures or treatments that reduce the number of workovers required for each well. The MMS's projections suggest that a producing well may expect to have 6-9 workovers or other well activities during its lifetime.

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 (30 CFR 250.703). Permanent abandonment operations are undertaken when a well bore 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 have hydrocarbon shows are plugged with cement.

Proposed Action Scenario: **Table 4-2** shows there are 80-111 workovers projected as a result of a proposed action. The projected number of workovers is a function of producing wells, which includes completions expected to occur on approximately 85 percent of the development wells drilled. One permanent abandonment operation per well is projected.

Gulfwide OCS Program Scenario: **Table 4-3** shows there are 148,300-167,000 workovers projected Gulfwide as a result of the OCS Program. Of these, 0.3-0.5 percent would be in the EPA, 77-76 percent in the CPA, and 22-24 percent in the WPA. The projected number of workovers is a function of producing wells, which includes completions expected to occur on approximately 85 percent of the development wells drilled. One permanent abandonment operation per well is projected.

4.1.1.4. Operational Waste Discharged Offshore

The primary operational waste discharges generated during offshore oil and gas exploration and development are drilling fluids, drill cuttings, produced water, deck drainage, sanitary wastes, and domestic wastes. During production activities, additional waste streams include produced sand and well treatment, workover, and completion (TWC) fluids. Minor additional discharges occur from numerous sources; these discharges may include desalination unit discharges, blowout preventer fluids, boiler blowdown discharges, excess cement slurry, and uncontaminated freshwater and saltwater.

The USEPA, through NPDES permits issued by the USEPA Region that has jurisdictional oversight, regulates all waste streams generated from offshore oil and gas activities. The USEPA published the most recent effluent guidelines for OCS oil and gas extraction point-source category in 1993 (58 FR 12454). On January 22, 2001 (66 FR 6850), the USEPA guidelines were amended to address the discharge of SBF and other nonaqueous drilling fluids.

The USEPA Region 4 has jurisdiction over all of the EPA and the part of the CPA that is off the coasts of Alabama and Mississippi. The proposed lease sale area is within the jurisdiction of Region 4. The USEPA Region 6 has jurisdiction over the rest of the CPA and all of the WPA. Each USEPA Region has issued general permits for discharges that incorporate the 1993 effluent guidelines as a minimum. Vessels and pipelines servicing the proposed lease sale area are likely to traverse USEPA Region 6. The USEPA Region 4's current general permit was issued on October 16, 1998 (63 FR 55718) and modified on March 14, 2001 (66 FR 14988). It will expire on October 31, 2003. Region 4 has not revised its general permit to incorporate the new guidelines for SBF and other nonaqueous-based drilling fluids. The USEPA Region 6's general permit was issued on November 2, 1998 (63 FR 58722) and modified on April 19, 1999 (64 FR 19156). It was modified again on February 16, 2002, to incorporate the new SBF guidelines and will expire on November 3, 2003. The USEPA Region 6's modification authorizes the discharge of drill cuttings produced using SBF and other nonaqueous-based drilling fluids and wastewater used to pressure test existing piping and pipelines. The USEPA Region 4 may allow wastewater discharges within 1,000 m of Areas of Biological Concern after a comprehensive individual permit review but not for facilities desiring coverage by the General Permit.

4.1.1.4.1. Drilling Muds and Cuttings

The largest amount of discharges from drilling operations are drilling fluids (also known as drilling muds) and cuttings. 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 to seal the well. Drill cuttings are the fragments of rock generated during drilling and carried to the surface with the drilling fluid.

The composition of drilling fluids is complex. The bulk of the mud consists of clays, barite, and a base fluid, which can be fresh or salt water, mineral or diesel oil, or any of a number of synthetic oils. Drilling fluids and muds used on the OCS are divided into three categories: water based, oil based, and synthetic based. Numerous chemicals are added to improve the performance of the drilling fluid (Boehm et al., 2001).

Water-based drilling fluids (WBF) have been used for decades to aid drilling on the continental shelf. The WBF may have up to 3 percent by volume diesel oil or mineral oil added for lubricity. The discharge of WBF and cuttings associated with WBF is allowed everywhere on the OCS under the general NPDES permits issued by USEPA Regions 4 and 6, as long as the discharge meets toxicity guidelines. The USEPA (1993a and b) estimated that 12 percent of all drilling fluids and 2 percent of all drill cuttings were brought to shore for treatment and disposal under the previous NPDES general permit criteria.

Discharge of WBF results in increased turbidity in the water column, alteration of sediment characteristics because of coarse material in cuttings, and trace metals. Occasionally, formation may be discharged with the cuttings, adding hydrocarbons to the discharge. In shallow environments, WBF 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.

Oil-based drilling fluids (OBF) are occasionally used for directional drilling and in drill-bore sections where additional lubricity is needed. Mineral oil is advantageous because it is less toxic than diesel oil. Studies on the effects of the marine discharge of OBF show that they do not readily disperse in the water column and reach the sediment as clumps. Hydrocarbon concentration and impacts to benthic community diversity and abundance have been observed within 200 m of the drill site with diminishing impacts measured to a distance of 2,000 m (Neff, 1987). Diesel OBF contains light aromatics such as benzene, toluene, and xylene. All OBF and associated cuttings must be transported to shore for recycling or disposal unless reinjected. All OBF are likely to be replaced by SBF in deepwater drilling because of the many advantageous features of SBF (Neff et al, 2000).

Since 1992, SBF have been increasingly used, especially in deep water, because they perform better than WBF and OBF. The SBF reduce drilling times and costs incurred from expensive drilling rigs, and are less toxic than OBF. For SBF, the discharge of drilling fluids is prohibited. A recent literature review (Neff et al., 2000) discusses the current knowledge about the fate and effects of SBF discharges on the seabed. Like OBF, SBF do not disperse in the water column and therefore are not expected to adversely affect water quality. They do, however, settle close to the discharge point and affect the local sediments. Unlike OBF, SBF do not contain aromatic compounds and are not toxic. The primary affects are smothering of the benthic community, alteration of sediment grain size, and addition of organic matter which can result in localized anoxia while the SBF degrade. Different formulations of SBF result in base fluids that degrade at different rates, thus affecting the impact. Esters and olefins are the most rapidly biodegraded SBF's. Bioaccumulation tests indicate that SBF and their degradation products should not bioaccumulate. It is assumed that discharged SBF's adhered to cuttings degrade within 2-3 years after discharge (Neff et al., 2000). However, colder temperatures at greater depths could retard biodegradation.

Under USEPA Region 4's general NPDES permit, cuttings wetted with SBF cannot be discharged and must be transported to onshore disposal or obtain coverage under an individual NPDES permit. The USEPA Region 4 expects to readdress SBF guidelines under a new permit that would replace the current permit once it expires on October 31, 2003. At present, no individual permit which includes the discharge of SBF wetted cuttings has been approved by USEPA Region 4 (Truman, personal communication, 2002).

Table 4-8(a) presents the estimated volumes of water-based and synthetic-based fluids and cuttings generated and discharged per depth from an average well drilled to 2,800 m below the seafloor in the proposed lease sale area. The upper portion of the well would be drilled with WBF while the remainder would be drilled with SBF. For this well the "switchover" from WBF to SBF would occur at approximately 800 m. 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.

From July 2002 to February 2003, operators within the proposed lease sale area have submitted eight exploration plans proposing to test deeper geologic horizons. The estimated volumes of WBF and SBF and cuttings generated and discharged per depth are shown in **Table 4-8(b)**. To estimate the drilling discharges from these deeper wells, another generic wellbore design was developed to approximate the quantity of drilling discharges (cuttings and drilling fluid that may adhere to these cuttings) from these wells. This deep well design is similar to the wellbore schematic seen in **Figure 4-2** (described in **Chapter 4.1.1.2.3.**, Exploration and Delineation Drilling), except additional casing strings and drilling liners have been included in the wellbore. The casing points for the various strings have been adjusted to reflect possible geologic conditions that may be encountered with the deep wellbores. While the generic wellbore in **Figure 4.2** had a total depth of approximately 2,800 m (9,150 ft), the deep well design extends the drilling depth to approximately 5,900 m (19,400 ft). For the deep well design, the "switchover" from a WBF to a SBF is expected to occur at approximately the 914-m (3,000-ft) depth. Estimates of cuttings for the deep well design include "wash out" volumes for the wellbore that are similar to those used in the original generic wellbore (drilling intervals from 0 to 914 m (0-3,000 ft) at 20-40% and 5-15% from 914 m (3,000 ft) to total depth of the well measured from the seafloor).

Deep wells drilled during the development phase of operation on a project may not include all of the casings used in the exploration wells because operators gain geologic information from the exploratory wells and adjust their development drilling programs accordingly.

These values are estimates for informational purposes only. Well depths in the proposed lease sale area are expected to extend as deep as 6,000-7,700 m below the seafloor. The estimated volume of WBF and cuttings generated would be discharged according to NPDES permit limitations. The estimated volume of SBF generated is the amount of the base fluid adhering to cuttings. Discharge of SBF and SBF adhered to cuttings is currently prohibited. The SBF is rented by the operator. At the end of drilling, the SBF is returned to the mud company for recycling. Internal olefins are the most prevalent base fluid for the SBF used in deepwater drilling in the GOM. However, some operators have used polyalpha olefins, esters, or their own proprietary blend as the base fluid. Since OBF are used under special circumstances and may be replaced with SBF, estimates of the amount of OBF muds and cuttings are not possible.

Drilling discharges of muds and cuttings are regulated by USEPA through a NPDES permit. Barite, barium sulfate, is a major component of all drilling fluid types (WBF, OBF, and SBF). Mercury and other trace metals are naturally occurring impurities in barite. Since 1993, USEPA has required concentrations of mercury and cadmium to be less than or equal to 1 ppm and 3 ppm, respectively, in the stock barite used to make drilling muds. Through mercury and cadmium regulation, USEPA can also control levels of other trace metals in barite. This reduces the addition of mercury to values similar to the concentration of mercury found in marine sediments throughout the GOM (Avanti Corporation, 1993a and b; USEPA, 1993a and b). Trace metals including mercury are of concern because of the potential for a toxic effect or bioaccumulation in some marine organisms. Mercury is of particular concern because it can be bioaccumulated in aquatic organisms. Concentrations of total mercury in uncontaminated estuarine and marine sediments generally are 0.2 μg/g dry weight or lower. Surface sediments collected 20-2,000 m 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 GOM OCS (Neff, 2002).

Atmospheric mercury deposition is believed to be the main source of anthropogenic mercury inputs into the marine environment. Mercury in barite has been suggested as a secondary source in the GOM. Trace mercury in barite deposits is present predominantly as mercuric sulfate and mercuric sulfide (Trefrey, 1998). Barite is nearly insoluble in seawater, thus trapping mercury and other trace metals in the barite grains. Therefore, unless the mercuric sulfide in the barite can be microbially methylated, this source of mercury is relatively unavailable for uptake into the marine food web.

In May 2002, sediment samples were collected at six offshore drilling sites for total mercury and methylmercury analysis (Trefrey, 2002). The results show more total mercury in sediment samples near the drilling site and drill cuttings. However, methylmercury is not elevated in sediment samples near or far from the drill site. Thus, the study indicates that mercury in barite used in drilling muds offshore is not contributing to elevated methylmercury. Additional studies are planned to further evaluate the potential for conversion of inorganic mercury to methylmercury.

Research conducted by Neff et al. (1989) showed no uptake of mercury in winter flounder exposed to barite-amended sediments. Inorganic mercury is converted to methylmercury in the environment. Methylmercury bioaccumulates through the food chain. It is bioaccumulated in the muscle of marine animals. Elevated levels of methylmercury have been found in top predatory fish and marine mammals (USEPA, 1997).

4.1.1.4.2. Produced Waters

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; and compounds used during the oil/water separation process. Formation water, also called connate water or fossil water, originates in the permeable sedimentary rock strata and is brought up to the surface commingled with the oil and gas. Injection water is used to enhance oil production and in secondary oil recovery.

Produced water contains chemicals, which dissolved into the water from the geological formation where the water was stored. 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.

The USEPA general permits allow the discharge of produced water on the OCS provided the discharge meets discharge criteria. Oil and grease cannot exceed 42 mg/l daily maximum or 29 mg/l monthly average. Region 4 does not allow any discharge within 1,000 m of an area of biological concern. The discharge must also be tested for toxicity on a monthly basis.

Estimates of the volume of produced water generated per well are difficult because the percent water is a site-specific phenomenon. Usually, produced-water volumes are small during the initial production phase and increase as the formation approaches hydrocarbon depletion. Produced-water volumes range from 2 to 150,000 bbl/day (USEPA, 1993a and b). 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.

The MMS maintains records of the volume of produced water discharged on the OCS. The information, for the years 1996-2000, is summarized in **Table 4-9**. The annual volume ranges from 457 MMbbl in 1996 to 586 MMbbl of produced water discharged overboard during 2000. As of this EIS's publication, a full year of data for 2001 was not available. The 1996-2000 data shows that leases in water depths greater than 1,000 m have a maximum annual average per well of 60,000 bbl of produced water discharged overboard. The majority of produced water is on the continental shelf off the coast of Louisiana. Very little water is produced off the coast of Texas because activity in this area is primarily gas fields. For deepwater operations, new technologies are being developed that may discharge produced water at the seafloor or at "minimal surface structures" before the production stream is transported by pipeline to the host production facility.

Proposed Action Scenario: An average annual rate of 1-2 MMbbl of proposed water is projected to be discharged overboard from 16 to 22 producing wells as a result of a proposed action. During the years of peak activity, 2-3 MMbbl per year of produced water are projected from a proposed action.

Gulfwide OCS Program Scenario: It is estimated that 532 MMbbl per year of produced water would be discharged overboard from OCS activities.

4.1.1.4.3. Well Treatment, Workover, and 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. 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.

Workover fluids are used to maintain or improve existing well conditions and production rates. Six to nine workovers are projected per producing well over their lifetime. Workover operations include casing and subsurface equipment repairs, re-perforation, acidizing, and fracturing stimulation. 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 fracturing (also considered stimulation), hydrochloric (HCl) 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.

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.

The USEPA Region 4, under the NPDES general permit (GMG280000, 63 FR 55718), allows the discharge of well-treatment, completion, and workover fluids, which meet the specified guidelines. 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. Both must meet the general toxicity guidelines in the NPDES general permit. Discharge and monitoring records must be kept.

4.1.1.4.4. Production Solids and Equipment

As defined by USEPA in the discharge guidelines (58 FR 12454, 66 FR 6849), 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 USEPA (1993a and b). A variety of solid wastes are generated including construction/demolition debris, garbage, and industrial solid waste. No equipment or solid waste may be disposed of in marine waters.

4.1.1.4.5. 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 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 averages 50 bbl/day/platform (USEPA, 1993a and b). The deck drainage is collected, the oil is separated, and the water is discharged to the sea.

4.1.1.4.6. 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 sanitary waste, floating solids are prohibited. Facilities with 10 or more people must meet and maintain the requirement of total residual chlorine greater than 1 mg/l. There is an exception in the USEPA Region 4 general permit for the use of marine sanitation devices (MSD).

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 and b). It is assumed that these discharges are rapidly diluted and dispersed; therefore, no analysis of the impacts would be performed for a proposed action.

4.1.1.4.7. Minor Discharges

Minor discharges include all other discharges not already discussed that may result during oil and gas operations. Minor or miscellaneous wastes include desalination unit discharge, blowout preventer fluid, boiler blowdown, excess cement slurry, and uncontaminated freshwater and saltwater. In all cases, the USEPA Region 4 general permit states that 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. No projections of volumes or contaminant levels of minor discharges are made for a proposed action because the impacts are considered negligible.

