Chapter 5

Environmental Consequences, Cumulative Impacts (2002 - 2006), and Mitigation Measures

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Chapter 5

Environmental Consequences, Cumulative Impacts (2002 - 2006), and Mitigation Measures

5.0 INTRODUCTION

The reader is encouraged to read section 1.2, Reader's Guide to the use of this document, to get a good understanding of how this EIS is organized.

Chapter 5 provides an analysis of how the Proposed Action will likely affect the environmental resources in or migrating through the study area. The analysis is provided on a resource-by-resource basis for the Proposed Action in isolation and with respect to the cumulative case. Available measures to mitigate adverse effects of the Proposed Action are also identified, with an estimate of the ameliorative effects of these measures for specific resource categories. Finally, this chapter includes a discussion of the effects of the two alternatives on the resources. The list of related environmental documents is presented in appendix 7. These documents are hereby incorporated into this EIS.

Impacts that could potentially occur as a result of delineation drilling are highly localized (Figure 1.0-3). However, the study area includes a considerably larger geographic area to facilitate the analysis of both near-term (through residual effects of the delineation drilling) and longer-term (through potential development and decommissioning of all 36 currently undeveloped OCS leases) (Figure 4.0-1). This was discussed in Chapter 4.

This chapter builds on the description of the affected environment provided in chapter 4. The structure of the analysis of the environmental consequences of the Proposed Action describes the impact-producing factors and defines the criteria employed for high, moderate, low, and negligible impacts for each resource category. The impacts are analyzed for all the projects combined, followed by those impacts associated with each separate project, as appropriate.

The basis for the cumulative effects analyses considers the aggregate of all the effects of all activities and the contribution of the Proposed Action. The effects of the other activities in the study area (past, present, and within the foreseeable future) are evaluated, and the likely effects of the Proposed Action are overlaid to provide a clear understanding of the contribution of the Proposed Action to the whole.

The cumulative effects of OCS activities are discussed for each resource category in two phases, or two different "futures," one of longer duration than the other:

- Chapter 5 provides an analysis of the effects over the near-term future (2002-2006). This is the timeframe projected through the time when no further residual effects associated from the Proposed Action are expected to occur.
- Chapter 6 provides an analysis of the effects of potential development of the 36 undeveloped OCS leases over the near- and long-term future (2002-2030). This Chapter also analyzes the cumulative effects of all existing offshore oil and gas activities and other related activities in the study area.

This approach to analyzing the effects of the Proposed Action as it influences other activities and conditions that exist within these timeframes provides the readers and decisionmakers an understanding of the incremental effects of the Proposed Action. In both cases, assumptions were made concerning the foreseeable future activities in and influencing the study area (section 5.1.2.2 and 6.1.2). A limited amount of information is currently known of how and when the reasonably foreseeable activities (both those associated with OCS development and with other influences on the environment) may occur. To provide a long-term analysis, the MMS developed a hypothetical development scenario for the 36 undeveloped OCS leases. This is described in detail in section 6.1.3.

5.1 BACKGROUND INFORMATION FOR IMPACT ANALYSES

5.1.1 PROPOSED ACTION (DELINEATION DRILLING)

The operators (Nuevo Energy Company, Aera Energy LLC, and Samedan Oil Corporation) of four OCS units (Bonito, Cavern Point, Point Sal, and Gato Canyon), are expected to propose to drill 4-5 delineation wells on those units (figure 1.0-3; table 1.0-2). These will be proposed in 4-5 revised Exploration Plans EP's).

The four proposed projects will use a semi-submersible drilling vessel, commonly referred to as a mobile offshore drilling unit (MODU). The MODU will move from one unit to another, sequentially drilling a total of 4-5 wells on the four separate unitized areas (table 1.0-2). Each of the four units has been previously-explored under EP's approved by the MMS. These EP's were found consistent with the California Coastal Management Plan by the California Coastal Commission. The operators of these units propose to drill delineation wells to complete their data on reservoir configuration and characteristics. It will take 68-92 days to drill and test each well. The first well would commence drilling in May 2002 and the last well in May 2003. The data received from these wells will assist the operators in determining how to develop and produce the underlying oil and gas reserves. Table 5.1.1.1-1 provides a summary of impact-producing factors associated with the Proposed Action (Delineation Drilling). Refer to section 2 for a complete description of the proposed projects.

5.1.1.1 IMPACT-PRODUCING FACTORS FOR THE PROPOSED ACTION

Exploring for hydrocarbon resources as a result of the Proposed Action requires a complex and interrelated series of operations that began with pre-lease geological and geophysical exploration under MMS permits, continued through leasing of offshore blocks, post-lease seismic surveying operations, exploration drilling, and, finally, the proposed drilling of delineation wells on the four units. Transportation of the personnel and supplies needed to maintain these operations are also part of the process. These diverse activities have associated potential impacts to offshore and onshore biological, physical, and socioeconomic resources. This section describes the various kinds of offshore activities that could affect the environmental and socioeconomic resources in the study area. The potential impacts associated with these activities are described in section 5.2.1 through 5.2.24.

Tables 2.1-2.4 show the magnitudes of the impact producing factors (IPF's) that are projected to occur in the various units from the Proposed Action. Also, table 5.1.1.1-1 presents a summary of these IPF's.

PERSONNEL

It is expected that approximately 140-145 individuals will be directly involved in the proposed drilling activities at each well site. Most of the employees will be working on the drilling rig and will stay with the rig. The offshore personnel will typically work shifts of 7 days on and 7 days off. Service personnel will move to and from the rig as needed. Other than employees of the drilling contractor, the personnel associated with these operations are generally already living and located in Santa Barbara and Ventura Counties.

INFRASTRUCTURE AND OPERATIONS

Delineation Wells. Delineation of petroleum-bearing formations is carried out from mobile drilling rigs or drillships. For the Proposed Action, a single semi-submersible type, or MODU, would be used (figure 2.1.3-1) to drill all the proposed delineation wells for the proposed project to minimize potential cumulative impacts. The analog rig to be used for the representative analysis will be the SEDCO 712. This drill rig is similar to rigs used in previously-approved EP's and has been used to drill seven wells in the Pacific OCS

Table 5.1.1.1-1. Summary of impact-producing factors associated with the proposed action (delineation drilling).

Wells Proposed to be Drilled on Each Unit	Time on Location (days)	Mud and Cuttings Volume Per Well (bbl)	Anchor Spread (ft)	Crew and Supply Boat Trips Per Month (Total)	Helicopter Trips/Month (Total)
Bonito – 1-2	88-90	2,957	3,000	20 (57-59)	30 (86-88)
Point Sal – 1	68	12,250	1,100-1,900	14 (31)	20 (44)
Purisma Point – 1	68	12,250	1,100-1,900	14 (31)	20 (44)
Gato Canyon – 1	92	2000 to 3000	2,500-3,500	11 (33)	28 (84)

Region in the past. The time required to drill and test each well is 68-92 days. One delineation well would be drilled on the Point Sal, Gato Canyon, and Purisima Point Units and one to two wells on the Bonito Unit.

Offshore Transport –Service Vessels. Support vessels associated with MODU drilling operations will operate out of Port Hueneme, with some possible crew boat trips originating from Carpinteria Pier. Due to the rough sea conditions north of Point Conception and distances involved, crews will be transferred to and from the MODU primarily by helicopter. Supply boat trips are projected to number 8-12 per month, which averages about 1 every 3 days. Currently, about 12-13 supply boat trips per month (1 every 2 to 3 days) are made to the four existing OCS platforms (Irene, Harvest, Hermosa, Hidalgo) in the Santa Maria Basin. An additional 12 supply boat trips per month (1 every 2 to 3 days) are made to existing OCS platforms (Hondo, Heather, and Harmony) in the western Santa Barbara Channel.

The Proposed Action includes the following list of service-vessel activities:

- Crew boats: It is expected that one 110-foot class crew boat will be used to support the delineation drilling operations. It is likely that the boat will be stationed in, and operate out of, Port Hueneme or the Carpinteria Pier and will travel through established corridors. Although crew boats may service other area platforms on the same trip, it is assumed for this analysis that crew boats serve the drilling rig exclusively. Approximately 2 (Gato Canyon) to 8 (Purisima Point, Point Sal, and Bonito) trips per month will be required. Based on a 2- to 3-month program per well, the following miles would be traveled to each unit: Bonito - 5,712 mi, Gato Canyon - 350 mi, Purisima Point - 2,640, Point Sal - 3,360.

- Standby boat: A standby boat will be stationed near the delineation rig at all times during operations. It is anticipated that this boat will be a 110-foot class vessel with a two-man crew. The primary purpose of this vessel is emergency response in the unlikely event of an oil spill. This vessel will not normally leave the drill site, except for emergency situations, and only when another vessel can act as standby. No trips for the standby vessel are planned other than initial mobilization and demobilization.

- Supply boats: It is expected that one 180-foot class supply boat will be used to support the delineation drilling operations. It is likely that the boat will be stationed in, and operate out of, Port Hueneme and will travel through predetermined corridors. Approximately 12 (Bonito) to 8 (Gato Canyon) trips per month will be required. Based on a 2- to 3-month program per well, the following miles would be traveled to each unit assuming they will originate from Point Hueneme: Bonito - 7,344, Gato Canyon - 2,500, Purisima Point - 3,960, Point Sal - 5,280.

- Anchor handling boats: An anchor handling boat will deploy the anchors. The boats run the anchor and anchor chain out to the required length, and lower the anchor onto the seafloor using a work wire.

Offshore Transport –Helicopters. Offshore southern California, helicopters are a primary means of transporting crew to and from the platforms. Helicopter traffic on the OCS operates primarily out of Santa Maria, Lompoc, and Santa Barbara airports. Most of the traffic is to and from platforms in the western Santa Barbara Channel and Santa Maria Basin. In addition, several international and numerous smaller airports, along with several military airfields, exist along the southern California coast, and air traffic is a daily occurrence in the region.

Helicopter trips in support of MODU drilling activities are expected to average 20-30 month (up to 1 per day). In comparison, about 150 helicopter trips (5 per day) are made monthly to the four Santa Maria Basin platforms. The Sea King, a two-engine helicopter, is expected to best represent the type of helicopters used for this program.

Because of noise and safety concerns, the Federal Aviation Administration (FAA) regulates flight patterns. FAA Circular 91-36C encourages pilots to maintain higher than minimum altitudes near noise-sensitive areas. Corporate policy (all helicopter companies) states that helicopters should maintain a minimum altitude of 700 ft while in transit offshore and 500 ft while working between platforms and drilling rigs. When flying over land, the specified minimum altitude is 1,000 ft over unpopulated areas and coastlines, and 2,000 ft over populated areas and sensitive areas including national parks, recreational seashores, and wildlife refuges. In addition, the guidelines and regulations promulgated by NMFS require helicopter pilots to maintain 1,000 ft of airspace over marine mammals.

Offshore Disturbances –Anchoring. The emplacement and anchoring/mooring of the MODU used for the exploration of oil and gas is known to impact the seafloor (USDOI, MMS, 1997a). Furthermore, the use of anchors are also known to cause seafloor disturbances within the area surrounding a given structure. Impacts on the seafloor potentially caused by the anchoring of rigs are of concern near sensitive areas within the Proposed Action area. Regulations and mitigating measures should protect the sensitive resources occurring within the Proposed Action area from potential bottom area disturbance.

The Sedco 712 rig has a mooring system designed for a maximum of 1,600 ft of water. The rig has eight Nippon model 4500LP 45,000-lbs anchors. The generic rig has eight 4,300' lengths of 3" chain on board and has access to an additional eight 1,000' segments of spare chain. A 3" regular die-locked and "oil rig" welded chain weighs 89.3 lbs./ ft in air and 77.6 lbs./ft in water.

The semi-submersible rig has two hulls upon which it floats while being towed to the designated location. At the designated location, the hulls are flooded with seawater to submerge them to a depth a little below the water's surface to its drilling position. Anchors will be deployed in their predetermined locations and then tested for proper tension. Typically, the anchor is loaded onto the boat, which then motors away from the rig. As the boat travels toward the anchor location, chain is released to the required length. At a position roughly half way from the rig, the workboat begins to lower the anchor on a work wire while continuing towards the final anchor location. Finally, the anchor is lowered to the seafloor and the appropriate amount of tension is placed on the chain. Surveyors will take the final location fix.

If the anchors do not hold a pretension determined by mooring calculations, tandem or "piggyback" anchors can be used. This is done by attaching the pendant line to the anchor shackle of another anchor and deploying it in a manner similar to the original anchor.

Offshore Disturbances –Space-use Conflicts. During OCS operations, the area occupied by the MODU, anchor cables, and safety zones is unavailable to commercial fishermen. The exploratory drilling rig will spend approximately 68-92 days on site.

Offshore Disturbances –Aesthetic Interference. Drilling rigs placed within sight of coastal beaches, parks, residences, and vacation lodging could cause some disruption of an unencumbered view of the marine seascape seaward of the coastline. Impacts to visual resources result from the presence of the MODU within an area that is in view of the public.

Offshore Disturbances –Abandoned Bottom Debris. Bottom debris is herein defined as material resting on the seabed (such as cable, tools, pipe, drums, and structural parts of platforms, as well as objects made of plastic, aluminum, wood, etc.) that is accidentally lost by workers from drillships. Varying quantities of ferromagnetic bottom debris may be lost per operation.

OPERATIONAL DISCHARGES OFFSHORE

The major operational wastes generated during offshore oil and gas activities include drilling fluids and cuttings. Other major wastes generated by the offshore oil and gas industry include the following: from drilling - waste chemicals, fracturing and acidifying fluids, and well completion fluids; deck drainage, and miscellaneous well fluids (cement, BOP fluid); and from other sources - sanitary and domestic wastes, gas and oil processing wastes, ballast water, storage displacement water, and miscellaneous minor discharges. All the effluents will be regulated by the new General National Pollutant Discharge Elimination System (NPDES) permit (EPA, 2000a). The limitations under this permit cover a wide range of parameters including, toxicity, metals, oil and grease, chlorine, and sheens, foam and floating solids.

Drilling Muds and Cuttings. Drilling mud is essentially water with a few basic components added to it to increase the fluid density. Drilling mud is used in the well bore to move drill cuttings to the surface, control formation pressure, maintain borehole stability, prevent formation damage, and cool and lubricate the drill bit and drill pipe.

Generic drilling fluid composition is anticipated to be in accordance with the NPDES General Permit currently in preparation by the EPA. The NPDES permit limitations do not allow for discharge of free oil, oil-based muds, or diesel oil. At this time, it is not possible to describe the precise characteristics of the drilling muds to be used. However, it appears that the drilling mud will most likely be water based. Generic drilling muds typically used to drill wells similar to those proposed here are listed in each project description (Point Sal and Purisima Point: page 4-5; Bonito: page 2-21; and Gato Canyon: pages 4-3 through 4-4). Drilling mud may be discharged intermittently during drilling and disposed of in bulk upon completion of the drilling program. If oil or synthetic based muds are used they will not be permitted to be discharged.

Drill cuttings are fragmented rock material ranging from clay to pebbles in size and are composed of shale, siltstone, sand, limestone/dolomite and approximately one percent drilling mud. Oil contaminated drill cuttings are proposed be transported to shore via supply boat for disposal at a state approved disposal site. Oil-free and cleaned drill cuttings will be disposed of in accordance with the NPDES permit requirements. Cuttings discharge volumes will be monitored and reported to the EPA.

Air Emissions. The major impact agents for air emissions expected from the proposed activities are emissions from equipment associated with exploratory drilling operations (main and crane engines) and emissions from crew/supply vessels and helicopter support for the drilling operations.

Emissions resulting from the proposed projects may have a potential to increase concentrations of air pollutants onshore. The primary regulated pollutants of concern in Santa Barbara County are oxides of nitrogen (NOx) and reactive organic compounds (ROC). Both NOx and ROC are considered precursors to ozone (O_3) formation, for which Santa Barbara County is presently in nonattainment. The major pollutant of concern associated with projects of this type and duration are NOx emissions due to the extensive use of propulsion and stationary combustion equipment.

Noise. Noise associated with the Proposed Action could result from operations related to the offshore drilling rig and service-vessel traffic (e.g., support boats and helicopters). Noise generated from these activities can be transmitted through both air and water, and may be continuous or transient. Offshore drilling 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 sources. Noise from the proposed OCS activities may affect resources near the activities. The level of underwater sound depends on receiver depth and altitude, aspect, and strength of the noise source. The time during which a passing airborne or surface sound source can be received underwater is increased in shallow water by multiple reflections.

Four to five delineation wells would be drilled as a result of the Proposed Action. Drilling operations often produce noise that includes strong tonal components at low frequencies, including infrasonic frequencies in at least some cases. Drilling noise from conventional metal-legged structures and semisubmersibles is not particularly intense and is strongest at low frequencies, averaging 5 Hz and 10-500 Hz, respectively (Richardson et al., 1995). Drillships are apparently noisier than semisubmersibles (Richardson et al., 1995). Sound and vibration paths to the water are through the hull of a drillship.

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. 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. A total of 264 helicopter trips are projected to occur as a result of the Proposed Action.

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. Sounds from support boats range from 400 to 7,000 Hz at 120-160 dB (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, which would usually be greater offshore. A total of 840 (approximately 2 per day) service-vessel trips are projected to occur as a result of the Proposed Action.

Test Fluids. Fluids from delineation well testing operations will be stored in a barge brought to the site by tug and moored with the semi-submersible drilling unit. The objective is to transfer, safely and efficiently, the test fluids to a barge that is equipped, capable, and of the appropriate size and draft for safely entering ports along the California coast.

A tug and barge system will be used to transport oil produced when testing the delineation wells. Under the Oil Pollution Act of 1990 requirements, barges are required to be double hulled. The barge design and systems would be in compliance with Coast Guard regulations. Test fluids will be transported by barge to the Long Beach/Los Angeles Harbor Complex or Point Hueneme where it will be transferred to an approved refinery, used oil-handling facility, or permitted hazardous waste handling and disposal contractor.

The offloading system would offload approximately 200 to 7,500 barrels per day (depending on the unit) to a barge moored to the semi-submersible. The maximum capacity of the barge would be 40,000-50,000 bbls.

5.1.2 CUMULATIVE ANALYSES

The CEQ handbook entitled "Considering Cumulative Effects under the National Environmental Policy Act" (CEQ, 1997) provides the following guidance:

> NEPA documents should only consider those past, present, and future actions that incrementally contribute to the cumulative effects on resources affected by the proposed action. Actions affecting other resources, or with cumulatively insignificant effects on the target resources, do not add to the value of the analysis.

Therefore, the cumulative impact analysis for the proposed delineation drilling will focus on those resources where the proposed action contributes to the cumulative effects.

However, in response to concerns raised in the initial scoping stages for this document, MMS and the Department agreed to prepare an additional analysis outside the traditional NEPA cumulative analysis. In July 1999, MMS made a commitment to the Governor of California to prepare an additional analysis. Also, in a November 12, 1999, response to Sara J. Wan, Chair of the California Coastal Commission, the then-Secretary of the Interior committed to providing a disclosure of the "additional exploration and development activities that the lessees are hoping to pursue, so that authorities and the interested public will have full disclosure of the proposed actions in question." This is in addition to "completion of an environmental analysis of the potential impacts associated with the proposed activity, including a cumulative analysis that takes into account changed circumstances that have occurred since the original plan approvals." This is the reason for the broader (in geographic and temporal terms), cumulative analysis included in section 6 as well as the traditional cumulative analysis of the Proposed Action through the residual effects of the delineation drilling activities provided in this section.

5.1.2.1 IMPACT-PRODUCING FACTORS OF THE CUMULATIVE CASE (2002-2006)

This section identifies impact-producing factors (IPF's) that are associated with the potential development of those of the 36 undeveloped leases that may be developed from existing platforms (for example, Cavern Point, Rocky Point, and Sword Units) and any potential future development of existing leases during the 2002-2006 timeframe (for example Tranquillon Ridge Unit). As discussed in section 5.1.1.1, exploring for, producing, and transporting hydrocarbon resources that could be developed require a complex and interrelated series of operations. The IPF's involving the proposed action will not be restated here. However, the effects from those and any cumulative activities are considered and discussed in each resource section (5.2.1 through 5.2.24).

Impact-producing factors for past and present activities are discussed in Section 4.0.1. Table 5.1.1.1-1 shows the IPF's that are projected to occur due to the proposal (Delineation Drilling). The list below gives the projects and activities which the analysts used to ascertain the potential for cumulative impacts over the 2002-2006 timeframe.

