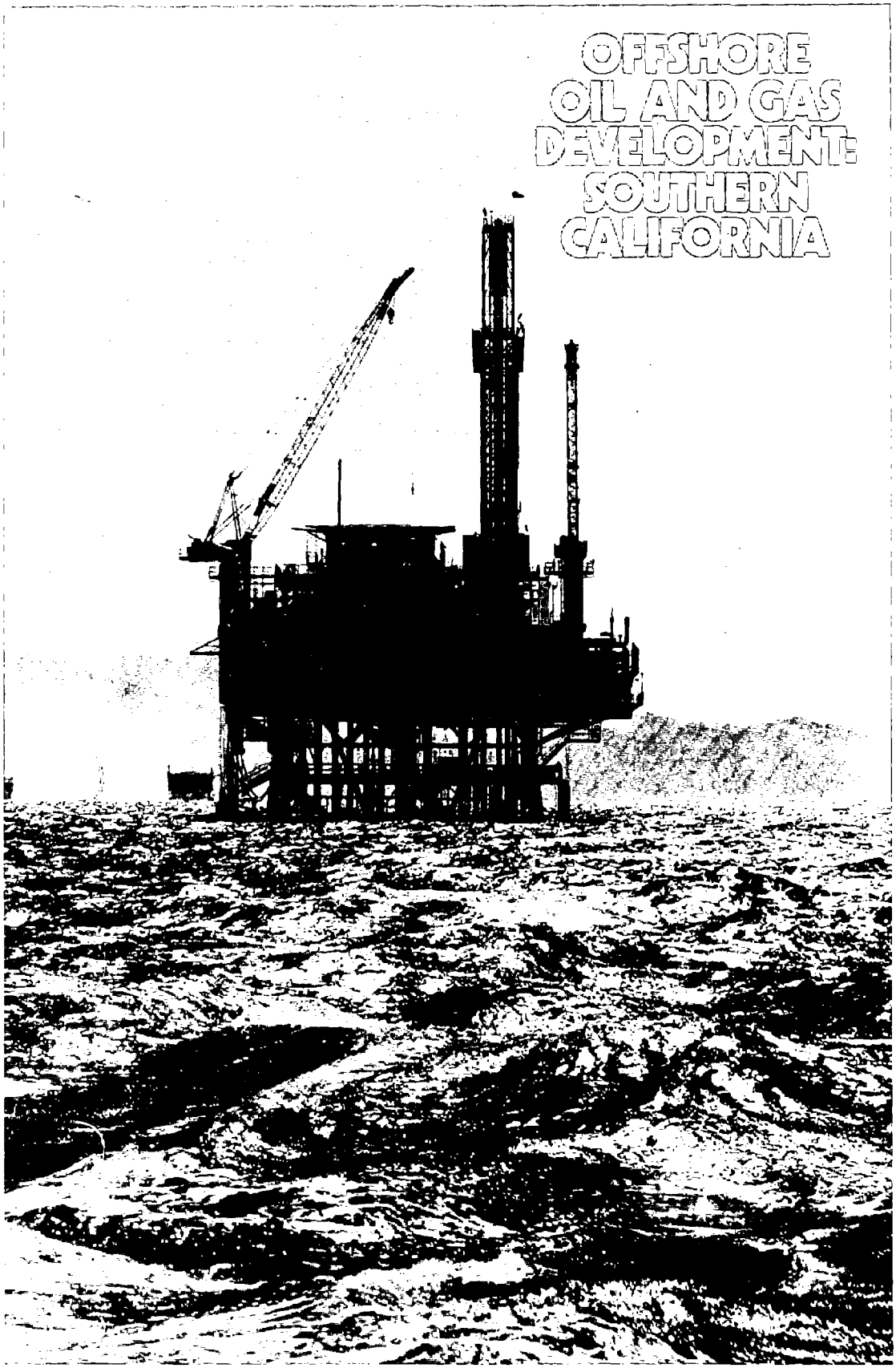
OFFSHORE OIL AND GAS DEVELOPMENT: SOUTHERN CALIFORNIA



OCS PROJECT TASK FORCE / OFFICE OF PLANNING AND RESEARCH

VOLUME ONE

OFFSHORE OIL AND GAS DEVELOPMENT: SOUTHERN CALIFORNIA

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PHOTOGRAPHY
Pages 409 and 434, courtesy of Clean Seas, Inc.; pages 521 and 563, courtesy of Exxon Company, USA; all others by OPR staff.

Copies of Offshore Oil and Gas Development: Southern California, Volumns 1 and 2 may be purchased from: General Services, Publications Section, P.O. Box 1015, North Highlands, 95660, (916/445-1020). $2.10 per set, includes: postage, handling, and sales tax.

This report was prepared with financial assistance from the Office of Coastal Zone Management, National Oceanic and Atmospheric Administration, under provisions of the Federal Coastal Zone Management Act of 1972.

OFFSHORE OIL AND GAS DEVELOPMENT: SOUTHERN CALIFORNIA

VOLUME ONE

A Staff Report

U.S. DEPARTMENT OF COMMERCE NOAA
COASTAL SERVICES CENTER
2234 SOUTH HOBSON AVENUE
CHARLESTON, SC 29405-2413

Prepared for the California Coastal Commission
by the OCS Project Task Force,
Office of Planning and Research

October 1977

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EDMUND G. BROWN JR.
GOVERNOR

Mr. Bradford Lundborg, Chairman
California Coastal Zone Conservation Commissions
1540 Market Street, Second Floor
San Francisco, California 94102

Dear Mr. Lundborg:

In fulfillment of a contract between this office and the California Coastal Commission, I hereby transmit this report on the implications of OCS development for southern California.

I believe this document more than satisfies the objectives your Commission established for it, and that it will serve well the long-term needs of the Commission and the State with regard to management of our OCS resources. I also believe that the report will prove itself of immediate value to the Commission in its work on local coastal programs, the Coastal Energy Impact Program, federal approval of the California Coastal Management Program, and coastal energy facilities permit decisions.

To obtain the widest range of viewpoints on the issues covered in this report, OPR made a major effort to involve all parties concerned with OCS matters. Over 600 individuals representing themselves, interest groups, petroleum companies, and State and local government agencies were given the opportunity to review each chapter in draft form. Twenty workshops were held on the report in the five southern coastal counties. Several working sessions were devoted to discussing key issues with selected scientists and engineers. Through numerous interviews and extensive questionnaires, OPR's OCS Task Force collected specific data on crucial aspects of current and projected OCS activities. The Task Force also met with major southern California OCS operators to discuss candidly both the industry's philosophical concerns with government intervention in OCS development and its practical concerns over implementing specific development proposals.

The problems dealt with in this report are complex, and their resolution will require an unprecedented level of cooperation between public and private institutions. The study, therefore, makes recommendations to all levels of government, to the petroleum industry at large, and to the proponents of specific developments that are or soon will be affecting the coast of southern California. We ask all interested parties to consider these recommendations carefully and to act on them to the fullest extent possible.

Mr. Bradford Lundborg

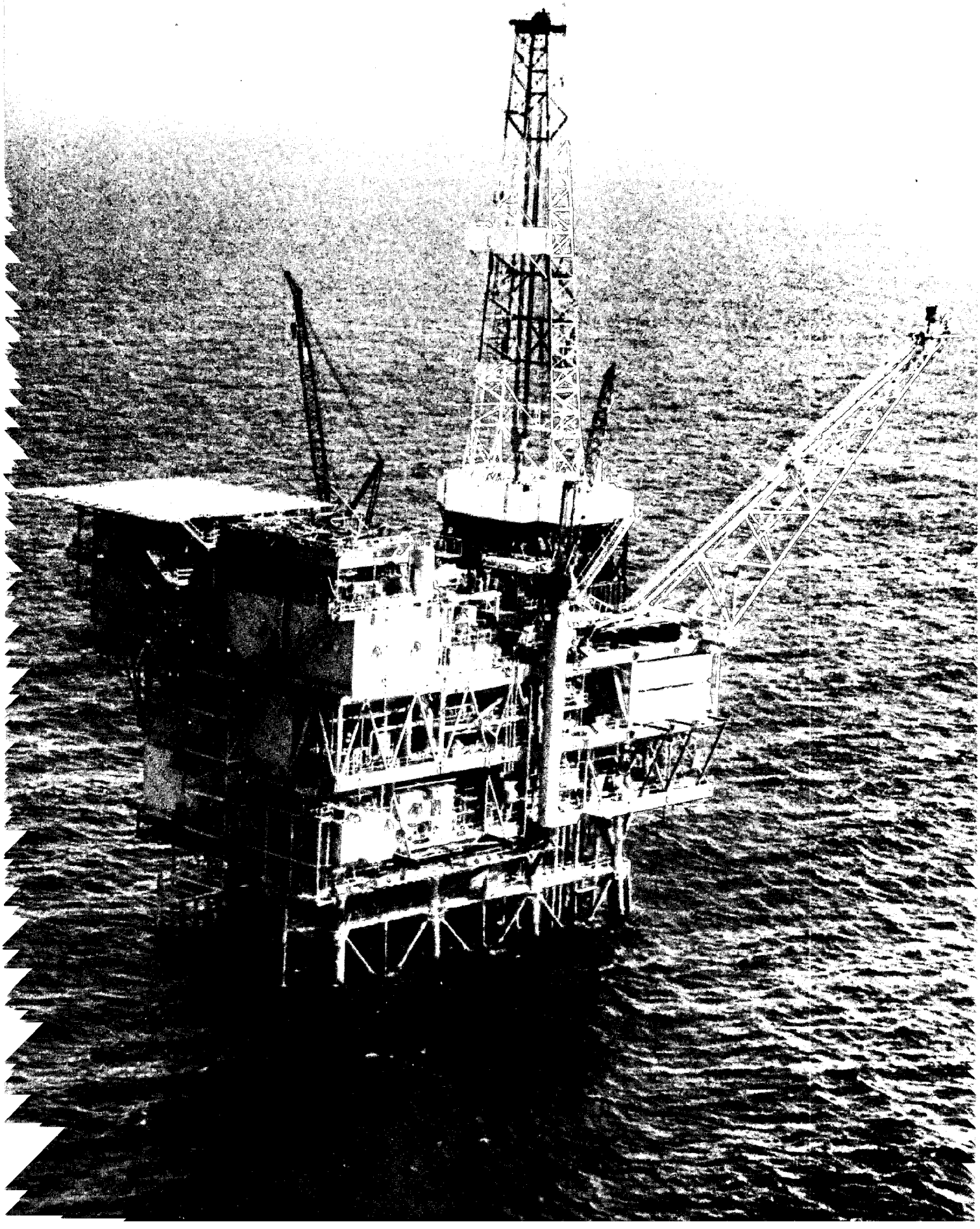
A major finding of the study is that this State's primary responsibility for overseeing OCS development should lie with the California Coastal Commission. Therefore, I urge members of the Commission, in their detailed consideration of all the findings and recommendations, to support the recommendations made to others, and to pay particular attention to those recommendations which express the Commission's goals and objectives for OCS-related oil and gas development.

The Office of Planning and Research is ready to answer any questions that you may have about the study, to meet with your staff to discuss the intricate details of pending OCS development proposals, and to present our major findings and recommendations to the Commission at your earliest convenience.

Sincerely,

Bill Press
Director

Photo opposite: Platform Hondo, located on the Santa Ynez Unit, Exxon Company, USA.



ACKNOWLEDGEMENTS

During the course of the study, many individuals and organizations freely contributed their advice and opinions on its direction and substance. Though not all will agree with the way some topics have been handled, we wish to express our appreciation to them and the agencies they represent for their concerted effort.

From the petroleum industry, we wish to thank Jack Hundley, Atlantic Richfield; Tom Hudson and Forrest Smith, Chevron Company, USA; Captain A. J. Bush, Clean Coastal Waters, Inc.; Darrell Warner, Exxon Company, USA; Richard Voils, Mobil Oil Corporation; Ben Piester, Phillips Petroleum; and, Hank Wright, Western Oil and Gas Association.

Representatives of the federal government we wish to thank include Bill Grant, Mike Carter, Tom Cooke, and Don Keene of the Bureau of Land Management; Lawrence McBride, Al Powers, and Peter Tweedt of the Department of the Interior; Dr. Jerry Gault of the National Oceanic and Atmospheric Administration; Lt. Richard Brandes, U.S. Coast Guard; and, Maury Adams, Henry Cullen, Bill La Velle, Hillary Oden, and Michael Reitz of the U.S. Geological Survey.

From state agencies, we wish to thank Paul Allen, Andy Ranzieri and Pete Venturini, Air Resources Board; Rob Solomon, Energy Commission; Walt Putman and Robert Bell, Department of Fish and Game; Glenn Ledingham, Division of Oil and Gas; Dr. James Rote, Resources Agency; Don Everitts, John Messer, Bob Paul, Dwight Sanders, Moose Thompson, and Dr. Ed Welday of the State Lands Division; and John White, Assembly Committee, Resources, Land Use and Energy.

Representatives of local governments we wish to thank include Dennis Allen, City of Long Beach; Steve Sachs and Art Letter, San Diego County CPO; Al Reynolds and Al McCurdy, Santa Barbara County OEQ; Graham Smith, City of Los Angeles Mayor's Office; Joe Chesler, Los Angeles County DOB; and Bob Davis, Huntington Beach.

Others we wish to thank include Jeff Frautschy, Joseph Reed, and Dr. Richard Schwartzlose, Scripps Institution of Oceanography; Dr. Ronald Kolpack, University of Southern California; and Dr. George Hampson, Woods Hole Oceanographic Institute.

Consultants who prepared major analyses for this report included George Taylor, Environmental Research and Technology, Inc., Santa Barbara; Sandra Baron, Mike Kavanaugh, Dr. Richard Norgaard, and Rob Wolcott, Public Interest Economics West (PIE West), San Francisco; and Ruthann Corwin and Patrick Heffernan, Santa Barbara. George Taylor is the author of "Air Quality Impacts of Outer Continental Shelf Development in the Santa Barbara Channel" which appears as the second part of Chapter 15. The PIE West consultants are the authors of Chapter 18, "Economic Effects: Benefits vs. Burdens" and of "The Santa Ynez Petroleum

Transportation Controversy" which appears as a part of Appendix 5. Ruthann Corwin and Patrick Heffernan are the authors of "Local Government and Offshore Oil: Santa Barbara Case Study" (unpublished). Staff of the State Lands Division prepared Appendix 1 of this report.

Support staff involved in the preparation of this report include Nancy Aurich (Project Administration Assistant), Cassie George, Joanne Haralson, Tad Hubbard, Carolyn Lentz, Loni Mahan, Lois Naylor, Randy Petersen, Tom Tesluk, and Mike Yeager. Cartographic work was prepared by Corinne Brainard, Marlin Dulay, David Howerton, and April Thanos. Professional staff who also contributed to the project include Bill Armstead, Claudia Ayers, Joe Wharton, and Woody Wilson.

The final report was designed and readied for publication by Allan Lind. It was edited by Claudia Buckner, Kay Munroe, and R. B. Read. The figures and maps were designed and executed under the direction of Marlin Dulay.

OCS Project Task Force: David Calfee, William Deller, Richard Grix, Richard Hammond (Project Director), Allan Lind, Trevor O'Neill, Carol Pillsbury, and Suzanne Reed (Project Manager).

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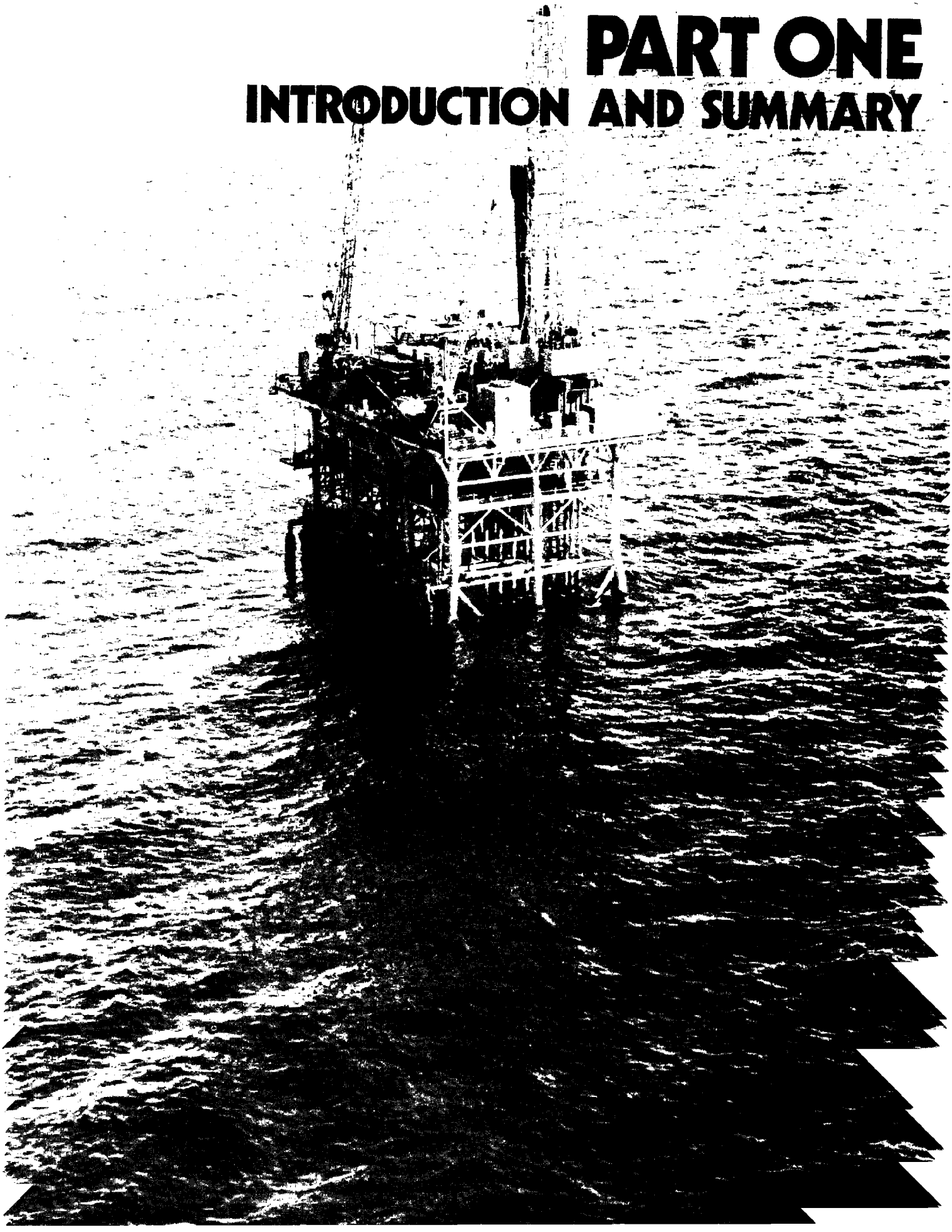
Front cover: Sun Production Company's Platform Hillhouse on the Dos Cuadras Offshore field.

Back cover: The Dos Cuadras Offshore field, from left to right: Sun's Platform Hillhouse and Union's Platforms "A," "B," and "C."

Photo opposite: Platform Holly on the South Elwood Offshore field, Atlantic Richfield Company.

PART ONE
INTRODUCTION AND SUMMARY



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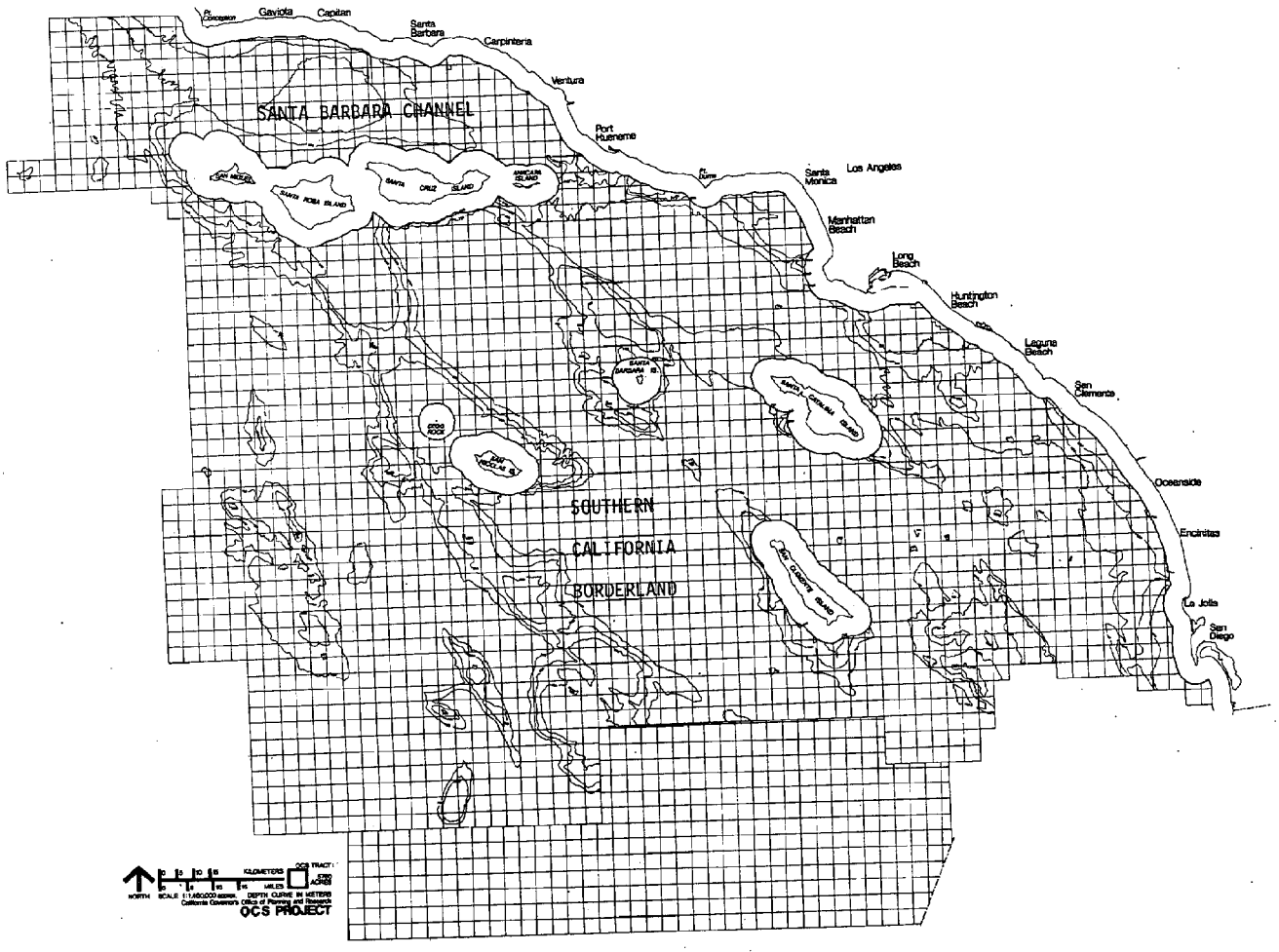
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San Clemente
Oceanside
Encinitas
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SANTA BARBARA CHANNEL
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SANTA ROSA ISLAND
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ANACAPA ISLAND
SANTA BARBARA IS.
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OCS PROJECT

CHAPTER 1:

INTRODUCTION

In late 1975, the California Office of Planning and Research prepared an initial study of effects of Lease Sale #35, Onshore Impact of Offshore Southern California Lease Sale No. 35. That study also identified critical gaps in federal impact assessments of southern California oil and gas development. Specifically, the study found that:

- Interior Department estimates of OCS resources were not made available in a form useful to state and local planners;
- the data necessary for the state to make an independent evaluation were withheld;
- the localized onshore consequences of new or expanded onshore facilities related to offshore oil and gas development were not identified;
- the impacts on air quality of offshore petroleum production, transportation, storage, processing, and distribution were ignored; and,
- the relationship of OCS development to California's coastal management program was inadequately discussed.

Building upon the information collected for the earlier study, this report, Offshore Oil and Gas Development: Southern California, describes in greater detail the specific effects of OCS development in southern California. The report examines localized adverse effects of OCS development and recommends changes in existing federal, state, and local institutional arrangements to lessen or eliminate these effects. The report also examines the potential for development and recommends means to achieve the most positive effects from OCS development. Finally, this report makes recommendations concerning the currently pending southern California OCS Lease Sale #48.

PERSPECTIVE

The southern California coastal and offshore areas are richly endowed with unique and irreplaceable natural resources. The warm ocean waters, islands, and coastal habitats support a diversity of marine mammals, fish, shellfish, and other marine organisms, as well as terrestrial plants, animals, and birds. Many species are rare and endangered. A number of southern California's industries depend on coastal and offshore resources, particularly commercial and sportfishing, tourism, and agriculture. In addition, by virtue of its underlying geology, this area is also one of the more attractive regions in the United States for oil and gas development.

Onshore production of oil and gas in southern California contributes significantly to California's present rank as the third largest petroleum-producing state in the U.S. Although the extent of the offshore petroleum resource remains to be determined, the petroleum industry and federal government rank southern California's OCS potential as extremely high. Offshore petroleum activities, however, threaten the recreational assets of the coast, the agricultural base, the unique characteristics of intertidal zones, offshore shallow banks and islands, and the quality of the air. Californians desire the preservation of these environmental resources, and are concerned that once our petroleum resources are depleted, we may also find that our air and waters have been irretrievably polluted and vulnerable habitats have been lost as well.

OFFSHORE OIL AND GAS DEVELOPMENT: 1896 TO 1976

Offshore development of oil and gas resources dates back to 1896 when the very first offshore production in the United States began in the tidelands of Santa Barbara County. The first state leases were sold in the 1950s. Today there are approximately 33 state oil and gas leases in the Santa Barbara Channel tidelands and another 19 off the Los Angeles and Orange County coasts. Production of oil and gas from these tideland leases is declining; and, with few exceptions, most of these will be exhausted in the next decade. Nevertheless, with renewed and accelerated federal leasing activity, southern California's period of greatest offshore development and production activity is just beginning.

In 1963, development of the federal OCS lands offshore of California began with issuance of 57 leases located in six different areas between Point Conception and the Oregon border. Lessees drilled a total of 21 exploratory wells on these leases between 1963 and 1967. All of these wells were later abandoned as unproductive and the leases quitclaimed.

In 1966, the Department of the Interior held a one-tract drainage sale in the Santa Barbara Channel to allow development of a known field which was being drained from an adjacent state lease. Two years later, California experienced its first major lease sale concentrated in one area: the Santa Barbara Channel.

As a result of the 1966 and 1968 lease sales, 72 federal leases were sold in the Channel OCS, of which 65 remain active today. Following the 1969 blowout at Union Oil Platform "A" in the Dos Cuadras field, then Secretary of Interior Hickle imposed a temporary moratorium on development of leases in the Santa Barbara Channel. Until 1976, only one Santa Barbara Channel operator, Exxon, submitted a development plan (Santa Ynez Unit) to the Department for approval. Thus, the Channel is still in a relatively early stage of development.

In December 1975, the Department of the Interior held southern California OCS Lease Sale #35. The Department offered approximately 217 tracts for sale, but only 56 were actually leased. Thus far, Sale #35 lessees have drilled 21 exploratory wells. Exploratory activities are greatest in the San Pedro Bay area where 17 wells have been drilled. Shell Oil Company has already identified a commercial discovery on its San Pedro Bay leases and has announced plans to develop this prospect. The first crude oil or gas production from Lease Sale #35 tracts should occur soon after 1979.

PROSPECTS FOR THE FUTURE

California now faces two additional lease sales. In 1979, the Department of the Interior proposes to offer tracts in the Southern California Borderland and Santa Barbara Channel (Lease Sale #48). In 1981, current Department plans call for offering tracts along the central and northern California coastline (Lease Sale #53). The Department is now preparing an environmental impact statement on Lease Sale #48 and has initiated environmental baseline studies for the Lease Sale #53 area.

As a result of the Interior Department's removal of federal obstacles to development in the Santa Barbara Channel in 1976 and Lease Sale #35 in 1975, southern California has entered a new era of offshore oil and gas development. State and federal lessees in both areas are actively pursuing exploration and development off the southern California coast. Future lease sales now contemplated for this area will sustain, if not increase, this activity through the next decade. Given the history of OCS development, it is not unreasonable to assume that some conflicts between OCS activities, coastal management, and environmental protection goals will occur as the pace of development accelerates offshore.

Recent changes in federal policy suggest, however, that future OCS leasing and management decisions will include greater participation by the affected state and local governments and will eliminate many potential conflicts. Further, in a letter to Governor Brown dated June 28, 1977, Secretary of the Interior Cecil Andrus stated, "This Administration seeks to cooperate with the states because of our confidence that the states will, when treated as partners, work in the national interest, as well as their own, in developing offshore reserves while protecting the environment." This change in attitude from previous Administrations, coupled with new planning tools created by the federal Coastal Zone Management Act Amendments of 1976, the California Coastal Act of 1976, and changes in federal OCS leasing and management legislation expected to become law this

year, lay a promising foundation for local/state/federal cooperation on OCS issues.

Clearly, unfounded or unreasonable regional objections should not override the national need to increase domestic energy supplies; but there is also a national and a regional need to minimize air pollution, damage from oil spills, and damage to wildlife from OCS-related activities. It is imperative that we both develop OCS energy resources and protect the environment. This report strikes that balance.

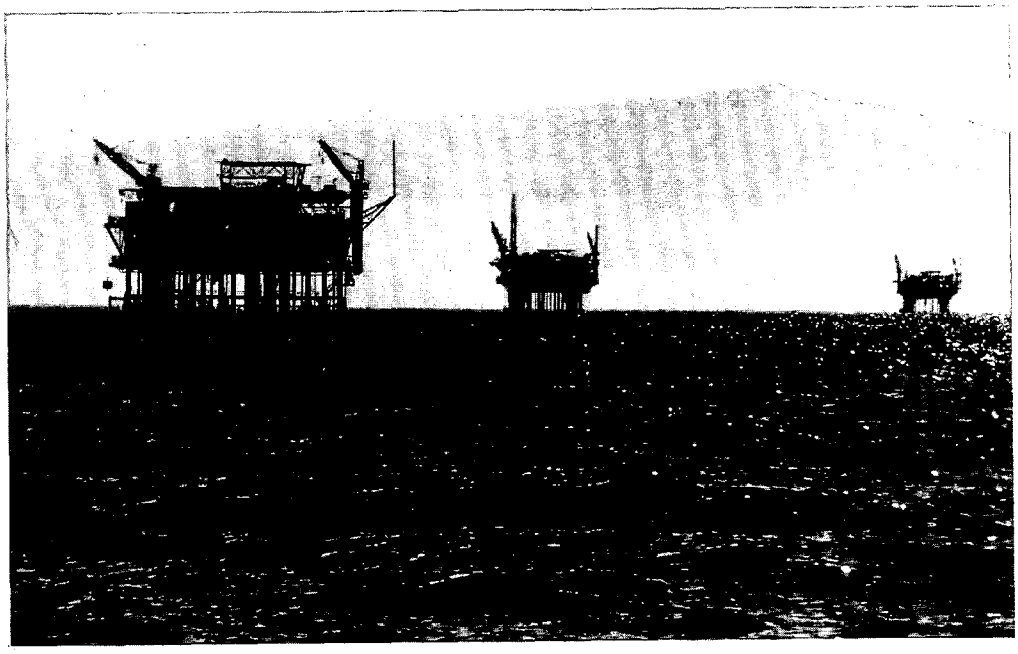


Photo above: Platforms Hogan (Phillips), Hope and Heidi (Chevron) on the Carpinteria Offshore field.

CHAPTER 2:

SUMMARY

Exploration and development in the Santa Barbara Channel is accelerating after completion of the Santa Barbara Channel EIS in 1976 and settlement of law suits stemming from the moratorium imposed after the 1969 blowout. Lease Sale #35 in December, 1975, opened an additional 56 tracts in the Southern California Borderlands to oil and gas development. Two lease sales formerly scheduled in 1978 for the California OCS have been delayed. Lease Sale #48 and #53, originally scheduled for March and October of 1978, respectively, have now been included in the new OCS leasing schedule covering the period 1979 through 1981. The Department of the Interior will hold Lease Sale #48 in 1979 and Lease Sale #53 in 1981.

The study area encompasses the outer continental shelf extending offshore from Point Conception in Santa Barbara County south to the international boundary with Mexico as well as inland areas to the extent that they are directly affected by OCS development. Topics covered by the report include institutional arrangements for managing the OCS, socio-economic and environmental effects of OCS development, facility siting, and future leasing. The report suggests changes in the present system of OCS management and also identifies opportunities for new OCS development. Recommendations are addressed to federal, state, and local governments and industry to carry out needed actions. The major policy and specific development proposals recommended in this report are summarized in the following paragraphs.

MANAGEMENT OF OCS DEVELOPMENT

California has little control over OCS development on federal offshore lands, but must live with the onshore economic, social, and environmental consequences of that development.

Federal OCS lands are leased on the basis of speculative estimates of oil and gas potential, without any direct information from exploratory drilling. Restructuring the federal OCS leasing process to permit pre-lease exploratory drilling and to separate exploration and development would provide an opportunity to decide whether a lease should be developed after weighing environmental risks against the value of the producible reserves. Administrative actions by the Interior Department could make state and local participation in the present process easier and more effective.

Congress should pass legislation requiring the Secretary of the Interior to accept the recommendations of an affected state's governor on proposed OCS action unless the Secretary determines they are not consistent with the overriding national interest. The Interior Department should acquire direct information from on-structure exploratory drilling to make tract-by-tract oil and gas resource estimates before tracts are offered for sale. Congress should amend the OCS Lands Act to (1) give the Secretary of the Interior authority to cancel any lease or permit if continued activity under that lease or permit would cause serious harm or damage to the surrounding environment, (2) shorten the primary lease term of OCS leases from five to three years to encourage early exploration, and (3) remove the limits on the Secretary of Interior's authority to apply new or revised regulations to leases maintained under the Act. The Interior Department should make possible more effective state and local government participation in the leasing and management process by involving them in the preparation of environmental impact statements (EISs) and in informal discussions with offshore operators on development plans. It should also provide copies of resource reports to the state at the same time they are issued to federal agencies and hold an environmental briefing for state and local representatives on the lease area before nominations are due.

ADEQUACY OF DECISION INFORMATION

There are three kinds of information state and local governments need most: oil and gas resource estimates, development plans, and environmental baseline studies. Oil and gas resource information, the basic building block for state and local planning efforts, is held closely by the industry and is not published in a useful or regular manner by the Interior Department. Offshore development plans, submitted to the Interior Department by OCS lessees, could be a valuable planning tool, if they included basic environmental and economic data in a form useable by state and local governments, but current law does not require lessees to make this information available. At the federal level, leasing decisions are proceeding without the benefit of environmental baseline information that would allow the formulation of appropriate trade-offs between development and environmental protection.

This section includes 17 recommendations for improving federal, state, and local decision-making information. We recommend that the Interior Department publish regularly updated resource estimates and provide California with access to the data upon which these estimates are based. In Chapter 13 we present means of improving intergovernmental coordination for the exchange of OCS information and suggest changes in the procedures for reviewing development plans to increase state and local government influence. Finally, we recommend that the Environmental Baseline Studies Program (EBSP) be restructured and that the BLM establish an EBSP Task Force.

AIR QUALITY

Preventing further degradation of air quality is one of the most critical environmental issues facing southern California. OCS oil operations contribute substantial amounts of reactive hydrocarbons, aggravating an already critical problem of smog in the South Coast Air Basin. Neither federal, state, nor local agencies presently regulate air emissions from OCS operations in federal waters. Tanker loading operations in particular are the largest source of hydrocarbon emissions. Predicting the effect on air quality from any particular OCS operation, however, is difficult because offshore meteorological data are sketchy and emission estimates for OCS-related operations vary widely.

This report recommends that OCS leasing and development should not be permitted in areas or under conditions which would allow violation of standards or further degradation of southern California air quality. OCS facilities should be subject to reviews, permit controls, and emission standards equivalent to those imposed upon similar facilities within state jurisdiction. Federal and state agencies, local jurisdictions, and industry should coordinate efforts to collect the necessary data for making accurate OCS air quality impact projections.

SENSITIVE COASTAL RESOURCES

Key natural resources that could be affected by OCS development include pinniped and seabird rookeries, wetlands, rocky intertidal areas, and offshore banks. In addition, the Channel Islands are richly endowed natural areas which should receive special protection from oil spills. Petroleum sanctuaries should be established around seal and sea lion rookeries. In these areas, no new leases should be sold and existing leases should be terminated. Shallow offshore banks, important as sources of food or as unique habitats, should be excluded from future lease sales and existing leases should be terminated or subjected to stringent controls. High priority

should be given to identifying critical seabird foraging areas where a spill could endanger entire breeding populations so that operations can be precluded or specially restricted to protect these populations. Several actions -- including the establishment of marine sanctuaries, legislation to create a Channel Islands National Park, and executive orders to clear up existing enforcement authority -- are recommended to strengthen the protection of sensitive natural resources on the Channel Islands. Environmental impact statements, exploration plans, and development plans should evaluate the vulnerability of economic and recreational resources in the event of a major spill, considering the adequacy of existing response plans and equipment to protect local interests.

OIL SPILLS

Oil is discharged as the result of a variety of OCS-related and oil transportation operations. The cumulative effect of these activities is such that at least one major oil spill, and many smaller spills, is likely to occur off the southern California coast in the future. The protection of valuable coastal resource areas is accorded high priority in state and local planning. Such planning improves when the trajectory of an oil spill in any given offshore area is known. The information needed for predicting spill trajectories, however, is presently inadequate. Further, once an oil spill has occurred, those who sustain real economic losses find that limited compensation is available under current law.

Most of the equipment available to contain an oil spill or to clean it up once it reaches shore is owned by industry cooperatives and stored in Santa Barbara, Los Angeles, and Long Beach Harbors. Some distribution of cleanup equipment close to sensitive areas has occurred, though presently many areas are still unprotected.

The report contains several recommendations to improve offshore meteorological data and spill trajectory prediction for planning purposes, as well as the re-deployment of equipment to provide maximum coverage for sensitive resources in the southern California areas. It calls for the state to establish a testing program for spill containment and cleanup equipment and to require periodic demonstrations of response capability by cleanup organizations. The report also recommends a state fund to provide compensation to spill victims, to finance cleanup and restoration, and to support state and local oil spill prevention and response activities.

ECONOMIC EFFECTS

Lease Sale #35 will not have a significant effect on the economy in southern California. The ratio of OCS-related activity to other economic endeavors is so small that new direct and indirect employment will be insignificant and increases in public service demands so small that they can be satisfied with existing excess capacity. Tax revenues comprise a small fraction of total revenues in the affected area, but they may be significant locally, depending upon the sites ultimately chosen.

FACILITIES PLANNING

Unitization and consolidation offer key opportunities for reducing the environmental effects of offshore oil and gas development and for recovering the greatest amount of oil and gas efficiently. Unitization is an established procedure for coordinating the exploration, development, and production facilities or activities of several companies who share a common petroleum reservoir or geologic structure. Consolidation refers to the sharing of petroleum-related facilities, such as pipelines, processing plants, or marine terminals. Unitization and consolidation have occurred voluntarily when advantageous to industry but have rarely been imposed by public agencies on OCS developers even when public interest would clearly dictate such intervention.

We recommend that the USGS, in cooperation with the California Coastal Commission, adopt guidelines to ensure that all OCS operations and facilities will be consistent with state and local coastal zone management programs. USGS should require (1) unitization of all leases sold according to common geologic structures and (2) consolidation of transportation, storage, treatment, and service facilities related to OCS exploration and development when it is both economically and environmentally desirable. Finally, this section recognizes the ability of industry to provide leadership on OCS development and recommends that industry take the initiative in defining the necessary detail for unitization and consolidation opportunities.

TRANSPORTATION

This section describes the existing oil and natural gas transportation system in southern California and compares the flexibility, costs, and environmental effects of pipeline and tanker/barge transportation systems.

Because of their relative safety, California should adopt a strong policy favoring pipelines over tankers whenever feasible and support the development of an integrated common carrier pipeline network linking production areas with refining centers and/or a west coast to mid-continent pipeline, if it is built. Further, all fixed structures associated with exploratory and production activities should be excluded from the Vessel Traffic Separation Scheme (VTSS) in the Gulf of Santa Catalina and the Santa Barbara Channel. If ocean floor production systems must be used, production wells could be drilled from surface vessels within the VTSS after appropriate precautions have been taken.

DEVELOPMENT SCENARIOS

Santa Barbara Channel production will probably exceed 100,000 B/D oil and 100,000 MCF/D natural gas in the early 1980s, reaching a peak near 200,000 B/D oil and 200,000 MCF/D gas in the mid 1980s. Additional leases and discoveries may slow the decline, but should not require onshore facilities beyond those necessary for the projected peak. Chapter 21 presents the state of development, resource and production forecasts, and onshore development options for various leased areas.

Major recommendations in this section are directed to the State Lands Commission, the Interior Department, and the oil industry. The State Lands Commission is urged to determine probable remaining lifetimes for production, processing, and transportation facilities on state lands, and to assist parties interested in the recycling of the sites from petroleum-related uses to other uses. The Interior Department is urged to withdraw its approval of the "offshore alternative" included in the Exxon/Santa Ynez development plan and to prepare resource analyses resolving a major discrepancy between the USGS and Exxon resource estimates which are necessary to assess the viability of Channel-wide transportation options. Industry should bring all new Channel OCS production ashore in two pipeline networks located at both ends of the Channel. It should process production from the eastern end at the existing Mobil-Rincon facility, and that from the western end at the proposed Exxon-Las Flores facility. It should evaluate the feasibility of an onshore pipeline to carry Channel Production to refineries as part of the EIS being prepared for Lease Sale #48. It should develop the four subareas created by Lease Sale #35, outside of the Santa Barbara Channel, according to lease-area plans. In order to promote the corrdinated development and transportation of offshore oil and gas, it should not begin development until lease-area plans are completed.

Because San Pedro Bay leases are likely to be developed before other subareas of Lease Sale #35, specific recommendations have been formulated: the treatment and separation of San Pedro Bay production should be handled at an expanded existing processing plant or at a new onshore facility in Huntington Beach or Los Angeles/Long Beach harbors area, and offshore processing stations should be discouraged in this area because of the unnecessary risk they would represent to navigational safety.

LEASE SALE #48

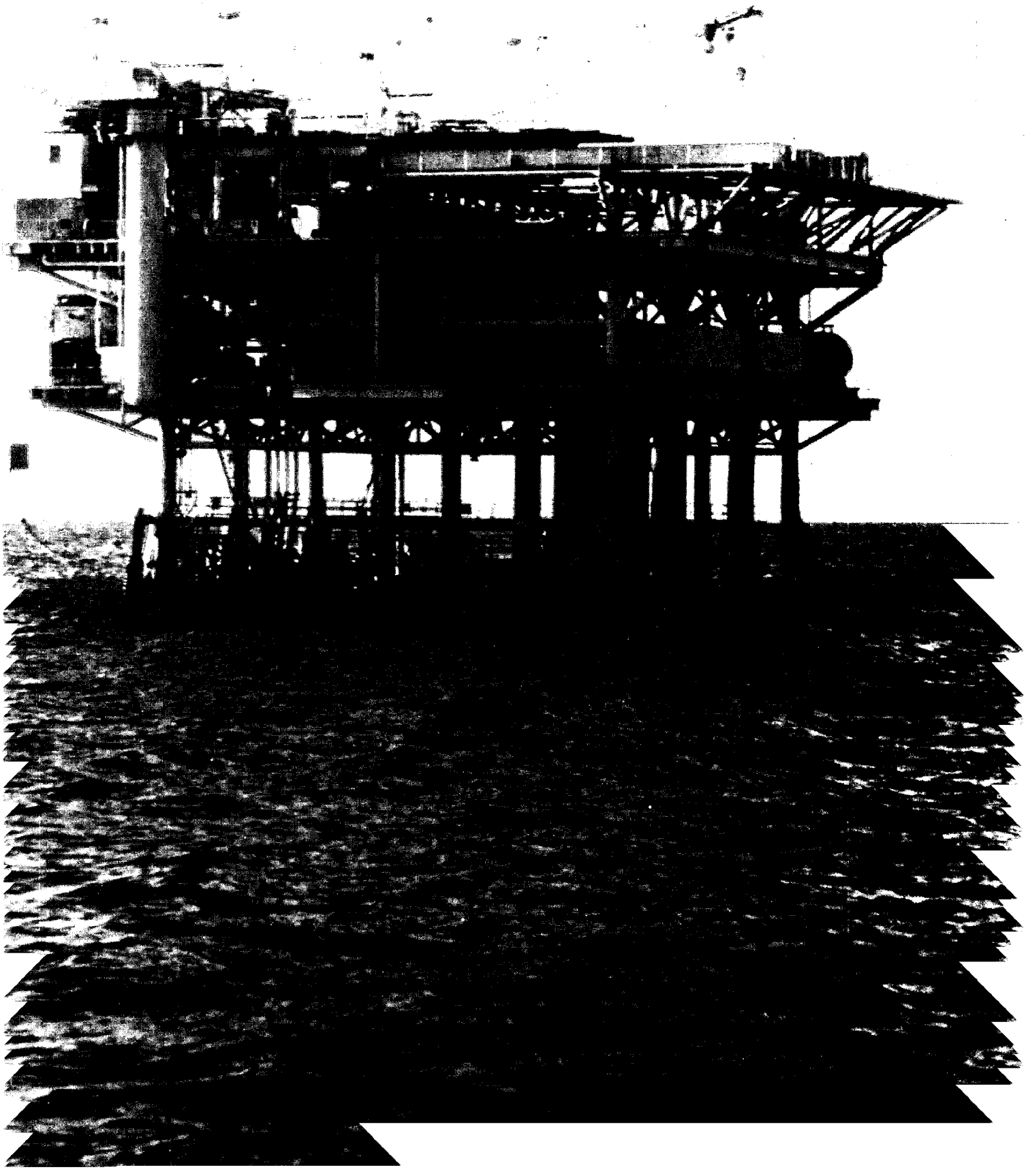
The State of California does not oppose OCS oil and gas leasing and development per se, but does object to leasing and development without adequate environmental safeguards. In selecting the 217 tracts for Lease Sale #48, the Department of Interior placed oil and gas resource potential over the concerns for environmental vulnerability expressed by California state and local governments as well as by other federal agencies. Oil resources from the OCS will only contribute to the projected west coast oil surplus, while OCS gas cannot eliminate California's need to import natural gas or seek substitute fuels to meet its natural gas demand.

Lease Sale #48 was delayed at the request of state and local governments but was recently rescheduled. California's position is that this lease sale should not be authorized until Congress amends the OCS Lands Act to increase state and local government influence over the leasing and development process and to strengthen environmental safeguards. These amendments are now under consideration by Congress and could be enacted this session.

The Interior Department should facilitate state and local involvement in the EIS process for Lease Sale #48 by distributing all work programs and preliminary drafts to state and local governments in a timely fashion, as well as holding public hearings on the DES and FES in each of the affected coastal counties. Future lease sales off southern California should place high priority on filling in areas leased on the Santa Rosa-Cortes Ridge and in San Pedro Bay, but only if development can proceed without siting permanent structures in the vessel traffic lanes. Further leasing in the Santa Barbara Channel should be considered in a separate EIS as opposed to inclusion of this area with the Southern California Borderlands now being considered by BLM in Lease Sale #48. Finally, we recommend that tracts along the San Diego coastline should not be offered until further baseline studies have been completed, including an assessment of the potential for this area to economically produce petroleum resources.

Photo opposite: Platform Houchin on the Carpinteria Offshore field, Phillips Petroleum

PART TWO
FINDINGS AND RECOMMENDATIONS



CHAPTER 3:

MANAGEMENT OF OCS DEVELOPMENT*

FINDINGS

CALIFORNIA HAS LITTLE CONTROL OVER OCS DEVELOPMENT. New offshore oil and gas development will occur primarily on federal OCS lands beyond the limit of California's jurisdiction. Federal policy determines the timing, size, and location of lease sales and federal agencies regulate industry exploration and development activities. OCS oil and gas development plans may include onshore processing, storage, and other facilities subject to state and local controls, but such facilities can be built in federal waters offshore beyond state and local jurisdiction. Hydrocarbon emissions, oil spills, and economic and social impacts, however, do not recognize jurisdictional lines. The course of offshore development will determine the onshore impacts California must bear, but the state and local governments of California can only comment on leasing and development plans and hope their concerns will be reflected in the decisions of federal officials. California may gain some control over OCS oil and gas development through the consistency provisions of the Coastal Zone Management Act as amended, but the effectiveness and scope of those provisions are uncertain.

LEASING BASED ON SPECULATIVE ESTIMATES. The Department of the Interior now selects and leases OCS tracts based only on speculative estimates of their oil and gas potential. Estimates of the resource potential of tracts are inferred from geophysical and geologic data collected before the sale, but there is no drilling to discover oil and gas until after the tracts are leased. Without drilling, estimates of recoverable resources depend on assumptions about the physical characteristics of the reservoir, the quantity of hydrocarbons present, and the physical properties of the hydrocarbons. Sometimes, in areas where there has been little or no history of oil and gas operations, test wells are drilled to collect geologic information. These wells are intentionally drilled low on

*For additional discussion, see Chapters 13 and 14.

geologic structures suspected of containing oil and gas, so as to prevent the discovery of oil and gas. Prior to leasing, however, the Interior Department rarely has any direct information on oil and gas resources from which to judge where leasing should be concentrated in order to increase domestic production or to weigh the benefits against the environmental risks of developing specific tracts. In a few instances, direct information is available from a well or wells drilled on a leased tract into a geologic structure that also underlies an unleased tract or from core wells drilled off southern California before the federal-state boundary was finally established.

SALE OF EXPLORATION AND DEVELOPMENT RIGHTS. When a lease is sold under the present system, successful bidders acquire vested rights to explore the lease tract and to develop and produce the oil and gas they discover. A decision to lease is virtually a decision to develop. At the time of the lease sale, however, only general information on geologic hazards and speculative estimates of oil and gas resources are available. New and specific information on geologic hazards associated with specific tracts and direct information on oil and gas reserves are collected and developed during the exploration phase. The grant of development and production rights with the lease precludes the federal government from using information developed in the exploration phase for judging the benefits and risks of developing particular tracts.

CANCELLATION OF LEASES. The authority of the Secretary of the Interior to cancel a lease should the continuation of oil and gas operations thereafter pose serious harm to human life, property, mineral deposits, or the environment which was not foreseen at the time the lease was issued is disputed. The Secretary may cancel a lease if the lessee fails to comply with any of the provisions of the OCS Lands Act, or of the regulations issued under the Act, or of the lease itself, but there is no authority for the Secretary to compensate lessees for their costs up to the date the lease is cancelled.

INCREASING OCS OIL AND GAS PRODUCTION. Increasing oil and gas production requires speedy and efficient exploration of offshore lands and development of discovered resources. The current federal strategy to increase offshore production relies on leasing large areas of the OCS without any direct information on the size, or even on the existence of underlying petroleum resources. Our national policy should strive to increase oil and gas supplies from the OCS by leasing in the most promising areas and fostering prompt exploration and development, not by leasing the maximum number of acres to the oil industry on the basis of mere speculative estimates of oil and gas potential. OCS oil and gas production can be increased without undue delay, incorporating informed and rational decisions, under alternative leasing systems that feature early drilling to discover hydrocarbons and do not simultaneously convey exploration and development rights.

PRIMARY LEASE TERM TOO LONG. The OCS Lands Act provides

that the primary term of OCS oil and gas leases is for : five years; so long as oil and gas are produced in paying quantities; or, the lessee conducts drilling or well reworking activities. The lease term is extended beyond the primary term therefore, if an exploratory drilling program is underway despite the lack of a discovery of commercial quantities of oil or gas. Industry has demonstrated its ability in southern California to obtain all necessary regulatory permits and begin exploratory drilling, and even, in some cases, production from OCS leases in less than one year. There is no credible reason that exploratory drilling could not be underway on most tracts off southern California in substantially less than five years. Lease tracts sold in deep water to encourage development of more advanced offshore technology or in areas like Alaska where extreme weather could severely restrict operations are two exceptions.

INCENTIVES FOR EARLY EXPLORATION. In the North Sea, the Netherlands grants exploration licenses requiring rents that double in the second year and double again in the sixth. The Netherlands also requires licensees to spend a minimum amount each year in exploratory efforts and to surrender a portion of the acreage covered by the license back to the government after a specified time. British and Norwegian production licenses require rental payments that escalate over time, but the rentals may be deducted from royalty payments. Such progressive rental schedules, mandatory work programs, and reductions in the acreage covered by a lease after a specified time may be effective incentives to early exploration and development in place of the current U.S. practice of holding rents steady on OCS tracts without commercial discoveries.

SECRETARY'S LIMITED REGULATORY AUTHORITY. New or revised regulations promulgated by the Secretary of the Interior apply to leases issued before the effective date of the regulations only when they are issued for "the prevention of waste and conservation of the natural resources of the outer continental shelf." As a result, new regulations providing for review and comment on development plans by coastal states do not apply to OCS leases in the Santa Barbara Channel and no lease tracts off California are affected by regulations releasing geologic and geophysical data and information.

EIR PROCESS. Environmental Impact Reports prepared pursuant to the California Environmental Quality Act afford California and its local governments an opportunity to analyze the effects of onshore development proposals within state jurisdiction. The EIR process is not initiated, however, until well after development plans are formulated and industry has chosen sites for onshore facilities. Nonetheless, the EIR can be an invaluable tool for assessing alternatives and for developing strategies to mitigate the environmental impacts of specific OCS-related facilities.

CALIFORNIA'S ROLE IN EXISTING FEDERAL LEASING AND DEVELOPMENT PROCESS CAN BE IMPROVED WITHOUT NEW LEGISLATION. Although new legislation is required to effect many necessary changes in the leasing and development process, several problems frustrating California's participation are solely administrative in nature:

a. Resource reports. BLM's request for resource reports on the possible effects of leasing on the environment or other conflicting uses of the OCS (e.g., shipping, fishing) is usually the state's first notification of the specific area proposed for leasing. California received the resource report request for Lease Sale #48 at least one month later than federal agencies. Copies of agency responses, which are useful in responding to the call for nominations, are generally not made available to state and local governments.

b. Call for nominations and tract selection. The Interior Department gave an environmental briefing to state and local representatives on areas being considered for Lease Sale #48, but it was held after the deadline for responses to the call for nominations. When BLM's Pacific OCS Office briefed state and local government representatives on tract recommendations being made to the directors of BLM and USGS in Washington, the recommendations were presented in a vague and general way, and no written copies of the recommendations were provided. Thus, state and local governments had no basis for comment on the specific tracts recommended by BLM's Pacific OCS Office. In any case, there was insufficient time for state and local government representatives to prepare responses before a meeting scheduled to discuss tract selection with Washington-based BLM and USGS officials.

c. Environmental impact statement. State and local governments are not involved in the preparation of draft EISs, so their concerns are often neglected. Public hearings are presently held too soon after announcement of the availability of the draft EIS for state and local governments to acquire a copy, review it, and prepare comments.

d. Development plans. State and local representatives have not been invited to discussions between USGS and offshore operators preceeding formal submittal of development plans, when state and local concerns might be accommodated more easily than after economic and regulatory commitments have been made.

RECOMMENDATIONS

1. STATE RECOMMENDATIONS. Congress should pass legislation requiring the Secretary of the Interior to accept the recommendations of an affected state's governor on the five-year leasing schedule, a proposed lease sale, exploration plan, or development plan unless the Secretary determines they are not consistent with national security or the overriding national interest.

2. PRE-LEASE DRILLING. The Interior Department should acquire direct information from exploratory drilling to make tract-by-tract oil and gas resource estimates before lease tracts are offered for sale. California should make information from drilling in nearby state lands available to the federal government to assist in making resource estimates. Where direct information on geologic structures underlying a tract under consideration for leasing is not available from a well drilled on an adjacent lease or onshore area, at least one test well should be drilled on those structures before leasing. These test wells should be drilled using the same procedures now employed in the drilling of deep stratigraphic test wells off structures; i.e., the well should be drilled by a group of companies at a location approved by USGS. The companies should share the costs of the well and the data from it. USGS should receive data from the well as a condition of the drilling permit. Companies not participating in the group before the well is drilled should be allowed to buy the well data after paying a proportionate share of the well costs plus a substantial penalty.

3. AUTHORITY TO CANCEL LEASES. Congress should amend the OCS Lands Act to give the Secretary of the Interior authority to cancel any lease or permit at any time when continued activity under that lease or permit would cause serious harm or damage to any human life, to property, to any mineral deposits, or to the marine, coastal, or human environment. Such damage or harm should be required to outweigh the benefits of continuing activity under the lease or permit and be of a type that would not decrease over a reasonable period of time. Lessees whose leases are cancelled should be paid equitable compensation, based on all expenditures incurred up to the date of cancellation less any revenues received from production, but not including anticipated revenues from future production.

4. LEASING ENVIRONMENTALLY SENSITIVE TRACTS. In cases where tracts are offered for sale because of high oil and gas potential in spite of high risks to the environment from development and production, the Secretary of the Interior should have the discretion to offer leases for these tracts that grant exploration rights and make development and production rights subject to a determination by the Secretary that production benefits outweigh all other costs, including environmental costs. Lessees would receive the right to drill for oil and gas, and would receive development and production rights if the Secretary decides development should proceed. Because of the limited and conditional nature of the rights granted with the lease, some bidding system other than cash bonus bidding should be used for leasing these tracts.

5. SHORTEN PRIMARY LEASE TERM. To encourage early exploration, Congress should amend Section 8(b)(2) of the OCS Lands Act to shorten the primary lease term of OCS leases from five to three years. Congress should give the Secretary of Interior discretion to offer leases with longer primary terms in areas where extreme weather conditions prevail, in deep water areas to encourage advances in offshore technology, or where other extraordinary considerations would justify it.

6. RE-EXAMINE INCENTIVES FOR TIMELY EXPLORATION. Congress and the Interior Department should consider alternatives to the present system of collecting rents from OCS lease tracts without commercial discoveries of oil and gas, including progressive rental schedules, mandatory work programs, and a requirement that a portion of the leased acreage be given up after a specific time.

7. APPLY NEW OR REVISED REGULATIONS RETROACTIVELY. Congress should amend the OCS Lands Act to authorize the Secretary of the Interior to prescribe and amend at any time such rules and regulations as he or she determines to be necessary and proper for the purposes of the Act and to apply such rules and regulations to all operations conducted under leases issued or maintained under the provisions of the Act. Regulations designed to serve purposes other than to conserve the natural resources of the OCS or to prevent waste -- e.g., to enhance the role of State and local governments in the OCS leasing process or to ensure safe OCS operations -- could then be applied to leases existing at the time the regulations are issued or revised. To protect the legitimate and vested proprietary rights of lessees, however, leases should not be subject to forfeiture or cancellation

for the violation of regulations not in effect on the date the lease was issued. Regulations applied to leases issued before the effective date of the regulations should be enforced, on those leases, by strong penalties.

8. EIR PREPARATION AND CONTENT. Environmental Impact Reports prepared in conjunction with applications to site OCS-related facilities should carefully examine alternatives to the proposal and possible strategies for mitigating impacts, including consolidation potentials. Analysis of mitigating strategies should be conducted in sufficient detail to provide a basis for formulating permit conditions. Regardless of whether a state, county, or city agency serves as the lead agency for an EIR, all agencies with permitting authority over the facility should be involved in preparation of the EIR from its inception.

9. IMPROVING STATE AND LOCAL ROLE IN PROCESS. The Interior Department should act now, under existing authority, to make the following changes in the leasing and development process:

a. Resource reports. Issue resource reports to the state at the same time they are issued to federal agencies. Provide copies to the states of all agency responses.

b. Call for nominations and tract selection. Hold an environmental briefing for state and local representatives on the lease area before nominations are due. Provide the state with copies of all responses

to the call for nominations from local governments and the public. Provide the state with a written copy of the tract selection recommendations made by the OCS Area Office. Increase from two to three weeks the time available to state and local officials to prepare responses to tract recommendations of the BLM and USGS area offices before meeting with Interior officials in Washington.

c. Environmental impact statements. Create an EIS task force with representatives of state and local government, the public, and industry to assist in the development of work programs, the selection of contractors, and review of drafts. Hold public hearings on a draft EIS no less than 45 days after it becomes available.

d. Development plans. Invite state and local representatives to participate in informal discussions with offshore operators and USGS personnel before formal submission of development plans.

CHAPTER 4:

ADEQUACY OF DECISION INFORMATION*

ACCESS TO RESOURCE INFORMATION

FINDINGS

RESOURCE ESTIMATES NECESSARY FOR LEASING DECISIONS. Before tracts are selected for leasing, resource estimates are necessary for devising a leasing strategy that concentrates exploration and development efforts in the most promising areas and for weighing estimated benefits against the environmental risks of developing sensitive lease tracts.

USGS HAS DATA. The USGS now receives all the geologic and geophysical data and information gathered by OCS explorers and lessees. These data are held confidential, with only generalized interpretations publicly available from USGS. Published USGS resource estimates are flawed by their timing, level of detail, and comparability, and are of little value to state and local governments attempting to plan for onshore development and to participate actively in the federal process for selecting and leasing OCS tracts.

PLANNING BASED ON RESOURCE ESTIMATES. OCS resource estimates, reserve estimates, and production forecasts are fundamental to planning for onshore facilities by state and local government. The data and information necessary to prepare these estimates are not available to either the State of California or to local governments. California is forced to rely on the Department of the Interior and individual oil companies to provide this information.

NEED FOR DETAILED DATA. The Interior Department invites state and local comments on a range of pre-lease activities to identify environmental concerns and to select tracts for the lease sale, but state and local comment on individual tracts is impossible without detailed resource estimates or access to geophysical and geologic data and information.

*For discussion, see Chapters 13 and 14.

TIMING. The Interior Department publishes OCS estimates and forecasts irregularly, when needed for Environmental Impact Statements or other Interior Department publications. Under present policy, these analyses are not prepared or revised on a systematic basis and do not incorporate new information gathered during exploration and development, or even reflect such basic circumstances as the failure to lease large areas included in the resource estimates made before a lease sale.

DETAIL INSUFFICIENT. USGS does not publish either resource or reserve estimates for individual tracts, leases, units, or structures. Instead, it publishes estimates covering multiple areas, even though individual estimates may have been prepared internally. At this gross level, it is impossible for state and local analysts to correlate these estimates with new information pertaining to specific individual fields or tracts.

ESTIMATES NOT COMPARABLE. The estimates and forecasts which USGS has prepared are conflicting and contradictory (see Chapter 14). Estimates for the southern California OCS draw from disparate data bases and use different assumptions and methods, so that useful comparisons cannot be made either between various USGS estimates, or between USGS estimates and those available from other sources.

CONFIDENTIALITY OF DATA NOT REQUIRED. The confidentiality of geologic and geophysical data and information is based upon Interior Department regulations rather than any statutory requirement. Neither the OCS Lands Act nor the Freedom of Information Act requires that such material be held confidential.

SECRETARY OF INTERIOR'S AUTHORITY. Data and information presently held by the Interior Department are subject to restrictions established by the contractual arrangements under which they were obtained. These generally call for confidentiality, though it is arguable that the Secretary's authority over OCS operations could allow the collection and release of such material from existing leases without that restriction. For future exploration permits and leases, the Secretary has authority to obtain OCS data and information under conditions which allow for public release in any manner deemed appropriate.

OFFSHORE DATA VALUABLE. Geologic and geophysical data and information are marketable commodities. Geophysical exploration is frequently conducted prior to a lease sale by independent contractors who collect the information on a speculative basis for sale to potential bidders. Fairness and maintenance of exploration incentives justify protecting contractors and their clients from indiscriminate publication. After a lease sale, geologic information is generally collected by OCS lessees who barter such information extensively among themselves. Lessees feel that they have purchased exclusive rights to geologic and geophysical data and information from their lease, including well data. This information is valued primarily for the competitive advantage it affords when nearby tracts are offered in

future lease sales and for negotiating transportation and processing agreements. Advance notice of any disclosure practice would allow lessees to adjust bids if necessary to assure that no unfairness results.

CALIFORNIA STATE AGENCIES. The California Division of Oil and Gas and the State Lands Commission have the expertise to analyze and interpret geologic and geophysical data and information, and the capability to handle that information in a confidential manner, as they have for state tidelands leases. At present, however, they do not have the manpower or funding necessary to undertake large scale analyses of OCS data and information.

DATA ANALYSIS EXPENSIVE. Analysis of geologic and geophysical information is costly. Duplication of Interior Department analyses of OCS data by state or local agencies would be wasteful.

NEED FOR STATE ACCESS TO INTERIOR DEPARTMENT DATA. State expenditures for analyses of geologic and geophysical data and information would be justified in specific instances where the Interior Department does not make public updated and detailed resource and reserve estimates and production forecasts or where conflicts between industry and Interior Department estimates frustrate the resolution of disputes over OCS leasing and development, e.g. the Santa Ynez controversy. Although such cases will probably occur infrequently, state agencies will need access to Interior Department data and information when they do.

RECOMMENDATIONS

10. ANNUAL RESOURCE AND RESERVE ESTIMATES. The Interior Department should develop and publish annually updated resource and reserve estimates and production forecasts for all leased areas. For areas without discoveries, resource estimates should be provided by structure, identifying the leases affected. For leases with credited discoveries, reserve estimates and production forecasts should be provided by field. These reports should specify the assumptions and generally identify the data and information used in making the estimates.

11. POST-SALE ESTIMATES. Immediately after a lease sale, the Interior Department should publish the tract-by-tract resource estimates used in evaluating bids so that pre-sale resource estimates can be revised to reflect the tracts actually leased.

12. DISCLOSURE TO CALIFORNIA. The Interior Department should provide California with access to all geologic, geophysical, and well test data and information the Department has. This access should be conditioned to assure the confidentiality of these data and information. After the pertinent tracts are leased, the state must be allowed, when necessary, to disclose oil characteristics and other factors which may affect development, processing, and transportation options. These include detailed resource and reserve estimates and production forecasts, based on interpretations of the data by the California State Lands Division or the California Division of Oil and Gas.

13. FUTURE LEASES. Future lease sales should include in their terms, under conditions to assure confidentiality, a stipulation providing for the release of geologic, geophysical, and well test data and information to California after the lease is sold.

14. FUTURE EXPLORATORY PERMITS. Future geologic and geophysical exploration permits should include a provision allowing the state access to all data and information provided to the Interior Department under stringent conditions to ensure confidentiality. This will enable California to participate effectively in the pre-leasing selection process while at the same time assuring the permittee that the market potential of his exploration efforts will not be substantially reduced.

15. INDEPENDENT INTERPRETATIONS. The California State Lands Division or the California Division of Oil and Gas should analyze and interpret geologic and geophysical data and information for the California state government when independent resource and reserve estimates are needed.

16. LOCAL PERMITTING AGENCIES. Local permitting agencies should consider the feasibility of requiring permit applicants to submit necessary geologic and geophysical data and information, including interpretations, to the agency or a mutually agreed-upon third party for evaluation where such information is needed to act on the permit application and not otherwise available. Such information may be needed to formulate conditions for expansion of onshore facilities, to determine whether the proposed facility can accommodate foreseeable needs, or to plan for consolidated use of facilities.

DEVELOPMENT PLANS

FINDINGS

LEARNING ABOUT DEVELOPMENT. There is no formal, ongoing process for adequately informing state and local governments about the progress and expected impacts of OCS development. The willingness of offshore operators to cooperate informally in providing information about proposed development varies widely.

NEW REGULATIONS. It was not until late 1975 that the Interior Department issued OCS Order #15 requiring offshore operators to disclose even the broad outlines of their development plans to state and local officials. The new order does not apply to any Santa Barbara Channel leases because they were sold prior to November 1975 and, even for leases sold after that date, does not provide for adequate disclosure and analysis for state and local planning purposes.

GENERALIZATIONS ONLY. Operators covered by the new regulations are required to disclose only the general outlines of their development proposals. The regulations do not provide for the disclosure of site-specific plans for onshore development, reserve estimates, or production forecasts for an assessment of economic effects or for any description of transportation plans. The general information required under the regulations, while an improvement, is not sufficiently precise to assure California the information necessary to evaluate offshore development plans or to plan adequately for the ensuing onshore impacts.

LIMITED REVIEW. USGS regulations provide the state only 60 days to comment on proposed development plans. The period is too short to allow adequate analysis, and the withholding of geologic and geophysical information precludes an independent assessment of technical aspects of the proposal.

RECOMMENDATIONS

17. DETAILED PLANS AND ESTIMATES. USGS should require operators to submit to California site-specific plans or options for offshore operations and onshore facilities, plans to utilize existing or expanded facilities in addition to new facilities, plans to transport oil after processing, and detailed estimates of economic effects of offshore oil and gas development along with the development plan.

18. LONGER REVIEW PERIOD. The time period for state review of development plans should be lengthened to 120 days, to begin upon receipt of the development plan by the state and to run concurrently with USGS review.

19. LEASES SOLD BEFORE NOVEMBER 1975. USGS should revise the regulations to allow California to review and comment on development plans for all leases, in offshore California, regardless of the date they were sold.

ENVIRONMENTAL BASELINE STUDIES

FINDINGS

ENVIRONMENTAL BASELINE INFORMATION. Southern California OCS leasing and development decisions have been made on the basis of incomplete environmental data and information. Environmental Impact Statements (EISs) have failed to identify fully southern California's critical environmental, commercial, and recreational resources and their sensitivity to oil and gas production activities. Thus it is difficult to make trade-offs between resource preservation and energy supply goals and to develop impact mitigation strategies. This inhibits constructive state and local government participation in tract selection, leasing, and development decisions.

POTENTIAL SOURCE OF INFORMATION. The Environmental Baseline Studies Program is a potential source for the detailed environmental information required by federal, state, and local governments in making leasing and development decisions. However, the major goal of the program is to produce information after tracts are leased and committed to development.

PROGRAM GOAL. The Environmental Baseline Studies Program goal of evaluating post-OCS development environmental consequences of OCS development is much less important to southern California state and local governments than the goal of having sufficient information on which to base pre-leasing and pre-development decisions.

RECOMMENDATIONS

20. RESTRUCTURE PROGRAM. The Environmental Baseline Studies Program should be restructured to fulfill federal, state, and local government needs for site-specific information on:

a. location of marine mammal and bird habitats;

b. identification of critical non-mineral and recreational resources;

c. location of areas critical to the preservation of commercial and recreational fisheries; and,

d. the potential of oil and gas development at particular sites to disturb these habitats, resources, and areas, especially those which are unique and irreplaceable.

This information should be published and made available to the public and used in selecting tracts to be included in the EIS.

21. ESTABLISH TASK FORCE. BLM should establish an Environmental Baseline Studies Program Task Force which includes representatives of California state and local governments, industry, and the scientific community to:

a. determine priorities and formulate work programs,

b. review RFPs and select contractors, and,

c. disseminate information to all interested parties in a systematic and timely manner.

STATE AND LOCAL PLANNING INFORMATION AND RESEARCH NEEDS

FINDINGS

EARLY COMMUNICATION. Early exchange of information among all affected parties -- federal, state, and local government and industry -- can reduce conflicts later in the leasing and permitting process when delays are more critical economically.

ADVANCE NOTICE. Publication of notices in the Federal Register and informal contacts do not assure that all appropriate state and local governments and other interested parties will be alerted in time to review and comment on proposed federal actions within the designated time. By the time governments have received notice, reviewed the proposal, prepared comments, and obtained necessary approval from the County Board of Supervisors, City Council, or Planning Commission, deadlines for comments have frequently passed. State agencies encounter similar delays.

FEDERAL ORGANIZATION. OCS responsibilities and functions are spread among several federal agencies. State and local government agencies seeking information on federal OCS policy or technical information often must contact a number of these federal agencies. Frequently, the federal agencies are slow to respond, refer the inquiry elsewhere, or are not well enough informed to direct the inquiry to the appropriate source for response. This results in frustration and delay, and further limits the ability of state and local government officials to express their views on federal and industry proposals for OCS leasing and development.

STATE ORGANIZATION. In California, OCS policy making and regulatory functions are spread among numerous state agencies, and there is no systematic means of coordination among them. Local governments, federal government personnel, and industry must, therefore, contact a number of state agencies in order to obtain or convey information on OCS-related proposals or actions.

TECHNICAL CAPABILITY. Once aware of a need to respond to a proposed federal or industry action, California state and local agencies find they lack staff time and expertise, sufficiently detailed description of the proposal, or adequate technical information about the potential impact of the proposal (whether it is leasing, exploration, or development) to prepare a substantive response, recommend mitigating strategies, or propose feasible alternatives. Consequently, federal officials often characterize state and local comments as too vague and generalized to merit serious consideration.

EXCHANGE OF INFORMATION AMONG STATES. Coastal states have experienced OCS development to varying degrees, and a number of

coastal states are performing OCS-related research projects with federal funds. These states can benefit from sharing experiences and information, but no mechanism presently exists to facilitate communication among them.

INFORMATION ON FEDERAL FUNDING. Funds are available from various federal agencies to support state and local government OCS-related projects, but there is no systematic mechanism at either the federal or state level to identify available funds, make state agencies and local governments aware of them, or assist state agencies and local governments to obtain them.

PRIVATE CONSULTANTS. Federal agencies often contract directly with private consultants to conduct OCS research designed to meet the information needs of California state and local governments. These consultants in turn seek interviews and request information from state and local government personnel in order to carry out their tasks. In some instances, state and local governments are then denied access to subsequent working drafts prepared by the consultant and must await formal release by the contracting agency to receive the final product. This manner of developing information for state and local governments is burdensome to them. The federal government would fulfill state and local government needs better by contracting with them directly to conduct the required research.

RECOMMENDATIONS

22. FEDERAL COORDINATION. Interior Department's Bureau of Land Management, in coordination with the Commerce Department's Office of Coastal Zone Management, should establish an OCS Information Clearinghouse to:

a. provide notification of significant OCS leasing and development actions;

b. provide an up-to-date account of OCS-related research being conducted by the federal government, state or local governments, academic or private institutions, and industry; and,

c. provide a complete guide to federal financial and technical assistance for OCS-related planning and efforts to mitigate impacts.

23. STATE COORDINATION. The Governor should ask the California Coastal Commission to assume responsibility for:

a. coordinating state and local agency responses to proposed federal government and industry actions on the OCS;

b. disseminating information among state agencies and providing local jurisdictions with technical assistance to participate in OCS leasing and development decisions and to anticipate that development in local coastal plans;

c. assisting state, regional, and local government agencies to identify and obtain federal funds to support OCS-related projects and programs; and,

d. maintaining communication and exchanging information with other states on OCS-related matters.

The Coastal Commission should be allotted additional funds and staff positions sufficient for carrying out these responsibilities.

24. RESPONDING TO LEASE SALES. In responding to OCS leasing proposals, state and local agencies should focus their attention on identifying:

a. specific tracts where the potential for adverse effects or conflict with current use is so great that development absolutely should not take place;

b. specific tracts where leasing and development can take place under prescribed stipulations and regulations; and,

c. alternatives to the proposed action, including specific conditions that should be imposed or mitigation strategies that should be pursued if the action is permitted to go forward.

25. FEDERAL FUNDS. Federal agencies should make funds available to California state agencies and southern California local governments to meet needs for:

a. support of staff at the state and county level to assist participation in the OCS leasing and development process and to review and prepare comments on environmental impact statements and proposed exploration and development actions;

b. updating baseline emissions inventories, establishment of air quality monitoring stations, and collecting meteorological data; and,

c. assessment of oil spill contingency capabilities and development of contingency plans.

26. USE OF STATE AND LOCAL AGENCIES FOR FEDERAL RESEARCH. Federal agencies should contract directly with California state or local agencies to accomplish research projects designed to meet state and local government information needs. Proposed work programs for such projects should be circulated to state and local agencies for review prior to completing Requests for Proposals (RFPs). State and local government agencies should receive RFPs as do private consultants, and those agencies that qualify should be given preference over qualified private consultants when the contract is awarded. Regardless of who performs the work, state and local government agencies, industry, and other interested parties should have access to the work in progress and the draft product for comment and review prior to its final, formal release.

CHAPTER 5:

AIR QUALITY*

FINDINGS

AIR QUALITY IMPACT CRITICAL. Preventing further degradation of air quality is one of the most critical environmental issues facing southern California. OCS oil production will aggravate an already critical photochemical oxidant problem, but additions to the state's natural gas supply will help alleviate sulfur oxide and ozone problems caused by natural gas users switching to other fuels.

OCS AIR POLLUTION. OCS oil operations (production, processing, and transportation) generate substantial amounts of reactive hydrocarbons. Since the dominant winds in southern California blow onshore from the northwest, OCS emission contributions must be taken into account in medium- and long-range air quality planning for southern California, from Santa Barbara to San Diego. While there is considerable controversy about the actual level of emissions from each type of operation, it appears that tanker loading is the largest OCS-related source of reactive hydrocarbons.

NEW SOURCE REVIEW. Major new OCS-related facilities proposed for construction within state jurisdiction in southern California will be subject to individual review under New Source Review rules (NSR). Because of the area's chronic violation of oxidant standards, those sources emitting more than 15 pounds per hour or 150 pounds per day of reactive hydrocarbons will not be allowed construction permits unless the facility falls within an exemption or the applicant can provide offsetting emission reductions from other sources acceptable to the local APCD, the ARB, and the EPA.

EMISSION FACTOR CONTROVERSIES. Permits for the construction and operation of OCS-related facilities within state

*For additional background, see Chapter 15 and Appendix 8.

jurisdiction may require an analysis of the proposal's air quality impact. Industry and government sources disagree over the factors which should be used in estimating emissions for these analyses. The oil industry believes published factors are too high and has undertaken a research program to establish more reliable numbers. The Western Oil and Gas Association is sponsoring research on tanker loading emissions in Ventura and San Luis Obispo Counties which should be published shortly, and the American Petroleum Institute is sponsoring research on fugitive emissions from platforms and onshore facilities which should be available in early 1978.

TANKER LOADING EMISSIONS. When crude oil tankers are empty, the residue in the cargo compartment vaporizes to form a rich hydrocarbon blanket which is displaced into the atmosphere when the cargo hold is filled with crude. No technology presently exists to recover these displaced vapors or to prevent their formation and emission. The volume and concentrations of emissions, however, may be reduced somewhat by slowing the loading rate and by only partially filling cargo compartments.

REGULATION OF OCS SOURCES. Offshore operations beyond the state's three-mile jurisdictional limit enjoy a de facto Clean Air Act exemption. The reviews, permit controls, and emission standards applied by federal, state, and local agencies onshore are not applied to OCS operations. EPA Regional Counsel Opinion 293 (September 15, 1975) affirmed the legality of such controls, but subsequent analyses have raised questions about that position. The USGS, which oversees OCS operations, has no regulations specifically governing either the equipment which must be installed or the operational procedures which must be observed to minimize air pollution. In the opinion of its General Counsel, the EPA can regulate air emissions from OCS operations as a condition for issuing a water discharge permit (NPDES), but the EPA has never asserted or tested this authority on any OCS facility.

OFFSHORE METEOROLOGY. Offshore operations in southern California may adversely affect air quality in southern Santa Barbara County, coastal Ventura County, and the South Coast and San Diego Air Basins. A common problem of the four APCDs in this area is that offshore meteorological conditions and air transport mechanisms are poorly understood, making it difficult to assess the effect of any particular offshore development proposal. None of the APCDs has sufficient staff or funding to perform the research necessary for these assessments throughout the entire offshore area.

RESEARCH NEEDS. The local APCDs in southern California have identified three key research and equipment needs for improving OCS air quality impact assessment: better emission factors, improved offshore meteorological information, and mobile monitoring stations.

RECOMMENDATIONS

27. PROTECTING AIR QUALITY. OCS leasing and development should not be permitted in areas or under conditions which would allow violation of standards or further degradation of southern California air quality.

28. REGULATING OFFSHORE FACILITIES. OCS facilities should be subject to reviews, permit controls, and emission standards equivalent to those imposed upon similar facilities within state jurisdiction. A number of avenues are available to approach this objective:

a. the Interior Department could develop regulations and operating orders explicitly addressing equipment and operating procedures for minimizing air pollution under its general authority to adopt regulations for "the conservation of natural resources";

b. the EPA could impose air-related conditions under its NPDES permit process;

c. Clean Air Act amendments could specify the permits, reviews, and standards which will be applicable to OCS facilities;

d. OCS Lands Act amendments could explicitly provide for the application of state air pollution permits, reviews, and standards to OCS facilities likely to contribute to onshore pollution; and,

e. the state and local APCDs could attempt to impose controls over OCS facilities affecting onshore air quality by adopting emission limitations as part of the State Implementation Plan and submitting them to the EPA for approval,

anticipating a legal challenge on the issue of whether the Clean Air Act established jurisdiction for such action.

29. AIR QUALITY ANALYSIS. Environmental Impact Statements prepared in conjunction with OCS leasing and development proposals should analyze OCS air quality impacts in sufficient detail to enable EPA, ARB, and local APCDs to determine if the proposal will cause a localized violation of an air quality standard or interfere regionally with the attainment or maintenance of air quality standards. This analysis should be accomplished through the cooperative efforts of BLM, EPA, and ARB.

30. COORDINATE EFFORTS. Federal and state agencies, local jurisdictions, and industry should coordinate efforts to collect meteorological data, standardize emissions factors, and develop reliable methods for making accurate OCS air quality impact projections. This should be used in the development of an EPA-approved State Implementation Plan.

31. TANKER EMISSIONS. The ARB should undertake an assessment of tanker contributions to oxidant formation in California, including the potential for enforceable controls restricting emissions to meteorological conditions and coastal areas where adverse effects would not exacerbate an already serious problem.

32. MARINE TERMINAL PERMITS. Permits for construction and operation of new or expanded marine terminals for handling OCS oil should be conditioned on operating controls or compensatory emission reductions that take into account tanker emissions during loading, unloading, and operations.

33. METEOROLOGICAL STUDY. The federal government should fund a cooperative study by the four southern California coastal APCDs of offshore meteorological conditions and air transport mechanisms. Such a study should provide information in a format useful to each of them for making air quality impact analyses of proposed offshore development.

34. PLATFORM MONITORING STATIONS. Industry should install wind monitoring and recording devices on offshore facilities as part of a coordinated program to improve the available data base (see Recommendation 8, Chapter 7, for additional details). Additional meteorological equipment, such as radiosondes to measure temperature, humidity, and wind profiles to around 1000 feet, and insolation measuring devices should be operated on platforms at locations sufficient to obtain an adequate data base of meteorological conditions in the OCS.

35. FEDERAL RESEARCH PROCEDURES. The ARB and local APCDs should be given an opportunity to review and respond to all federally issued RFPs for air quality research to be performed in California and to review interim and final reports on the research. Federal government agencies should place the highest priority on using the ARB or local APCDs rather than private contractors to conduct such research, and to evaluate research in progress.

CHAPTER 6:

SENSITIVE COASTAL RESOURCES*

FINDINGS

MANY HABITATS SENSITIVE. Many important habitats found in the Southern California Bight are sensitive to petroleum development activities as well as to oil spills resulting from these activities. Pinniped and seabird rookeries, wetlands, rocky intertidal areas, and offshore banks are especially vulnerable.

OFFSHORE BANKS. The Southern California Bight is an atypical continental margin. Its highly irregular submarine topography is distinctly different from the shelf-and-slope configuration characteristic of most of the North American continental margin. Numerous rocky outcrops form subsurface ridges and banks shallow enough to support complex and highly productive assemblages of plants and animals within the photic zone. These offshore banks are important to commercial fishing interests and constitute essential habitats for certain unique marine species. They are vital feeding grounds for seabirds and pinnipeds, especially during the breeding season. These areas include Osborne Bank, Tanner Bank, Cortes Bank, Thirty-Mile Bank, Forty-Mile Bank, North-East Bank, Lasuen Knoll, and shallow banks in the Santa Rosa-Cortes Ridge area.

SEABIRDS. Oil spills pose a tremendous hazard to all marine-associated birds. Seabirds are particularly vulnerable to oiling and subsequent death as a result of exposure. Birds breeding on the Channel Islands depend exclusively on adjacent waters for foraging. Foraging needs are highest during the nesting season. According to the preliminary findings of BLM's baseline studies, many seabird populations are already in jeopardy. An oil spill during the nesting season could devastate those populations.

*For additional discussion, see Chapter 16.

PINNIPEDS. The Southern California Bight possesses the world's largest and most diverse pinniped community in temperate waters. Human activity in southern California has forced these marine mammals to abandon their historic mainland rookeries. Today, seals and sea lions breed and haul out almost exclusively on the Channel Islands. Petroleum-related activities, including crew staging and transport, seismic exploration, drilling, platform assembly and installation, pipe laying, tanker lightering, vessel repairs, and other disturbances near major breeding and haul out grounds on the Channel Islands could eliminate the last remaining breeding areas in southern California for sea lions, fur seals, and harbor seals.

ROCKY INTERTIDAL AREAS. Tide pools and their unique inhabitants are a heavily utilized marine resource in California. In southern California, rocky intertidal areas exist in limited and widely dispersed coastal sites. These areas have considerable scientific, recreational, educational, and ecological value. Many marine species depend on tide pools during some part of their life cycle.

COASTAL WETLANDS. Many studies have underscored the need to protect and maintain California's remaining coastal wetlands. Estimates of wetland acreage lost to urbanization in southern California range from 75 to 90%. All sources agree on the critical value of the remaining marshes and mudflats, which provide essential habitats for hundreds of fish and wildlife species, including several rare and endangered species.

WETLAND PROTECTION ESSENTIAL. Because of their critical value and their vulnerability to damage, wetlands require special protection from oil spills. If contamination occurs, cleanup operations alone could cause further damage to the wetlands because cleanup cannot be accomplished without significant removal of vegetation. This would disrupt nesting and feeding areas, particularly during breeding and migration seasons. If cleanup is not undertaken, the dense vegetation and thick sediments of a marsh tend to entrap oil and release it periodically during storms or other disturbances over months or even years.

CHANNEL ISLANDS. The eight Channel Islands are of great ecological significance because of their location astride a major biogeographic transition of the Pacific Coast, the Point Arguello-Point Conception break. The Channel Islands support several species of terrestrial flora and fauna not found on the mainland. The intertidal and subtidal areas surrounding the islands support many unique one degree endemics (organisms with a north-south range of 60 miles) and an abundance of diverse tidepool plants and animals. The islands also provide refuge for animals with low tolerance for human disturbance.

SAN MIGUEL ISLAND. San Miguel Island and its associated rocks are the most important pinniped habitats in southern California. Six species of seals and sea lions inhabit the

island, and five species breed there. The microclimate and topography of San Miguel make it an ideal habitat for both northern and southern pinniped species. Such diversity in one geographical area is unique. Eight species of sea birds also depend on the Island for breeding and nesting.

SAN MIGUEL JURISDICTION. The United States Navy owns San Miguel Island, adjacent Prince Island and associated rocks, but the National Park Service (NPS) manages them as a unit of the Channel Islands National Monument. The NPS management is governed by a cooperative agreement between the two federal agencies. Under the agreement NPS is primarily responsible for enforcing federal laws to protect archaeological resources, the flora and fauna and the natural environment of the islands. Living marine and terrestrial resources are managed by the NPS in cooperation with federal and state fish and wildlife agencies.

SANTA BARBARA ISLAND. Santa Barbara Island is a major breeding and haul out ground for pinnipeds as well as an important nesting area for nine species of sea birds. Osborne Bank, just south of the island, is an important fishing area and one of the three areas in the Bight where the rare purple coral is found.

ANACAPA ISLAND. At this time, Anacapa Island is the only consistently used California nesting and breeding area for the endangered Brown Pelican, and provides nesting habitat for six species of marine and shore associated birds.

RECOMMENDATIONS

36. IDENTIFY FORAGING AREAS. BLM's baseline studies should give high priority to identifying the specific foraging areas of seabirds by species and density of use. In areas where foraging levels are so high that a major spill could endanger the breeding population of any southern California sea bird:

a. no further leases should be offered;

b. existing leases should be terminated through repurchase; and,

c. existing leases not terminable should be regulated so that drilling operations do not take place during the critical spring-summer breeding season.

37. ESTABLISH PINNIPED SANCTUARIES. A sanctuary of at least six miles should be established around all pinniped breeding

grounds. A larger sanctuary should be established around San Miguel Island to preserve its vital role as a major breeding ground for pinnipeds and sea birds. Within these sanctuaries, no new leases should be offered, existing leases should be terminated or repurchased, and oil-related disturbances such as boat traffic, pipelining, and anchorage for repair and maintenance should be prohibited.

38. PROTECT OFFSHORE BANKS. In order to protect the unusual and highly productive shallow areas of the offshore banks within the photic zone, USGS should not approve any permit for the location of a structure within or above the seventy meter depth contour of the Osborne Bank, Tanner Bank, Cortes Bank, or Santa Rosa-Cortes North Ridge until studies on the potential effects of oil and gas operations on the biological communities of the offshore banks are completed and specific protection strategies are devised for those resources. Furthermore, because the red and purple forms of Allopora coral found on the offshore banks are so unusual and slow to recover from any damage, the Interior Department should survey the locations of these coral communities on all offshore banks and not permit any structure to be placed in these locations.

39. PROTECTION OF SAN MIGUEL AND PRINCE ISLANDS. To strengthen management capability and responsibility in a single agency, ownership of these islands should be transferred from the Department of the Navy to the Department of the Interior for administration by the National Park Service.

40. CREATE CHANNEL ISLANDS NATIONAL PARK. A Channel Islands National Park including San Miguel, Anacapa, Santa

Barbara, Santa Cruz, Santa Rosa, and San Nicholas Islands should be created by Congress. The legislation should provide appropriate restrictions to ensure well managed public access as well as protection of associated marine and terrestrial species.

41. A MARINE SANCTUARY. The Secretary of Commerce should designate the waters within twelve miles of the Channel Islands as a marine sanctuary under the provisions of the Marine Protection, Research, and Sanctuaries Act of 1972 (PL 92-532) in order to protect their value as a habitat for marine flora and fauna, and as vital foraging grounds for pinnipeds and sea birds breeding on the islands.

SENSITIVE ECONOMIC RESOURCES

FINDINGS

SOUTHERN CALIFORNIA LIFESTYLE RELATED TO COASTLINE. The southern California lifestyle is strongly associated with the region's marine and coastal environment. Marine recreation is a multi-million dollar industry. Damage from a major spill to southern California's recreational resources, including beaches, marinas and harbors, recreational fishing and diving areas, and commercial fishing areas, could cause substantial economic losses.

BEACHES. Southern California's most heavily-used recreational resource is its extensive beaches. Over 12 million people used southern California's beaches in 1976. Because of their great length, beaches are impossible to protect entirely from spilled oil. Removal of oil from beaches is a straightforward but labor-intensive task.

FISHING INDUSTRY. Commercial and sport fishing originating from California harbors generates more than $600 million annually through sales of the catch and the support of canneries, retail outlets, harbor activities, and related trades. Economic loss to the industry from a large spill could occur as a result of:

a. damage to commercial and sport species;

b. destruction of larval stages of commercial and sport species;

c. the cost of cleaning oiled vessels; and,

d. harbor closures and loss of fishing time.

RECOMMENDATION

42. FEDERAL AND INDUSTRY RESPONSIBILITY. Environmental impact statements, exploration plans, and development plans should specifically evaluate the vulnerability of recreational and economic resources and the spill response capabilities in local communities potentially affected by an oil spill. Such documents should include specific locations of exposed resources, an analysis of response time, and response capability, and competing demands on equipment use and potential economic loss to the community.

CHAPTER 7:

OIL SPILLS*

FINDINGS

MARINE OIL SPILL SOURCES. Marine sources of oil spills off California include production facilities, tankers and other vessels, pipelines, and marine terminal and transfer operations. On a world-wide basis, spills from offshore production facilities account for less than 3% of oil entering the oceans from marine sources. Spills from offshore production platforms do not occur often, but they can be very large. During the 1969 Santa Barbara Channel blowout, the largest recorded oil spill off California, an estimated 77,000 barrels of oil were spilled.

OIL SPILLS LIKELY. The amount of oil produced, transported, and transferred off California -- and thus the opportunity for oil spillage -- is increasing. The number of conflicts between different offshore oil-related activities, such as the rigs now drilling in San Pedro Bay vessel traffic lanes, is also increasing. The probability of an oil spill occurring at any given time from any particular source is extremely low, but the cumulative effect of many separate oil-related activities is such that at least one major oil spill and many smaller spills are likely to occur off southern California in the future.

OIL SPILLAGE CAN BE REDUCED BUT NOT ELIMINATED. Improvements in operating technologies and procedures, together with more thorough state and federal enforcement of oil spill prevention regulations, can reduce substantially the number and size of spills. After the 1969 blowout, both industry and government took steps to reduce the likelihood of oil spillage. As a result, there has not been a recorded spill from production platforms in state or federal waters off California since 1969. Nevertheless, since many spills are caused by accident

*For detailed discussion, see Chapter 17.

or human error, the risk of major spills can never be completely eliminated.

NATURAL SEEPS. Natural seeps are a source of chronic, low-level oil pollution in southern California waters. Estimates of seepage rates in the Santa Barbara Channel range from 40-670 B/D. Seepage rates may be influenced by oil and gas production operations, but existing information is not sufficient to resolve this issue.

SPILLS LIKELY TO MOVE TOWARDS SHORE. General wind and wave current patterns off southern California are such that most spills -- except those originating in the Outer Banks -- will move toward mainland or island coasts with a time-to-shore of hours, days, or weeks. Natural physical, chemical, and biological forces exist which can disperse and degrade spilled oil, but the rates at which these forces work are generally too slow to remove spilled oil from the water surface before it comes ashore.

AT-SEA CONTAINMENT AND RECOVERY OF OIL SPILLS OFTEN IMPOSSIBLE. Oil spill cleanup equipment has improved considerably in recent years, but at-sea containment and recovery of spilled oil is often impossible. The effectiveness of existing equipment falls off dramatically if cleanup must be undertaken at night, in fog, in storms, or in anything rougher than moderately calm seas. Other factors influencing the success of at-sea containment and recovery operations include the time lag between the spill and the deployment on-scene of containment booms and the training and experience of the personnel conducting the cleanup operation.

OIL SPILLS HARMFUL. Spilled oil reduces the amenity and the recreational and economic value of coastal and marine resources. The biological effects of spilled oil vary widely, depending on the unique circumstances of each spill. Oil spills always have the potential to cause significant short-term and long-term damage to coastal and marine life. Some crude oil spills do not cause measurable damage. Others cause substantial damage.

INDUSTRY AND COAST GUARD CLEAN UP MOST SPILLS. Under federal law, the containment and removal of spilled oil in coastal or marine waters is undertaken by the party responsible for the spill, under the supervision and, if necessary, the direction of the U.S. Coast Guard. During spill emergencies, the Coast Guard coordinates its activities with other federal and state authorities through a Regional Response Team. If the responsible party cannot be identified or is not responding properly, the Coast Guard has the authority and the funds to hire a spill cleanup cooperative or contractor directly. State and local agencies do not have the funds to do this, and rely on industry and the Coast Guard to clean up offshore spills.

STATE ROLE IN OIL SPILL RESPONSE. For spills in state or

federal waters, California's role during cleanup operations is that of observer, advisor, and assistant to the Coast Guard -- except that California has veto power over the use of dispersants or other chemical agents in state waters. Under California's Oil Spill Contingency Plan, which has been recommended as a model state plan by the American Petroleum Institute, the Department of Fish and Game maintains liaison between local and other state officials and the federal and industry personnel directly involved in the spill response.

LOCAL ROLE IN OIL SPILL RESPONSE. Of all jurisdictional levels, local governments of coastal communities are most directly affected by oil spills and least directly involved in oil spill cleanup operations. Local agencies provide onshore logistic support for offshore containment and recovery operations, but do not participate in actual cleanup efforts unless and until oil comes ashore. Coastal communities have expressed strong concern about oil spill response procedures, yet many coastal communities are uninformed or poorly informed about the respective roles of federal, state, local, and industry organizations in responding to oil spills.

USE OF CHEMICAL AGENTS CONTROVERSIAL. Industry has developed chemical agents intended to disperse, sink, or otherwise modify the behavior of oil slicks. The use of these chemical agents, especially dispersants, is the subject of much controversy. On the one hand, chemical dispersants promote the removal of oil from the water surface into the water column, and thereby reduce the potential threat to seabirds and intertidal organisms. Also, such chemical agents are less expensive than attempting physical containment and recovery. On the other hand, dispersants are themselves toxic, do not always function effectively, and if successful in dispersing oil into the water column, their use prevents physical removal of the oil from the water. Present state and federal policies advocate the physical containment and recovery of spilled oil as a first priority. Dispersants are permitted only in extraordinary circumstances where their use is likely to eliminate a direct and immediate threat to human safety or to a particularly valuable resource which cannot be otherwise protected. A slick moving toward a pinniped rookery in sea conditions prohibiting containment or removal might provide such a case.

SPILL CLEANUP EQUIPMENT PRIVATELY OWNED. Almost all oil spill containment and recovery equipment in California is owned by private companies, either individually or through cooperative industry associations. There are three such cooperatives in southern California, which store their equipment in Santa Barbara, Los Angeles, and Long Beach harbors. There are additional cooperatives in northern California, and the Coast Guard maintains some equipment at several of its coastal installations. State and local agencies in California do not own significant amounts of spill containment or removal equipment.

LITTLE BOOM AVAILABLE AT PLATFORMS. A key factor in the effectiveness of oil spill cleanup operations is the speed with which an oil slick can be surrounded and contained in the water. At present, offshore producers keep minor amounts of "first aid" containment boom and recovery equipment on offshore platforms, and rely on shore-based equipment to deal with spills larger than five or ten barrels. This practice, sanctioned by the State Lands Division and the U.S. Geological Survey, builds in unnecessary delay, reducing the chances for successful at-sea containment and recovery of larger spills.

CLEAN-UP CAPABILITY OF OIL SPILL COOPERATIVES UNKNOWN. Industry spokesmen state that existing oil spill cleanup cooperatives in southern California have the ability to contain and recover spilled oil under most of the sea and weather conditions occurring off southern California. The three cooperatives were established after the 1969 blowout, and have never had to respond to a major offshore spill. Each cooperative does stage periodic demonstrations to familiarize personnel of the companies belonging to the cooperative with available equipment, but no cooperative rehearses full-scale spill response procedures under simulated emergency conditions. This being the case, the ability of the cooperatives to contain and recover spilled oil in a timely fashion under a range of environmental conditions is simply unknown.

NATURAL AREAS NEED BETTER PROTECTION. Spilled oil cannot always be kept from coming ashore. When oil moves ashore, it is sometimes possible, through strategic deployment of containment booms, to divert oil away from especially sensitive or valuable coastal resources and toward areas of lesser importance or vulnerability. Harbors, marinas, and similar areas generally receive high priority for such defensive booming because their restricted entrances make such diversion practicable and because oil spill damages in such areas are highly visible, easily calculated and legally compensable. In areas of high natural value -- such as wetlands, rookeries, or estuaries -- oil spill damages are often difficult to appraise or to express as economic losses, and lawful compensation is uncertain at best. Such areas may not receive protection commensurate with their true value. To its credit, Clean Seas, Inc. of Santa Barbara has begun to distribute cleanup equipment at selected locations along the coast to shorten response time and provide greater protection for estuaries, marshes, and other vulnerable resources within its area of response, whose configuration makes such defensive booming practical. The other cooperatives, based in Long Beach and Los Angeles harbors, have not yet taken similar steps.

BETTER FEDERAL ENFORCEMENT NEEDED. The 1969 blowout was caused by operator errors that might have been avoided if federal regulations had been properly enforced. Since the blowout, the U.S. Geological Survey has strengthened its OCS regulations and increased its Pacific OCS inspection force from two to 11 full-time employees. In the same period, 56 more leases have been sold, new oil fields have been found, and new platforms

installed. Additional inspectors will be needed to maintain adequate enforcement of OCS pollution control regulations in the future.

OCEANOGRAPHIC AND METEOROLOGICAL INFORMATION LACKING. Knowledge or prediction of the likely trajectories of spilled oil off California is useful for assessing the potential effects of air and water pollutants discharged at offshore facilities. Data on the prevailing winds, waves, and surface water currents in the vicinity of offshore oil-related facilities are often non-existent or unavailable to public agencies.

CALIFORNIA SPILL TRAJECTORY PREDICTIONS INADEQUATE. Existing oil spill trajectory analyses do not provide an adequate basis for "best possible" contingency planning. The Interior Department did not conduct an original oil spill trajectory analysis for any of its three previous California OCS Lease Sales, but will do so as part of the environmental impact statement for proposed Lease Sale #48.

FEDERAL SCIENTISTS STUDY SPILL TRAJECTORIES IN THE FIELD. NOAA and the Coast Guard have recently established mobile oil spill monitoring teams. When significant spills occur, these teams fly to the spill and track slick movement, measuring winds, surface water currents, and other environmental factors. These field data can be used to verify or correct slick trajectory predictions based on theoretical calculations or laboratory experiments.

LACK OF FUNDS HAMPERS FIELD INVESTIGATION OF SPILL EFFECTS. Proper scientific field studies of the biological effects of spilled oil are impeded by many factors. For best results, chemical and biological studies should be initiated within hours or days after the oil comes ashore and be repeated at regular intervals for at least several years. For such studies to be undertaken, there must be available scientists with requisite competence, inclination, freedom, and an assured source of funds. As a practical matter, this combination of circumstances almost never exists -- the West Falmouth spill study being one of the rare exceptions -- and such studies are either foregone entirely, begun after weeks or months of delay, or terminated before long-term effects can be established. In sum, most oil spills are not properly studied, and neither short-term nor long-term effects are known with any degree of precision. One obstacle which can be removed is the delay or premature termination of such studies due to lack of funds. Were public funds available to initiate studies promptly and to maintain them for as long as necessary, determining the actual effects of spilled oil on coastal and marine life would be substantially less difficult. Establishment of a public fund to support research would help provide a sounder basis for public policy decisions on offshore activities with oil spill potential.

COMPENSATION FOR SPILL DAMAGES DIFFICULT. For individuals

and public entities damaged by oil spills, existing state and federal legal remedies are woefully inadequate. Many of the real economic losses suffered in a major spill are not recognized as "damages" subject to recovery at law. Even for legally compensable oil spill damages, a victim must be ready to undertake protracted and costly litigation to obtain compensation. The American Petroleum Institute and a number of major oil companies support federal legislation to establish a spill liability fund to provide such compensation.

RECOMMENDATIONS

43. INCREASE FEDERAL ENFORCEMENT AND MONITORING FUNDS. Congress should increase the funds available to the U.S. Geological Survey in order that USGS can at least maintain existing levels of enforcement of pollution control regulations as the number of California OCS production facilities increases. Congress should also continue support for the Coast Guard/NOAA spill monitoring teams.

44. INCREASE SPILL CONTAINMENT BOOM STORED AT OFFSHORE PLATFORMS. The State Lands Division and the U.S. Geological Survey should require that at least 1,500 feet of heavy-duty containment boom, and a boat suitable for deploying it, be maintained at each production facility serving oil fields off California. Where, by reason of geographic location or prevailing winds and currents, potential spills from any particular field pose a direct threat to especially sensitive coastal resources, such as estuaries, marshes or pinniped rookeries, the containment boom requirements for that field should be increased. For fields with several production platforms, the boom and vessel should be kept at a central platform so the equipment can be promptly delivered to any of the platforms on that field.

45. RELOCATE ONSHORE EQUIPMENT TO PROTECT SENSITIVE

NATURAL AREAS. The three southern California spill cooperatives should earmark a portion of their spill containment boom to protect estuaries, salt marshes, and other specific coastal resources with both the high natural value and the restricted connection to the ocean which makes such defense practicable. This boom should be sited so as to reduce to a practical minimum the time needed to deploy it in diverting spilled oil away from the designated resources.

46. REQUIRE OIL SPILL CLEANUP ORGANIZATION INSPECTIONS AND "FIRE DRILLS." Oil spill cleanup organizations should be required to undergo annual inspections of personnel training programs, response procedures, equipment inventories, and equipment locations, and should be required to respond to unannounced, in-water oil spill "fire drills" simulating emergency spill conditions. These inspections and drills could be implemented voluntarily by the industry, or as a condition of federal, state, or local permits for oil-related facilities. In order to avoid overlapping and perhaps conflicting demands on the cleanup organizations relied upon by applicants for federal, state, and local permits, the Resources Agency would be an appropriate place to vest authority for initiating "fire drill" emergency simulations and conducting annual inspections, in consultation with interested federal and local agencies.

47. BRIEF LOCAL OFFICIALS AND INTERESTED PUBLIC ON SPILL RESPONSE PROCEDURES. The California Department of Fish and Game should conduct a series of workshops in the coastal

counties of southern California to inform local officials and the interested public of: a) the procedures followed by industry, federal, and state personnel responding to oil spills; and, b) the responsibilities and opportunities for local participation in oil spill cleanup operations within the context of the national and state oil spill contingency plans.

48. JOINT STATE-LOCAL-INDUSTRY ACTION TO IMPROVE RESPONSE. Each coastal county should, with the assistance of the Resources Agency and oil industry representatives, evaluate existing procedures for responding to oil spills within its jurisdiction, and develop its own contingency plan to make local resources available to assist industry and federal oil spill cleanup efforts. As part of its planning, each county should: a) compile an inventory of publicly-owned equipment and personnel potentially useful in spill cleanup operations; b) identify access routes for delivering equipment to all coastal areas within each county; c) identify and rank specific coastal areas vulnerable to and threatened by potential oil spills; and, d) compare county protection priorities with those of the industry cooperatives responding to spills threatening those areas. As a first step to improve protection of specific coastal resources, county and local governments should consult with cleanup organizations to assure that equipment is provided, earmarked, or stored at locations suitable to assure the necessary protection. As a last resort, these governments should consider purchasing and stockpiling containment booms in

appropriate locations, and arranging for its deployment to protect specific designated areas in an oil spill emergency.

49. RETAIN CONTROL OVER USE OF CHEMICAL DISPERSANTS. Existing federal and state policy advocating the physical containment and recovery of spilled oil should be maintained, spelling out the permitted use of chemical dispersants only in extraordinary circumstances.

50. COLLECT WIND, WAVE, AND CURRENT DATA AT OFFSHORE FACILITIES. The State Lands Division and the U.S. Geological Survey should require that instruments suitable for measuring and recording wave, surface current, and wind data be installed and maintained on all offshore drilling, production, and terminal facilities off California and that the data collected be publicly available. Costs of purchase, installation, and maintenance should be borne by the operator of the facility. The instrument specifications should be established by SLD and USGS in consultation with the California Department of Navigation and Ocean Development and the National Oceanic and Atmospheric Administration, so that the data can be stored and retrieved from existing state and federal oceanographic data systems (e.g., California's Coastal Engineering Data Network and the National Oceanographic Data Center). Where a facility is sufficiently close to another, already instrumented, or to an existing meteorological station, so that data already being collected is substantially applicable, this provision should be waived.

51. ESTABLISH AN OIL SPILL FIELD RESEARCH FUND. Congress should establish a $10 million field research fund to support

study of the short-term and long-term biological and ecological effects of oil spills. When spills occur, the fund should be used to employ qualified scientists undertaking chemical and biological sampling and analyses in the affected area without delay and for as long as necessary. Uniform sampling, surveying, and analytical methods should be established by the agency administering the fund.

52. SPILL COMPENSATION FUND. The state should establish a spill liability compensation fund financed through a per-barrel oil transfer fee on oil transported across state tidelands to provide a source for private and public claimants to obtain adequate redress for harms not now recognized as "legal damages" and without the uncertainty and expense of protracted litigation. If federal legislation is enacted adequately assuring these objectives, the state fund should be phased out.

53. CIVIL LIABILITY. The state legislature should amend the Porter-Cologne Water Pollution Control Act to allow the imposition of civil penalties for major oil spills in excess of those now allowed under a restrictive interpretation of the current legislation.

CHAPTER 8:

ECONOMIC EFFECTS OF LEASE SALE #35*

FINDINGS

PRE-LEASE SALE ESTIMATES ARE SPECULATIVE. Economic analyses can become more precise as development unfolds. The effects of exploration-phase employment and income depend on the number of tracts actually leased, possibly only 20-30% of those offered. The amount of oil or gas discovered on leased tracts determines the employment impacts and facility needs of the development and production phase. Local public service demands are created by the settlement patterns of imported workers, which may not correspond with the siting of facilities and service bases. Actual tax impacts on any community cannot be determined until the development phase, when particular facilities are proposed for specific locations.

ASSUMPTIONS ARE CRITICAL. Conclusions concerning economic impacts are sensitive to assumptions about oil and gas reserves, location of onshore facilities and construction sites, worker residence patterns and ratios of local to imported labor. Conclusions about economic impacts of Lease Sale #35 cannot be validly transferred to describe the cumulative effect of subsequent sales or the consequences of offshore development on rural, less densely populated areas of California with no history of oil development and no local pool of skilled labor.

EMPLOYMENT AND PUBLIC SERVICE IMPACTS. The impacts of Lease Sale #35 will be felt primarily in the adjacent counties of Ventura, Los Angeles, and Orange. These impacts will be so small that new direct and indirect employment will be insignificant, with imperceptible increases in public service demand. These conclusions would hold true even if the level of new OCS activity were three times that currently anticipated.

PRICE IMPACTS. In Los Angeles and Orange counties,

*For full discussion, see Chapter 18.

short-term price increases for housing and consumer durables will be inconsequential. Price increases may approach 2% in Ventura.

TAX IMPACT. New facilities inspired by Lease Sale #35 will constitute only a small fraction of the total assessed valuation of each of the affected counties. In Los Angeles, Orange, and Ventura counties, for example, net taxable base is over $35 billion. Optimistic estimates of new facilities from OCS Sale #35 are only $160 million, or less than 0.46%. It is unlikely that any one county will get all of the facilities. However, any municipality which is the site for one or more of the facilities may realize a substantial tax windfall which exceeds new service demands. Precise locations for these facilities will not be known until late in the development process.

ENVIRONMENTAL COSTS NOT COUNTED. Caution must be exercised in assessing net local benefits from price, public service, employment, and tax and transfer analyses alone. These do not include environmental costs which may be substantial, but for which there is no widely accepted measure of value. The ultimate balancing of OCS economic benefits against potential environmental costs is a highly judgmental process.

PRICE OF OIL AND GAS. Production from OCS Lease Sale #35 will not affect the price paid by southern California consumers for petroleum products or natural gas. New OCS gas may, however, partially alleviate projected gas shortages and reduce costs and dislocation caused by switching to higher-cost substitute fuels.

EFFECTS OF OTHER OFFSHORE ENERGY PROJECTS. This analysis was limited to the economic effects of the exploration and development of tracts leased in OCS Lease Sale #35. The economic effects of other energy-related activities offshore or in the coastal zone (e.g., development on oil and gas leases in the Santa Barbara Channel, future OCS leasing in southern California, construction and operation of a liquid natural gas (LNG) terminal, the proposed SOHIO project for transporting Alaskan oil) were not examined in this study. Consequently, the economic effects of these coastal-related energy activities may, by themselves or in combination with the effects of exploring and developing the tracts leased in Lease Sale #35, have significant impacts on southern California.

RECOMMENDATION

54. DETAILED ANALYSIS AND COOPERATIVE PLANNING. When new OCS development may substantially affect the structural relationships or overall volume of economic activity in an area,

the Department of the Interior should aid in the preparation of detailed site-specific analyses of these effects and cooperate with local governments in identifying and planning for public service expenditures necessitated by the development. Such impacts are not expected in southern California in the immediate future. Communities identified as most likely to experience appreciable new development as a result of Lease Sale #35 are Ventura, Port Hueneme and possibly Huntington Beach.

CHAPTER 9:

FACILITIES PLANNING*

FINDINGS

POTENTIAL FOR DUPLICATION. The demands placed on existing offshore oil and gas related facilities and the need for new facilities in southern California will increase as development activities accelerate in the Santa Barbara Channel and Lease Sale #35 areas. There is a potential for unnecessary duplication of offshore production systems and onshore support facilities. To limit the effects of offshore related oil and gas operations, it may be desirable to require: (1) that area plans be prepared for specified offshore leased areas; (2) that certain leases overlying geologic structures likely to contain oil and gas be unitized; and, (3) that related onshore facilities be consolidated.

LEASE-AREA PLANNING: COORDINATING DEVELOPMENT OVER LARGE OCS AREAS. Offshore southern California leases have been acquired in six separate geographic areas:

Santa Barbara Channel West
Santa Barbara Channel East
Santa Rosa-Cortes Ridge North
Santa Rosa-Cortes Ridge South (Tanner Banks)
Santa Barbara Island Offshore
San Pedro Bay

Each area has unique resource development problems resulting from its relative distance to shore, water depth, estimated recoverable resources, and number of leases sold. The most efficient and environmentally safe solutions to these problems are obtained when each area is planned for as a whole. Lease-area planning also permits the sharing of development risks and costs by operators within the area and serves to maximize the natural resources of the outer continental shelf.

*For further discussion, see Chapter 19.

UNITIZATION: COORDINATING DEVELOPMENT ON SPECIFIC GEOLOGIC STRUCTURES. Unitization occurs when companies owning leases overlying a single geologic structure merge ownership and control of the area or structure through an agreement whereby a single company or committee acts as the operator for exploration, development, and/or production of all leases affected by the agreement. Unitization may be entered into voluntarily or it can be required by the Geological Survey.

CONSOLIDATION: FOR COORDINATING DEVELOPMENT AND/OR UTILIZATION OF SPECIFIC FACILITIES. Consolidation occurs when two or more companies use the same site or facilities for development, transportation, processing, or storage functions, rather than each company constructing and operating such facilities solely for its own needs.

CALIFORNIA COMMITTED TO COORDINATION.
State agencies have consistently pursued the coordination of offshore and onshore petroleum facilities since 1975. The California coastal zone management program is the principal government mechanism through which such coordination initiatives are advocated. Local governments have demonstrated the same commitment through such actions as the formation of the joint industry/government working group investigating better ways of coordinating offshore and onshore development in the Santa Barbara Channel.

RECOMMENDATIONS

55. CONSISTENCY WITH COASTAL ZONE MANAGEMENT PROGRAMS.

USGS, in cooperation with the California Coastal Commission, should promulgate specific and detailed guidelines for achieving consistency of all OCS operations and facilities with state and local coastal zone management programs. In California, the USGS Pacific Area Supervisor should require all operations and facilities related to offshore California OCS exploration and production to be consistent with state and local consolidation policies. The Pacific Area Supervisor should periodically reassess the consolidation opportunities by performing an inventory of existing facilities and their level of use, and re-examining OCS production prospects and the Department of the Interior's leasing schedule. USGS should solicit the assistance of state and local agencies in performing this periodic review.

56. INDUSTRY RESPONSIBILITIES. Industry must recognize its responsibility to develop the OCS and all related facilities in a manner consistent with California's coastal zone management program and the goals of state and local environmental planning agencies. Because of its expertise, industry should take the initiative in defining consolidation strategies designed to minimize land use and environmental impacts.

L E A S E - A R E A P L A N N I N G

FINDINGS

AUTHORITY FOR LEASE-AREA PLANNING. Such authority is derived from the OCS Lands Act which requires that "the Secretary shall administer the provisions of this Act ... in order to provide for the prevention of waste and conservation of the natural resources of the Outer Continental Shelf." The area supervisors of the Geological Survey and the Bureau of Land Management are delegated some discretion in carrying out this mandate for the Secretary which would allow their initiation of such lease-area plans. Precedent for lease-area planning has been set by Interior's commitment to pipeline corridor planning.

OBJECTIVES AND PRODUCTS OF LEASE-AREA PLANS. The objectives of lease-area planning are to coordinate development of potential offshore resources in a given area, eliminate unnecessary duplication of essential facilities, and eliminate uncertainties of future development for each leased area. The products of a lease-area plan would include timing parameters for exploration and development, requirements for future unitization of leases within the study area, clearly defined transportation and processing options, and criteria for development approval agreed to by government and industry. Lease-area plans would be flexible enough to accommodate the necessary and inevitable changes that come to light as new wells are drilled and new information becomes available.

LEASE-AREA PLANNING TO EXPEDITE OFFSHORE DEVELOPMENT. Lease-area plans would provide offshore operators with timing priorities for each operator's exploration and/or development activities in a given area. This would allow separate companies the opportunity to share the use of mobile drilling rigs, pipelaying barges, heavy construction equipment, or other costly operations by adjusting their separate exploration and/or development schedules accordingly. Lease-area plans would provide governmental agencies with timing parameters for permit processing by all regulators involved in offshore-related development. This would allow an opportunity to consolidate permit review and approval procedures, eliminating the enormous duplication of effort and protracted time ordinarily required for project approval. Lease-area plans would impose timing constraints on both industry and government, allowing each side to determine how to make the most efficient use of its own and the other's limited time and manpower.

RECOMMENDATION

57. LEASE-AREA PLANS SHOULD BE PREPARED JOINTLY BY INDUSTRY AND GOVERNMENT. Lease-area plans for existing leased areas should be undertaken jointly by representatives of companies holding leases in the planning area, and representatives of affected federal, state and local permitting agencies. Plans for proposed lease areas should be undertaken jointly by representatives of Western Oil and Gas Association, California Independent Producers Association, and affected permitting agencies. Lead responsibility for lease-area plans should be in the office of the Secretary of the Interior. When one operator is ready to commence development before other operators are ready to participate in a lease-area plan, then this lease-area plan requirement could be waived by the Interior Department, providing that the objectives of lease-area plans are incorporated in the initial plan of development.

U N I T I Z A T I O N

FINDINGS

UNITIZATION: VOLUNTARY OR MANDATORY. When there is a clear economic advantage to unitization, petroleum companies form units voluntarily. USGS, however, has authority to require unitization in the interests of conservation. The courts have liberally interpreted this to imply the conservation of all natural resources, including air, water, and marine life.

UNITIZATION'S NUMEROUS BENEFITS. It allows exploration and development programs to be based on the nature of the oil and gas prospects, rather than on lease boundaries and ownership considerations, which are basically irrelevant to the task of locating and recovering commercial deposits of oil and gas. Unitization increases overall recovery from reservoirs by permitting use of the most efficient "natural drive" and secondary recovery methods not otherwise available in some types of competitive practices. Unitization also eliminates many costs and facilities, resulting in:

1) financial savings to companies;

2) environmental/land use savings to onshore communities;

3) fewer administrative permits, with savings both to companies and to communities; and,

4) accelerated development of oil and gas resources.

TIMING OF UNITIZATION. Unitization occurs most often after initial exploration has begun and discoveries have been made. Where unitization has occurred prior to exploration, industry motivation has been to retain leases beyond their initial five-year term.

INDUSTRY SUPPORTS VOLUNTARY UNITIZATION. Unitization of leases overlying a competitive reservoir is actively sought by many petroleum companies because it saves costs and achieves an equitable arrangement for the recovery of petroleum resources. Voluntary unitization allows the petroleum companies greater freedom of choice in what, when, and with whom they unitize.

INTERIOR RECOMMENDED MANDATORY UNITIZATION. A Department of Interior staff analysis performed in 1975 recommended that DOI pursue mandatory unitization of frontier areas, including the southern California Outer Banks. The staff report also recommended that DOI consider mandatory unitization of leases already sold in the Santa Barbara Channel.

DISADVANTAGES OF MANDATORY UNITIZATION. Mandatory unitization would offer California the advantages of accelerated development already noted, but it would also narrow industry's flexibility in making investment decisions. As a condition of future lease sales, it might reduce speculative bids by industry and thus lower lease sale revenues. Industry contends that in some instances mandatory unitization could prolong exploration and impede efficient development.

ABUSE OF UNITIZATION. Unitization may be employed as a lease-holding device, effectively delaying rapid exploration and development of OCS resources. OCS regulations provide for the extension of the primary term for unitized leased tracts if "diligent and good faith" efforts are being made to explore and/or develop any one tract in the unit. This privilege has extended the lease-term of four tracts in the Santa Ynez Unit which have never been directly explored.

POTENTIAL NEW UNITS OFFSHORE OF CALIFORNIA. If mandatory unitization were required, it would affect leased tracts in the Outer Banks and San Pedro Bay and the Santa Barbara Channel leases sold in 1968. There are 20 non-unitized leases in the Channel located in four different areas.

COMMON OWNERSHIP MAY OBVIATE UNITIZATION. Where all tracts leased over a complete geologic structure are held by a single

company or single consortium of companies, the goals of unitization are effectively satisfied. Unitization serves little purpose in these instances other than to extend the primary term of leases within the unit boundary. Examples of tracts leased over a complete geologic structure held by a single company or single consortium of companies include the San Miguel Unit and the proposed Santa Cruz Unit in the Santa Barbara Channel.

RECOMMENDATIONS

58. UNITIZATION OF NEW LEASES. USGS should require unitization of all leases sold in Lease Sale #35, according to common geologic structures which they overlay except those contained within a single lease or group of leases held in common ownership, and of all potential leases that could be sold as a result of lease Sales #48 and #53 with the same exception. One plan for mandatory unitization is outlined in Appendix A of Chapter 19. Unitization of the remaining non-unitized leased tracts in the Santa Barbara Channel is not recommended at this time because these groups are held in common ownership.

59. STATE AND LOCAL GOVERNMENT INVOLVEMENT. The Interior Department should institute procedures for involving state and local governments in unitization decisions to the extent that they affect onshore land use decisions and regional energy supply issues. It is not the intention of this recommendation to subordinate national energy policy to state or local interests.

C O N S O L I D A T I O N

FINDINGS

CONSOLIDATION'S NUMEROUS BENEFITS. Consolidation of sites and facilities offers most of the same advantages offered by unitization. In addition, consolidation reduces:

a. industrial land requirements near the coastline,

b. conflict with other coastal land uses,

c. the number of potential sources of oil spill and air pollution,

d. the amount of energy and raw materials used in construction and operation of the facilities,

e. the costs of facility operations, and,

f. adverse scenic effect of additional industrial facilities in coastal areas.

EXISTING POLICIES FOR CONSOLIDATION. Express policies of California's coastal zone management program (see California Coastal Act of 1976) and Santa Barbara County require that facilities related to offshore petroleum exploration and production be consolidated wherever feasible.

CONSOLIDATION RARE IN CALIFORNIA. In the past, industry has consolidated facilities when operating economies have been apparent. Generally, however, companies operating off the California coast have preferred to construct and operate their own facilities in order to maximize flexibility in production and marketing strategies. Historically this has resulted in a proliferation of offshore pipelines, small onshore oil and gas processing plants, and tanker terminals along the coastlines of Santa Barbara and Ventura County and between Long Beach and Huntington Beach.

INDUSTRY RESISTANCE TO CONSOLIDATION STRATEGY. Industry opposition to consolidation is variously based on contentions that:

a. indiscriminate application of consolidation strategies would increase capital costs prohibitively, especially for small-scale operations;

b. the information exchange and inter-company cooperation that must attend planning for and operation of consolidated facilities may lead to a loss of competitive advantage and violation of antitrust laws;

c. the uncertainty of information regarding recoverable reserves, production rates, and timing of production restricts the precision with which consolidated facilities can be planned;

d. a company's flexibility in production and marketing strategies will be impaired by facilities that must be designed and operated to meet the needs of other companies; and,

e. physical properties of oil and gas produced from different reservoirs would contaminate each other.

NO LOSS OF PATENTS OR PROPRIETARY INFORMATION. The inter-company cooperation required for consolidation of facilities related to offshore petroleum has not jeopardized technical patents and proprietary information in facilities already consolidated.

NO CAUSE FOR ANTITRUST VIOLATION. When public agencies require petroleum companies to consolidate facilities for environmental or other public policy reasons, inter-company planning efforts necessary to construct and operate the facility are not in violation of antitrust law, absent a showing of intent to act in restraint of trade.

CONSOLIDATION NOT PRECLUDED BY VARIANT CRUDE CHARACTERISTICS. There are no physical properties of offshore petroleum resources that prevent commingling. The commingling of crudes can occur at any point between recovery at production stations and eventual delivery via tanker or pipeline to a refinery. With limited exceptions, the combination of crudes differing as to gravity, sulfur content, or viscosity always results in averaging of respective characteristics in proportion to the constituent volumes mixed. The main consequence of commingling one crude oil with others will be to affect its marketability, which varies according to the demand for the crude derived. If crude oils are to be commingled, producers prefer to do so after by-products and wastes have been separated, making it easier to compute the value of their respective marketable crudes and the amount of royalty they must pay.

THE TIMING COMPLICATION. Inter-company planning for consolidated facilities is complicated by the great latitude leaseholders are allowed in proceeding toward development. Under existing laws and regulations, a lessee is permitted five years following a lease sale to take significant steps toward development. Unitization can extend this period further for some leases. Successful bidders proceed with exploratory activity on widely variant schedules, depending on:

a. the amount of capital invested in the lease purchase,

b. the prospects for petroleum recovery,

c. the success of initial exploratory wells, and,

d. internal company investment decisions.

Within a geographic area leased in a single sale, acquisition of resource information and development decisions of individual companies may be spread over a five- to ten-year period.

ENVIRONMENTAL "HOTSPOTS." In some instances, consolidation of facilities may raise environmental problems more serious than those it solves. The increased activities at a single site could,

for example, exceed point source air pollution standards which might not otherwise occur if several smaller dispersed facilities were utilized.

DIFFICULTIES OF ECONOMIC ANALYSIS. Economic analysis of consolidation options by public decision makers is complicated by:

a. incomplete information about the producible petroleum resource;

b. incomplete information regarding the capital investment and marketing strategies of individual companies involved; and,

c. inadequate analytical tools for measuring the economic value to society of environmental improvement, mitigation of adverse environmental effects, or elimination of the risks of environmental damage.

RECOMMENDATIONS

60. NEED FOR A FEDERAL POLICY. USGS should adopt a policy in clear and explicit terms that requires consolidation of transportation, storage, treatment, and service facilities related to OCS exploration and development where feasible and unless there are strong economic or environmental reasons consolidation is not desirable. USGS should promulgate explicit regulations to effect this policy for existing leases. BLM should incorporate a consolidation policy in lease stipulations for future lease sales.

61. FEDERAL ROLE IN CONSOLIDATION. Any EIS and other reviews of any development plans should include detailed consideration of possibilities for consolidating crude oil transportation, storage, and treatment operations of the development area in question with similar operations occurring in the same geographic area and time frame. Discussion of consolidation opportunities should include detailed accounts of economic, timing, engineering, and environmental issues. Such analyses

will require the cooperative efforts of the Department of the Interior and state and local agencies to resolve jurisdictional problems.

CHAPTER 10:

TRANSPORTATION*

FINDINGS

General

TWO PHASES OF TRANSPORTATION. Offshore oil and gas is transported:

a. between the production platform and the processing facility, where emulsified or associated oil, gas, and water are separated and treated; and,

b. between the processing facility and refinery or gas company transmission system.

Transportation options are tankers, barges, or pipelines for crude oil, and pipelines or liquefied natural gas (LNG) carriers for natural gas. All crude oil and natural gas presently produced in southern California are transported by pipelines to processing facilities; crude oil is then either pipelined or tankered to refineries, and natural gas is pipelined to gas company transmission lines.

PIPELINE ROUTING DECISIONS. Pipeline developers seek the route providing the best combination of lease distance, shallowest water depth, and avoidance of geologic hazards. In the Santa Barbara Channel and San Pedro Bay, the shortest routes from oil and gas fields to shore are also the shallowest. In the outer banks, the shortest routes encounter impractical water depths and the optimum pipeline route thus involves substantially longer distances than a direct route to shore.

TANKER ROUTING DECISIONS. Optimum tanker or barge routing requires the shortest navigational course consistent with navigational safety. All southern California coastal traffic passes through Santa Barbara Channel and San Pedro Bay leased areas.

*For further discussion, see Chapter 20.

ECONOMIC DETERMINANTS OF OIL AND GAS TRANSPORTATION MODES. The major economic determinants for a crude oil transport system between offshore producing areas and onshore facilities are:

a. size and projected life of the oil field;

b. market value of the oil and gas;

c. rate of production;

d. amount of capital investment required for development;

e. distance from the field to the receiving point on land;

f. operating costs of the system;

g. water depths; and,

h. topography of the ocean floor.

DESTINATION OF SOUTHERN CALIFORNIA OFFSHORE OIL AND GAS. All natural gas produced off southern California is consumed in southern California. The distribution of offshore crude oil is less certain, but it is estimated that over 80% is refined and consumed in the Los Angeles Basin. The distribution of offshore production depends in part on the availability of transportation systems but is more sensitive to market demands and government regulations.

Crude Oil Transportation

OIL CHARACTERISTICS AS DETERMINANTS OF TRANSPORTATION MODES. The characteristics of California crude oils do not, in general, dictate the transportation mode used. Instead, they impose design or operational constraints on whichever mode the operator selects. The properties of crude oil significant in pipeline design are viscosity and specific gravity. Viscosity of the oil governs the pipe dimensions, which in turn establish the material and laying costs and fix the size and number of pumping stations. Viscosity and specific gravity together determine the energy required to pump the crude oil.

SULFUR AS A DETERMINANT OF CRUDE OIL TRANSPORTATION. Sulfur content may affect the design of a transportation system. Sulfur compounds are undesirable in oil and must be reduced to acceptable levels for a refinery; hence, the choice of destinations for the crude is limited by refinery desulfurization capabilities. Of more importance to the selection of a transportation mode is the amount of hydrogen sulfide gas (H_2S) in crude oil. Crude oil high in sulfur is referred to as "sour" and can be corrosive when combined with water. Platform treatment can reduce H_2S in oil (or natural gas) to levels acceptable for pipeline transshipment,

but further "stripping" at a processing plant is required before shipping companies will accept sour crude for transport by tanker. A pipeline system can be designed and operated to transport commingled high sulfur and low sulfur oil without "batching" (moving separate quantities of oil in alternating intervals).

PRODUCING AREA TO PROCESSING SITE. Processing plants are located as close as possible to production areas to reduce transportation costs. The costs of transporting unprocessed crude oil by tanker to processing sites is normally prohibitive because the purchaser would be paying for shipment of emulsified waste water and other impurities as well as the crude oil. Where the transportation costs become too high, or if onshore processing facilities are unavailable, oil producers have proposed offshore processing plants, with the transshipment of the processed crude to refineries by tanker (see, for example, Santa Ynez Unit and Santa Clara Unit development proposals). Such offshore alternatives remain undesirable for OCS development off the southern California coastline because they increase the risks of oil spills entering the marine environment. Navigational safety is also impaired by additional unnecessary fixed structures in the OCS.

PROCESSING PLANT TO REFINERY. Fluctuations in crude oil production and demand argue for flexible delivery systems between processing plants and refineries. Under ideal conditions, both producer and refiner prefer a pipeline network. Direct pipelines are preferable because the throughput can be regulated, thereby avoiding the use of tankers and eliminating tanker-related storage requirements at the processing end. A pipeline network can also link several processing plants with one or more refineries to allow selective delivery of different crudes or blends of crude as market demand requires. Refineries are always located close to market areas because of higher transportation costs past the refining stage.

COSTS OF CONSTRUCTING CRUDE OIL PIPELINES. Based on actual costs of existing onshore pipelines, the cost of line pipe and installation labor usually constitutes over 70% of the investment required to construct an onshore pipeline. Other average costs for onshore pipelines are land (.3%), right-of-way (2.3%), pipe fittings (2.5%), buildings (2.8%), pumping equipment (6.7%), other station equipment (8.7%), storage tanks (5.2%), delivery facilities (.7%), and miscellaneous appurtenances (1.3%). Estimates for onshore pipeline costs in southern California may differ slightly from these estimates where highly urbanized areas are encountered. Offshore pieplines cost twice to ten times as much as same-diameter onshore pipelines, depending on the length required and water depths encountered. The primary difference is in installation costs which are proportionately much higher for offshore pipelines.

Natural Gas Transportation

PRODUCTION SITE TO PROCESSING PLANT. All natural gas produced offshore must be transported by pipeline from production sites to processing plants for treatment and separation. Where processing sites are not available or the quantities of gas produced are too small to justify a pipeline, natural gas is typically flared or reinjected into the underlying geology (flaring is not permitted off southern California). Offshore processing of natural gas discoveries in southern California waters has not proven economically feasible under current technology.

PROCESSING SITE TO GAS COMPANY: PIPELINES VS. LNG. Liquefied natural gas (LNG) operations have been developed for large natural gas fields separated by thousands of miles from potential customers. Southern California OCS leases are not "remote," given this context, nor are the expected quantities of natural gas of a scope to justify the costs of such an operation. LNG also offers undesirable risks, especially when compared to pipeline transport. Pipeline routes from all leased areas off southern California to mainland gas company transmission lines appear to be within reach of pipeline technology projected to be available in the next five years.

Pipelines and Pipelaying

FLEXIBILITY IN PIPELINE CAPACITY. The throughput, or capacity, of an existing natural gas or crude oil pipeline is limited to the maximum allowable working stress of the pipeline walls, fittings, and valves but can be increased in some instances by replacing an existing pump with a larger one, or by adding new pumps on the line. Throughput of crude oil pipelines may vary depending on the viscosity of crude oil shipped in them: heating more viscous crudes will permit an increase in throughput over non-heated systems. An operator can provide for flexibility in a new pipeline's capacity, even with an unknown production rate, by designing the line for the highest anticipated throughput, but with a provision for adding more pumping units as required. For example, a 36-inch crude oil pipeline once proposed by Socal between Estero Bay and Richmond was designated to accommodate throughput rates of 340,000, 420,000, or 570,000 barrels of oil per day, depending on whether two, four, or five pumping stations were put into operation.

PIPELAYING CAPABILITY. Water depth is a principal limiting factor to offshore pipeline transportation systems. The maximum depth of pipelines currently in operation is 600 feet in the North Sea, but this will be increased to 850 feet when Exxon completes Platform Hondo in the Santa Barbara Channel. Experimental pipelines have been installed at depths of 1,000 and 1,200 feet, and a pipelaying ship designed with a capability of laying a 24-inch diameter pipe at a 3,000-foot depth is

due to be launched in 1977. The trend of recent developments in pipelaying equipment and the goals being set by industry-sponsored research programs indicate that all leased areas off southern California can be serviced by on-bottom pipelines within five years.

WATER DEPTHS AND PIPELINE ROUTES. The greatest depth encountered by any present lease off southern California is 2,500 feet (only one lease encounters this depth). Gathering lines between all leases and central gathering stations of leased areas would not encounter greater depths. Gathering stations in the Outer Bank areas can be located in water depths less than 850 feet for all OCS lease areas, and trunklines connecting these gathering stations with the mainland can avoid depths greater than 1,600 feet.

CALIFORNIA'S ONSHORE CRUDE OIL PIPELINE SYSTEM. Little is known of the crude oil pipeline network in California: no public agency has mapped all the crude oil pipelines, let alone determined their ownership, current throughput, surplus capacities, costs, or conditions of use. Some information has become available in these areas as a result of the efforts of industry and government working together in the Santa Barbara Channel area.

THE MAJOR PIPELINE CORRIDORS. Six major pipeline corridors control the flow of crude oil in California:

a. the lower San Joaquin Valley to Los Angeles Basin;

b. the Valley to the San Francisco Bay region;

c. the Ventura area to the Los Angeles Basin;

d. a highly integrated and complex network (over 1,000 separate pipelines) in the Los Angeles Basin moving crude delivered from the San Joaquin Valley, Ventura, Los Angeles and Long Beach Harbors, and local production to the various refineries in the basin;

e. Central California Coast (Estero Bay and Avila Beach) to the San Joaquin Valley, permitting shipment to or from the coast and to the Bay region from Estero Bay; and,

f. the Four Corners Pipeline, the only designated common carrier line in California, linking the Los Angeles Basin and the Four Corners area.

In addition, at each producing area there are numerous gathering lines connected to the main trunklines. A surplus capacity of 216,000 B/D could be achieved in lines running from the San Joaquin Valley to Los Angeles and the Bay Area with additional heating stations and pumps.

CALIFORNIA'S ONSHORE PIPELINES ARE PRIVATE. Crude oil pipelines offshore are common carriers if they cross unleased federal submerged lands. Once crude oil is brought ashore, it is delivered to refinery centers by either pipelines or tankers. California is exceptional among oil producing states in that all but one of the onshore crude oil pipelines in the state are privately owned and nearly all are operated by major, integrated companies. Crude oil carried in these pipelines, however, is not necessarily produced by the parent company owning the lines, nor is it used in that company's refineries. Essentially these pipelines are operated like common carriers, but the pipeline company "purchases" the crude oil from the producing company at one end of the line, carries it to the other end, and then resells it (possibly to the initial owner or to a competitor). Operators of private pipelines thereby avoid common carrier status in that they transport their "own" crude oil. This poses certain limitations on the flow of offshore crude oil or any crude oil in that private pipeline owners regulate the costs of the crude oil moving through them and can control access as well.