4.1.1.4.8. Vessel Operational Wastes

The USCG defines an offshore supply vessel as a vessel propelled by machinery other than steam that is of 15 gross tons and less than 500 gross tons (46 CFR 90.10-40). Operational waste generated from supply vessels that support oil and gas operations include bilge and ballast waters, trash and debris, and sanitary and domestic wastes.

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 if the oil concentration is less than 100 ppm. Discharges may occur within 12 nmi 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).

The discharge of trash and debris is prohibited (33 CFR 151.51-77) unless it is passed through a comminutor and can pass through a 25-mm mesh screen. All other trash and debris must be returned to shore for proper disposal with municipal and solid waste facilities. All vessels with toilet facilities must have a MSD that complies with 40 CFR 140 and 33 CFR 149. Vessels complying with 33 CFR 159 are not subject to State and local MSD 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. State and local governments regulate gray water from vessels. Gray water is not federally regulated in the GOM.

4.1.1.4.9. Assumptions About Future OCS Operational Wastes

As oil exploration and production expands into deeper water, some characteristics of waste (type, volume, and discharge location) would change. The WBF and SBF would be the most commonly used drilling fluids. The use of SBF would increase and replace the use of OBF in most deepwater situations. The USEPA Region 6 has modified its general permit to allow the discharge of cuttings wetted with SBF.

The USEPA Region 4 (under which the proposed lease sale area falls) is expected to do so in 2003. The discharge of cuttings wetted with SBF would result in fewer cuttings brought to shore for disposal. New technologies in deep water may result in operational waste discharged at the seafloor. The movement into deep water would result in fewer total platforms but greater volumes of discharges at each platform.

4.1.1.5. Trash and Debris

The OCS oil and gas operations generate trash and debris materials made of paper, plastic, wood, glass, and metal. Most of this trash is associated with galley and offshore food service operations and with operational supplies such as shipping pallets, containers used for drilling muds and chemical additives (sacks, drums, and buckets), and protective coverings used on mud sacks and drilling pipes (shrink wrap and pipe-thread protectors). Some personal items, such as hardhats and personal flotation devices, are accidentally lost overboard from time to time. Generally, galley, operational, and household trash is collected and stored on the lower deck near the loading dock in large receptacles resembling dumpsters. These large containers are generally covered with netting to avoid loss and are returned to shore by service vessels for disposal in landfills. Drilling operations require the most supplies, equipment, and personnel, and therefore, generate more solid trash than production operations.

The MMS regulations, USEPA's NPDES general permit, and USCG regulations implementing MARPOL 73/78 Annex V prohibit the disposal of any trash and debris into the marine environment. Victual matter or organic food debris may be ground up into small pieces and disposed of overboard from structures located more than 20 km from shore.

Over the last several years, companies have employed trash and debris reduction and improved handling practices to reduce the amount of offshore trash that could potentially be lost into the marine environment. Improved trash management practices, such as substituting paper and ceramic cups and dishes for those made of styrofoam, recycling offshore trash, and transporting and storing supplies and materials in bulk containers when feasible, are commonplace and have resulted in a marked decline in accidental loss of trash and debris.

4.1.1.6. Air Emissions

Any OCS activity that uses equipment that burns a fuel, transports and/or transfers hydrocarbons, or results in accidental releases of petroleum hydrocarbons or chemicals would cause emission of air pollutants. Some of these pollutants are precursors to ozone, which is formed by complex photochemical reactions in the atmosphere.

The criteria pollutants considered here are NO_2, CO, SO_x, volatile organic compounds (VOC), and PM_{10}. Criteria pollutant emissions from OCS platforms and drilling operations are estimated using the emission rates presented in **Table 4-10**. These emission rates are derived from a 1991-1992 MMS inventory of offshore OCS structures (Steiner et al., 1994) that takes into account deepwater activities.

Tables 4-10 and 4-11 present average annual emission rates from OCS infrastructure in the GOM and the EPA, respectively. Emissions of air pollutants during loading, storage, and transportation of crude oil and gas are calculated using the methodology and emission factors presented in USEPA publication AP-42 of 1985 with supplements A, B, and C. Helicopter emissions are calculated using the methodology presented in the previous reference.

Flaring is the venting and/or burning of natural gas from a specially designed boom. Flaring systems are also used to vent gas during well testing or during repair/installation of production equipment. The MMS operating regulations provide for the flaring or venting of natural gas for a limited time and volume upon approval by MMS. Flaring may occur for short periods (typically 2-14 days) as part of unloading/testing operations necessary to remove potentially damaging completion fluids from the wellbore, to provide sufficient reservoir data for the operator to evaluate a reservoir and development options, and in emergency situations. Emissions from flaring are included in the emissions tables and in the modeling analysis (since platform emissions include flaring along with all other sources).

4.1.1.7. Noise

Noise associated with OCS oil and gas development results from seismic surveys, the operation of fixed structures such as offshore platforms and drilling rigs, and helicopter and service-vessel traffic. Noise generated from these activities can be transmitted through both air and water, and may be extended or transient. Offshore drilling and production involves various activities that produce a composite underwater noise field. The intensity level and frequency of the noise emissions are highly variable, both between and among the various industry sources. Noise from proposed OCS activities may affect resources near the activities. Whether a sound is or is not detected by marine organisms would depend both on the acoustic properties of the source (spectral characteristics, intensity, and transmission patterns) and sensitivity of the hearing system in the marine organism. Extreme levels of noise can cause physical damage or death to an exposed animal; intense levels can damage hearing; and loud or novel sounds may induce disruptive behavior or other responses of lesser importance.

When the MMPA was enacted in 1972, the concept that underwater sounds of human origin could adversely affect marine mammals was not considered or recognized (MMC, 2002). Concern on the effects of underwater noise on marine mammals and the increasing levels of manmade noise introduced into the world's oceans has since become a major environmental issue (Jasny, 1999). It is generally recognized that commercial shipping is a dominant component of the ambient, low-frequency background noise in modern world oceans (Gordon and Moscrop, 1996) and that OCS-related, service-vessel traffic would contribute to this. For the GOM, that contribution to existing shipping noise is likely insignificant (USDOI, MMS, in preparation). Another sound source more specific to OCS operations originates from seismic operations. Airguns produce an intense but highly localized sound energy and represent a noise source of possible concern. The MMS has almost completed a programmatic EA on G&G permit activities in the GOM (USDOI, MMS, in preparation). The EA includes a detailed description of the seismic surveying technologies, energy output, and operations; these descriptions are incorporated here by reference.

Marine seismic surveys direct a low-frequency energy wave (generated by an airgun array) into the ocean floor and record the reflected energy waves' strength and return arrival time. The pattern of reflected waves, recorded by a series of hydrophones embedded in cables towed by the seismic vessel (streamers) or ocean bottom cables (OBC) placed on the ocean floor, can be used to "map" subsurface layers and features. Seismic surveys can be used to check for foundation stability, detect groundwater, locate mineral deposits (coal), and search for oil and gas. Most commercial seismic surveying is carried out for the energy sector (Gulland and Walker, 1998). Two general types of seismic surveys are conducted in the GOM relative to oil and gas operations. High-resolution site surveys collect data up to 1 km deep through bottom sediments and are used for initial site evaluation for potential structures as well as for exploration. This involves a small vessel and usually a single airgun source and is also usually restricted to small areas, most often a single lease site.

Seismic exploration and development surveys are often conducted over large survey areas (multiple leases and blocks) and obtain information on geological formations to several thousands meters below the ocean floor. For "2D" surveys, a single streamer (hydrophones) is towed behind the survey vessel, together with a single source (airguns) (Gulland and Walker, 1998). Seismic vessels generally operate at low hull speeds (<10 knots) and follow a systematic pattern during a survey, typically a simple grid pattern for 2D work with lines no closer than half a kilometer.

In simplistic terms, "3D" surveys collect a very large number of 2D slices, perhaps with line separations of only 25-30 m. A 3D survey may take months to complete and involves a precise definition of the survey area and transects, usually a series of passes to cover a given survey area (Caldwell, 2001). In 1984, industry operated the first twin streamers. By 1990, industry achieved a single vessel towing two airgun sources and six streamers. Industry continues to increase the capability of a single vessel, now using eight streamer/dual source configurations and multi-vessel operations (Gulland and Walker, 1998). For exploration surveys, 3D methods represent a substantial improvement in resolution and useful information relative to 2D methods. Many areas in the GOM previously surveyed using 2D have been or would be surveyed using 3D. It can be assumed that for new deepwater areas, 3D surveys would be the preferred method for seismic exploration, until and if better technology evolves.

A typical 3D airgun array would involve 15-30 individual guns. The firing times of the guns are staggered by milliseconds (tuned) in an effort to make the farfield noise pulse as coherent as possible. In short, the intent of a tuned 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). The noise generated by airguns is intermittent, with pulses generally less than one second in duration, for relatively short survey periods of several days to weeks for 2D work and site surveys (Gales, 1982) and weeks to months for 3D surveys (Gulland and Walker, 1998). Airgun arrays produce noise pulses with very high peak levels. The pulses are a fraction of a second and repeat every 5-15 seconds. In other words, while airgun arrays are by far the strongest sources of underwater noise associated with offshore oil and gas activities, because of the short duration of the pulses, the total energy is limited (Gordon and Moscroup, 1996). This is an important factor when evaluating potential effects on marine animals.

At distances of about 500 m and more (farfield), the array of individual guns would effectively appear to be a single point source (Caldwell, 2001). In the past, sound-energy levels were expected to be less than 200 dB re^{-1}µPa-m (standard unit for source levels of underwater sound: 200 decibels, reference pressure 1 micropascal, reference range 1 meter) at distances beyond 90 m from the source (Gales, 1982). Gulland and Walker (1998) state a typical source would output approximately 220 dB re^{-1}µPa-m, although the peak-to-peak source level directly below a seismic array can be as high as 262 dB re^{-1}µPa-m (Davis et al., 1998b). More recently, it has been estimated a typical 240-dB seismic array would have a 180 dB re^{-1}µPa-m level at approximately 225 m from the array (USDOI, MMS, in preparation). The 180 dB re^{-1}µPa-m level is an estimate of the threshold of sound energy that may cause hearing damage in cetaceans (U.S. Dept. of the Navy, 2001). Until further studies are completed, NOAA Fisheries continues to use this estimated threshold. It is unclear which measurements of a seismic pulse provide the most helpful indications of its potential impact on marine mammals (Gordon et al., 1998). Gordon et al. speculate that peak broadband pressure and pulse time and duration would be most relevant at short ranges (hearing damage range) while sound intensity in 1/3 octave bands is a more useful measurement at distance (behavioral effects).

Information on drilling noise in the GOM is unavailable to date. From studies mostly in Alaskan waters, drilling operations often produce noise that includes strong tonal components at low frequencies, including infrasonic frequencies in at least some cases. Drillships are apparently 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.

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 hertz (Hz) at a distance of 30 m 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 ensonify broad areas. 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). 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 than in deep water. Helicopters, while flying offshore, generally maintain altitudes above 700 ft during transit to and from the working area and an altitude of about 500 ft while between platforms.

Service vessels transmit noise through both air and water. The primary sources of vessel noise are propeller cavitation, propeller singing, and propulsion; 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. 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 unladen vessels. 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). Given the amount of vessel traffic from all sources in the GOM, CSA concludes that the contribution of noise from offshore service vessels is a minor component of the total ambient noise level (USDOI, MMS, in preparation). In the immediate vicinity of a service vessel, noise could disturb marine mammals; however, this effect would be limited in area and duration.

4.1.1.8. Offshore Transport

4.1.1.8.1. 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. These products include unprocessed (bulk) oil and gas; mixtures of gas and condensate; mixtures of gas and oil; processed condensate, oil, or gas; produced water; methanol; and a variety of chemicals used by the OCS industry offshore. Product stream quality, available pipeline capacity, and existing infrastructure would be factors influencing the potential for new pipelines in the proposed lease sale area. **Figure 4-3** shows the existing and proposed pipelines in and near the proposed lease sale area.

Pipelines in the GOM are designated as either trunklines or gathering lines. Gathering lines are typically shorter segments of small-diameter pipelines that transport the well stream from one or more wells to a production facility or from a production facility to a central facility serving one or several leases, e.g., a trunkline, central storage, or processing terminal. Trunklines are typically large-diameter pipelines that receive and mix similar production products and transport them from the production fields to shore. A trunkline may contain production from many discovery wells drilled on several hydrocarbon fields. The OCS-related pipelines near shore and onshore may merge with pipelines carrying materials produced in State territories for transport to processing facilities or to connections with pipelines located further inland (**Chapter 4.1.2.1.7.**, Coastal Pipelines).

Regulatory processes and jurisdictional authority concerning pipelines on the OCS and in coastal areas are shared by several Federal agencies. The MMS is responsible for regulatory oversight of the design, installation, and maintenance of OCS producer-operated oil and gas pipelines. The DOT is responsible for establishing and enforcing design, construction, operation, and maintenance regulations, and for investigating accidents for all OCS transportation pipelines beginning downstream of the point at which operating responsibility transfers from a producing operator to a transporting operator. The MMS's responsibility extends upstream from the transfer point described above. **Chapter 1.5.**, Postlease Activities (Pipelines, and Pollution Prevention), discusses MMS's requirements in more detail.

Pipelines installed in water depths less than 200 ft (61 m) are required to be buried to a depth of at least 3 ft (30 CFR 250.1003). In addition, pipelines crossing fairways require a COE permit and must be buried to a depth of at least 10 ft and to 16 ft if crossing an anchorage area. Pipelines constructed as a result of a proposed action are not projected to be constructed in less than 200 ft or cross a fairway or anchorage area; therefore, no pipeline burials are projected as a result of a proposed action.

The bundling of pipelines is a cost-saving technique of laying more than one pipeline together. This procedure is less frequent in deep water due to safety, maintenance and repair, and security issues. Therefore, new pipelines constructed as a result of a proposed action are not projected to be bundled.

The merging of new pipelines with existing pipelines is based on two main issues: the capacity of the line and the compatibility of the products. The FERC can institute equal access by deciding if the merging line has enough capacity to handle the proposed inflow and if the new product would be compatible with the current product flowing through the line. It is expected that pipelines constructed as a result of a proposed action would connect to existing or proposed pipelines in and near the proposed lease sale area (**Figure 4-3**), resulting in no new pipeline landfalls.

The method for installing offshore pipelines in deeper water, like the proposed lease sale area, is the J-lay method. Lengths of pipe are joined to each other by welding or other means while supported in a vertical or near-vertical position by a tower. As more pipe lengths are added to the string, the string is lowered to the ocean floor. The configuration resembles a "J." Pipelines projected to be installed as a result of a proposed action would be in water depths greater than 500 m, where DP lay barges would be used. Therefore, pipelines constructed as a result of a proposed action would be installed using the J-lay method with a DP lay barge. Anchoring would not be required.