- Geological and Geophysical Surveys
- Development and Production activities (includes the installation of jackets, topsides, pipelines, and drilling. Production activities include bringing the oil and gas to the surface, handling of oil and gas on the platform and sending the oil and gas to shore).
- Vessel and Helicopter Support Activities
- Produced Water
- Site Characterization Surveys for OCS Development
- Shallow Hazards Surveys
- Subsurface Investigation and Testing
- Extended reach drilling
- Pipeline installation and abandonment
- Oil spills
- Crude Oil Tankering
- Fiber Optic Data Transmission Cables
- State Tidelands Projects
- Spill Remediation
- Point and Nonpoint Source Discharges
- Commercial Fishing Activities
- Military Operations and Commercial Space Launches

Section 4.0.1 presents a detailed discussion of these factors for Past and Present activities and Section 5 discusses those factors as they relate to reasonable foreseeable and future activities.

5.1.2.2 REASONABLY FORESEEABLE ACTIVITIES

The projects described in this section include Federal OCS oil and gas projects, State Tidelands oil and gas projects, and other energy and non-energy activities (Military Activities, Commercial Fishing Activities, Crude Oil Tankering, etc.). All of the projects described are located in the vicinity of the Santa Barbara Channel and Santa Maria Basin offshore Santa Barbara County, Ventura County, and San Luis Obispo County. It should be noted that information on many of these projects is limited because they are in the preliminary stages of development.

There are two categories of Reasonably Foreseeable activities:

First are activities that are ongoing and expected to continue through the period of delineation drilling, 2002-2006.

Second are oil and gas activities that may begin during the period of delineation drilling, 2002-2006.

ONGOING ACTIVITIES

ANTICIPATED FUTURE ACTIVITIES ON EXISTING LEASES

Section 4.0.1 describes past and present offshore oil and gas activities in State and Federal waters. Original recoverable reserves and peak production from State and Federal offshore facilities is shown in figure 4.0.1-1. Production on existing State and Federal offshore facilities peaked in approximately 1969 and 1995 respectively and we assume production will continue to decline.

Additional production from new wells would slow the decline of production and is expected to occur over the life of the existing facilities. Table 5.1.2.2-1 shows the number of wells expected to be drilled by field from existing Federal platforms. No new production wells are expected on State Platforms with the exception of Platform Holly (see State Tidelands below). Discharge volumes are expected to be at or below the levels identified in table 4.0.1-7. Helicopter and vessel support is assumed to be at or below the levels identified in table 4.0.1-5.

Operational impacts associated with the development and production of oil and gas resources from these existing facilities have been fully analyzed, mitigated and permitted by applicable Federal, State and local authorities.

The risk of an oil spill from the existing OCS facilities has previously been individually and cumulatively analyzed and reviewed (section 5.1.3). Oil spill

Table5.1.2.2-1. Federal offshore oil and gas wells expected to be drilled from existing platforms by field.

Platform	Operator	Location [1]	Field	Wells drilled 2001-2006	Wells drilled 2007-Decommissioning
Edith	Nuevo	Huntington Beach	Beta	1	1
Ellen	Aera				
Elly [2]					
Eureka					
Gail	Venoco	Port Hueneme	Sockeye	2	1
Grace	Venoco	Mandalay	Santa Clara	0	0
Gilda	Nuevo			0	0
Gina	Nuevo	Port Hueneme	Hueneme	1	1
Hermosa	Arguello, Inc.	Point Arguello	Pt Arguello	6	6
Harvest					
Hildago					
Habitat	Nuevo	Carpinteria	Pitas Point	2	2
Hillhouse	Nuevo	Summerland	Dos Cuadras	2	1
A					
B					
C					
Henry	Nuevo	Carpinteria	Carpinteria	0	0
Hogan	POOI	Carpinteria	Carpinteria	5	5
Houchin					
Heritage	Exxon	SYU	Sacate	3	3
Heritage			Pescado	0	0
Harmony			Hondo	3	3
Hondo					
Irene	Torch	Point Pedernales	Point Pedernales	1	1

[1] Number refers to location on Figure POCS Region with Fields
[2] Platform Elly is an offshore processing facility to process production from Platforms E11en, Edith, and Eureka.

response planning as required by MMS has been implemented and is currently in place. Oil spill prevention and response efforts offshore California are coordinated between the MMS and the California Office of Spill Prevention and Response. Among other measures, this coordination provides for the sharing of technical expertise in drilling, production, pollution prevention, and other related areas of offshore operations and safety.

There are no scheduled or anticipated oil and gas lease sales scheduled or anticipated in Federal or State waters. Therefore, with no new leasing, once the development of the 36 undeveloped leases occurs (see section 6.1.3), no additional new production platforms would be installed.

DECOMMISSIONING

Over the next 28 years all existing oil and gas platforms in Federal and State waters are expected to be removed (table 4.0.1-5). Some decommissioning has already occurred. The Offshore Storage and Treatment Vessel and Single Anchor Leg Mooring was removed from the Santa Ynez Unit in Federal waters in 1994 and Platforms Hazel, Heidi, Hilda, and Hope were removed from State waters in 1996. No decommissioning projects are expected to occur during delineation drilling (2002-2003).

CRUDE OIL TANKERING

Oil spills resulting from vessel collisions and other marine transportation-related accidents have the potential to cause significant impacts on the marine, coastal, and human environments, and contribute to cumulative environmental impacts. Marine transportation of Alaskan and foreign-import oil is an activity that occurs offshore California. Table 4.0.1-8 shows volume and number of oil tankers offshore California visiting Ports of San Francisco and of Los Angeles/ Long Beach and El Segundo. In 2000, 877 oil tankers visited the ports of Los Angeles/Long Beach and El Segundo. Of these tankers, 192 were United States flagged oil tankers and 685 were foreign flagged oil tankers (pers. Comm., Reed Crispino, Marine Exchange, March, 2001).

The long-term oil supply outlook for California remains one of declining in-State and Alaska supplies leading to increasing dependence on foreign oil sources, according to the California Energy Commission (CEC) (1999). Since 1989, California refineries have received about half of Alaska's total production. If this trend remains unchanged into the 20-year future, then supply volumes from Alaska to California would decline by 61 percent from current levels. Although it is possible that Alaska production could increase with the opening of new areas for development, no decisions have yet been made. In 1998, the foreign component of California's oil supply represented 16 percent of total supply - triple the amount in 1992 (CEC, 1999).

California refineries receive about half of their total oil supplies by marine tankers. As California petroleum product demand increases and in-State crude oil supplies decline, marine tanker deliveries will increase. Based on the CEC estimates, the rate of import growth varies between 2 to 3 percent per year, while the total demand increases at 1 percent per year (CEC, 1999).

The CEC (1999) estimates that import of 168 to 257 million more bbls per year are expected by 2017 based on a very gradual decline in California in-state supply. The volume of 168 million bbls translates into the equivalent of about 220 more oil tanker deliveries to California ports per year in 2017, based on the use of medium class size tankers (about 120, 000 dead weight tons). The 257 million barrel estimate means 337 more tanker deliveries per year, about one per day.

MILITARY OPERATIONS AND COMMERCIAL SPACE LAUNCHES

The Point Arguello Unit and Rocky Point Unit leases are located in the Naval Air Warfare Center Weapons Division (NAWCWD) Point Mugu Sea Range (PMSR). The PMSR covers a 36,000 square-mile area offshore San Luis Obispo, Santa Barbara, Ventura, Los Angeles, Orange, and San Diego Counties. The PMSR currently supports test and evaluation of sea, land, and air weapons systems as well as various categories of training activities. The NAWCWD has recently proposed to expand operations in the PMSR and has prepared a Draft Environmental Impact Statement/ Oversea Environmental Impact Statement for the proposal (U.S. Navy, 2000), which provides a detailed discussion of the operations conducted in the PMSR. The operations include missile testing, and training exercises including fleet, amphibious, and special warfare training. The PMSR has been operated by the Department of the Navy for more than 50 years

The Point Sal, Purisima Point, and Bonito Units are also in the vicinity and operational area of the Western Space and Missile Center (WSMC) at Vandenburg Air Force Base. Space vehicles launched at WSMC fly over various sectors of the project area. During such overflights, the area beneath the flight path may be subject to hazards resulting from falling debris and jettisoned components; but such events are extremely rare.

To minimize potential hazards and conflicts with military operations, the MMS has placed stipulations on the OCS leases in the project area. The stipulations control vessel traffic in designated areas, include "hold-harmless" requirements, and reserve the right of the United States to suspend offshore operations temporarily for national security reasons. Prior to a vehicle launch, provisions for control of air and marine traffic, stabilization of platform operations, and for personnel shelter and evacuation measures are coordinated by the WSMC, U.S. Coast Guard, MMS, and the platform operators. These measures have proven to be effective in minimizing hazards and conflicts.

COMMERCIAL FISHING ACTIVITIES

Commercial fisheries in the Southern California Bight (SCB) and Santa Maria Basin (SMB) date back to the mid-nineteenth century. Commercial fishing occurs at various locations off the coast of southern and central California. The nearshore waters along the coast from Los Angeles to Monterey counties and the waters just off the Channel Islands contain giant kelp beds that provide habitats for numerous species of commercially important fish and shellfish species. The majority of fish are caught within these areas.

Fishes in the SCB and SMB support important commercial and recreational fisheries; more than 100 species appear in the catches. The commercial landings at ports within the southern and central California account for about 4 percent of the total U.S. catch (approximately 2.7×10^9 kg, or 6×10^9 lb). Los Angeles area ports rank among the top 10 ports in the United States in quantity and value of commercial catch. Recreational fishermen in the SCB and SMB land about 60 percent of the total recreational catch in California. Fishermen on private and commercial passenger vessels account for more than 80 percent of the recreational catch. Recreational landings in the SCB and SMB account for about 5 percent of the total recreational landings in the continental United States

About 64 commercial fish and shellfish species are fished using up to 15 gear types, the most common of which are trawl, drift and set nets, purse seines, traps, and hook-and-line gear. Troll gear, harpoons, and diving are also common in certain areas of the SCB and SMB. Many fishers of the area do not fish for just one species, or use only one gear-type. Most switch fisheries during any given year depending on market demand, prices, harvest regulations, weather conditions, and fish availability. There are twelve major ports between San Diego and Point Sur, California which provide over 1,500 commercial fishing berths for the commercial fleet.

POINT SOURCE DISCHARGES

Only five Publicly-Owned Treatment Works (POTWs), or sewage treatment plants, discharge into either rivers or the Pacific Ocean in San Luis Obispo County. All the dischargers are small, according to EPA criteria (less than 25 million gallons discharged per day [mgd]). The six POTWs that discharge treated effluent to the Santa Barbara Channel are all small dischargers whose effluents are at a mixed primary/ secondary level of treatment (SCCWRP, 1996).

There are no other industrial wastewater discharges north of Point Conception. However, several power plants spaced along the coastlines of southern Santa Barbara county, and Ventura and northern Los Angeles Counties, do discharge heated water, and some chlorine is used to prevent fouling of heat exchangers.

NONPOINT SOURCE DISCHARGES

Urban and storm water runoff is the largest source of unregulated pollution to waterways and coastal areas of the United States. Locally, urban and storm runoff results in an increase in health risks to swimmers near storm drains, high concentrations of toxic metals in harbor and ocean sediments, and toxicity to aquatic life.

Storm water runoff from urban areas is a major source of pollution in the coastal waters of the SCB. Because runoff is an untreated pollution source, it contains high concentrations of contaminants and is a significant health hazard to humans. The SCB has multiple sources of nutrients, particulates and contaminants that discharge into the coastal ocean, including submerged outfalls, rivers, creeks, storm drains, atmospheric inputs, ocean dumping, and advection (Anderson et al., 1993).

The runoff systems in southern California are different from those in other areas because the flow is mostly confined to the winter months. Over the dry months, contaminants accumulate in the flow systems and are then released as pulses when winter storms strike. During winter storms, these drainage systems release most of the fresh water that flows into the coastal ocean.

GUADALUPE DILUENT SPILL AND REMEDIATION (1998 TO 2003)

The Guadalupe Oil Field site is located on the central coast of California approximately 15 miles south of San Luis Obispo. It is part of the Unocal LeRoy Lease which covers approximately 3,000 acres within the Nipomo Dunes system, a Secretary of the Interior-designated National Natural Landmark. The City of Guadalupe is located approximately three miles east of the site. Oil exploration and production began on the site with the Sand Dune Oil Company in October 1947. Unocal acquired the field in the early 1950s and continued to operate it until March 1990. At its peak, in 1988, there were 215 potential producing wells. The crude oil produced from the site was extremely viscous, with a density that causes the crude oil to behave like asphalt at ambient conditions. Unocal used several methods to enhance recovery of this heavy crude, including diluent mixing. The term diluent is derived from "dilute" and it refers to any additive (in this case a refined hydrocarbon blend piped into the field from the Santa Maria refinery) that is used to thin the crude. Over time, leaks that developed in the tanks and pipelines used to distribute it around the field, have led to serious contamination of the ground water below the site. Diluent has accumulated in 64 plumes (separate-phase) at the water table in the dune sand aquifer (about 10 to 130 feet down), with some plumes as much as 6 ft thick. Ground water passing through these areas, has become contaminated because some of the diluent dissolves (dissolved-phase) into the water and moves downstream with the ground water flow. This has resulted in ground water contamination beneath much of the site, with a flux towards the Pacific Ocean (to the west) and the Santa Maria River (to the south).

Remedial activities that have already taken place at the Guadalupe Oil Field under emergency permits issued by the County of San Luis Obispo or the Coastal Commission, include installation of a bentonite wall, beach excavation, installation of an High-density polyethylene (HDPE) wall, installation of a sheetpile wall, breaching of the Santa Maria River, installation of a polyvinylchloride (PVC) barrier wall, the removal of a sump, and other work. The technologies that are proposed will be used to either remove the diluent through excavation, bioremediation or pumping, or contain the diluent through physical or hydraulic barriers. Unocal has also proposed to abandon the site. This would include removal of most pipelines from the field, and all surface facility tanks, buildings and other miscellaneous equipment.

AVILA BEACH TANK FARM SPILL AND REMEDIATION (1997 TO 2002)

The community of Avila Beach, California is located on the northern end of San Luis Bay near Point San Luis. The Unocal Avila Terminal facility has been used for petroleum hydrocarbon storage and transfer activities since 1910. Petroleum products, including gasoline, diesel, fuel oil and crude oil, were pumped from the tank farm located on a bluff overlooking the town through a network of underground pipelines beneath Front Street to Avila Beach Drive and over the San Luis Obispo Creek bridge to the Unocal pier. In addition, gasoline and diesel fuel were pumped from tankers to the tank farm for distribution to county consumers. Unocal has spilled petroleum products including: gasoline, diesel and crude oil to soil and ground water beneath the beach, roads, commercial and residential properties of Avila Beach. These spills were reportedly caused by historic leaks from Unocal's pipelines and possibly the tank farm. Five pipelines are currently active, and another 5 to 10 lines are abandoned in place under Front Street. There are no known leaks in the active pipelines at this time. Unocal has not used these pipelines since the summer of 1996.

Unocal's remediation efforts are divided into four main areas of concern: the beach, which is divided into the west and east beaches; under Front Street; north of Front Street, and the intertidal plume. All four areas have underground gasoline-grade, diesel-grade, and crude or residual-grade hydrocarbon contamination. The hydrocarbons are found both above and below ground water, are attached to the soil grains (sand and silt) and within the soil pore spaces. Over 460 soil borings and 70 monitoring wells were taken and analyzed by various agencies. Levels of hydrocarbon contamination exceeded those found to cause cancer, reproductive toxicity, and other acute and chronic health problems.

Legal efforts on the part of local activist groups, joined by the California Attorney General's office, and the Regional Water Quality Control Board, the County of San Luis Obispo produced an agreement that will require Unocal to fully remediate the contamination and rebuild the town and economy of Avila Beach. Unocal's remediation project includes two general aspects: excavation of all petroleum contamination under the beach, Front Street, and all areas where contamination exceeds 100 parts per million, and excavation and removal of the petroleum, and replacement with new, clean soil and nutrients. Monitoring and sampling, including testing of groundwater four times a year will help ensure the project meets State standards.

FIBER OPTIC DATA TRANSMISSION CABLES

The timing of fiber optic cable installation is unknown, however the operations are expected to be conducted in the period 2001-2003.

Global West (Global Photon) Fiber Optic Cable Project

Global West is a proposed fiber optic telecommunications project that would link major metropolitan areas along the California coast using buried undersea cable. The cable would contain seven landfalls including San Francisco, Monterey Bay North, Monterey Bay South, San Luis Obispo, Santa Barbara, Manhattan Beach and San Diego. The currently proposed routing of this cable is through a portion of the Sword Unit.

MCI Worldcom Fiber Optic Cable Project

The MCI Worldcom fiber optic cable project is proposed to consist of five cables that will be landed at the Montana de Oro State Park landing site. These cables would land through new directional bore pipes constructed adjacent to the AT&T landing. Currently only three of the five cables would be installed, the remaining two to be installed once demand requires.

PAC Landing Corp (Tyco/Global Crossing) Fiber Optic Cable System

The proposed PAC Landing Corp fiber optic cable project entails the offshore landing of three cables and consolidation of cables into one line extending to a telecommunications switching facility located in the City of Grover Beach. The telecommunications facility has already been constructed. Three cables would be installed in State waters, two of which would be part of the Pacific Crossing Submarine Cable (PC-1) System and the third cable would be part of the Pan-American Crossing Submarine Cable System (PAC). The Grover Beach landing site would provide a connection for cable originating in Japan and proceeding to Washington State. The site would also be the Pacific origin of the PAC Cable System, which would proceed to Mexico from Grover Beach.

AT&T China-U.S. Cable E1 and China-U.S. Cable S7 Systems

The AT&T China/U.S. fiber optic cable project is proposed to consist of two cables that will be landed at the Montana de Oro State Park landing site. The two cables will be housed within the last remaining directional bore pipe constructed by AT&T in 1992. The China-U.S. Cable E1 cable is proposed to follow an alignment that is located north of the AT&T TPC-5 Segment T1 cable. The China-U.S. Cable S7 cable is proposed to follow an alignment located between the AT&T TPC-5 Segment T1 and AT&T HAW-5 cables. Installation of this system was scheduled to begin in 2000 but it is not known when the project will take place.

Oil And Gas Activities That May Begin During Delineation Drilling

The following oil and gas activities may begin during delineation drilling (2002-2003) and include Federal Offshore OCS Projects; Cavern Point Unit Exploration, development of some of the 36 undeveloped leases including Rocky Point Unit, Sword Unit, and Cavern Point Unit leases, Exploration Well Abandonment, OCS-P 0320 #2, Exploration Well Abandonment, OCS-P 0241 #2, and State Tidelands Projects; the Tranquillon Ridge Project, the South Elwood Project, the Cojo Point Project, and the Molino Gas Project.

FEDERAL OFFSHORE OCS PROJECTS

Cavern Point Unit Exploration: 2002-2003

Venoco Inc. (Venoco) is the current operator of the Cavern Point Unit. The unit includes Leases OCS-P 0210 and 0527 in the Santa Barbara Channel offshore Ventura County. The Cavern Point Unit is bounded by the Channel Islands National Marine Sanctuary on the south and the producing Santa Clara Unit on the north and east. Up to two exploratory wells are planned to be drilled into the unit from Platform Gail (Santa Clara Unit). Drilling, evaluating, and (if appropriate) abandoning the first well will occur during the third and fourth quarters of 2002 and take approximately 100 days. No construction of either offshore or onshore facilities is proposed. If the exploratory wells find hydrocarbons in the Cavern Point Unit, they will serve as the basis for planning and future evaluation of potential development. According to current scenarios, oil and gas would be transported from Platform Gail via existing pipeline to Platform Grace, then onshore to the Carpinteria facility. Gas also would be transported to shore via existing pipeline.

Rocky Point Unit Development (2002-2013)

Arguello Inc. is the current operator of the Rocky Point Unit. The Rocky Point Unit includes Leases OCS-P 0451, 0452, and 0453 in the southern Santa Maria Basin. Twenty development wells, 14 oil wells and 6 service wells, would be drilled from Platforms Harvest, Hermosa, and Hidalgo. Seven wells each would be drilled from Platforms Harvest and Hermosa and six from Platform Hidalgo. The wells would be extended-reach wells with horizontal displacements of 4.6-6.4 km (2.5-3.5 miles). Drilling each well would require 3 to 4 months beginning in 2002.

Oil would be dehydrated and stabilized on the platforms, then sent to the Gaviota facility via the PAPCO pipeline. At Gaviota, the oil would be metered and heated, stored temporarily in the Gaviota Terminal Company storage tanks, then transported via the All-American Pipeline to various refining destinations.

Rocky Point gas would be sweetened on the platforms and used 1) to generate electricity and heat for platform operations, 2) sent to shore to fuel the Gaviota co-generation units, and 3) injected into the Point Arguello Field, the Rocky Point Field or both.