COMMON CARRIER VS. PRIVATE CRUDE OIL PIPELINES. The major oil companies in California prefer private ownership of crude oil pipelines because it gives them an added measure of control over crude oil marketing. Transportation costs charged by common carrier oil pipeline companies are regulated by the Interstate Commerce Commission (ICC). Tariffs for privately owned crude oil pipelines are not regulated, allowing the pipeline company to set its own price for purchasing crude and reselling it. In 1974, the Joint Committee on Public Domain of the California State Legislature recommended that private carrier pipelines be regulated or controlled as common carriers to allow access to all producers, and to insure a competitive crude oil market.

SOUTHERN CALIFORNIA'S ACCESSIBLE ONSHORE NATURAL GAS PIPELINE SYSTEM. Natural gas pipelines are regulated by the State Public Utilities Commission and are well documented. Several natural gas companies serve the southern California coastline from Point Conception to San Diego. Natural gas transmission and trunk lines are within two miles of any landfall between Point Conception and the Mexican border. Engineering feasibility studies may be required before OCS natural gas could be transshipped through these lines. Many of these gas lines have the capacity to carry OCS natural gas production Although new connecting pipelines may be required in some areas.

Marine Transport: Tankers and Barges

MARINE TRANSPORT USED WHEN PIPELINES NOT AVAILABLE. Crude oil produced from the Long Beach-to-Huntington Beach offshore area is delivered to Los Angeles refineries by pipeline, while crude oil produced from the Santa Barbara Channel is delivered to refineries by pipelines and tankers. Tankers are used between the Channel producing areas and Los Angeles because existing pipelines are used to capacity. Tankers

are used between the Channel and Bay area refineries because the two areas are not now linked by pipeline.

ENVIRONMENTAL RISKS: TANKER VS. PIPELINE. Every study of transportation alternatives for southern California OCS production to date has concluded that pipelines are safer to use than tankers or barges. The volume of oil projected to enter the marine environment as a result of tanker and barge casualties and transfer operations is significantly greater than the volume of oil expected from pipeline accidents. The spill factor for tankers is almost seven times greater than that for pipelines. Marine terminals also are undesirable from an air quality standpoint. Emissions resulting from tanker loading operations are the largest source of air pollution resulting from oil and gas development.

VESSEL TRAFFIC PATTERNS IN SOUTHERN CALIFORNIA. The majority of foreign and domestic merchant vessel traffic in southern California is confined to legally established vessel traffic lanes from Point Conception to south of the Los Angeles and Long Beach Harbors complex. Estimates for the number of vessels per day in these lanes are:

	Northbound	Southbound
Offshore of Point Arguello	7.3/day	8.2/day
Between Pt. Conception and Port Hueneme	6.6/day	6.0/day
Between Port Hueneme and LA/LB Harbors	12/day	10.6/day
Between LA/LB Harbors and Canal Zone	5/day	3.5/day

Crude oil and product tanker movements to and from the five active marine terminals in the Channel, the four marine terminals at El Segundo, and the one marine terminal at Huntington Beach are included in these traffic estimates. Tankers originating in Los Angeles or Long Beach Harbors or El Segundo move through the northbound lane to the Channel, leave the lane to make several calls at the Channel marine terminals, and return by way of the southbound lane to the Harbors or El Segundo for offloading.

PROJECTED VESSEL TRAFFIC INCREASES CAUSED BY SOUTHERN CALIFORNIA OFFSHORE CRUDE OIL PRODUCTION. If an onshore pipeline is not constructed to deliver Santa Barbara Channel production, as many as 40 new roundtrips per month can be expected by 1980. New production from South Elwood, Summerland, and Carpinteria offshore fields could add seven roundtrips per

month; the Santa Ynez Unit could add 11 round trips per month; new production from Platforms C and Henry could add five round trips per month from the Union marine terminal at Ventura; and new production from the Santa Clara and Hueneme Units could add ten round trips per month. Since the peak round trip estimates occur at different times between 1979 and 1983, they do not add up to the estimated total of 40 round trips projected to occur in 1980. If pipeline options are not constructed for the Outer Banks areas, an additional 40 round trips per month for all three areas could occur in 1983.

NAVIGATIONAL SAFETY: POTENTIAL FOR COLLISION OR RAMMINGS. The potential exists for a collision or ramming between OCS exploration or production structures and passenger, cargo, or tank ships. The Coast Guard has established the voluntary Vessel Traffic Separation Scheme (VTSS) from Point Conception to south of San Pedro Bay. Most commercial vessels operating off the southern California coast use these lanes. In the Santa Barbara Channel, 20 of the 65 active leases are intersected by the designated shipping lanes; and seven of the thirteen federal OCS leases in San Pedro Bay are either within these traffic lanes or the adjacent separation and buffer zone. In 1976, the U.S. Coast Guard recorded an average five vessels per day inbound and 3.5 vessels per day outbound from Los Angeles/Long Beach Harbors in the lanes. These estimates refer to passenger or cargo vessels, tankers, sea-going barges, and Navy vessels with drafts more than 18 feet; they do not include smaller barges, commercial or sport fishing boats, pleasure boats, tugs, research vessels, Coast Guard vessels, or the Catalina ferry. Six hundred small vessels traverse the waters between Los Angeles and Santa Catalina daily, creating problems of traffic congestion in this area. Much controversy has focused on the permits issued for structures to be positioned in or near the Vessel Traffic Separation Scheme. It is the responsibility of the Corps of Engineers (COE) to prevent obstructions to navigation and to issue permits for fixed structures in navigable waters. The COE has promulgated proposed guidelines, applicable only to exploratory vessels in the Gulf of Santa Catalina VTSS.

PROJECTED VESSEL TRAFFIC INCREASES CAUSED BY ELK HILLS OIL, ALASKAN OIL, AND LNG (ALASKAN AND/OR INDONESIAN). Increased tanker traffic caused by these sources and the traffic areas affected depends on final destinations approved for each proposal. If a major crude oil port and/or LNG terminal is constructed north of Point Conception, no increases should be experienced to the south. If Sohio's Alaskan crude oil terminal is constructed in Long Beach Harbor, all of the Long Beach-bound Alaskan tanker fleet will pass through the Channel en route to Long Beach or Valdez. If an LNG terminal is constructed at Oxnard, all LNG deliveries from either Alaska or Indonesia will be by way of the Channel. If an LNG terminal is constructed at Point Conception, the Channel will not experience increased vessel traffic from LNG tankers.

If the Elk Hills production is delivered to Port Hueneme, vessel traffic in either direction will experience an increase. The maximum projected traffic volumes for these sources follows:

Source	Round Trips Per Day	
Crude oil from Valdez to Long Beach	1.1	assumes 1,200,000 B/D and mean tanker size of 136,825
Elk Hills oil from Port Hueneme to LA/LB Harbors or San Francisco	1.3	assumes 200,000 B/D and average tanker size of 35,000 DWT
LNG from Alaska and Indonesia to Point Conception, LA/LB, and Oxnard	3.5 - 4.6	assumes each facility is operating at design capacity of 4 billion cubic feet per day

RECOMMENDATIONS

62. PIPELINES VS. TANKERS. The State of California should require the development of an efficient, common carrier crude oil pipeline network linking all offshore producing areas with California refining centers and west coast to mid-continent pipeline systems, if developed. It should be the policy of the state that pipelines are preferred to tankers in all cases, but that current or future use of tankers or barges may be acceptable as an interim solution while feasibility studies of pipeline corridors (described in Chapter 11) are carried out and evaluated. If crude oil pipelines prove to be unfeasible or environmentally more damaging than tankers, the use of tankers or barges should be permitted for the life of the producing area.

63. NO FIXED STRUCTURES IN TRAFFIC LANES. The Corps of Engineers should revise and broaden its proposed guidelines to exclude all fixed structures associated with exploratory and production activities from the lanes of the Vessel Traffic

Separation Scheme (VTSS) in the Gulf of Santa Catalina and the Santa Barbara Channel. Areas beneath the lanes may be explored from vessels outside of the VTSS with slant drilling techniques commonly used on production platforms and islands. Production of areas beneath the lanes may be from surface structures located outside the lanes or by ocean floor production systems beneath the lanes. Ocean floor production systems, where feasible, are preferred to surface structures in either case. If ocean floor production systems must be used, production wells may be drilled from surface vessels within the VTSS after appropriate precautions have been completed.

CHAPTER 11:

DEVELOPMENT SCENARIOS*

SANTA BARBARA CHANNEL

FINDINGS

TIDELANDS OPERATIONS IN DECLINE. Most of the oil and gas fields in state waters are approaching the end of their productive lifetimes. There are more than 20 processing and terminal facilities supporting these tidelands fields. These facilities range in age from ten to 40 years, and nearly all are operating substantially below capacity. Many are obsolete. Some will be abandoned in the near future, while others may remain economically viable for 20 years or more. Most of these facilities are well maintained, but many contrast sharply with the surrounding environment, and some are a blight on the landscape.

EXISTING PRODUCTION. There are two Santa Barbara Channel OCS oil fields already in production: Dos Cuadras and Carpinteria. These two fields combined now produce about 40,000 B/D oil and 15,000 MCF/D natural gas.

SURGE OF ACTIVITY EXPECTED. Seven other oil and gas fields have been found so far in the Channel OCS leases sold in 1968. In ordinary circumstances, several of these fields would be in production by now, but after the 1969 blowout, the Interior Department restricted drilling and production activities. With the release in 1976 of an environmental impact statement on Santa Barbara Channel oil and gas development, the Interior Department is moving to allow operators to resume "normal" development. With the removal of these restrictions a surge of development activities in the Channel can be expected.

APPROVED, PROPOSED, AND POTENTIAL DEVELOPMENT PLANS. Development plans calling for the installation of new platforms in the Hondo and Dos Cuadras fields have been approved by the U.S. Geological

*For further discussion, see Chapters 14 and 21.

Survey. Three other development plans have been submitted to USGS and are now pending. Four other discoveries have been made in the Channel OCS, and their development feasibility is now being evaluated.

OCS PRODUCTION WILL RISE SHARPLY. As these new fields are developed, Channel OCS production will rise to more than 100,000 B/D oil and 100,000 MCF/D natural gas in the early 1980s. Total Channel production (state and federal leases) could reach 200,000 B/D oil and 200,000 MCF/D natural gas in the mid-1980s. Between 1976 and 2000, at least 700 MM barrels oil and 850 BCF natural gas could be produced from existing Channel OCS discoveries alone.

ADDITIONAL DISCOVERIES POSSIBLE. Exploratory wells have been drilled on only 35 of the 65 existing Channel OCS leases. Only 19 of these 35 leases have been explored with more than one well. New discoveries could be made on any of the leases currently without discoveries. Moreover, less than half of the Channel OCS available for leasing is now actually leased. Nearly all of the unleased Channel OCS tracts are included in proposed Lease Sale #48.

PEAK PRODUCTION IN 1980s. Channel-wide production from existing discoveries will peak in the 1980s and decline thereafter. If new fields are found, their production is likely merely to slow the overall decline following the 1980s peak, rather than push Channel-wide production to new peaks in the 1990s. The facilities required for the development of the existing Channel discoveries may suffice to accommodate all future Channel discoveries as well.

LAST CHANCE FOR CHANNEL-WIDE PLANNING. The development proposals now being submitted will set the pattern for all future Santa Barbara Channel oil and gas development. The opportunity exists to program this development to meet Channel-wide requirements rather than the exclusive needs of individual companies. Given the status of Santa Barbara Channel oil and gas development, this is likely to be the last such opportunity.

RECOMMENDATIONS

64. DETERMINE FUTURE NEED FOR EXISTING FACILITIES. The State Lands Commission should determine probable remaining lifetimes for all state tideland operations (marine terminals, platforms, artificial islands, ocean floor wells, pipelines) and their related onshore components (storage areas, processing plants, service facilities) to assist local planners and operators in preparing re-use plans for sites capable of being recycled.

Where public uses are anticipated, re-use planning can determine appropriate means of conveying title to the property from industry to a public entity. If a site is to be recycled for public use, landscape treatment of the site to achieve mature planting appropriate to the intended purpose should be carried through in advance of the change in use.

65. TWO PROCESSING PLANTS SUFFICIENT. All new Channel OCS production should be accommodated at two processing plants: the existing Mobil-Rincon facility, designed for 95,000 B/D oil and 60,000 MCF/D gas, and the proposed Exxon-Las Flores facility designed for 80,000 B/D oil and 90,000 MCF/D gas. These two plants could process the levels of production projected for all known oil and gas fields in the Channel and could be expanded to accommodate production from future discoveries in the Channel OCS.

66. PROCESSING OPTIONS AVAILABLE. As an alternative to consolidating all of the eastern Channel processing at Mobil-Rincon, new production could be distributed among the existing Chevron-Carpinteria, Phillips-La Conchita, and Mobil-Rincon processing plants. This alternative may be preferable if the net regional air quality impact resulting from these three point sources is no greater than the impact resulting from concentrating all processing requirements at Mobil-Rincon alone for the same throughput.

67. EASTERN CHANNEL OFFSHORE PIPELINE NETWORK. Operators in the eastern end of the Channel should devise a pipeline network that:

a. minimizes the average length and number of pipelines required to bring natural gas and crude oil to shore; and,

b. provides access to and capacity for maximum anticipated production from all east Channel leases.

The network could consist of at least two trunk line corridors, the already existing one originating at the Dos Cuadras field and the other, tentatively being considered by Mobil and Chevron, originating at the Hueneme Offshore field. (See Recommendations 10 and 12 of this Chapter.) A third corridor may be required to serve the proposed Santa Cruz Unit, the Oak Ridge Unit, and the Pitas Point Unit. This pipeline should connect these three potential areas with Mobil-Rincon via the existing pipelines between the Dos Cuadras field and Mobil-Rincon or by a new direct route.

68. WESTERN CHANNEL OFFSHORE PIPELINE NETWORK. If the existing leases to the north of San Miguel and Santa Rosa Islands prove to contain economically recoverable petroleum resources and are permitted to develop, these areas should be connected by pipelines to the Santa Ynez Unit processing plant site. Connecting pipelines between Santa Ynez production facilities should be designed to accommodate any increased throughput that could result from the leases near San Miguel and Santa Rosa Islands.

69. ONSHORE PIPELINE STRATEGY. Once ashore, crude oil should be collected from the various processing plants and delivered through a jointly owned pipeline system to California refinery centers or to a west coast to mid-continent pipeline system as proposed for Alaskan oil or Elk Hills oil if, after careful study, such a strategy should prove both economically feasible and environmentally less damaging than the alternative of tankering crude oil. A definitive analysis of this strategy could be accomplished as a part of the EIS being prepared for Lease Sale #48, or through

a grant from the Office of Coastal Zone Management through CEIP (Coastal Energy Impact Program), or as a condition to future offshore development proposals by industry.

DOS CUADRAS OFFSHORE FIELD

FINDING

PLATFORM C INSTALLED. Platforms A and B are already in production, producing about 34,000 B/D oil and 11,000 MCF/D natural gas. Union constructed Platform C in February 1969 and intended to install it immediately. Following the 1969 blowout at Platform A, however, Interior withdrew the permit for installation of Platform C. In 1971 Interior denied Union's second application. Union filed suit challenging the decision, and the litigation was settled in Union's favor in August 1976. Union installed Platform C in March 1977 with production projected to begin by fall 1977. Union expects Platform C production to peak in 1979 at about 7,000 B/D oil and 2,400 MCF/D natural gas. Recoverable reserves in the Dos Cuadras field are estimated at 88 MM barrels oil and 27 BCF natural gas.

RECOMMENDATION

NO RECOMMENDATION. Since Platform C is not subject to further review, and because it requires no new onshore facilities, no recommendation is made.

CARPINTERIA OFFSHORE FIELD

FINDINGS

SUN'S PLATFORM HENRY CONTINGENT ON LITIGATION AND EXPLORATORY WELL. Existing production in the federal portion of the Carpinteria field -- about 4,800 B/D oil and 2,600 MCF/D natural gas -- is from two Phillips platforms on Lease 0166. The Carpinteria field extends into Sun's lease 0240, and Sun has tried since 1970 to obtain permission to install Platform Henry. Construction and emplacement of Platform Henry is contingent upon resolution of pending litigation and upon the results of further resource evaluation. It is estimated by USGS that Henry could recover 13 MM barrels oil and nine BCF natural gas. We estimate that a peak flow of 6,000 B/D oil and 4,000 MCF/D natural gas could occur in 1980 if the litigation is resolved by 1978 and Sun concludes that Platform Henry is still a desirable proposal.

HENRY PRODUCTION TO MOBIL-RINCON. Sun's proposed Platform Henry has been designed as a satellite production facility to Platform Hillhouse on the nearby Dos Cuadras field. Equipment on Henry would consist of the minimum necessary to produce and

test wells and transport the product. Sun Oil's development plan proposes connecting Platform Henry by pipeline with Platform Hillhouse where Sun maintains significant processing capability. From Hillhouse, Sun would transport oil and gas through existing pipelines to the Mobil-Rincon processing plant for further processing. Sun Oil owns part interest in Mobil-Rincon.

PHILLIPS-LA CONCHITA OPTION AVAILABLE. A development alternative would be to connect Platform Henry by pipeline to Phillips Oil platforms Hogan and Houchin, located in the Carpinteria field and linked by pipeline to the Phillips-La Conchita processing plant. This alternative would allow surplus capacity at Mobil-Rincon to be reserved for other future production in the Channel. Peak production anticipated from Platform Henry is well within the capacity of the Phillips-La Conchita processing plant, but no surplus water treatment capability is available.

RECOMMENDATION

70. TRANSPORTING OIL AND GAS FROM PLATFORM HENRY. In reviewing Sun's development plan for Platform Henry, USGS should evaluate the option of redesigning Platform Henry in order to send production by pipeline to the existing Phillips platforms, and from there to the Phillips-La Conchita facility for processing. If such redesign renders the project economically infeasible, the original development plan should be approved.

S A N T A Y N E Z U N I T

FINDINGS

SANTA YNEZ UNIT CONTROVERSY. Development of the Santa Ynez Unit is the subject of considerable debate at both local and state levels. The major issue is the means of transporting processed crude oil to refineries: marine transport vs. onshore pipelines. Exxon argues that it must use tankers or barges because production levels and economic factors make a pipeline infeasible. State and local agencies believe an onshore pipeline would be economically viable, would reduce air pollution and oil spill risks, and could be used by other Santa Barbara Channel producers who would otherwise use tankers and barges. The Coastal Commission issued a permit to Exxon containing provisions for interim use of a marine terminal pending completion of a pipeline feasibility study. Exxon believes this permit lacks sufficient safeguards and assurances to enable it to accept the terms involved and, therefore, has pursued an offshore alternative beyond state jurisdiction.

SANTA YNEZ DEVELOPMENT PLAN. The initial plan for this unit is for development of one platform on a portion of the Hondo field, with provisions for subsequent production systems on the remainder of the field and future development of two additional fields within the unit area boundary. The development plan includes the initial platform, pipelines to shore, a new oil and gas processing plant in Las Flores Canyon, and a new marine terminal in state waters directly offshore. If onshore facilities could not be obtained by Exxon, the plan includes an offshore alternative for processing and transshipment of crude oil to refineries moored in federal waters. The Department of the Interior approved the development plan in 1974 and approved the offshore alternative contingent on a finding that, after diligent and good faith efforts, Exxon was unable to secure the necessary onshore permits under reasonable terms and conditions.

INFLUENCE ON SANTA BARBARA CHANNEL DEVELOPMENT. The Santa Ynez Unit contains half of the estimated potential reserves in the federally leased Santa Barbara Channel. Exxon's development decisions, therefore, will strongly influence options for Channel-wide oil and gas development. Specifically, crude oil produced elsewhere in the Channel could be transported through a pipeline developed for Santa Ynez Unit production, reducing the costs of such a pipleine and also the need for tankers in the Channel as a whole.

POTENTIAL OIL AND GAS RESERVES. Conservative estimates show that the Santa Ynez Unit contains more oil and gas than all other Santa Barbara Channel fields combined. High and low estimates for the unit vary widely. USGS and Exxon concur on estimated oil in place (three to five billion barrels). USGS has estimated that 730 million to 1.1 billion barrels of oil with a gas-oil ratio (GOR) of 500 cubic feet of gas per barrel could be recovered from the unit. Exxon states that only 420 million barrels of recoverable oil with a GOR of 1,500 have been identified as recoverable from the unit.

POTENTIAL PRODUCTION RATES. Assuming 420 million barrels of recoverable oil, Exxon predicts peak oil production from the unit at 80,000 B/D and has designed its onshore processing plant for that limit (the offshore alternative is designed for 60,000 B/D). The recovery of 730 to 1,100 MM barrels with a reasonable rate of production implies peak flow rates of about 150,000 to 200,000 B/D. If the additional 300 to 700 MM barrels of oil estimated by USGS is in fact recoverable, and Exxon fully develops the unit, either the peak production rate will exceed the current design parameters by as much as 120,000 B/D, or the producing lifetime will be considerably longer than the 20 to 30 years common to most offshore fields, or both.

USGS ROLE CRUCIAL. USGS is the only public agency with access to information relied upon by Exxon to prepare its reserve estimates. The Survey's 1973 estimate, however, has increased

uncertainty about recoverable reserves in the unit. California agencies are dependent upon Exxon and the Geological Survey for Santa Ynez Unit resource information and cannot independently reconcile the conflicting reserve and production estimates. The key to early resolution of the controversy lies with the Geological Survey.

PROGRESS IN THE SANTA YNEZ UNIT CONTROVERSY. Exxon's decision to proceed with an offshore alternative is not irreversible, and a mutually satisfactory agreement is still possible, either by negotiation or legal action. The California Attorney General has filed an action to enjoin the Department of the Interior from permitting Exxon to proceed with its offshore alternative. New developments in the last year, including passage of the Coastal Act of 1976, allow the State to consider alternative conditions for Exxon's onshore processing plant: such conditions have recently been forwarded to the Department of the Interior. The Santa Barbara County Board of Supervisors adopted by unaminous vote a resolution urging that Santa Barbara Channel crude oil be transported by onshore pipeline rather than by tankers, and that an industry/government task force convene to evaluate specific pipeline options. Initial meetings of the task force are now underway.

OPPORTUNITIES FOR ONSHORE PIPELINE TRANSPORTATION OF SANTA YNEZ CRUDE OIL. Several options exist for transporting Santa Ynez Unit crude oil north, south, or east by pipeline:

a. The original 140-mile pipeline route to Los Angeles remains a viable alternative deserving additional study;

b. An alternative route to Los Angeles refineries via the Santa Clara River Valley to Saugus and then south is also deserving of study;

c. An alternative involving the conversion of Arco's existing Casitas gas transmission line between Ventura and the Cuyama Valley to a crude oil transmission line could allow for the moving of Santa Ynez Unit crude to the Elk Hills-Bakersfield area, where existing pipelines link northern, southern, and central California refineries; or,

d. The Point Conception LNG proposal, which would produce a new pipeline corridor for two large natural gas pipelines between that area and Bakersfield (and then to Los Angeles), affords an additional option for pipeline routing into the Elk Hills-Bakersfield area that has not yet been explored.

RECOMMENDATIONS

71. WITHDRAW EXXON'S OFFSHORE PERMIT. The Department of the Interior should withdraw its approval of Exxon's offshore alternative on the grounds that Exxon does in fact have the option of a reasonable onshore development opportunity.

72. GEOLOGICAL SURVEY SHOULD ANALYZE SANTA YNEZ UNIT RESERVE ESTIMATE. The USGS should obtain all geologic and geophysical data and information held by Exxon pertaining to the Santa Ynez Unit as provided for by USGS regulations (30 CFR 261). Using this information, the Survey should conduct a detailed analysis of the resource potential of the unit and make its findings public so that they may contribute to the evaluation of transportation alternatives.

73. INTERIM USE OF TANKERS ACCEPTABLE. Any onshore pipeline used to transport Santa Ynez Unit and other Santa Barbara Channel production to refineries would take several years to construct. To avoid delay in bringing Channel production to refineries, state and local officials should permit the interim use of tankers, under operating procedures comparable to those negotiated for Arco's South Elwood facility, while the onshore pipeline is evaluated. If the pipeline is found to be economically feasible, interim use of tankers should be permitted to continue until detailed design and construction of the pipeline are complete. If the pipeline is infeasible, the interim permit should be made permanent.

SANTA CLARA UNIT

FINDINGS

RESERVE AND PRODUCTION ESTIMATES. If one platform is installed, production could peak at 16,000 B/D oil and 16,000 MCF/D natural gas in 1982, with 44.6 MM barrels oil and 44.6 BCF natural gas ultimately recovered. With three platforms, production could peak at 38,000 B/D oil and 45,600 MCF/D natural gas in 1983, with 113 MM barrels oil and 136 BCF natural gas ultimately recovered.

DEVELOPMENT OPTIONS. According to Chevron's Plan of Development, up to three platforms would be constructed and connected by pipelines to one of four alternative processing sites:

a. Mobil-Rincon, using existing surplus capacity;

b. Chevron-Carpinteria, requiring some expansion;

c. a new processing facility to be constructed in the Ventura-Oxnard area; or,

d. an offshore processing facility.

Whichever alternative is used to process Santa Clara production, Chevron has indicated a preference to transport the processed oil to refineries via tankers, rather than by pipeline.

RECOMMENDATIONS

74. PROCESS AT EXISTING FACILITIES. Santa Clara production should be delivered to the Mobil-Rincon processing facility through a joint pipeline which also carries Mobil's Hueneme Offshore Field production. Mobil-Rincon is preferred over Chevron-Carpinteria because it has substantially more surplus capacity, is accessible to existing onshore crude oil pipelines, is more remotely located from existing urban settlement, is not visible from the highway or nearby beaches, and is not dependent on a marine terminal for transshipment of crude oil to refineries as is Chevron-Carpinteria.

75. IMPOSE AIR QUALITY SAFEGUARDS. Expansion permits for either onshore facility should require that no additional reactive hydrocarbons be emitted as a result of the increased throughput.

H U E N E M E O F F S H O R E F I E L D

FINDINGS

MOBIL OPERATOR OF HUENEME FIELD. Mobil Oil operates two adjoining leases three to nine miles due west of Port Hueneme on behalf of itself and Union. Exploratory drilling has led to discovery of the Hueneme Offshore field underlying both leases.

PLAN OF DEVELOPMENT SUBMITTED AND PENDING. Mobil submitted a proposed Plan of Development to USGS in May, 1976, and USGS action is still pending. The Plan proposes installation of one platform, from which an estimated 19 MM barrels of oil could be recovered, with peak flow of 8,500 B/D in 1980. Mobil

expects to use all produced natural gas for energy requirements on the platform. Mobil's proposed options for processing the produced crude oil include the existing Mobil-Rincon facility, a new processing facility in Ventura County in the area of McGrath Lake, near Mandalay Beach, and, possibly, the Carpinteria facility owned by Chevron.

OPTIONS FOR BRINGING HUENEME FIELD PRODUCTION ASHORE. Mobil's proposed options for pipelining Hueneme produced petroleum to shore include, in order of preference:

a. a pipeline to the proposed Chevron Santa Clara Unit platform, then a joint pipeline to a common onshore processing facility;

b. a pipeline directly to the Mobil-Rincon facility, if a joint pipeline with Chevron is not feasible;

c. a pipeline direct to the Dos Cuadras platforms and connecting pipeline to shore; and,

d. a pipeline direct to a new onshore facility near Mandalay Beach.

RECOMMENDATION

76. CONSOLIDATE DEVELOPMENT OF HUENEME FIELD WITH SANTA CLARA UNIT. Hueneme production should be transported to shore via the Santa Clara Unit platform and processed at the Mobil-Rincon plant.

P I T A S P O I N T U N I T

FINDINGS

"PROMISING" DISCOVERIES. The Geological Survey credited the Pitas Point Unit with a commercial discovery in 1969, but Texaco has not decided whether to develop the find. Texaco recently completed its third well on 0234, calling the results "promising." If Texaco develops the Pitas Point discovery, platforms could be proposed for OCS-P-0234 and connected with a four-mile pipeline to Platform A on the Dos Cuadras Field or a ten-mile pipeline connection to the Mobil-Rincon processing plant ashore. No reserve estimates are available.

RECOMMENDATIONS

77. PROCESS PITAS POINT OIL AT MOBIL-RINCON. If Texaco develops a Pitas Point discovery, production should be processed at Mobil-Rincon. Production from the Pitas Point Offshore field

should be accommodated in the existing surplus capacity of the 12-inch pipelines connecting the Dos Cuadras Field and Mobil-Rincon. This alternative is preferred to constructing a new pipeline directly to shore.

78. SIZE PITAS POINT TRANSPORTATION FACILITIES TO HANDLE OAK RIDGE. Pipelines, compressors, and pumps intended for Pitas Point production should be of a size to accommodate potential production from the Oak Ridge Unit.

O A K R I D G E U N I T

FINDINGS

NO DISCOVERIES YET. Five exploratory wells have been drilled in the nine-lease Oak Ridge Unit, but none has been certified by the Geological Survey as a discovery. Additionally, two lease-line wells, drilled cooperatively with Pauley in an adjoining leased tract have not been certified.

NO RECOMMENDATION. Because no discovery has been made, no recommendation is offered at this time.

S A N M I G U E L U N I T (0 1 7 4 , 0 1 7 5 , 0 1 7 6 , 0 1 7 7 , 0 1 7 8 , 0 1 7 9)

FINDINGS

NO DISCOVERIES YET. These six leases were designated by USGS as the San Miguel Unit on January 19, 1977. One exploratory well has been drilled on lease 0176. Exxon is the designated operator of the unit.

NO RECOMMENDATION. Because no discovery has been made, no recommendation is offered at this time.

S A N T A C R U Z L E A S E S (0 2 0 0 , 0 2 0 1 , 0 2 0 6 , 0 2 1 1 , 0 2 1 2 , 0 2 1 3 , 2 2 1)

FINDINGS

NO DISCOVERIES YET. Exxon, Arco, and Chevron own the seven leases immediately north of Santa Cruz Island. In 1976, a proposal

to unitize the leases to form the Santa Cruz Unit was submitted to USGS with Chevron proposed as the unit operator. This unit proposal has since been withdrawn, following drilling of the first exploratory well in the area. The primary term of these leases currently expires July 2, 1978.

POTENTIAL RESOURCES. The only well drilled in the area found no producible resource. Based on very inconclusive data, however, Chevron estimates that "potential resources" of ten to 35 million barrels of oil and ten to 35 billion cubic feet of gas could be discovered.

NO RECOMMENDATION. Because no discovery has been made, no recommendation is offered at this time.

PAULEY LEASES (0218, 0226)

FINDINGS

NO DISCOVERIES YET. Eight exploratory wells have been drilled. Pauley and partners were making plans to drill the ninth well, when it was prevented from doing so by the USGS at the time of the Union Oil Company's oil spill. Pauley and partners filed suit in the U.S. Court of Claims to recover revenue lost by being prevented from going ahead with drilling and development on the two leases plus the imposition of total liability. The suit is still in litigation.

NO RECOMMENDATION. Because no discovery has been made, no recommendation is offered at this time.

ANACAPA LEASES (0198, 0199)

FINDINGS

NO DISCOVERIES YET. Exxon is the sole owner of these leases located three to five miles northeast of Anacapa Island. The first exploratory well for either of these leases was begun in January 1977. The primary term of the leases currently expires July 2, 1978.

NO RECOMMENDATION. Because no discovery has been made, no recommendation is offered at this time.

SOUTH ELWOOD OFFSHORE FIELD

FINDINGS

PRODUCTION TO INCREASE. South Elwood is the largest field in the Santa Barbara Channel tidelands. Arco estimates that more than 55 MM barrels of oil and 80 BCF natural gas could be recovered from Platform Holly. Arco has obtained all necessary drilling permits and the rezoning needed to expand its Elwood facility to accommodate the expected production increases. Santa Barbara County approval includes conditions that strongly encourage conversion from tanker transport of the processed crude to the use of an onshore pipeline and would control the air quality impacts associated with interim use of tankers. The rezoning conditions adopted by the County are in substantial agreement with evolving state policies for accommodating offshore oil and gas related development. Arco still requires a permit from the California Coastal Commission.

RECOMMENDATION

79. ARCO SHOULD BE APPROVED. The proposed Arco Elwood facility should be approved by the Coastal Commission as conditioned by Santa Barbara County. The Commission should obtain commitments from Arco to evaluate and participate in an onshore pipeline if it should prove feasible.

SUMMERLAND AND CARPINTERIA (STATE) OFFSHORE FIELDS

FINDINGS

PRODUCTION MAY INCREASE. Chevron has obtained permission to drill up to 36 new production wells at its four platforms in the Summerland and Carpinteria tidelands fields. These wells could boost ultimate recovery from the two fields by as much as eight MM barrels oil and 16 BCF natural gas. New production would be processed at the existing Chevron Carpinteria facility and no expansion is required.

NO RECOMMENDATION. Because no additional permits are required for this development, no recommendation is offered at this time.

EXXON-LAS FLORES CANYON CONSOLIDATION OPPORTUNITY

FINDINGS

TIMING AND LOCATION ARE FAVORABLE FOR CONSOLIDATION. Exxon, Arco, and Aminoil (previously Burmah) each proposed to construct new petroleum-related facilities roughly at the same time and within six miles of each other. The new facilities would duplicate each other's processes: two oil and gas processing plants and two marine terminals were proposed. Consolidation of these operations could eliminate unnecessary duplication and could provide for more efficient operations. The opportunity for consolidation still exists.

THE EXXON PROPOSAL. Exxon proposed to construct a new oil and gas processing facility at Las Flores Canyon and a new marine terminal at El Capitan to handle anticipated production from the Santa Ynez Unit. Ultimate design dapacities for the Exxon proposal included 80,000 barrels of oil and 90,000 MCF of gas per day treatment and separation capacity, initial storage for 220,000 barrels of oil and double this amount for ultimate storage, and up to 25,000 barrels per hour pumping throughput for the marine terminal. Exxon expects production from the Hondo field to peak at around 60,000 barrels of oil and 90,000 MCF of gas per day by 1985. The Las Flores Canyon facility is now an inactive proposal by Exxon, but legal proceedings initiated by the state may reactivate it.

THE ARCO PROPOSAL. Arco has proposed to replace its existing processing plant with a new and larger facility on the same site in order to accommodate increased production from Platform Holly in the South Elwood Offshore field, which is owned by Arco and Aminoil and operated by Arco. Design capacities called for processing up to 20,000 barrels of oil and 5,000 MCF of gas per day and storage for 100,000 barrels of oil. Transshipment of the crude oil produced was assumed to be handled through a long-term agreement with Aminoil. Arco expects production to peak in 1979 or 1980.

THE AMINOIL PROPOSAL. Aminoil proposed a new marine terminal at Naples to replace its existing marine terminal at Elwood. This proposed facility could store 338,000 barrels of oil onsite and transfer 17,500 barrels of oil per hour to tankers moored offshore. This proposal was intended specifically to handle the anticipated increase in production from Platform Holly.

SAN MIGUEL LEASES COULD USE LAS FLORES CANYON. If the San Miguel Unit contains commercial deposits of oil and gas, and production can be managed so as not to disturb pinniped rookeries on the Channel Islands, processing capability on the mainland coast may be required. The Santa Ynez Unit development plan, and particularly the Las Flores Canyon proposal, is the only facility in the west end of the Channel likely to

be capable of handling any production from San Miguel. East Channel facilities are considered too far away to be practical for processing requirements. Both Las Flores Canyon and the San Miguel Unit would be operated by Exxon.

INITIAL COUNTY PROPOSAL FOR CONSOLIDATION. Timing and location opportunities created by the separate Exxon, Arco, and Aminoil projects have led to an integrated consolidation proposal by the County of Santa Barbara. As initially conceived, both Santa Ynez Unit and South Elwood Offshore field production would be processed and stored at Las Flores Canyon and transported to refineries by the same system. Processing and storage of the oil produced from both areas at the same site could be accomplished within existing design constraints because their peak rates of production would not overlap. Transportation options would include the new El Capitan marine terminal or an onshore pipeline if it should prove feasible. This consolidation at Las Flores Canyon would eliminate the Arco-Elwood processing plant and the Aminoil marine terminal.

CURRENT COUNTY PROPOSAL FOR CONSOLIDATION. The current county proposal for consolidation revises the initial concept by retaining the Arco-Elwood facility for processing only. South Elwood Offshore production would be stored at Las Flores Canyon and crude oil transportation to refineries would be as described above.

CRUDE OIL TRANSPORTATION IS THE CRITICAL OBSTACLE TO ACHIEVING CONSOLIDATION. Exxon and Arco have indicated that consolidation of storage and transportation functions for both producing areas is acceptable in principle. However, agreement between the State and Exxon as to the method of determining a transportation mode for crude oil has not been reached. Until a method is agreed upon, consolidation at Las Flores Canyon will not occur.

RECOMMENDATION (See also Recommendations 8, 9, 10, and 16 of this Chapter.)

80. DELAY ACTION ON AMINOIL-NAPLES. Any permit applications regarding the Aminoil-Naples proposal should be held in abeyance pending final resolution of the law suit involving Exxon and the State of California, or until 1979, whichever occurs first. Following a determination by the Santa Barbara County Counsel that the suit has not or will not be adequately resolved in 1979 or soon thereafter, the Aminoil-Naples proposal may be considered.

MOBIL-RINCON PROCESSING PLANT

FINDINGS

OWNERS, LEASEHOLDINGS, AND PROPERTIES. The Mobil-Rincon facility is owned jointly by Gulf, Texaco, Union, and Mobil (GTUM), and Sun, Superior Oil, and Marathon (the SSM Group). These two lease-holding groups control 14 leases in the eastern end of the Channel and four of the six discoveries currently recognized by USGS. These two groups share ownership in the 12-inch oil and gas lines connecting the Dos Cuadras field with Mobil-Rincon and the 22-inch oil transmission line connecting Mobil-Rincon with Ventura. Between them, these two groups own four of the seven federal OCS platforms in the Santa Barbara Channel.

MOBIL-RINCON IS STRATEGICALLY LOCATED. Mobil-Rincon is the largest processing plant near the eastern end of the Santa Barbara Channel and is closer to all discovery areas and designated units in the eastern Channel as a whole than any other existing processing plant. The processing site itself is not visible from the Ventura Freeway (101) or other public viewing points because of its siting above the coastal shelf.

CAPABILITY TO HANDLE NEW PRODUCTION. Mobil-Rincon is currently operating below its full capability. Present surplus capacity can accommodate maximum projected rates of crude oil and nautral gas production from Platforms C (Union), Henry (Sun), Hueneme (Mobil), and the three Santa Clara Unit platforms (Chevron) with some surplus capacity still remaining. Treatment and disposal of waste water is a constraining factor and may require equipment changes. Additional production from the Pitas Point Unit discovery (Texaco) and any remaining undiscovered fields in the eastern Channel could be handled at Mobil-Rincon, but some expansion may be required. The processing plant site can accommodate additional equipment capable of doubling throughput capacity for the plant without altering existing site grades or making the equipment visible from important viewing points.

ADVERSE EFFECTS OF MOBIL-RINCON EXPANSION. Increased throughput at Mobil-Rincon could cause significant localized air pollution as a result of increased hydrocarbon emissions from the plant. Areas affected by these emissions are not easily identified because wind data for the area are extremely limited. Considering only very general wind information, it appears that Ojai Valley may receive some air pollution as a result of any activity at Mobil-Rincon.

RECOMMENDATIONS

81. PROCESS NEW EAST CHANNEL PRODUCTION AT MOBIL-RINCON.

The State Lands Commission, the California Coastal Commission, and the Ventura County Planning Commission should adopt a policy

encouraging the use of the existing Mobil-Rincon for new production from eastern Channel OCS development.

82. ENCOURAGE WATER SEPARATION AT PLATFORMS. Expansion of Mobil-Rincon would be required in order to handle increased production during 1982-1986. To minimize expansion requirements, produced water should be separated at the platforms if feasible.

83. METEOROLOGICAL DATA IS NEEDED. The users of Mobil-Rincon should immediately establish a meteorological data gathering system to determine the existing and potential air quality impacts of the Mobil-Rincon facility. Such data collection must be available in evaluating any expansion proposal for the site operations.

L E A S E S A L E # 3 5

FINDINGS

FOUR DISTINCT PLANNING AREAS. Each of the four sub-areas of Lease Sale #35 are more or less independent of each other, and each may require separate development strategies. The four areas are Santa Rosa-Cortes Ridge North, Santa Rosa-Cortes Ridge South (Tanner Banks), Santa Barbara Island, and San Pedro Bay. The first three areas (the Outer Banks) are remotely located from existing oil and gas developments while San Pedro Bay is essentially contiguous with the Long Beach-to-Huntington Beach oil and gas region.

LEASE SALE #35 PLANNING PROBLEMS. The remoteness and the fragile environmental conditions of the Outer Banks are major concern for any future oil and gas development in these areas. Development in San Pedro Bay could pose serious problems as the fixed offshore structures would be built in the existing vessel traffic separation scheme.

OUTER BANKS TRANSPORTATION OPTIONS. There are two options for transporting crude oil produced from the Outer Banks, either surface transport or pipelining. If surface transport is used, all Outer Banks production would be delivered directly to the petroleum terminals of California's major ports. With the pipeline option, there is but one feasible route from the Santa Rosa-Cortes South area to the mainland -- north along the Santa Rosa-Cortes Ridge until the Channel Islands are reached. Production from

the Santa Rosa-Cortes North fields can be included in south area production or move independently of it in a pipeline from the Channel Islands to a landfall in the Ventura area. Again, there is but one feasible pipeline route from the Santa Barbara Island area to the mainland -- north to the Channel Islands by following the submarine ridge connecting Santa Barbara Island with Anacapa Island. This line could tie into the pipeline carrying production from the Santa Rosa-Cortes areas to Ventura.

SAN PEDRO BAY TRANSPORTATION OPTIONS. Surface transport is not likely to be competitive with pipelining new production in San Pedro Bay since the platforms will be close to land. With pipelining, there are two transport ways to San Pedro Bay production to shore: a common pipeline gathering system that would take all production to a single landfall area, or separate pipelines running from each discovery. There are two basic routes for a common pipeline: one to Huntington Beach, because it is the closest landfall to a majority of the leases; the other to Long Beach, because it has the best access to refineries in the Los Angeles Basin.

RECOMMENDATIONS

84. LEASE-AREA PLANS. Each of the four sub-areas of Lease Sale #35 should be developed according to lease-area plans prepared jointly by industry and government. (See Chapter 19 for a description of lease-area plans.) These plans would coordinate all phases of development on an area-by-area basis to allow for optimum resource recovery. The lease-area plans would consider the timing, rates of production, and transportation modes for each area as a whole, after exploration of each area is sufficiently complete to determine the probable recoverable resources. No development or production should commence prior to completion of a lease-area plan with the exception provided for in recommendation #57 of Chapter 9.

85. OUTER BANKS TRANSPORTATION STRATEGY. If commercially recoverable resources are discovered in the Outer Banks and analysis indicates that pipelines to shore are economically and technically feasible, a single pipeline network serving the various producing areas should be utilized. Future lease sale offerings in the Outer Banks should be designed to maximize the economic incentives for pipeline

construction, and development plan approvals should be conditioned to encourage participation in a single pipeline system. An offshore crude oil pipeline company, similar to the natural gas Pacific Offshore Pipeline Company (POPCO), could be formed to develop and maintain the necessary system. (See Chapter 10 for additional findings.)

86. SAN PEDRO BAY TRANSPORTATION STRATEGY. Transportation of crude oil and natural gas produced in San Pedro Bay should be through one integrated pipeline network. Huntington Beach, or Long Beach, may be the preferred landfall; each should be evaluated on economic, environmental, and social considerations. (See Chapters 20 and 21 for further background.)

SAN PEDRO BAY (SEE ALSO NAVIGATIONAL SAFETY IN CHAPTER 10)

FINDINGS

OWNERSHIP. Six different petroleum company consortiums own San Pedro Bay leases. Groups led by Chevron and Shell Oil Company are clearly the dominant lease holders. Other consortiums are headed by Gulf, Texaco, Mobil, and Challenger. All lease holders, with the exception of Challenger, have world-wide and southern California OCS production experience; and all own onshore property in the vicinity of San Pedro Bay.

OIL AND GAS POTENTIAL. San Pedro Bay is generally regarded as containing the best oil and gas prospects offered in Lease Sale #35. USGS estimates that 355 to 946 MMB of oil and 301 to 821 BCF of natural gas could be recovered from the several prospects underlying the San Pedro Bay leases. Exploration to date by Shell and Chevron discovered the existence of oil and gas accumulations in a portion of one prospect; Shell has indicated that recoverable oil and gas identified to date may be less than 200 MMB of oil and 34 BCF of natural gas.

POSSIBLE PRODUCTION. Production from this early discovery is dependent on many factors; Shell has indicated it could begin by 1979. Under typical operating conditions, a new offshore field of 200 MMB of oil and 34 BCF of natural gas would result in a peak production rate of 30,000 to 40,000 B/D oil and 7,000 to 8,000 MCF/D natural gas. If recoverable reserves equal to the USGS high range estimates are discovered in San Pedro Bay, peak production rates in excess of 200,000 B/D oil and 180,000 MCF/D gas could occur.

AVAILABLE TREATMENT AND SEPARATION FACILITIES (PROCESSING PLANTS). There is no existing or planned processing plant or combination of plants available for handling production at the rates mentioned above. At least one new processing plant site will be required in the vicinity of San Pedro Bay to accommodate this new production. Possible onshore sites with oil-related zoning exist in Los Angeles and Long Beach Harbors and the City of Huntington Beach. Offshore processing is a possible alternative to onshore processing.

TRANSPORTATION OF OIL AND GAS TO PROCESSING SITES. Federal leases in San Pedro Bay range from three to ten miles offshore. Based on typical OCS development in southern California and the Gulf, this proximity to the mainland makes pipelining crude oil and natural gas to shore economically and environmentally preferable to offshore processing solutions or barging produced crude oil to a processing site. There are no pipelines between the federal leases in San Pedro Bay and onshore areas. The closest mainland area already developed for oil and gas extraction is Huntington Beach. Other possible landfalls would be in Los Angeles/Long Beach Harbors; pipeline routes to these destinations, however, would have to avoid areas used heavily for dredging or fill.

AVAILABLE PIPLEINES TO TANK FARMS AND REFINERIES. Los Angeles and Long Beach Harbors are served by numerous pipelines connecting Long Beach production sites and major tanker loading operations with the many refineries in the Los Angeles Basin. Major pipeline operators in the Harbors are Mobil, Union, Texaco, and Arco. Pipelines from the Harbors or Huntington Beach have a direct tie-in with the Four Corners Pipeline.

RECOMMENDATION

87. PROCESSING SITE SELECTION. The major lease holders in San Pedro Bay -- Shell, Chevron, and Gulf -- should consider the possibilities of consolidating the treatment and separation of produced oil and gas at an expanded, existing processing plant or at a new facility onshore. The Interior Department and state agencies should notify all OCS operators in San Pedro Bay that a floating, offshore processing station is an unacceptable alternative for this area because of the significant risk of rammings and the additional environmental risk represented by the oil contained in the offshore processing equipment. (See also Recommendation 2 of Chapter 10.)

CHAPTER 12:

OCS LEASE SALE #48*

FINDINGS

NEW LEASING OPPOSED UNDER CURRENT CONDITIONS. The State of California and local governments oppose Lease Sale #48 on several grounds: 1) critical environmental and oil and gas resource information has not been provided for analysis; 2) leases do not permit the Secretary of Interior to cancel a lease if new information reveals extraordinary environmental hazards; 3) state and local governments are given an inadequate role in the federal OCS management process; 4) leases are proposed for sale near sensitive environmental and recreational resources; and, 5) the enactment of amendments to the OCS Lands Act embodying many needed reforms is expected soon. The State of California does not oppose OCS oil and gas leasing and development per se, but does object to leasing and development without the above safeguards.

TRACTS SELECTED. The Department of Interior has selected 217 tracts for Lease Sale #48 EIS including all the unleased areas of the Santa Barbara Channel outside the ecological preserve. Preliminary tract selection implies a commitment to lease: no OCS sale for which an EIS was prepared has ever been cancelled.

NEGATIVE NOMINATIONS. State and local governments identified specific tracts for exclusion from Lease Sale #48 based on concerns for air quality, oil spill risks, navigational hazards to shipping, and disturbance of ecologically productive areas, including sensitive bird, seal, and sea lion breeding grounds. Interior Department tract selections reflect an overriding concern for oil and gas potential, however, and virtually ignore the negative nominations made by state and local governments.

*For additional discussion see Chapter 22.

FEDERAL AGENCIES SHARE CALIFORNIA'S ENVIRONMENTAL CONCERNS. The Environmental Protection Agency recommended deletion of the Santa Barbara Channel from Lease Sale #48 because of the hazardous potential for adverse effects. The U.S. Marine Mammal Commission recommended the establishment of a six-mile buffer zone around certain islands in the Channel and a delay of further Channel leasing pending the completion of environmental baseline studies. The U.S. Fish and Wildlife Service reaffirmed its proposal for buffer zones, as posited in Lease Sale #35.

CALIFORNIA ENERGY NEEDS. Oil from Lease Sale #48 will not be needed in California before 1990 at the earliest. The Federal Energy Administration projects an early West Coast crude oil surplus of 400,000 to 800,000 barrels per day, due in large part to Alaskan production. Current projections indicate the critical natural gas shortage in southern California beginning in 1980. OCS gas may help alleviate projected shortages, but it will not eliminate the need to augment the gas supply by extraordinary measures such as the importation of LNG.

TWO MAJOR CONCERNS ELIMINATED. The Department of the Interior's new (May 17, 1977) National OCS Leasing schedule and policy appear to eliminate two major state and local government concerns over Lease Sale #48 until at least early 1979 and emphasize "providing adequate time ... for resolving conflicts and involving coastal states in a significant manner" in the OCS leasing and development process. The new schedule practically assures the Amendments to the Outer Continental Shelf Lands Act will be enacted in time to effect the Lease Sale #48 process.

PREPARATION OF THE EIS CONTINUES. Even though Lease Sale #48 has been postponed, the BLM is continuing the preparation of an EIS. The timeframe for completing the EIS has been expanded, but the EIS will still consider tracts opposed for leasing by California state and local governments.

RECOMMENDATIONS

88. LEASE SALE #48 SCHEDULE. Lease Sale #48 should not be rescheduled until Congress enacts equitable oil spill liability legislation and amendments to the OCS Lands Act providing for the release of environmental and oil and gas resource information to state and local governments, a stronger state and local voice in leasing and development decisions, and an opportunity for the Secretary of Interior to decide after exploration, whether lease tracts will be developed.

89. LEASE SALE #48 EIS. State and local governments should accept the Interior Department's invitation to participate in preparation of the EIS. The State should establish an EIS task force to review the Interior Department's drafts and monitor the preparation, commenting, and public hearing processes of the EIS. The Interior Department should distribute all work programs and preliminary drafts to state and local governments in a timely fashion.

90. OPR. The Governor's Office of Planning and Research should coordinate state and local government involvement in the Lease Sale #48 EIS process and the formulation of lease stipulations until the Coastal Commission is given responsibility for coordinating California's involvement in OCS activities (see Recommendation 13 of Chapter 4).

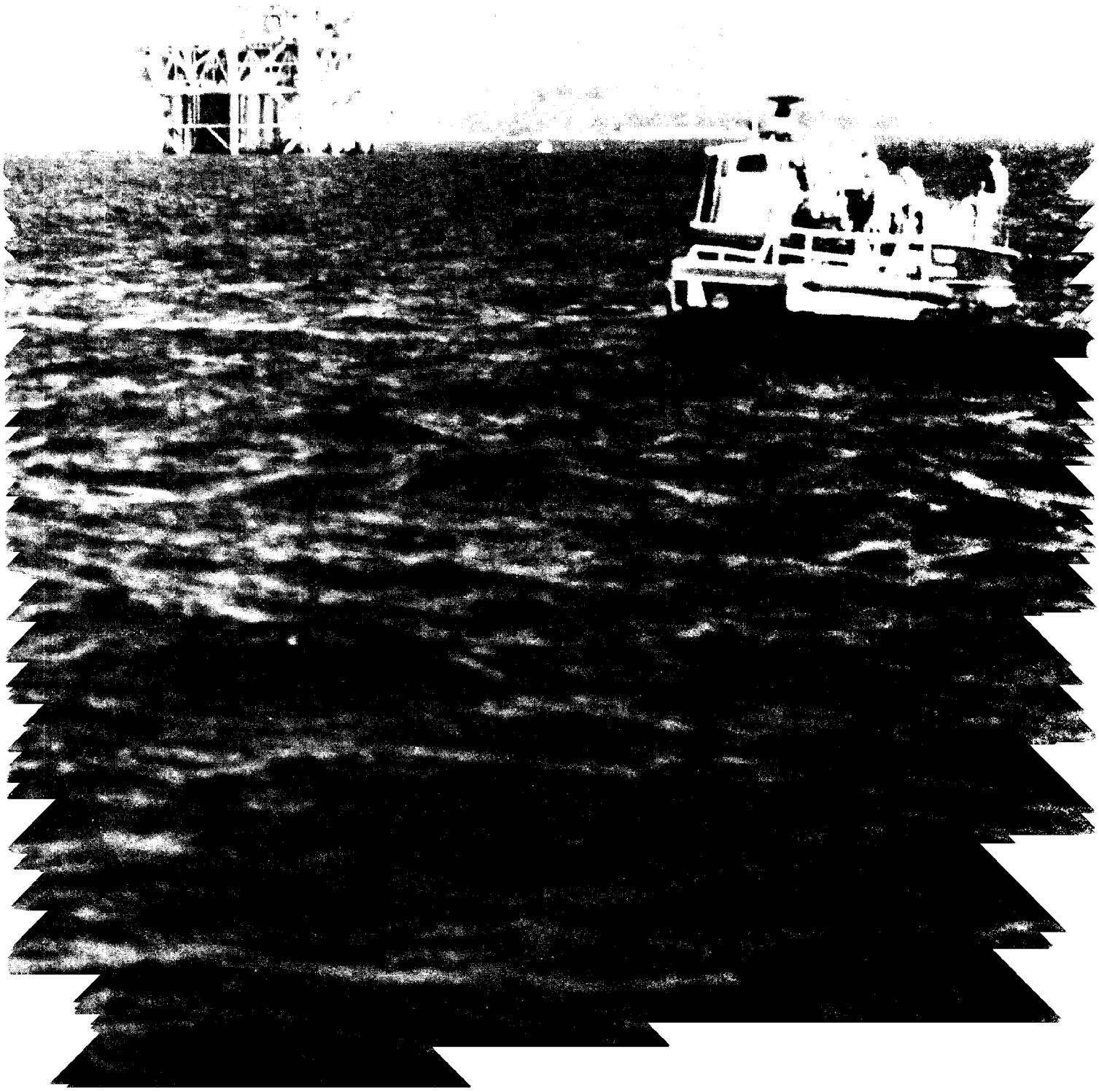
91. EIS HEARINGS. The Interior Department should hold public hearings on the DEIS and EIS in each of the affected coastal counties, allowing at least 45 days to review the documents prior to the scheduling of hearings.

92. PREFERENCE FOR ADDITIONAL LEASES. When additional tracts are leased off southern California, the first priority should be filling in areas leased in Lease Sale #35 on the Tanner Banks and the Santa Rosa-Cortes Ridge in order to improve the economics of an offshore oil pipeline from those areas and to increase the chance that gas discoveries are sufficiently large to justify development. Fill-in tracts in the San Pedro Bay should also be fully considered for priority leasing but only if development can proceed without siting permanent structures in the vessel traffic lanes

(see Recommendation 2 of Chapter 10). California state and local government should further identify and document in the greatest possible detail tracts that are acceptable for future leasing.

Photo opposite: Clean Seas, Inc., deploying Vikoma Seapack boom for containment of a hypothetical oil spill. Platform Houchin (Phillips) in background.

PART THREE
BACKGROUND REPORTS



CHAPTER 13

OCS MANAGEMENT: THE PLAYERS AND THE RULES

Offshore oil and gas development on the outer continental shelf (OCS) is managed through a complex system involving government at all three levels -- federal, state, and local -- each with its own responsibilities and powers. This chapter examines the federal leasing and management system, the regulation of OCS-related onshore development, and the relationship of the federal Coastal Zone Management Act to offshore oil and gas development. Legislation pending in the U.S. Congress on the printing date of this report will put into law some procedures described in this chapter that have been carried out as a matter of regulation or practice. It will also strengthen the role of the states in the OCS leasing and management process and provide more stringent environmental safeguards.

UNDERSTANDING THE FEDERAL LEASING AND MANAGEMENT PROCESS

The Outer Continental Shelf Lands Act mandates procedures for the leasing and development of offshore oil and gas lands. 1/ The Act authorizes the Secretary of the Interior to offer oil and gas lease tracts no larger than 5,760 acres (nine square miles) for competitive bidding. Leases are for a five-year term, or for as long as oil and gas are produced in paying quantities or the lessee conducts drilling or well reworking activities to restore or increase production from a well.

The Secretary of the Interior delegates the responsibility for leasing and managing offshore lands to two bureaus within the Interior Department: the Bureau of Land Management (BLM) and the U.S. Geological Survey (USGS). BLM acts as a leasing agent and property manager. USGS performs technical studies of the geology and mineral resources of federal lands and regulates the safety of oil and gas drilling operations.

LEASING OF FEDERAL OCS LANDS

PRE-LEASE SALE EXPLORATION

Before the Department conducts a lease sale, it grants permits to explore broad offshore areas by passive methods -- including measurements of changes in the

earth's magnetic field and local variations in the earth's gravity, and identification of natural oil seeps -- to identify promising geologic formations. 2/ The industry then collects geophysical and geologic data to gain more detailed knowledge of promising areas.

Geophysical data collection techniques include seismic, gravity, and magnetic surveys. By measuring the velocity of shock or seismic waves sent through various rock formations beneath the sea, it is possible to evaluate petroleum potential and identify hazardous conditions such as surface faulting, slide areas, or shallow gas pockets. Identifying hazardous areas is necessary to assure that an area is safe for drilling and installation of platforms. Slight changes in the force of gravity or small warps in the earth's magnetic field indicate changes in the rock structure and rock densities below the ocean floor. 3/

Geologic exploration of the OCS involves bottom sampling, shallow-core drilling, and, in some cases, deep stratigraphic test drilling. Data from these activities are used to determine the general geology of an area. Bottom samples are collected by dropping a weighted tube to the ocean floor and retrieving it with an attached wire line. Shallow-core drilling uses conventional rotary drilling equipment, and is usually limited to the recovery of several feet of consolidated rock. In areas where there has been little or no drilling to discover oil and gas, a deep stratigraphic well may be drilled to gather information on the relative position of the strata or rock layers of the earth's crust. Federal regulations prohibit these wells from being drilled beyond a limited depth on geologic structures in order to prevent the actual discovery of oil and gas in advance on a lease sale and to reduce the possibility of a blowout. 4/ Often a number of oil companies will join with USGS to drill a stratigraphic test well under a shared cost agreement.

Private businesses contract with oil companies or the federal government to conduct exploratory activities. A single company or the federal government may arrange independently to obtain exploratory data, or join in a number of combinations to share the costs of such work. Exploration companies sometimes collect data on a speculative basis and offer it for sale on the open market.

Anyone engaging in pre-lease sale exploration must obtain an "exploratory permit" from the Area Supervisor of the USGS. In California and other coastal states which have cooperative agreements with the Department of the Interior, the applicant must stipulate that he will abide by the regulations of the adjoining coastal state and obtain the permission of the U.S. Corps of Engineers to ensure that exploration activities will not create a hazard. He must also comply with health and safety regulations of the Coast Guard and Occupational Health and Safety Administration. Under new regulations effective June 23, 1976, geologic and geophysical data collected on the OCS under an exploratory permit must be made available to the USGS. 5/

FIVE-YEAR LEASING SCHEDULE

A five-year national leasing schedule guides generally BLM's OCS leasing activities. The schedule identifies broad geographic areas such as "Southern California" and "Mid-Atlantic" and lease sale dates for each area. BLM is not required to adhere strictly to the schedule; and in practice, most lease sales are delayed several months beyond the originally scheduled date. USGS assists the BLM in preparing the five-year leasing schedule by recommending areas with promising oil and gas potential. BLM issues a draft schedule through the

Federal Register for comment by other federal agencies, states, local governments, the oil industry and other interested parties. Based on comments concerning oil and gas potential, environmental impacts, proximity to market, market value, energy demand and supply, and availability of technology, BLM publishes a final national leasing schedule indicating dates for sales and major events in the process leading up to an actual sale for each area. 6/

One of the principal motives for developing federal OCS resources has been demands for the governmental revenues which lease sales produce. OCS revenues are substantial, averaging about $3.5 billion annually and totaling over $6.7 billion in fiscal year 1974. 7/ In recent years, however, the need to increase OCS oil and gas production has overridden the importance of increasing OCS revenues.

On April 18, 1973, President Nixon ordered the OCS leasing rate increased from one million acres per year to three million acres per year. Nixon announced on January 23, 1974, only nine months later, that the leasing rate would be further accelerated to ten million acres per year beginning in 1975. There were several reasons for these enormous increases. In part, they responded to the energy crisis and the Arab oil embargo. Additionally, the acceleration of the leasing rate in January, 1974, against the recommendations of BLM and USGS, strengthened the role of the Interior Department in energy issues against the encroachments of the new Federal Energy Office, subsequently the Federal Energy Administration. 8/ Had the ten-million-acre goal been achieved in 1975, the amount of acreage leased in that one year would have almost equalled the total acreage leased in the previous 21 years of the program. In fact, only about 1.7 million acres of the OCS were leased in 1975.

When President Ford took office in August, 1974, he initially affirmed the ten-million acre per year leasing goal. However, widespread opposition from states, environmentalists and the U.S. Congress caused him to reduce this goal to six sales per year with all areas where little or no leasing had occurred previously (frontier areas) opened by 1978. After encountering numerous delays in implementing this schedule, Secretary of Interior Kleppe issued a revised national leasing schedule on January 12, 1977. The schedule called for leasing in all frontier areas by 1980.

ENVIRONMENTAL BASELINE STUDIES

In frontier areas, BLM conducts biologic and oceanographic studies to determine an environmental baseline against which the effects of future oil and gas development activities can be measured. Generally, separate contractors perform four tasks: (1) conduct a survey of published reports on the environment and marine resources of the area; (2) make a survey to establish the baseline for future comparisons; (3) perform research necessary to close gaps in the data; and (4) establish a monitoring program to detect environmental changes caused by exploration and development.

RESOURCE REPORTS

BLM's first step in carrying out the lease sale process for a particular area is to request resource reports from various federal agencies and the governors of adjacent states. The Geological Division of USGS provides information on the general geology and environmental hazards of the region. This summary report and the supporting data are available to the public, but the information is not site-specific.

Other federal agencies and adjacent states report to BLM on the possible effects of leasing on the environment and potential conflicts with other offshore and coastal activities including shipping, fishing, recreation, or national defense.

Resource report requests are the first official indication of specific tracts being considered for inclusion in a lease sale area. Resource reports filed by the Environmental Protection Agency, Fish and Wildlife Service, National Park Service, U.S. Coast Guard, National Oceanic and Atmospheric Administration, and the Defense Department contain information which is valuable to state and local government for evaluating their own concerns over a proposed lease sale. BLM does not automatically publish the resource reports. However, the Pacific Coast OCS office did make Lease Sale #48 reports available to California state and local governments upon request.

CALL FOR NOMINATIONS

After evaluating resource reports, BLM issues a call for nominations of individual tracts in the lease sale area. Notice of the call appears in the Federal Register and a press release. Oil companies indicate positively nominated tracts in which they have an interest. In addition, any interested public agencies or persons, such as state and local governments and environmental groups, may positively or negatively nominate tracts, or recommend special conditions for leasing. The environmental, technical, or economic reason for excluding or offering a tract only under special conditions should accompany such nominations in order to have them fully considered by BLM.

All nominations are submitted to the BLM Director, with copies to the BLM field office and the USGS Area Oil and Gas Supervisor for the area of the proposed sale. Usually, nominations are due 60 days after the call. The Interior Department now plans to hold lease sales 19 months after issuing the call for nominations.

TRACT SELECTION

For California lease sales, the Pacific Coast OCS office of BLM reviews resource reports and nominations with the area USGS office to select tracts for further evaluation in the lease sale environmental impact statement. Oil and gas potential, avoidance of geologic hazards, extreme environmental impacts, and danger of drainage by production on adjacent leased tracts, are criteria that influence tract selection. These tract selections are presented to Department officials in Washington, D.C. BLM announces the approved tract selections usually 60 to 90 days after nominations close.

ENVIRONMENTAL IMPACT STATEMENT

The National Environmental Protection Act (NEPA) requires the preparation of an environmental impact statement (EIS) prior to any major federal action. 9/ After selecting tracts, BLM, with assistance from other federal agencies, begins to prepare a draft environmental impact statement (DEIS) on the proposed lease sale. In 1976, the Pacific OCS office of BLM initiated a new policy of inviting state and local government participation in the preparation of the DEIS for Lease Sale #48. A DEIS may take as long as one year to prepare. The President's Council on Environmental Quality (CEQ) reviews the completed DEIS, and BLM publishes notice of its availability for public review in the Federal Register and in a news release.

No regulation requires the BLM to hold a public hearing on the DEIS. However, as a matter of practice, BLM schedules at least one public hearing, and often more, in locations adjacent to the lease sale area. Hearings occur about 30 days after the DEIS becomes publicly available, and there is a period of 45 days after the hearing for interested parties to submit additional comments.

After the comments have been reviewed, BLM prepares the final environmental impact statement (FEIS). Completion of the FEIS may require from two to four months. The FEIS serves as the basis for the Secretary's decision to hold a sale, exclude specific tracts from the offering and/or to offer particular tracts for sale only under special conditions. The public review procedure for the FEIS is the same as that for the DEIS.

DECISION BY THE SECRETARY OF THE INTERIOR

After publication of the FEIS, BLM prepares a Program Decision Option Document (PDOD) for the Secretary, containing economic and environmental information relating to the proposed lease sale. It lists all recommended special lease conditions and all tracts proposed for leasing. No earlier than 30 days after submission of the FEIS to the CEQ, the Secretary decides whether to hold the proposed sale and which tracts to offer for sale and what the lease terms will be.

LEASE SALE

At least 30 days before he holds a lease sale, the Secretary publishes a notice of the sale in the Federal Register and issues a press release. The notice specifies tracts to be offered for sale; lease conditions -- including any special stipulations for particular tracts -- bidding procedures; and the date, place, and time for receiving and opening bids.

Only U.S. citizens and nationals; aliens admitted for permanent residence; U.S. corporations; or associations of such citizens, nationals, resident aliens, or corporations may bid. Bidders who have an average daily production in excess of 1.6 MMB of crude oil, natural gas, or liquefied petroleum products cannot submit joint bids together. 10/ Under this provision, the following companies cannot bid jointly: Texaco, Exxon, Amoco, British Petroleum-Alaska, Chevron, Gulf, Mobil, Shell, and Standard of California.

Each bid is sealed and accompanied by a check, money order, or bank draft in the amount of 20% of an amount specified by the Secretary as the bonus bid. All bids are read publicly; the Interior Department then has 30 days to make the decision, on the basis of tract evaluations, to either accept or reject the highest bid on each tract. USGS calculates tract evaluations based on resource estimates derived from geologic and geophysical data. These tract-specific resource estimates and tract evaluations are not available to state and local governments or to the public. The highest bidder must pay, upon notice of acceptance, the balance of the bonus and the first year's rental. 11/ He must also furnish a corporate surety bond in the sum of $50,000 conditioned on compliance with all lease terms, unless he already maintains or furnishes a bond in the sum of $300,000 conditioned on compliance with the terms of leases held by him in the Gulf of Mexico, along the Pacific Coast, or along the Atlantic Coast. 12/ Leases become effective on the first day of the month following the signing, or earlier, if specified.

MANAGEMENT OF FEDERAL LANDS UNDER LEASE

After the issuance of a lease, the USGS enforces regulations and OCS Orders and lease stipulations, collects rents and royalties, and supervises lease operations. The Area Oil and Gas Supervisor for each region performs these functions. The Director of USGS designates lease supervisors from the Conservation Division. The Supervisor responsible for California is the Pacific Area Oil and Gas Supervisor in Los Angeles.

RENTS AND ROYALTIES

For each year prior to the discovery of oil and gas on a tract, a rental rate of $3.00 per acre in unproven areas and $10.00 per acre in proven areas is paid to USGS. The Secretary of Interior fixes a royalty rate at no lower than 12 1/2% of production. 13/ The royalty rate is 16 2/3% on most tracts, but a rate of 33 1/3% was set for six highly promising tracts in San Pedro Bay offered in Lease Sale #35.

REGULATIONS, OCS ORDERS, AND LEASE STIPULATIONS

A complex array of regulations, orders, and lease stipulations governs oil and gas exploration, development, and production on the OCS. USGS enforces regulations, orders, and stipulations pertaining to exploration, development, and production activities and disposal of royalty oil; and BLM grants pipeline rights-of-way. The Secretary promulgates regulations pursuant to the Outer Continental Shelf Lands Act 14/ as necessary "for prevention of waste and [for] conservation of the natural resources of the Outer Continental Shelf ...." 15/ Such resources include "marine life, recreational potential, and aesthetic values, as well as the reserves of gas and oil." 16/ Other agencies, including the Coast Guard and U.S. Army Corps of Engineers, also issue and enforce regulations relating to some aspects of offshore oil and gas development as explained below.

OCS Orders are formal and numbered orders that govern most of the daily drilling and production operations on leases in a region or major portion of a region. The USGS Area Oil and Gas Supervisors issue OCS Orders, with the prior approval of the Chief of the Conservation Division, USGS. 17/ Twelve OCS Orders are now in effect in the Pacific area. One may obtain copies of these Orders from the USGS Pacific Area Oil and Gas Supervisor in Los Angeles. The Supervisor may also issue Orders to govern lease operations on a specific lease or leases. 18/

Lease stipulations may vary from lease tract to lease tract. They are usually detailed lease terms and tailored to geologic and biological conditions found in specific areas or lease tracts. For example, Stipulation 6 for Lease Sale #35 placed special conditions on drilling and production conducted in or near unique biological areas of the Tanner Bank and Cortes Bank. In other instances, lease stipulations may be used to provide detailed procedures for requirements stated more broadly in regulations or OCS Orders. When the Secretary of the Interior decides to hold a lease sale, he also decides what lease stipulations will apply to specific lease tracts. Lease stipulations appear in the Federal Register along with notice of the lease sale.

State and local governments and other interested persons may recommend new or modified regulations, OCS Orders, and lease stipulations to the Interior

Department. Regulations and OCS Orders are formulated through a formal process conducted in accordance with the Administrative Procedures Act. 19/ Drafts of the regulation or order appear in the Federal Register for review and comment. The agency proposing the regulation or order revises it after reviewing the comments and publishes the finalized version in the Federal Register.

The Secretary develops lease stipulations in a different manner from regulations and orders. The DEIS recommends appropriate lease stipulations. These are then subject to industry, government, and public review through the EIS review and public hearing process. In addition, any party may recommend lease stipulations to the Secretary during the period when he is considering the decision to hold a lease sale.

POST-SALE EXPLORATION

The present federal leasing and management system prohibits the drilling of any wells to discover oil and gas until after a lease sale. The drilling of exploratory wells distinguishes pre-sale exploration and post-sale exploration.

If the record owner does not conduct operations on a lease, he must designate an operator for the lease to the Oil and Gas Supervisor. 20/ If a single company owns a lease, that company will usually be the operator. If a consortium of companies owns a lease, which is a common arrangement, the consortium selects one of the joint owners as operator.

Before exploratory drilling can begin, the operator must obtain approval of an exploratory drilling plan and various permits from USGS. The exploratory drilling plan must include: (1) a description of drilling vessels, platforms, or other structures, showing their location, design, and major features, including features pertaining to pollution prevention and control; (2) the general location of each well, including surface and projected bottom-hole location for directionally drilled wells; (3) structural interpretations based on available geologic and geophysical data; and, (4) such other pertinent data as the Supervisor may prescribe. 21/

USGS prepares an environmental assessment of the exploratory drilling plan within 30 days of the date the plan was filed and decides whether an EIS is required. All major federal actions significantly affecting the quality of the human require preparation of an EIS. 22/

CEQ guidelines to identify such actions state that agencies evaluate the need for an EIS with a view to the overall cumulative outcome of proposed and related federal actions and projects. Although the proposed action may affect only a small area, the statement must be prepared if there is the potential that oil and gas development may change the environment. CEQ guidelines specifically state that highly controversial proposed actions "should be covered in all cases." 23/ EISs for exploratory drilling on the OCS are generally not the rule; however, there was an exception requiring an EIS for the resumption of exploratory drilling in the Santa Barbara Channel when the moratorium on drilling imposed after the 1969 blowout was lifted. In the event the USGS Area Supervisor determines an EIS is necessary, state and local governments and other interested persons or groups have an opportunity to comment on the proposed drilling through the DEIS and FEIS review processes.

After the USGS approves an exploratory drilling plan, the operator must obtain a permit to drill. The application, filed with USGS, must include information regarding the proposed wells, meet requirements for controlling wells, be consistent with the exploratory plan, and describe the blowout-prevention program. 24/ The BLM and Fish and Wildlife Service review and comment on the exploratory drilling plan and drilling permit application. The U.S. Army Corps of Engineers must also issue a permit before drilling can begin.

It is the responsibility of the Corps of Engineers to prevent obstructions to navigation in the navigable waters of the U.S., including the OCS. 25/ The Corps must approve the location of all offshore structures, including movable drilling rigs engaged in exploratory drilling. The installation of adequate markings, beacons, or other devices specified by the Corps is necessary before gaining permit approval. USGS regulations and OCS Orders ensure compliance with Corps permit requirements. The Corps of Engineers circulates applications for exploratory permits to various California State agencies for comment through the Resources Agency Clearinghouse.

The Federal Water Pollution Control Act enables OCS operators to discharge or dump into navigable waters any pollutant, brines, drilling mud, or cuttings from drilling operations only under a permit issued by the Environmental Protection Agency (EPA). 26/ An operator must submit a discharge permit application to EPA at least six months before he plans to begin drilling operations. EPA publishes notice of the application in a newspaper of general circulation in the area adjacent to the proposed drilling and notifies interested federal and state government agencies, public interest groups, and individuals. In California, EPA invites the State Water Resources Control Board to comment on the application. Any group or person in California who wishes to comment on discharge permit applications should notify the EPA Regional Administrator in San Francisco.

EPA must consider all the environmental consequences, including impact on water quality, of granting a discharge permit and may condition the permit as necessary to prevent adverse impacts. 27/

Finally, the Coast Guard regulates lighting and markings on platforms and floating drilling rigs, oil spilled or discharged into OCS waters, and the safety of offshore operations. 28/

If oil and gas are discovered, they must be produced in paying quantities or the lease will not be extended beyond its primary term of five years. Paying quantities simply means production in quantities sufficient to yield an economic return in excess of operating costs. 29/ USGS determines whether a discovery meets this requirement. Under current practice, there is no announcement when USGS makes such a determination.

The lessee may abondon the tract or change his drilling strategy by changing the exploratory plan if he does not make a commercial discovery of oil and gas. If he decides to abondon the tract, the lessee must submit to the Supervisor a statement of reasons for abondonment and a detailed plan for carrying out abandonment operations, and the lessee must provide for capping and cementing the well. 30/ The Supervisor must approve the abandonment in writing, according to USGS requirements. 31/

Oil companies sometimes undertake geophysical and geologic exploratory activities after a lease sale. Depending on how many data are available from pre-lease

exploration, or on whether the first exploratory well on a lease tract finds marginal or no commercially producible quantities of oil, more geophysical and geologic information and exploratory drilling may be necessary to define the size and location of the oil-bearing structure. Operators conduct post-lease sale geophysical and geologic exploration under permits and conditions similar to those required by USGS for pre-lease sale exploration.

DEVELOPMENT

Before an operator can develop an oil or gas field and commence production, he must submit a development plan to USGS for approval. The development plan contains the same elements as the exploratory drilling plan: (1) a description of drilling vessels, platforms, or other structures showing the location, design, and major features, including features pertaining to pollution prevention and control; (2) the general location of each well, including surface and projected bottom-hole location for directionally drilled wells; (3) structural interpretations based on available geologic and geophysical data; and, (4) such other pertinent data as the Supervisor may prescribe. 32/

Once again, the USGS makes an environmental assessment within 30 days and decides whether an EIS is necessary. If the Supervisor determines approval of the development plan constitutes a major federal action significantly affecting the environment, then state and local governments and other interested persons or groups may comment on the environmental effects of the plan through the EIS review process. EISs were prepared on the partial development plan for the Santa Ynez Unit 33/ and for resumption of oil and gas development in the Santa Barbara Channel. 34/

Recent amendments to USGS regulations allow states to review parts of development plans and additional information on proposed development activities and their anticipated impacts. 35/ Thirty days before submitting a development plan to USGS, the operator must supply to the governors of directly affected states a description of all offshore and onshore facilities and operations proposed in the plan or directly related to the proposed development. The USGS Supervisor requires that development plans specify the location, size, requirements for land, labor, materials, and timing of development and operation, in addition to any other related economic or environmental information. After the development plan goes to USGS, the Supervisor provides to the governors of directly affected states a copy of the development plan, except for those portions designated by the operator and approved by the Supervisor for exclusion. USGS may withhold information that reveals: (1) commercial and financial information and privileged or confidential trade secrets; or, (2) geologic and geophysical information and data maps concerning wells.

After approval of the development plan, the operator must obtain a drilling permit from USGS and a permit from the Corps of Engineers for installation of any platform, subsea production system, or artificial island. 36/ California State agencies have an opportunity to review and comment on these permit applications through the Resources Agency Clearinghouse.

Both the USGS and the U.S. Coast Guard issue and enforce safety and pollution control regulations. 37/ In addition, the Occupational Safety and Health Administration (OSHA) of the Labor Department has authority to enforce safety standards on fixed structures on the OCS, including platforms and artificial islands. 38/

At present, there is some confusion over the division of responsibility between OSHA and the Coast Guard for safety of offshore operations. The Coast

Guard maintains its safety regulations are adequate, but OSHA claims it should regulate working conditions on platforms, just as it does in other industrial work places, under the explicit authority granted by the Occupational Safety and Health Act. 39/ An incident in the Santa Barbara Channel illustrates the confusion that now exists around this issue: the building contractor on Exxon's Hondo Platform denied OSHA inspectors access to investigate employee complaints of unsafe working conditions on the platform; the building contractor claimed that only the Coast Guard, not OSHA, had authority to inspect working conditions on the platform. 40/ This confusion would be resolved under legislation to amend the OCS Lands Act that is now pending in the U.S. Congress.

TRANSPORTATION

Transportation of oil and gas from the OCS is either by pipeline or by tankers and barges. All production in California to date and nearly all production in the Gulf of Mexico has been transported by pipeline.

PIPELINES. There are two types of pipelines on the OCS, gathering lines and transmission lines. Gathering lines move oil and gas from producing wells to a central point for treatment, storage, or measuring and terminate at the final metering point under USGS jurisdiction. Pipelines moving hydrocarbons beyond this point are transmission lines.

The proposed location and design of gathering lines are included in the development plan which USGS must approve before development can proceed. Gathering lines located entirely on one lease require no right-of-way easement. If a gathering line will cross other leases, however, USGS must notify the lessees of those tracts and grant an easement before the line is built. USGS does not require a rental charge for the easement since these easements are considered an extension of lease production facilities. 41/

Oil and gas transmission lines are either common carriers or private carriers. Common carrier lines transport oil or gas for a fee without descrimination against any shipper. Private carriers transport oil or gas belonging to the owner(s) of the pipelines. BLM grants rights-of-way for common carrier oil or gas transmission lines and charges rent for each pump station and for the length of the right-of-way used. 42/ The Interstate Commerce Commission (ICC) regulates rates for and access to common carrier oil transmission lines. 43/ Before constructing a common carrier gas pipeline from the OCS to shore, the operator must obtain a Certificate of Public Convenience and Necessity from the Federal Power Commission (FPC). The FPC also sets natural gas prices and transmission rates for these lines and must approve any plans to abandon a gas pipeline. 44/

All oil pipelines from the OCS in California are private carriers regulated by USGS. Oil transported in these lines is generally metered onshore; therefore, these pipelines are seen as an extension of a lease operation. Private carrier gas transmission lines, however, are treated as common carriers for most regulatory purposes. 45/

The Corps of Engineers must issue a permit for the construction of pipelines on the ocean floor. 46/ For pipeline construction within the territorial sea (less than three miles from shore), the Corps must issue a dredge and fill permit. 47/ The Corps requires another permit for dumping material dredged during the construction and burial of the pipeline in ocean waters beyond the territorial

seas. 48/ The Corps circulates each of these permit applications to California state agencies for comment through the Resources Agency Clearinghouse.

All pipelines on the OCS must meet the requirements of the Office of Pipeline Safety Operations (OPSO) in the Department of Transportation. 49/ OPSO regulations apply to the design, installation, inspection, testing, construction, extension, operation, replacement, and maintenance of pipelines. Pipelines in place off California's OCS are buried only near the shore to protect them from damage by the surf. 50/ OPSO regulations, however, now require burial of new pipelines which cross shipping lanes or harbor areas, in order to prevent damage from anchors.

TANKERS AND BARGES. The Coast Guard establishes and administers certification requirements for tankers and barges. The Federal Maritime Commission supervises rate schedules and licensing for common carriers, tankers, and barges. 51/

Use of an offshore processing, storage, or terminal facility in connection with transporting oil production by tanker, instead of by pipeline, must be approved by USGS as part of an OCS development plan. USGS and Coast Guard safety and pollution control regulations also apply to such facilities. In addition, the Corps of Engineers must issue a permit for such installations, since they pose a potential hazard to navigation. State agencies have an opportunity to comment on the permit application filed with the Corps through the Resources Agency Clearinghouse. EPA requires a permit for any discharge of pollutants from offshore facilities. The California Water Resources Control Board then comments on these permit applications.

SHIPPING LANES AND SAFETY FAIRWAYS. The Coast Guard and Corps of Engineers have authority to establish regulatory mechanisms to prevent vessel collisions in congested areas of the OCS and territorial sea. In congested waters, the Coast Guard may establish a Vessel Traffic Separation Scheme (VTSS) with traffic lanes separating vessels going in opposite directions. A VTSS does not affect the placement of platforms or floating drilling rigs. 52/ The Corps of Engineers may establish safety fairways, however, prohibiting the installation of any fixed structures in the fairway, including platforms or movable drilling rigs. 53/

VTSSs established in the Santa Barbara Channel and Gulf of Santa Catalina cross many federal oil and gas lease tracts, creating a conflict between OCS oil and gas development and shipping. In addition, the tract selection for currently pending OCS Lease Sale #48 includes a number of tracts located in the vessel traffic lanes. The Coast Guard requested the Corps of Engineers to establish a safety fairway in the traffic lanes crossing lease tracts in San Pedro Bay. The State of California supported the Coast Guard's request, 54/ but the BLM and the Western Oil and Gas Association (WOGA), an oil industry group, opposed it. 55/ The Corps has decided to allow exploratory drilling within the VTSS under guidelines designed to minimize hazards to navigation and has deferred a final decision on establishing a fairway until lessees complete "substantial" exploratory work in the area.

UNITIZATION

OCS lease tract boundaries are drawn without consideration or knowledge of where accumulations of oil and gas exist. A grid, superimposed on the OCS, determines tract boundaries. Oil and gas accumulations are commonly called pools or reservoirs. Often a reservoir underlies leases belonging to two or more individual

owners, creating a strong incentive for each competing owner to produce rapidly as much oil and gas as possible before the reservoir is exhausted. 56/ This could lead to the drilling of unnecessary wells and a reduction in total oil and gas recovery. Production of oil and gas at a precipitate rate unduly lowers the pressure that drives the oil and gas out of the reservoir, and ultimate recovery from the reservoir is reduced. In addition, effective use of secondary and tertiary recovery operations is nearly impossible where the petroleum reservoir involves more than one lease tract and the owners are competing for the available resources.

Unitization is an agreement among several lease tract owners in a prospective or producing oil and gas field, or part of a field, that provides for development and operation of several tracts as a unit by a single operator selected from and agreed to by the lessees. Owners share proportionately the expenses of the unit and ownership of the produced oil and gas. Unitization can occur anytime after a lease sale, but it usually occurs after discovery of an oil or gas reservoir and before development and production. 57/ Since the lease tracts within the unit are developed and operated as though they were one, the terms of all the leases are extended as long as oil and gas are produced in paying quantities from, or the operator conducts drilling or well reworking activities on, any least tract within the unit area.

USGS encourages voluntary unitization and has the authority to compel unitization to conserve oil and gas or other marine resources, including marine life and recreational and aesthetic values. 58/

PRODUCTION CONTROLS

USGS regulates the rate of production from OCS leases and units through review and approval of the maximum efficient rate of production (MER) from oil and gas reservoirs and the maximum production rate (MPR) from individual wells. MER is the maximum rate at which oil and gas can be steadily withdrawn from a reservoir without detriment to ultimate recovery. MPR is the approved maximum daily rate at which oil may be produced from a specified oil and gas well. Operators must make quarterly production reports to USGS; and if operators overproduce, they are subject to mandatory suspension (shut-ins) of production. The USGS Supervisor may allow an operator forced to curtail or suspend production because of storm, hurricane, emergencies, or other conditions peculiar to offshore operations to make up his production losses through production rates above the MER. 59/

ADVISORY BOARDS

Three groups presently advise the Interior Department on OCS oil and gas development: the National Petroleum Council, the National OCS Advisory Board, and the OCS Environmental Baseline Studies Advisory Committee. The National Petroleum Council (NPC), composed primarily of oil industry representatives and a few consumer and environmental groups, advises the Secretary of Interior on a wide range of issues, including OCS oil and gas development. The National OCS Advisory Board is a board of representatives from each of the coastal states (except Hawaii); it advises the Secretary of the Interior on all facets of offshore oil and gas policy. The Board is divided into six regional boards, one of which -- the Pacific regional board -- includes representatives of California, Oregon, and Washington. Bill Press, Director of the Governor's Office of Planning and Research, is California's representative on the OCS Advisory Board. The OCS Environmental Baseline Studies Advisory

Committee is basically a technical panel, composed of representatives from the coastal states, that advises BLM on its environmental studies program. It is considered a committee of the National OCS Advisory Board but actually meets and operates quite independently of the Board. Bill Northrop, Executive Director of the State Lands Commission, is California's representative on that board.

REPORTS AND INSPECTIONS

USGS requires OCS to submit detailed reports on their operations and production. Operators must keep complete records of all well operations at a location convenient to the USGS Supervisor and must provide copies of these records to the Supervisor upon request. 60/ The Supervisor must also receive monthly reports of all operations and production. 61/

Under recently revised regulations, geologic interpretations and geophysical data and interpretations submitted to USGS under these requirements are not available to the public without the consent of the lessee(s) for as long as the lease remains in effect or for ten years, whichever is less. USGS cannot release geologic data and analyzed geologic data to the public without the consent of the lessee(s) for as long as the lease remains in effect or two years, whichever is less. The Supervisor may release any of this data or interpretive information, with the approval of the Directors of USGS, if he determines that earlier release is necessary for the proper development of the field or area. 62/ These disclosure provisions apply only to information from leases issued after June 23, 1976. Leases issued in Lease Sale #35 in 1975 and in the Santa Barbara Channel in 1968 are, therefore, not subject to these provisions.

USGS inspects offshore facilities and operations and enforces regulations and orders. In the Santa Barbara Channel, USGS has eight inspectors to inspect five producing platforms, floating drilling rigs, jack-ups, and two onshore facilities that receive production from the platforms. There are daily inspections of operations in the Dos Cuadras field (Platforms Hillhouse, A, and B), and weekly inspections in the Carpinteria field (Platforms Houchin and Hogan). Floating drilling rigs or jack-up drilling rigs that have been out of service for some time and are new to the Pacific area receive a comprehensive inspection by USGS before they commence drilling. After normal drilling begins, USGS conducts inspections at least once a week. USGS inspectors witness all operations or tests considered critical or non-routine that occur on production platforms, floating drilling rigs, or jack-up rigs. Processing of all oil and gas now produced from the OCS takes place at the Phillips La Conchita plant or the Mobil Sea Cliff plant. Both plants are near Rincon Point and are inspected weekly by USGS. 63/

Each onshore and offshore facility receives a comprehensive inspection by USGS every six months. All equipment must conform to USGS regulations and OCS orders. Operators face specific enforcement actions for "incidents of noncompliance" (INC). Depending on the hazard presented by a particular INC, the operator may receive a warning and seven days to correct the INC. For more serious INCs, USGS may order the operator to shut-in the affected equipment or the entire platform, drilling rig, or onshore facility. Lessees are subject to loss of lease, imprisonment, or a fine for noncompliance with regulations or OCS orders, but USGS has never invoked this penalty in the Pacific OCS to date. 64/ In addition to facility and operations inspections, the public may examine inspection records at the Ventura and Los Angeles offices of the Conservation Division of USGS. 65/

A SUMMARY OF FEDERAL STATUTES AND AGENCY RESPONSIBILITIES RELATING TO OCS DEVELOPMENT

This section summarizes the federal laws relevant to offshore oil and gas development and the major roles of federal agencies in OCS activities as of March, 1977. The Carter administration and several members of Congress have proposed a number of changes in the leasing and management system, however, including amendments to the OCS Lands Act and a division of responsibility for leasing and developing offshore lands between the Interior Department and a new Department of Energy. Laws and responsibilities summarized below may change as the result of new legislation or executive or administrative actions.

FEDERAL STATUTES RELEVANT TO OFFSHORE OIL AND GAS DEVELOPMENT

Anadromous Fish Conservation Act. 16 U.S.C. 757. This Act authorizes the Secretary of the Interior to enter into cooperative agreements with states to conserve anadromous fishes. Federal monies are available to help reduce harm to the anadromous fishery resources of the coastal states from offshore development.

Clean Air Act Amendments of 1970. 42 U.S.C. 1857-1857f. The Clean Air Act sets general guidelines and minimal air quality standards on a nationwide basis. States are responsible for developing comprehensive plans for all regions within their boundaries. The requirements of the Act and state programs apply to any OCS-related facility or activity onshore or within the three-mile-wide territorial sea, but it is unclear whether the Clean Air Act operates to regulate air quality offshore beyond three miles.

Coastal Zone Management Act of 1972. 16 U.S.C. 1451-1464. The Coastal Zone Management Act (CZMA) provides federal funding to states to assist them in developing and administering their own coastal zone management programs. Amendments to the Act enacted in 1976 created a program to compensate states for the onshore effects of the location of coastal-dependent energy facilities. Once a state has devised a federally approved coastal zone management plan, the Act requires federal agencies conducting or supporting activities directly affecting the state's coastal zone to do so in a manner consistent to the maximum extent practicable with the state's plan. Furthermore, activities requiring a federal license or permit affecting land or water use in the coastal zone must be consistent with an approved state plan or be otherwise necessary for the national security. Lastly, the CZMA authorizes federal grants to states of up to 50% of the cost of acquiring, developing, and operating estuarine sanctuaries.

Commercial Fisheries Research and Development Act of 1964. 16 U.S.C. 779-779f. This Act authorizes the Commerce Department to make federal funds available to states to research and develop commercial fisheries in areas affected by offshore development.

Department of Transportation Federal-Aid Highway Provisions. 23 U.S.C. 138, 317. Under this Act, the Secretary of Transportation must cooperate with various federal agencies and with the states in developing transportation plans and programs that include measures to maintain and enhance the natural beauty of the lands traversed. Roads servicing OCS-related onshore facilities that cross federal lands or were built with federal aid must comply with these provisions.

Federal Water Pollution Control Act Amendments of 1972 (FWPCA). 33 U.S.C. 1251 et seq. The Federal Water Pollution Control Act Amendments (FWPCA) limit and control the discharge of oil or other hazardous substances into the sea. The FWPCA applies only to offshore facilities and vessels within 12 miles of shore. A permit from EPA is required if these activities result in discharges into the water.

Fish and Wildlife Act of 1956. 16 U.S.C. 742a-754. This Act established the United States Fish and Wildlife Service in the Interior Department to study, protect, and manage fish resources. The Secretary of the Interior must investigate all changes or diminution in the number of food fishes of the coastal waters and report to the Congress his recommendations for actions to protect fish in these areas.

Fish and Wildlife Coordination Act. 16 U.S.C. 661-6673. This Act authorizes the Secretary of the Interior to assist government and non-government organizations in the protection of all species of wildlife and requires notification of the Department of Commerce if a particular offshore development harms wildlife.

Fish Restoration and Management Projects. 16 U.S.C. 777-777k. Federal funds for the management and restoration of fisheries are available from the National Oceanic and Atmospheric Administration of the Commerce Department under the authority of this Act.

Intervention on the High Seas Act. 33 U.S.C. 1471-1487. The Intervention on the High Seas Act gives the Secretary of Transportation responsibility to take those measures necessary to protect the United States' marine resources, wildlife, coastal zone and estuaries, and shorelines and beaches against polluting oil discharges from ships on the high seas. The Secretary may coordinate all efforts to eliminate the threatened pollution and remove or destroy the ship and cargo creating the danger, if necessary. This Act derives authority in international law from the Convention Relating Intervention on the High Seas in Cases of Oil Pollution Casualties, opened for signature November 29, 1969, T.I.A.S. 8068. The law pertains to all ships on the high seas except warships and other ships owned by foreign governments engaged in noncommercial service.

Marine Mammal Protection Act. 16 U.S.C. 1361, 1362, 1371-1384. This Act prohibits the taking of pinnipeds in offshore waters.

Marine Protection, Research, and Sanctuaries Act of 1972. ("Ocean Dumping Act") 33 U.S.C. 1401-1444. This Act authorizes the designation of marine sanctuaries by the Secretary of Commerce with the approval of the President. Also under the Act, the Environmental Protection Agency regulates the dumping of materials in the territorial sea, contiguous zone, or ocean waters.

National Environmental Policy Act of 1969 (NEPA). 42 U.S.C. 4321-4347. NEPA sets national policies to protect the environment and create and maintain conditions under which man and nature can exist in productive harmony. The Act requires federal agencies to prepare and consider an environmental impact statement before taking any major action that could significantly affect environmental quality, including offshore oil and gas leasing and development.

National Historic Preservation Act. 16 U.S.C. 470 et seq. The National Historical Preservation Act protects historical and cultural resources, including

those on offshore lands. Mandatory procedures for protecting these resources appear in 36 C.F.R., Part 800, under the authority of Executive Order 11593 and this Act.

Natural Gas Act. 15 U.S.C. 717-717w. The Natural Gas Act authorizes the Federal Power Commission (FPC) to regulate natural gas pipelines engaged in interstate commerce, including those transporting gas produced from the OCS.

Natural Gas Pipeline Safety Act of 1968. 49 U.S.C. 1671-1684. The Department of Transportation sets and enforces standards for the design, installation, inspection, testing, construction, and maintenance of natural gas pipelines, including those on the OCS, pursuant to this Act.

Occupational Safety and Health Act of 1970 (OSHA). 29 U.S.C. 651-678. OSHA authorizes the Secretary of Labor to set and enforce mandatory occupational safety and health standards for work places. The Act specifically applies to OCS activities.

Oil Pollution Act Amendments of 1973. 33 U.S.C. 1001-1015. This Act prohibits the discharge of oil or oily mixtures from ships within 50 miles of land except in certain specific instances. The Act outlines sections of the International Convention for the Prevention of the Pollution of the Sea by Oil (1954). Small discharges from ships en route to the coast are exempt.

Outer Continental Shelf Lands Act. 43 U.S.C. 1331-1343. The OCS Lands Act of 1953 established the jurisdiction of the United States federal government over mineral resources of the Outer Continental Shelf beyond the three-mile territorial limit. State laws consistent with the Act apply to the OCS. The Act gives the Secretary of Interior authority to lease OCS tracts by competitive bidding and provides general guidelines and directives for managing the exploration, development, and production of the oil and gas resources. The Coast Guard regulates the safety of offshore activities and shares responsibility with the U.S. Army Corps of Engineers for insuring safe navigation under the Act.

Ports and Waterways Safety Act of 1972. 33 U.S.C. 1221-1227. This Act authorizes the Department of Transportation to establish vessel traffic service and systems for ports, harbors, and other waters subject to congested vessel traffic.

Submerged Lands Act. 43 U.S.C. 1301-1315. The Submerged Lands Act grants coastal states exclusive rights to the resources of offshore lands up to three geographical miles from the shoreline. Federal rights and powers relating to navigation, commerce, national defense, and international affairs within the three-mile territorial sea are retained by the federal government and not affected by this law.

Wildlife Restoration. 16 U.S.C. 669-669i. Federal funds are available to states under this Act for wildlife restoration projects.

OCS RESPONSIBILITIES OF FEDERAL AGENCIES

Department of Commerce National Oceanic and Atmospheric Administration (NOAA). Several offices within the National Oceanic and Atmospheric Administration have OCS-related responsibilities: Office of Coastal Zone Management (marine sanctuaries and coastal zone management); National Marine Fisheries Service (commercial

fisheries and other living marine resources); Environmental Data Service (OCS marine environmental assessment data management); National Ocean Survey (tides, currents, and other environmental features affecting the design and location of offshore structures); National Sea Grant Program (marine research funds); Environmental Research Laboratory (assessment study of petroleum development on the Alaskan OCS); and, the National Wildlife Service (historic storm data, weather forecasts, and hurricane warnings). All federal agencies must notify the Department of Commerce National Oceanic and Atmospheric Administration of any proposal to grant a license or permit that might affect marine life and habitats. NOAA provides meteorological, oceanographic, fisheries, and marine wildlife data to other agencies for assessments of environmental impacts and recommends mitigating conditions for protection of marine and coastal resources. In addition, NOAA assists the Department of Interior in the conduct of environmental baseline studies.

Department of Defense Corps of Engineers. The U.S. Army Corps of Engineers has responsibility for preventing obstructions to navigation on the OCS. The Corps issues permits and sets and enforces regulations for fixed offshore structures, including platforms, artificial islands, pipelines, and exploratory drilling vessels. In congested areas, the Corps of Engineers has authority to establish safety fairways within which the installation of permanent structures is prohibited.

Environmental Protection Agency (EPA). The Environmental Protection Agency has responsibilities for preventing and reducing air and water pollution. EPA sets national ambient air quality standards for air pollutants and reviews state implementation plans designed to achieve those standards. EPA's air pollution controls apply to onshore facilities related to offshore petroleum development and could directly affect offshore operations. EPA issues permits for the discharge of pollutants into offshore waters and works with the Coast Guard to carry out a national oil spill prevention and cleanup program.

Executive Office of the President/Council on Environmental Quality (CEQ). CEQ advises the President on matters affecting the environment. CEQ establishes guidelines for the preparation of environmental impact statements under the National Environmental Policy Act and annually publishes substantive analyses of various environmental issues, including OCS oil and gas development.

Federal Power Commission (FPC). The FPC regulates the price and transportation of natural gas in interstate commerce, including all gas produced from the OCS. The Commission issues permits for the construction and operation of OCS and other interstate gas pipeline and storage facilities used with such pipelines, sets the wellhead price of OCS gas, and must assure the nondiscriminatory transportation and purchase of natural gas.

Interstate Commerce Commission (ICC). The ICC regulates rates and access to common carrier oil pipelines in interstate commerce, including oil pipelines from the OCS.

Department of the Interior/Bureau of Land Management (BLM). BLM has responsibility for leasing offshore lands and collecting lease bonuses and rents. In administering lease sales, BLM receives nominations and selects tracts for inclusion in the sale; prepares an environmental impact statement for each sale, makes an economic, engineering, and geologic evaluation of tracts to be leased; and

receives bonus bids and determines whether to award leases to the highest bidders on individual tracts. BLM also grants rights-of-way for oil and gas transmission lines from the OCS to shore.

Department of the Interior/Fish and Wildlife Service. The Fish and Wildlife Service provides biological assistance and recommendations for lease stipulations to BLM and USGS for OCS leasing and development activities pursuant to Secretarial Order 2974 dated April 30, 1975.

Department of the Interior/United States Geological Survey (USGS). Before BLM leases offshore lands, the USGS makes broad area surveys to assess hydrocarbon potential, grants permits for the conduct of geophysical and geologic exploration, participates in the preparation of environmental impact statements on proposed lease sales, and advises BLM on the resource potential and dollar value of specific lease tracts. USGS has the primary responsibility for supervising exploration, development, and production activities on OCS leases. This post-lease supervision includes issuing and enforcing safety regulations, issuing geophysical and geologic exploration permits, reviewing exploration and development plans, issuing drilling permits, granting rights of use and easements for OCS pipelines on the OCS, and collecting royalties.

Department of Labor/Occupational Safety and Health Administration (OSHA). In conjunction with the Department of Health, Education, and Welfare (HEW), OHSA sets safety and health standards for fixed structures on the OCS. OSHA conducts inspections at the request of employers or workers and enforces the safety and health regulations.

Department of Transportation/Coast Guard. The Coast Guard has several responsibilities for safety and the prevention of pollution on the OCS. The Coast Guard establishes and enforces safety regulations for platforms and other fixed structures, insures proper marking of platforms to prevent collisions with vessels, and inspects floating drilling rigs. The Coast Guard enforces federal oil pollution laws in both federal and state waters offshore, shares responsibility with the Environmental Protection Agency for oil spill prevention and cleanup, and coordinates the National Oil and Hazardous Substance Pollution Contingency Plan. In congested waters, the Coast Guard may establish a voluntary Vessel Traffic Separation Scheme (VTSS) such as those established in the Santa Barbara Channel and Gulf of Santa Catalina, with traffic lanes separating vessels going in opposite directions. In establishing such a scheme, the Coast Guard has no authority over the drilling operations of floating drilling rigs or the placement of platforms. These facilities and operations fall under the U.S. Army Corps of Engineers' or U.S. Geological Survey's authority to regulate the location of fixed structures on the OCS.

Department of Transportation/Office of Pipeline Safety. The Office of Pipeline Safety issues and enforces regulations applying to the design, installation, inspection, testing, construction, extension, operation, replacement, and maintenance of natural gas and petroleum pipelines crossing state lines, including OCS pipelines. This jurisdiction includes transmission pipelines, offshore gathering lines, and onshore gathering lines in nonrural areas.

IMPROVING MANAGEMENT OF OCS RESOURCES

As established by the Outer Continental Shelf Lands Act of 1953, the stated goals of the federal OCS leasing and management program are: (1) to promote

orderly and timely resource development; (2) to protect the environment; and, (3) to assure the receipt of a fair market return for the public's resources. These are fitting goals, but to date the structure of the federal leasing and management system has hampered the development of policies to achieve these goals. The present system also frustrates efforts by state and local governments to participate in the process. Within the federal government and within the state government of California, coordination among agencies involved in OCS issues needs improvement.

DECIDING TO LEASE

The decision to lease an OCS tract is fundamental. Because federal oil and gas leases presently convey rights to develop and produce oil and gas found in commercial quantities, a lessee will develop a tract if he discovers sufficient oil and gas to economically justify development.

Estimates of the resources underlying lease tracts are key factors in leasing decisions. Inferences about the geology of prospective areas drawn from seismic surveys and samples of rock outcroppings from the ocean floor serve as a basis for these resource estimates. If BLM proposes to lease an area adjacent to already leased tracts, well data from these tracts can supplement information from seismic surveys and rock samples taken in the unleased areas. Although these data make it possible to identify geologic structures that may contain oil or gas, as well as estimates of their hydrocarbon potential, the only way to know if oil and gas are in fact present and to assess the size and characteristics of the reservoir is to drill an exploratory well. The current leasing system does not provide for exploratory drilling until after a tract is leased. Thus, pre-lease resource estimates are necessarily speculative. Leasing on the basis of speculative estimates without direct information on the presence of oil and gas hampers efforts to achieve the goals of the federal OCS program.

TIMELY AND ORDERLY DEVELOPMENT. The need to lessen the nation's dependence on foreign sources of oil and gas has given the goal of timely and orderly development of OCS resources special urgency. To increase domestic fuel supplies from the OCS, we must explore for oil and gas and bring what we find into production as rapidly as possible, without sacrificing the environment or giving away the public's resources at less than a fair market price.

Speeding exploration of the OCS currently requires accelerated leasing because the Department of the Interior does not permit exploratory drilling on tracts before they are sold. Leasing conveys development and production rights in addition to exploration rights for a tract. This automatically commits to development any leased tract containing commercial quantities of oil and gas. This commitment to develop large areas of the OCS without direct information on the presence of oil and gas prevents the federal government from pursuing leasing strategies that concentrate industry efforts in the most promising areas. The result is exploration and development of the OCS at a rate and in a manner that meets the individual business management needs of various oil companies, irrespective of overall OCS planning and management goals.

FAIR MARKET RETURN. Calculating minimum acceptable bids for tracts is difficult without direct information on oil and gas resources because geophysical and geologic data presently available before exploratory drilling are subject to wide differences in interpretation. Large variations in bids among oil companies and the valuation of the USGS for specific tracts demonstrate the degree of uncertainty associated with determining tract values before a lease sale.

For example, USGS's pre-sale value on Tract #76 in Lease Sale #35 off southern California was $24,543,360. This tract received a high bid of $5,276,160. After the sale, USGS reviewed its original valuation for this tract and assigned it a new value of $144,000. This is the minimum offer the Interior Department will accept on any OCS tract offered for sale anywhere and reflects a judgment by USGS that the tract contains no resources or an insufficient amount for a lessee to make a profit. The high bid for Tract #76 was accepted. 66/

If competitive market conditions exist, the federal bonus bidding system should provide a fair market price for the public's resources. In southern California Lease Sale #35, however, there appeared to be a lack of competition, possibly attributable to the accelerated leasing rate in the last few years. In Lease Sale #35, only 70 tracts received bids out of 231 offered for sale. Out of those 70 tracts, 40 received one bid and nine received two bids. Of the 56 tracts leased, 30 had one bid and six had two bids. 67/

Both the oil industry and the federal government can make educated guesses about the oil and gas potential of tracts; but before the lease sale, neither government nor industry knows how much oil and gas is present or even whether it is present at all. Federal OCS leasing is essentially a gamble for both industry and government. One cannot know the actual quantity of recoverable oil and gas in a reservoir until it is produced, but a much better estimate of the recoverable resources is possible with direct information from exploratory drilling than without it.

ENVIRONMENTAL PROTECTION. One of the ways in which the Interior Department seeks to protect the environment is to delete tracts where development would be environmentally harmful from the list of tracts offered at lease sales, or to offer such tracts for sale subject to special conditions (lease stipulations). Deciding whether to offer tracts for sale or to offer them under special conditions is especially difficult where the environmental risks and resource potential are closely balanced, since the only resource estimates available under the present system are so speculative and imprecise.

Although a memorandum of understanding on tract selection procedures between BLM and USGS requires USGS to include a tract-by-tract resource estimate in the joint BLM-USGS tract selection recommendations sent to Washington by the field offices of the two bureaus, 68/ USGS officials recently told the U.S. General Accounting Office (GAO) that this information has never been provided for any OCS sale. Furthermore, the USGS officials told GAO they did not believe collecting sufficient information to make such an estimate so early in the leasing process is worthwhile. 69/

BLM's Pacific OCS Office Manager, Bill Grant, asked USGS to estimate the quantity of oil or gas per acre for each tract under consideration for Lease Sale #35. Sufficient geologic information did not exist within government or the oil industry to make such an estimate, but USGS did not attempt to obtain the data on its own. Instead, USGS compared onshore basins and oil fields with unexplored areas offshore that exhibit similar geologic characteristics. This process produced estimates of areas comprised of many tracts, without any indication of how those resources might be distributed among the tracts. 70/

When balancing the resource potential of specific tracts proposed for sale in Lease Sale #35 against the environmental risks of leasing and developing those

tracts, Interior Department officials had only speculative resource estimates for the general areas in which the tracts were located.

PRE-LEASE DRILLING. In order to improve the quality of resource information for making tract selection decisions, the Interior Department should acquire direct information from exploratory drilling to make tract-by-tract oil and gas resource estimates before lease tracts are offered for sale. In some areas in southern California, direct information will be available from a well or wells drilled on a leased tract into a geologic structure that also underlies an unleased tract or from core wells drilled off southern California before the federal-state boundary was finally established. The state of California should work out an arrangement with the federal government to make information from drilling in state lands available to USGS for use in making resource estimates. In instances where direct information on geologic structures underlying a tract under consideration for leasing is not otherwise available, at least one test well should be drilled on those structures before those tracts are offered for lease.

This drilling should be carried out in the same manner as deep stratigraphic test wells are now drilled before lease sales: the wells should be drilled by groups of private companies sharing the costs of the wells and the data from them. These groups should be privately organized, and select the location of the well. Approval of the well location and a drilling permit from USGS should be required before the well could be drilled. As a condition of the permit, information from the test well should be made available to USGS. Companies not participating in the group when the well is drilled should be allowed to buy the well data only after paying a proportionate share of the well costs plus a substantial penalty.

A limited pre-lease drilling program should provide substantially better resource information for making tract selection decisions than is available under the present leasing system. Before drilling, the only information available for making resource estimates is geophysical data from magnetic, seismic, and gravity surveys, data on the surficial geology, and data from deep stratigraphic wells deliberately drilled at locations designed to prevent the discovery of oil and gas. In most cases, these data will only permit the identification of structural features and faults and help define the characteristics of the sedimentary basin. Estimates of recoverable resources based on these data depend on assumptions about the physical characteristics of the hydrocarbon reservoir, the quantity of hydrocarbons present, and the physical properties of the hydrocarbons. Once an exploratory well is drilled at a location selected for the purpose of producing the most information, the presence of hydrocarbons and the reservoir intervals can be established, the porosity of the rock can be ascertained, the pressure of the reservoir can be checked, and the fluid saturation can be measured. With complicated tests, it is possible to analyze the chemical and physical properties of the hydrocarbons and the drive mechanism of the field. In addition, geophysical information can be related to the known geology at the point the well is drilled.

One persistent question is how much drilling is enough to evaluate a prospective oil and gas field adequately. The oil industry can point to numerous examples where a large discovery was made only after many wells were drilled in unsuccessful attempts to find oil or gas and most companies had abandoned the area. Drilling one well or a few wells on a geologic structure cannot give sufficient information to make a definitive estimate of the resource potential of that structure, but that is not the purpose of the pre-lease drilling program recommended here.

The business community fears that federally sponsored pre-lease exploratory drilling will lead to nationalization of the oil and gas industry. However, a pre-lease exploratory drilling program would change the government role in the leasing system very little. The Department of the Interior will select tracts for lease sales based on whatever estimates of resource potential are available. The fact that these tract selection decisions by the Interior Department have determined, and will continue to determine, which OCS tracts the oil industry will have the opportunity to lease, explore, and develop would not be changed by the initiation of the pre-lease drilling program proposed here. This program is designed to give the Secretary of the Interior substantially better founded estimates of resource potential than he now has when making tract selection decisions. The pre-lease drilling program recommended here would not increase the involvement of the federal government in deciding which OCS tracts will be leased and developed, but it would enable the federal government to make more informed leasing decisions.

Moreover, this pre-lease drilling proposal maintains the important role the oil industry plays in OCS exploration. The federal government would not conduct or finance exploratory drilling. A limited number of exploratory wells would be drilled before leasing by a group of private companies in the same manner that deep stratigraphic wells are drilled under current procedures. A drilling permit from USGS would be required, but a USGS drilling permit is also required under existing procedures for any exploratory well drilled after a lease sale. Nearly all of the exploratory work would be conducted, just as it is under current procedures, by private companies after the lease sale.

It is possible that the capital available to the oil industry to explore and develop the OCS and other energy sources may be increased by a pre-lease drilling program. Large sums are currently paid by the oil industry in cash bonuses for rights to explore for and produce oil and gas from the OCS with little assurance of a return on the investment. It is a very risky investment. For example, a group of oil companies headed by Exxon U.S.A. paid cash bonuses totalling $632 million for six tracts in the Gulf of Mexico off the coast of Florida. Since July 1974, eight dry holes have been drilled on these tracts. In other areas, the oil industry has discovered large quantities of oil and gas on tracts thought to have a relatively low potential. Some argue that the federal government has not received a fair market return from the oil companies for the public's resources under the existing system. Regardless of who wins that argument, if the federal government has, in fact, received a fair return, it has been due to the happenstance that the industry's drilling program may enable the oil companies to make better informed bids for OCS tracts and thereby lessen the chances of a windfall for either the government or the industry. The federal leasing system should be designed to recover a fair return for the public's resources, not a windfall.

This pre-lease drilling program need not cause undue delays in the delivery of oil and gas from OCS lease tracts as long as the oil companies work diligently in good faith with the Interior Department to implement it. In many cases, wells drilled before leasing should allow post-lease exploratory drilling programs to proceed more rapidly than they do now. The important thing is to increase exploration of the OCS and production of offshore oil and gas without sacrificing good management practices and abandoning the basic goals of the OCS leasing and development program, not to see how quickly proprietary rights to OCS oil and gas can be transferred from the government to the oil companies.

CONTROL OF DEVELOPMENT AFTER LEASING

The Secretary of the Interior's authority to control offshore development after leasing is limited by the provisions of the Outer Continental Shelf Lands Act and court interpretations of that Act. 71/

REGULATORY AUTHORITY. As noted above, the Secretary of the Interior is authorized to prescribe such rules and regulations as may be necessary to carry out the provisions of the Act. The Secretary may also prescribe and amend, at any time, such rules and regulations as he determines to be necessary and proper in order to provide for the prevention of waste and the conservation of the natural resources of the OCS. New or amended rules or regulations issued for these purposes apply to all operations conducted under leases issued or maintained under the Act. 72/

New or revised regulations apply to leases issued before the effective date of the regulations only when those regulations are issued for the prevention of waste and conservation of the natural resources of the OCS. The courts have interpreted the phrase "natural resources of the OCS" broadly, to include "marine life, recreational potential, and aesthetic values, as well as the reserves of gas and oil." 73/

Problems arise, however, when new regulations are issued or revised for a primary purpose other than conservation of the natural resources of the OCS or the prevention of waste, as in increasing safety or enhancing the role of state and local governments in the OCS leasing and development process. It is arguable that allowing coastal states to review and comment on development plans and releasing geologic and geophysical data and information will result in the conservation of the natural resources of the OCS, but the Interior Department has, in fact, applied regulations issued for these purposes only to leases issued after the effective date of the regulations.

Congress should amend the OCS Lands Act to permit the Secretary of the Interior to prescribe and amend at any time such rules and regulations as he or she determines to be necessary and proper for the purposes of the Act and to apply such rules and regulations to all operations conducted under leases issued or maintained under the provisions of the Act. There is no apparent reason why the Secretary's power to issue and revise regulations and apply them to existing leases should be limited to changes for the conservation of the natural resources of the OCS or the prevention of waste, and this limitation would be removed by amending the OCS Lands Act. To protect the legitimate and vested proprietary rights of lessees, however, leases should not be subject to forfeiture or cancellation for the violation of regulations not in effect on the date the lease was issued. Regulations applied to leases issued before the effective date of the regulations should be enforced on those leases by strong penalties.

CANCELLATION OF LEASES. As explained above, a lease producing oil or gas or both may be forfeited and cancelled under existing law whenever owners of leases fail to comply with any of the provisions of the OCS Lands Act, or of the lease, or of the regulations issued under the authority of the OCS Lands Act and in effect when the lease was issued. 74/ The Secretary of the Interior may cancel leases not producing hydrocarbons whenever owners fail to comply with the Act, the regulations, or the lease and such failure continues for a period of thirty days after the mailing of a registered letter to the lease owner notifying the owner of the violation. 75/ A lease cannot be cancelled for the violation of regulations issued or modified after the issuance of the lease, although any person who knowingly and

willingly violates such a regulation may be found guilty of a misdemeanor and punished. 76/ The Secretary may cancel any lease obtained by fraud or misrepresentation. 77/

In most instances, existing provisions are adequate for the purposes of the OCS leasing and development program and equitable to both the public and the oil industry. Difficulties arise, however, in two situations: 1) where risks to human life, property, mineral deposits, or the environment which were not known at the time the lease was issued are disclosed during the conduct of oil and gas operations under a lease; or, 2) where a tract on which oil and gas operations pose a high risk to the environment is leased because of a high resource estimate that is found to be overoptimistic after exploratory drilling. The Secretary of the Interior may decide the risks of continuing operations in either case outweigh the immediate national interest in exploring and drilling for oil and gas, but the Secretary's authority to stop operations is limited under existing law.

In these situations, the Secretary may cancel the lease only if continued operations will violate the provisions of the OCS Lands Act, or of the lease, or of the regulations in effect when the lease was issued. Otherwise, the Secretary can only act to suspend operations temporarily by issuing an order or regulation in the interest of conservation. 78/ Such a suspension must be temporary in nature, not so open-ended as to constitute a virtual cancellation of the lease owner's vested rights to develop and produce oil and gas. 79/ "A suspension whose termination was conditioned on the occurrence of events or the discovery of new knowledge which can be anticipated within a reasonable period of time would be a valid exercise of the Secretary's regulatory power, and not a fifth amendment taking." 80/ The violation of rules, orders, and regulations issued after a lease has been executed is not a ground for cancellation of a lease. 81/

A regulation could, conceivably, be drafted that would enable the Secretary to cancel leases issued after the effective date of that regulation if either of these two situations occurs. That would have an inequitable result, however, because the Secretary could not compensate lease owners under existing law for the loss of their rights. Lease owners could lose millions of dollars in bonus bids and exploration and development costs through no fault of their own. 82/

A better approach would be to amend the OCS Lands Act to give the Secretary of the Interior authority to cancel any lease at any time when continued activity under that lease would cause serious harm or damage to any human life, to property, to any mineral deposits, or to the marine, coastal, or human environment. Such damage or harm should be required to outweight the benefits of continuing activity under the lease and be of a type that would not decrease over a reasonable period of time. Lessees whose leases are cancelled should be paid equitable compensation, based on all their costs, less any revenues they may have already received from production. They should not be compensated for anticipated revenues from future production.

In those instances where tracts are thought to have high oil and gas potential and to have high environmental risks from development and production activities, the Secretary of the Interior should have the discretion to offer leases for these tracts that grant exploration rights and make development and production rights subject to a determination by the Secretary that production benefits outweigh all other costs, including environmental costs. Lessees would receive the right to drill for oil and gas, and would receive development and production rights if the

Secretary decides development should proceed. The most reasonable time for the Secretary to make this decision is when the development plan is reviewed. Because of the limited and conditional nature of the rights granted with these leases, some bidding system other than cash bonus bidding should be used for leasing these tracts.

LEASE TERMS. The Interior Department has little real control over how rapidly exploration and development occur on the OCS because leases are currently issued for a primary term of five years or for as long as oil and gas are produced in paying quantities or the lessee conducts well drilling or well reworking activities. The five-year primary term allows unnecessary delays.

Industry has demonstrated its ability to begin drilling shortly after lease sales. Exploratory drilling began in the San Pedro Bay within seven months of Lease Sale #35. In the Santa Barbara Channel, a commercial find on the Dos Cuadros field was announced within six weeks of the lease sale and Platform A was installed and producing oil in less than one year after the sale.

The five-year primary term also frustrates efforts to consolidate facilities required to transport and process OCS oil and gas by allowing exploration and development to proceed at significantly different rates on tracts sold at the same time in the same areas.

Congress should change the primary term of OCS leases from five to three years through amendments to the OCS Lands Act. All that is required for extending the lease beyond the primary term is that well drilling activities be underway, and three years is ample time for operators to begin exploratory drilling if they are sincerely interested in developing offshore oil and gas in a timely manner. The Secretary of the Interior should be given the discretion to offer leases with longer primary terms in areas where extreme weather conditions prevail, in deep water to encourage advances in offshore technology, or where other extraordinary conditions would justify it.

INCENTIVES FOR TIMELY EXPLORATION. Lease owners must pay annual rents of ten dollars per acre in areas proven to hold oil and gas deposits and three dollars per acre in unproven areas on lease tracts without commercial discoveries. There is no evidence whether these rents, which come to $57,600 in proven areas and $17,280 in unproven areas, are effective incentives to early exploration. By comparison, the Netherlands charges low rents under its exploration licenses in the North Sea, but the rental rate increases over time. In addition, licensees are required to spend a minimum sum each year in exploration efforts and to give up their rights to explore portions of the area covered by their license at specific times. 83/ Rents collected under British and Norwegian production licenses also increase over time, but these rentals can be deducted from royalty payments after production begins. 84/

The present system in the United States of charging a flat and unchanging rent on unproductive OCS leases should be examined by the Congress and the Interior Department to see if other mechanisms, such as a progressive rental schedule, a mandatory work program, or a requirement that a portion of the leased acreage be surrendered back to the government after a specified time would provide more efficient incentives for rapid exploration and development.

CALIFORNIA'S ROLE IN OCS POLICY MAKING

The current leasing system provides the state and local governments of California many opportunities to comment on proposed leasing and development activities but gives them little control over these activities. Although offshore oil and gas development will continue in state-controlled submerged lands, most new development will occur on federal OCS lands beyond the three-mile limit of California's jurisdiction. Federal policy determines the timing, size, and location of lease sales on the OCS; and federal agencies regulate industry exploration, development and production. OCS oil and gas development plans may include onshore facilities subject to state and local controls, but those facilities may also be built in federal waters offshore -- beyond state and local jurisdiction. Hydrocarbon emissions, oil spills, and economic and social impacts, however, do not recognize jurisdiction lines. The manner in which offshore development takes place will determine its effects on California, but the state and local governments of California can only comment on proposed leasing and development plans and hope that their concerns will be reflected in the decisions of federal officials. California and other coastal states may gain some control over OCS oil and gas development through the consistency provisions of the Coastal Zone Management Act, as amended, 85/ but the effectiveness and extent of those provisions is very uncertain.

National policy should not be subservient to one region's concerns, but the state and local governments of California do have legitimate interests in OCS leasing and development. There is a national interest in minimizing air pollution, potential damage from oil spills, and damage to wildlife from oil and gas related activities off southern California; but the people who live in southern California naturally have a special concern because they are directly affected.

Congress should amend the OCS Lands Act so that state and local concerns will be effectively voiced within the leasing and development process. The Secretary of the Interior should be required to accept the recommendations of an affected coastal state's governor on the five-year leasing schedule, a proposed lease sale, exploration plan, or development plan unless the Secretary determines that the governor's recommendations are not consistent with national security or the overriding national interest. In doing so, the Congress must take care not to weaken the consistency provisions of the Coastal Zone Management Act, as amended, regardless of the uncertain relationship between those provisions and offshore oil and gas activities. Giving governors of coastal states limited power over oil and gas activities is consistent with our federal system of government and recognizes the joint interests of the nation and coastal states in OCS development.

INTERIOR DEPARTMENT ADMINISTRATIVE POLICIES

Within the structure of the present leasing and development system, the Interior Department could significantly increase the effectiveness of state and local participation by administrative actions.

RESOURCE REPORTS. The request for resource reports on the possible effects of leasing on the environment or other conflicting uses of the OCS (e.g., shipping and fishing) is usually the first indication that the state has of the specific area being considered for leasing. California received the resource report request for Lease Sale #48 at least one month later than federal agencies. Copies of resource

reports, which are useful in responding to the subsequent call for nominations, are not generally made available to state and local governments. BLM should issue resource report requests to states at the same time they are issued to federal agencies and promptly provide copies of all responses to the state and local governments.

CALL FOR NOMINATIONS AND TRACT SELECTIONS. The Interior Department gave an environmental briefing to state and local representatives on areas being considered for Lease Sale #48, but the briefing was held after the deadline for responses to the call for nominations had passed. When BLM's Pacific OCS Office briefed state and local government representatives on tract recommendations being made to the directors of BLM and USGS in Washington, the recommendations were discussed only in a vague and general way, and no written copies of the recommendations were provided. This prevented state and local governments from being able to respond to those specific recommendations, which are made on a tract-by-tract basis. In any case, state and local government representatives were given insufficient time to prepare for a tract selection meeting with Interior Department officials in Washington two weeks later to discuss those recommendations.

The Interior Department should hold environmental briefings on areas under consideration for lease before nominations are due. Responses to the call for nominations from state and local governments and the public should be distributed. State and local governments should be given written copies of the specific tract recommendations made by the area offices to Washington and allowed three weeks to prepare comments on those recommendations.

ENVIRONMENTAL IMPACT STATEMENTS. In the past, state and local governments have not been involved in the preparation of EISs, even though they should be involved to ensure that their concerns are not neglected. BLM's efforts to involve state and local governments in drafting the EIS for Lease Sale #48 are positive steps. Public hearings on draft EISs, however, have been held so soon after the draft became available that state and local governments lacked sufficient time to obtain a copy, review it, and prepare detailed comments. Public hearings should be held no less than forty-five days, rather than thirty days, after the draft EIS becomes available.

DEVELOPMENT PLANS. State and local representatives have not been invited to informal discussions between USGS and offshore operators preceding formal submittal of development plans, when state and local concerns might be accommodated more easily than at a later time, after commitments have been made. State and local representatives should be invited to participate in these meetings when the location of facilities for producing, transporting, storing, or treating offshore oil and gas are discussed.

ACCESS TO RESOURCE DATA

The California state and local governments are hampered in their efforts to comment on proposed OCS leasing and development activities and to plan for onshore OCS-related development by a lack of specific resource estimates, reserve estimates, and production forecasts. This information is necessary for state and local governments to recommend appropriate lease stipulations, to recommend the deletion of tracts from the lease sale with hazardous conditions that cannot be lessened or avoided, and to respond to federal requests for comments on exploratory and development plans and permits for drilling, platforms, pipelines, and other facilities.

Resource estimates, reserve estimates, and production forecasts are primary factors in determining which means of producing, processing, and transporting oil and gas are feasible. Onshore effects, in turn, depend on the types and size of onshore facilities required for processing and transport.

FEDERALLY CONTROLLED DATA. The federal government collects geophysical and geologic data necessary to prepare resource estimates, reserve estimates, and production forecasts through the Geologic Division and the Conservation Division of the USGS.

GEOLOGIC DIVISION. The Geologic Division collects geophysical data and bedrock samples from rock outcroppings on the ocean floor, and, using these data, produces general estimates of the resource potential of broad areas of the OCS. These interpretive reports and the geophysical data and rock samples are available to the general public in the open files of the Geologic Division.

CONSERVATION DIVISION. The Conservation Division contracts with private exploration companies for the collection of these data and also buys information offered for sale on the open market by the exploration companies. But these data from exploration companies are supplied under strict conditions of confidentiality that prevent their disclosure not merely to the general public, but to state agencies as well. The Conservation Division also has access to information from all geophysical and geologic surveys and receives well data from leased tracts. Lessees are required to submit well logs, cores, core analyses, paleosamples, well test results, and production information to the Conservation Division. 36/ California, the Gulf of Mexico, and the Gulf of Alaska are the only OCS areas where exploratory and development drilling have taken place, and, therefore, presently the only sources of well data.

DISCLOSURE OF DATA. Under revised regulations issued in 1976, raw geophysical data will be made public ten years after the issuance of the exploratory permit. The processed geophysical data, reprocessed geophysical data, and interpreted geophysical data will be released ten years after it is submitted to USGS. Nonetheless, a public notice is issued immediately upon the identification of any hydrocarbon deposits or environmental hazards discovered during geological exploration and considered significant by the Director of USGS. All other geologic data, analyzed geologic information, and interpreted geologic information will be made public ten years after the permit is issued. All geologic data and information obtained from deep stratigraphic drilling will be released five years after completion of the well or 60 days after issuance of the first federal lease within 50 miles of the well, whichever is earlier.

The new regulations also provide for the public release of data and information collected after leases are issued. Geologic data and analyzed geologic information will be made public with the lessee's consent while the lease remains in effect or after two years, whichever is earlier. Interpreted geologic information, geophysical data, analyzed geophysical information, and interpreted geophysical information will be released to the public with the lessee's consent while the lease remains in effect or after ten years, whichever is earlier.

Before these new regulations were established, Interior Department policy did not allow disclosure of any of this information, which is considered proprietary. These regulations became effective on June 23, 1976, and apply only to permits or leases issued after that date. As a result, none of the post-lease geophysical or

geologic information held by the Conservation Division is currently available to the state or local governments of California.

HOLDING DATA CONFIDENTIAL. The Interior Department's general policy of keeping confidential all resource data and information obtained from exploration companies or through submissions of lessees has been based on the general grant of authority to the Secretary in the OCS Lands Act to administer the federal OCS oil and gas program. 87/ The OCS Lands Act is silent on whether these types of information must be kept secret.

It is uncertain whether the Freedom of Information Act (FOIA) forbids the disclosure of detailed resource data and information. Generally, the FOIA requires federal agencies to make information available to the public. 88/ The Act does not apply to matters that are "(3) specifically exempted from disclosure by statute; (4) trade secrets and commercial or financial information obtained from a person and privileged or confidential; ...or (9) geological and geophysical information and data, including maps, concerning wells." 89/ Read literally, the statute does not require this information to be kept secret -- it simply exempts the information from the provisions of the FOIA requiring that it be made available to the public. The courts have differed, however, on whether information falling within exemptions of the FOIA may be released or must be withheld from the public.

In Pennzoil Oil Co. v. Federal Power Commission, 90/ companies producing natural gas offshore objected to an FPC order stating that detailed reserve information and background data required of the producers by the FPC would be made public. The companies contended that the information consisted of trade secrets and confidential geophysical information, publication of which would significantly damage their financial interests. The producing companies claimed public disclosure of this information is absolutely barred by exemptions four and nine of the FOIA. The Fifth Circuit Court of Appeals held that "the mere fact that this information is encompassed within the exclusions of the Freedom of Information Act does not prohibit its disclosure." 91/ The Court said, "Interpreting the statute as an absolute bar to the release of certain information would be at war with the basic principles embodied in the Freedom of Information Act." 92/ Nevertheless, the Court held that the Freedom of Information Act is not irrelevant in determining whether information encompassed in its exclusions should be disclosed and stated that "where releasing the information serves no legitimate function, this court will prohibit disclosure." 93/ A balancing of the public and private interests involved is required, the Court said, to determine whether disclosure should be allowed. 94/

Some courts have held the FOIA itself implies that parties submitting business information to the federal government have a right to protection from having that information disclosed, at least to competitors. 95/ In another case, the Court of Appeals for the District of Columbia Circuit held that "FOIA is neutral with regard to exempt information; it neither authorizes or prohibits the disclosure of such information." 96/

Parties seeking to prevent the disclosure of information have argued that the FOIA must be interpreted in light of 18 U.S.C. §1905, a statute that makes it a crime for a federal employee to disclose in any manner or to any extent not authorized by law any information coming to him or her in the course of his or her employment or duties concerning or relating to trade secrets or to other confidential statistical data (among other things) of any person, firm, partnership,

corporation, or association. Since information of this nature would be exempt from disclosure under exemptions four or three (which exempts matters "specifically exempted from disclosure by statute") of the FOIA, its disclosure is not authorized under the FOIA and its disclosure is prohibited under §1905. 97/ This argument has been adopted by some courts 98/ and rejected by others. 99/ The most complete statement of this view can be found in Westinghouse v. Schlesinger, 100/ which is now on appeal to the U.S. Supreme Court.

The decision in Westinghouse, which relies heavily on the ruling of the Supreme Court in FAA Administrator v. Robertson, 101/ has been questioned recently in Crown Central Petroleum Corp. v. Kleppe. 102/ In Crown, Judge James R. Miller, Jr., states his belief that the enactment of Public Law 94-409 effectively overrules FAA Administrator v. Robertson, and, consequently, the decision in Westinghouse to the extent that it held that §1905 is a statutory exemption applicable to the FOIA through exemption three of that Act. 103/

To sum up, it is unclear whether the Interior Department could exercise discretion and release detailed offshore resource data and information collected from offshore operators pursuant to USGS regulations to the public. The circuit courts of appeal are in disagreement; and an important case presenting similar issues, Westinghouse v. Schlesinger, is on appeal to the Supreme Court. Some information on offshore oil and gas resources and reserves is already published, however, by the Interior Department.

FEDERAL REPORTS. The Interior Department makes estimates of OCS oil and gas resources public in EISs and other Interior Department publications, using confidential information from the Conservation Division or information in the open files of the Geologic Division or both. These estimates are flawed by the timing of their release, their level of detail, and their inability to be compared.

Because the Interior Department publishes OCS estimates irregularly, only when needed for an EIS or other publication, these analyses are not prepared or revised on a systematic basis. The estimates do not incorporate new information gathered during exploration and development, or even reflect such basic facts as the failure to lease large areas covered in pre-lease sale estimates.

USGS and BLM do not publish estimates for individual tracts, units, or structures. Instead, estimates are published covering multiple areas, even though more detailed estimates may have been prepared internally. Since published estimates are aggregated, it is impossible for state and local analysts to correlate these estimates with new information pertaining to specific individual fields or tracts.

Estimates and forecasts prepared by the Interior Department are conflicting and contradictory. Those for the southern California OCS aggregate different areas and water depths, draw on differing resource data, and use varying methods and assumptions. Thus, useful comparisons cannot be made among various Interior Department estimates or between Interior Department and industry estimates. Sometimes, estimates given in different Interior Department publications will conflict directly. For example, the Santa Barbara Channel EIS estimate of remaining recoverable resources in unleased portions of the Channel is 40-150 MMB. At a BLM briefing in December, 1976, seven months later, an estimate of 40-900 MMB was given.

The Interior Department, through USGS, should develop and publish an updated, annual resource and reserve estimate and production forecast for all leased areas. For areas without discoveries, resource estimates should be provided by structure, identifying the leases affected. For leases with credited discoveries, reserve estimates and production forecasts should be provided by field. These reports should specify the data, information, and assumptions used in making the estimates. Immediately after a lease sale, the Interior Department should publish the tract-by-tract resource estimates used in evaluating bids so that pre-lease sale resource estimates can be revised to reflect the tracts actually leased.

STATE ACCESS. Most of the information needs of the California state and local governments will be met if the recommendations above are adopted. But, the estimated amounts of recoverable oil and gas may become central to important policy issues, as in the present controversy over the means of transporting oil from Exxon's Santa Ynez Unit in the Santa Barbara Channel.

Without geologic and geophysical data and information, which is held by both the oil industry and the Interior Department, the State must accept industry and/or Interior Department interpretations since it is unable to make its own independent analysis. This analysis is necessary in view of the variability of interpretations. Exxon states that it has from 400 to 500 MMB of recoverable oil in the Santa Ynez Unit, for example, while USGS estimates from 730 to 1100 MMB. This is critical in a controversy of this nature, because Exxon maintains there is insufficient oil in the Santa Ynez Unit to justify building the pipeline favored by state and local government officials for the prevention of oil spills and protection of air quality.

The California Division of Oil and Gas and the California State Lands Division have the expertise to analyze and interpret geologic and geophysical data and information in a confidential manner, as they have for state tidelands leases. At present, however, they do not have the manpower or the funding necessary to undertake large-scale analysis of OCS data and information.

Analysis of geologic and geophysical data is expensive, and duplication of Interior Department analyses of OCS data would be wasteful in most cases. However, in those instances where conflicting resource estimates or the Interior Department's failure to develop necessary analyses in a timely fashion justify state expenditures for such analyses, the Division of Oil and Gas or the State Lands Division should perform such analyses.

When they do occur, the Governor should request either the State Lands Division or the Division of Oil and Gas to prepare the necessary reserve or resource estimates. The Interior Department should permit that designated agency access to geologic, geophysical, and well data and information held by the Department under strict conditions of confidentiality. These conditions must permit the state to use estimates based on this data and other information (i.e., oil characteristics, production forecasts, and other factors that affect development, processing, and transportation options) in public forums or documents, in the same manner that estimates based on confidential data held by the USGS are sometimes used in reports or briefings. Otherwise, the use of this information would be precluded in the debate of important OCS issues, and the state and local governments would continue at a disadvantage in debates with the oil industry and the federal government.

For future lease sales, the Interior Department should go further than the revised regulations for the release of resource data. 104/ The Secretary of the Interior should require that coastal states have access to geologic, geophysical, and well data developed by lessees and geologic and geophysical data collected under permits on unleased tracts. Like information from operations on existing leases, these data should be subject to strict conditions of confidentiality while estimates by state agencies based on these data should be allowed to be used in public documents or forums.

The oil industry and contractors who work for them are greatly concerned about the handling of resource data and information because geologic and geophysical data and information are valuable and marketable commodities. This information is valued primarily for the competitive advantage it affords when nearby tracts are offered in future lease sales and for negotiating agreements to share costs of pipelines and processing facilities. Providing California State agencies access to resource data as recommended here should not, however, significantly increase the risks of the disclosure of proprietary data to a company's competitors. Both the California State Lands Division and the California Division of Oil and Gas have proven they can handle proprietary data in a confidential manner. There is no recommendation here to release geophysical or geologic data to the public, but only to permit the State Lands Division or the Division of Oil and Gas access to the data. These state agencies would review only a small portion of the data collected offshore -- that data relevant to a dispute over a particular development proposal, such as Exxon's proposed offshore storage and treatment facility for the Santa Ynez Unit. In any case, providing California or other coastal states access to resource data from leases sold in the future should not cause a competitive hardship upon lessees, since bidders with advance notice of this requirement could discount their bids to reflect any loss of competitive advantage they might have anticipated from their exclusive possession of information relevant to subsequent sales.