Pipelines located in deep water endure high hydrostatic pressure, cold temperatures, low visibility, varying subsurfaces, and strong bottom currents, which can all lead to great physical stress on the pipe and installation equipment. Depending on the location, pipeline installation activities in deepwater areas can be difficult both in terms of route selection and construction. 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). A 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 significant 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 (reviewed by MMS) 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 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 and chemical techniques that can be applied to manage these potential accumulations. The leading strategy to mitigate these deleterious effects is to minimize heat loss from the system by using insulation. Other measures include forcing plunger-like "pigging" devices through the pipeline to scrape the pipe walls clean and the continuous injection of flow-assurance chemicals (e.g., methanol or ethylene glycol) into the pipeline system to minimize the formation of flow-inhibiting substances. However, the great water depths of the OCS and the extreme distance to shoreside facilities make these flow-assurance measures difficult to implement and can significantly increase the cost to produce and transport the product. Companies are continuously looking for and developing new technologies such as electrically and water-heated pipelines and burial of pipelines in deep water 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. Such systems minimize the costs, revenue loss, and risks from the following:

- hydrate formation during steady state or transient flowing conditions;
- paraffin accumulation on the inner pipe wall that can result in pipeline plugging or flow rate reductions;
- adverse fluid viscosity effects at low temperatures that lead to reduced hydraulic performance or to difficulties restarting a cooled system after a short shut-in; and
- additional surface processing facilities required to heat produced fluids to aid in the separation processes.

Formation of gas hydrates in deepwater operations is a well-recognized and potentially hazardous operational problem in water depths greater than 1,000 ft (300 m). Seabed conditions of high pressure and low temperature become conducive to gas hydrate formation in deep water. Gas hydrates are ice-like crystalline solids formed by low-molecular-weight hydrocarbon gas molecules (mostly methane) combining with produced water. The formation of gas hydrates is potentially hazardous because hydrates can restrict or even completely block fluid flow in a pipeline, resulting in a possible overpressure condition. The interaction between the water and gas is physical in nature and is not a chemical bond. Gas hydrates are formed and remain stable over a limited range of temperatures and pressures.

Hydrate prevention is normally accomplished through the use of methanol, ethylene glycol, or tri-ethylene glycol as inhibitors, and the use of insulated pipelines and risers. Chemical injection is sometimes provided both at the wellhead and at a location within the well just above the subsurface safety valve. Wells that have the potential for hydrate formation can be treated with either continuous chemical injection or intermittent or "batch" injection. In many cases, batch treatment is sufficient to maintain well flow. In such cases, it is necessary only to inject the inhibitor at well start-up, and the well would continue flowing without the need for further treatment. In the event that a hydrate plug should form in a well that is not being injected with a chemical, the remediation process would be to depressurize the pipelines and inject the chemical. Hydrate formation within a gas line can be eliminated by dehydrating the gas with a glycol dehydrating system prior to input of gas into the line. In the future, molecular sieve and membrane processes may also be options for dehydrating gas. Monitoring of the dewpoint downstream of the dehydration tower should take place on a continuous basis. In the event that the dehydration equipment is bypassed because it may be temporarily out of service, a chemical could be injected to help prevent the formation of hydrates if the gas purchaser agrees to this arrangement beforehand.

Hydrocarbon flows that contain paraffin or asphaltenes may occlude pipelines as these substances, which have relatively low melting points, form deposits on the interior walls of the pipe. To help ensure product flow under these conditions, an analysis should be made to determine the cloud point and hydrate formation point during normal production temperatures and pressures. To minimize the formation of paraffin or hydrate depositions, wells can be equipped with a chemical injection system. If, despite treatment within the well, it still becomes necessary to inhibit the formation of paraffin in a pipeline, this can be accomplished through the injection of a solvent such as diesel fuel into the pipeline.

Pigging is a term used to describe a mechanical method of displacing a liquid in a pipeline or to clean accumulated paraffin from the interior of the pipeline by using a mechanized plunger or "pig." Paraffin is a waxy substance associated with some types of liquid hydrocarbon production. The physical properties of paraffin are dependent on the composition of the associated crude oil, and temperature and pressure. At atmospheric pressure, paraffin is typically a semisolid at temperatures above about 100 ^{o}F and would solidify at about 50 ^{o}F. Paraffin deposits would form inside pipelines that transport liquid hydrocarbons and, if some remedial action such as pigging were not taken, the deposited paraffin would eventually completely block all fluid flow through the line. The pigging method involves moving a pipeline pig through the pipeline to be cleaned. Pipeline pigs are available in various shapes and are made of various materials, depending on the pigging task to be accomplished. A pipeline pig can be a disc or a spherical or cylindrical device made of a pliable material such as neoprene rubber and having an outside diameter nearly equal to the inside diameter of the pipeline to be cleaned. The movement of the pig through the pipeline is accomplished by applying pressure from gas or a liquid such as oil or water to the back or upstream end of the pig. The pig fits inside the pipe closely enough to form a seal against the applied pressure. The applied pressure then causes the pig to move forward through the pipe. As the pig travels through the pipe, it scrapes the inside of the pipe and sweeps any accumulated contaminants or liquids ahead of it. In deepwater operations, pigging would be used to remove any paraffin deposition in the pipelines as a normal part of production operations. Routine pigging would be required of oil sale lines at frequencies determined by production rates and operating temperatures. 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.

Review of pipeline applications includes the evaluation of protective safety devices such as pressure sensors and automatic valves, and the physical arrangement of those devices proposed to be installed by the applicant for the purposes of protecting the pipeline from possible overpressure conditions and for detecting and initiating a response to abnormally low-pressure conditions. Once a pipeline is installed, operators conduct monthly overflights to inspect pipeline routes for leakage. **Chapter 1.5.**, Postlease Activities (Pollution Prevention), discusses this topic in depth.

Applications for pipeline decommissioning must also be submitted for MMS review and approval. Decommissioning applications are evaluated to ensure they will render the pipeline inert, to minimize the potential for the pipeline becoming a source of pollution by flushing and plugging the ends, and to minimize the likelihood that the decommissioned line will become an obstruction to other users of the OCS by filling it with water and burying the ends.

Proposed Action Scenario: Four pipelines (2 natural gas and 2 crude oil) with a total length of 50-800 km are projected as a result of a proposed action. **Figure 4-3** shows several existing and proposed pipelines that extend into deep water (>500 m) in and near the proposed lease sale area. It is expected that pipelines from proposed action facilities would connect to these existing or proposed pipelines, resulting in no new pipeline landfalls. Because of the projected water depth in which the proposed pipelines would be installed, the scenario assumes no anchoring due to DP lay barges, no bundling, and no burying.

The number and length of new pipelines were estimated using the amount of production, number of wells, and number of structures projected as a result of proposed action, rather than the number of leases resulting from a proposed lease sale. The range in length of pipelines projected is due to the uncertainty of the location of new wells or structures, and which existing or proposed pipelines would be utilized. Many factors would affect the actual transport system, including company affiliations, amount of production, product type, and system capacity.

Gulfwide OCS Program Scenario: From 2003 to 2042, 27,600-52,400 km of new pipeline are projected as a result of the Gulfwide OCS Program (**Table 4-3**).

4.1.1.8.2. 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. A trip is considered the transportation from a service base to an offshore site and back; in other words, a round trip. Based on MMS calculations, an average of 6-9 vessel trips are required per week for 42 days in support of drilling an exploration well and for 33 days in support of drilling a development well. A platform is estimated to require two vessel trips per week over its 33-year production life. All trips are assumed to originate from the service base.

There are currently approximately 376 supply vessels operating in the GOM. Over the 40-year life of a proposed action, supply vessels would retire and replacement vessels would be built. In general, the new type of vessels built would continue to be larger, deeper drafted, and more technologically advanced for deepwater activities. In the short term, if any oversupply of deepwater vessels develops, some of the smaller deepwater vessels (200-220 ft) would be forced to work in shallow waters where they would compete with the older 180-ft vessels for jobs. Oversupply could result from lower OCS activity (decreased demand) or from construction of too many vessels (increased supply).

Support of deepwater operations (such as those expected in the proposed lease sale area) would continue to be the future of the service-vessel industry. Compared to shelf-bound service vessels, deepwater service vessels have improved hull designs (increased efficiency and speed), a passive computerized anti-roll system, drier and safer working decks, increased cargo capacity (water, cement, barite, drilling muds, etc.), increased deck cargo capability, increased cargo transfer rates to reduce the time and risk alongside structures (e.g., TLP), dual and independent propulsion systems, true dynamic positioning systems, fuel and NO_x efficient engines, and Safety of Life at Sea (SOLAS) capability (*WorkBoat*, 1998). Service vessels primarily used in deep water are OSV's, fast supply vessels, and AHTS's (*WorkBoat*, 2000). Other deepwater specialty service vessels include well stimulation vessels. The OSV's and AHTS's carry the same type of cargo (freshwater, fuel, cement, barite, liquid drilling fluids, tubulars, equipment, food, and miscellaneous supplies) but have different functions. The AHTS's also differ from the supply vessels by their deepwater mooring deployment and towing capabilities.

Consolidation may continue within the industry as smaller operations are unable to compete with the larger, more advanced companies. Also, issues such as logistics and boat pooling would continue to emerge as bottom line accounting persists to direct the offshore oil and gas industry.

Proposed Action Scenario: Service-vessel trips projected for a proposed action are 8,000-9,000 trips (**Table 4-2**). This equates to an average annual rate of 200-225 trips. Service-vessel trips during peak-year activity (year 11) are estimated as 300-500 trips.

Gulfwide OCS Program Scenario: The projected number of service-vessel trips estimated for the Gulfwide OCS Program is 11,889,000-12,479,000 over the 2003-2042 period (**Table 4-3**). This equates to an average rate of 297,225-311,975 trips annually.

4.1.1.8.3. 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. A trip is considered the transportation from a helicopter hub to an offshore site and back; in other words, a round trip. Based on MMS calculations, an average of 3-10 helicopter trips are required per week for 42 days in support of drilling an exploration well and for 33 days in support of drilling a development well. A platform is estimated to require two helicopter trips per week over its 33-year production life. All trips are assumed to originate from the service base.

Deepwater operations (such as those expected in the proposed lease sale area) require helicopters that travel farther and faster, carry more personnel, are all-weather capable, and have lower operating costs. There are several issues of concern for the helicopter industry's future. Because the tasks the offshore helicopter industry provides are the same tasks supply vessels provide, they are competition for one another. Fast boats are beginning to erode the helicopter industry's share of the offshore transportation business, particularly in shallow water. The exploration and production industry is outsourcing more and more operations to oil-field support companies who are much more cost conscious and skeptical about the high cost of helicopters. Another consideration for the helicopter industry is new technology such as subsea systems. These systems decrease the number of platforms and personnel needed offshore, therefore reducing the amount of transportation needed.

Proposed Action Scenario: Helicopter trips projected for a proposed action are 7,000-9,000 trips (**Table 4-2**). This equates to an average annual rate of 175-225 trips. The number of helicopter trips during peak year activity (year 11) is estimated as 300-400 trips.

Gulfwide OCS Program Scenario: The projected number of helicopter trips for the Gulfwide OCS Program is 27,997,000-50,692,000 trips over the 2003-2042 period (**Table 4-3**). This equates to an average rate of 699,925-1,267,300 trips annually.

4.1.1.8.4. Alternative Transportation Methods of Natural Gas

As the country's gas consumption is expected to increase by 65 percent over the next 20 years (USDOE, EIA, 2001b), industry is looking at alternative methods of transporting OCS gas in the GOM. These methods involve transporting natural gas as LNG or compressed natural gas (CNG) in specially designed vessels. The focus has been on deep water where it is costly and technically challenging to install pipelines to transport gas. The LNG and CNG options may make it economically viable to produce marginal gas fields. The CNG option may also be an economical way of transporting "stranded" associated gas instead of the gas being flared or reinjected. Although both technologies could bring gas to shore, most discussions suggest the use of offshore terminals and the existing nearshore pipeline infrastructure. The offloading platforms would require USCG-designated safety zones with "no surface occupancy" restrictions for oil and gas exploration, development, and production operations.

In the LNG process, gas is super-cooled, reducing its volume to a fraction of its gaseous state. Then, tankers with specially designed cargo holds transport the LNG to terminals for regasification. At present, LNG is being imported into four existing U.S. terminals, and more terminals are proposed. The LNG imports already travel through the GOM to one of the existing terminals at Lake Charles, Louisiana.

The CNG process uses less of the energy because liquefaction and regasification are not required as it is with LNG. The CNG technology is not currently being used to transport gas. The first application of CNG would be a pilot project shipping gas from Venezuela or Trinidad to Curacao (Cran and Stenning Technology Inc., 2001).

4.1.1.9. Hydrogen Sulfide and Sulfurous Petroleum

Sulfur may be present in oil as elemental sulfur, within H_2S gas, or within organic molecules, all three of which vary in concentration independently. Although sulfur-rich petroleum is often called "sour" regardless of the type of sulfur present, the term "sour" should properly be applied to petroleum containing appreciable amounts of H_2S, and "sulfurous" should be applied to other sulfur-rich petroleum types. Using this terminology, the following matrix of concerns is recognized:

Potentially Affected Endpoint	Sour Natural Gas	Sour Oil	Sulfurous Oil
Engineering components or facility equipment and pipeline	Corrosion	Corrosion	N/A
On-platform industrial hygiene	Irritation, injury, and lethality from leaks	Irritation, injury, and lethality from outgassing from spilled oil	Irritation, injury, and lethality from exposure to sulfur oxides produced by flaring
Off-platform general human health and safety	Irritation, injury, and lethality from leaks	Irritation, injury, and lethality from outgassing from spilled oil	Irritation, injury, and lethality from exposure to sulfur oxides produced by flaring
Marine and coastal species and habitats	Irritation, injury, and lethality from leaks	Synergistic amplification of oil-spill impacts from outgassing	No effects other than impacts hydrocarbon contact and acid rain

4.1.1.9.1. Sour Oil, Sour Gas, and Sulfurous Oil in the Gulf of Mexico

4.1.1.9.1.1. Occurrence

Sour oil and gas occur sparsely throughout the GOM OCS (e.g., about 65 operations had encountered H_2S-bearing zones in the GOM as of mid-1998), but principally offshore of the Mississippi Delta (Louisiana), Mississippi, and Alabama. Occurrences of H_2S offshore of Texas are in Miocene rocks and occur principally within a geographically narrow band. The occurrences of H_2S offshore Louisiana are mostly on or near piercement domes with caprock and are associated with salt and gypsum deposits. Examination of industry exploration and production data show that H_2S concentrations vary from as low as fractional parts per million in either oil or gas to 650,000 ppm in the gas phase of a single oil well near the Mississippi Delta. The next highest concentrations of H_2S encountered to date are in the range of 20,000-55,000 ppm in some natural gas wells offshore of Mississippi/Alabama. There is some evidence that petroleum from deepwater plays may be sulfurous, but there is no evidence that it is sour.

Only 5 percent of all wells drilled on the OCS to date have penetrated sediments below 15,000 ft subsea. The MMS estimates that there could be 5-20 Tcf of recoverable gas resources below 15,000 ft. Deep gas reservoirs on the GOM continental shelf are likely to have high corrosive content, including H_2S. To encourage exploration and development of deep gas prospects on the continental shelf, MMS offered incentives in the form of royalty relief on deep gas production from any new leases issued in Lease Sale 178 (March 2001). Such royalty relief may well be extended to deep gas production on other existing and future leases.

4.1.1.9.1.2. Treatment (Sweetening)

Removal of H_2S from sour petroleum may proceed in one of two ways. The product can either be "sweetened" (removal of H_2S from the hydrocarbons) offshore or it can be transported onshore to a processing facility equipped to handle H_2S hydrocarbons, where the product is sweetened. Several processes based on a variety of chemical and physical principles have been developed for gas sweetening. The processes include solid bed absorption, chemical solvents (e.g., amine units), physical solvents, direct conversion of H_2S to sulfur (e.g., Claus units), distillation, and gas permeation (Arnold and Stewart, 1988). Gas streams with H_2S or SO_2 are frequently treated offshore by amine units to reduce the corrosive properties of the product. A by-product of this process is a concentrated acid gas stream, which is frequently treated as a waste and flared if SO_2 emissions are not of concern. In cases where SO_2 emissions must be minimized, other options for handling acid gas must be sought. Sulfur recovery units to further process the H_2S to elemental sulfur or reduced sulfur compounds is a common method of treating acid gas streams. Reinjection of acid gas is an option that has also been considered. The feasibility of reinjecting acid gas in the offshore environment has not been demonstrated. In addition, MMS conservation requirements may not allow reinjection of this gas. Another option would be to send the untreated gas to shore for treatment; this requires the use of "sour gas" pipelines built to handle the highly corrosive materials.