Sword Unit Development (2002-2014)

Samedan Oil Company (Samedan) is the current operator of the Sword Unit. The Sword Unit includes leases OCS-P 0319, 0320, 0323, and 0323A. A portion of lease OCS-P 0323 has been relinquished and the remaining lease was redesignated 0323A to reflect the change. Eleven development wells, 10 oil wells and 1 service well would be drilled from Platform, Hermosa, OCS-P 0316. The wells would be extended-reach wells with horizontal displacements of 6.4-8.3 km (3.5-4.5 miles). Drilling each well would require 3 to 4 months beginning in 2002.

Oil would be dehydrated and stabilized on the platforms, then sent to the Gaviota facility via the PAPCO pipeline. At Gaviota, the oil would be metered and heated, stored temporarily in the Gaviota Terminal Company storage tanks, then transported via the All-American Pipeline to various refining destinations.

Sword gas would be sweetened on Platform Hermosa and used 1) to generate electricity and heat for platform operations, 2) sent to shore to fuel the Gaviota co-generation units, and 3) injected into the Point Arguello Field.

Cavern Point Unit Development (2003-2015)

The Cavern Point Unit includes Leases OCS-P 0210 and 0527 north of Santa Rosa Island in the Santa Barbara Channel. Eleven development wells, 10 oil wells and 1 service wells, would be drilled from Platform Gail. The wells would be extended-reach wells with horizontal displacements of 6.4-8.3 km (3.5-4.5 miles). Drilling each well would require 3 to 4 months beginning in 2003. The service well would be drilled into the Sockeye Field and would not be an extended reach well.

The oil and gas would be sent to the Carpenteria onshore processing facility via Platform Grace using existing pipelines. The gas sent to shore would be sour and that there would be limited processing offshore. The oil and gas would be processed using existing capacity. Produced water is injected or disposed overboard.

EXPLORATION WELL ABANDONMENT, OCS-P 0320 #2 (2003)

Well OCS-P 0320 #2 was drilled and temporarily abandoned in 1985. Samedan proposes to permanently abandon well OCS-P 0320 #2. The well would be abandoned using the Mobile Offshore Drilling Unit (MODU) used for delineation drilling after the delineation drilling operations have been completed.

Sequence of activities is as follows; 1) the MODU would anchor over the well, 2) the well would be entered and temporary plugs removed, 3) permanent cement plugs would be placed, 4) the wellhead and casing would be removed, and 5) anchors removed and the MODU moved offsite. Samedan estimates 11 days to conduct abandonment activities.

EXPLORATION WELL ABANDONMENT, OCS-P 0241 #2 (2003)

Torch Operating Company proposes to permanently abandon well OCS-P 0241 #2. The well was drilled and temporarily abandoned in 1968. The well would be abandoned using a MODU after delineation drilling have been completed.

Sequence of activities is as follows; 1) the MODU would anchor over the well, 2) the well would be entered and temporary plugs removed, 3) permanent cement plugs would be placed, 4) the wellhead and casing would be removed, and 5) anchors removed and the MODU moved offsite. It would likely take 11 days to conduct abandonment activities.

STATE TIDELANDS PROJECTS

Molino Gas Project (2001 and 2005)

Molino Energy Company gained approval for the project from the County of Santa Barbara in 1996. The project involves use of ERD technology from an onshore site to recover sweet gas reserves in offshore State Tidelands. The drilling site is located just east of the Gaviota facility. It was initially envisioned that the project could produce up to 60 MMcfd of sales quality sweet gas and up to 1,050 BPD of natural gas liquids (NGL)s over a project life of 20-25 years. The gas would be sold to SoCal Gas and transported directly into the transmission line. The NGLs would initially be trucked to the Gaviota facility and later shipped to the facility via a new pipeline. The ERD wells that have been drilled to date have not been successful and exploratory drilling ceased in 1998.

Benton Oil and Gas Company assumed all project responsibilities in 2001. Benton plans to drill 3-6 exploration wells between 2001 and 2005.

Cojo Point Project (2002-2003)

The County of Santa Barbara has received a preliminary application from Union Oil of California to proceed with the decommissioning of the marine terminal facility and associated oil storage tanks that are no longer in use at Cojo Point. Cojo Point is located along the northern margin of the Santa Barbara Channel, just east of Point Conception. Details regarding the project are not available at this time.

TRANQUILLON RIDGE PROJECT (2003-2030)

Nuevo Energy Company (Nuevo), is seeking approval to develop the Tranquillon Ridge area offshore Point Pedernales in the southern Santa Maria Basin from an existing OCS platform, Platform Irene. Platform Irene is located on Lease OCS P-0441, approximately 6 miles northwest of Point Pedernales. State and local agencies are preparing an Environmental Impact Report (EIR) on the proposed project. The California State Lands Commission's decision on the project will be contingent in part upon the EIR, and its decision to grant a State Tidelands lease for the project.

Current operations at Platform Irene include drilling and production of the Federal Point Pedernales Field, transportation of production via pipeline from offshore to onshore, and oil dehydration and gas processing at the Lompoc processing facility. One well from Platform Irene is producing from Tranquillon Ridge. Processed oil is transported by pipeline to refineries. Liquefied petroleum gas and NGLs are shipped by truck. The Lompoc facility is currently permitted to operate under a County of Santa Barbara FDP. The permitted production and processing capacities are 36,000 BPD oil and 15 MMcfd of gas.

The proposed Tranquillon Ridge Project would involve the drilling of up to 30 Extended Reach Drilling (ERD) wells (22 development wells and 8 utility and re-drills) from Platform Irene into State Tidelands. Total well drilling and completion times are anticipated to range between 60 and 120 days per well. Oil and gas produced by the proposed project would be transported to shore via the existing pipeline system to the Lompoc processing facility.

The Tranquillon Ridge project would extend over approximately 15 years. Nuevo estimates that the project will recover 180-200 MMbbl of oil and 40 Bcf of gas.

5.1.3. OIL SPILLS: RISK, MOVEMENT, AND RESPONSE

The purpose of this Section is to provide the reader with information regarding oil spill risk, movement of spilled oil on water, and the sources of petroleum hydrocarbons (PHC's) to the sea. Other topics discussed include, how oil changes when it is spilled on water, responses to oil spills, and how various organizations respond to oil spills and the tools they have available in the "response tool box".

5.1.3.1.OIL SPILL RISK ASSESSMENT

A major environmental concern with offshore oil and gas activities is the potential for oil spills and the resulting effects on biological resources, such as listed species. The largest oil spill in the Pacific OCS Region occurred in 1969, when a well blowout on Platform A off Santa Barbara spilled an estimated 80,000 bbl into the Channel (Van Horn et al., 1988). A number of preventive measures have been initiated since that time, including stringent regulations covering OCS operational and environmental safety, a rigorous MMS inspection program in the Pacific Region, continuous evaluation and improvement in OCS facilities' oil spill response, and the development of a highly organized oil spill response structure (Bornholdt and Lear, 1997). No spill of this magnitude has occurred anywhere on the U.S. OCS since 1969, and these measures make a reoccurrence a highly unlikely event.

Table 5.1.3.1-1 lists the hydrocarbon spills that occurred in the Pacific OCS Region from OCS oil and gas activities from 1969 through 1999. During that period, 843 oil spills were recorded. The total volume of oil spilled in the Region is dominated by the Santa Barbara spill. Since 1969, these spills have ranged in size from less than 1 to 163 bbl, for a total of slightly less than 830 bbl. For comparison, natural oil seeps at Coal Oil Point in the Santa Barbara Channel are estimated to discharge approximately 100-170 bbl of oil per day (Hornafius et al., 1999).

In the course of normal, day-to-day platform operations, occasional accidental discharges of hydrocarbons may occur. Such accidents are typically limited to discharges of quantities of less than 1 bbl of crude oil. As shown in table 5.1.3.1-1, 836 spills of less than 50 bbl (99 percent of the total) occurred on the Pacific OCS between 1971 and 1999, resulting in slightly less than 320 bbl of oil being discharged into the ocean. Due to the infrequency and small volumes of these accidental discharges, spills of less than 50 bbl are not considered to be a significant impact-producing agent for the majority of marine and coastal resources discussed in this document.

Larger oil spills may occur from well blowouts (if wells are free flowing), pipeline breaks, operational errors, or vessel-platform collisions. Only 5 of the 45 total spills (since 1969) of greater than 1 bbl measured 50 bbl or more in volume (table 5.1.3.1-1); the largest of these was the 163-bbl Platform Irene pipeline spill in September 1997.

5.1.3.1.1. ESTIMATED SPILL RISK FOR THE PROPOSAL

The proposal for delineation drilling of 4 to 5 wells involves minimal risks of an oil spill. Tables 5.1.3.1-2 and 5.1.3.1-3 indicate less than a 0.05 percent probability of one or more spills from delineation drilling (the lowest value calculated by MMS spill data). Oil spills during exploration or delineation drilling of wells from mobile drilling platforms are very rare events according to the MMS and Coast Guard data base. Wells drilled during the exploration and delineation phases of oil and gas activity tend to be drilled and plugged quickly with little exposure to the large volume of oil or gas processed through the well bores during production. In addition, special precautions are taken to stop the drilling at regular intervals to monitor well pressures at each production zone. The exploration and delineation well is plugged according to MMS regulations immediately after the well has been drilled and tested. Therefore the risk of a spill is considered to be minimal and poses almost no risk to the marine environment. Spills during delineation drilling for these proposed projects are not considered further in the spill risk assessment. However, the effects of three size classes of oil spills are analyzed in the cumulative section of this EIS and in the section below on the possible length of shoreline that could be oiled by each.

Barging of Well Testing Fluids. The Proposed Action involves the transport by barge of the fluids pumped from the four to five delineation wells to be drilled. These fluids are generally crude oil of various viscosities (depending upon the location and stratum being tested) combined with water present in most oil formations or other fluids injected into the well to allow thick crude oil to flow. The fluids are pumped from the mobile drilling vessel at intervals to test the flow rate of the well and then the wells are plugged according to MMS regulations at the end of the testing. Volumes of fluids associated with well testing for the proposed wells are less than approximately 50,000 bbl of combined oil and other fluids. Calculating the probability of a spill from the Proposed Action (based upon barging spill rates for coastal United States waters) yields an extremely low probability of < 0.05 percent for one or more spills. Therefore, oil spills of the testing fluids associated with the proposal are considered an extremely low risk and are not considered in the proposed project assessment.

5.1.3.1.2. ESTIMATED SPILL RISK FOR THE CUMULATIVE ANALYSIS

MMS has estimated the mean number of oil spills and probability of one or more spills for two spill size ranges (50 to 999 bbl; and greater than or equal to 1,000 bbl) that could occur as a result of reasonably foreseeable cumulative actions in the region of the proposal (tables 5.1.3.1-2 and 5.1.3.1-3). Based on a

Table 5.1.3.1-1. **Crude, diesel, or other hydrocarbon spills recorded in the Pacific OCS Region, for OCS oil and gas activities, 1969 through 1999 (volumes in barrels).**

	Less than or equal to 1 bbl		Greater than 1 bbl less than 50 bbl		Equal to or More than 50 bbl		Total	
Year	**No.**	**Volume**	**No.**	**Volume**	**No.**	**Volume**	**No.**	**Volume**
1969	0		0		2	80,900.0	2	80,900.0
1970	0		0		0		0	
1971	0		0		0		0	
1972	0		0		0		0	
1973	0		0		0		0	
1974	0		0		0		0	
1975	1	0.1	0		0		1	0.1
1976	3	1.1	1	2.0	0		4	3.1
1977	11	2.2	1	4.0	0		12	6.2
1978	4	1.2	0		0		4	1.2
1979	5	1.7	1	2.0	0		6	3.7
1980	11	4.9	2	7.0	0		13	11.9
1981	21	6.0	10	75.0	0		31	81.0
1982	24	3.2	1	3.0	0		25	6.2
1983	56	7.7	3	6.0	0		59	13.7
1984	65	4.7	3	36.0	0		68	40.7
1985	55	9.3	3	9.0	0		58	18.3
1986	39	5.5	3	12.0	0		42	17.5
1987	67	7.5	2	11.0	0		69	18.5
1988	47	3.7	1	2.0	0		48	5.7
1989	69	4.1	3	8.0	0		72	12.1
1990	43	3.6	0		1	100.0	44	103.6
1991	51	5.8	1	10.0	1	50.0	53	65.8
1992	39	1.2	0		0		39	1.2
1993	32	0.7	0		0		32	0.7
1994	18	0.4	2	33.0	1	50.0	21	83.4
1995	25	0.9	1	1.4	0		26	2.3
1996	39	0.9	1	5.0	1	150.0	41	155.9
1997	20	2.5	0		1	163.0	21	165.5
1998	29	1.0	0		0		29	1.0
1999	22	0.5	1	10.0	0		23	10.5
Totals	796	80.4	40	236.4	7	81,413.0	841	81,729.8

Table 5.1.3.1-2. Spill Risks 50 – 999 Barrels.

	Estimated Mean Number of spills: 50 - 999 bbls	**Probability of One or More Spills (%)**
Proposal (4-5 Delineation Wells) (2002-2006)	None	Less than 0.05
Cumulative w/o Proposed Action (2002-2006)		
• Existing Federal Oil and Gas Development	0.97	62.1
• Existing State Oil and Gas Development	0.25	23.2
• Proposed Federal (Rocky Pt, Cavern Pt., Sword) Oil and Gas Development	0.12	11.4
• Proposed State (Tranquillon Ridge) Oil and Gas Development	0.08	7.7
Total Risk (less Tankering)	1.42	75.9
• Alaskan and Foreign Tankering (Crude Oil)	NA[1]	99
Cumulative w/o 36 undeveloped leases (2002-2030)		
• Existing Federal Oil and Gas Development	2.96	94.9
• Existing State Oil and Gas Development	0.49	38.8
• Proposed State (Tranquillon Ridge) Oil and Gas Development	1.55	78.8
Total Risk (less Tankering)	5.0	99
• Alaskan and Foreign Tankering (Crude Oil)[1]	NA	99
Development of 36 leases (incl. Rocky Pt., Cavern Pt., Sword)		
• Most likely case (0.558 Bbls)	4.35	98.8
• High Case (0.660 Bbls)	5.115	99

[1] Spills less than 1000 barrels not recorded in database.

Table 5.1.3.1-3. Spill Risks Greater than 1000 Barrels.[1]

	Estimated Mean Number of spills: >1,000 bbl	**Probability of One or More Spills (%)**
Proposal (4-5 Delineation Wells) (2002-2006)	None	Less than 0.05
Cumulative w/o Proposed Action (2002-2006)		
• Existing Federal Oil and Gas Development	0.173	15.9
• Existing State Oil and Gas Development	0.044	4.4
• Proposed Federal (Rocky Pt, Cavern Pt., Sword)) Oil and Gas Development	0.021	2.1
• Proposed State (Tranquillon Ridge) Oil and Gas Development	0.014	1.4
Total Risk (less Tankering)	0.252	23.3
• Alaskan and Foreign Tankering (Crude Oil)	0.99	63.9
Cumulative w/o 36 undeveloped leases (2002-2030)		
• Existing Federal Oil and Gas Development	0.53	41.2%
• Existing State Oil and Gas Development	0.087	8.4
• Proposed State (Tranquillon Ridge) Oil and Gas Development	0.276	24.2
Total Risk (less Tankering)	0.893	59.1
• Alaskan and Foreign Tankering (Crude Oil)	5.742	99
Development of 36 leases (incl. Rocky Pt., Cavern Pt., Sword)		
• Most likely case (0.558 Bbls)	0.774	53.9
• High Case (0.660 Bbls)	0.911	59.8

[1]Spills of 10,000 bbl or greater are a subset of spills of 1,000 bbl or greater.

larger spill data set from the U.S. OCS (MMS, unpubl. data) and cumulative oil production figures, these estimated mean number of spills and the probability of one or more spills were calculated using the method of Anderson and LaBelle (1994). In addition, table 5.1-1 (appendix 5.1) lists the estimated risks of spills 50 to 999 bbls and greater than or equal to 1,000 bbls for individual units and fields. Oil spill estimates are based on the estimated production of oil over the life of the proposed projects, with subsea pipeline transport of hydrocarbons to shore.

The mean size of an oil spill from Alaskan and foreign tankers is statistically larger than the mean spill size from a platform or pipeline. In the discussion of spill sizes below, the largest spill size analyzed (22,800 barrels) is from a hypothetical tanker spill and is based upon the mean tanker spill size in the database.

Estimated Most Likely Spill Size

An effort also was made to estimate the most likely size of a spill. The MMS's U.S. Oil Spill Database (C. Anderson, unpubl. data) includes Pacific and Gulf of Mexico OCS spills of greater than 1.5 bbl recorded between 1971 and 1999. The database contains platform and pipeline spills, but no barge or tanker spills. Of the 2,125 total spills in the database, 106 are in the range of 50-999 bbl. The mean volume of these spills is 158.6 bbl, and 75 percent (79) are of less than 200 bbl. More than 95 percent (101) are of less than 500 bbl. Given these data and the experience in the Pacific Region over the last 30 years and nationally over the past 15 years, it seems reasonable to assume that such a spill would probably be less than 200 bbl, and almost certainly less than 500 bbl in volume.

The most likely maximum size of a major oil spill from future development – the maximum most probable discharge – 2,000 barrels, is based upon the volumes of oil in various pipelines and vessels (i.e., tanks and other containers on platforms) as described in the U. S. Coast Guard Area Contingency Plans for oil spill response (e.g., USCG, 1999). This is the maximum volume of oil calculated to be spilled from a break in the longest Point Arguello Unit pipeline, the Hermosa to shore pipeline (A. D. Little, 2001).

In addition to possible spills from oil and gas platforms and pipelines, spills can originate from Alaskan and foreign tankers and other shipping activities in the area. It is obvious from the estimated mean number of spills and the probability of one or more spills given in the tables above, that the greatest risk of an oil spill in the area comes form these tanker and shipping vessels. The mean (average) spill size derived from the U.S. Coast Guard data base for accidents in U.S. Waters is 22,800 barrels for the period 1985 – 1999 and the median spill size is 5,600 barrels.

This EIS analyzes potential environmental effects of three sizes of spills based upon the discussion above: 200 barrels, 2,000 barrels, and 22,800 barrels. These spill sizes correspond to the <u>most likely</u> spill size from the proposed and cumulative oil and gas activities; the <u>maximum reasonably foreseeable</u> spill size from the proposed and cumulative oil and gas activities; and the <u>mean spill</u> size for a tanker spill.

The level of impacts from spills will depend on many factors, including the type, rate, and volume of oil spilled and the weather and oceanographic conditions at the time of the spill. These parameters would determine the quantity of oil that is dispersed into the water column; the degree of weathering, evaporation, and dispersion of the oil before it contacts a shoreline; the actual amount, concentration, and composition of the oil at the time of shoreline or habitat contact; and a measure of the toxicity of the oil. The estimate of the maximum reasonably foreseeable volume of an oil spill (2,000 bbls see paragraph above) from oil and gas operations used in this analysis suggests that oil is unlikely to remain in the water (beyond dispersed, weathered tar balls) in appreciable amounts for more than ten days. Therefore, a ten-day oil-spill trajectory analysis was used to establish the primary geographic boundaries for the EIS. In addition, primary environmental impacts are based upon an oil spill reaching a resource within ten days after the spill.

ESTIMATED OF LENGTH OF AFFECTED COASTLINE

Estimating the length of coastline that may be affected by an oil spill is necessary to determine potential impacts by oil spills on resources considered in the EIS. The following discussion provides information on the empirical methods used to determine this. Using the multiple regression equations developed by Glenn Ford (Ford, 1985; Ford and Bonnell, 1987), an attempt was made to estimate the length of coastline that might be contacted by spill sizes indicated in the section above.

The equation used is: $\log(\mathrm{COAST}) = -0.8357 + 0.4525 \log(\mathrm{VOL}) + 0.0128 (\mathrm{LAT}) + \mathrm{ZS}$

-where COAST is the length of coastline contacted in kilometers,

-VOL is the spill volume in barrels,

-LAT is the spill latitude and

-Z is a correction factor applied to S the standard deviation of the residual variation.

This version of the equation explained 64.8 percent of the total variance. Inclusion of additional variables for wave height (WAVE), wind speed (WIND), or sea surface temperature (TEMP) did not significantly improve the fit of the equation. Ford (1985) felt that the variable LAT obtained at least some of its predictive power from its high intercorrelation with the WAVE, WIND, and TEMP variables. It should be noted that this model does not account for weathering, clean-up efforts, or any other complicating factors.