It should be noted that some of the oil companies (Exxon, Chevron, Mobil, Arco, and Phillips) operating off California have been cooperative in supplying state agencies with information on their offshore reserves and estimated resources. In contrast, Texaco refused to supply any information on their operations off California to the OCS Project Staff writing this report.

STATE REVIEW OF DEVELOPMENT PLANS

Coastal states will receive information on development plans under new regulations that allow governors to review and comment on development plans before USGS approval can be given. 105/ But this, too, falls short of the need of state and local governments. The period allowed for review and comment is so short (sixty days) that it will be very difficult to analyze the submitted material and produce meaningful comments to USGS within the allotted time. The information submitted to the states is also incomplete. Geologic and geophysical information and well data and maps are withheld, preventing the states from making an independent assessment of the resource potential and possible hazards. The federal government requires this information in order to make its own independent analysis, but states are left to rely on the judgment and assurances of the operators and USGS. As noted above, the willingness of offshore operators to cooperate informally in providing information about proposed development varies widely. Production schedules are essential in estimating the size of onshore facilities and in planning for the level of OCS-related impacts over time, but there is no requirement for operators to supply production forecasts to the states.

The draft of OCS Order 15, putting into effect the new regulations providing for state review of development plans, raises additional problems. 106/ The draft requires only general information on a county-by-county basis on the size and number of offshore operations and onshore facilities. This general information is insufficient for planning purposes in California, where the five southern coastal counties have over 400 miles of coastline. Operators are required to assess acreage and the general location of new facilities to be constructed, but in areas like California where oil and gas processing plants, pipelines, refineries, and terminals already exist, states need information about plans to use existing or expanded facilities. Information is required on the transportation of oil and gas to shore, but the disposition of oil onshore after initial processing is also important; this has been the major issue in the Exxon/Santa Ynez controversy. Estimates of persons engaged in onshore support activities are not disaggregated to identify direct and indirect employment for each component of onshore and offshore activities, preventing the states from making independent evaluations of these estimates or anticipating the effects of changes in the operator's plans.

USGS should require operators to provide site-specific plans or options for offshore operations and onshore facilities, plans to utilize existing or expanded facilities as well as new facilities, plans to transport oil after processing, and detailed estimates of the economic effects of planned offshore oil and gas development. The period for state review of development plans should be lengthened to 120 days, to begin upon receipt of the development plan by the state and to run concurrently with USGS review.

FEDERAL COORDINATION

Within the Interior Department, OCS activities are coordinated through the Office of OCS Program Coordination under the Assistant Secretary for Program Development and Budget. Secretarial Order 0274 states, in detail, how BLM, USGS, and the Fish and Wildlife Service will interact on OCS-related activities. There is no established procedure, however, for agencies outside the Interior Department to participate in the OCS policy-making process beyond responding to the request for resource reports early in the leasing process and acting on any permits over which they have jurisdiction. For example, such agencies as EPA or the National Maritime Service in NOAA have no real opportunity to contribute to reviews of exploration and development plans. Some procedure within the federal government should be established to enable agencies with expertise in marine resource issues outside of the Interior Department to contribute more to leasing and development decisions.

STATE COORDINATION

OCS policy-making and regulatory functions in California are spread among several state offices, boards, commissions, and departments; and there is no systematic coordination of their activities. Local governments, federal officials, and the industry sometimes are forced to contact a number of state agencies to obtain or convey information on OCS-related proposals or actions. State officials involved in OCS issues keep in touch on an informal basis, and the OCS Project in the Governor's Office of Planning and Research has performed some coordinating functions; but the focus of the state's OCS activities should be in the line state agency responsible for coastal issues, the California Coastal Commission.

The Coastal Commission should take primary responsibility for: (1) coordinating state and local government responses to proposed federal government and industry actions; (2) disseminating information among state agencies and providing local jurisdictions with technical assistance to participate in OCS leasing and development decisions and to anticipate that development in local coastal plans; (3) assisting state, regional, and local government agencies to identify and obtain federal funds to support OCS-related projects and programs; and, (4) maintaining communication and exchanging information with other states on OCS-related matters. Additional funds and staff positions should be allotted to the Coastal Commission to carry out these responsibilities.

ENVIRONMENTAL BASELINE STUDIES PROGRAM

A major concern of California state agencies and local governments is the quality of environmental resource information upon which OCS leasing and development decisions are based. The Bureau of Land Management's major effort to acquire such information is made through its Environmental Baseline Studies Program. The Bureau instituted this program in 1973 to fulfill its obligation under the National Environmental Policy Act "to utilize a systematic, interdisciplinary approach that would ensure the integrated use of the natural and social sciences in any planning and decisionmaking which may have a significant impact on the human environment." 107/

Baseline studies have been undertaken in every frontier area off the U.S. coast where Outer Continental Shelf leasing and development is taking place or lease sales are planned. As described by BLM, the objectives of the Baseline Studies Program are to:

1. provide information about the OCS environment that will enable the Department and the Bureau to make sound management decisions regarding the development of mineral resources on the federal OCS;

2. answer questions concerning the impact of oil and gas exploration and development on the marine environment;

3. establish a basis for prediction of the impact of OCS oil and gas activities on frontier areas; and,

4. provide data that will result in modification of leasing regulations, operating regulations, or OCS operating orders to permit more efficient resource recovery with maximum environmental protection. 108/

The Baseline Studies Program consists of seven major study elements:

1. Historical Data Summaries;

2. Conferences;

3. Reconnaissance Studies;

4. Benchmark Studies;

5. Fates and Effects Studies;

6. Modeling; and,

7. Site Specific Monitoring. 109/

Historical Data Summaries summarize existing information and update the current status of the data base for biology, chemistry, geology, and toxicology. In addition to identifying available information for use in the environmental impact statement on a lease sale, a central purpose of this element is to identify data and information gaps and future research needs.

Conferences are held to provide BLM with guidance on structuring and integrating baseline studies. The Bureau forms committees to examine particular subject areas or research problems such as persistence of hydrocarbons in the marine environment. The Southern California Baseline Studies Program was initiated at a conference held on December 5-7, 1974, where representatives of state, federal, and local government; industry; and the academic community presented recommendations on structuring research and establishing priorities for the studies. 110/

Reconnaissance Studies consist both of broad area characterizations and site specific investigations designed to yield qualitative information on areas of particular interest or concern.

Benchmark Studies are long range studies conducted over many years to establish the range of variation in biological, physical, geologic, and chemical features of a lease area. The Studies provide information that will enable the Bureau to identify particularly sensitive environments that should not be opened to oil and gas or other mineral development.

Fates and Effects Studies provide information on transport, dispersal, biological, chemical, and physical alteration and ultimate fate of contaminants introduced to the marine environment by OCS development. The effects of these contaminants on the environment are also investigated.

Modeling efforts use information and data produced by other elements of the Baseline Studies Program to predict spill frequencies, pollutant trajectories, wave energy, and environmental impacts.

Site Specific Monitoring is conducted at a small site under development in order to determine the type, magnitude, and effects of contaminants introduced into the marine environment by drilling rigs and OCS activities.

While program designs vary from region to region, Baseline Studies are generally conducted in four phases. Phase I surveys the existing environmental knowledge concerning a proposed leasing area. Phase II is the actual baseline survey and data collection to establish a benchmark for future comparisons with past oil and gas development conditions. Phase III is programmed to accomplish specialized research that fills data and information gaps identified in Phases I and II. Finally, Phase IV is the long range monitoring of a leased area and is designed to detect changes over time in environmental conditions that result from oil and gas exploration and development. 111/

Progress to date in southern California includes completion of Phase I and the publication of A Summary of Knowledge of the Southern California Coastal Zone and Offshore Areas prepared by the Southern California Ocean Studies Consortium. 112/

The first year of Phase II, a benchmark sampling program of intertidal, benthic, and water column stations, has also been completed. 113/ In addition, the first year census study of marine birds and mammals by the Bureau of Land Management was released in April 1977. 114/ This effort is particularly significant in that survey activities conducted while Lease Sale #35 was in progress identified critical bird and pinniped habitats in the northern Santa Barbara Channel. Identification of these sensitive resources resulted in deletion of 29 partial or whole tracts south of San Miguel and Santa Rosa Islands and five tracts off Santa Barbara Island. 115/

Phase II studies in the Lease Sale #35 areas also resulted in the inclusion of special stipulations in leases for the Tanner-Cortes Bank area. The stipulations require lease operators to conduct special biological surveys before they begin any drilling. They also prohibit dumping of drill cuttings and drilling muds on the drill site. 116/

In fiscal year 1975, the Bureau of Land Management awarded four contracts for conduct of the Southern California Environmental Baseline Studies Program totaling $4,629,260, as follows: 117/

Contractor	Purpose	Cost	Date of Award
Southern California Academy of Sciences	Organize and administer conference/workshop "Recommendations for Baseline Research in Southern California Relative to Offshore Development"	$ 18,996	11/15/74
Regents of the University of California	Bird, Pinniped, and Mammal Study	$ 652,000	3/28/75
National Aeronautics and Space Administration (Ames Research Center)	Supply film and processing in support of bird and mammal study	$ 28,000	5/1/75
Science Applications, Inc.	Environmental baseline data collection, storage and analysis	$3,930,264	6/30/75

Fiscal year 1976 contracts involve continuation of work begun in 1975.

Baseline studies conducted during Lease Sale #35 made some contribution to the tract selection process. Nevertheless, both the Southern California and the National Baseline Studies Program have been subject to severe criticism. One forum for the expression of concerns over the program has been the National OCS Advisory Board and its Outer Continental Shelf Environmental Studies Advisory Committee. These bodies were organized in late 1975 to advise the Secretary on OCS leasing and development management policy. 118/

The principle objection to the program has been that studies have not begun well enough in advance of lease sales to enable full and complete assessment of proposed lease areas before leases are offered for sale. Critics also feel that research and data collection are not focused sufficiently to provide detailed information required to project adverse effects and plan to correct them. The

program is designed to identify the adverse consequences of oil and gas drilling and production activities after areas are already committed to development. 119/

Recommendations for improving the Program include increasing coordination of research and exchange of information among federal agencies and state governments and structuring and administering the Program in closer coordination with the OCS leasing program so that information from the studies provides timely and pertinent information for pre-lease sale decisionmaking.

Early in 1976, the OCS Advisory Board urged the Department to incorporate nearshore and onshore studies in the Baseline Studies Program. In response to this recommendation the Bureau of Land Management, in cooperation with the Department of Commerce's Office of Coastal Zone Management, initiated a study of state information needs for OCS planning activities. The results of this effort were published in May 1977, and the Department has taken steps to implement recommendations made in the report. 120/

While some improvements in the Environmental Studies Program have been made over the last year, momentum behind this effort has increased under new leadership in the Department of the Interior. In addition to the Department's internal evaluation and restructuring of the manner in which environmental baseline studies are designed and administered, the National Academy of Sciences is expected to publish a detailed critique of the Program in late 1977. 121/

Finally, postponement of Lease Sale #48 from March, 1978, to at least early 1979 automatically increases the amount of environmental baseline studies data and information that will be available for incorporation in the Environmental Impact Statement and for making tract evaluation and selections. It is now incumbent upon state and local governments to make their data and information needs known and to participate to the greatest extent possible in restructuring the environmental baseline studies program.

STATE AND LOCAL CONTROLS

Production and processing of federal OCS oil and gas generally requires that state and local governments review and approve some part of the operation. Typically, in California, the facilities falling within this category include pipelines to shore (within the state's three-mile jurisdictional limit), processing and storage facilities, and marine terminals with oil storage tanks and one or more additional pipelines across state-owned tidelands.

Onshore facilities are not, however, always required. Some North Sea operations store and process oil offshore on fixed or floating processing, storage, and transfer facilities which could serve the Santa Ynez Unit within federal waters, thereby avoiding the jurisdiction of the Coastal Commission and its permit conditions. Where onshore facilities are involved, however, state and local governments have some means available to review and establish conditions for their location and operation.

LOCAL PLANNING AND ZONING

Cities and counties in California have the primary authority for planning and controlling land uses within their jurisdiction. State law requires every city and county to adopt a plan consisting of a statement of development policies accompanied

by maps and a text describing objectives, principles, and standards. 122/ Each plan must address nine major problem areas: land uses, traffic circulation, housing, conservation, open space, seismic safety, noise, scenic highways, and safety. But the treatment of these problems and other issues addressed in the plan is generally left to local determination. State law merely establishes the basic procedural requirements which must be observed before the local legislative body adopts or amends a plan. These include public notice, public hearing, and a planning commission report.

Zoning ordinances regulating the use of land and buildings are the basic tools for implementing a general plan. These ordinances are valid only to the extent they are consistent with the general plan and, like the plan, they may be adopted or amended by the local legislative body only after hearings and a report from the local planning commission. Zoning ordinances usually take the form of rules specifying the uses which will be permitted in zones identified in the general plan. Each type of zone usually recognizes uses that are permitted as a matter of right and others which may be allowed only with a conditional use permit issued by the local legislative body following a review of the particular design and operational features of the proposed facility.

Zoning ordinances, then, are the reference point for land use decisions. If oil-related facilities are allowed as a matter of right, no further discretionary decisions are left to local authorities. If, however, oil-related development is prohibited or allowed only on a conditional basis, public agencies retain some discretion for regulating the design and operation of proposed facilities. Where a development is inconsistent with the general plan, the developer must obtain local legislative approval in a two-step process before the facility can be sited. First, the general plan must be amended following state requirements for public notice and hearing; then the zoning ordinance must be amended following a similar procedure of public notice and hearings. Where a proposed facility is consistent with the general plan, but because of its nature or location is not allowed as a matter of right, the developer must obtain local legislative approval in a one-step process. This decision is usually framed in one of two ways: as a rezoning to allow uses previously prohibited by the ordinance; or as approval of a conditional use permit subject to conditions affecting the design and operation of the facility to assure compatibility with existing uses. Rezoning and conditional use permits create similar hurdles for developers. Both are discretionary decisions by the local legislative body and may be made only after compliance with state procedural requirements including a planning commission hearing and recommendations and compliance with the EIR requirements of CEQA. It is, of course, possible that this could also become a two-step approval if a zoning change was required and the facility was of a type requiring a conditional use permit, regardless of zoning.

SANTA BARBARA REGULATIONS

The content of zoning ordinances varies from jurisdiction to jurisdiction. Santa Barbara has always been concerned about oil development and therefore offers a good model to study. Oil and gas facilities are allowed in Santa Barbara only after a detailed case-by-case review by the Planning Commission and County Board of Supervisors. The County zoning ordinance allows processing facilities in three types of districts: General Agricultural, "O" Zone Overlays, and Planned Manufacturing (PM). The ordinance alone would allow facilities in some cases without conditional use permits or other case-by-case review, but a 1967 policy resolution by the Board of Supervisors is quite restrictive. The resolution requires "PM" zoning for all oil and gas processing facilities.

"PM" zoning imposes very tight control over the design of proposed uses. Since the PM designation must be applied for by the land owner, the resolution, in effect, mandates a rezoning for every processing plant. The rezoning request must be accompanied by a development plan which is submitted to the Board of Supervisors for approval. In addition, before any building permits are issued, the developer must submit to the Planning Commission a "precise plan" which incorporates design and operational controls required by the Commission and the Board of Supervisors. The procedure affords the County a great deal of discretion and control when approving oil-related facilities.

In Santa Barbara, the first step in obtaining a conditional use permit or rezoning is to apply to the Planning Department. The Department's initial review determines whether the applicant has requested the proper action (rezoning, new or amended conditional use permit, etc.) or whether the request should be recharacterized, thus changing the steps ultimately required for approval. Once an application is accepted, it is reviewed concurrently by the County Office of Environmental Quality in order to begin environmental impact assessment and by a committee of agencies (parks, public works, planning, petroleum administrator, APCD, etc.) to assess its conformity with other county policies. The Planning Department staff uses both these reviews in preparing a report to the Planning Commission. The Planning Commission then acts on the plan change, rezoning, or permit as appropriate, and sends the matter to the Board of Supervisors for final action.

The issues raised in Santa Barbara for resolution through permit conditions and development plan approval generally deal with measures to ameliorate adverse effects at the site: air and noise emission and water discharge limits; grading, excavation road building, landscaping, and screening conditions; and, environmental monitoring. The rezoning ordinance for the Las Flores Canyon processing facility, for example, incorporated seventy-three conditions covering the above areas and including assumption by the operator of liability without fault for offsite damage and for the periodic testing of oil spill containment and cleanup equipment at the County's request on an unscheduled basis. The County began environmental impact analyses early in the application process to provide the specific information needed for permit and rezoning conditions to mitigate adverse results without unduly delaying an application while these factors were reviewed.

C O A S T A L A C T

The Coastal Act of 1976 (SB 1277) sets forth statewide policies for conserving and developing the coastal zone and requires that between 1978 and 1980 each local government within the coastal zone bring its general plan and zoning ordinances into conformity with the statewide coastal policies. 123/ The Act establishes policies on public access, recreation, development, and protection of marine and land resources in the coastal zone. While these subjects must be addressed in the general plan, the Coastal Act specifies the content of the policies which coastal jurisdictions must implement through their general plans.

The Coastal Act requires a permit for any development within the coastal zone. In the initial states of implementing the Act, these permits will be granted by the State Coastal Commission. After local governments develop Local Coastal Plans (LCPs) and the state commission certifies them as adequate, the permit authority will be delegated to local governments. The state commission will continue to assure that LCPs are consistent with Coastal Act policies and to review and approve LCP amendments before they take effect.

State coastal development permits must be obtained in addition to any other permits required by state or local law. Thus, until LCPs are certified, the Coastal Act adds another permit requirement. Once a local government obtains approval of its LCP, however, the coastal permit should create no delay beyond that currently found in local land-use decisions, because local governments can choose to proceed concurrently on conditional use and coastal development permits, or to rely exclusively on conditional use permits, so long as they incorporate the substance of statewide coastal policy.

Even with an approved LCP, the devolution of permit authority to local government is not absolute. Local decisions concerning any "major energy facility" or involving a conditional use permit may be appealed to the State Commission. This means, in practice, that virtually all permit decisions for OCS-related onshore development will be subject to appeal. The Coastal Act anticipates that in some cases the State's role may be even more intrusive than merely to decide permit appeals. Where an LCP is unduly restrictive, the State Commission may step in and amend it to facilitate energy siting upon a finding:

> that a public need of an area greater than that included within the certified local coastal program would be met, that there is no feasible, less environmentally damaging way to meet such need, and that the proposed amendment is within the policies of (the Act). 124/

Depending on the circumstances, any of the general Coastal Act policies regarding beach access and protection of the land and marine environment may apply to a proposed OCS-related development. There are five policies, however, explicitly aimed at shaping OCS-related development. Section 30232 calls for "protection against the spillage of crude oil, gas (and) petroleum products" and "effective containment and cleanup facilities and procedures" for spills that do occur. Section 30250 expresses a preference for new industrial development "within, contiguous with, or in close proximity to" existing developed areas. Section 30260 recignizes the need for accommodating "coastal dependent facilities" and provides that they "shall be encouraged to locate or expand within existing sites and shall be permitted reasonable long-term growth." Two additional sections express opposition to the proliferation of single-company, single-purpose facilities along the coast. Section 30261 calls for "multicompany use of existing and new tanker facilities...to the maximum extent feasible and legally permissible." Section 30262 provides for the accommodation of oil and gas development when "new or expanded facilities" are "consolidated to the maximum extent feasible and legally permissible" in order to reduce the number of wells, support facilities and sites necessary for economic production.

It is not yet possible to determine the effect of these policies. They will undoubtedly be elaborated on a case-by-case basis as they are applied by local governments and the State Commission to establish permit conditions for particular development proposals. One apparent problem with the case-by-case approach is that some of the policies, such as consolidation, cannot be carried out in a vacuum by one local government. The configuration of leases from previous sales in the Santa Barbara Channel and from Lease Sale #35 suggests two potential areas for cross-jurisdictional cooperation. In the eastern end of the Santa Barbara Channel, operators from several units have indicated the technical feasibility of landing and processing crude in either Santa Barbara or Ventura Counties, suggesting the desirability of cooperative planning to encourage consolidation without necessitating

the intervention of the State Commission for that purpose. Similarly, production from the leases in San Pedro Bay can be feasibly landed in either Los Angeles or Orange County. Cooperative planning will be necessary to implement Coastal Act policies with regard to this development.

AIR QUALITY PERMITS

In addition to other required state and local development approvals, onshore processing, storage, and transportation facilities with any air emissions may also require one or more air-related permits. These are discussed in Part Four, Chapter III.

BRIDGING THE GAP: CZMA

The CZMA was enacted in 1972 to encourage states to develop comprehensive Coastal Zone Management Programs. 125/ That Act provides federal financial assistance to states for the purpose of developing both coastal zone planning and management programs. In addition to federal financial assistance, one of the incentives for state participation was the promise of a new federal-state partnership through which federal programs and decisions affecting the coastal zone would be coordinated and made consistent with the state's program when it matured from the planning into the implementation phase. California is now at the crossroads between planning and implementation. The development of the California Coastal Plan and the work currently being undertaken by the Coastal Commission pursuant to the recent Coastal Act (SB 1277) have been supported by planning grants under Section 305 of the CZMA. Passage of the Coastal Act should qualify California for management grants under Section 306 of the CZMA as soon as the federal office of Coastal Zone Management approves the state's management program. That approval will trigger application of the Act's so-called "consistency provisions" to federal programs, activities, licenses, permits, and grants within or affecting California's coastal zone.

The CZMA requires federal programs and activities to be consistent with states' coastal programs and sets out procedures for determining whether they are or not. The Act creates a mechanism to review both the lease sale and subsequent permits for consistency with the state plan. Section 307(c)(1) of the Act provides:

> Each Federal agency conducting or supporting activities directly affecting the coastal zone shall conduct or support those activities in a manner which is, to the maximum extent practicable, consistent with approved state management programs.

This brings the initial federal decisions regarding timing, size, location, and conditions of a lease sale within the consistency provisions of the Act. In addition, the CZMA has always contemplated that individual decisions, below the general program level, would also be tested for consistency. The 1972 Act contained general language requiring a certification of consistency by "any applicant for a required federal license or permit to conduct an activity affecting land or water uses in the coastal zone...." 126/ This language would have probably applied to OCS operators, but it has been superseded by Section 307(c)(3)(B) in the 1976 CZMA Amendments which addresses OCS operating permits directly and requires that OCS exploration and development plans be consistent with the states' coastal program.

"CONSISTENCY" FOR LEASE SALES

At first blush, the general consistency requirement for "federal activities" (Section 307(c)(I)) seems to provide a major new tool for California to review and shape all or part of an adjacent offshore leasing program. Issues that might be appropriate for resolution at this stage include the deletion of particular tracts or areas because their development is incompatible with state environmental concerns or the inclusion of lease stipulations regarding pipeline corridors, schedules for timing development, or location and operation of onshore facilities to promote consolidation or otherwise assure compatability with state policies. A detailed analysis of the Act and its implementing regulations, however, points out major procedural and substantive hurdles qualifying that conclusion.

LEGAL HURDLES

The substantive mandate of the CZMA is that each federal agency "conducting or supporting activities directly affecting" a state's coastal zone shall do so in a manner "which is, to the maximum extent practicable, consistent with an approved state implementation program" (emphasis added). In the case of a lease sale, the first question is whether a sale alone is an activity which directly affects the coastal zone. That subsequent activities like drilling, platform placement, and transportation and processing -- which can occur only after a sale -- may affect the coastal zone is patent; but it is not self-evident that the sale alone has a direct effect. The second question -- whether the leasing program is consistent "to the maximum extent practicable" -- becomes a real issue only if a court can first be persuaded that a sale alone directly affects the state's coastal zone.

The Office of Coastal Zone Management (OCZM) has proposed a strict definition of maximum practicable consistence to restrict the loopholes through which federal agencies might attempt to squeeze past state requirements. 127/ The thrust of the OCZM implementing regulations is unambiguous; it is to forcefully encourage federal agencies, insofar as that can be justified within their basic mandate, to tailor their activities so that the concerns of coastal states and local governments are fully reflected. Between this noble intention and its successful execution, however, lies a legal, political and administrative briar patch.

SETTLING DISPUTES

When conflicts between federal and state programs arise and the affected agencies can reach an agreement, there is no problem. Where such an amicable resolution is not obtained, however, a key concern for the State of California and local governments is whether they can enjoin an action, such as a lease sale, which they have determined to be inconsistent with state policies.

The 1972 CZMA established no mechanism to enforce the consistency clause regarding federal activities or to appeal federal decisions made over state objections. It was presumably intended that where a compromise could not be negotiated, the aggrieved state or local government would proceed directly to federal court for judicial relief. In the 1976 CZMA Amendments, Congress cut off this easy access to judicial review and brought consistency disputes within the mediation process established for approving initial state plans. To implement this provision, the OCZM has proposed an elaborate procedure which must be followed before going to court.

OCZM's proposal includes a mandatory negotiation period, a formal administrative hearing, a "mediation conference" and proposed decision by the Secretary of Commerce, a review of the decision by OMB, and finally, a determination by the Secretary of Commerce whether the proposed federal action is consistent with the state program or not. 128/ The San Francisco Bay Conservation and Development Commission (BCDC) estimates that at a minimum, the mediation process will take eight months. 129/ At the end of the process, even if a state prevails, there may be no final resolution. The Secretary of Commerce has no authority to halt any federal activity. Thus, if he finds that an activity is inconsistent with a state's program, he merely reports that decision to the President for transmittal to Congress. In the meantime, while the mediation is underway, the federal agency may proceed with its program. Since state concurrence with a determination of consistency is not a precondition to any federal activity, and the Secretary has no direct authority over other federal agencies, a state may ultimately have to proceed to court for an enforceable judgment if no settlement is reached.

The BCDC, reflecting its own position and that of Coastal Commission staff, strongly objected to the "cumbersome, protracted process" proposed in the regulations:

> (They) will render the consistency provisions unuseable for all but those agencies with large staffs and plenty of time to devote to this kind of thing. Neither BCDC nor the Coastal Commission has either the staff or the inclination to expend our very limited resources in this fashion when the end result is at best a recommendation to the President that he make a report to Congress.... (T)hese regulations permit federal agencies to bury disagreement over consistency in a process that because of its length and complexity almost guarantees a lack of federal accountability. 130/

Despite the complexity of the mediation process, the OCZM defends the basic approach on two primary grounds. The first defense is that the CZMA amendments require mediation and may encourage compromise settlements since, if a judicial relief were available at the outset, "a federal agency extreme position" and "a state extreme position" would be offered the court without the benefit of "the findings, guidelines for review, proposed resolutions, and final determinations developed by the Secretary who is charged with administering the National Coastal Zone Management Program." 131/ The second response is that despite its complexity, the process provides for consistency determinations in a neutral forum before the Secretary of Commerce that will ultimately better serve state interests than review procedures established by interested federal agencies whose activities are being challenged.

CONCLUSIONS

Final conclusions concerning the impact of the CZMA on the Department of Interior OCS leasing program are still premature. The consistency provision does not change the basic position of the state with regard to its ability to influence the timing, size, location, and special lease conditions of an OCS lease sale. Those decisions are still exclusively federal decisions. To challenge them in any way, a state must carry the burden of demonstrating their inconsistency with the coastal plan and pursuing the matter through a protracted mediation procedure whose outcome is not binding even if the state prevails. The mediation process, however, may provide a workable framework for resolving differences where there is good faith among the parties. The key to that resolution lies not so much in recourse to the provisions of the CZMA, as in the willingness of the Interior Department to cooperate with a state when conflicts are identified.

CONSISTENCY FOR EXPLORATION AND DEVELOPMENT PLANS

The CZMA establishes two different procedures through which the consistency of proposed developments can be checked against state coastal policies. OCS operators have the choice of either procedure in seeking approval. Since California's Coastal Program has not yet been approved by OCZM and thus the consistency requirements are not yet in effect, there is no experience to indicate which of the alternative routes will be invoked by operators seeking state certification that their proposals are consistent with coastal policies.

The 1972 Act provided that federal "licenses and permits" for activities affecting the coastal zone could be issued only following a determination that the activity was consistent with an approved coastal program. 132/ Although there is no explicit legislative history on the point, it is reasonable to infer that federal approvals for exploration and development plans would have been covered by the general term "licenses and permits." Other approvals, such as pipeline and platform location permits from the U.S. Army Corps of Engineers, would clearly fall within the consistency provisions. The 1976 amendments to the CZMA eliminated all ambiguity about the inclusion of exploration and development plans within the consistency provisions of the Act. Section 307(c)(3)(B) provides that any person submitting an OCS exploration or development plan to the Secretary of Interior shall:

> attach to such plan a certification that each activity which is described in detail in such plan complies with (the affected) state's approved management program and will be carried out consistent with such program. No federal official or agency shall grant such person any license or permit for any activity described in detail in such plan until such state or its designated agency receives a copy of such certification and plan, together with any other necessary data and information and until --
>
> (i)(ii))(The state actually or presumptively concurs in the certification or consistency), or
>
> (iii) the Secretary finds...that each activity which is described in detail in such plan is consistent with the objectives of this title or is otherwise necessary in the interest of national security. (emphasis added)

Thus, an operator can proceed under the 1976 amendments to obtain a single state review of his development based upon detailed descriptions of proposed activities in the exploration and development plans, or he can seek approvals piecemeal under the 1972 procedure as various federal permits are required. In either case, the state role is stronger than that provided with regard to "federal activities" discussed above. Instead of putting the burden on the state to demonstrate that a proposed action is inconsistent and to enforce such a determination, the burden here is on the applicant to demonstrate that the action is consistent. Further, unlike the case with federal activities where an activity may continue pending the outcome of a consistency determination, the finding of consistency is here a pre-condition to the issuance of a license or permit. The provisions, however, by no means constitute a state veto of federally permitted activities. In the case most likely to arise from OCS development, the Secretary of Commerce may override a state's objection if it is found that "the activity is consistent

with the objective of this title...." The OCZM views this procedure as a "variance" and has proposed regulations consistent with that view. 133/ To override a state's objection, the Secretary must first find that the activity is consistent with the broad purposes of the CZMA. This is an imprecise standard with a great deal of discretion since the purposes include, among others, the conflicting directives "to preserve, protect, develop, and where possible, to restore or enhance the resources of the Nation's coastal zone for this and succeeding generations...." 134/ The refinement proposed in OCZM regulations is a requirement that the Secretary find, in addition, that the activity would "not have a significant negative impact upon the integrity of the Management program" and that requiring consistency would "impose an unreasonable burden upon the applicant." 135/

For disputes between a state and an applicant, the administrative procedure is almost identical to that provided for disputes between a state and a federal agency over the consistency of the agency's activity. The only difference is that appointment of a hearing officer is optional, and OMB is not consulted. The Secretary's decision is final for purposes of judicial review.

The interaction of the general 1972 provision for "licenses and permits" and the 1976 amendment for exploration and development plans may vary from case to case. The 1976 provision exempts each activity "described in detail" in an approved exploration or development plan from any further consistency review. This allows OCS operators the option of seeking a one-stop consistency review for all the federally permitted aspects of their operations or of presenting each successive phase of the development piecemeal for review as a new federal permit is required.

Interior Department regulations concerning exploration and development plans pave the way for piecemeal review by narrowly circumscribing the scope of those documents to exclude production schedules, transportation plans, and onshore development. Exploration and development plans are defined to include:

1) description of the drilling vessel or platform;
2) general location of each well;
3) structural interpretations based upon available data; and,
4) other data prescribed by the USGS Area Supervisor. 136/

OCS order #15 does require lessees to provide the state with information concerning onshore facilities and operations expected to accompany proposed development. This information is purely advisory, however, since Interior Department regulations define "development plan" 137/ so narrowly that associated facilities are excluded from consistency review.

Because of the narrowness of the issues that must be offered for state review in exploration and development planning, the 1976 CZMA amandments have provided little substantive change in the state's role from that previously established through license and permit review under the Act. The primary difference seems to be that the Act now affords a lease operator the opportunity to seek a comprehensive consistency review for all required federal permits at an early stage, if he so desires. Operators, however, need not seek an early review and may proceed seriatim seeking an additional certification of consistency at each step where a federal permit is required.

From an operator's perspective, there are some difficulties with an early mandatory review. Planning is a process of discarding old proposals and generating new ones as exploratory work provides increasingly more reliable information upon which the economics of various alternative development patterns can be assessed. In this climate of uncertainty, operators often see little benefit from early discussion which tends to commit them to any particular proposal for development. The problem, from a public planner's perspective, is that the lack of an early mandatory review forces piecemeal consideration of development without an opportunity to assess cumulative effects or to gauge the realistic range within which plans are uncertain or may be modified. The CZMA amendments of 1976 offer the operator a chance to seek one early review by the state. But that review may come too early in the development process to allow him to provide sufficient detail on proposed activities so that the state could approve the proposal and waive further opportunities to comment and assess the consistency of the development with coastal policies.

CONCLUSION

CZMA provisions allowing the state to certify the consistency of development plans and federal permits, despite their inherent limitations, should nevertheless provide a significant new tool for reviewing offshore proposals. The potential can be seen by looking back at what might have happened had the procedure been available when the Interior Department approved Exxon's floating plans for a storage and terminal facility just outside state waters on the Santa Ynez Unit. The ground for the decision was that California failed to offer a permit under "reasonable" terms after Exxon's "good faith effort" to obtain one. That determination by the Secretary of Interior was made without any formal proceeding which allowed the state to present its case on the necessity or reasonableness of the permit conditions offered. Implementation of the consistency provisions of the CZMA should provide both a process and the substantive grounds for resolving disputes of this type to better reflect the state's coastal management objectives.

FOOTNOTES

1. U.S.C. 1331 et seq.

2. Don Kash, et al., Energy Under the Oceans (Norman, Oklahoma: University of Oklahoma Press, 1973), pp. 27-28.

3. Congressional Research Service, Effects of Offshore Oil and Natural Gas Development on the Coastal Zone (Washington, D.C.: Government Printing Office, 1976), pp. 68-70; Department of the Interior, Leasing and Management of Energy Resources on the Outer Continental Shelf (Washington, D.C.: GPO, 1976), pp. 13-14.

4. Department of the Interior, op. cit., pp. 14-15.

5. 30 C.F.R., Federal Register, 40 (June 23, 1976), pp. 25893-25897.

6. M. V. Adams, et al., Mineral Resource Management of the Outer Continental Shelf (Washington, D.C.: GPO, 1975), Geological Survey Circular 720, pp. 7-8.

7. Committee on Appropriations, U.S. House of Representatives, Hearings on Department of the Interior and Related Agencies Appropriations for 1977, Part 4 (Washington, D.C.: GPO, 1976), pp. 131-33.

8. General Accounting Office, Outlook for Federal Goals to Accelerate Leasing of Oil and Gas Resources on the Outer Continental Shelf (Washington, D.C.: GPO, March 19, 1975), pp. 8-10.

9. 42 U.S.C. 4321 et seq.

10. Federal Register, 40 (October 1, 1976), p. 45171.

11. 43 C.F.R. Part 3300.

12. 43 C.F.R. Part 3304.1.

13. 43 U.S.C. 1337(b)(3); 67 Stat. 464, 8(b)(3).

14. 43 U.S.C. 1334(a)(1); 67 Stat. 464, 5(a)(1).

15. Ibid.

16. Union Oil v. Morton (9th Cir., 1975), 512 F.2d 743, 749, citing Gulf Oil v. Morton (9th Cir., 1973), 493 F.2d 141.

17. 30 C.F.R. Parts 250.2(j), 250.11.

18. 30 C.F.R. Part 250.11.

19. 5 U.S.C. 551 et seq.

20. 30 C.F.R. Part 250.31.

21. 30 C.F.R. Part 250.34(a).

22. 42 U.S.C. 433s(c); 83 Stat. 852, 102(2)(c).

23. 40 C.F.R. Part 1500.6.

24. 30 C.F.R. Parts 250.34, 250.41, 240.91; Kash et al., op. cit., p. 44; Irvin M. Waitsman, Summary of Federal Responsibilities in Oil and Gas Leasing on the Outer Continental Shelf (Boston: New England River Basins Commission, December, 1974), p. 7.

25. 43 U.S.C. 1333(f); 67 Stat. 463, 4(f).

26. 33 U.S.C. 1343, 40 C.F.R. Part 125.

27. Memorandum of G. William Frick, General Counsel, to Rebecca W. Hanmer, Director of Federal Activities, dated September 23, 1976.

28. 43 U.S.C. 1333(e)(1).

29. Pacific OCS Order No. 4.

30. 30 C.F.R. Part 250.44.

31. Pacific OCS Order No. 3.

32. 30 C.F.R. Part 250.34(b).

33. Department of the Interior, U.S. Geological Survey, Final Environmental Statement, Proposed Plan of Development, Santa Ynez Unit, Santa Barbara Channel, Off California (Washington, D.C.: GPO, 1974).

34. Department of the Interior, U.S. Geological Survey, Final Environmental Statement, Oil and Gas Development in the Santa Barbara Channel, Outer Continental Shelf Off California (Washington, D.C.: GPO, 1976).

35. Federal Register, 40 (November 4, 1975), p. 51199.

36. U.S.C. 1333(f); 67 Stat. 463, 4(f).

37. 43 U.S.C. 1333(3)(1).

38. 29 U.S.C. 653(a).

39. 29 U.S.C. 651 et seq.

40. Mikeael F. Reitz, U.S.G.S., Ventura, personal communication to Bill Deller, OCS Project staff; Lt. Commander Foster Thompson, Coast Guard, personal communication dated November 29, 1976, to Bill Deller, OCS Project staff; J. Ray McDermott, OSHA, personal communication dated December 1, 1976, to Bill Deller, OCS Project staff.

41. Don Kash, et al., op. cit., pp. 64-66.

42. 43 U.S.C. 1334(c), 43 C.F.R. Part 2883.

43. 49 U.S.C. 1(1)(b).

44. 15 U.S.C. 717, 717 f.

45. Don Kash, et al., op. cit., pp. 66-67.

46. 33 U.S.C. 403, 43 U.S.C. 1333(f); 33 C.F.R. Part 209.

47. 33 U.S.C. 1344; 33 C.F.R. Part 209.

48. 33 U.S.C. 1413; 33 C.F.R. Part 209.

49. 49 C.F.R. Parts 190-195; 82 Stat. 720, 3a; 49 U.S.C. 1671 et seq.; 80 Stat. 937, 6; 18 U.S.C. 831-835; 49 U.S.C. 1655.

50. Maury Adams, U.S.G.S., April 5, 1977.

51. Don Kash, et al., op. cit., p. 63.

52. 33 U.S.C. 1224.

53. 33 U.S.C. 403, 43 U.S.C. 1333(f); 33 C.F.R. Part 209.

54. Letter from Resources Secretary Claire T. Dedrick to Col. Hugh G. Robinson, Los Angeles District Engineer, December 2, 1976.

55. "U.S.C.G. Must Explain San Pedro--Sealane Stance," The Oil and Gas Journal, 74 (February 2, 1976), p. 52.

56. M. V. Adams, et al., op. cit., p. 24.

57. Ibid., p. 24.

58. Ibid., p. 25, 43 U.S.C. 1334(a)(1); 30 C.F.R. 250.50; Union Oil v. Morton (9th Cir., 1975) 512 F.2d 743, 749, citing Gulf Oil v. Morton (9th Cir., 1973) 493 F.2d 141. (Regulations relating to unitization are at 30 C.F.R. 250.50, and 30 C.F.R. Part 126.)

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60. 30 C.F.R. Part 250.38.

61. 30 C.F.R. Part 250.93.

62. 30 C.F.R. Part 250.97, Federal Register, 41 (June 23, 1976), p. 25893.

63. Department of the Interior, U.S. Geological Survey, Final Environmental Statement, Oil and Gas Development in the Santa Barbara Channel, Outer Continental Shelf Off California (Washington, D.C.: GPO, 1976), III, pp. IV-33 to IV-37.

64. Ibid., pp. IV-35 to IV-38.

65. Pacific OCS Order 12, Michael F. Reitz, U.S.G.S., Ventura, personal communication to Bill Deller, OCS Project staff.

66. U.S. General Accounting Office, Outer Continental Shelf Sale #35--Problems Selecting and Evaluating Land to Lease (Washington, D.C.: GPO, 1977), p. 29.

67. Ibid., pp. 30-31.

68. OCS Tract Selection for General Oil and Gas Lease Sales (GS-BLM), dated August 19, 1971, reproduced in U.S. Department of the Interior, Regulations Pertaining to Mineral Leasing, Operations and Pipelines on the Outer Continental Shelf (Washington: 1975), p. 75.

69. U.S. General Accounting Office, op. cit., p. 20.

70. Ibid., p. 21.

71. 43 U.S.C. 1331 et seq.; 67 Stat. 462.

72. 43 U.S.C. 1334(a)(1).

73. Union Oil Co. v. Morton (9th Cir., 1975) 512 F.2d 743, 749, citing Gulf Oil v. Morton (9th Cir., 1973) 493 F.2d 141.

74. 43 U.S.C. 1334(b)(2), Union Oil v. Morton (9th Cir., 1975) 512 F.2d, 743, 747.

75. 43 U.S.C. 1334(b)(1).

76. 43 U.S.C. 1334(a)(2).

77. 43 U.S.C. 1337(i).

78. 43 U.S.C.1334(a)(1); 30 C.F.R. Part 250.12.

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81. Ibid., p. 749.

82. See memorandum of September 26, 1975, from Jay L. Shavelson, Assistant Attorney General, State of California, to Preble Stolz, Director, Office of Planning and Research; and memorandum dated October 31, 1975, from Assistant Solicitor for Minerals Frederick N. Ferguson on Authority to terminate OCS oil and gas leases.

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84. Ibid., p. 22.

85. 16 U.S.C. 1451 et seq., as amended by P.L. 94-370, 90 Stat. 1013.

86. 30 C.F.R. Part 250; Don Kash, et al., op. cit., p. 152.

87. 43 U.S.C. 1334.

88. 5 U.S.C. 552.

89. 5 U.S.C. 552(b).

90. Pennzoil Oil v. Federal Power Commission (5th Cir., 1976) 534 F.2d 627.

91. Ibid., p. 632.

92. Ibid., p. 630.

93. Ibid.

94. Ibid., p. 632.

95. National Parks and Conservation Association v. Morton (D.C. Cir., 1974) 498 F.2d 765; Westinghouse Electric Corp. v. Schlesinger (46th Cir., 1976) 542 F.2d 1190 (U.S. appeal pending).

96. Charles River Park "A," Inc., v. Department of H.U.D. (D.C. Cir., 1975) 519 F.2d 935, 942.

97. See Westinghouse Electric Corp. v. Schlesinger (4th Cir., 1976) 542 F.2d 1190, 1201, n. 27 (U.S. appeal pending).

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99. See, e.g. Sears, Roebuck and Co. v. General Services Administration (D.C. Cir., 1974) 509 F.2d 527; Grumman Aircraft Engineering Corp. v. Renegotiation Board (D.C. Cir., 1970) 425 F.2d 578; and M.A. Schapiro v. S.E.C. (DDC, 1972) 339 F. Supp. 467.

100. Westinghouse v. Schlesinger, supra.

101. FAA Administrator v. Robertson (1975) 422 U.S. 255, 45 L.Ed.2d 164, 95 S. Ct. 2140.

102. Crown Central Petroleum Corp. v. Kleppe (Md. D.C., 1976) 424 F. Supp. 744.

103. Ibid., p. 752.

104. 30 C.F.R. Parts 250.97, 251, Federal Register, 41 (June 23, 1976), pp. 25891-25897.

105. 30 C.F.R. Part 250.34.

106. Proposed OCS Order 15, Federal Register, 41 (October 20, 1976), p. 46355.

107. 42 U.S.C. 4321 et seq.; U.S. Department of the Interior, Bureau of Land Management, "Marine Environmental Study Plan for the Southern California Outer Continental Shelf Area Southern California Borderland Region," October 15, 1976, pp. 2-3.

108. Ibid.

109. Memorandum to Chairman, Outer Continental Shelf Environmental Studies Advisory Committee from Donald Truesdale, Assistant Director, Minerals Management, U.S. Department of the Interior, Bureau of Land Management, November 5, 1976.

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116. Ibid., p. 133.

117. Ibid., p. 42.

118. See Annual Report 1976, Outer Continental Shelf Environmental Studies Advisory Committee, U.S. Department of the Interior, February 28, 1977, p. 7, for discussion of origin, organization, and functions of National OCS Advisory Board and Outer Continental Shelf Environmental Studies Advisory Committee.

119. See "Potential Petroleum Development on the Central and Northern California OCS: The Need for a Coordinated Environmental Studies Program in a Frontier Area," statement by Dr. James W. Rote, Assistant Secretary for Resources, California Resources Agency, October 22, 1976; and Annual Report 1976, Outer Continental Shelf Environmental Studies Advisory Committee, U.S. Department of the Interior, February 28, 1977, for recommendations to improve the Environmental Baseline Studies Program.

120. Bureau of Land Management and Office of Coastal Zone Management, State Information Needs (Washington, D.C.: GPO, 1976).

121. Personal communication from Ralph W. Johnson, Professor of Law, University of Washington, to Suzanne Reed, Governor's Office of Planning and Research, July 7, 1977.

122. Cal. Govt. Code, §65100 et seq.

123. Cal Pub. Res. Code, §3000 et seq.

124. Cal. Pub. Res. Code, §30515.

125. 16 U.S.C. 1451 et seq.

126. Coastal Zone Management Act, §307(c)(3).

127. "That a federally conducted or supported activity ... be consistent with a management program except to the extent that deviation therefrom is justified because: (1) some circumstance arose after the approval of the management program which was not foreseen at the time of the approval, and (2) a consistent action would thereafter impose an unreasonable burden on the federal agency in relation to the negative impact of the deviation on the integrity of the management program."

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129. Correspondence from Charles R. Roberts, Executive Director, Bay Conservation and Development Commission, to Robert Knecht, Director, Office of Coastal Zone Conservation Commission, September 14, 1976.

130. Ibid.

131. Correspondence from Robert Knecht to Charles R. Roberts, October 13, 1976.

132. Coastal Zone Management Act, §307(c)(A).

133. Federal Register, 41 (September 28, 1976), p. 42883.

134. Coastal Zone Management Act, §303(a).

135. Federal Register, 41 (September 28, 1976), p. 42878, §921.1(p).

136. 30 C.F.R. Part 250.34(a)(b).

137. 30 C.F.R. Part 250.34(c).

CHAPTER 14

THE RESOURCE BASE: EDUCATED GUESSES

It has long been known that the sedimentary basins off southern California contain substantial amounts of recoverable oil and gas. In state waters, in fact, recovery of oil and gas has proceeded since 1896, and several fields have been in continuous production for more than 50 years (Table 1). Development of the oil and gas resources in state waters is now essentially complete. After peaking in the late 1960s, production is now about 175,000 B/D oil and 60,000 MCF/D natural gas, and will decline in the future. 1/

Exploitation of the oil and gas resources in federal waters off California, however, is just getting underway, although the first California OCS leases were sold in 1966 and 1968. Development of these leases was delayed for several years after the Santa Barbara Channel blowout, and only two OCS fields are now in production, producing about 40,000 B/D oil and 15,000 MCF/D natural gas. Exploratory drilling has been undertaken on only half of the 65 active leases in the Channel OCS. Recently, the Interior Department lifted its restrictions, and the pace of exploration and development in the Channel is accelerating. In the 1980s, Channel OCS production will exceed 100,000 B/D oil and 100,000 MCF/D natural gas, and could reach double those amounts.

Lease Sale #35 opened up the remainder of the southern California OCS for oil and gas development. Exploratory drilling is underway on the San Pedro Bay and Tanner Banks leases. One discovery has already been certified by the U.S. Geological Survey, 2/ and the prospects for additional discoveries are good. Another California OCS lease sale has been proposed for the spring of 1978.

OCCURRENCE OF PETROLEUM

In order for an oil or gas field to exist, a series of general conditions must obtain. 3/ There has to be a source rock in which the petroleum is formed, a reservoir rock from which the petroleum can be extracted, a cap rock which keeps the petroleum in the reservoir rock, and a structure or trap which concentrates the petroleum within the reservoir rock.

Petroleum is created in sedimentary rocks. The original sediments must be rich in organic compounds and must be buried before the organic material can be oxidized. If the sediments are buried at sufficient depth (on the order of thousands of feet), temperature and pressure will increase to the point where the organic compounds are converted into petroleum hydrocarbons. The nature of the hydrocarbons formed -- oil, gas, condensate, etc. -- depends on the temperature and pressure in

TABLE 1:
CALIFORNIA TIDELANDS OIL AND GAS FIELD STATISTICS*

FIELD	YEAR OF FIRST PRODUCTION	YEAR OF PEAK PRODUCTION	PEAK ANNUAL PRODUCTION	PEAK DAILY PRODUCTION	1975 AVERAGE DAILY PRODUCTION		CUMULATIVE PRODUCTION		ESTIMATED RESERVES	
					Oil (B/D)	Gas (MCF/D)	Oil (B/D)	Gas (MCF/D)	Oil (B/D)	Gas (MCF/D)
SANTA BARBARA CHANNEL										
Alegria	1962	1970	77,033 BBL	211 B/D	81	213	451,434	3,382,167	392,000	468,000
Caliente	1962	1967	4,284,901 MCF	11,740 MCF/D	-	948	-	3,646,417	-	2,385,000
Carpinteria	1966	1969	10,435,543 BBL	28,590 B/D	3,979	4,742	22,207,611	19,234,051	12,133,000	10,919,000
Coal Oil Point	1961	1966	232,136 BBL	636 B/D	37	122	1,289,085	3,178,884	81,000	201,000
Elwood	1929	1931	7,769,859 BBL	21,287 B/D	115	542	76,475,704	66,171,624	30,000	1,328,000
Gaviota	1960	1964	8,994,473 MCF	24,692 MCF/D	-	8	-	69,921,000	-	279,000
Molino	1962	1967	30,576,437 MCF	83,771 MCF/D	-	9,242	-	223,771,366	140,000	13,829,000
Point Conception	1965	1970	153,617 BBL	420 B/D	209	107	842,486	330,245	580,000	200,000
Rincon	1928	1960	1,271,457 BBL	3,483 B/D	1,094	576	29,841,999	31,279,409	6,158,000	1,703,000
South Elwood	1965	1968	1,929,085 BBL	5,285 B/D	3,277	-	9,903,377	7,689,900	63,182,000	89,848,000
Summerland	1958	1964	3,792,551 BBL	10,390 B/D	711	3,639	24,478,351	85,075,136	6,585,000	19,816,000
West Montalvo	1953	1958	608,693 BBL	1,668 B/D	235	-	5,322,056	3,242,723	578,000	-
					9,738	20,139	171,000,000	717,000,000	90,000,000	132,000,000
LOS ANGELES BASIN										
Belmont	1947	1968	4,295,682 BBL	11,769 B/D	6,720	1,647	41,226,757	31,567,788	11,637,000	3,532,000
Huntington Beach	1930	1972	16,092,650 BBL	45,733 B/D	36,820	4,896	445,772,417	287,511,711	104,278,000	15,888,000
Torrance	1956	1958	857,170 BBL	2,348 B/D	1,256	1,690	5,474,590	4,646,906	2,826,000	3,983,000
Venice	1966	1968	445,162 BBL	1,247 B/D	320	134	2,178,868	1,223,105	321,000	172,000
West Newport	1953	1957	352,539 BBL	966 B/D	287	107	4,024,187	1,309,848	979,000	270,000
Wilmington	1939	1969	64,775,754 BBL	177,468 B/D	120,836	26,966	835,953,144	437,695,427	366,047,000	98,157,000
				SUB-TOTAL	166,249	35,440	1,335,000,000	764,000,000	486,000,000	122,000,000
				GRAND TOTAL	175,987	55,579	1,506,000,000	1,281,000,000	576,000,000	254,000,000

*Statistics supplied by California Division of Oil and Gas, California State Lands Division, and the Conservation Committee of California Oil Producers.

the source rock, as well as the length of time the organic compounds are exposed to these conditions. For example, heavy crude oils are thought to be relatively "young" hydrocarbons, while natural gas and carbon are regarded as more "mature."

After formation, some petroleum hydrocarbons may migrate from their original source rock locations, either through pore spaces in the rock or along fractures caused by faulting or other tectonic activity. If not blocked by impermeable rock layers, hydrocarbons may reach the surface of the ocean floor to form natural seeps. Thousands of natural oil and/or gas seeps exist both offshore and onshore in Southern California.

The rock from which oil or gas can be produced is called reservoir rock. Rocks of reservoir quality exhibit three main characteristics. They have relatively high porosity with open spaces between their constituent mineral grains where fluids may collect. They have relatively high permeability, with the pore spaces interconnected so that fluids can move through the rock. Finally, there must be an impermeable cap rock overlying the reservoir rock to contain the oil and gas within the reservoir rock. Three fluids are often found in reservoir rocks: oil, gas and salt water. Gas, lightest of the three, tends to occupy the highest possible position in the reservoir. Water, the heaviest, tends to lie in the lowest position, with oil somewhere between the two. Sandstone is the most common reservoir rock in California, although fractured shales are prominent in recent discoveries.

The final requirement for the existence of petroleum in commercial quantities is a structure or trap, which accumulates the petroleum. Traps may be structural in origin -- folds, anticlines, domes -- or stratigraphic, or they may occur as a result of faulting activity. Faulted anticlines are the most common trap in California offshore oil and gas fields discovered to date. Oil and gas fields often contain more than one producing zone, and may be formed by more than one kind of trap.

C A L I F O R N I A O F F S H O R E

The southern California OCS is structurally unique among the OCS areas of the United States. Extensive and continuing tectonic activity during the last 20 million years has created a complex pattern of ridges and basins interlaced by a series of active and inactive fault systems. The southern California offshore can be divided for discussion purposes into the Borderland and the Santa Barbara Channel, with the Santa Barbara Channel Islands separating these two distinct regions.

BORDERLAND

The Borderland is characterized by numerous ridges and basins, which in their NW/SE alignment lie generally parallel to the Peninsular mountain ranges on the mainland. 4/ Topographic relief is as much as 7,500 feet, with elevations ranging from almost 1,500 feet above sea level to more than 6,000 feet below sea level. The Borderland itself can be divided into the inner basin area and the outer basin area, separated by the ridge system which includes Santa Catalina Island. The inner basin area includes Santa Monica and San Pedro basins and the San Diego trough. The Santa Monica and San Pedro basins, as extensions of onshore basins with extensive petroleum development, are considered the most promising areas for petroleum discoveries in the Borderland. The Santa Monica basin was excluded from OCS Sale #35. The San Pedro basin tracts, however, were included, and they received the highest bonus bids. They were also the first OCS Sale #35 leases to undergo exploratory drilling.

The petroleum potential of the outer basin area is essentially unknown, in part because the prospective sedimentary basins are not extensions of known coastal basins, and in part because of the great depths encountered in much of the area.

Over 90 % of the Borderland lies in depths greater than 200m (656 feet), and much of it in depths exceeding 500m (1,640 feet). 5/ The world's tallest production platform, recently installed in the Santa Barbara Channel, rises from a depth of 267m (867 feet). Thus, most of the borderland -- including all of the sedimentary basins in the outer basin area -- is beyond the reach of existing or anticipated production systems. Reflecting this constraint, the leases offered in OCS Lease Sale #35 and considered for OCS Lease Sale #48 lie near shore or along the crests of the ridges and banks separating the basins (see Figure 4 in Chapter 22).

The Deep Stratigraphic test well drilled on the flank of the Cortes Ridge, together with limited core samples, provide some information on the petroleum potential of the outer basin area. 6/ The conditions which have permitted substantial oil and gas recovery from the Los Angeles and Ventura coastal basins -- thick sedimentary sections and turbidite reservoir sands -- appear not to exist seaward of Santa Catalina Island. Thus, while petroleum may be found in the outer basin area, it will not be found under the same conditions as in the highly-productive coastal basins. 7/

Potential source and reservoir rocks do, however, exist in the outer basin, and commercial oil and gas fields may well be found. The prospective formations in the outer basin ridges are generally older than their counterparts in the coastal basins. This suggests that outer basin discoveries could be comparatively high in natural gas.

SANTA BARBARA CHANNEL

As the Department of Interior notes, "the Santa Barbara Channel is a tectonic depression that forms the westward extension of the Ventura basin and a submerged part of the Transverse Range province of southern California." 8/

The Channel is an established petroleum province, with 13 offshore oil and gas fields now in production. More than 1,100 offshore wells have been drilled, with some 250 completed as production wells. 9/ Most oil has been taken from upper Miocene and Pliocene sandstones, well over 10,000' thick in the eastern Channel. Dry gas fields have been found only in the western Channel tidelands, where the Pliocene sandstones are much thinner, and where older formations are prospective. Similarly, western Channel OCS discoveries exhibit high gas-oil ratios compared to most eastern channel fields. Monterey fractured shales, which heretofore contributed a very small percentage of production from the Channel region, are the basis for the recent Santa Ynez and Santa Clara unit discoveries and for the expected production increases from the South Elwood field in the Channel tidelands.

The petroleum geology of the shallower portions of the Channel, especially the near-shore eastern channel areas, is reasonably well-known. Deeper water areas -- primarily the central and western channel OCS -- are much less well-known, probably because production technology for these deeper waters does not now exist, but also because the rest of the Channel contains comparable or better prospects in much shallower water.

The leasing patterns in the Channel reflect the generally high petroleum potential of the area, and the problem posed by water depth. Practically all of the tidelands are leased and developed, or reserved in petroleum sanctuaries. Almost half of the Channel OCS has been leased, with most of the leases in the near-shore and eastern portions of the Channel.

Almost all unleased OCS tracts lie in the central and western channel, roughly between Coal Oil Point and Point Conception. Despite the relatively great depths (up to 1,900 ft.) all of these tracts were nominated by oil companies for inclusion in proposed Lease Sale #48, and may be offered for sale in 1978.

HISTORY OF CALIFORNIA OFFSHORE PRODUCTION

TIDELANDS

Offshore production began in California -- and in the United States -- in 1896 in the Santa Barbara Channel, when wells were drilled from piers into the old Summerland field. 10/ The State was neither issuing leases nor collecting royalties, and these wells were drilled under lease from the littoral owners. Drilling was entirely unrestricted until 1921 when, with passage of the California Mineral Leasing Act, the state began issuing permits for oil and gas exploration in the tidelands and submerged lands. The Rincon field was discovered in 1927, and the Elwood and Capitan fields in 1929.

The California Supreme Court's 1928 decision in Boone vs. Kingsbury effectively stripped the State of the power to reject permit applications for tidelands prospecting. Immediately thereafter, the Legislature imposed an interim moratorium on further tideland leases or permits. In 1929, as a result of substantial crude oil overproduction and related beach despoliation, the Legislature prohibited altogether the issuances of new leases for mineral extraction from tide or submerged lands.

In 1851, California began granting tide and submerged lands to political subdivisions of the state, to be held in trust for general commerce, navigation, fisheries and recreation purposes. The City of Long Beach received such a grant in 1911. In 1932, the Wilmington field was discovered, and subsequently found to extend offshore into the tide and submerged lands granted to Long Beach. The California Supreme Court ruled in 1938 that Long Beach had the right to develop the tideland oil reserves, and in 1939 the Long Beach Oil Development Company completed the first production well on such a tideland grant.

In 1938 and 1939, the Legislature created the State Lands Commission and placed the administration of all state lands under its jurisdiction. The Commission was allowed to issue exploration permits, but new oil and gas production were allowed only where the State's submerged lands were being drained by wells on adjacent lands not owned by the State.

During this period, it was generally assumed that the tidelands -- the land between high tide and low tide -- belonged to the adjacent state. As well, most coastal states believed that they owned the submerged lands out to three miles offshore. After World War II, with technology developing to produce oil and gas in ever greater depths, the question of federal-state ownership of offshore resources emerged as a major issue. The Supreme Court ruled in 1947 that the federal government held paramount rights to the lands and minerals of the three-mile strip off the coast of California. Shortly thereafter, an Interim Agreement was negotiated between California and the United States to permit existing offshore operations to continue pending further litigation and possible Congressional action. Under this agreement, the State Lands Commission continued to administer the three-mile strip, with all revenues held in escrow. 11/

In 1953, Congress passed the Submerged Lands Act and the Outer Continental Shelf Lands Act. The first returned jurisdiction of the three-mile strip to the adjacent

coastal state, while the second established a framework for federal administration of the submerged lands lying seaward of the three-mile boundary. The California Legislature responded in 1955 with the enactment of the Cunningham-Shell Act, under which these state offshore lands were opened up for exploration and development.

The Cunningham-Shell Act represented a compromise between the interests advocating on the one hand, unrestrained offshore oil development and on the other, preservation of the scenic and economic values of California's highly-developed coastal zone. State land could be leased, provided that probable drainage of oil or gas from state lands could be demonstrated. The 1955 Act restricted the issuance of new leases to the tidal and submerged lands lying between the City of Newport Beach and a point six miles south of the town of Oceano in San Luis Obispo. Further, certain scenic coastal lands -- and the adjacent state waters -- in Los Angeles, Santa Barbara, and San Luis Obispo counties, and San Clemente and Santa Catalina islands were excluded from future leasing, except where probable drainage could be demonstrated. Finally, the oil and gas resources in state waters from Newport Beach south to the Mexican border were required to be developed by slant drilling from onshore sites, wherever necessary to preserve and protect the highly developed recreational and residential areas.

The 1938 Act provided that wells could be drilled into the state tidelands only from the uplands or from filled lands. A court's liberal interpretation of the term "filled lands" led to deliberate fill-in for the purpose of oil production. Belmont Island was constructed in 1954 to develop the Belmont offshore field. Similarly, Rincon Island was constructed in 1958 to tap the offshore portion of the Rincon field. The Cunningham-Shell Act enlarged the lease terms to permit drilling from platforms or other fixed or floating structures in, on, or over the tidal and submerged lands. In 1958, Chevron and Exxon installed platform Hazel in the Summerland offshore field, the first such platform to be installed in state waters.

OUTER CONTINENTAL SHELF (OCS)

For many years, the boundary between state tidelands and federal OCS lands in the Santa Barbara Channel was in dispute. California argued that the Channel waters constituted "inland waters", so that the three-mile line separating state and federal jurisdiction should be drawn seaward of the Channel Islands. The federal government disagreed, arguing that only the waters and submerged lands for a distance of three miles off the mainland and around each island fell under state jurisdiction. In 1965, the U.S. Supreme Court settled the dispute in favor of the federal government, clearing the way for federal leasing in the Channel OCS.

Before 1965, California had permitted core holes to be drilled in the disputed area of the channel. Information gathered from these wells was closely guarded by the sponsors of each well. In order that a greater number of potential lessees would have comparable information, the Interior Department allowed 53 core holes to be drilled in the Channel OCS between November, 1965 and February, 1968, in the same locations as the earlier state-sanctioned core holes. 12/

The Carpinteria field lies partly in state waters and partly in federal waters. The state portion was brought into production in 1966. This created the possibility of drainage of the federal portion of the field from the state portion. To protect against this, the Interior Department issued on January 1, 1967, a lease for the federal portion of the Carpinteria field. This was the first California OCS lease.

On February 6, 1968, 71 additional Santa Barbara Channel OCS leases were sold. Excluded from the sale was the area extending two miles seaward of the Santa Barbara Petroleum Sanctuary, which was set aside as a Federal Ecological Preserve. Within

six weeks of the lease sale, discovery of the Dos Cuadras field was announced.

On January 29, 1969, a blowout occurred at Union's Platform A in the Dos Cuadras field, resulting in a major oil spill. 13/ In response, the Secretary of the Interior 1) suspended for several months all drilling and production activities on Channel OCS leases (affecting six leases); 2) conducted a safety clearance review of the remaining leases; and 3) established a buffer zone contiguous to and seaward of the Federal Ecological Preserve. Subsequently, the Interior Department turned down applications by Union and Sun to install production platforms in the Dos Cuadras and Carpinteria fields.

Aside from the Dos Cuadras and Carpinteria fields, 15 discoveries or extensions have been announced on the Channel OCS leases. Exxon submitted an initial development proposal for the Hondo field in the Santa Ynez Unit to USGS in 1971. After lengthy review and the release of an Environmental Impact Statement (EIS) on the proposal, the Interior Department approved the plan in 1974. USGS released an EIS on Channel OCS oil and gas development in 1976. In January, 1977, Interior Secretary Kleppe announced his decision that "development of existing oil and gas leases in the Santa Barbara Channel should proceed in accord with existing laws and regulations." 14/ Development proposals for the Hueneme and Santa Clara Unit discoveries have been submitted to the Geological Survey and are now pending.

In December, 1975, the Interior Department held OCS Sale #35 and sold 56 additional California OCS leases. Of these leases, 13 lie in the San Pedro basin, with the remainder in the outer basin area. Exploratory drilling has begun, and a commercial discovery has been announced by USGS for one of the San Pedro basin leases. 15/

Another California OCS Lease sale is proposed by the Interior Department to be held in the spring of 1978. The area of interest includes both the Santa Barbara Channel and the Borderland.

PRESENT STATUS

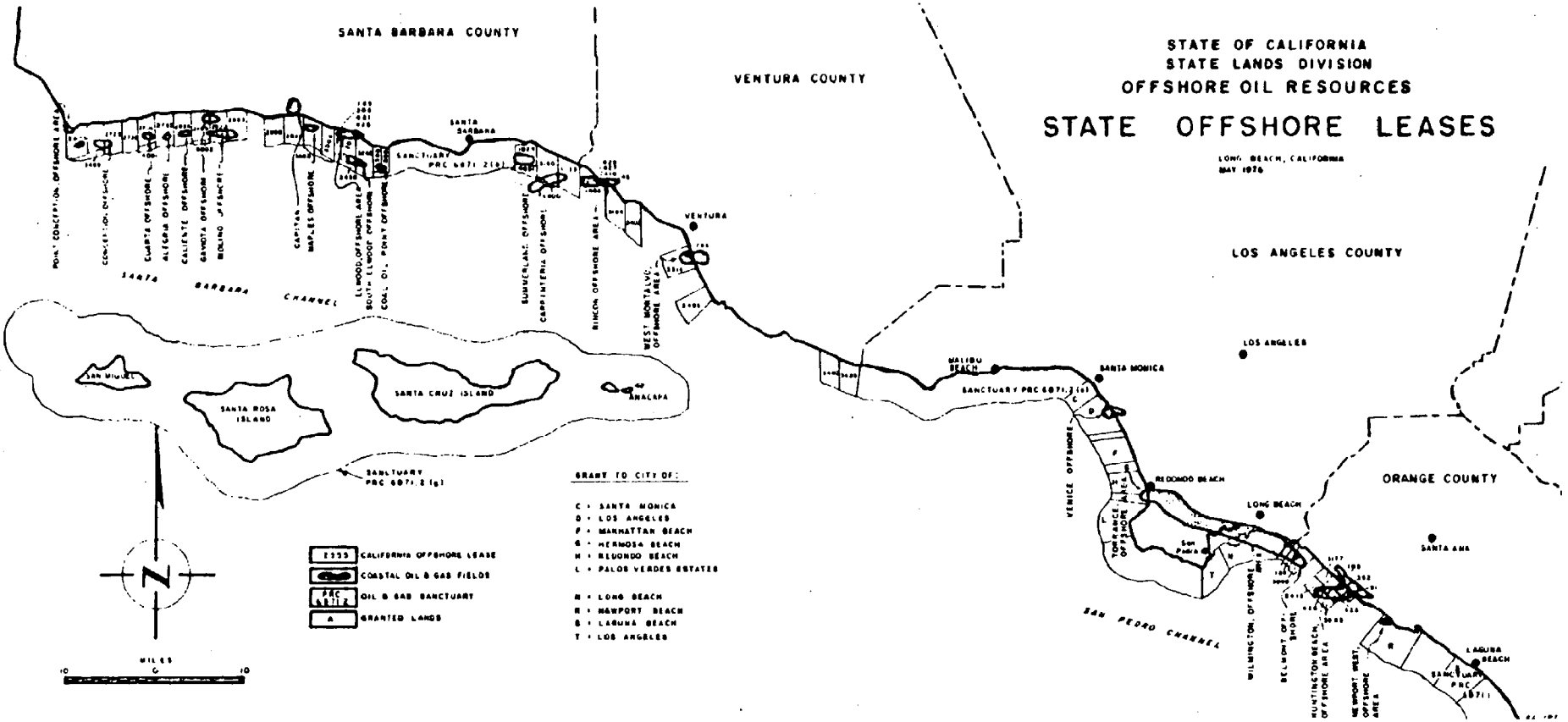
T I D E L A N D S

Development of the state's oil and gas resources off Southern California is essentially complete. Fifteen oil fields and three gas fields are now in production in state waters served by nine platforms, seven artificial islands, and 42 sea-floor production systems, as well as numerous onshore wells slant-drilled to tap offshore fields. State offshore gas production peaked in 1968, oil production in 1969. Average daily production in 1975 amounted to 170,723 B/D oil and 53,046 MCF/D natural gas and will decline in the future. Figure 1 shows the location of all California's tidelands oil and gas fields.

O C S

Development of OCS oil and gas resources off California is just beginning. Exploratory wells have been drilled on only 40 of the 121 active OCS leases off California. Two fields -- Dos Cuadras and Carpinteria -- are in production, and in 1975 produced about 40,000 B/D oil and 15,000 MCF/D natural gas. Six production platforms have been established, and development plans calling for installation of four more platforms have been submitted to USGS. Seven commercial discoveries have been announced by USGS -- six in the Santa Barbara Channel, and one in the San Pedro Basin. California OCS oil and gas production is certain to rise sharply in the early 1980s as these discoveries are brought into production.

FIGURE 1:
CALIFORNIA'S TIDELANDS OIL AND GAS FIELDS



Source: Hydrocarbon Potential of California's Offshore Lands.
State Lands Division, - 1976.

PROSPECTS

Petroleum resources are distinguished from petroleum reserves on the basis of discovery through exploration or development drilling. Oil and gas discovered or thought to exist on the basis of such drilling we consider to be petroleum reserves. Oil and gas whose existence is suspected but not yet demonstrated by such drilling, we consider to be petroleum resources. We define the terms used in this report as follows:

Petroleum resources: the oil and gas not yet discovered but thought to exist in favorable geologic settings, and estimated to be economically recoverable;

Proven petroleum reserves: the estimated quantities of crude oil and natural gas which geologic and engineering data demonstrate with reasonable certainty to be recoverable under existing economic and operating conditions from known reservoirs; and

Inferred petroleum reserves: reserves eventually to be added to known fields through extensions, revisions, and new reservoirs ("pays"). 16/

All of the oil and gas thought to be recoverable from the leases sold in Lease Sale #35 are considered resources, and for these we present the resource estimates published by USGS and the Western Oil and Gas Association. 17/ Similarly, we consider the oil and gas believed to exist in the Santa Barbara Channel OCS in unleased areas or in leases without USGS-certified discoveries to be petroleum resources, and not reserves. The oil and gas estimated to be recoverable from existing fields or from certified discoveries in the Channel OCS we treat as reserves. We classify as proved reserves the oil and gas estimated to be recoverable from the fields now in production and those discoveries for which operators have submitted development proposals to USGS. The oil and gas estimated recoverable from the remaining discoveries we classify as inferred reserves.

RESOURCE ESTIMATES

Resource estimates amount to educated guesses as to the amount of oil and gas which might be recovered from a given area. The most certain method of determining whether economic concentrations of oil and gas exist in an area is to drill, at a cost of several million dollars each, a series of exploratory wells. In the absence of such direct and site-specific exploratory drilling information, it is possible to construct resource estimates on the basis of indirect and general information, but estimates of this kind must rely on incomplete knowledge and a chain of assumptions which may or may not be valid. Great caution must be exercised in their use.

Nonetheless, resource estimates are widely used despite their limitations, because the stakes involved in offshore oil and gas development are so high. The federal government itself makes and uses resource estimates to help decide which OCS areas to offer for lease, to determine the fair market value of each tract offered, and to project potential environmental effects. Oil companies also make and use resource estimates to nominate tracts for leasing, to formulate bids, to set exploration priorities (the best prospects are usually explored first), and to make investment decisions. State and local governments historically have not made resource estimates for federally controlled OCS areas because of the considerable expense involved, the absence of direct financial benefit from OCS production, and

their lack of control over OCS operations. Rather, they rely on the estimates produced by the Department of the Interior and other groups to anticipate onshore activities and effects, and to some extent, to determine political and philosophical attitudes towards OCS development.

In simplified form, resource estimates are constructed in four steps:

1. identification of basin and rock types;
2. identification of structures;
3. estimates of oil and gas in place;
4. estimates of the oil and gas capable of being recovered. 18/

Resource estimates may be presented either as a single set of numbers -- one each for potentially recoverable oil and gas -- or as pairs of numbers, representing low-range and high-range estimates for both oil and gas. Resource estimates presented in low-range/high-range format sometimes (but not always) include "confidence" limits. When confidence limits are included, the low-range estimate is usually associated with 95 % confidence, the high range estimate with 5 % confidence.

Information used to make resource estimates comes from a variety of sources. The USGS conducts regional geologic studies, with emphasis on proposed leasing areas. These studies include sampling and analysis of rock outcrops on the sea floor and the preparation of maps describing the surficial geology of the areas. But surficial geology provides very limited information on prospective oil and gas reservoirs, which usually lie thousands of feet below the sea floor.

Three geophysical methods are commonly used to obtain information on subsurface geologic conditions. Magnetic surveys help define the characteristics of sedimentary basins, including the thickness of sediments and the presence and general location of structural features and faults. Gravity surveys provide additional information on the structure of sedimentary basins. Seismic reflection surveys supply structural and stratigraphic information with greater precision and specificity than either gravity or magnetic studies. USGS, oil companies and independent contractors all conduct geophysical surveys of these types in prospective leasing areas. In the Southern California OCS, USGS alone had gathered 18,000 miles of seismic lines, and even more gravity and magnetic data, by September of 1975. 19/

As noted, some nearshore portions of the California OCS, specifically the Santa Barbara Channel and the San Pedro basin, are considered extensions of onshore or coastal sedimentary basins. The onshore and tidelands portions of these basins have produced oil and gas for many years, and their petroleum geology is reasonably well known. Also, some direct information is available from existing OCS leases in the Channel and from core holes drilled in the 1950s and 1960s in the Channel and the San Pedro basin. For these reasons, resource estimates for the unleased OCS portions of these two areas can be made with a greater degree of confidence than is usually possible.

Other parts of the California OCS, such as the Tanner and Cortes Banks, are essentially unknown. These areas are geologically distinct from onshore or coastal basins, so that no extrapolation is possible, and little or no exploratory drilling information is available. In such "wildcat" areas considered or offered for lease, oil companies may form a consortium to drill a deep stratigraphic test well, as was the case on the flank of the Cortes Bank in 1975. Present USGS policy requires that such wells be drilled "off-structure," where oil and gas are least likely to be found. From this type of well, the stratigraphy of the sections encountered can be determined and correlated with seismic reflections and with the individual strata identified from bottom samples collected in the actual prospect areas. Geologic and chemical analyses are conducted on samples of all strata encountered to determine their suitability as petroleum source or reservoir rocks. Much of this information can be extrapolated to the tracts offered for lease.

LEASE SALE NO. 35

Prior to Lease Sale #35, the two most widely circulated sets of resource estimates for the sale areas were those of the USGS and the Western Oil and Gas Association (WOGA) a trade association for the oil and gas companies operating in Southern California.

USGS estimated recoverable oil and gas in the areas offered for lease at 1.25 - 2.25 billion barrels of oil and 1.9 - 4.0 trillion cubic feet of gas, distributed as follows:

TABLE 2:
USGS LEASE SALE NO. 35 RESOURCE ESTIMATES 20/

Area	Millions BBL Oil	Million MCF Gas
San Pedro Bay	709 - 946	602 - 821
Santa Rosa Cortes (North)	242 - 431	603 - 1,108
Santa Rosa Cortes (South)	239 - 660	613 - 1,785
Santa Barbara - Santa Catalina	67 - 219	103 - 342

The Western Oil and Gas association released a report in October, 1974, predicting 6 - 19 billion barrels of oil potentially recoverable, with 14 billion barrels the "most likely" amount. 21/

The wide discrepancy between the two sets of estimates is not hard to explain. WOGA was not actually making its own resource estimates, nor did it use the proprietary company information. In 1971, Frank Parker, a consulting geologist, estimated that the Southern California OCS contained 75 billion barrels of oil in place. 22/ WOGA took Parker's estimate, scaled it down to 54 million barrels to cover the 7,700,000 acre "call for nominations" area of Lease Sale #35 and applied a recovery factor of 25 % +- to arrive at its 14 billion barrel "most likely" estimate. When the 1,300,000 acres actually offered for lease were identified WOGA reduced its 6 - 19 billion barrel estimate to "range from about 10 billion barrels downward, depending upon the correlation adjudged between these tracts and Parker's potential petroleum areas." 23/ In any event, WOGA's stated purpose was not to estimate as accurately as available information permitted the amount of oil and gas to be recovered from the Lease Sale No. 35 tracts, but to posit the highest possible yield of offshore oil and gas, so as to evaluate the maximum possible environmental impacts stemming from recovery. Their primary concern was to avoid criticism for understating potential impacts. 24/ In addition, WOGA was not a disinterested party and may have felt that publicizing this very high estimate would supply Interior with stronger reasons for holding Lease Sale #35, despite widespread state and local opposition. 25/

USGS, on the other hand, was attempting to make as accurate an estimate as it could. USGS based its estimates on all the data and information available to it in 1974, including Parker's 1971 paper. The USGS estimates pertain to the actual 1,300,000 acres offered for lease, not to the 7,700,000 acre "call for nominations" area. Further, the USGS estimates do not rule out a yield greater than 2.25 billion barrels of oil; they simply assign to this possibility of less than one in 20. Inasmuch as only 310,000 of the 1,300,000 acres offered for lease were actually sold, both sets of estimates are probably high. Of the two, however, the USGS estimates must be considered more reliable.

In the Lease Sale #35 Final Environmental Statement, the Bureau of Land Management (BLM) presents the following set of low-range and high-range estimates:

TABLE 3:
BLM LEASE SALE NO. 35 RESOURCE ESTIMATES 26/

Area	Million BBL Oil	Million MCF Gas
San Pedro Bay	709 - 6,259	602 - 7,023
Santa Rosa Cortes (North)	242 - 2,136	603 - 7,035
Santa Rosa Cortes (South)	239 - 2,110	613 - 7,152
Santa Barbara - Santa Catalina	67 - 591	103 - 1,202
Total	1,257 - 11,096	1,921 - 22,412

These BLM numbers represent a compromise between the USGS and WOGA estimates. The USGS "low-range" estimates have been used for the low range; WOGA's 14 billion barrel estimate is used for the high range. The rationale for this compromise is not clear. It may be that BLM, as did WOGA, used the extremely high estimates in order not to be accused of understating the potential effects of the development activities. In view of the highly charged atmosphere surrounding the events culminating in Lease Sale #35, BLM may have believed it politic to publish estimates embracing both divergent sets of estimates.

The final Environmental Statement on Santa Barbara Channel oil and gas development presents yet another set of resource estimates for the Lease Sale #35 tracts, adjusted, according to the text, to reflect the actual tracts leased:

TABLE 4:
USGS LEASE SALE NO. 35 REVISED RESOURCE ESTIMATES 27/

Area	Million BBL Oil	Million MCF Gas
San Pedro Bay	355 - 3,310	301 - 3,500
Santa Rosa Cortes (North)	100 - 850	240 - 2,800
Santa Rosa Cortes (South)	120 - 1,555	310 - 3,580
Santa Barbara - Santa Catalina	13 - 120	20 - 240
Total	588 - 5,655	781 - 10,120

The analytical basis for these figures is not stated, though the numbers appear to be modifications of the earlier BLM compromise between USGS and WOGA figures. USGS personnel have informally indicated to the OCS Planning Project that these figures were hurriedly assembled in the final days before publication of the document and were not based on a rigorous analysis. 28/

For planning purposes, state and local officials need the most reliable resource estimates available. With respect to Lease Sale #35, the question is whether WOGA or USGS estimates are more reliable. On the basis of the limited information

in the public domain, it seems clear that the original USGS estimates are more dependable than those of WOGA. The California State Lands Division independently reviewed both sets of estimates and concluded that USGS estimates were "reasonable and acceptable." 29/ WOGA has stated that its estimates did not draw on proprietary information, and that its figures "may be too high to use in estimating the amount of oil and gas that may be produced." 30/ In Parker's own words, his overall value of 75 billion barrels of oil is "a fair estimate if the thickness and extent of the Pliocene and upper Miocene strata are as shown on the maps and sections. However, these critical factors are based on scanty information and liberal interpretations." As USGS points out in a 1976 review of the petroleum potential of the Southern California OCS:

> These strata are now known to be much thinner and of more limited area than inferred by Parker, and he was unaware that older sediments were widely exposed over much of the truncated Santa Rosa Cortes Ridge. The immaturity of potential source rocks was not known, and the presence of adequate reservoir sands was given little discussion. Parker's estimates were based largely on comparisons with the Los Angeles basin, a questionable premise in consideration of our present knowledge. 31/

In September, 1975, Dr. J. C. Taylor of the USGS presented data suggesting that the southern California OCS oil and gas prospects were poorer than previously suspected. 32/ In view of these pieces of evidence, the OCS Planning Project concludes that the USGS resource estimates are the best figures available for the tracts sold in Lease Sale #35. For planning purposes, we shall use the following figures:

TABLE 5:
LEASE SALE NO. 35 RESOURCE ESTIMATES 33/

Area	Million BBL Oil	Million MCF Gas
San Pedro Bay	355 - 946	301 - 821
Santa Rosa Cortes (North)	100 - 431	240 - 1,108
Santa Rosa Cortes (South)	120 - 660	310 - 1,785
Santa Barbara - Santa Catalina	13 - 120	20 - 240
Totals	588 - 2,157	871 - 3,954

SANTA BARBARA CHANNEL OCS

Resource estimates have been published by the Interior Department for existing leases in the Channel OCS without discoveries, and for Channel OCS tracts which have not yet been leased: 34/

Existing Leases Without Discoveries: USGS has estimated that the existing Channel OCS Leases without discoveries may contain 40-200 MMB of recoverable oil and 20-100 BCF of recoverable natural gas; and,

Unleased Channel OCS Tracts: About half of the Channel OCS is available for leasing, but not now leased. The enthusiastic response of the oil industry to the call for nominations for proposed Lease Sale #48 underscores the petroleum potential of the unleased Channel OCS tracts. The Interior Department has issued conflicting resource estimates for these unleased tracts. In its 1976 Final Environmental Impact Statement on Channel oil and gas development, USGS estimated

the unleased tracts to contain 40-150 MMB of recoverable oil and 20-70 BCF of recoverable gas. 35/ In a December, 1976, briefing on proposed Lease Sale #48 BLM estimated unleased Channel OCS tracts to contain 30-900 MMB recoverable oil and 7-525 BCF recoverable gas. In his January 6, 1977, press release, Interior Secretary Kleppe estimated those tracts to contain 40-50 MMB recoverable oil and 20-70 BCF recoverable gas. 36/ The State of California cannot determine which of these estimates represents Interior's best thinking. For planning purposes, the OCS task force will use the middle estimate: 40-150 MMB recoverable oil and 20-70 BCF recoverable natural gas.

RESERVE ESTIMATES

If an exploratory well encounters hydrocarbons, the operator conducts tests to determine the flow rates and the physical characteristics of the producing formation(s). If the test results are encouraging, the operator drills wells to determine the configuration of the prospective field. When this exploration program is completed and the reservoir's physical characteristics have been determined, it becomes possible to estimate the discovery's reserves, the amount of oil and gas capable of being produced from the discovery. 37/

The first step is to estimate the area and thickness of the productive zone or zones. Since exploratory wells are often widely spaced, there is room for considerable interpretation, and allowance must be made for variations in thickness throughout the reservoir. The volume of the reservoir, multiplied by the effective porosity of the producing formation(s), determined by laboratory analysis of core samples or by well-logging devices, yields the reservoir capacity.

The percentage of a reservoir's pore spaces occupied by oil (rather than water) is called the reservoir's oil saturation, and commonly varies between 50 % and 90 % of the total liquid in the reservoir. Reservoir capacity, multiplied by the oil saturation percentage, gives an estimate of the oil-in-place in the reservoir.

However, much of the oil-in-place in a reservoir cannot be extracted. The recovery factor, or percentage of oil-in-place which can be produced, varies from less than 10 % to more than 50 %, averaging for all oil fields in the United States about 32 %. Every oil field has a different recovery factor, depending on the geologic characteristics of the reservoirs, the physical properties of the oil itself, the drive mechanism pushing the reservoir's oil to the well bore, the operator's production methods, and production costs in proportion to the selling price for the produced oil. California crude oils are usually heavier and more viscous than the crude oils produced in the rest of the country. This is one reason why the recovery factor in the average California oil field -- roughly 24 % for all fields and 10 % for offshore fields -- is below the national average.

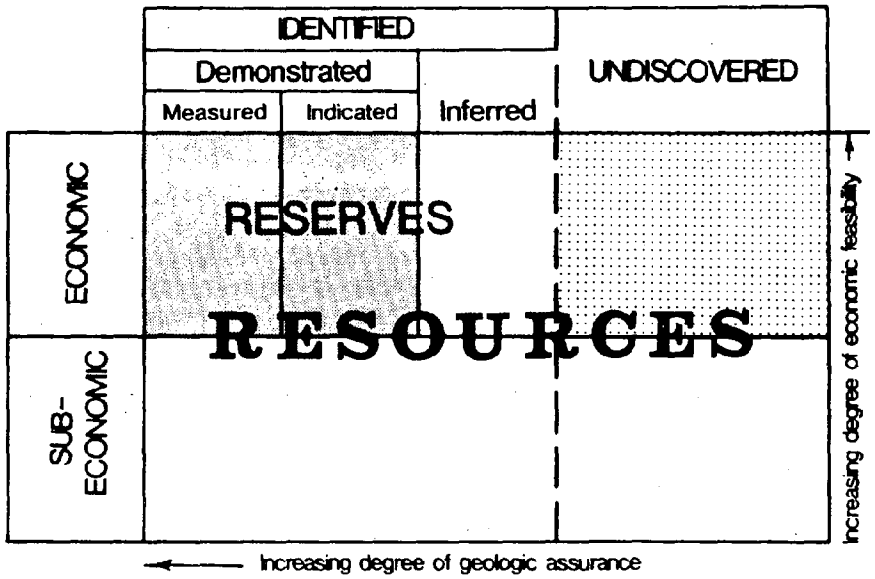
There are four kinds of reservoir drive mechanisms which push oil toward a producing well: dissolved gas drive, powered by the expansion of natural gas coming out of solution in the oil as production reduces reservoir pressure; water drive, created by the movement of water into the reservoir as reservoir pressure declines; gas cap drive, where a gas cap expands into the oil reservoir as reservoir pressure falls; and gravity drive, which occurs in steeply-dipping, highly permeable reservoirs. Most oil fields exhibit several kinds of drive mechanisms. The recovery factor is different for each kind of drive mechanism, as shown in Table 6:

TABLE 6:
PRIMARY RECOVERY FACTORS 38/

Mechanism	Recovery Range (in percent)	Average Recovery (in percent)
Dissolved Gas Drive	5 - 30	30
Gas Cap Drive	20 - 55	32
Water Drive	30 - 80	50
All Primary Drive	5 - 80	30

Both resources and reserve estimates are sensitive to economic and technological constraints (see Figure 2). 39/

FIGURE 2:
PETROLEUM RESOURCES OF THE UNITED STATES



Diagrammatic representation of petroleum resource classification by the U.S. Geological Survey and the U.S. Bureau of Mines (modified from McKelvey, 1973).

At any given level of technical capability and permitted selling price, some quantity of petroleum known to exist will not be produced because production costs would exceed the expected return. A good example is the Wilmington field in the Los Angeles basin. The natural drive mechanisms of the Wilmington reservoirs have been depleted, and extensive water flooding and other secondary recovery techniques are used to maintain production. Wilmington output is considered "lower tier" production by the Federal Energy Administration, and the permitted sales price is set by FEA at about $4.50/barrel. At this price, many of the wells in the field will soon be shut-in and abandoned. Were FEA to permit Wilmington production to be sold for more than $4.50/barrel, the producing lifetime of the field would be extended, and ultimate recovery would increase. The practical effect of this action would be to increase the proved reserves of the field.

Given these uncertainties, it is not surprising that reserve estimates will vary. The American Association of Petroleum Geologists publishes an annual summary of cumulative production and estimated reserves (which together constitute estimated ultimate recovery) for all United States oil fields. One study has compared the ultimate recovery estimates made at the time of field discovery with the estimate made nine years after discovery, and found the latter to range from 60% larger to 30% smaller than the original estimates. 40/ Another study found that:

> ... estimates of the quantity of oil in a reservoir, on average, continue to increase for at least 30 years and approach 5.8 times the original estimate. 41/

Table 7 presents reserve estimates for California tidelands oil and gas fields, as calculated by the State Lands Division effective January 1, 1976.

TABLE 7:
ESTIMATED CALIFORNIA TIDELANDS OIL AND GAS RESERVES 42/

	Oil Reserves (MMB)		Gas Reserves (BCF)	
	Proved	Inferred	Proved	Inferred
A. Ventura - Santa Barbara Basin				
1. Existing State Leases	93.8	137.3	156.5	218.6
B. Los Angeles Basin				
1. Existing State Leases	154.7	5.8	23.2	0.9
2. Granted Land Leases	314.4	15.0	66.0	3.2
TOTAL RESERVES	562.9	158.1	245.7	222.7

Table 8 presents reserve estimates for Santa Barbara Channel OCS discoveries derived from the individual fields and discovery estimates compiled by the OCS Task Force.

TABLE 8:
SANTA BARBARA CHANNEL OIL AND GAS RESERVES

	Oil Reserves (MMB)	Gas Reserves (BCF)
Proved	264	224
Inferred	468	698
TOTAL	732	922

PRODUCTION FORECASTS

Every oil field has a range of potential production rates, defined by reservoir properties, the size of the field, and other physical characteristics. Within this range, actual production rates are often determined by economic or political considerations.

When a field is first brought into production, oil flows into the production wells on the strength of the reservoir's natural drive mechanism. This phase of production, powered by the reservoir's own forces, is known as primary recovery. Under primary recovery, an oil field's output rises within a few years to its peak production rate, after which the reservoir's natural drive mechanism loses some of its original force. Almost immediately after peaking, production begins to decline, ultimately reaching the economic limit.

To slow the decline rate, thereby increasing ultimate recovery from the field, fluids can be injected into the reservoir to provide an artificial drive mechanism. Production obtained through such artificial stimulation is known as secondary recovery. Water-flooding is a secondary recovery technique commonly used in California oil fields, as in the state's two largest tidelands fields, Wilmington and Huntington Beach. Advanced methods for enhancing production include the injection of chemicals into a reservoir to reduce the surface tension of the oil-in-place, or the injection of steam to lower the oil's viscosity. These so-called tertiary recovery methods are expensive and not yet in wide use.

Natural gas production rates are especially difficult to predict. Under current pricing regulations, natural gas is less rewarding to produce than oil. Operators often forego marketing produced natural gas in order to use it -- through reinjection or gas-life operations -- to boost oil production. Moreover, many platforms rely on natural gas as a power source. For these reasons, the amount of gas sold from a platform is often much less than the amount of gas produced.

From the many choices available for each field or discovery, the OCS Task Force has constructed production forecasts for California tidelands and OCS oil and gas fields, which, we hope, are both possible -- in view of the geologic information available to us -- and plausible within the economic, technological, and political context of offshore oil and gas operations. Table 9 presents our production forecasts for the Santa Barbara Channel OCS. Individual field scenarios are included in Chapter 10 (Development Scenarios).

TABLE 9:
CALIFORNIA TIDELANDS PRODUCTION SCENARIO, 1976 - 1993*

Year	Oil (B/D)	Gas (MCF/D)			
1976	156,900	45,300	1985	72,100	30,200
1977	146,900	41,500	1986	62,300	25,600
1978	137,500	42,500	1987	54,100	21,700
1979	139,400	62,300	1988	47,000	18,600
			1989	40,600	16,100
1980	128,100	56,200			
1981	118,400	51,500	1990	35,500	13,600
1982	109,400	47,000	1991	29,800	10,300
1983	96,500	42,400	1992	25,300	8,600
1984	83,200	35,700	1993	22,100	7,500
			TOTAL	549 MMB	210 BCF

*For notes and sources, see Appendix 2.

TABLE 10:
SANTA BARBARA CHANNEL OCS PRODUCTION SCENARIOS, EXISTING DISCOVERIES*

	CASE I		CASE II		CASE III		CASE IV	
Year	Oil (B/D)	Gas (MCF/D)	Oil (B/D)	Gas (MCF/D)	Oil (B/D)	Gas (MCF/D)	Oil (B/D)	Gas (MCF/D)
1976	38,000	15,000	38,000	15,000	38,000	15,000	38,000	15,000
1977	34,000	13,000	34,000	13,000	34,000	13,000	34,000	13,000
1978	49,000	12,000	50,000	12,000	50,000	12,000	50,000	12,000
1979	54,000	12,000	62,000	12,000	62,000	12,000	62,000	12,000
1980	50,000	53,000	77,000	64,000	78,000	67,000	78,000	67,000
1981	46,000	51,000	74,000	67,000	86,000	84,000	86,000	84,000
1982	42,000	50,000	81,000	83,000	100,000	109,000	100,000	109,000
1983	40,000	49,000	84,000	94,000	120,000	145,000	120,000	145,000
1984	30,000	37,000	85,000	103,000	132,000	168,000	132,000	168,000
1985	23,000	28,000	84,000	103,000	137,000	182,000	147,000	197,000
1986	18,000	21,000	76,000	95,000	144,000	197,000	183,000	256,000
1987	14,000	16,000	70,000	88,000	131,000	181,000	194,000	274,000
1988	10,000	12,000	65,000	84,000	126,000	174,000	186,000	264,000
1989	8,000	9,000	61,000	79,000	122,000	172,000	179,000	256,000
1990	6,000	7,000	47,000	80,000	110,000	154,000	173,000	249,000
1991	5,000	6,000	37,000	46,000	96,000	135,000	168,000	244,000
1992	3,000	4,000	26,000	35,000	82,000	119,000	156,000	229,000
1993	2,000	3,000	20,000	27,000	74,000	108,000	136,000	201,000
1994	2,000	3,000	16,000	20,000	59,000	86,000	121,000	179,000
1995	1,000	2,000	12,000	15,000	48,000	69,000	112,000	165,000
1996	1,000	2,000	10,000	12,000	39,000	56,000	88,000	130,000
1997	1,000	1,000	8,000	10,000	32,000	45,000	71,000	104,000
1998			6,000	8,000	25,000	36,000	57,000	84,000
1999			5,000	6,000	21,000	30,000	47,000	69,000
2000			4,000	4,000	18,000	26,000	37,000	54,000
	174MMB	147BCF	413MMB	429BCF	717MMB	874BCF	1006MMB	1307BCF

*1997 and 2000 are arbitrary cut-off dates for these scenarios and are not intended to suggest that Channel OCS production will cease at those times. Figures rounded to nearest thousand. For Case assumptions, see Notes, Appendix 2.

FOOTNOTES

1. Numerous documents present summaries of tidelands oil and gas production as well as pertinent statistics. Especially important are: California Division of Oil and Gas, California Oil and Gas Fields, Volume 2, South, Central, Coastal and Offshore California, published annually; California State Lands Division, Hydrocarbon Potential of California Offshore Lands and San Pablo Bay, August 1976; and, Conservation Committee of California Oil Producers, Annual Review of California Oil and Gas Production, 1975.

2. The discovery was made on Shell's Lease 301 (Tract 262) in San Pedro Bay.

3. Much of this material is taken from Western Oil and Gas Association, Environmental Assessment Study, Proposed Sale of Federal Oil and Gas Leases, Southern California Outer Continental Shelf, Subsection II-A, "Petroleum Exploration," October 1974. See also U.S. Department of the Interior, U.S. Geological Survey Final Environmental Statement 1, Oil and Gas Development in the Santa Barbara Channel Outer Continental Shelf Off California, March 1976, Appendices I-2, I-3, and pp. I-205 ff.

4. U.S. Department of the Interior, Geological Survey Circular 730, Geologic Appraisal of the Petroleum Potential of Offshore Southern California: The Borderland Compared to Onshore Coastal Basins, 1976.

5. Ibid., p. 13.

6. U.S. Department of the Interior, Geological Survey, Open File Report 76-232, Geological and Operational Summary, Southern California Deep Stratigraphic Test OCS-CAL 75-70 No. 1, Cortes Bank Area Offshore Southern California, 1976.

7. U.S. Department of the Interior, Geological Survey Circular 730, op. cit., p. 1.

8. U.S. Department of the Interior, Geological Survey Professional Paper 679, Geology, Petroleum Development, and Seismicity of the Santa Barbara Channel Region, California, 1969, pp. 5-8.

9. See summary on Santa Barbara Channel oil and gas operations in Section I of U.S. Department of the Interior, Geological Survey Final Environmental Statement, op. cit., March 1976.

10. Much of this material on the history of California offshore production is taken from The Offshore Petroleum Resource, Resources Agency of California, 1971, especially pp. 67-76.

11. See also Outer Continental Shelf Oil and Gas Leasing Off Southern California: Analysis of Issues, Committee of Commerce, U.S. Senate, November 1974.

12. See also Section 1 of U.S. Department of the Interior Geological Survey Final Environmental Statement, op. cit., March 1976.

13. For useful summary of events surrounding the blowout, see Resources Agency of California, op. cit., pp. 134-139.

14. Press release, January 6, 1977, Office of the Secretary of the Interior.

15. See footnote 2.

16. Adapted from Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1975, American Gas Association, American Petroleum Institute, and Canadian Petroleum Association, 30, May 1976, pp. 13-20; Hydrocarbon Potential of California Offshore Lands and San Pablo Bay, California State Lands Division, August 1976, p. 27; and, Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States, Geological Survey Circular 725, U.S. Department of the Interior, 1975, pp. 8, 9.

17. USGS estimates contained in Final Environmental Statement 1, Proposed 1975 Outer Continental Shelf Oil and Gas General Lease Sale Offshore Southern California (O.C.S. Sale No. 35), Bureau of Land Management, U.S. Department of the Interior, August 1975 and in U.S. Geological Survey Final Environmental Statement 1, op. cit., March 1976. Western Oil and Gas Association estimates presented in Western Oil and Gas Association, op. cit., October 1974, and in the open letter of Harry Morrison, Western Oil and Gas Association, August 1, 1975.

18. A good discussion of resource estimate methodologies is contained in Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States, Geological Survey Circular 725, U.S. Department of the Interior, 1975.

19. Oil and Gas Journal, September 22, 1975, p. 66.

20. The actual USGS estimates were higher, because the Santa Monica Bay area was included in the USGS overall resource estimate. However, the Santa Monica Bay tracts were withdrawn before Lease Sale #35 was held. The individual area resource estimates (San Pedro Bay, Santa Rosa Cortes North, Santa Rosa Cortes South, and Santa Barbara-Santa Catalina) are unchanged, but we have modified the overall USGS Lease Sale #35 resource estimate to reflect the deletion of Santa Monica Bay tracts. See Bureau of Land Management Final Environmental Statement 1, op. cit., U.S. Department of the Interior, August 1975.

21. Western Oil and Gas Association, op. cit., Executive Summary, p. iii.

22. Parker's paper, Petroleum Potential of Southern California Offshore, is presented in the American Association of Petroleum Geologists' Memoir 15, Future Petroleum Provinces of the United States--Their Geology and Potential, 1, p. 178-191.

23. Western Oil and Gas Association, op. cit., Executive Summary, p. 17.

24. Harry Morrison, Western Oil and Gas Association, op. cit.

25. For example, 37 local and regional governments in southern California joined in litigation to halt Lease Sale No. 35.

26. U.S. Department of the Interior, Bureau of Land Management, op. cit., 2, p. 592, Table VIII.

27. U.S. Department of the Interior, Geological Survey, Final Environmental Statement 1, op. cit., p. I-183, Table I-4.

28. This statement was made to the OCS Task Force by "Deep Strat," a USGS official who asked to remain anonymous. The table in question does not appear in the Draft Environmental Impact Statement but only in the Final EIS.

29. California State Lands Division, Resource Appraisal, Offshore Southern California OCS Sale #35, for Governor's Office, Office of Planning and Research, 1975, 3 (Resource Assessment), p. 3-1.

30. Harry Morrison, Western Oil and Gas Association, op. cit.

31. The direct USGS quote, and the Parker quote, are from U.S. Department of the Interior, Geological Survey Circular 730, op. cit., pp. 30, 31.

32. Oil and Gas Journal, September 22, 1975, p. 66.

33. This table uses the USGS high range estimates presented in the Final Environmental Statement, U.S. Department of the Interior, Bureau of Land Management 1, op. cit., p. 1, and the USGS low range estimates presented in U.S. Geological Survey Final Environmental Statement 1, op. cit., March 1976, p. I-183.

34. U.S. Department of the Interior, Geological Survey, Final Environmental Statement, op. cit., p. 167.

35. Ibid.

36. See footnote 14.

37. Much of the material in this section is taken from Initial Report on Oil and Gas Resources, Reserves, and Productive Capacities, Federal Energy Administration, Office of Policy and Analysis and Office of Energy Resource Development, June 1975, pp. 21-38.

38. Ibid., p. 33.

39. U.S. Department of the Interior, Geological Survey Circular 725, op. cit., p. 8.

40. E. L. Dillon and L. H. Van Dyke, Exploratory Drilling in 1965, American Association of Petroleum Geologists' Bulletin, 1966, 50, pp. 1114-1138; quoted in H. W. Menard, Exploration History and Random Drilling Models, in press.

41. M. Hubbert, Degree of Advancement of Petroleum Exploration in United States, American Association of Petrolum Geologists Bulletin, 51, pp. 2207-2227; also quoted in Menard, op. cit.

42. California State Lands Division, op. cit., August 1976.

CHAPTER 15

AIR QUALITY: OMISSIONS AND EMISSIONS

This Chapter is divided into two parts. Part One reviews the regulation of air quality impacts on the OCS. Part Two contains a highly technical review of air quality impacts of OCS development on the Santa Barbara Channel.

SUMMARY

The following is a concise outline of the major conclusions and recommendations of this study:

1. In general, oil industry-related pollutant concentrations are directly dependent upon production: the more oil produced, the higher the pollutant level.

2. Tanker loading has a significant effect on local and regional ozone concentrations. In terms of ozone formation, pipelines are preferable to tanker transport.

3. If tankers are used for transporting local crude, several measures should be used in order to reduce the air quality impact: slow loading, partial filling, and coordinated scheduling seem most useful.

4. In order to ensure compliance with one-hour state standards for SO_2 and H_2S, treatment and separation facilities should be limited in size. Several smaller facilities are preferable to one very large one.

5. Analysis of various production/processing/transport scenarios for Exxon's Hondo platform and selected facilities indicates that a marine terminal could significantly affect local ozone concentrations, that an offshore processing facility would affect Goleta/Santa Barbara air quality more significantly than would a Las Flores Canyon site, and that near-plant SO_2 and H_2S concentrations at Las Flores might approach or exceed air quality standards unless emission controls or plant size restrictions were adopted.

6. The available data base leaves much to be desired. Notable deficiencies were found in the meteorological data set (particularly wind and upper air sounding data) and in offshore oil industry emissions information. In order to allow more definitive impact statements in the future, it is suggested that these deficiencies be corrected as soon as possible.

PART ONE

The regulatory structure for maintaining air quality in California is resolved into three levels of federal, state, and local jurisdiction. The extent of that jurisdiction, however, and the applicability of existing permit and review procedures to guarantee equivalent trade-offs or to control emissions resulting from OCS development is questionable. Offshore regulations applicable to OCS activities are needed to complement and strengthen state and local efforts to assure the attainment and maintenance of air quality standards onshore. Amendments to the Clean Air Act and the OCS Lands Act appear to offer an expeditious solution to the many legal uncertainties surrounding air quality jurisdiction of the OCS.

PART TWO

Using available meteorological and emissions information, potential air quality impacts of petroleum-industry activity on the Santa Barbara Channel were estimated. The ARTSIM* photochemical/diffusion model was used for assessing reactive pollutant buildup, while primary pollutant concentrations were modeled using ERT's Point Source Diffusion Model (PSDM). ARTSIM modeling included simulation of carryover effects and point source emission impacts (platforms, processing facilities, and marine terminals). In addition, photochemical impacts of natural oil seeps and accidental offshore spills were modeled.

Results of the simulations indicate that tanker loading could significantly increase local ozone concentrations, and that a 6,000 barrel spill in the Channel could, under unfavorable meteorological conditions, lead to high ozone buildup as well. Sulfur dioxide and hydrogen sulfide concentrations approaching or exceeding California one-hour standards were predicted in the vicinity of large processing facilities.

Suggested mitigating measures include area-wide tanker use strategies, partial tanker filling, limitation of size of processing facilities, and use of effective vapor control systems. Additional suggestions include broadening the local meteorological, air quality, and emissions data base.

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* ARTSIM stands for Atmospheric Reaction and Transport Simulation.

PART ONE: AIR QUALITY REGULATIONS AND RESEARCH PRIORITIES

AIR QUALITY REGULATIONS

It is widely acknowledged that some degree of air pollution will result from oil and gas production activities on California's Outer Continental Shelf (OCS). In areas with serious air pollution problems, such as the Los Angeles basin, any new source of pollutants is critical, no matter how small. This section examines the regulatory structures for maintaining air quality in California, the agencies within that structure, and the laws by which they operate. Special attention is given to those problems and planning strategies which may affect oil and gas production activities resulting from federal OCS leases.

FEDERAL AUTHORITY

Federal involvement in air quality regulation began with passage of the Air Pollution Control Act of 1955. Subsequent decisions culminated in the Clean Air Act (CAA) Amendments of 1970 -- the heart of the current federal, state, and local regulatory system. The federal role established by the CAA is to identify pollutants, establish standards, and oversee state and local enforcement. Federal guidelines establish a minimum threshold of regulation, above which states may impose tougher regulatory requirements but below which they may not fall. Sections 108 through 111 of the CAA establish the mechanism for regulating OCS activities affecting air quality.

Section 109 requires the EPA Administrator to establish national ambient air quality standards (NAAQS) for identified pollutants. The legal mechanism to achieve ambient standards is the State Implementation Plan (SIP) mandated by Section 110 of the Act. Section 111 requires EPA to identify causes of stationary sources which may "contribute significantly" to air pollution and establish federal performance standards that reflect the degree of emission limitation which can be achieved by the best available control technology. EPA can theoretically control emissions from any industrial processor facility, but only one of the standards it has promulgated applies to OCS-related sources. Thus most OCS facilities are not presently regulated.

NEW SOURCE PERFORMANCE STANDARDS FOR OCS-RELATED OPERATIONS

The single new source performance standards (NSPS) established for OCS-related sources sets hydrocarbon limits from petroleum storage tanks of 40,000-barrel capacity or larger. 1/ The NSPS requirement that storage tanks have a floating roof and a vapor recovery system, or its equivalent, is well within the limits of technological and economic feasibility, and has not created a substantial problem for OCS-related facilities. There are currently no new source performance standards for platforms, processing plants, gas plants, pipelines, or marine terminals, although any of these located within state jurisdiction must obtain local permits for construction and operation. The EPA does not expect its NSPS for other oil and gas-related facilities, such as platforms and processing plants, to be articulated before late 1978.

The EPA has delegated enforcement authority for NSPS to local air pollution control agencies. To promote uniform interpretation of the regulations, EPA

guidelines identify the administrative procedures local agencies should adopt for implementation and enforcement of the standards.

STATE AUTHORITY

The apparent complexity of air quality regulation stems in part from overlapping federal, state, and local authority. The national program established by the Clean Air Act requires EPA to establish minimum national standards and leaves implementation to state and local governments. The EPA retains authority to review state programs and substitute its own in whole or in part when it deems the state effort inadequate. The state program mirrors that structure. The Air Resources Board (ARB) is the EPA analogue. It sets standards and delegates their implementation to local Air Pollution Control Districts, while retaining the authority to impose a state program where necessary. Similarly, just as federal standards establish a minimum floor which the state may exceed, state standards establish only the minimum requirements for local programs.

LOCAL CONTROLS

Local involvement in air pollution control in California predates both state and federal action. The severity of air pollution in Los Angeles was recognized in the mid-1940s and resulted in the passage of the County Act of 1947. This allowed counties in California to form air pollution control districts (APCDs). APCDs have the sole responsibility for controlling emissions from stationary sources located within their jurisdiction. They are authorized to establish regulations to conduct a permit/review procedure before pollutant-emitting industries or operations can be constructed or modified. Two general classes of permits are required by the APCD:

Basic Equipment: This class includes any article, machine, equipment, or contrivance which emits, or has the potential to emit, air contaminants; and,

Air Pollution Control Equipment: This class includes any article, machine, equipment, or contrivance that eliminates, reduces, or controls the issuance of air contaminants.

A corporation, company, individual owner, or governmental agency seeking to construct or modify a facility which uses the equipment described above must apply for a permit. Before granting the authority to construct or a permit to operate, each application must be accompanied by complete data, plans, descriptions, specifications, and drawings to show how the proposed equipment is designed, the manner in which it will be operated, and how emissions will be controlled. 2/ The detailed process of environmental review conducted by the APCD is shown in Figure 1.

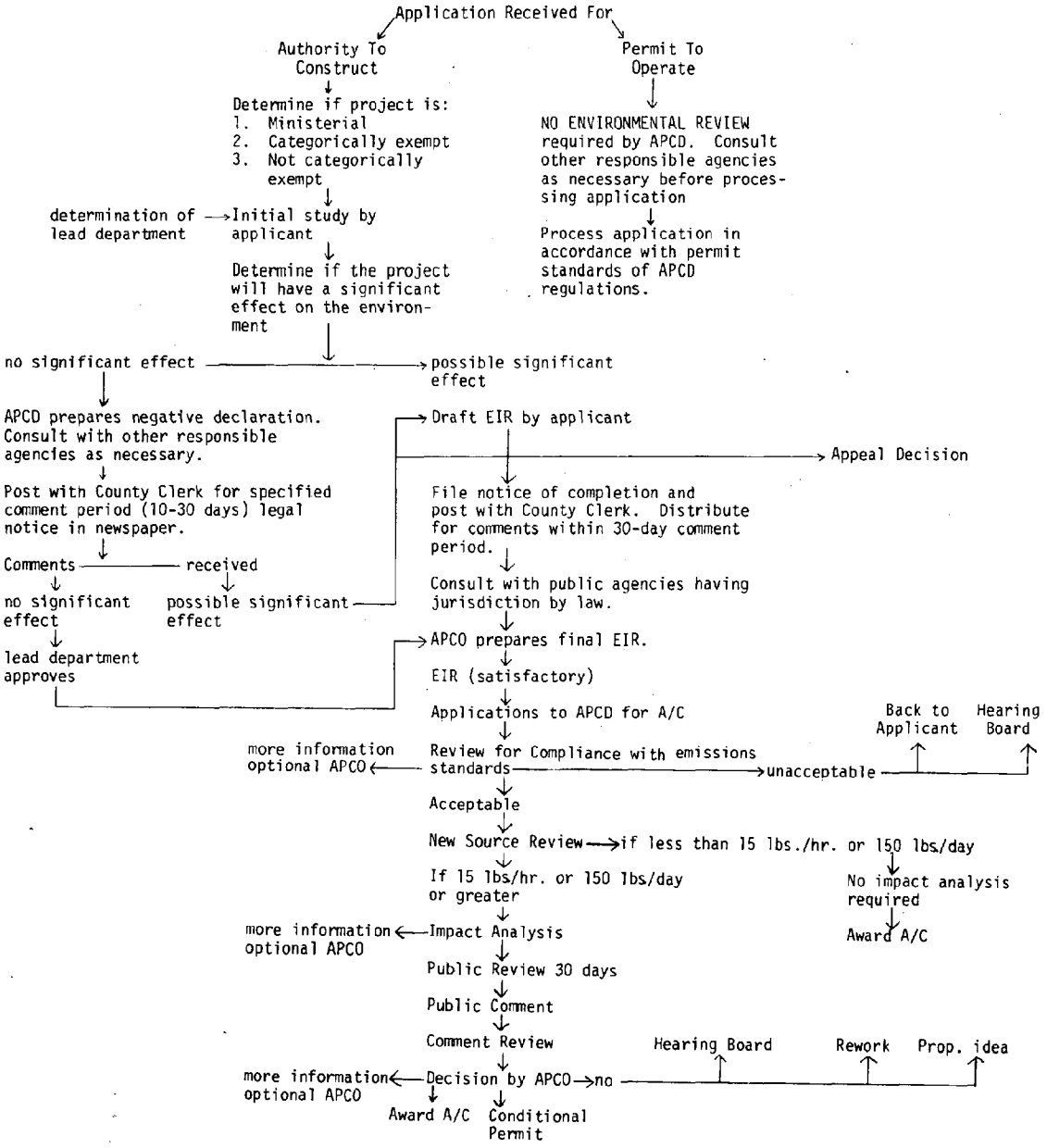
AIR RESOURCES BOARD.

The California State Air Resources Board (ARB) was created in 1967 by the Mulford-Carrell Air Resources Act in response to a federal legislative initiative requiring the establishment of a single state agency for air pollution. The ARB has five principal responsibilities:

1. to divide the state into air basins (see Figure 2);

2. to set ambient air quality standards (where federal and state standards differ, the more stringent standard prevails);

FIGURE I:
AIR POLLUTION CONTROL DISTRICT GENERAL ENVIRONMENTAL REVIEW PROCESS FLOW CHART



Source: "Compilation of Air Pollution Control Regulations and Standards," Energy Resources Conservation and Development Commission, Facility Siting Division, June 8, 1976, p. 23.

FIGURE 2:


CALIFORNIA AIR BASINS
NORTHEAST PLATEAU
NORTH COAST
SACRAMENTO VALLEY
LAKE CO.
MOUNTAIN COUNTIES
LAKE TAHOE
SCALE IN MILES
0
100
SAN FRANCISCO BAY AREA
NORTH CENTRAL COAST
SAN JOAQUIN VALLEY
GREAT BASIN VALLEYS
SOUTH CENTRAL COAST
SOUTHEAST DESERT
SOUTH COAST
SAN DIEGO

3. to promulgate rules and regulations largely through the State Implementation Plan;

4. to establish emission standards for all stationary and non-vehicular sources within each basin; and,

5. to develop test procedures to measure compliance with its stationary emissions standards and those of APCDs. 3/

The State Implementation Plan (SIP) is specifically mandated by Section 110 of the Clean Air Act. Each state's SIP is to provide for the attainment of both primary and secondary air quality standards. EPA sets primary standards at levels necessary to protect public health and less rigorous secondary standards at levels necessary to protect the public welfare from known or anticipated adverse effects of regulated pollutants.

The simplest form of air pollution control regulation is merely an "emission limitation" which restrains the amount of any pollutant that may be discharged from a particular source. The attainment of ambient standards, however, requires a more sophisticated control system since the quality of ambient air at any point depends not only upon the total amount of emissions, but upon the location of their sources as well. The CAA recognizes this fact, requiring implementation plans to contain:

> emission limitations ... and such other measures as may be necessary to insure attainment and maintenance of such (ambient) standard, including, but not limited to, land use and transportation controls. 4/ [Emphasis added.]

The EPA determined in 1971 that one of the "other measures necessary" was preconstruction review of proposed new sources with authority to prohibit the construction of those which would interfere with the attainment or maintenance of ambient standards. 5/ Compliance with these new source review (NSR) procedures and standards poses a potentially difficult hurdle for OCS-related sources.

The other general CAA requirements for a SIP are that it must:

1. provide for the attainment of primary health-related standards within three years and secondary standards within a "reasonable time";

2. establish emission limitations, schedules, and timetables for compliance;

3. provide for the review of new or modified sources of emissions to assure compliance with NSPS established by EPA; and,

4. assure that emissions of pollutants from one air quality basin will not interfere with the attainment of standards in another basin. 6/

The state's legal authority to enforce the above requirements must be built into the SIP. EPA regulations also require the SIP to include authority for the state to override local APCD standards and to assume enforcement powers if the APCDs cannot achieve and maintain air quality standards.

The EPA reviews all SIPs and will substitute its own guidelines and programs for those that are judged inadequate to meet national ambient air quality standards.

The EPA may also override state authority in instances where the state fails to enforce its SIP. If the EPA fails to act against violators of national emission standards or state and federal compliance orders, then private citizens may file suit against the EPA for nonperformance of its statutory duties.

California's implementation plan is a compilation of the rules, regulations, and strategies adopted by the local APCDs. The ARB submits to the EPA quarterly the revisions of the SIP control strategies and all APCD rules and regulations. Currently, the ARB is rewriting the existing SIP. This revised version will contain both existing and proposed control strategies, updated projections of future emissions and air quality, and individual plans for the 14 air basins in California. The new SIP should be ready for submission to the EPA by early 1977. 7/

California's original SIP was rejected because, among other reasons, EPA determined that NSR rules were inadequate. Most of the districts had adopted rules which called for intensive review only of those new sources emitting more than 100 tons/year of a regulated pollutant, and which allowed one integrated facility, such as a refinery, to be broken into constituent parts for review purposes, thus avoiding the intent of the rule. EPA did, however, accept the NSR rules of a few districts and approved them as part of the SIP, thus conferring on the rules the status of enforceable federal regulations.

Where EPA rejected proposed district rules, the agency promulgated its own NSR regulations. This is the case in Santa Barbara, Ventura, Los Angeles, Orange, and San Diego counties. In these counties, a double permit system is in effect. The APCD enforces its NSR rule, and EPA enforces the NSR rule it has adopted for the district. When modified NSR rules are submitted to EPA as part of the SIP and found acceptable, the agency will terminate its separate permit system and adopt the District's rules as federal regulations, leaving enforcement to the District.

In order to re-establish state and local control over new source permits, the ARB has developed a second generation of NSR rules and is urging their adoption by the APCDs. New or modified rules submitted to the ARB will be forwarded to EPA as part of the SIP, if they meet ARB guidelines. If the ARB determines that an APCD rule proposed for inclusion in the SIP is inadequate, it is sent back to the APCD with suggested revisions. If an APCD fails to revise its rules, or submits revised rules which are still inadequate, the ARB prescribes NSR rules for the district that cannot be amended except with approval of the ARB Executive Office. This is what happened to the Southern California Air Pollution Control District (SCAPCD). The ARB adopted NSR rules for the District on October 8, 1976. While these rules are not presently applicable outside the District, the ARB intends them as guidelines for APCDs seeking to have NSR rules included in the SIP for approval by EPA so that local control can be re-established over the permitting and regulatory process.

The ARB-suggested NSR rules require each district's air pollution control officer (APCO) to review proposed stationary sources or modifications to existing sources if it is suspected the resulting emissions will exceed certain rates. The emission "cutoff" rates, beyond which review is required, are 15 lb/hr or 150 lb/day for any pollutant for which there is a state or national standard, except carbon monoxide. These rates also apply to any precursor pollutant (such as reactive hydrocarbons) that contributes to the formation of a pollutant for which standards exist. The cutoff rates for carbon monoxide are 150 lb/hr or 1500 lb/day.

The APCO must deny a permit for construction of any modified source if its emissions will cause or contribute to continued violation of state or national

ambient air standards within the district, regardless of whether the source is meeting other applicable standards or not.

EMISSION TRADE-OFFS. A facility may be constructed in an area where standards are currently exceeded, or where its emissions will prevent the attainment or maintenance of standards only if an equivalent reduction in emissions can be achieved from facilities already within the area. These emission trade-offs are allowed only at the discretion of agencies administering the NSR program. In California, presently, this would be the EPA and/or those APCDs that operate with approved NSR regulations. However, any permit to construct and operate granted by an APCD is conditional for 90 days, pending ARB review.

EXEMPTIONS. The Exemptions allowed from NSR vary according to each APCD's rules. Pollution-control equipment is generally exempted, as is public service equipment. Exemptions are granted to a source that would result in a demonstrable basin-wide benefit. Modifications to accommodate changes in fuel sources -- necessary because of diminishing natural gas supply -- are exempt, with certain qualifications.

There is some room for interpretation in the NSR exemptions allowing for a new or modified source to locate within an area if it has been determined that:

1. unique and innovative control technology will be used, resulting in significantly lower emission rates from the source than would have occurred using known best available control technology (BACT); and,

2. the development of control technology will be significantly advanced, benefitting both environmental and public health concerns.

A source providing demonstrable basin-wide benefit, for example, might include a desulfurization facility like the one built in El Segundo. Under normal new source review, such a facility would be denied its permit to construct; but if denied, then the area would be without a source of low-sulfur fuel oil. It may be judged more beneficial to have the low-sulfur fuel oil available and to tolerate the added pollutants from the facility itself.

No APCD may grant an exemption without approval of both the ARB and the EPA. NSR rules that fail to provide for the ARB and/or EPA to override the granting of exemptions are unacceptable to the ARB and will not be submitted to the EPA.

NEW SOURCE REVIEW AND OCS

NSR is a potentially significant hurdle for OCS-related facilities in the South Coast area. The region's present inability to comply with oxidant standards requires that permits for new reactive hydrocarbon sources be denied unless the facility falls within an exemption, or the applicant can provide offsetting emission reductions from other sources in the area which are acceptable as trade-offs to the EPA, ARB, and the local APCD.

New source review rules are of recent origin and have not, as yet, been applied to OCS-related facilities. Their potential effect, however, extends to all facilities within state jurisdiction (e.g., oil and gas processing plants, storage tanks, pumping stations, and marine terminals), and possibly to some platforms and other OCS facilities beyond the state's three-mile limit as well. Tanker loading operations appear to be the most significant source of reactive hydrocarbon emission from OCS-related facilities.

After a tanker is unloaded, hydrocarbons vaporize from the tank residue and form a rich blanket in the cargo hold which must be displaced into the atmosphere as the tank compartments are filled with crude oil. These emissions may be reduced in volume and intensity to some degree by varying the loading rate and level to which cargo compartments are filled, but there is no demonstrated technology for vapor recovery. Since the tanker, not the loading terminal itself, is the point of origin for reactive hydrocarbon emissions, there was some question whether the rules regarding stationary sources could be applied. The ARB faced this issue with SOHIO's permit application for a loading terminal in Long Beach and amended the proposed South Coast NSR rule to charge tanker emissions against the marine terminal:

> ...where all or part of a stationary source is a facility used to load cargo onto or unload cargo from cargo carriers other than motor vehicles, the Air Pollution Control Officer shall consider such carriers to be parts of the stationary source.... Emissions from such carriers shall include those that result from the operations of the carriers' engines; the purging or other method of venting vapors; and from the loading, unloading, storage, processing, and transfer of cargo. 8/

Historically, most of the OCS and tidelands oil production from the Santa Barbara Channel has been transported to the Los Angeles area, where over 54% of the state's refining capacity is located. Three small (8"-10") pipelines link the Santa Barbara-Ventura area with refineries. The pipelines, however, already operate at near capacity carrying onshore production. Most local offshore production is loaded into tankers. Unless a pipeline is constructed from this producing center to refineries, expanded OCS production from existing leases will have to be transported by tanker and is expected to have a significant adverse effect on local air quality. An air quality analysis for the Santa Barbara County Regional Transportation Plan states bluntly:

> ...should tankships continue to be the only mode of crude oil transport, the South Coast would not be expected to meet the 8 pphm federal oxidant standard by 1995. If all tankship emissions are eliminated through vapor recovery or conversion to pipeline transport, the oxidant standard would be achieved by 1984. 9/

JURISDICTION OVER OCS FACILITIES

Offshore facilities beyond the State's three-mile jurisdictional limit enjoy a de facto Clean Air Act exemption. No such facilities have yet been subjected to the reviews, permit controls and emission standards applied by federal, state, and local agencies onshore.

INTERIOR DEPARTMENT. Under court interpretations of the OCS Lands Act, the Interior Department has broad authority for "conservation of the natural resources of the outer continental shelf...." 10/ This phrase was interpreted in Gulf Oil Corporation v. Morton to encompass all the natural resources of the shelf, not merely the mineral resources. 11/ Although a case has never been decided exactly on this point, clean air is probably among the natural resources which the Secretary may act to conserve.

OCS regulations take a broad view of the Interior Department's jurisdiction stating:

> ...all operations conducted on a lease by or on behalf of a lessee are

> subject to the regulations in this part, and are under the jurisdiction of the Supervisor... 12/

Subsequent regulations, however, are directed at water pollution and oil spills (30 C.F.R. §250.43) and are devoid of any reference to air pollution. Despite the Department's broad jurisdiction, this study has discovered no instance in which its authority has been exercized to affect either operating procedures or equipment specifically to reduce air pollution effects of OCS operations. Air quality has been virtually ignored in the Interior Department's regulation of OCS activities.

ENVIRONMENTAL PROTECTION AGENCY. The extent of EPA's jurisdiction is unclear, since the Agency has not yet attempted to exercise its regulatory authority in circumstances which would precipitate litigation and a judicial interpretation of the Clean Air Act on this issue.

The OCS Lands Act provides:

> The Constitution and laws and civil and political jurisdiction of the United States are extended to the subsoil and seabed of the Outer Continental Shelf and to all artificial islands and fixed structures which may be erected thereon for the purpose of exploring for, developing, removing, and transporting resources therefrom, to the same extent as if the Outer Continental Shelf were an area of exclusive federal jurisdiction located within a state. 13/

This provision can be read to make the New Source Performance Standards developed by EPA under Section 111 of the CAA applicable to the Outer Continental Shelf. 14/ It can also be read to extend the application of other federal air pollution regulations to the OCS.

Section 110 of the CAA empowers EPA, in the event of an inadequate state plan (SIP), to adopt added regulations "for a state." Such regulations have been held to be federal law, and as such, would presumably be applicable on the OCS. 15/ Whether EPA has the authority to adopt an SIP which applies beyond the geographic boundaries of a state, however, is disputed.

The CAA requires each state to adopt "a plan which provides for implementation, maintenance, and enforcement of (primary standards)...within such state" [emphasis added]. 16/ Proponents favoring a narrow construction of state and federal jurisdiction argue that the terms "within such state" act to limit the area for which regulations may be developed. They argue that a state's authority is limited to areas within the state and since EPA's power is derivative, that EPA's authority is thus necessarily confined to the area where the state is to prepare an implementation plan. 17/ That assertion, however, is not self-evident. It appears reasonable to interpret the terms not as limiting the area for which regulations may be adopted, but as merely establishing a minimum standard against which proposed regulations will be tested. In this case, their effect is not to prevent EPA from adopting regulations which would apply beyond the boundaries of a state -- on the OCS for instance -- but to require that as a minimum any plan provide for attainment of standards within the state.

EPA has not formally adopted a position interpreting the Clean Air Act's applicability to OCS activities and identifying the extent of the agency's authority. At the time of this writing, EPA Region IX (West Coast) was preparing to request a formal opinion of EPA's Office of General Counsel establishing

guidelines for the agency's action on OCS activities under the CAA. 18/

Apart from the CAA, there is one additional statutory base upon which EPA may be able to assert some controls over OCS air pollution. The Federal Water Pollution Control Act gives EPA permitting authority over both navigable waters within the state's 3 mile boundary and out to the 12 mile boundary of the contiguous zone. Section 201(a) generally prohibits the discharge of "any pollutant" without an NPDES permit. OCS facilities within the contiguous zone usually require NPDES permits for disposal of drill cuttings, brines, or treated sewage. These permits may provide a means for regulating some OCS air emissions.

EPA has recently concluded that non-water-quality effects, such as air emissions, otherwise beyond the jurisdiction of the agency may be considered in reviewing new source discharge permits and may provide the basis for denying or conditioning such permits. The General Counsel's opinion states:

> NEPA requires EPA to consider all of the environmental impacts of its actions in connection with the issuance of new source discharge permits and the requirement to consider environmental impacts carries with it the power to deny or condition permits based on environmental reasons (apart from those approved in the Federal Water Pollution Control Act) alone. 19/

This opinion appears to lay the groundwork for EPA to assert jurisdiction over air emissions of OCS facilities within the 12-mile contiguous zone. The agency has not yet tested this authority on any OCS facility. If the authority is ultimately upheld, it will provide an avenue for establishing EPA jurisdiction over some OCS facilities. Several questions remain, however: (1) what standards and controls will be applied to these "extra-jurisdictional" facilities? (2) what controls, if any, can be applied to facilities outside the 12-mile contiguous zone? and, (3) whether operators will modify operations to escape the necessity for NPDES permits in order to avoid potentially costly air quality regulations.

STATE AND LOCAL JURISDICTION. The OCS Lands Act provides for the extension of some state laws to OCS facilities in the following terms:

> To the extent that they are applicable and not inconsistent with this subchapter or with other federal laws and regulations of the Secretary now in effect or hereafter adopted, the civil and criminal laws of each adjacent state...are declared to be the law of the United States for that portion of the subsoil and seabed of the Outer Continental Shelf, and artificial islands and fixed structures erected thereon, ... [emphasis added] 20/

For state and local regulatory requirements governing air pollution to be applied on the OCS, three potentially fatal legal questions must be answered satisfactorily: (1) Are they consistent with the OCS Lands Act? (2) Are they consistent with regulations in effect or subsequently promulgated? and, (3) In the case of APCD regulation, are they "state law" for this purpose?

Opponents of state and local regulation beyond three miles argue that the Act contemplates five-year lease terms which convey the right to "produce" oil and gas. Any regulation which established a pre-condition interferes with that right to produce and is thus inconsistent with the OCS Lands Act. 21/ Proponents of extending state and local controls argue that the Act's "right to produce" was not intended to be absolute. It was intended that the right be

reasonably conditioned by civil and criminal laws of the adjacent state. Subsequent federal legislation, including the Clean Air Act and NEPA, demonstrate a strong commitment to environmental protection, including air quality. State laws in pursuit of these goals -- which do not prohibit production from OCS leases, but merely subject it to reasonable conditions -- are not necessarily inconsistent with the OCS Lands Act.

The requirement that state law not be inconsistent with the Secretary of Interior's regulations presents perhaps the most difficult legal problem for proponents of asserting state jurisdiction. Insofar as the Secretary's regulations are silent on air pollution, the argument made above that reasonable state regulations may be applied, still obtains. If, however, the Secretary adopts regulations specifically controlling air pollution from OCS facilities, state regulations that had the effect of prohibiting a facility the Secretary allowed, would undoubtedly be held "inconsistent" with the Secretary's regulations and thus invalid.

In the case of local regulations, there is one additional legal hurdle which must be surmounted before they can be applied to OCS facilities. Exxon raised this issue in a memorandum to EPA which contends, in part, that the OCS Lands Act incorporates only statewide law -- not local regulations. 22/ In support of this position, Exxon argues that the OCS Lands Act repeatedly distinguished between states and their political subdivisions and even made provision for projecting state lines seaward to establish which state would have its civil and criminal laws apply to OCS structures, while at the same time it made no similar provision for extending the lines of political subdivisions seaward.

Each of the options for establishing air emission controls presents slightly different problems. With Interior Department regulation or EPA regulation under the FWPCA, a major question is what standards will be applied. Neither option necessarily requires regulations to be consistent with those established for similar facilities onshore. While regulatory authority may be found in these cases, the controls and substantive standards will not necessarily be those of the Clean Air Act, case law interpreting the CAA will not be applicable, and citizen suit provisions of the CAA will not apply.

Efforts to impose state or local controls directly under the OCS Lands Act, or to include them in an SIP, or have EPA impose them in SIP under the Clean Air Act are all subject to legal attack on issues which may take years to resolve in court.

Amendments to the Clean Air Act and the OCS Lands Act, actively under consideration in the 95th Congress, appear to offer a clean way to resolve some of these legal uncertainties and assure that offshore regulation will complement and strengthen state and local efforts to assure the attainment and maintenance of air quality standards onshore.

AIR POLLUTION CONTROL COUNCILS

In air basins comprised of more than one APCD, an air pollution control council is formed with responsibility to develop a basin plan, including the rules and regulations to be adopted by districts within the basin. Once the council adopts a NSR rule, each district in the basin is obliged by law to adopt and enforce it, or to show cause why it should adopt an alternate rule. Thus, all districts within a basin will have the same NSR rule unless the ARB and the council agree that a particular district may deviate.

Special legislation established regional air pollution control districts for the Bay Area and the South Coast Air Basin. The South Coast Air Quality Management District (SCAQMD) is a recent creation which began its operations on February 1, 1977, and assumed the powers and duties of the existing Southern California Air Pollution Control District. Ventura County and southern Santa Barbara County, which had been part of the predecessor South Coast Air Pollution Control District, are not included within the new entity. The legislation would allow them to join the new SCAQMD, but neither is anxious to submit voluntarily to the controls which will be applied in the new district, where ambient air standards are exceeded over 200 days per year.

The SCAQMD was given responsibility under AB 250 to prepare and implement at the earliest feasible date an air management plan to provide for the rapid abatement of existing emission levels. The air management plan will incorporate a regional plan, prepared by the Southern California Association of Governments (SCAG), relating to transportation, land use, energy (production and development), and other planning elements.

AIR QUALITY MAINTENANCE PLANNING

Areas which have the potential for exceeding any national ambient standard within the period 1975-1985 are designated as Air Quality Maintenance Areas (AQMA) for which an Air Quality Maintenance Plan (AQMP) must be submitted to EPA. The AQMP must assess the anticipated growth in the area, project anticipated emissions and identify control strategies to achieve ambient air quality standards.

All of the southern California coast counties from Point Conception south to the Mexican border are within designated air quality maintenance areas, as well as the central coastal counties from Sonoma to Monterey, with the exception of Northern Santa Cruz (see Figure 3). OCS activities off these areas will produce emissions which must be taken into account when future emission projections and control strategies are developed.

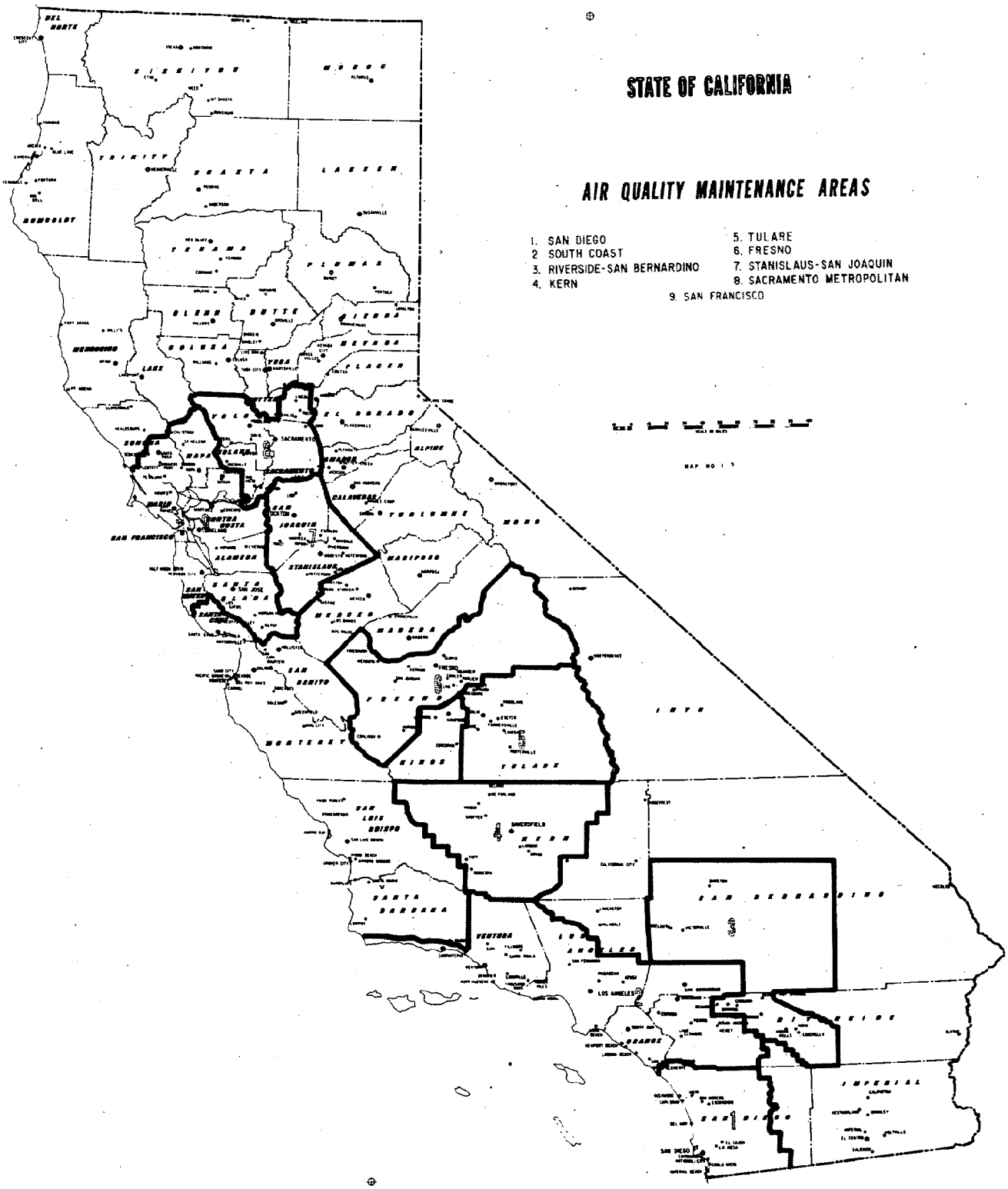
Air Quality Maintenance planning provides a forum for identifying trade-offs needed to achieve air quality standards. Since the plans must be approved by ARB before they are included in the SIP and must then be approved by EPA in its review of the SIP, the process can spotlight conflicts between OCS activity and other growth and development. To the extent OCS emissions can be anticipated, their contribution to the violation of ambient standards must be offset by reductions from other sources. If their contribution cannot be completely offset, EPA or ARB may require the imposition of more stringent area-wide controls. Santa Barbara and Ventura APCDs and the SCAQMD are all including OCS emissions within their emission projections, since active leases lie directly offshore. San Diego APCD is reluctant to raise its future emission estimates by including any OCS contributions at all, because the numbers are so speculative: the county has no current leases or production directly offshore and will not have any unless efforts to oppose Lease Sale #48 or to have San Diego tracts eliminated fail.