4.1.1.9.1.3. Requirements for Safety Planning and Engineering Standards

The MMS reviews all proposed actions in the GOM OCS for the possible presence of H_2S. Activities found to be associated with a presence of H_2S are subjected to further review and requirements. Federal regulations at 30 CFR 250.417 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. All operators on the OCS involved in production of sour gas or oil (i.e., greater than 20 ppm H_2S) are also required to file an H_2S contingency plan. This plan delimits procedures to ensure the safety of the workers on the production facility. In addition, all operators are required to adhere to NACE's Standard Material Requirement MR.01-75-96 for Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment (NACE, 1990). These engineering standards serve to enhance the integrity of the infrastructure used to produce the sour oil and gas, and further serve to ensure safe operations. The MMS has issued a final rule governing requirements for preventing hydrogen sulfide releases, detecting and monitoring hydrogen sulfide and sulfur dioxide, protecting personnel, providing warning systems, and establishing requirements for hydrogen sulfide flaring. The rule went into effect on March 28, 1997. An associated NTL (98-16) titled "Hydrogen Sulfide (H_2S) Requirements" was issued on August 10, 1998, to provide clarification, guidance, and information on the revised requirements. The NTL provides guidance on sensor location, sensor calibration, respirator breathing time, measures for protection against sulfur dioxide, requirements for classifying an area for the presence of H_2S, requirements for flaring and venting of gas containing H_2S, and other issues pertaining to H_2S-related operations.

4.1.1.9.2. Environmental Fate of H_2S

4.1.1.9.2.1. Atmospheric Release

Normal dispersion mechanisms in the surface mixed layer of the atmosphere (wind, etc.) cause natural gas leaks and associated H_2S to disperse away from release sites. The MMS reviews of proposed sour gas operations are based on the conservative assumptions of horizontal, noncombusted releases to achieve environmentally conservative results, although vertical release or combustion of the gas plume (greatly reducing potential exposure) would be possible. Both simple Gaussian estimation techniques (conforming to air quality rules) and more rigorous analytical modeling are used in MMS reviews of activities associated with a presence of H_2S. For a very large facility (throughput on the order of 100 MMcfd of produced natural gas) with high concentration levels (on the order of 20,000 ppm) and using very calm winds (speed of <1 m per second (sec)), H_2S levels reduce to 20 ppm at several kilometers from the source; H_2S levels are reduced to 500 ppm at 1 km. Six sites within the Eastern GOM meet this description. One site is off Alabama and the other sites are in the CPA to the west of the proposed lease sale area. Most "sour gas" facilities have H_2S concentrations below 500 ppm, which reduces to 20 ppm within the dimensions of a typical platform (or considerably less).

4.1.1.9.2.2. Aquatic Release

Hydrogen sulfide is soluble in water with 4,000 ppm dissolving in water at 20°C and one atmosphere pressure. This implies that a small sour gas leak would result in almost complete dissolution of the contained H_2S into the water column. Larger leaks would result in proportionally less dissolution, depending on turbulence, depth of release, and temperature; and H_2S could be released into the atmosphere if the surrounding waters reach saturation or the gas plume reaches the surface before complete dissolution. Because the oxidation of H_2S in the water column takes place slowly (on the order of hours), the chemical oxygen demand of H_2S is spread out over a long time interval (related to the ambient current speed) and should not create appreciable zones of hypoxia, except in the case of a very large, long-lived submarine release.

4.1.1.9.3. H_2S Toxicology

4.1.1.9.3.1. Humans

The Occupational Safety and Health Administration's permissible exposure limit for H_2S is 20 ppm. A permissible exposure limit is an allowable exposure level in workplace air averaged over an 8-hour workshift. The American Conference of Governmental Hygienists recommends a time weighted average concentration of 10 ppm. The time-weighted average is a concentration for a normal 8-hour workday to which nearly all workers may be repeatedly exposed, day after day, without adverse affect. This is 10 times lower than the "immediately dangerous to life and health" level of 100 ppm set by the National Institute for Occupational Safety and Health. Despite a normal human ability to smell H_2S at levels below 1 ppm, H_2S is considered to be an insidious poison because the sense of smell rapidly fatigues, failing to detect H_2S after continued exposure. At 20 ppm MMS requires an operator to develop and file a H_2S Contingency Plan, and at 500 ppm an operator is required to model atmospheric dispersion of total, horizontal, noncombusted rupture.

4.1.1.9.3.2. Wildlife

While impacts on humans are well documented, the literature on the impact of H_2S on wildlife is sparse, with no information available for marine mammals and turtles.

In general, birds seem more tolerant of H_2S than mammals, indicating that birds may have a higher blood capacity to oxidize H_2S to nontoxic forms. In tests with white leghorn chickens, all birds died when inhaling H_2S at 4,000 ppm. At 500 ppm, no impact was observed on ventilation, while between 2,000 and 3,000 ppm respiratory frequency and tidal volume become irregular and variable in these birds (Klentz and Fedde, 1978). In the western United States, oil production and geothermal operations often flare or vent pipes to release the natural gases accumulated during drilling, storage, and pipeline operations, with significant impacts on wildlife (Maniero, 1996). Numerous instances of dead birds at the release site have been reported in the literature; extremely high concentrations of H_2S would occur at these sites.

4.1.1.9.3.3. Fish

Most adult marine fish will avoid any water column that is contaminated with H_2S, provided an escape route is available. In terms of acute toxicity testing, fish can survive at levels reaching 0.4 ppm (Van Horn, 1958; Theede et al., 1969). Walleye eggs (*Stizostedion vitreum*) did not hatch at levels from 0.02 to 0.1 ppm (USEPA, 1986). The hatchability of northern pike (*Esox lucius*) was substantially reduced at 25 ppb with complete mortality at 45 ppb. Northern pike fry had 96-hour lethal concentration where 50 percent of organisms die (LC_{50}) values that varied from 17 to 32 ppb at O_2 levels of 6 ppm. Sensitive eggs and fry of northern pike exhibited no observable effects at 14 and 4 ppb, respectively (Adelman and Smith, 1970; USEPA, 1986). In a series of tests on the eggs, fry, and juveniles of walleyes, white suckers (*Catostomus commersoni*), and fathead minnows (*Pimephales promelas*), with various levels of H_2S from 2.9 to 12 ppb, eggs were the least sensitive while juveniles were the most sensitive. In 96-hour bioassays, fathead minnows and goldfish (*Carassius auratus*) varied greatly in tolerance to H_2S with changes in temperature (Smith et al., 1976; USEPA, 1986). Pacific salmon (*Oncorhynchus* sp.) experienced 100 percent mortality within 72 hours at 1 ppm.

On the basis of chronic toxicity testing, juveniles and adults of bluegill *(Lepomis macrochirus*) exposed to 2 ppb survived and grew normally. Egg deposition in bluegills was reduced after 46 days of exposure to 1.4 ppb (Smith et al., 1976; USEPA, 1986). White sucker eggs were hatched at 15 ppb, but juveniles showed growth reductions at 1 ppb. Safe levels for fathead minnows were between 2 and 3 ppb. For *Gammarus pseudolimnaeus* and *Hexagenia limbata*, 2 and 15 ppb, respectively, were considered safe levels (USEPA, 1986).

4.1.1.10. New or Unusual Technologies

Technologies continue to evolve to meet the technical, environmental, and economic challenges of deepwater development. The MMS prepared a programmatic EA to evaluate potential effects of deepwater technologies and operations (USDOI, MMS, 2000). As a supplement to the EA, MMS prepared a series of technical papers that provides a profile of the different types of development and production structures that may be employed in the GOM deepwater (Regg et al., 2000). The EA and technical papers were used in the preparation of this EIS.

The operator may identify NUT's in its EP, DWOP, and DOCD or through MMS's plan review processes. 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 MMS 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 Gulfwide 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 GOM OCS waters. Having no operational history, they have not been assessed by MMS through technical and environmental reviews. New technologies may be outside the framework established by MMS regulations and, thus, their performance (safety, environmental protection, efficiency, etc.) has not been addressed by MMS. 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.

The MMS has developed a dynamic NUT's matrix to help facilitate decisions on the appropriate level of engineering and environmental review needed for a proposed technology. Technologies will be added to the NUT's matrix as they emerge, and technologies will be removed as sufficient experience is gained in they 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 that MMS does not have sufficient information to determine its potential impacts to the environment. In this later case, MMS will seek to gain the necessary information from operators or manufacturers regarding the technologies to make an appropriate determination on its potential effects on the environment.

Alternative Compliance and Departures: The MMS project-specific engineering safety review ensures that equipment proposed for use is designed to withstand the operational and environmental condition in which it would operate. When an OCS operator proposes the use of technology or procedures not specifically addressed in established MMS regulations, the operations are evaluated for alternative compliance or departure determination. Any new technologies or equipment that represent an alternative compliance or departure from existing MMS regulation must be fully described and justified before it would be approved for use. For MMS to grant alternative compliance or departure approval, the operator must demonstrate an equivalent or improved degree of protection as specified in 30 CFR 250.141. Comparative analysis with other approved systems, equipment, and procedures is one tool that MMS uses to assess the adequacy of protection provided by alternative technology or operations. Actual operational experience is necessary with alternative compliance measures before MMS would consider them as proven technology.

4.1.1.11. Decommissioning and Removal Operations

During exploration, development, and production operations, the seafloor around activity sites within the proposed lease sale area becomes the repository of temporary and permanent equipment and structures. In compliance with Section 22 of MMS's Oil and Gas Lease Form (MMS-2005) and OCS regulations (30 CFR §250.1710 – wellheads/casings and 30 CFR §250.1725 – platforms and other facilities), lessees are required to remove all seafloor obstructions from their leases within one year of lease termination or relinquishment. These regulations require lessees to sever bottom-founded structures and their related components at least 5 m below the mudline to ensure that nothing would be exposed that could interfere with future lessees and other activities in the area. The structures are generally grouped into two main categories depending upon their relationship to the platform/facilities (piles, jackets, caissons, templates, mooring devises, etc.) or the well (i.e., wellheads, casings, casing stubs, etc.).

Since the water depths in the proposed lease sale area range from 1,600 to 3,000 m, the types and numbers of platforms or facilities would be greatly limited. Drilling operations would be conducted from floating drilling rigs (FDR), primarily semisubmersibles and drillships. Most of the FDR's that would be used in the proposed lease sale area are DP vessels (DPV); vessels that employ onboard thrusters, computer-linked to global positioning systems to maintain stationkeeping above the drillsite. Some semisubmersibles possess anchoring capabilities that could be used in the shallowest depths of the proposed lease sale area; however, most drilling is projected to be conducted using DPV's due to the temporary nature of exploratory drilling coupled with the complexities and economics of ultra-deep mooring operations.

Production facilities in the proposed lease sale area would be semisubmersibles, SPAR's, and subsea systems. The TLP's, while suitable to the proposed lease sale's shallower water depth, is generally not economically feasible and FPSO's have not been authorized for use in the EPA. Despite the extreme water depths, the semisubmersibles and SPAR's would be held to the seafloor using standard catenary and taut mooring systems using an array of anchor devises (i.e., fluted, suction pile, suction embedded, plate, etc.). The mooring equipment is designed for disengagement and retrieval from the seafloor using handling tugs or heavy lift vessels (HLV) during facility decommissioning. Subsea systems consist of temporary and semipermanent seafloor equipment (i.e., manifolds, umbilicals, jumpers, flowlines, etc.) that eventually ties back to a supporting surface facility. Much like moorings, most subsea equipment is deployed in a manor to allow for retrieval once production has ceased. Any bottom-founded, subsea equipment or mooring devices that are not fully recoverable would be required to be removed to at least 5 m below the mudline (30 CFR §250.1728(a)).

Due to the amount of drilling activities that would occur throughout the life of a proposed action, the most prolific number of seafloor structures are projected to be well related (i.e., wellhead, casing, casing stub, etc.). An operator may choose to temporarily or permanently abandon a well depending upon a its usefulness and the status of the lease. A temporary well abandonment allows the operator to save the wellbore for future uses, to determine economic viability, and/or to await the construction/arrival of special equipment or facilities. Temporary well abandonment operations follow a set of guidelines (30 CFR §250.1721 & §250.1722) that ensures wellbores are adequately plugged, tested, and monitored; however, water depths in the proposed lease sale area eliminate additional regulations concerning navigation aids and fisheries protection devices. Permanent well abandonments also follow plugging guidelines (30 CFR §250.1715) to prevent any hydrocarbon seepage from reaching the seafloor or marine environment, but the wellhead or casing must be removed to at least 5 m below the mudline (30 CFR §250.1716(a)).

To comply with the aforementioned requirements for below mudline severing of wellheads, casings, and "unrecoverable" equipment and moorings, the lessees would be limited to methods that take into account the economic, regulatory, and operational restrictions of removals in ultra-deep water. Severing techniques available for use in the GOM can be grouped into explosive or nonexplosive methodologies. Gulfwide, the majority of permanent well abandonments and structure removals are performed using explosive charges since they offer the lessee a lower expense, quicker setup and severing time, and assuredness of cut. Conditions of the Structure Removal NTL (2001-G08), however, require a Section 7 ESA Consultation for any removal proposing explosives in water depths greater than 200 m because of possible affects on sperm whales. After discussing the time requirements of ESA Consultations (4-8 months) and related regulatory stipulations from MMPA with industry representatives, MMS projects no explosives would be used for decommissioning and removal operations in the proposed lease sale area. Despite the higher costs and longer on-site times, nonexplosive removal techniques offer the lessees fewer regulatory restrictions and mitigative conditions.

Depending on accessibility and the shape/configuration of the object to be cut, nonexplosive techniques are available that would allow for either internal or external severing. Internal-severing equipment is generally emplaced using the downhole capabilities of a FDR. For operations involving concentrically symmetrical objects, internal mechanical cutters are placed into the wellbore or accessible, bottom-founded equipment to sever the structure using hydraulically controlled blades. Abrasive slurry and abrasive jet cutters are also limited to concentrical objects, but in place of mechanical blades, a nozzle propels a mixture of pressurized water and abrasive particles (i.e., sand, slag, garnet, etc.) against the walls of the target to perform the severing. Due to the extreme water depths in the proposed lease sale area, most external-severing devices would need to be deployed or emplaced using ROV's. Some abrasive jet cutters have been modified into ROV-deployable, external-severing systems, but like their internal counterparts, they are limited to cylindrical objects. When an operation involves irregular, nonsymmetrical objects, mechanical cutting tools such as blades, hydraulic shears, and diamond wire saws/cutters can be mounted on ROV's. Operators also intend to rely on the versatility and availability of cutter-equipped ROV's for both normal and emergency severing of mooring lines and chains, pipelines, and other open-water components. However, bottom-founded structures present the main limitation to all external severing methods because it is necessary to jet or remove enough of the seafloor around the object to allow an external cut to be made at least 5 m below the mudline.

Since all water depths in the proposed lease sale area are greater than 800 m, OCS regulations would 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 with reporting requirements on the remnant's description and height off of the seafloor to MMS – data necessary for subsequent reporting to the U.S. Navy. Additionally, industry has indicated that it plans to use the alternate removal depth options, coupled with quick-disconnect equipment (i.e., detachable risers, mooring disconnect systems, etc.) to fully abandon-in-place wellheads, casings, and other minor, subsea equipment without the need for any severing devices.