Example

If VOL = 2,000 bbl and LAT = 34.5 (the approximate latitude of Point Conception), then:

log (COAST) = -0.8357 + 0.4525 log (2,000) + 0.0128 (34.5) = 1.09

Hence, COAST = 12.3 kilometers. This represents the median length of coastline that spills of this volume would be expected to contact.

Using the same methodology, the maximum number of kilometers of coastline affected was estimated for three spill sizes and five levels of probability (table 5..1.3.1-4):

Thus, for the 200-bbl spill, only 5 percent of the spills would be expected to contact more than about 18 km (11.2 mi) of shoreline, 25 percent more than 8 km (5.0), and so on.

The estimates above for the length of shoreline that may be affected by a hypothetical oil spill are based upon a statistical analysis (multiple linear regression of spill size, length of shore oiled, and various environmental factors) of historical spills. These estimates are used by EIS analysts in conjunction with the results of the oil spill trajectory analyses (section 5.1.3.2, below) and the probability of spills of three size categories to discuss the potential impacts to marine resources. In the case of the largest spill category, 22,800 bbl mean spill size from tankering, the length of coastline and probability of shore contact may be overestimated. This is because oil tankers have voluntarily agreed to transit the coast at a minimum distance of 80.6 km (50 mi) for the past few years. Therefore, a spill from a tanker would most likely begin at a point distant from land. This is not reflected well in the existing data base of oil spills (thus biasing the shoreline length analyses) and probability of shoreline contact (because the oil spill trajectory analyses do not take into account oil weathering or other processes which act to reduce the amount of oil with time.)

Table 5.1.3.1-4. The probability of an oil spill contacting the coastline for various spill sizes and the length of coastline contacted.

Spill Size (bbl)	Probability of Contacting a Length of Coastline (%)	Length of Coastline Contacted (km)
200	95	1.04
	75	2.45
	50	4.43
	25	8.01
	5	18.9
2000	95	2.84
	75	6.76
	50	12.3
	25	22.4
	5	52.5
22,800	95	8.87
	75	20.89
	50	37.84
	25	68.4
	5	161.4

5.1.3.2 CONDITIONAL OIL SPILL RISK ANALYSIS

The probabilities presented in this analysis are in the conditional context that assumes an oil spill has occurred for the cumulative impact analysis. As stated above, no oil spills are assumed for the proposed delineation wells. However, for the cumulative analysis, we assume a 200 bbl oil spill to be the most likely case, and a 2000 bbl spill to be the maximum most probable discharge (see section above). We then address the issue of resources impacted if either of these scenarios do occur. To do this we look at two oil spill models and a surface current data set assuming a spill did occur. The three analyses described below provide estimates of oil spill trajectory and potential landfall. They include MMS's Oil Spill Risk Assessment (OSRA) Model calculation, an analysis of 306 free-floating surface drifter trajectories deployed by the Scripps Institution of Oceanography (Scripps), and the National Oceanic and Atmospheric Administration's (NOAA) "General NOAA Oil Modeling Environment" (GNOME) oil spill model. These three analyses indicate a similar area of possible oil contact to the south. When the winds are relaxed for an extended period of time, the drifter data shows that oil can be transported north along the coast. Use of these three analyses is a conservative approach to identifying the possible area of oil contact for the Pacific Region. The summary of results of this composite analysis is presented in this section. A more detailed presentation of the three separate analyses can be found in appendix 5.2 Conditional Oil Spill Risk Analysis.

The MMS OSRA Model analysis calculates numerous trajectories from pre-designated launch points by combining observed wind data with seasonally-averaged ocean current fields and applying a local wind effect to estimate the movement of oil over the surface layer of the water. The seasonally averaged current fields were provided by Scripps Institution of Oceanography (Scripps) and are based on several years of current meter and free-floating drifter data. Shoreline segments are partitioned into their USGS Quad maps, and probabilities of oil spill landfall for each shoreline segment are calculated. Offshore boxes giving probabilities of oil spill intrusion into their defined region are presented as part of a more comprehensive regional OSRA Model analysis contained in OCS Report MMS2000-057. Oil spill size or weathering (evaporated or dispersed) are not modeled in the OSRA analysis to allow for a maximum estimate of spill travel times and extent. Results for OSRA Model runs for the nine launch points listed in table 5.1.3.2-1 are included as part of the composite analysis presented in subsection 5.1.3.2.2 Oil Spill Trajectory Analyses.

The free-floating surface drifters were designed to follow the surface current (top 1 meter of the water column) and not to track or mimic an oil spill. However, the drifter analysis provides good information on surface currents, which are one of the major component determining spill movement, by describing statistics on actual trajectories of free-floating surface drifters. When the winds are relaxed, or in areas where local winds do not dominate, drifter trajectories could mimic the movement of an oil spill. For example, the drifter trajectories indicate that when the winds are relaxed, oil could be transported north along the coast. A description of the surface drifters and their deployment strategy is found along with a more detailed presentation of comprehensive drifter analysis in appendix 5.2 Conditional Oil Spill Risk Analysis, appendix subsection 5.2.3. Surface Drifter and GNOME Model Data and Analysis. The drifter analyses consists of analyses done specifically for the Lion Rock and San Ynez Units, and drifter analyses previously written for the Rocky Point and Cavern Point projects that apply well to the Point Arguello and Santa Clara Units, and Platform Hillhouse located in the northeastern Santa Barbara Channel. These latter drifter analyses are entitled: “Surface Drifter Analysis for the Rocky Point Unit Project Oil Spill Risk Assessment” and “Surface Drifter Analysis for the Cavern Point Unit Project Oil Spill Risk Assessment.” The drifter analyses completed for the Lion Rock and San Ynez Units were done for each of the three flow regimes characteristic of the Santa Barbara Channel-Santa Maria Basin (SBC-SMB) area. The free-floating drifter launch points are illustrated in figure 5.1.3.2-1. Examples of drifter plots for each of these three flow regimes can be found in figures 4.4-12a and b, 4.4-13a and b, and 4.4-14a and b. The drifter analyses previously written for the Rocky Point and Cavern Point projects were done according to seasonal months coinciding with those of the MMS OSRA Model analysis performed for those same projects.

The GNOME analysis was run according to the environmental forcing and criteria for winds and currents described in Section 4.4 Physical Oceanography, subsections 4.4.4.4 to 4.4.4.7. Calculations were performed for 200 and 2000 bbl spills at each of the nine launch points listed in table 5.1.3.2-1. Over 180 GNOME model runs were conducted. As is the case for part of the drifter analysis, GNOME model results were generated for the three major flow regimes described in Section 4.4: Relaxation, Convergent, and Upwelling. Scripps provided synoptic current fields for the GNOME model that were derived by averaging surface current observations by dominant flow regime rather than over time, such as the seasonal averages. This means that the GNOME Model output for each run gives trajectory results specific to one of the three characteristic flow regimes that occur in the SBC-SMB area. The synoptic current fields for these three flow regimes were based on five years of concurrent moored current data and free-floating drifter trajectories. Synoptic current fields, used by the GNOME model, for the relaxation, convergent, and upwelling current flow

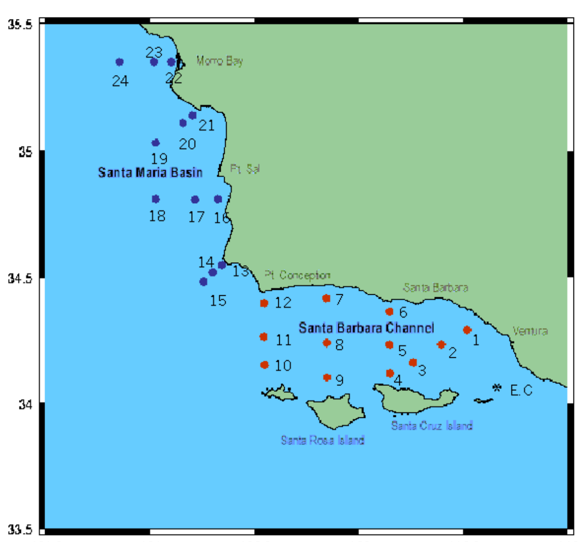
Table 5.1.3.2-1. Launch point locations for GNOME and OSRA analyses.

Lease	Launch Pt.	Unit	Latitude N	Longitude W
0409	SMB A	Lion Rock Unit	34 56’ 07.80”	120 49’ 55.60”
0315	Harvest	Point Arguello Unit	34 28 08.89	120 40 50.94
0316	Hermosa	Point Arguello Unit	34 27 19.83	120 38 47.00
0450	Hidalgo	Point Arguello Unit	34 29 42.05	120 42 08.24
0188	Hondo	Santa Ynez Unit	34 23 26.63	120 07 13.91
0190	Harmony	Santa Ynez Unit	34 22 36.03	120 10 03.09
0182	Heritage	Santa Ynez Unit	34 21 01.41	120 16 45.06
0205	Gail	Santa Clara Unit	34 07 30.29	119 24 00.78
0240	Hillhouse	Northeastern Channel	34 19 52.84	119 36 11.69

regimes are illustrated in figures 5.1.3.2-2 through 5.1.3.2-4 respectively. Further description of these flow regimes can be found in Section 4.4 Physical Oceanography. Results of GNOME model runs are given in terms of estimated barrels of oil beached, location of beaching, barrels floating, barrels weathered (evaporated or dispersed), or barrels moving out of the model domain. Run scenarios are conducted for 200 and 2000 bbl spills over 3 and 10 days. For these more detailed results, please see appendix 5.2 Conditional Oil Spill Risk Analysis.

The OSRA Model calculations, the GNOME Model results, and the drifter data provide important insights concerning potential areas affected by an oil spill occurring in the area of proposed activity. The MMS OSRA model gives us seasonal results over a large domain covering the entire affected area. The GNOME model provides oil spill trajectory results based on current flow regimes strongly characteristic of the area. One of these flow regimes is very likely to be occurring during an actual spill event. So the GNOME Model gives us trajectories based on calculations using mean wind and current fields established from analyzing 6 years of data, but over a smaller model domain. The drifter analysis is based on actual field observations and provides information on surface current variability to be considered with the computer-generated results calculated for the SBC-SMB area by the GNOME and OSRA Models. Where the local winds do not dominate, the drifter data like the two models, provide reasonably good estimates of the locations of oil spill contacts over the entire affected area. This composite of the three analyses present a more complete picture of what may result from an oil spill event occurring in the area of proposed activity where the current and wind regimes are very complex.

Figure 5.1.3.2-1. Launch point locations for free-floating surface drifter deployments



5.1.3.2.1 SUMMARY DISCUSSION

As stated in the introduction, there is only a remote probability that an oil spill of 200 bbl or greater

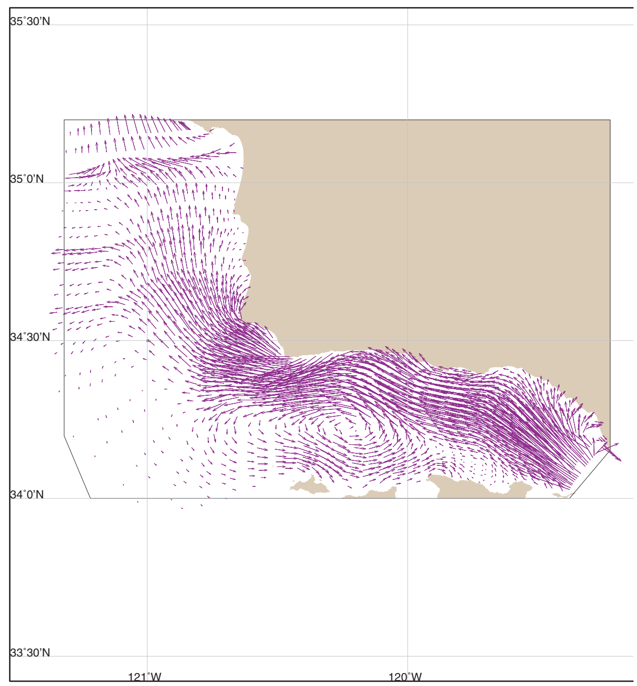


Figure 5.1.3.2-2. Synoptic representation of the relaxation current flow regime characteristic of the Santa Barbara Channel-Santa Maria Basin area prepared by Scripps scientists and used by NOAA in their GNOME Model.

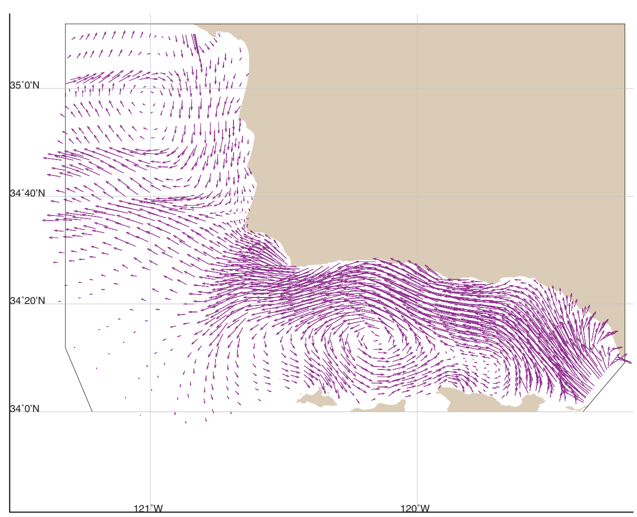


Figure 5.1.3.2-3. Synoptic representation of the convergent current flow regime characteristic of the Santa Barbara Channel-Santa Maria Basin area prepared by Scripps scientists and used by NOAA in their GNOME Model.

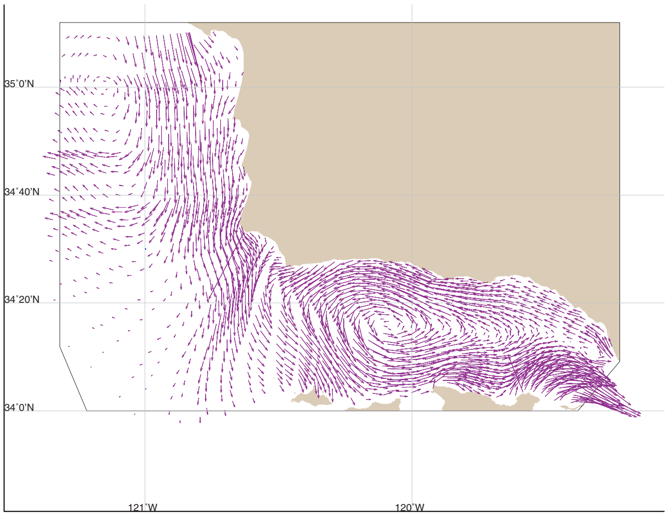


Figure 5.1.3.2-4. Synoptic representation of the upwelling current flow regime characteristic of the Santa Barbara Channel-Santa Maria Basin area prepared by Scripps scientists and used by NOAA in their GNOME Model.

will occur for the proposed delineation well projects. The probabilities presented in the Oil Spill Trajectory Analysis section are in the conditional context that a significant oil spill has occurred for the cumulative impact analysis.

For the cumulative impact analysis, the geographical limits of the potentially affected area are defined by the farthest locations on the California coastline that could be contacted by oil within 10 days of a spill event occurring in the area of proposed developed activities. The drifter analysis indicates that during an extended period of relaxed winds, the extreme northern boundary of the potentially affected area is Pt. Lobos on the central California coast. The drifters also indicate that during this same wind condition, the northern limits of the area where contact with a spill is "most likely" is Ragged Point, which is further south on the central California coast. Both the drifter and the OSRA Model analyses indicate that both the extreme and "most likely" southern boundaries of the potentially affected area coincide at Santa Catalina Island in the Southern California Bight, and Palos Verdes on the Southern California mainland.

The analysis indicates that spilled oil from activity as far away as the eastern-most Unit in the SBC, the Santa Clara Unit, may contact the shoreline as far north as Point San Luis on the central California coast. The central California coast is found most likely to be contacted by oil from a spill occurring during a relaxation flow regime. The relaxation flow regime occurs 27 percent of the time during a year (Section 4.4 Physical Oceanography).

The composite analysis indicates that oil from a spill occurring anywhere in the SBC may contact either the SBC mainland, the Channel Islands, or both. The Channel Islands have the highest probability of contact, according to both models and the drifter data, with San Miguel and Santa Rosa Islands being the most likely islands contacted by spilled oil. The area between Goleta Point and Gaviota seems to be the most likely area along the SBC mainland to experience contact with spilled oil. Oil spill contact with SBC shorelines is most likely during a convergent or upwelling flow regime. These flow regimes occur 31 and 35 percent of the time respectively during the year. This is because there is strong re-circulation within the SBC associated with these two flow regimes. During a convergent flow regime, a spill in the northern area of the SBC tends to affect the western-most Islands: San Miguel and Santa Rosa a little more than the others. During an upwelling flow regime, a spill in the same area will tend to affect the eastern most Islands: Santa Cruz and Anacapa a little more than their western neighbors. Purisima Point to Point Arguello on the central California coast and San Miguel and Santa Rosa Islands in the SBC are the most likely areas of shoreline contact with oil spilled in the Lions Rock Unit during an upwelling event.

Spills occurring in the eastern portion of the SBC (in the Santa Clara Unit) will likely move south and southeast out of the SBC by way of the eastern SBC entrance, and into the area offshore of the Santa Monica Bay-Redondo Beach coastlines in the Southern California Bight. The composite analysis indicates that at times Santa Catalina Island, and to a lesser extent San Nicolas Island, may be contacted by a spill occurring in the SBC. This is largely during the spring when the upwelling flow regime occurs most prominently. Additionally, the composite analysis indicates that a spill in the SBC could affect the southern California shoreline as far south as Palos Verdes. The probability that spilled oil will continue south of Santa Catalina Island within a 10 day time frame is remote.

5.1.3.2.2 OIL SPILL TRAJECTORY ANALYSES

The geographical limits of the potentially affected area are defined by the farthest locations on the California coastline that could be contacted with oil within 10 days of a spill event occurring in the area of proposed developed activities. For cumulative impact concerns, our analysis indicates that the extreme northern boundary of the affected area is Pt. Lobos on the central California coastline and the extreme southern boundary is Santa Catalina Island in the Southern California Bight, and Palos Verdes on the Southern

California mainland. The limits of the area where contact with a spill is "most likely" is Ragged Point on the central California coast to Palos Verdes and Santa Catalina in the Southern California Bight. Figures 5.1.3.2-5 to 5.1.3.2-6 depict the potentially affected area.

The aggregate of the three analyses provides both time-dependent and scenario-driven results. The different analyses present results by either 3-month season or by characteristic synoptic flow regime. The frequency and relative dominance of all three flow regimes differ for each calendar month. Table 5.1.3.2-2 presents this information determined from 5 years of continuous synoptic current data. The table shows OSRA model seasons defined by calendar month along with the dominant flow regime and relative frequency of occurrence of all flow regimes for each particular month. There is a mix of all three flow regimes for each month, and therefore for each 3-month OSRA season. There is no season where one flow regime is exclusive.

The frequencies that relaxation, upwelling, or convergent flow events occur during winter, as defined above, are 38, 32, and 30 percent of the time respectively. Since the relaxation flow event is only slightly more dominant than the other two, results for all three flow regimes will be reported for the winter season.

The dominant flow regime during the spring, as defined above, is upwelling with a 66 percent frequency of occurrence. Results for this flow regime will be reported for the spring season.

The dominant flow regimes during the summer, as defined above, are convergent and upwelling with a 37 and 35 percent frequency of occurrence respectively. Results for these two flow regimes will be reported for the summer season.

The dominant flow regimes during the fall, as defined above, are relaxation and convergent with a 44 and 40 percent frequency of occurrence, respectively. Results for these two flow regimes will be reported for the fall season.

The Drifter, GNOME, and OSRA analyses results are summarized in the composite analysis below for each of the Units listed in table 5.1.3.2-1. Complete OSRA Model results are contained in OCS Report MMS2000-057. Examples of OSRA Model output in GIS format for hypothetical oil spills during all 4 seasons at Platforms Hidalgo and Gail are presented in figures 5.1.3.2-11 through figures 5.1.3.2-14 and figures 5.1.3.2-19 through 5.1.3.2-22, respectively. Detailed tabular results of the Drifter and GNOME analyses are contained in appendix 5.2 Conditional Oil Spill Risk. Examples of GNOME Model output for 2000 bbl spills during for all 3 flow regimes at platforms Hidalgo and Gail are illustrated in figures 5.1.3.2-7 through 5.1.3.2-10 and figures 5.1.3.2-15 through 5.1.3.2-18, respectively. Two illustrations for the relaxation flow event, one during a 4 m/s NW wind and one during a 4 m/s SW wind, are included in these illustrations for both platforms.