AIR CONSERVATION PROGRAM

The ARB is in the early stages of developing an Air Conservation Program intended to protect areas of superior air quality from degradation. The program stems from EPA regulations requiring the SIP to prevent significant deterioration in areas where existing air was better than required by secondary standards.

EPA's regulations focus on protecting against particulate and sulfur dioxide

FIGURE 3:


STATE OF CALIFORNIA
AIR QUALITY MAINTENANCE AREAS
1. SAN DIEGO
2 SOUTH COAST
3. RIVERSIDE-SAN BERNARDINO
4. KERN
5. TULARE
6. FRESNO
7. STANISLAUS-SAN JOAQUIN
8. SACRAMENTO METROPOLITAN
9. SAN FRANCISCO

emission increases. In its initial stages, California's ACP may go beyond this threshold, but will still be limited to primary pollutants such as sulfur dioxide, particulate matter, hydrogen sulfide, and carbon monoxide. Because the data base is limited and the modeling techniques have not yet been validated, ARB staff does not believe it is possible to predict the long-range transport of secondary pollutants, such as oxidant and nitrogen dioxide, in much of the non-urban area covered by the program. 23/ The ARB, however, intends to expand the program to all pollutants as soon as that becomes feasible.

The ARB has identified four classifications into which those areas of the state, with the exception of AQMAs where standards are not expected to be met, will be divided:

Class A -- Least Deterioration Areas
Class B -- Minimum Deterioration Areas
Class C -- Agricultural and Silvicultural Areas
Class D -- Urban/Industrial Areas

The ACP will have no impact on OCS development from Point Conception south, since these coastal counties are already designated AQMAs because ambient standards are not expected to be met. North of Point Conception, however, any offshore oil operations could conflict with ACP goals and classifications.

OCS AIR QUALITY IMPACT ASSESSMENT AND RESEARCH

An OCS air quality impact analysis of the Santa Barbara and Ventura County areas represents an effort to make reasonable and accurate projections of the effect OCS operations in the Santa Barbara Channel will have on air quality in the adjacent coastal areas. The following discussion identifies the methods presently available for making this kind of assessment and indicates current deficiencies in the assessment process. The concluding segment specifies certain research priorities identified as necessary for improving the local APCD's ability to make adequate OCS air quality impact assessments.

AIR QUALITY MODELING

The tool used most extensively in this kind of analysis is the air quality computer simulation model. Air quality modeling is a systematic method for quantitatively relating pollutant emissions from sources to pollutant concentrations at receptors (locations where instruments measuring pollutant concentrations are placed). The models are designed to simulate the action of the atmosphere in mixing, modifying and transporting pollutants.

Models simulate the meteorology of an area -- particularly the wind patterns determining the transport and dispersion of pollutants -- or the chemical transformation of pollutants within a given air parcel, or both. The choice of model is dependent on many factors -- most importantly, the type of source, the scale of analysis desired, and the coordinate system used.

SOURCE TYPES

Point, line, and area are the three general source types. A point source

emits pollutants from one specific point in space -- e.g., power plants, storage tanks, marine terminals. Line sources occur when pollutants are emitted at a constant and uniform rate along a line, such as a freeway or heavily-traveled street. The area source is used when numerous small point and line sources result in uniform emissions from an area. Urban areas and large parking lots are examples of area sources. 24/ The facilities involved in OCS operations are all of the point source types, but become area sources when clustered.

SCALES OF ANALYSIS

The scales of analysis for air quality modeling are the microscale, the mesoscale, and the regional. Microscale analysis deals with the local effect of a single source or group of sources. The methodology for microscale estimates is based on the Gaussian dispersion model and is usually applied to point and line sources. The study area for a microscale analysis generally ranges from one to ten kilometers across in the direction of the average wind. 25/

Mesoscale analysis is used to determine the effect of area and line sources. The study area is delineated by a grid system, and source rates for each grid are identified. This facilitates the estimation of pollutant dispersion.

Regional (or basin) analysis incorporates a grid system as well. This larger scale is desirable when following the transport of primary pollutants that undergo photochemical oxidation and then affect areas some distance from the source. Regional models are based on solution of the conservation-of-mass equation, a numerical solution involving the use of either a eulerian or lagrangian coordinate system. 26/

COORDINATE SYSTEMS

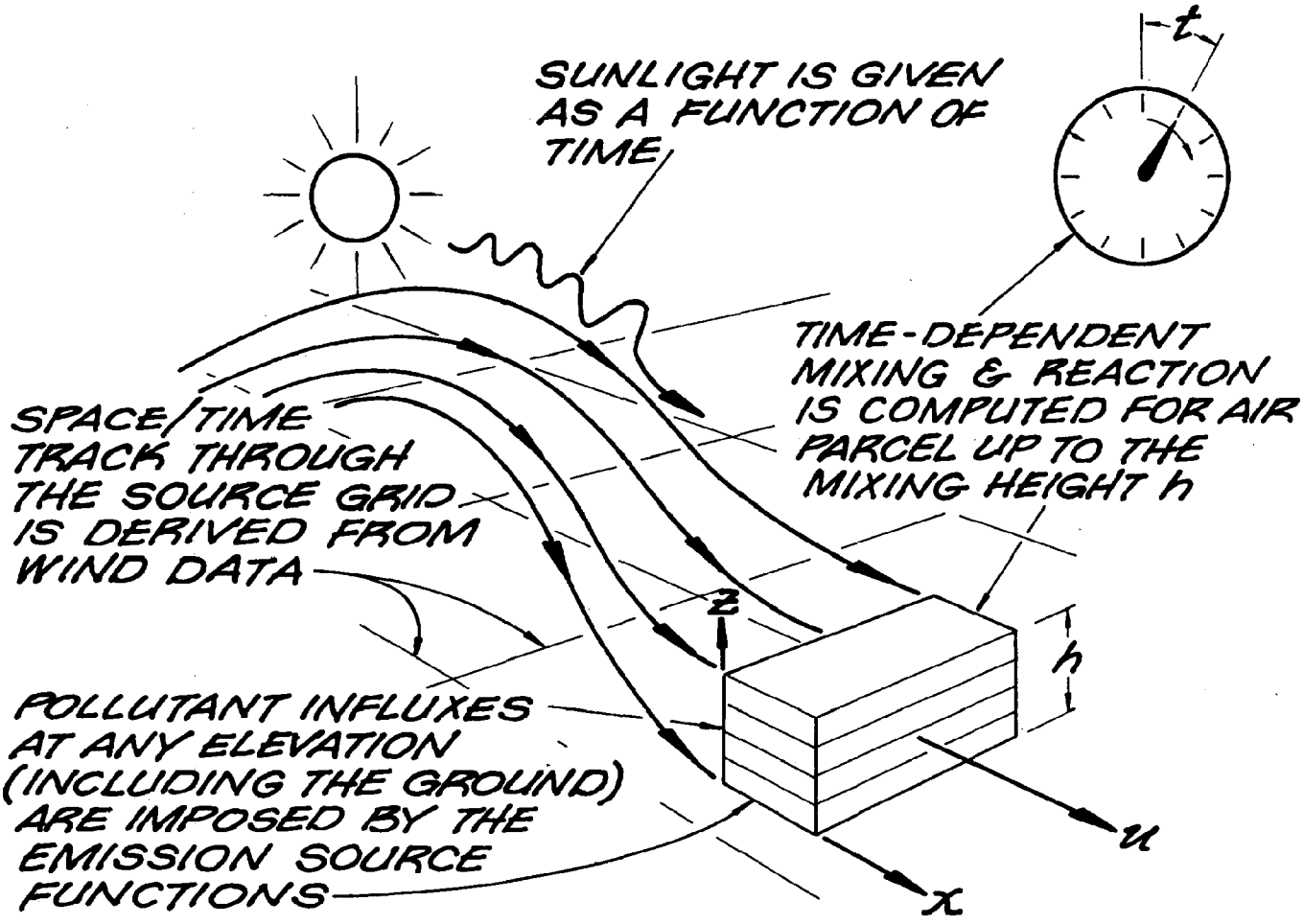
The eulerian coordinate system is fixed to the ground. Models using the eulerian solution are referred to as grid models, in which the study region is divided into a three-dimensional array of cells. Each cell may vary from one to four kilometers (0.6 to 2.5 miles) in a side and on the order of 10 to 100 meters (33 to 330 feet) in height. The size of each cell will depend on the size of the study area, on the spatial distribution of pollutant emissions, on terrain effects that may alter surface winds, and on inversions. 27/ Each grid contains a description of the temporal and spatial distribution of both stationary and mobile emissions, meteorological conditions, and initial air quality concentrations either specified or calculated from known data. The conservation-of-mass equation is then integrated to yield the pollutant concentrations within each grid for a given time.

The lagrangian coordinate system is attached to a fictitious vertical air column moving horizontally on a trajectory determined by the direction of the large-scale winds (see Figure 4). Models using the lagrangian solution are called trajectory models, in which the column of air is followed through the study area. Air pollutants are emitted into the column as fluxes at the ground surface, and as it passes over the study area chemical reactions take place within the column. 28/

GAUSSIAN MODELS

Gaussian models offer a more simplified approach to analyzing the distribution of pollutants. Models based on eulerian or lagrangian coordinate systems can predict the distribution and concentration of both inert and reactive pollutants on a regional level. Gaussian models, however, are applicable only for

Figure 4



SCHEMATIC OF DIFFUSION MODEL FOR AIR POLLUTION SIMULATION

SOURCE:
ESCHENROEDER ET AL
"CONCEPTS & APPLICATIONS OF PHOTOCHEMICAL SMOG MODELS"
GRC, JUNE 1971

inert pollutants and only in microscale analysis. The Gaussian model is limited to certain optimum conditions that enhance its predictive capabilities. It is best applicable when:

1. wind flow is restricted to the horizontal direction;
2. sources and meteorology are not time-dependent;
3. there are no terrain variations; and,
4. emissions are coming from a continuous and non-varying point source.

The spreading cloud of pollutants downwind of a continuous point source is referred to as a plume. The plume constituents are normally distributed in the horizontal and vertical crosswind directions. Figure 5 shows the coordinate system used to describe the plume's distribution. The model used by Environmental Research and Technology to determine the impact of non-reactive pollutants from point sources in the Los Flores Canyon is based on the Gaussian distribution depicted in Figure 2. Most Gaussian models use four assumptions to describe the dispersion of emissions from a point source: 29/

1. the downwind concentration at any location is directly proportional to the emission rate of the sources;
2. the more turbulent the atmosphere, the more rapid the spread of the plume in the transverse direction;
3. the maximum concentration at ground level is found directly downwind on the plume line, and is inversely proportional to the downwind distance from the source; and,
4. the maximum concentration decreases with higher wind speeds.

TRAJECTORY MODELS

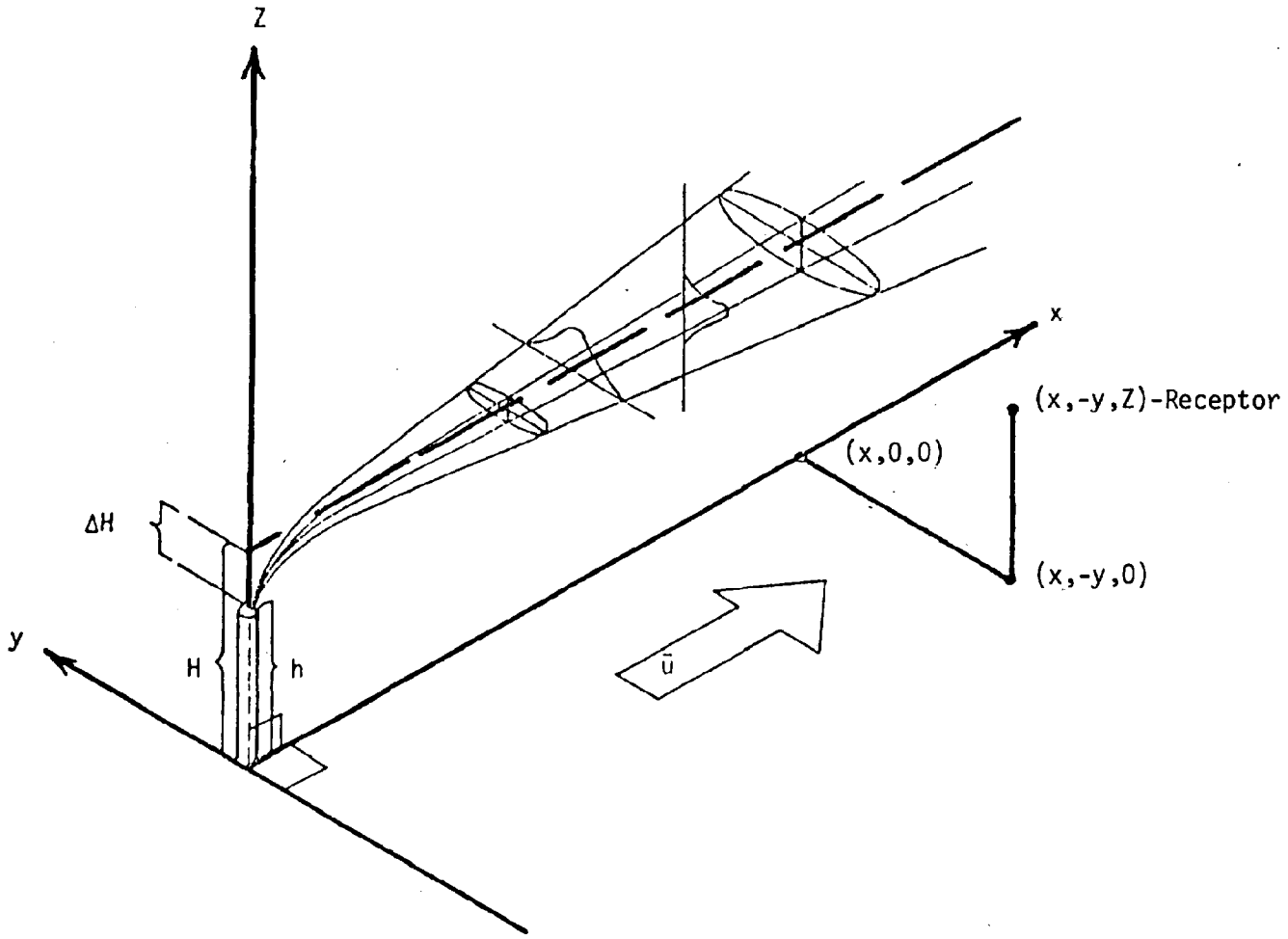
In the ERT study, reactive pollutants contributing to ozone buildup from Las Flores Canyon emissions and from offshore OCS activities were analyzed using a semi-lagrangian model on a regional scale. The model computes the time-dependent behavior of a moving air parcel in which a multicomponent gaseous mixture undergoes diffusion and photochemical reaction. As implied by the lagrangian formulation, the air parcel carries its own set of coordinates in a trajectory aligned with the wind direction and traveling at the prevailing horizontal wind speed. However, surface emissions and pollutant levels beneath the trajectory are described temporally (time of day, day of week) and spatially (by location) within a grid system.

The photochemical subsection of the model considers the various chemical processes occurring within the parcel as functions of species concentration, reaction rate, and solar ultraviolet radiation. When these processes are combined with background emissions and meteorological data the model then predicts how air pollutants from a source will be distributed temporarily and spatially, as well as their relative concentration at a receptor.

The diffusion part of the model involves a wind field and dispersion analysis that calculates an air parcel trajectory using surface wind data and a terrain factor to account for physical barriers such as mountain ranges or large hills. Of particular interest to our analysis are those trajectories that pass over present and proposed OCS development areas and later cross urban and/or industrial land.

ADVANTAGES OF TRAJECTORY MODELS. Trajectory models, unlike Gaussian models, require large amounts of detailed data for computers to simulate the movement of an air parcel and the diffusion and photochemical reactions taking place within the parcel. The more complex trajectory modeling offers certain advantages that

FIGURE 5:
COORDINATE SYSTEM SHOWING GAUSSIAN DISTRIBUTIONS IN THE HORIZONTAL AND VERTICAL



h = Actual Stack Height
H = Effective Stack Height
ΔH = Initial Plume Rise Due to the Buoyancy and momentum of Stack Gases
ū = Mean Wind Velocity and Direction

SOURCE: D. Bruce Turner, Workbook of Atmospheric Dispersion Estimates, U.S. Department of Health, Education, and Welfare, 1970, p. 5.

the simplified Gaussian approach does not. 30/ It has the capability to:

1. make project-level analysis;
2. locate sources that produce hot spots (areas of high impact) for pollutant emissions;
3. predict pollutant concentrations in valleys through simulation of air movements; and,
4. analyze areas where terrain affects surface winds.

It is also less costly to simulate a single trajectory than to analyze the transport and diffusion of pollutants over an entire grid.

LIMITATIONS OF TRAJECTORY MODELS. Under certain conditions the use of trajectory models is inappropriate. All computer models are limited to the amount of data available as well as to assumptions about the atmospheric conditions which they simulate. Trajectory models have the following limitations:

1. they are not applicable where vertical wind shear is an important consideration;
2. because of this exclusion of vertical winds, they are not directly applicable when working with convergent or divergent wind flow fields;
3. they are not applicable to multi-day runs;
4. the trajectories calculated are sensitive to the exposure of wind stations; therefore, surface wind data must be consistent with model assumption;
5. current models do not incorporate elevated point sources; and,
6. large volumes of data are required. 31/

INPUTS TO TRAJECTORY MODELS. Trajectory models applied on a regional scale and incorporating photochemical reactions require a huge body of information about emissions, meteorological factors, and air quality. A model's ability to simulate events in the atmosphere with a high degree of confidence is directly enhanced by the quantity and quality of the data base.

The following discussion evaluates emissions inventories, meteorological data, and initial concentration fields, as well as detailing the problems with using existing air quality bases.

EMISSION INVENTORY

An emission inventory provides estimates, by category, of vehicular, aircraft, power plant, refinery, and distributed area sources, including their temporal variations. The emission sources spatially distributed over a grid system have a temporal resolution of one hour, since air quality standards are generally based on a one-hour exposure time.

For the emissions inventory, the following information is required: 32/

1. Vehicles

   a. spatial distribution of daily vehicle miles traveled (VMT);
   b. temporal (hourly) distribution of vehicle miles traveled;
   c. average emissions rates (mass/distance) of CO, NOx, and HC;
   d. spatial and temporal distributions of average vehicle speed;
   e. variations in emissions rates with average speed for CO, NOx, and HC; and,

f. effects on average emissions rate of cold-start and hot-running operations.

2. Aircraft

a. ground operations emissions rates of CO, NOx, and HC as a function of traffic level, mode of operation, aircraft class or type, location, and time; and
b. flight operation emissions rates as a function of the same variables as those for ground operations including taxiing, landing, and take-off.

3. Power Plants

a. emissions rates of NOx for each plant as a function of type of fuel burned, time of day, and time of year;
b. emission rates of NOx and organic gases for each refinery; and,
c. emission rates of CO, NOx, and organic gases as a function of location for distributed stationary sources.

For all of the above emission inventories, the ratio of NO to NO_2 is also needed.

In order to evaluate the impact of OCS developments on air quality, OPR entered into an agreement with Santa Barbara and Ventura counties Air Pollution Control Districts (APCDs) to update their emission inventories of major gaseous pollutants and particulates arising from stationary (point and area) and mobile sources in the county. In the process of accomplishing the emissions inventory, the Ventura APCD selected the following method:

Task 1. Preparation of Inventory Format

a. Classification of all known stationary, mobile, and area sources of pollutants within the county.
b. Identification of sources of information for the inventory.
c. Development of questionnaires, field data sheets, and emission-source summary sheets.

Task 2. Development of Inventory

a. Training of extra-help employees to review sources of data for the inventory, and assignment of specific tasks.
b. Compilation of emission inventory of the known stationary sources emitting more than 0.1 tons per year of pollutant. Registration of the data in EPA's EIS format. Sources for the data include APCD permit files, field surveys, field inspections, interviews, literature surveys, County Planning Department publications, and ARB files.
c. Compilation of mobil source inventory. The best data source for this inventory (unavailable at the time of the Ventura County analysis) is a Caltrans study of recent vehicular traffic in the South Coast Air Basin. This study supplies average daily travel (ADT) in miles, by link (any road segment between intersections). These data are then made compatible with the Universal Transverse Mercator (UTM) location system, using 1X1 kilometer grids and a grid

aggregation interface program developed by the ARB. The result of this program gives mobile emissions (in tons per day) for each UTM grid square. The Caltrans data on normal daily peaks in vehicle traffic allow this program to reflect temporal variations.

Task 3. Storage of Data on Magnetic Tape

In order to make optimum use of the information obtained in Task 2, the data are stored on magnetic tape in the format of EPA's Emission Inventory System through the Comprehensive Data Handling System, Emissions Inventory/Permit and Registration Subsystem (EIS and P&R) Program. The information is also stored in a form compatible with similar data obtained in other areas along the South Coast. This integrated data base can then be used for evaluations of onshore impacts on air quality of pending offshore oil developments in southern California waters.

GRID SYSTEMS

Because a grid coordinate system is more appropriate for large areal analysis than the Gaussian, the logical choice of grid system for OCS analysis is one based on an areal emissions inventory using a data base appropriate to trajectory models. The grid parcels can be virtually of any size and shape, but the UTM grid square system offers certain advantages: all grid squares are of identical size and shape, and good resolution is obtainable even with the relatively large-size grid (1X1 km) employed at Santa Barbara. Resolution improves as grid size is reduced, but computation time increases. Thus, the analyst must make a trade-off between fineness of resolution and complexity.

Before choosing a grid size, the study region -- and hence the grid boundaries -- must be defined. Because of the multidisciplinary expertise required to develop data for the model, the boundary selection for an area should be coordinated with local land-use planning agencies, APCDs, and transportation planners. Major factors to consider in defining the region should include: (1) populated areas; (2) areas of high pollutant concentrations; (3) areas of high emissions; (4) topography and terrain features; and, (5) local master plans for future developments. 33/

METEOROLOGICAL DATA

The meteorological data needed for the model must include the following comprehensive information:

1. wind speed and direction -- both at the surface and aloft -- as a function of location and time;
2. temperature -- as a function of height (to permit estimations of stability), location of the inversion layer and inversion base, and strength of the inversion;
3. vertical turbulent diffusivity in terms of height, ground location, and time of day. This is estimated as a function of the following variables: turbulent energy dissipation rate, wind shear, vertical temperature gradient, wind speed, and surface roughness; and
4. isolation -- as a function of ground locations, elevations, and time of day.

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The meteorological data used for the wind field and dispersion analysis in Santa Barbara were gathered from a variety of sources. Data utilized were from the National Weather Service (NWS) stations, Vandenberg AFB (surface and upper air data), and Federal Aviation Administration airport data. Star printouts were obtained from the National Climatic Data Center in the form of stability-wind roses, giving monthly and annual frequencies of wind-speed and direction as functions of Pasquill-Gifford stability class. Such information allows simultaneous assessment of both trajectory and dispersion characteristics for long-term average cases. The wind information was then converted to IBM system format.

Past meteorological data for any area in California are also available from the Meteorological Department of the ARB. Their data contain all weather observations, available for every hour or for every third hour. In cost-benefit terms, a broader base of wind information has significant advantages over information on the temperature structure of the lower atmosphere: ten wind stations can be provided at the same cost of a single temperature station, supplying information that is much greater in quantity and more useful.

INITIAL CONCENTRATION DATA

Air quality data required to establish initial concentration fields at the surface and aloft for a full three-dimensional simulation are: concentrations for CO, NO, NO_2, O_3, total hydrocarbons (THC), and reactive classes (RHC).

In summary, then, the amount and quality of data needed for an air quality simulation model are dependent on: (1) the availability of a complete and up-to-date emissions inventory for the area; (2) the number of surface air quality and meteorological monitoring stations and their locations; and, (3) the frequency of measurements of vertical temperature profiles and of wind and air quality aloft.

L I M I T S T O M O D E L I N G A P P L I C A T I O N S

Urban areas with a number of air monitoring and meteorological stations may already have a sufficient emissions inventory and an aerometric data base to use in photochemical models. However, before deciding to use a model based on the existing data bases, an APCD should be able to answer the following questions: 34/

1. Are the air and meteorological monitoring stations located so that they measure representative data consistent with model assumptions describing the temporal and spatial distribution of surface winds and air quality?
2. Are the air monitoring networks located near a localized source of pollutant emissions?
3. Is there a standardized height above the ground for the entire network from which the air and meteorological measurements are made?
4. Are the recorded hourly values of air quality concentrations and surface wind measurements based on an integrated hourly average or on instantaneous reading?
5. How often are the air and meteorological instruments calibrated to provide quality assurance control of the data collected?
6. Are stationary source inventories up to date?
7. Is the vehicular emission inventory based on the latest emission factors published by EPA?
8. Is the transportation simulation model used to predict vehicle kilometers traveled sensitive to changes in gasoline prices, availability of mass transit alternatives, and future trends in population growth?

If answers to the above questions are unsatisfactory, a significant investment to obtain baseline data must be made before a computer simulation model can be used to project air quality impacts with any accuracy.

EXISTING EMISSIONS INVENTORIES

In California, emissions inventories for mobile and stationary sources are prepared by different agencies. The California Department of Transportation (Caltrans) develops the vehicular emissions, while the APCDs and ARB develop stationary source emissions. All stationary source emissions have a numerical description (geo-code) indicating their location within an area. One problem in using these data has been that there is no standard format. Each agency has evolved its own coordinate system to geo-code emission source. As a consequence, preparing trajectory models that use a variety of agency sources has been difficult. Other problems that arise in obtaining emissions data are: 35/

1. the highway cruse model of emission factors as published by the EPA does not always represent actual conditions;
2. the aircraft emission data, as required by air quality models, are generally not available;
3. stationary source inventories are commonly two to three years behind current conditions; and,
4. no consistency exists in defining reactive hydrocarbons. The State ARB has recently established a three-class system of reactivity that will make it even more difficult to use second generation kinetic mechanisms in models that group hydrocarbons into five classes: (1) methane, (2) paraffins, (3) olefins, (4) aromatics, and (5) aldehydes.

EXISTING METEOROLOGICAL DATA BASES

The existing sources of meteorological data for use in regional models are primarily airports, APCD air monitoring stations, and nearby military bases. The meteorological data monitored consist of surface wind speeds and directions, and, in some instances, information from two daily rawinsonde releases measuring the vertical temperature. In evaluating the existing data, it is important to keep in mind that the meteorological data will be used to calculate the representative one-hour wind flow fields on a temporal and spatial basis for each grid of the whole study area. Similarly, the temperature measurements must be able to represent and describe the temporal and spatial changes of inversions for the entire area.

The following problems arise when using existing data:

1. in most areas there are too few ground stations to describe the surface wind flow field;
2. the instruments monitoring surface winds are often insensitive to speeds of less than 3 miles/hour;
3. the readings recorded at airports are generally instantaneous and do not represent the one-hour average;
4. the APCD wind stations, generally located atop buildings, monitor the localized air flow around and over the building rather than the representative surface winds;
5. in regions where terrain alters the inversion by thermal heating, one or two rawinsonde releases are not representative for the region, nor are they sufficient to describe the temporal behavior;

6. virtually no measurements are made of winds aloft; and,
7. measurements of insolation are rarely made, and then only at one location, making it difficult to account for spatial variation of radiation intensity in large urban areas. 36/

EXISTING AIR QUALITY DATA BASE

The air monitoring network in California consists of a system of ground stations developed during an earlier, simplistic stage of the art. For the most part, the stations were built where land was cheap and were located relatively close to each other to make it easier for technicians to service the instruments. These stations were not located or intended to provide -- either individually or collectively -- anything like a representative sampling of regional air quality.

Briefly sketched, the generic inadequacies of these stations are as follows:

1. they are insufficient in number to describe the temporal and spatial distribution of pollutants needed to establish initial concentration fields or to verify operative models;
2. they exhibit no standards for placement of air intake or for location. Most are located near arterial thoroughfares and have low intakes, designed to monitor vehicular exhaust: thus they register unusually high concentrations of CO, HC, NOx, and NO_2, plus abnormally low O_3. When they are located atop tall buildings the reserve obtains: low CO, HC, and NOx concentration, high O_3. Readings of these kinds are clearly not sufficiently representative for regional modeling;
3. air quality measurements aloft are virtually lacking in urban areas, although the information collected is important in determining initial concentration fields and is necessary for monitoring O_3 buildup beneath elevated inversions that can vary from one day to the next;
4. instrumentation is not standardized among the stations. In some urban areas wet chemical methods are used, in others dry techniques or a combination of the two. Careful correlation is required if these disparate data are to be used;
5. presently lacking is a program of frequent calibration of instruments, necessary to assure the quality of data retrieved; and,
6. all stations within the network must be equipped to monitor reactive (RHC) and total hydrocarbons (THC). Presently, many stations lack this capability. 37/

O C S E M I S S I O N S

Baseline meteorological and air quality data are the primary ingredients of the computer model. Once this information is processed, the model can be used to simulate the effect of emissions from the various types and intensities of OCS activity and development. Emissions of NOx, CO, SO_2, TSP, THC, and RHC can all be analyzed under both normal conditions and abnormal ones (spills, blowouts, etc.).

With normal OCS operations, it is necessary to identify all sources where emissions will occur or are likely to occur. For every source, an emission factor is then determined and applied to the throughput of oil and gas for each activity (production, transport, treatment, storage, etc.). A given volume of throughput, multiplied by the emission factor of the appropriate source for these operations,

yields a number representing the amount of pollutants released. Specific emission factors are employed for each particular pollutant emanating from a source.

Emission factors for the following OCS operations and emission sources were used to arrive at pollutant levels for the ERT analysis included as part of this report:

Platform Emissions

1. diesel engines;
2. wastewater separation;
3. turbine natural gas compressor (fugitive emissions);
4. pump seals;
5. compressor seals; and,
6. relief valves.

Tanker Emissions

1. loading (fugitive);
2. transit (engines);
3. berthing (engines);
4. ballasting; and,
5. vapor emissions from loading.

Natural Gas Production

1. H_2S; and,
2. SO_2.

In addition to the pollutant sources listed above, emissions resulting from oil spills of various magnitudes were modeled as well.

The present status of emission factors is far from ideal: they are both incomplete and of questionable reliability. Many of the EPA's emission factors are outdated due to changes in technology and improvements in research techniques. Published emission factors for OCS activities are particularly disparate and unsatisfactory. They are either conflicting (as between the EPA and the oil industry) or non-existent.

RESEARCH PRIORITIES

Limitations of data, funding, and time preclude opportune development of any complete, detailed analysis of air quality impacts from OCS-related activities and development on southern California. However, the information and experience gained in this study should enable state and local agencies to identify data gaps and determine research priorities for improving their assessment of OCS impact. The resumption of drilling and development activity in Lease Sale #35 and the imminence of further OCS leases off California render this improvement in analytic capability absolutely essential if OCS development is to proceed without serious degradation of California air quality.

Given funds and time, the most important items for further research of OCS impact on air quality -- as identified by APCDs in order of priority -- are:

1. determination of reliable oil-production emission factors;

2. determination of wind, inversion, radiation characteristics, and temperature profiles between oil production sources and major receptor areas;
3. determination of optimum locations and standardized instrumentation for air monitoring stations;
4. determination of reliable projections of oil throughputs, including tract locations, projected tanker loading locations and schedules, pipeline locations and throughputs, projected storage sites, and storage tank characteristics and throughputs; and,
5. use of the data base outlined in (1) through (4) to model the impact on air quality from current and projected OCS oil production activities.

The Santa Barbara and Ventura county APCDs, in their responses to an OPR questionnaire, identified specific types of needed research. Emission factors are required for the following areas of OCS activity:

1. offshore operations where vapors escape as fugitive emissions from well heads, production manifolds, crude processing equipment, and maintenance procedures;
2. onshore processing and crude oil treatment where vapors are generated;
3. transferring products to large storage vessels where vapor volume displacement and working losses occur;
4. tanker loading and ballasting; and,
5. problems or accidents involving any of the above.

Both counties noted that the lack of meteorological and emission data severely hampers prediction of air quality. The quality of data presently collected at fixed air monitoring stations and airports does not enable accurate assessment, particularly of NOx and RHC.

These county APCDs identified, as the optimum tool for predicting the effect of OCS emissions, a mobile monitoring system with portable ambient air quality measuring equipment supplying both meteorological and emissions data. The layout and costs for such a system proposed for use by the Santa Barbara APCD are as follows:

System I: Ambient Air Quality Monitoring Van

	Estimated Cost
Design Engineering and Interior Layout	$12,000
Monitoring Equipment Hydrocarbon analyzer, oxides of nitrogen monitor, ozone monitor, sulphur dioxide monitor, hydrogen sulphide monitor, carbon monoxide sampler and analyzer, Hi-Volume sampler, coefficient of haze meter	48,000
Sample Gathering, Conditioning and Dilution System	8,000
Meteorological Data System	5,000
Control Systems	8,000

		Estimated Cost
Recorders		$ 6,000
Calibration Gases and Sources		4,000
Special Lord Mounts for Instruments		2,000
Power Supply and Conditioning		2,000
GMC Van		22,000
System Installation and Integration		25,000
(Vehicle modification	$ 8,000)	
(Electrical and instrument installation	12,000)	
(Equipment test and check-out	5,000)	
Support, Maintenance, and Indirect Charges for 2 yrs.		30,000
Total Estimated Cost		$177,000

This system would provide the minimum mobile capacity to measure hydrocarbons, the primary air pollutant from oil production operations. By moving the monitoring System I to appropriate locations, adequate onshore data for diffusion modeling can be obtained.

The Santa Barbara APCD estimates a six-month procurement and assembly time for System I -- two months to clear County procedures, four months assembly time. It would take almost a year before data are reduced, processed, and introduced into a model for consideration in OCS impact assessment. However, an alternative assembly of minimal equipment could be implemented in 60 to 90 days at a cost of $37,000 to $40,000, plus vehicle costs. Data from this interim system could be available in less than six months. The details for System II are given below:

System II: Hydrocarbon Mobile Monitor

	Estimated Cost
Hydrocarbon Analyzer 0-100%, NOIR	$ 3,000
FID Hydrocarbon Analyzer 0.01 to 10,000 ppm	6,000
Chromatagraphic Analyzer 0.001 - 100 ppm	10,000
Power Supply and Conditioning Equipment	3,000
Meteorological Portable Units	3,000
Equipment Integration and Installation	7,500
Engineering Design	4,500
Chart Recorders	1,500
Subtotal Equipment	$38,500

Unit A

Chevy 1/4 T Van plus Above Equipment	$46,500

Unit B

GMC Travel Van plus Above Equipment	$60,500

A mobile monitoring program, such as either of the systems detailed above, can also measure such oil-related items as:

1. onshore hydrocarbons (HCs) near platforms;
2. seep effects from OCS added HCs;
3. tanker emission effects;
4. crude storage emissions;
5. fugitive emissions;
6. upset condition measurements; and,
7. sour gas impact projections.

Santa Barbara needs to expand its air monitoring network to provide baseline information for quantifying and forecasting air quality. An adequately articulated network could perform the following tasks:

1. quantify the existence of present air contaminants;
2. establish a chain of measurement stations on and off the South Coast;
3. provide data links, control handling, and central processing;
4. increase the meteorology base for greater impact trajectory coverage;
5. prepare data for air quality models; and,
6. improve the methodology base for air quality assessment.

The baseline information, together with the mobile monitoring program, would make possible the development of fully rationalized measures for minimizing OCS effects and preventing air quality degradation. The data generated from the program proposed by the Santa Barbara APCD would greatly assist in the establishment and verification of emission factors for OCS-related sources and would provide information and methods applicable to the entire west coast.

Substantial improvement of baseline information on pollutant levels, emission sources, and meteorological conditions would enable better trajectory modeling for the Santa Barbara/Ventura coastal areas. With this information, and adequate funding, several combinations of petroleum development could be modeled. The effect of current, increased, and reduced tanker usage and loading could be analyzed and modeled, along with such alternative measures as pipelines and new loading/unloading techniques -- e.g., the use of inert gas to displace oil in tanks.

Receptor-oriented trajectories (possible only with mobile receptors), instead of the usual source-oriented trajectories, have been suggested for particularly sensitive or critical onshore sites -- schools, residential areas, air monitoring stations. Advantages of this approach include the ability to analyze all hours rather than merely the time of trajectory passage (or "worst hour"), to produce a ranking of hours by concentration of pollutants, and to calculate total day-dosage at the receptor.

A study has also been proposed to break Santa Barbara County HC emissions into reactivity classes. A mean reactivity (expressed as Source Molar Reactivity or Source Weight Reactivity) would be assigned for each UTM grid square, as well as masses of emittants by class for all squares. Reactivity/mass figures for critical point sources (such as OCS facilities) would be determined.

PART TWO: AIR QUALITY IMPACTS OF OUTER CONTINENTAL SHELF DEVELOPMENT IN THE SANTA BARBARA CHANNEL*

The Santa Barbara Channel is at once both a potential source of crude oil and natural gas and a sensitive environmental area. The Channel, with its significant quantities of oil resources, became a major focal point for new production following the reduction in supply and escalating price of foreign crude in 1973-74 -- the period of the "energy crisis."

But this was also the period of greatest environmental concern this country has ever seen. Many new environmentally oriented agencies, both public and private, came into existence, and legislation aimed at preserving or attaining high-quality environmental conditions increased significantly. In addition, certain events, particularly the 1969 Platform A blowout in federal waters off Santa Barbara, created strong local anti-oil feelings and spawned several citizen groups whose aim was to limit or eliminate Channel oil development.

California, which consumes more vehicle fuel than any other state, is particularly vulnerable to a shortage of oil and gasoline. Nevertheless, concern for clean air, clean water, and a healthy biota is widespread. Despite extreme pro-oil viewpoints, many citizens and organizations recognize that a compromise between energy production and environmental quality may indeed be achievable. No longer can the various aspects of the situation be considered independently; economics, quality of life, and quality of environment are in most cases interdependent, and any realistic analysis of one aspect must consider the others.

The present study was initiated at the request of the State of California Office of Planning and Research (OPR) and the Santa Barbara County Office of Environmental Quality (OEQ). Analysis of the impacts of current and future OCS development upon the air quality of coastal regions was the subject of the investigation. Several tasks were conducted in the course of the project: available data on air quality, meteorology, and emissions were collected and edited; estimates of future offshore production were obtained from industry and public agencies; photochemical smog (ozone) impacts were modeled using a chemistry/photochemistry/diffusion model; and, primary pollutant concentrations were determined using a Gaussian-type analysis scheme.

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* Prepared for the California Governor's Office of Planning and Research and Santa Barbara County Office of Environmental Quality by George H. Taylor, Environmental Research & Technology, Inc., 2030 Alameda Padre Serra, Santa Barbara, California 93103.

The author expresses appreciation to the following agencies and individuals for their assistance in contributing or providing data necessary for successful completion of the project: the Governor's Office of Planning and Research (Suzanne Reed, Trevor O'Neill, Allan Lind); Santa Barbara County Office of Environmental Quality (Al McCurdy); Santa Barbara County Air Pollution Control District (John Laird); Ventura County Air Pollution Control District (Doug Tubbs, Bill Thuman, Craig Barberio, Dave Barnes); CALTRANS headquarters (Richard Salmen); and Exxon, U.S.A. (through Bruce Wales, Dames & Moore, Inc.). In addition, the help of ERT staff members Alan Eschenroeder, Richard Nordsieck, Khanh Tran, Veda Bohlander, and Alan Lloyd is greatly appreciated.

This report is intended to identify local areas which would be most adversely affected by future OCS development, to determine the magnitude of such air quality problems, and to provide decisionmakers with measures to mitigate those impacts in the most efficient and economically desirable manner possible.

SUMMARY

Air quality impacts of Outer Continental Shelf (OCS) petroleum industry development in the Santa Barbara Channel upon the Counties of Santa Barbara and Ventura were assessed using the ARTSIM photochemical/diffusion model, which predicted concentrations of reactive pollutants, and the PSDM diffusion model, for primary pollutant modeling. ARTSIM modeling stressed ozone formation resulting from two emissions effects: ambient background levels of precursor substances, which represent day-to-day carryover effects; and, local-scale point source impacts, in which downwind in-plume concentrations resulting from emissions from platforms, treatment facilities, and marine terminals were modeled. In addition, the increase in ozone from hydrocarbon emissions from natural oil seeps and an accidental oil spill was assessed. PSDM calculations focused on levels of sulfur dioxide and hydrogen sulfide in the vicinity of large emitters of these substances.

Changes in ambient background concentrations of ozone precursors (notably hydrocarbons and oxides of nitrogen) were estimated for three levels of possible Channel oil development: existing facilities only; moderate increase in the number of facilities and total production; and, heavy development and production. Results of the simulations indicate that, with only existing facilities in operation, future study area ozone concentrations would be significantly lower than current levels, due to declining production of the petroleum leases and reductions in vehicle emissions as a result of more stringent vehicle pollution standards. Moderately increased future development, with its corresponding increases in emissions, would offset auto emissions decreases and result in ozone levels very similar to those currently observed. Heavy increases in development in the Channel would yield ozone concentration significantly higher than at present.

During point source simulations, it was observed that tanker loading activities represented the most significant local source of ozone-forming precursors. In addition, accidental spills of oil on the sea could lead to large increases in downwind ozone levels.

Concentrations of sulfur dioxide and hydrogen sulfide could, in some cases, exceed ambient air quality standards in the vicinity of large treatment and separation facilities, according to PSDM simulations. Emission control and/or limitations of facility size were suggested as means of reducing such concentrations.

Mitigation of ozone impacts could be accomplished by: limiting development of Channel oil/gas leases; using pipelines rather than tankers for transport; and, utilizing onshore rather than offshore sites for storage and handling to reduce routine loading/storage emissions. If tankers are used in the Channel, mitigating measures could include: loading partially (15 feet was suggested as final ullage distance); loading slowly; and, limiting simultaneous tanker loadings to one within any predetermined radius of influence (estimated at 25 miles for the Santa Barbara south coast).

Finally, it was suggested that the local meteorological data base be expanded significantly in order to improve the validity of future air quality impact studies. In particular, additional surface and upper-air wind data stations should be set up.

COMMENTS ON PREVIOUS AIR QUALITY IMPACT ANALYSES FOR SANTA BARBARA CHANNEL AND VICINITY

OIL AND GAS DEVELOPMENT IN THE SANTA BARBARA CHANNEL OUTER CONTINENTAL SHELF OFF CALIFORNIA, UNITED STATES GEOLOGICAL SURVEY, 1976

In its impact analysis of Santa Barbara Channel Oil and Gas Development, the USGS has presented a comprehensive overview of every conceivable oil- or gas-related effect. In formulating such an all-encompassing document, however, some topics have been covered in a cursory manner: air quality impacts, in particular, suffer from this inadequacy.

The most glaring example of inadequate assessment of impacts concerns formation of photochemical smog, of which oxidants (notably ozone) are primary constituents. Admittedly, oxidant formation, involving a complex array of chemical and photochemical reactions, is rather difficult to quantify; notable among the more simple models are those relating precursor concentrations (HC and NO_x) to peak oxidant, as in the well known "roll-back" modeling. In the USGS document, however, even the relatively simple procedures have been ignored. The discussion in question (page III-217) begins

> In terms of smog formation, the paraffin hydrocarbons emitted from the cargo holds during loading are expected to yield less oxidants than an equivalent amount of vehicular emissions. Vehicular sources emit substantial amounts of aromatic and olefinic compounds, both of which yield higher oxidant concentrations than an equal amount of paraffinic compounds.

True enough, and well stated, although vehicle emissions tend to be spread over wide areas and are relatively steady, while tanker loading emissions are intermittent and essentially point-source in nature. It is shocking, therefore, to read the sentence immediately following the above passage:

> Thus, marine terminal operations are expected to have only a minor impact on regional air quality.

This statement grossly understates potential oxidant impacts of tanker loading. Although admittedly less reactive than vehicular exhaust components, tanker loading HC is emitted in such large quantities that downwind ozone concentrations can be severely affected by the reactive HC fraction (which can exceed 1,000 lbs/hr during loading operations). The real problem, then, is the local effect, and to deny its importance using the logic exhibited above is certainly not valid.

SOUTHERN CALIFORNIA OUTER CONTINENTAL SHELF OIL DEVELOPMENT: ANALYSIS OF KEY ISSUES, ENVIRONMENTAL SCIENCE AND ENGINEERING, UNIVERSITY OF CALIFORNIA, LOS ANGELES, 1976

The approach used in this document for modeling air quality impacts of OCS development is considerably more comprehensive and scientifically defensible than that utilized in the USGS document. In addition to assessing impacts of routine emissions, Environmental Science and Engineering (ESE) has included oil spill and oil fire impact analyses, as well as a discussion of chemical and photochemical mechanisms involved in oxidant production. Primary pollutants (e.g., CO, SO_2) are handled by means of Gaussian-type modeling, generally a valid approach over such homogeneous terrain as the ocean and level coastal plains.

The most serious deficiency in the ESE report involves photochemical smog analysis. ESE's approach is to treat oxidant production solely as a function of reactive hydrocarbon concentrations, with particular emphasis placed on attainment (or nonattainment) of the 160 $\mu g/m^3$ with three-hour federal standard. Since even the most simple oxidant models in common use treat peak oxidant concentration as a function of morning levels of both RHC and NO_x, ESE's method seems unduly simplified. ESE's statement that "the federal standard . . . is the level needed to assume an ozone limit of 0.09 ppm" is simply not a valid one in all areas and circumstances.

In conclusion, then, ESE's major air quality shortcoming lies in its scientifically invalid analysis of what is probably southern California's major pollution problem, photochemical smog. Impacts of other pollutants are discussed in a thorough, valid manner.

ONSHORE IMPACT OF OFFSHORE SOUTHERN CALIFORNIA OCS SALE #35, GOVERNOR'S OFFICE OF PLANNING AND RESEARCH, 1976

In its appraisal of OCS air quality impacts, OPR drew heavily from previous EIR publications and included very little original analysis or interpretation. As such, the document suffers from the deficiencies of its predecessors: in particular, oxidant impact analysis is treated in a cursory and, at times, incorrect manner.

The oxidant impact approach used in the OPR report is similar to the ESE method discussed previously: the nonmethane hydrocarbon (NMHC) standard is used in lieu of the more complex photochemical analysis. As stated in the previous section, this approach can be viewed as an oversimplification of what is a complex local and regional problem affected by a number of distinct variables.

The OPR report is valuable chiefly as a review of existing impact assessments and emissions characteristics, despite its shortcomings with regard to photochemistry. Reviews of air quality trends and legal aspects are of particular merit.

ENVIRONMENTAL SETTING

GEOGRAPHICAL CHARACTERISTICS

The Santa Barbara Channel, lying east-west, is located approximately 170 kilometers northwest of Los Angeles. Bounded on the north by the southern Santa Barbara County coastline, on the east by the Ventura County coast, and on the south by the Channel Islands (Anacapa, Santa Cruz, Santa Rosa, and San Miguel), the Channel measures roughly 110 kilometers in length (east-west dimension) and 40 kilometers in width. The Outer Continental Shelf (OCS) portion of the Channel, comprising those areas more than three miles from mainland and Channel Island shorelines, is under federal jurisdiction; as of January 1, 1973, about 40% of the Channel OCS acreage was held by federally issued oil and gas leases. 38/

The south coast of Santa Barbara County consists primarily of an east-west oriented coastal plain, generally less than eight kilometers in width, backed by the Santa Ynez mountains, whose crest averages about one kilometer in elevation. The coastal plain, which is cut by numerous small, seasonal streams, is widest (about ten kilometers) near the city of Santa Barbara. Along much of the shoreline, narrow sand beaches front steep 20- to 30-meter sea cliffs. Between Santa Barbara and Ventura, the coastal plain is discontinuous and generally less than three kilometers in width. 39/

The eastern shore of the Channel, extending from Ventura to Point Mugu, is characterized by a wide coastal plain of low relief extending about 15 kilometers inland. In addition, several alluvial valleys penetrate the mountainous areas to the north and east; the major such valleys comprise the drainages of the Ventura and Santa Clara Rivers, Arroyo Las Posas, and Arroyo Santa Rosa.

The Channel Islands, an east-west chain about 100 kilometers in length, form a seaward extension of the Santa Monica Mountains, which terminate ashore at Point Mugu. Santa Cruz, the largest of the islands, is approximately 38 kilometers in length.

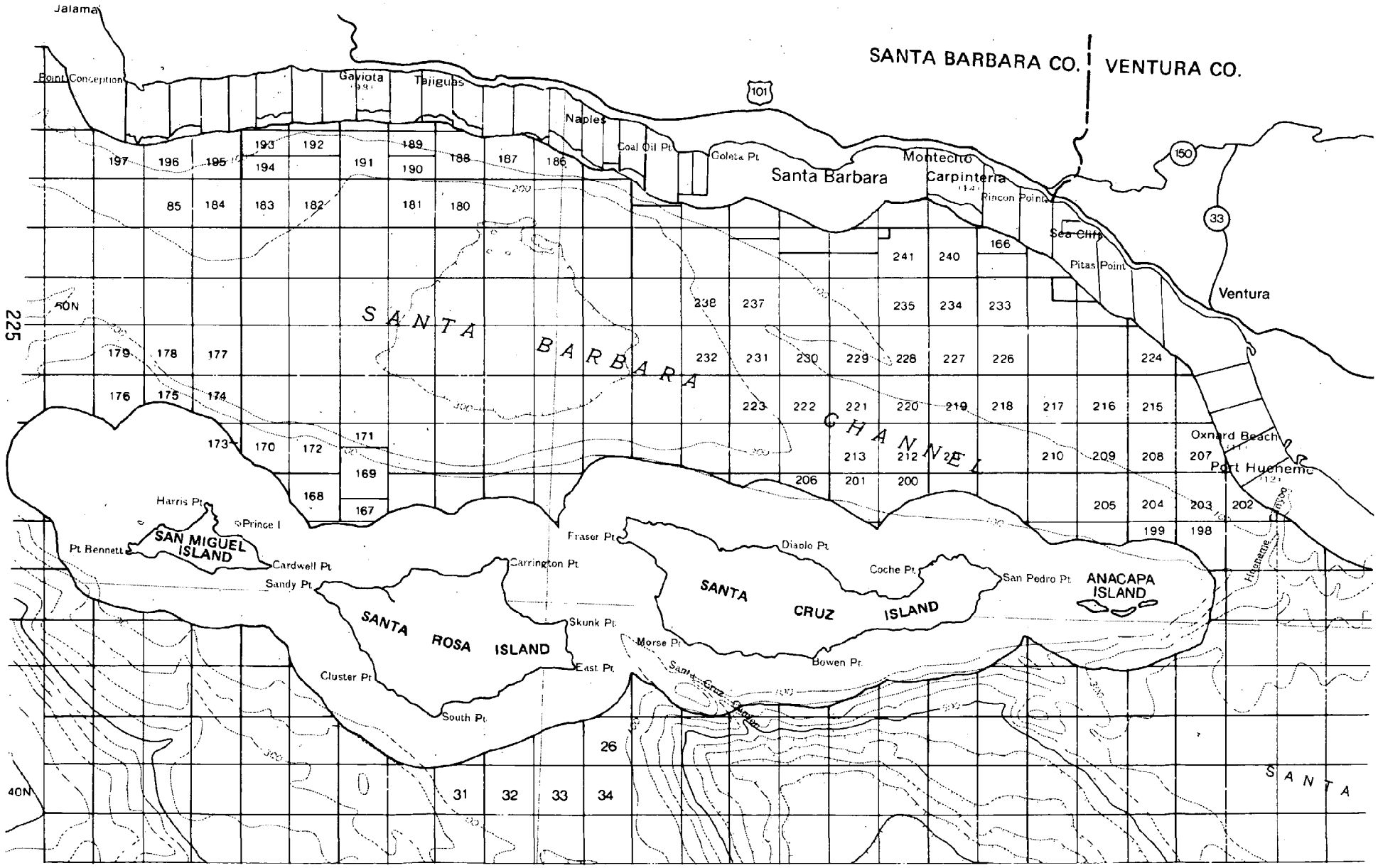
Underwater topography in the Channel comprises several distinct regions: the Santa Barbara Basin, lying in the center of the Channel and reaching a depth of 625 meters; the Mainland Shelf, a submarine terrace paralleling the coast and varying in width from four to five kilometers west of Santa Barbara to 20 kilometers off western Ventura County; the Channel Islands Shelf, which extends approximately four kilometers northward from the island chain; the Goleta and Oxnard slopes, which separate the Mainland Shelf and the Santa Barbara Basin; and, the Channel Island Slope, lying between the Basin and the Channel Island Shelf. Other notable marine features include the Pescado Fan, Dos Cuadras Ridge, Twelve-Mile Reef, and Hueneme and Mugu Submarine Canyons.

Figure 1 is a map of the study area, showing the Santa Barbara Channel and surrounding onshore areas as well as the three-mile boundary which separates state tidelands from federal OCS waters.

METEOROLOGICAL CHARACTERISTICS

Prevailing large-scale circulation along the Santa Barbara-Ventura coast results in predominant westerly to northwesterly air flow throughout the year.

FIGURE 1:
BASE MAP, SANTA BARBARA CHANNEL AND VICINITY



The region is dominated by the persistent East Pacific High, a nearly stationary anticyclonic feature which is generally centered just off the coast. During summer, with the midlatitude storm track far to the north, the position of the anticyclone is nearly invariant; winter months, however, see a southward migration of the high, allowing cyclonic systems from the Pacific to enter. These storms provide the study region with the major portion of its annual rain.

Because of topography and land-sea temperature differences (the latter heightened by the cool temperature of the California Current), small-scale circulation can differ significantly from regional patterns. Areas near the coast are subject to a marked diurnal reversal which features daytime onshore (sea breeze) winds and nighttime offshore (land breeze) winds. This sea-land regime is relatively shallow; as a result, winds are often funneled through coastal valleys and canyons. This effect is most pronounced in Ventura County, where several long, steep-walled river valleys (notably the Ventura and Santa Clara River Valleys) penetrate to interior basins, allowing coastal air parcels to travel many miles inland.

The typical shallowness of the marine layer near the coast is caused, in large part, by temperature inversions, which are present in all seasons but are stronger and more common in summer and fall. 40/ Three basic types can be identified: marine inversion, caused by cooling of low-level air passing over the cool ocean surface; radiation inversions, caused by nocturnal cooling, which weaken or disappear during warmer hours of the day; and, subsidence inversions, a result of large-scale descent of air along the east side of the East Pacific High. 41/ As a result of the inversions, upward air motion is inhibited, resulting in confinement of low-level parcels to valleys and coastal plains below the level of surrounding mountains. Severe or persistent periods of inversion entrapment combined with inadequate ventilation can result in heavy buildup of atmospheric pollutants in the region.

As mentioned earlier, precipitation in the study region falls chiefly in winter months, with the major portion occurring between November and April, usually in conjunction with mid-latitude synoptic-scale cyclonic storms. Summer thunderstorms and tropical disturbances occasionally provide warm-season rainfall.

An additional feature which exerts a significant effect upon the study area is the so-called Santa Ana condition, characterized by strong easterly winds caused by a high pressure system located over the Plateau region of the western United States. As a result of katabatic heating of the descending air near the coast, the winds tend to be very warm and dry; in addition, channeling within the valleys produces strong, gusty winds at many locations. Although such winds tend to advect pollutants onshore, resulting in relatively clean air near the coast, weak Santa Anas can transport air pollutants from the Los Angeles basin, to the southeast, into the study region. Santa Ana conditions are most common during fall and winter months, often preceding the passage of a midlatitude frontal system.

C L I M A T E

The Santa Barbara-Ventura area is characterized by a Mediterranean climate, with mild temperatures and predominantly winter precipitation, and corresponds to the Csb class of the Köppen climatic classification system. 42/ Due primarily to the marine influence, coastal areas undergo rather small diurnal and

annual temperature variations; inland areas, on the other hand, experience larger maximum-minimum differences. This coastal inland dichotomy results in the previously mentioned sea-land breeze wind regime common to the region.

Inversion height is an important parameter influencing air pollution potential (a measure of the trapping of pollutants near the surface). In general, lower inversion heights produce higher concentrations by limiting the volume of air in which pollutants are confined. Table 1 lists average monthly inversion heights at Ventura airport in 1965; in most cases, inversions were higher in afternoon hours, although June and August figures showed a reversal of this trend.

Solar radiation is another important factor which influences air pollution levels. During winter, when solar zenith angle (and, therefore, incoming radiation) is lowest, inversions are less likely to "burn off" as a result of upward convection of warm air near the surface, and may persist throughout the day. Primary pollutants such as sulfur dioxide (SO_2), hydrogen sulfide (H_2S), and carbon monoxide (CO) are likely to be highest during winter, when inversion height is generally lower and persistence can be high. Photochemical reactions, however, typically proceed over time scales measured in hours (depending on ultraviolet intensity). As a result, photochemically produced secondary pollutants (such as ozone) normally reach maximum concentrations in summer months when solar radiation is greatest. Higher summer surface temperatures give rise to a surface-based unstable layer which grows vertically and erodes the overlying inversion layer. This dilutes primary pollutant concentrations between the ground and the inversion base. 43/

TABLE 1:
AVERAGE INVERSION BASE HEIGHTS AT VENTURA AIRPORT, 1965 44/

MONTH	TIME (PST)	HEIGHT ABOVE MEAN SEA LEVEL (m.)
June	0300	762
	1500	610
July	0300	85
	1500	299
August	0300	305
	1500	259
September	0300	195
	1500	521
October	0300	15
	1500	132
November	0300	183
	1500	348
December	0300	15
	1500	317

E X I S T I N G E M I S S I O N S

Surface emission fluxes used in the base-year ARTSIM* runs were determined according to four source types: vehicular, non-petroleum stationary, petroleum

*ARTSIM is ERT's air quality model and is described in ARTSIM BASELINE RUNS, p. 236.

16—76658

onshore, and petroleum offshore. Using available emissions inventories, traffic data, and petroleum production information, as well as pertinent emission factors, source fluxes were calculated for each source type for 1 x 1 km UTM (Universal Transverse Mercator system lines, as on USGS topographic maps) grid squares. Finally, total flux for each square was determined by summing those from the four source types.

Since surface wind data were obtained only for hourly intervals, it was necessary to interpolate between successive hourly positions in order to determine times of grid-square-boundary crossings. For simplicity, while the air parcel center remained over a grid square, emissions from that square alone were used; whenever the parcel crossed a boundary between squares, emissions were updated to accommodate those of the new square only, with emissions from the previous grid square stopped. The times and positions of each boundary crossing were obtained by assuming winds invariant for the duration of the hour.

VEHICULAR EMISSIONS

Emission fluxes from the four classes of motor vehicles (cars, light-duty trucks, heavy-duty gasoline powered vehicles, and heavy-duty diesel trucks) were obtained from the headquarters and District 07 offices of the California Department of Transportation (CALTRANS). Using link-node information and their FREEWAY-11 program, CALTRANS was able to provide data on average daily emissions per UTM grid square for five pollutants: total hydrocarbons (THC), reactive hydrocarbons (RHC), oxides of nitrogen (NO_x), carbon monoxide (CO), and sulfur dioxides (SO_x). By applying available diurnal variation data (also obtained from CALTRANS), it was possible to convert emissions from CALTRANS units (kg/day) to hourly totals (kg/hr) in order to reflect time variations in traffic. Fluxes of NO_x, RHC, and CO were retained for ARTSIM input.

Vehicular mixes, representing overall averages for both freeway and surface street travel, were obtained from CALTRANS (Santa Barbara data) and the Ventura County APCD (Ventura data). Table 2 lists the respective vehicle distributions for the two counties, weighted by total miles traveled.

TABLE 2:
MILEAGE-WEIGHTED VEHICLE MIXES ASSUMED FOR EMISSIONS CALCULATIONS
(Percentage of Total Traffic)

VEHICLE TYPE	SANTA BARBARA	VENTURA
Light-duty autos	.796	.811
Light duty trucks	.130	.134
Heavy-duty gasoline powered vehicles	.067	.049
Heavy-duty diesel vehicles	.008	.006

STATIONARY SOURCES

Included in the class 2 source type are all stationary facilities except petroleum production and processing facilities (thus, class 2 includes fugitive

emissions from gasoline marketing operations). The emissions fluxes for the UTM grid squares were furnished by the Ventura and Santa Barbara APCD offices. Since available data provides only daily totals of emissions, it was necessary to divide this latter figure by the number of daily hours of operation in order to estimate emissions for a single hour.

OFFSHORE PETROLEUM FACILITIES

In general, class 3 comprises production platforms and tankers (the latter in both loading/unloading and travel modes). Unfortunately, the emissions information corresponding to such activity is rather sparse, and those data which are available have been the subject of a great deal of controversy. During the course of the current study, every effort has been made to obtain as much emissions information as possible. Selection of factors for this study was made on the basis of measurement method used, date of publication, and applicability to petroleum facilities. These figures represent our current best estimates of local petroleum-related offshore emissions.

PLATFORM EMISSIONS. During petroleum production, emissions of hydrocarbons result from evaporation of oil and gas, and from exhaust emissions of diesel engines, gas turbines, and gas burners. 45/ Leach has presented a complete, well-organized procedure for emissions estimation. 46/ His results, which fall between published high and low estimates, have been utilized in Tables 3 and 4. Table 3 lists these emission factors as functions of total oil/gas production. In Table 4, average hourly emission rates (assuming 24-hour production) for the six major primary pollutants are listed, according to oil and gas production rates.

Production rates for existing offshore platforms (for 1976) were obtained from Kinney and O'Neill. 47/ By applying the emission rates in Table 4 to the production figures, emissions estimates for each existing Santa Barbara Channel platform can be obtained.* Tables 5 and 6 list estimated production and emission rates for oil and gas production, respectively, based on the emission factors in Table 4.

TANKER EMISSIONS. Emissions attributable to the transportation of crude oil by barge or tankship are due primarily to two operations: combustion of fuels while underway or in berth; and displacement of vapors during venting or purging. In general, hydrocarbon losses tend to be largest during the latter operation, and can contribute significantly to local and regional emissions totals. 48/

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*The values in Table 3 represent aggregate emissions for the various source types per unit -- 10^3 barrels -- of production.

TABLE 3:
EMISSION FACTORS (lb/10^3 barrels produced) FOR PETROLEUM PRODUCTION

EMISSION SOURCE TYPE	THC	RHC	NO_x	CO	SO_2	TSP
Diesel Engines	14.9	13.9	43.2	17.0	7.9	7.0
Wastewater Separation*	8.0	5.2	--	--	--	--
Turbine Compressors**	--	--	600.0	--	0.6	--
Pump Seals	74.0	48.0	--	--	--	--
Compressor Seals	4.0	2.6	--	--	--	--
Relief Valves	8.0	5.2	--	--	--	--

*Assumed to occur onshore and thus not applied to platform emissions list.
**Emissions in lb/10^6 SCF gas burned.

TABLE 4:
EMISSION RATES (lb/hr) FOR OIL AND GAS PRODUCTION AND PROCESSING

POLLUTANT	OIL PRODUCTION (per 10^3 B/D)	OIL PROCESSING AND STORAGE	GAS PRODUCTION (per 10^6 SCF/D)	GAS PROCESSING
THC	2.22	2.88	--	8.75
RHC	1.63	1.86	--	2.80
NO_x (as NO_2)*	0.9	1.8	2.1	6.10
CO	.71	--	--	--
SO_2	.33	--	--	.44
TSP	.33	--	--	--

*From information provided by Laird. 49/

TABLE 5:
OIL PRODUCTION AND ESTIMATED EMISSION RATES FOR SANTA BARBARA CHANNEL PLATFORMS, 1976

PLATFORM	TRACT	OWNER	PRODUCTION (B/D)	EMISSIONS (lb/hr) THC	RHC	NO_x	CO	SO_2	TSP
Holly	S. Ellwood	ARCO	3,500	7.8	5.7	3.2	2.5	1.2	1.2
Hazel	Summerland	SOCAL	700	1.6	1.1	0.6	0.5	0.2	0.2
Hilda	Summerland	SOCAL	700	1.6	1.1	0.6	0.5	0.2	0.2
Heidi	Carpinteria	SOCAL	1,900	4.2	3.1	1.7	1.3	0.6	0.6
Hope	Carpinteria	SOCAL	1,900	4.2	3.1	1.7	1.3	0.6	0.6
Houchin	Carpinteria	Phillips	2,270	5.0	3.7	2.0	1.6	0.7	0.7
Hogan	Carpinteria	Phillips	2,270	5.0	3.7	2.0	1.6	0.7	0.7
Hillhouse	Dos Cuadras	Sun	10,400	23.1	17.0	9.4	7.4	3.4	3.4
A	Dos Cuadras	Union	13,550	30.1	22.1	12.2	9.6	4.5	4.5
B	Dos Cuadras	Union	13,550	30.1	22.1	12.2	9.6	4.5	4.5

TABLE 6:
GAS PRODUCTION AND ESTIMATED EMISSIONS FOR SANTA BARBARA CHANNEL PLATFORMS, 1976

PLATFORM			PRODUCTION (10^6 SCF/D)	NO_x EMISSIONS (lb/hr)
Holly	S. Ellwood	ARCO	0	0
Hazel	Summerland	SOCAL	1.7	3.6
Hilda	Summerland	SOCAL	1.7	3.6
Heidi	Carpinteria	SOCAL	2.3	4.8
Hope	Carpinteria	SOCAL	2.3	4.8
Houchin	Carpinteria	Phillips	1.2	2.5
Hogan	Carpinteria	Phillips	1.2	3.5
Hillhouse	Dos Cuadras	Sun	4.4	9.2
A	Dos Cuadras	Union	4.7	9.9
B	Dos Cuadras	Union	4.7	9.9

Fuel combustion emissions from tanker operations are dependent upon ship size, loading/unloading rates, and number of hours of operation, and are much greater (by about an order of magnitude) during transit than while loading.* Leach, in his analysis of OCS Sale #35 impacts, has made the following assumptions: average tanker size, 175,000 bbl. (25,000 DWT); vessel speed, eight kts; sulfur content, 0.2% by weight. 50/ In his analysis, he uses EPA emission factors. 51/ Table 7 lists emission rates for the six major pollutants using the above assumptions.

TABLE 7:
EXHAUST EMISSION RATES FOR 175,000 BARREL TANKERS ACCORDING TO THE CALCULATIONS OF LEACH

POLLUTANT	EMISSION RATE (lb/hr) UNDERWAY	IN BERTH
THC	7.2	.72
RHC	4.7	.47
NO_x	11.2	1.1
TSP	16.0	1.6
SO_2	14.2	1.7
CO	9.6	1.0

Tanker loading and unloading fugitive vapor emissions have been the subject of intense controversy in recent years. Even today, no definitive, widely accepted

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*While in berth and loading, the ship's engines are operated at about 10% of cruise power to provide "hotel services." It is assumed that the pumping emissions associated with loading were generated at the marine terminal rather than on the vessel.

emission factors are in use. Leach proposed an emissions rate of 2.0 lbs THC/10^3 gallons loaded, a compromise between several published figures. 52/ Laird prefers a lower value: 1.2 lbs THC/10^3 gallons. For our purposes, however, the data provided by MacKenzie and Rau are preferred, because of the thoroughness of their study and recent date of publication. 53/ According to that publication, loading emissions are functions of tank condition prior to loading (see Table 8 below) and a load-generated component.

TABLE 8:
ARRIVAL HYDROCARBON CONCENTRATIONS

CARGO TANK ARRIVAL CONDITION CATEGORY	AVERAGE HC ARRIVAL CONCENTRATION (% BY VOLUME)	RANGE OF ARRIVAL CONCENTRATIONS (% BY VOLUME)
CLEANED	2.5	0 - 5.0
DIRTY BALLASTED	5.0	2.0 - 8.0
EMPTY & UNDISTURBED	8.0	2.5 -13.5

Total loading emissions can be determined according to

$$E = \frac{C \cdot V}{100} + P \cdot A \cdot (G-U)$$

where E = Total volume of HC emitted (ft^3)
C = HC arrival concentration (Table 8)
V = Volume of cargo loaded (ft^3)
P = True vapor pressure (TVP) (psia)
A = Surface area of cargo (ft^2)
G = HC generation coefficient = 0.36 $ft^3/psia \cdot ft^2$
U = Final ullage correction ($ft^3/psia \cdot ft^2$)
and where the two right-hand-side terms correspond to arrival and load-generated components, respectively.

Since emission rates decrease with increasing anker size, we assume a 70,000 DWT tanker (expected to be an upper bound for local tankships and thus a conservative figure), TVP of 6 psia, based on estimated Reid vapor pressure of 7.0 psia and crude oil temperature of 80°F, and tank conditions 45% cleaned, 10% ballasted, 45% empty and undisturbed (figures provided by MacKenzie and Rau as typical of a vessel of such size). The result is an emission factor of 1.9 lbs THC/10^3 gal loaded -- 1.2 lbs from arrival HC + 0.7 lbs generated component. This value, which closely approximates Leach's, falls nearly midway between those of Laird and EPA, and is far lower than API estimates reported by MacKenzie and Rau (the latter two rates are 2.7 and 4.6 lbs THC/10^3 gal, respectively).

Reactivity of the fugitive HC generated during tanker loading (and later, in assessing spill impacts) was assumed to be .30. Most of the HC emitted in such situations belongs to the alkane class of compounds. The reactions involving alkanes (or olefins, an important constituent of auto exhaust) take place more

slowly. In the current study, this difference in ozone formation potential was modeled by assuming much lower reactivity values for alkanes.

Estimates of the daily throughput, storage, capacity, and pumping rate of local marine terminals were obtained from Lind. 54/ Using these figures and the above emission factors for tanker loading, it was possible to calculate emission rates for each facility. In addition, fugitive emissions from storage tanks were estimated using Leach's 55/ figure of .05 lb/hr/10^3 bbl stored.* Table 9 lists pumping rates and storage capacities as well as computed emission rates for both existing and possible future terminal sites, assuming maximum pumping and storage.

TABLE 9:
PUMPING RATES, STORAGE CAPACITY, AND HC EMISSIONS FOR LOCAL MARINE TERMINALS

TERMINAL	PUMPING RATE (bbl/hour)	STORAGE (bbl)	LOADING EMISSIONS (lb/hr)** THC	LOADING EMISSIONS (lb/hr)** RHC	STORAGE EMISSIONS (lb/hr)*** THC	STORAGE EMISSIONS (lb/hr)*** RHC
EXISTING						
M1 Union/Cojo	3,250	55,000	259.4	77.8	4.9	1.5
M2 GETTY/Gaviota	9,000	275,000	718.2	215.5	24.3	7.3
M3 AMINOIL/Ellwood	5,000	160,000	399.0	119.7	14.1	4.2
M4 SOCAL/Carpinteria	12,000	268,000	957.6	287.3	23.6	7.1
M5 GETTY/Ventura	10,000	320,000	798.0	239.4	28.2	8.5
M6 UNION/Ventura	10,000	273,000	798.0	239.4	24.1	7.2
M7 EDISON/Mandalay	11,875	315,000	949.6	284.9	27.8	8.3
POSSIBLE FUTURE SITES						
M8 EXXON/Los Flores	13,000 to 26,000	440,000	1995.0	598.5	38.8	11.6
M9	17,500	338,000	1396.5	419.0	29.8	8.9
M10	20,000	1,000,000	1596.0	478.8	88.2	26.5

**Emissions generated while loading is occurring, assuming ten-hour loading time.
***Representing average hourly values (assumed steady over 24-hour period).

ONSHORE PETROLEUM FACILITIES

Emissions data for onshore petroleum production, handling, and processing facilities were obtained from the Santa Barbara and Ventura County APCD emissions inventories. Figures obtained were based on either actual measurement or on calculations from relevant emission factors.

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*Assuming floating roof tanks with conditions representing average of "new tank" and "old tank" characteristics.

It is expected that increases in offshore oil production will cause sizable growth of the throughput of onshore treatment and separation (T & S) facilities; in addition, the number of such facilities along the coast may increase significantly. Table 10 lists T & S throughputs for those facilities known to be in operation in 1976. 56/ In Table 11, estimated T & S emissions in 1976, computed by applying emission factors in Table 4 to the throughputs in Table 9, are presented. Expected future trends will be discussed in a later section of this report.

TABLE 10:
ESTIMATED THROUGHPUTS OF EXISTING TREATMENT AND SEPARATION FACILITIES, SANTA BARBARA - VENTURA COAST, 1976

LOCATION	OWNER	THROUGHPUTS	
		OIL (B/D)	GAS (MCF/D)
Gaviota	ARCO	80	195
Molino	Shell	Ø	2,000
Tajiguas	Phillips	Ø	4,000
Ellwood	AMINOIL	100	500
Ellwood	ARCO	3,500	Ø
Carpinteria	SOCAL	4,460	7,920
La Conchita	Phillips	4,540	2,270
Rincon	ARCO	700	100
Rincon	Mobil	34,500	11,300
Rincon	Norris	500	
Seacliff	Chanslor	2,600	13,700

TABLE 11:
ESTIMATED EMISSIONS FROM TREATMENT AND SEPARATION FACILITIES, 1976

LOCATION	OWNER	EMISSIONS (lb/hr)			
		THC	RHC	NO_x	SO_2
Gaviota	ARCO	.23	.15	.15	--
Molino	Shell	12.96	8.37	8.10	--
Tajiguas	Phillips	39.40	12.60	27.45	1.98
Ellwood	AMINOIL	.29	.10	.18	--
Ellwood	ARCO	10.08	6.51	6.30	--
Carpinteria	SOCAL	82.14	33.06	56.34	3.48
La Conchita	Phillips	32.94	14.80	22.02	1.00
Rincon	ARCO	2.88	1.86	1.80	--
Rincon	Mobil	148.24	95.81	131.03	4.97
Rincon	Norris	1.44	.93	.90	--
Seacliff	Chanslor	142.44	48.00	98.70	6.78

OIL AND GAS DEVELOPMENT SCENARIOS

O'Neill has published a set of production scenarios representing various levels of Santa Barbara Channel oil and gas production. 57/ The three cases outlined represent low, middle, and high estimates of future production and were adopted in order to reduce the rather large number of possible production levels into a small, yet meaningful, set of combinations.

O'Neill's Case 1 (low estimate) scenario assumes that future production is restricted to platforms now in place -- Dos Cuadras, Carpinteria, Summerland, South Ellwood, and Hondo. Production would peak in 1980 with 65,700 B/D and 49 MM SCF/D gas.

Case 2 represents a mid-range estimate for future Channel development. In formulating this alternative, O'Neill assumed new platforms in Dos Cuadras, Carpinteria, Hueneme, Santa Clara (three platforms, Northern field), and Santa Ynez (full development, Exxon estimate of 423 million barrels recovery) OCS tracts, increased production at Conception, Summerland, and Carpinteria tideland tracts, and 17 new wells drilled at Holly (but denial of permission to ARCO to expand its onshore processing facilities). Peak development, which would occur in 1985, would total 165,300 B/D oil and 134 MM SCF/D gas.

The third and final production scenario represents an expected upper bound for future Channel production. Case 3 is similar to Case 2, except that Santa Ynez production assumes the USGS recovery estimate of 730 million barrels of oil (30-year production time), that the Southern field in the Santa Clara unit is brought into production, that Pitas Point production takes place, and that ARCO is allowed to expand its South Ellwood onshore facility and install a Stretford unit to clean its produced gas. Peak development for this scenario would occur in 1988 and total 350,000 B/D oil and 253.3 MM SCF/D gas.

Table 12 is a list of future oil and gas production estimates for the Santa Barbara Channel using O'Neill's Cases 1, 2, and 3 scenarios with the assumptions listed above.

TABLE 12:
ESTIMATED FUTURE OIL AND GAS PRODUCTION, SANTA BARBARA CHANNEL

	1976	1980	1983	1985	1987	1989	1991
CASE 1 (LOW ESTIMATE)							
Oil (10,000 B/D)	48.3	65.7	44.1	37.1	31.5	26.7	22.3
Gas (10,000,000 SCF/D)	31.0	49.0	29.0	25.0	21.0	18.0	15.0
CASE 2 (MID-RANGE ESTIMATE)							
Oil (10,000 B/D)	48.3	120.1	153.5	165.3	139.5	132.5	107.4
Gas (10,000,000 SCF/D)	31.0	72.0	118.0	134.0	113.0	107.0	89.0
CASE 3 (HIGH ESTIMATE)							
Oil (10,000 B/D)	48.3	101.3	202.1	269.9	336.6	315.0	255.2
Gas (10,000,000 SCF/D)	31.0	46.4	129.7	206.0	237.0	228.0	184.5

ARTSIM BASELINE RUNS

Preliminary tasks involved in the air quality impact simulations included selection of the days and trajectories to be modeled, acquisition and processing of meteorological, air quality, and emissions data, and calibration of the model runs in order to equate ARTSIM pollutant concentrations with those observed at the respective air monitoring locations. Sampling days were selected from among both high-oxidant and average days; each oxidant monitoring station in the study area was used as a receptor location for at least one case; and, trajectories were selected in order to model the onshore impact of every Santa Barbara Channel offshore lease unit.

Upon completion of the base year calibration runs, in which initial pollutant concentrations were varied within reasonable bounds until satisfactory correspondence with observed levels was obtained, future year trajectories were modeled using the same air parcel path but different emissions and initial concentrations using projected population and emission factor information. The latter simulations became the basis for the OCS impact runs (see ARTSIM OCS IMPACT SIMULATION RUNS).

DESCRIPTION OF THE MODEL

The ARTSIM (Atmospheric Reaction and Transport SIMulation) model was developed by ERT as a predictive tool for aiding decisionmakers in assessing regional and local air pollution impacts. A successor to ERT's well known DIFKIN model, a pioneer in the field of reactive pollutant modeling, ARTSIM can be used to predict the behavior of pollutants emitted from distributed sources (such as transportation networks and residential areas) as well as concentrated industrial sources. In essence, ARTSIM computes the time-dependent behavior of a moving air parcel in which a multicomponent gaseous mixture undergoes simultaneous diffusion and chemical reactions.

ARTSIM is a semi-Lagrangian model in which the air parcel carries its own set of coordinates in a trajectory aligned with the mean wind direction and traveling at the prevailing horizontal wind velocity. The basic ARTSIM equation sets the time rate of change of concentration equal to a diffusion term and a reaction term. Numerical integration of this equation, subject to meteorological and chemical conditions, yields concentrations of each pollutant as a function of height and time. The boundary conditions at the surface set the emission level of pollutants; in addition, emissions can be introduced at some specified above-ground elevation.

A simplified flow chart of ARTSIM input, processing, and output appears in Figure 2. Input parameters specified by the user include meteorological conditions (vertical eddy diffusivities, mixing height, and winds), pollutant data (initial concentrations and surface emissions), and ultraviolet intensity; chemical rate constants, unless specified, revert to default values within the program. Output consists of concentration of each of the species at up to ten user-specified vertical points at specified time intervals along the trajectory path.

In the current study, 16 reactions involving ten species were modeled in cells bounded at 0, 100, 200, 300, and 400 m above the surface. Species for which concentrations were calculated are nitric oxide (NO), reactive hydrocarbons (HC), nitrogen dioxide (NO_2), ozone (O_3), nitrous acid (HNO_2), nitrogen trioxide (NO_3), nitrogen pentoxide (N_2O_5), hydroxyl (OH), oxidized hydrocarbon radicals (RO_2), and carbon monoxide (CO). The 16 reactions included in the chemical module are:

1. $PHOTON+NO_2 \longrightarrow NO+O_3$
2. $NO+O_3 \longrightarrow NO_2+O_2$
3. $O+HC \longrightarrow 8RO_2$
4. $OH+HC \longrightarrow 8RO_2$
5. $RO_2+NO \longrightarrow NO_2+ .1250H$
6. $RO_2+NO_2 \longrightarrow PAN$
7. $OH+NO \longrightarrow HNO_2$
8. $OH+NO_2 \longrightarrow HNO_3$
9. $O_3+HC \longrightarrow RO_2$
10. $PHOTON+HNO_2 \longrightarrow OH+NO$
11. $NO_2+O_3 \longrightarrow NO_3+O_2$
12. $NO_3+NO_2 \longrightarrow N_2O_5$
13. $N_2O_5 \longrightarrow NO_3+NO_2$
14. $N_2O_5+H_2O \longrightarrow 2HNO_3$
15. $NO+NO_2+H_2O \longrightarrow 2HNO_2$
16. $NO_2+Particles \longrightarrow Products$

At present, the ARTSIM chemical module is being expanded significantly to update the HC/NO_x mechanism and to include sulfur chemistry. Since validation studies have not yet been completed, however, the simpler 16-reaction module was used in the current project.

The ARTSIM trajectory section is driven by a supplementary program which interpolates available surface wind data by means of a weighting factor (which weighted winds at each station inversely with distance from the air parcel). Wind data are generally reported hourly; thus, it is necessary to assume winds to be invariant through each one-hour period. Although trajectories over the ocean or homogeneous land surfaces need no further processing, those which cross complex terrain (e.g., mountain-valley areas) occasionally require modification: it is sometimes necessary to alter the path to account for low-level channeling of flow within valleys or around hilly areas.

Vertical eddy diffusivities (K_z) are specified at the top and bottom of the parcel and midway between those levels for which concentrations are calculated; in our case, K_z parameters were listed at 0, 50, 150, 250, 350, and 400 meters above the surface, and updated hourly. The diffusivities were obtained by using rawinsonde data and a computation method based on vertical thermal structure (lapse rate) and wind shear (see Appendix I for description of this method).

Chemical rate constants are specified in units of min^{-1} for first-order reactions and ppm^{-1} min^{-1} for second-order reactions. Values can be inserted by the user; otherwise, the existing default constants are utilized. Photodissociation rate values, however, are time-dependent (proportional to solar zenith angle); currently in use at ERT is an EPA program which determines these values as functions of latitude, longitude, day of year, and time of day, updating them every ten minutes. 58/

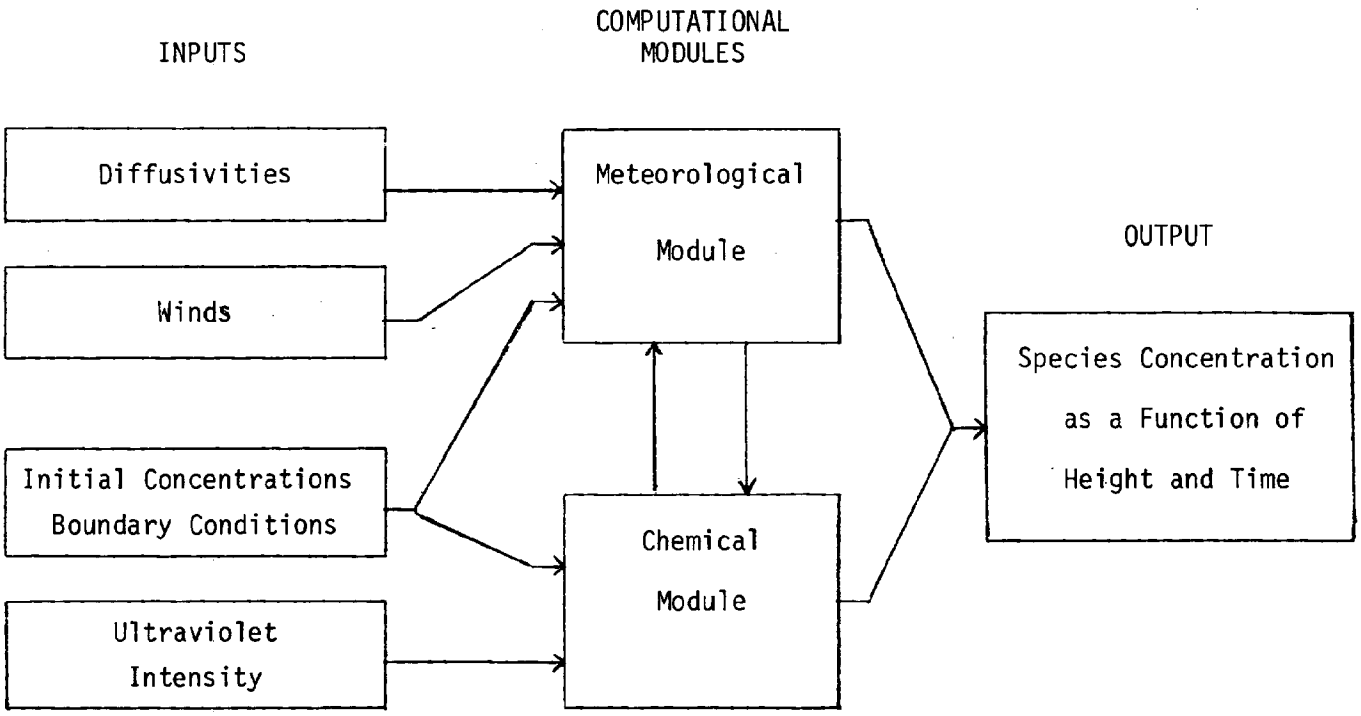

Figure 2 ARTSIM Flow Diagram

Emission fluxes from the surface, or elevated sources, are obtained from inventories and calculated either internally or externally (in our case, the latter, again for reasons of cost). For use in ARTSIM, units must be converted from the standard mass/time to meters/minute in order to obtain flux velocities. The flux terms represent boundary conditions at the bottom of the vertical mesh; the upper boundary condition (at 400 m, the top of the cell) is zero pollutant flux.

Initial pollutant concentrations comprise the final input parameters required by ARTSIM. Values of NO, HC, NO_2, O_3, HNO_2, and CO are specified at the five vertical levels as initial conditions; concentrations of the remaining four pollutants (NO_3, N_2O_5, OH, and RO_2) are computed based on known chemical relationships using concentrations of the first six substances. Initial conditions are subject to more uncertainty than the other input parameters since most trajectories originated over the ocean, where air quality data are nonexistent. However, by assuming certain initial pollutant ratios (e.g., HC (ppm):NO_x (ppm)$\simeq$5:2 and NO_2:NO$\simeq$2:1) and varying the initial levels to allow ARTSIM predictions to match observed air quality data later in the day, adequate results were obtained. 59/

BASE YEAR CALIBRATION RUNS

Selection of modeling days and trajectories for the simulation study was done on the basis of oxidant concentration, predominantly high-oxidant days with some typical or average cases, and trajectory path, to evaluate impacts of each lease tract and to include every air monitoring station as a receptor. Meteorological data (surface winds, upper air soundings), surface emission fluxes, and ultraviolet intensity were determined for the individual simulation days and put into ARTSIM. Initial pollutant concentrations, the only remaining ARTSIM data requirement, could not be determined precisely since all parcel paths began over the Channel; as a result, it was necessary to estimate the initial conditions on the basis of onshore data, varying the levels of the respective pollutants until satisfactory correlation with air quality measurements was obtained when the parcel reached the receptor later in the day.

As mentioned above in the description of the model, the trajectory-generation program used in the current study utilized surface wind observations from one or more stations to determine the position of the parcel every hour. Since nearly all wind data are in the form of hourly averages or hourly observations, winds must be assumed invariant through each one-hour period. Distance of the parcel from each wind station is determined for every hourly location; the subsequent calculation of parcel movement utilizes a weighting factor proportional to the inverse of the distance from parcel to wind station (e.g., wind vectors for a station one km from the parcel would be weighted twice as heavily as those for a station two km away). In certain instances, it was deemed necessary to modify the trajectories somewhat in order to account for terrain influences: trajectories reaching such inland stations as Ojai, Simi, and Santa Paula, for example, were altered by assuming low-level winds to be channeled through valleys or canyons, rather than directly over high terrain. Coastal area station trajectories, however, needed no such modification.

Trajectories were calculated to correspond to various arrival times during the day. Selection of a single case was based on two considerations: oxidant concentration (peak or near-peak preferred) and lease tracts traversed. Table 13 lists the simulation days, arrival times, and station locations selected for

the current study, and includes ozone concentrations for each station at the arrival time.

TABLE 13:
DAYS, ARRIVAL LOCATIONS AND TIMES, AND OBSERVED OZONE CONCENTRATIONS FOR THE TRAJECTORIES SELECTED FOR USE IN THIS STUDY

DATE	ARRIVAL LOCATION	ARRIVAL TIME (PST)	CONCENTRATION UPON ARRIVAL (pphm)
7/18/74	Fairview (SBCo)	1400	16
7/18/74	State St. (SBCo)	1400	18
5/1/75	Cathedral Oaks (SBCo)	1300	10
7/9/75	Camarillo (VCo)	1400	9
7/10/75	Simi Valley (VCo)	1400	19
7/10/75	Ojai (VCo)	1300	19
9/25/75	Santa Paula (VCo)	1300	12
9/25/75	Ventura (VCo)	1400	16

FUTURE YEAR BASELINE RUNS

Selection of the future years for ARTSIM modeling was based upon the paths of individual trajectories: the year of expected peak production for the particular tract or facility traversed was chosen in order to simulate maximum expected emissions. Petroleum facility emission fluxes were obtained by applying previously discussed emission factors to future production estimates. 60/ Non-petroleum emissions and initial pollutant concentrations were determined by applying future population and vehicle emission factor projections (see below).

VEHICLE EMISSIONS

Nordsieck has estimated vehicle emissions for future years by applying EPA future emission factors to projected daily vehicle miles (DVM) for the Santa Barbara South Coast. 61/ Vehicle mixes listed in EXISTING EMISSIONS were assumed constant for future years. Table 14 lists Nordsieck's future estimates of RHC, NO_x, and CO, as well as ratios of current-to-future emissions. The latter ratios were applied to CALTRANS figures (see EXISTING EMISSIONS) to obtain future vehicle emissions by UTM square, which were in turn used for ARTSIM modeling. Emissions for peak years not shown in Table 14 were acquired by interpolating between listed values.

TABLE 14:
FUTURE VEHICLE EMISSIONS ESTIMATES FOR SANTA BARBARA COUNTY SOUTH COAST (tons/day)

SANTA BARBARA COUNTY	1973	1977	1980	1985	1990	1995
RHC EMISSIONS	9.69	7.40	5.45	2.84	2.12	2.08
RATIO TO 1976 EMISSIONS	1.22	.93	.68	.36	.27	.26
NO_x EMISSIONS	16.3	16.1	13.6	11.2	11.2	11.7
RATIO TO 1976 EMISSIONS	1.01	1.0	.84	.69	.69	.72
CO EMISSIONS	110.4	81.1	59.6	41.2	38.1	39.3
RATIO TO 1976 EMISSIONS	1.25	.92	.67	.47	.43	.44

TABLE 15:
FUTURE VEHICLE EMISSIONS ESTIMATES FOR VENTURA COUNTY (tons/day) 62/

VENTURA COUNTY	1973	1977	1980	1985	1990	1995
RHC EMISSIONS	4.72	2.19	2.20	2.10	2.10	2.10
RATIO TO 1976 EMISSIONS	1.65	.78	.79	.75	.75	.75
NO_x EMISSIONS	2.12	2.09	2.33	2.58	2.56	2.52
RATIO TO 1976 EMISSIONS	1.01	1.00	1.11	1.23	1.22	1.20
CO EMISSIONS	6.62	7.00	7.16	6.21	6.44	6.70
RATIO TO 1976 EMISSIONS	.96	1.01	1.04	.90	.93	.97

OTHER NON-PETROLEUM INDUSTRIES

Emissions from aircraft and non-petroleum stationary sources were also obtained from Nordsieck. Table 16 lists projected RHC, NO_x, and CO values. As in the previous case, emissions for years not listed were obtained by interpolating the values in the table.

TABLE 16:
FUTURE AIRCRAFT AND STATIONARY SOURCE (NON-PETROLEUM) EMISSIONS FOR SANTA BARBARA COUNTY SOUTH COAST (tons/day) 63/

SANTA BARBARA COUNTY	1973	1977	1980	1985	1990	1995
RHC EMISSIONS	4.72	2.19	2.20	2.10	2.10	2.10
RATIO TO 1976 EMISSIONS	1.65	.78	.79	.75	.75	.75
NO_x EMISSIONS	2.12	2.09	2.33	2.58	2.56	2.52
RATIO TO 1976 EMISSIONS	1.01	1.00	1.11	1.23	1.22	1.20
CO EMISSIONS	6.62	7.00	7.16	6.21	6.44	6.70
RATIO TO 1976 EMISSIONS	.96	1.01	1.04	.90	.93	.97

Ventura County estimates based on values obtained from Schere are shown in Table 17.

TABLE 17:
FUTURE AIRCRAFT AND STATIONARY SOURCE (NON-PETROLEUM) EMISSIONS ESTIMATES FOR VENTURA COUNTY (tons/day) 64/

VENTURA COUNTY	1973	1977	1980	1985	1990	1995
RHC EMISSIONS	12.35	6.55	6.96	7.21	7.62	8.04
RATIO TO 1976 EMISSIONS	1.49	.79	.84	.87	.92	.97
NO_x EMISSIONS	25.82	28.66	33.48	40.29	42.56	43.98
RATIO to 1976 EMISSIONS	.91	1.01	1.18	1.42	1.50	1.55
CO EMISSIONS	123.43	144.71	157.48	147.55	161.74	178.76
RATIO TO 1976 EMISSIONS	.87	1.02	1.11	1.04	1.14	1.26

PETROLEUM INDUSTRY EMISSIONS

Emission factors for petroleum production, processing, and transport were obtained from Leach, as outlined in EXISTING EMISSIONS, and were applied to future production estimates (see OIL AND GAS DEVELOPMENT SCENARIOS) in order to estimate total emissions within the study area. For the baseline situation, Case 1 development (existing facilities only) was assumed. Table 18 lists production and emissions estimates for selected future years, while Table 19 shows total study area emissions for the same years.

TABLE 18:
EMISSIONS FROM PETROLEUM PRODUCTION, PROCESSING, AND TRANSPORT FOR SANTA BARBARA-VENTURA STUDY AREAS (tons/day) -- CASE 1 DEVELOPMENT (EXISTING FACILITIES)

SANTA BARBARA-VENTURA	1976	1980	1985	1990	1995
OIL PRODUCTION (10,000 B/D)	48.3	65.7	37.1	24.5	16.3
GAS PRODUCTION (10,000,000 SCF/D)	31.0	49.0	25.0	16.3	10.8
EMISSIONS					
RHC	1.20	1.65	.93	.67	.44
NO_x	.34	.47	.26	.19	.13
CO	.14	.18	.10	.08	.05

TABLE 19:
TOTAL STUDY AREA EMISSIONS, FUTURE YEARS (tons/day) -- CASE 1 DEVELOPMENT (EXISTING FACILITIES)

TOTAL STUDY AREA	1976	1980	1985	1990	1995
RHC	55.8	42.4	28.0	24.2	24.7
NO_x	86.2	85.2	85.8	89.9	94.9
CO	434.3	366.4	291.7	310.9	338.2

ARTSIM OCS IMPACT SIMULATION RUNS

In order to assess potential impacts of future Santa Barbara Channel petroleum production and handling upon the air quality of the study region, two alternative simulation techniques were employed in determining ARTSIM input parameters. The first approach, modeling of the influences of petroleum facility emissions upon ambient levels of the precursors (NO_x and RHC) and thence upon oxidant concentration, consisted of varying the initial pollutant concentrations in proportion to regional emissions. Surface emissions fluxes were held constant in order to isolate the ambient air quality impact of variations in initial conditions alone. The second technique was designed to model potential impacts of individual point sources (platforms, T & S facilities, marine terminals) at certain onshore receptor locations. Future baseline runs and O'Neill's Cases 1, 2, and 3 production scenarios formed the basis for the simulations.

OXIDANT VARIATION DUE TO CHANGES IN AMBIENT PRECURSOR CONCENTRATIONS

As outlined in DESCRIPTION OF THE MODEL, oxidant (ozone) buildup in the chemical module of the ARTSIM program results from the interaction of several precursor species: RHC and NO_x, in particular, are generally thought of as ozone producers, with NO, NO_2, and O_3 in a dynamic equilibrium described by reactions 1 and 2 in the chemical scheme outlined in ARTSIM BASELINE RUNS. In addition, the ratios of initial concentrations of RHC:NO_x and NO_2:NO heavily influence peak ozone levels. Local monitoring data were used in estimating the above concentrations and ratios for use in baseline and subsequent ARTSIM runs. These values were then modified by incorporating emissions for the three petroleum development scenarios to obtain three sets of initial concentration conditions. By making ARTSIM runs in which only these initial pollutant levels were varied, the impact of petroleum facility emissions upon background precursor levels, and thus upon oxidant formation, was assessed.

Table 20 lists forecast values of emissions (tons/day) from petroleum facilities in the Santa Barbara Channel and adjacent shoreline for the three development scenarios outlined earlier, using emission factors also listed earlier in this chapter. Table 21 lists emissions from petroleum facilities as percentages of total study area emissions for the examples in Table 20. Case 1 development (current facilities only) constitutes the baseline emissions case: scaled future year initial conditions were allocated to petroleum-facility and non-petroleum components according to the percentages listed in Table 21. Initial conditions for the Case 2 and 3

scenarios were obtained by adding this non-petroleum component to the respective petroleum-facility emissions listed in Table 20.

TABLE 20:
ESTIMATED EMISSIONS DUE TO PETROLEUM FACILITIES WITHIN THE STUDY AREA (tons/day)

	1976	1980	1985	1990	1995
CASE 1 DEVELOPMENT					
RHC	1.20	1.65	.93	.67	.44
NO_x	.34	.47	.26	.10	.13
CO	.14	.18	.10	.08	.05
CASE 2 DEVELOPMENT					
RHC	1.20	2.97	4.19	3.10	1.58
NO_x	.34	.85	1.18	.88	.45
CO	.14	.34	.46	.34	.17
CASE 3 DEVELOPMENT					
RHC	1.20	3.43	6.80	9.63	2.40
NO_x	.34	.98	1.93	2.74	.68
CO	.14	.39	.76	1.08	.27

TABLE 21:
PERCENTAGES OF TOTAL STUDY AREA EMISSIONS RESULTING FROM OFFSHORE AND COASTAL PETROLEUM FACILITIES

	1976	1980	1985	1990	1995
CASE 1 DEVELOPMENT					
RHC	2.2	3.9	3.3	2.8	1.8
NO_x	.39	.55	.30	.21	.14
CO	1.03	.05	.03	.02	.01
CASE 2 DEVELOPMENT					
RHC	2.2	7.0	15.0	12.8	6.1
NO_x	.39	1.0	1.4	1.0	.47
CO	.03	.09	.16	.11	.05
CASE 3 DEVELOPMENT					
RHC	2.2	8.1	24.3	39.8	9.0
NO_x	.39	1.1	2.2	3.0	0.7
CO	.03	.11	.26	.35	.08

To demonstrate the above technique by way of example, let us examine an impact simulation for the trajectory of May 1, 1975, which arrived at the Cathedral Oaks (Santa Barbara) monitoring station at 1300 PST. The trajectory originated over the ocean west of Santa Barbara (the simulation run began at 0700) and passed over the Hondo site in the Santa Ynez tract about 1100 PST. This sample day represented a moderate ozone day, with peak ozone of 9 pphm occurring at the time of arrival of the air parcel; this can be considered an average summer ozone day for the Santa Barbara area. Initial concentrations RHC, NO_2, and NO obtained during calibration exercises appear in Table 22.

TABLE 22:
INITIAL POLLUTANT CONCENTRATIONS FOR CALIBRATION RUNS, 5/1/75 (see text)

HEIGHT ABOVE SURFACE (m.)	POLLUTANT CONCENTRATIONS (pphm)		
	RHC	NO_2	NO
0	4.0	3.0	1.8
100	3.5	2.6	1.6
200	2.5	1.9	1.1
300	2.0	1.5	0.9
400	1.5	1.1	0.7

1985 was selected as the future year for modeling purposes since it represented the peak production year for both the middle (Case 2) production scenario and the Santa Ynez lease tract. In comparing total 1985 study area emissions for the three development cases, Ventura County emissions were neglected owing to the large distance between the trajectory origin and Ventura. Surface initial pollutant concentrations of RHC, NO_2, NO, and O_3 for Cases 1, 2, and 3 are listed in Table 23: separate ARTSIM runs were made using the three sets of initial concentrations, and holding all other input variables (surface emissions, meteorology, sunlight) constant. The results, shown graphically in Figure 3, indicate a range in peak O_3 from 5.0 pphm (Case 1) to 10.5 (Case 3); the Case 2 peak (8.8 pphm) was very close to the 1975 calibration value of 9 pphm.

For the purposes of modeling initial condition impact upon Ventura County, a trajectory of September 25, 1975, arriving at the City of Ventura at 1400 PST was chosen. Peak ozone on that day was higher at the Ventura station, which lies only a few miles from the shoreline, than at locations further inland, an indication that morning precursors exerted a major effect upon oxidant. If onshore surface emissions for the same day were a major O_3-producing factor, inland O_3 would be expected to be higher than at Ventura -- in fact, this latter condition is the normal summer situation in the area. Unlike the Santa Barbara run, non-petroleum emissions from both counties were used for comparison purposes: since typical gradient-level winds are northwesterly in the study area (i.e., directed from Santa Barbara toward Ventura), it follows that transport of Santa Barbara emissions to Ventura County is more common than the reverse.

TABLE 23:
INITIAL SURFACE-LEVEL POLLUTANT CONCENTRATIONS FOR 1985 SIMULATION RUNS -- TRAJECTORY OF 5/1/75

DEVELOPMENT CASE	POLLUTANT CONCENTRATIONS (pphm)			
	RHC	NO_2	NO	O_3
CASE 1 (EXISTING)	1.54	2.10	1.26	1.70
CASE 2 (MID-RANGE)	3.02	2.26	1.36	1.70
CASE 3 (HIGH)	3.78	2.37	1.43	1.70

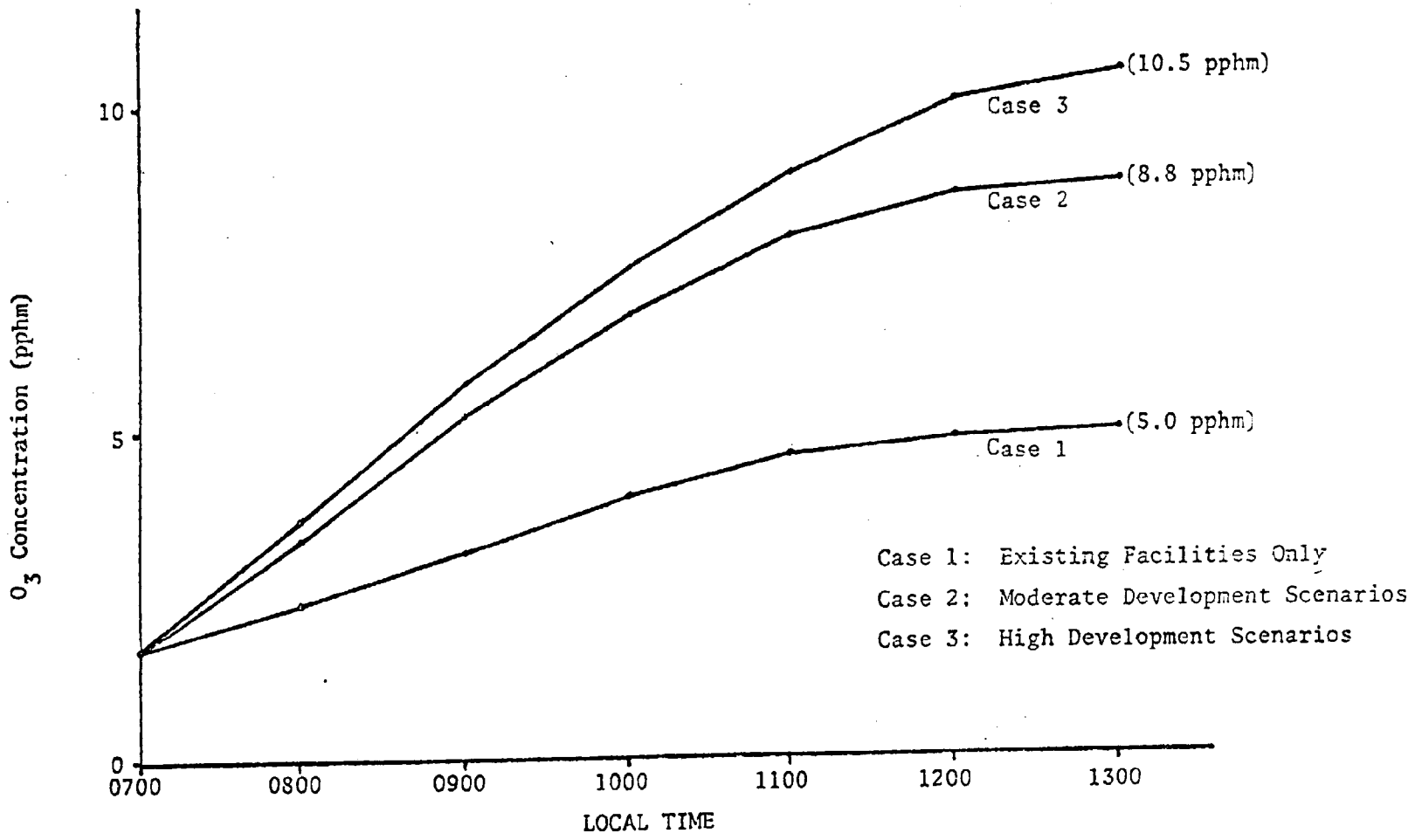

Figure 3 Ozone Concentration vs. Time for Varying Initial Conditions, Trajectory of 5/1/75, Using Scaled Initial Conditions and Surface Emissions for 1985. (Santa Barbara Moderate-O_3 Case).

Initial pollutant concentrations obtained from the calibration exercise (in which peak O_3 was 16.6 pphm) appear in Table 24.

TABLE 24:
INITIAL CONCENTRATIONS OF RHC, NO_2, and NO FOR VENTURA CALIBRATION RUN, 9/25/75 TRAJECTORY

HEIGHT ABOVE SURFACE (m.)	POLLUTANT CONCENTRATION (pphm)		
	RHC	NO_2	NO
0	6.5	3.0	1.5
100	5.5	2.5	1.3
200	5.0	2.3	1.2
300	5.0	2.3	1.2
400	4.0	1.8	

1985 was again selected as the future modeling year for the simulations; surface initial concentrations of RHC, NO_2, NO, and O_3 are listed in Table 25.

TABLE 25:
SURFACE-LEVEL INITIAL CONCENTRATIONS OF RHC, NO_2, NO, AND O_3 FOR 1985 IMPACT SIMULATION, VENTURA (units pphm)

DEVELOPMENT	RHC	NO_2	NO	O_3
CASE 1 (EXISTING)	4.6	2.2	1.1	2.1
CASE 2 (MID-RANGE)	5.2	2.4	1.2	2.1
CASE 3 (HIGH)	5.8	2.5	1.3	2.1

Results of the three ARTSIM runs, in which only initial concentrations were varied, are presented in Figure 4. Differences in magnitude of peak ozone between the three development cases were less than for the Santa Barbara case discussed earlier, since non-petroleum emissions were higher for the latter case, differences between Cases 1, 2, and 3 petroleum emissions constituted smaller percentages of total study area emissions, nevertheless, Case 1 and Case 3 peak O_3 differed by about 3 pphm (14.9 versus 17.8); the Case 2 peak was 16.9 pphm.

Additional simulation runs were made to reflect two additional oxidant day types: a high oxidant day for Santa Barbara and an average oxidant day for Ventura. In the former case, a trajectory arriving at the State St. ARB station on July 18, 1974, was selected (corrected peak hourly average ozone on that day was 18 pphm). The latter situation was modeled using the trajectory of July 9, 1975, which arrived at Camarillo at 1400 PST (peak hourly average O_3, 9 pphm). Methodologies for both runs were the same as those outlined above for the previous simulations. Results for Cases 1, 2, and 3 initial conditions appear in Figures 5 and 6 respectively, while plots of the four trajectories are shown in Figure 7. Table 26 lists Cases 1, 2, and 3 results for the four sampling days.

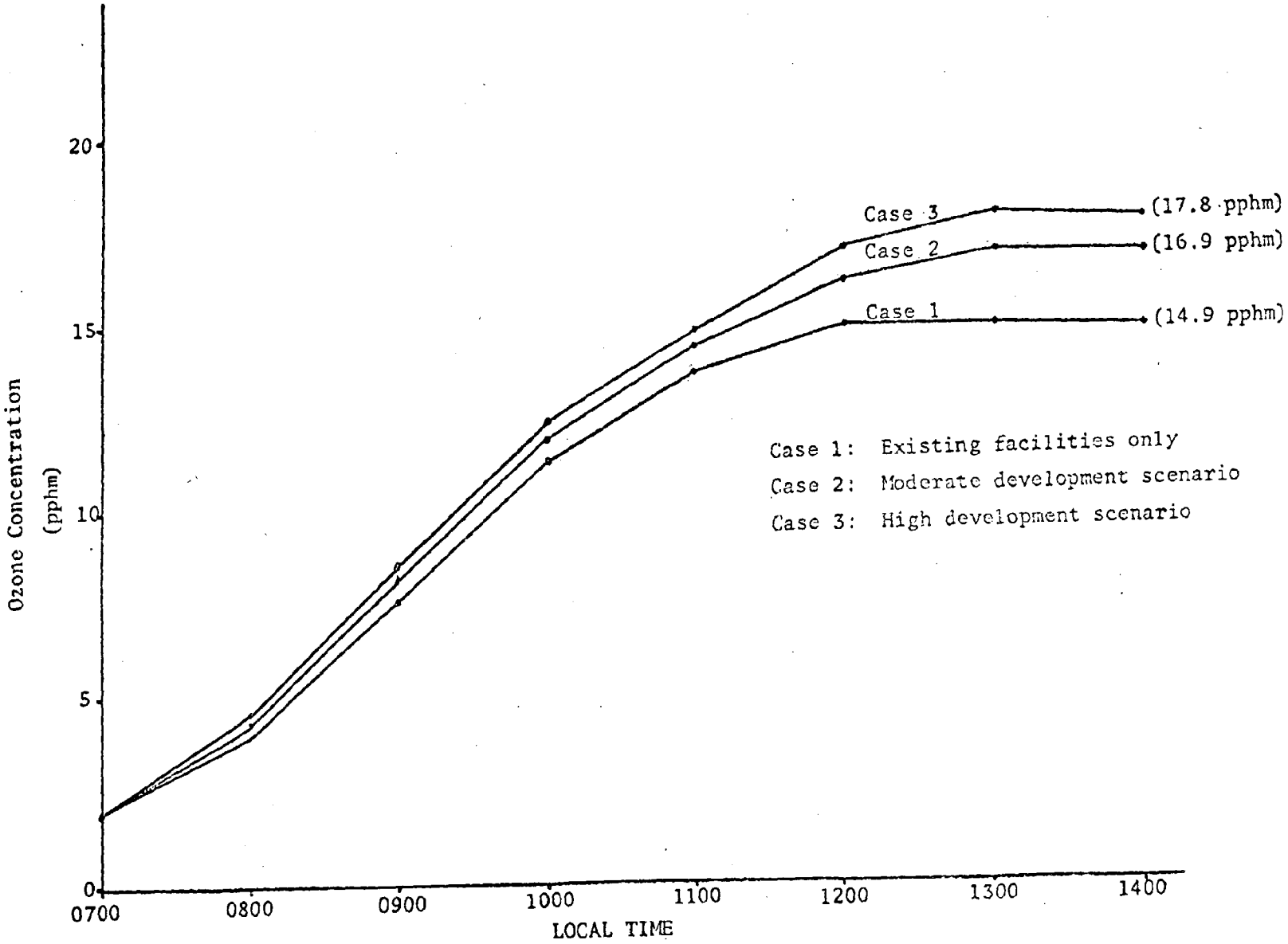

Figure 4 Ozone Concentration vs. Time for Varying Initial Condition Trajectory of 9/25/75, Using Scaled Initial Conditions and Surface Emissions for 1985 (No Petroleum Facility Fluxes) -- (Ventura High- O_x Case)

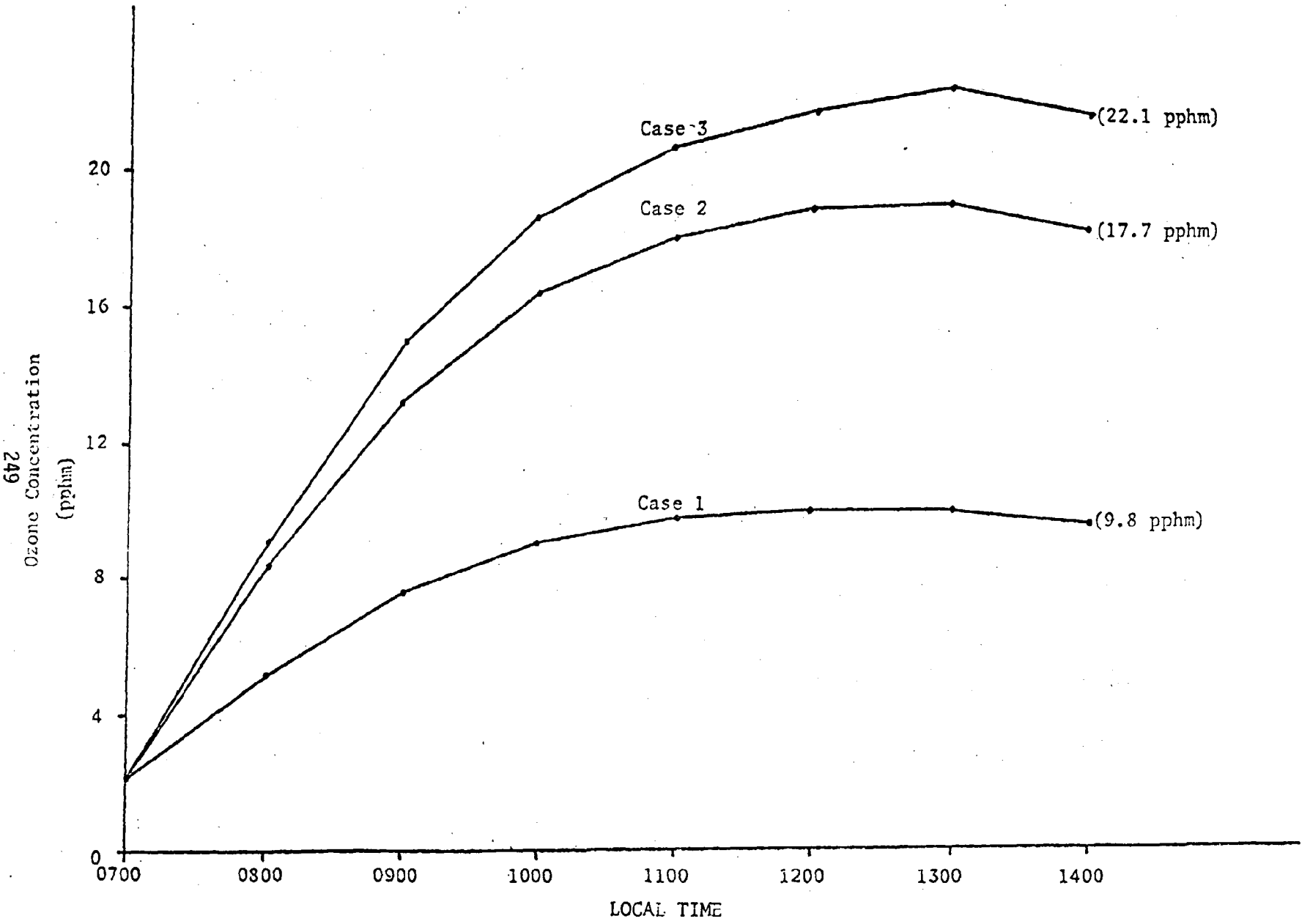

Figure 5 Ozone Concentration vs. Time for Varying Initial Concentrations
Calibration: 7/18/74 Station: State St. Arrival: 1400
Future Year Modeled: 1985--(Santa Barbara High-O_x Case)

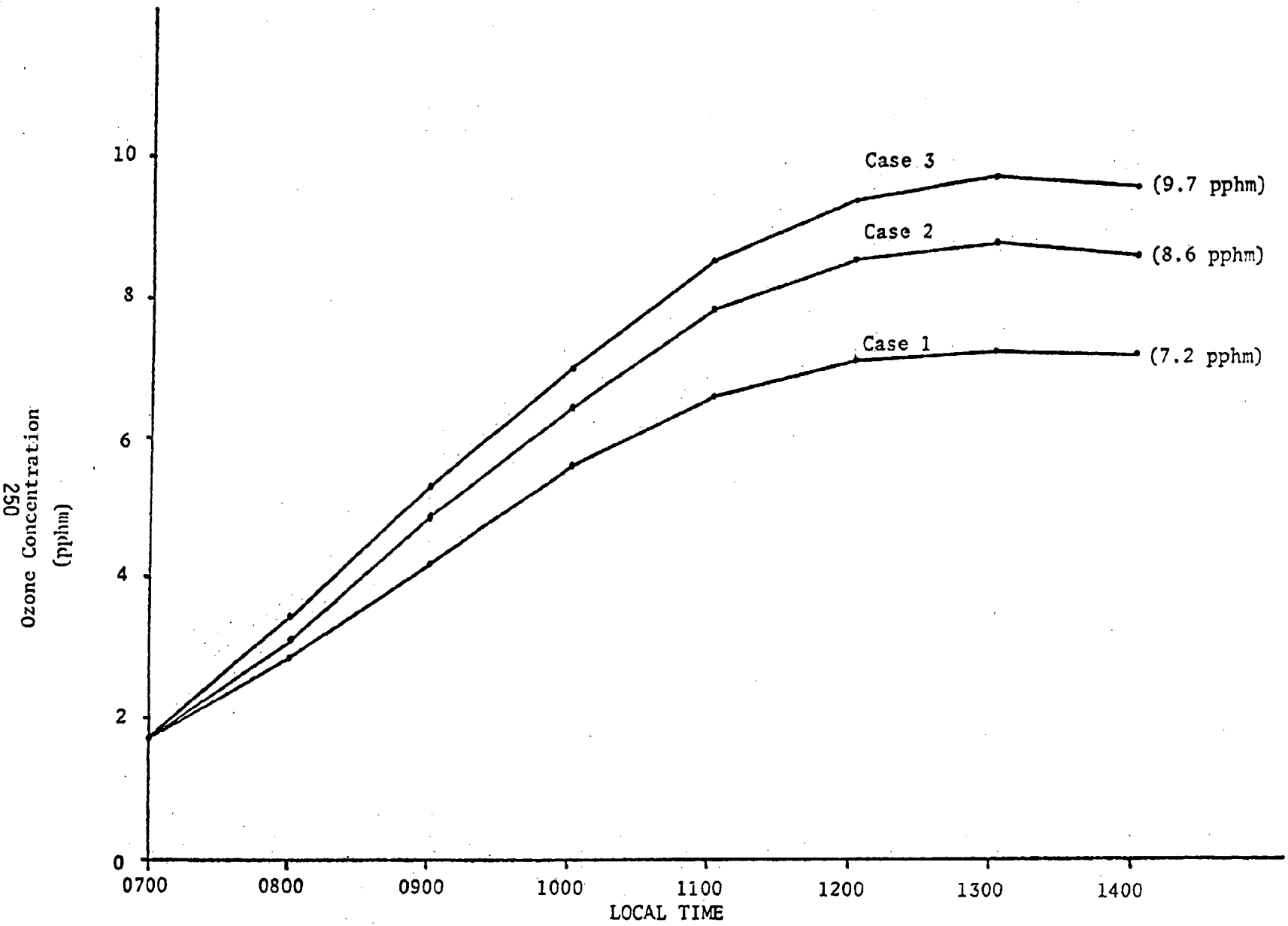

Figure 6 Ozone Concentration vs. Time for Trajectory of 7/9/75. Arriving at Camarillo using Case 1, 2, and 3 initial conditions--(Ventura Moderate O_3 Case)

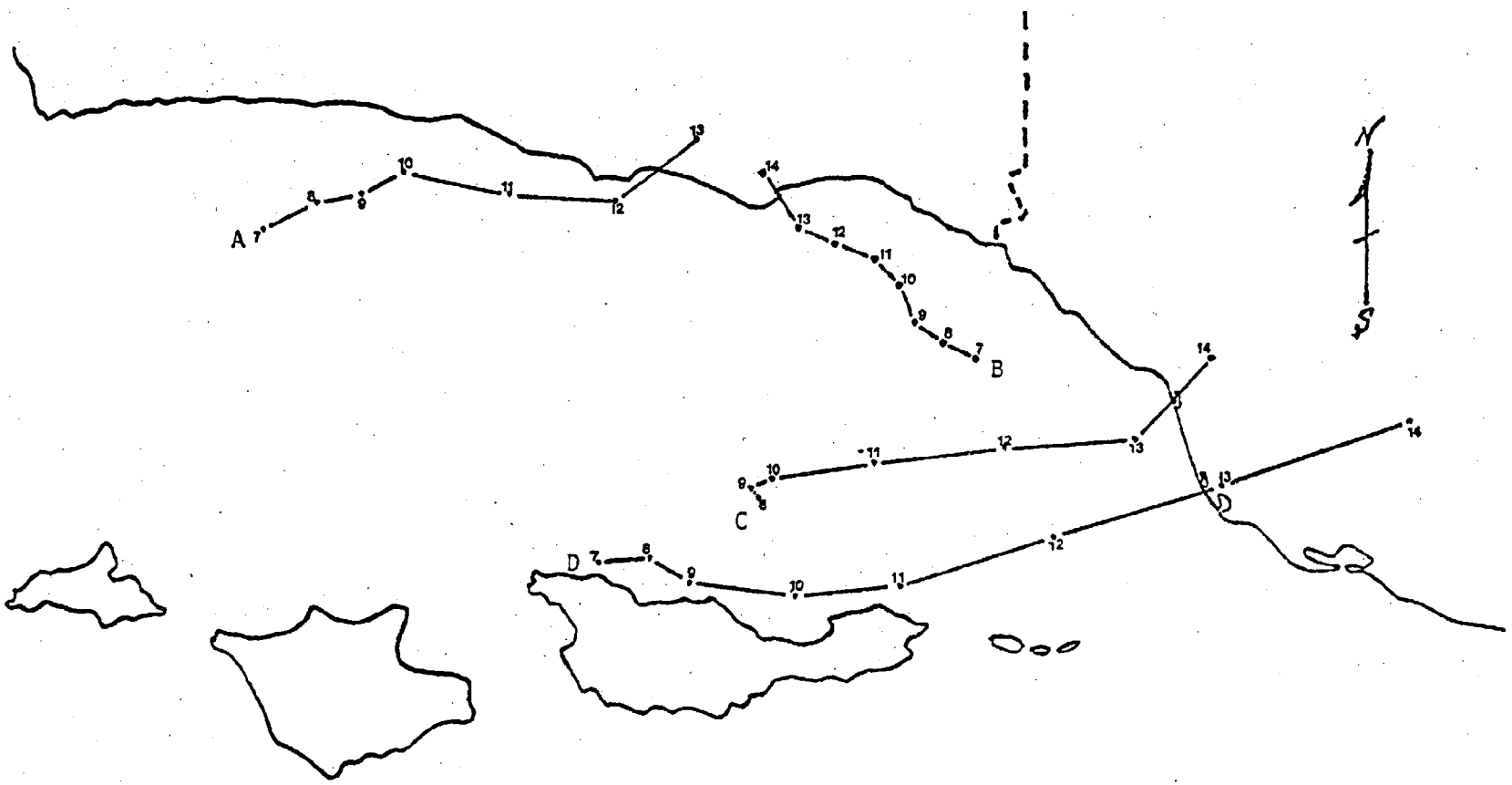

Figure 7 Trajectories used in Initial Condition simulation
A: 5/1/75 B: 7/18/74 C: 9/25/75 D: 7/9/75

TABLE 26:
RESULTS OF THE SIMULATIONS TO ASSESS OZONE IMPACTS
CASE 1, 2, AND 3 OIL DEVELOPMENT

	DATE OF ORIGINAL TRAJECTORY	STATION	FUTURE YEAR	OIL DEVELOPMENT SCENARIO	O_3 CONCENTRATION AT ARRIVAL (pphm)
A	5/1/75	Cathedral Oaks	1985	Case 1	5.0
				Case 2	8.8
				Case 3	10.5
B	7/18/74	State Street	1985	Case 1	9.8
				Case 2	17.7
				Case 3	22.1
C	9/25/75	Ventura	1985	Case 1	14.9
				Case 2	16.9
				Case 3	17.8
D	7/9/75	Camarillo	1985	Case 1	7.2
				Case 2	8.6
				Case 3	9.7

IMPACTS OF POINT SOURCE EMISSIONS UPON OXIDANT CONCENTRATIONS

The second method for assessing OCS oil facility impacts entails the inclusion of point source emission fluxes from individual facilities in the ARTSIM input module, and comparing oxidant concentrations at onshore monitoring stations for various emissions combinations. In each case, the baseline run includes vehicles and other non-petroleum-site emissions but neglects all petroleum production and handling facilities. Representative emissions from the latter were then included in subsequent simulation runs, with all other variables (including initial concentrations) being held constant.

OFFSHORE PRODUCTION PLATFORMS

Estimates of emissions from offshore production platforms were obtained from the work of Leach and have been listed in this chapter. 65/ Trajectories were selected to encompass both average and high oxidant days for each county.

The trajectory of May 1, 1975, selected earlier for modeling initial concentration impacts, was used again here since it represented a moderate ozone day for Santa Barbara and also traversed the Santa Ynez tract and Exxon's Hondo discovery. Case 2 initial conditions (see OXIDANT VARIATION DUE TO CHANGES IN AMBIENT PRECURSOR CONCENTRATIONS above) were used for both runs. Anticipated emissions for the Hondo platform, assuming production of 80,000 B/D in 1985, were inserted in the second run. The results, depicted graphically in Figure 8, illustrate the initial ozone-scavenging effects of NO emissions. After several hours, however, ozone concentration overtook and surpassed that of the baseline case, reaching a level of 10.2 pphm at the time of arrival at Cathedral Oaks (versus 8.8 pphm for the baseline case).

Subsequent platform-impact runs were conducted for four additional trajectories incorporating emissions from three separate potential platforms. Ozone

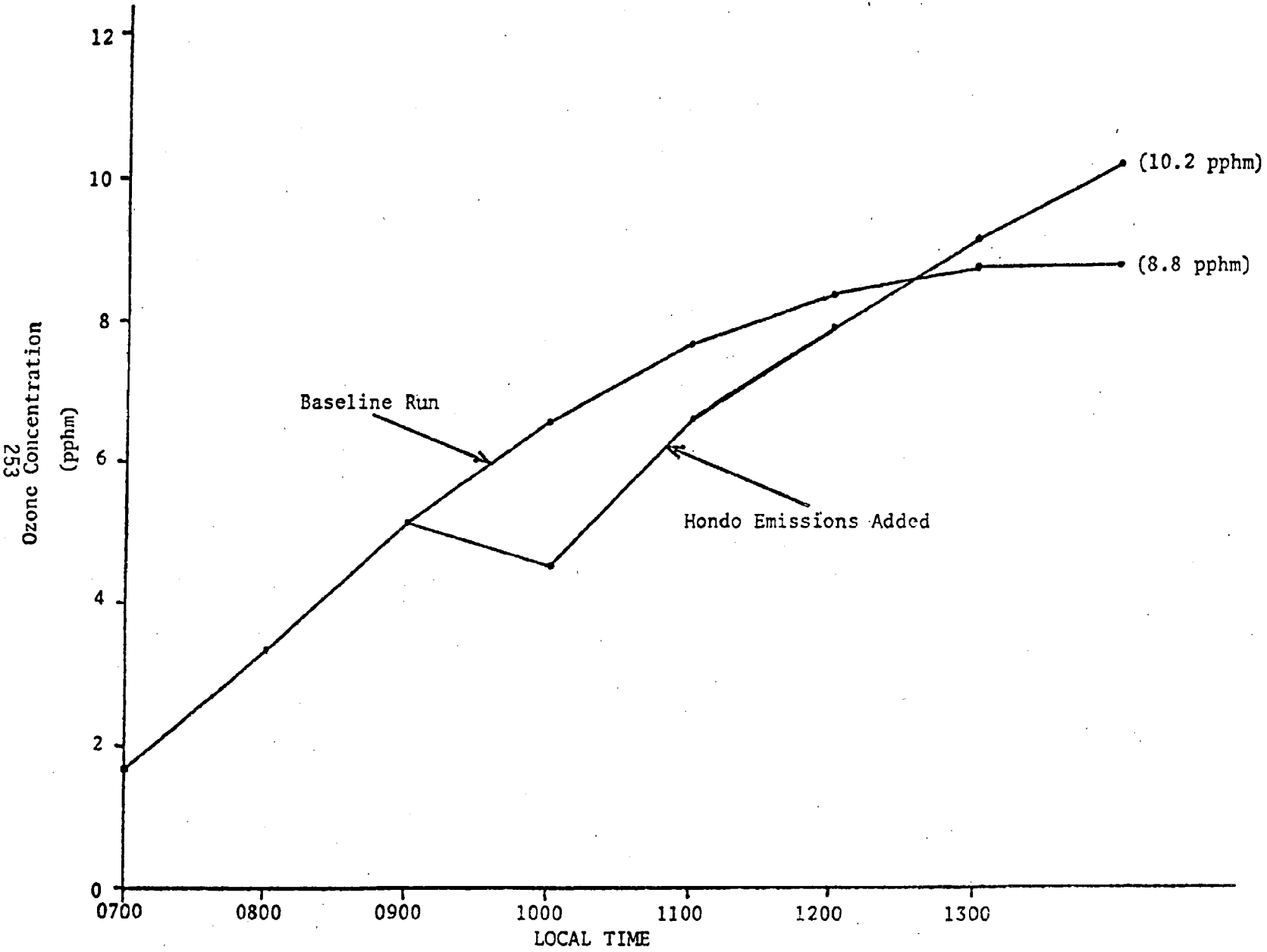

Figure 8 Ozone Concentration vs. Time for Trajectory of 5/1/75 Arriving at Cathedral Oaks. Modeling effects of Hondo

concentration at time of arrival at the respective monitoring station is listed in Table 27 for both baseline and platform impact runs for each of the modeling days. As is evident, ozone increases from platform emissions are greatest on the moderate ozone days, both in magnitude and percentage, compared to baseline values. Figure 9 shows plots of the trajectories described here.

TABLE 27:
OZONE IMPACTS OF OFFSHORE PLATFORMS FOR SELECTED MODELING DAYS

DATE OF ORIGINAL TRAJECTORY	STATION	PLATFORM (TRACT) MODELED	FUTURE YEAR	PEAK O_3 CONCENTRATION (pphm) NO PLATFORM	WITH PLATFORM	% INCREASE
A 5/1/75	Cathedral Oaks	Hondo (Santa Ynez)	1985	8.8	10.2	15.9
B 7/18/74	Fairview	(Oak Ridge)	1985	18.6	19.0	2.2
C 7/10/75	Ojai	(Pitas Pt.)	1985	18.9	19.5	3.2
D 9/25/75	Camarillo	(Oak Ridge)	1983	16.1	16.8	4.2
E 7/9/75	Camarillo	(Santa Clara)	1983	8.8	9.7	10.2

TREATMENT AND SEPARATION FACILITIES

According to Lind, 14 onshore treatment and separation (T & S) facilities were in operation in 1976 to handle Santa Barbara Channel oil and/or gas. 66/ By far the largest throughput occurred at Mobil's Rincon facility, an estimated 34,500 barrels oil and 11,300,000 cubic feet gas per day. Emission factors for T & S operations are discussed earlier, and estimated emissions for existing study area facilities are listed in Table 11.

Lind's prognoses for future Channel development indicate that, if petroleum production increases significantly, the majority of existing facilities would experience increased throughput and new plants could be built. 67/ The extent and location of increased throughput would, of course, depend upon the characteristics of offshore production.

Still unresolved at present is the fate of Exxon's handling facility to support offshore operations at the Hondo site. Originally proposed was an onshore T & S plant at Las Flores Canyon which could process both oil and gas and handle throughput from the entire Santa Ynez unit, for which production estimates are as high as 300,000 B/D. Owing to conditions imposed by the State of California Coastal Commission concerning transport of the processed crude through a pipeline, Exxon has announced plans to construct an offshore processing plant in federal waters near Hondo, and has received permission from the Interior Department to do so. Expected throughput at the offshore facility would not exceed 60,000 B/D, according to Exxon, and gas processing would not be possible. Emissions from the proposed offshore site were included as one of the modeling scenarios in this section.

Methodology for the T & S impact simulations was identical to that used in the platform runs described in the preceding section. Future baseline runs assumed Case 2 (moderate development) initial conditions, and no oil production-related

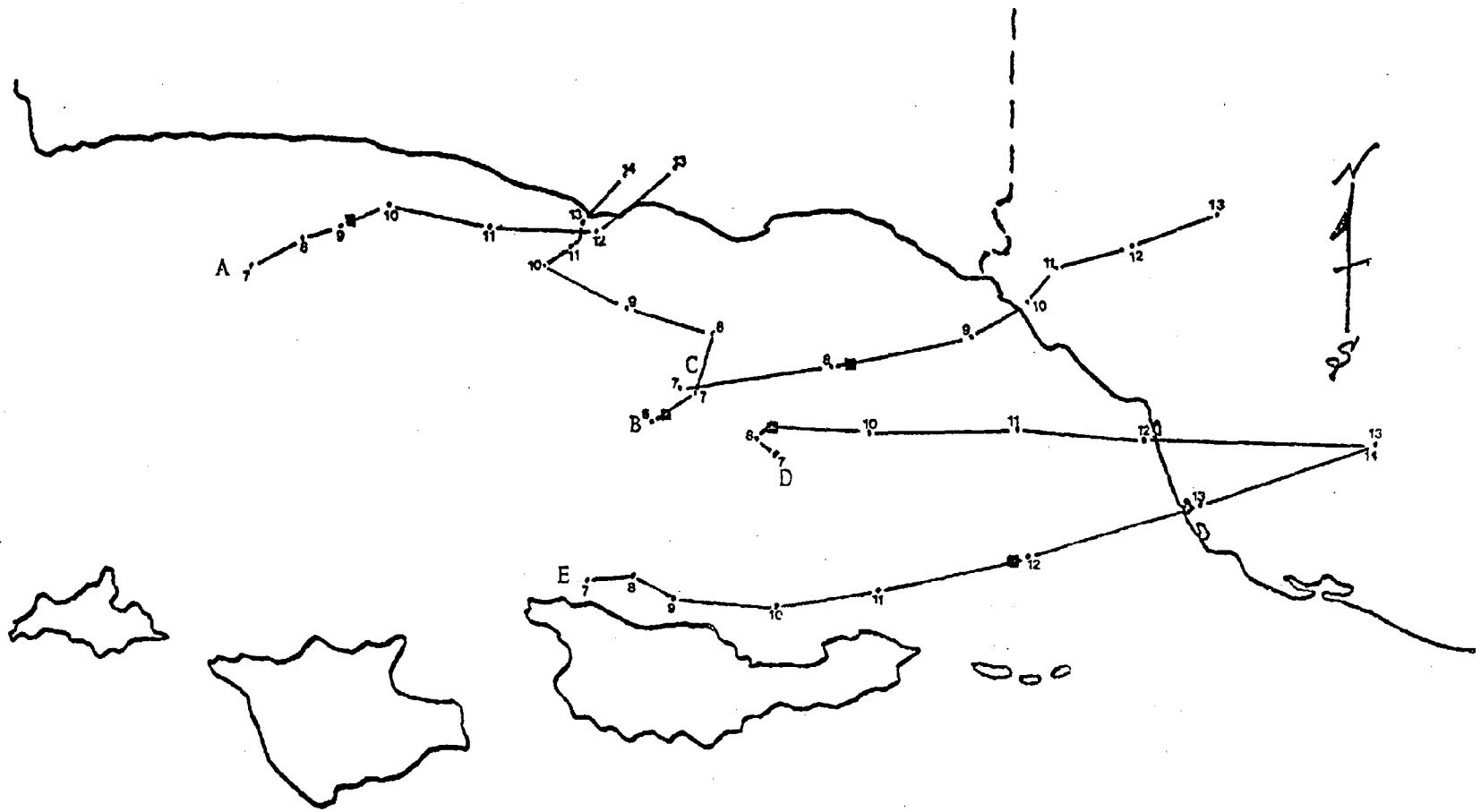

Figure 9 Trajectories Utilized in Platform impact simulation
A: 5/1/75 B: 7/18/74 C: 7/10/75 D: 9/25/75
E: 7/9/75

emissions. In subsequent runs emission fluxes expected within lease units traversed by the trajectory were inserted and ozone production for the simulations compared.