Site clearance guidelines for operations in the proposed lease sale area would be limited to exploratory or delineation well sites. Requirements outlined in MMS's Site Clearance NTL (98-26) limits the lessees to conducting stationary or towed, high-frequency (500 kHz) sonar verifications over 600-ft (183-m) diameter search areas, centered over the well sites. Since the previously-mentioned removal regulations allow for the objects or portions of objects to be left on the seafloor, MMS is currently discussing alternatives to the deepwater site clearance requirements, with pending modifications to the NTL.

Proposed Action Scenario: **Table 4-2** shows the number of production structures and wells projected to be installed/drilled by water-depth subarea. Two production structures are projected to be removed as a result of a proposed action; no explosives would be used. The MMS anticipates that all facility related equipment and moorings would be left on the seafloor following approved, alternate removal depth requests under 30 CFR §250.1728(b)(3). Of the 30-40 wells projected to be drilled as a result of a proposed action, none are projected to be removed using explosives. Agency forecasts indicate that the majority of wellhead structures would be abandoned-in-place as per removal regulations under 30 CFR §250.1716(b)(3), with the remainder being severed using nonexplosive methods.

Gulfwide OCS Program Scenario: **Tables 4-3 through 4-6** show the number of structures removed by water-depth subarea for the total Gulfwide OCS Program and by planning area. The number of structures to be removed in the next several decades is projected to exceed the number of production structures installed. It is estimated that a total of 10-12 production structures would be removed from the EPA during 2003-2042; however, it is anticipated that none of the existing or proposed structures in the EPA would require the use of explosives for their removal. It is estimated that a total of 5,350-6,110 production structures would be removed from the CPA during 2003-2042. The number of production structures installed landward of the 800-m isobath in the CPA to be removed using explosives during the interval of 2003-2042 is estimated at 3,676-4,183. It is estimated that a total of 943-1,174 production structures would be removed from the WPA during 2003-2042. It is estimated that 629-783 production structures installed landward of the 800-m isobath in the WPA would be removed using explosives during 2003-2042.

It is estimated that 8,996-11,333 exploration and delineation wells would be drilled Gulfwide as a result of the OCS Program. **Table 4-3** shows the estimated range of exploration and delineation wells by water depth subarea. Of these wells, approximately 0.5-0.7 percent would be in the EPA, 76-79 percent in the CPA, and 20-24 percent in the WPA. An estimate of 1-10 percent of permanently abandoned well casing stubs or wellhead structures would be removed by explosives Gulfwide (89-1,133 stubs) over years 2003-2042 of the OCS Program. Activity is projected to be relatively stable for the first 10 years of the analysis period, followed by a steady reduction in the annual rate of exploration and delineation wells to 50 percent.

4.1.2. Coastal Impact-Producing Factors and Scenario

This section describes the coastal infrastructure and activities (IPF's) associated with a proposed action that could potentially affect the biological, physical, and socioeconomic resources of the GOM. When appropriate, coastal IPF's associated with the Gulfwide OCS Program are discussed because some proposed action, IPF's (i.e., infrastructure) affect resources that are geographically Gulfwide and, therefore, are necessary for the cumulative analysis.

4.1.2.1. Coastal Infrastructure

4.1.2.1.1. Service Bases

A service base is a community of businesses that load, store and supply equipment, supplies and personnel that are needed at offshore work sites. Although a service base may primarily serve the OCS planning area and coastal subarea in which it is located, it may also provide significant services for the other OCS planning areas and coastal subareas. Expected proposed action service bases were ascertained based on well and platform plans in the proposed lease sale area and within 50 mi of the proposed lease sale area. In addition, information received from EPA Lease Sale 181 lessees with respect to potential service bases for the proposed lease sale area was used as a proxy for activity associated with a proposed action. Therefore, the ports in the Fourchon and Venice, Louisiana, and Mobile, Alabama, areas are expected to be used as primary service bases for a proposed action. Furthermore, five other ports are expected to be used as secondary service bases: Cameron, Houma, Intracoastal City, and Morgan City, Louisiana; and Pascagoula, Mississippi.

Fourchon is expected to receive 60 percent of the total number of projected vessel trips (both crew and supply) associated with a proposed action during the exploration phase. Venice is expected to service 30 percent, while Mobile is expected to receive only 10 percent of projected vessel trips. These percentages are expected to change during the development and production phase. If exploration in the EPA is successful, ECO plans to construct a C-Port in the Mobile area. This would shift vessels from Fourchon and Venice to Mobile during the development and production phase. Fourchon and Mobile are each expected to receive 45 percent of the total number of projected vessel trips associated with a proposed action, while Venice is expected to receive 10 percent.

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 of the industry. All supplies must be transported from land-based facilities to marine vessels or helicopters to reach offshore destinations. This uses both water and air transportation modes. The intermodal nature of the entire operation gives ports (which traditionally have water, rail, and highway access) a natural advantage as an ideal location for onshore activities and intermodal transfer points. 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 must influence the dynamics of port development.

Issues and concerns that must be addressed at the local level have resulted from the significant prosperity that has followed the industry. These extend beyond specific port needs into the community itself. Most of these problems can be nullified with additional infrastructure. However, additional infrastructure is difficult to develop. It is expensive to construct and requires substantial planning and construction time prior to completion. Rapidly developing technology has resulted in changing needs for the offshore oil and gas industry. This has placed a burden on the ports to provide the necessary infrastructure and support facilities required to meet the needs of the industry in a timely manner.

To continue to offer a viable service and to stay current with technological trends and industry standards, ports must be able to incorporate offshore oil and gas industry information into their planning for future infrastructure development, staffing needs, and other impacts associated with rapid industrial growth. 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 and State waters. Some channels in and around the service bases would be deepened and expanded in support of deeper draft vessels and other port activities, some of which would be OCS related.

As OCS operations have progressively moved into deeper waters, larger vessels with deeper drafts have been phased into service, mainly for their greater range, faster speed, and larger carrying capacity. Services bases with the greatest appeal for deepwater activity have several common characteristics: strong and reliable transportation systems; adequate depth and width of navigation channels; adequate port facilities; existing petroleum industry support infrastructure; location central to OCS deepwater activities; adequate worker population within commuting distance; and insightful strong leadership. Typically, deeper draft service vessels require channels with depths of 6-8 m.

Proposed Action Scenario: A proposed action would not require any additional service bases. The ports in the Fourchon and Venice, Louisiana, and Mobile, Alabama, areas are expected to be used as primary service bases for a proposed action. The ports of Cameron, Houma, Intracoastal City, and Morgan City, Louisiana; and Pascagoula, Mississippi, are expected to be used as secondary service bases.

Gulfwide OCS Program Scenario: The Gulfwide OCS Program activities would continue to lead to a consolidation of port activities at specific ports especially with respect to deepwater activities (i.e., Fourchon, Galveston, and Mobile if Chouest builds a C-Port there). The Gulfwide OCS Program would require no additional service bases.

4.1.2.1.2. Helicopter Hubs

Helicopter hubs or "heliports" are facilities where helicopters can land, load, and offload passengers and supplies, refuel, and be serviced. These hubs are used primarily as flight support bases to service the offshore oil and gas industry. There are 128 heliports in the analysis area that support OCS activities. Three helicopter companies dominate the GOM offshore helicopter industry: Air Logistics, Era Aviation, and Petroleum Helicopters, Inc. A few major oil companies operate and maintain their own fleets, although this is a decreasing trend. Instead of running their own fleets, oil and gas companies are increasingly sub-contracting the whole operation on a turnkey basis to independent contractors. More and more operations are outsourcing to oil-field support companies, such as Baker Hughes, who are much more cost conscious and skeptical about the high cost of helicopters. Another consideration for the helicopter industry is new technology such as subsea systems. These systems decrease the number of platforms and personnel needed offshore, therefore reducing the amount of transportation needed.

To meet the demands of deep water (travel farther and faster, carry more personnel, be all-weather capable, and have lower operating cost), the offshore helicopter industry is purchasing new helicopters. While some heliports located farther inland have closed or consolidated, some heliports are expanding or opening due to more of the industry's work being farther offshore.

Expected proposed action helicopter hubs were ascertained based on well and platform plans in the proposed lease sale area and within 50 mi of the proposed lease sale area. In addition, information received from EPA Lease Sale 181 lessees with respect to potential helicopter hubs for the proposed lease sale area was used as a proxy for activity associated with a proposed action. Therefore, the ports in the Fourchon and Venice, Louisiana, and Mobile, Alabama, areas are expected to be used as primary helicopter hubs for a proposed action. Furthermore, five other ports are expected to be used as secondary helicopter hubs: Cameron, Houma, Intracoastal City, and Morgan City, Louisiana; and Pascagoula, Mississippi. Venice is expected to receive 50 percent of the total number of projected helicopter trips associated with a proposed action. Fourchon and Mobile are each expected to service 25 percent of projected helicopter trips. These percentages are not expected to change during the phases of development.

Proposed Action Scenario: A proposed action would not require additional helicopter hubs. The ports in the Fourchon and Venice, Louisiana, and Mobile, Alabama, areas are expected to be used as primary helicopter hubs for a proposed action. The ports of Cameron, Houma, Intracoastal City, and Morgan City, Louisiana; and Pascagoula, Mississippi, are expected to be used as secondary helicopter hubs.

OCS Progam Scenario: Minimal helicopter hub construction or closures are anticipated. While some heliports located farther inland have closed or consolidated, some heliports are expanding or opening because of more of the industry's work being farther offshore. No new heliports are projected as a result of the Gulfwide OCS Program; however, they may expand at current locations.

4.1.2.1.3. Construction Facilities

4.1.2.1.3.1. Platform Fabrication Yards

Given the platform fabrication industry's characteristics and trends therein, it is not likely that new yards would emerge. 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 Louisiana and Texas for over 50 years, the existing fabrication yards possess a compelling force of economic concentration to prevent the emergence of new fabrication yards. There are 43 platform fabrication yards in the analysis area.

With respect to the deepwater development (such as those expected in the proposed lease sale area), the challenges for the fabrication industry stem from the greater technical sophistication and the increased project complexity of the deepwater structures, such as compliant towers and floating structures. The needs of the deepwater projects are likely to result in two important trends for the fabrication industry. The first is the increasing concentration in the industry, at least with respect to the deepwater projects. As technical and organizational challenges continue to mount up, it is expected that not every fabrication yard would find adequate resources to keep pace with the demands of the oil and gas industry. The second trend is the closer integration—through alliances, amalgamations, or mergers—among the fabrication yards and engineering firms.

Proposed Action Scenario: No new facilities are expected to be constructed as a result of a proposed action.

Gulfwide OCS Program Scenario: No new facilities are expected to be constructed in support of Gulfwide OCS Program activities. Some current yards may close, be bought out, or merge over the 2003-2042 period resulting in fewer active yards in the analysis area.

4.1.2.1.3.2. Shipyards

The 1980's were dismal for the shipbuilding industry. Several mergers, acquisitions, and closings occurred during the downturn. Of those that have remained, 94 are located within the analysis area (**Table 4-7**). Several large companies dominate the oil and gas shipbuilding industry. Most yards in the analysis area are small. To a great extent, growth would be based on a successful resolution of several pertinent issues that have affected and would continue to affect shipbuilding in the U.S. and particularly in the analysis area: maritime policy, declining military budget, foreign subsidies, USCG regulations, OPA 90, financing, and an aging fleet.

Proposed Action Scenario: No new facilities are expected to be constructed as a result of a proposed action.

Gulfwide OCS Program Scenario: No new facilities are expected to be constructed in support of Gulfwide OCS Program activities. Some current yards may close, be bought out, or merge over the 2003-2042 period, which would result in fewer active yards in the analysis area.

4.1.2.1.3.3. Pipecoating Facilities and Yards

There are currently 19 pipecoating plants in the analysis area (**Table 4-7**). Pipecoating 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 segments. The coated pipe is stored (stacked) at the pipeyard until it is needed offshore.

To meet deepwater demand, pipecoating companies have been expanding capacity or building new plants. A new trend in the industry is single-source contracts where the pipe manufacturing, coating, welding, and laying are all under one contract. This results in a more efficient, less costly operation. At present, though, only foreign companies have this capability.

Proposed Action Scenario: No new facilities are expected to be constructed as a result of a proposed action.

Gulfwide OCS Program Scenario: Current capacity, supplemented by recently built plants and expansions, are anticipated to meet Gulfwide OCS Program demand. No new facilities are expected to be constructed in support of Gulfwide OCS Program activities.

4.1.2.1.4. Processing Facilities

4.1.2.1.4.1. Refineries

A refinery is an organized arrangement of manufacturing units designed to produce physical and chemical changes to turn crude oil into petroleum products. In the refinery, most of the nonhydrocarbon substances are removed from crude oil and it is broken down into its various components and blended into useful products.

In the early 1980's, the Crude Oil Entitlements Program ended and crude oil prices were no longer controlled. This caused the number of petroleum refineries to drop sharply, leading to 13 years of decline in U.S. refining capacity. The decade of the 1990's was characterized by low product margins and low profitability. Refining operations consolidated, the capacity of existing facilities expanded, and several refineries closed. Most refineries are part of major, vertically integrated oil companies that are engaged in both upstream and downstream aspects of the petroleum industry. These companies dominate the refining industry, although most majors are spinning off their refinery facilities to independents or entering joint ventures to decrease the risk associated with low refining returns. The analysis area hosts over one-third of the petroleum refineries in the U.S. Most of the region's refineries are located in Texas and Louisiana (**Table 4-7**), representing 55.04 and 38.49 percent, respectively, of total U.S. refining capacity.

Two significant environmental considerations facing U.S. refiners are Phase 2 CAAA of 1990 reformulated motor gasoline (RFG) requirements and the growing public opposition to the use of methyl tertiary butyl ether (MTBE). In order to meet Phase 2 RFG requirements, U.S. refiners would incur numerous expenses and make substantial investments. The MTBE is an additive that increases the oxygen content of motor gasoline, causing more complete combustion of the fuel and less pollution. It was a relative inexpensive way for refiners to meet Phase 1 CAAA RFG requirements. Since March 1999, eight states have adopted bans on the use of MTBE because of concerns about groundwater contamination. This would cause additional outlays of money and some restructuring of current facilities in order to move to ethanol.

Distillation capacity is projected to grow from the 1998 year-end level of 16.3 million barrels per day to between 17.6 million and 18.3 million barrels per day in 2020. Almost all of the capacity additions are projected to occur on the Gulf Coast. Financial, environmental, and legal considerations make it unlikely that new refineries would be built in the United States; therefore, expansion at existing refineries likely would increase total U.S. refining capacity in the long-run. Refineries would continue to be used intensively, in a range from 93 to 96 percent of design capacity.

Proposed Action Scenario: No new facilities are expected to be constructed as a result of a proposed action.

Gulfwide OCS Program Scenario: No new facilities are expected to be constructed in support of Gulfwide OCS Program activities. While financial, environmental, and legal considerations make it unlikely that new refineries would be built in the U.S., expansion at existing refineries likely would increase total U.S. refining capacity over the 2003-2042 period.

4.1.2.1.4.2. Gas Processing Plants

After raw gas is brought to the earth's surface, it is processed at a gas processing plant to remove impurities such as water, carbon dioxide, sulfur, and inert gases and transformed into a saleable, useable energy source. The total number of natural gas processing plants operating throughout the U.S. has been declining over the past several years as companies have merged, exchanged assets, and closed older, less efficient plants. However, this trend was reversed in 1999. Louisiana, Mississippi, and Alabama's capacity is undergoing significant increases as a wave of new plants and expansions try to anticipate the increased gas coming ashore from new gas developments in the GOM. At present, there are 35 gas processing plants in the analysis area that process OCS gas (**Table 4-7**).