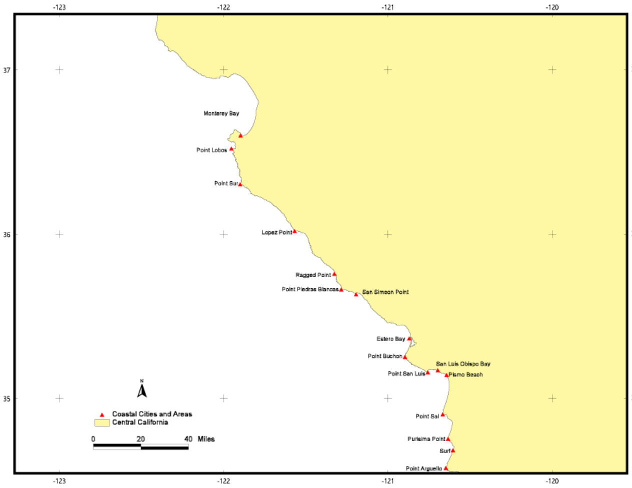


Figure 5.1.3.2-5. Coastal cities and areas of the central California coastline that are part of the affected area.

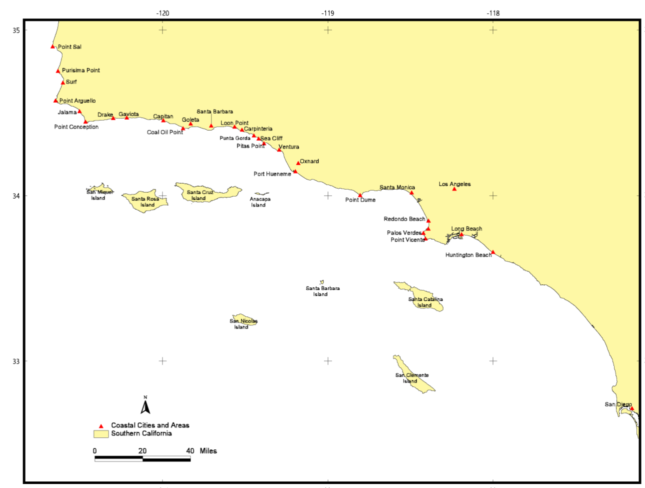


Figure 5.1.3.2-6. Coastal cities and areas of the southern California coastline that are part of the affected area.

Results from the two models and the drifter data present numbers that are estimates, and therefore the reader is advised to view them as such. OCS Report MMS 2000-057 refers to OSRA Model generated probabilities of contact from hypothetical oil spill trajectories to land segments as estimates. NOAA defines results from GNOME model runs, that lists numbers of barrels "Evaporated and Disbursed," "Beached," "Off Map"(out of the model domain), and "floating", as a "Best Guess." So the GNOME Model results should not be viewed as precise numbers. Drifter analysis

Table 5.1.3.2-2. Comparison of seasonal months with the frequency and relative dominance of the three characteristic flow regimes per calendar month (Section 4.4 Physical Oceanography).

OSRA Season	Calendar Month	Dominant Flow Regime	Days of Continuous Current Data	Upwelling (%)	Convergent (%)	Relaxation (%)	Other (%)
Winter	December	Relaxation	146.5	9.22	34.30	49.32	7.17
Winter	January	Relaxation	155.0	30.16	26.13	37.42	6.29
Winter	February	Upwelling	141.0	51.77	26.06	19.15	3.01
Spring	March	Upwelling	154.5	53.07	33.98	2.43	10.52
Spring	April	Upwelling	150.0	86.00	8.83	2.67	2.50
Spring	May	Upwelling	155.0	47.74	32.10	14.68	5.50
Summer	June	Upwelling	150.0	44.67	32.83	17.33	5.17
Summer	July	Relaxation	155.0	22.42	32.10	32.90	12.58
Summer	August	Convergent	155.0	28.87	35.32	27.58	8,23
Fall	September	Relaxation	152.0	20.07	36.35	37.99	5.59
Fall	October	Convergent	155.0	19.03	41.94	32.74	6.29
Fall	November	Relaxation	135.0	5.37	33.52	53.15	7.96

results are from a relatively small data set from a statistical point of view. Therefore the reader is advised to view the percentages attached to drifter data as estimates.

LION ROCK UNIT ANALYSES

The Lion Rock Unit is the northernmost location of the 36 undeveloped leases. Location SMB-A (table 5.1.3.2-1) serves as the launch point for the GNOME and OSRA Model analyses. Drifter launch points 17, 18, 19, and 20 (figure 5.1.3.2-1), located offshore Purisima Pt. to Avila Beach in the SMB, were selected as the launch points for the Lion Rock Unit drifter analysis. Seventy-two trajectories for drifters launched from these locations were analyzed to estimate the possible trajectory of oil during three different flow regimes characteristic to the SMB area. Appendix table 5.2-4 summarizes this data.

During the relaxation flow regime the composite analysis indicates that both computed and observed trajectories are generally directed to the north going with the prevailing poleward current. During the upwelling and convergent flow regimes, trajectories generally head south either well offshore west of the SBC toward the equator or through the SBC and into the south portion of the Southern California Bight.

The information provided below list areas that could be contacted by a spill, without consideration for the actual chance of the spill occurring or contacting an area. If a spill were to occur the chance of shoreline contact and volume of oil contacting shoreline will vary greatly with a number of factors including: location of spill, volume and characteristics of spilled oil, wind and current conditions, sea conditions, and the success of the oil spill containment and response operations.

WINTER (DECEMBER – FEBRUARY):

The composite results of all three analyses indicates that land contact during the winter season can occur in any of the following areas:

- The Santa Maria Basin as far south as Pt. Arguello to as far north as Pt. Lobos, specifically: Pt. Lobos, San Simeon Pt. to Estero Bay, Pt. Buchon, and Pismo Beach, and Pismo Beach to Pt. Sal to Purisima Pt. to Surf and Pt Arguello,
- The Santa Barbara Channel at Pt. Conception, San Miguel Island and Santa Rosa Island, and
- The south Southern California Bight at Santa Monica Bay and San Clemente Island.

SPRING (MARCH – MAY):

The composite results of all three analyses indicates that land contact during the spring season can occur in any of the following areas:

- The Santa Maria Bight at Estero Bay, Pt. Buchon, Pismo Beach, Pt. Sal, Purisima Pt. to Surf and Pt. Arguello,
- The Santa Barbara Channel at Pt. Conception and from the western end of San Miguel Island to Santa Rosa Island, and
- The south Southern California Bight at Santa Monica Bay and San Clemente Island.

SUMMER (JUNE – AUGUST):

The composite results of all three analyses indicates that land contact during the spring season can occur in any of the following areas:

- The Santa Maria Basin at Estero Bay, Pt. Buchon, Pismo Beach, Pt. Sal, Purisima Pt., Surf, and Pt. Arguello,
- The Santa Barbara Channel at Pt. Conception and San Miguel and Santa Rosa Islands, and
- The south Southern California Bight at Santa Monica Bay and San Clemente Island.

FALL (SEPTEMBER – NOVEMBER):

The composite results of all three analyses indicates that land contact during the spring season can occur in any of the following areas:

- The Santa Maria Basin as at Pt. Lobos, Pt. Buchon, Pismo Beach, Pt. Sal, Purisima Pt., Surf, and Pt. Arguello, and
- The Santa Barbara Channel at Pt. Conception and San Miguel Island.

POINT ARGUELLO UNIT ANALYSES.

The Point Arguello Unit is the general location of Platforms Hidalgo, Harvest, and Hermosa which serve as launch points for the GNOME and OSRA Model analyses. Examples of GNOME Model output for 2000 bbl spills during all 3 flow regimes at platforms Hidalgo are illustrated in figures 5.1.3.2-7 through 5.1.3.2-10. Examples of OSRA Model output in GIS format for hypothetical oil spills during all 4 seasons at Platform Hidalgo are presented in figures 5.1.3.2-11 through 5.1.3.2-14. Drifter launch points 12, 13, 14, and 15 (figure 5.1.3.2-1), located offshore Pt. Arguello and Pt. Conception in the transition area between the SMB and the SBC, were selected as the launch points for the Point Arguello Unit drifter analysis. Drifter analysis results reflect the documented trajectories of 65 free-floating surface drifters deployed at these launch points. This data is discussed in more detail in the paper: "Surface Drifter Analysis for the Rocky Point Unit Project Oil Spill Risk Assessment" contained in appendix 5.2 Conditional Oil Spill Risk Analysis, appendix exhibit 5.2-1.

During the relaxation flow regime the composite analysis indicates that trajectories are generally directed to the north along the central California coat along with the prevailing poleward current. During the upwelling flow regime the trajectories generally head either south-southeast through the western island passes of the SBC or south, offshore of the western SBC, toward the equator. During the convergent flow regime, trajectories generally head west, well offshore the SBC.

The information provided below list areas that could be contacted by a spill, without consideration for the actual chance of the spill occurring or contacting an area. If a spill were to occur the chance of shoreline contact and volume of oil contacting shoreline will vary greatly with a number of factors including: location of spill, volume and characteristics of spilled oil, wind and current conditions, sea conditions, and the success of the oil spill containment and response operations.

WINTER (DECEMBER – FEBRUARY):

The composite results of all three analyses indicates that land contact during the winter season can occur in any of the following areas:

- The Santa Maria Basin at Ragged Pt., Pt. Piedras Blancas, Pt. Estero, Pt. Buchon, Pt. San Luis, Pismo Beach, Pt. Sal, Purisima Pt., Surf, Pt. Arguello, and Jalama.
- The Santa Barbara Channel at Pt. Conception and San Miguel, Santa Rosa, Santa Cruz, and Anacapa Islands.
- The south Southern California Bight at Santa Catalina Island

SPRING (MARCH – MAY):

The composite results of all three analyses indicates that land contact during the spring season can occur in any of the following areas:

- The Santa Maria Basin at Pt. Arguello,
- The Santa Barbara Channel at Pt. Conception and the San Miguel, Santa Rosa, Santa Cruz, and Anacapa Islands, and South Santa Rosa Island, and
- The south Southern California Bight at Palos-Verdes, and Santa Catalina and San Nicholas Islands.

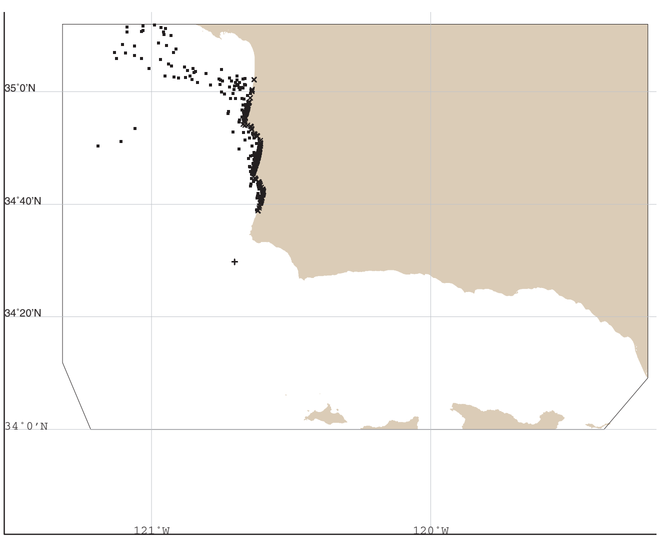


Figure 5.1.3.2-7. GNOME Modeled 10 day, 2000 bbl oil spill scenario for platform Hidalgo (depicted by "+"), located offshore of Point Arguello, during a relaxation flow regime and a 4 m/s NW wind. GNOME model output indicates that of 2000 bbl released: 358 bbl beach, 950 bbl evaporate or are dispersed, 318 bbl are still floating, and 374 bbl have moved out of the model domain heading north in the Santa Maria Basin.

SUMMER (JUNE – AUGUST):

The composite results of all three analyses indicates that land contact during the summer season can occur in any of the following areas:

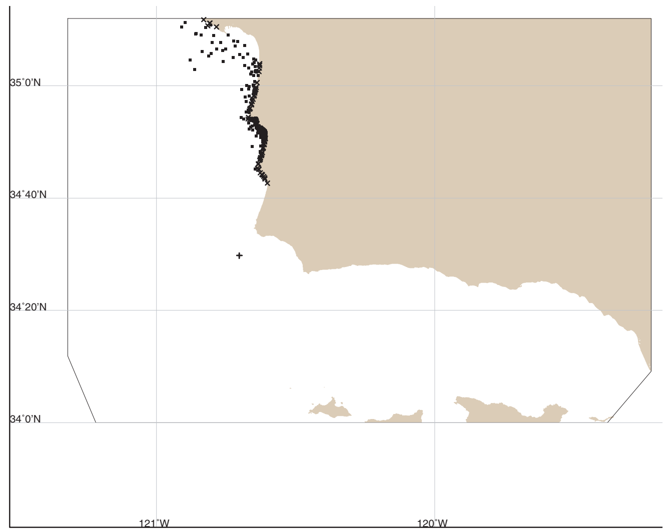


Figure 5.1.3.2-8. GNOME Modeled 10 day, 2000 bbl oil spill scenario for platform Hidalgo (depicted by "+"), located offshore of Point Arguello, during a relaxation flow regime and a 4 m/s SW wind. GNOME model output indicates that of 2000 bbl released: 296 bbl beach, 942 bbl evaporate or are dispersed, 220 bbl are still floating, and 542 bbl have moved out of the model domain heading north in the Santa Maria Basin.

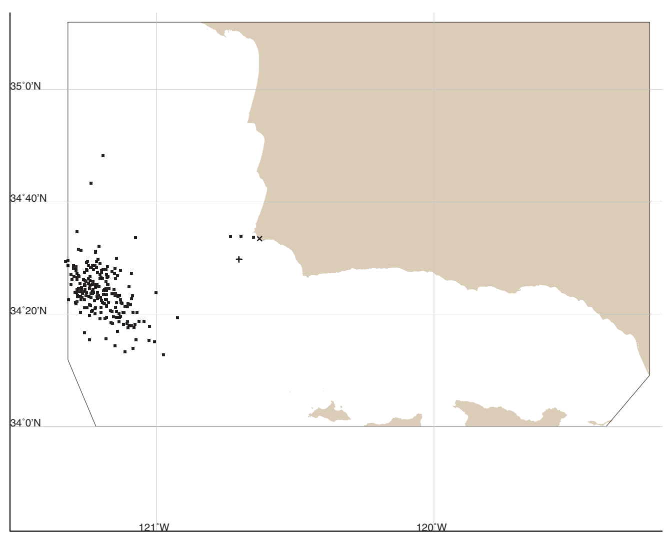


Figure 5.1.3.2-9. GNOME Modeled 10 day, 2000 bbl oil spill scenario for platform Hidalgo (depicted by "+"), located offshore of Point Arguello, during a convergent flow regime and a 7m/s NW wind. GNOME model output indicates that of 2000 bbl released: 2 bbl beach, 946 bbl evaporate or are dispersed, 446 bbl are still floating, and 606 bbl have moved out of the model domain heading west out of the Santa Maria Basin.

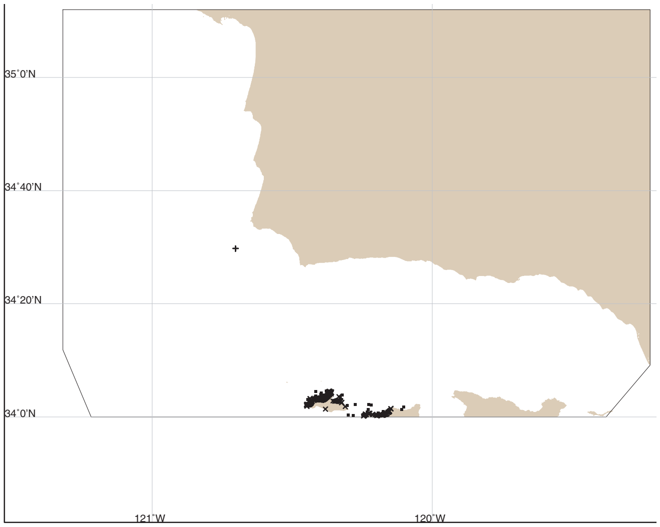


Figure 5.1.3.2-10. GNOME Modeled 10 day, 2000 bbl oil spill scenario for platform Hidalgo (depicted by "+"), located offshore of Point Arguello, during an upwelling flow regime and a 8m/s NW wind. GNOME model output indicates that of 2000 bbl released: 596 bbl beach, 974 bbl evaporate or are dispersed, 128 bbl are still floating, and 302 bbl have moved out of the model domain heading south to southeast offshore of the Southern California Bight

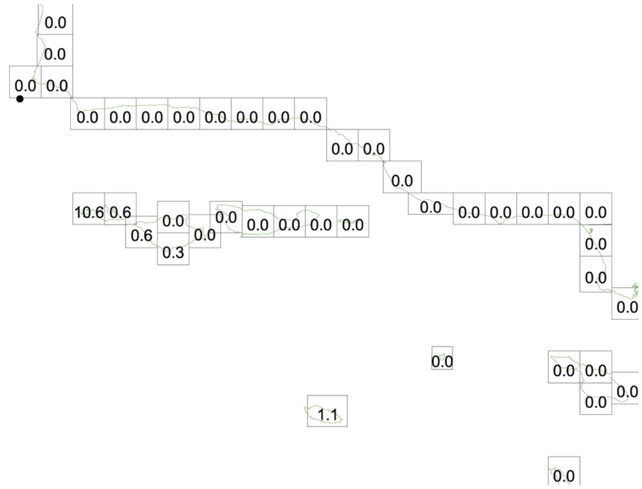


Figure 5.1.3.2-12. MMS OSRA Model output for a 10 day event at platform Hidalgo during the spring season. The boxes are U. S. Geological Survey 7.5 Minute Quad series maps presenting the calculated probabilities (in percentages) of oil contact with the shoreline contained within each map.

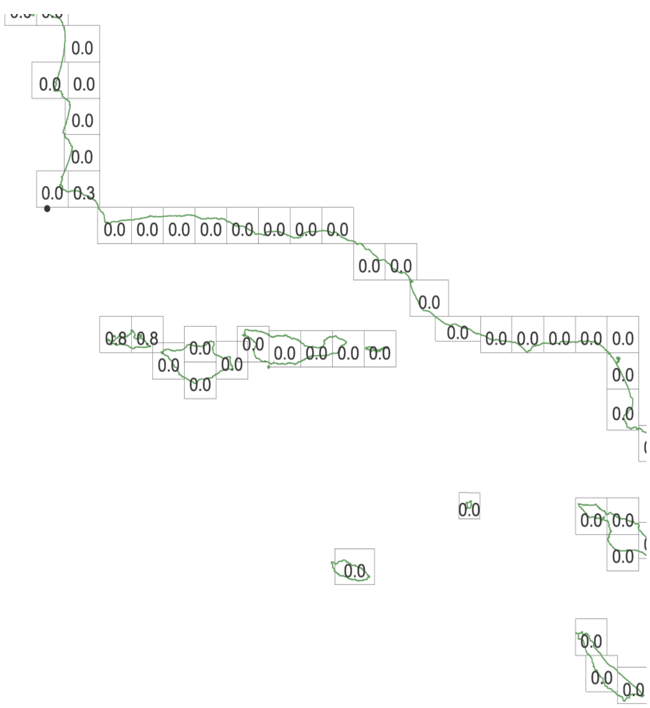


Figure 5.1.3.2-11. MMS OSRA Model output for a 10 day event at platform Hidalgo during the winter season. The boxes are U. S. Geological Survey 7.5 Minute Quad series maps presenting the calculated probabilities (in percentages) of oil contact with the shoreline contained within each map.

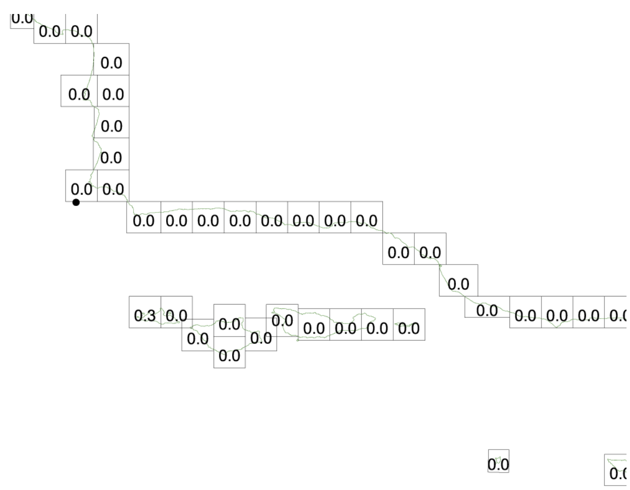


Figure 5.1.3.2-13. MMS OSRA Model output for a 10 day event at platform Hidalgo during the summer season. The boxes are U. S. Geological Survey 7.5 Minute Quad series maps presenting the calculated probabilities (in percentages) of oil contact with the shoreline contained within each map.