The trajectory of May 1, 1975, was again selected to model emissions impact of Santa Ynez unit facilities. In addition to the baseline case, two emissions scenarios were modeled: the first assumed that OS&T storage tanks and production loading were controlled, the second that vapor recovery took place. Production of 60,000 B/D was assumed (future year 1985). Emissions would result from loading (the processing plant would be a converted tanker), storage, and processing. Figure 10 shows ozone-time history for the three simulation runs.

Additional impact simulations for T & S facilities were conducted for the following sites and receptor locations: Mobil/Rincon -- Ojai; Ventura coastline (possible future site) -- Simi; Mandalay Beach (possible future site) -- Santa Paula. Results of the runs, listing peak baseline/impact run ozone values, appear in Table 28. The magnitude of ozone increase from T & S emissions was largest for the Simi trajectory (presumably because of Simi's distance from the coast, allowing ample ozone buildup time, and because the projected Ventura coastline plant would have higher throughput than any of the other three listed in Table 28). Plots of the trajectories appear in Figure 11.

Table 28:
OZONE IMPACTS OF TREATMENT AND SEPARATION FACILITIES FOR SELECTED MODELING DAYS

DATE OF ORIGINAL TRAJECTORY	STATION	FACILITY MODELED	FUTURE YEAR	PEAK O_3 CONCENTRATION (pphm) NO FACILITY	WITH FACILITY	% INCREASE
A 5/1/75	Cathedral Oaks	Hondo Offshore	1985	8.8	10.4	18.2
B 7/10/75	Ojai	Mobil/Rincon	1985	18.0	19.9	10.6
C 9/25/75	Santa Paula	Mandalay Beach	1983	12.8	14.3	11.7
D 7/10/75	Simi	Ventura Coastline	1993	16.3	18.8	15.3

MARINE TERMINALS

Pollutant emissions resulting from marine terminal activities can be divided into two groups: exhaust emissions generated by ship engines and released through stacks, and ullage vapors displaced from cargo tanks during loading, unloading, or purging operations. Emissions factors for these processes were discussed in earlier sections of this chapter.

The procedure for assessing ozone impact of marine terminal emissions was identical to that used for platform and T & S impacts discussed previously. Baseline runs were selected for both prevailing and high O_3 days, and for existing as well as proposed terminals. Impact runs assumed that tanker loading was in progress at the time the air parcel traversed the site. Peak O_3 values were then compared for the tanker and no-tanker cases.

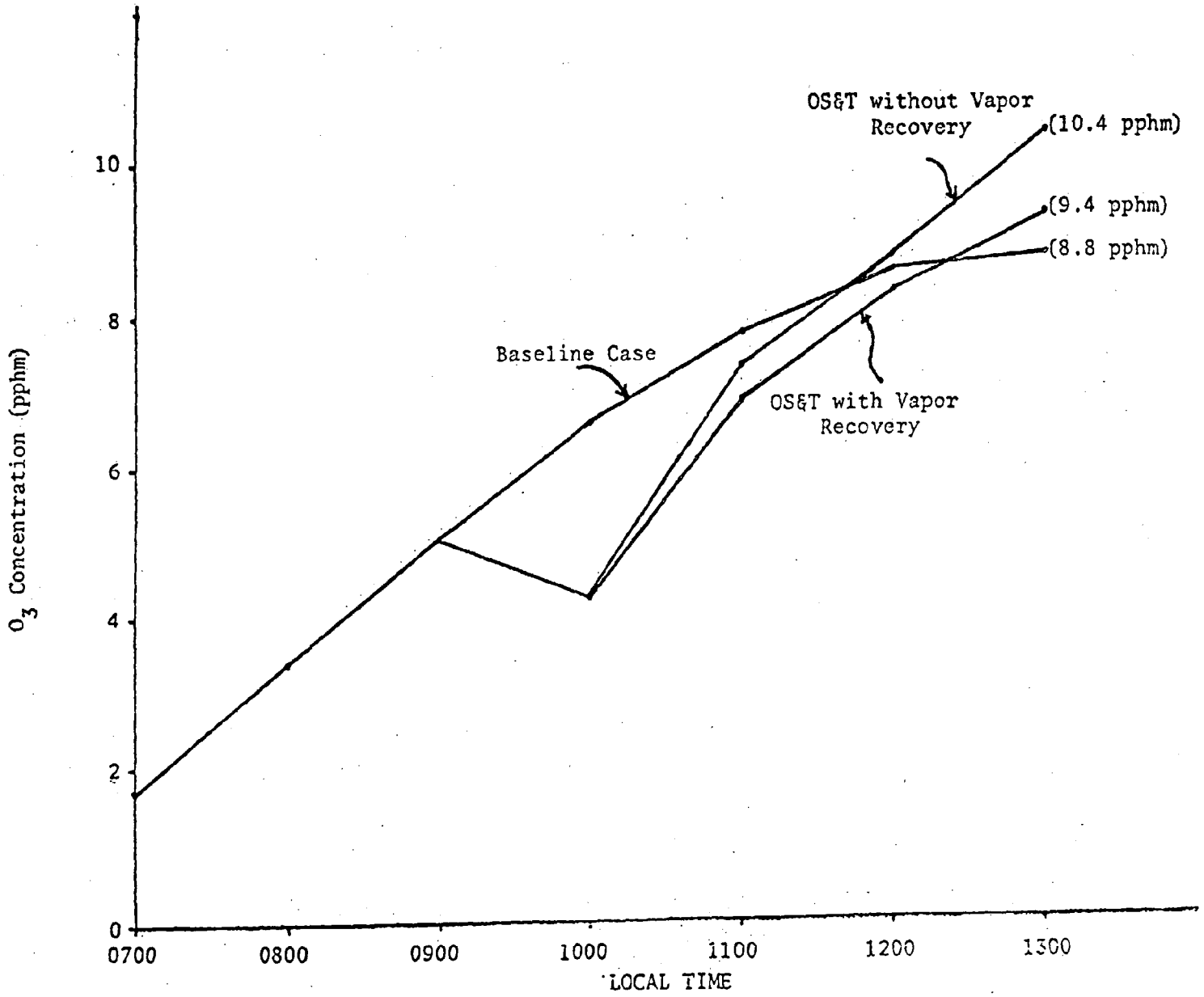

Figure 10 Ozone Concentration vs. Time for Trajectory of 5/1/75 Arriving at Cathedral Oaks. Effects of Hondo OS&T with

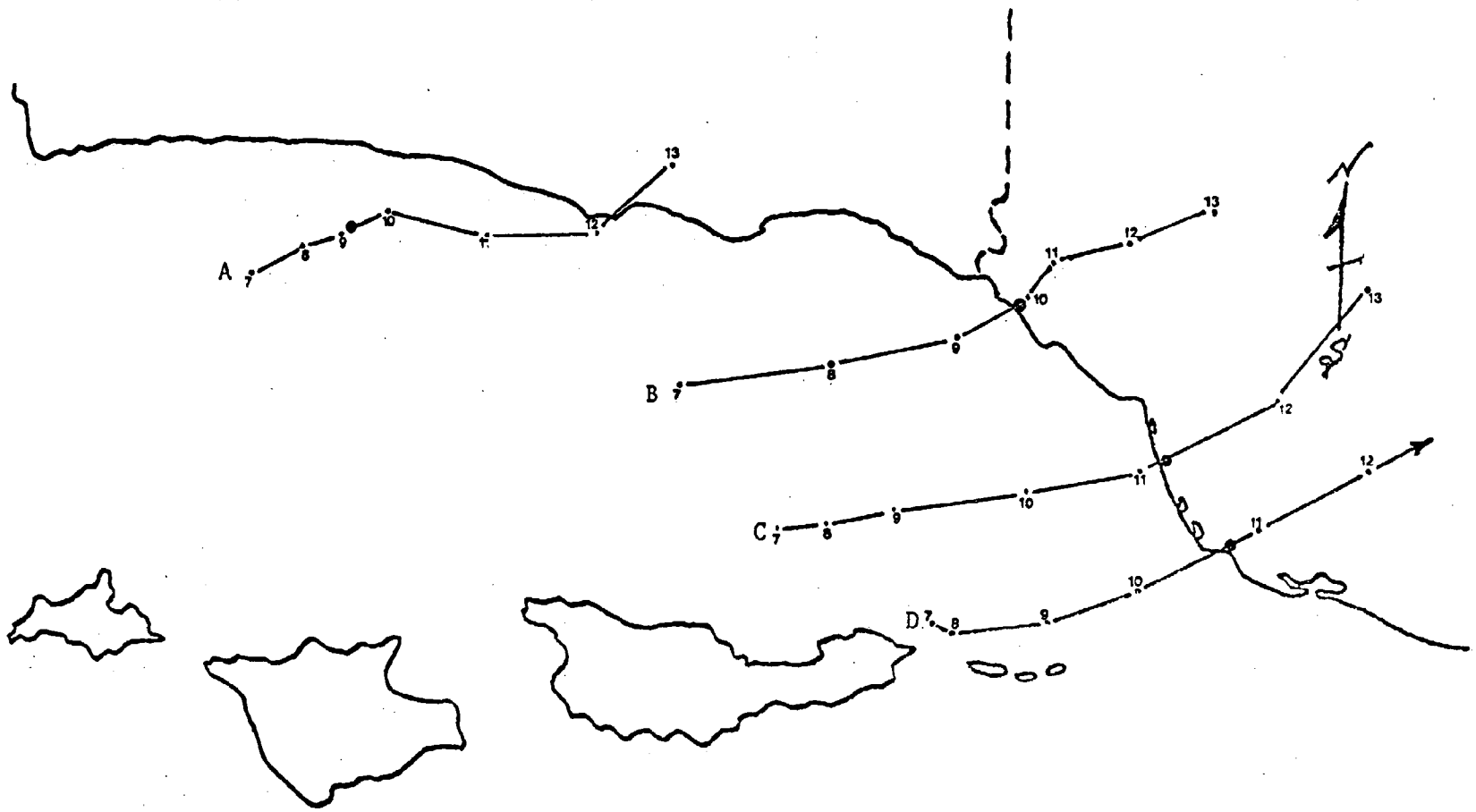

Figure 11 Trajectories utilized in T & S facility simulation
A: 5/1/75 B: 7/10/75 Ojai C: 9/25/75 D: 7/10/75 Simi

Computer simulations indicate that marine terminal impacts would be far greater than those of the other facilities studied. As an example, the results for the trajectory of July 18, 1974, which passed over AMINOIL's Ellwood terminal prior to arriving at the Fairview APCD station, are shown in Figure 12. Combustion and ullage emissions, according to the simulation, increased peak O_3 from 18.6 to 20.1 pphm (an 8% increase) despite the fact that the AMINOIL facility is one of the smallest study area terminals.

The potential impact of a larger facility was modeled by considering the trajectory of July 19, 1975, which arrived at Simi at 1300 after passing over a site which Lind indicates might be the location of a future Ventura County marine terminal. 68/ Lind projects that the terminal would have a pumping rate of 20,000 barrels per hour and therefore would emit over 470 lb/hr RHC from ullage losses alone (see Table 9 of this chapter). The baseline run for this example reached a peak O_3 concentration of 16.3 pphm. When marine terminal emissions were added, however, O_3 jumped to 20.4 pphm at 1300, an increase of 25%.

In the case of Exxon's Hondo production, several handling and transportation scenarios have been discussed. In an attempt to model all possible contingencies, four alternative plans were considered. The first assumes that emissions from only the platform are generated offshore -- this is the "pipeline alternative" case, and assumes that no marine vessels are involved in oil transport on the given day. The second case assumes that Exxon's offshore processing facility is built, and includes emissions from the platform, the converted tanker, and a 6,000 barrel per hour marine terminal. For the third and fourth cases, an onshore processing facility with offshore marine terminal was assumed. Emission fluxes were based on Lind's low and high pumping rate estimates for the terminal of 13,000 and 25,000 barrels per hour, respectively. 69/

Ozone impacts for the various alternatives, using the trajectory and conditions of May 1, 1975, are displayed in Figure 13. O_3 concentration at the time of arrival at the Fairview station was lowest for the baseline case (8.8 pphm) and grew increasingly for the platform-only (10.2 pphm), platform plus offshore complex (15.9 pphm), platform plus 13,000 barrels per hour terminal (23.4 pphm), and platform plus 25,000 barrels per hour terminal (36.4 pphm) cases. Figure 14 shows plots of the four trajectories used in the simulation.

Results of the marine terminal simulations are listed in Table 29.

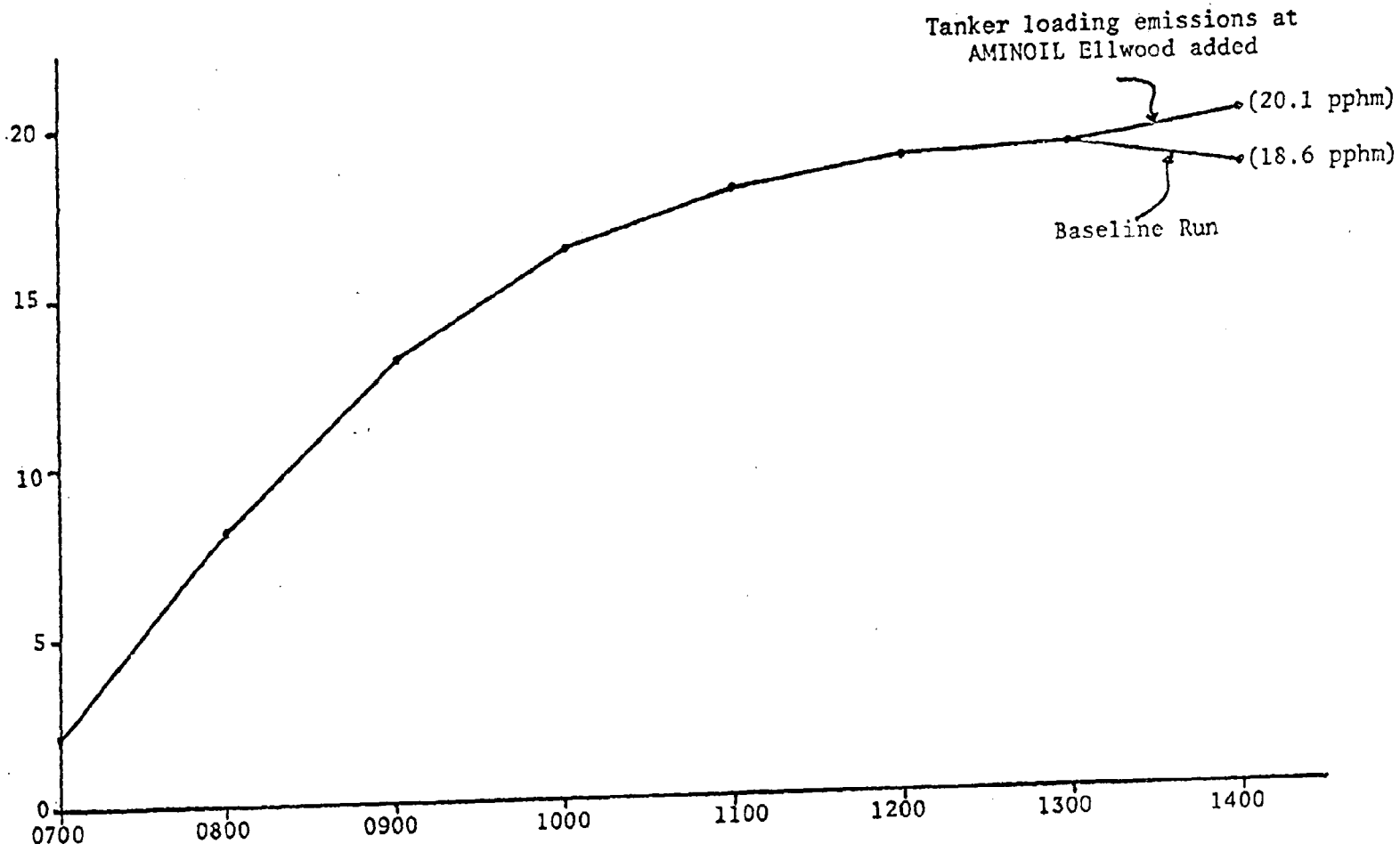

Figure 12 Ozone Concentration vs. Time. Point Source Emissions Impact. Trajectory of 7/18/74, arriving at Fairview Station.

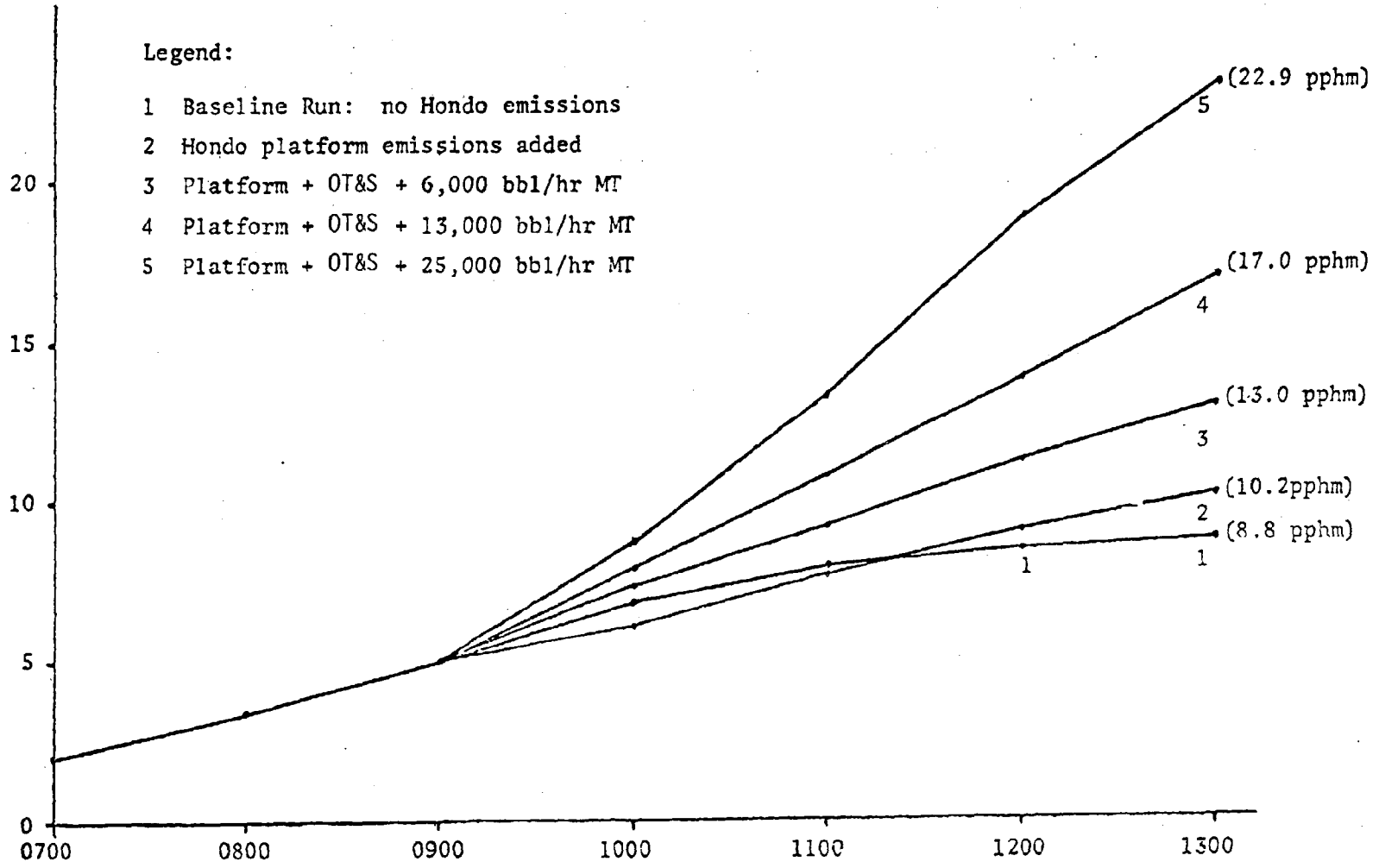

Figure 13 Ozone Concentration vs. Time. Point Source Emissions Impact. Trajectory of 7/18/74, arriving at Fairview Station.

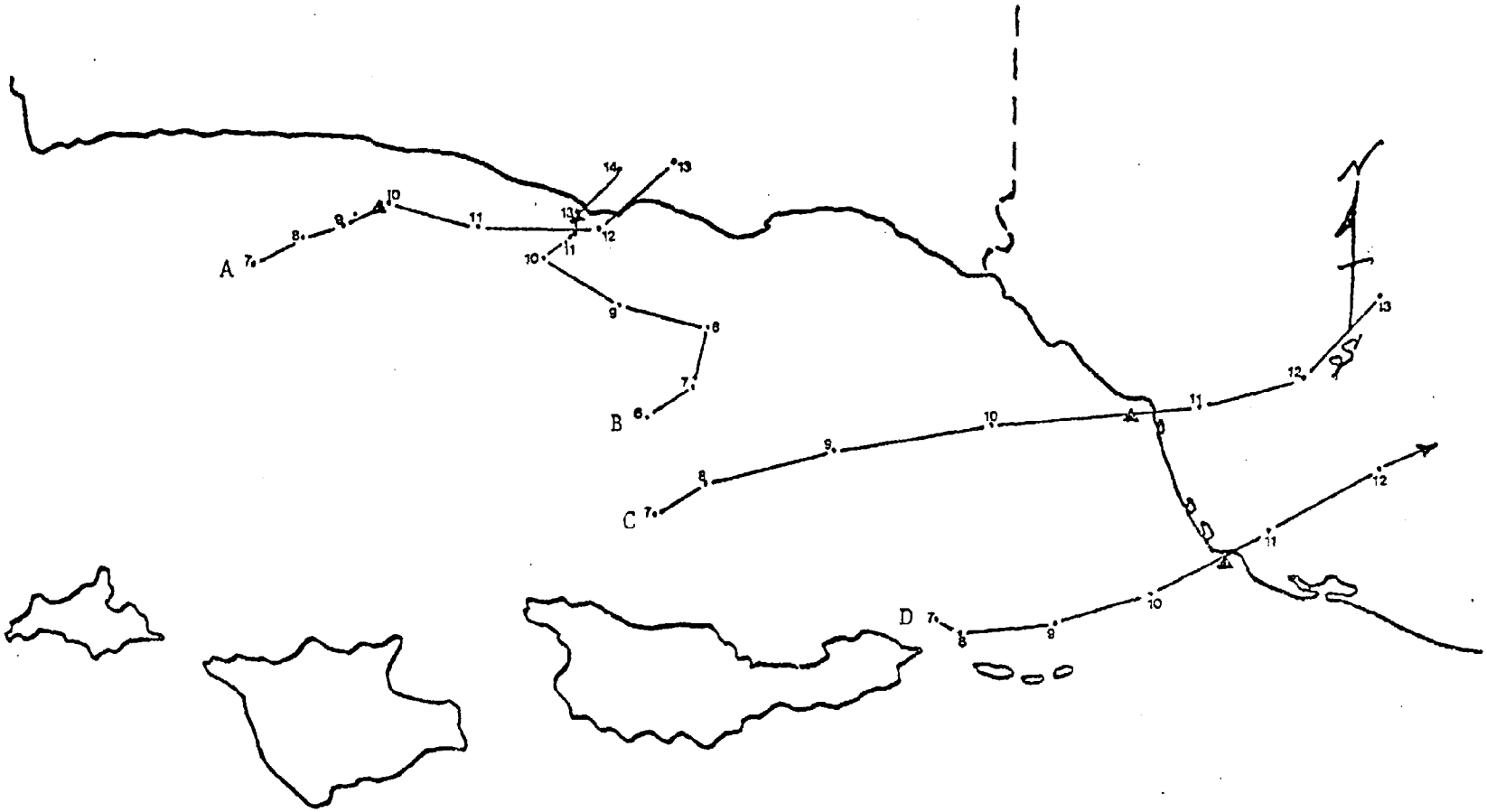

Figure 14 Trajectories Utilized in Marine Terminal simulations
A: 5/1/75 B: 7/18/74 C: 9/25/75 D: 7/10/75

TABLE 29:
OZONE IMPACTS OF MARINE TERMINAL EMISSIONS FOR SELECTED MODELING DAYS

DATE OF ORIGINAL TRAJECTORY	STATION	FACILITY MODELED	FUTURE YEAR	PEAK O_3 CONCENTRATION (pphm) NO FACILITY	WITH FACILITY	% INCREASE
A 5/1/75	Cathedral Oaks	Platform Only	1985	8.8	10.2	15.9
		Platform + OT&S + 6,000 barrels per hour MT	1985	8.8	13.0	47.7
		Platform + OT&S + 13,000 barrels per hour MT	1985	8.8	17.0	93.2
		Platform + OT&S + 25,000 barrels per hour MT	1985	8.8	22.9	160.2
B 7/18/74	Fairview	AMINOIL Ellwood	1985	18.6	20.1	8.1
C 7/10/75	Santa Paula	Union or Getty (Ventura)	1983	18.4	20.0	8.7
D 7/10/75	Simi	Ventura County (proposed)	1993	16.3	20.4	25.2

Tanker fugitive emissions have been a source of controversy for many years (see ENVIRONMENTAL SETTING). Emission fluxes have been shown to be functions of a number of factors: tanker size, area-to-volume ratio, composition of previous cargo, ullage, vapor pressure, and tank condition are notable examples. It may be fallacious, therefore, to select a single emission factor to account for all combinations of the above variables. For that reason, it was decided to conduct a sensitivity analysis for marine terminal oxidant impact in which a variety of emission factors for fugitive HC was utilized.

The simulation run selected was the July 10, 1975, Simi-arrival trajectory which passed over a hypothetical Ventura County terminal (future year 1993). Three emission factors were selected (in addition to the 1.9 lb/10^3 gal used previously): 4.0 lbs/10^3 gal loaded, representing an upper bound; 1.3 lbs/10^3 gal, from MacKenzie and Rau 70/ for 250,000 DWT ships; and, 0.8 lbs/10^3 gal, selected as a lower bound for loading emissions. Table 30 lists results of the simulation. In all cases, ozone increase over the baseline peak value (16.3 pphm) was significant. Peak ozone for the impact runs varied from 18.2 pphm (with the lowest emission factor) to 25.0 pphm (with the highest). Even using the lower figure, projected ozone increase from the 20,000 barrels per hour loading facility would be approximately 12%.

TABLE 30:
OZONE IMPACT OF HYPOTHETICAL VENTURA COUNTY MARINE TERMINAL FOR VARIOUS LOADING EMISSION RATES; TRAJECTORY OF 7/10/75, SIMI, USING 1993 CONDITIONS

EMISSION RATE (lbs HC/10^3 gal LOADED)	PEAK O_3 CONCENTRATION (pphm) NO FACILITY	WITH FACILITY	% INCREASE
0.8	16/3	18.2	11.6
1.3	16.3	19.2	17.5
1.9	16.3	20.4	25.2
4.0	16.3	25.0	53.2

IMPACT OF HYDROCARBON EMISSIONS FROM SEEPS

Seepage of crude oil from the ocean bottom has occurred for many years along the coast of California. In particular, certain offshore areas west of Santa Barbara have been known to emit particularly large quantities of oil. What is perhaps the largest seep lies seaward of Coal Oil Point and was the scene of a study conducted by Meteorology Research, Inc., to determine vapor emissions of hydrocarbon compounds from the resultant slick. Published in 1976, the study yielded an estimated emission rate of 63 gm/sec, or about six tons/day. 71/

Using the trajectory of July 18, 1974, which traversed the normal path of the slick, the oxidant effect of the HC vapors was assessed. A reactivity of 30% and plume width of 100 meters were assumed in determining RHC content and plume entrainment time, respectively. The results, as shown in Figure 15, indicate an increase in O_3 at the Fairview station from 18.6 pphm (baseline case) to 19.0 pphm, with seep emissions included. This increase is approximately one-fourth as large as the similar increase indicated for the nearby AMINOIL terminal (see previous section).

IMPACT OF HYDROCARBON EMISSIONS FROM OIL SPILLS

In the past, occasional spills of crude oil and processed liquids have occurred on offshore and inland waters. The most immediate example of such a spill in the study area was the 1969 blowout of a well at Union's Platform A, located on the Dos Cuadras tract in OCS waters. Estimates of the total volume of oil released range from 18,000 to several hundred thousand barrels. 72/ In addition to platform accidents, spill categories include terminal operations, pipeline failures, and ship incidents.

Few published analyses of hydrocarbon vapors released from oil slicks on water are in existence. Those which are available tend to be rather limited in scope. Nevertheless, by assembling excerpts from several different publications, it was possible to formulate a model relating spill volume to slick size, film thickness, and percent evaporation (by carbon number) as functions of time after the spill. The formulation, which is rather lengthy, is described in detail in Appendix II.

Assuming an original spill volume of 1,000 tons (about 6,600 barrels), we obtained an estimated slick area of 1.3 km^2 after one day, and 5.9 tons/hr RHC emitted from the surface, or 4.5 tons/hr·km^2. Thus, assuming a hypothetical day-old slick in calm seas off the Ventura County coast, the trajectory of July 10,

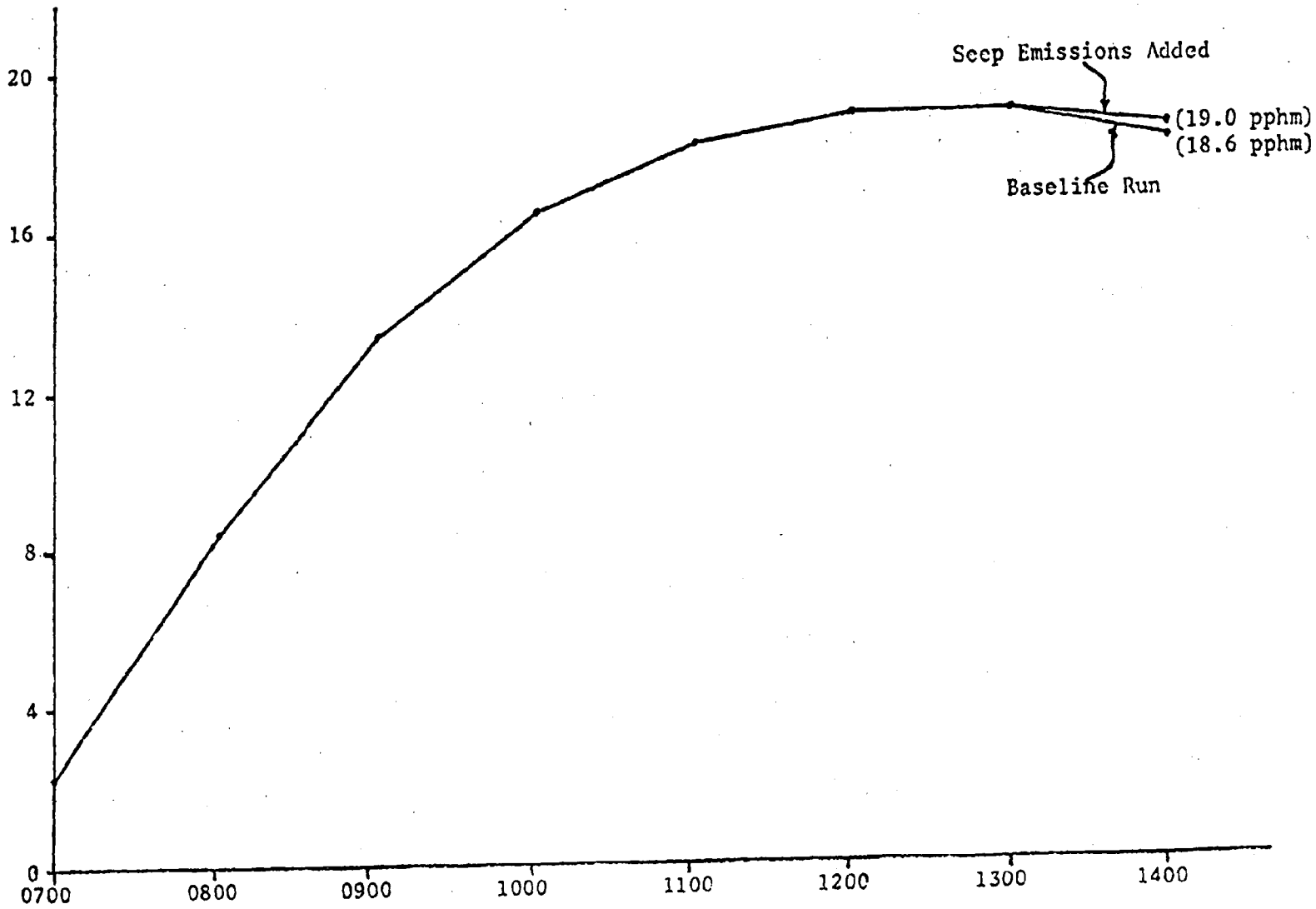

Figure 15 Ozone Concentration vs. Time. Point Source Emission Impact. Trajectory of 7/18/74, arriving at Fairview Station.

1975, arriving at Simi, was chosen for the analysis, using predicted initial conditions and surface emissions for 1983. The result was an increase in ozone at the receptor from 17.0 pphm (baseline run) to 28.1 pphm (spill emissions added). Ozone-time histories appear in Figure 16. It is felt that this run represents worst-case conditions since calm seas and a higher ozone potential day were assumed.

It should be pointed out that the ARTSIM version used in the modeling (ten species including only one hydrocarbon) does not distinguish among individual hydrocarbon classes such as olefins and alkanes; the former is much more reactive and is an important component of motor vehicle exhaust, while spill emissions are composed primarily of the latter. In order to compensate for this discrepancy, spill-emitted HC was given a reactivity value of 30% despite the fact that some reactivity-classification systems assign a value greater than 80%.

The ARTSIM spill-emissions runs have indicated that oil spills can be a significant source of reactive hydrocarbon species which can lead to high ozone increases under certain conditions. It is hoped that, in the future, more sophisticated modeling techniques, including improved emissions information and several hydrocarbon species, will enable a better understanding of a potentially crucial air quality problem.

RADIUS OF INFLUENCE OF LARGE POINT SOURCES

The results of the tanker impact simulations described above indicated that fugitive hydrocarbons released during loading could lead to greatly enhanced in-plume ozone concentrations in the study area. It was suspected that additive effects of two intersecting or concurrent plumes might yield further ozone increases. In order to assess such a dual-plume effect, an attempt was made to determine the effective radius of influence of a tanker-loading plume and thus suggest appropriate spacing between successive terminals undergoing simultaneous loading.

Analysis of the many trajectories calculated for worst-case ozone days indicated a predominance of relatively low-wind speeds along the Santa Barbara County south coast. Velocities frequently fell in the five to seven mph range. Assuming an ozone buildup time of four hours, total transport of 20 to 28 miles might be expected. In order to verify this result, which was obtained in a somewhat subjective manner, the following procedure was employed:

1. Assume:
   - wind speed of 5 mph
   - F (stable) stability
   - 25 mile downwind distance
   - source strength 127 gm/sec (corresponding to 13,000 barrels per hour tanker loading rate with resultant fugitive HC emissions)
   - σ_y, σ_z according to Turner 73/
2. Using the Gaussian plume formula for centerline concentrations downwind of a continuous point source,

$$\overline{X} = \frac{Q}{2\pi \bar{u} \sigma_y \sigma_z}$$

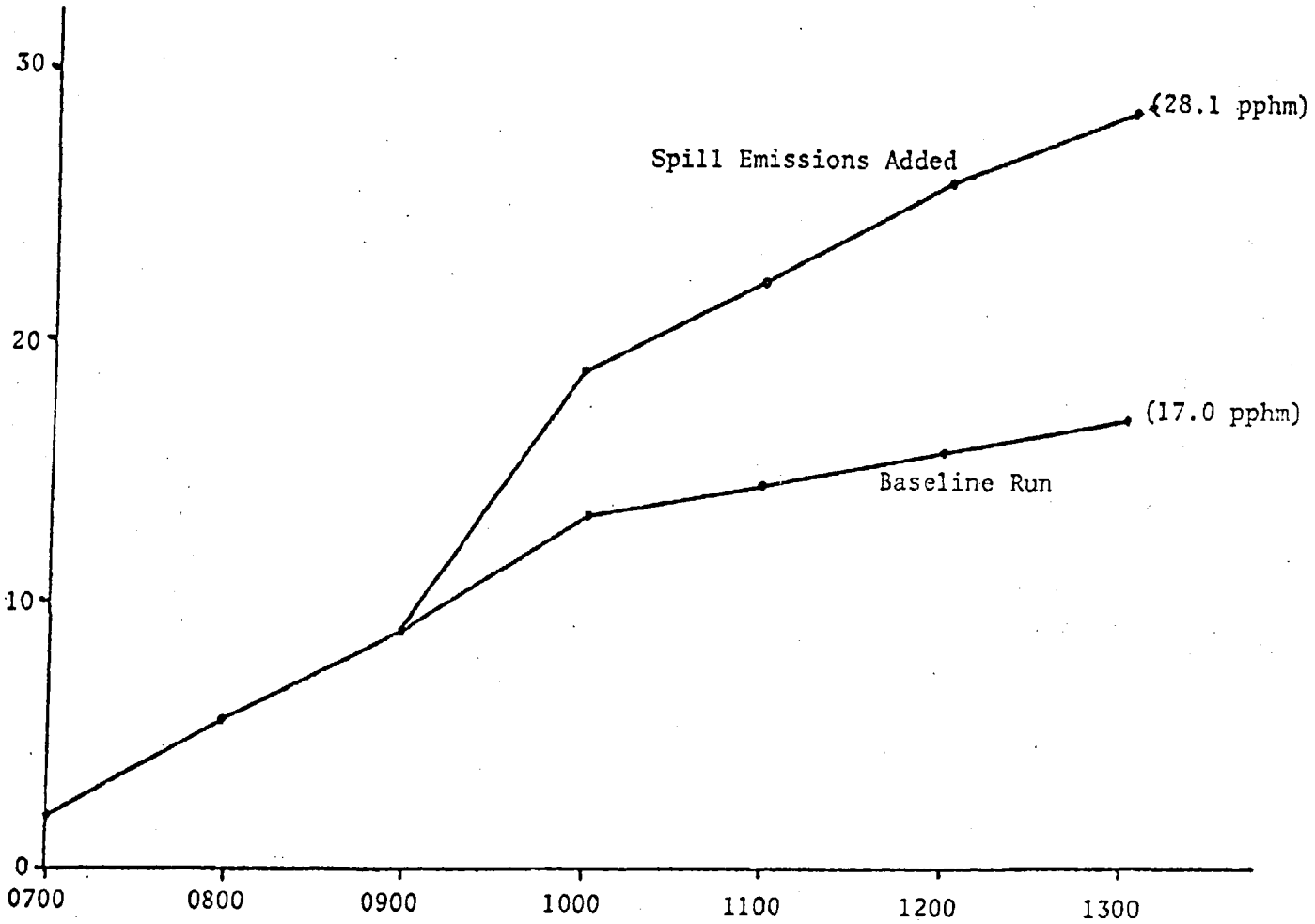

Figure 16 Ozone Concentration vs. Time. Point Source Emissions Impact. Trajectory of 7/18/74, arriving at Fairview Station.

where $\bar{X}$ = concentration (g/m^3)

Q = source strength (g/sec)

$\bar{u}$ = wind speed (m/sec)

σ_y, σ_z = horizontal and vertical diffusion coefficients, respectively

The concentrations of RHC at 25 miles is 134.2 ug/m^3, which represents 84% of the federal three-hour standard.

3. Using the over-water σ_y and σ_z of Harrison and Maas, 74/, RHC concentrations of nearly 5000 ug/m^3 are obtained. These diffusion coefficients were determined during a monitoring study near the Coal Oil Point seep off Goleta, but were measured during the month of January and hence may not be directly applicable to summer smog-season conditions.

AIR QUALITY IMPACTS OF OTHER POLLUTANTS

NITROGEN DIOXIDE (NO_2)

NO_2 has traditionally been of less concern than oxidants within the study area because of the fact that the federal (5 pphm annual average) and California (25 pphm hourly average) ambient air quality standards are rarely exceeded. NO_2 is known as a secondary pollutant, since it occurs chiefly as a result of atmospheric chemical processes involving primary pollutants, those emitted directly into the atmosphere, particularly nitric oxide (NO). Concentrations of NO_2 to be used in air quality modeling were obtained from the output of the ARTSIM model, in which NO_2 is one of the reactive species.

Onshore NO_2 impacts of petroleum production and related operations were assessed in the same way as oxidant impacts discussed in the previous chapter: from ambient background levels (initial condition simulation) and as a direct result of point source emissions. In using the first technique, it was assumed that the initial NO_2:NO ratio remained constant* for any level of NO_x emissions. The latter used the assumption that all NO_x was emitted as NO.

Results of the initial condition simulation for NO_2 are shown in Table 31. In all cases, the difference between NO_2 concentrations for Cases 1, 2, and 3 development was negligible; the largest spread was only 0.5 pphm.

Point source emissions impacts were, in some cases, more significant. Platform impacts, for example, as shown in Table 32, range from a 0.4 pphm increase (9/25/75 Camarillo) to a 1.8 pphm increase (5/1/75 Cathedral Oaks), generally larger than initial concentration effects but still rather small changes. T & S

*NO_2:NO = 2.1 75/

facilities, however, would produce much higher NO_2 impacts, as shown in Table 33. Among the cases studied, the Exxon offshore facility would create the greatest impact, an increase of over 8 pphm from 1.8 to 9.9; nevertheless, all the values shown fall well within the California one-hour standard of 25 pphm. Finally, NO_2 air quality calculations for marine terminal emissions (including tanker emissions both in-berth and underway) resulted in negligible increases over baseline values.

TABLE 31:
IMPACTS ON NO_2 CONCENTRATIONS FOR INITIAL CONDITION SIMULATIONS (ONE-HOUR AVERAGES)

DATE OF ORIGINAL TRAJECTORY	STATION	FUTURE YEAR	NO_2 CONCENTRATION (pphm) CASE 1	CASE 2	CASE 3
5/1/75	Cathedral Oaks	1985	1.8	2.2	2.3
7/18/74	Fairview	1985	1.7	1.8	1.8
9/25/75	Ventura	1985	3.2	3.3	3.3
7/9/75	Camarillo	1983	1.8	1.9	2.0

TABLE 32:
IMPACTS OF OFFSHORE PLATFORMS UPON NO_2 CONCENTRATIONS FOR SELECTED DAYS (ONE-HOUR AVERAGES)

DATE OF ORIGINAL TRAJECTORY	STATION	FACILITY MODELED	NO_2 CONCENTRATION (pphm) NO PLATFORM	WITH PLATFORM
5/1/75	Cathedral Oaks	Hondo	1.8	3.6
7/18/74	Fairview	Oak Ridge	1.6	2.3
9/25/75	Camarillo	Oak Ridge	3.6	4.0
7/10/75	Ojai	Pitas Point	2.4	3.1
7/9/75	Camarillo	Santa Clara	1.8	2.5

TABLE 33:
IMPACTS OF T & S FACILITIES UPON NO_2 CONCENTRATIONS FOR SELECTED DAYS (ONE-HOUR AVERAGES)

DATE OF ORIGINAL TRAJECTORY	STATION	FACILITY MODELED	NO_2 CONCENTRATION (pphm) NO FACILITY	WITH FACILITY
5/1/75	Cathedral Oaks	Hondo	1.8	9.9
7/10/75	Ojai	Offshore Mobil/ Rincon	2.4	5.0
7/10/75	Simi	Ventura Coastline (possible future)	3.0	6.1
9/25/75	Santa Paula	Mandalay (possible future)	2.9	4.9

CARBON MONOXIDE (CO)

As reported earlier in the ARTSIM BASELINE RUNS section, petroleum facility CO effluent would represent a very small percentage of total study emissions. Results of the ARTSIM simulation, as might be expected, showed almost no difference in CO levels as a result of petroleum activities for either the initial condition simulations or point source impact runs.

SULFUR OXIDES (SO_x)

Sulfur oxides, in particular sulfur dioxide (SO_2), are emitted as a product of combustion of fuels containing sulfur compounds. According to Leach sulfur oxides emitted during oil production and transport would result from diesel engine exhaust and gas flaring. Using a production level of 200,000 B/D, Leach estimated Channel SO_2 emissions at 1.39 tons per day. 76/ This figure represents less than 2% of SO_x emitted in the study area. Since long-term, annual, averages of SO_2 have never exceeded the three pphm federal annual standard, it is expected that oil-industry-related SO_2 emissions would exert a negligible impact upon long-term ambient concentrations in the study area. 77/

It is expected, therefore, that the most significant effect of SO_2 emissions would be short-term local concentrations in the immediate vicinity of a facility. The most stringent short-term standards are California's one-hour (50 pphm) and 24-hour (four pphm) limits. In order to model the SO_2 impacts, ERT's Point Source Diffusion Model (PSDM), a Gaussion-type model, was used. In regions of homogeneous terrain (including over-water areas), the Gaussian assumption has been shown to give reasonably good approximations of actual observed concentrations. 78/ For that reason, PSDM was selected for modeling of primary pollutants SO_2 and H_2S over flat terrain (water and coastal plains).

Emission rates of SO_2 for platforms, T & S facilities, and tankers are listed in the EXISTING EMISSIONS section. All sources listed, with the exception of tankers in transit, represent fixed, continuous point sources and were modeled using PSDM. Tanker movement impacts were assessed by designing a hypothetical worst case in which the ship is assumed to remain for an hour within a moving air parcel of one square kilometer and 50-meter depth. The SO_2 emissions of 14.2 lb/hr were assumed to be evenly distributed throughout the parcel. The result is an hourly average concentration of 4.9 pphm, which represents less than 10% of the state one-hour standard. Thus, even this highly unlikely and unfavorable meteorological occurrence would result in rather low SO_2 levels.

PSDM-derived SO_2 concentrations were determined for three source types: platforms, T & S facilities, and tankers in berth. Peak one-hour average concentrations are listed in Table 34 for selected existing and possible future facilities by Pasquill-Gifford stability, wind speed, and downwind receptor distance. In only one case does predicted one-hour SO_2 approach the California standard of 50 pphm: the Ventura coastline T & S facility mentioned by Lind as a possible alternative for future development, 79/ with maximum expected throughput of 150,000 B/D oil and 150 million SCF/D gas.* According to the PSMS calculations, such a facility,

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*This facility is purely hypothetical. It assumes oil and gas that would be produced in the Outer Banks would be processed onshore. To date, there have been no discoveries made in these areas. Even if commercial discoveries are made, the processing of crude oil and natural gas might occur on fixed structures at the producing site rather than at a consolidated onshore plant.

which would emit an estimated 74.2 lb/hr of SO_2, would yield worst-case one-hour SO_2 concentrations of 44.5 pphm, which represents 89% of the state standard. According to the five-year stability-wind rose for nearby Point Mugu, this condition would occur about 1.4% of the time (total for all wind direction, D stability, and appropriate wind speed class). 80/ Although the maximum concentrations fall below the standard, it is felt that the effect may be a critical one in view of other SO_x emissions which might occur in the vicinity of such a facility (e.g., tanker traffic emissions, increased vehicle emissions).

TABLE 34:
MAXIMUM ONE-HOUR CONCENTRATIONS OF SO_2 FOR VARIOUS OIL AND GAS FACILITIES
(ASSUMED MIXING DEPTH 100 METERS)

FACILITY	PRODUCTION THROUGHPUT	SO_2 EMISSIONS (lb/hr)	SO_2 CONCENTRATION (pphm)	DOWNWIND DISTANCE (m.)	STABILITY	WIND SPEED (m/sec)
PLATFORM A	13,550 B/D*	4.5	1.3	1000	D (Neutral)	5.4
PLATFORM HONDO	60,000 B/D**	19.9	5.9	1000	D	5.4
T & S (Chanslor)	2,600 B/D*	6.8	4.0	100	D	12.1
T & S (Ventura Coast)	150,000 B/D**	74.2	44.2	100	D	12.1
TANKER	175,000 B/D	1.7	1.4	700	E (Stable)	3.6

*1976 figures
**possible future throughputs

HYDROGEN SULFIDE (H_2S)

Emissions of H_2S result almost entirely from venting and processing losses in the handling and treatment of natural gas. 81/ According to Leach, such losses amount to 2.6 lbs H_2S per 10^6 SCF gas processed (assuming 0.9% H_2S content by volume of raw gas, and total losses of 210 lbs per 10^6 SCF processed), and would occur exclusively during processing operations. H_2S impacts were assessed using PSDM, with throughputs (and thus emissions) obtained from Lind. 82/ Results of the simulations, showing maximum H_2S one-hour concentrations predicted for several existing and possible future processing sites, appear in Table 35. Although maximum concentrations expected for currently operating facilities are less than the California one-hour standard of three pphm, PSDM calculations indicate violations for each of Lind's three largest future throughput totals: at Mobil/Rincon (assuming processing at that location of all GTUM and Sun tract gas); at Exxon/Las Flores (onshore processing of all Santa Ynez unit gas, assuming peak future throughput of 100 x 10^6 SCF/D); and at the Ventura coastline alternative (assuming throughput of 150 x 10^6 SCF/D). These findings indicate potential future problems at large gas processing facilities, and point out the necessity for careful analysis

of H_2S emissions impacts at T & S sites. The conditions described in Table 35 are rather common. 83/ Slightly unstable conditions and appropriate wind speed class (0-1.3) occurred at Point Mugu 1.4% of the time over a five-year period (total for all wind directions), or an average of 123 hours per year. National standards are violated if NAAQS concentrations are exceeded more than once per year.

TABLE 35:
MAXIMUM EXPECTED ONE-HOUR H_2S CONCENTRATIONS RESULTING FROM NATURAL GAS PROCESSING EMISSIONS (ASSUMED MIXING DEPTH 100 METERS)

FACILITY	THROUGHPUT (10^6 SCF GAS/DAY)	H_2S EMISSIONS (lb/hr)	H_2S CONCENTRATION (pphm)	DOWNWIND DISTANCE (m.)	STABILITY	WIND SPEED (m/sec)
CHANSLOR	13.7*	1.48	1.3	100	C (slightly unstable)	0.9
MOBIL/ RINCON	11.3*	1.22	1.1	100	C	0.9
MOBIL/ RINCON	86.1*	9.33	8.3	100	C	0.9
EXXON/ LAS FLORES	100.0**	10.83	9.7	100	C	0.9
VENTURA COASTLINE	150.0**	16.25	14.5	100	C	0.9

*1976 figures
**possible future throughputs

CONCLUSIONS

SUMMARY OF FINDINGS

The most immediate conclusion drawn from the OCS Development Inpact Study is that certain aspects of oil and gas production and handling can significantly affect local and regional air quality. Impacts of oil industry processes on concentrations of both primary (SO_2, H_2S, CO) and secondary (O_3, NO_2) pollutants were assessed using three methods: a Gaussian-type model for primary pollutants; ARTSIM photochemical/diffusion model to assess effects of changes in ambient precursor levels; and, ARTSIM again to model impacts of individual point or area sources. Of chief concern in this study were concentrations of O_3, SO_2, and H_2S; but all pollutants listed above were discussed.

Among routine process emissions expected to occur in and near the Channel, fugitive hydrocarbons released during tanker loading would, according to the simulations, have the greatest impact upon O_3 and NO_2 concentrations. In order to account for variations in loading procedures, ship size, and other conditions, a sensitivity analysis was carried out using several emission rates, because the choice of a single value to apply to all loadings might not be valid. Results of the sensitivity

analysis indicated that ozone increases (above baseline values) are directly proportional to loading emissions. Doubling the emission rate, for example, would very nearly double the ozone increase. An additional observation is that relative ozone increase (percentage above baseline values) caused by marine terminal emissions was greatest for the moderate ozone day modeled; that is probably due to the fact that background concentrations of NO (which acts locally as an ozone scavenger and thus can create short-term ozone decreases) were lower on moderate O_3 days than on "worst case" days.

It is evident from the simulations that loading rate is a crucial emission parameter since the mass of HC liberated is proportional to volume loaded. Thus higher loading rates imply higher emission rates. For that reason, slower loading appears to be a potential mitigating measure. Other methods for reducing tanker impacts include partial loading and temporal-geographic restrictions. Much of the hydrocarbon-rich vapor which is liberated during loading lies very near the liquid surface and thus is released only as the crude reaches the top of the tank. Approximately 83% of generated-component vapor emissions (those resulting from the liquid being loaded rather than previous-load residue) occur during the final 15 feet of filling. 84/ Since generated-component HC represented 37% of total tanker loading emissions, the latter would be reduced by 31% if final true ullage (distance between the liquid surface and roof of the tank) of 15 feet was maintained. This measure alone would reduce the tanker-loading emission factor from 1.9 to 1.3 lbs/10^3 gal, and would represent a reduction of over 2,400 lbs hydrocarbons for every 100,000 barrels loaded.

Additional minimization of tanker impacts might be possible if timing and siting considerations were followed. For example, it is clear that multiple tanker loadings on one day could yield significantly higher study area ozone concentrations than in a case of one tanker per day. The effect would be magnified if the marine terminals were relatively close together. ERT's analysis indicates that the east-west orientation of the south coast of Santa Barbara County, which nearly parallels the prevailing wind direction, increases the chances of a single air parcel passing over more than one marine terminal. The May 1, 1975, trajectory, for example, passed directly over Exxon's proposed offshore terminal and later came within one kilometer of Aminoil's Coal Oil Point facility. If simultaneous loadings were to occur in such a situation, the additive effects of the superimposed plumes upon local ozone concentrations could be significant. Preliminary findings indicate that the radius of influence of marine terminal emission along the above stretch of coastline is of the order of 25 miles during certain atmospheric conditions. Scheduling of tanker loading to prevent more than one simultaneous event within such a radius may be a key mitigating measure for tanker influences in the study area. Due to differences in terrain and atmospheric conditions, the aforementioned radius of influence will vary for different locations. Additional research is needed before a universally applicable relationship between location, atmospheric conditions, and radius of influence can be obtained.

Thus, although the impact results reported in this chapter indicate that tanker loading would exert a significant effect on local ozone concentrations, it is felt that such influences could be minimized by adopting the three aforementioned mitigating measures: load the tankers slowly; maintain an ullage of 15 feet; and, adopt a radius of influence standard which would limit tanker loadings to one per day within any such distance.

During the point source impact simulations described in this chapter, effects of emissions from individual sites were analyzed. In some instances, however,

wind direction may be such that a facility lies within the plume of an upwind source, causing a localized additive effect. Such an effect would be most common and dramatic when sources are close together and aligned along prevailing wind streamlines; for example, the three Dos Cuadras rigs are oriented east-west in an area which sees frequent westerly winds. The ozone impact would be most significant if transport between two marine terminals were to occur.

It appeared that the Hondo and Aminoil (Coal Oil Point) terminals might at times lie on the same streamline. Similar occurrences for other terminal combinations might occur as well.

Analysis of short-term SO_2 and H_2S concentrations outlined in the AIR QUALITY IMPACTS OF OTHER POLLUTANTS section has indicated that California one-hour air quality standards would be approached or exceeded near large T & S facilities. The highest one-hour SO_2 concentration predicted by ERT's PSDM model was 44.2 pphm, which represents 88% of the state standard. If other sources contributed ambient levels of only six pphm, violation would occur. The state H_2S standard, in fact, would be exceeded because of T & S emissions alone: according to the modeling results, any gas processing throughput greater than 32MM CF/D would result in local exceedances of the three pphm one-hour standard. In both cases, the favored mitigating measures involve limitation of facility size (since emissions are expressed as functions of throughput) and removal of sulfur compounds before effluent is released into the atmosphere.

The OCS impact study was hampered by what proved to be a rather sparse data base. In particular, valid wind and emissions information was not always available. It is hoped that, in the near future, valid and comprehensive field measurement programs and the deployment of additional monitoring stations will enable air quality researchers to conduct more definitive impact studies. ERT's suggestions for future data base expansion are discussed in a subsequent section of this chapter.

EXXON HONDO/LAS FLORES SCENARIOS

Because of current interest, Exxon's Santa Ynez tract production and related treatment and transport activities were studied in more detail than were any of the other individual facility sites. Although Platform Hondo is currently nearing completion, the ultimate configurations of the other facilities have not been decided. For that reason, a wide range of possible alternatives was modeled.

At present, Exxon is proceeding with plans to construct an offshore storage/marine terminal facility instead of the originally proposed onshore plant at Las Flores Canyon. According to our findings, the offshore alternative would have a greater effect on same-day ozone concentrations in the Goleta-Santa Barbara area than would the onshore site, assuming equal emissions at the two sites. The proposed offshore facility location would lie upwind of urban areas more frequently than would the Las Flores site. In addition, transport from the OT&S to the urban areas (winds slightly south of west) is much more common on moderate-to-high ozone days than is transport from Las Flores (west-northwest winds). Finally, the configuration of the offshore facility (a converted tanker in conjunction with storage barges) indicates that fugitive HC emissions from double-loading (continuous transfer from platform to OT&S and intermittent loading onto seagoing tanker) would be higher per unit of production than for the onshore facility. However, throughput for the offshore site would be limited to about 60,000 B/D, while estimates for onshore throughput range as high as 300,000 B/D. 85/ Thus, although emission rates are higher, per unit throughput, for the offshore facility,

the potentially greater capacity of a Las Flores site could lead to differences in total emissions.

In order to assess ozone impacts of various consolidation scenarios, ARTSIM runs were made for several hypothetical cases: a single 60,000 B/D T & S facility; two 30,000 B/D facilities; and, three 20,000 B/D plants. In the second and third cases, the facilities were assumed to be five kilometers apart and traversed by the trajectory. The result indicated negligible ozone differences for the three runs. Concentrations of SO_2 and H_2S, however, would be affected significantly by siting/throughput considerations. According to the simulation results reported in AIR QUALITY IMPACTS OF OTHER POLLUTANTS, worst-case SO_2 concentrations, directly proportional to throughput, would be twice as high near a 60,000 B/D facility as those near a 30,000 B/D plant. H_2S, proportional to gas processing throughput, exhibits similar behavior, with emissions at a 70MM CF/D facility twice those at a 35MM CF/D site. From the standpoint of primary pollutant concentrations, then, several small facilities are more desirable than one large one. Recommended throughput limitations and possible mitigating measures were discussed above.

Tanker loading rates, already identified as a critical emissions parameter, are highly dependent upon the size and throughput of the handling facilities. In addition, loading time, storage capacity, and frequency of tanker visits are interdependent variables which influence emissions. Consequently, the three loading rates selected and modeled for the proposed Exxon marine terminal represent a rather large matrix of the above variables. For example, consider the 6,000 barrel per hour rate estimated for Exxon's offshore alternative. If we assume production of 60,000 B/D, ten-hour loading time, and 120,000 barrel per tanker loading, 15 tanker visits per month are required; 80,000 B/D production would require 20 visits per month if loading time and storage remained constant; finally, 80,000 B/D production, 240,000 barrel storage, and 20-hour loading time would require 15 loadings per month. Thus, by varying one or more parameters and using the three (6,000, 13,000, and 25,000 B/M) loading rates, virtually any likely combination of loading time or storage capacity can be modeled.

According to the impact results shown in Figure 27, the low, medium, and high loading rates yield significantly different downwind ozone concentrations. It is suggested, therefore, that loading rate specifications be carefully considered in formulation of planning decisions for such a facility. This aspect and other potential mitigating measures were discussed at length in the preceding section.

SUGGESTIONS FOR ADDITIONAL RESEARCH

The major problem confronting air quality researchers in the Santa Barbara-Ventura area is lack of a comprehensive, well documented data base. Among the more notable deficiencies, meteorological data and offshore emissions information stand out.

Wind and stability are the meteorological parameters deemed most important in modeling pollutant behavior near the surface. Pollutant concentrations are a function of both advective and diffusive processes in the atmosphere; the former are determined from wind speed and direction information, while the latter are functions of stability. Although Ventura County has a number of surface wind stations, the south coast of Santa Barbara County has only one continuous wind station with readily available data: the Santa Barbara airport. In addition,

data from the Santa Barbara Channel, over which all of the trajectories used in this study originated, is very sparse. Deployment of additional wind monitors along the Santa Barbara coast and in the Channel would greatly enrich the existing meteorological data base and increase the validity of future air quality research. Suggested optimum locations for such monitors are:

1. the Point Conception area;
2. Santa Barbara (preferably near the Harbor);
3. Carpinteria;
4. the Santa Barbara Channel (the obvious choice would be on a drilling platform); and,
5. the Channel Islands.

A number of methods for determining stability have appeared in the literature. A simple, widely used method employs wind speed and solar radiation data. Vertical temperature structure (lapse rate and wind shear) obtained from rawinsonde soundings, is frequently used (our formulation utilized both) in stability classification systems. However, sounding data is not always available; only at Point Mugu are regularly scheduled sounding measurements taken. Unfortunately, the great expense involved in providing sounding data (either balloon- or aircraft-measured) is a serious drawback. Since lapse rates seem to correlate well at coastal stations, it may be desirable to add measurement sites further inland rather than at other coastal locations. 86/ The characteristics of study area stability parameters* have been largely unexplored; further research would be quite useful in air quality transport studies using tracer materials.

Most of the assumptions used to determine emissions from oil and gas production and handling facilities have been a source of debate between the various agencies involved. In some cases, emission rate calculations are based on outdated or inadequate information or are not universally applicable. In particular, offshore emission data are extremely sparse; platform and tanker information is often woefully inadequate. Now in progress are several measurement studies designed to improve the available data base. Results of these studies are anxiously awaited by researchers. But with equipment and techniques changing rapidly, it may be necessary to continue the measurement process at regular intervals in the future.

Improved modeling techniques will allow more accurate and sophisticated characterization of air pollution processes. Among the noteworthy fields currently being explored by modelers are: use of a larger number of chemical species and reactions (an updated version of ARTSIM currently being tested has about 30 species); modification of trajectory models to assess more accurately the influences of large point sources; and, development of efficient but accurate grid models employing an Eulerian (cells fixed in space) approach to air quality modeling. Although more expensive than the simple, more commonly used models, the above methods can be far more reliable, especially where a complete, appropriate data base exists.

With the likelihood of further industrial activity in the study area, particularly in oil- and gas-related processes, every effort should be made to provide planners with a data base that is sufficiently comprehensive to ensure the validity of such studies. Only then can decision makers provide the public with the valid, well informed judgment required to successfully balance environmental quality with the energy and economic needs which concern us all.

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*See glossary.

APPENDIX A

VERTICAL EDDY DIFFUSITY MODEL USED IN THE ARTSIM CALCULATIONS

Vertical eddy diffusity (K_z) profiles used in the ARTSIM simulation were obtained from a model which can be used for unstable, neutral, and stable cases with and without inversion layers present. The scheme is based on the neutral-stability work of Blackadar, with non-neutral consideration derived partially from the work of Egan-Mahoney, Ragland-Peirce, and Fulle. 87/ Measured profiles published by Pasquill were used for the purpose of checking the accuracy of the resultant values. 88/

NEUTRAL CASE

The given parameters specified by the user for the neutral case are:

u_g = geostrophic wind speed (m/sec)

z_o = roughness height (m)

As an initial step, determine u_*, the frictional velocity. Using the Ragland-Peirce method,

$$C_g = 0.16(\log_{10}Ro - 1.8) \tag{1}$$

where

$$R_o = \frac{u_g}{z_o f}$$

f = Coriolis parameter $\simeq 10^{-4}$ sec^{-1}

Then

$$u_* = C_g u_g \tag{2}$$

The parameters $u_n(z)$ and $K_n(z)$ represent the mean wind speed and eddy diffusivity value, respectively, at a height z above the surface, for the neutral case. They are determined according to

$$u_n(z) = \frac{u_*}{k} \ln \frac{z}{z_o} \tag{3}$$

$$K_n(z) = k^2 z^2 \overline{u}\,(z)/(1+kz/\lambda)^2 \tag{4}$$

where

k = von Karman constant = 0.4

$\lambda = 2.7 \times 10^{-4}\, u_g/f$

NONNEUTRAL CASES

Diffusivity calculations for nonneutral situations are centered around determination of an appropriate stability parameter. Some researchers have used qualitative stability classifications based on surface wind speed and isolation and represented by letter designations; however, a more useful parameter is one based on a quantitative approach. A commonly used stability parameter in such calculations is the Monin-Obhukov length L,

$$L = \frac{-u_*^3 \rho c_p \Theta}{kgH} \tag{5}$$

where

u_* = friction velocity

ρ = air density

c_p = pressure constant for dry air

Θ = ambient potential temperature

k = von Karman constant

g = gravitational acceleration

H = heat flux

with a range

$L < 0$	unstable
$L \to \infty$	neutral
$L > 0$	stable

Because straightforward calculation of L is sometimes difficult (due chiefly to the heat flux measurement), other methods have been devised for its quantification, including formulae based on Richardson's number. If vertical temperature and wind structure are known, L can be determined using a relationship developed by Fulle, which involves a stability paremeter a,

$$a = \frac{1}{(10+\gamma)^2} + .0025 \frac{\partial u}{\partial z}^{-1/2} \tag{6}$$

where

$$\gamma = \frac{T}{z} \ (^{o}C/100 \text{ m.}) \tag{7}$$

z = height above surface (m.)

u = wind speed at height z (m/sec)

Fulle's stability parameter was then separated into stable and unstable regimes, and L determined:

$$a > 9.02 \text{ (stable regime)}$$

$$L = \frac{5}{\ln(a/9.02)} \tag{8}$$

$$a < 9.02 \text{ (unstable regime)}$$

$$L = -\frac{1}{\ln\frac{9.02}{a}}$$

The vertical wind profile for both stable and unstable cases can be estimated by using the neutral wind profile $u_n(z)$ determined in (2) such that

$$u(z) = u_n(z)(1+1/L)^{1/2} \tag{9}$$

UNSTABLE CASE ($L<0$): The formulation of Egan-Mahoney is modified by the addition of the term $(1+kz/\lambda)^{1/2}$ and becomes

$$K(z) = \frac{k_n(z)(1-1/L)(1-16z/L)^{1/2}}{(1+kz/\lambda)^{1/2}} \tag{10}$$

where $K_n(z)$ = neutral eddy diffusivity from (3)

$\lambda = 2.7\times10^{-4}ug/F$

$(1-1/L)$ represents frictional velocity change

$(1-16z/L)^{1/2}$ is the heat flux term

STABLE CASE ($L>0$): Egan-Mahoney's stable case equation is used here with slight modification:

$$K(z) = K_n(z)(1-4/L)(1+4.7z/L)^{-1/4} \tag{11}$$

where $(1-4/L)$ represents frictional velocity change

$(1+4.7z/L)^{-1/4}$ is the heat flux term

INVERSION CONDITIONS

If an air parcel is capped by a temperature inversion, the eddy diffusivity within the lower layer can be estimated by modification of equations (3), (9), and (10). In all such cases, the resulting (Kz) obtained in the equations is multiplied by the term introduced by Egan-Mahoney

$$(H-z/H)^{1/3}$$

where H = height of the inversion base.

MODEL COMPARISON

Pasquill has presented a set of diffusivity profiles based on statistical theory and observations. In order to compare Pasquill's results with those of the model, calculations of the latter were computed using similar geostrophic wind, roughness height, and stability. As evidenced in Figure A1, which gives profiles for unstable, neutral, and stable cases, respectively, the correlation between the two schemes is reasonably good, although the height of maximum k_z is in all cases lower in the current model than in the Pasquill profiles.

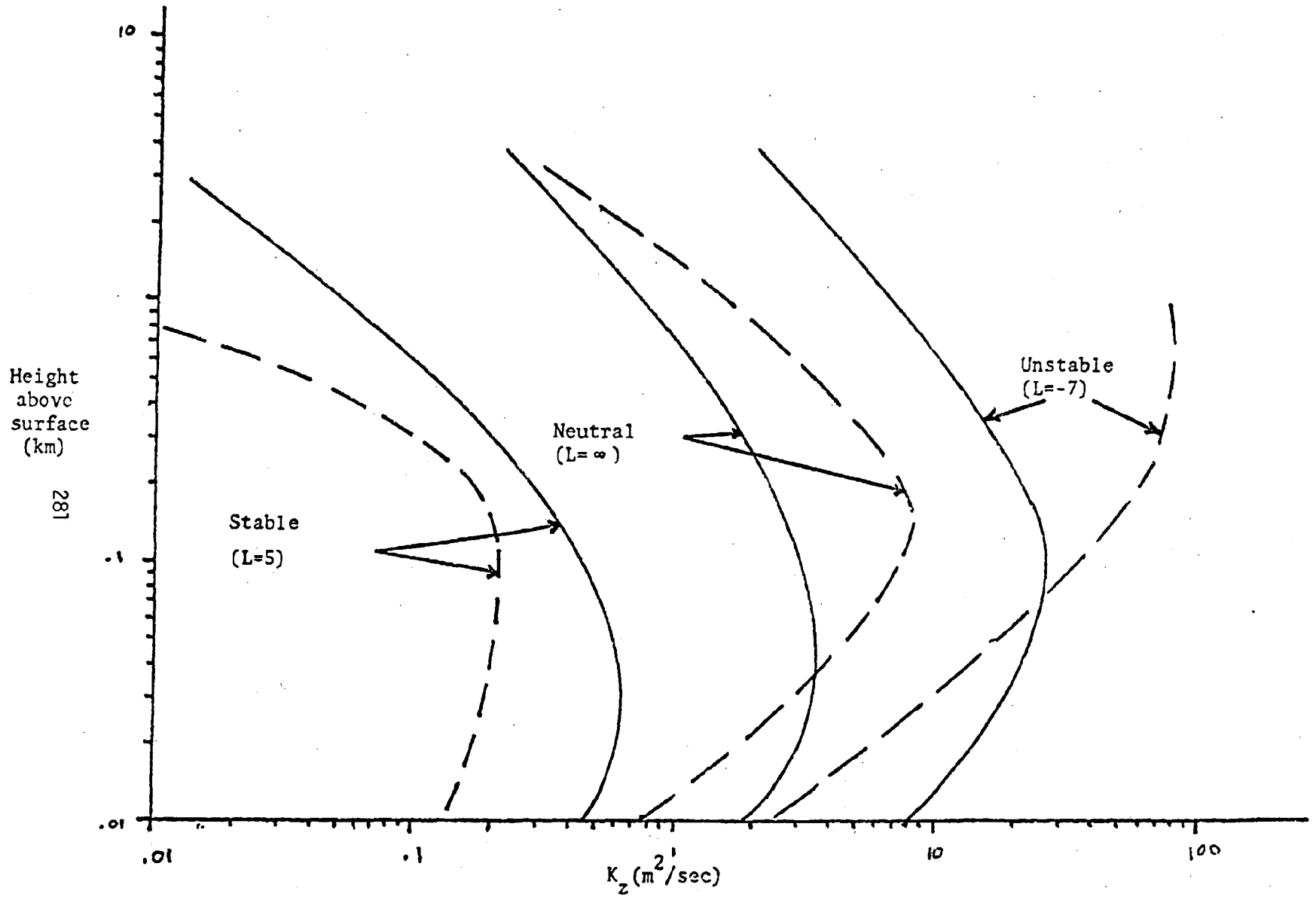

Figure A1 Vertical Eddy Diffusivities (K_z) versus Height from Current Model (solid lines) and Pasquill[5] (dashed lines); Ug=4m/sec, z_o = 3 cm.

APPENDIX B

HYDROCARBON VAPOR EMISSIONS FROM A SPILL OF CRUDE OIL ON WATER

For our purposes, the ideal oil spill emissions analysis would contain a detailed listing of hydrocarbon vapor composition, evaporation rates by species as a function of time, and composition of nonevaporated fractions. Unfortunately, such studies are, to the author's knowledge, nonexistent. In lieu of more appropriate data, we are limited to a breakdown of HC by molecular weight rather than individual species. According to Dr. Thomas Powers of Exxon Research and Engineering Co., much of the HC vapor which would evaporate from a spill is of the alkane series, characterized by relatively low reactivity compared to such hydrocarbon series as olefins and alkynes. 89/

The first step in our analysis is to determine specific gravity of crude oil by carbon number. Using averages of a number of values obtained from Bland and Davidson, we have:

TABLE A1:
CARBON NUMBER VS. SPECIFIC GRAVITY FOR CRUDE OIL 90/

CARBON NUMBER	SPECIFIC GRAVITY
3	.536
4	.602
5	.642
6	.666
7	.702
8	.715
9	.718
10	.760
11	.797
12	.791
13	.792
14	.775
15	.798
18	.777
21	.778

From Smith and MacIntyre, we obtain boiling point as a function of carbon number:

TABLE A2:
CARBON NUMBER VS. BOILING POINT FOR CRUDE OIL 91/

CARBON NUMBER	BOILING POINT (^{o}F)
4	21
5	96
6	146
7	190
8	236
9	305
10	340
11	370

The points listed in the above tables are plotted in Figure A2, with curves drawn to fit the respective values.

Calculation of mass fraction content comprised the next step. Distillation data for both Santa Barbara and Ventura County crudes were obtained from Bland and Davidson, listing volume percentages and specific gravities of crude fractions for successive cut temperatures. 92/ Averaging the respective values for each county, the following values were obtained:

TABLE A3:
FRACTIONAL VOLUME OF COMPONENTS OF LOCAL CRUDE

FRACTION NO.	TEMPERATURE RANGE (^{o}F)	MEAN TEMPERATURE (^{o}F)	FRACTIONAL VOLUME
1	77-122	99.5	.0185
2	122-167	144.5	.0235
3	167-212	189.5	.0545
4	217-257	234.5	.0640
5	237-302	279.5	.0540
6	302-347	324.5	.0460
7	347-392	369.5	.0400
8	392-437	414.5	.0435
9	437-482	459.5	.0470
10	482-527	504.5	.0555

Thus fraction 1, that which had vaporized below 122°F, represented an average of 1.85% of the samples.

Since the tables in Bland and Davidson also contained listings of specific gravities of the fractions, it was possible to determine fractional mass vaporized at each cut point using the relationship:

$$FML = \frac{\Delta V}{V_o} \cdot \frac{SG_F}{SG_0}$$

where FML = fractional mass loss

ΔV = volume vaporized at each cut point

V_o = original volume of sample

SG_F = specific gravity of fraction

SG_0 = specific gravity of original sample

Table A4 contains FML calculations using the above data.

TABLE A4:
FRACTIONAL AND CUMULATIVE MASS LOSS FOR LOCAL CRUDE OIL SAMPLES

FRACTION NO.	MEAN SPECIFIC GRAVITY	FRACTIONAL MASS LOSS	CUMULATIVE MASS LOSS
1	.647	.014	.014
2	.677	.018	.032
3	.725	.046	.078
4	.752	.056	.183
5	.770	.048	.181
6	.790	.042	.223
7	.808	.037	.261
8	.824	.041	.302
9	.837	.045	.347
10	.851	.055	.402

Next, using mean boiling temperatures (Table A3) and specific gravities (Table A4) for the ten fractions, approximate carbon numbers were approximated using the two curves in Figure A2.

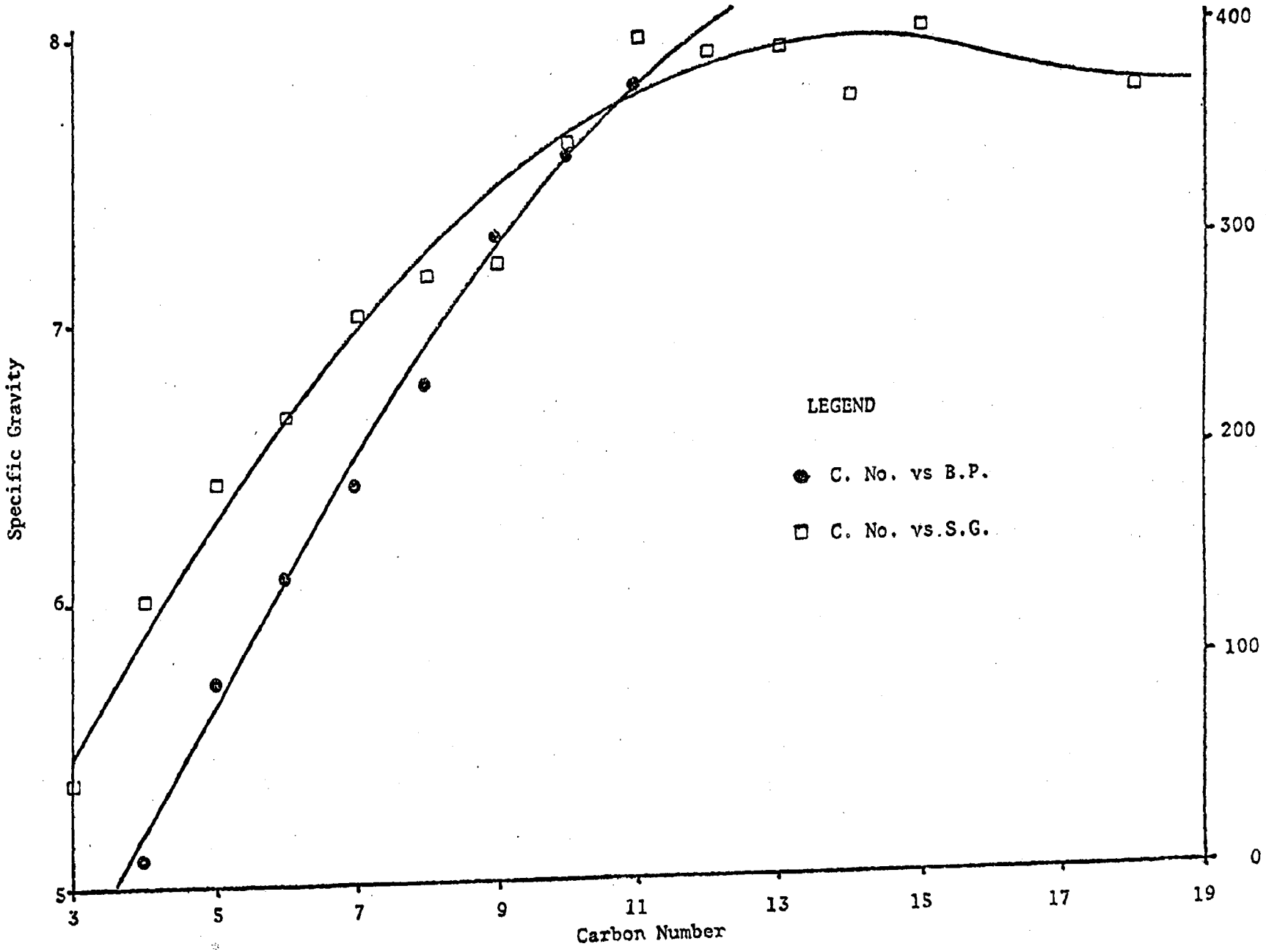

Figure A2 Carbon Number vs Specific Gravity and Boiling Point.

TABLE A5:
CARBON NUMBERS FROM BOILING POINT AND SPECIFIC GRAVITY RELATIONSHIPS

FRACTION NO.	CARBON NUMBER FROM BOILING POINT (C_{NBP})	CARBON NUMBER FROM SPECIFIC GRAVITIES (C_{NSG})
1	5.27	5.49
2	6.20	6.46
3	7.73	7.34
4	8.92	8.23
5	10.0	9.11
6		10.0
7		10.89
8		11.77
9		12.66
10		13.54

Using the above results and the mass fraction data in Table A4, the relationship between carbon number and cumulative mass fraction of the crude was determined. The results are plotted in Figure A3.

Krieder has published diagrams which show weathering losses of crude oil on water as functions of time and carbon number. 93/ Curves show the minimum carbon number present in the oil for several days after the spill; weathering characteristics are shown for three film thicknesses (0.1, 0.5, and 1.9 mm). Assuming a thickness of 0.5mm and Kreider's figure, we can plot minimum carbon number present in the oil as a function of spillage. The results appear in Figure A4. Using these data in conjunction with the curves in Figure A3 (using C_{NSG} for carbon number less than 10 and C_{NBP} otherwise), we are able to approximate fractional mass loss as a function of days of weathering:

TABLE 6:
FRACTIONAL MASS LOSS VS. DAYS OF WEATHERING

DAYS AFTER SPILL	MINIMUM CARBON NUMBER PRESENT	MASS FRACTION LOST	FRACTION REMAINING
1	11.8	.299	.701
2	12.6	.342	.658
3	13.1	.365	.635
4	13.7	.409	.591
7	14.3	.450	.550
12	14.8	.485	.515
17	13.1	.510	.490
21	13.2	.525	.475

Using the value for one-day age, when .299 of the original mass has been evaporated (or otherwise lost), let us assume:

- specific gravity of separator liquid .897
- density of water 62.4 lb/ft^3
- 1 gallon water = 8.34 lb
- 1 gallon separator liquid = 7.48 lb
- 1 barrel separator liquid = 42 gal = 314.3 lb

Thus, after one day, .299 x 314.3 = 94.3 lb per barrel are lost from the surface. Assuming a reactivity of .30 implies that 28.3 lbs reactive HC are lost. 94/

From the work of Fay, which analyzes the behavior of an oil slick under calm conditions, it is possible to estimate the size of a slick. 95/ Assuming a slick length of 1.4 km after one day, we obtain an area of 6.2 km (assuming circular configuration), and thickness of

$$h = \frac{\text{volume of spill}}{2\pi \cdot \text{length}^2}$$

Using Fay's example (10,000 ton, or 66,380 bbl spill), we obtain a thickness of 0.8 mm after one day and 0.5 mm after 2.3 days. Results of our analysis for both a 10,000 and 1,000 ton spill are listed in Table A7.

TABLE A7:
EMISSIONS OF HYDROCARBONS FROM AN OIL SLICK

SPILL SIZE (tons)	DAYS AFTER SPILL	EMISSIONS (tons/hr) AREA (km^2)	THC	RHC
10,000	1	6.2	92.4	27.7
	2	8.0	117.9	35.4
1,000	1	1.3	19.9	6.0
	2	1.7	25.4	7.6

The above emission values were divided by the respective slick areas to obtain fluxes per 1 x 1 km square, the value used in ARTSIM runs as described in the section IMPACT OF HYDROCARBON EMISSIONS FROM OIL SPILLS. According to MIT's Analysis of Oil Spill Statistics, analysis of marine terminal spills indicates that probabilities for first-day emissions exceeding those above are about .07% (10,000 ton spill) and 0.15% (1,000 ton spill). 96/

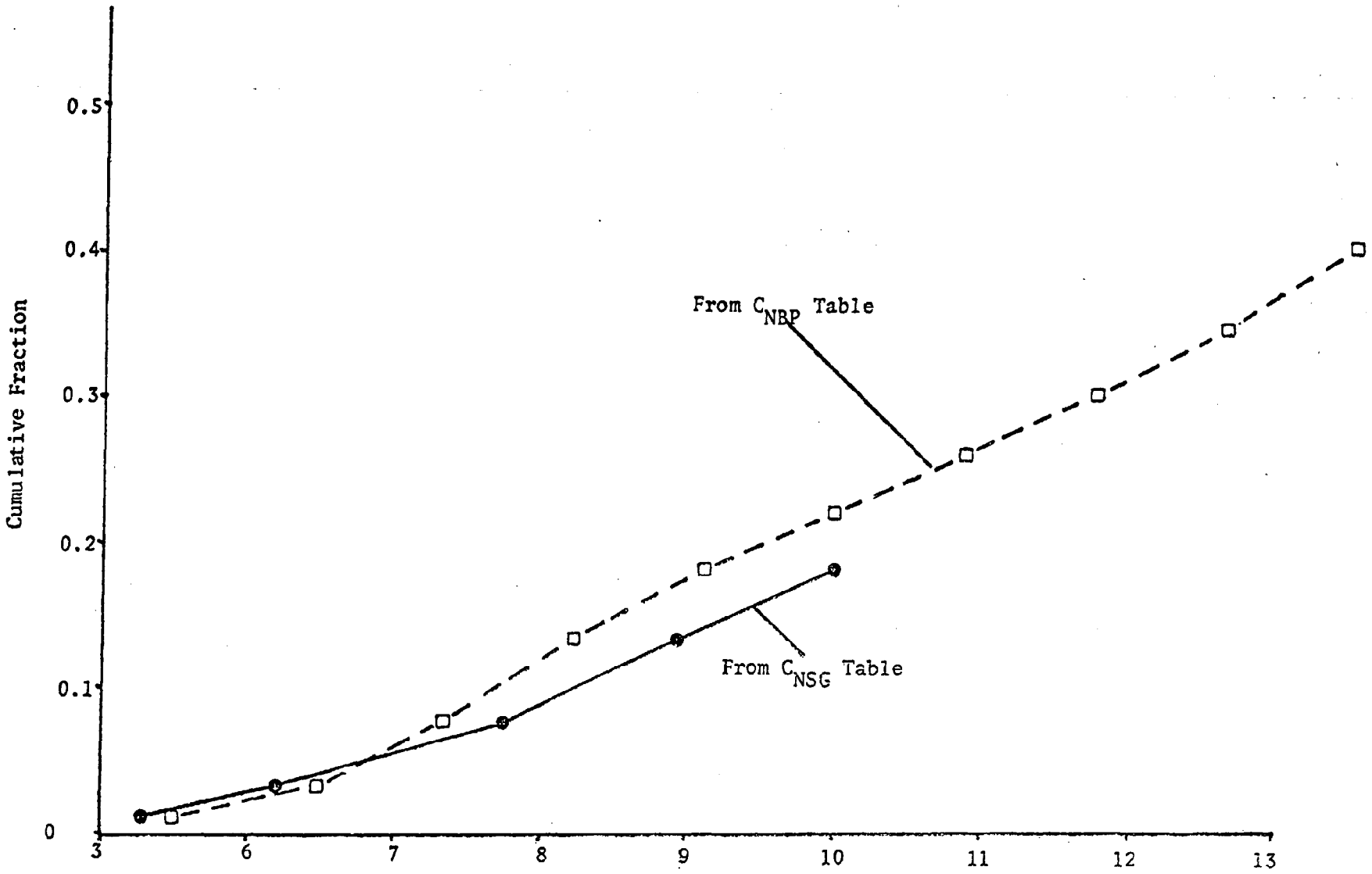

Figure A3 Carbon Number versus Cumulative Mass Fraction of Local Crude

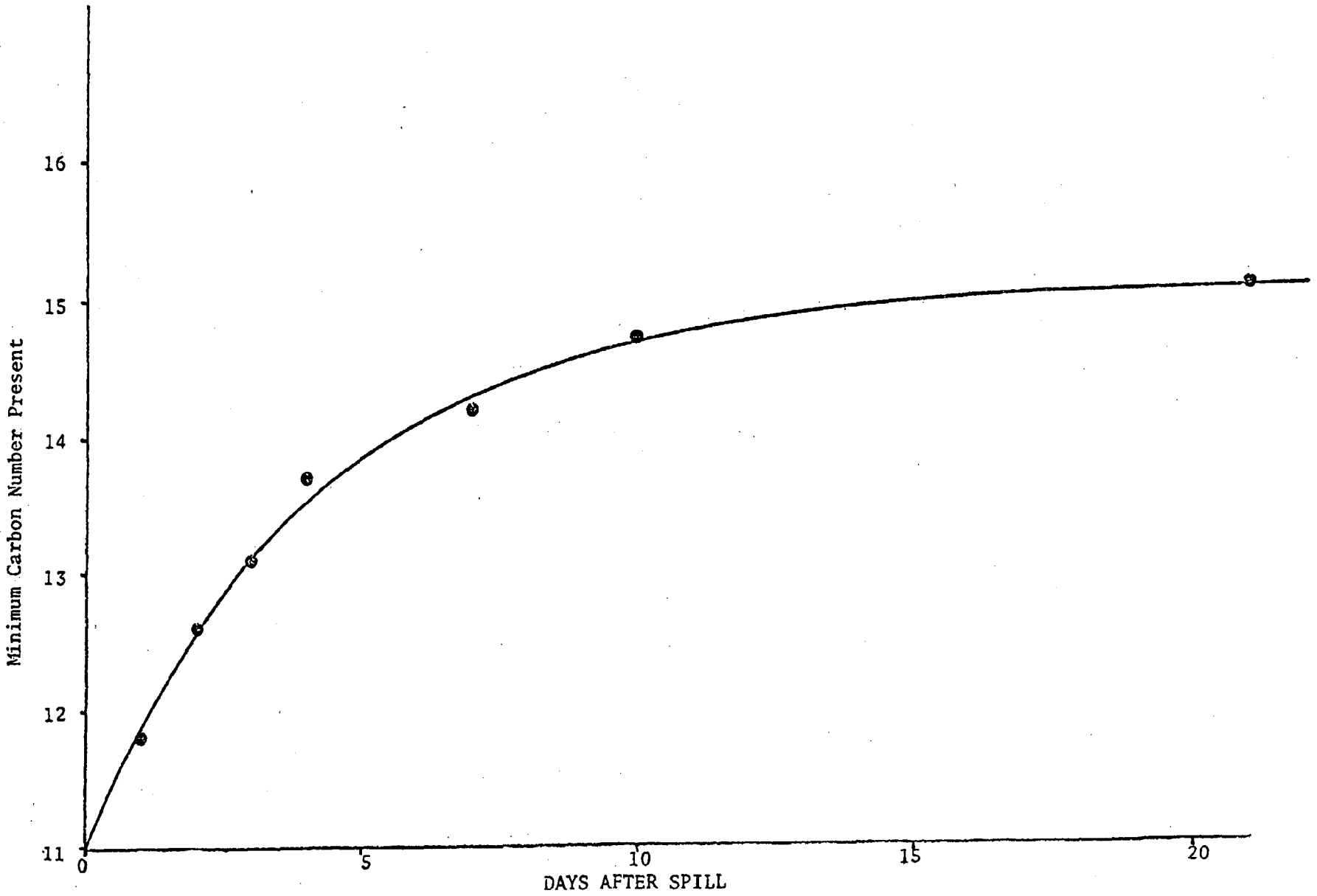

Figure A4 Minimum Carbon Number Present in Spilled Oil.

APPENDIX C

POINT SOURCE DIFFUSION MODEL (PSDM)

PSDM was designed to provide estimates of the downwind profile of short-term concentrations resulting from the emissions of elevated point sources (such as tall stacks). Ground-level pollutant concentrations along the direction of the plume centerline can be computed for each of up to 3,840 weather conditions, including eight stability classes, six wind speed classes, and 16 wind direction classes. The concentrations are calculated at each receptor in a polar grid system which is defined at specified downwind distances.

SPECIFICATION OF METEOROLOGICAL CATEGORIES

PSDM predicts downwind concentrations expected during a spectrum of stability classes (including very unstable to stable) by the well known Gaussian diffusion model for an elevated, continuously emitting point source (see Equation 1). Unless otherwise specified, PSDM has five stability classes (for computational efficiency, the seven Turner classes have been condensed to five): PSDM classes 1-4 correspond to Turner classes A-D, respectively; and, PSDM class 5 combines Turner categories E, F, and G. The user may override the default parameters to specify up to eight stabilities.

PSDM also incorporates default* wind speed classes which vary with stability category as presented in Table A8. Generally, the lightest winds occur with Stability Class 2, and the strongest with Stability Class 4. Six wind speed classes can be specified for each stability.

A total of 16 default wind direction classes are considered in PSDM calculations. All are of equal 22 1/2% sector size beginning with 0^0-22 $1/2^0$.

PSDM also considers up to five mixing depth dategories for each stability category, wind direction, and wind speed class. This combination of eight stability categories, six wind speed classes, 16 wind directions, and five mixing depths gives a total of 3,840 weather conditions for which one- and three-hour average pollutant concentrations can be calculated.

EQUATION 1:

$$\overline{x}(0,0,z) = \frac{Q(x,-y,H)}{2\pi\sigma_y\sigma_z\overline{u}} \exp - \frac{y^2}{2\sigma_y^2} \cdot \exp - \frac{(z-H)^2}{2\sigma_z^2} + \exp \frac{(z+H)^2}{2\sigma_z^2}$$

where (x,y,z) are the (upwind, crosswind, vertical) components of a Cartesian coordinate system, such that the receptor point is located at or vertically above the origin (expressed in units of length), and the source at the point (x,-yH)

$\overline{x}(0,0,z)$ is the ground-level pollutant concentration from an elevated point source at a receptor (0,0,z) (units mass/length^3)

---

*Values used in the program unless otherwise specified.

H is the effective height (stack height plus plume rise) of emission and, therefore, the centerline height of the plume (units length)

$Q(x,-y,H)$ is the source strength (mass/time)

σ_y, σ_z are dispersion coefficients that are measures of crosswind and vertical plume spread, respectively, and are functions of downwind distance and stability (units length)

$\bar{u}$ is average wind speed (units length/time)

CALCULATION OF SHORT-TERM CONCENTRATIONS

The concentrations are calculated by Equation 1 with y = 0. The dispersion parameters σ_y and σ_z are given by

$$\sigma_y = AY * X^{BY} + CY$$
$$\sigma_z = AZ * X^{BZ} + CZ$$

where the coefficients and exponents AY, BY, CY, AZ, BY, CZ are dependent upon both stability and downwind distance x as given by the ranges

(1) $X2 < x$

(2) $X1 < x \leq X2$

(3) $x \leq X1$

Default values of the coefficients and exponents are independent of the last parameter and are those suggested by the ASME (see Table 32).

Three-hour average concentrations are estimated using an option which simulates the variability in wind direction that typically occurs over this longer period. The plume is allowed to meander evenly through a sector whose width is stability-dependent. This sector averaging is specified as a modification of Equation 1 as follows:

$$\bar{\chi}_{3HR} = \bar{\chi}_{1HR} * \sigma_y * F3HR/x$$

where

$$F3HR = \frac{\sqrt{2\pi}}{\tan \theta/2}$$

and θ is the sector width.

The default values for F3HR are:

$= 45^0$ for stability 1

$= 33.75^0$ for stabilities 2, 3, and 4

$= 22.5^0$ for stability 5

TABLE A8:
SPECIFICATION OF PSDM ATMOSPHERIC STABILITY AND WIND SPEED CLASSES

STABILITY CLASS	DESCRIPTION	WIND SPEED CLASS 1 (mph)	2 (mph)	3 (mph)	4 (mph)	5 (mph)
1	Very unstable	2	3	4	5	7
2	Unstable	2	4	6	8	12
3	Slightly unstable	2	4	6	8	12
4	Neutral	4	8	12	20	45
5	Stable	2	4	6	8	12

TABLE A9:
DEFAULT DISPERSION PARAMETERS USED IN CALCULATING σ_y AND σ_z

STABILITY CLASS	VALUES OF COEFFICIENTS AND EXPONENTS AY	BY	CY	AZ	BZ	CZ
1	0.40	0.91	0.	0.40	0.91	0.
2	0.36	0.86	0.	0.33	0.86	0.
3	0.32	0.78	0.	0.22	0.78	0.
4	0.32	0.78	0.	0.22	0.78	0.
5	0.31	0.71	0.	0.06	0.71	0.

The wind speed $\bar{u}$ is specified as an increasing function of height. The vertical variations in wind speed are treated using a power law formulation of vertical wind shear:

$$\bar{u} = u_0 \frac{Z}{ZWIND}^{WEXP}$$

where u_0 is the reference wind speed (m/s)

Z is the height above the surface (m.)

ZWIND is the height at which u_0 was measured (m.)

WEXP is an array of stability dependent exponents

TRAPPING

PSDM also considers the result of the effluent plume being trapped below an elevated inversion lid. Conditions beneath the lid vary from very unstable to neutral stabilities. Lidded conditions require a modification of Equation 1.

To account for the lid, image sources are created above the lid and below the ground which add to the total concentration. The height of the inversion is set at five specified heights. If the rise of the point source plume is at least ten meters (or some other specified distance) higher than inversion height, the

plume is considered to pass through the inversion into stable air and disperse only gradually to the ground. If the calculated plume rise is less than ten meters above the inversion height, the plume is considered trapped by the inversion and the trapping model is used.

PLUME RISE

PSDM uses the most recent Briggs plume rise equations in forms which depend on stability. The formulation includes calculation of both transitional and equilibrium plume rise.

For neutral and unstable conditions (PSDM stabilities 1-4):

$$\Delta h = \frac{1.6F^{1/3} x^{2/3}}{\bar{u}} \quad x < 3.5x^* =$$

$$\frac{1.6F^{1/3}(3.5x^*)^{2/3}}{\bar{u}} \quad x \geq 3.5x^*$$

where h = plume rise (m.)

F = buoyancy flux (m^4/sec^3)

x^* = downwind distance at which atmospheric turbulence dominates entrainment in plume rise (m.)

$x^* = 14F^{5/8}$ for $F < 55 m^4/sec^3$

$34.49F^{2/5}$ for $F \geq 55 m^4/sec^3$

$3.5x^*$ = downwind distance at which plume reaches equilibrium level (m.)

For stable conditions (PSDM stability 5):

$$\Delta h = \frac{1.6F^{1/3} x^{2/3}}{\bar{u}} \quad x < 2.4 \frac{\bar{u}}{s}^{1/2}$$

$$= 2.9 \frac{F}{u^*s}^{1/3} \quad x \geq 2.4 \frac{\bar{u}}{s}^{1/2}$$

where s = stability parameter based on atmospheric lapse rate

$= VPTG^*G/TA$

where VPTG = rate of change of potential temperature with distance (default value $.0137^oK/m$)

G = gravitational acceleration ($9.8 m/sec^2$)

TA = ambient air temperature (default 290^oK)

For a calm atmosphere ($\bar{u} < 1.37$ m/sec),

$$\Delta h = 5.0F^{1/4}s^{-3/8}$$

THE EFFECTS OF TERRAIN

The PSDM program accounts for terrain elevations by permitting the plume to be lifted a fraction, TER, of the difference between the height of the receptor (the point on the ground for which the concentration is being computed) and the height of the stack base, with the additional restriction that the plume shall always be at least 1-TER of the height above the ground that it would be if there were no topography. Default value of TER is .50. The simultaneous consideration of both the plume rise as a function of downwind distance and of the topography surrounding the point source provides a realistic simulation of the downwind transport of effluent released in areas characterized by irregular terrain.

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GLOSSARY OF AIR POLLUTION TERMS

ADVECTION. Transport of material (e.g., pollutants) through the atmosphere by winds.

AIR BASIN. A region in which the air quality is determined by the meteorology and emissions within it, with minimal influence on and impact by contiguous regions. In California, the 14 air basins have boundaries established by the Air Resources Board. While the above criterion is the major consideration, the boundaries may be the borders of counties if such borders are close to the boundary of the natural air basin.

AIR MONITORING. Sampling for and measuring of pollutants present in the atmosphere.

AIR PARCEL. Any air mass assumed to be relatively independent of mass interchanges with its surroundings.

AIR POLLUTION CONTROL BOARD (APCB). The board of directors for the APCD: the County Board of Supervisors in single county APCDs; in multi-county APCDs, it consists of members from each county's Board of Supervisors, except special cases such as BAAPCD (Bay Area APCD).

AIR POLLUTION CONTROL DISTRICT (APCD). Local governmental agencies on the county level with the legislative authority to adopt and enforce all rules and regulations necessary to control non-vehicular sources of air contaminants.

AIR POLLUTION CONTROL OFFICER (APCO). The appointee of the local APCD with the duties of implementing and enforcing all rules and regulations as prescribed by the APCD.

AIR QUALITY MAINTENANCE AREA (AQMA). Areas which, due to current air quality and/or projected growth rates, may have the potential for exceeding any national ambient air quality standard within the next 20 years. These areas were identified pursuant to federal regulations (Federal Register, June 18, 1973) and are contained in ARB's Revision 5 of State Implementation Plan.

AIR QUALITY MAINTENANCE PLAN (AQMP). A comprehensive plan to assure the achievement and/or maintenance of the national air quality standards through the long term (20-25 years). The plans are to be formulated at the local level and will integrate direct source controls, land use plans, and transportation strategies which will be implemented at the state and local level to achieve and maintain the air quality standards. AQMPs are required by the Clean Air Act and subsequent EPA regulations.

AIR QUALITY STANDARDS. A quantification of allowable levels of air pollution. There are two types of National Ambient Air Quality Standards (NAAQS)--the primary standards and the secondary standards. (See National Primary Standards and National Secondary Standards.) Under provision of the Mulford-Carrell Act, the State Air Resources Board is required to set state air quality standards. However, since there are no specified dates set for attainment of the standards, the state air quality standards are essentially air quality goals.

ALKANE (PARAFFIN) SERIES. A hydrocarbon series characterized by single covalent bonds and hence relatively low reactivity. Examples: methane, propane, octane.

ARTSIM MODEL. Atmospheric Reaction and Transport SIMulation, a semi-Lagrangian model in which chemical and photochemical reactions and vertical diffusion mechanisms are used in calculating air pollutant concentrations within a moving air parcel.

BACKGROUND LEVEL. Amounts of pollutants present in the ambient air due to natural sources. Examples, marsh gases, pollen, windblown dust.

BOUNDARY CONDITIONS. The values of a variable at each point along the boundaries of a region for a single analysis.

BOUNDARY LAYER. The lowest levels of the earth's atmosphere, within which most air pollutants are confined.

CARBON MONOXIDE (CO). A colorless, odorless, toxic gas produced by the incomplete combustion of carbon-containing substances. One of the major air pollutants, it is emitted in large quantities in the exhaust of gasoline-powered vehicles.

DIFFUSIVITY. A constant of proportionality that relates the flux of a component of a non-uniform fluid to the gradient of concentration of that component. Value of the diffusivity depends on molecular or turbulent disturbances in the fluid mixture.

DISPERSION MODEL. A mathematical representation and solution of the physical processes that result in the spread of pollutants in the atmosphere. The phenomenon of direct interest in predicting the dispersion of pollutants is turbulent diffusion. Consequently, dispersion models are sometimes called diffusion models. However, turbulent diffusion and diffusion models are misnomers. The phrases refer to the spreading of a cloud of particles in a turbulent fluid at a rate many orders of magnitude greater than that from molecular diffusion alone. The spreading is really not due to a "diffusion" phenomenon such as results from molecular collisions but rather is a result of the rapid, irregular motion of lumps of fluid (called eddies) in a turbulence.

EMISSIONS FACTORS. An expression of the estimated emissions of air pollutants/unit time/activity. Examples of activities are low density residential land use, vehicle miles traveled for a certain model and year automobile or truck, and landing-takeoff cycles of aircraft. Emissions factors are being developed by the Environmental Protection Agency and the Air Resources Board for use in the preparation of emissions inventories and emissions projections for planning purposes.

EMISSIONS INVENTORY. An inventory of the spatial distribution of sources of air polluting emissions and pollutant types and quantities from each source within a given geographic area for a given time period. The locations of emissions from stationary sources and mobile sources are presented separately in an emissions inventory.

EMISSIONS RATE. The mass of specific pollutants emitted into the atmosphere by one or more sources within a certain time period (e.g., lbs/hr).

EMISSIONS STANDARD. The maximum amount of a pollutant that is permitted to be discharged from a polluting source; e.g., the number of pounds of dust that may be emitted from an industrial process.

EULERIAN GRID CELL. A unit of an analysis grid that is fixed in space.

FLUX. The rate per unit area at which material or energy moves across a plane perpendicular to the flow.

GAUSSIAN MODEL. A pollutant dispersion model based on the Gaussian concentration equation, which assumes a constant fractional decrease in concentration per unit distance from a stationary or moving center of dispersion.

HYDROCARBON (HC). Any of a vast family of compounds containing carbon and hydrogen in various combinations; found especially in fossil fuels. Some of the hydrocarbon compounds are major air pollutants; they may be active participants in the photochemical process or carcinogenic.

INVERSION. The phenomenon of a layer of warm air lying over and trapping cooler air below. A special problem in areas having large sources of emissions because the contaminating substances cannot be dispersed through the layer of warm air, and high levels of air pollution result.

LAGRANGIAN ANALYSIS. A modeling type which involves the behavior and characteristics of an air parcel moving along a trajectory through the atmosphere.

MIXED LAYER. Layer of air near the ground where turbulent mixing of pollutants occurs. It is limited by an inversion base, if one is present.

MONITORING. The sampling and measuring, on a continual or continuous basis, of air pollutants.

NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS). Standards for air quality as set by the EPA Administrator, prescribed in terms of maximum concentrations permissible for various pollutants and averaging times.

NATIONAL PRIMARY STANDARDS. The levels of air quality necessary, with an adequate margin of safety, to protect the public health. Each state must attain the primary standards no later than three years after that state's implementation plan is approved by the Environmental Protection Agency (EPA).

NATIONAL SECONDARY STANDARDS. The levels of air quality necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant. Each state must attain the secondary standards within a "reasonable time" after implementation plan is approved by the EPA.

NEW SOURCE PERFORMANCE STANDARDS (NSPS). Regulations promulgated by EPA that establish the maximum permissible emission levels from certain types of new sources.

NITROGEN OXIDES (NOx). Gases formed from atmospheric nitrogen and oxygen when combustion takes place under conditions of high temperature and high pressure; considered major pollutants. Also formed in industrial processes, such as the production of nitric acid.

NO SIGNIFICANT DETERIORATION. Pursuant to a court decision, EPA adopted regulations for preventing significant deterioration of air quality in those areas of the states where air quality is at levels better than the NAAQS. The regulations apply only to particulate matter and sulfur dioxide.

OFFSHORE STORAGE AND TERMINAL FACILITY (OS&T). An OS&T is a permanently moored vessel used for the storage of crude oil pending arrival of a tanker to transport the oil to its destination. An OS&T may be a modified tanker (as proposed by Exxon for the Santa Ynez Unit) or a barge-like vessel. Once its usefulness has ended, an OS&T may be moved and re-used elsewhere.

OLEFIN SERIES. A hydrocarbon series characterized by a double bond between two carbon atoms, resulting in relatively high reactivity. Examples: ethylene, propylene.

OXIDANT. Substances in the air such as ozone which make available oxygen or oxygenated compounds for chemical reaction. Oxidants may be formed from the reaction of certain reactive hydrocarbons and nitrogen dioxide, under the influence of sunlight.

OXIDE. A compound of two elements, one of which is oxygen.

OZONE (O_3). A pungent, colorless, toxic gas. As a product of the photochemical process, it is a major air pollutant.

PARTICULATE MATTER (PM). A particle, or particles, of solid or liquid matter such as soot, dust, aerosols, fumes, and mists.

PARTS PER MILLION (PPM). A volumetric measure of concentration in which is given the number of parts of a specific pollutant in a million parts of air.

PLUME. The spreading pollutants emitted by a fixed source, such as a smokestack.

POINT SOURCE. A stack of other highly localized pollutant source. Contrasted to an area source.

POINT SOURCE DIFFUSION MODEL (PSDM). ERT's Gaussian-type model designed to provide estimates of downwind short-term concentrations of pollutants emitted by surface-based or elevated point sources.

PRIMARY POLLUTANTS. Pollutants emitted directly from sources.

PURGING. The process of flushing cargo tank atmospheres with inert gas for the purpose of reducing the concentration of hydrocarbon gas. Thereby, pollutants which are dispersed in the cargo tank gases are released into the atmosphere.

RAWINSONDE. An electronic device carried aloft by a buoyant balloon to measure temperature, dewpoint, pressure, and winds at various levels in the earth's atmosphere.

REACTIVE HYDROCARBON (RHC). A hydrocarbon that readily combines with radicals and thereby contributes to ozone production.

RECEPTOR. Commonly used in air quality discussions to describe any human, animal, plant, or material that can be adversely affected by air pollutants.

SECONDARY POLLUTANTS. Pollutants formed by chemical and photochemical reactions in the atmosphere.

SIMULATION MODEL. A mathematical description of real physical and/or chemical processes. The responses of the model to input variations are analogous to those of the real processes.

SOURCE REVIEW. A general term used to describe any one of a number of specific reviews that need to be conducted on proposed facilities that will produce pollutants. The review is designed to determine the acceptability of the source with regard to

types and amounts of pollutants that will be produced as the existing pollution controls and/or strategies within the area of impact.

STABILITY. The relative amount of turbulent mixing which occurs in the atmosphere; a function of temperature differences; wind shear, and other meterological parameters. Higher stabilities (i.e., more stable atmospheric characteristics) imply less turbulent mixing.

STANDARD OF PERFORMANCE. An emission limitation imposed on a particular category of pollution sources, either by EPA, the state, or the local APCD. Limitations may take the form of emissions standards or of requirements for specific operating procedures.

SULFATES. Principally the sulfur oxides SO_3, HSO_4, and H_2SO_4 (not SO_2) that are generally found as aerosols and particulates. Major sources are power plants, refineries, chemical industry processes, and recently demonstrated to be a by-product of the catalytic converter installed on new automobiles.

SULFUR OXIDES (SOx). Pungent, colorless gases formed primarily by the combustion of fossil fuels containing sulfur; considered major air pollutants. Sulfur oxides may damage the respiratory tract as well as vegetation.

SURFACE FLUX. The rate per unit area at which some quantity passes through or is emitted from the surface.

TRAJECTORY. The path taken by an air parcel as it is advected by the wind; calculated directly (e.g., tracking of balloons) or indirectly (interpolation of wind station data).

TRANSPORT. Generally used in air quality discussions to describe the physical phenomenon whereby pollution is carried from the site of emission to another site.

UNIVERSAL TRANSVERSE MERCATOR (UTM) System. An arbitrary system of east-west and north-south lines spaced one kilometer apart which intersect to form one-square-kilometer squares when superimposed on the earth's surface.

VENTING (or BREATHING). Hydrocarbon emissions escaping from cargo tanks from either the ullage hatches or pressure-vacuum valves. It is a consequence of natural phenomena such as barometric pressure changes, ambient temperature changes, and vapor growth.

VEHICLE MILES TRAVELED (VMT). A term used to describe the number of miles traveled by vehicles in a specified area during a given time.

WIND SHEAR. The spatial variation of wind velocity.

CHAPTER 16

SENSITIVE RESOURCES: INVALUABLE VALUES

The Southern California Bight with its irregular coastline, its submarine ridges rising steeply out of deep basins, and its bordering offshore islands, provides habitat for a multitude of marine species. The Channel Islands and the shallow offshore banks are also sufficiently isolated from the mainland and from one another to permit the development of numerous endemic populations of marine flora and fauna. This isolation also provides a refuge for over 80 species of resident and migrant seabirds, as well as breeding and pupping areas for five species of seals and sea lions. 1/

The development of leases sold in the three previous OCS sales could result in a variety of conflicting resource uses of the marine and coastal environments of southern California. Adverse effects on marine organisms, seabirds, endangered wildlife species, recreational resources, and other environmental attributes could occur as a result of chronic and catastrophic discharges of oil and other toxic substances, modification and destruction of habitat during pipeline construction, and the alteration of natural conditions and unique ecological sites which may result from human disturbance, structures, and other development pressures. For all species, greatest concern is for the possible impact of some phase of petroleum development on scarce, unique, or otherwise critically important habitats upon which they depend.

This inventory of sensitive resources has been compiled for the five affected counties' coastlines and for the eight offshore islands in order to help planners order priorities and devise strategies for protecting these resources. Three categories of critical resources are discussed with regard to their environmental and economic value: (1) officially designated environmentally sensitive areas; (2) other habitat areas of particular value and/or vulnerability; and, (3) areas of economic and recreational importance.

Areas in each category were chosen for inclusion on the basis of two criteria: biological sensitivity and geographical vulnerability. In order to be considered, each resource or habitat type had to be sensitive to oil development as well as potentially threatened by that development.

The accompanying maps indicate the location of sensitive resources, illustrating where the greatest concentrations of critical habitats and recreational activity occur.

The base maps for the inventories are the coastal portions of the standard USGS 7½" quadrangles, 1:24,000, reproduced at 37% of the original to a scale of 1:62,500 approximately. The islands were initially scaled at 1:62,500; they are also reproduced at 37% of the original, to a scale of 1:165,000.

CRITICAL HABITATS

Certain habitat types have been repeatedly identified in the literature as being sensitive to disturbances from petroleum development activities. Spilled oil, in particular, has a great potential for damaging pinniped and seabird rookeries, wetlands, rocky intertidal areas, kelp beds, and offshore reefs. The biological sensitivity and geographical vulnerability of each of these important habitats found in the Southern California Bight are discussed below.

PINNIPED ROOKERIES AND MAJOR HAUL-OUT AREAS

According to the Marine Mammal Commission, the Channel Islands and surrounding waters support one of the world's most diverse assemblages of marine mammals. Historically, seal and sea lion populations in the Southern California Bight were much larger. Pinnipeds once bred in great numbers along the southern California mainland coast and still do in areas north of Point Conception where little or no human activity is present. Human activity in southern California has disturbed these marine mammals to such an extent that they no longer breed at their previously established coastal rookeries. 2/ Today, seals and sea lions breed and pup almost exclusively on the Channel Islands.

The most thorough study to date of the marine mammals inhabiting the southern California waters and offshore islands is being conducted under the auspices of the Bureau of Land Management baseline studies program, by contract with scientists at the University of California, Santa Cruz, and Irvine. The six-month progress report characterized the pinniped population as follows:

> Many thousand seals and sea lions are found in the Southern California Bight either as year-round residents or as seasonal transients. Major populations of the northern elephant seal, Mirounga augustirostris, the California sea lion, Zalophus californianus, and the harbor seal, Phoca vitulina, pup and breed each year on the rocks and beaches of the Channel Islands. In addition, the northern fur seal, Callarhinus ursinus, and the Steller sea lion, Eumetopias jubata, have the southernmost extension of their breeding range in these islands. With the presence of rare Guadalupe fur seals, Arctocephalus townsendi, an endangered species, the Southern California Bight possesses the largest and most diverse pinniped community in temperate waters. 3/

From census data contained in the above report, major breeding and haul-out areas have been mapped. Highest densities of animals are found on San Miguel Island, where a survey at the peak of the sea lion breeding season found 15,337 pinnipeds, primarily clustered on the west end. San Miguel Island and its associated rocks form the most important pinniped habitat in southern California. Six species of seals and sea lions inhabit the island, and five breed there. According to the U.S. Fish and Wildlife Service, San Miguel Island has an ideal environment for pinnipeds because of its climate and the configuration of its low,

sandy beaches. Because it is located where warm and cold currents meet, the island demarcates the southern range of northern species of pinnipeds and the northern range of southern species.

San Nicholas Island is the second largest hauling-out ground, followed by Santa Barbara and to a lesser extent, San Clemente islands. San Nicholas and Santa Barbara islands support breeding populations of the northern elephant seal, the California sea lion, and the harbor seal. A very large rookery of California sea lions is found on the western side of San Clemente Island, as well as a smaller number of northern elephant seals.

Pinnipeds are also found on Santa Rosa, Santa Cruz, Anacapa, and Santa Catalina islands, but not in the numbers or concentrations found on San Miguel, Santa Barbara, San Nicholas, and San Clemente.

According to Linstedt-Siva, several mainland sites are used by harbor seals as haul-out grounds and possibly breeding grounds. 4/ These remote beaches appear to be used primarily at night, and have largely escaped detection. The most important site identified to date is at Burmah Beach where up to 165 individuals have been observed.

The maps indicate where concentrations of pinnipeds were found consistently during the first six months of the marine mammal/bird baseline study, including the scattered mainland sites. A final report based on the entire first year's effort will be released imminently and will include an annual cycle for each island for each species, behavioral information, at-sea census data, and estimates of the total breeding population of each species, as well as distribution and density of pinnipeds on land. No attempt is made, on the maps at the end of this chapter, to represent such a degree of specificity. Rather, each symbol indicates geographically defined areas where pinnipeds were consistently observed in close aggregations.

These areas are considered extremely sensitive according to the EIS for OCS Lease Sale #35, which stated that:

> The greatest danger to marine mammals is disturbance of pinnipeds from drilling operations and from platform construction or onshore separation and storage facilities on the islands near breeding and hauling-out areas. Activities associated with platform installation, exploratory drilling and production operations off San Miguel and Santa Barbara islands could cause significant reductions in sea bird populations and the potential elimination of sea lions, fur seals, and harbor seals from their principal breeding area in southern California. The ultimate outcome of rookery abandonment is the elimination of pinnipeds from southern California waters. 5/

It was further concluded that drilling activities within three miles of rookeries were potentially dangerous to pinniped populations, and the following alternative was offered:

> No offshore structure, either temporary or permanent, will be placed closer than six (6) statute miles from the shorelines (mean high tide level) of San Miguel and Santa Barbara islands in order to provide a minimum buffer zone for pinniped and sea bird rookeries located on these islands. This restriction includes exploratory drilling structures. 6/

The Bureau of Land Management considered six miles a minimum requirement in order to reduce the possibility of ship traffic and human activity interfering with the normal behavior of the sea birds and pinnipeds. That distance would also provide more time to set up containment equipment before an oil slick could reach the shore.

Although little is known about the sensitivity of pinnipeds to petroleum, it is acknowledged that petroleum is more debilitating to fur seals than to sea lions or elephant seals because of the fur seals' pelage. 7/

Unquestionably, the greatest known danger to pinnipeds is disturbance during critical periods in their life cycles -- breeding, pupping, and nursing. Thus, in the event that an oil spill should reach the shore of the rookeries, the presence of spill cleanup crews and equipment could conceivably cause more damage to the pinnipeds than the spill itself.

In commenting on OCS Lease Sale #35, the U.S. Fish and Wildlife Service also recommended that an ecological buffer zone should be established around the Channel Islands, especially San Miguel and Santa Barbara, in order to protect them from the possible adverse effects of exploration and development. 8/

The Marine Mammal Commission similarly urged that further exploration or leasing in the Channel be delayed until environmental baseline studies are completed and a better understanding is reached of the potential for OCS activities to harm the marine mammal population. The Commission also recommended that the three-mile buffer zone around San Miguel, Santa Rosa, and most of Santa Cruz Islands be extended to six miles, in order to protect pinniped habitats. 9/

Tracts southwest of San Miguel were withdrawn from OCS Lease Sale #35, but tracts adjacent to Santa Barbara Island were offered and subsequently leased. More tracts adjacent to Santa Barbara Island will be included in BLM's environmental impact statement for OCS Sale #48. Tracts north and south of the Northern Channel Islands are also included, as can be seen from the map following. Tracts in the same area, immediately adjacent to the three-mile state boundary were leased by BLM in 1968, and exploration has taken place in the tracts north of San Miguel Island.

As the intensity of petroleum development activity builds in offshore California waters as a result of Lease Sale #35 and the pending Lease Sale #48, a minimum of six miles must be established and maintained as a buffer zone between important pinniped breeding grounds and all forms of petroleum-related activity.

RARE AND ENDANGERED SPECIES HABITAT

Rare and endangered animals are at the limit of their tolerance as a result of human disturbance and habitat destruction.* Minimization of further encroachment on areas essential for their continued survival is the aim of endangered species legislation, both federal and state. Legal support for the preservation of threatened species is provided by the California Department of Fish and Game and the U.S. Fish and Wildlife Service (U.S. Department of Interior).

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* Major habitats of species on the federal and state threatened lists are indicated on the maps at the end of this chapter.

The State's Endangered Species Act, passed by the Legislature in 1970, defined rare and endangered wildlife and gave the Fish and Game Commission authority to designate which animals in California are endangered.

These terms have been defined by the Legislature:

> Endangered - "is an animal of a species or subspecies of bird, mammal, fish, amphibian, or reptile, the prospects of survival and reproduction of which are in immediate jeopardy from one or more causes, including loss of habitat, change in habitat, over-exploitation, predation, competition, or disease."
>
> Rare - "is an animal of a species or subspecies of bird, mammal, fish, amphibian or reptile that, although not presently threatened with extinction, is in such small numbers throughout its range that it may be endangered if its environment worsens."

It is unlawful to take, possess, or sell an animal designated as endangered or rare.

Also in 1970, the Legislature passed the California Species Preservation Act, directing the Department of Fish and Game to inventory all threatened fish and wildlife, and report to the Governor and the Legislature every two years on the status of these animals. California was the first state to provide protective legislation prohibiting the importation, taking, possession, and sale of endangered and rare species.

Of 49 rare and endangered species statewide, nine are found in the Southern California Bight. 10/ The following six species rely on either the mainland coast or the islands for habitat:

Island Fox, Urocyon littoralis, rare

Guadalupe Fur Seal, Arctocephalus townsendi, rare

California Brown Pelican, Pelicanus occidentalis californicus, endangered

California Least Tern, Sterna albifrous browni, endangered

Light-Footed Clapper Rail, Rallus longirostris levipes, endangered

Belding's Savannah Sparrow, Passerculus sandwichensis beldingi, endangered

Habitats of the following three endangered species are less well-known due to infrequent sitings as their numbers have declined drastically in recent years:

California Black Rail, Laterallus jamaicensiscoturniculus, rare

American Perigrine Falcon, Falco peregrinus auatum, endangered

Southern Bald Eagle, Haliaeetus leucocephalus leucocephalus, endangered

These three species once nested extensively on the mainland coast and/or the Channel Islands, but the location of the few remaining nesting sites for each is now a well-kept secret. For this reason, they are not included on the maps.

The California Department of Fish and Game has recommended that critical habitats essential to the survival of these animals be placed under public stewardship or protected by law.

The federal Endangered Species Act of 1973 strengthened earlier legislation and extended federal authority over migratory and resident as well as foreign species of plants and animals declared threatened by the Secretary of the Interior. The law makes it a federal offense to take endangered or threatened wildlife and requires all federal agencies to use their authorities to carry out programs for conservation of endangered and threatened species and to take action to assure that their programs do not jeopardize the continued existence of endangered or threatened species or result in the destruction or modification of critical habitat.

Species on the federal endangered and threatened list, whose habitat could be affected by oil and gas development, are the following:

California Brown Pelican, Pelicanus occidentalis californicus

Light-Footed Clapper Rail, Rallus longirostris levipes

California Least Tern, Sterna albifrous browni

The following species on the federal list are found in the Southern California Bight but were not mapped because of uncertainty about habitat areas and their potential to be affected by petroleum development. 11/

Pacific Right Whale, Eubaleaua spp., all species

Grey Whale, Eschrichtius gibbosus

Blue Whale, Balaenoptera musculus

Finback Whale, Balaenoptera physalus

Sei Whale, Megaptera nouacangliae

Sperm Whale, Physetercatodon

Southern Bald Eagle, Haliaeetus leucocephalus leucocephalus

American Peregrine Falcon, Falco peregrinus auatum

El Segundo Blue (butterfly), Shijimiaeoides battoides allyui

In addition, the U.S. Fish and Wildlife Service has proposed that seven terrestrial species native to San Clemente Island, sometimes compared to the Galapagos, be added to the endangered species list. 12/ More recently, several endemic snails have also been proposed for protection, the most important being the California brackish water snail, Tryonia imitator, found largely in coastal lagoons in southern California.

KELP BEDS AND THEIR ASSOCIATED FLORA AND FAUNA

The kelp beds of southern California are named for the dominant algal

species, Macrocystis pyrifera, which often grows in dense forest-like stands along the coast in waters from 20 to 80 feet deep. 13/ Though some controversy still exists, it is generally accepted that kelp plants are not damaged by oiling. However, kelp provides an important subtidal marine habitat for a rich and diverse flora and fauna which may be adversely affected by oil trapped and held in the fronds or emulsified and spread to submerged animals on the bottom. 14/ The EIS for OCS Lease Sale #35 summed up the importance of kelp beds as habitat in the following manner:

> We feel kelp beds are such an important marine habitat to southern California that a generalized overview section should be included. Associated with kelp beds in southern California and northern Baja California are over 810 kinds of organisms. This species count was taken from North (1971) who listed 57 species of fishes, and Bright who listed over 625 invertebrate species (74 common) associated with kelp beds. The majority of these species may not have an obligatory relationship with giant kelps, but they utilize every conceivable nook and crevice of the plant and adjacent area thereby greatly increasing the total habitat available to them. 15/

Also, fish and invertebrates use kelp and other marine algae for shelter, food, and a place to lay their eggs. 16/ Therefore, the beds are vitally important to the marine sportfishing industry (party boat) since many sport fish are found in association with kelp beds. 17/

Kelp is also a commercial resource in its own right; it has been harvested and processed in California since 1910. As can be seen from the list below, kelp is an important biological and economic resource, according to values estimated for two of the state's 74 commercial beds. Values can be considered to be conservative as they are based on 1950-1960 dollars.

Resource	Value, dollars
Commercial Fish	130,000
Sport Fish	90,000
Lobster	50,000
Abalone	10,000
Kelp	500,000
Total	780,000

(Value of marine resources from the vicinity of the Pt. Loma and La Jolla kelp beds (squares 842 and 860) for 1955-56, except for kelp where a yield of 25,000 tons was assumed and is considered to be about average for plentiful years, based on data from the Department of Fish and Game.) 18/

Kelp beds are scattered rather irregularly along the mainland coast. California beds have decreased in size since the early 1900s when they covered approximately 100 square miles. Today they cover less than 75 square miles. 19/ The decline was especially severe in southern California where some of the major beds have all but disappeared from temperature changes, sewage discharges, and kelp grazers. 20/

The kelp beds extending from Point Conception to the Santa Barbara city

limits are very dense and contribute a large percentage to the commercial harvest. Kelp forests are also scattered in relatively dense stands from southern Ventura County to northern Los Angeles County, in western Santa Monica Bay, and along the Orange County coastline. San Diego County has very large beds intermittently from Carlsbad to Point Loma. The offshore islands all have kelp beds surrounding them, their size and extent varying according to season, substrata, etc. Santa Barbara Island has especially dense and extensive beds surrounding it. Leases sold in OCS Sale #35 and those that may be sold in Lease Sale #48 are a serious potential threat to these heavily fished beds. The commercially important Point Conception beds are similarly threatened by development of the Santa Ynez Unit in the western Santa Barbara Channel. The scattered beds off the Orange County coast would be affected by a spill emanating from the San Pedro Bay leases and in the more distant future, the exceptionally large beds off the Point Loma peninsula and La Jolla could be affected by oil spilled from tracts selected for EIS consideration in OCS Lease Sale #48. Finally, all kelp beds surrounding the four northern Channel Islands are threatened by existing and future petroleum activity in the Channel.

The actual size and configuration of the kelp beds varies yearly and seasonally, so precise mapping of the beds is not possible. Two of the most current sources were used, however, to give the approximate location and size of the major kelp stands. Esca-Tech's Aerial Reconnaissance in Support of the Bureau of Land Management's Southern California Baseline Studies and Analyses provided the most precise survey to date. The incomplete draft of Prominent Southern California Marine Resources being developed by the California Department of Fish and Game was also used for comparative purposes. Unfortunately, only the first and second surveys of Esca-Tech's aerial reconnaissance, which were conducted less than one month apart (during October), are available and hence do not represent a full seasonal range of kelp distribution. The contractors for that survey found an increase in bed size on the sheltered side of the islands during the winter months, a fact not represented on the sensitive resource maps. 21/ In addition, the capabilities of the infra-red film limited penetration to a depth of 1 cm., while use of USGS 1:24,000 base maps precluded representation of any kelp strands less than 100 feet wide. Subsequently, Esca-Tech's 1:24,000 kelp-bed maps were reproduced on 11" x 17" sheets at varying scales which ranged on the southern coast from approximately 1:47,000 to 1:62,500 and for the islands at approximately 1:30,000. From these small-scale maps, the kelp beds were transferred to our USGS 1:24,000 base maps. The location, size, and extent of kelp beds were then interpolated: for these several reasons, the beds are thus presented in a generalized form. To the extent that they are inaccurate, the error is one of under-representation.

ROCKY INTERTIDAL

Tide pools and their unique inhabitants are one of the most heavily exploited of California's marine resources. In the southern part of the state, recreational, scientific, and educational pressures are especially intensive, as rocky intertidal areas exist only in widely spaced stretches along the coast. However, the intertidal zone is most important for its ecological role. Many marine species depend on tide pools during some part of their life cycles, either for spawning, or during the juvenile or latter stages of their lives. 22/ The Southern California Bight supports an especially diverse variety of intertidal organisms, as it is a transitional area with a great number of 1^{0} endemics (organisms with a North-South range of 60 miles) in addition to the many better-known tide pool plants and animals. 23/

Because of the distance between intertidal areas on the mainland, repopulation in the event of a large spill could take years, as recruitment in these areas must normally come from within. The islands, on the other hand, have 80% rocky shoreline, but are too distant from the mainland to represent a sure source of recruitment. The EIS for OCS Lease Sale #35 summed it up this way:

> The damage from a large case 1 oil spill could be severe to the rocky shore intertidal. Smothering should cause the principal damage to specific upper intertidal species of plants and animals where all individuals oiled will die. The toxic effect from crude oil reaching shore in three or four hours is unknown, but will not be as severe as is caused by refined oil spills. Although the entire intertidal community will not be killed, many individuals of a variety of species will be. Reproduction and repopulation will be retarded for several months, and the extinction of rare endemics is a possibility. Biological recovery will take up to five years. However, the time required for the decimated intertidal community to return to pre-spill conditions is unknown.
>
> Cleanup operations of intertidal areas could cause total destruction of the rocky shore communities and significantly harm the communities of the sandy beach areas actually cleaned. 24/

Because of the damage to rocky intertidal areas that could result from both accidentially released petroleum and subsequent cleanup operations, adequate spill response capability should be available to prevent oil from reaching tidepools on the mainland shore in the event of a major spill.

Each of the five southern counties has rocky intertidal areas which could be given priority for protection. As can be seen from the maps, Santa Barbara and Los Angeles counties have the greatest percentage of shoreline characterized as "rocky" by the U.S. Corps of Engineers. Rocky intertidal areas comprise 24 percent or 26 miles of the shore of both counties. About 11 miles, or 15 percent of the San Diego shoreline is rocky, while Orange and Ventura counties have only three miles of rocky shoreline each. 25/ Two relatively undisturbed rocky intertidal areas on the Santa Barbara County mainland are considered by Dr. Adrian Wenner, a marine biologist at the University of California, Santa Barbara, to be critical for repopulation in the event of a large channel oil spill. 26/ Wenner has proposed that Point Conception and Naples, along with the west end of Santa Cruz Island, be given reserve status by the state because of their strategic location in terms of channel currents.

OFFSHORE BANKS

The Southern California Bight represents an atypical continental margin with a highly varied topography quite different from the more characteristic continental shelf-and-slope configuration. Bordering deep basins are numerous rocky outcrops forming ridges which are shallow enough to support very complex associations of plants and animals. Some of these areas, such as Osborne Bank, Tanner Bank, Cortes Bank, Thirty-Mile Bank, Forty-Mile Bank, and shallow bank areas in the Santa Rosa-Cortes Ridge were first identified by fishermen.

While the regional significance of the offshore banks to commercial fishing interests is well known, the significance of these areas as habitat for unique marine floral and faunal species, such as the purple coral, is just beginning to

be understood. Information about the offshore banks is inadequate to date, but as new data appear the ecological value of these shallow areas continues to be reaffirmed.

The marine mammal/bird portion of the BLM baseline studies program identified several of the banks as areas of great importance to seabirds. Most prominent among those was the northern half of the Santa Rosa-Cortes Ridge, as well as Osborne Bank, Forty-Mile Bank, the San Clemente Escarpment, and Lasuen Knoll. The Santa Rosa-Cortes Ridge was shown to harbor a tremendous concentration of cetaceans (whales, dolphins) and pinnipeds as well, during the month of July. 27/

To date, there is no published information on the banks off southern California, but from conversations with the principal investigators for BLM's subtidal baseline research on Tanner and Cortes Banks, and from several unpublished sources, these heretofore "unknown" areas have been described as follows: "The Tanner-Cortes Bank region is an extremely high energy environment characterized by rocky ridges and pinnacles rising from the sea floor to within three feet of the surface in some cases." 28/ These are shallow water areas in a deep ocean setting, as far as 120 miles offshore. In addition to the spectacular relief, all researchers have noted extremely clear water, apparently so because muddy runoff from land seldom reaches this far out. As a result of the clear water and concomitant high light levels, as well as the presence of the California current which bathes the banks in nutrients and planktonic organisms, productivity and diversity of plant life appear to be exceptionally high. Dense stands of brown algae cover the banks to a depth of 100 feet. Below this canopy, where light levels are reduced by shading, dozens of varieties of red and brown algae proliferate. These include a number of forms normally found intertidally, or in shallow nearshore waters, or in areas distant from southern California. These algae thrive together on Cortes Bank in a very uncommon mixture of species. The depth of the photic zone on these outer banks is not precisely known; however, algae have been observed as deep as 200 feet.

The fauna of Tanner and Cortes Banks seem to be highly unusual by virtue of the juxtaposition of the flora and fauna of shallow rocky substrates and the deep-water, open-ocean community of the California current. Dense schools of pelagic fish are found together with unusually abundant benthic, near-shore fish. All researchers surveyed stated that there were more fish seen on the banks per dive than seen anywhere else in the Southern California Bight. The three most common species sighted were sheephead Pimelometopon pulchrum, blue rockfish Sebastes mystinus and ocean white fish Caulolatilus princeps. Sheephead are much sought after by skin divers. Blue rockfish -- the most important sport fish in northern California and very important in southern California as well -- are also fished commercially. Ocean white fish are not heavily fished but are regarded as excellent sport fish. Quast conducted a series of belt transects in five areas of Baja California and southern California and found the greatest densities in Papalote Bay, Mexico, where a mean of 26 sheephead per acre were counted. 29/ Smith's estimate for Tanner Bank was 177 sheephead per acre. Although the methods used were different, with Quast's evidently yielding lower results, the large numbers of fish found on Tanner Bank remains quite significant. Packs of sea lions are often observed feeding among these dense schools.

The invertebrate communities on the banks also have been described as being very unusual and quite striking. The invertebrate fauna include, for example: previously undescribed species of nudibranches; huge aggregations of sea anemones and solitary corals; sea stars and urchins; gorgonian octocorals; both red and

purple forms of the rare, fragile hydrocoral Allopora; large numbers of the cowrie Cypraea spadicea (a shell-collector's item); and, sufficient abalones and lobsters to be of commercial value. Thus, the areas of Cortes Bank and Tanner Bank lying within the photic zone appear to represent an extremely uncommon environment compared to other locations in the Southern California Bight.

Although quantitative data from these subtidal investigations have not yet been analyzed, preliminary assessment of data gathered to date has yielded tentative identification of 94 new species and confirmed the presence of the purple coral in dense colonies on Tanner and Cortes banks. 30/ It was reports of the presence of hydrocorals on the outer banks that first prompted BLM to initiate preliminary surveys of the area, then to fund a separate subtidal baseline investigation of Tanner and Cortes banks. As a result of these early surveys, Stipulation 6 of OCS Lease Sale #35 was promulgated. Stipulation 6 requires distant dumping of drilling muds and cuttings in order to protect the biological resources of Tanner and Cortes banks.

Protection of coral communities is essential because of the slow growth of the species. It grows only between one-half and one centimeter per year (personal conversation with Dr. Gay Asterello 5-10-77). Protection was gained for purple coral found in California waters by state establishment of the Farnsworth Bank Ecological Preserve southwest of Santa Catalina Island. This bank is similar to Tanner and Cortes banks in federal waters but much smaller (only 200 by 575 yards). It contains the purple phase of Allopora, which is rare in California, but the red phase is even more scarce and has never been reported in southern California except at Cortes and Tanner banks. Of 244 colonies of Allopora counted on Tanner Bank, 242 were red. 31/

Though the other banks in the Southern California Bight are even less studied than Tanner and Cortes, it has been reported that purple coral is also found on Osborne Bank, five miles south of Santa Barbara Island. The Osborne Bank area is also one of the most productive grounds for both sport and commercial fisheries. 32/ Three tracts west of the Santa Barbara Island were sold in Lease Sale #35, and three more are being studied in the EIS for Lease Sale #48 just northwest of Osborne Bank. Sale of these leases, and development of those sold in Sale #35, would threaten Osborne Bank in the event of a spill. Lasuen Bank, between Santa Catalina Island and the Orange County coastline, is also a heavily fished area, and tracts just north of this bank were sold in Lease Sale #35. Tanner and Cortes Banks, the shallowest and best studied of the offshore banks in federal waters, are the most threatened by petroleum development activity. Exploration is currently taking place on both.