According to a study published by the Gas Research Institute, offshore GOM is the only area of the U.S. that offers potential new gas supplies for gatherers/processors. This is also the only region where any significant exploration is occurring. The MMS anticipates the construction of as many 4-16 new gas-processing plants along the Gulf Coast to process gas associated with the Gulfwide OCS Program (**Table 4-7**).

Proposed Action Scenario: No new facilities are expected to be constructed as a result of a proposed action.

Gulfwide OCS Program Scenario: Due to the potential for gas in the GOM OCS, MMS anticipates 4-16 new gas processing plants would be constructed along the Gulf Coast in support of Gulfwide OCS Program activities. Of these new plants, 1-5 are expected to be located in Texas, 3-9 in Louisiana, and 0-2 in the Mississippi-Alabama area.

4.1.2.1.5. Terminals

Terminals are onshore receiving facilities for OCS oil and gas, which includes pipeline shore facilities, barge terminals, and tanker port areas. All proposed action production associated with a proposed action is projected to be transported by pipeline. Barge terminals would only be used for production from shallower water, and tanker port areas would receive production shuttled from FPSO's in the CPA and WPA only.

4.1.2.1.5.1. 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. Pipelines carrying only dry gas do not require pipeline shore facilities; the dry gas is piped directly to the gas processing plant (**Chapter 4.1.2.1.4.2.**). Some processing may occur offshore at the platform; only onshore facilities are addressed in this section.

Pipeline shore facilities may separate, process, pump, meter, and store oil, water, and gas depending on the quality of the resource carried by the pipeline. After processing and metering, the liquids are either piped or barged to refineries or storage facilities. The gas is piped to a gas processing plant for further refinement, if necessary; otherwise, it is transported via transmission lines for distribution to commercial consumers. Water that has been separated out is usually disposed into on-site injection wells.

A pipeline shore facility may support one or several pipelines. Typical facilities occupy 2-25 ha. Although older facilities may be located in wetlands, current permitting programs prohibit or discourage companies from constructing any new facilities in wetlands.

Proposed Action Scenario: No new pipeline shore facilities are projected as a result of a proposed action. It is projected that a proposed action would represent a small percent of the resources handled by shore facilities in coastal Subarea LA-3.

Gulfwide OCS Program Scenario: A total of 12-20 new pipeline shore facilities are projected as a result of the Gulfwide OCS Program. Three to four new facilities are projected to be constructed in coastal Subarea LA-3.

4.1.2.1.6. Disposal and Storage Facilities for Offshore Operational Wastes

Both the GOM offshore oil and gas industry and the oil and gas waste management industry are undergoing significant changes. New drilling technologies and policy decisions as well as higher energy prices should increase the level of OCS activity and, with it, the volumes of waste generated. The oil-field waste industry, having been mired in somewhat stagnant conditions for almost two decades, has developed new increments of capacity, and some new entrants into the market have added to industry capacity and the diversity of technologies available for the industry to use.

Facilities that accept OCS-generated waste that is not unique to oil and gas operations, such as municipal waste landfills and hazardous waste treatment, storage and disposal facilities, are diverse and specialized and manage waste for the broad base of U.S. industry. The OCS activity does not generate a large part of the waste stream into these facilities and is not expected to be material to the overall capacity of the industry. Capacity of industrial waste management facilities is for the most part abundant, as U.S. industries have learned to minimize wastes they ship to offsite facilities for management.

Proposed Action Scenario: No new disposal and storage facilities would be built as a result of a proposed action.

Gulfwide OCS Program Scenario: No new disposal and storage facilities are expected to be constructed in support of Gulfwide OCS Program activities.

4.1.2.1.6.1. Nonhazardous Oil-field Waste Sites

Long-term capacity to install subsurface injection facilities onshore is itself not scarce, and oil-field waste injection well permits do not generally attract much public opposition. With the volume of produced water frequently exceeding the volume of oil a well produces by tenfold or more, the main limitation to widespread use of land-based subsurface injection facilities is the space at docks and the traffic in and out of ports.

With the addition of Trinity Field Services to the market, the OCS market has its first salt dome disposal operation in a competitive location, with 6.2 million barrels of space available initially. This is enough capacity to take 8-10 years' worth of OCS liquids and sludges at current generation rates and a potential of several times that amount with additional solution mining. Salt domes are well-known and well-documented geological structures, and others could be placed into service as demand dictates. Salt caverns are a finite resource, but nevertheless have the potential to take decades' worth of OCS offsite NOW generation.

Proposed Action Scenario: No new NOW waste sites would be built as a result of a proposed action. Capacity to manage waste generated by a proposed action's drilling and production activities is adequate for the present.

Gulfwide OCS Program Scenario: No new NOW waste sites would be built as a result of the Gulfwide OCS Program. Oil and gas waste management facilities along the Gulf Coast have adequate capacity now and for a hypothetical future that includes a doubling of current waste volumes.

4.1.2.1.6.2. Landfills

The use of landfarming of OCS waste is likely to decline further, particularly with greater availability of injection methods for wastes containing solids. Future regulatory efforts are likely to discourage the practice by adding requirements that damage the economics if not by an outright ban on future permits.

Even though growth in OCS waste volumes can be expected to follow a linear relationship with increased OCS drilling and production activity, landfills would continue to be a small factor in the reduction of trash generated by OCS activity. Assuming a landfill (1) presently had OCS waste constituting 5 percent of its waste stream, (2) the remaining life of a landfill was 20 years at current fill rates, and (3) OCS waste doubled but the rest of the incoming waste stream remained flat, then the OCS activities would cause the landfill to be close at the end of 19 years as a result of the OCS contribution increase. With no waste received from OCS activities at all, the landfill would close in 21 years.

Proposed Action Scenario: No new landfills would be built as a result of a proposed action.

Gulfwide OCS Program Scenario: No new landfill waste sites would be built as a result of the Gulfwide OCS Program. Landfills are a small factor in the reduction of trash generated by OCS activity.

4.1.2.1.7. Coastal Pipelines

This section discusses OCS pipelines in coastal waters (State offshore and inland waters) and coastal onshore areas. See **Chapter 4.1.1.8.1.** for a discussion of pipelines in Federal offshore waters. The OCS pipelines near shore and onshore may join pipelines carrying production from State waters or territories for transport to processing facilities or to distribution pipelines located farther inland. See **Chapter 4.1.3.1.2.** for a discussion of pipelines supporting State oil and gas production.

Pipelines in coastal waters may present a hazard to commercial fishing where bottom-trawling nets are used; this is one reason that pipelines must be buried in waters less than 200 ft. Pipeline burial is also intended to reduce the movement of pipelines by high currents and storms, to protect the pipeline from the external damage that could result from anchors and fishing gear, and to minimize interference with the operations of other users of the OCS. For the nearshore sections of OCS pipelines, COE and State permits for constructing pipelines require that turbidity impacts to submerged vegetation be mitigated through the use of turbidity screens and other turbidity reduction or confinement equipment.

As a mitigation measure to avoid adverse effects of barrier beaches and wetlands, most pipeline landfalls crossing barrier beaches and wetlands would be directionally bored under them.

The cumulative analysis discusses the MMS/USGS National Wetland Research Center's (NWRC) current study of coastal wetland impacts from pipeline construction and associated widening of canals utilizing USGS habitat data. Preliminary results from this study are summarized below (Johnston and Barras, personal communication, 2002):

> Approximately 15,400 km (9,570 mi) of OCS pipelines have been constructed in Louisiana from the 3-mi State/Federal boundary to the CZM boundary. Of those pipelines, approximately 8,000 km (4,971 mi) crossed wetland (marsh) or upland habitat. The remaining 7,400 km (4,598 mi) crossed waterbodies. Sources of OCS pipeline data were Penn Well Mapsearch, MMS, National Pipeline Mapping System, and the

Geological Survey of Louisiana pipeline datasets. Additionally, based on USGS 1978 habitat data, approximately 56 percent of the length of pipelines crossed marsh habitat and 44 percent crossed upland habitat. Using USGS landloss data from 1956 to 2002 within a 300-m (984-ft) buffer zone (150 m (492 ft) on each side of the pipeline), the total amount of landloss attributed to OCS pipelines was 34,400 ha (85,968 ac). This number represents 0.04 km^2 (4.00 ha, 9.88 ac) per linear km of pipeline installed. When one divides 34,400 ha by the 46-year period (1956-2002), the loss per year is 746 ha (1,843 ac) for the 8,000 km (4,971 mi) of OCS pipeline. This represents 11.9 percent of the total landloss in the Louisiana pipeline study area. Note that from the period 1990-2002 (based on the preliminary data by USGS), the total landloss due to pipelines for the study area was approximately 25 km^2 (approximately (~) 10 mi^2) or 525 ac/yr, which represents a dramatic decline from the 1956-1978 and 1978-1990 analysis periods (**Table 4-12**). Many of these pipelines were installed prior to the implementation of the NEPA of 1969 and the State of Louisiana's Coastal Permit Program in 1981. Additionally, given the width of the buffer, 300 m (984 ft) versus actual pipeline-canal width, which may be 31-61 m (100-200 ft) wide, an unknown portion of the increase in open water is attributed to other factors unrelated to OCS pipelines. To address this, selected OCS pipelines are being studied in greater detail to ascertain direct and secondary impacts to the extent possible and the information from that analysis will be included in future NEPA documents.

Technologies have been and continue to be developed that decrease the impacts of OCS pipelines on wetlands and associated sensitive habitat. For example, the proposed 30-in Endymion pipeline would deliver crude oil from South Pass Block 89 to the LOOP storage facility near the Clovelly Oil and Gas Field. Based on a review of the data in the COE permit application (No. 20-020-1632), the pipeline construction would have zero impacts to marshes (emergent wetlands) and beaches because the operator is using horizontal, directional (trenchless) drilling techniques to avoid damages to these sensitive habitats. Additionally, the proposed route traverses open water to the extent possible.

Proposed Action Scenario: No new pipeline landfalls or new pipelines in State waters are projected as a result of a proposed action. The four new pipelines projected are expected to tie into existing or proposed pipelines extending into deep water in and near the proposed lease sale area (**Figure 4-3**). It is likely that oil production from a proposed action would be transported through pipelines coming ashore in Louisiana, near Timbalier Bay, Grand Isle, or east of the Mississippi River. Gas production would likely be transported through pipelines coming ashore in Mississippi or Alabama.

Gulfwide OCS Program Scenario: Recently, the trend is for new OCS pipelines to tie into existing systems rather than creating new landfalls. From 2003 to 2042, 23-38 new landfalls are projected as a result of the Gulfwide OCS Program (**Table 4-7**).

4.1.2.1.8. Navigation Channels

The current system of navigation channels around the northern GOM is believed to be generally adequate to accommodate traffic generated by a proposed action and the future Gulfwide OCS Program. Gulf-to-port channels and the GIWW that support the prospective ports are sufficiently deep and wide enough to handle the additional traffic. As exploration and development activities increase on deepwater leases in the GOM (such as those in the proposed lease sale area), vessels with generally deeper drafts and longer ranges would be used as needed to support deepwater activities. Therefore, several OCS-related port channels may be deepened or widened during the life of a proposed action to accommodate deeper draft vessels. Typically, no channel deeper than 8 m would be needed to accommodate these deeper draft vessels.

Proposed Action Scenario: Current navigation channels would not change as a result of a proposed action. In addition, no new navigation channels would be required by a proposed action. Channels associated with the primary and secondary service bases for a proposed action would be used more than other OCS navigation channels.

Gulfwide OCS Program Scenario: A few OCS-related port channels may be deepened or widened during the 2003-2042 period to accommodate deeper draft vessels necessary for deepwater development. The Gulfwide OCS Program would require no new navigation channels.

4.1.2.2. Discharges and Wastes

4.1.2.2.1. Onshore Facility Discharges

The primary onshore facilities that support offshore oil and gas activities include service bases, helicopter hubs at local ports/service bases, construction facilities (platform fabrication yards, pipeyards, shipyards), processing facilities (refineries, gas processing plants, petrochemical plants), and terminals (pipeline shore facilities, barge terminals, tanker port areas). A detailed description of these facilities is given in **Chapter 3.3.5.8.**, OCS-Related Coastal Infrastructure. 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 regulates point-source discharges as part of NPDES. Facilities are issued individual permits that limit discharges specific to the facility type and the waterbody receiving the discharge. The USEPA is currently assessing methods of regulating nonpoint-source discharges, which are primarily run-off from facilities. Other wastes generated at these facilities are handled by local municipal and solid waste facilities, which are also regulated by USEPA.

4.1.2.2.2. Coastal Service-Vessel Discharges

Operational discharges from vessels include sanitary and domestic waters, bilge waters, and ballast waters. Support-vessel operators servicing the OCS offshore oil and gas industry may still legally discharge oily bilge waters in coastal waters, but they must treat the bilge water to limit its oil content to 15 ppm prior to discharge. Sanitary wastes are treated on-board ships prior to discharge. State and local governments regulate domestic or gray water discharges.

4.1.2.2.3. Offshore Wastes Disposed Onshore

All wastes that are not permitted to be discharged offshore by USEPA must be transported to shore or reinjected downhole. A detailed description of these methods is given in **Chapter 4.1.1.4.**, Operational Waste Discharged Offshore. Drilling muds and cuttings from operations that use OBF cannot be discharged offshore. The USEPA Region 4 (under which the proposed lease sale area falls) does not permit the discharge of cuttings wetted with SBF; an individual permit must be obtained to discharge in Region 4. Region 6 does permit the discharge of cuttings wetted with SBF provided the cuttings meet the criteria outlined in the NPDES general permit (GMG290000) effective February 6, 2002. Drill cuttings contaminated with hydrocarbons from the reservoir fluid must be disposed of onshore. Prior to 1993, an estimated 12 percent of drilling fluids and 2 percent of cuttings failed NPDES compliance criteria for offshore discharge and were required to be reinjected or brought to shore for disposal (USEPA, 1993a and b); these pre-1993 percentages are based on data related to the use of OBF. More recent data is not available; however, the increased use of SBF in deepwater drilling and the discharge of the derived cuttings may result in a decrease in drilling waste brought to shore. Depending on the vessel size used, from 20 to 40 25-bbl cutting boxes of waste and from 2,000 to 25,000 bbl of waste fluids in tanks may be transferred to shore.

The USEPA allows TWC fluids to be commingled with the produced-water stream if the combined produced-water/TWC 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 TWC fluids with the produced-water stream to meet NPDES requirements (USEPA, 1993a and b). Analysis of the MMS database shows that about 78 percent of all platform complexes have less than 10 well slots and therefore would probably bring their TWC waste to shore. Spent TWC 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 TWC wastes are transferred to commercial waste-treatment facilities and disposed 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.

Current USEPA NPDES general permits prohibit operators 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, 1993a and b).

4.1.2.2.4. Beached Trash and Debris

Trash lost overboard from OCS platforms and support activities can wash ashore on Gulf coastal lands. However, according to the Ocean Conservancy (formerly the Center for Marine Conservation), beachgoers are a prime source of beach pollution, leaving behind nearly 75 tons of trash per week. Other sources of coastal trash are runoff from storm drains and antiquated storm and sewage systems in older cities. Such systems allow co-mingling and overflow of raw sewage and industrial waste into nearby rivers and coastal areas. Commercial and recreational fishers also produce trash and debris by discarding plastics (e.g., ropes, buoys, fishing line and nets, strapping bands, and sheeting), wood, and metal traps.