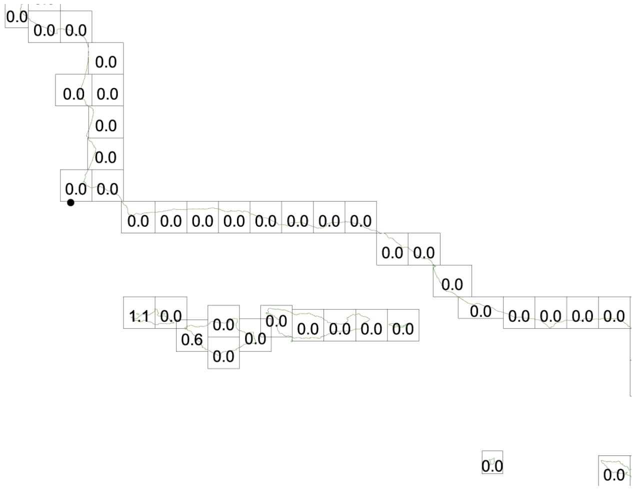


Figure 5.1.3.2-14. MMS OSRA Model output for a 10 day event at platform Hidalgo during the fall season. The boxes are U. S. Geological Survey 7.5 Minute Quad series maps presenting the calculated probabilities (in percentages) of oil contact with the shoreline contained within each

- The Santa Maria Basin at Pt. Sal and Pt. Arguello,
- The Santa Barbara Channel at Pt. Conception and the San Miguel, Santa Rosa, Santa Cruz, and Anacapa Islands, and
- The south Southern California Bight at Palos Verdes and Santa Catalina Island.

FALL (SEPTEMBER – NOVEMBER):

The composite results of all three analyses indicates that land contact during the fall season can occur in any of the following areas:

- The Santa Maria Basin at Pt. Piedras Blancas, Pt. Estero, Pt. Buchon, Pt. San Luis, Pismo Beach, Pt. Sal, Purisima Pt., Surf, Pt. Arguello, and Jalama,
- The Santa Barbara Channel at Pt.Conception, and the San Miguel and Santa Rosa Islands, and
- The south Southern California Bight at Palos-Verdes.

SANTA YNEZ UNIT ANALYSES.

The San Ynez Unit is the general location of Platforms Heritage, Harmony, and Hondo which serve as launch points for the GNOME and OSRA Model analyses. Drifter launch points 5, 6, 7, and 8 (figure 5.1.3.2-1), located in the northwest and north central area of the SBC, were selected as the launch points for the San Ynez Unit drifter analysis. Drifter analysis results reflect the documented trajectories of 104 free-floating surface drifters deployed at these launch points. Appendix table 5.2-3 summarizes this data.

During the relaxation flow regime the composite analysis indicates that trajectories are primarily directed to the west along the northern shoreline of the SBC and out its western entrance where one to three events occur: (1) they turn the corner at Point Arguello where they proceed north along the central California coast, (2) they continue west further offshore, and/or (3) they turn south to southeast toward the Baja or the San Miguel, Santa Rosa, and possibly the Santa Cruz Islands. Other trajectories will head west, south west, or southeast toward the western Channel Islands.

During the convergent flow regime the composite analysis indicates that primarily the trajectories initially go west along the SBC mainland, but then become entrained in the cyclonic gyre in the western end of the SBC where they eventually re-enter the SBC heading in a southwesterly direction. The few trajectories that escape the western SBC will either go north along the central California coast, continue west toward the central Pacific, or go southwest toward the Baja. The majority of trajectories remain in the SBC within the cyclonic gyre or turn Southeast toward the three western-most Channel Islands.

During the upwelling flow regime the composite analysis indicates that most trajectories become entrained in the SBC's western cyclonic gyre, but then continue in a southeasterly direction heading toward either the easternmost two Channel Islands or out of the eastern SBC entrance along the Southern California Bight coastline.

The information provided below list areas that could be contacted by a spill, without consideration for the actual chance of the spill occurring or contacting an area. If a spill were to occur the chance of shoreline contact and volume of oil contacting shoreline will vary greatly with a number of factors including: location of spill, volume and characteristics of spilled oil, wind and current conditions, sea conditions, and the success of the oil spill containment and response operations.

WINTER (DECEMBER – FEBRUARY):

The composite results of all three analyses indicates that during the winter season land contact may occur in any of the following areas:

- The Santa Maria Basin at Pt. Lobos, Lopez Pt., Pt. Sur North, Pt. Sur, Cambria, Pt. San Luis, Pismo Beach, Pt. Sal, Purisima Pt., Santa Maria River mouth, Surf, and Pt. Arguello,

- The Santa Barbara Channel at Pt. Conception, Drake, Capitan, Gaviota, Coal Oil Pt., Santa Barbara, Sea Cliff, Ventura, Oxnard, Pt. Mugu, and San Miguel, Santa Rosa, Santa Cruz, and Anacapa Islands, and
- The south Southern California Bight at Santa Monica, Palos Verdes, and San Nicholas Island.

SPRING (MARCH – MAY):

The composite results of all three analyses indicates that during the spring season land contact may occur in any of the following areas:

- The Santa Maria Basin at Pismo Beach,
- The Santa Barbara Channel at Santa Barbara, Coal Oil Pt., Ventura, Oxnard, Pt. Mugu along the mainland, and San Miguel, Santa Rosa, Santa Cruz, and Anacapa Islands, and
- The south Southern California Bight at Santa Monica and Palos Verdes.

SUMMER (JUNE – AUGUST):

The composite results of all three analyses indicates that during the summer season land contact may occur in any of the following areas:

- The Santa Maria Basin at Pismo Beach and Purisima Pt.,
- The Santa Barbara Channel at Drake, Capitan, Gaviota, Coal Oil Pt., Santa Barbara, Sea Cliff, Ventura, Oxnard, Pt. Mugu along the SBC mainland, and San Miguel, Santa Rosa, Santa Cruz, and Anacapa Islands, and
- The south Southern California Bight at Santa Monica to Palos Verdes.

FALL (SEPTEMBER – NOVEMBER):

The composite results of all three analyses indicates that during the fall season land contact may occur in any of the following areas:

- The Santa Maria Basin at Pt. Lobos, Lopez Pt., Pt. Sur north, Pt. Sur, Cambria, Pt. San Luis, Pismo Beach, Pt. Sal, Purisima Pt., Santa Maria River mouth, Surf, and Pt. Arguello,
- The Santa Barbara Channel at Pt. Conception, Drake, Capitan, Gaviota, Coal Oil Pt., and Sea Cliff along the SBC mainland and San Miguel, Santa Rosa, and Santa Cruz Islands.
- The south Southern California Bight at San Nicolas Island.

PLATFORM HILLHOUSE ANALYSES

Platform Hillhouse is located in the northeast Santa Barbara Channel, just north of the Pitas Point Unit. Its location serves as the launch points for the GNOME and OSRA Model analyses. Drifter launch points 1, 2, 3, E.CE (figure 5.1.3.2-1), located in a southwest to northeast transect from western Santa Cruz Island to Carpenteria on the mainland and at the eastern Santa Barbara Channel entrance, were selected as the launch points for the Platform Hillhouse drifter analysis. Drifter analysis results reflect the documented trajectories of 85 free-floating surface drifters deployed at these launch points. This data is discussed in more detail in the report: "Surface Drifter Analysis for the Cavern Point Unit Project Oil Spill Risk Assessment" contained in appendix 5.2 Conditional Oil Spill Risk Analysis, appendix exhibit 5.2-2.

During the relaxation flow regime the composite analysis indicates that trajectories are primarily directed to the west along the northern shoreline of the SBC and out its western entrance where the majority turn the corner at Point Arguello and continue north along the central California coast. Other trajectories will frequently continue west, but some will go southwest toward the equator, or southeast toward the western Channel Islands.

During the convergent flow regime the composite analysis indicates that the trajectories initially travel west along the mainland shoreline but then the majority turn south to southeast inside the western portion of the channel toward the San Miguel and Santa Rosa Islands. Some trajectory is directed out the southwestern corner of the western SBC entrance.

During the upwelling flow regime the composite analysis indicates that the trajectories, as in the convergent case, initially travel west but then turn to the south and southeast sooner than during a convergent flow regime. Trajectories continue south to southeast toward the eastern-most Channel islands: Santa Catalina and Anacapa Islands and out the eastern entrance of the SBC to continue into the Southern California Bight.

The information provided below list areas that could be contacted by a spill, without consideration for the actual chance of the spill occurring or contacting an area. If a spill were to occur the chance of shoreline contact and volume of oil contacting shoreline will vary greatly with a number of factors including: location of spill, volume and characteristics of spilled oil, wind and current conditions, sea conditions, and the success of the oil spill containment and response operations.

WINTER (DECEMBER – FEBRUARY):

The composite results of all three analyses indicates that during the winter season land contact may occur in any of the following areas:

- The Santa Maria Basin at Estero Bay, Pt. San Luis, San Luis Obispo Bay, Pismo Beach and the entire area from Pt. Sal to Purisima Pt. to Pt. Arguello,
- The Santa Barbara Channel at Jalama, Pt. Conception, Capitan, Gaviota, Coal Oil Pt., Goleta Pt., Santa Barbara, Carpenteria, Carpenteria to Point Hueneme, Sea Cliff to Pitas Pt., and Ventura on the mainland and San Miguel, Santa Rosa, Santa Cruz, and Anacapa Islands, and
- The south Southern California Bight at south Santa Cruz Island, south Santa Rosa Island, Pt. Dume, Santa Barbara Island, Pt. Vicente to Redondo Beach, Santa Catalina Island, and San Nicolas Island.

SPRING (MARCH – MAY):

The composite results of all three analyses indicates that during the spring season land contact may occur in any of the following areas:

- The Santa Barbara Channel at Pt. Conception, Gaviota, Coal Oil Pt., Santa Barbara, Pitas Pt. to Punta Gorda, Ventura, Oxnard, Port Hueneme and Pt. Dume along the mainland, and the San Miguel, Santa Rosa, Santa Cruz, and Anacapa Islands, and
- The south Southern California Bight at south Santa Cruz Island, south Santa Rosa Island, Redondo Beach, Pt. Vicente, San Nicolas Island, and San Clemente Island.

SUMMER (JUNE – AUGUST):

The composite results of all three analyses indicates that during the summer season land contact may occur in any of the following areas:

- The Santa Maria Basin at Pismo Beach and Estero Bay,
- The Santa Barbara Channel at Pt. Conception, Capitan, Goleta Pt., Gaviota, Santa Barbara, Santa Barbara to Loon Pt., Carpenteria, Punta Gorda to Pitas Pt. to Ventura, Port Hueneme, Pt. Dume, and San Miguel, Santa Cruz, Santa Rosa, and Anacapa Islands, and
- The south Southern California Bight at South Santa Cruz Island, south Santa Rosa Island, Redondo Beach, Pt. Vicente, and San Nicolas Island.

FALL (SEPTEMBER – NOVEMBER):

The composite results of all three analyses indicates that during the Fall season land contact may occur in any of the following areas:

- The Santa Maria Basin at Estero Bay, Pt. San Luis, San Luis Obispo Bay, and the entire area from Pismo Beach to Pt. Sal to Purisima Pt., and Pt. Arguello,
- The Santa Barbara Channel at Pt. Conception, Capitan, Gaviota, Goleta Pt., Goleta to Coal Oil Pt., Santa Barbara, Carpenteria, and Ventura along the mainland shoreline and San Miguel, Santa Rosa, Santa Cruz, and Anacapa Islands, and
- The south Southern California Bight at south Santa Cruz Island.

SANTA CLARA UNIT (PLATFORM GAIL) ANALYSES

The Santa Clara Unit contains Platform Gail, which is located just north of the northbound vessel traffic lane near the eastern SBC entrance. Its location serves as the launch points for the GNOME and OSRA Model analyses. Examples of GNOME Model output for 2000 bbl spills during for all 3 flow regimes at platform Gail are illustrated in figures 5.1.3.2-15 through 5.1.3.2-18. Examples of OSRA Model output in GIS format for hypothetical oil spills during all 4 seasons at Platform Gail are presented in figure 5.1.3.2-19 through figure 5.1.3.2-22. Drifter launch points 1, 2, 3, E.CE (figure 5.1.3.2-1), located in a southwest to northeast transect from western Santa Cruz Island to Carpenteria on the mainland and at the eastern Santa Barbara Channel entrance, were selected as the launch points for the Santa Clara Unit drifter analysis. Drifter analysis results reflect the documented trajectories of 85 free-floating surface drifters deployed at these launch points. This data is discussed in more detail in the report: "Surface Drifter Analysis for the Cavern Point Unit Project Oil Spill Risk Assessment" contained in appendix 5.2 Conditional Oil Spill Risk Analysis, appendix exhibit 5.2-2.

During the relaxation flow regime the composite analysis indicates that trajectories are primarily directed to the west along the northern shoreline of the SBC and out its western entrance where the majority turn the corner at Point Arguello and continue north along the central California coast. Other trajectories will frequently continue west, but some will go southwest toward the equator, or southeast toward the western Channel Islands. Some trajectories head north toward the Gaviota-Capitan portion of the SBC mainland or southwest toward the western-most Channel Islands: San Miguel and Santa Rosa.

During the convergent flow regime the composite analysis indicates that trajectories initially either go northwest towards the Carpenteria to Ventura portion of the SBC mainland with the majority of trajectories changing course to directly west along the SBC mainland. They then proceed to turn south to southeast, along with the western cyclonic gyre, toward the San Miguel, Santa Rosa, and Santa Cruz Islands and their Island passes.

During the upwelling flow regime the composite analysis indicates that almost 100 percent of the trajectories are directed southeast out of the eastern SBC entrance and into the Southern California Bight.

The information provided below list areas that could be contacted by a spill, without consideration for the actual chance of the spill occurring or contacting an area. If a spill were to occur the chance of shoreline contact and volume of oil contacting shoreline will vary greatly with a number of factors including: location of spill, volume and characteristics of spilled oil, wind and current conditions, sea conditions, and the success of the oil spill containment and response operations.

WINTER (DECEMBER – FEBRUARY):

The composite results of all three analyses indicates that during the winter season land contact may occur in any of the following areas:

- The Santa Maria Basin at Estero Bay, Pt. San Luis, San Luis Obispo Bay, and the area from Pt. Sal to Purisima Pt. to Pt. Arguello,
- The Santa Barbara Channel at Jalama to Coal Oil Pt. including: Pt. Conception, Drake, Gaviota, Capitan, Naples, and Coal Oil Pt.; Goleta Pt., Santa Barbara to Loon Pt., Carpenteria to Pt. Hueneme including: Carpenteria, Punta Gorda to Pitas Pt., Ventura, and Laguna Pt. on the mainland and San Miguel, Santa Rosa, Santa Cruz, and Anacapa Islands.
- The south Southern California Bight at South Santa Cruz Island, Pt. Dume, Pt. Vicente to Redondo Beach, Santa Catalina Island, and San Nicolas Island.

SPRING (MARCH – MAY):

The composite results of all three analyses indicates that during the spring season land contact may occur in any of the following areas:

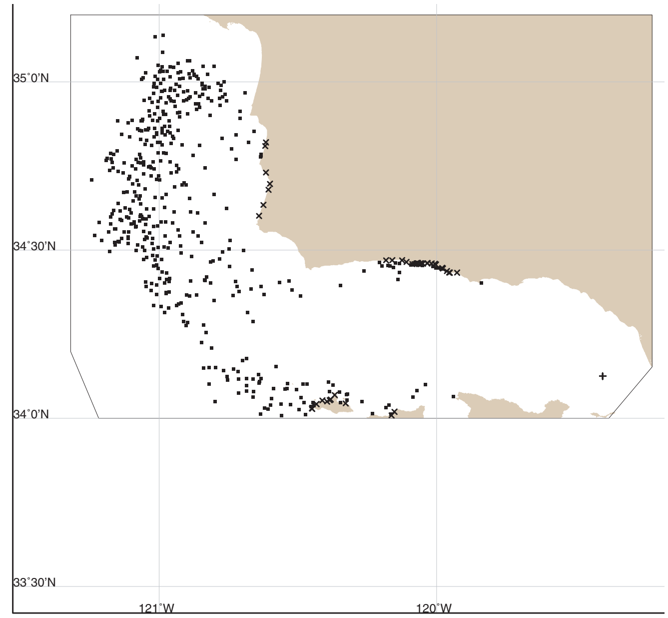


Figure 5.1.3.2-15. GNOME Modeled 10 day, 2000 bbl oil spill scenario for platform Gail (depicted by "+"), located in the center of the Channel near its eastern entrance, during a relaxation flow regime and a 4 m/s NW wind. GNOME model output indicates that of 2000 bbl released: 94 bbl beach, 974 bbl evaporate or are dispersed, 924 bbl are still floating, and 8 bbl have moved out of the model domain heading west out of the Santa Maria Basin and south to southeast offshore of the Southern California Bight.

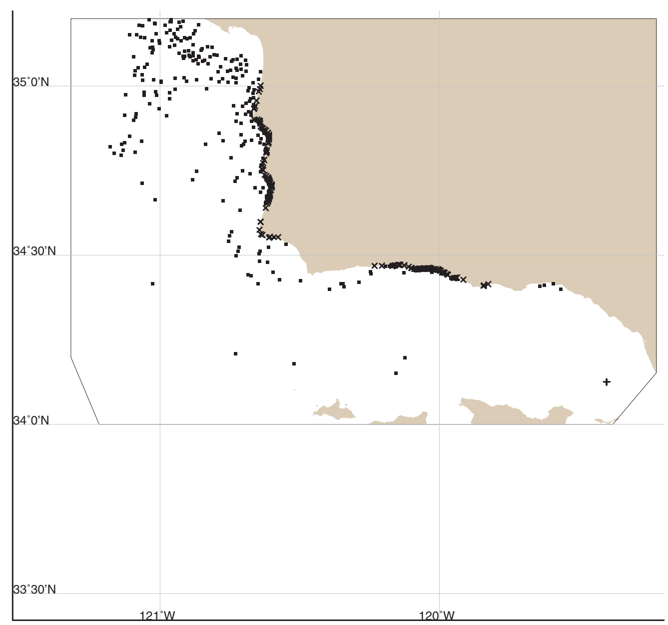


Figure 5.1.3.2-16. GNOME Modeled 10 day, 2000 bbl oil spill scenario for platform Gail (depicted by "+"), located in the center of the Channel near its eastern entrance, during a relaxation flow regime and a 4 m/s SW wind. GNOME model output indicates that of 2000 bbl released: 316 bbl beach, 978 bbl evaporate or are dispersed, 534 bbl are still floating, and 172 bbl have moved out of the model domain heading north out of the Santa Maria Basin.

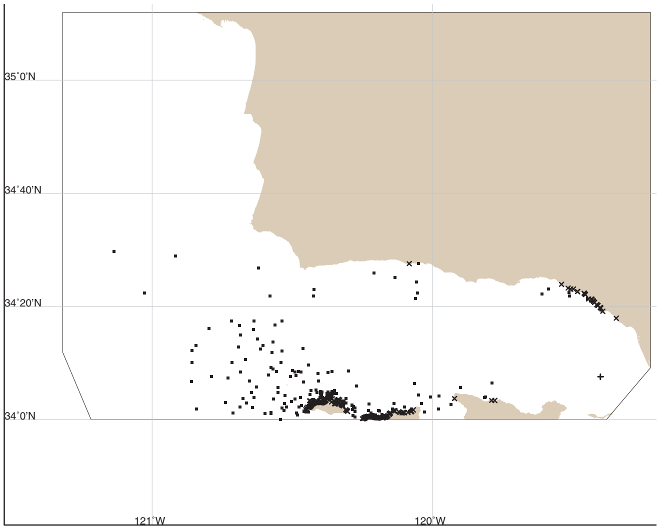


Figure 5.1.3.2-17. GNOME Modeled 10 day, 2000 bbl oil spill scenario for platform Gail (depicted by "+"), located in the center of the Channel near its eastern entrance, during a convergent flow regime and a 7 m/s NW wind. GNOME model output indicates that of 2000 bbl released: 410 bbl beach, 964 bbl evaporate or are dispersed, 366 bbl are still floating, and 260 bbl have moved out of the model domain heading south to southeast offshore of the Southern California Bight

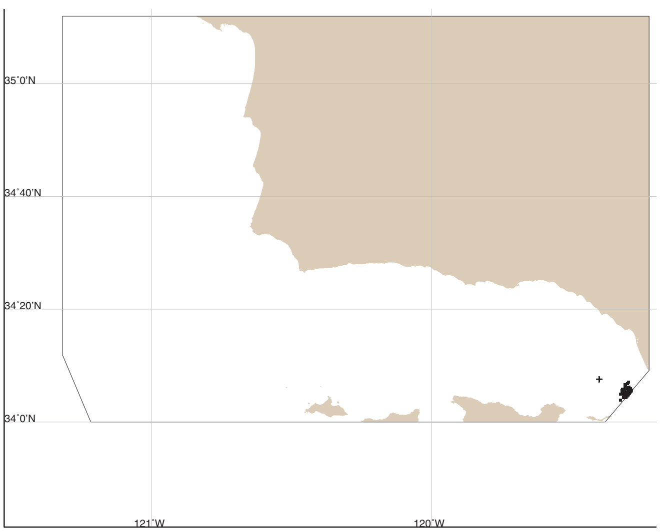


Figure 5.1.3.2-18. GNOME Modeled 7 hour, 2000 bbl oil spill scenario for platform Gail (depicted by "+"), located in the center of the Channel near its eastern entrance, during an upwelling flow regime and a 1.5 m/s NW wind. GNOME model output indicates that of 2000 bbl released: 0 bbl beach, 148 bbl evaporate or are dispersed, 160 bbl are still floating, and 1692 bbl have moved out of the model domain heading southeast out of the eastern Santa Barbara Channel entrance and along the southern California coastline. After 3 and 10 days, the GNOME model gives the same output of 150 bbl of oil evaporated and dispersed and 1850 bbl out of the model domain heading southeast out of the Santa Barbara Channel by way of its eastern entrance and along the southern California coastline.