Although exact deliniation of the coral communities on Tanner and Cortes banks has not yet been made, Secretarial Order 2978, "Outer Reefs" states that "...These reefs are unique formations and their associated marine life is of great scientific interest and value to students of the sea and it is in the public interest to protect these formations of great scientific and aesthetic importance for the benefit and enjoyment of the people. There is an immediate threat to these coral reefs resulting from their being subject to commercial exploitation that places them in danger of being destroyed...." 33/

In order to protect the unusual and highly productive shallow areas of the offshore banks within the photic zone, USGS should not approve any permit for the location of a structure within or above the 70-meter depth contour of the Osborne

Bank, Tanner Bank, Cortes Bank, or Santa Rosa-Cortes North Ridge until studies on the effects of oil and gas operations on the biological productivity of the offshore banks are completed and specific protection strategies are devised for those resources. Furthermore, because the red and purple forms of Allopora coral found on the offshore banks are so unusual and slow to recover from any damage, the Interior Department should survey the locations of these coral communities on all offshore banks and not permit any structure to be placed in these locations.

COASTAL WETLANDS

Many studies have underscored the need to protect and maintain the waters, tideflats, and marshes of California's estuarine areas -- those areas collectively referred to as coastal wetlands (Bauer and Speth, 1974). Wetlands and estuaries provide a number of services in the public good as functioning ecosystems: flood control, data source for scientific investigations, pollution abatement, spawning grounds for both sport and commercial fish, and feeding and breeding grounds for many species of waterfowl, shore, and marshbirds. 34/

Coastal wetlands have been greatly diminished following the great influx of population to the southern California area during and following World War II. Hendrickson estimates that there were once 26,000 acres of productive wetland habitat in southern California. 35/ Estimates of wetland acreage lost to urbanization statewide range from 60 to 70%, and for southern California alone from 75 to 90%. 36/ Despite the differences in these estimates, all sources are in agreement with regard to the value of these remaining wetland areas. The 8,500 acres of marsh and mud flats remaining in southern California provide essential habitat for hundreds of fish and wildlife species, including several rare and endangered birds which are almost totally dependent upon coastal wetlands. The remaining California wetlands are, therefore, increasingly valuable and increasingly critical to ecological balance. Recognizing this, the policy for estuaries and wetlands in the California Coastal Plan states that "...all remaining coastal estuaries and wetlands and buffer areas necessary to protect wetlands and their wildlife and bird habitat values shall be preserved, enhanced, and where possible, restored." 37/

Regarding the sensitivity of these valuable areas to oil spill, the U.S. Fish and Wildlife Service has stated that:

> If oil from a large spill were to enter an estuary, extremely adverse biological impacts could result, including elimination of several endangered bird species (clapper rail and California least tern) and certain temporary and permanent floral and faunal species from the oiled estuary. Further destruction of estuaries in southern affiliated species (sic) will be eliminated from the coast because of nursery ground and habitat destruction. 38/

Protection of wetlands from spilled oil should receive highest priority because of:

1. the disturbance to nesting and feeding areas necessitated by cleanup operations (particularly during breeding and migration seasons);
2. the vulnerability of shorebirds and waterfowl to coating by oil and subsequent death from chilling and ingestion of hydrocarbon compounds;
3. the nature of the dense vegetation surrounding the open water areas of a marsh, which would tend to entrap oil and prevent removal; and,

4. the tendency of sediments in a shallow, tidally influenced area to trap hydrocarbons and release them slowly thereafter. 39/

Since most oil cleanup methods would in themselves damage wetlands habitats, the preferred course of action is to prevent oil from getting into these areas. 40/

Most wetlands open to the sea by way of relatively narrow channels. Thus, oil containment booms could be designed or adapted to fit these channels and could, perhaps, be stored nearby for rapid deployment.

Wetland areas considered most vulnerable to spills from OCS activity are those with unrestricted openings to the ocean as well as close proximity to lease areas and/or shipping lanes. In Santa Barbara County, the Santa Ynez River, Goleta Slough, and El Estero (Carpinteria Marsh) are important wetlands of this type, supporting 150 local species of water-associated birds, plus providing stopping points for thousands of birds in the Pacific Flyway.

Significant numbers of shorebirds, waterfowl, and a variety of other water-associated birds are dependent on these Santa Barbara coastal wetlands for survival. The County possesses a scant 900 acres of such wetlands, 80% of them located at Goleta Slough, Carpinteria Marsh, and on the Santa Ynez River. 41/

The Santa Clara River estuary, Mugu Lagoon, and the Ventura River mouth comprise the vulnerable wetlands of Ventura County -- some 2,290 acres of marsh and mud flat habitats. Mugu Lagoon itself contains 95% of the county's wetlands. It is estimated that in excess of 200 species use the marsh and mud flats of Mugu Lagoon and other wetlands of the county. The light-footed clapper rail, a species now in danger of extinction, is found at Mugu Lagoon, one of the few remaining areas in California supporting clapper rails. 42/

Mugu Lagoon is considered by Hendrickson to be the largest and most pristine coastal wetland habitat in southern California. 43/ The other Ventura County wetlands, though only 5% of the total, are extremely important because of the generally arid nature of the adjacent area. In Los Angeles County, all that remains of the large wetland marshes and mud flats that once covered the coastal area of that county are Ballona Creek, a 350-acre degraded wetland, and Colorado Lagoon. About 96% of the county's marshes and mud flats have been lost to dredging, filling, and other developments, destroying the value of these habitats for wildlife. The primary value of the remaining marsh acreage is that it provides wildlife a small oasis of natural habitat at the edge of a metropolitan desert.

Orange County has two important wetlands potentially threatened by OCS development. The salt marshes, mud flats, and protected waters of Anaheim Bay, Bolsa Bay, and Upper Newport Bay are critical to the maintenance of shorebird and waterfowl populations in the county, the state, and the Pacific Flyway. These three bays contain almost all of the remaining wetland acreage in the county. 43a/ Fortunately, upper Newport Bay is not threatened and will not be discussed here. Bolsa Bay and the approximately 1,500 acres of degraded wetland known as Bolsa Chica is not threatened unless the Department of Fish and Game makes its proposed Channel cut to restore tidal action to the marsh -- an action that would improve the quality of the wetlands but would also render them vulnerable to oil spill.

Over 100 species of birds utilize Anaheim Bay, including 23 known resident species. Breeding colonies of light-footed clapper rails are found in the Bay and the adjoining Seal Beach National Wildlife Refuge. Other endangered species found in this estuarine complex are the California brown pelican, the American peregrine falcon, and the least tern. 44/

The Department of Fish and Game has estimated that the Anaheim-Bolsa-Sunset Bay Complex annually supports 720,000 migratory waterfowl use-days, 126,000 resident waterfowl use-days, and 540,000 migratory species (other than waterfowl) use-days.

Vulnerable coastal wetlands in San Diego County include, in order of vulnerability: Tijuana River Estuary, Santa Margarita River, Aqua Hedionda Lagoon, San Elijo Lagoon, Los Penasquitos Lagoon, and Batiquitos Lagoon. The latter three lagoons and the Santa Margarita River are open to tidal action only during certain times of the year, however. Buena Vista Lagoon and San Diequito Lagoon are both restricted from tidal action by flood gates, making it unlikely that oil could enter either wetland.

Of the above areas, the 400-acre Tijuana Estuary remains the least disturbed and thus the most important wildlife habitat, but it is also potentially threatened. Twenty tracts directly off the San Diego coast will be included in the Bureau of Land Management's EIS for OCS Lease Sale #48. A group of ten tracts lies directly off San Diego Bay and just above the Tijuana Estuary. The extensive wetlands in lower San Diego Bay would probably not be reached by a spill because of the configuration of the Bay, but the Tijuana Estuary is definitely threatened if development of those leased tracts proceeds.

All other wetland areas in San Diego County have been altered or degraded to some extent by human encroachment but still remain essential as wildlife habitats. The size of these wetlands ranges from 250 to 600 acres of well-developed salt marsh communities and open water area. A very thorough description of each can be found in the San Diego Coast Regional Commission's report entitled "Life in the Sea."

S E A B I R D R O O K E R I E S

The Channel Islands and surrounding waters provide essential feeding, nesting, and breeding areas for resident and migrant seabirds in the Southern California Bight. These pelagic (open ocean) birds are the most conspicuous and numerous avian group found in the OCS lease areas. 45/ They comprise such large species as shearwaters, petrels, murrelets, auklets, and gulls. Some of these birds spend most of their lives on or above the open ocean, coming ashore only in selected areas to breed and nest.

These migratory species, as classified under the conditions of bilateral treaties with Canada, Mexico, and Japan (pending), are protected under provisions of the Migratory Bird Treaty Act. Other birds are additionally protected by the Bald Eagle Act of 1940, the Endangered Species Conservation Act of 1969, and the Endangered Species Act of 1973. The U.S. Fish and Wildlife Service is responsible for enforcing these acts, establishing and maintaining a system of refuges, and implementing management programs.

In order to resolve resource conflicts that could occur as a result of

development of leases sold in OCS Sale #35, the U.S. Fish and Wildlife Service recommended several preliminary strategies to protect seabirds:

> No oil exploration, development, or production facilities be placed upon the offshore rocks of the proposed lease sale area; no oil exploration, development, or production activities be conducted on or within the vicinity of Anacapa Island or important pinniped and seabird breeding areas on San Miguel and if it is determined that brown pelicans feed in extensive numbers in the vicinity of OCS Lease Sale Area Santa Rosa-Cortes South, that oil operations be restricted to minimize the possibility of an oil spill affecting the species. 46/

These recommendations were made in view of the fact that oil spills are known to be a tremendous hazard to marine-associated birds. The vulnerability of most aquatic birds to oiling and subsequent death is well documented in the literature. 47/ In its analysis of the effect of oil on aquatic birds, the Santa Barbara Channel EIS concluded that in the event of a major oil spill in the Santa Barbara Channel, the most visible damage to marine ecosystems is the damage to populations of marine birds present on the waters of the Channel at the time of a given pollution incident. 48/ The EIS for OCS Lease Sale #35 quoted Erickson (1963) who noted that oil pollution may serve as an agent of intermittent but continuing attrition, especially on those migrant birds using coastal and offshore waters.

Norris further concluded that it is reasonable to expect that the foraging of most, if not all, of the seabirds breeding in the Channel Islands would be adversely affected by oil spilled on the sea surface. 49/ During the breeding season, birds are restricted in the area over which they may forage by their commitment to a fixed nesting site. During this same period, food requirements are at a maximum, as the adults need to forage not only for their own needs, but also in order to gain energy for egg production or for feeding growing young.

Foraging generally takes place close to the breeding colonies indicated on the inventory maps. Areas observed to support high densities of feeding birds (in addition to those areas immediately adjacent to breeding colonies) were: over the crown and sides of the northern Santa Rosa-Cortes Ridge; the Santa Barbara Channel; Osborne Bank; Forty-Mile Bank; the San Clemente Escarpment; and, in late spring, inshore areas such as Lasuen Knoll. 50/ As can be seen from the maps, all seabird rookeries are now found on the Channel Islands, though historically most species once bred and nested on the mainland as well.

From their experience with large oil spills, the U.S. Fish and Wildlife Service has concluded that some birds are more vulnerable to damage by oil pollution than others. The following factors determine the vulnerability of avian species:

1. diving and pursuit seabirds are highly susceptible to oil pollution because they spend much time in the water;
2. among diving birds, those who roost on the water at night are more vulnerable to oiling because of increased exposure and the increased chance of coming on a slick unawares in the night;
3. the number of individuals of a given species affected by an oil spill is determined by their total number and distribution as well as by

the extent of the spill. For example, a flocking species found in large numbers in inshore areas where there is less chance of avoiding an oil slick (e.g., surf scooters and Western grebes) is more likely to suffer heavy mortality in the event of a spill than a solitary species that roosts on land;

4. diving species that become flightless during molt or that do not fly because of social bonds with flightless young (common murre, Xantu's murrelet) and that spend most of their time in the water are particularly vulnerable; and,
5. young birds are not thermoregulated (i.e., still retain their down, or have feathers not yet protectively coated) and are more susceptible to lower concentrations of oil than adults. 51/

The Fish and Wildlife Service analysis of birds meeting the above criteria of vulnerability indicated, on the basis of feeding and nesting behavior, that these particularly susceptible birds are distributed throughout the lease area in as yet undetermined numbers. The marine mammal/bird baseline studies being conducted under the auspices of the Bureau of Land Management will attempt to quantify the seabirds of the Bight by species composition, habitat requirements, sensitivity to oil pollution, etc. Though the final results of the first year's research have not been published, a six-month progress report revealed more information on the subject than has been published to date. The progress report characterized the state of aquatic bird populations this way:

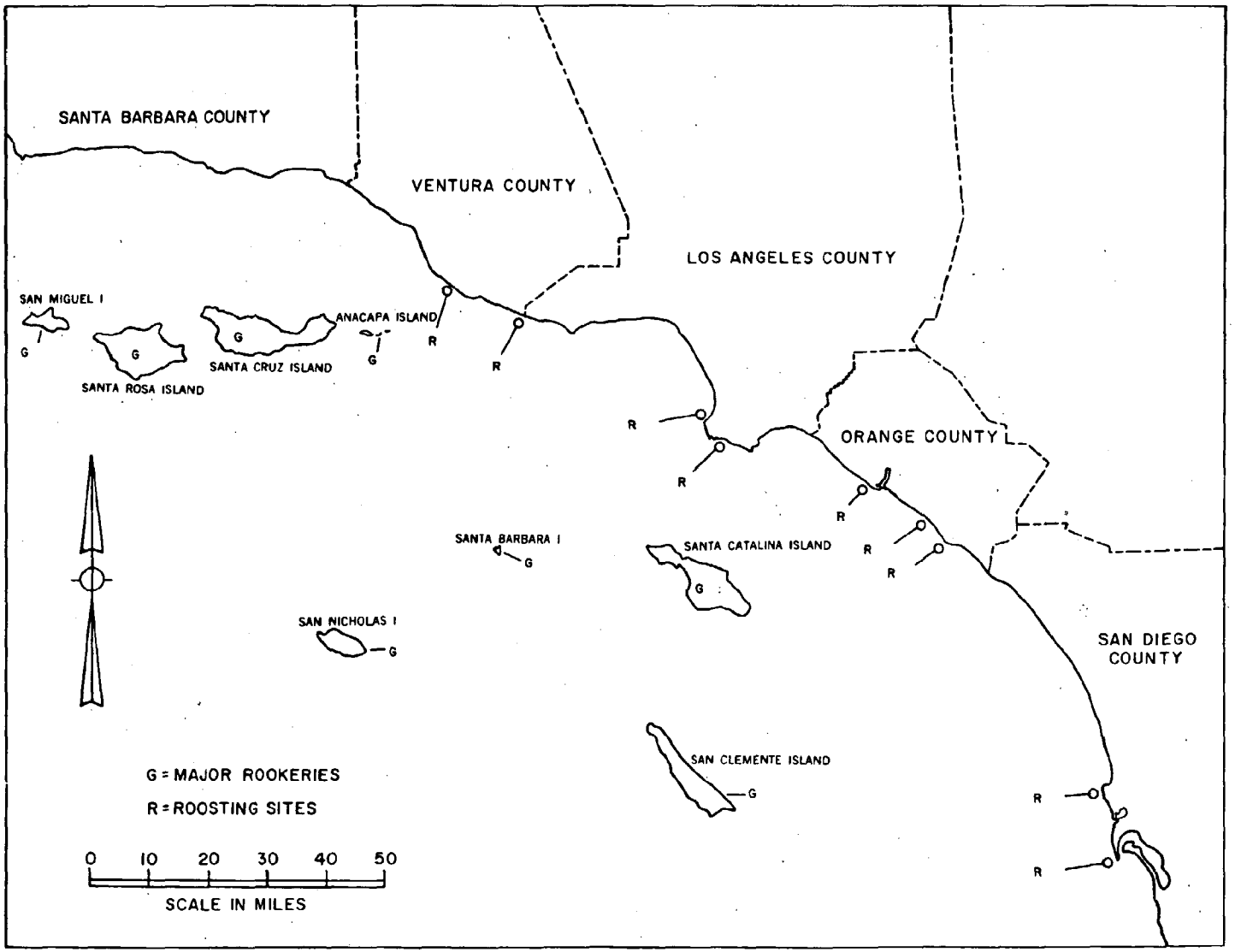
> Finally, the avifauna is complex; perhaps 150 species occur more or less abundantly in the Southern California Bight...(but) for many nesting seabirds of the Channel Islands, the present populations are remnants of once much larger populations. The health of the present populations in many cases is not good; disturbance, chemical pollution, predators, and perhaps other factors are resulting in reproductive failure. The future of these populations appears to be in jeopardy, and they should be protected from future insult if they are to maintain viable populations in southern California. 52/

In view of the sensitivity of many seabirds to oil spills and their vulnerability as a result of Lease Sales #35 and #48, the protection of Channel Island breeding areas and the surrounding waters which provide foraging areas is essential to the survival of these species.

As can be seen from Figure 1, according to the California Department of Fish and Game, all of the eight offshore islands in southern California are major seabird rookeries. 53/ The list below, compiled from several sources, shows which bird species breed on each of the Channel Islands. 54/

Island	Breeding Species
San Miguel (Prince Island, Castle Rock Richardson Rock)	Ashby storm petrel, double-crested cormorant, Brandt's cormorant, pelagic cormorant, western gull, pigeon guillemot, Xantu's murrelet, Cassin's auklet, black oyster catcher, snowy plover
Santa Rosa	Brandt's cormorant, pigeon guillimot, pelagic cormorant, black oyster catcher, snowy plover

FIGURE 1:
SEABIRD ROOKERIES, AND ROOSTING SITES



Island	Breeding Species
Santa Cruz (Gull Island, Scorpion Rock)	Ashby storm petrel, brown pelican, pelagic cormorant, western gull, pigeon guillimot, Cassin's auklet, black oyster catcher, Brandt's cormorant, double-crested cormorant, Xantu's murrelet, snowy plover
Anacapa	brown pelican, double-crested cormorant, western gull, black oyster catcher, pelagic cormorant
Santa Barbara (Sutil Islet and Shag Rock)	Ashby storm petrel, double-crested cormorant, Brandt's cormorant, western gull, pigeon guillimot, Xantu's murrelet, black oyster catcher, double-crested cormorant, Cassin's auklet, black storm petrel
San Nicholas (Begg Rock)	Brandt's cormorant, western gull, snowy plover
Santa Catalina (Bird Rock)	western gull, double-crested cormorant, Brandt's cormorant, black oyster catcher
San Clemente (Castle Rock and N.W. Harbor Islet)	western gull, pelagic cormorant, Brandt's cormorant, black oyster catcher

Numerous other sea and shore-associated avian species use the islands and surrounding waters as feeding and resting sites. These include loons and grebes, shearwaters, herons, ducks and geese, rails, plovers, sandpipers, phalaropes, jaegers, auks, and many species of gulls and terns.

ECONOMIC AND RECREATIONAL RESOURCES

In responding to the Bureau of Land Management's resource report requests for the Lease Sale #48 area, the Director of the Department of the Interior's Bureau of Outdoor Recreation (BOR) characterized the southern California coastal and offshore area as "one of the best known and most heavily used recreation and resort destinations in the United States." According to BOR, "The seasonally warm-water beaches of southern California are intensively used by the 13 million plus residents of southern California and 8.5 million visitors to the region." In pointing out that the entire southern California coastal and offshore area is a recreational resource of "special significance," BOR emphasized that the "special significance intensifies around the Channel Islands, inshore waters, shoreline, estuaries, and accessible stretches of coast in the vicinity of population centers and resort destinations." 55/

The southern California lifestyle is strongly associated with the region's marine and coastal environment. Marine recreation is a multi-million dollar industry and any degradation of recreational resources caused by an oil spill could result in substantial economic losses. Of those, the major

categories of resources vulnerable to damage are beaches, recreational fishing areas and their associated harbors and marinas, commercial shellfishing areas, and diving spots.

B E A C H E S

One of the most heavily used of southern California's recreational resources is its expansive beaches. Over 12 million people visited the major state beaches in southern California last year.

Recreational use of southern California's beaches returns millions of dollars in revenue yearly. Tourism, and recreational enjoyment in general, are dependent upon the quality of the experience provided. In addition to heavy human use, which occurs primarily during the summer months, beaches are used during the winter as feeding areas for migrating shorebirds and waterfowl. 56/

In the Ventura County Coastal Study of 1974, the County Parks Commissions noted:

> The singularly most unique recreational feature of Ventura County is its long Pacific shoreline. Few coastal counties in California have more miles of beaches suitable for boating facilities, day and overnight camping, fishing, clamming, surfing, and general play use. Without doubt, the Ventura coastline is the County's outstanding recreational resource.

The southern five counties are noted for their expansive beaches, almost all of which are suitable for swimming.

A total of 83.5 miles (76%) of Santa Barbara County's shoreline is classed as sandy beach, of which about 67% yet, for the most part, is privately owned and remains undeveloped. The 14 miles of federally-owned sandy beach is mostly within the boundary of Vandenberg Air Force Base. The 9.5 miles of state and county-owned beaches receive nearly 750,000 visitors annually. Such heavy use precludes nesting activities on the beach; however, during the off-season for bathers and during early morning and late evening hours of the summer the beaches are visited by shorebirds. 57/ With the exception of the shoreline north of Point Conception, all Santa Barbara County beaches are vulnerable to oiling from current and future petroleum development in both state and federal waters.

About 38 miles (93%) of the Ventura County shoreline is classed as sandy beach, of which 28 miles (74%) is in public ownership. For the season of 1968-1969, the Department of Parks and Recreation estimated that its beaches in Ventura County accommodated over one million visitors. This use occurs primarily during the summer months. However, during the winter migration of shorebirds and water fowl, the beaches provide feeding areas for long-billed plover, whimbrel, sanderling, western sandpiper, and the least sandpiper. 58/

Development plans have been submitted to USGS for the Hueneme and Santa Clara units in federal waters just off the western Ventura County coast. Actual development, however, will probably not begin until early 1980. The eastern Ventura County coast currently is not threatened by any offshore activity.

About 51 miles (77%) of the Los Angeles County shoreline is classed as sandy beach. City, county, and state beaches in Los Angeles are among the most heavily used in the state, particularly during the summer months. However, during the off season the beaches are used by migrating shorebirds as nesting sites. Federal OCS development does not directly threaten the Los Angeles coastline, since tracts in Santa Monica Bay were deleted from Lease Sale #35. Increased marine traffic, however, could pose an indirect threat if Santa Barbara Channel OCS production is transported by tanker.

Orange County has 38 miles of sandy beaches, comprising approximately 92% of its coastline. Nearly 23 miles of the beach areas are in public ownership and thus support intensive recreational use. The habitat is also available for bird nesting and feeding during evening and morning hours. 58a/ Platforms in state tidelands and grant lands have been producing off Long Beach, Seal Beach, and Huntington Beach without major mishap for the last 20 years. Thirteen federal leases were sold off the Orange County coast in OCS Lease Sale #35. Shell Oil Company has a certified discovery, and is in the process of exploring development options with state and federal agencies. Development drilling could begin as early as 1978. An additional 27 tracts along the county's coast are being studied for possible leasing in OCS Lease Sale #48.

About 65 miles (85%) of the San Diego County shoreline is classed as sandy beach. Over half (41 miles) of the beaches are in public ownership and heavy recreational use occurs during the summer time, except on federally-owned lands such as Camp Pendleton. Federal lands with limited access priviledges have provided essential refuge for at least 75 of the 471 pairs of least terns that depend on county beaches for nesting sites.

Development of existing leases in southern San Pedro Bay poses a possible oil spill risk to northern San Diego County beaches. The greatest potential threat to the county's coastline would be the sale of the 20 tracts chosen for future study in the EIS for OCS Sale #48. They extend along the entire coastline, approximately 5 to 12 miles offshore. Because of their great length, beaches are impossible to protect entirely from spilled oil. In the event of a spill, mainland beaches are relatively easy, but still expensive, to clean. Losses could be significant in the case of a spill of long duration such as the Santa Barbara blowout. Damage to shorebirds and waterfowl nesting and feeding areas could also be significant during nesting and migrations.

Sandy areas, which comprise only 20% of the islands' shorelines would present a different problem in the event of a spill. Beaches on the relatively undisturbed islands are available for nesting and year-round use by shorebirds and waterfowl. Pinniped rookeries also tend to be located on sandy areas where large numbers of animals can congregate during the breeding season. Losses from a spill adjacent to the islands would be ecological, not economic, and cleanup efforts would probably only exacerbate the situation. Economic losses could occur, however, on Santa Catalina Island.

Sandy areas are indicated on the inventory maps at the end of this chapter.

SKIN AND SCUBA DIVING AREAS

Diving, like many other recreational activities that are coastal dependent, is a fast-growing sport in California. Using either a snorkel and mask or SCUBA gear, divers engage in spear fishing, shellfishing, underwater exploration, and photography.

These underwater activities are carried out in rocky subtidal and reef areas where water clarity is greater and marine life abundant. Pressures are great in some areas, because while there is no shortage of ocean to dive in, there is a shortage of areas of high scenic and biotic interest and which are accessible and in a near-natural state. 59/

Diving is greatest in the marine life refuges, in areas where there are extensive kelp beds offshore, and around the islands, especially the five northern islands and Santa Catalina. The threat of degradation by an oil spill is greatest in the western Santa Barbara Channel, adjacent to the Channel Islands and in the refuges along the Orange County Coast.

Diving areas with high use and desirability are shown on Figure 2. They were mapped according to information provided in Coastal County Fish and Wildlife Resource Utilization by the Department of Fish and Game and the Chart Guide for Southern California Boating, Diving and Fishing.

RECREATIONAL FISHING AND SUPPORT HARBORS

The excellent recreational fishing opportunities available in California coastal waters have received national attention because of both the abundance of fish and the variety of species available.

Partyboat, skiff, pier, jetty, surf, rock, and spear fishing are all popular methods used to catch the many kinds of fin and flatfish available to the southern California angler. Demand for high-yield fishing areas is great. The large kelp beds, the offshore islands and offshore banks are heavily fished. In 1971, commercial partyboats for chartering sport fishermen to fishing waters provided 4,600,000 fish for 725,000 anglers. 60/ Onshore, available piers and jettys, suitable sandy beaches for surfishing, and rocky areas for rockfishing are all heavily used.

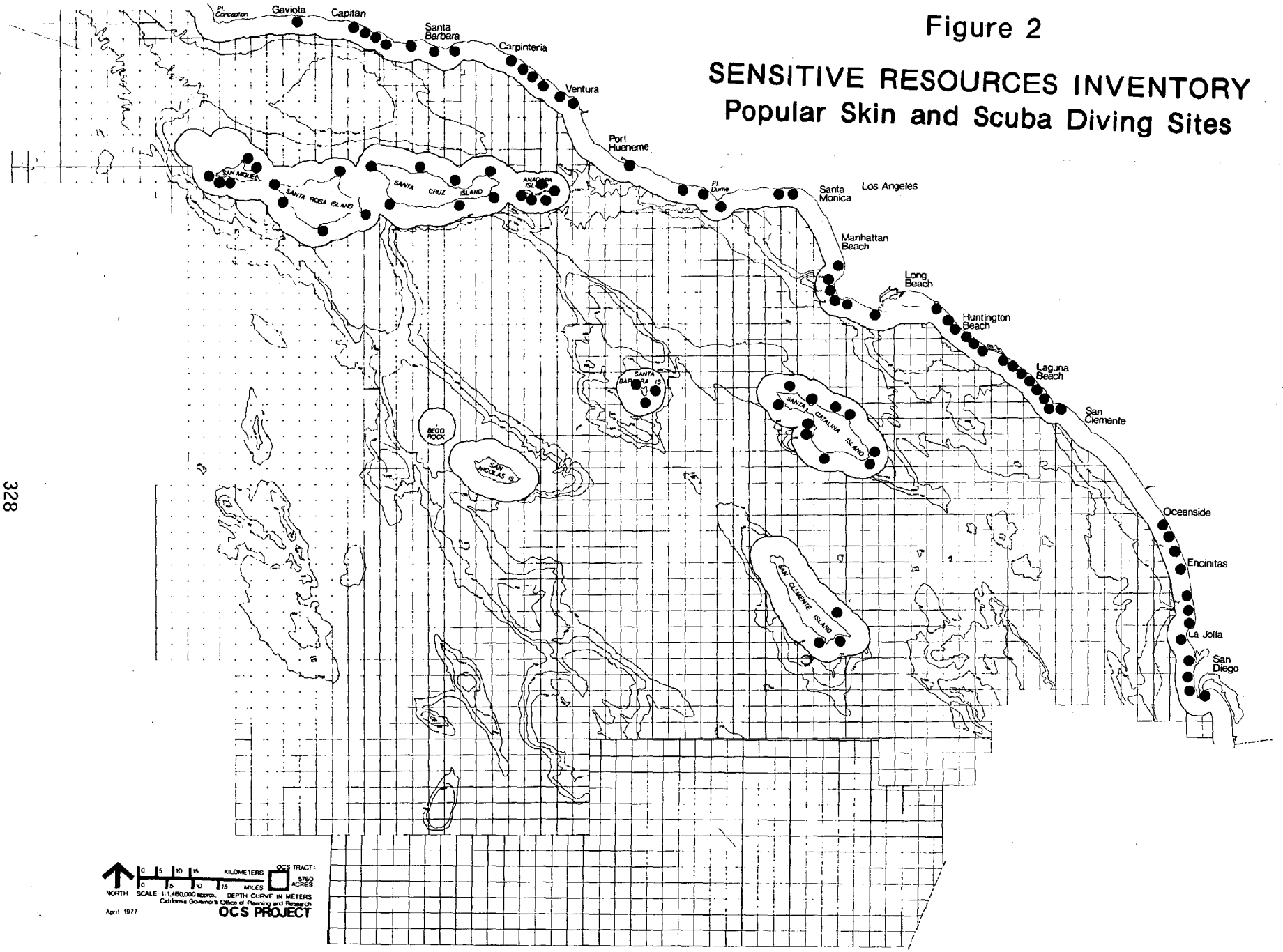
Gruen and Gruen, in a report to the Resources Agencies, characterized sport fishing as a "...form of recreation that brings considerable external benefits to California from the expenditures of anglers and from the nature of the experience." The lists below summarize the findings concerning the economic value of sport fishing in California and the sport fishing habits in southern California. 61/

Net Economic Value of Marine Sport Fishing in California 1970

Total California Angler Days	Assumed Value Per Day (Low to High Range)	Net Economic Value
11,910,000	$2	$ 23,820,000
11,910,000	3	35,730,000
11,910,000	4	47,640,000

Figure 2

SENSITIVE RESOURCES INVENTORY
Popular Skin and Scuba Diving Sites



Estimate for 1970 of Marine Sport Fishing Activity in Southern California By Type of Fishing

	Southern California Angler Days
Piers & Jetties	3,730,395
Shoreline	1,467,877
Partyboats	691,092
Private Boats	1,180,924
Other	198,660
Total	7,268,948

Source: A Socio-economic Analysis of California's Sport and Commercial Fishing Industries, a report to the Resources Agency by Gruen and Gruen, 1972.

Sport fishing in California produced over $14 million in gross expenditures in 1970 as well as substantial "secondary" income or employment derived from the gross expenditures of consumers. Potential loss of income to a particular area should be of considerable concern to decisionmakers. On a statewide level, the secondary income effects of sport fishing ($300-400 million) are larger than those of commercial fishing ($200-300 million). Popular sport fishing areas in southern California are shown in Figure 3.

The National Conference on Marine Recreation found that services to recreational fishermen provided a dominant share of the income to a multitude of coastal communities. 62/ Much of this revenue is brought in by turnover support facilities and services provided by various harbors.

Harbor areas of the offshore islands are shown generally in Figure 4, below. For the mainland, harbors and marinas have also been mapped, but as part of the "Inventory of Petroleum-Related Facilities" (Appendix 3) in the back of this report. Marinas and harbors--both mainland and island locations--are considered as sensitive resources for the purposes of this chapter because of their vulnerability to oil spills. The adverse effects of an oil spill to marinas and harbors are related to the following:

1. damage to fishing grounds;
2. destruction of larval stages of commercially valuable species;
3. the high cost of cleaning oiled vessels; and,
4. harbor closure and resultant loss of fishing time.

Recreational shellfishing is also a very popular activity, with high demand for suitable areas. Clam beds in cobble and sandy beaches along the coast are heavily used, and rock crabs support a sizable sport fishery as well. 63/ The California spiny lobster, rock scallops, and various species of abalone are highly prized, but are able to be taken only by skin and scuba divers.

Marinas and harbors are fairly easily protected from an oil spill through use of booms; this does not, however, prevent losses incurred from prevention of boat use. Recreational fishing grounds, on the other hand, are less easily delineated

Figure 3

SENSITIVE RESOURCES INVENTORY
Popular Sport Fishing Sites

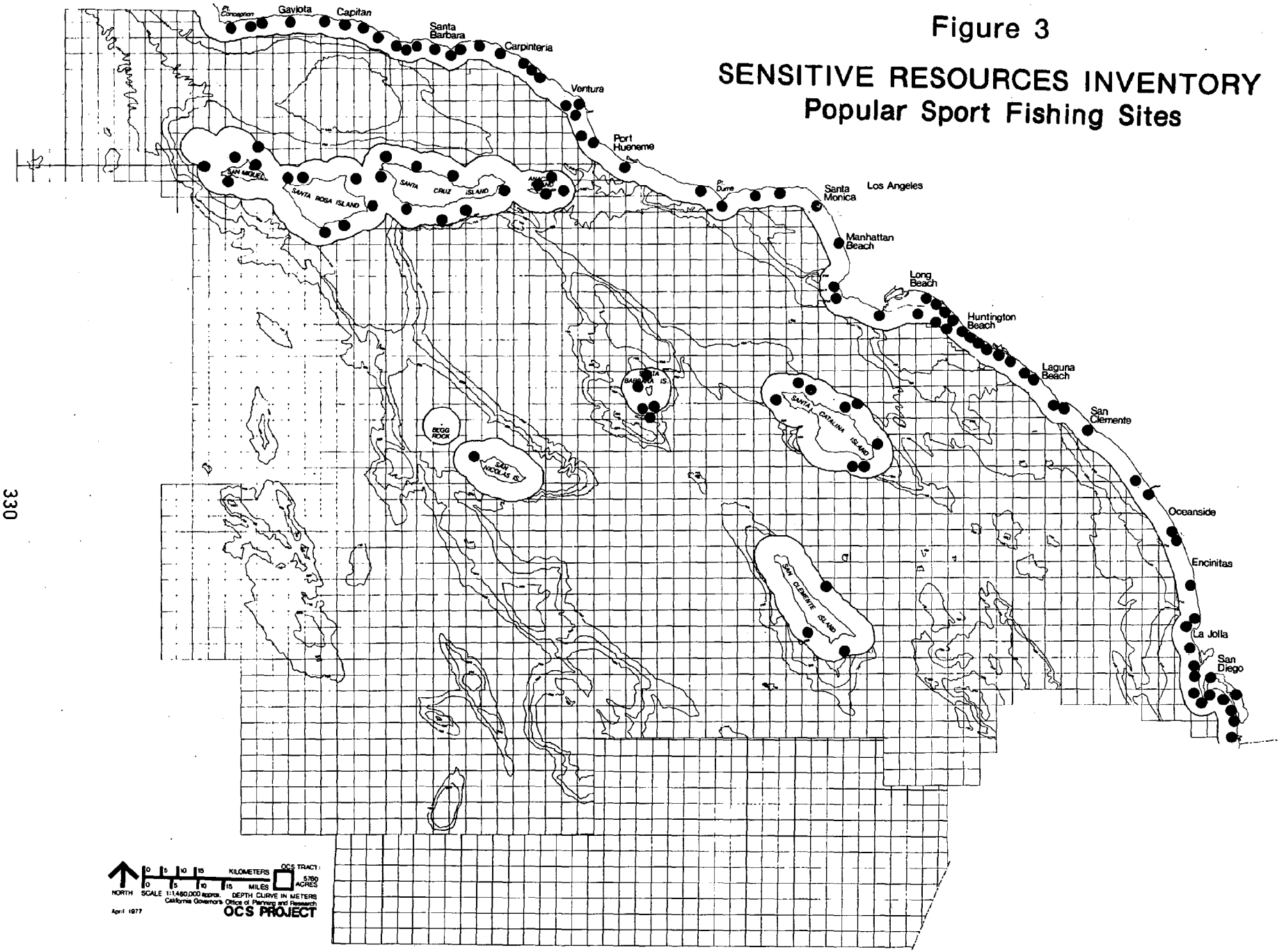
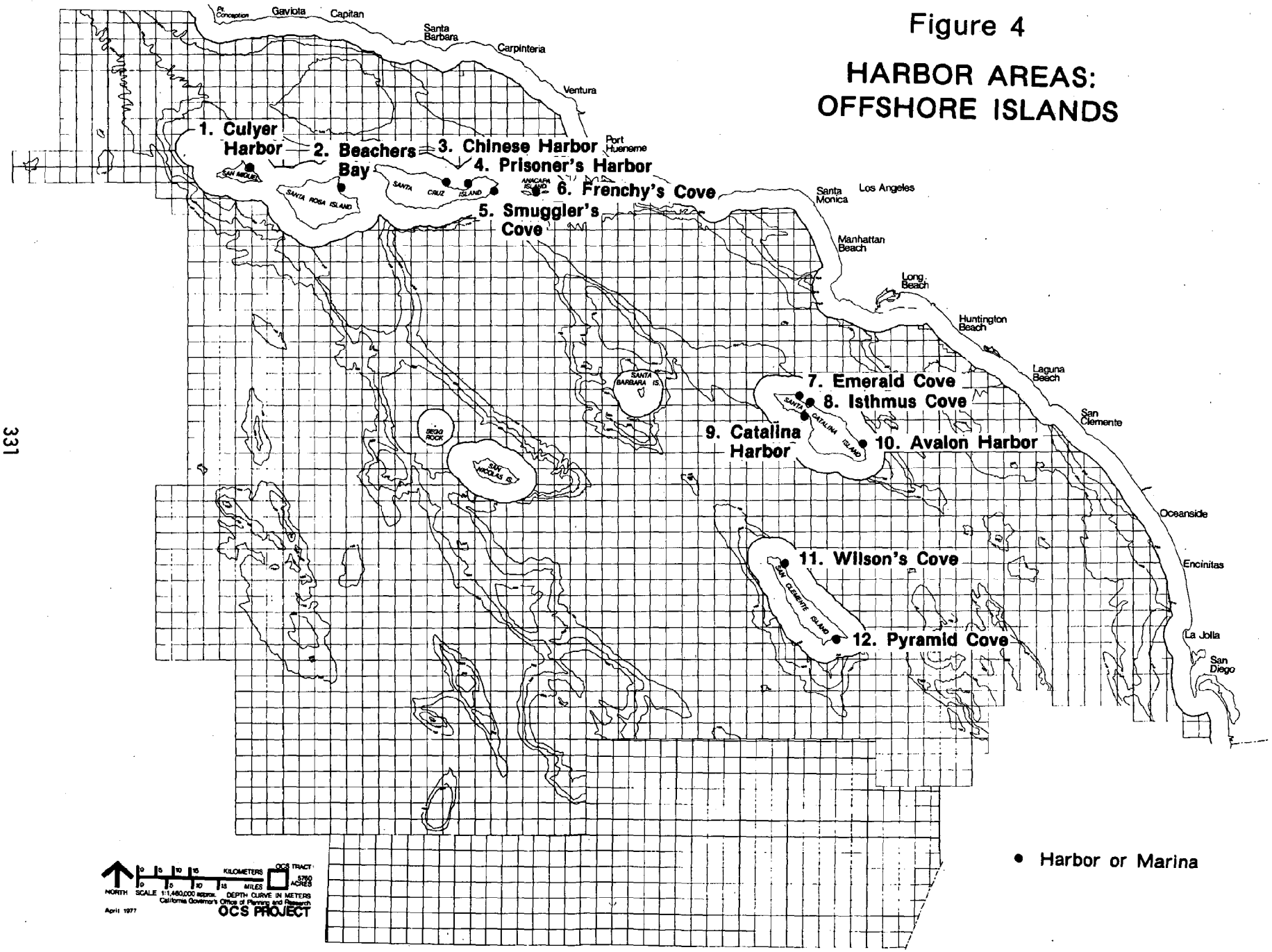


Figure 4

HARBOR AREAS: OFFSHORE ISLANDS



and protected. Heavily recruited areas are scattered all along the mainland coast, and may correspond to artificial reefs, kelp beds, areas of high productivity, or nearby urban areas. Because of the importance of many recreational fishing areas, local governments and harbor districts, in cooperation with the Department of Navigation and Ocean Development (DNOD) and the Department of Fish and Game, should assess their vulnerability to recreational and economic loss as well as to environmental degradation in the event of an oil spill, in order to determine whether existing spill-response plans and equipment are sufficient to protect these vital interests.

Areas of heavy recreational shellfishing and finfishing, as well as major marinas and harbors, are indicated on the maps by individual symbols. Their locations were determined from the following sources: Coastal County Fish and Wildlife Resources and their Utilization, by the California Department of Fish and Game; the draft of Prominent Southern California Marine Resources, also by the California Department of Fish and Game; and, the Chart for Southern California Boating, Diving, and Fishing.

THE COMMERCIAL SHELLFISHERY

The animals which make up the shellfish resource of southern California (except for the squid*) are benthic organisms, which spend their lives on the bottom, usually in relatively shallow waters. Because they are so dependent upon this restricted area, and are not highly mobile like fish, they are most vulnerable to the effects of pollution or habitat disturbances. Though the entire southern California fishery could be affected by an oil spill through loss of ability to use boats in the spill area, fin and flat fish are thought simply to vacate a spill area. The shellfish, however, would be affected directly by spilled oil. Figure 5 shows generally the locations of popular shellfishing areas offshore of southern California.

Though mollusks (clams, oysters, abalone, and scallops) constitute those organisms properly referred to as "shellfish" the term is commonly used in referring to both the mollusks and crustaceans. The southern California commercial shellfish catch is made up of two crustacean species: the rock crab and the spiny lobster. Several other crustacean species such as the spot prawn and the ocean shrimp support smaller fisheries and are not reflected in Table 1 which shows the value and amount of shellfish landed in each of the five coastal counties.

Abalone and squid are the molluskan species that make up the remainder of the commercial catch. Because commercial clammers are restricted to the same bag limits as sportfishermen, a viable fishery does not exist for clams. 64/ The fishery for abalone and lobster, the most highly prized species, depends upon rocky areas along the mainland coast, the offshore islands, and offshore banks. 65/

The mainland coast of Santa Barbara County supports commercial harvests of lobster, crab, and abalone. The largest southern California harvests of rock crab come from the offshore area from Goleta to Santa Barbara Point. 66/ Abalone is harvested from the rich kelp beds around Point Conception, north to Point Arguello and east to Rocky Point. Lobsters are taken off Point Conception, Gaviota, Tajiquas, El Capitan, Coal Oil Point to Santa Barbara Point, Montecito, Carpenteria, and Punta Gorda. 67/ The Ventura coast, on the other hand, has few extensive kelp

*The shell of the squid, not popularly regarded as a shellfish, is internalized--a thin, chitinous (cartilage-like) structure.

Figure 5

SENSITIVE RESOURCES INVENTORY
Commercial and Recreational Shellfishing Sites

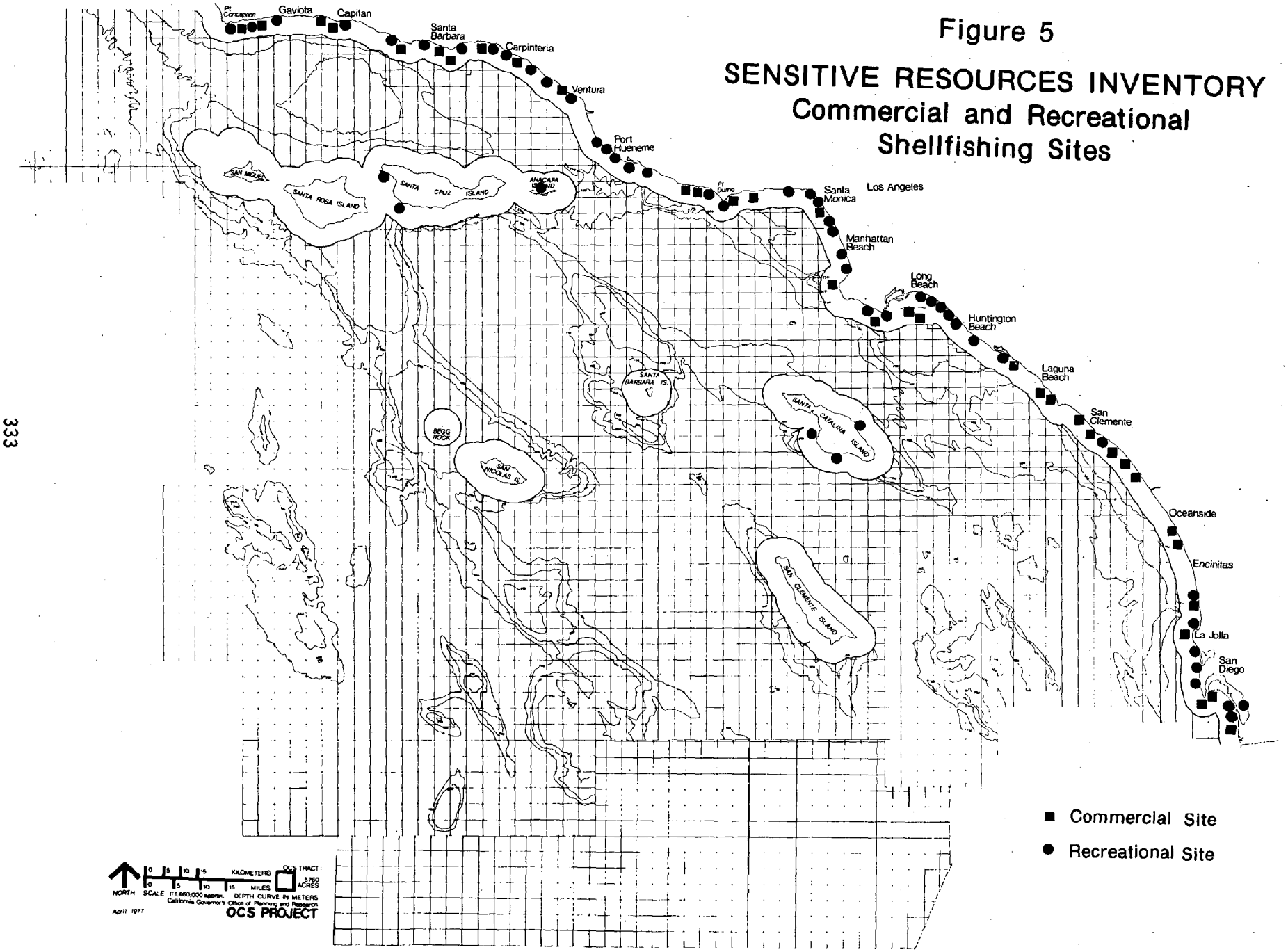


TABLE 1: COMMERCIAL SHELLFISH LANDINGS IN SOUTHERN CALIFORNIA

SANTA BARBARA COUNTY COMMERCIAL SHELLFISH LANDINGS

SPECIES		1966	1967	1968	1969	1970
ABALONE:	lbs.	1,442,336	1,330,278	1,109,032	1,166,239	1,043,683
	value	$279,013	$263,268	$292,211	$376,183	$356,084
	$/lb.	.193	.198	.263	.322	.341
ROCK CRAB:	lbs.	102,102	77,798	102,623	126,435	135,228
	value	$6,398	$4,982	$6,588	$11,189	$11,078
	$/lb.	.063	.064	.064	.088	.082
SPINY LOBSTER:	lbs.	95,524	84,916	93,114	75,488	47,599
	value	$77,460	$69,636	$79,722	$77,880	$58,127
	$/lb.	.811	.820	.856	1.032	1.221

VENTURA COUNTY COMMERCIAL SHELLFISH LANDINGS

ABALONE:	lbs.	109,466	50,279	112,368	58,060	46,663
	value	$21,656	$10,162	$28,704	$18,250	$15,658
	$/lb.	.198	.202	.255	.314	.336
SPINY LOBSTER:	lbs.	27,995	26,746	18,525	20,539	32,946
	value	$22,701	$21,933	$15,861	$21,190	$40,234
	$/lb.	.811	.820	.856	1.032	1.220
SQUID:	lbs.	1,305,038	2,592,543	2,660,395	3,036,160	4,878,300
	value	$17,160	$38,696	$37,318	$43,109	$70,561
	$/lb.	.013	.015	.014	.014	.014

LOS ANGELES COUNTY COMMERCIAL SHELLFISH LANDINGS AND SHIPMENTS

ABALONE:	lbs.	1,045,753	772,158	1,525,777	1,276,354	1,014,220
	value	$186,566	$149,685	$363,479	$414,491	$330,474
	$/lb.	.178	.194	.238	.325	.326
ROCK CRAB:	lbs.	207,536	235,217	234,585	300,077	315,752
	value	$25,399	$27,477	$29,777	$37,505	$41,348
	$/lb.	.122	.117	.127	.125	.131
SPINY LOBSTER:	lbs.	160,894	173,689	89,497	104,051	70,381
	value	$137,886	$151,321	$85,902	$118,110	$82,623
	$/lb.	.857	.871	.960	1.135	1.174
SQUID:	lbs.	6,513,192	5,776,010	7,693,532	6,182,983	11,085,253
	value	$91,736	$98,937	$117,389	$124,206	$249,584
	$/lb.	.014	.017	.015	.020	.022

ORANGE COUNTY COMMERCIAL SHELLFISH LANDINGS

ABALONE:	lbs.	144,081	35,665	37,763	2,870	1,700
	value	$26,521	$7,100	$8,835	$935	$586
	$/lb.	.184	.199	.234	.326	.345
SPINY LOBSTER:	lbs.	39,275	35,319	19,308	23,269	9,241
	value	$33,659	$30,770	$18,533	$26,412	$10,848
	$/lb.	.857	.871	.960	1.135	1.174

SAN DIEGO COUNTY COMMERCIAL SHELLFISH LANDINGS AND SHIPMENTS

ABALONE:	lbs.	638,921	587,419	740,978	514,768	479,093
	value	$101,915	$108,167	$174,763	$148,527	$133,836
	$/lb.	.160	.184	.236	.289	.279
SPINY LOBSTER:	lbs.	165,400	129,214	91,406	82,897	59,857
	value	$137,624	$114,273	$92,605	$99,811	$69,925
	$/lb.	.832	.884	1.013	1.204	1.168

Source: California Department of Fish and Game, 1973

beds and does not support significant commercial shellfish harvesting. Some lobsters are taken just south of Pitas Point and crabs are taken just south of Point Mugu only. Squid is also taken in that area near the Los Angeles-Ventura County border.

The most important shellfishing area in Los Angeles County is seaward of the San Pedro breakwater out to Dago Bank, a distance of about 2.7 miles. This area is heavily fished for both rock crab and lobster. The Palos Verdes headlands are also very important to the shellfishery. Abalones are taken offshore from Point Vicente to White Point, as are lobsters. Lobsters are also taken off Dume Cove, Malibu Point, the Marina Del Rey breakwater, and Santa Monica and Leo Carillo Beach State Parks.

The majority of crabs and lobsters in Orange County are taken just outside the marine life refuges near Dana Point, the Laguna Coast and south of Newport. Lobsters are also taken in the scattered kelp beds off San Clemente. 68/

The La Jolla and Point Loma kelp beds in southern San Diego County are the most important mainland fishing grounds for lobster and abalone. 69/ Some rock crab is taken there as well. Lobster is also taken at scattered sites offshore of San Onofre, north of the Santa Margarita River, Agua Hedionda Lagoon, south of Del Mar, and San Elijo State Beach.

Lobster and abalone are also taken around the islands and on the offshore banks, though the crab fishery has not yet been developed there. Commercial lobster and abalone boats concentrate entirely around Santa Rosa and Santa Cruz Islands, but are restricted to the south side of Anacapa, the seaward side of Santa Catalina, and the west side of Santa Barbara by the Department of Fish and Game. San Clemente and, to a lesser extent, San Nicholas are fished heavily except their north ends, which are restricted by the Navy. Cortes Bank is also fished commercially for lobster and abalone. 70/

The two most important mainland areas for commercial shellfishing in the Southern California Bight -- the western Santa Barbara Channel and offshore from La Jolla to Point Loma in San Diego -- are among those most threatened by oil and gas activity. The Santa Ynez unit stretches from west of Point Conception to Capitan, while the Department of Interior is studying an additional 52 tracts in the western Channel and north of Point Conception for possible sale. Industry pressure to lease these areas is high. The threat to the San Diego shellfishing grounds is less only in terms of scale: 13 tracts off the La Jolla/Point Loma region have been selected for inclusion in the EIS for OCS Lease Sale #48, scheduled for March, 1978.

The northern Channel Islands all have numerous leases either to the north or south, and three isolated leases lie to the west of Santa Barbara Island, where commercial shellfishing is concentrated. None of the above leases, however, had yet been developed. Leasing has also taken place on Cortes Banks, but there are no commercial discoveries there yet.

OFFICIALLY DESIGNATED UNIQUE BIOLOGICAL ENVIRONMENTS

Officially recognized "unique biological environments" are protected by

the state or federal government from certain perturbations that could diminish their biological value. The purpose and adequacy of the protected status afforded these areas are discussed here, together with their vulnerability to oil spills.

The State of California has three categories of protected environments: Areas of Special Biological Significance, State Oil and Gas Sanctuaries, and Ecological Reserves and Marine Life Refuges.

The Federal government administers one category of unique biological environments in the Southern California Bight -- National Monuments, under authority of the National Park Service (Department of the Interior).

Two additional categories have been established pursuant to federal law, but as yet no geographical areas have been designated: these are Marine Sanctuaries and Estuarine Sanctuaries.

MARINE SANCTUARIES

The Marine Protection, Research and Sanctuaries Act of 1972 authorizes the designation of marine sanctuaries in ocean waters from the near high tide line to the outer edge of the Continental Shelf. Once a marine sanctuary has been designated, no federal license, permit, or, presumably, lease can be granted for activity within the sanctuary without the Secretary of Commerce's certification that such activity will not be inconsistent with the purposes of the Act.

The Secretary of Commerce should designate the waters within twelve miles of the Channel Islands as a marine sanctuary in order to protect their value as a habitat for endemic marine species and as foraging grounds for seabirds and pinnipeds.

ESTUARINE SANCTUARIES

Section 312 of the Federal Coastal Zone Management Act provides the Secretary of Commerce with the authority to award matching grants to coastal states for the acquisition and development of estuarine sanctuaries. The main intent of this program is to ensure undisturbed areas for scientific research and public education on the ecological relationship of estuarine systems. The only candidate area in southern California is Upper Newport Bay, which is not threatened by OCS development.

NATIONAL MONUMENT

To be a part of the National Park System, a natural area must be an expanse or feature of land or water of such scenic and scientific value and quality as to merit preservation as a national park, national monument, or national preserve. The eight Channel Islands clearly meet these criteria: all are of primary ecological significance because of their location astride a major biogeographic transition zone of the Pacific Coast, the Point Arguello-Point Conception break. The Channel Islands support species of terrestrial flora and fauna not found on the mainland, while in their intertidal and subtidal areas are found many unique 1^0 endemics and an abundance of diverse tidepool plants and animals. Importantly, the islands also provide refuge for animals with low tolerance to human disturbance.

Channel Islands National Monument, including only Santa Barbara and Anacapa

islands, was established by presidential proclamation on April 26, 1938. However, because of the unique historical, biological, ecological, archeological, and paleontological values present in a relatively undisturbed setting, there have been subsequent proposals to create a Channel Islands National Park including Santa Barbara, Santa Rosa, San Miguel, Santa Cruz, and Anacapa islands.

San Miguel Island is administered jointly by the Department of the Navy and the Department of the Interior pursuant to a memorandum of agreement between the agencies dated May 7, 1963, recognizing the importance of the Department of the Interior's participation in the "...protection and study of these priceless national possessions" (San Miguel and the smaller adjacent Prince Island).

An amendment to that memorandum, dated August 21, 1976, states that "...in the event the Department of the Navy determines it no longer requires the use of the islands, the USDI, National Park Service, shall seek authorization for the islands to be preserved and protected indefinitely, a unit within the National Park System." Thus, if the Navy relinquishes jurisdiction of San Miguel, it will likely become part of Channel Islands National Monument.

The intent of the National Monument designation is best embodied in the language of the enabling Act that established the National Park Service in 1916 and remains a principal National Park Service goal today:

> The service thus established shall promote and regulate the use of the federal areas known as national parks, monuments, and reservations...by such means and measures as conform to the fundamental purpose of the said parks, monuments and reservations, which purpose is to conserve the scenery and the natural and historic objects and the wildlife therein and to provide for the enjoyment of the same in such manner and by such means as will leave them unimpaired for the enjoyment of future generations. 71/

In May 17, 1976, comments to the Bureau of Land Management regarding the call for nominations for OCS Lease Sale #48, the National Park Service stated that if subsequent exploratory drilling and/or development occurs on tracts nominated, especially those adjacent to San Miguel and Santa Barbara Islands, "Channel Islands National Monument may experience adverse visual, recreational and wildlife impacts." The U.S. Fish and Wildlife Service also expressed concern, pointing out that a study of calculated slick transport for the Channel Islands area conducted for the Western Oil and Gas Association indicates that Santa Barbara Island would very likely be affected by oil spills occurring west and northwest of it. 72/ They suggest that an ecological buffer zone is desirable around all of the Channel Islands, and that the two islands in greatest need of protection from possible adverse effects of OCS Lease Sale #35 are San Miguel and Santa Barbara.

As the intensity of petroleum activity builds in the Southern California Bight, strong measures must be taken to protect these vital and irreplaceable natural resources. A Channel Islands National Park including San Miguel, Anacapa, Santa Rosa, Santa Barbara, Santa Cruz, and San Nicholas Islands should be created

by Congress. The legislation should provide appropriate restrictions to insure well-managed public access as well as protection of associated marine and terrestrial species.

The Secretary of Commerce should designate the waters within twelve miles of all the Channel Islands as a marine sanctuary under the provisions of the Marine Protection, Research, and Sanctuaries Act of 1972 (PL 92-532) in order to protect their value as habitat for seabirds, pinnipeds, and marine flora and fauna.

STATE OIL AND GAS SANCTUARIES

State offshore lands extend from the mean high tide line for a distance of three geographical miles offshore and include all lands within that limit leased for oil and gas exploration and development, those available for leasing, and those located within codified sanctuaries specifically excluded from oil and gas leasing. The California State Legislature has designated these oil and gas sanctuaries to prohibit oil development in what are regarded to be critical offshore areas. 73/

The Public Resources Code of California requires that development of publicly-owned mineral resources is not to be undertaken at the expense of environmental values, and Sections 6871.1 and 6871.2 exclude certain state-owned offshore lands from petroleum leasing or exploration. These sanctuaries were established under Chapter 1724, Statutes of 1955 (the Cunningham-Shell Tidelands Act) and are administered by the State Lands Commission. 74/ This Act expressed the philosophy that oil and gas could be developed compatibly with other uses of coastal and nearshore areas. Sanctuary areas were established in sensitive regions in which leasing was excluded except when oil and gas underlying the sanctuaries might be subject to drainage by wells on adjacent lands.

Although no federal leasing can take place in Oil and Gas Sanctuaries, the State could be forced to open up such an area for a drainage sale if adjacent leasing threatened the State's interests. Therefore, the Commission has continued to recommend that buffer zones, such as those presently in existence near Santa Barbara, should be established and maintained adjacent to sanctuaries. Without adequate buffer zones, the protected status of State Oil and Gas Sanctuaries is seriously threatened.

Figure 6 shows that Oil and Gas Sanctuaries cover all submerged state lands in southern California not previously leased by the state, with the exception of Santa Barbara and San Nicholas Islands. Protected status should be extended by the Legislature to include these two islands, especially Santa Barbara because of the federal leases adjacent to it.

AREAS OF SPECIAL BIOLOGICAL SIGNIFICANCE (ASBS)

The State Water Resources Control Board seeks to maintain water quality in Areas of Special Biological Significance (ASBS), defined as those areas containing biological communities of such extraordinary, even though unquantifiable, value that no acceptable risk of change in their environments as a result of man's activities can be entertained. The State and Regional Boards prohibit the direct discharge of wastes into an ASBS or its immediate vicinity, with the exception of vessel wastes, dredging, or the disposal of dredging spoil.

FIGURE 6:
OIL AND GAS SANCTUARIES



23—76658

Wastes presently being discharged into ASBS are being phased out or required to comply with regulations preventing waste substances in detectable levels. Discharges outside the designated boundary are required to be monitored to demonstrate that the effluent is not detectable within the ASBS. 75/

Though the intent of this designation is to protect marine life from wastewater discharges, petroleum discharges into an ASBS would be included, according to an interpretation by the Bureau of Land Management in the final EIS for OCS Lease Sale #35:

> The existence of communities of such high value that the discharge of any pollutants into the area is unacceptable, puts a responsibility on other potential polluters to follow the spirit of the law. Any pollution resulting from offshore oil activities which enters an intertidal area or near-shore area designated as an ASBS would be unacceptable according to the intent of this law, and the State Water Resources Control Board has indicated that any discharges or other forms of detectable pollution resulting from OCS leasing which enter ASBS would fall under their jurisdiction. Even a small spill would greatly impact an ASBS if it went ashore, because a form of pollution would involve an unacceptable risk in accordance with ASBS law. (Emphasis added)

ASBSs are not evenly distributed along the coast. All mainland ASBSs are found in the three southern counties (Los Angeles, San Diego, and Orange), and all appear to be areas that were threatened with overuse. ASBS boundaries are designated, however, around all of the offshore islands -- to a distance of one nautical mile offshore or to the 300-foot isobath, whichever is greater -- except for Santa Catalina, of which only selected portions of shoreline and surrounding waters have ASBS status.

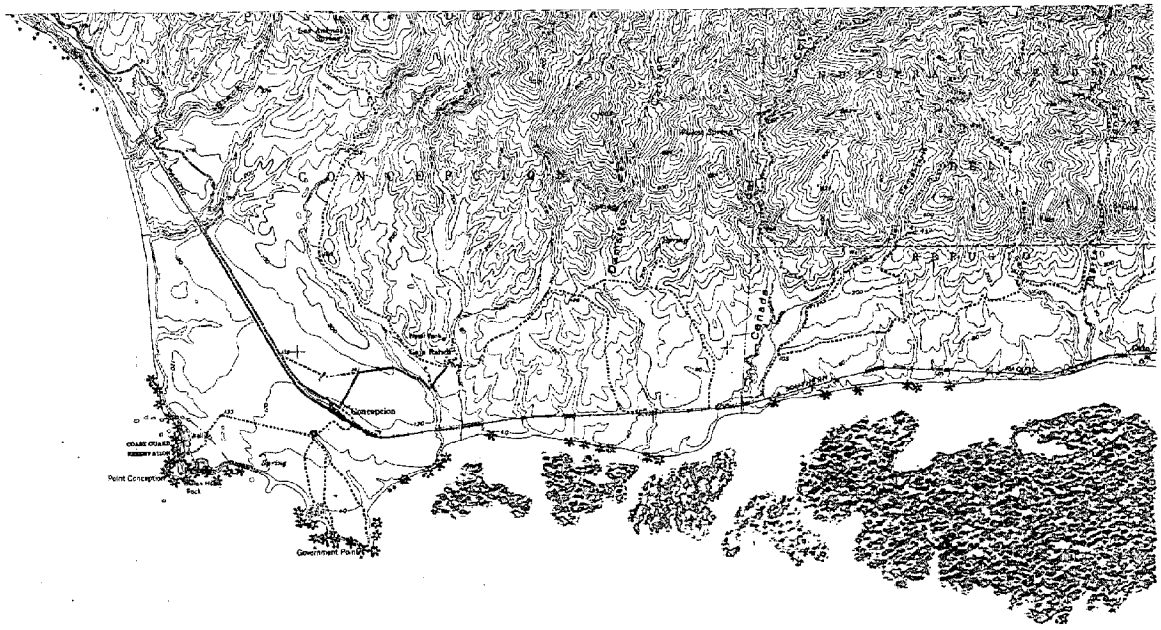
ECOLOGICAL RESERVES AND MARINE LIFE REFUGES

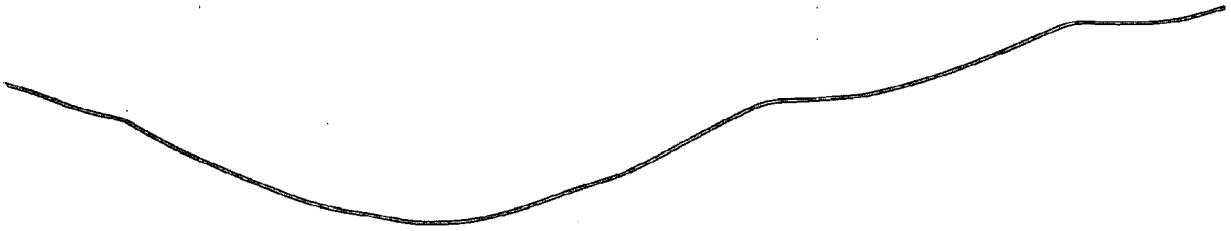
Because of the value, scarcity, and vulnerability of rock intertidal areas -- particularly in southern California where they exist only in limited and widely dispersed coastal sites -- the Legislature and the Fish and Game Commission have established marine life refuges and reserves to protect intertidal communities. Protection is limited to restrictions on the taking of marine invertebrates and plants, though the definition of a reserve refers more broadly to land or land/water areas preserved in a natural condition for scientific study and for the benefit of the general public in observing native flora and fauna. 76/

In order to assure adequate protection, Smith and Johnson maintain that, "Establishment of marine reserves should exclude many uses including, but not limited to, harbor development, fishing, outfalls and pipelines..." (emphasis added). 77/ Such broad protection, however, is not now afforded. In practice, since the Fish and Game Commission and the Legislature have extended protection to marine invertebrates along the entire California coast between the high tide mark and 1,000 feet offshore, the regulations for adjacent "unprotected" waters differ only slightly from those for marine reserves. Thus, while the marine life refuge and classification remains a testimony to the value of an area and prevents recreational overuse, it still does not afford legal protection against possible degradation from industrial development either inside the reserve boundary or beyond.

There are fourteen areas in southern California with reserve or refuge status. Orange County has the lion's share with nine; Santa Catalina Island and San Diego each have two; and, Los Angeles has only one refuge. Santa Barbara and Ventura counties have no areas with this protected status, because their unique intertidal areas have not been subjected to pressures as great as those in the southern three counties. All of the refuges and reserves in Orange County, Bolsa Chica, are potentially threatened by the development of leases in San Pedro Bay. Point Fermin Marine Life Refuge, while not directly menaced by OCS leases, is just north of Los Angeles and Long Beach Harbors, and thus is threatened by tanker traffic in the harbor vicinity. San Diego and La Jolla ecological reserves will be vulnerable to oil spill damage only if leases off San Diego that will be included in the EIS are ultimately sold.

It is apparent that the special status of marine life refuges and reserves offers little protection or legal recourse from an oil spill, but rather singles them out as areas to be given priority in oil spill contingency planning.





NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS

0 1 2 MILES

40 ACRES

10

SENSITIVE RESOURCES INVENTORY

POINT CONCEPTION TO GATO

1

California Governor's Office of Planning and Research

OCS PROJECT

1977



NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS
0 1 2 MILES

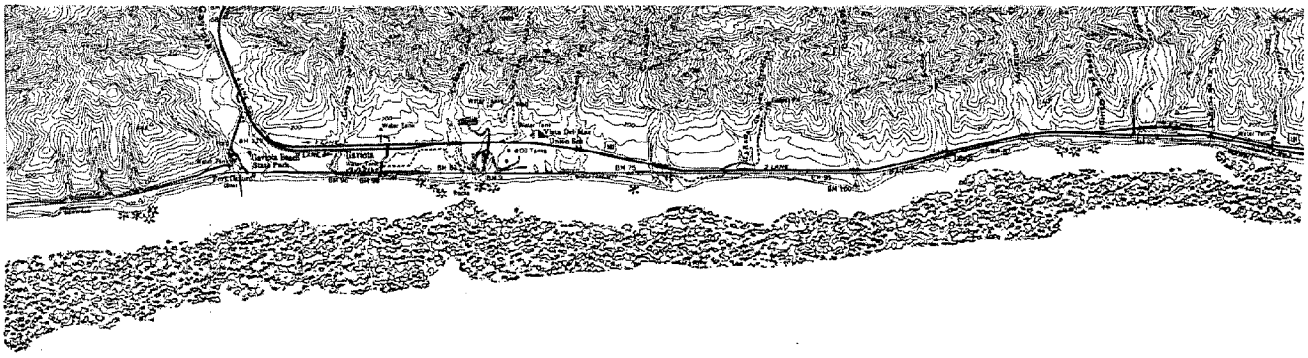
40
10
ACRES

SENSITIVE RESOURCES INVENTORY

SAN AUGUSTINE TO SACATE

2

California Governor's Office of Planning and Research
OCS PROJECT
1977





NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS

0 1 2 MILES

40 ACRES

10

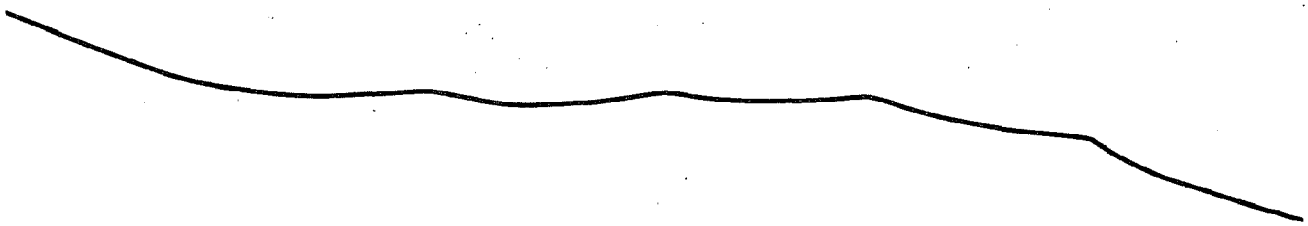
SENSITIVE RESOURCES INVENTORY

GAVIOTA TO LENTO

3

California Governor's Office of Planning and Research
OCS PROJECT
1977





NORTH

0 1 2 3 KILOMETERS

0 1 2 MILES

40 10 ACRES

SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

SENSITIVE RESOURCES INVENTORY

TAJIGUAS TO CAPITAN

4

California Governor's Office of Planning and Research

OCS PROJECT

1977



NOTE: Pinniped haul-out sites are located at Naples/Aminoil Beach and at Devereaux Slough/Coal Oil Point.

NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS

0 1 2 MILES

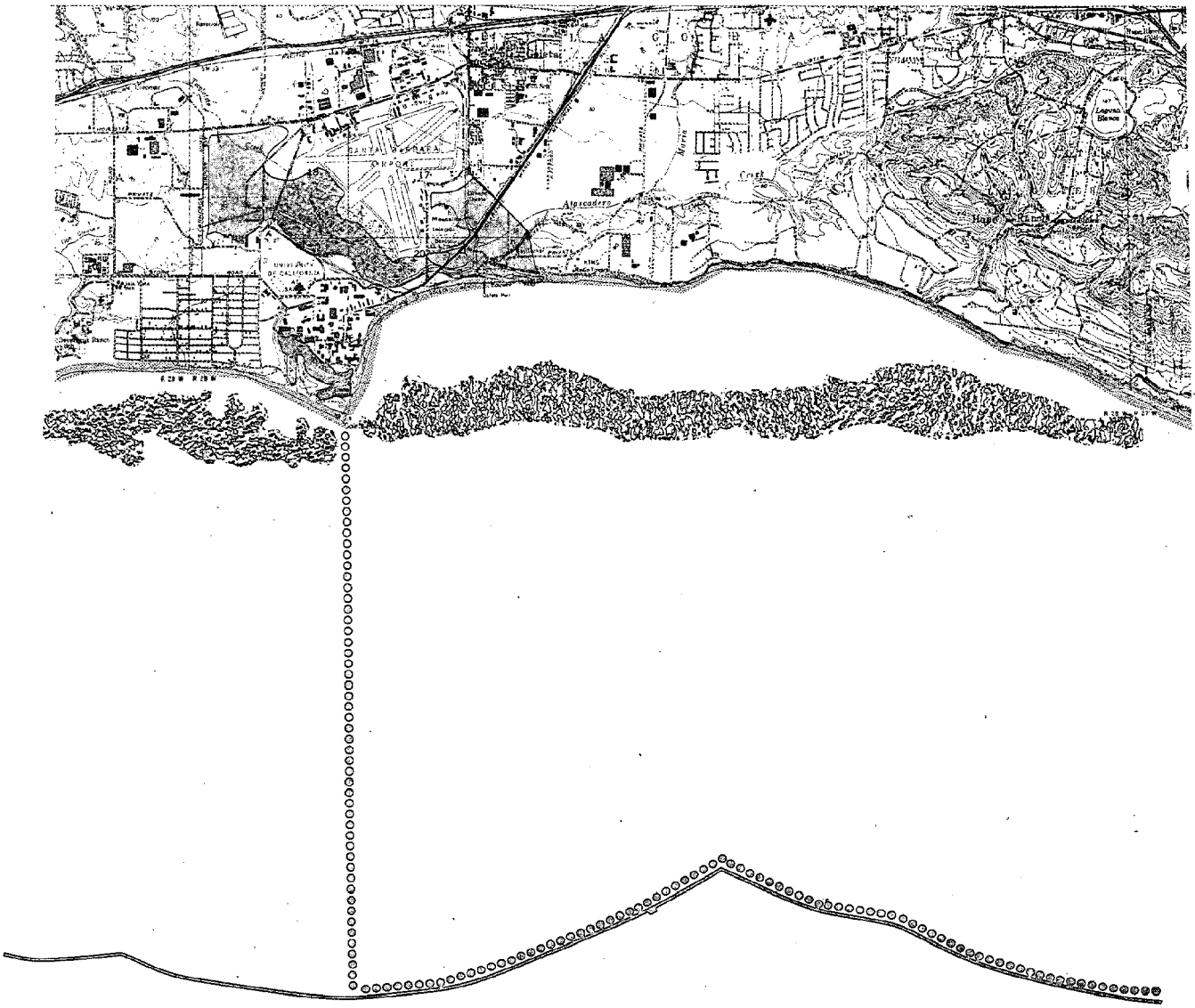
40 ACRES 10

SENSITIVE RESOURCES INVENTORY

NAPLES TO COAL OIL POINT

5

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: Rare and Endangered Species Habitats are located at Goleta Slough; the endangered species are the Light-Footed Clapper Rail and the Belding's Savannah Sparrow.

A pinniped haul-out site is located at Goleta Rocks near the mouth of Goleta Slough.

NORTH

0 1 2 3 KILOMETERS 40

0 1 2 MILES 10

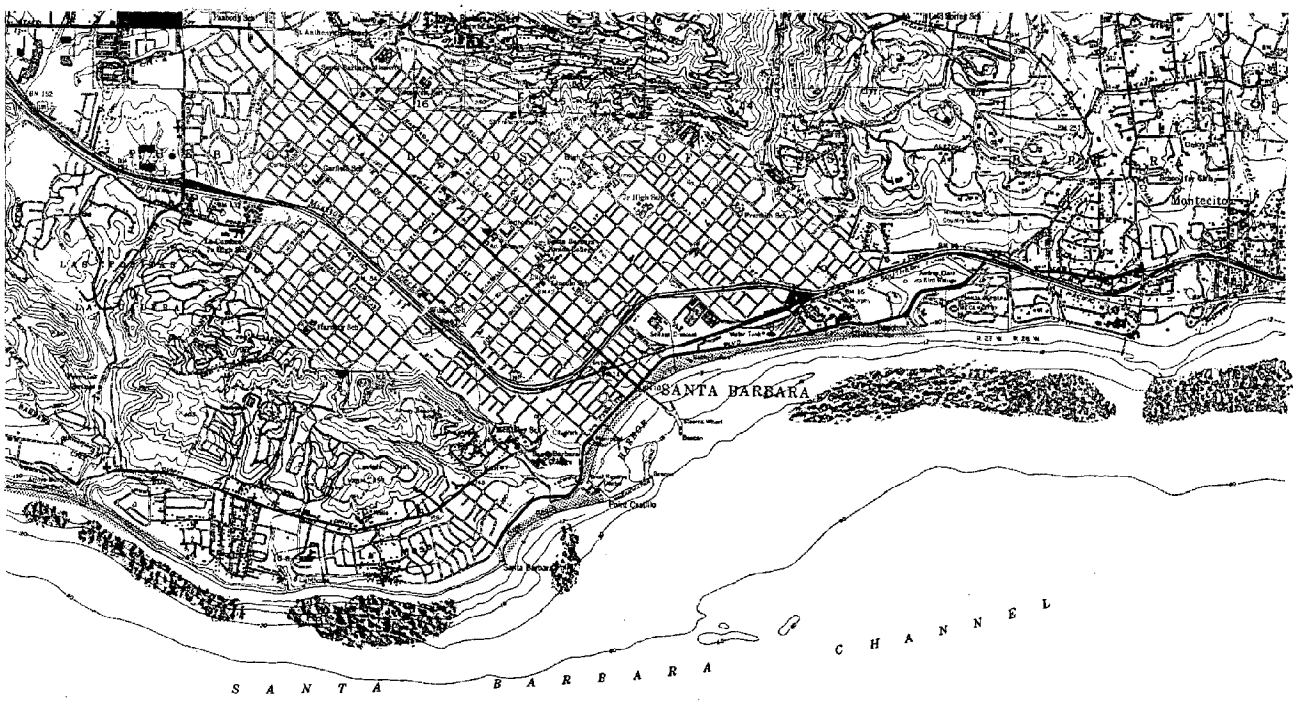
SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET ACRES

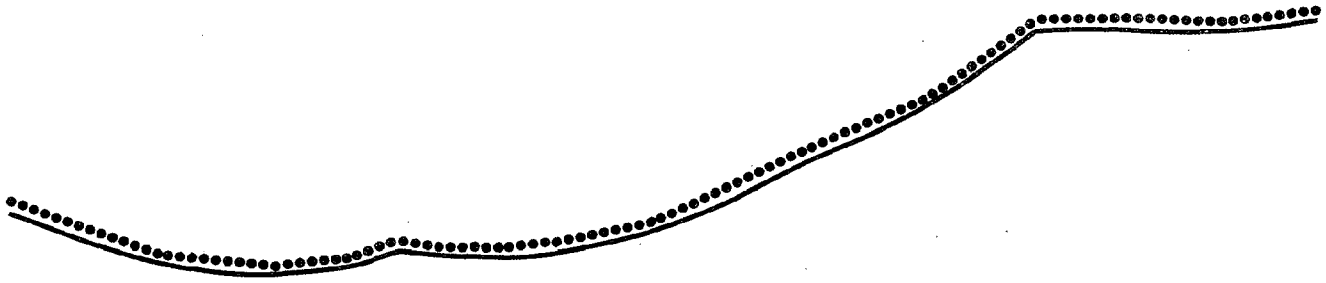
SENSITIVE RESOURCES INVENTORY

GOLETA

6

California Governor's Office of Planning and Research
OCS PROJECT
1977





0 1 2 3 KILOMETERS
0 1 2 MILES
40 ACRES
10

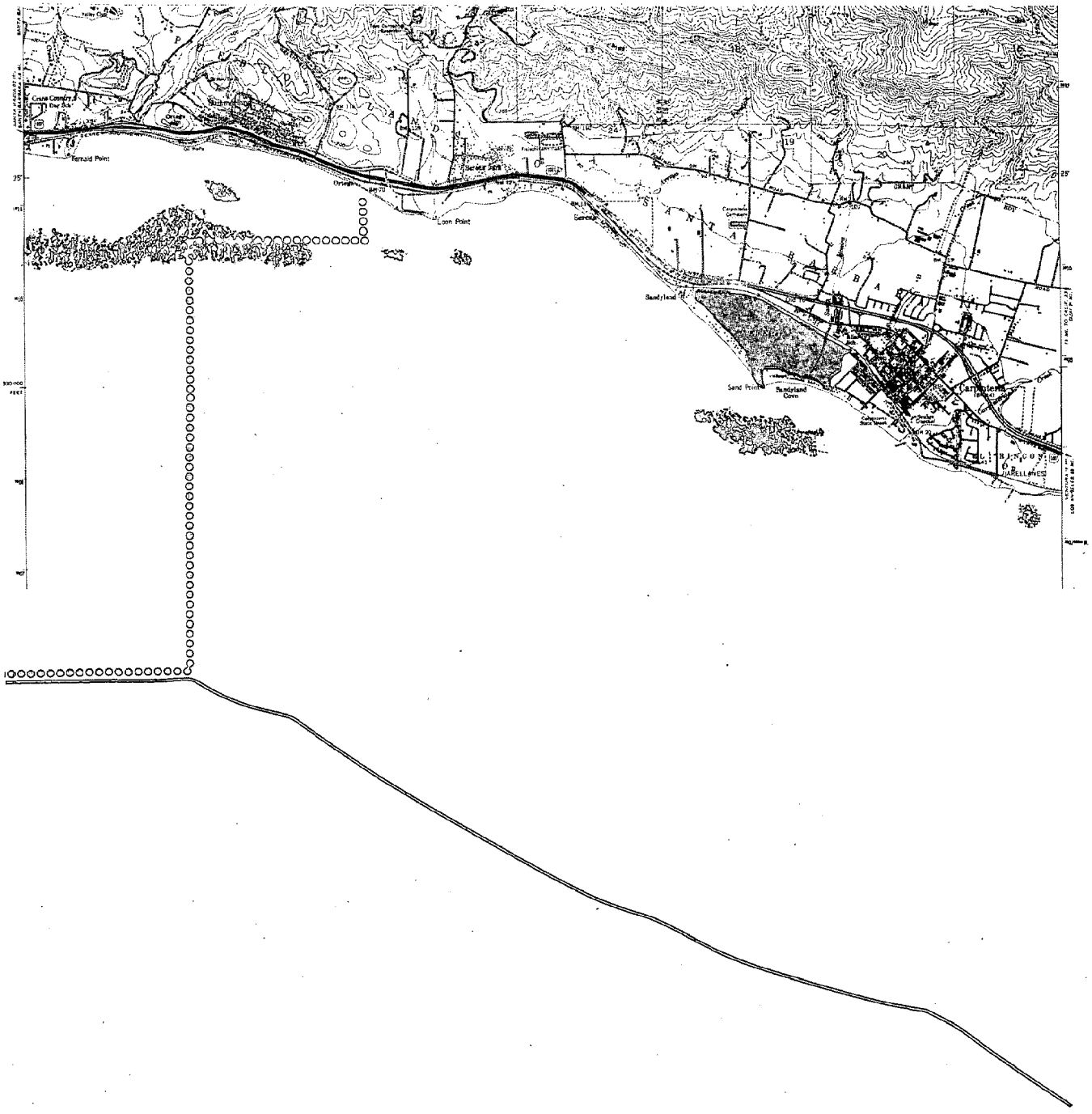
NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

SENSITIVE RESOURCES INVENTORY

SANTA BARBARA

7

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: Rare and Endangered Species Habitats are located at El Estero and Carpinteria; the endangered species are the Light-Footed Clapper Rail and the Beldings Savannah Sparrow.

A pinniped haul-out site is located near the Chevron Oil Pier.

NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

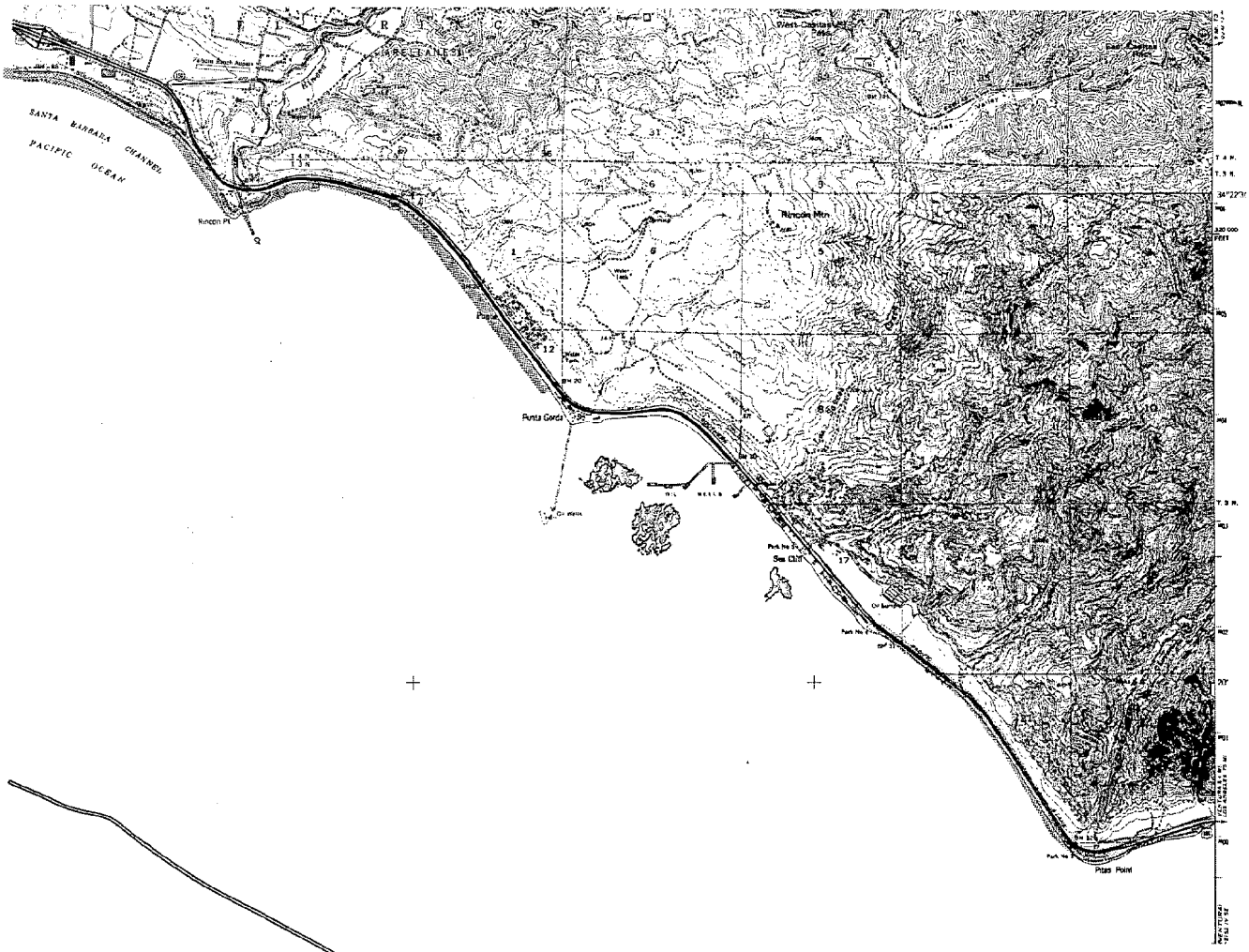
0 1 2 3 KILOMETERS
0 1 2 MILES
40 ACRES
10

SENSITIVE RESOURCES INVENTORY

SUMMERLAND TO CARPINTERIA

8

California Governor's Office of Planning and Research
OCS PROJECT
1977



0 1 2 3 KILOMETERS
0 1 2 MILES
40 ACRES
10

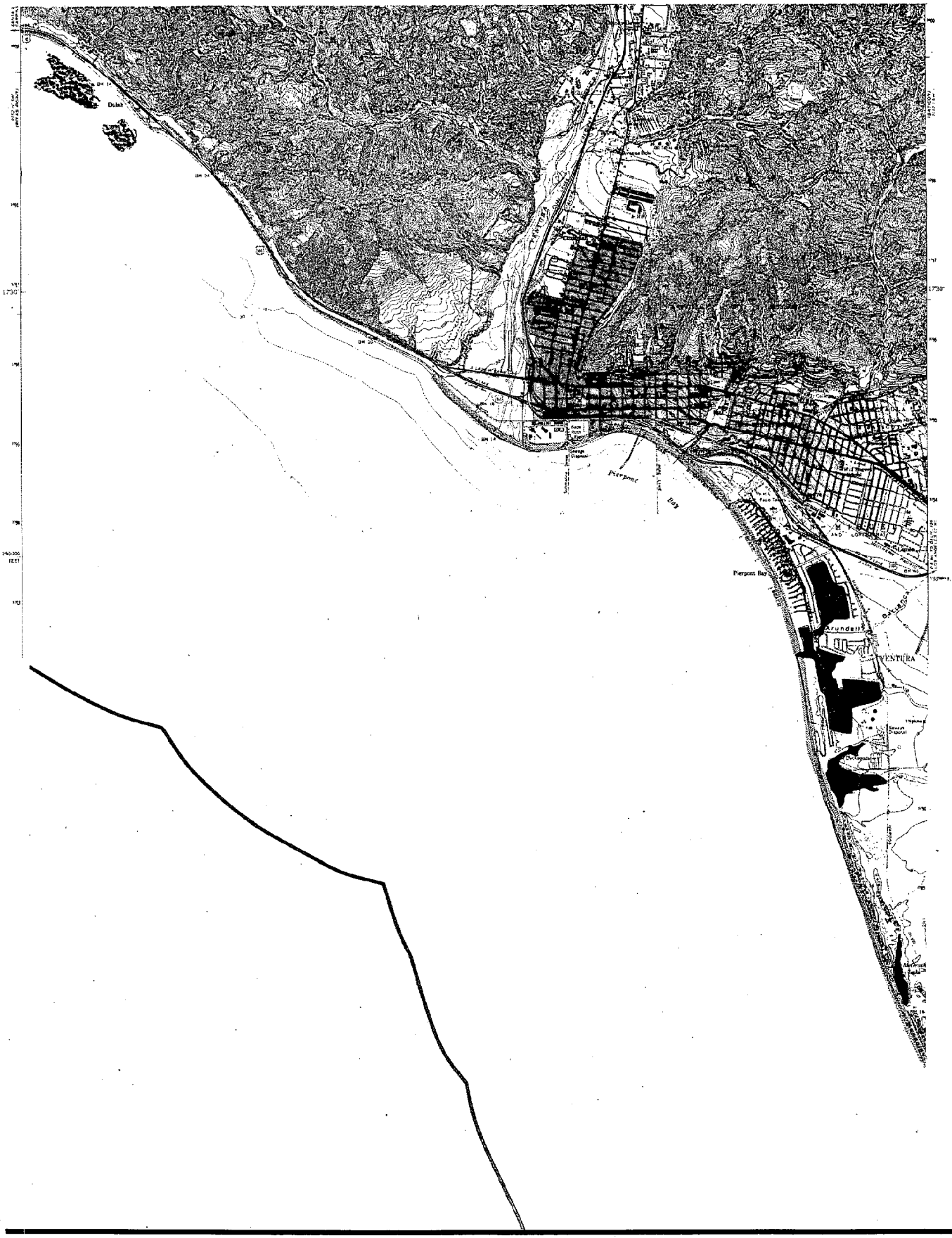
NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

SENSITIVE RESOURCES INVENTORY

RINCON POINT TO PITAS POINT

9

California Governor's Office of Planning and Research
OCS PROJECT
1977



NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS

0 1 2 MILES

40 ACRES

10

SENSITIVE RESOURCES INVENTORY

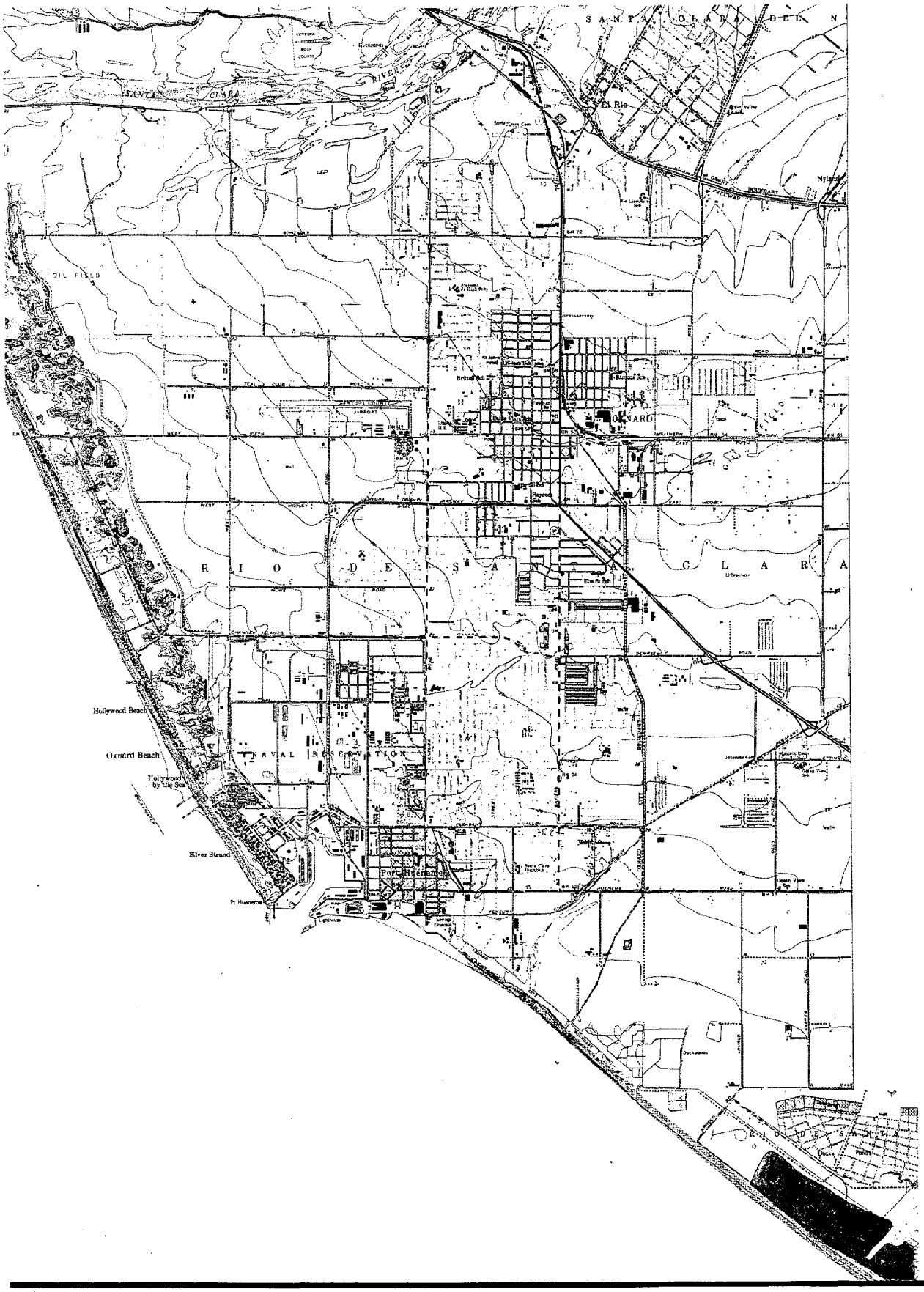
VENTURA

10

California Governor's Office of Planning and Research

OCS PROJECT

1977



NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS 40

0 1 2 MILES 10

ACRES

SENSITIVE RESOURCES INVENTORY

PORT HUENEME

11

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: Rare and Endangered Species Habitats are located at Mugu Lagoon; the endangered species is the California Least Tern.

A pinniped haul-out site is located at the sand flats in Mugu Lagoon.

NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS

0 1 2 MILES

40 ACRES

10

SENSITIVE RESOURCES INVENTORY

POINT MUGU

12

California Governor's Office of Planning and Research
OCS PROJECT
1977



NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS

0 1 2 MILES

40 ACRES 10

SENSITIVE RESOURCES INVENTORY

SEQUIT POINT

13

California Governor's Office of Planning and Research

OCS PROJECT

1977



NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

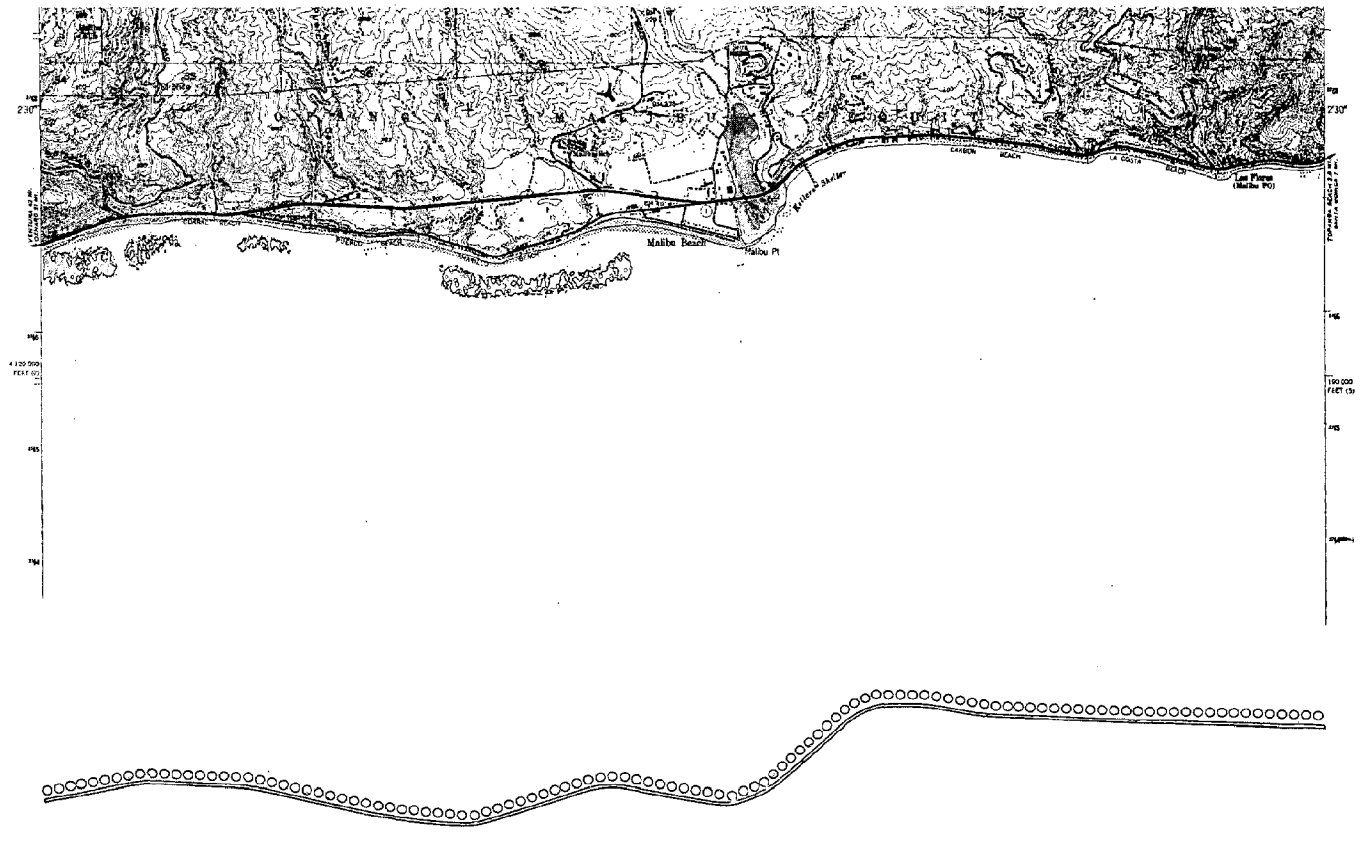
0 1 2 3 KILOMETERS
0 1 2 MILES
40
10
ACRES

POINT DUME

14

SENSITIVE RESOURCES INVENTORY

California Governor's Office of Planning and Research
OCS PROJECT
1977



NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS

0 1 2 MILES

40 ACRES

10

SENSITIVE RESOURCES INVENTORY

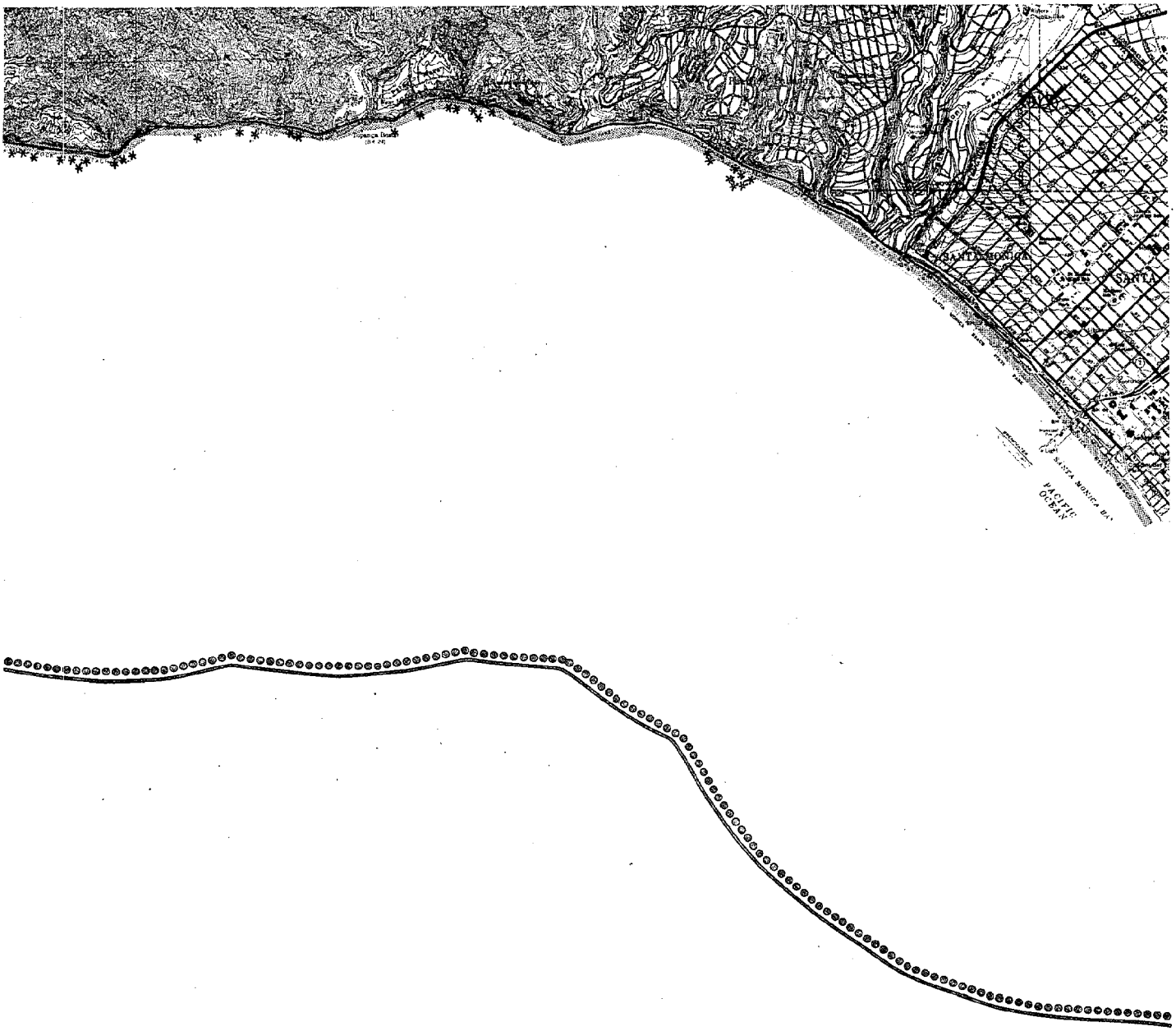
MALIBU BEACH TO LAS FLORES

15

California Governor's Office of Planning and Research

OCS PROJECT

1977



NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS
0 1 2 MILES

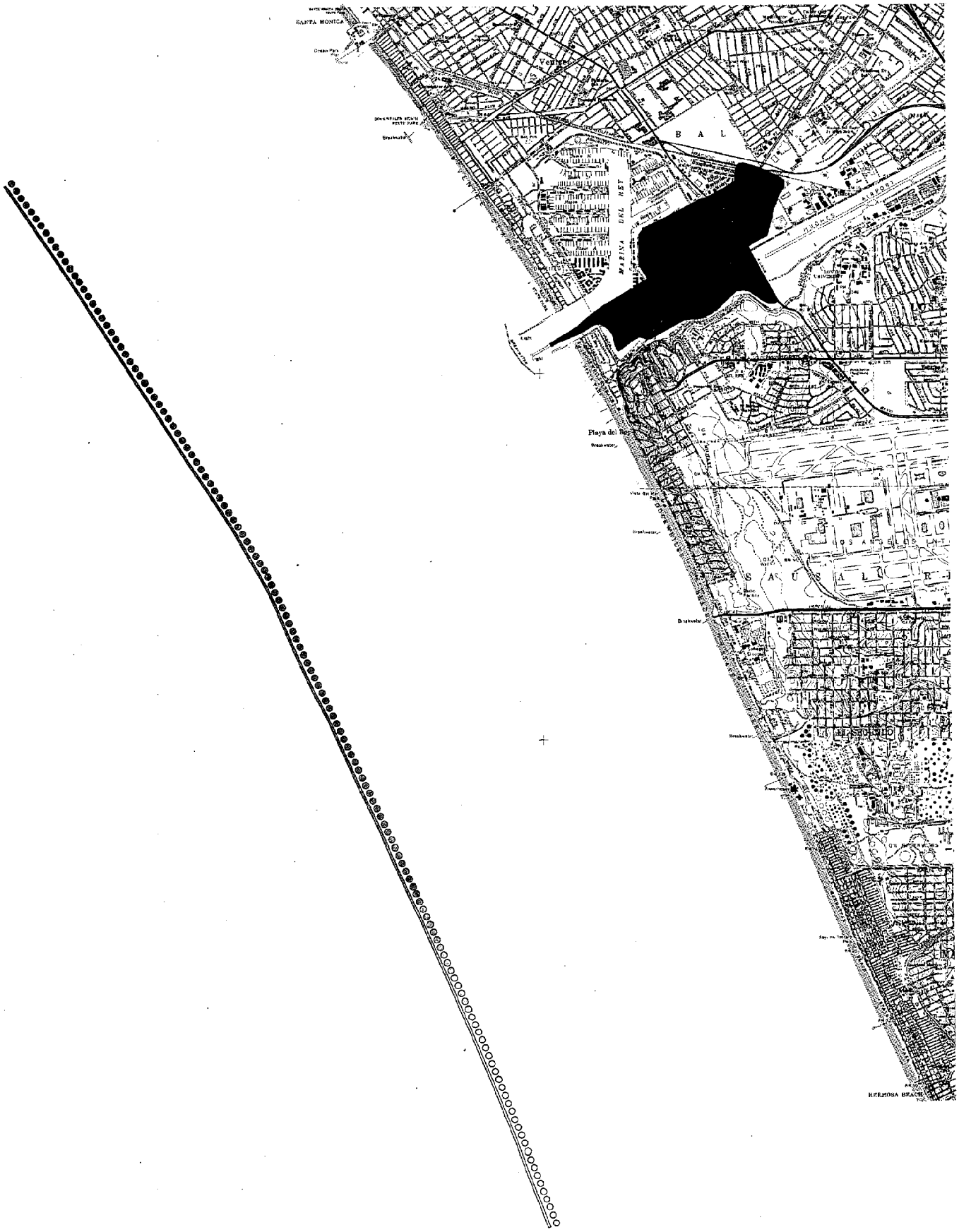
40 ACRES
10

SENSITIVE RESOURCES INVENTORY

TOPANGA BEACH TO SANTA MONICA

16

California Governor's Office of Planning and Research
OCS PROJECT
1977



NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS 40

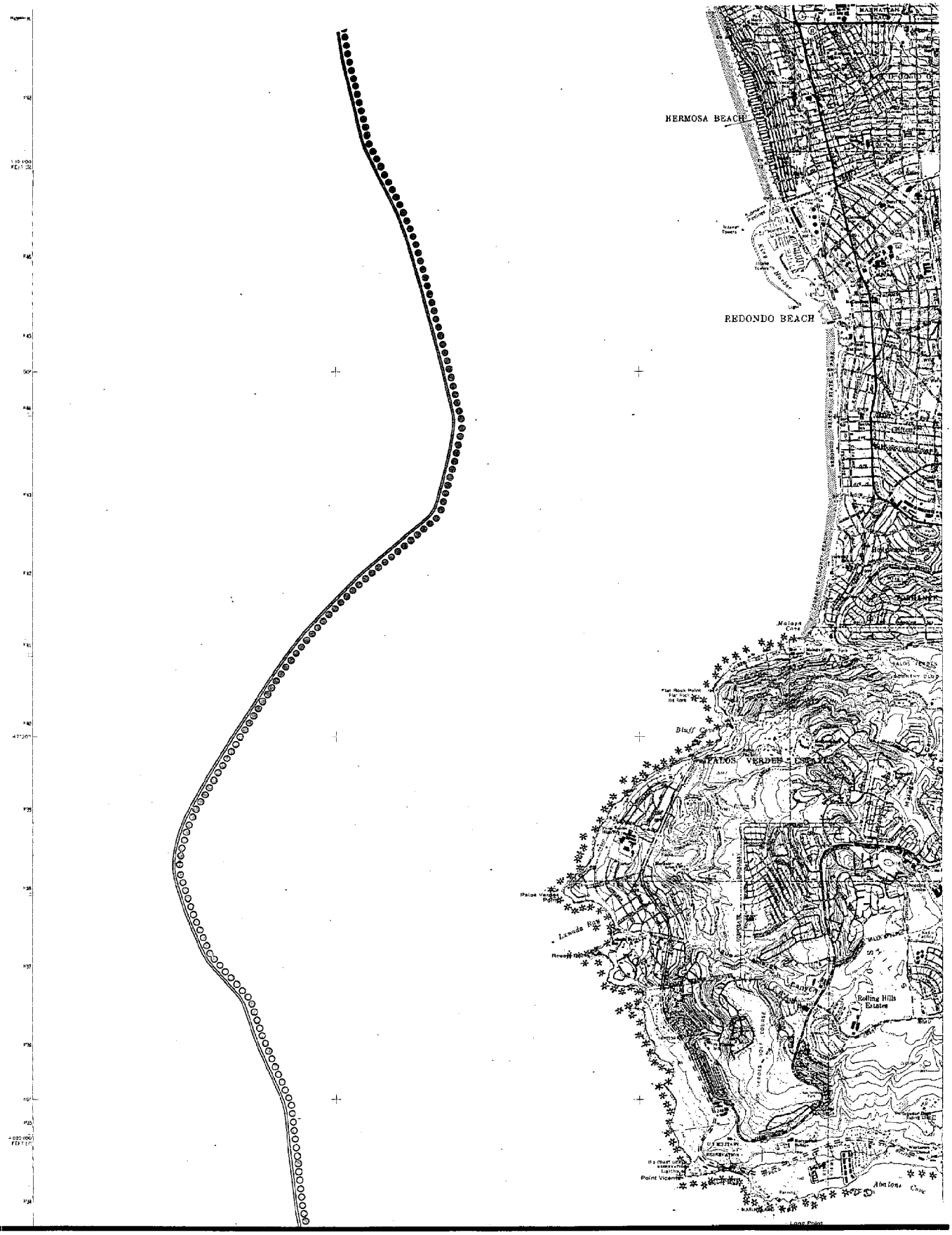
0 1 2 MILES 10 ACRES

SENSITIVE RESOURCES INVENTORY

VENICE TO MANHATTAN BEACH

17

California Governor's Office of Planning and Research
OCS PROJECT
1977



NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS 40
0 1 2 MILES 10
ACRES

SENSITIVE RESOURCES INVENTORY

HERMOSA BEACH TO POINT VICENTE

18

California Governor's Office of Planning and Research
OCS PROJECT
1977



NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS 40

0 1 2 MILES 10

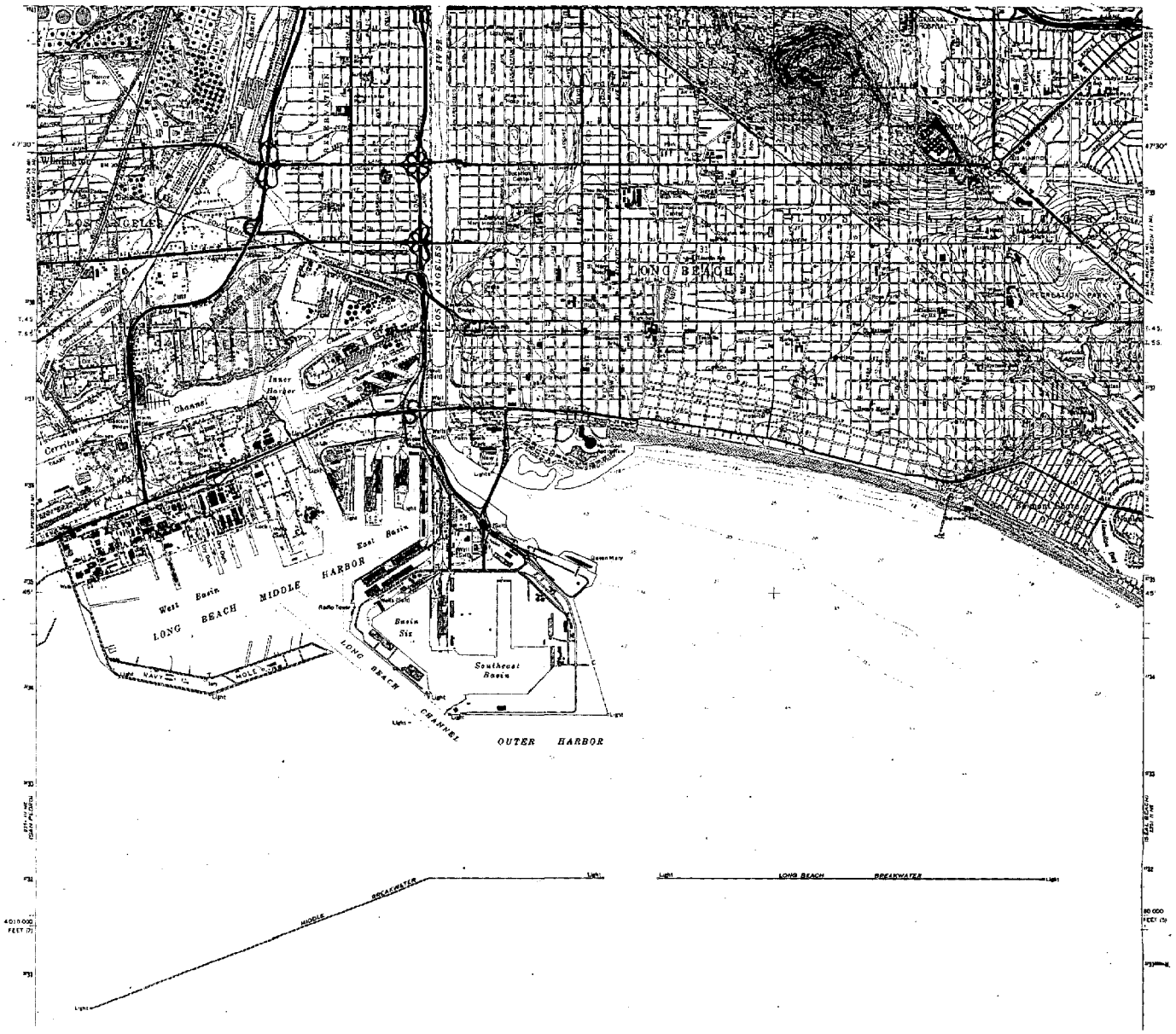
ACRES

SENSITIVE RESOURCES INVENTORY

PORTUGUESE BEND TO LOS ANGELES HARBOR

19

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: Rare and Endangered Species Habitats are located at Terminal Island; the endangered species is the California Least Tern.

NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS

0 1 2 MILES

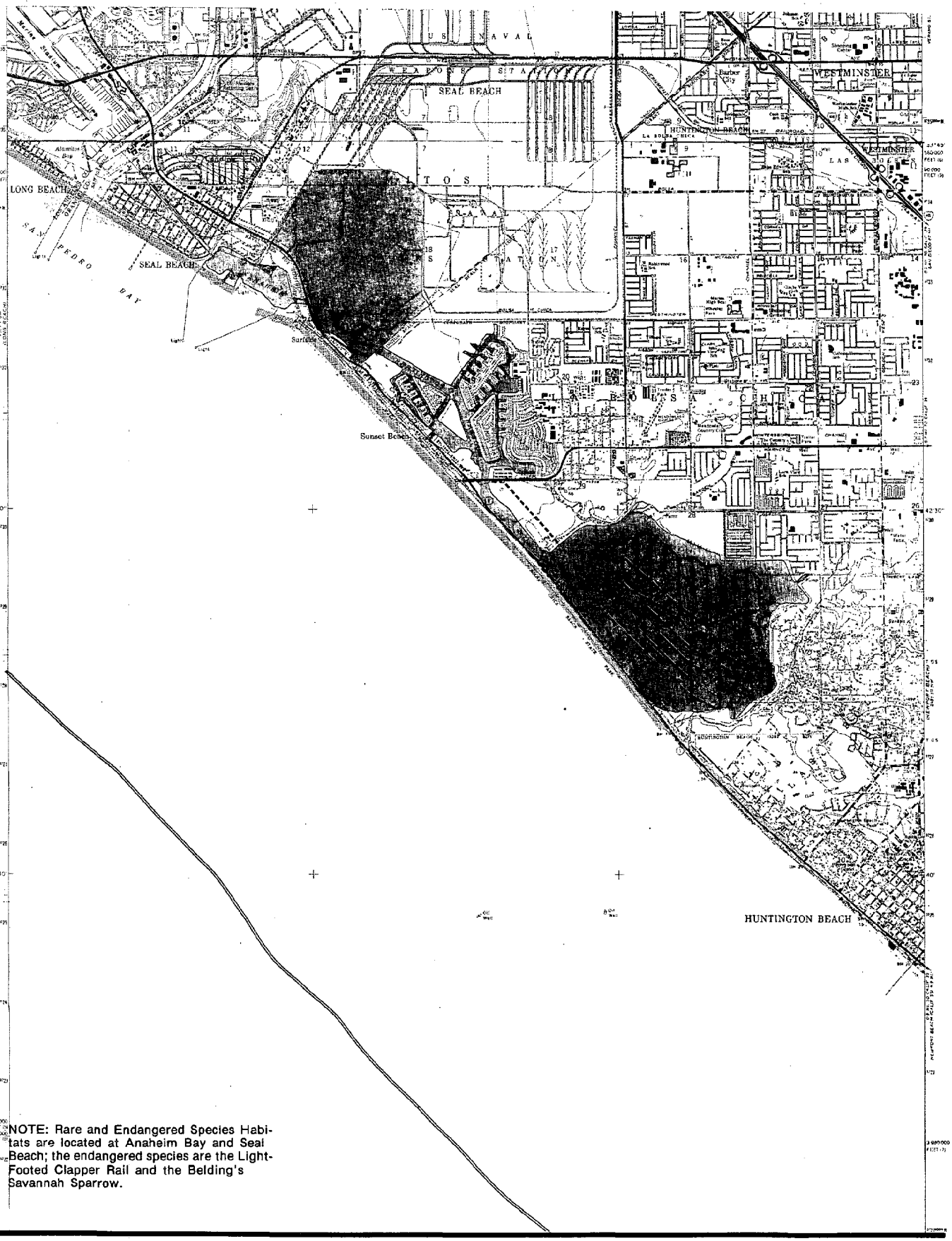
40 ACRES 10

SENSITIVE RESOURCES INVENTORY

LONG BEACH

20

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: Rare and Endangered Species Habitats are located at Anaheim Bay and Seal Beach; the endangered species are the Light-Footed Clapper Rail and the Belding's Savannah Sparrow.

NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS 40
0 1 2 MILES 10
ACRES

SENSITIVE RESOURCES INVENTORY

SEAL BEACH TO HUNTINGTON BEACH

21

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: Rare and Endangered Species Habitats are located at the wetlands of the Santa Ana River and at Upper Newport Bay; the endangered species are the California Least Tern and the Light-Footed Clapper Rail.

NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

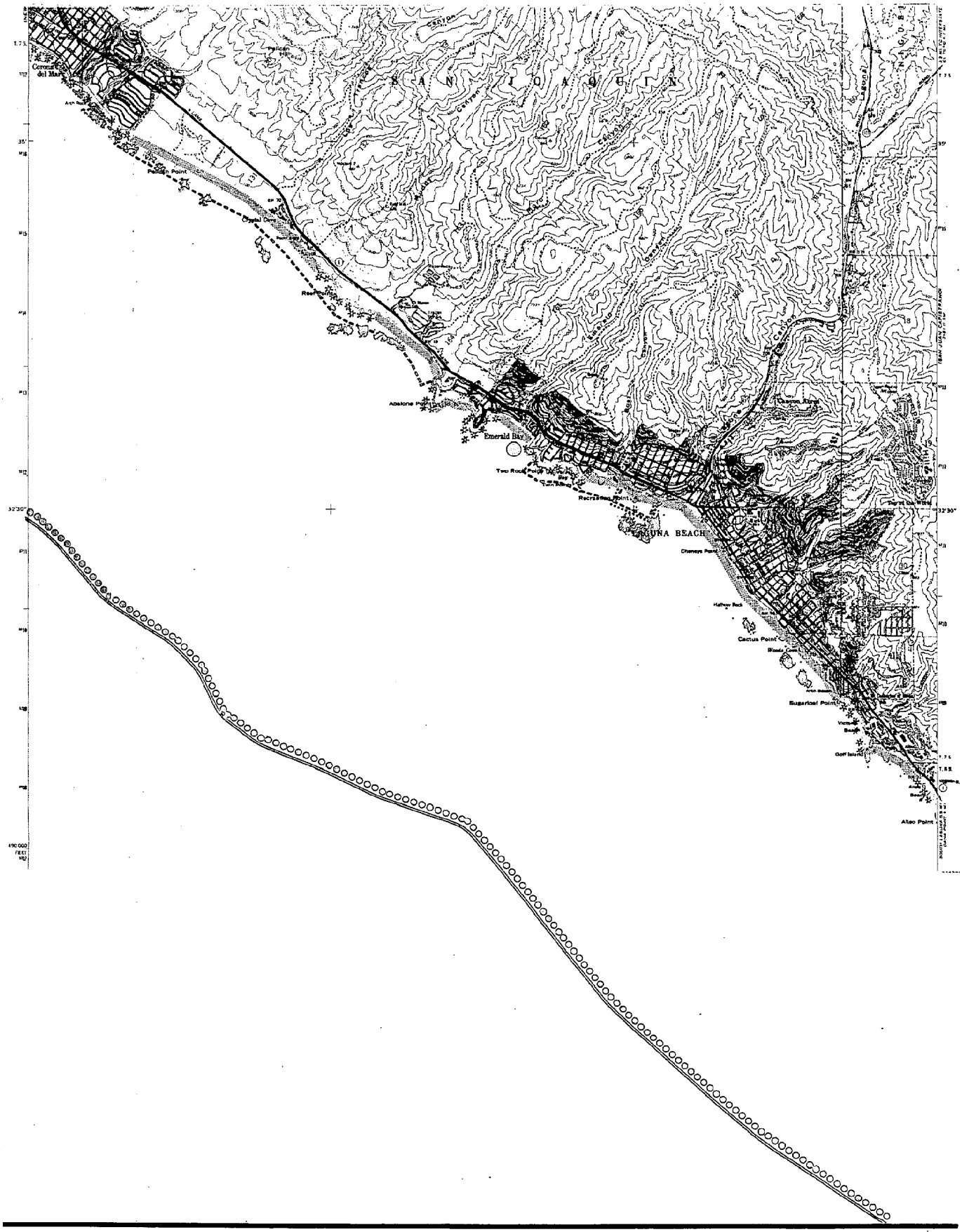
0 1 2 3 KILOMETERS
0 1 2 MILES
40 ACRES
10

SENSITIVE RESOURCES INVENTORY

NEWPORT BEACH

22

California Governor's Office of Planning and Research
OCS PROJECT
1977



0 1 2 3 KILOMETERS
0 1 2 MILES
40 10 ACRES

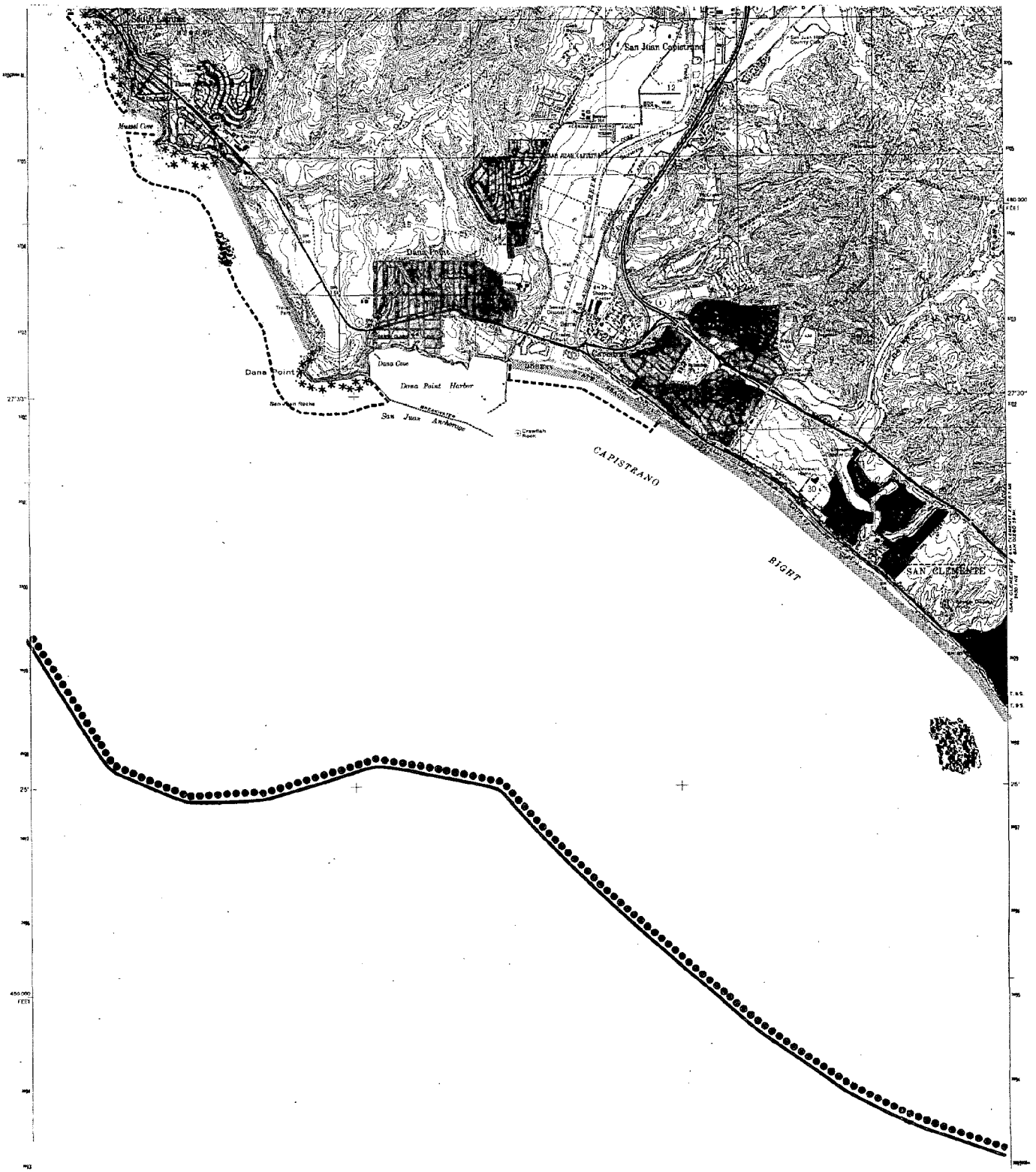
NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

SENSITIVE RESOURCES INVENTORY

LAGUNA BEACH

23

California Governor's Office of Planning and Research
OCS PROJECT
1977



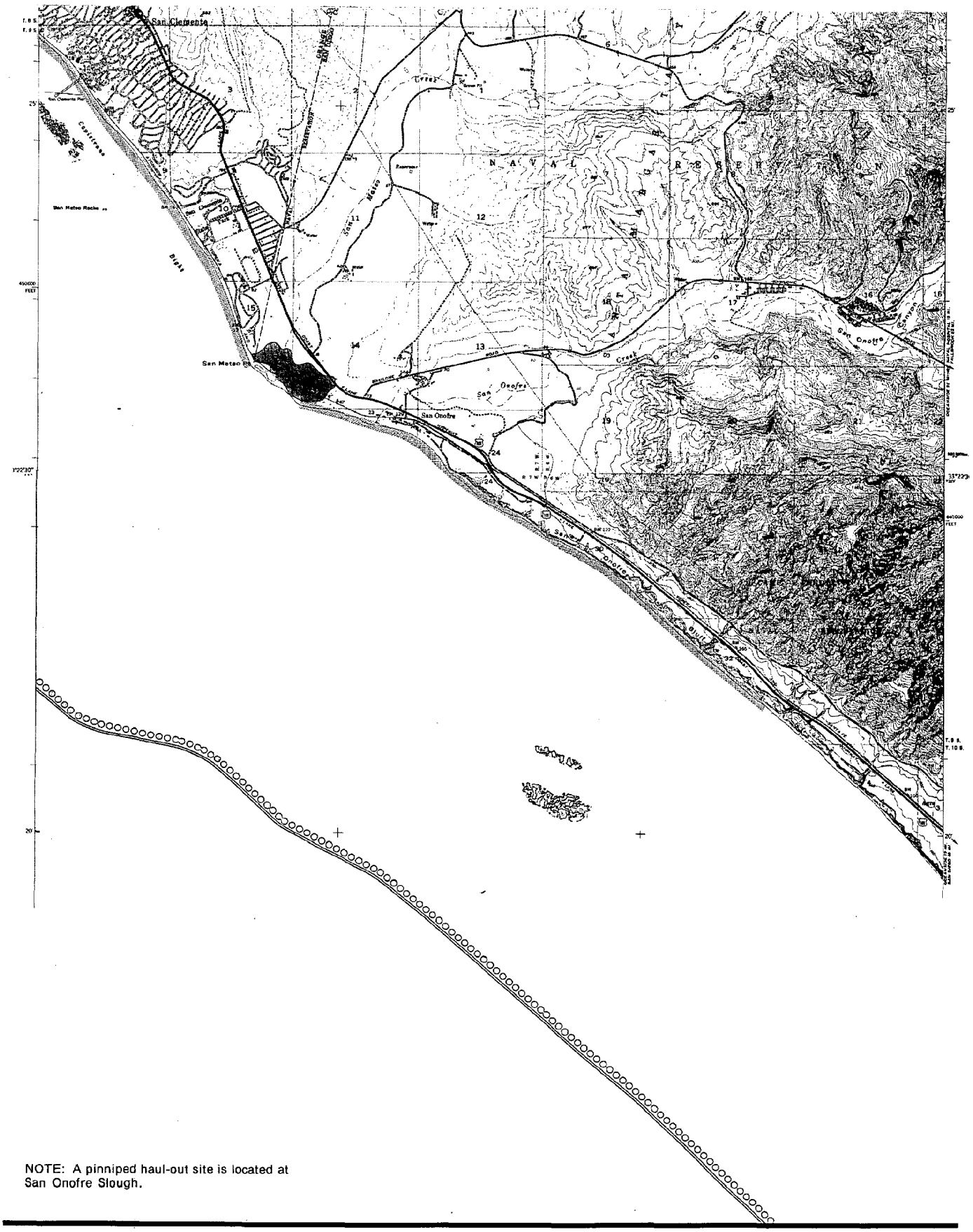
0 1 2 3 KILOMETERS 40
0 1 2 MILES 10
NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET ACRES

SENSITIVE RESOURCES INVENTORY

MUSSEL COVE TO SAN CLEMENTE

24

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: A pinniped haul-out site is located at San Onofre Slough.

NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS

0 1 2 MILES

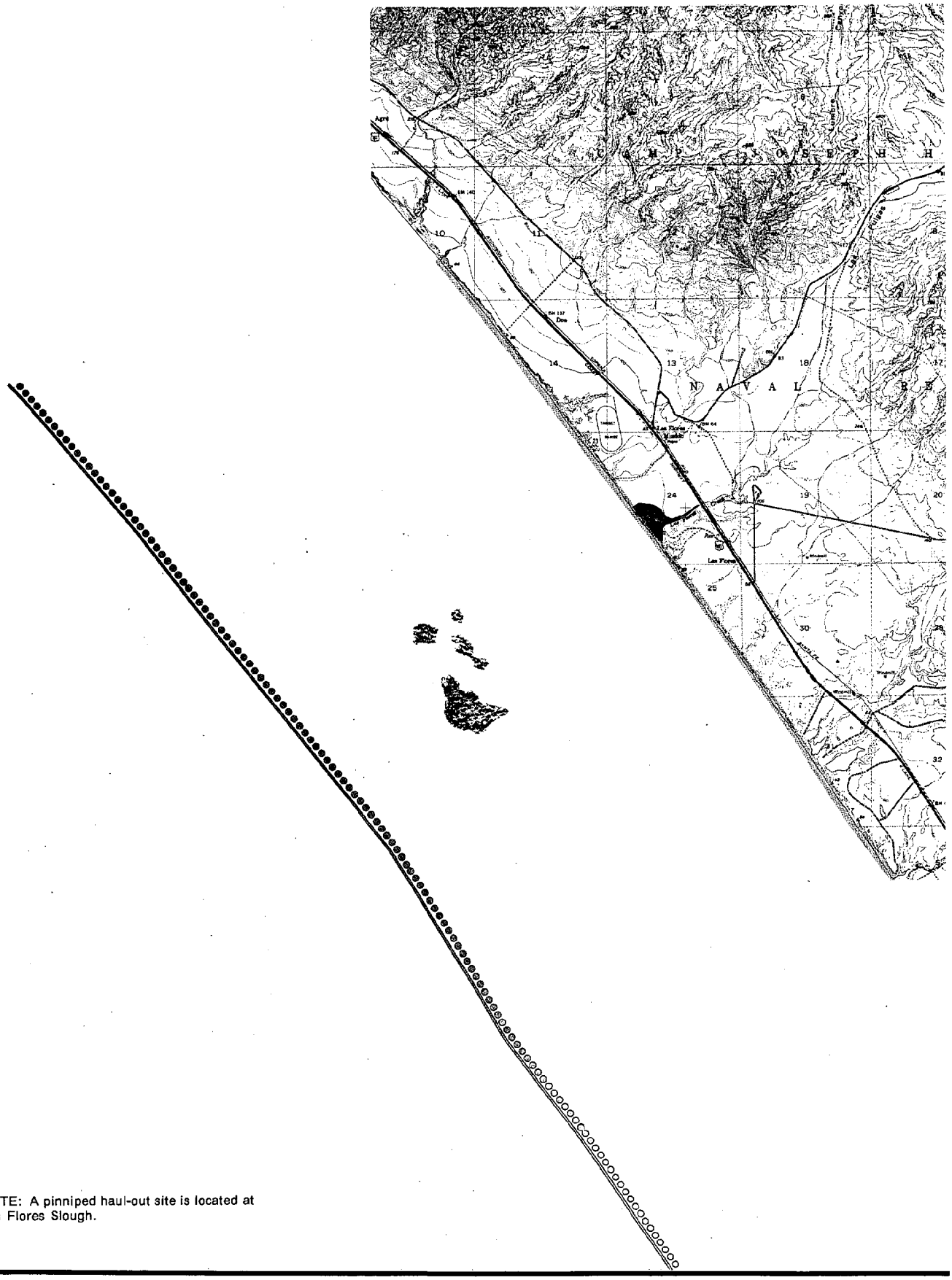
40 ACRES 10

SENSITIVE RESOURCES INVENTORY

SAN MATEO POINT TO SAN ONOFRE

25

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: A pinniped haul-out site is located at Las Flores Slough.

NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS
0 1 2 MILES

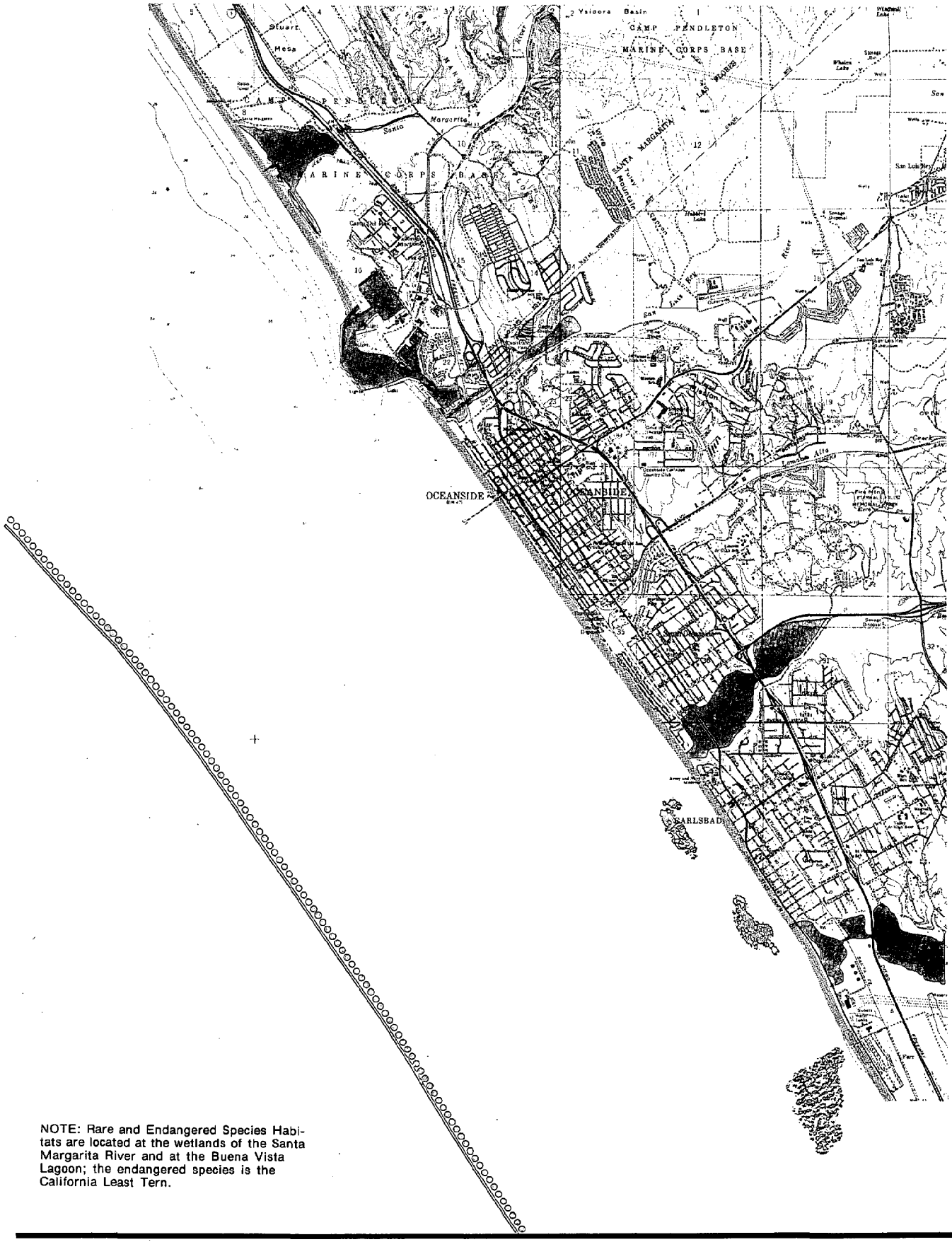
40
10
ACRES

SENSITIVE RESOURCES INVENTORY

LAS PULGAS CANYON

26

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: Rare and Endangered Species Habitats are located at the wetlands of the Santa Margarita River and at the Buena Vista Lagoon; the endangered species is the California Least Tern.

NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

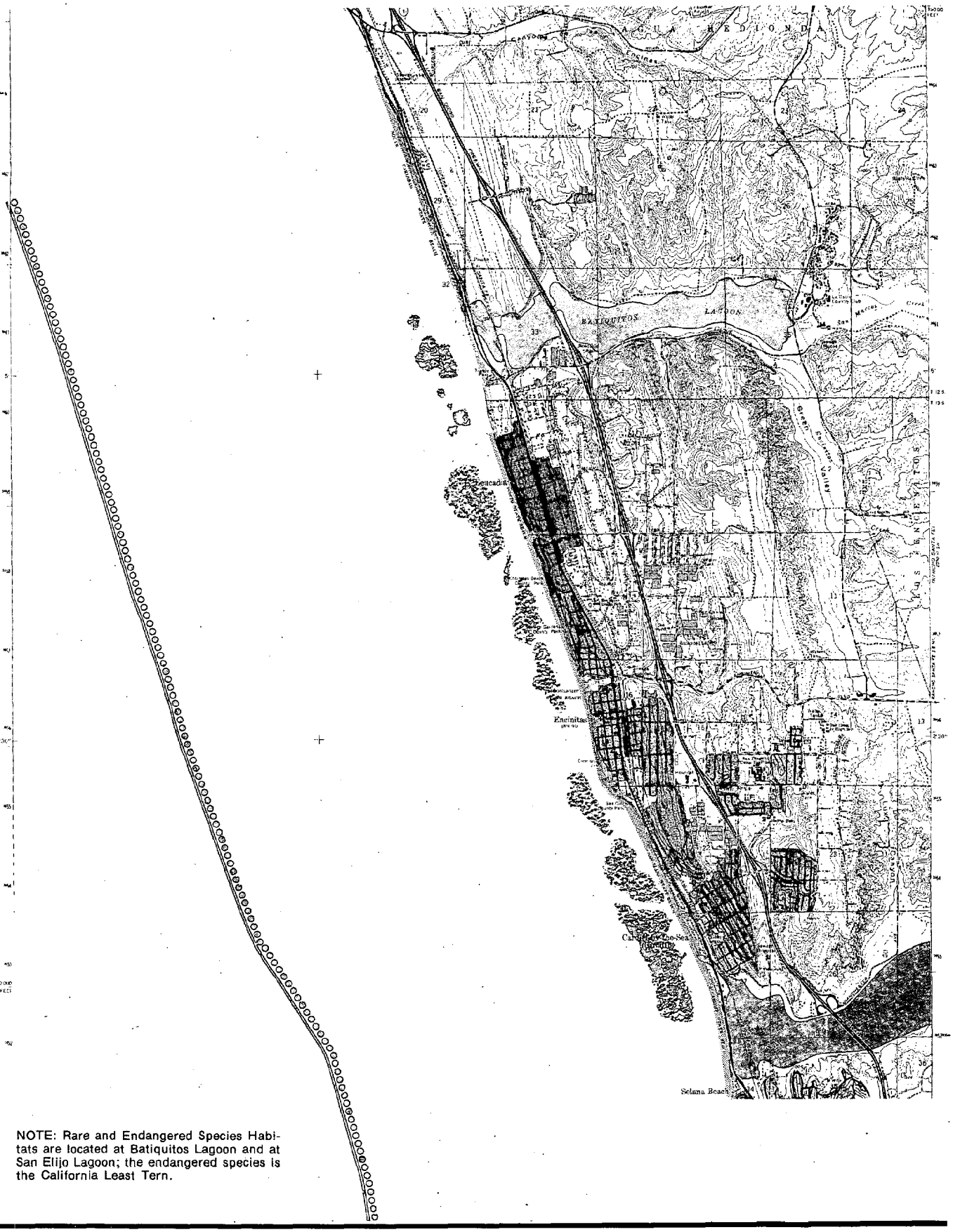
0 1 2 3 KILOMETERS 40
0 1 2 MILES 10
ACRES

SENSITIVE RESOURCES INVENTORY

OCEANSIDE TO CARLSBAD

27

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: Rare and Endangered Species Habitats are located at Batiquitos Lagoon and at San Elijo Lagoon; the endangered species is the California Least Tern.

NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS

0 1 2 MILES

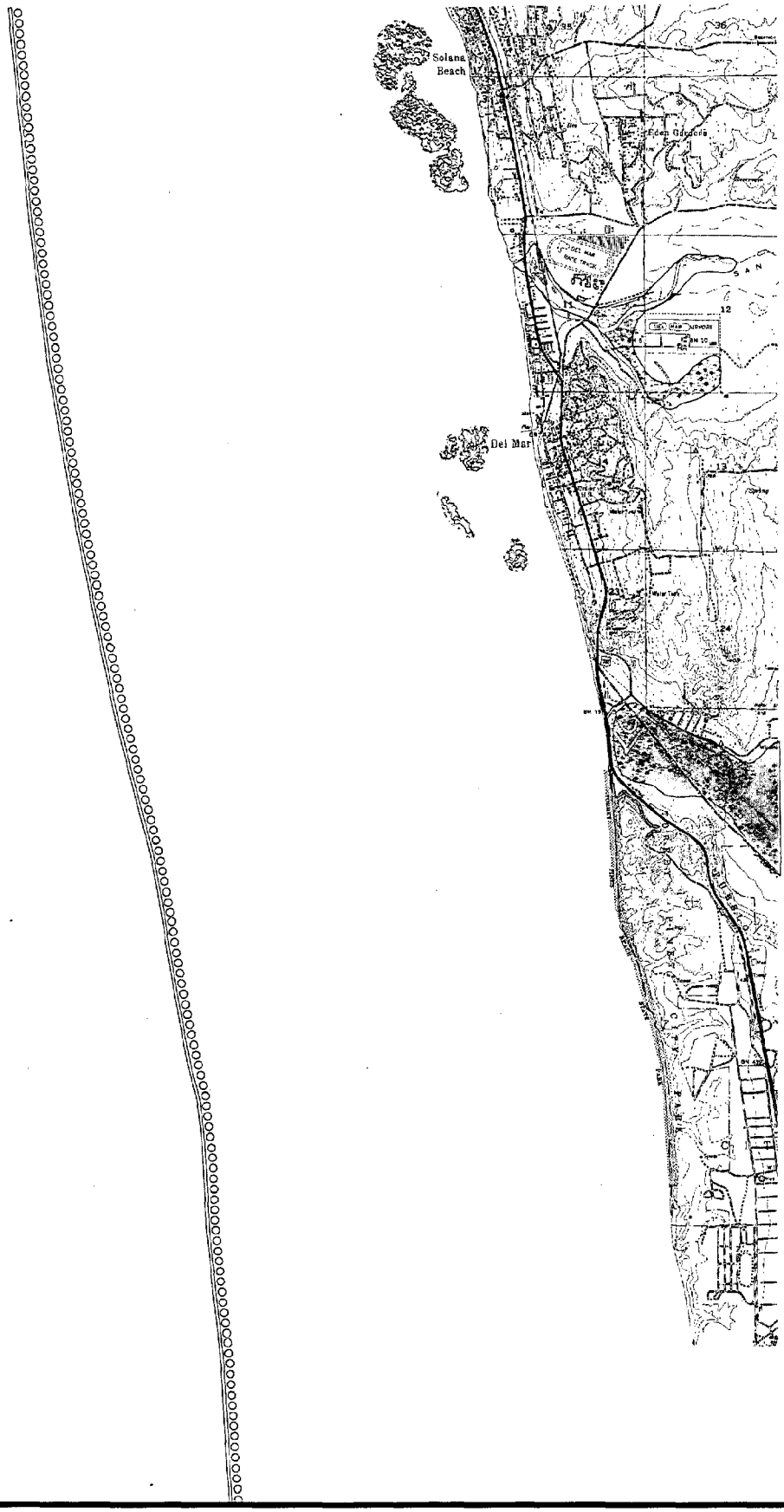
40 ACRES 10

SENSITIVE RESOURCES INVENTORY

SOUTH CARLSBAD TO SAN ELIJO LAGOON

28

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: Rare and Endangered Species Habitats are located at Los Penaquitos; the endangered species are the Light-Footed Clapper Rail, the California Least Tern, and the Belding's Savannah Sparrow.

NORTH

0 1 2 3 KILOMETERS

0 1 2 MILES

40 10 ACRES

SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

SENSITIVE RESOURCES INVENTORY

SOLANA BEACH TO TORREY PINES

29

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: Rare and Endangered Species Habitats are located at Mission Bay; the endangered species are the California Least Tern and the Light-Footed Clapper Rail.

NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS
0 1 2 MILES
40 ACRES
10

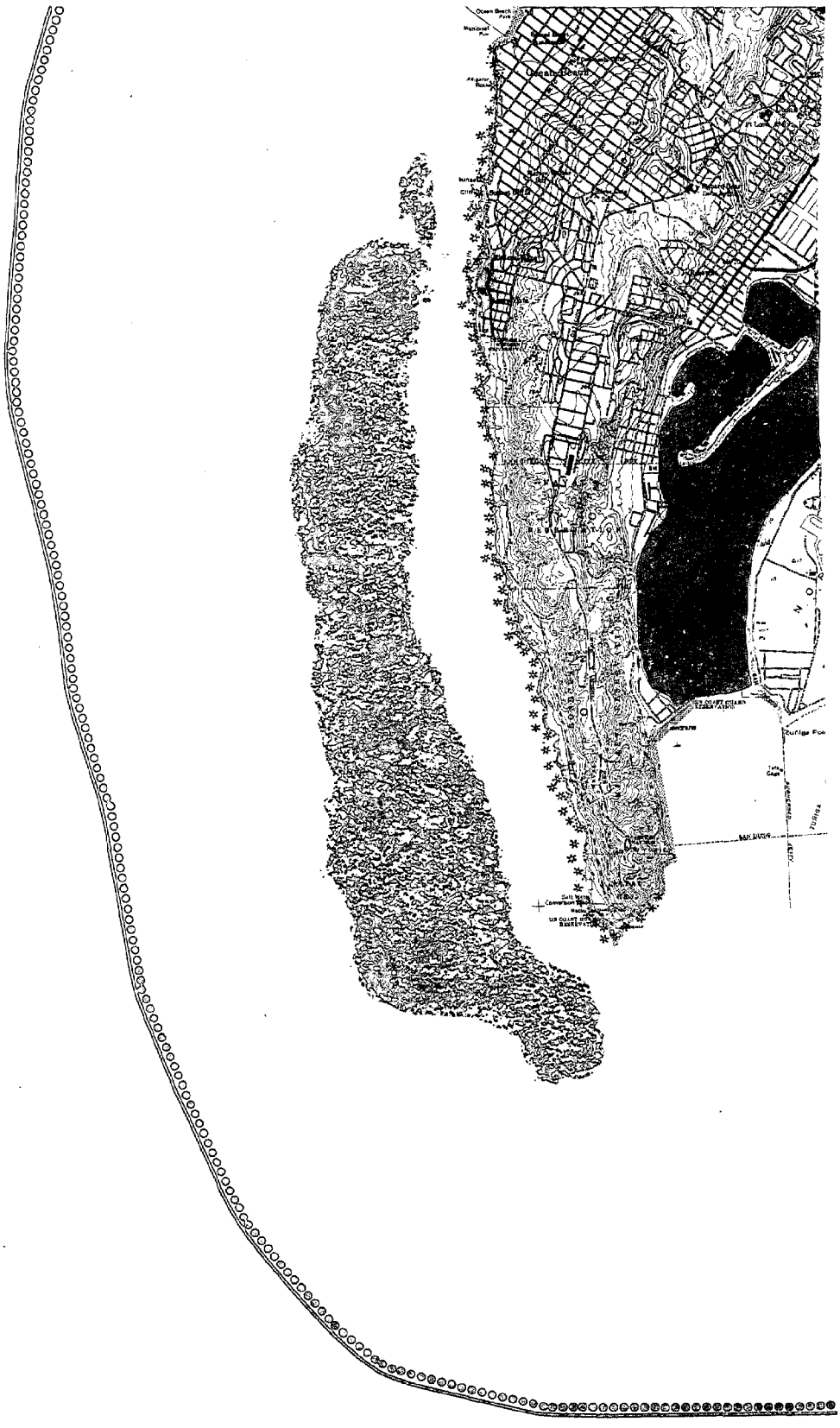
SENSITIVE RESOURCES INVENTORY

POINT LA JOLLA TO MISSION BAY

30

California Governor's Office of Planning and Research
OCS PROJECT
1977

25—76658



NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS

0 1 2 MILES

40 ACRES

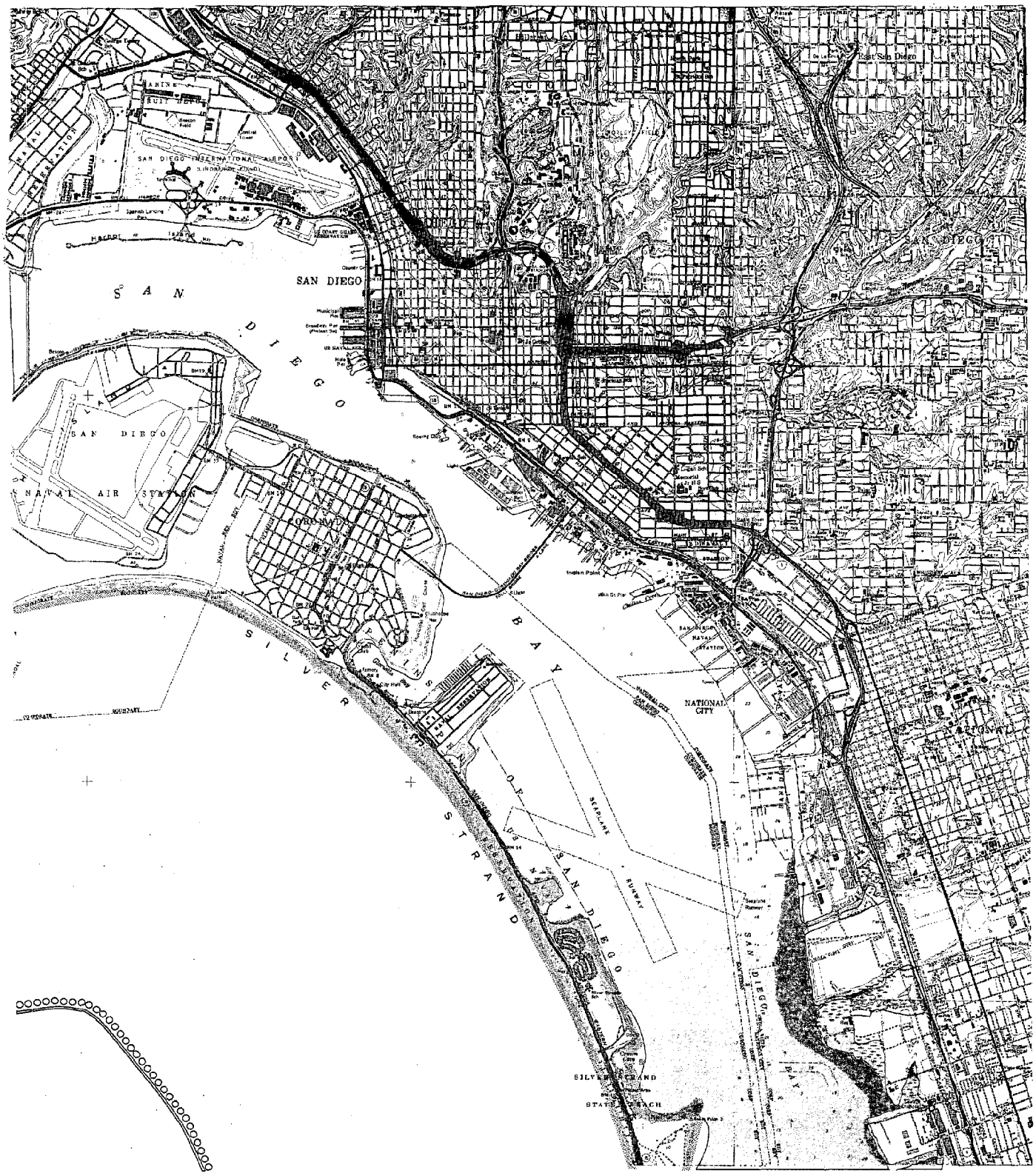
10

SENSITIVE RESOURCES INVENTORY

POINT LOMA

31

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: Rare and Endangered Species Habitats are located at the tidal flats of San Diego Bay; the endangered species are the Light-Footed Clapper Rail, the California Least Tern, and the Belding's Savannah Sparrow.

NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS 40

0 1 2 MILES 10

ACRES

SENSITIVE RESOURCES INVENTORY

SAN DIEGO

32

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: Rare and Endangered Species Habitats are located at Lower San Diego Bay and at the wetlands of the Tijuana River; the endangered species are the Light-Footed Clapper Rail, the Belding's Savannah Sparrow, the California Brown Pelican, and the California Least Tern.

NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS 40

0 1 2 MILES 10

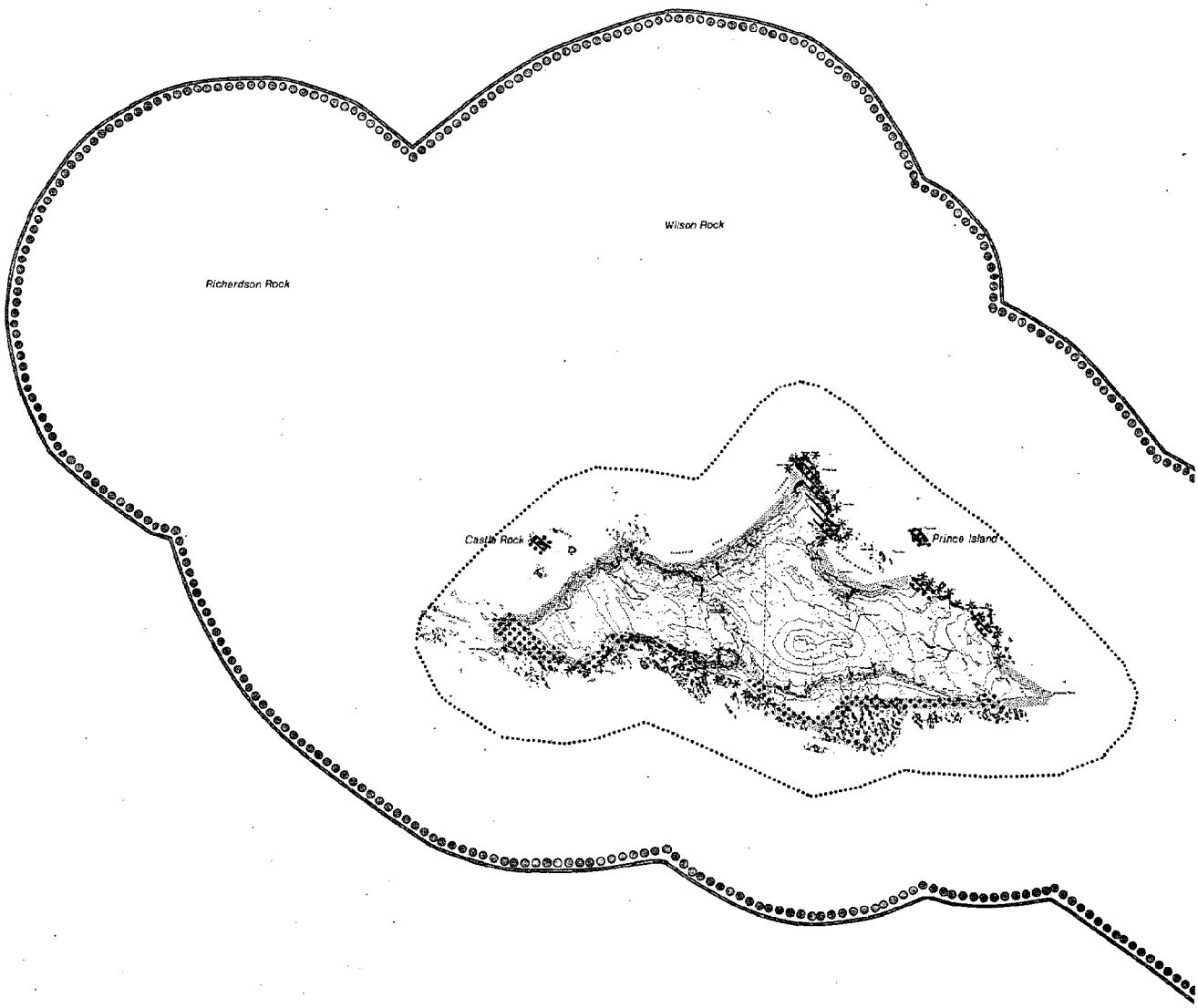
ACRES

SENSITIVE RESOURCES INVENTORY

IMPERIAL BEACH

33

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: Rare and Endangered Species habitats are located on San Miguel Island; the endangered species is the California Brown Pelican; the rare species are the Guadalupe Fur Seal and the Island Fox.

NORTH SCALE 1:165,000 CONTOUR INTERVAL: 20 FEET

0 1 2 3 5 7 KILOMETERS 160

0 1 2 3 4 5 MILES 40

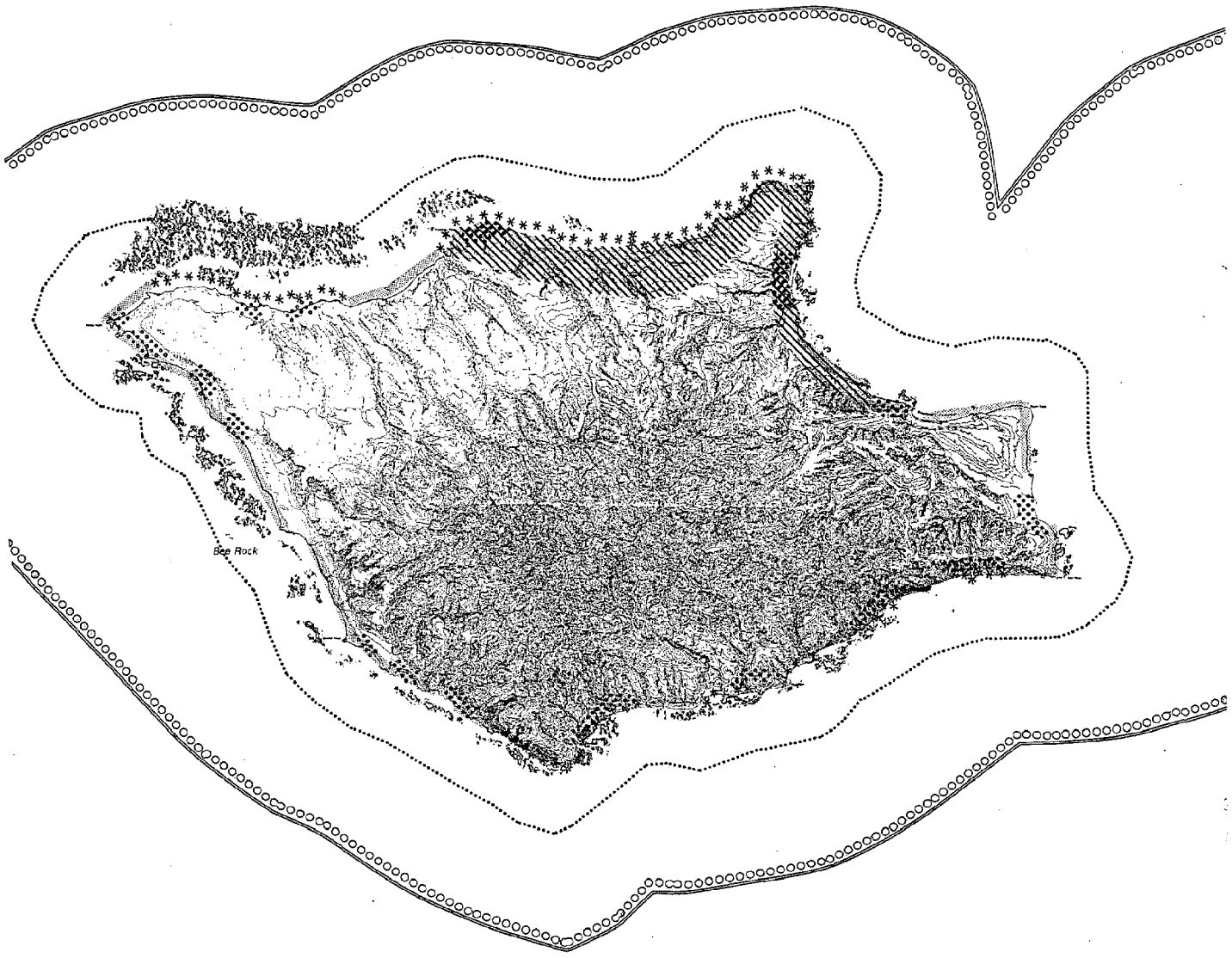
ACRES

SENSITIVE RESOURCES INVENTORY

SAN MIGUEL ISLAND

34

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: Rare and Endangered Species Habitats are located on Santa Rosa Island; the endangered species is the California Brown Pelican; the rare species is the Island Fox.

NORTH SCALE 1:165,000 CONTOUR INTERVAL: 20 FEET

0 1 2 3 5 7 KILOMETERS

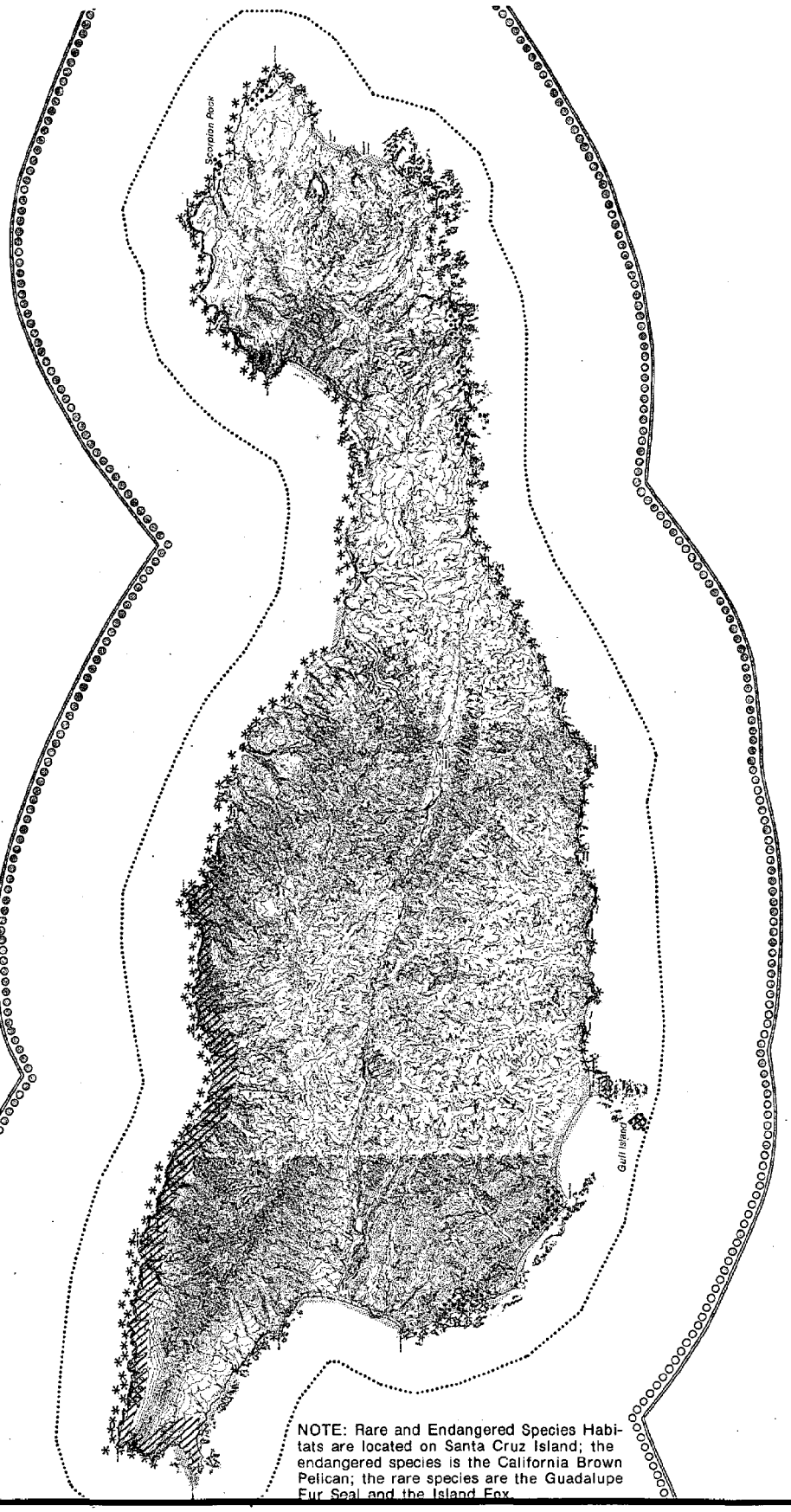
0 1 2 3 4 5 MILES

160 40 ACRES

SENSITIVE RESOURCES INVENTORY

SANTA ROSA ISLAND

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: Rare and Endangered Species Habitats are located on Santa Cruz Island; the endangered species is the California Brown Pelican; the rare species are the Guadalupe Fur Seal and the Island Fox.

NORTH SCALE 1:165,000 CONTOUR INTERVAL: 20 FEET

0 1 2 3 5 7 KILOMETERS 160

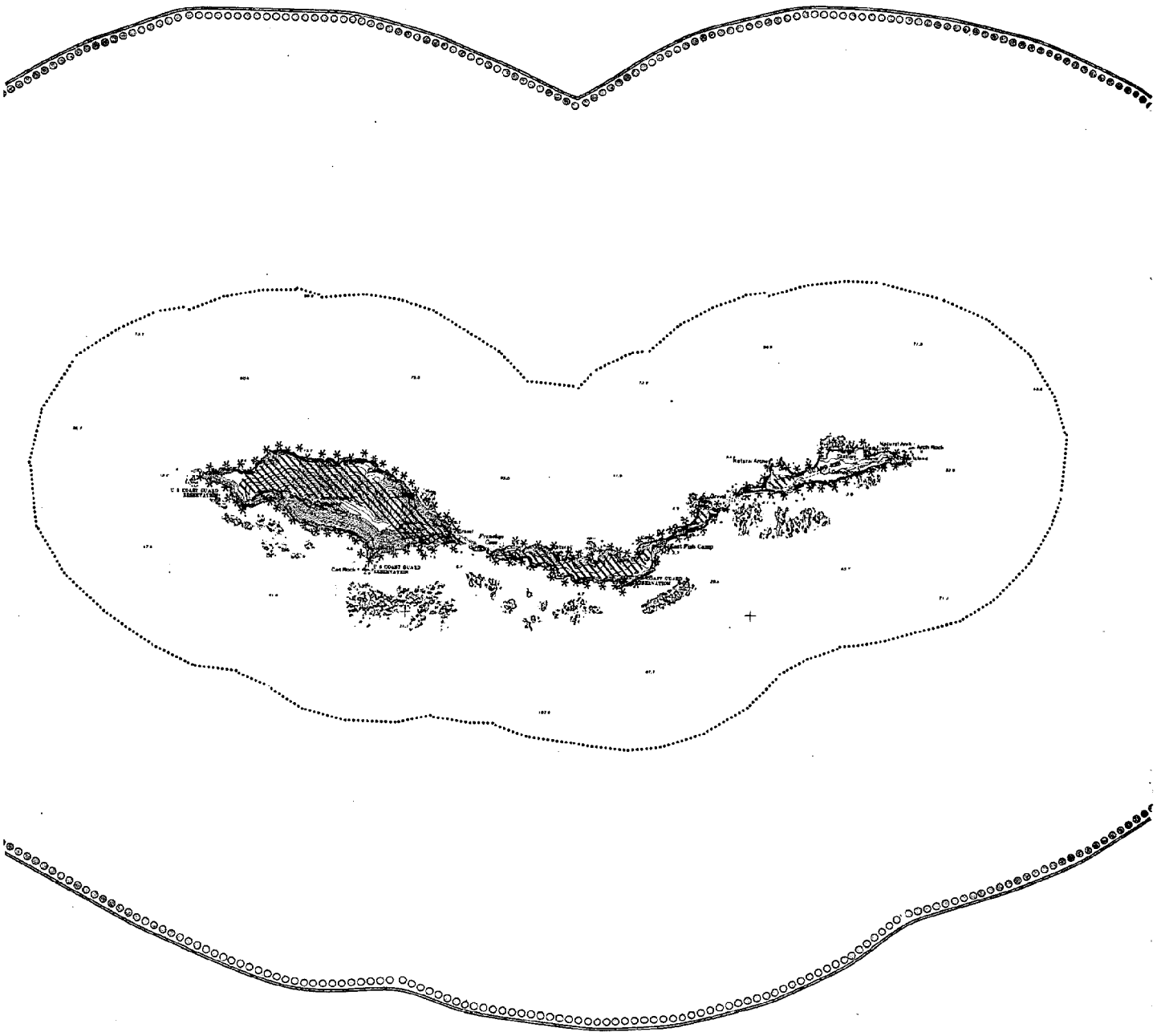
0 1 2 3 4 5 MILES 40

ACRES

SENSITIVE RESOURCES INVENTORY

SANTA CRUZ ISLAND

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: Rare and Endangered Species Habitats are located on Anacapa Island; the endangered species is the California Brown Pelican.

Anacapa Island is administered as a National Monument by the National Park Service.

NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS

0 1 2 MILES

40 ACRES

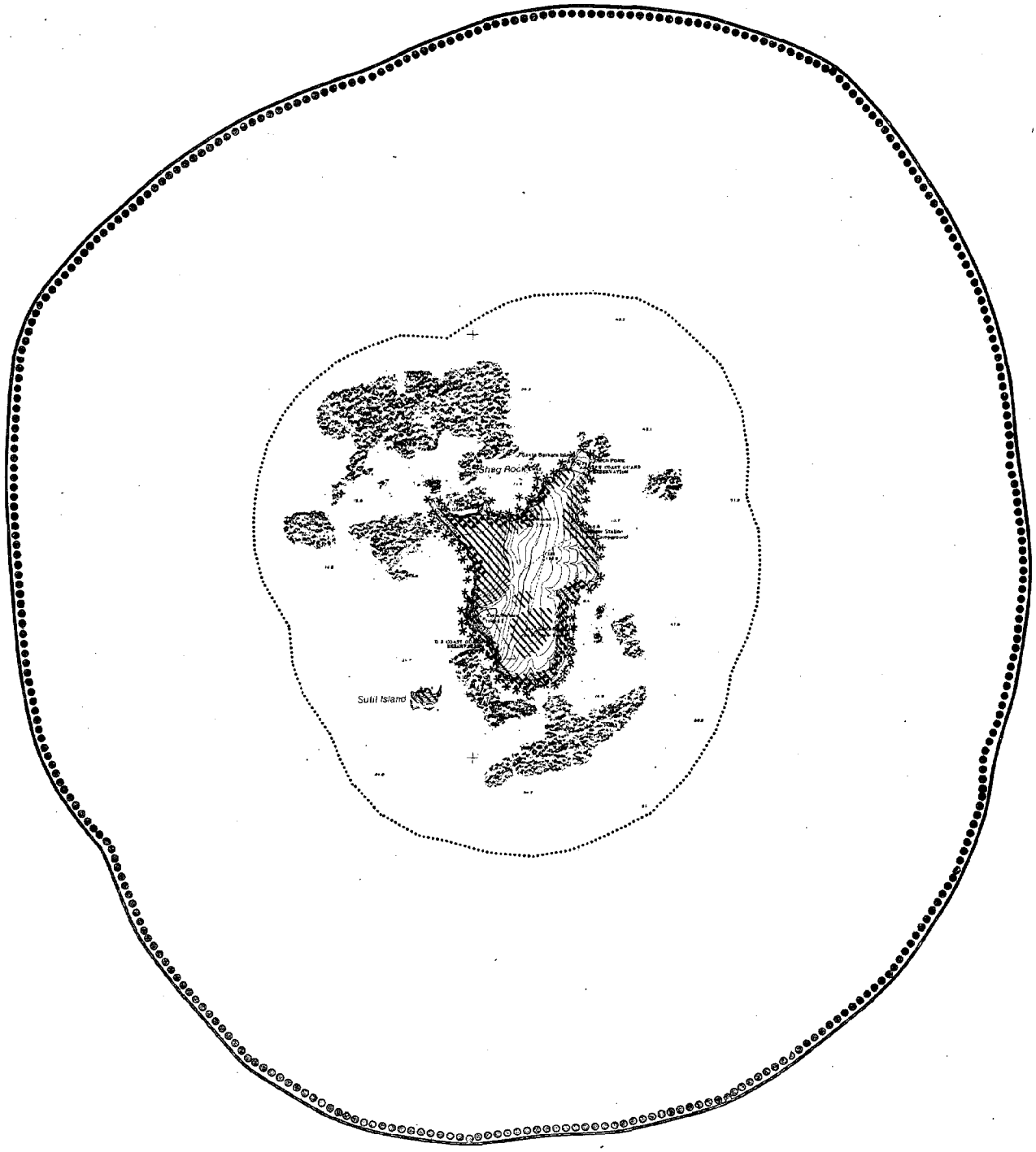
10

SENSITIVE RESOURCES INVENTORY

ANACAPA ISLAND

37

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: Santa Barbara Island is administered as a National Monument by the National Park Service.

NORTH SCALE 1:165,000 CONTOUR INTERVAL: 20 FEET

0 1 2 3 5 7 KILOMETERS 160

0 1 2 3 4 5 MILES 40

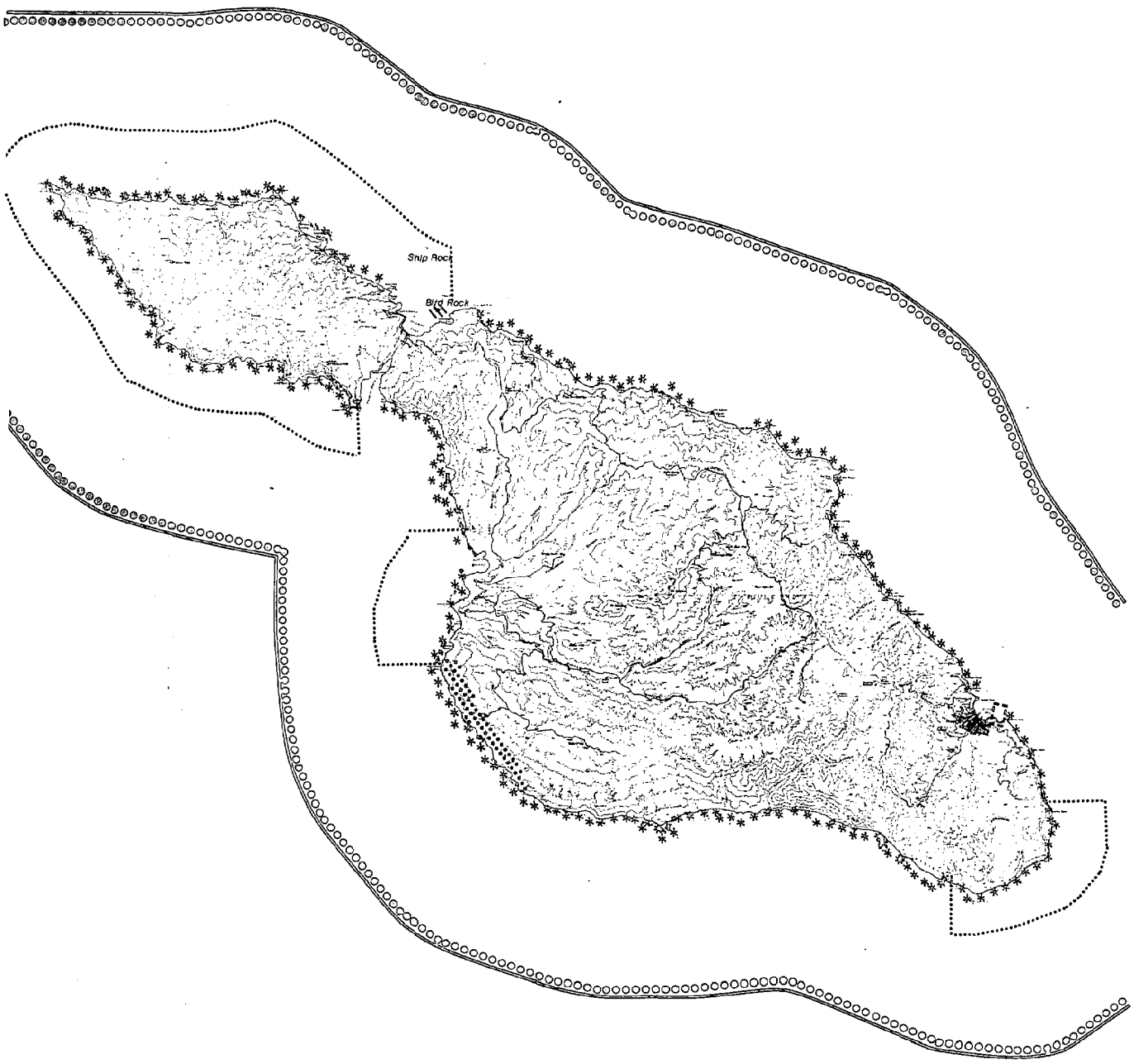
ACRES

SENSITIVE RESOURCES INVENTORY

SANTA BARBARA ISLAND

38

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: Rare and Endangered Species Habitats are located on Santa Catalina Island; the rare species are the Guadalupe Fur Seal and the Island Fox.

NORTH SCALE 1:62,500 CONTOUR INTERVAL: 20 FEET

0 1 2 3 KILOMETERS

0 1 2 MILES

40 ACRES

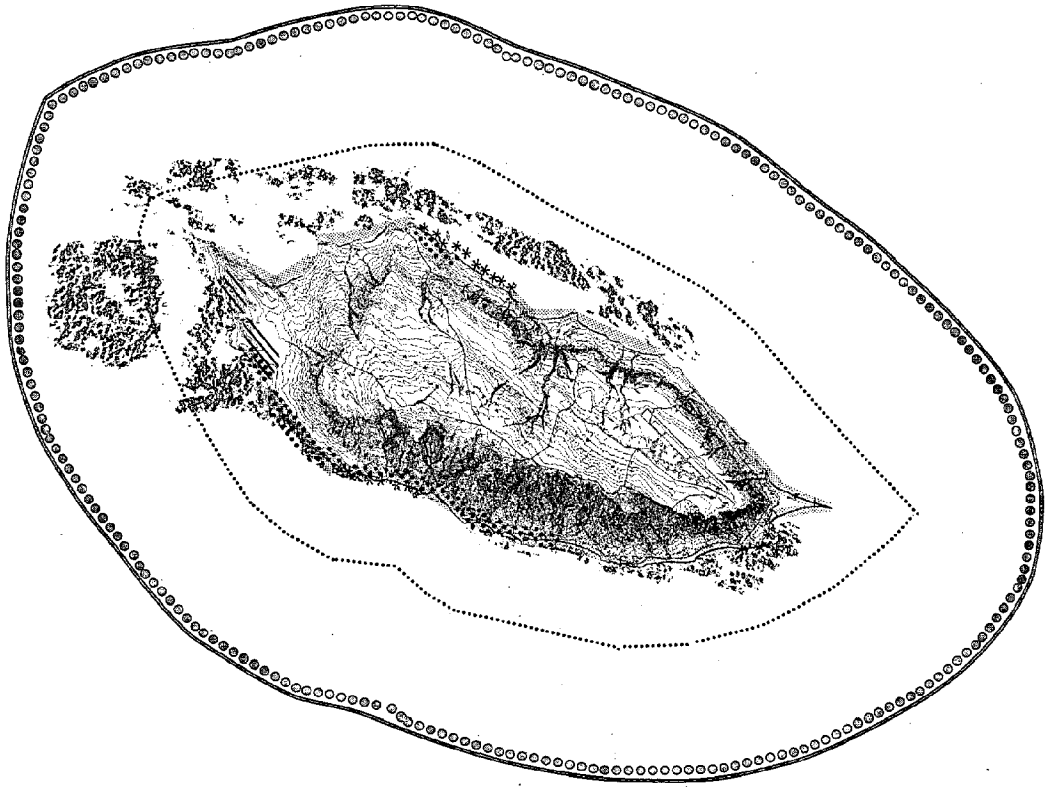
10

SENSITIVE RESOURCES INVENTORY

SANTA CATALINA ISLAND

39

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: Rare and Endangered Species Habitats are located on San Nicolas Island; the rare species is the Island Fox.

NORTH SCALE 1:165,000 CONTOUR INTERVAL: 20 FEET

0 1 2 3 5 7 KILOMETERS

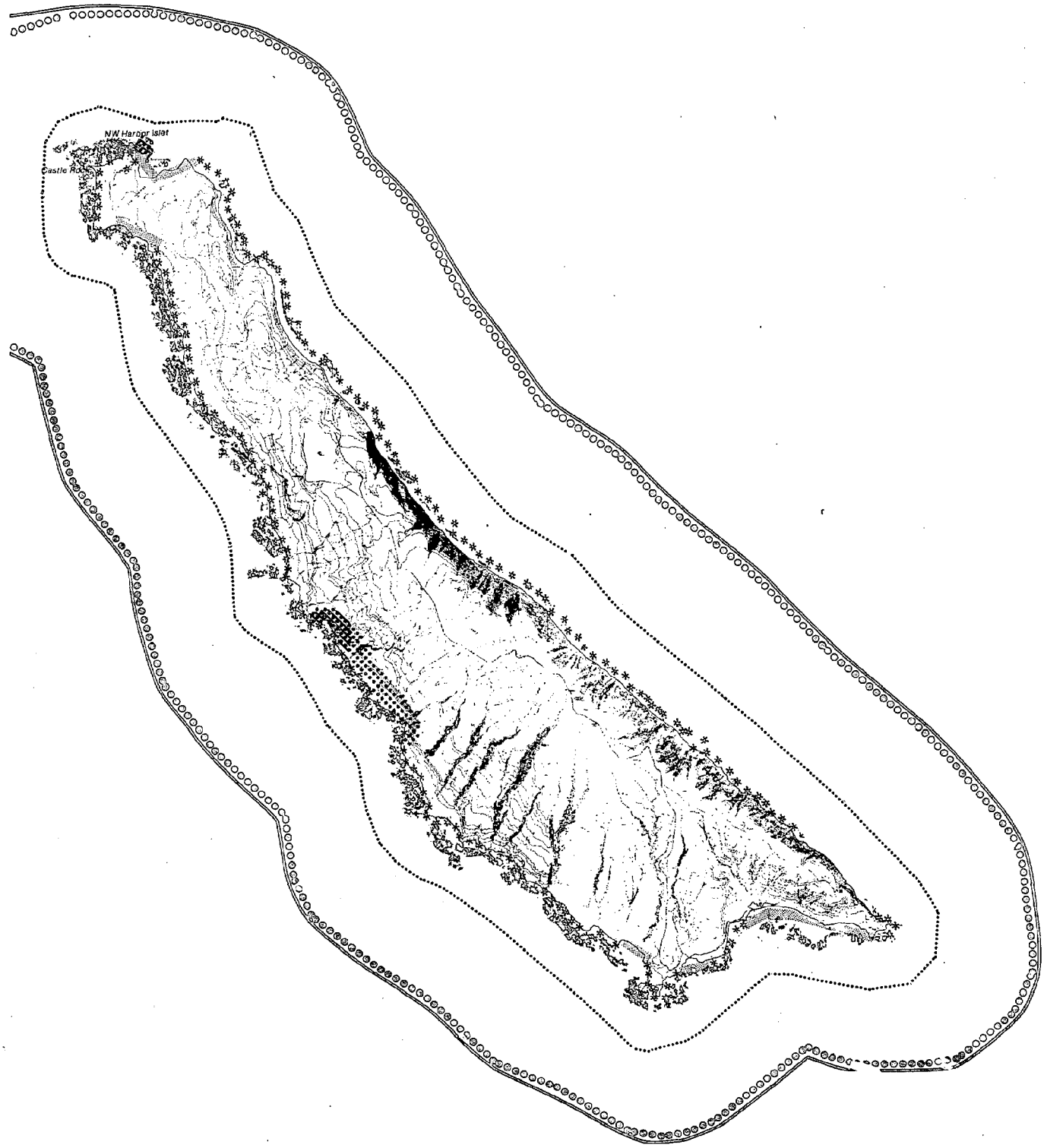
0 1 2 3 4 5 MILES

160 ACRES 40

SENSITIVE RESOURCES INVENTORY

SAN NICOLAS ISLAND

California Governor's Office of Planning and Research
OCS PROJECT
1977



NOTE: Rare and Endangered Species
Habitats are located on San Clemente Island;
the rare species are the Guadalupe Fur Seal
and the Island Fox.

NORTH SCALE 1:165,000 CONTOUR INTERVAL: 20 FEET
0 1 2 3 5 7 KILOMETERS 160
0 1 2 3 4 5 MILES 40
ACRES

SENSITIVE RESOURCES INVENTORY

SAN CLEMENTE ISLAND

41

California Governor's
Office of Planning and Research
OCS PROJECT
1977

FOOTNOTES

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2. U.S. Bureau of Land Management, Final Environmental Statement, OCS Sale #35, 1975.

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9. Marine Mammal Commission, memo to Mr. C. Berklund, Bureau of Land Management, re: Comments on Leasing in the Outer Continental Shelf -- Offshore California September 8, 1976.

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26. Lindstedt-Siva, op. cit.

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30. Personal communication, from Dr. Gilbert Jones, to Carol Pillsbury, OCS Project Staff, April 20, 1977. See also Smith, op. cit.

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32. U.S. Bureau of Land Management, op. cit.

33. Federal Register, #176, 40 (September 10, 1975), p. 42039.

34. U.S. Department of the Interior, Fish and Wildlife Service, op. cit.

35. J. Hendrickson, "Ecology of Southern California Coastal Salt Marshes," Proceedings of the Symposium on Plant Communities of Southern California, J. Latting, ed., California Native Plant Society, Special Publication No. 2, p. 49.

36. California Coastal Zone Conservation Commission, California Coastal Plan, 1975; R. D. Bauer and J. W. Speth, Acquisition Priorities for the Coastal Wetlands of California, 1974; California Department of Fish and Game, Status Report on the Coastal Wetlands of Southern California, 1969; and California Department of Fish and Game, Draft Atlas of Prominent Southern California Marine Resources, 1976.

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41. U.S. Bureau of Land Management, op. cit.

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43. Lindstedt-Siva, op. cit.

43a. U.S. Bureau of Land Management, op. cit.

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58a. U.S. Bureau of Land Management, op. cit.

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66. Personal communication from Robert Bell, California Department of Fish and Game, to Carol Pillsbury, OCS Project Staff, April 14, 1977.

67. California Department of Fish and Game, Draft Atlas, op. cit.

68. Ibid.

69. Personal communication from Robert Bell, California Department of Fish and Game, to Carol Pillsbury, OCS Project Staff, April 14, 1977.

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71. 16 U.S.C. 1.

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CHAPTER 17

OIL SPILL: PREDICTING THE UNPREDICTABLE

SOURCES OF OIL IN OCEAN WATERS

Oil spills from offshore production activities are only one of many pathways for petroleum hydrocarbons into the oceans. The National Academy of Sciences (NAS) has estimated that more than six million metric tons of oil per year enter the world oceans from all sources. 1/ Table 1, below, is taken from the NAS study to show the relative amounts of petroleum that enter the oceans each year. From Table 1, it can be seen that, on a worldwide basis, non-marine sources -- river and urban runoff from developed or industrial areas on land, atmospheric rainout -- are estimated by NAS to contribute more than half (54%) of the oil reaching the oceans. Tankers are the largest marine source (34.9%), with natural seeps contributing an estimated 9.8% and offshore production only 1.3%. Thus, in terms of the overall budget for oil entering the oceans, oil spilled in the course of offshore operations contributes only a small fraction of the total load.

TABLE 1:
GLOBAL BUDGET FOR PETROLEUM ENTERING THE OCEANS 2/

SOURCE	MILLION METRIC TONS PER ANNUM	PERCENTAGE CONTRIBUTIONS
Transportation Tankers, dry docking, terminal operation, bilges, accidents	2.133	34.9
Coastal refineries, municipal and industrial waste	0.8	13.1
Offshore oil productions	0.08	1.3
River and urban runoff	1.9	31.1
Atmospheric fallout	0.6	9.8
Natural seeps	0.6	9.8
Total	6.113	100.0

But oil entering the oceans from land sources, whether through river runoff, atmospheric transport, or outfall pipes, is diluted before it reaches the ocean and rapidly disperses once in the ocean, greatly reducing its impact on the concentration of petroleum hydrocarbons in any particular coastal or marine area. Oil spills, in contrast, create heavy concentrations of oil in comparatively small areas. The dosage or concentration of oil strongly influences the effects of oil on coastal and marine resources. For this reason, offshore oil spills -- despite their relatively small contribution to the total petroleum load -- are a major part of the oil pollution problem.

Table 1 provides a useful perspective on worldwide oil pollution sources. In the waters off southern California, however, the percentage contribution from each source may be quite different. For example, there is relatively little rainfall and therefore little river runoff in southern California, so the contribution from this source is doubtless well below the 31% noted globally. On the other hand, much of the coastal zone in southern California is heavily developed, and the Los Angeles basin has about 1,200,000 B/D refining capacity, so here the percentage contribution from coastal refineries and municipal and industrial wastes is probably greater than the worldwide 13.1%. As for the contribution from offshore production activities, 1.3% may be a reasonable worldwide estimate, but in those very few areas of the world where offshore production occurs, such as southern California, Texas, and Louisiana, the contribution from this source is apt to be considerably greater than the worldwide average. Similarly, the contribution from natural seeps in the Santa Barbara Channel may be greater than 9.8%, while in the rest of southern California the percentage contribution from natural seeps may be below the estimated international average.

SOURCES OF OIL IN SOUTHERN CALIFORNIA COASTAL WATERS

Table 2 presents statistics on oil spills occurring in Coast Guard District 11 (from the Mexican border to the Santa Barbara/San Luis Obispo County border) during 1973-1975.

TABLE 2:
COAST GUARD DISTRICT 11 OIL SPILLS, BY SOURCE, 1973-1975
(VOLUME IN GALLONS) 3/

	1973		1974		1975	
	Number	Volume	Number	Volume	Number	Volume
Total	820	154,826	803	899,851	809	243,289
Tankers	131	8,826	76	22,001	47	93,719
Barges	13	64	10	310	3	21
Other Vessels	228	8,213	226	16,730	243	13,625
Marine Terminals	29	9,085	28	1,386	18	439
Other Transportation (Trucks, Trains, etc.)	11	16,707	21	101,349	28	24,305
Pipelines	15	24,813	36	740,899	24	47,345
Non-Transportation (Tank Farms, etc.)	46	76,195	39	13,730	58	60,299
Miscellaneous/Unknown	347	10,946	367	3,446	388	3,536

The number of spills reported to the Coast Guard declined slightly from 1973 to 1975, while the amount of oil spilled increased substantially. Table 3 compares the relative contribution of each source with respect to the number and volume of reported spills.

TABLE 3:
COMPARISON OF SOURCES, COAST GUARD DISTRICT 11 OIL SPILLS, 1973-1975 4/

SOURCE	NUMBER OF POLLUTING INCIDENTS	PERCENTAGE OF TOTAL	VOLUME (GALLONS) OF OIL SPILLED	PERCENTAGE OF TOTAL
Tankers	254	10%	124,546	10%
Barges	26	1%	395	1%
Other Vessels	697	29%	38,568	3%
Marine Terminals	75	3%	10,910	1%
Pipelines	75	3%	813,057	63%
Other Transportation	60	2%	142,361	11%
Non-Transportation	143	6%	150,224	12%
Miscellaneous/Unknown	1,102	45%	17,928	1%

Several general observations should be made about oil spill statistics. 5/ The amount of oil spilled in any incident can vary tremendously, from less than one gallon to more than ten million gallons. Because of this variation, it is not always helpful to discuss average spill size. Most spills involve comparatively small volumes of oil. For example, spills from "other vessels" and "miscellaneous/unknown" sources accounted for 74% of the number of spills reported in District 11 during that period but only 4% of the volume of oil spilled. Most of the oil spilled during any reporting period comes from a handful of very large spills. For example, one pipeline spill in 1974 accounted for 55% of the total volume of oil estimated to have been spilled in District 11 during the entire 1973-1975 period. If this pipeline spill hadn't occurred, the percentage contributions in terms of volume of oil spilled would be markedly different. Conversely, if either the 1969 Santa Barbara Channel blowout or the 1976 Sansinena tanker spills had occurred during the 1973-1975 period, both the overall totals and the percentage contributions of each category would be markedly different.

With respect to the causes of oil spills, Table 4 presents Coast Guard data for all reported spills on the West Coast during 1973-1975. For the spills with known causes, human error accounted for the largest numbers. Likewise, many of the spills attributed to other causes -- such as equipment failure, structural failure, vessel collisions, and vessel groundings -- also stem from human error through poor maintenance, improper use or operation, etc.

Of particular concern to this study are the sources of oil spills that involve the development of oil and gas offshore of southern California. The most significant causes of spilled oil resulting from offshore development include production platforms, pipelines, tankers and crude oil transfer operations. These sources of spilled oil are discussed below. In addition, the relative contribution of oil in southern California coastal waters caused by natural seeps is also described.

TABLE 4:
CAUSES OF WEST COAST OIL SPILLS, 1973-1975 6/

Cause	Number of Spills	Percent of Total Number of Reported Spills	Volume Spilled (Gallons)	Percent of Total Volume of Reported Spills
Unknown	2,975	48%	204,000	5%
Personnel Errors	1,370	22%	212,100	5.5%
Equipment Failures	885	14%	1,260,000	33%
Structural Failures	460	6.5%	832,300	22%
Intentional Discharges	260	4%	35,500	1%
Natural and Chronic Causes	215	3.5%	8,000	1%
Vessel Collisions	40	1%	1,156,000	30%
Vessel Groundings	20	1%	105,000	3%

PRODUCTION PLATFORMS

The potential for major platform spills, especially from a blowout, is greatest during drilling operations. A blowout occurs when a well is drilled into a zone of unexpected high pressure, and platform safeguards are unable to prevent oil from escaping to the surface. If the well casing is inadequate, and the strata between the high pressure zone and the ocean floor are weak and fractured, as was the case in the 1969 Santa Barbara Channel blowout, oil may continue to escape to the ocean after the well is again under control. (The amount of oil spilled during the 1969 blowout is disputed, with estimates ranging from 10,000 to over 700,000 barrels. 7/). Aside from blowouts, major spills can occur at platforms as a result of fires, explosions, vessel rammings, or other accidents.

Once production has been achieved at a platform, minor spills can occur at any time. The incidence of production spillage depends both on the care of platform operators and the diligence of government inspectors. A report on Chevron's 1970 spill in the Gulf of Mexico described the situation at that time:

> Spills varying in size from a few gallons to many barrels are endemic to the Gulf of Mexico.... Oil appears on the Gulf waters from...numerous operations connected with the drilling (and) operations of the wells. U.S. Coast Guard's reconnaissance flights report three to seven pollution incidents every week, and many of these identify with the company or individual responsible. However, the cause of each incident is not generally documented, and action to prevent a recurrence is not often taken. 8/

Since 1970, USGS has strengthened its spill-prevention regulations and enforcement standards. As a consequence, the number of spills in the Gulf of Mexico has dropped significantly in recent years. 9/

Based on historical spill data, Massachusetts Institute of Technology scientists have calculated 10/ that for a small oil field (defined by MIT as containing 122 MMB recoverable oil), there is a 25% chance that at least one platform spill larger than 1,000 barrels will occur; that for a medium oil field (567 MMB recoverable oil), the probability is 70%; and that for a large oil field (2,044 MMB recoverable oil), the probability is over 95%. Further, the MIT scientists calculated that if a platform spill of over 1,000 barrels occurs, there is an 80% chance that the spill will exceed 2,380 barrels, and a 35% chance that it will exceed 23,800 barrels. 11/ It should be noted that these predictions do not allow for improvements in drilling procedures or technologies, but merely extrapolate into the future on the basis of historic spill rates.

PIPELINES

All of the crude oil produced off California is brought ashore through pipelines. Pipeline accidents -- leaks, ruptures, etc. -- can result in minor or major oil spills. Most pipeline spills are very small. For example, the average size of the 1,643 pipeline spills occurring in the United States in 1971 was less than ten barrels. 12/ On the other hand, the largest U.S. pipeline spill recorded to date, in the Gulf of Mexico in 1967, discharged 161,000 barrels over ten days. 13/ The only crude oil spill resulting from a pipeline serving production platforms off California occurred on December 16, 1969, at Union's Platform A, site of the blowout earlier that year, with 900 barrels spilled before the line could be shut down and repaired. 14/ The pipeline spills shown in Table 2, preceding, for 1973, 1974 and 1975 occurred onshore and made their way into harbor waters.

TANKERS

About 400,000 B/D of foreign crude oil are delivered by tankers at southern California terminals. 15/ As well, much smaller amounts of crude produced from Santa Barbara Channel tidelands leases are carried by tanker to Los Angeles Basin and San Francisco Bay terminals. The relationship between tanker spills, tanker arrivals, and the volume of petroleum delivered at southern California ports and terminals is illustrated in Table 5.

Oil spillage occurs routinely during tanker operations. Of the oil estimated by the National Academy of Sciences to be discharged from tankers at sea or at terminals, only 16% was spilled during accidents, while 84% was spilled during careless terminal operations or the deliberate discharge of oiled ballast water. 17/ Major tanker spills usually result from accidents -- collisions, rammings, groundings, fires, or explosions. The two major spills of petroleum products in California waters were the 1971 collision between the tankers Oregon Standard and Arizona Standard in the entrance to San Francisco Bay and the 1976 Sansinena explosion in Los Angeles Harbor. Each resulted in spills of about 20,000 barrels of Bunker C oil.

Vessels other than bulk oil carriers contribute frequent small-volume spills. In Coast Guard District 11 during 1973-1975, such vessels accounted for 29% of the reported spills with known sources, but for only 3% of the total volume of oil spilled during that time period (see Table 3). These spills usually involve petroleum products rather than crude oil.

TABLE 5:
TANKER SPILLS VS. TANKER ARRIVALS AND VOLUME TRANSFERRED,
SOUTHERN CALIFORNIA, 1973-1975 16/

Port or Terminal	Percent of Annual Average West Coast Volume of Crude Oil & Petroleum Product Handled at Ports (1973-1975)	Percent of Annual Average West Coast Tanker Arrivals (1973-1975)	Percent of 1975 West Coast Tanker Spills
Los Angeles Harbor	17.2%	16.7%	18.5%
Long Beach Harbor	14.9%	10.2%	11.3%
El Segundo/ Santa Monica Bay Terminals	7.5%	6.2%	2.0%
Ventura Harbor	1.5%	1.9%	0
Encina Terminal	1.1%	0.8%	0
Port Hueneme	1.0%	1.2%	1.0%
San Diego	0.6%	1.1%	1.0%
Carpinteria/ Santa Barbara Area Terminals	0.4%	0.7%	1.0%
Huntington Beach	0.2%	0.2%	0

TRANSFER OPERATIONS

Transfers may be conducted between production platform and vessel (as Exxon intends to do with its initial Santa Ynez Unit production), between vessel and vessel (as do Chevron and Shell near San Clemente Island by lightering mid-East crude from very large crude carriers, VLCCs, to small tankers capable of entering California ports), or between vessels and terminals (as performed at 21 marine terminals in southern California). Oil spills may occur during any of these transfer operations.

NATURAL SEEPS

Natural seeps are a source of chronic small-volume spillage in southern California waters, especially in the Santa Barbara Channel where more than 2,000 seeps have been identified. Estimates of seepage rates in the entire Channel range from 40 to 670 barrels per day. 19/ Surveys conducted in 1958 and 1960 reported more than 100 pounds oil/1,000 square feet on some Channel beaches. Similar surveys conducted in 1974-1976 found less than 10 pounds oil/1,000 square feet at most sites. One study of historic seepage data has concluded that the areal extent of active seeps in the Channel is 20% smaller in 1976 than it was in 1946. While much remains to be learned about natural seep phenomena, these examples suggest that natural seepage activity in the Channel has declined in recent years. 20/

Seepage activity in the Channel may be influenced by offshore production activity, but existing evidence is inconclusive. It may be that the reduction in reservoir pressures caused by oil production is reducing seepage rates. This seems to be the case at Union's Platform A, where seepage rates rose sharply when production wells were suspended at the time of the December, 1969 spill. 21/

On the other hand, Union's drilling practices led to the formation of several of the existing Platform A seeps in the first place. Further, it has been suggested that some of the "natural" seeps in the Channel are actually oil wells which were not properly abandoned. 22/ The State Lands Division is conducting research on natural seeps and the potential relationships between seepage rates and offshore oil operations, and will submit its findings to the legislature by January 1, 1978.

FUTURE OIL SPILLS IN SOUTHERN CALIFORNIA COASTAL WATERS

Since the Torrey Canyon and Santa Barbara Channel oil spills in the late 1960s, both the oil industry and the U.S. Geological Survey have taken steps to prevent or reduce oil spillage. Although reliable statistics are not available for the years preceding 1970, it is likely that fewer small-volume spills are occurring now than was the case before 1970. In the Gulf of Mexico, for example, USGS reports that the amount of oil spilled at production facilities in spills of 50 barrels or less declined by 52% between 1971 and 1975 (Table 6).

TABLE 6:
VOLUME OF OIL SPILLED, GULF OF MEXICO OCS, 1971-1975 23/

Year	Total Volume Spill 50 BBL	Total Volume Spill 50 BBL	Total Volume All Spills
1971	1,493	1,285	2,778
1972	1,032	150	1,182
1973	921	22,175	23,096
1974	667	22,721	23,388
1975	711	266	977

USGS attributes this decline to changes in the operating philosophy of the offshore producers, tougher USGS operating orders, and a substantial increase in the USGS inspection force. Off California, there have been no recorded spills from OCS tidelands or production platforms or pipelines since December, 1969. This suggests that effective steps can be and have been taken to prevent the more easily prevented spills from occurring in the course of offshore production operations.

Through technological advances, improved operating procedures, and more stringent enforcement of pollution control regulations, it is possible to reduce the likelihood of oil spills. 24/ Unfortunately, the primary causes of oil spillage -- accident and human error -- cannot be eliminated. In the Gulf of Mexico, during the 1971-1975 period when small spills were reduced by 50%, five major spills (1,000 barrels) occurred. There will probably be more major spills there in the future.

All of the offshore oil-related facilities or activities with spill potential -- production platforms, drilling rigs, pipelines, tankers, and terminals -- will increase, either in number or in volume of oil handled, in the waters off California. The scale of conflict between these separate activities is also increasing. Drilling rigs are now operating on San Pedro Bay

and Santa Barbara Channel leases within either the vessel traffic lanes themselves or the separation zone between traffic lanes. Two of the fields discovered in the Santa Barbara Channel OCS lie under the northbound vessel lane and the recent discovery in San Pedro Bay falls within both north and southbound areas. These conflicts further increase the chances of oil spillage beyond the potential associated with each separate activity or facility.

The probability of a major spill occurring off California, or anywhere else, at any given time from any particular source is very small. Still, there has been one major tanker spill and one major platform spill off southern California in the last eight years. That there have been major spills in the past proves that major spills can occur off California. The increase in offshore oil-related activities with oil-spill potential enhances the probability that another major oil spill will occur.

In its Environmental Impact Statement on Lease Sale #35, BLM predicted that "a major spill will ultimately occur and many minor spills will occur" as a result of the lease sale. 25/ Considering the 56 OCS leases sold in Lease Sale #35, the 65 active leases in the Santa Barbara Channel OCS, the 200,000 B/D oil now produced off southern California, the 400,000 B/D foreign crude oil now delivered to southern California together with the prospect of additional crude oil from Alaska, Elk Hills, and proposed Lease Sale #48, we believe that at least one major oil spill and numerous minor spills are likely to occur off California in the future.

FATE OF SPILLED OIL IN THE MARINE ENVIRONMENT

Spilled oil undergoes various transformations, some physical, some chemical, and some biological, when it enters the marine environment. Of these several kinds of transfer, briefly considered in this section, the most important is the movement of the spilled oil through the action of wind and water currents. This movement is also of most significance in terms of human response, and is therefore considered in greater detail in the following section, Trajectories.

Most crude oils and petroleum products have a lower specific gravity than sea water and will therefore float when spilled onto water. Spilled oil spreads out after release, and an oil slick will increase in size until the spreading and retarding forces acting on the oil are in equilibrium. If left alone, the original slick is likely to separate after several days into discrete patches of oil several millimeters thick surrounded by larger areas covered by thinner film of oil.

Oil slicks move readily under the influence of winds and water currents. In the absence of water currents, a slick will move generally downwind at about 3.5% of the wind speed. If winds and water currents are both present, slick movement can be estimated by combining the water current vector (direction and speed) and wind vector (direction and 3.5% of speed).

Immediately after a spill occurs, natural forces begin to transfer oil from the surface slick into all components of marine environment -- the atmo-

sphere, water column, sediments, and inhabitants (Figure 1). Evaporation, wind-generated sea spray, and bubbles bursting through the slick all act to transfer oil into the atmosphere. It has been estimated that evaporation can remove as much as 50% of the hydrocarbons over the lifetime of an "average" crude oil slick. 26/ The volatility and solubility of petroleum hydrocarbons are both inversely proportional to molecular weight, so that evaporation and dissolution primarily affect the lighter hydrocarbons. 27/

Oil is also removed from the water surface by adsorption and absorption onto non-buoyant particles, such as silts, clays, and organic debris. For example, a severe rainstorm occurred shortly after the start of the 1969 Santa Barbara Channel blowout. The heavy runoff caused by this rain carried unusually large amounts of suspended sediments into the Channel, which in turn carried substantial quantities of the spilled oil with them into the Channel sediments. Within four months after its onset, oil from the blowout was found to be present in sediments throughout much of the Channel. 28/ Once in the sediments, petroleum hydrocarbons can persist for years. 29/ Finally, wind and wave forces may drive floating oil into either of two kinds of emulsions: water-in-oil (like butter) or oil-in-water (like milk). Water-in-oil emulsions are more viscous, less readily dispersed, and slower to be degraded than oil-in-water emulsions.

Microbial organisms begin to degrade oil as soon as it is spilled, but the rates of degradation for different petroleum fractions vary widely. 30/ The petroleum fractions most readily attacked by bacteria -- paraffins and alkanes -- are also the least toxic. The highly toxic aromatics are attacked much more slowly. 31/ Larger organisms take up petroleum hydrocarbons through respiratory or digestive surfaces. Once inside the organism, petroleum hydrocarbons may be metabolized, stored unaltered in tissue, or eliminated without substantial modification. When placed in unpolluted sea water, some organisms can cleanse themselves of many, but not all, petroleum hydrocarbons. Petroleum hydrocarbons do not appear to increase in concentration at successively higher levels of the food web. 31a/

OIL SPILL TRAJECTORIES

Oil spill trajectory analyses serve two useful purposes. In terms of risk analysis, they provide better advance knowledge of the potential consequences of offshore development proposals, OCS leasing decisions, the siting of new marine oil terminals, etc. For existing offshore activities with oil spill potential -- production platforms, offshore storage and transfer facilities, etc. -- such analyses assist contingency planning and the positioning of cleanup equipment to permit faster response and to provide better protection for threatened shoreline areas.

An oil spill trajectory model is simply a mathematical formula which expresses the separate contributions of wind and water currents to the movement of an oil slick. To simulate or predict oil spill trajectories in a given area, one selects representative wind and water current velocities and directions from data available for the study area, chooses initial spill sites, and then moves the slick around according to the formula and the wind and water current values used. With the assistance of a computer, it is possible to simulate hundreds of trajectories from a given spill site in a brief time. In theory, if not always in practice, such repetition helps identify the range of possible trajectories -- and thus the coastal areas at risk -- and permits an estimate of possible trajectories -- and thus the coastal areas at risk -- and permits an estimate of the probability of a slick following any given path or coming ashore at any given location.

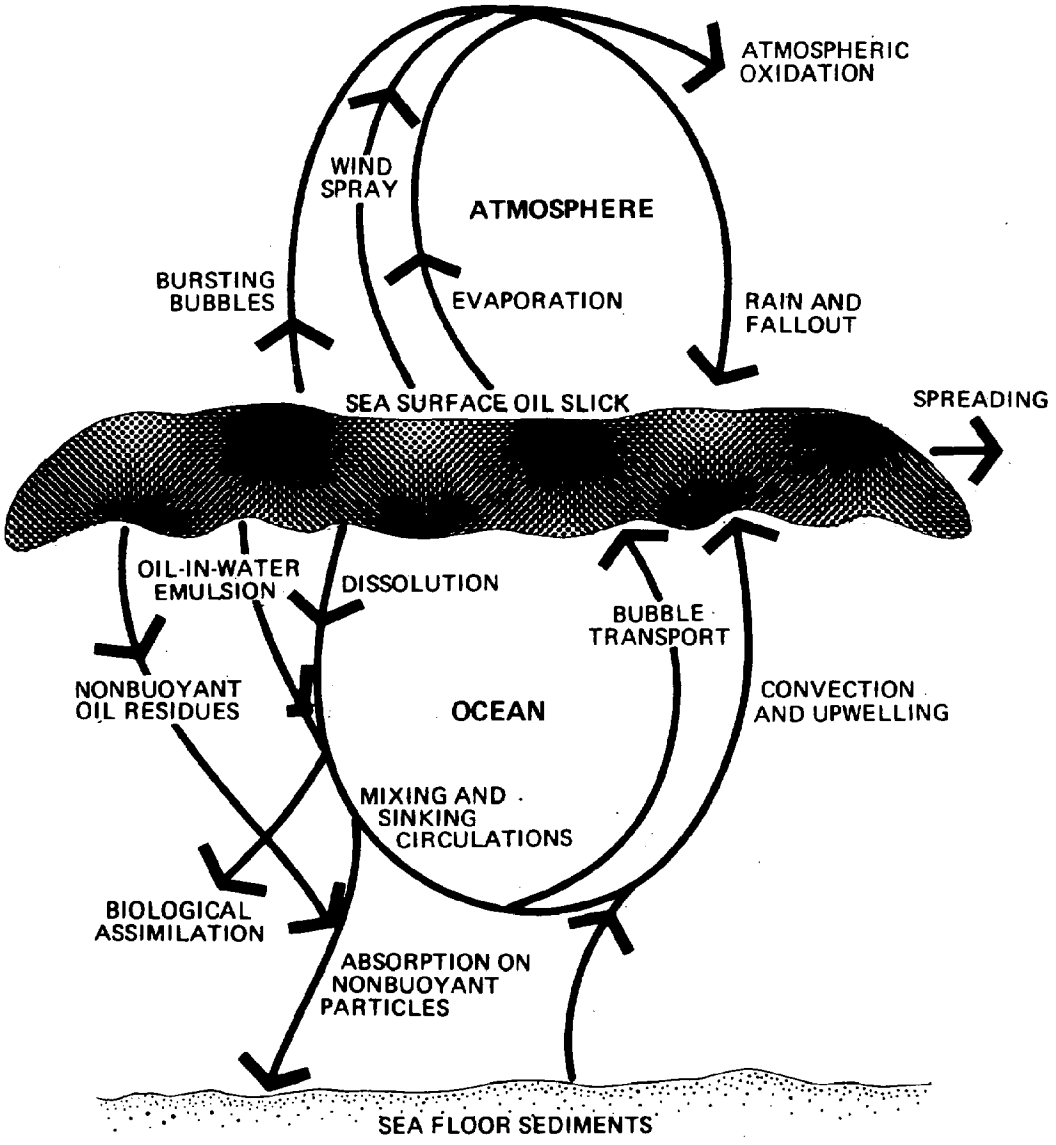


Figure 1: NATURAL FORCES WHICH DISPERSE AND DEGRADE OIL SLICKS ON WATER

Source: William D. Garrett, "Impact of Petroleum Spills on the Chemical and Physical of the Air-Sea Interface," Santa Barbara Oil Symposium: Offshore Petroleum Production, An Environmental Inquiry, December, 1970, p. 91.

It is important to recognize both the strengths and the weaknesses of these trajectory studies. The forces and processes influencing slick movement are complex, variable, and not entirely understood. To conduct a spill trajectory model which completely and accurately characterizes all these variables defies current data and methodology. Of necessity, therefore, all models incorporate a series of simplifying assumptions. There is danger of oversimplification. If we assume the direction and velocity of wind and water currents to be constant and uniform in time and space throughout a study area, it is relatively easy to predict spill trajectories. But in the southern California OCS, as in most areas, wind and water currents are neither constant nor uniform, and trajectories predicated on such an assumption will be of little value. Thus every spill trajector's model incorporates a different and highly localized set of simplifying assumptions. Its predictive value depends on three main factors: the mathematical formula selected to characterize wind and water contributions to slick movement, the quality and format of the wind and water current data available for the study area, and the degree of the sophistication with which the two are combined.

THE WIND FACTOR

In addition to the wind's direct effect on surface water movement ("wind drift"), wind also drives surface waves, inducing a current movement ("Stokes drift") separate from and perhaps additive to the wind drift. 32/ A third kind of wind-induced surface water movement, a "leeway effect," has been proposed, 33/ and others may well be found. The exact processes through which wind-induced forces move an oil slick are not presently known.

The varied contributions of surface winds to the movement of a floating oil slick have been studied theoretically, experimentally, and through field observations. The results of these studies are not in close agreement. 34/ Because the "correct" overall wind factor is not precisely known, most trajectory models assume the wind factor to be a constant percentage of the wind speed, usually between 3% and 4%. For example, if the wind factor is assumed to be a constant 3%, and there are no water currents to consider, a 10-knot breeze would push an oil slick downwind at 0.3 knots. 35/

In theory, Coriolis forces arising from the earth's rotation should deflect slicks away from straight downwind, to the right of the Northern Hemisphere, to the left in the Southern Hemisphere. As with the wind drift factor, theoretical, experimental, and field results do not agree on the extent of Coriolis deflection. 36/ Many spill trajectory models assume a 0° Coriolis deflection angle -- that is, no Coriolis deflection -- while others use 15° or 20°.

THE WATER CURRENT FACTOR

It is commonly assumed that the component of a slick's movement caused by water currents (other than those induced by winds) equals the water current vector: that is, in the absence of winds an oil slick will move at the same speed and in the same direction as the water on the surface of which the slick floats. Difficulties arise in determining which water currents the model should include. One can choose from permanent (geostrophic) currents, tidal currents, longshore currents, Kelvin shelf waves, shelf eddies, inertial currents, and others. 37/ As a practical matter, it is not possible to construct a model and secure data

to reflect the separate contribution of each of these kinds of movement. With the exception of permanent (geostrophic) currents, most of these phenomena are short-lived (minutes or hours) relative to the lifetime of a slick (days or weeks). 38/ Further, the net movement of surface water by these ephemeral actions is usually small. Therefore, most models include only a single vector for water current movement, and values chosen are generally considered to represent the long-term or geostrophic currents operating in the study area. While tidal currents will be important in harbors or other confined waters or near shore, their influence is probably negligible in most of the southern California OCS. 39/

WINDS AND WATER CURRENTS OFF SOUTHERN CALIFORNIA

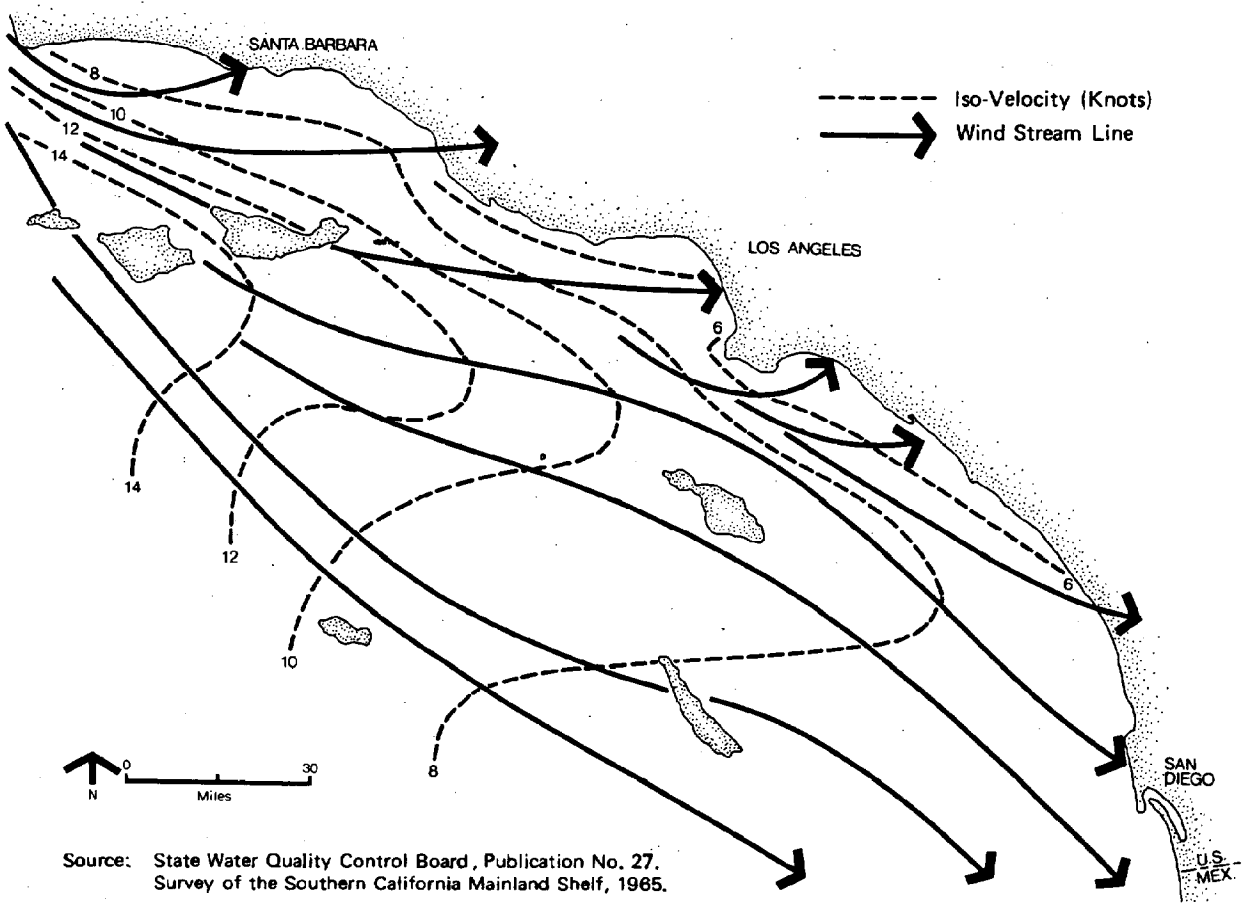
The major winds and water currents operating in the Southern California OCS are powered by phenomena operating far offshore in the open Pacific. Seaward of a line drawn southeast from Point Arguello, the winds and water currents generally reflect undisturbed, open-ocean conditions and, as such, are relatively constant and predictable. 40/ The summer winds, originating in the semi-permanent East Pacific High Pressure area, usually flow from the northwest at speeds up to 15 knots (Figure 2). In winter, as the East Pacific High moves south, the winds weaken and become more erratic, though still generally coming from the west quadrant. The California current moves to the southeast throughout the year at speeds ranging from 0.25 to 0.75 knots. 41/

Within the Southern California Bight, local and regional forces come into play, complicating wind and water current patterns. The configuration of southern California Bight and the array of coastal mountains splinter the oceanic northwest winds entering the Bight into weaker and more erratic breezes, with considerable local variation (See Figure 3).

The daily land-breeze/sea-breeze cycle, driven by the differential heating and cooling of ocean and land during every 24-hour period, influences wind patterns in a belt along the coast extending at least 50 miles to sea. (Figure 4). 42/ Much of the Santa Barbara Channel is in the wind shadow of the Santa Ynez and Topa Mountains, while each island creates local anomalies in the overall wind patterns. Santa Ana winds (steady offshore breezes of several day's duration) occur periodically along the southern California coast.

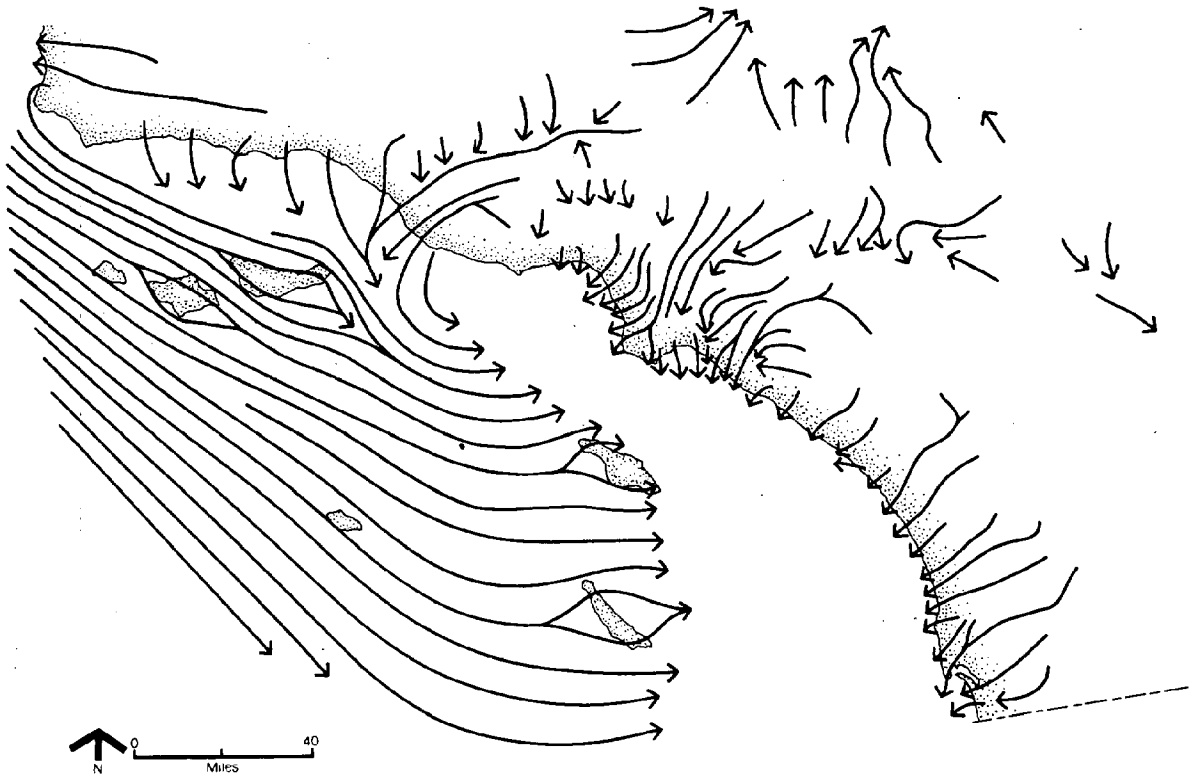
Seaward of the Santa Rosa-Cortes Ridge, the southeast-moving California Current is a permanent feature. Near the Tanner and Cortes Banks, the California Current swings to the east. Before reaching the mainland it splits, one fork moving back into the southern California OCS, known as the Davidson Currents, and the other continuing south along Baja California. This northern fork flows through the southern Channel Islands as a northwest-moving counter-current during the summer, fall, and winter. In the spring, this counter-current disappears. 43/ Between the southern Channel Islands and the mainland, the surface currents are complex and variable. Figure 5 illustrates this overall current pattern. There is no consensus as to the surface currents operating in this portion of the southern California OCS. Some postulate a continuation of the northwest counter-current; others postulate a return to southeast currents; and still others postulate the northwest flow offshore with southeast eddy currents nearer shore. Upwelling of deep water to the surface, which creates offshore currents, occurs periodically in some parts of the southern California OCS.

Figure 2: ANNUAL AVERAGE WINDS IN THE SOUTHERN CALIFORNIA BIGHT.

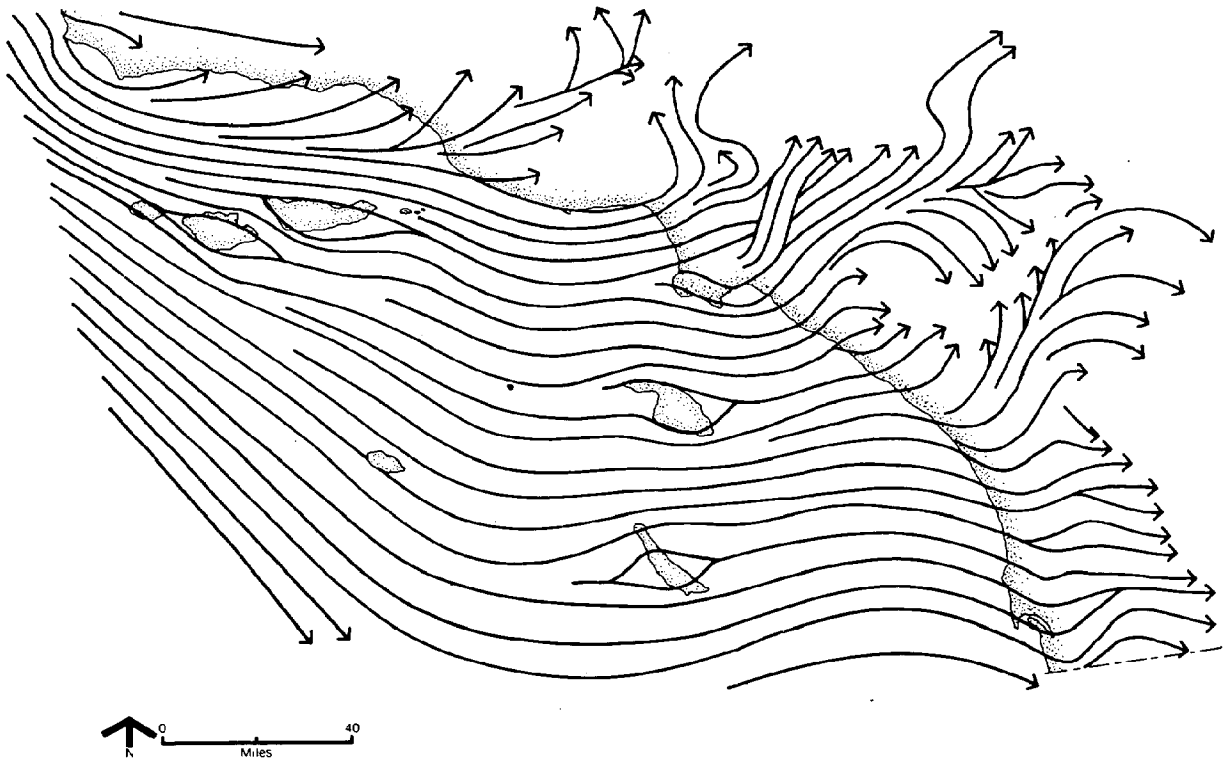


Source: State Water Quality Control Board, Publication No. 27. Survey of the Southern California Mainland Shelf, 1965.

Figure 4 : DAILY ONSHORE BREEZE-OFFSHORE BREEZE CYCLE, SOUTHERN CALIFORNIA BIGHT.



STREAMLINE CHART FOR JANUARY, 0000-0700 PST



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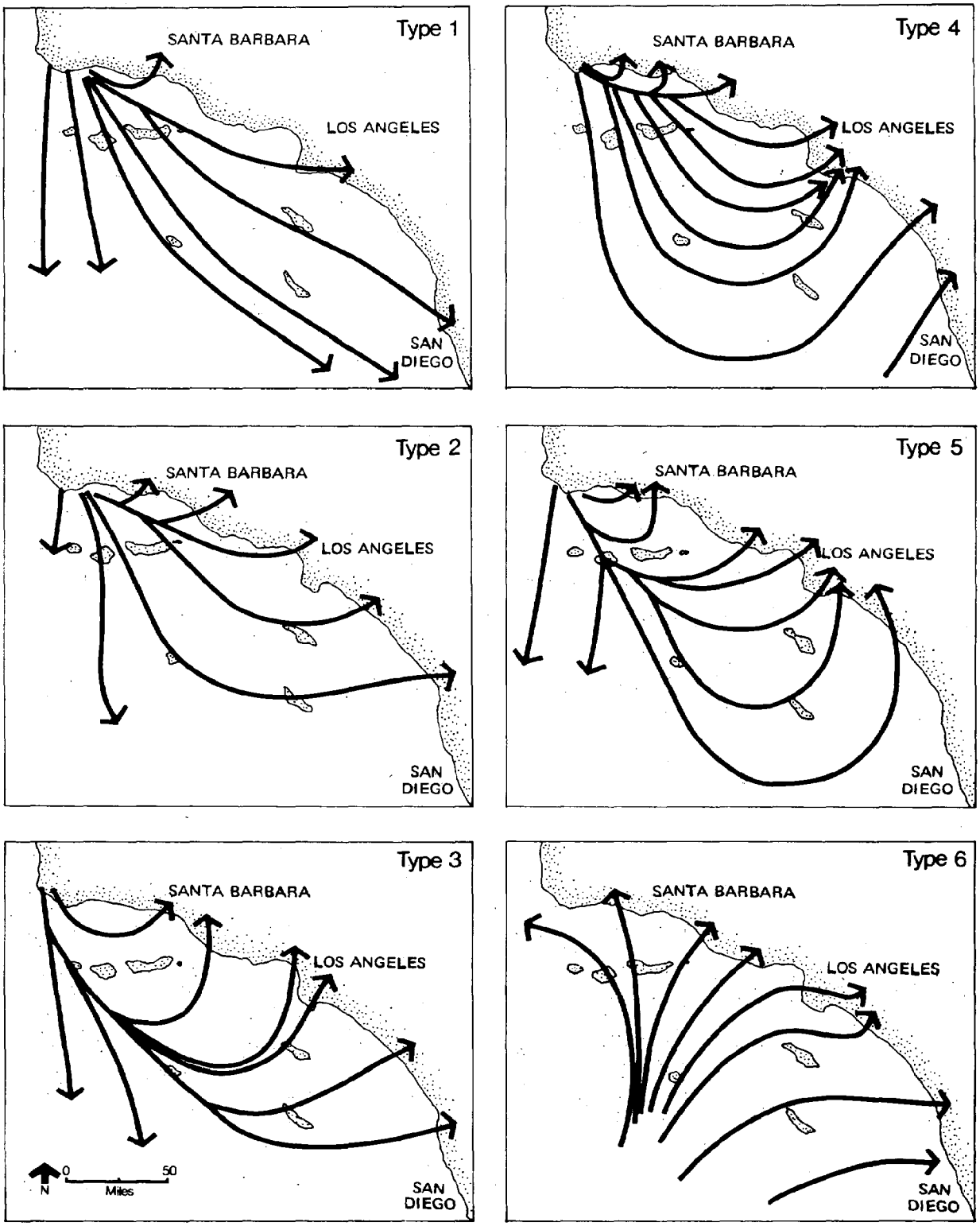
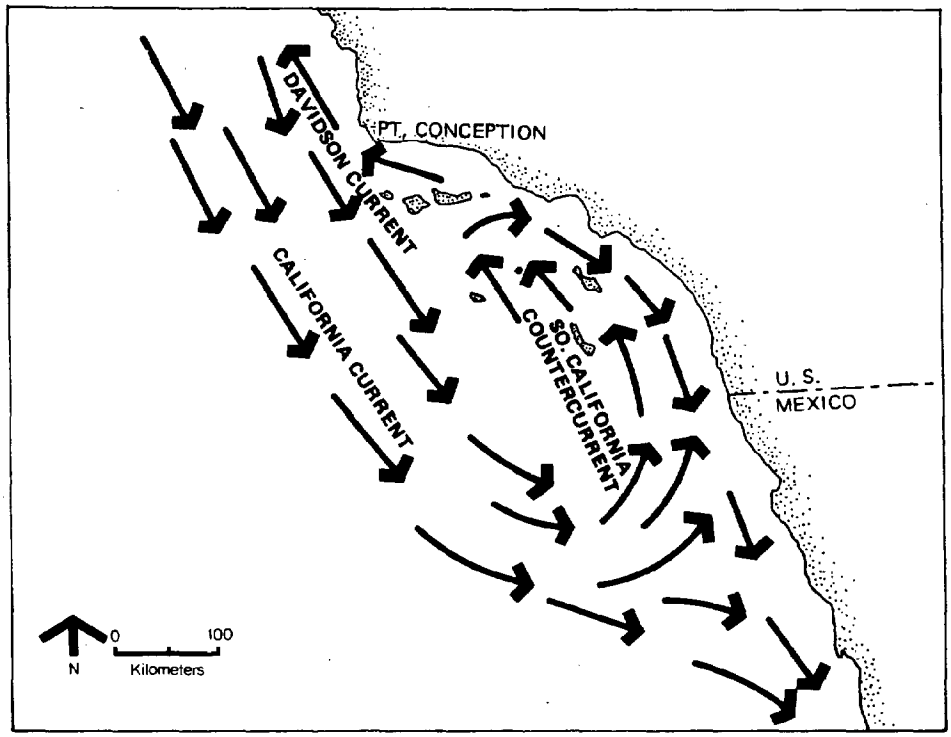


Figure 3: SIX COMMON WIND PATTERNS IN THE SOUTHERN CALIFORNIA BIGHT.

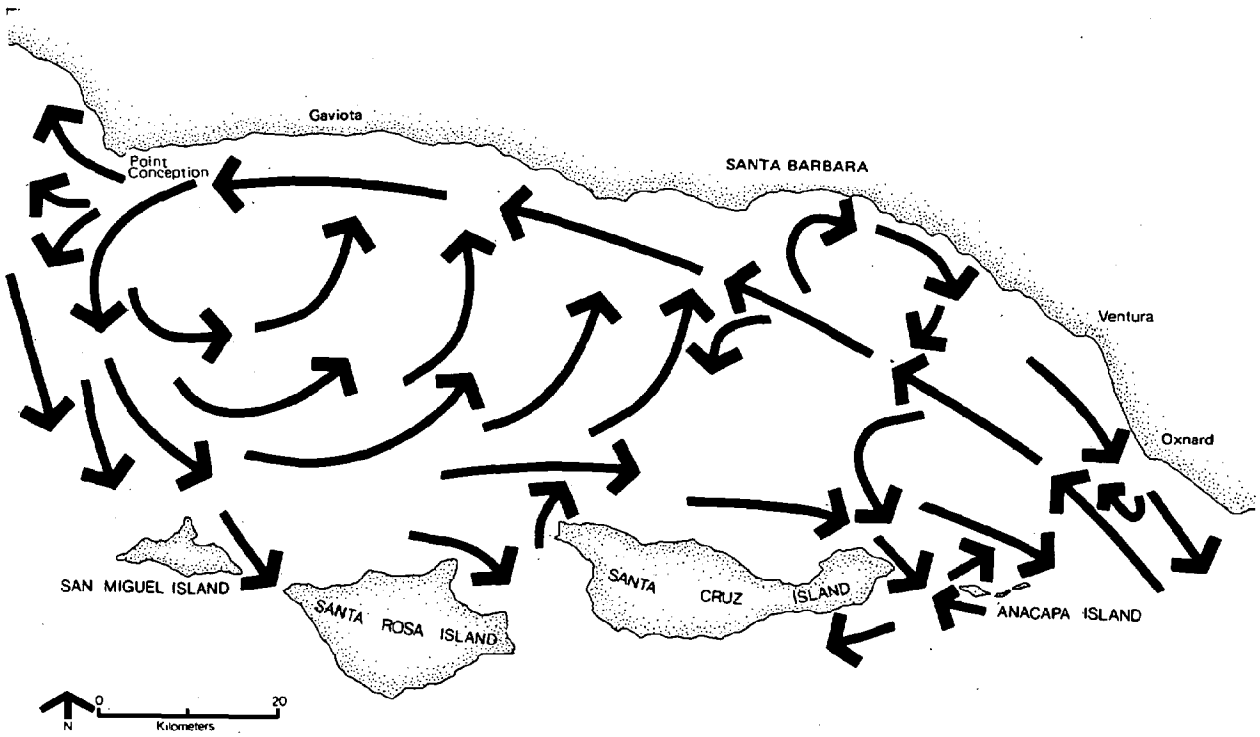
Source: State Water Pollution Control Board. Oceanographic Survey of the Continental Shelf of Southern California, Publication No. 20, 1959, pp. 24-26.

Figure 5: GENERALIZED PATTERN OF SURFACE CURRENTS OFF SOUTHERN CALIFORNIA.



Source: United States Department of the Interior, Geological Survey. Final Environmental Statement – Oil and Gas Development in the Santa Barbara Channel Outer Continental Shelf of California, Figure II - 19, 1976.

Figure 6: GENERALIZED PATTERN OF SURFACE CURRENTS, SANTA BARBARA CHANNEL.



Source: Ronald L. Kolpack, "Relationship of Migration of Natural Seep Material to Oceanography of Santa Barbara Channel," unpublished report, August 1976.

It is clear that winds and water currents in the southern California OCS are complex, with considerable variation. With the assistance of a computer, though, it is possible to construct a spill trajectory model which captures this variation sufficiently to produce useful spill trajectory predictions. The limiting factor in the southern California OCS is not the models themselves, but the wind and water current data available for use in such models.

WIND AND WATER CURRENT DATA SOURCES

The Navy maintains an archive of wind measurements taken by ships in the southern California OCS. 44/ These are available as monthly or annual wind summaries for one-degree quadrangles. These summaries provide helpful information on the variability of winds from one location to another, but they do not capture the variability of wind speed and direction at the same location over time. Moreover, these data are probably biased by mariners' natural tendency to avoid areas of bad weather.

A wealth of long-term wind data is available from meteorological stations and airports along the California coast and on some of the islands. The data may be presented as continual hourly observations or as monthly, seasonal, or annual summaries. Unfortunately for oil spill modelling purposes, most of these stations are either so near to topographic obstructions (Santa Barbara airport is shielded by the Santa Ynez Mountains, Long Beach airport by Signal Hill) or at such elevations (the Santa Catalina wind station is at 1580 feet elevation, San Nicholas at 507 feet, San Clemente at 906 feet) 45/ that taking their data as representative of the winds at the ocean surface is a doubtful proposition.

The southern California OCS has been studied as thoroughly as any ocean area in the world. Vast amounts of oceanographic data, collected at different times, in different areas, by a variety of methods and for a variety of purposes, are available from public and private research organizations. The best summary of long-term (geostrophic) currents in the southern California OCS was assembled by scientists from Scripps Institution of Oceanography as part of the California Cooperative Fisheries Investigation (CALCOFI). 46/ However, the scale at which these data are presented, and the geographic areas covered, impose limitations on their utility for oil spill trajectory modelling.

For example, the CALCOFI current summaries are presented at such a gross scale that it is almost impossible to determine the local variations known to exist and to have critical bearing on oil spill movement in certain areas. This problem is most acute immediately south of San Miguel and Santa Rosa Islands. Furthermore, the CALCOFI summaries do not include the Santa Barbara Channel (because of the scale used). Kolpack has described general current patterns in the Channel but admits that more surface current information is required before local currents can be reliably predicted 47/ (Figure 6).

In summary, enormous quantities of data exist for both winds and water currents in the southern California OCS, but neither type is entirely satisfactory for oil spill trajectory studies. The best wind data would contain continual hourly observations from a series of stations on the water, but such data are not now available. The CALCOFI current summaries are useful but are at such a scale that several important spill trajectory questions, hinging on current patterns in relatively small areas, cannot be answered. A discussion of three spill trajectory studies conducted for the southern California OCS illustrates the significance of these shortcomings.

SOUTHERN CALIFORNIA OCS SPILL TRAJECTORY ANALYSES

INTERSEA RESEARCH CORPORATION

Intersea Research Corporation analyzed oil spill trajectories in the southern California OCS as part of the Western Oil and Gas Association's Environmental Impact Assessment study for OCS Lease Sale #35, 48/ using CALCOFI monthly geostrophic current summaries and the Navy's archived wind data. IRC divided the study area into half-degree quadrangles and derived wind and surface water current vectors (direction and velocity) for each quadrangle. The two vectors within each quadrangle were resolved into one resultant slick drift vector, and the separate slick drift vectors were manually integrated into oil slick trajectories for the southern California OCS. Separate charts were prepared for January, April, July, and October to demonstrate seasonal variation. These trajectories are illustrated in Figure 7.

In addition, IRC undertook "reverse trajectory" studies for five ecologically sensitive areas. This technique involved plotting backwards over time wind and water current vectors to determine the location of potential spills that could conceivably foul these sensitive areas. Figure 8 illustrates these reverse trajectories, assuming a five-day drift for each spill during each season of the year.

DEVANNEY

The Environmental Protection Agency commissioned J. W. Devanney III to study potential slick trajectories in the areas considered for sale in Lease Sale #35, and published his report in July, 1975. 49/ Devanney used the same slick movement formula as IRC, except that he assumed the wind drift factor to be 3.5% instead of 3%.

For wind data, Devanney used hourly wind measurements collected over a ten-year period, Devanney was able to address the variability of the winds over time at each station. After dividing the compass into eight 45-degree octants, Devanney analyzed his data to determine for each octant (plus one category for calm conditions) the probability that the wind would be from the same octant or from any of the other octants three hours later. He also computed the mean wind speed and variance for each direction and season at each station. From this analysis, Devanney prepared wind-transition probability matrices for each of four seasons at each of his three stations.

For current information, Devanney tested four hypotheses: zero current throughout the southern California OCS, a constant 0.3-knot southeast current throughout the southern California OCS (taken as representative of the California Current), a constant 0.2-knot northwest current throughout the southern California OCS (taken as representative of the Davidson Current), and the July CALCOFI currents. The results of the Devanney analysis are illustrated in Figure 9.

IRC and Devanney arrived at significantly different results. IRC concluded that the wind contribution to slick drift was from two to five times greater than that of the current, and that general slick drift was to the southeast at five to 20 nautical miles per day. 50/ Devanney concluded that for all of his current hypotheses except the zero current hypothesis, the current contribution to slick movement was consistently greater than that of the wind. 51/ The significance of

this point is demonstrated by the predictions each study makes for the OCS leases immediately south of Santa Rosa Island. IRC trajectories predict that any spill originating in these tracts will be carried to the southeast and away from San Miguel, Santa Rosa, and Santa Cruz Islands throughout the year. Devanney concludes, "most of the spills which initiate immediately south of the western Channel Islands (San Miguel, Santa Rosa, Santa Cruz) will reach the islands and not be driven to the south under either the CALCOFI current assumption or the zero geostrophic current assumption." 52/ These differences are illustrated in Figure 10.

A serious flaw in the IRC study was its method for determining the wind vector in each of its one-half degree quadrangles. IRC took as its wind vector the average speed and direction of the "dominant wind," defined by IRC as the "primary direction mode of the compass rose" which included at least 50% of the observations. 53/ IRC's wind vector did not represent the average speed and velocity of 100% of the wind observations in any one-half degree quadrangle, but rather the average speed and direction of that 50% of the observations representing what IRC considered to be the "dominant wind." Thus, in using this "average" wind vector, IRC in fact overstated both the velocity and the persistence of the actual winds. 54/ This casts some doubt on IRC's conclusion that most slicks originating in the Southern California Bight will be driven south and southeast, and not come ashore in California.

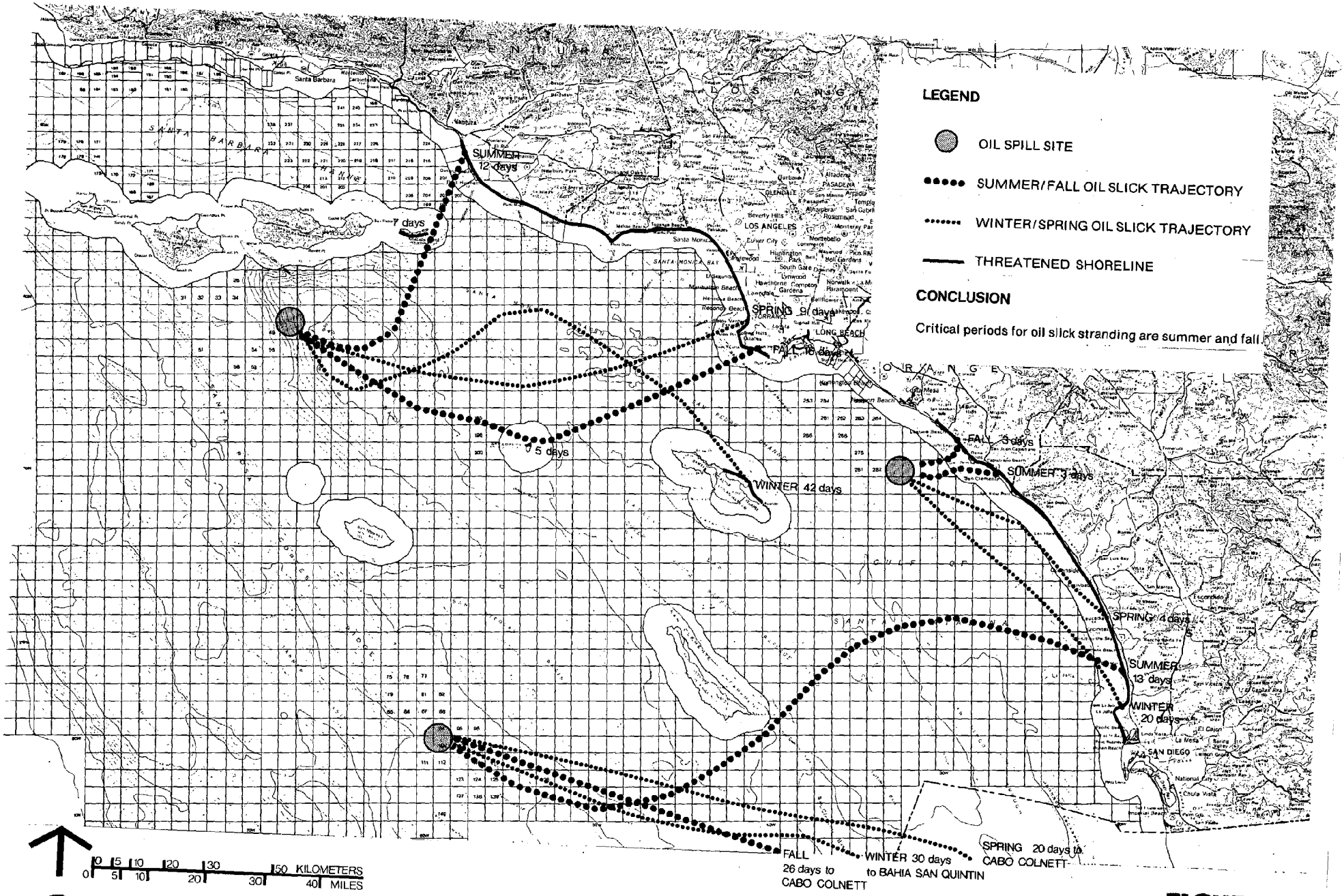
Devanney's method for computing the wind's contribution to slick movement more closely approximates the actual winds in the study area, but the value of his slick trajectory predictions is also limited by the data he chose to use. As noted previously, his wind data were collected at stations either hundreds of feet above sea level (San Clemente, Santa Catalina) or separated from the ocean by a large hill (Long Beach airport). Three of the four current hypotheses on which he based his trajectory predictions are of dubious validity. But his fourth hypothesis, using July CALCOFI currents, is reasonable, and the trajectories he obtained with this current hypothesis are distinctly different from those IRC calculated (again, see Figure 10).

BUREAU OF LAND MANAGEMENT

In its final EIS for Lease Sale #35, the Bureau of Land Management attempted to link offshore oil activities, potential slick movement, and vulnerable coastal resources in a risk analysis. 55/ The basis of this analysis was the proximity of the individual lease areas to coastal resources. BLM assigned "proximity values" to each tract according to its distance from natural resources, cultural resources, and areas of multiple-use activities. 56/ Though the intent of this massive effort is laudable, the results of the analysis are of limited value because potential oil spill trajectories from the tracts were not addressed except through BLM's mechanical proximity analysis.

OTHER OIL SPILL TRAJECTORY ANALYSES

Most oil-spill trajectory studies are either funded or conducted by federal agencies, most commonly the National Oceanic and Atmospheric Administration (NOAA), the Coast Guard, and the Department of the Interior. Recent activities and current plans for trajectory analysis by each of these agencies are described below.



OIL SPILL STUDIES

INFORMATION BASED ON TRAJECTORY STUDIES PERFORMED BY DAMES & MOORE/ INTERSEA RESEARCH FOR THE WESTERN OIL AND GAS ASSOCIATION (WOGA) ENVIRONMENTAL ASSESSMENT STUDY (1974).

FIGURE 7

California Governor's Office of Planning and Research

OCS PROJECT

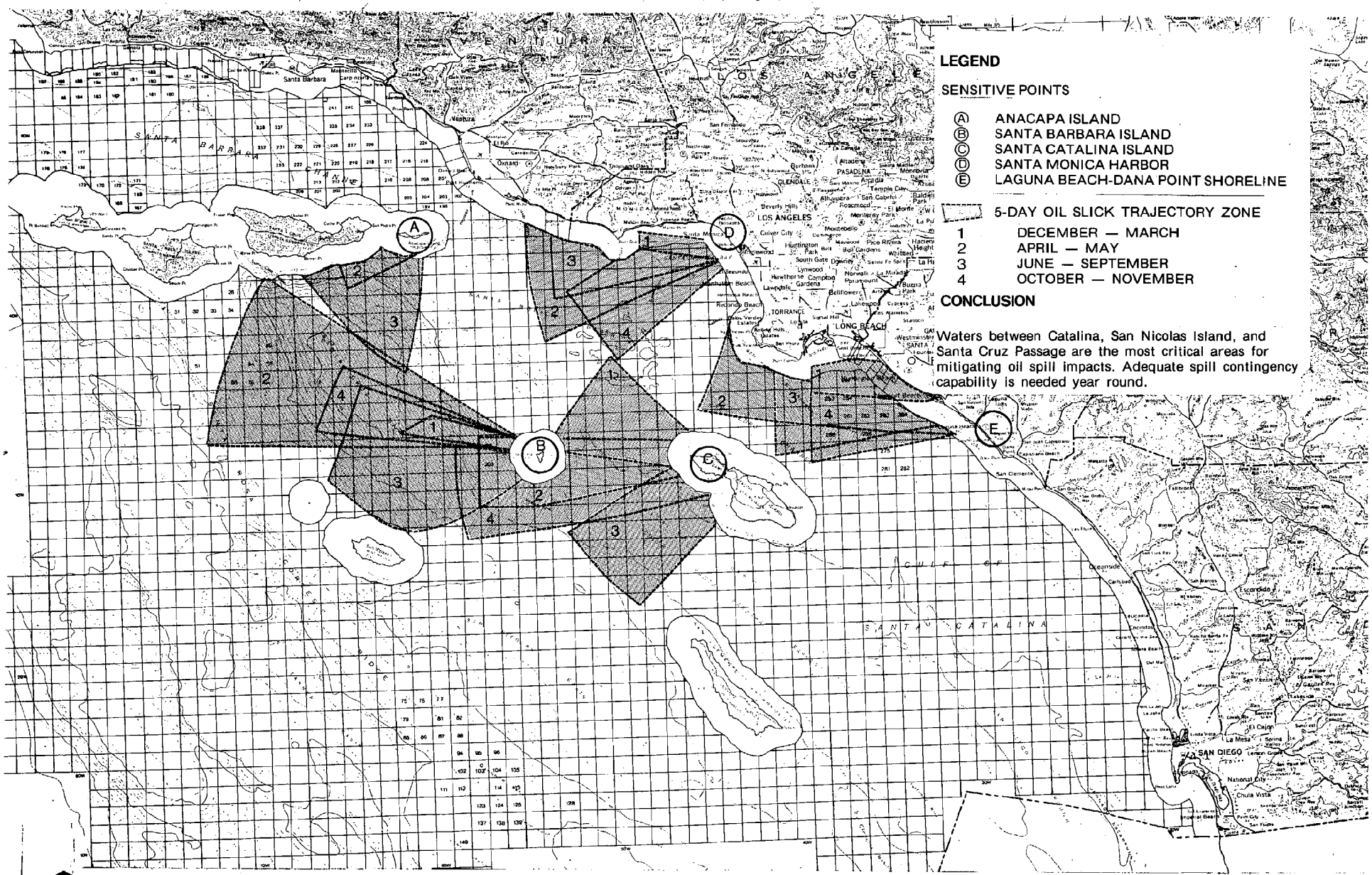


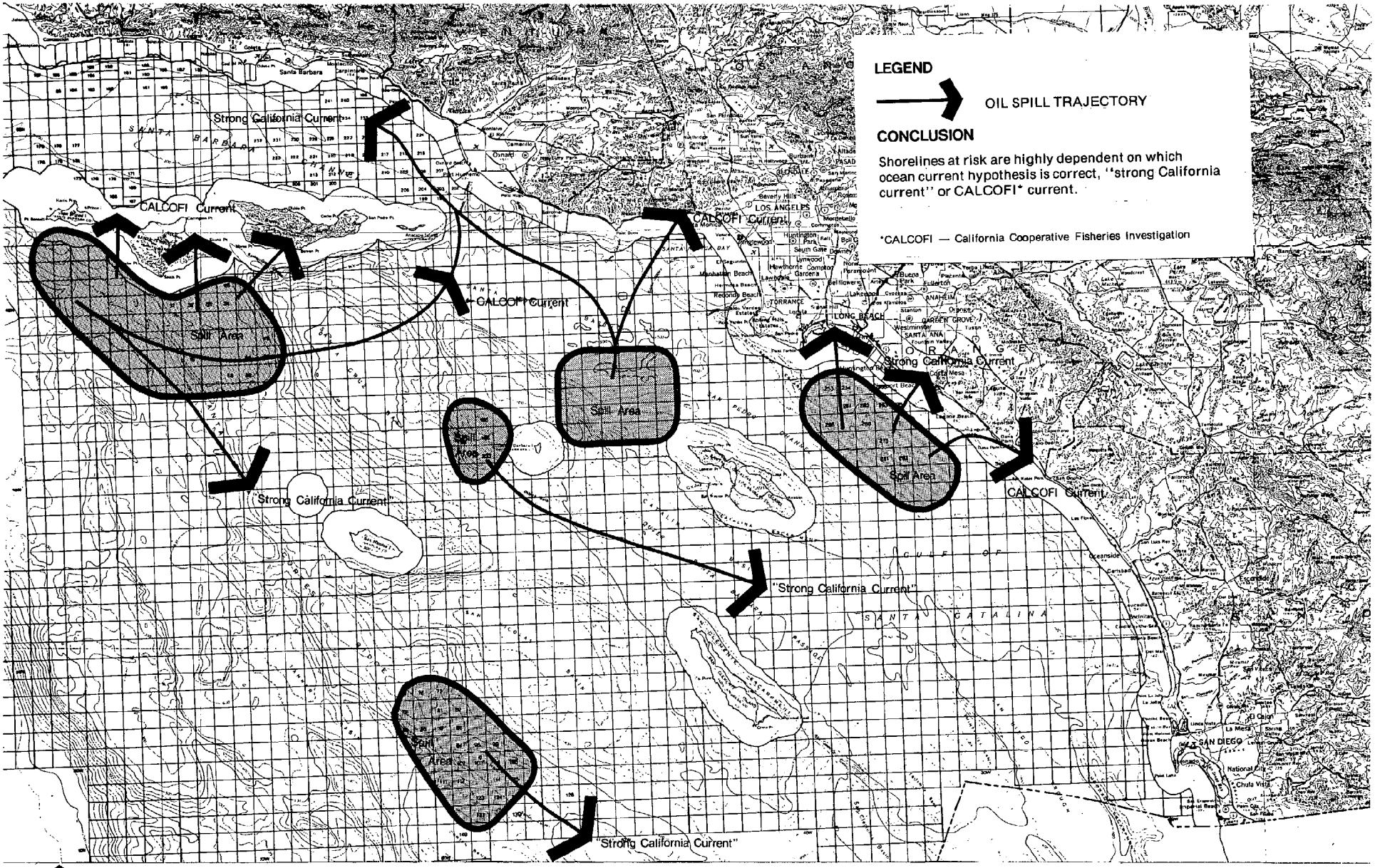
FIGURE 8

OIL SPILL STUDIES

INFORMATION BASED ON TRAJECTORY STUDIES PERFORMED BY DAMES & MOORE/INTERSEA RESEARCH FOR THE WESTERN OIL AND GAS ASSOCIATION (WOGA) ENVIRONMENTAL ASSESSMENT STUDY (1974).

California Governor's Office of Planning and Research

OCS PROJECT



OIL SPILL STUDIES

INFORMATION BASED ON INTERPRETATION OF THE MARTINGALE REPORT (DEVANNY) IN ONSHORE IMPACT OF OFFSHORE SOUTHERN CALIFORNIA OCS SALE NO. 35 SOLOMON ET AL, 1976.

FIGURE 9

California Governor's Office of Planning and Research

O C S PROJECT

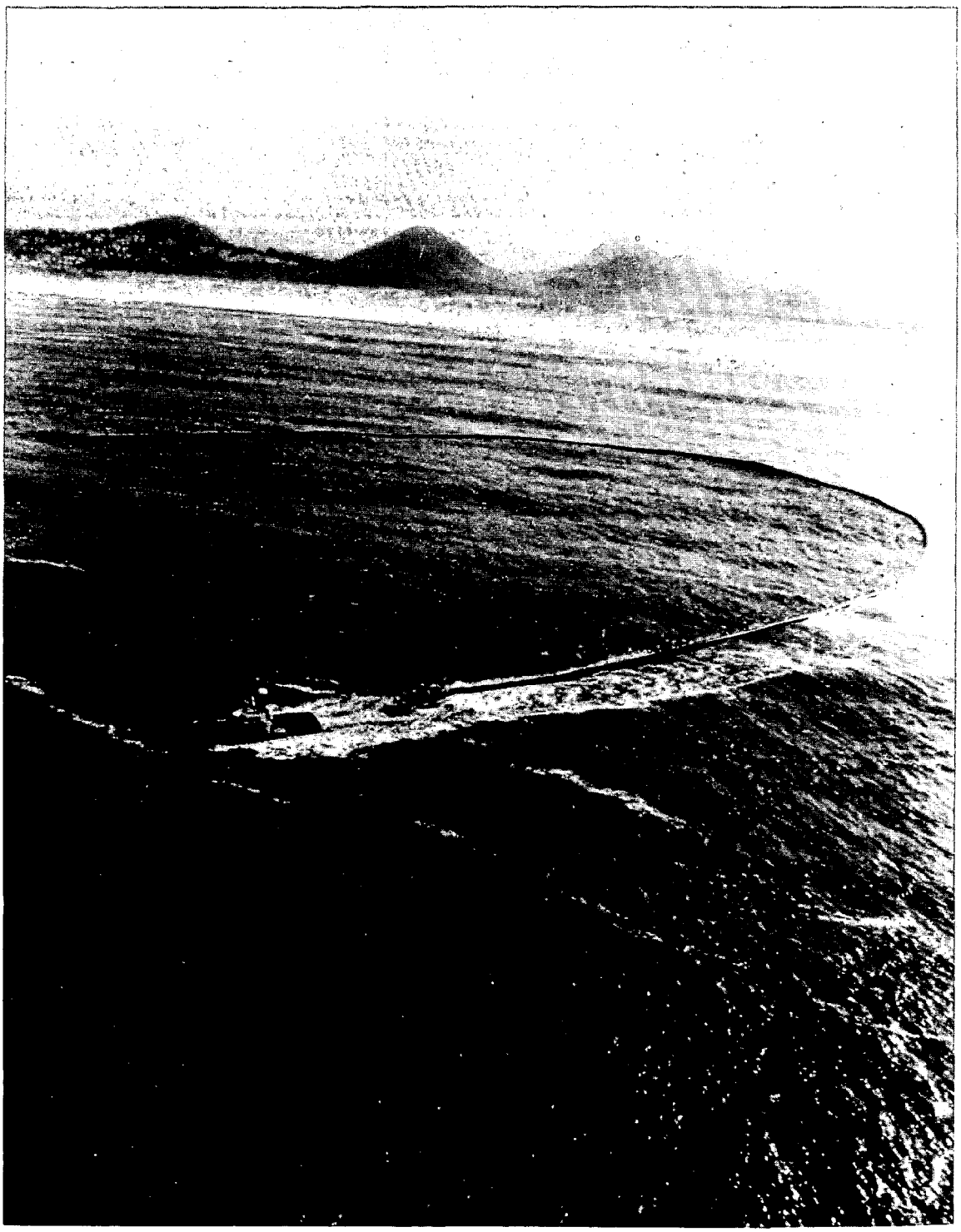
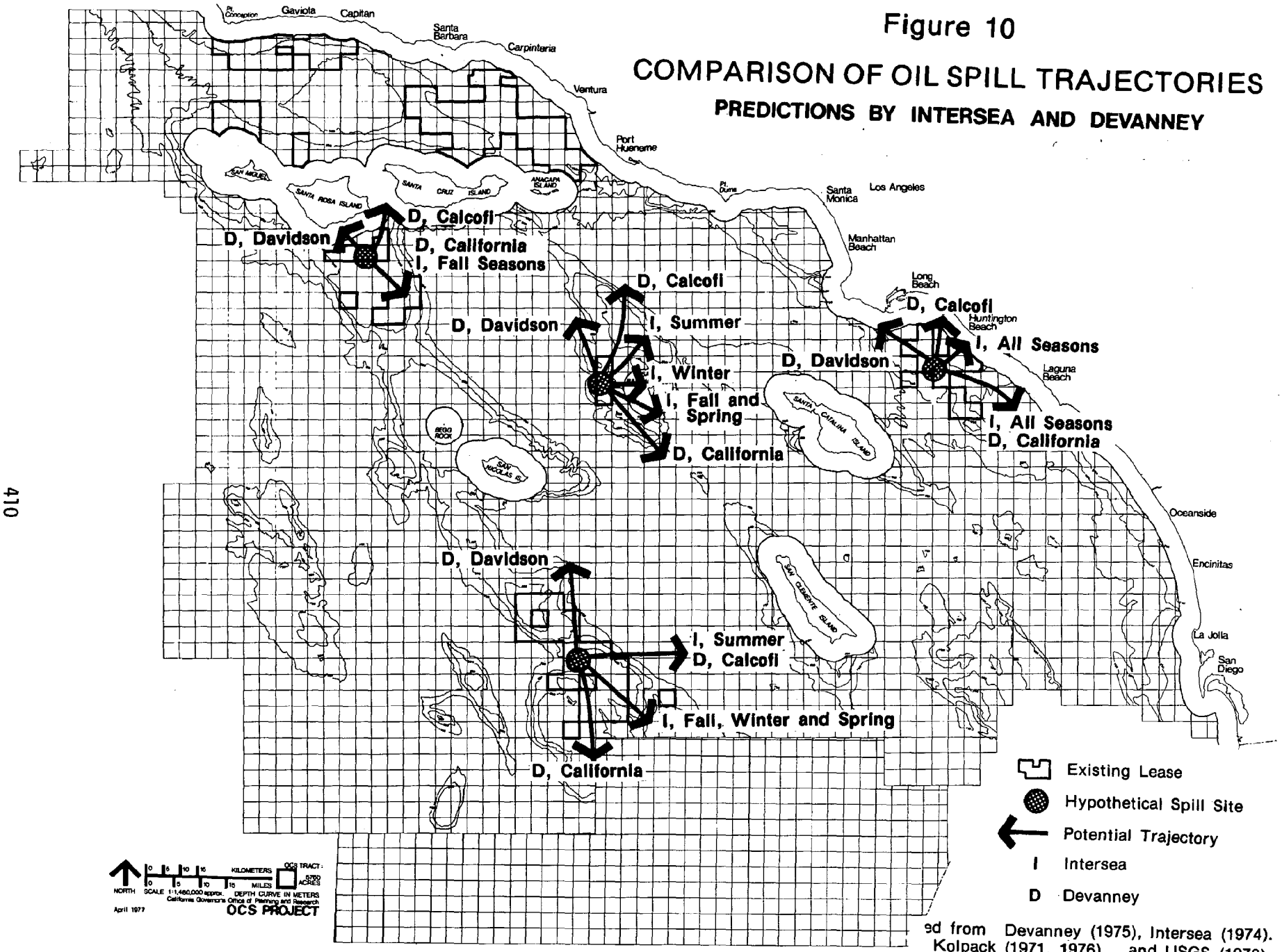


Photo above: Vikoma Seapack being deployed by Clean Seas, Inc.

Figure 10

COMPARISON OF OIL SPILL TRAJECTORIES

PREDICTIONS BY INTERSEA AND DEVANNEY



ed from Devanney (1975), Intersea (1974). Kolpack (1971, 1976), and USGS (1976).

NOAA. BLM commissioned NOAA to conduct extensive environmental baseline research in the Gulf of Alaska as a precursor to selling oil and gas leases in this frontier OCS area. NOAA measured winds and ocean currents continually for several years and developed a sophisticated numerical model of the Gulf of Alaska. Based on NOAA's findings, Interior deleted 16 tracts from those offered in the Northern Gulf of Alaska Lease Sale (OCS Lease Sale #39). Interior Secretary Kleppe, announcing the deletion, stated:

> New data very recently received from the National Oceanic and Atmospheric Administration (NOAA) of the U.S. Department of Commerce regarding wind and current patterns indicates that drilling west of Kayak Island poses a higher environmental risk than previously estimated...On the basis of these studies, I now consider the environmental risks too great to lease these tracts at this time. 57/

On February 4, 1976, Governor Askew requested that Florida be designated an "adjacent coastal state" under the Deepwater Port Act of 1974 (PL 93-627) in connection with the Lousiana Offshore Oil Port (LOOP) proposal for a deepwater port off Lousiana. Such designation would have given Florida more control over the federal decisions regarding the proposed deepwater ports. Under Section 9(a)(2) of the Act, the Secretary of Transportation may confer such status upon a petitioning State "if he determines that there is a risk of damage to the coastal environment of such state equal to or greater than the risk posed to a state directly connected by pipeline to the proposed deepwater port." Before making this determination, the Secretary must consider NOAA recommendations.

NOAA's analysis of the situation had three components: 58/ (1) a spill size/frequency/distribution analysis; (2) a trajectory analysis, which together enabled a comparison of the risk of exposure to oil spillage faced by Lousiana and Florida; and, (3) an analysis of the vulnerable coastal resources of the two states which, taken with the exposure analysis, permitted a comparison of the potential damage risked by the two states. 58/ NOAA used in its slick movement formula a wind factor of 3.1%, a permanent current vector derived from best available water current data, and a Coriolis deflection angle of 15°. NOAA concluded that the risk of damage to Florida's coastal environment was from 1.3 to 7.2 times greater than the risk to Lousiana and recommended to Transportation Secretary Coleman that Florida be granted "adjacent coastal state" status.

In the spring of 1978, NASA will launch "SeaSat," a satellite with special equipment for observing and measuring oceanographic phenomena. A consortium of California research institutions, headed by Cal Tech's Jet Propulsion Laboratory and funded in large measure by NOAA, will collect continual wind and current data in the southern California OCS for six weeks in 1977 to verify and calibrate the later "SeaSat" measurements.

NOAA and the Coast Guard have created four Spilled Oil Research Teams. Their mission is to conduct field studies at the site of actual spills. By measuring on-site winds, water currents, and actual slick movement, NOAA and the Coast Guard hope to improve the accuracy of spill trajectory predictions. 59/

COAST GUARD. Under the National Oil and Hazardous Material Contingency Plan, the Coast Guard coordinates all oil spill cleanup operations. In 1975, the Coast Guard developed two spill trajectory models for possible use on the East Coast but

has not yet sponsored such studies for West Coast use. 60/ The Coast Guard also has a Search and Rescue computer program, used in marine rescue operations, which predicts the movement of distressed vessels or persons caused by currents and winds. The possible application of this program to slick predictions is presently under investigation.

DEPARTMENT OF THE INTERIOR. Prior to the Mid-Atlantic Lease Sale (#40), USGS conducted an oil spill risk analysis for BLM. 61/ As NOAA did in its analysis of Florida's petition for "adjacent coastal state" status, USGS conducted its analysis in three parts: the probabilities of oil spill occurrence; potential spill trajectories; and, the location and vulnerability of specific natural and cultural resources in the study area. On the strength of these analyses, USGS computed the probabilities, for each season, of spills reaching the implicated coastal resources.

For the spill trajectory portion of its analysis, the USGS model used surface current velocities taken from drift bottle studies, and wind records from seven years of continual observations at Barnegat Lightship off New Jersey. With these wind records, USGS computed, by a method similar to that used by Devanney in his southern California OCS study, six-hour wind transition probability matrices for each of the four seasons. The slick movement formula employed a wind drift factor of 3.4% and a Coriolis deflection angle of 20°. USGS conducted a similar oil spill risk analysis for the tracts considered for lease in the proposed South and North Atlantic OCS Lease Sale (#42). 62/

Three southern California OCS Lease Sales have been held to date, and 121 leases are in various stages of exploration, development, or production; but the Interior Department has never calculated potential oil spill trajectories for these leases. A fourth southern California OCS Lease Sale (#48) has been proposed for the spring of 1978. BLM's Pacific OCS office has stated that a spill trajectory analysis comparable to those done by USGS for the Atlantic OCS Lease Sales will be undertaken jointly by BLM and USGS as part of the EIS for the proposed sale. 63/ Such a trajectory analysis would be of immediate value in contingency planning for spills from the existing 121 leases, as well as in identifying potential impacts arising from Lease Sale #48.