The Ocean Conservancy sponsors both international beach cleanups as well as a national marine debris monitoring program. Data from the beach cleanups are shown in **Table 4-13**. The data includes all coastal beaches and adjacent waters. The exact location and source of the trash is unknown.

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, to beachfront residents, and to users of recreational beaches. Cleanup of OCS trash and debris from coastal beaches adds to operation and maintenance costs for coastal beach and park administrators.

4.1.2.3. Noise

Service-vessel and helicopter traffic is the primary sources of OCS-related noise in coastal regions. Sound generated from these activities is transmitted through both air and water, and may be continuous or transient. The intensity and frequency of the noise emissions are highly variable, both between and among these sources. The level of underwater sound detected depends on receiver depth and aspect, and the strength/frequencies of the noise source. The duration that a passing airborne or surface sound source can be received underwater may be increased in shallow water by multiple reflections (echoes). Service vessels and helicopters (discussed in **Chapters 4.1.1.8.2. and 4.1.1.8.3.**) may add noise to broad areas. Sound generated from service-vessel and helicopter traffic is transient in nature and extremely variable in intensity.

Service vessels transmit noise through both air and water. The primary sources of vessel noise are propeller cavitation, propeller singing, and propulsion; 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. The intensity of noise from service vessels is roughly related to ship size and speed. Sounds from support boats range from 120 to 160 dB at 400-7,000 Hz (USDOC, NMFS, 1984). 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 unladen vessels. Noise increases with ship speed; ship speeds are often reduced in restricted coastal waters and navigation channels. During the peak year of activity, a range of 300-500 service-vessel trips is projected to occur annually as a result of a proposed action.

Helicopter sounds contain dominant tones (resulting from rotors) generally below 500 Hz (Richardson et al., 1995). Helicopters often radiate more sound forward than backward, and the underwater noise is generally brief in duration as compared with the duration of audibility in the air. From studies conducted in Alaska, a Bell 212 helicopter was 7-17.5 dB noisier (10-500 Hz band) than a fixed-wing Twin Otter for sounds measured underwater at 3-m and 18-m depths (Patenaude et al., 2002). Water depth and bottom conditions strongly influence the propagation and levels of underwater noise from passing aircraft. Lateral propagation of sound is greater in shallow than in deep water. Interestingly, the amount of sound energy received underwater from a passing aircraft does not depend strongly on aircraft altitude. However, characteristics such as more rapid changes in level, frequency, and direction of sound may increase the prominence of sound low-flying aircraft to marine mammals (Patenaude et al., 2002). Wursig et al. (1998) noted highly variable responses of GOM marine mammals to survey aircraft. Reactions by marine mammals to aircraft are most commonly seen when aircraft are flying less than 500-600 ft. Helicopters, while flying offshore, generally maintain altitudes above 700 ft during transit to and from the working area. During the peak year of activity, a range of 300-400 helicopter trips is projected to occur annually as a result of a proposed action.

4.1.3. Other Cumulative Activities Scenario

4.1.3.1. State Oil and Gas Activities

4.1.3.1.1. Leasing and Production

Louisiana

The Office of Mineral Resources holds regularly scheduled lease sales on the second Wednesday of every month. As in Texas, the State of Louisiana's offshore oil and gas leasing program is conducted on a regular basis irrespective of the Federal OCS mineral leasing program.

In recent years, oil and gas production in the State of Louisiana, as in Texas, has been declining. The MMS projects that the State's offshore production would continue this trend over the analysis period.

Mississippi

The State of Mississippi does not have an offshore oil and gas leasing program. The MMS does not expect the State to institute such a program in the near future.

Alabama

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. The MMS does not expect the State to institute such a program in the near future.

Florida

The State of Florida has experienced very limited drilling in coastal waters. At present, a moratorium has stopped drilling activity in Florida State waters, and the State has no plans for lease sales in the future. At present, no offshore drilling rigs are operating within the State and there are no plans for future drilling offshore.

4.1.3.1.2. Pipeline Infrastructure for Transporting State-Produced Oil and Gas

The pipeline network in the Gulf Coast States is extensive, and transports both State and OCS production. See **Chapter 3.3.5.9.2.** for a discussion of the existing pipeline infrastructure for transporting State-produced oil and gas.

4.1.3.2. Other Major Offshore Activities

4.1.3.2.1. Dredged Material Disposal

Dredged material is described at 33 CFR 324 as any material excavated or dredged from navigable waters of the United States. According to the USEPA, "virtually all ocean dumping occurring today is dredged material, sediments removed from the bottom of waterbodies in order to maintain navigation channels and berthing areas" (USEPA, 1996).

In response to the Marine Protection, Research, and Sanctuaries Act of 1972, as of February 1996, the USEPA finalized the designation of 27 dredged material disposal sites in the GOM. Another 12 sites in the GOM were considered interim sites pending completion of baseline or trend assessment surveys and then the final designation or termination of use of these sites (40 CFR 228.14). Since then, one interim site was approved on a final basis (40 CFR 228.15). Of the 39 designated and interim sites, 7, 21, and 11sites are located in the EPA, CPA, and WPA, respectively. These sites range in area from 0.5 mi^2 to 9 mi^2 and are all within 20 mi of shore.

The COE issues permits for ocean dumping using USEPA's environmental criteria. These permits are subject to USEPA's concurrence. Under the Clean Water Act, the USEPA requires testing of dredge material prior to its disposal to ensure there are no unacceptable adverse impacts to the marine environment.

According to the COE's Ocean Disposal Database (ODD) more than 655 million m^3 of dredged material were disposed in the GOM from 1976 to 2000, which is an average of 27 million m^3 per year (U.S. Dept. of the Army, COE, 2002). The USEPA, COE, and other interested parties are working to identify appropriate uses for dredged material rather than disposing of the material offshore. These uses may include beach nourishment or wetland habitat development.

A discussion of dredging operations in inland coastal regions around the GOM is presented in **Chapter 4.1.3.3.3.**

4.1.3.2.2. Nonenergy Minerals Program in the Gulf of Mexico

This section discusses the impacts of the acquisition of nonenergy minerals (sand, shale, and gravel) from Federal waters in the EPA. There are many submerged shoals located on the OCS that are expected to be long-term sources of sand (sand borrow sites) for coastal erosion management. This sand is needed because of the general diminishing supply of onshore and nearshore sand. The renourishment cycles for beaches or coastal areas require quantities of sand that are not currently available from State sources. The offshore sites are an environmentally preferable resource because OCS sands generally lie beyond the local wave base and the influence of the nearshore physical regime where long-term dredging can result in adverse changes to the local wave climate and the beach. In addition, the offshore sites could provide compatible sand for immediate/emergency repair of beach and coastal damage from severe coastal storms. The economics of dredging in deeper waters is improving as dredging technology advances.

Sand Resources Programs

The MMS has been developing and procuring contracts to provide needed environmental information regarding environmental management of OCS sand resources. The potential for exploitation of sand resources has grown rapidly in the last several years as similar resources in State waters are being depleted or polluted. Several OCS areas are being examined as possible sources of aggregate for construction purposes. At present, there are no sand leases in the EPA.

In 1999, the study *Environmental Survey of Identified Sand Resource Areas Offshore Alabama* (Byrnes and Hammer, 1999) was published. This survey provided (1) an assessment of the baseline benthic ecological conditions in and around the five previously-identified proposed borrow sites (**Figure 4-4**); (2) evaluated the benthic infauna resident in the five potential borrow sites and assessed the potential effects of offshore dredging activity on these organisms, including an analysis of the potential rate and success of recolonization; (3) developed a schedule of the best and worst times for offshore dredging with regard to transitory pelagic species; (4) evaluated the potential for modification to waves because of offshore dredging within the five proposed sand borrow areas; and (5) evaluated the impacts of offshore dredging and subsequent beach nourishment in terms of potential alteration of sediment transport patterns, sedimentary environments, and impacts to local shoreline processes. The information gathered during this study would likely be used should a decision be made to proceed with the preparation of an EA or an EIS in support of a negotiated agreement with the State of Alabama for access to Federal sand resources. The information gathered during the course of this study would also enable MMS to monitor and assess the potential impacts of offshore dredging activities and to identify ways that dredging operations can be conducted so as to minimize or preclude long-term adverse impacts to the environment.

Another study, *Synthesis of Hard Mineral Resources on the Florida Panhandle Shelf: Spatial Distribution and Subsurface Evaluation* (McBride, 1999), produced regional baseline information on the hard mineral resources, geologic framework, and long-term sediment dynamics of the Florida Panhandle Shelf (Mobile Bay, Alabama, to Choctawhatchee, Florida (**Figure 4-5**)). The study's objectives were to (1) quantify hard mineral resource deposits; (2) establish the regional three-dimensional architecture of hard mineral deposits; (3) produce seafloor elevation models; (4) determine patterns and processes of shelf sediment transport; (5) integrate seafloor elevation models with geologic data to establish form-process relationships; (6) disseminate research results; and (7) incorporate appropriate data on hard minerals into the Louisiana State University (LSU) Coastal Studies Institute's Gulfwide Information System.

The *Wave Climate and Bottom Boundary Layer Dynamics with Implications for Offshore Sand Mining and Barrier Island Replenishment in South-Central Louisiana* (Stone, 2000) study produced measurements of wave characteristics at two locations on Ship Shoal to validate a spectral wave propagation model (STWAVE). The objectives of the study were to (1) obtain direct field measurements of bottom boundary layer hydrodynamic processes and suspended sediment transport; and (2) obtain direct field measurements of temporally and spatially varying directional wave parameters at several locations on Ship Shoal.

Sand sources that are to be used on a continual, multiyear, multiuse basis may require biological/physical monitoring to ensure that long-term adverse impacts to the marine and coastal environment do not occur. However, there exists no standard approach or methodology for properly monitoring the effects of ongoing dredging operations. The recently completed studies, *Development and Design of Biological and Physical Monitoring Protocols to Evaluate the Long-term Impacts of Offshore Dredging Operations on the Marine Environment* (Research Planning, Inc. et al., 2001a) and *Examination of Regional Management Strategies for Federal Offshore Borrow Areas along the United States East and Gulf of Mexico Coasts* (Research Planning, Inc. et al., 2001b), addressed those concerns and issues. In addition, extensive damage to a beach area as the result of a severe storm may necessitate that a sand borrow area be used prior to the completion of the environmental work needed to support decisions on conditions of lease agreements. Therefore, some form of "conditions of approval" or "stipulation(s)" might be necessary if leases are to be issued.

The objectives of the above studies were as follows:

- provide MMS with an appropriate and sound design for a physical/biological monitoring system to evaluate the near-term, long-term, and cumulative effects of using Federal sand borrow areas on the U.S. East and Gulf Coasts;
- examine the feasibility and appropriateness of including Federal, State, and local authorities with an interest in the use of offshore Federal sand in a regional management concept for developing ways to assure and monitor the responsible, environmentally sound, long-term management of Federal offshore sand areas; and
- if, in Year 1 of the study, the study team determines that it is feasible and appropriate to manage Federal offshore sand resources on a regional basis, to develop detailed plans and fully identify the relevant parties by geographic area to meet the needs of Federal, State, and local interests to facilitate the environmentally acceptable and cost-effective near and long-term use of Federal sand borrow areas offshore the U.S. East and Gulf Coasts.

In many cases, physical and biological monitoring of borrow areas may be necessary to preclude adverse impacts to the marine environment. An appropriate "condition of approval" or "stipulation" to support a lease for these areas might be the monitoring of the biological and physical regime during operations to ensure that no adverse impacts are or would occur. The study outlined above would provide a blueprint for these monitoring operations. To date, proposed coastal erosion management projects have been examined on a case-by-case, project-specific basis. These resources must be managed on a long-term, system-wide basis in such a way as to ensure that environmental damage would not occur as a result of continual and prolonged use.

4.1.3.2.3. Marine Transportation

An extensive maritime industry exists in the northern GOM. **Figure 3-12** shows the major ports and domestic waterways in the analysis area, while **Tables 3-33 and 3-34** present the 1999 channel depth, number of trips, and freight traffic of OCS-related waterways. Marine transportation within the analysis area should grow linearly based on historical freight traffic statistics given current conditions. Should any infrastructure changes occur, the marine transportation would reflect these changes. For example, if a port in the analysis area (or outside the analysis area) deepened its channel or constructed new railroads or highways into the port area, then the number of trips and the volume of commodities into and out of the port would change accordingly. Or if a refinery near one of the ports were to close, then tanker traffic to that port may decrease.

Tanker imports and exports of crude and petroleum products into the GOM are projected to increase (USDOE, EIA, 2001a). In 2000, approximately 2.08 BBO of crude oil (38% of U.S. total) and 1.09 BBO of petroleum products (13% of U.S. total) moved through analysis area ports. By the year 2020, these volumes are projected to grow to 2.79 BBO of crude oil and 1.77 BBO of petroleum products. Crude oil would continue to be tankered into the GOM for refining from Alaska, California, and the Atlantic.

Proposed Action Scenario: Marine transportation is not expected to change as a result of a proposed action.

Gulfwide OCS Program Scenario: Gulfwide OCS Program activities over the 2003-2042 period are not expected to change marine transportation. The number of trips and volume of commodities into and out of analysis area ports are expected to grow linearly based on historical freight traffic statistics.

4.1.3.2.4. Military Activities

The air space over the GOM is used extensively by DOD for conducting various air-to-air and air-to-surface operations. Eleven military warning areas and six water test areas are located within the GOM (**Figure 2-1**). These warning and water test areas are multiple-use areas where military operations and oil and gas development have coexisted without conflict for many years.

The EPA has five designated military warning areas that are used for military operations. These areas total approximately 34.1 million ac. Portions of Eglin Water Test Areas (EWTA) comprise an additional 33.6 million ac in the EPA. The total 67.7 million ac is about 89 percent of the area of the EPA.

The entire proposed lease sale area (1.5 million ac) is within either a military warning area or an EWTA. The northeastern corner of the proposed lease sale area is in Military Warning Area 155. Portions of this military warning area comprise 0.9 million ac of the northeastern corner of the proposed lease sale area. Portions of EWTA 1 and 3 comprise the remaining 94 percent (1.4 million ac) of the proposed lease sale area.

The Navy uses the GOM waters for shakedown cruises for newly-built ships, for ships completing overhaul or extensive repair work in GOM shipyards such as Pascagoula, Mississippi, and for various types of training operations. While no aircraft carriers are currently home-ported in the GOM, carriers may from time-to-time conduct flight operations in the GOM. No areas in the GOM have been designated as Naval operating areas requiring restrictions on the navigation of other vessels.

Future uses of the Eastern GOM by the military are uncertain at present, but activities are expected to increase rather than decrease. The new F-22 fighter aircraft may be based at Eglin or Tyndall Air Force Bases in Florida, and a new generation of theater missile defense weapons systems may require the large air and water spaces of the Eastern GOM for development and testing. The Eastern GOM is the largest area of the continental U.S. in which long-range systems can be deployed. Using areas outside the U.S., such as Pacific Ocean ranges, would increase costs and decrease flexibility tremendously.

The DOD reviewed the proposed lease sale area prior to Lease Sale 181 in December 2001 with both current and future military requirements in mind and determined at that time that future lease sales in this reduced area would not interfere with current and future military uses provided that certain operational restrictions be placed on any leases resulting from such lease sales (**Chapter 2.3.1.3.1.**, Military Warning Areas Stipulations – Hold and Save Harmless, Electromagnetic Emissions, and Operational Restrictions).