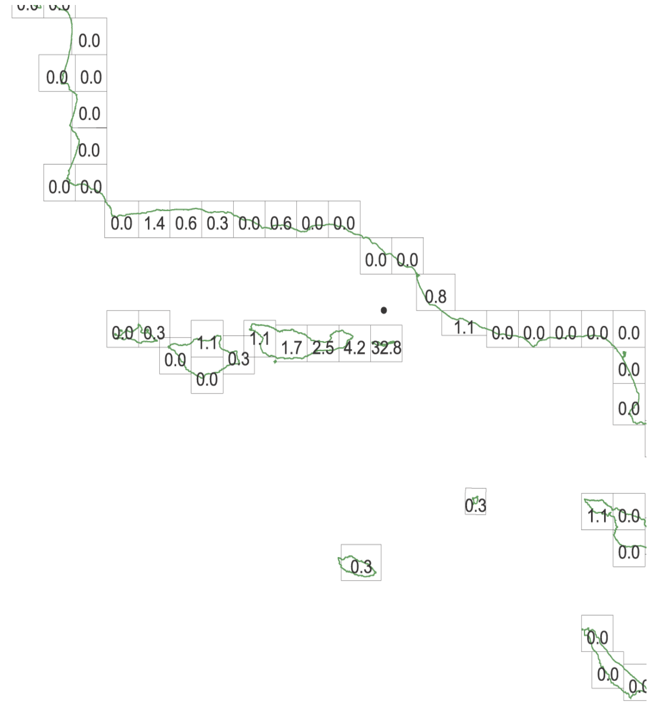


Figure 5.1.3.2-19. MMS OSRA Model output for a 10 day event at platform Gail during the winter season. The boxes are U. S. Geological Survey 7.5 Minute Quad series maps presenting the calculated probabilities (in percentages) of oil contact with the shoreline contained within each map.

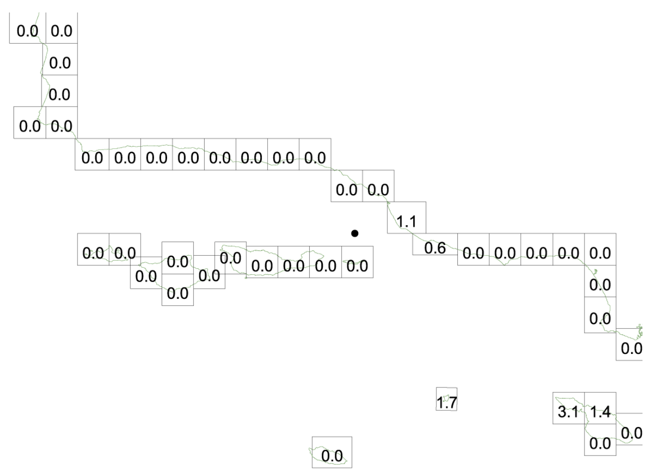


Figure 5.1.3.2-20. MMS OSRA Model output for a 10 day event at platform Gail during the spring season. The boxes are U. S. Geological Survey 7.5 Minute Quad series maps presenting the calculated probabilities (in percentages) of oil contact with the shoreline contained within each map

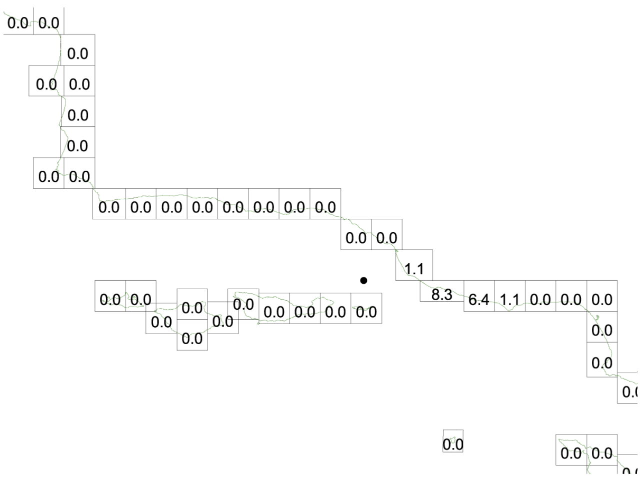


Figure 5.1.3.2-21. MMS OSRA Model output for a 10 day event at platform Gail during the summer season. The boxes are U. S. Geological Survey 7.5 Minute Quad series maps presenting the calculated probabilities (in percentages) of oil contact with the shoreline contained within each map.

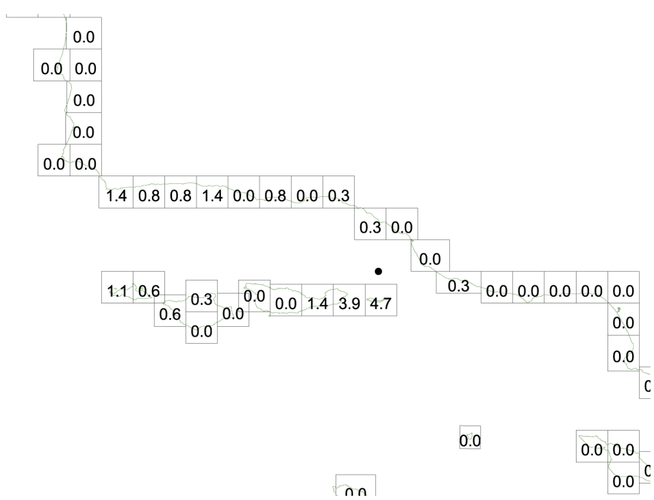


Figure 5.1.3.2-22. MMS OSRA Model output for a 10 day event at platform Gail during the fall season. The boxes are U. S. Geological Survey 7.5 Minute Quad series maps presenting the calculated probabilities (in percentages) of oil contact with the shoreline contained within each map.

- The Santa Barbara Channel at Pt. Conception, Santa Barbara to Loon Pt., Punta Gorda to Pitas Pt., Carpenteria, Pitas Pt. to Ventura, Port Hueneme, and Laguna Pt. on the mainland and San Miguel, Santa Rosa, Santa Cruz, and Anacapa Islands, and
- The south Southern California Bight at Pt. Dume, Redondo Beach, and Pt. Vicente on the mainland, and South Santa Cruz, south Santa Rosa, San Nicolas, Santa Barbara, and Santa Catalina Islands.

SUMMER (JUNE – AUGUST):

The composite results of all three analyses indicates that during the summer season land contact may occur in any of the following areas:

- The Santa Maria Basin at Pt. Sal to Purisima Pt.,
- The Santa Barbara Channel at Pt. Conception, Gaviota, Goleta, Goleta Pt. to Coal Oil Pt., Santa Barbara to Loon Pt., Carpenteria, Punta Gorda to Pitas Pt. to Ventura, and Pt. Hueneme along the mainland, and the San Miguel, Santa Rosa, Santa Cruz, and Anacapa Islands, and
- The south Southern California Bight at Pt. Hueneme to Pt. Dume, Laguna Pt., Redondo Beach, Pt. Vicente along the mainland, and south Santa Cruz, south Santa Rosa, San Nicolas, and Santa Catalina Islands.

FALL (SEPTEMBER – NOVEMBER):

The composite results of all three analyses indicates that during the fall season land contact may occur in any of the following areas:

- The Santa Maria Basin at Estero Bay, Pt. San Luis, San Luis Obispo Bay, and the area from Pismo Beach to Pt. Sal to Purisima Pt. to Pt. Arguello,
- The Santa Barbara Channel at Pt. Conception, Capitan, Gaviota, Naples, Goleta to Coal Oil Pt., Santa Barbara to Loon Pt., Carpenteria, Punta Gorda, Pitas Pt., Ventura, Pt. Hueneme along the mainland, and San Miguel, Santa Rosa, Santa Cruz, and Anacapa Islands, and
- The south Southern California Bight at Laguna Pt., Pt. Dume, south Santa Cruz Island, and south Santa Rosa Island.

This concludes the summary of the trajectory analyses performed for the Lion Rock, Point Arguello, San Ynez, and Santa Clara Units, and for Platform Hillhouse. Please see appendix 5.2 Conditional Oil Spill Risk Analysis for a detailed presentation of the results of the OSRA, drifter, and GNOME analyses.

5.1.3.3 OIL SOURCES, BEHAVIOR, AND SPILL RESPONSE

5.1.3.3.1 SOURCES OF OIL

Sources of oil that could enter the marine environment include:

- Oil and gas exploration;
- Oil and gas development and production;
- Tankers, barges, and other shipping; and
- Natural seeps.

Municipal and industrial wastes and urban runoff also contribute oil to the marine environment, likely in amounts much greater than those contributed by any other single source. See section 5.2.2 for further detail on these sources of hydrocarbons. For the purposes of this discussion, we will only examine the potential for oil spills from the sources listed above.

These are summarized below with additional detail given in appendix 5.3.

OIL AND GAS EXPLORATION ACTIVITIES

Exploration activities include the mobilization and operations on the drilling vessel as well as support vessel operations. The two general potential sources for spills during exploration activities, include spills during drilling operations due to loss of well control (blowout) and spills from other exploratory sources including those related to support vessels.

Technological innovations today have greatly lessened the risk from exploration drilling, including:

- Increased knowledge of undrilled geology from such methods as 3-D seismic surveys and improved data processing;
- A better ability to control wells that by intensive monitoring of a plethora of downhole data while drilling is occurring; and
- Intensive training and drills by facility workers, resulting in a readiness and an instant responsiveness to unexpected events.

Spills during drilling due to loss of well control. A total of 38 OCS blowouts have occurred nation-wide from 1992 to date. Of these, four separate events resulted in a total hydrocarbon spillage of 302 bbl, and one of those accounted for the largest spillage of 150 to 200 bbl of oil (as well as 806 bbl of synthetic drilling mud)[1]. Twenty-six of the 38 events occurred during drilling, and 13 occurred during exploration operations. Three events occurred in the Pacific OCS Region, both as a result of development operations; only one of these, in November 2000, spilled approximately 1 gallon of oil (see the website: http://www.mms.gov/stats/OCSincident.htm and appendix 5.3 for additional information).

Spills from other exploratory sources including those related to support vessels. When only exploration activities are accessed in the MMS Pacific Region database, of 239 exploratory wells drilled from 1970 to present (all from MODUs), a total of 78 hydrocarbon spills occurred, spilling about 50 bbl of hydrocarbons. Most of the exploration drilling occurred during the 1980s; the last Pacific Region exploratory well was drilled in 1989.

OIL AND GAS DEVELOPMENT AND PRODUCTION ACTIVITIES

In the Pacific OCS Region from 1970 through 2000, a total of 881 spill events resulted in 780 bbl of oil spilled from all sources related to development and production activities, while about 950 million bbl of oil was produced. The largest spill from a Pacific Region facility since 1970 was 163 bbl from a pipeline from Platform Irene in 1997. As noted earlier, the 1969 event resulted in 80,000 bbl of oil spilled.

There are four potential phases in development and production activities during which spills could occur:

- Platform installation;
- Development drilling;
- Production and pipelines; and
- Decommissioning

The MMS oil spill database does not contain information that allows differentiation between these phases and the frequency of spills and the type of hydrocarbon spilled. Therefore, the following discussion will only address generic possibilities and scenarios, rather than statistics.

Platform installation. Spills of diesel, lube oil and hydraulic oil are the most common types of spills to occur during platform installation and construction activities since no wells would have been drilled at that time. These types of spills can occur during all phases (including exploration) of offshore oil and gas activities. Transfer of diesel fuel between the supply vessel and the derrick barge can result in small spills during the transfer process. Lube and hydraulic oils are stored in drums or cans. To our knowledge, no drums of these types have been dropped into the sea that resulted in the spillage of oil. However, lines and hoses have broken resulting in small spills of lube and hydraulic oils into the sea.

Development drilling. During development drilling, the possibility of crude oil spills arises, only when oil is found. Loss of well control can and has happened. Of the 881 spills events that have occurred from 1970 to the late-1980's, when drilling activities was high in the Pacific Region, 1 in 25 events occurred during drilling or while equipment was in a well during other operations.

Most platforms have diesel fuel onboard even if they are powered from shore by electrical cable. The diesel is used for powering some cranes and for backup generators, especially for running fire water pumps in case of emergencies. Diesel is commonly stored in tanks in the pedestals that support the superstructure of the cranes. The use of hydraulic and lube oils continues in this phase since various pumps, compressors and other machinery require one or both of these.

Production and pipelines. Hydrocarbon spills may occur during production of oil and gas and while the oil and gas is treated and pumped through pipelines to shore (all oil and gas is piped to shore in the Pacific OCS Region). By far, the most spills occur during this phase, as this phase lasts the longest, over 30 years in some cases. The largest spills that occurred on a facility during this phase were two-17 bbl spills. Otherwise, the 1997 Platform Irene pipeline spill of 163 bbl has been the largest in this phase (and largest overall since 1969).

Produced water discharges also contribute oil into the sea. This effluent is regulated under the National Pollutant Discharge Elimination System (NPDES) regulations under the Environmental Protection Agency purview. The effluent is treated prior to discharge by various means. The most common treatment system used involves a combination of heat, chemicals (for example, emulsion breakers) and the use of mechanical forces (such as corrugated plates, bubbling air, etc.). Under normal operating and treatment circumstances, no slick will form on the ocean surface as from an oil spill. However, since NPDES permits allow some dissolved components of oil to remain in the effluent (currently ranging in the POCSR from 29 to 72 ppm) some amount of oil is discharged into the sea from this effluent. See section 6.2.2 for more detailed information on oil and grease in produced water discharges.

Decommissioning. The potential for oil spill from decommissioning activities is similar to those from platform installation. Since platform operations will cease, there is no chance for spills from oil wells. Thus, the greatest chance of spills from this phase would be due to the attendant vessels, including the derrick barge and the supply vessels.

1 This occurred during deep-water drilling in the Gulf of Mexico when a riser accidentally disconnected.

TANKERS, BARGES AND OTHER SHIPPING

Vessels that carry hydrocarbons, either as cargo or as fuel or both, ply the waters of the Study. The history of spills in the west coast from vessels is brief (USCG, 2000). Since the early 1970s, six vessels have spilled various types of oil, totaling about 9,000 bbl, within the study area (see appendix 5.3 for additional detail).

NATURAL SEEPS

At least 50 oil seepage areas exist between Point Arguello and Huntington Beach with at least 38 in the Santa Barbara Channel. Altogether, it is estimated that 40 to 670 bbl of oil per day seep into the sea in the Santa Barbara Channel with the most concentrated occurring near Coal Oil Point where about 25 to 400 bbl/day seep out (Hornafius, et al., 1999; Quigley, et al., 1999). Seepage areas are also known to exist from Point Arguello to Monterey.

ONSHORE SOURCES

Sources of oil that could enter rivers and, perhaps, the sea, include municipal and industrial waste and urban runoff, refineries, oil and gas production facilities, oil and gas processing facilities, and pipelines.

One refinery is located near the Santa Maria River in San Luis Obispo County while several others are located near the Los Angeles Harbor and sea shore near Los Angeles International Airport. To our knowledge, no spills from those refineries have entered either rivers or the sea.

Two separate, but related, production spills have occurred on the San Luis Obispo County coast. They are the Guadeloupe Dunes diluent spill and the Avila Beach oil spill. They are both under ground spills formed by both the diluent (diluent is a light hydrocarbon used to thin oil in formations to ease the pumping of the oil to the surface) and the oil seeping and contacting ground water, where it was transported further from the original spill site. The diluent spill was first noticed when hydrocarbons appeared in the surf zone. The source of the "spill" was traced to underground pools of diluent which had settled atop of ground water, then seeped downhill to the ocean. The Coast Guard with Unocal the State, developed a response to the situation, which is ongoing. Further searches revealed many such pools scattered about the oil field. The Avila Beach spill is another that is under ground. It was the result of long-term seepage of oil from tanks on the slopes above the town of Avila Beach. Again, Unocal was the responsible party and has undertaken the entire cost of the clean up action.

Oil and gas processing facilities are located mostly near the shore and some are located in canyons that also contain small seasonal streams. In some cases, much effort has been expended to prevent any spilled oil from reaching the sea where there is a potential for oil to spill into a small stream and hence into the sea.

Processing facilities range in oil-handling capability from large (for example, Exxon's Los Flores Canyon), to medium (Nuevo's Mandalay Beach) to small (Pacific Offshore Operators', Rincon plant). All of these examples take wet oil from offshore, separate the water and dewater the gas, send the treated water back offshore for disposal, and ship the oil and gas into the local pipeline infrastructure. All are located on or near the shore, or in a canyon (in the Las Flores Canyon case). No oil spills from these facilities have been known to reach the sea or any nearby local stream which runs to the sea.

Pipelines are the primary way that oil is shipped both from offshore to onshore and from one place to another onshore. Since pipelines that run along the shore often cross small streams and some major rivers, the potential for a breakage and subsequent leakage into the stream or river exists. Examples are the 1997 Northridge earthquake which caused an ARCO pipeline to brake in six places; a Unocal pipeline running from a tank farm in Avila Beach which broke and spilled oil which ran down a cliff into the shallow tidal waters; a Berry Petroleum pipeline break with oil flowing into a nearby agricultural drainage pond near McGrath State Beach.

5.1.3.3.2. BEHAVIOR AND WEATHERING PROCESSES: HOW OIL CHANGES WHEN SPILLED AT SEA

When oil is spilled at sea it will normally break up and be dissipated and dispersed into the marine environment over time. This dissipation is a result of a number of chemical and physical processes and are collectively known as weathering. Some of the processes, like dispersion of the oil into the water, cause part of the oil to leave the sea surface, while others, like evaporation or the formation of water in oil emulsions, cause the oil that remains on the surface to become more persistent. The time dissipation takes depends on a series of factors, including the amount and type of oil spilled, the weather conditions and whether the oil stays at sea or is washed ashore. Physical properties such as the density, viscosity and pour point of the oil also affect the speed and the resulting form of the oil during these weathering processes.

There are eight main processes that cause oil to weather (ITOPF, 2001). They are: spreading, evaporation, dispersion, emulsion, dissolution, oxidation, sedimentation/sinking, and biodegradation. The processes of spreading, evaporation, dispersion, emulsification and dissolution are most important during the early stages of a spill whilst oxidation, sedimentation and biodegradation are more important later on and determine the ultimate fate of the oil (ITOPF, 2001; Fingas, 2000).

<u>Tar Balls and Mats</u>. Heavy oil residues, or tar balls, often remain after all the short-term weathering processes have occurred. These residues are normally made up of the least volatile components of the oil (MMS, 1996). Tarballs, which are often found on shorelines, and have a solid outer crust surrounding a softer, less weathered interior, are a typical example of this process. The process forms an outer protective coating of heavy compounds that results in the increased persistence of the oil as a whole (ITOPF, 2001). The oil may come from spills, but may also arise from natural seeps or from deliberate (but illegal) operational releases from ships during bilge-cleaning operations (Fingas, 2000). For additional information on sources of oil and weathering processes, sea NRC, (1985).

5.1.3.3.3. OIL SPILL RESPONSE

This very broad topic is summarized here and expanded in appendix 5.3. A typical response potentially involves many Federal, State, and local agencies, as well as the spiller of the oil (known as the Responsible Party – RP) and various oil spill clean-up entities in the form of cooperatives and contractors. The volume of the oil normally determines the identity and number of entities involved in the response. As discussed above, the EIS examines three different oil spill scenarios. They are:

- 50 to 1,000-bbl spill with a most-likely volume of 200 bbl or less;
- 2,000 bbl, assumed to occur from a pipeline; and
- A 22,800 bbl tanker spill.

The agencies that would always be involved in an oil spill response are the U. S. Coast Guard and the State of California's Office of Oil Spill Prevention and Response (OSPR, contained, administratively, within the Department of Fish and Game). The Coast Guard, the State and the RP all constitute the Unified Command (UC), where all information and all decisions are made regarding spill response strategy and day-to-day planning. MMS's responsibilities are summarized below and given in more detail in appendix 5.3.

Other agencies and private organizations that might participate in a response (depending on size and location) could include the local county's Office of Emergency Services, Fire Department, Harbor Patrol, Department of Transportation's Office of Pipeline Safety, U. S. Park Service, Federal Emergency Management Agency, U. S. Fish and Wildlife, California Department of Fish and Game (the wildlife part), and various contractors that would provide personnel, equipment, food and housing services, disposal of oily debris and hazardous materials, and other services.

PLANS

Planning for an oil spill response is essential to insure an effective, efficient and organized response. Oil Spill Response Planning is conducted at four distinct levels: the National, Regional, Area, and the Facility/Vessel. The first three levels of response planning are conducted by government agencies charged with protecting the environment under the National Response System. The Area level of response planning includes input from both state and local government, as well as industry and other interested parties, while the facility response planning is conducted by the owner or operator of the oil and gas facility from which a spill could impact navigable waters (see appendix 5.3 for additional detail on these levels of oil spill response planning).

For a good example of a generic, recently-written OSRP, see the main text and the key appendices A, C, D, E and F of Padre and Associates (2001). This plan covers oil spill response in the eastern Santa Barbara Channel and Santa Maria Basin area. The plan was written in accordance with MMS regulation found at 30 CFR 254. The main text of the plan describes the typical response organization and actions to be taken by an oil and gas operator. Appendix A discusses the spill response equipment available in this area and its maintenance and inspection. Appendix C describes a worst case discharge scenario for this area, where the discharged oil may occur, the resources at risk and the response for this spill. Appendices D and E are plans for the use of dispersants and *in-situ* burning, respectively. These spill response technologies could be used if their used demonstrated that a net environmental benefit would result. This section also includes the approval process for use of these technologies and procedures for their use. Appendix F discusses the spill response training and drills offshore personnel will undergo to prepare for a spill response.

Operator Response. Any operator's strategy for dealing with oil spills is to prevent their occurrence. Well-engineered facilities, good housekeeping practices, adequate equipment maintenance and adherence to proper operational procedures are diligently employed to reduce the likelihood of an oil spill to the lowest possible level. In the unlikely event that an oil spill occurs, response operations would be initiated immediately. Throughout all response operations, the highest priority would be placed upon personnel safety, in addition, environmental resource considerations would be taken into account in the selection of response techniques and equipment and in the conduct of response operations.

The initial response to a spill at a site of delineation activities will be from onsite equipment stationed on dedicated spill response vessels at the drill site. Additional response resources for spills beyond the capabilities of the onsite equipment will be provided by the oil spill cooperative.

<u>Notifications</u>. Upon the spillage of oil, the operator's first concern is always the safety of the personnel at the site. Next, the RP begins to discern the cause of the spill and attempts to abate (shut off) the source. MMS personnel, when notified, would assist in this endeavor. While these initial actions are occurring, notifications to the U. S. Coast Guard's National Response Center, and the State of California's Office of Emergency Services are made[2], along with several other agencies, including the State Lands Commission, the Coast Guard at Long Beach and Santa Barbara, OSPR and the Oiled Wildlife Care Network. Several other agencies would be notified ,when time and if circumstances warrant (see appendix 5.3). If the spill is from a platform or pipeline under MMS's jurisdiction, MMS would be included in the initial notification as noted above, and be on-scene as rapidly as possible. If the spill were from a tanker as described in the scenario, above, the notifications would be substantially be the same, except for MMS and other agencies with no direct jurisdiction.

The second type of entity to be commonly notified would be the local oil spill cooperative. For the Santa Barbara Channel and Santa Maria Basin that would be Clean Seas, and for offshore Los Angeles, Clean Coastal Waters. These two co-ops have response equipment and contractors (including a fishing vessel-based organization, the Fisherman Oilspill Response Team). Other co-op type organizations that could contribute personnel and equipment include the Coast Guard's Pacific Strike Team, the oil industry's Marine Spill Response Corporation, and the National Response Corporation, another major independent contractor.

<u>Equipment and Personnel Deployment</u>. Once oil is in the water from either a platform or pipeline, equipment is deployed either directly from the spilling facility, or a co-op, or both. On-scene oversight is usually provided by a local co-op representative who, with the use of helicopter overflights, properly positions booms and vessels to most efficiently attack the thickest part of the oil slick.

Beach debris removal, wildlife capture and rehabilitation, and public concerns all are concerns the UC must address for any spill. A spill from a tanker, in addition to being very large, as compared to one from a platform or pipeline, would generally entail the mobilization of nearly all the resources discussed above and, potentially, others from other states and even countries. The *Exxon Valdez* spill was just such an event, and equipment from all over the world was eventually mobilized to Prince William Sound, Alaska.

Day-to-Day Spill Response. The emergency phase of a spill lasts until the major assets are in-place and working. The UC is formed and four sub-units are set-up: Finance, Logistics, Operations, and Planning. The general philosophy is to initially overreact to any incident, so depending on the size of the spill, more or less equipment and personnel would be added or released from the spill scene. Night-time and foggy operations can continue, but often on a more limited basis.

As a spill response continues, various auxiliary issued must be addressed. These include disposal of oily debris, recycling, disposal at sea of water separated from recovered oil, contaminated debris, sorbent use/reuse, petroleum-contaminated soil recycling and reuse, temporary storage, treatment of oily wastes, characterization of recovered material, transportation, hazardous waste, and nonhazardous wastes. All of these topics have their individual considerations that must be accounted for in any oil spill response. Additional information is given in appendix 5.3.

EQUIPMENT

Operators in the Pacific Region are required to keep sufficient equipment on or near the platform to enable them to initiate immediate containment activities. For a secondary level response, equipment at the platform is supplemented by equipment kept onshore and operated by oil spill cooperatives formed by the lessees and operators. For example, Clean Seas has pre-staged equipment located at Morro Bay, Avila Bay, Santa Barbara Harbor, the Carpinteria Yard, in the Ventura/Port Hueneme area, and at Point Mugu Navy Base. Various types of response equipment are stored at these locations. The three major cooperatives also have at least six dedicated ocean-going vessels with containment and recovery equipment for oil spill response.

If the Federal OSC so requests, the Navy and the USCG can provide additional oil spill response equipment and personnel located at Stockton and at Hamilton Air Force Base in northern California. Also, the Marine Spill Response Corporation has established a Southwest Region Response Center at Port Hueneme on the Santa Barbara Channel. Equipment from this center may be used for response to a spill from OCS exploration and production operations if so directed by the Federal OSC.

The three oil spill response cooperatives on the California coast—Clean Bay, Clean Seas, and Clean Coastal Waters—have formally agreed to provide each other response assistance within the boundaries established by State and Federal regulatory authorities. These cooperatives have also been acquiring new equipment to supplement their existing inventories. See appendix 5.3 for details on the sources, amounts, and types of mechanical equipment available for oil spills within the study area.

MMS RESPONSIBILITIES

MMS's primary responsibilities, by law, are abatement of the initial spill and investigation of the cause. However, MMS believes that prevention of oil spills is much preferable to cleaning up spilled oil. This prevention strategy includes a regulatory scheme that requires the use of the best available and safest technologies at any facility, training standards for the operator's personnel and a rigorous inspection program. This strategy ensures that industry operates well-engineered facilities, with good housekeeping practices, adequate equipment maintenance, and adherence to proper operational procedures to reduce the likelihood of an oil spill. For additional information on MMS's responsibilities, see appendix 5.3.

To insure that a facility is prepared in the unlikely event that oil is spilled, the MMS has a comprehensive oil spill response exercise program in place. The program tests a facility operator's response, as well as their knowledge and understanding of their individual OSRP. For planning purposes, the MMS adheres to the requirements of the USCG's National Preparedness for Response Exercises Program (PREP)[3]. Facility operators must exercise their entire response plan at least once every 3 years (triennial exercise). To satisfy the triennial exercise requirement an owner or operator must conduct the following aspects of their response capability:

- Annual spill management tabletop exercise;
- Annual deployment exercise of spill response equipment staged at onshore locations;
- Annual notification exercise; and
- Semiannual deployment exercise of any response equipment which the owner or operator must maintain at the facility of on dedi-

2 Both of these notifications go to entities who disseminate the information to many other agencies, usually by fax. In some cases, multiple notifications are made to the same agency by this methods, via the NRC or State OES, as well as directly by phone from the RP.

cated vessels (MMS-initiated or actual spill responses can be used for credit for one of these exercises).

ALTERNATIVE RESPONSE TECHNOLOGIES – OFFSHORE

Dispersants. Dispersants are a class of spill-treating agents that, when applied to oil on water, form the oil into droplets which are driven into the top layer of water column (Fingas, 2001). Surface active agents (surfactants) are the key components of a chemical dispersant. These compounds contain both a water compatible and an oil compatible group. Because of this molecular structure, the surfactant locates at the oil-water interface, reduces the interfacial tension, and enabling the oil slick to break up into small oil droplets. Once the droplets are dispersed into the water column, they are subjected to natural processes such as spreading by currents and biodegradation (National Research Council (NRC), 1989; SL Ross, 2000) A number of papers have been written explaining how dispersants work (Fingas 1988 and Fingas et al., 1997; 1995; 1993) and summarized in American Petroleum Institute (1999; 1997). Appendix 5.3 contains more information on the NRC (1989) study which asked two questions:

- Do dispersants do any good? (that is, are they effective?); and
- Do dispersants do any harm (that is, are they toxic?).

Effectiveness. "Dispersant effectiveness" is defined as a measure of how effective the application of dispersant might be on a targeted part of a slick. It is not to be confused with dispersant "operational efficiency" which relates to operational factors such as having sufficient stockpiles of chemicals, application platforms, and fast response capabilities. Also, "dispersant effectiveness" means the effectiveness of the dispersant under field conditions, rather than laboratory conditions. Unfortunately, there is little quantitative information on the effectiveness of dispersants when used in the field. This is because (1) there have been only a handful of open-ocean trials; and (2) there are no acceptable surface-sampling or remote sensing methods available for measuring the overall thickness or volume of a spill on the sea surface, and no acceptable methods for determining total volume of dispersed oil in the water column. Most quantitative information comes from a number of laboratory tests, which are poor simulators of dispersant-use in the field. The five most popular laboratory tests today (Swirling Flask, Labofina, IFP, MNS and Exdet; see Nordvik et al. 1993) have different designs and produce different results for identical dispersant/oil combinations. Although the results from any laboratory test can be useful in providing relative values of dispersant effectiveness between dispersant/oil combinations, they should not be trusted to predict absolute dispersant effectiveness values in the field.

A critical factor in the strategy of dispersant application is that the viscosity of the oil increases rapidly with weathering, which is a function of evaporation and emulsification (see appendix 5.3 for additional information). When an oil is highly viscous the applied chemical may simply "roll off" the oil or does not penetrate and mix with the mass of oil. Because more viscous oil is more difficult to disperse, response within a few hours is generally essential to high effectiveness.

Two other critical factors to consider when applying dispersants are the type of oil and sea energies available. Both of these factors, in turn, affect how much dispersant is needed for any specific application. For example, assuming the same amount of dispersant is used in both low and high sea energy conditions, diesel and light crude oils will be dispersed at rates greater than 50 percent under any conditions. Medium crude oils, those that would disperse only under ideal conditions, need a greater amount of sea energy in order to show any significant dispersibility. Heavy oils, such as Intermediate Fuel Oil and Bunker C, do not disperse at a rate of greater than 10 percent under any circumstances (Fingas, 2001).

A study conducted by McAuliffe, et al. (1981) offshore southern California gives some "rules of thumb" regarding dispersant effectiveness. While some of these may appear to be obvious conclusions, they are nevertheless, important considerations when deciding how to attack an oil spill:

- Chemical dispersion is more effective than natural dispersion in relatively calm seas;
- Dispersant treatment by air is superior, in most cases, to dispersant treatment by boat;
- Weathered oil is not dispersed as effectively as fresh oil; and

[3] U. S. Coast Guard's PREP was developed to meet the intent of section 4202 (a) of OPA90. PREP plays a key role in assuring that to successful responds to major oil and hazardous chemical incidents occurs. PREP incorporates the exercise requirements of the U. S. Coast Guard, the EPA, the Research and Special Programs Administration (RSPA) [Office of Pipeline Safety] and the MMS. Using PREP guidelines and participating in PREP exercises will satisfy all OPA90-mandated federal pollution response exercise requirements. For more information on the PREP program, see the website at: http://www.uscg.mil/hq/nsfcc/nsfweb/nsfcc/prep/prephome.html.

- A dispersant that performed poorly in the laboratory also performed poorly in the field.

Toxicity. The toxicity of dispersants is the other issue of concern. The wreck of the *Torrey Canyon*, offshore England in 1967, was the first occasion where dispersants, or dispersant-like substances were used to address oil spills. Unfortunately, the materials used in that event were extremely toxic and affected the shoreline organisms and habitats more severely than did the oil alone. That experience gave the concept of using dispersants a somewhat undeserved reputation since the substances used during the *Torrey Canyon* incident were of the first generation toxic-type (NRC, 1989). Other early dispersants exhibited toxicities in the 5 to 50 mg/l LC_{50} range. Since then, the formulation of dispersants has evolved into carefully controlled combinations of lower-toxicity solvents with surfactants with LC_{50}s ranging from 200 to 500 mg/l (Fingas, 2001).

Once an oil slick is dispersed, then what? In most places, oil slicks are subjected to surface currents, winds, and waves. If the oil is all or paritally removed from the water surface, these factors that directly affect the movement and weathering of the oil, become detached from any changes in the characteristics of the oil. Subsurface currents then predominate. If the dispersed droplets are small enough they will have little buoyancy and will be carried away and diluted by normal ocean current and movement. One of the inputs to a decision regarding tradeoffs (discussed below) is where the oil might go if subsurface currents become the predominant influence on the plume of dispersed oil.

As with other Alternative Response Technologies (for example, in-situ burning) the decision to apply dispersants is a balancing of tradeoffs. Since dispersants are never 100 percent effective, any responder would have to ask if the process of apply dispersants is worth the costs (both environmental and economic) of attacking the spill by only mechanical means. A succinct summary of biological tradeoffs is from NRC (1989):

- In open waters, organisms on the surface will be less affected by dispersed oil than by an oil slick;
- Organisms in the water column, particularly the upper layers, could experience greater exposure to oil components if the oil was dispersed;
- In shallow water habitats with poor circulation, benthic organisms could be more immediately exposed to dispersed oil;
- Although some immediate biological effects of dispersed oil may be greater than for untreated oil, long-term effects on most habitats, such as mangroves, are less and the habitat recovers more quickly if the oil is dispersed before it reaches that area;
- Studies have shown that dispersed oil does not adhere as much as untreated oil to some organisms or habitats; and
- The application of dispersants after oil contacts some habitats, such as salt marshes, rocky shorelines and, sand and mud flats, is generally not effective and could do more harm than good.

A comprehensive discussion on the logistics of dispersant planning and application is beyond the scope of this discussion. However, some key factors that members of the Unified Command must consider in their decision-making process are:

- availability of dispersant product;
- characteristics of platforms (payload, pump rate, speed);
- spill conditions (e.g., type of spill, behavior of the oil, distance offshore);
- ability to identify thick oil areas and position spray equipment accordingly;
- availability of effectiveness monitoring; and
- weather and daylight hours.

In-situ burning. While mechanical removal is the preferred method, it is recognized that in-situ burning can be a viable option in conjunction with, or in lieu of, mechanical or other types of recovery. In-situ burning has been demonstrated to be a very useful response tool in open water conditions when used in conjunction with a fire resistant boom. In-situ burning greatly reduces the need for recovery, storage, transportation, and disposal of a large percentage of the spilled oil. Numerous burn tests have been done in the lab, in test tanks, and in the field (including one during the second day of the Exxon Valdez spill cleanup operation), which demonstrate the feasibility and effectiveness of this technique.

Currently, California does not permit the burning of oil within the State or on State waters. In-situ burning can be used in the State of California and its waters by Federal preemption of this Code, which is only possible under specific circumstances. In-situ burning may be considered in waters beyond three miles of the shore, which are under Federal jurisdiction. The Federal On-Site Coordinator (FOSC) would need to obtain approval from the Environmental Protection Agency (EPA) representative to the Regional Response Team (RRT). In all cases, the State of California will be notified of the use of in-situ burning.

Preliminary laboratory testing has been conducted on the crude oil currently being produced from the Santa Barbara Channel and Santa Maria Basin Areas. The results of these tests indicate that the crude oil has a low percentage of volatile components that would cause difficulty to ignite the oil. Therefore, in-situ burning of discharged oil may not be an appropriate mitigation measure. Information on the equipment needed and the procedures that would be followed in preparation for in-situ burning are contained in appendix 5.3.

Other issues that must be included in any discussion on in-situ burning are efficiency and environmental effects. Burning efficiency is calculated as the difference between the percentage of residue left and the initial amount of oil and is largely a function of oil thickness within the fireproof boom. During the Exxon Valdez spill, a test burn using the 3M fire resistant boom was conducted 2 days following the spill. In this test, an estimated 357 to 714 bbl of North Slope crude oil were burned in approximately 75 minutes with an estimated efficiency of 98 percent. The volume elimination rate for this test using a single 500-foot boom was estimated to be between eight to 16 bbl per minute (Allen, 1990).

The primary objective of oil spill abatement and cleanup is to reduce the effect of spilled oil on the environment. The use of in-situ burning may be considered when the preferred techniques are judged to be inadequate and the environmental benefit of in-situ burning outweighs its adverse effects. Some critics of in-situ burning have raised questions about the effects of air pollution resulting from the process. Tests conducted by MMS, Environment Canada, and the American Petroleum Institute, to better quantify air quality data related to in-situ burn processes indicated that burn products reach safe levels within several kilometers of the burn site and that the eventual concentrations of particulates and associated pollutants are several orders of magnitude below acutely toxic levels. Additional research is needed to fully document these hazards and to develop methods to minimize these hazards.

In August 12, 1993, MMS, USCG, Canadian Coast Guard, and Environment Canada also co-sponsored a large-scale in-situ test burn off the coast of Newfoundland, Canada. Environment Canada published a preliminary report that included the following findings:

- Burning at sea is feasible and practical.
- The fireproof boom stood up throughout the tests, but more work is necessary for it to last longer. Sea motion combined with heat appears to have reduced the life of the boom (48 hours in test tanks). The total burn during the tests lasted 4 hours.
- Some observations from the burns did not correspond to previous test tank data. First, several effects, such as the rapid sea burns noted in test tanks, did not occur at sea. Second, burn rate calculations must more accurately account for the effects of wind. Even a small amount of wind (8-11 km/hr during the second burn) drove the oil far into the apex of the boom and thereby reduced the burning rate to about two-thirds of previous calculations.
- Burning outside of the fire-resistant boom occurred on about three occasions as a result of too much oil in the boom, but did not result in sheening. Either some form of containment occurred naturally, or the overflow was very viscous.

ALTERNATIVE RESPONSE TECHNOLOGIES–ONSHORE

Shoreline cleaning agents, bioremediation and no action are other options for oil spill responders. Each of these involve tradeoffs, have their own strengths and weaknesses, and have their particular roles during the response to an oil spill. Appendix 5.3 contains additional detail on these tools.

5.2 ENVIRONMENTAL IMPACTS OF ALTERNATIVE 1: THE PROPOSED ACTION

5.2.1 IMPACTS ON AIR QUALITY

The following significance criteria levels were used in the impact analysis for air quality to determine whether the proposed delineation projects emissions could result in air quality impacts.

High - Project may cause or contribute to a violation of Federal or State ambient air quality standards, *and* exceed threshold emission levels that have been determined to result in significant impacts to air quality. Impacts deemed to be high are considered to be significant.

Moderate - Project does *not* result in any violations of Federal or State ambient air standards, but does exceed threshold emission levels that have been determined to result in significant impacts to air quality. Impacts deemed to be moderate are considered significant, but are mitigable to an insignificant level.