4.1.3.3. Other Major Influencing Factors on Coastal Environments

4.1.3.3.1. Submergence of Wetlands

Submergence of wetlands along the Gulf Coast is primarily caused by (1) eustatic sea-level rise – a reduction in the volume of water stored in polar ice caps, and (2) land subsidence – caused by various localized natural and manmade events such as down-warping or horizontal movement of the earth's crust, weighted surface compression; and oxidation, consolidation, settling, and dewatering of surface sediments (Swanson and Thurlow, 1973). In localized areas, subsidence and sea-level rise can be offset by sedimentation, placement of dredged material, and peat formation. Peat formation (horizons) refers to the soil material deposited in deep water that are highly colloidal in nature, as well as compact and rubbery (Nyle, 1990). Radiocarbon dating peat horizons is used to identify long-term (greater than 100 years) average rates and patterns of subsidence along coastal Louisiana. Using conventional radiocarbon age, depth, and below current sea-level relationships, subsidence rates are easily calculated (Kulp and Howell, 2001).

During this century, the rate of eustatic sea-level rise along the Louisiana coast has been relatively constant at 2.3 millimeters (mm) per year (yr) (23 cm/century), although the rate has varied from a sea-level decrease of 3 mm/yr to a maximum increase of 10 mm/yr over decade-long periods (Turner and Cahoon, 1988). Submergence in the GOM is occurring most rapidly along the Louisiana coast and more slowly in other coastal states. Depending on local geologic conditions, the subsidence rate varies across coastal Louisiana from 3 to 10 mm/yr. One of the major factors causing greater submergence rates in Louisiana is reduced sedimentation, resulting from deltaic abandonment, flood control, and channelization of the Mississippi River.

Fluid withdrawal can cause localized subsidence above the producing reservoirs. In coastal Louisiana, about 400 km^2 of wetlands have a subsidence potential greater than 10 cm because of fluid withdrawal (Turner and Cahoon, 1988).

4.1.3.3.2. River Development and Flood Control Projects

In recent decades, alterations in the upstream hydrology of the rivers draining into the northern GOM have resulted in various coastal impacts. Dams and reservoirs on upstream tributaries trap much of the sediment load in the rivers. The suspended sediment load of the Mississippi River has decreased nearly 60 percent since the 1950's, largely as a result of dam and reservoir construction upstream (Tuttle and Combe, 1981; Turner and Cahoon, 1988).

In a natural system, over-bank flooding introduces sediments into adjoining wetlands. Flood control on the Mississippi and other rivers has largely eliminated flood-borne sedimentation in the GOM coastal wetlands, contributing to their deterioration.

Channelization of the Mississippi and other rivers in conjunction with flood control levees has also contributed to wetland loss and has interrupted wetland creation around the GOM by preventing distribution of alluvial sediments across deltas and flood plains. Prior to channelization, the flow of rivers was distributed among several distributary channels that delivered sediment over a broad area during high river stages. Today, sediment from the Mississippi River is primarily discharged through the main channel directly to the deep waters of the continental slope. The only significant exception to this scenario is the diversion of approximately 30 percent of the Mississippi River flow to the Atchafalaya River; this diversion does not capture 30 percent of the sediment flow, however, because most of the sediment is restricted to the deeper river channel.

4.1.3.3.3. Dredging

Dredging operations include sediment and gravel harvesting; pipeline installation; canal installation, maintenance, and modifications; harbor installation and maintenance; and stream channelization.

Numerous channels are maintained throughout the onshore cumulative activity area by Federal, State, county, commercial, and private interests. Proposals for new and maintenance dredging projects are reviewed by Federal, State, and county agencies as well as by private and commercial interests to identify and mitigate adverse impacts upon social, economic, and environmental resources.

Typically, the USCOE schedules surveys every two years on each navigation channel under its responsibility to determine the need for maintenance dredging. Maintenance dredging is then performed on an as-needed basis. Dredging cycles (1-6 years) vary broadly from channel to channel and channel segment to channel segment. The USCOE is charged with maintaining all larger navigation channels in the cumulative activity area. The USCOE dredges millions of cubic meters of dredged material per year in the cumulative activity area. Some shallower port-access channels may be deepened over the next 10 years to accommodate deeper draft vessels.

Materials from maintenance dredging are primarily disposed of on existing dredged-material disposal banks and in dredged-material disposal areas. Additional dredged-material disposal areas for maintenance or new-project dredging are developed as needed and must be evaluated and permitted by the USCOE and relevant State agencies prior to construction. Some dredged sediments are dispersed into offshore waters at established disposal sites.

When placing the material on a typical dredged material disposal site, the usual fluid nature of the mud and subsequent erosion causes widening of the site, which may bury adjacent wetlands, submerged vegetation, or nonvegetated water bottoms. Consequently, adjacent soil surfaces may be elevated, converting wetlands to uplands, fringes of shallow waterbodies to wetlands, and some nonvegetated water bottoms to shallower water bottoms or emergent areas that may become vegetated due to increased light at the new soil surface.

Dredged materials from channels are often contaminated with toxic heavy metals, organic chemicals, pesticides, oil and grease, and other pollutants originating from municipal, industrial, and vessel discharges and nonpoint sources, and can result in contamination of areas formerly isolated from major anthropogenic sources (USEPA, 1979). The vicinities around harbors and industrial sites are most noted for this problem. Hence, sediment discharges from dredging operations can be major point sources of pollution in coastal waters in and around the GOM. In addition, inland and shallow offshore disposal can change the navigability and natural flow or circulation of waterbodies.

In 1989, USEPA estimated that more than 90 percent of the volume of material dumped in the oceans around the U.S. consisted of sediments dredged from U.S. harbors and channels (USEPA, 1989). As of February 1997, in response to the Marine Protection, Research, and Sanctuaries Act of 1972, USEPA had finalized the designation of eight dredged-material disposal sites in the cumulative activity area. Another four sites in the GOM are considered interim sites for dredged-material disposal. These sites primarily facilitate the COE's bar-channel dredging program. Generally, each bar channel of navigation channels connecting the GOM and inland regions has 1-3 disposal sites used for disposal of maintenance dredged material. These are usually located in State waters. Some designated sites have never been used.

Installation and maintenance of any navigation channel and many pipeline canals connecting two or more waterbodies changes the hydrodynamics in their vicinity. These changes are typically associated with saltwater intrusion, reduced freshwater retention, changed circulation patterns, changed flow velocities, and erosion. When these channels are permitted for construction through sensitive wetland habitats or when sites are permitted for dredged-material disposal, measures are required to mitigate unavoidable adverse environmental impacts. Structures constructed to mitigate adverse hydrodynamic impacts and accelerated erosion include dams, weirs, bulkheads, rip-rap, shell/gravel mats, and gobi mats.

Generally, little or no maintenance is performed on mitigation structures. Therefore, many mitigation facilities, particularly in regions where the soil is poorly consolidated and has a high organic content, are known to become ineffective within a few years of construction. The number of mitigation structures associated with navigation and pipeline channels is unknown.

4.1.3.4. Major Sources of Oil Inputs in the Gulf of Mexico

Petroleum hydrocarbons can enter the GOM from a number of sources. These sources include both natural geochemical processes and onshore and offshore activities of man. Major sources of petroleum hydrocarbon inputs to GOM waters include, in order of the greatest source to the least source are as follows: (1) municipal wastewater discharges; (2) natural seepage; (3) spills; (4) Mississippi River runoff; (5) nonpoint-source urban runoff; (6) industrial wastewater discharges; and (7) produced water from offshore oil production. Numerical estimates of the relative contribution of these sources to oil inputs in the GOM are presented in **Table 4-14**. Although the GOM comprises one of the world's most prolific offshore oil-producing provinces as well as having heavily traveled tanker routes, inputs of petroleum from onshore sources far outweigh the contribution from offshore activities. Man's use of petroleum hydrocarbons is generally concentrated in major municipal and industrial areas situated along coasts or large rivers that empty into coastal waters.

The following paragraphs provide a description of these oil input sources.

4.1.3.4.1. Municipal Wastewater Discharges

Significant amounts of petroleum hydrocarbons end up in the wastewaters of cities from a variety of sources, especially the operation of motor vehicles. The actual amount of petroleum hydrocarbons discharged at municipal plants depends on the level of treatment, and plant design and operation. It is assumed that all municipalities along the Gulf Coast use primary treatment. Even considering this, MMS estimates that the discharge of wastewaters from municipalities located in the coastal zone of the GOM contribute the largest amount of oil and grease to GOM waters (0.35 million metric tons annually (Mta)).

4.1.3.4.2. Natural Seepage

Based on geologic potential, Wilson et al. (1973) estimated that the U.S. and Mexican Gulf areas could be seeping as much as 204,000 bbl of oil per year (0.027 Mta) (**Table 4-14**). Twenty years later, MacDonald et al. (1993) estimated the volume of natural seepage for an area of the continental slope off Louisiana by using satellite imagery. He estimated a natural seepage rate of about 120,000 bbl per year (0.016 Mta) from a 23,000-km^2 area. Given that MacDonald's estimate would be a significant subset of Wilson's estimate, Wilson's estimate appears to be within reason and is still used.

4.1.3.4.3. Spills

Oil spills can happen from a large variety of sources, including tankers, barges, other vessels, pipelines, storage tanks and facilities, production wells, and mystery sources. **Table 4-14** shows the relative contribution of spills to the overall input of oil to the GOM. This amount is far less than what is contributed by wastewater and seeps. The total contribution of petroleum inputs to GOM waters from spills is estimated to be about 80,000 bbl per year or 0.011 Mta (**Table 4-14**). The projected contribution from non-OCS-related spills (0.0096 Mta) is approximately an order of magnitude greater than the amount projected to be spilled annually from OCS-related spills (0.0013 Mta). **Table 4-15**, discussed in **Chapter 4.3.1.**, Oil Spills, provides the estimated future annual contribution of the various sources. **Chapter 4.3.1.** also summarizes estimates of spills that could occur as a result of a proposed action.

4.1.3.4.4. Mississippi River Runoff

The Mississippi River carries large quantities of petroleum hydrocarbons into GOM waters from land-based drainage that occurs far upriver but that eventually reaches the Mississippi River or its tributaries. The GOM sediment samples collected within a broad crescent around the Mississippi River show petroleum contamination from the River's discharge (Bedding, 1981; Brooks and Giammona, 1988). Although the hydrocarbon burden measured at the mouth of the Mississippi River is also from coastal inputs, MMS's estimates found in **Table 4-14** only includes the amount of hydrocarbons in the Mississippi River outfall that would be contributed upriver from New Orleans.

4.1.3.4.5. Nonpoint-Source Urban Runoff

Significant volumes of petroleum hydrocarbons are deposited in urban areas from a variety of sources: asphaltic roads; the protective asphaltic coatings used for roofs, pipes, etc.; oil used in two-cycle engines such as outboard boat motors and lawn equipment; gas station runoff; and unburned hydrocarbons in car exhaust. These sources are either directly flushed by rainfall and runoff into storm drains and into coastal waters or rivers, or are weathered, broken down, and then dispersed. The Automotive Information Council estimated in 1990 that 8.3 MMbbl (approximately 1.2 Mta) of used motor oil waste is generated annually in the U.S. by do-it-yourselfers (Automotive Information Council, 1990). They estimate that 60 percent of this is poured on the ground, thereby adding 5.7 MMbbl of oil to the urban environment annually (0.814 Mta). Much of this discarded oil contributes to the petroleum loading found in municipal wastewater and urban runoff.

4.1.3.4.6. Industrial Wastewater Discharges

Coastal Refineries: Other major land-based sources of petroleum hydrocarbons in GOM waters include refineries and other industry effluents. **Chapter 3.3.5.8.5.**, Processing Facilities, describes the extensive refinery operations occurring along the Gulf Coast.

Non-Refinery Industrial Discharges: The MMS estimates that wastewaters from industries located along the GOM's coastal zone, including those located in the southern Mississippi River industrial corridor, contribute about 0.004 Mta. Many of the other industries operating in the Gulf Coast area support the oil and gas industry and are described in **Chapter 3.3.5.8.**, OCS-Related Coastal Infrastructure. **Chapter 3.3.5.1.2.**, Land Use, also provides an overview of the other major Gulf Coast industries.

4.1.3.4.7. Produced Water

The OCS operations routinely discharge small amounts of oil in wastewater discharges, primarily in produced waters. Produced water, when discharged overboard (after treatment that removes the majority of the entrained oil content), is limited by the USEPA effluent limitation guidelines to a monthly average of 29 mg/l oil content (USEPA, 1993). A typical annual amount of OCS-produced water to be discharged in the future was estimated based on annual historical quantities reported to MMS for the last 6 years **Chapter 4.1.1.4.2.**, Produced Waters). The average annual value of 532 MMbbl per year was converted to liters than multiplied by the monthly average oil and grease (29 mg/l) to estimate the contribution to the petroleum levels in GOM waters from OCS discharged produced waters. This calculation results in an estimate of 0.002 Mta of petroleum hydrocarbons entering GOM waters from operational, OCS produced-water discharges (**Table 4-14**).

4.1.3.4.8. Other Sources

There are other sources of petroleum hydrocarbons not estimated in this exercise and, therefore, a complete mass balance cannot be done. For example, vessel operational discharges have changed due to new regulations. In 1985, operational discharges (bilge and ballast water and oily tank wastes) from vessels dominated the major sources of oil inputs. Since then, the MARPOL regulations have significantly reduced the levels of operational discharges associated with vessel operations. Terminals are now required to maintain onshore disposal facilities for receipt of this waste; although full compliance with these requirements is not yet attained. At this time, a review of the effectiveness of the more restrictive discharge requirements is still ongoing, so no new numbers are available to estimate vessel contributions. The MMS expects that National Academy of Science's 1985 projection, 47 percent of the amount of oil entering the world ocean is from operational discharges from vessels, to be reduced significantly when they publish their updated projections. Other minor inputs from erosion of sedimentary rocks, atmospheric inputs, and dredged material disposal are not quantified. The contribution from international petroleum sources, such as Mexico and Cuba, was not calculated.

4.2. ENVIRONMENTAL AND SOCIOECONOMIC IMPACTS - ROUTINE OPERATIONS

4.2.1. Alternative A – The Proposed Actions

The proposed actions are proposed Lease Sales 189 and 197. The lease sales are scheduled to be held in December 2003 and March 2005, respectively. Each lease sale would offer for lease all unleased blocks in the proposed lease sale area in the EPA. It is estimated that each proposed lease sale could result in the discovery and production of 0.065-0.085 BBO and 0.265-0.340 Tcf of gas during the period 2003-2042. A description of the proposed actions is included in **Chapter 1.2.** Alternatives to the proposed actions and mitigating measures are also described in **Chapters 2.3.2. and 2.3.1.3.**, respectively.

The analyses of the potential impacts are based on a scenario for a typical proposed action. These scenarios provide assumptions and estimates on the amounts, locations, and timing for OCS exploration, development, and production operations and facilities, both offshore and onshore. A detailed discussion of the development scenarios and major impact-producing factors from routine activities associated with a proposed action is included in **Chapter 4.1.** The two proposed mitigating measures (Marine Protected Species and Military Areas Stipulations) are considered part of the proposed action(s) for analysis purposes.

The scenario and analysis of potential impacts of oil spills and other accidental events are discussed in **Chapter 4.3.** The Gulfwide OCS Program and cumulative scenarios are discussed in **Chapter 4.1.** The cumulative impact analysis is presented in **Chapter 4.5.**

4.2.1.1. Impacts on Air Quality

The following activities potentially degrade air quality: platform construction and emplacement; platform operations; drilling activities; flaring and burning; survey and support vessel operations; pipeline laying operations; evaporation of volatile petroleum hydrocarbons during transfers and from surface oil