POTENTIAL SOUTHERN CALIFORNIA OCS SPILL TRAJECTORIES

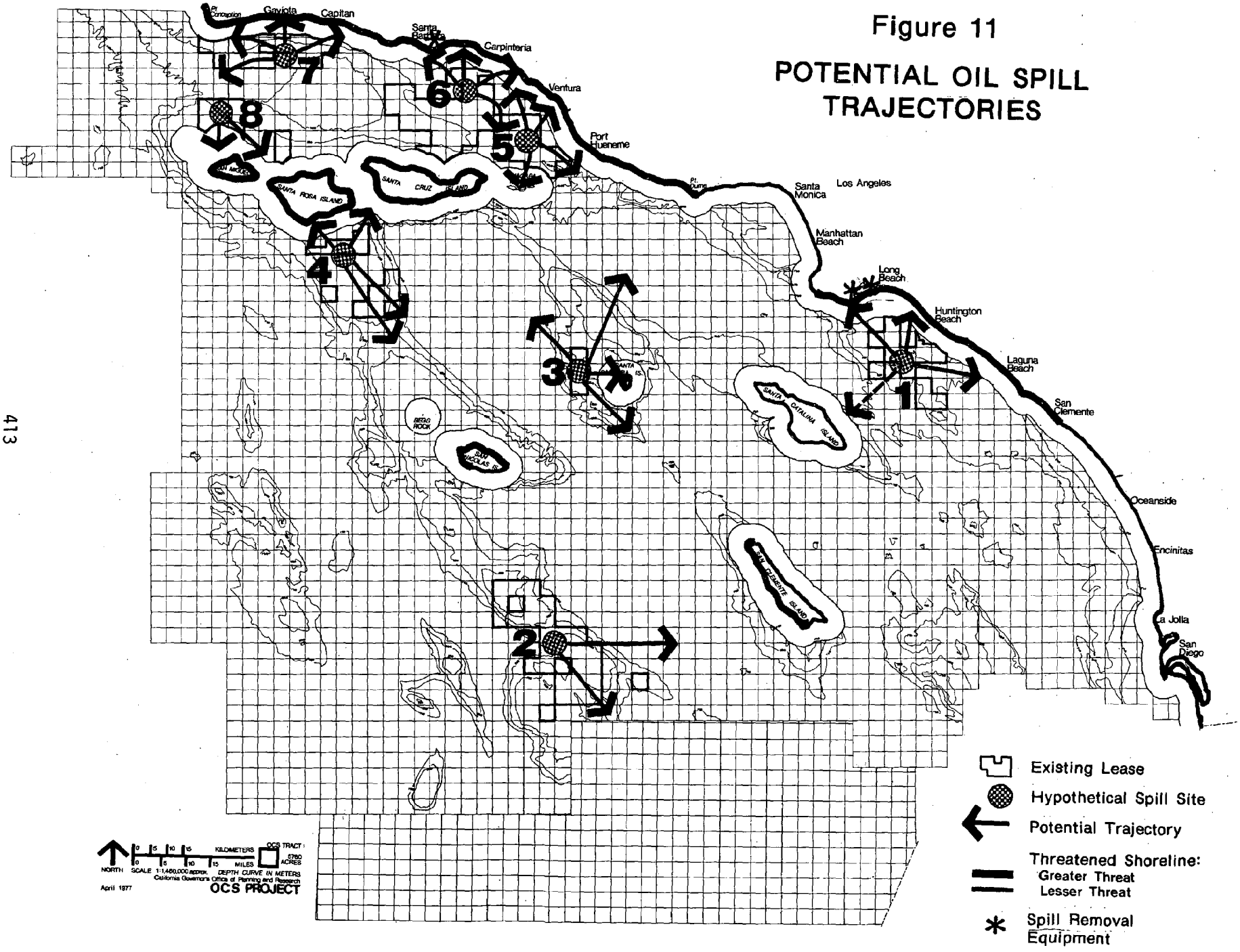
To illustrate potential trajectories for spills from California OCS leases, we have selected eight offshore locations broadly representing the geographic distribution of existing leases. For each site, we have attempted to identify the wind and current factors likely to control or influence oil slick movement, potential trajectories for spills originating at each site, and the shoreline areas potentially threatened by spills from the sites. Figure 11 shows the location of the eight potential spill sites, our trajectory conclusions, and the relatively threatened shorelines. Conditions at each spill site are described below.

SITE 1: SAN PEDRO BAY

Winds are usually from the west quadrant (i.e., blowing towards shore). Currents are complex but generally parallel to shore. Hence, slicks would most likely come ashore, with a time-to-shore of hours or days. The shoreline at risk extends from Point Fermin to San Diego, with the most threatened area from San

Figure 11

POTENTIAL OIL SPILL TRAJECTORIES



Pedro to Laguna Beach. Santa Ana winds or seasonal upwelling could increase time-to-shore.

SITE 2: TANNER BANKS

The California Current and westerly winds will push most slicks to south or east. The mainland shoreline is not severely threatened because time-to-shore might be weeks or months. All of San Clemente Island is threatened, with time-to-shore on the order of days or weeks, especially in the summer.

SITE 3: SANTA BARBARA ISLAND

Winds here are generally from the west quadrant. Currents are complex but often northwest (summer, fall, winter) or southeast (spring). All of Santa Barbara Island is threatened, with a time-to-shore of hours or days. The mainland shoreline is less threatened, because the time-to-shore would likely be days or weeks.

SITE 4: SANTA ROSA CORTES NORTH

This is a transition area between the southeast-moving California Current to the west and the northwest-moving countercurrent to the east. Currents and winds are complex, and slick trajectories are difficult to predict. Devanney predicts slick movement toward the islands; Intersea Research Corporation predicts slick movement away from the islands. If slicks move toward San Miguel, Santa Cruz, and Santa Rosa, time-to-shore would be hours or days.

SITE 5: HUENEME/SANTA CLARA

The daily land-breeze/sea-breeze cycle will strongly influence slick movement. Slicks would likely come ashore in Ventura County between Rincon Point and Point Dume, with a time-to-shore of hours or days. Slicks could also move toward Anacapa Island.

SITE 6: DOS CUADRAS/CARPINTERIA/PITAS POINT

The 1969 blowout originated in the Dos Cuadras field. Again, the daily land-breeze/sea-breeze cycle will strongly influence slick movement. The shoreline most threatened would be from Goleta Point to Port Hueneme, with a time-to-shore of hours or days. As happened during the blowout, however, oil could come ashore anywhere in the Channel, either on the mainland or on any of the islands.

SITE 7: SANTA YNEZ

The shoreline most threatened would be from Gaviota to Goleta Point, with a time-to-shore of hours or days. During weak winds, currents could push slicks cross-Channel onto Richardson Rock, Wilson Rock, and San Miguel Island.

SITE 8: SAN MIGUEL/SOUTHWEST CHANNEL

Winds and currents throughout the year would push slicks onto San Miguel and Santa Rosa Islands, with a time-to-shore of hours or days.

THE EFFECTS OF A SPILL

BIOLOGICAL EFFECTS

The biological effects of spilled oil are the subject of considerable controversy, with a literature that is voluminous, often equivocal, and occasionally contradictory. Essential issues are hotly disputed, and general consensus does not exist among scientists who have conducted research on the subject. The weight of scientific evidence available today leaves little doubt that petroleum hydrocarbons can cause damage -- short-term, long-term, lethal, or sublethal -- to coastal and marine organisms. What will be the precise effects of any given oil spill is another question entirely.

Most petroleum hydrocarbons are toxic and can kill coastal and marine organisms either chemically or physically. 64/ Chemically, death may occur as a result of poisoning, either through direct contact or ingestion (e.g., scallops, crabs, lobsters). Physically, death may occur through coating and smothering of intertidal organisms (e.g., barnacles, limpets) or through disruption of the body insulation of warm-blooded animals (e.g., diving birds). 65/

Petroleum hydrocarbons can also have sublethal or indirectly lethal effects, such as the destruction or reduction of a species' food supply, reduction of reproduction success, and synergistic effects which may reduce resistance to other stresses. Feeding, reproducing, and other behavioral activities of many marine species are triggered by the presence of chemical compounds in concentrations as low as one part per billion. Petroleum hydrocarbons, even at exceedingly low concentrations, can mask or mimic these chemicals, thereby disrupting biological processes dependent on such chemical signals. 66/

Spilled oil can have acute (short-term) or chronic (long-term) biological effects. The immediate and visible effects of oil spills often receive the most attention and publicity, but many ecologists believe that the subtle and less immediate obvious effects of spilled oil pose a larger potential threat to the long-term health and productivity of coastal and marine populations, communities, and ecosystems. 67/ One reviewer has separated the biological effects of spills into three categories:

> First-order effects include the direct effect of petroleum products on the biota. These effects may be toxic; physical, such as suffocation; or physiological, such as internal disturbances following ingestion. All of these may result in immediate mortality, torpidity, or poor health. These are generally short-term effects which usually affect all species to some degree and show up within hours or days;
>
> Second-order effects include changes in populations of each species with respect to size-frequency and age structure, productivity, standing crop, reproductive abilities, etc. These are generally intermediate-term effects which show up in weeks, months, and for some long-lived species, years; and

Third-order effects include changes at the community or ecosystem level with respect to relationships within or between trophic levels, species composition and/or abundance, and other aspects of community dynamics. These changes are often the result of subtle, sublethal effects which may not show up for months or years. 68/

FACTORS INFLUENCING THE EFFECTS OF SPILLED OIL

With the exception of sea birds, which are consistently reported to be killed in substantial numbers, the observed effects of oil spills vary widely, ranging from negligible 69/ to catastrophic. 70/ Some of the factors influencing the extent of damage caused by any given spill are the dosage of oil, the type of oil, local weather conditions, the location of the spill, the time of year, the methods used for cleanup, and the area's previous exposure to oil.

DOSAGE OF OIL. Toxic effects increase at higher concentrations of petroleum hydrocarbons. Most species have finite tolerances for oil and exhibit avoidance behavior (if mobile), sublethal effects such as narcosis or cell damage, and finally death as higher concentrations of petroleum hydrocarbons are reached. 71/ High concentrations can result from small spills as well as from large if winds, waves, and currents push the spilled oil into a confined area, such as an embayment or cove.

TYPE OF OIL. No two crude oils are the same, and each contains thousands of compounds, primarily hydrocarbons. Because the proportion of hydrocarbons in crude oils varies from field to field, and even from formation to formation within a field, their overall toxicity varies as well. The same thing is true of the different hydrocarbon fractions. Aromatic hydrocarbons -- such as benzene, toluene, xylene, and napthalene -- are thought to be the most immediately poisonous fraction. 72/ Refined oils often contain a higher percentage of aromatics than crude oils and are usually considered to pose a greater threat to exposed organisms.

The relative toxicity of refined and crude oils is a subject of especially fierce controversy. It has been argued that crude oils are so much less toxic than refined oils that the two should be treated as entirely different substances. In support of this argument, some have asserted that no crude oil spill has ever been demonstrated to cause significant or lasting biological damage.

It is true, as noted above, that crude oils generally contain lower concentrations of aromatic hydrocarbons than refined oils, and thus should have lesser toxic potential. Table 8 compares the characteristics of four California offshore crude oils as reported by Exxon. 73/ Aromatics are present in each of these crudes, though constituting only 2-4% by volume of the total crude. In contrast, the #2 fuel oil which caused much damage in the West Falmouth spill contained about 41% aromatics. 74/ On the other hand, Blumer has cited published analyses of California crude oils which state that the aromatic content of the environmentally most stable fraction (characterized by Blumer as boiling above 325°C.) ranges between 50-60% in Los Angeles basin crudes, and 45-49% in Ventura basin crudes. 75/ Thus, California crude oils do contain aromatics, and though they constitute only a small percentage of the total crude in comparison with the percentage in many refined products, aromatics appear to be present in substantial quantities in the crude oil fraction most resistant to evaporation, dissolution, or other weathering. Therefore, the difference in toxic potential between crude and refined oils appears to be of degree, rather than kind.

In keeping with this difference in degree, product spills are more often observed to cause extensive biological damage than crude oil spills.

TABLE 8:
COMPARISON OF PROPERTIES OF SANTA YNEZ CRUDE OIL WITH
OTHER SANTA BARBARA CHANNEL AND CALIFORNIA CRUDE OILS

	EXXON SANTA YNEZ UNIT	DOS CUADRAS	CARPINTERIA	EAST WILMINGTON
TOTAL CRUDE				
Gravity, °API	18.1	27	28.8	19
Sulfur, Wt. %	4.89	1.13	1.32	1.5
Visc. @ 100°F, SSU	1316	81	68	533
LIGHT NAPTHA (C5-175°F)				
Yield, Vol. %	3.2	4	5.2	3
RON Clear	58.5	77.9	73.2	80.3
HEAVY NAPTHA (175-375°F)				
Yield, Vol. %	10.6	17.6	20.8	8.7
KEROSENE/Jet (375-530°F)				
Yield, Vol. %	10.6	14.3	13.7	12.8
Aromatics, Vol. % of Kerosene/Jet	38.3	28.7	14.8	29.1
Aromatics, Vol. % of Total Crude	4.05	4.1	2.02	3.72
LIGHT GAS OIL/DIESEL (530-650°F)				
Yield, Vol. %	9.1	11.7	10.1	12.3
GAS OIL (650-1050°F)				
Yield, Vol. %	29.2	34.2	29.7	35.9
RESIDUUM (1050°F+)				
Yield, Vol. %	36.5	16.3	19.4	26.9
Sulfur, Wt. %	7.62	2.25	2.62	2.34

Dr. Dale Straughan, who led the team of scientists studying the effects of the Santa Barbara Channel blowout, has also participated in a study of the Metula crude oil spill in the Straits of Magellan. She has concluded that the Santa Barbara spill did not cause significant damage, but that the Metula spill did, especially in the intertidal zone. 76/ Moreover, the Argea Prima, Chryssi P. Goulandris, and Ocean Eagle and Urquiola tanker spills all involved crude oil and were reported to cause significant damage. 77/

LOCAL WEATHER CONDITIONS. Wind, wave, and current conditions at the time of a spill control the trajectory of the slick, the rate at which the oil is dispersed and degraded, and the success or failure of containment and removal operations, each of which in turn influences the effects of a spill. The winds and currents during the first days of the Santa Barbara blowout were such that significant quantities of oil did not come ashore until five days after the blowout began. 78/ The lag permitted more of the oil to be removed from the surface slick through evaporation and solution than would have been the case under different wind and current

conditions. Also, a severe storm occurred in the Channel a week after the blowout began, crippling containment operations and increasing the amount of oil ultimately reaching the beaches. 79/ The tidal range in an area where oil comes ashore, together with surf conditions during the time the oil is on the shore, will influence the size of the coastal area actually oiled by the slick. Water and air temperatures will influence the behavior of the oil as well as the rates at which microbial degradation of the oil proceeds. As a general rule, metabolic rates double for every 10°C increase in ambient temperature. Hence, all other factors being equal, the higher the ambient temperature, the faster microbial organisms will attack the spilled oil.

LOCATION OF THE SPILL. Spills occurring far offshore are less likely to come ashore, will undergo more weathering and dispersion before reaching the coast, and provide more time to undertake containment and removal operations than do spills occurring close to shore. The configuration and nature of the coastal area threatened by a spill -- embayment, headland, open coast, harbor, rocky shore, sandy beach, wetland, etc. -- will also influence the effects of a spill because coastal resources vary widely in their sensitivity and vulnerability to oil spill damage.

TIME OF YEAR. The time of year in relation to the life cycle of species inhabiting an area is an important factor. 80/ Many larval and juvenile forms -- such as crab larvae, fish fry, or newly set oyster spats -- are considered especially vulnerable to oil, so that a spill occurring at this stage in the life cycle of these species would probably cause greater damage than a spill occurring at other times of year. Similarly, if the Santa Barbara Channel blowout had occurred when elephant seals and sea lions were nursing their pups, pup mortality might have been considerably higher. 81/ Again, sea bird populations fluctuate greatly during the year, especially in wintering and breeding areas such as the Santa Barbara Channel. Thus, the populations at risk, and hence the potential damage from a spill, vary considerably depending on the time of the year.

CLEANUP METHODS. Much, though not all, of the damage caused by the Torrey Canyon spill resulted from the indiscriminate use of dispersants which were later found to be as toxic as the spilled oil itself. 82/ The French used chalk to sink about 150,000 barrels of Torrey Canyon oil in order to prevent it from coming ashore on the Brittany coast. 83/ No studies were conducted to determine the effect of this chalk/oil mix on the benthic organisms involved, though French fishermen subsequently reported fouled fishing gear and contaminated catches. 84/

PREVIOUS EXPOSURE TO OIL. The previous exposure of an area to petroleum hydrocarbons may influence the effects of an oil spill on that area. In the Santa Barbara Channel, for example, natural seeps have been active for thousands of years, increasing the background levels of petroleum hydrocarbons in Channel waters and causing locally heavy concentrations of oil (e.g., Coal Oil Point). Some scientists have suggested that chronic exposure to natural seep oil has reduced species diversity at Coal Oil Point 85/ and increased the tolerance for petroleum hydrocarbons of some of the intertidal species there, 86/ but the available evidence is not conclusive. 87/

CASE STUDIES

Research on the fate and effects of spilled oil has been widely undertaken only since the 1969 Torrey Canyon spill, and present understanding is far from

complete. Laboratory tests have demonstrated the toxicity of petroleum hydrocarbons for many organisms. But laboratory environments cannot precisely duplicate conditions in the field, so that extrapolation or generalization on the basis of laboratory results is an uncertain proposition. Field experiments involving the deliberate oiling of selected areas are rarely undertaken in the United States, though some research of this type has been conducted in other countries. 88/

Post-spill field studies have several handicaps. When scientists study an area where an oil spill has occurred, they generally lack specific information on the natural communities existing in that area prior to the spill. This complicates the task of determining whether any biological or ecological changes have, in fact, occurred. Where such changes are detected, it is often difficult to sort out the effects of spilled oil from the effects of other natural and human activities, or to establish cause-effect relationships. Even where oil spill effects can be demonstrated, it is hard to predict the long-term results of the spill unless surveys and analyses are repeated at regular intervals for years after the spill.

In short, it is very difficult to determine in the field the short-term or long-term effects of an oil spill. In addition, the post-spill field studies which are available are not easily compared because of differences in study methods and spill circumstances. Two of the most publicized and controversial oil spill field studies conducted to date involve the West Falmouth oil spill and the Santa Barbara blowout, each of which occurred in 1969. A synopsis of the spills, the post-spill studies, and the controversial issues raised by each is presented here to illustrate the difficulties inherent in any assessment of the effects of spilled oil.

WEST FALMOUTH. On September 15, 1969, the barge Florida spilled 4,000 barrels of #2 fuel oil into Buzzards Bay, Massachusetts, a short distance from the town of West Falmouth. Over the next several days, much of the oil came ashore in Wild Harbor Cove. Scientists from nearby Woods Hole Oceanographic Institute and the Marine Biological Laboratory, Woods Hole, undertook chemical and biological studies to assess the short- and long-term effects of the spill. Their chemical analysis established the presence and persistence of oil in the study area; their biological surveys demonstrated the effect of the oil on resident organisms. These studies are still being carried out and will likely continue into the foreseeable future. It should be noted that the West Falmouth spill study is the first in which chemical and biological studies have been carried out simultaneously, in a quantitative fashion, over extended periods of time.

In the first hours and days after the spill, there was a massive kill affecting fish, shellfish, worms, crabs, lobsters, and other crustaceans and invertebrates. 89/ Benthic (seafloor) samples collected a week after the spill revealed that 95% of the organisms recovered were dead, with many of the remaining organisms dying. Comparable destruction occurred in the tidal rivers and marshes into which oil had been pushed by the winds and tides. West Falmouth shell fisheries were closed for two years, and the shellfish beds in the most heavily oiled areas remain closed today, more than seven years later. 90/ Recolonization began about a year after the spill, but the area has not yet recovered its pre-spill status. Essentially unmodified oil remains in the sediments; marsh grasses are still stunted; and bait fish and fiddler crab populations appear to be suffering long-term damage as a result of the spill. 91/

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SANTA BARBARA CHANNEL BLOWOUT. Union Oil Company's fifth development well on Platform A blew out on January 28, 1969. The blowout was brought under control ten days later, but oil still leaks from the ocean floor seeps created by the blowout. The amount of oil discharged during the blowout is disputed. One estimate, however, places the amount of oil released in the first 100 days after the blowout at 77,000 barrels. 92/ Favorable winds delayed the arrival of the oil onshore in significant quantities until four or five days after the blowout began. Numerous studies were initiated to assess the effects of the spill, especially in the intertidal zone. Scientists of the Allan Hancock Foundation at the University of Southern California conducted the major study, which was terminated in June of 1970. 93/ Barnacles, surf grass, and algae suffered significant damage, mainly from smothering by the crude oil. Thousands of sea birds were killed. With these exceptions, the scientists were unable to demonstrate large-scale damage to organisms in the study area. Recolonization of the oiled intertidal areas began within a year.

COMPARING THE WEST FALMOUTH AND SANTA BARBARA SPILLS

Clearly, the circumstances of each of these spills were quite different. The West Falmouth spill involved a refined (#2 fuel) oil, comparatively high in aromatics. In the Santa Barbara spill, the oil did not come ashore in significant quantities until four or five days after the spill, while at West Falmouth the oil was ashore in a matter of hours. At West Falmouth, winds, currents, and waves concentrated the oil into a relatively confined area, while the Santa Barbara blowout oil was spread along miles of open coast.

Still, the dramatic difference in observed effects of these two much-publicized oil spills has aroused considerable controversy. Those who believe that oil spills do pose a serious threat to coastal and marine life cite the West Falmouth study, arguing that because substantial damage resulted from that spill, it could result from any other spill, and challenge the validity of the Santa Barbara study on the grounds that the methods chosen to study the effects of that spill were inadequate. On the other hand, those who believe that oil spills do not pose a serious threat to coastal and marine life cite the Santa Barbara study, and minimize the applicability of the West Falmouth study to crude oil spills on the grounds that the West Falmouth involved a refined product. Among the major issues in dispute are: (1) the importance of the type of oil spilled and (2) the scientific methods chosen to study spill effects.

TYPE OF OIL SPILLED. Dr. Dale Straughan was a principal author of the USC report on the Santa Barbara blowout. She has concluded that the major reason for the difference in observed effects between the two spills was the type of oil spilled. 94/ She reasons that the Santa Barbara spill involved a crude oil which tended to float, was relatively insoluble in water, and was comparatively low in aromatics, while the West Falmouth spill involved a refined oil which was more readily dispersed throughout the water column and which was comparatively high in aromatics. This, she concludes, accounts for the fact that the primary effects of the Santa Barbara spill were the (physical) smothering of intertidal organisms and fouling of sea birds, while the West Falmouth spill resulted in (chemical) poisoning of organisms throughout the study area, underwater and in the sediments as well as at the water's edge. Some take this argument one step further and assert that because the West Falmouth spill involved refined oil, the results of

the West Falmouth spill study are entirely irrelevant to the potential effects of a crude oil spill.

Dr. Max Blumer, centrally involved in the West Falmouth spill studies, disagrees with both of these lines of reasoning. He argues that fuel oil is derived from crude oil, that the aromatics present in refined products are also present in crude oils, and that because aromatics are toxic when in refined oils, they must also be toxic when in crude oil. He therefore believes that the results of the West Falmouth spill study are applicable to crude oil spills. 95/

Dr. Blumer also challenges the argument that the difference in the oil type accounts for the difference in observed results between the West Falmouth and Santa Barbara spills. Woods Hole scientists analyzed samples of the oil which came ashore after the Santa Barbara blowout and found that aromatics and other toxic hydrocarbons were in fact present. This being the case, Blumer has concluded that the difference in observed effects between the two spills was not the result of the different type of oil spilled, but the difference in study methods. 96/

STUDY METHODS. In the West Falmouth spill study, scientists conducted sophisticated chemical analyses (gas chromatography, mass spectroscopy) of sediments and organisms in the spill area to establish the presence and persistence of petroleum hydrocarbons from the spilled oil. Concurrent biological examinations were conducted on all organisms collected at the various sampling stations. The results of these chemical and biological studies -- conducted on a monthly basis from the 1969 spill to the present -- together constitute persuasive evidence of the spill's short-term and continuing long-term biological effects.

The scientists studying the effects of the Santa Barbara blowout, on the other hand, did not make extensive use of gas chromatography or mass spectroscopy analyses in their studies and were thus unable to document the presence, concentrations, or persistence of hydrocarbons in their sediment and organism samples at the level of specificity achieved in the West Falmouth study. Moreover, the biological survey methods used in the Santa Barbara study, especially those used on benthic organisms, were such that not all species in the study areas were examined, but only some species. The methods used in the Santa Barbara study have led some scientists to question the validity of its overall conclusions. Others assert that the design of the Santa Barbara study was such that the scientists were not in a position to determine the actual effects of the blowout.

For example, Dr. J. H. Connell, a zoologist at the University of California at Santa Barbara, states in a review of the USC study:

> The plankton and offshore benthos (Chapters 3, 4, 5, and 9) were sampled and reported in such a way as to make it impossible to decide whether there was or was not an effect of oil...
>
> The fauna and flora of the intertidal shore (Chapters 8 and 17), although much easier to observe, were also poorly studied. With no observations on unpolluted or undisturbed beaches, and using the wrong methods of sampling, without replication or analysis, there is no possibility of a rational conclusion being drawn concerning the effects of oil pollution...
>
> It is clear that because standard scientific procedures were

> not employed in most cases, there is almost no basis for drawing any conclusions about the effects of oil. 97/

Some support for this criticism comes from the USC report itself. In discussing his survey methods, Dr. Kristian Fauchald, author of the chapter on benthic fauna, states:

> ...the survey technique in itself may not be able to show elimination or reduction of sensitive and delicate organisms due to oil pollution, since this technique nearly automatically places the emphasis on common or large or otherwise obvious important organisms. A study of the smaller, lesser known organisms such as polychaetous annelids or amphipod crustaceans might be of more value in estimating the effects of pollutants in the water than a survey of the large common organisms...Other, more detailed techniques may have to be applied to the problem of determining whether or not the benthic environment has been partially or wholly destroyed by pollutants. 98/

CONCLUSION. In a review of observed effects of the Santa Barbara blowout, Dr. Straughan states:

> ...we have been unable to prove large scale damage to plankton, benthos, or marine mammals as a result of the oil spill in January 1969. This does not mean that these populations escaped completely unharmed, but it does indicate a lack of acute catastrophic effects. (Emphasis added.) 99/

In view of the many scientists and observers who looked for spill effects in the months following the blowout, it would have been difficult for massive short-term damage to go unnoticed. It thus seems safe to conclude that the blowout did not cause acute catastrophic effects. But to assert that the blowout had no long-term effects, or that the USC study proved that no such damage resulted is to overreach the available facts. 100/ If the USC study design had incorporated chemical analyses and quantitative biological surveys, and if the study had continued beyond 1970, it might have been possible to establish the actual effects of the blowout. But because these steps were not taken, the effects of the blowout, especially the long-term effects, remain unknown.

The West Falmouth spill study demonstrates that oil spills can cause significant, lasting damage. The Santa Barbara blowout study demonstrates that serious short-term damage is not an inevitable consequence of oil spillage. Beyond this, there does not exist sufficient information to place these two spills in proper perspective, nor to judge accurately the extent of the threat posed by oil spills to California's coastal and marine life. Every crude and refined oil is different, every ecosystem is different, and the circumstances of every spill -- location, size, wind and sea conditions, etc. -- are different. The reported effects of oil spills studied in the past range from negligible to catastrophic, depending upon the unique circumstances of each spill. As a practical matter, it is impossible to predict with much confidence what the consequences of any future oil spills will be. Still, the information available today demonstrates that petroleum hydrocarbons, whether in crude or refined oils, have, at a minimum, the potential to cause damage -- short-term, long-term, lethal, sublethal -- to coastal and marine life.

NON-BIOLOGICAL EFFECTS

In a region such as southern California, the impact of spilled oil on the amenity and recreational value of coastal and marine resources can be substantial, though difficult to express in economic terms. A detailed discussion of this matter is to be found in the middle section of the preceding chapter. Some insight into the costs of spilled oil can be obtained by reviewing the aftermath of the Santa Barbara and West Falmouth spills. One estimate places the economic cost of the Santa Barbara blowout at more than $16,000,000. 101/ A class action suit filed by beachfront property owners and boat owners after the blowout resulted in an award of $4,500,000 damages. Following the West Falmouth spill, 975 acres of shellfish beds were shut down for two years, and 60 acres remain closed today, more than seven years after the spill. One estimate places the market value of the clams and scallops destroyed at $250,000. The owner of the barge/tug responsible for the spill made an out-of-court settlement of $100,000 to the town of Falmouth and $200,000 to the State of Massachusetts as partial compensation for these and other losses resulting from the spill. 102/

LEGAL ASPECTS

Coastal governments and residents face two key issues in the case of a spill: 1) Are legal incentives sufficient to encourage rapid and thorough cleanup; and, 2) Will victims be adequately compensated. The short answer to these questions, subject to the qualifications discussed below, is that adequate cleanup is generally assured, while compensation is not.

Federal and state laws create a hodgepodge framework for preventing spills, encouraging cleanup efforts, and compensating victims. The basic law for our purpose of examining OCS-related oil spills is the Federal Water Pollution Control Act of 1970 (FWPCA) which applies to both federal and state waters. It is useful to examine California laws against this comprehensive backdrop because shortcomings in the state legislation, particularly with regard to cleanup, are mostly repaired by federal provisions that fill in the gaps. Not all gaps however are closed. 103/

STATE SPILL PREVENTION AND CLEANUP

Various provisions of state law prohibit negligent and intentional discharges of oil into state waters and establish criminal or civil penalties for such action. State law also fixes cleanup liability on spillers for negligent or intentional spills. State law has not been interpreted to establish any sanction or impose any liability for accidental spills unless negligence can be proved. For cleanup liability, this gap is more apparent than real, because the FWPCA makes spillers liable for cleanup costs without regard to fault. For damage liability, however, the gap is real indeed. Neither the FWPCA nor any California water pollution control legislation imposes damage liability on non-negligent spillers. Unless an injured party can establish the spiller's liability through some other statute, he will have to absorb his damages without a remedy.

The state's comprehensive legislation, the Porter-Cologne Water Quality Control Act, (Cal. Water Code, §13300 et. seq.) provides for cleanup orders and

civil penalties. Cleanup orders are rarely used because the provisions of the FWPCA are used instead, and the civil penalties have been narrowly construed in a manner which severely hampers their use.

The California Supreme Court interpreted Water Code Section 13350(a)(3) to require the state to show proof of intent or negligence before being awarded monetary penalties for oil spills up to $6,000 per day for each day that an actual discharge occurred (People v. Superior Court, S.F. 23326, 16 Cal 3d. 30, February, 1976). Since most spills occur within a relatively short period, this interpretation sharply reduces the provision's effectiveness as a spill deterrent. It also limited the provision's usefulness as a route through which the State could seek rough compensation for the loss or damage to public resources whose actual value is sometimes too speculative to allow recovery otherwise.

Several other code provisions also cover oil pollution. The California Fish and Game code (Section 5650) makes it unlawful under threat of criminal penalty to deposit or "permit to pass into...the waters of the State" any petroleum. The California Harbors and Navigation Code (Section 133) makes it a misdemeanor to discharge oil from any vessel into the State's navigable waters except in case of "unavoidable accident, collision, or stranding." Section 151 of that code also establishes a civil penalty of up to $6,000, in addition to full liability for government cleanup costs, for "any person that intentionally or negligently causes or permits any oil to be deposited in the waters of this state."

The prohibitions contained in California law may be sufficiently broad to include spills that occur on the OCS and then migrate into the State's three-mile jurisdiction. This study has, however, uncovered no instance where state or local agencies have attempted to assert civil or regulatory jurisdiction over spillers outside the three-mile statutory limit. For practical purposes, then, federal law establishes the standards for regulation of oil pollution originating within OCS waters.

FEDERAL SPILL PREVENTION AND CLEANUP

The Federal Water Pollution Control Act Amendments of 1972 104/ (FWPCA) attempts to achieve three objectives: spill prevention, spill cleanup, and assessment of liability for cleanup costs. The Act does not assure compensation of victims or posit ways to provide compensation or restoration for public resources destroyed or damaged by a spill.

The Act deals with prevention in two ways: First, it addresses the problems of operation and maintenance of vessels and onshore and offshore facilities by authorizing the President to issue regulations "establishing procedures, methods, and equipment and other requirements for equipment to prevent discharges of oil and hazardous substances," 105/ violations of which are punishable by civil penalties of up to $5,000. 106/ Second, the Act prohibits any oil discharge in "harmful quantities," with violations subject to negotiable civil penalties of up to $5,000 assessable by the Coast Guard. 107/ "Harmful quantities" is defined by regulation as amounts sufficient to "cause a film or sheen upon or discoloration of the surface...or cause a sludge or emulsion to be deposited beneath the surface..." 108/ As a practical matter, this regulatory test is met with a discharge of approximately 50 gallons per square mile. 109/

The key to any spill cleanup is early mobilization of equipment before the

spill becomes widely dispersed. In order to facilitate cleanup, the Act requires the person in charge of a vessel or facility (including offshore platforms) from which a discharge occures to notify the Coast Guard "immediately." 110/

The FWPCA authorizes the President to "act to remove" any oil spill "unless he determines such removal will be done properly by the owner or operator of the vessel, onshore facility, or offshore facility from which the discharge occurs." 111/ In practice, the primary reliance for cleanup is upon the spiller. 112/ As a back-up, the National Contingency Plan provides a mechanism for the Coast Guard to monitor these efforts to intervene directly where necessary and to reimburse states for the costs they incur in removing the discharge. 113/

To encourage rapid mobilization of cleanup efforts, the Act also authorized the establishment of a revolving oil spill cleanup fund of $35 million, 114/ which was funded at a level of $20 million, available for financing federal and state cleanup costs and reimbursing spillers for their own cleanup costs where they can demonstrate they are not liable under the Act. The fund has dwindled to a level of about $1 million, reflecting the difficulty of identifying spillers in order to assess cleanup costs. 115/

CLEANUP LIABILITY

In the case of OCS "drilling or production operations," Interior Department regulations issued under the OCS Lands Act make the lessee financially responsible for "the control and total removal of the pollutant, wheresoever found," resulting from the operations. If the lessee fails to take necessary cleanup measures, the USGS Area Supervisor is authorized to do so at the lessee's expense. 116/ These regulations, promulgated immediately following the Santa Barbara blowout, establish absolute, unlimited liability for spill cleanup from any OCS lease, wherever located.

The FWPCA covers a broader scope of facilities, but more limited geographic range than the OCS regulations. The FWPCA is applicable only to the bounds of the twelve-mile contiguous zone, but within that zone it covers all vessels and onshore and offshore facilities, except those OCS facilities under Interior Department jurisdiction. 117/ Where the FWPCA does apply, it establishes a facility operator's liability for actual loss to the United States for "removal of the oil...from the water and shorelines for the taking of such other actions as may be necessary to minimize or mitigate damage to the public health or welfare, including, but not limited to, fish, shellfish, wildlife, and public and private property, shorelines and beaches." 118/ State cleanup efforts are reimbursable as well, if performed pursuant to the National Contingency Plan. 119/

Liability for cleanup costs is imposed regardless of fault. It does not depend upon proof of negligence. Liability is limited by law to $8 million for onshore and offshore facilities and $14 million for vessels, except in the case of "willful negligence" or "willful misconduct," in which case the operator or owner is fully liable for all cleanup costs. 120/ Liability can be avoided only where it is proven the spill was solely due to: 1) an act of God; 2) an act of war; 3) acts of a third party; 4) negligence on the part of the U.S. Government; or, 5) a combination of the above. 121/

Several limitations should be noted concerning the federal framework. First, neither the FWPCA nor the Interior Department regulations include restoration or

restocking of damaged aquatic resources within their provisions for "control" or "removal" of polluting oil. 122/ Second, federal statutes provide for no compensation to damaged private parties. The FWPCA merely states that it does not affect the operator's obligations to third parties. 123/ The Interior Department regulations provide that "the lessee's liability to third parties...shall be governed by applicable law," 124/ which means California common law or Federal Admiralty law, depending on the circumstances.

FINANCING CLEANUP OPERATIONS

The Federal Water Pollution Control Act assumes that a spiller will provide the first line of defense in containing and cleanup of oil spills. If a spiller does not act, the Coast Guard is authorized to undertake cleanup at the spiller's expense. The incentive for a spiller's quick response is that his own cleanup may be less expensive than the government's. If the Coast Guard orders the cleanup, both federal and state containment and cleanup costs are reimbursable, either from the spiller, or from the Oil Spill Contingency Fund. The FWPCA makes no provision for reimbursing expenditures by local governments or private parties. These efforts are not eligible for Contingency Fund reimbursement and the Act does not impose liability upon the spiller to reimburse them.

The only way local government and private cleanup expenditures may be recovered is from the spiller. For "phantom" spills, where the identity of the spiller is not established, there is no mechanism to reimburse these costs. When the responsible party is known, cleanup costs must be recovered through court action, just like damage claims. Actions to recover cleanup costs are subject to the same hurdles: the legal process is time-consuming and expensive; and negligence may have to be established concerning highly technical operations beyond the knowledge of the injured party.

COMPENSATION OF VICTIMS

A potential plaintiff damaged by an oil spill faces numerous obstacles to complete and adequate compensation. The first problem is how to identify the polluter. In spectacular spills like the Santa Barbara blowout in 1969, the Torrey Canyon grounding in 1967, or the San Francisco Bay collision in 1971, identification does not pose an insuperable difficulty. In more routine spills, however, private plaintiffs may be left completely without remedy. Even the Coast Guard, with its considerable legal and technical resources, has been thwarted by this problem, and inability to identify and recover from polluters is the major reason for the dramatic depletion of the "revolving" spill cleanup fund established by the FWPCA. Coast Guard studies indicate that between 1971 and 1973, they could identify discharges of a mere 31% of the spills involving fund expenditures. Even more striking is the fact that by April, 1974, they had succeeded in obtaining full or partial compensation from an even more meager 8% of the "known source incidents," or somewhat less than 3% of the spills involving fund expenditures. 125/ There is no reason to expect private plaintiffs to be more successful.

Where the spiller is known and where individual damage claims are not excessive, the oil industry has a very good record of settling claims. When the American Petroleum Institute solicited claims-settlement data from member companies, respondents indicated that between 1971 and 1974, 1332 of 1339 claims were settled out of court for a total of $598,208, an average of less than $500 per claim. The API study did not include the 1969 Santa Barbara spill, where settlement took six

years and where payment for legally cognizable damages exceeded $14 million; nor did it attempt to sample unsatisfied potential claimants with injuries that could not be attributed to an identified spiller, nor whose injuries were not legally recognized as damages by law. The number of unsatisfied claimants cannot be precisely determined, but they surely exist, since over 45% of spills off southern California from 1973-75 were "phantom" spills where the spiller could not be identified. 126/

The second problem is to establish the polluter's liability. Depending on whether the spill occurs from a vessel or a platform and whether the injury is to a maritime or non-maritime interest, the applicable law for establishing liability and damages may be either Federal Admiralty law or California common law. 127/ Cases involving drilling accidents or marine traffic may prove difficult for individual plaintiffs to establish negligence on the part of the spiller since many of the issues are complex and technical and the sequence of events is probably outside the knowledge of the injured party. Onshore drilling has long been held an ultrahazardous activity in California so that the driller is absolutely liable for damages, once a plaintiff has proved the spiller was negligent. 128/ In the Santa Barbara spill, however, the defendants consistently maintained that specific proof of negligence had to be presented. The government plaintiffs who chose to litigate the Santa Barbara spill spent over one and one-half years in discovery proceedings, which did not begin until three years after the spill. 129/

LIMITS OF DAMAGES

The third major problem in adequately compensating victims is that many of the harms most feared by coastal communities are not legally compensable in the common law. 130/ Even in cases where liability is admitted, negotiations drag on interminably before settlement, to the disadvantage of small plaintiffs. The word "damages" is a term of art denoting a compensation or indemnity which may be recovered in the courts by any person who has wrongly suffered injury. 131/ A definitive answer as to whether damages are recoverable for any particular injury in a specific case must await a court's determination.

There is general agreement that damages include costs relating to repair or replacement of real and personal property damaged by oil -- beaches, docks, small boats, fishing gear, etc. Under some circumstances, inconvenience and discomfort would be included as well. In some limited cases, claimants may recover for consequential economic losses, such as loss of profits in the fishing or tourist industry, and for injury to the marine environment and its living resources. The outcome in any particular case depends on a host of factual legal distinctions.

Generally, courts have been reluctant to permit individual recovery for marine pollution unless a claimant can demonstrate a special injury setting him apart from the public at large. Courts have found such special injury in the case of commercial clamdiggers 132/ and fishermen. 133/ In one case, the court distinguished the clamdiggers' plight from that of local businesses without beach-front property that "claim only of a loss of customers indirectly resulting from alleged pollution." 134/ In the fishermen's case, arising out of the 1969 Santa Barbara blowout, the court carefully warned:

> ...our holding in this case does not open the door to claims that may be asserted by those other than commercial fishermen, whose economic or personal affairs were discommoded by the oil spill of January 28, 1969. Nothing said in this opinion is

> intended to suggest, for example, that every decline in the general commercial activity of every business in the Santa Barbara area following the occurrences of 1969 constitutes a legally cognizable injury for which the defendants may be responsible." 135/

Claimants such as hotels, restaurants, and other small businesses depending on tourists have generally been denied recovery for their economic losses in marine pollution cases unless they happen to own waterfront property which was directly affected. Even in cases where a commercial fisherman can recover, it is not established that employees may recover their losses as well. Courts have split on whether crew members may recover their lost wages when a vessel is inoperable from negligence of the owner of another vessel. 136/

The ownership of beachfront property may be a determining factor as to whether a business may recover at all, and of the extent of damages. In addition to claims for injuries to real or personal property, courts have generally entertained claims from affected property owners for economic injury, such as loss of profit or loss or impairment of earning capacity. At least one court has allowed property owners to recover damages for intangible harm such as annoyance, inconvenience, and discomfort beyond the rental value of the property for the time when its use was impaired by an oil spill. 137/ Persons who were similarly annoyed, inconvenienced, or discomforted by the fouling of a public beach, however, have no special and particular injuries setting them sufficiently apart from the public-at-large to establish legally cognizable damages. This was the reasoning in a case arising from the Santa Barbara spill, where pleasure boat operators were denied recovery for "loss of use" of their craft as a result of the spill. 138/

The right of state and local governments to recover damages for loss of proprietary income, such as fees paid by park visitors and concessionaire and leasehold income, is generally conceded. 139/ However, the right of state and local governments to recover for damage to the marine environment and natural resources has been hotly contested, as have the standards for measuring those damages. 140/ Another disputed area is the right of state and local governments to recover damages, loss of tax revenue from real and personal property, and business activities affected by a spill. This was claimed in the Santa Barbara spill, but the defendants asserted there was no legal basis for such a claim. 141/ Since a settlement was reached, no court has ruled on the validity of the tax loss as a damage element.

In summary, many of the injuries arising from an oil spill have no legal remedy. Damages for intangible losses such as annoyance or inconvenience, as might be experienced by tourists and residents, are restricted to real property owners whose property interest was physically harmed. Even with economic losses, existing law provides damages to only a portion of the claimants who suffer from a spill. The principal claimants with no current legal avenue for relief include the owners of hotels, motels, trailer parks, campgrounds, restaurants, stores, and the like, whose businesses depend upon the tourist trade but who are not physically affected by an oil spill. They have no current right to recover for loss of profits resulting from a business decline attributable to oil pollution. Similarly, their employees and even employees of businesses directly and physically affected by oil pollution have no clear right to damages for lost wages. The third claimant group without legal remedy is state and local governments that suffer tax revenue losses from a pollution incident. Claimants who may or may not

have a legal right to recover for economic loss include charter boat operators, diving instructors, and others whose business depends upon the sea.

LEGISLATIVE REMEDIES

The Interior Department has predicted that at least one major spill is a virtual certainty from the southern California OCS areas leased in December, 1975. For a large oil field discovery in this area, there is over a 95% chance of a platform spill exceeding 1000 barrels during the 30-year development and production period. For medium and small finds, the chances of such a spill were estimated at 70% and 25% respectively. If a large platform spill does occur, Interior estimated an 80% chance it would exceed 2380 barrels and a 35% chance it would exceed 23,000 barrels. 142/ Other federal leases, state offshore oil operations and tanker traffic, of course, all provide additional potential sources of spills.

In light of this risk, it is essential that state and federal laws protect the public and public entities from the threat of loss or harm from OCS or non-OCS oil spills. That protection does not now exist. As indicated above, there are several major inadequacies in the current law:

1. absolute liability is not clearly the standard for imposing liability for damages resulting from oil spills;
2. the state and its citizens are subject to protracted and expensive litigation to recover costs and damages resulting from some oil spills;
3. some losses resulting from oil spills are not recoverable under traditional notions of "legal damages"; and,
4. protracted and expensive litigation is especially unfair for the individual citizen whose claim for costs and damages amounts to only a few thousand dollars.

In order to address these problems, oil spill liability funds have been proposed at both the state and federal level. The thrust of these efforts is to create a fund to compensate damaged parties on a timely basis, without expensive litigation and unfettered by an array of legal technicalities limiting recovery where it is deserved. Most proposals would start and replenish the fund through recovery from spillers and a small tax on oil operations. The fund thus maintains incentives for spill prevention and internalizes spill costs upon the responsible parties.

The California Legislature dealt with two major spill liability fund bills (SB 387, AB 4008) in the 1975-76 Session. Both generally followed the outline described above, but neither reached a floor vote. Two piecemeal spill fund bills at the federal level have been enacted in conjunction with the Trans-Alaskan Pipeline Act and the Deepwater Port Act of 1974. The 94th Congress produced no liability legislation, although spill fund provisions were included in both the House and Senate versions of the OCS Amendments and were the subject of several bills in each body. The House Merchant Marine and Fisheries Committee reported the Comprehensive Oil Pollution Liability and Compensation Act of 1976 (HR 14862) on September 9, 1976. The bill represented a compromise between the three major versions introduced, but it died late in the session without further action by the House.

The House bill is worth examining, however, because it contains the essential

elements of a workable compensation fund. The bill provided for a $200 million fund from oil terminal fees, which would be available to claimants for cleanup and removal costs as well as for damages. The fund would be liable, except in the case of war or riot or where the claimant's own gross negligence or willful misconduct caused the loss. Spillers would in turn be strictly liable to the fund in all cases where the fund was used, with the sole exception of cases where the incident was caused by the act or omission of a third party. In that case, the claimant would still be compensated, but the fund would either spread the loss over all fee payers or proceed after the negligent third party.

The liability legislation provided recovery for some damages not generally permitted by common law. Owners and lessors of real or personal property directly affected by a spill were allowed to claim damages, including cleanup costs, injury to property, and loss of use of property. Non-riparian claimants, such as hotel owners whose property is not in direct contact with a spill but who nonetheless might suffer business losses, would have been denied recovery by common law. These claimants and their employees would be allowed damages for loss of profit or income if they derive more than 25% of their earnings from activities using an affected property or resource. They could also claim damages for loss of use of the natural resource. The definition of state and local government damages was expanded. For personal or riparian real property, government claimants could recover damages for cleanup costs, injury to property, and loss of use of injured property, as well as any other cleanup costs authorized under the FWPCA. In addition, the loss of tax revenues caused by injury of real or personal property for one year could be claimed. Finally, states (but not local governments) would be able to recover for injury to natural resources, though the measure of damages was not spelled out.

RECOMMENDATION

The State should support the enactment of state or federal legislation to establish a spill liability compensation fund financed through equitable taxes on oil operations and providing a source for private and public claimants to obtain adequate redress for harms not now recognized as "legal damages" and without the uncertainty and expense of protracted litigation.

OIL SPILL RESPONSE

The 1969 Santa Barbara Channel blowout caught industry and government unprepared and painfully demonstrated the inadequacy of then-existing equipment and procedures to clean up offshore oil spills. 143/ The embarrassingly large gap between what was needed and what was available, between predicted performance of equipment and actual field performance, triggered substantial efforts by industry and government to devise more effective oil spill cleanup methods. Two areas of concentration have been contingency planning to improve the speed of response, and developing cleanup equipment capable of functioning under a wider range of field conditions.

CONTINGENCY PLANS

An oil spill is an emergency requiring immediate and coordinated action. The most effective way to limit the damage caused by a spill is to contain and remove

from the water as much of the oil as possible as rapidly as possible. With many different agencies, organizations, jurisdictions, and authorities involved in cleanup operations, there are numerous opportunities for confusion and delay. In order to streamline the response, oil spill contingency plans have been drawn up by federal agencies, state agencies, local agencies, and industry organizations. These contingency plans specify lines of authority, procedures to be followed, and equipment available for use in responding to spills.

FEDERAL

The National Oil and Hazardous Materials Pollution Contingency Plan establishes the frame within which oil spills are cleaned up in the United States. 144/ The Coast Guard administers the plan for spills in coastal waters, the contiguous zone, and the high seas. Through a memorandum of understanding between the Secretaries of Transportation and Interior, the USGS has exclusive authority over measures to control oil spills at and within 500 yards of OCS facilities. 145/

Under the plan, Coast Guard personnel investigate all reported offshore spills, notify the party responsible (if known) of his obligation to clean up the spill, and supervise or -- if necessary -- direct the cleanup operation. If, for whatever reason, cleanup is not promptly begun by the responsible party, the Coast Guard can hire the private organizations to do the work. Most spills are cleaned up by private personnel working for either the spiller, the oil spill cleanup cooperative in whose area the spill occurs, or an independent cleanup contractor. The Coast Guard seldom finds it necessary to undertake the actual cleanup itself, though it often provides communications equipment, containment boom, and other federal resources to assist the private cleanup operation. Regardless of who actually cleans up the spill, the Coast Guard retains final authority over procedures and equipment used, and together with various federal and state agencies, controls the use of dispersants and other chemical agents. 146/

To improve coordination among the many government agencies participating in or monitoring spill cleanup operations, the National Plan provides for the establishment of Regional Response Teams (RRT). Within Region 9, which includes California, Arizona, Nevada, and Hawaii, sub-Regional Response Teams (SRT) have been formed. Primary members of the SRT for southern California include the Coast Guard, EPA, the Departments of Defense and Interior, and California's Department of Fish and Game.

STATE

California has its own oil spill contingency plan, which has been recommended as a model state plan by the American Petroleum Institute. 147/ Under California's plan, a State Support Team (SST) and a State Interagency Oil Spill Committee (SIOSC) have been established to coordinate the activities of State agencies with each other and with federal, local, and industry agencies and organizations. The SST has designated the Director of the Department of Fish and Game as the State Operating Authority (SOA) in charge of state activities under the plan.

Because federal law reserves ultimate authority over cleanup operations to the Coast Guard and other federal agencies, the State's role in offshore cleanup operations is that of observer, assistant, and advisor -- with the important exception that the State has veto power over the use of chemical agents in state waters. In practice, Department of Fish and Game personnel investigate all spills in state

waters and many spills in federal waters, monitor, assist, and advise federal and industry cleanup operations, and maintain liaison between local, state, federal, and industry agencies and organizations. California does not have a fund to pay for private cleanup efforts and must tap the Coast Guard's revolving fund to require the services of industry or private cleanup organizations.

LOCAL

The role of local officials during spill cleanup operations is generally limited to monitoring and providing onshore logistical support for industry and federal efforts, such as controlling traffic, arranging for the use of local harbor facilities, providing for the disposal or recycling of recovered oil, identifying coastal access point, etc. When oil comes ashore, the focus of the overall cleanup operation shifts to the oiled shoreline areas, and local and state personnel and equipment may be directly involved in the task of removing the oil and restoring -- to the extent possible -- oiled areas to pre-spill condition.

State officials assist local governments to improve local knowledge and participation in spill cleanup operations, and to develop local contingency plans. In 1974, the Department of Fish and Game sponsored workshops in Long Beach and Santa Barbara to acquaint local officials there with federal, state and industry spill response procedures (see Appendix 8). The County of Los Angeles Department of Beaches recently completed an inventory of beach access routes within Los Angeles County as the first step in the oil spill contingency plan it is developing (see Appendix 9).

INDUSTRY

The U.S. Geological Survey requires the operators of all OCS facilities to prepare oil spill contingency plans describing the type, quality, and location of spill control equipment available to the operator, and the procedures to be followed in the event of a spill. 148/ Similar requirements have been imposed by various state and federal agencies on oil-related facilities within three miles of shore. 149/

Industry has organized three oil spill cleanup cooperative associations in southern California to respond to offshore oil spills. Clean Seas, Inc., based in Santa Barbara, will respond to spills in state and federal waters between Cape San Martin (north of Estero Bay) and Point Dume. Clean Coastal Waters, Inc., in Long Beach, will respond to spills in state waters between Point Dume and the Mexican border. The Southern California Petroleum Contingency Organization (SCPCO), also based in Long Beach, is being established to respond to spills originating at the leases sold in Lease Sale #35.

These cooperatives function in a straightforward fashion: member companies, generally including all offshore producers in the cooperative's response area as well as other potential spillers, are assessed annual fees based on the level of their offshore activities. These funds are used to purchase and maintain stockpiles of containment boom, skimming devices, workboats, chemical agents, radios, etc., at a central location, and to train industry personnel in the use of the equipment. In the event of a spill, the cooperative delivers to the company or to the spill site whatever equipment the company requests, together with laborers provided through contractors retained by the cooperative. Cooperatives will make their equipment and services available to non-member companies and agencies (such

as the Coast Guard) if the equipment is not being used by member companies at the time.

In southern California, most containment and recovery equipment suited for open ocean cleanup operations is stored and maintained by the cooperatives at central locations onshore. 150/ Under existing state and federal regulations, offshore producers keep small amounts of "first aid" spill containment and recovery equipment at production or drilling facilities, and rely on the shore-based equipment to deal with spills larger than five to ten barrels. For Lease Sale #35 operators, many of whose leases lie 40 to 100 miles from the mainland, the SCPCO has stockpiled some of its equipment on Santa Catalina Island, and is trying to develop a system to deliver and deploy containment boom by helicopter. 151/ If this helicopter system can be made to work effectively and reliably, it will sharply reduce response time and thus increase the chances for successful oil spill cleanup.

CLEANUP EQUIPMENT

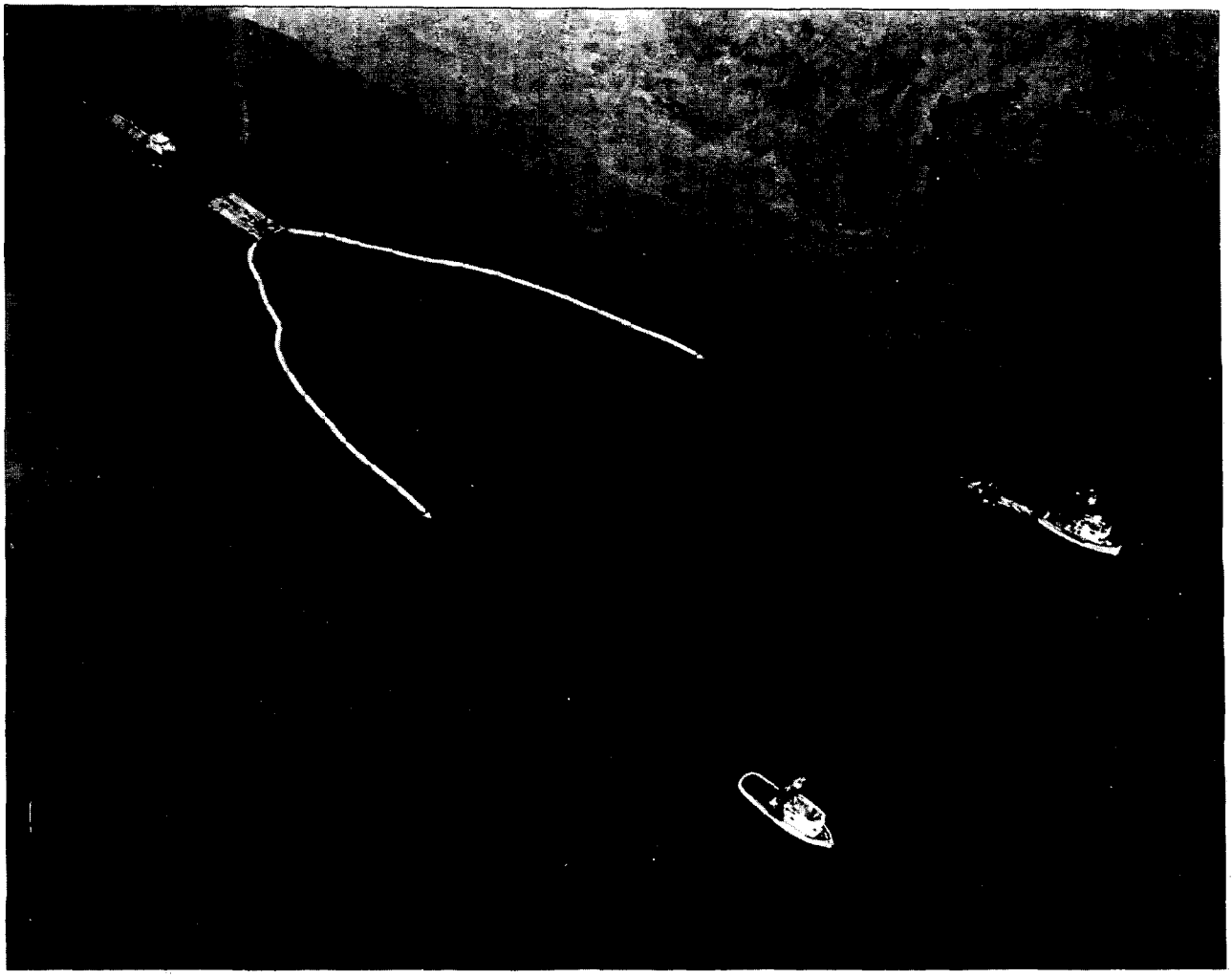
State and federal policies advocate the physical removal of spilled oil from water whenever possible. 152/ For this reason, first priority in spill cleanup operations is always given to at-sea containment and recovery attempts. Speed of response is critical to the success of such efforts, because: oil slicks are thickest immediately after the spill occurs and thus most easily contained and removed; water-soluble toxic hydrocarbons have not yet been released from the slick in large quantities; and the slick has less time to spread or move toward shore. 153/

Containment booms are floating barriers which, under suitable circumstances, prevent the spread or passage of an oil slick from one side of the boom to the other. At sea, booms are commonly used to: (1) surround an oil slick to prevent its further spread or movement; and, (2) help concentrate the spilled oil in order to facilitate recovery of the oil from the water. Along the shore, booms are often deployed across the entrance to harbors, marinas, or estuaries to prevent slicks from entering and fouling such areas or to steer the oil toward recovery devices. 154/

To recover spilled oil from the water, a variety of skimming devices have been developed. One kind of skimmer uses weirs or near-surface intakes to pump in fluids from the water surface or just below. Another type of skimmer uses belts of a material that preferentially absorbes oil and repels water; the belts are continuously rotated into and out of the water, with oil from the slick squeezed off into a holding tank while the belt continues back into the water in an endless cycle. For any skimmer to work at top efficiency, the spilled oil must be concentrated at the skimming site. Containment booms and sorbents -- materials that float, absorb oil, and repel water -- are commonly used in conjunction with skimmers to increase recovery rates. Figure 12 is a photo of a skimmer in operation.

In addition to the response time, the success or failure of at-sea containment and recovery operations depends heavily on the environmental conditions under which the attempt is made. Under calm ocean conditions, as shown in Figure 12, existing containment and recovery equipment will function effectively, and successful at-sea recovery of the spilled oil is likely to be accomplished. But the effectiveness of containment booms and skimmers falls off dramatically as ocean conditions worsen. The booms will not perform effectively if water currents exceed one to two knots, the exact failure point depending on the type of boom used. Currents of sufficient velocity to hamper containment efforts are generally found

FIGURE 12: OIL SKIMMER OPERATION (SOURCE: CLEAN SEAS INC.)



only near shore, or in restricted bodies of water such as harbors, tidal basins, or river mouths. In open ocean cleanup operations, currents are usually of less importance than the sea state, which is largely determined by wind and wave conditions.

The operating limit for a containment boom is often expressed in terms of wave height; for example, Brand X boom may be rated by its manufacturers as capable of containing oil in waves up to six feet. But wave height alone is not the determining factor, because wave period, wave steepness, and the amount of turbulence at the ocean surface are also important. If winds are moderate, and waves in the vicinity of the slick consist only of smooth, long-period swells, Brand X may indeed contain oil effectively until wave height exceeds six feet. But if local winds superimpose short-period, steep-sided wind-chop on top of the swell -- as often occurs in the Santa Barbara Channel or San Pedro Bay in late afternoon -- or if the waves are breaking, Brand X may cease to be effective when wave height exceeds three feet.

The efficiency of skimming devices is similarly dependent on sea conditions. Pump or weir type skimmers take in water as well as oil, and the oil-water recovery ratio falls off rapidly as the sea state worsens. Endless-belt skimmers are designed to achieve a high oil-water ratio, but their recovery rate also drops off in rougher sea states. As has been noted elsewhere, the most prominent characteristic of skimming devices is the variance between predicted and actual performance. 155/ Generally speaking, effective skimming is unlikely to take place when ocean conditions are anything other than moderately calm. 156/ In addition to their effect on cleanup equipment, environmental conditions also influence the effectiveness of the people using the equipment. It is much more difficult and hazardous to undertake at-sea operations at night or during fogs than it is during daylight or clear conditions.

OIL SPILL CLEANUP AGENTS

An oil spill cleanup agent (OSCA) is any substance applied to oil on water or on the shoreline in order to disperse, remove, or otherwise control the oil. 157/ Any OSCA applied in or on state waters must be licensed by the State Water Resources Control Board, and the use of an OSCA is supervised and enforced by the Department of Fish and Game. Dispersing, collecting, and sinking agents have all been developed for application on oil slicks. Biodegradants and burning agents are under development, but not yet considered effective. Collecting agents include gelling and herding chemicals and sorbents, the function of which is to absorb, congeal, gel or demulsify oil, leaving an end product which remains afloat for later collection or burning. Sinking agents increase the specific gravity of floating oil to the point where it sinks through the water column to the seafloor. Dispersants act by altering the surface tension of the oil, to increase the spreading of slicks and promote the emulsification and mixing of oil into the water column.

CHEMICAL DISPERSANTS

During the 1967 Torrey Canyon spill, large quantities of dispersants were used. Because dispersants were heavily used on the shoreline itself, and because the brands used were themselves highly toxic, the biological damage caused by the dispersants was found to be at least as great as that caused by the oil itself. 158/ Since then, industry has developed more acceptable dispersants; some recently

developed products are reputed to be 10,000 times less toxic than those used in 1967. But the use of dispersants remains the subject of considerable controversy.

Advocates argue that: (1) by increasing the surface area of an oil slick, dispersants accelerate the rates of physical, chemical, and biological degradation of spilled oil and lower the concentration of oil in the water; (2) by reducing the tendency of oil droplets to adhere to each other and to solid surfaces, dispersants can reduce the number of birds killed; (3) dispersants are the least expensive method of dealing with spilled oil; and, (4) by transferring oil from the water surface into the water column, dispersants reduce the chance of oil coming ashore in heavy concentrations, thereby reducing the potential for shoreline damage.

Opponents argue that: (1) dispersants remain toxic -- though not as toxic as earlier versions -- so that their use actually increases the toxic load on organisms in the affected area; (2) by spreading spilled oil over a greater area, dispersants increase the number of organisms exposed to potential damage from both the oil and the dispersants; (3) if dispersants function effectively, they eliminate any chance of physically recovering the spilled oil; and, (4) by removing the surface appearance but not the actual presence of oil, dispersants are merely a cosmetic solution to oil spills.

Because dispersants have both desirable and undesirable attributes, California and federal authorities have adopted regulations restricting but not altogether prohibiting their use. 159/ As noted earlier, first priority is always given to the physical removal of spilled oil from the water. But at-sea containment and recovery is often impossible, and situations may arise where dispersants offer the only chance to prevent an oil slick from coming ashore and fouling sensitive coastal resources. Under present law, state and federal authorities have the flexibility to permit the controlled use of dispersants if their use is likely to result in less overall damage than would occur if the slick were left alone.

In practice, dispersants are rarely used off California. A good example of the circumstances under which dispersants might be considered for use is provided by the tanker Irene's Challenger, which broke up near Midway Island on January 18, 1977. 160/ A three million gallon crude oil slick formed and, under the winds prevailing at that time, began to move toward a Hawaiian fur seal sanctuary about 40 miles away. Adequate containment and removal equipment could not be delivered to the site in time to keep the oil away from the sanctuary. Federal spill response team officials on the scene judged the potential threat to the seals to outweigh the potential threat caused by using dispersants and made preparations to apply dispersants if the slick continued to move toward the sanctuary. By the time the slick had approached within 20 miles, however, the winds shifted, moving the slick away from the sanctuary and out into the open ocean. Since the threat was gone, the overriding need for dispersants no longer existed and none was applied.

ASSESSMENT

Oil spill cleanup procedures and equipment have improved substantially since the 1969 blowout, but if a spill occurs in anything other than ideal conditions -- daylight, calm seas, near a cooperative -- the success of at-sea containment and recovery attempts remains an open question. In part, this reflects the difficulties inherent in preparing for and responding to phenomena which may occur at any time, anywhere off southern California, and which may vary in size from 1-1,000,000

gallons and cover tens of square miles, under a wide range of environmental conditions.

This problematical status also reflects the fact that the three southern California oil spill cleanup cooperatives -- industry's main line of defense against offshore spills -- were established after the Santa Barbara blowout and have not yet had the opportunity to demonstrate their capabilities during a major offshore oil spill. Each cooperative conducts periodic at-sea equipment demonstrations, to which government and industry officials are invited, but none of the cooperatives conduct full-scale rehersals of spill response procedures. This being the case, the ability of existing procedures and equipment to contain and recover spilled oil at sea in a timely fashion under a range of environmental conditions is simply unknown.

Considering the variety of oil spill sources, the uncertainties as to the fate of spilled oil, the complexities of predicting spill trajectories, the very real threat of damage from spilled oil, and finally the spill response capability available in southern California today, the need for protection strategies cannot be underestimated. Three basic protection strategies are proposed: prevention, at-sea cleanup, and defensive precaution.

PREVENTION

Prevention is the best solution to the oil spill problem. At existing offshore oil and gas leases, careful industry procedures, together with vigorous government enforcement of spill prevention regulations, can minimize the number and volume of spills. Advances in drilling, production and safety technologies can further reduce the incidence of spills. After the 1969 blowout, state and federal authorities strengthened existing spill prevention regulations, imposing new requirements, and the U.S. Geological Survey increased its Pacific OCS inspection force from two to 11 full-time employees. As a result, there has not been a reported spill from a production platform in state or federal waters off California since December, 1969. California OCS oil-related activities are going to increase as additional leases are brought into production, and to maintain existing levels of enforcement in the future USGS will have to expand its enforcement staff and budget.

Another way to prevent oil spills is to reject altogether or attach special conditions to proposed activities with spill potential. These decisions should be based on oil spill trajectory analyses and on the identification of particularly important coastal and marine resources vulnerable to spills from the proposed activity. These analyses can identify sites from which spills would have unusually large potential for causing damage. Based on this knowledge, proposals can be denied or shifted to less risky locations, or special conditions can be imposed to provide a larger-than-ordinary safety margin against oil spillage. During Lease Sale #35, for example, Santa Monica Bay tracts were withheld from sale because the potential risks associated with activities there were judged to outweigh the oil and gas benefits, and special conditions were imposed on leases in close proximity to Santa Barbara and Santa Cruz islands. California has recommended a series of similar actions for many of the tracts proposed by the Interior Department to be leased in Lease Sale #48.

AT SEA CLEANUP

No offshore oil facility can be made spill-proof, because many spills occur

as a result of accidents or human error. In view of the large and growing number of oil-related activities off California, major and minor oil spills are likely to occur despite the best efforts of industry and government. When a spill occurs, the primary objective of the response is to keep damage to a minimum. The surest way to do so is to contain and remove the spilled oil from the water as quickly as possible.

Most of the factors influencing the chances for successful recovery of spilled oil at sea -- local sea conditions, size and location of the spill, time of day, etc. -- are fixed by the random circumstances of the spill and cannot be altered. One of the decisive factors which can be influenced is the response time, the lag between a spill and the deployment of containment boom at the scene. Under existing regulations, offshore producers store only minimal amounts of containment boom at offshore platforms and rely on centrally located, shore-based equipment delivered by boat for responding to spills larger than five or ten barrels. Joint ownership of this equipment reduces costs to individual operators and ensures uniform equipment for all member companies. Also, the central onshore location simplifies the task of maintaining and preparing the equipment for emergency response. But it also builds needless delay into the response time for spills larger than five to ten barrels. Several existing production platforms in the Santa Barbara Channel, for instance, are more than 30 miles from the Clean Seas, Inc. storage yard in Carpinteria.

The delay in delivering containment equipment to these platforms by boat, the only transportation now available, would be considerable. An obvious solution is to maintain more heavy-duty containment boom at offshore platforms as a stop-gap measure. This would not increase the operational limits of existing containment equipment, nor eliminate the need for recovery devices and containment boom stored at central onshore locations. But by requiring that more containment boom be stored at production platforms, USGS and the State Lands Division could improve the odds of early at-sea recovery of spilled oil, reducing the potential for damage from major spills.

D E F E N S I V E P R E C A U T I O N

When it is impossible to contain and recover spilled oil at sea, it is sometimes possible to reduce shoreline damage. Containment booms or, in extreme cases where no alternative is available, dispersants can be used to keep oil away from specific areas, by diverting it or by changing its physical properties so that natural forces move it toward areas judged to be of lesser value, whether natural or human, or lesser vulnerability.

ESTUARIES, SALT MARSHES, AND WETLANDS

Estuaries, salt marshes and wetlands, for example, are highly productive areas that provide essential habitats for many coastal and marine species. Oil entering such areas may cause substantial damage. Moreover, it is particularly difficult to remove oil from marshes and wetlands, and cleaning such areas once they have been oiled is apt to cause as much damage as the spilled oil itself. Estuaries, salt marshes and wetlands, therefore, deserve special protection during oil spill emergencies. Because these areas generally have restricted communication with the ocean, defensive booming is a practical protection strategy. Depending on the circumstances, booms could be set across the entrance to such an area either to steer the arriving oil to a skimming site, to deflect the oil to

either side of the entrance, or simply to delay or reduce the amount of oil entering. Defensive booming is unlikely to keep all oil away from the protected areas, but it can significantly reduce the fouling and damage suffered by sensitive and valuable resources.

Industry has already taken the first step toward such a protection strategy in the Santa Barbara Channel. In a study commissioned by Arco, biologist June Lindstedt-Siva has identified ten biologically valuable areas along the Channel coast deserving special protection. 161/ Four of these are estuary, salt marsh and wetland sites between Goleta and Point Augu suitable for defensive booming. 162/ Clean Seas, Inc., the cooperative responding to spills in the Channel, is in the process of deploying five vans carrying containment boom and other spill cleanup equipment at Morro Bay, Gaviota, Port Hueneme, and Santa Barbara, for the stated purpose of protecting harbors, estuaries, and other coastal resources. A sixth van is maintained at the central Clean Seas, Inc. yard in Carpinteria. Clean Coastal Waters, Inc., the cooperative responding to spills in state waters from Point Dume to the Mexican border, has not yet taken comparative action.

BEACHES AND ROCKY INTERTIDAL AREAS

Other coastal resources are not suited for defensive booming. Rocky intertidal and beach areas, for example, generally are too extensive for such tactics to be effecitve. As with salt marshes, no effective method has been devised for cleaning oiled rocky intertidal areas, since the two primary methods used in the past -- steam cleaning or detergent washing -- were found to kill organisms surviving the original spill. In comparison, oiled beaches are considerably easier to clean. Three specific rocky and sandy beach areas in the Santa Barbara Channel area have been proposed as possessing special biological significance particularly for the repopulation of damaged areas after a large spill. 163/ For these areas, at-sea containment and removal would be best, with the use of dispersants or other cleanup agents held in reserve as a final option to be exercised only after a review by the Regional Response Team.

PINNIPED ROOKERIES

Pinnipeds are disturbed by all human activities. Both defensive booming and the cleaning of oiled rookeries and haul-out sites are self-defeating strategies, because the actions themselves would constitute significant disruptions. Protection strategies must focus on preventing spilled oil from reaching pinniped rookeries and haul-out sites, either through the prohibition of oil-related activities in locations where spills would move towards pinniped sites or by requiring additional containment boom and skimmers at oil-related facilities in such areas. If spills occur and move toward pinniped sites despite these precautions, no further defense may be feasible.

FOOTNOTES

1. National Academy of Sciences, Petroleum in the Marine Environment (Washington, D.C.: National Academy of Sciences, 1975), pp. 1-16.

2. Ibid., p. 104. Percentage contributions added.

3. U.S., Federal Energy Administration, North Slope Crude: Where To? How? IV-E (November 1976), p. 81.

4. Ibid., p. 89.

5. A good discussion and analysis of oil spill statistics is contained in J. W. Devanney III and Robert J. Stewart, Bayesian Analysis of Oil Spill Statistics, presented at the January 1974 meeting of the New England Section of The Society of Naval Architects and Marine Engineers (October 1974). See also V. F. Keith and J. D. Porricelli, "Analysis of Oil Outflows due to Tanker Accidents," Proceedings of Joint Conference on Prevention and Control of Oil Spills (Washington, D.C.: American Petroleum Institute, 1973).

6. U.S., Federal Energy Administration, op. cit., pp. 93-94.

7. U.S., Department of the Interior, Geological Survey, estimates that 10,000 barrels of oil were spilled in the first ten days of the blowout. A. A. Allen, in his report to the U.S. Senate Interior Committee Subcommittee on Minerals, Materials, and Fuels (1969) Santa Barbara Oil Spill, estimated that 77,000 barrels of oil were discharged during the first 100 days after the slick. Foster et al., Santa Barbara Oil Spill, Part 1: Initial Quantities and Distribution of Pollutant Crude Oil, Environmental Pollution (2), pp. 97-133, estimated that between 78,000 and 780,000 barrels of oil were spilled.

8. Alpine Geophysical Associates, Inc., Oil Pollution Incident: Platform Charles, Main Pass Block 41 Field, Louisiana (May 1971).

9. Elmer P. Danenberger, Oil Spills, 1971-75, Gulf of Mexico Outer Continental Shelf, U.S. Department of the Interior Geological Survey Circular 741, p. 47. Estimated inputs are taken from National Academy of Sciences, op. cit., with "Percentage of Total" figures computed by U.S. Geological Survey.

10. J. W. Devanney and R. J. Stewart, "Analysis of Oil Spill Statistics," Primary Physical Impacts of Offshore Petroleum Developments (Cambridge: Massachusetts Institute of Technology, April 1974). See discussion in U.S. Department of the Interior, Bureau of Land Management, Final Environmental Statement: Proposed 1975 Outer Continental Shelf Oil and Gas General Lease Sale Offshore Southern California (1975), I, pp. 32-87.

11. U.S., Department of the Interior, Bureau of Land Management, op. cit., p. 85.

12. Don E. Kash et al., Energy Under the Oceans (Norman, Oklahoma: University of Oklahoma Press, 1973), p. 292.

13. Ibid., p. 287.

14. H. T. Cypher, Acting USGS Oil and Gas Supervisor, Pacific Area, "Tabulation of Accidents -- Federal Oil and Gas Operations in the Outer Continental Shelf, Pacific Area," unpublished memorandum, August 4, 1976.

15. Letter from Ralph J. Bowman, Union Oil Company of California, to Trevor O'Neill, OCS Project staff, March 2, 1977.

16. U.S., Federal Energy Administration, op. cit., p. 151.

17. From National Academy of the Sciences, op. cit., p. 6, Table 1-5. Tanker contribution (LOT [Load-on-TOP] tankers, non-LOT tankers, terminal operations, tanker accidents) estimated to be 1,283,000 tons/year. Tanker accidents contribute 200,000 tons/year or 15.6%. LOT tankers, non-LOT tankers, and terminal operations contribute 1,083,000 tons, or 84.4%.

18. Interview with Walter Putman, Inspector, California Department of Fish and Game, March 1977.

19. Interview with Dr. Peter Fischer, California State University-Northridge, October 1976.

20. Interview with Dr. Ed Welday, California State Lands Division, March 1977.

21. California Resources Agency, The Offshore Petroleum Resource (1971), p. 137.

22. Interview with William Gesner, Santa Barbara County Environmental Quality Advisory Board, March 1977.

23. Danenberger, op. cit., p. 29.

24. Ibid., p. 1.

25. U.S., Department of the Interior, Bureau of Land Management, op. cit., II, p. 155.

26. National Academy of Sciences, ibid., p. 45.

27. Ibid., p. 46.

28. William D. Garrett, "Impact of Petroleum Spills on the Chemical and Physical Properties of the Air-Sea Interface," Santa Barbara Oil Symposium: Offshore Petroleum Production, An Environmental Inquiry (Santa Barbara, California, December 1970) p. 91.

29. Ronald L. Kolpack, ed., Biological and Oceanographical Survey of the Santa Barbara Channel Oil Spill, 1969-1970 (University of Southern California: Allen Hancock Foundation, 1971), II, pp. 341-343.

30. See Max Blumer and Jeremy Sass, "Oil Pollution: Persistence and Degradation of Spilled Fuel Oil," Science, 176 (June 9, 1972), pp. 1120-1122; and Kolpack, op. cit.

31. Max Blumer, "Scientific Aspects of the Oil Spill Problem," Environmental Affairs, I (April 1971), p. 63.

31a. National Academy of Sciences, op. cit., p. 66.

32. U.S., Department of Commerce, National Oceanic and Atmospheric Administration, Deepwater Ports Project Office, Analysis of the Risk of Damage to the States of Florida and Louisiana from the LOOP, Inc., Proposed Deepwater Port, 1976, pp. F2-6.

33. Ibid., p. F-2.

34. See, for example, ibid., p. F-3, Figure F-1 and also MIT, A Review and Evaluation of Basic Techniques for Predicting the Behavior of Surface Oil Slicks, 1976, Table 1, p. 3-65.

35. One researcher found the wind factor to be a function of wind speed; that is, a different percentage factor at different wind speeds. See Wu (1968) in MIT, op. cit., p. 3-65.

36. For example, Hughs (1956) found 0.3° deflection to the left. See MIT, op. cit., Table 1, p. 3-65.

37. NOAA, op. cit., p. F-4.

38. See MIT, op. cit., Figure 4.5-1, p. 4-64. Also see J. W. Devanney III, Estimates of Spill Trajectory Likelihoods for the Southern California OCS, Martingale Technical Report 75-2, 1975, p. 23.

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46. J. G. Wyllie, Geostrophic Flow of the California Current at the Surface and at 200 Meters, California Cooperative Oceanic Fisheries Investigations, Atlas #4, 1966.

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48. Intersea Research Corporation, "Study of Potential Trajectories of Oil Spilled in the Proposed Southern California Offshore Lease Area," in Western Oil and Gas Association Environmental Assessment Study -- Proposed Sale of Federal Oil and Gas Leases, Southern California Outer Continental Shelf, Appendix 3, 1974.

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50. Intersea Research Corporation, op. cit., p. 1.

51. See, generally, Devanney, op. cit., pp. 32 ff.

52. Ibid., p. 116.

53. Intersea Research Corporation, op. cit., p. 31. IRC included neither the Navy wind summaries nor its own "average" or "dominant" wind vectors in the report. It is thus impossible to determine the extent to which this apparent methodological error skewed the ultimate results of IRC's study.

54. Dr. R. J. Stewart, personal communication,to Trevor O'Neill, OCS, Nov. 22, 1976.

55. United States Department of the Interior, Bureau of Land Management, Final Environmental Statement -- Proposed 1975 Outer Continental Shelf Oil and Gas General Lease Sale Offshore Southern California (OCS Sale #35), 1975, Volume 2, pp. 425-453 and Volume 4, Appendix 17, pp. 691-725.

56. Ibid; see matrix tables, Volume 4, Appendix 17, pp. 691-725.

57. U.S., Department of the Interior, "Secretary Kleppe Deletes Additional 16 Tracts from the Northern Gulf of Alaska (OCS-39) Sale," news release, April 6, 1976.

58. See footnote 32.

59. Dr. Jerry Galt, NOAA Pacific Marine Environmental Laboratory, personal communication to Trevor O'Neill, OCS Project Staff, December 3, 1976.

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64. Numerous summaries of the reported and potential effects of oil on coastal and marine organisms are in print. See, for example, Donald F. Boesch et al., Oil Spills and the Marine Environment, 1973; National Academy of Sciences, op. cit.; California State Lands Division, Draft Environmental Impact Report, Development of South Elwood Offshore Oil Field, Appendix A, 1974; Bureau of Land Management, Final Environmental Impact Statement, OCS Sale #35, op. cit., and U.S. Department of the Interior, 1975, II, pp. 141 ff.

65. Boesch et al., op. cit., pp. 35 ff.

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90. Interview with George Hampson, Woods Hole Oceanographic Institution, March 1977.

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97. J. H. Connell, "Submission to the Royal Commission on Oil Exploitation on the Great Barrier Reef: A Review of D. Straughan, Biological and Oceanographical Survey of the Santa Barbara Channel Oil Spill," I, Biology and Bacteriology (1971), pp. 11-12.

98. Kristian Fauchald, "The Benthic Fauna in the Santa Barbara Channel Following the January 1969 Oil Spill," in Dale Straughan, Biological and Oceanographical Survey of the Santa Barbara Channel Oil Spill, I, Biology and Bacteriology (1971), p. 73.

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100. The USC study did not prove that significant and lasting damage did not occur as a result of the blowout; as Straughan carefully concludes, the study was only unable to prove that such damage did occur.

101. W. J. Mead and P. E. Sorenson, "Estimate of the Costs of the Santa Barbara Oil Spill of 1969," Draft Environmental Statement, Oil and Gas Development in the Santa Barbara Channel Outer Continental Shelf Off California, III, Department of the Interior, pp. 183-185.

102. Interview with George Souza, Shellfish Warden of West Falmouth, August 1976 and April 1977.

103. On March 18, 1977, as this study was in final preparation, President Carter, in a message to Congress, proposed a federal program for reducing the incidence of oil spills and providing a $200 million federal fund to be used both for cleanup of spills and for compensation of damages caused by them. As reported by The Washington Post, the President's program includes six proposals: (1) a single new law to fix responsibility for spills regardless of their source, supplanting presently fragmented state and federal laws; (2) ratification by the U.S. Senate of the 1973 International Convention for the Prevention of Pollution from Ships, which prohibits purging of tanker holds into sea waters; (3) an international conference in the fall of 1977 to set stricter standards for tanker construction, oil transfer equipment, and inspections thereof; (4) Coast Guard boarding and inspection, at least once annually, of every foreign flag tanker entering U.S. waters, and maintenance of computerized data on all such tankers; (5) development of ability to respond "adequately" to any spill up to 100,000 tons within six hours (news reports did not specify the agency to be vested with this responsibility); and (6) establishment of the cleanup and compensation fund, source of which was not specified in local reports.

104. U.S.C.A., § 1321. In 1970 following the Torrey Canyon grounding in 1967 and the Santa Barbara Blowout in 1969, Congress passed the Water Quality Improvement Act of 1970 which added two new sections to the FWPCA, Sections 11 and 12, dealing with the control of oil pollution and hazardous substances respectively. These sections were combined and slightly revised in the 1972 amendment to the FWPCA, becoming Section 311 of the amended act.

105. U.S.C.A., § 1321(j)(1)(C). Executive Order 11735, 38 Federal Register 21234 (1973), delegates the President's authority to the Department of Transportation for vessels and transportation-related onshore and offshore facilities. The Coast Guard has issued regulations prescribing equipment requirements for oil transfer facilities and vessels. 33 C.F.R., parts 154-65 (1972). EPA's regulations for non-transportation related facilities are found at 38 Federal Register 34161 (1973).

106. U.S.C.A., § 1321(j)(2).

107. U.S.C.A., § 1321(b)(6).

108. 40 C.F.R., part 110.3.

109. "Outline of Legislation Concerning the Prevention and Clean-Up of Oil and Hazardous Substances Discharged into Waters," prepared for Texas Coastal and Marine Council, Oil Spill Primer, June, 1975.

110. U.S.C.A., § 1321(b)(5). Notification, of course, opens the discharger to clean-up liability and civil penalties, but failure to notify the Coast Guard is a criminal offense punishable by fines up to $10,000 and one year's imprisonment (33 U.S.C.A., § 1321(b)(5). Compliance with the duty to report spills does not appear to bar criminal prosecution under the 1899 Refuse Act, 33 U.S.C.A., § 407, which prohibits discharges into navigable waters without a permit with sanctions including one year's imprisonment (U.S. v. Mobil Oil Corporation, 464 F 2d 1124 (5th Cir., 1972).

111. U.S.C.A., § 1321(C).

112. See Don Kash et al., op. cit., pp. 166-169.

113. U.S.C.A., § 1321(C). For a more detailed discussion of the National Contingency Plan and an assessment of federal, state, local, and private industry cleanup capabilities, see Section 5 of Governor's Office of Planning and Research, OCS Project Task Force, Offshore Oil and Gas Development: Southern California (Prelim. Draft), Aug. 1976.

114. U.S.C.A., § 1321(k).

115. The 1976 Department of Transportation Appropriation Act (Pub. L. 94-134, 89 Stat. 695) included $10 million to replenish the Fund. See Maxine Lipeles, Oil: Study of Pollution Insurance Liability Laws, Environmental Policy Institute, Washington, D.C., April 1976, p. 17.

116. C.F.R., pt. 250.43(b).

117. Don E. Kash et al., op. cit., p. 165; Lance D. Wood, "Requiring Polluters to Pay for Aquatic Natural Resources Destroyed by Oil Pollution," 8 Natural Resources Law 556 (1976); Charles Lettow, "Marine Pollution," in Environmental Law Institute, Federal Environmental Law (1974), p. 672.

118. U.S.C.A., § 1321(f).

119. U.S.C.A., § 1321(c)(2)(H).

120. U.S.C.A., § 1321(f).

121. Ibid.

122. Lance D. Wood, op. cit., pp. 556, 575.

123. U.S.C.A., § 1321(o).

124. C.F.R. 250.43(c).

125. Phil Van Voorhis, "Pollution Fund Statistics," memorandum to Chief of Marine Environmental Protection Division and Chief of Budget Division, U.S. Coast Guard, April 12, 1974, cited in Lipeles, op. cit., p. 18.

126. North Slope Crude: Where To? How?, Federal Energy Administration, San Francisco, California, IV-89, November 1976.

127. See, e.g., Oppen v. Aetna Insurance Company, 485 F2d 252 (1973); Union Oil Company v. Oppen, 501 F2d 558 (1974); Petition of New Jersey Barging Corporation, 168 F. Supp 925 (1956); Burgess v. M/V Tamano, 370 F. Supp 247 (1973).

128. Ibid. See Green v. General Petroleum Corporation, 205 Cal. 328, 270 p. 952 (1928).

129. Interview with Barry Cappello, City Attorney Santa Barbara, August 18, 1976. Plaintiffs included City and County of Santa Barbara, City of Carpinteria, and State of California.

130. In Santa Barbara, for example, it was not until May 1, 1970 -- more than 16 months after the January 28, 1969, spill -- that fishermen entered a stipulation with Union Oil Company that "all legally compensible damages" would be compensated. It was another four years before litigation ended disputes over the damages allowed by that settlement agreement, Union Oil Company v. Oppen, 501, F2d 558 (1974).

131. Black's Law Dictionary, 466 (4th ed., 1968).

132. Burgess v. M/V Tamano, 370 F.Supp. 247 (1973).

133. Union Oil Co. v. Oppen, 501 F2d 558.

134. Burgess v. M/V Tamano, 370 F.Supp. 247, 251.

135. Union Oil Co. v. Oppen, 501 F2d 558, 570.

136. Recovery granted: Carbone v. Ursich, 209 F2d 178; recovery denied: Casado v. Schooner Pilgrim, Inc., 171 F.Supp. 78; Guarassi v. Panama Canal Co., 271 F.Supp. 678; Henderson v. Arundel Corp., 262 F.Supp. 152.

137. Petition of New Jersey Barging Corp., 168 F.Supp. 925.

138. Oppen v. Aetna Insurance Co., 485 F2d 252.

139. In the litigation by the City and County of Santa Barbara, City of Carpinteria, and State of California stemming from the 1969 Santa Barbara blowout, Union Oil did not object to loss of proprietary income as a damage element.

140. Burgess v. M/V Tamano, 370 F Supp. 247 (upheld the State's right to recover).

141. California et al. v. Union Oil et al., Civil Action No. 69-1-68-RM (C.D. Cal), Memorandum of Defendants Re: Suggested Procedure to Facilitate Settlement and Disposition of Case, May 10, 1973.

142. DEIS, OCS Sale #35, vol. 2, pp. 38-39; FEIS, OCS Sale #35, vol. 2, p. 85.

143. A good description of the equipment and procedures tried out during the blowout is contained in Tetra Tech, Inc., Environmental Assessment Report, Crude Oil Transportation System: Valdez, Alaska to Long Beach, California -- Sea Leg, Appendix C, pp. C21-25.

144. 40 C.F.R., Chapter V, Part 1510. The Coast Guard has issued a regional plan for Federal Region 9, including California, Arizona, Nevada, and Hawaii, and a subregional plan for Coast Guard District 11 (Mexican border to the southern border of San Luis Obispo County).

145. United States Departments of the Interior and Transportation, "Memorandum of Understanding," August 10, 1971. Published inter alia, in United States Department of the Interior, Regulations Pertaining to Mineral Leasing, Operations and Pipelines on the Outer Continental Shelf, August, 1975.

146. In state waters, California's Department of Fish and Game has final authority over the use of chemical agents. In federal waters, the Coast Guard shares authority with EPA. Within 500 yards of all OCS facilities, USGS controls all abatement and clean-up measures.

147. There are actually two contingency plans at the state level. Under the State of California's Oil Spill Contingency Plan itself, the Department of Fish and Game (DFG) in the Resources Agency plays the leading role. DFG has constructed its own Oil and Hazardous Materials Contingency Plan, separate from but compatible with the state plan.

148. Pacific OCS Order #7. Also, see 30 C.F.R. 250.34.

149. The State Lands Division oil spill contingency plan requires all drilling and production activities on existing leases in State waters. See California State Lands Commission, Procedures for Drilling and Production Operations from Existing Facilities on Tide and Submerged Lands Currently Under State Oil and Gas Leases. The Environmental Protection Agency requires operators of all non-transportation-related facilities -- such as drilling rigs and production platforms -- in navigable waters (out to three miles offshore) to prepare Spill Prevention, Control and Countermeasure Plans (SPCCs). See 40 CFR 112. The Coast Guard imposes comparable requirements on vessels and transportation-related facilities in navigable waters. See Memorandum of Understanding between the Secretary of Transportation and the Administrator of the Environmental Protection Agency, November 24, 1971.

150. Smaller amounts are owned and stored by the Coast Guard at its Pacific Strike Force base at Hamilton Air Force Base and at its Terminal Island base. As well, some of the operators maintain equipment at refineries and marine terminals.

151. Interview with Jack Hundley, Arco, April, 1977.

152. According to Section 2001.3 of Annex 10 to the National Plan: "This Schedule advocates development and utilization of sorbents, skimmers, booms, and other mechanical control methods to remove or mitigate oil." According to Section 2301 of California's Oil Spill Cleanup Agents (OSCA) Rules and Regulations, the board (State Water Resources Control Board, which administers the regulations) advocates development and utilization of mechanical and other control methods that will result in removal of oil from the environment with subsequent proper disposal.

153. For an excellent summary of oil spill response equipment, see Tetra Tech, Inc., op. cit., Appendix C.

154. See California Department of Fish and Game, Oil Spill Procedure Guide, February 1975 revision.

155. Don E. Kash et al., op. cit., pp. 74-75.

156. As for most spill response equipment, it is quite difficult to pin down the exact sea state at which any particular skimmer becomes ineffective. Clean Seas, Inc., in its own descriptive brochure, states that its heaviest-duty and largest-volume skimmer "will operate successfully in moderate sea states" (emphasis added). In the same brochure, CSI characterizes its "Sea Dragon" skimmer as "operable in a moderate sea state," and its Mack II skimmer as capable of functioning in "light to moderate sea states."

157. Title 23, Subchapter 10, California Administrative Code.

158. J. E. Smith, op. cit.

159. Under Section 2332 of California's OSCA rules and regulations, dispersants may not be applied to shorelines and may be used in State waters "only if waterfowl areas, recreational beaches, marinas, or shore facilities are threatened; and mechanical control devices or collecting agents are judged to be inadequate or infeasible by [DFG or SWRCB]." Section 2003.1 of Annex 10 to the National Plan provides that "Dispersing agents may be used in any place, at any time, and in quantities designated by the OCS (Coast Guard On-Scene Commander or Coordinator) when their use will:
--In the judgment of the OSC, prevent or substantially reduce hazard to human life or limb or substantially reduce explosion or fire hazard to property;
--In the judgment of the EPA RRT member or on a case-by-case basis, in consultation, whenever possible, with appropriate state and federal agencies, prevent or reduce substantial hazard to a major segment of the population(s) of vulnerable species of waterfowl; or
--In the judgment of the EPA RRT member on a case-by-case basis, in consultation, whenever possible, with appropriate state and federal agencies, result in the least overall environmental damage, or interference with designated water uses."

160. Interview with Harold Takanake, EPA respresentative to District 9 Regional Response Team (which advises Coast Guard on spill cleanup operations off California and Hawaii), April 1977.

161. June Lindstedt-Seva, Oil Spill Response Planning for Biologically Sensitive Areas of the Santa Barbara Channel, unpublished report prepared for Atlantic Richfield Co. (ARCO), August 1976.

162. Goleta Slough, Carpinteria Marsh, Santa Clara River mouth, and Magu Lagoon.

163. Point Conception, Naples Beach and reef, and the west end of Santa Cruz Island. Proposed by Dr. Adrian Wenner, University of California, Santa Barbara, quoted in Lundstedt-Siva, op. cit.

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CHAPTER 18

ECONOMIC EFFECTS: BENEFITS VS. BURDENS

The industries involved in extracting and refining crude oil and natural gas are beginning to play an increasingly significant role in California's economy. While total personal income in the state increased from $98,132 million in 1973, to $104,835 million in 1975, personal income derived from the industries involved in oil and gas extraction, and petroleum and coal products, increased from $781 million to $1,121 million during the same period. 1/ Thus, over the three years, the petroleum-related income increased by 44%, while total personal income in the state rose by 18%.

Such figures suggest that the economic impact of Lease Sale #35 on southern California must be very sizeable. However, work completed by the Governor's Office of Planning and Research, Onshore Impact of Offshore Southern California OCS Sale No. 35, for convenience, referred to as OCS Sale No. 35 in future pages, does not bear this out. 2/ Extrapolating from the projections in this report, we have attempted to calculate, as accurately as possible, the nature and scale of the economic impacts of Lease Sale #35 on the southern California region from the sub-county level to the regional five-county level.

In other studies of this type, input-output techniques have been used to forecast employment and income resulting from OCS development.**However, since that method is based on a series of very rigid assumptions which generally have national rather than regional application, it was not used here for analysis of Lease Sale #35, where the anticipated economic impacts affect a relatively small area. Appendix I contains a more detailed discussion of input/output analysis, along with our reasons for rejecting it in our report. As for the method we have used which will prove both more reliable and more serviceable for staffs of local and state agencies, a general cautionary word is in order: because the best available employment data pertain to the Southern California region as a whole, our calculations for regional employment and income may be expected to have greater reliability than the estimates at county level.

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* We wish to acknowledge with gratitude the assistance of Professor David Starrett of Stanford University in the development of an overall analytical framework for assessing regional economic effects of OCS activity.

** For example, see Thomas Grigalunas, Offshore Petroleum and New England, University of Rhode Island, 1975.

Given the mobility of labor throughout the southern California region, county-specific projections of economic impacts can only serve as general indicators of future economic effects. As more reliable data become available, particularly after the initial exploration phase has been completed, local governments may extend this analysis to obtain closer estimates of effects. Although we have restricted our efforts here to the effects of Lease Sale #35 on Ventura, Orange, and Los Angeles counties, our method can also be applied to the Santa Barbara Channel tracts, as well as to future lease sales, such as #s 48 and 53. Consequently, local government will be able to assess the cumulative effects of several lease sales.

The report first presents scenario development at both the regional and sub-regional levels. It then analyzes the economic impacts of the following:

1. effects on induced employment and income, with specific emphasis on multiplier derivation;

2. effect on prices, with particular reference to housing and consumer durables;

3. effects on such public services as schools, fire and police protection, and sewer services; and,

4. effects on taxes and transfers, with attention given to equity considerations.

Following this section, the report gives a brief set of guidelines for use in analyzing the economic effects of future sales.

SCENARIO DEVELOPMENT

REGIONAL EMPLOYMENT AND INCOME ESTIMATES

This section focuses on wage and salary income derived from OCS development, rather than on capital expenditures for facilities, equipment, or materials. It is assumed that most such purchases will not take place in the study region, because of existing capacity or of the probability that construction will take place in other areas.

In developing its forecast, OCS Sale No. 35 distinguishes between potential and actual effects. Estimates of employment presented in many documents prepared prior to the actual occurrence of Lease Sale No. 35 were frequently based on the assumption that all tracts offered in that sale would be leased. However, OCS Sale No. 35 stresses that:

> Although it would have been impossible to predict that only 56 of the 297 tracts originally offered would actually be leased, production and employment effects cannot and should not be based on the assumption that all tracts offered will be awarded. 3/

Even with this information available, OCS Sale No. 35 emphasizes that employment estimates cannot be derived with a great degree of certainty beyond the exploration phase of development. At the current time,

> the exploratory phase represents the only "sure employment" resulting from the lease sale. Assuming that exploration begins in 1976, and that the first commercial discovery is made within 2 years, additional employment effects could then be calculated with more certainty on the basis of confirmed discoveries. 4/

Keeping such considerations in mind, the following scenario for regional impact analysis of Lease Sale #35 has been developed.

OCS operations are divided into three phases -- exploration, development, and production. At any particular site, these activities occur consecutively, but within a large field all of the operations may be underway simultaneously. Employment figures for all phases of operations are based upon the number of tracts awarded, 56. Employment and income estimates pertain solely to primary jobs generated by OCS services and trades.

In the exploration phase, employment hinges upon the number of rig-years necessary to drill approximately two wells per tract, a total of 112 wells. It is assumed that four to six rigs will be in simultaneous operation over a four- to six-year period of exploration. Assuming four wells are drilled in one rig-year, we have an expected total of 28 rig-years for the exploratory phase.

The number of platforms required during the development phase depends upon the estimates of derived resource reserve. We assume that platform fabrication will take place over a five- to eight-year period, that drilling operations will necessitate a maximum of 20 platforms, and that there will be 1.5 rigs in operation over a total of three rig-years per platform. Thus, it is expected that six rigs will be in operation over a ten-year period -- a maximum 60 rig-years if all platforms remain in constant use. Estimates of onshore facility construction are rather questionable owing to the amount of surplus capacity currently available in several existing processing plants in the area and to possible future consolidation policies encouraged by the Coastal Commission. The number and size of the anticipated plants is the major variable to be considered. It is assumed that construction will take place throughout a six- to ten-year period.

Throughout the production phase, the most significant variable is the amount of resource in place, with particular emphasis given to the number of years of productive life for each field. We assume productive life to be approximately 40 years, with the number of years at peak level to be about 20. The major factor affecting onshore facility operation is the average production per day -- this we assume to be approximately 100,000 barrels for the 56 tracts. It should be noted that employment estimates for refinery workers were omitted from this report because of the general uncertainty as to the location of new refineries. 5/

Wage and salary income were projected on the basis of estimates presented in OCS Oil and Gas -- an Environmental Assessment. 6/ These estimates by the Council on Environmental Quality (CEQ) have a greater degree of reliability for the purposes of this report than do the wage and salary listings for workers in the petroleum and mining industries appearing in the monthly bulletins published by the Department of Labor's Bureau of Labor Statistics, such as the Monthly Labor Review and in Employment and Earnings, because the CEQ breaks down wages and salaries by the different phases of OCS operations. The following figures provided by the CEQ for average base earnings, by work category, are presented in 1970 dollars:

OCS Development Operations	CEQ Yearly Salary Estimates
Exploratory Drilling	$13,000
Platform Fabrication	12,500
Development Drilling	13,000
Oil and Gas Production -- Offshore	10,000
Oil and Gas Production -- Onshore Facility Operations*	11,500
Support Services	10,000

A weighting index derived from the average weekly earnings for production or non-supervisory workers in oil and gas extraction for the period 1970-1975 was applied to the above estimates to arrive at salary equivalents in 1975 dollars. The inflationary salary index is as follows:

Time (From March to March)	1970 1971	1971 1972	1972 1973	1973 1974	1974 1975
Inflationary Wage and Salary Increase	3.0%	6.7%	4.1%	14.9%	16.4%

After application of the wage and salary index to the CEQ estimates, the following base projections, in 1975 dollars, were derived:

OCS Development Operations	Yearly Salary Estimates
Exploratory Drilling	$20,000
Platform Fabrication	19,000
Development Drilling	20,000
Oil and Gas Production -- Offshore	15,500
Oil and Gas Production -- Onshore Facility Operations	17,500
Support Services	15,500
Onshore Facility Construction**	14,000

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* Computed from direct employee compensation in the refinery industry for three Atlantic regions. $11,500 is the mean value.

** Salaries for construction workers were derived from 1975 weekly gross income averages for production or non-supervisory workers, Monthly Labor Review, IC, (July, 1976).

These salary estimates are roughly comparable to the estimates derived from the Final Environmental Statements, OCS Sale No. 35, 7/ where it is assumed that the figures, in 1972-1973 dollars, list Exploratory Drillings at $20,000, Development Well Drillings at $16,000, and Production Operations at $14,000.

Our CEQ-derived annual wage and salary estimates were then multiplied by annual employment forecasts in order to determine income derived from each phase of OCS operations. Table 2 lists annual employment and income for each phase of operations for the lifetime of the project, 1976-2000. These annual figures are then summed in order to present total employment and total income for each phase. Table 1 shows total employment and income forecasts, by year, for all phases of OCS operations. The sum of employment produced by Lease Sale #35 over the lifetime of the project thus equals 44,380 man-years and total income equals 777.30 million dollars.

TABLE 1:
TOTAL EMPLOYMENT AND INCOME IMPACTS BY YEAR AND OVER THE LIFE-TIME OF THE PROJECT FOR VENTURA, ORANGE AND LOS ANGELES COUNTIES

Year	Total Employment	Local Employment	Imported Employment	Total Income (Millions of $)
1976	976	800	176	18.17
1977	1850	1334	516	35.65
1978	2450	1778	672	47.45
1979	2825	2075	750	54.50
1980	3220	2410	810	61.39
1981	2566	2096	470	47.75
1982	2278	1828	450	41.99
1983	2540	2130	410	45.41
1984	2400	2070	330	42.15
1985	2500	2170	330	43.80
1986	2300	2048	252	39.80
1987	1925	1751	174	32.85
1988	1650	1476	174	28.00
1989	1250	1232	18	20.00
1990	1250	1232	18	20.00
1991-95	1250	1232	18	20.00
1996-2000	1230	1212	18	19.69
	44,380	38,650	5,730	777.30 (in 1975 dollars)

* Calculated by dividing total salaries by total employees in each category in Table III-32 of the Final Environmental Statement, OCS Sale No. 35. See also Table III-34 in that document.

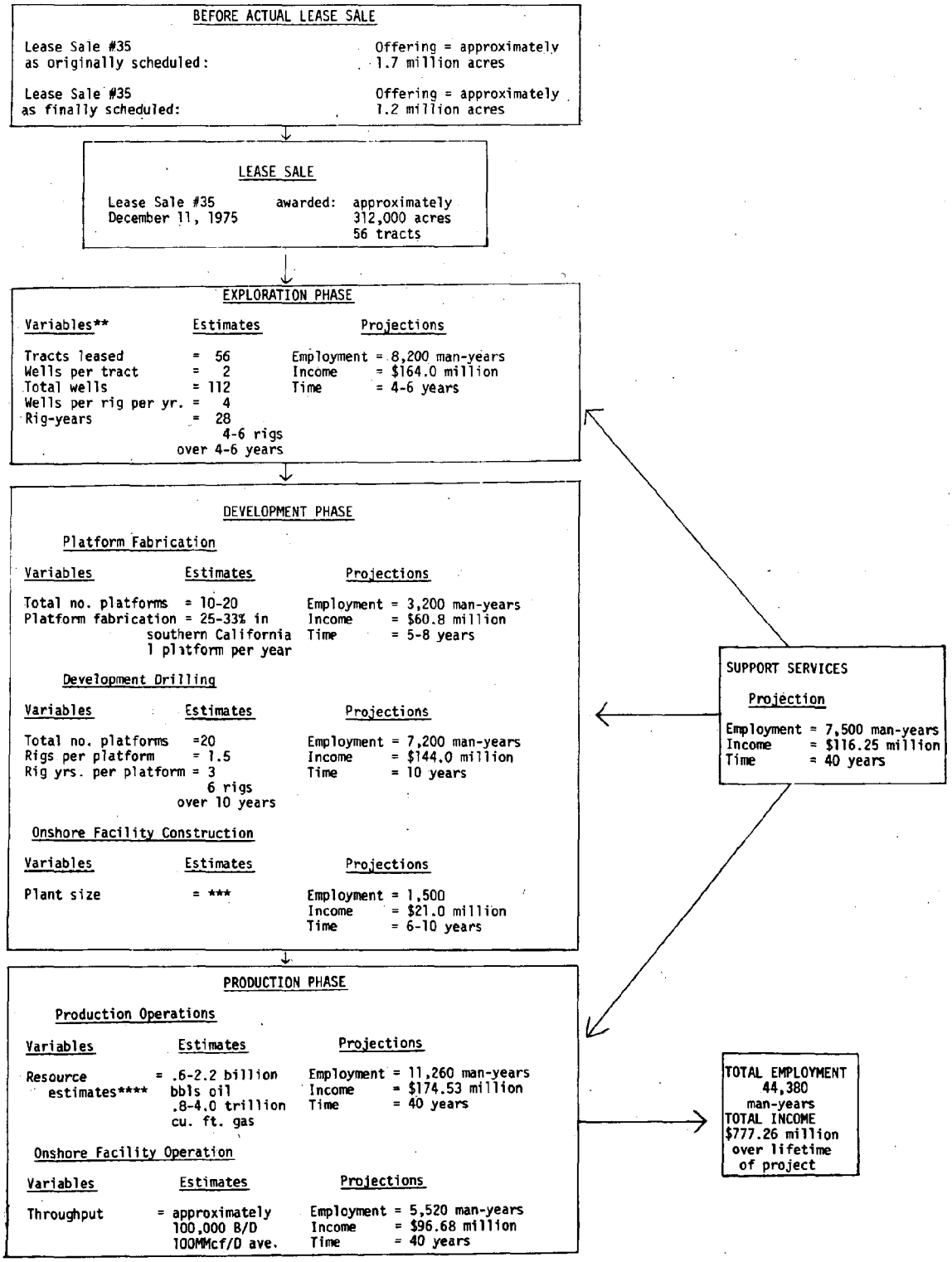
TABLE 2:
EMPLOYMENT AND INCOME IMPACTS FOR VENTURA, LOS ANGELES AND ORANGE COUNTIES *

	Year	Total Employment	Local Employment	Imported Employment	Total Income (Millions of $)
EXPLORATORY DRILLING	1976	676	536	140	13.52
	1977	1550	1070	480	31.0
	1978	1550	1070	480	31.0
	1979	1550	1070	480	31.0
	1980	1550	1070	480	31.0
	1981	676	536	140	13.52
	1982	388	268	120	7.
	1983	260	180	80	5.20
	1984	0	0	0	0
	.	.	.	.	.
	.	.	.	.	.
	.	.	.	.	.
	2000	0	0	0	0
		8,200	5,800	2,400	164.0
PLATFORM FABRICATION	1976	0	0	0	0
	1977	0	0	.	0
	1978	200	200	.	3.8
	1979	300	300	.	5.7
	1980	300	300		5.7
	1981	400	400		7.6
	1982	400	400		7.6
	1983	400	400		7.6
	1984	400	400		7.6
	1985	300	300		5.7
	1986	300	300		5.7
	1987	200	200		3.8
	1988	0	0		0
	.	.	.	.	.
	.	.	.	.	.
	.	.	.	.	.
	2000	0	0	0	0
		3,200	3,200		60.8
DEVELOPMENTAL DRILLING	1976	0	0	0	0
	1977	0	0	0	0
	1978	400	244	156	8.0
	1979	600	366	274	12.0
	1980	800	488	312	16.0
	1981	800	488	312	16.0
	1982	800	488	312	16.0
	1983	800	488	312	16.0
	1984	800	488	312	16.0
	1985	800	488	312	16.0
	1986	600	366	234	12.0
	1987	400	244	156	8.0
	1988	400	244	156	8.0
	1989	0	0	0	0
	.	.	.	.	.
	.	.	.	.	.
	.	.	.	.	.
	2000	0	0	0	0
		7,200	4,392	2,808	144.00
ONSHORE FACILITY CONSTRUCTION	1976	0	0	0	0
	1977	0	0	0	0
	1978	0	0	.	0
	1979	75	75	.	1.5
	1980	150	150	.	2.1
	1981	150	150		2.1
	1982	150	150		2.1
	1983	300	300		4.2
	1984	300	300		4.2
	1985	150	150		2.1
	1986	150	150		2.1
	1987	75	75		1.05
	1988	0	0		0
	.	.	.	.	.
	.	.	.	.	.
	.	.	.	.	.
	2000	0	0	0	0
		1,500	1,500		21.0

	Year	Total Employment	Local Employment	Imported Employment	Total Income (Millions of $)
SUPPORT SERVICES	1976	300	264	36	4.65
	1977	300	264	36	4.65
	1978	300	264	36	4.65
	1979	300	264	36	4.65
	1980	300	282	18	4.65
	.	.	.	.	.
	.	.	.	.	.
	.	.	.	.	.
	2000	300	282	18	4.65
		7,500	6,978	522	116.25
PRODUCTION OPERATIONS	1976	0	0	0	0
	1977	0	0	.	0
	1978	0	0	.	0
	1979	0	0	.	0
	1980	80	80		1.24
	1981	160	160		2.48
	1982	160	160		2.48
	1983	320	320		4.96
	1984	400	400		6.2
	1985	640	640		9.92
	.	.	.		.
	.	.	.		.
	.	.	.		.
	1995	640	640		9.92
	1996	620	620		9.61
	.	.	.	.	.
	.	.	.	.	.
	.	.	.	.	.
	2000	620	620	0	9.61
		11,260	11,260		174.53
ONSHORE FACILITY OPERATION	1976	0	0	0	0
	1977	0	0	.	0
	1978	0	0	.	0
	1979	0	0	.	0
	1980	40	40		.7
	1081	80	80		1.4
	1982	80	80		1.4
	1983	160	160		2.8
	1984	200	200		3.5
	1985	310	310		5.43
	.	.	.	.	.
	.	.	.	.	.
	.	.	.	.	.
	2000	310	310	0	5.43
		5,520	5,520		96.68

* Average wage and salary income assumptions: EXPLORATORY DRILLING = $20,000 in 1975 dollars; PLATFORM FABRICATION = $19,000 in 1975 dollars; DEVELOPMENT DRILLING = $20,000 in 1975 dollars; FACILITY CONSTRUCTION = $14,000 in 1975 dollars; PRODUCTION OPERATIONS = $15,5000 in 1975 dollars; ONSHORE FACILITY OPERATIONS = $17,5000 in 1975 dollars; and for SUPPORT SERVICES throughout the lifetime of the project = $15,500 in 1975 dollars. Employment estimates calculated from OCS Sale No. 35, Chapter 8.

FIGURE 1:
LEASE SALE #35, EMPLOYMENT AND INCOME ESTIMATIONS 1976-2000*



*All employment and income estimates pertain to both direct and indirect calculations. Employment projections are in man-years summed over the entire phase. Income projections are in 1975 dollars.

**All physical variable estimates are based on assumptions in OCS Sale No. 35.

***Forecasts for onshore facilities depend on available surplus capacity of existing facilities and the effects of consolidation policies encouraged by state and local regulatory agencies.

****From resource estimates by OCS Task Force.

SUB-REGIONAL EMPLOYMENT AND INCOME ESTIMATES

Almost all of the effects resulting from Lease Sale #35 will probably be felt in Ventura, Los Angeles, and Orange Counties. Because the populations of Los Angeles and Orange Counties are larger than that of Ventura County, this report treats Orange and Los Angeles Counties as one region and Ventura County as another. The difficulties involved in forecasting whether staging operations would take place in the Los Angeles/Long Beach area or in Huntington Beach also made this necessary. Furthermore, due to the relative importance of the oil and gas industries to Ventura County, it was assumed that the same percentage of key workers would be imported into both this region and into the larger Los Angeles/Orange area. The ratios for local-versus-imported workers implicit in Table 1 will thus be utilized for the sub-regional, or county-level, analyses as well.

Table 3 presents monthly employment and quarterly wage statistics for the oil and gas industries for each of the three counties. Although oil and gas related employment and income in the Los Angeles area is roughly 7 times that in Ventura County, the percentage of total oil and gas industry wages is about 2% for the Ventura area versus approximately .5% for either Los Angeles or Orange County. About 60% of all California wage income derived from the oil and gas industries occurs in the three counties, and Los Angeles County alone possessed 45% of the State's total in the period from July to September, 1974.

TABLE 3:
MONTHLY EMPLOYMENT AND QUARTERLY WAGES FOR ALL INDUSTRIES AND OIL AND GAS EXTRACTIVE INDUSTRIES IN CALIFORNIA AND VENTURA, LOS ANGELES, AND ORANGE COUNTIES (JULY - SEPTEMBER 1974)

	California	Ventura	Los Angeles	Orange
All Industries				
Number of Employees:				
July	8,008,676	121,299	3,021,166	566,580
August	8,078,460	121,555	3,012,278	551,631
September	8,254,770	124,269	3,058,952	548,591
Total Quarterly Wages	$20,054,609,462	$274,293,778	$7,823,996,485	$1,315,103,965
Oil & Gas Extractive Industries				
Number of Employees:				
July	23,767	1,627	9,731	2,254
August	23,806	1,582	9,760	2,181
September	23,763	1,615	9,749	2,171
Total Quarterly Wages	$84,996,038	$5,557,041	$38,171,163	$7,052,081

* From State of California, Employment Development Department, California Employment and Payrolls July-September 1974, March 10, 1976.

In calculating the employment derived from the Santa Rosa-Cortez Ridge North, Santa Rosa-Cortez Ridge South, Santa Barbara Island, and the San Pedro Bay tract regions, the following assumptions have been made:

Phase	Operations Base or Product Disposition Area *			
	Santa Rosa Cortez-North	Santa Rosa Cortez-South	Santa Barbara Is.	San Pedro Bay
Exploration	PH	LA/LB/HB	LA/LB/HB	LA/LB/HB
Development	PH	LA/LB/HB	LA/LB/HB	LA/LB/HB
Production	PH	LA/LB/HB	LA/LB/HB	LA/LB/HB
Onshore Facility Operations	PH	PH	PH	LA/LB/HB

Given these considerations, it is necessary to derive a relative weighting scheme for the four regional tract areas in order to project scenarios. This was achieved by using the number of wells drilled for each area as a common denominator for deriving relative employment estimates. The following numbers of wells are likely to be drilled in each area, and although these estimates are based on the best currently available information, it is important to recognize that they are not rigid projections:

Tract Areas	Anticipated Wells	Percent of Total
San Pedro	30	27
Santa Rosa Cortez-North	22	20
Santa Rosa Cortez-South	54	48
Santa Barbara Islands	6	05
Total =	112	

Given the results obtained above, and the information contained in the previous table, it is assumed throughout the rest of our calculations that about 20% of the employment from exploration, development, production, and service operations will take place in Ventura County, as well as approximately 33% of construction and about 73% of onshore facility employment. It is assumed that all employment derived from platform fabrication will occur in the Los Angeles-Long Beach area. It is further expected that about 80% of all regional staging employment for exploration, development, and production and 27% of onshore facility employment will occur in the Los Angeles-Long Beach area.

These results appear in Tables 4 and 5 presenting total employment (local and imported) and total income by OCS phase for each region. Average yearly totals for employment and income are also calculated. Table 6 presents a breakdown, by year, of the combined yearly average estimates derived from Tables 4 and 5 giving the estimates for yearly employment and income for each region over the first ten years of OCS development for Lease Sale #35.

* Port Hueneme is abbreviated by PH, and Los Angeles-Long Beach-Huntington Beach by LA/LB/HB

TABLE 4:
VENTURA COUNTY
EMPLOYMENT AND INCOME EFFECTS BY DEVELOPMENT PHASE

	Total Employment (in man years)	Local Employment	Imported Employment	Total Income (in millions of $)	Average Yearly Local Employment	Average Yearly Imported Employment	Average Yearly Total Employment	Average Yearly Income (in millions of $)
Exploratory Drilling 1976-1983	1,640	1,160	480	$32.80	145	60	205	$4.10
Platform Fabrication 1978-1987	-	-	-	-	-	-	-	-
Development Drilling 1978-1988	1,440	878	562	$28.80	80	51	131	$2.62
Onshore Facility Construction 1979-1987	500	500	-	$7.00	56	-	56	.78
Production Operation 1980-2000	2,252	2,252	-	$34.91	107	-	107	$1.66
Onshore Facility Operation 1980-2000	4,030	4,030	-	$70.58	192	-	192	$3.36
Support Services 1976-2000	1,500	1,396	104	$23.25	56	4	60	.93

TABLE 5:
LOS ANGELES - ORANGE COUNTIES
EMPLOYMENT AND INCOME EFFECTS BY DEVELOPMENT PHASE

	Total Employment (in man-years)	Local Employment	Imported Employment	Total Income (in millions of $)	Average Yearly Total Employment	Average Yearly Local Employment	Average Yearly Imported Employment	Average Yearly Income
Exploratory Drilling 1976-1983	6,560	4,640	1,920	$131.20	820	580	240	$16.40
Platform Fabrication 1978-1987	3,200	3,200	-	$ 60.80	320	320	-	$ 6.08
Development Drilling 1978-1988	5,760	3,514	2,246	$115.20	524	320	204	$10.47
Onshore Facility Construction 1979-1987	1,000	1,000	-	$ 14.10	110	110	-	$ 1.56
Production Operations 1980-2000	9,008	9,008	-	$139.62	429	429	-	$ 6.65
Onshore Facility Operation 1980-2000	1,490	1,490	-	$ 26.10	71	71	-	$ 1.24
Support Services 1976-2000	6,000	5,582	418	$ 93.00	240	223	17	$ 3.72

These estimates are used in later sections of this report to arrive at projections for peak years of employment and income, as well as the average values over the first ten years of development. While estimates of total years of employment, either by phase or by the project as a whole, have been presented in Figure 1, as well as in Tables 2, 4 and 5, it should be emphasized that it is very easy to overstate the effects of long-term projects like the one under consideration here by focusing on total rather than on yearly employment. In order to avoid this statistical exaggeration, the employment and income effects for the first ten years of the project are represented (Table 6) as average annual figures for each year, and it is these estimates which will be used as a base in conducting the economic analyses that follow.

TABLE 6:
AVERAGE YEARLY EMPLOYMENT AND INCOME EFFECTS FOR VENTURA, ORANGE, AND LOS ANGELES COUNTIES OVER FIRST TEN YEARS OF PROJECT

	VENTURA				ORANGE - LOS ANGELES			
Year	Average Total Employment (in man-years)	Average Local Employment	Average Imported Employment	Average Total Income (in millions of $)	Average Total Employment (in man-years)	Average Local Employment	Average Imported Employment	Average Total Income (in millions of $)
1	265	200	65	$5.03	1060	803	257	$20.12
2	265	200	65	$5.03	1060	803	257	$20.12
3	396	200	116	$7.65	1904	1443	461	$36.67
4	452	336	116	$8.43	2014	1553	461	$38.23
5	751	635	116	$13.45	2514	2053	461	$46.12
6	751	635	116	$13.45	2514	2053	461	$46.12
7	751	635	116	$13.45	2514	2053	461	$46.12
8	751	635	116	$13.45	2514	2053	461	$46.12
9	546	490	56	$9.35	1694	1473	221	$29.72
10	546	490	56	$9.35	1694	1472	221	$29.72

Thus it will be noted that the estimates shown in Table 6 are relatively insignificant. We have arbitrarily (Table 6-A) multiplied these estimates by three in order to highlight the fact that even three times the estimates (referred to as upper bound) are relatively small. The following range of figures for total employment (local and imported) and total income, based on calculating a ten-year average for the estimates listed in Table 6, will be used in later sections of this report.

TABLE 6-A

	Ventura	Los Angeles/Orange
Average Income Impact/year (in millions of dollars)		
Estimate	$9.9	$35.9
3 X Estimate	29.7	107.7
Average Number of Local Employees/year		
Estimate	95	370
3 X Estimate	285	1,110
Average Number of Local Employees/year		
Estimate	454	1,576
3 X Estimate	1,362	4,728

ECONOMIC IMPACTS

INDUCED EMPLOYMENT AND INCOME EFFECTS

To this point in our discussion we have been concerned with regional first-round OCS-related employment and income. Now our focus shifts to the regional effects from second-round employment and income, also known as induced impacts since they result from the first round. The relationship between these two categories may be described as follows: round one ends with completion of the development phase, when production commences. Round two consists of the production of goods and services to replace the commodities consumed in round one. Because some of the income earned in round one is saved, round two effects are smaller than round one.

We assume that all employment, and hence income, resulting from OCS-related projects is new employment. This implies that all project-related workers in round one and round two are either unemployed at the start of the project or are bid away from other jobs.* It is possible that some of the goods and services industries will not require new workers to meet second round demand. In that case, our estimates will be liberal, because income would have been earned even if Lease Sale #35 had not taken place.**

* If workers are bid away from other current employment, such a situation could precipitate a slight regional wage increase. However, this type of effect is not relevant for conducting an analysis of first-order impacts, as presented here.

**See Onshore Impact of Offshore Southern California OCS Sale No. 35, p. VIII-28.

We use a regional multiplier, described in Appendix Z, to calculate how many second-round jobs are created by first-round spending. For the Los Angeles/Orange area the multiplier equals 1.0 and for Ventura County it equals .5. This means that for every job created by OCS development in the Los Angeles/Orange area, one new job will be created by induced spending. Similarly, for every worker employed during the first round of spending in the Ventura area, .5 workers will be needed for the second round.

Table 7 shows total domestic, or local employment, stemming from the first and second rounds of OCS development. We estimate average, new yearly employment to equal 729 for Ventura County and 3,522 for Los Angeles/Orange Counties. We have again arbitrarily multiplied these derived estimates by three to indicate that even at the statistically optimal (and unrealistic) upper bound, the effects remain of slight significance to the regional economics.

TABLE 7:
AVERAGE NEW YEARLY DOMESTIC EMPLOYMENT AND INCOME
FROM LEASE SALE #35

	Ventura (M=.5)		Los Angeles/Orange (M=1.0)	
	Estimate	3 X Estimate	Estimate	3 X Estimate
Average Yearly Domestic Employment	729	2,186	3,522	10,566
Average Yearly Domestic Income	$12.3 Million	$37.0 Million	$58.4 Million	$175.2 Million

Table 7 presents Average Yearly Domestic Employment (AYDE) and Average Yearly Domestic Income (AYDI) resulting from first- and second-round local spending. The relevant equations are:

$$AYDE = StM(SH)$$
$$AYDI = \$17{,}500\ (s + M(S + .5T))$$

s = local employment
t = imported employment
M = multiplier
$17,500 = average yearly wage (calculated from Table 1)

Imported employment (t) is multiplied by 1.5 to reflect the assumption that only 50% of the imported workers are expected to reside near the development areas. First- and second-round yearly income averages $12.3 million for Ventura and $58.4 million for Los Angeles/Ventura. These estimates are also arbitrarily multiplied by three to present upper bounds.

PRICE IMPACTS

In estimating the price effects from Lease Sale #35, housing and consumer durables provide sensitive indicators because they represent a large share of family budgets and because a small increase in the price of these items may involve substantial sums of money. In the short run, the supply of consumer durables and housing is fixed, therefore increases in demand will result in increased price. In the long run, increases in demand will be balanced by increases in supply, and no long-run price increases are created by demand alone.

To arrive at an estimate of the increase in demand from OCS employment we assume that it is proportional to the percent change in income. Then we use elasticity measures to translate the demand increases into price increases.*

In order to estimate the short-run price effects, it was first necessary to estimate total income, by county, in 1975 dollars. This was done by quadrupling first-quarter figures for wage income for 1975. 8/ For our purposes, there was no loss in reliability in utilizing this simplification.** Next, new income was calculated from Table 6, by averaging income-effect per year over the first ten years of the project, in 1975 dollars.***

The following table presents estimates for change in demand (x), which is equal to new income divided by total income:

County	Income(1975)	New Income Estimate	X
	(Millions of Dollars)		
Ventura	1,119.5	9.9	.0088
LA/Orange	38,091.7	35.9	.0009

The table, below, shows the change in demand at the upper bound.

County	Income(1975)	3x New Income Estimate	X
Ventura	1,119.5	29.7	.0265
LA/Orange	38,091.7	107.7	.0028

---

* The price elasticity (e) of demand measures the sensitivity of the quantity of a particular commodity demanded to a change in its price. It is more precisely defined as the percentage change in quantity demanded resulting from a 1% change in price of the given commodity, i.e., $e = -\frac{d(Q)Q}{d(P)P} = \frac{d(Q)P}{d(P)Q}$
Here, 1/e is weighted by x, or the increase in demand generated by OCS Lease Sale #35, in order to estimate the resulting percentage change in price.

** Until data for the entire 1975 period are made available, the most precise estimate of 1975 income can be made by comparing the quarterly figures for 1974, and then projecting any seasonal variations to the 1975 January-March data.

***Unlike the previous section of this report, new income here is taken to equal total local plus imported income, even though this results in an overstatement of the estimated effects.

By applying elasticity estimates to the change in demand, we obtain percentage increases in prices for the selected goods. Table 8 shows price increases for houses, kitchen and household appliances, new cars, and net purchases of used cars. The short-run price elasticity estimates for the last two of these commodity categories were taken from Consumer Demand in the United States, 1929-1970. 9/ Because it is very difficult to estimate a value for e (elasticity of demand) which pertains to new housing purchases, the short-run price elasticity for housing was roughly approximated at .5.*

TABLE 8:
ESTIMATED PRICE EFFECTS IN VENTURA COUNTY
AND LOS ANGELES AND ORANGE COUNTIES
FROM LEASE SALE #35, FOR SELECTED COMMODITIES

	Ventura			Los Angeles/Orange	
Commodity	Elasticity	Estimate	3 X Estimate	Estimate	3 X Estimate
Housing	-.5000	.018	.053	.002	.006
Consumer Durables					
Kitchen and Household Appliances	-.6253	.014	.042	.001	.004
New Cars and Purchases of Used Cars	-.9578	.009	.028	.001	.003

It can be seen from Table 7 that the short-run effects for Ventura County are much larger than those for Los Angeles and Orange Counties, where all calculated price effects for both estimated and upper-bound income levels are statistically significant. In Ventura County, where the estimated price effects equal an increase of 5.3% at the most for new housing, it should be recognized that this estimate is the least reliable of the three commodity categories. The price effects on kitchen and other household appliances, and on automomobile purchases, are expected to increase 4.2% at most. Both of the preceding figures are based on the upper-bound estimate for new income. For the lower estimates, based on the expected income effects, the corresponding price increases in Ventura County are calculated at 1.8% for new housing, and 1.4% for auto purchases, kitchen and other household appliances.

Because the price effects from increased housing demand may be the most significant of the economic consequences of Lease Sale #35, current housing and population figures are presented in Tables 9 and 10 in order to gain a more precise understanding of present housing capacity. Table 9 demonstrates that for Ventura,

* This figure was derived by using, as a lower bound, the value for e = -.1874, which pertains to "Other Housing" in Consumer Demand in the United States, 1929-1970, and which comprises transient hotels, tourist cabins, clubs, schools, and institutions (types of housing commonly occupied by the highly mobile workers typically employed in the exploration and development phases) and the value of e = -.6523, for kitchen and other houshold appliances, as an upper bound.

Los Angeles and Orange Counties in the years 1970-1975, added housing units have increased at a faster rate than population. Although annual housing production in the future is expected to be lower than the peak years of the 1960s, the rate of projected housing growth is still anticipated to be larger than that of population. It is assumed that over the 1970-1990 period, population will increase by 21.9% in the large region comprising Ventura, Los Angeles, Orange, Imperial, Riverside, and San Bernardino Counties, while housing units are expected to increase by 32.9%. 10/

In the Ventura County area, the expected, average yearly number of new dwelling units required by employment from Lease Sale #35, is assumed to vary roughly between 50 and 150.* The current vacancy rates shown in Table 10 for the three prime areas of Ventura, Port Hueneme, and Oxnard can easily support this expected influx of new employees and their families to Ventura County, even when taking into account the current 1970-1975 baseline rate of yearly population growth of 2.85%, and the current annual increase in new housing units of 5.70% for the county as a whole, as presented in Table 9.

TABLE 9:
HOUSING AND PUPULATION FIGURES
VENTURA, LOS ANGELES AND ORANGE COUNTIES, AS OF 1975**

	Ventura	Los Angeles	Orange
Total Housing Units 1975	144,108	2,695,401	607,631
Added Housing Units 1970-75	31,979	157,638	144,828
Simple Annual Housing Growth Rate 1970-75	5.7%	1.24%	6.26%
Total Population 1975	432,407	7,020,772	1,684,500
Added Population 1970-1975	53,910	- 17,992	264,114
Simple Annual Population Growth Rate 1970-75	2.85%	- .05%	3.72%

* These figures are calculated by multiplying the average number of imported workers over the first ten years of the project, calculated from Table 12, by the relocation factor of 50%, presented in OCS Sale No. 35. Also, see the following section on public services.

** SCAG-76 Growth Forecast Policy, Development Guide, Southern California Association of Governments, Los Angeles, CA, January 1976.

TABLE 10:
TOTAL HOUSING UNITS AND VACANCY RATES IN VENTURA COUNTY
FOR CITIES WITH A POPULATION OF AT LEAST 10,000*

	Housing Units	Vacancy Rate
Ventura County	148,327	----
Ventura	25,688	5.29%
Port Hueneme	5,968	11.6%
Oxnard	29,921	7.7%
Camarillo	8,361	4.64%
Santa Paula	6,350	3.8%
Thousand Oaks	19,167	5.9%
Simi Valley	19,061	2.4%

CONCLUSIONS

Approximately 777 million dollars and 44,380 man-years of employment will be created in a 20-year period in the southern California region that includes Los Angeles/Orange and Ventura Counties. On the average, this means about 2200 jobs and 38.8 million dollars of income per year. In percentage terms, OCS activities will contribute less than 1% per year to southern California's economy.

Throughout the entire region about 4,250 non-project related jobs would also be created. Of these non-project related jobs, 83% would occur in Los Angeles/Orange, the remainder in Ventura. Further, we could find no evidence that the project will bring about a sustained increase in the price of durable consumer goods or housing. Two other points bear repeating: first, cumulative effects resulting from future lease sales may reverse these findings, and second, the numerical value of our estimates is not exact. We are convinced, however, that changes in economic activity brought about by Lease Sale #35 will be inconsequential.

* From "Semi-Annual Population Estimates, January 1976", Ventura County Planning Department.

PUBLIC SERVICES

Lease Sale #35 will result in a net inmigration of population into Los Angeles, Orange, and Ventura Counties. This net inmigration, consisting primarily of petroleum-related employees and their families, will expand and diminish as specific development phases are begun and others are completed.

PUBLIC SECTOR INVESTMENT

An increase in the population of a community imposes a cost to that community. The cost will take one of two forms: (1) an increase in local expenditures to construct, operate, and maintain new facilities; or, (2) a reduction in quality of service because of the increased number of users of an existing facility -- e.g., school systems, waste water treatment system, or police and fire departments.

Investment decisions by the public sector are primarily a function of demographic factors. The community, in attempting to make the most efficient use of each expenditure, will seek to project, as accurately as possible, the growth in relevant demographic variables (e.g., population, age distribution) in order to prepare for the public services needed to sustain the community by ensuring that new or existing services be capable of serving the future influx of people. The measure of this ability is called excess capability. Local communities, particularly those smaller in size, are unable to finance internal capital requirements brought about by the need to expand services. Hence, they are particularly sensitive to cyclical costs of debt issuance. In many instances, communities will aggregate a number of small issuances and go to the capital market with one major issuance in an effort to reap the savings of lower debt costs. As a result, precisely calculating the size of needed capital facilities is critical.

In specifying the amount of excess capacity to be built into a public service system, it is implicit that such systems will service up to some upper bound or threshold level of population or economic activity. Beyond that level service quality will deteriorate or new capital will be required. As the influx of new employees proceeds, it is possible that these thresholds could be exceeded, requiring local governments to accelerate debt issuance schedules, to purchase such high relative-cost variables as fuel oil, or to allow growth to assume patterns of land use inferior to those possible under more controlled conditions.

We may find that a specific lease sale will lead to effects which take a community very close to, yet not beyond, a critical growth threshold. Ignoring costs associated with environmental deterioration, such a project will probably bring in, on balance, a net benefit to the community. If, however, another lease sale occurs shortly thereafter, the threshold may be exceeded, with the probable result that social costs would exceed benefits. Hence, any one lease sale by itself may not constitute a problem to local governments, but it is the potential accumulation of them, with attendant effects, that must be planned for over the long run.

FOCUS ON VENTURA COUNTY. While the major onshore effects from Lease Sale #35 will be felt in Los Angeles, Orange, and Ventura Counties, the only perceptible impact on public services will occur in Ventura County. The reasoning behind this assumption is apparent when the reader takes note of the infinitesimally small proportion of imported residents in the Orange and Los Angeles demographic bases.

METHOD OF ASSESSING EFFECTS ON PUBLIC SERVICES

The method employed to assess the effects on public services is closely related to the assessment of employment and price effects.

Assuming prices as given, we measure the increase in total demand by the ratio: # of new residents / # of total residents = X. Alternatively, new demand may be measured by new income / total income. A choice between the two would depend on which is more appropriate to the public service being assessed.

The next step is to measure current excess capacity of public service systems (Y). If X>Y, then new capacity, measured by (X=Y) times total supply, is required. If, however, Y>X, then the threshold is not met and no perceptible opportunity costs are borne by the community.

Measures of supply vary, depending upon which type of service is being assessed. When measuring excess capacity in wastewater treatment systems, the appropriate unit of measure is million gallons per day. Excess capacity in primary and secondary school systems is calculated on the basis of pupil/teacher and pupil/classroom ratios, while capacity in highway systems is most effectively assessed using some measure of congestion. Police and Fire Department capacity is much more difficult to specify, though a commonly accepted criterion is 1.5 policemen per thousand population and 2.5 - 3.0 minute response time to any fire alarm.

It is important to emphasize that we assume no change in the effective price of a public service and that people demand a constant proportion of their income be spent on public services.

In order to demonstrate a range of potential effects, we derive an estimate for X (increase in total demand) and also an upper bound equal to three times this estimate. The estimate is derived by multiplying the average number of imported employees per year over the first ten years of the project (1976-1985), as taken from Table 6, times average density per dwelling unit in Ventura County (3.0). 11/ This result is then multiplied by .5, the relocation factor assumed throughout. The value of X will be identical for each service impact assessment in Ventura County. The estimate and upper bound values are:

$$\frac{95 \cdot 3.0 \cdot .50}{432{,}400^{*}} = 0.00033 = X_1 = \text{estimate}$$

$$\frac{285 \cdot 3.0 \cdot .50}{432{,}400} = 0.00084 = X_2 = \text{upper bound}$$

These results are noteworthy because the values for X are not significantly different from zero.

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* See footnote 15.

If we were, moreover, to assert that a 1% increase in demand for public services as measured by X was the lower threshold of significance, it would require an inmigration of approximately 28 times the size we project for Lease Sale #35 to reach that level.

It is only valid to conclude at this point that we are not able to measure percentage excess capacities within the X_1 or X_2 value ranges of zero. We will, however, proceed with calculations of excess supply function values of Y so as to demonstrate the relative growth-supporting capability of Ventura County public services, should ultimate cumulative effects approach the range of significance of X.

POLICE AND FIRE

The impact of Lease Sale #35 upon public expenditures for, and quality of, police and fire service to communities within the study area will not be discernible.

Public Interest Economics-West conducted telephone interviews with the Ventura City, Oxnard, and Port Hueneme Police Departments as well as the County of Ventura Sheriff's Department. Each indicated that a net population growth in the 500-to-2,000 range would not affect current capital facilities planning. A very marginal increase in the police and fire force may result if new residents settle in the same locale or in remote unincorporated areas.

The Police Departments of both Oxnard and Port Hueneme indicated that they currently employ 1.2 to 1.35 policemen per thousand population. This is marginally below the statewide average of 1.55.* The average is even lower for smaller-sized communities.

Telephone interviews were conducted with representatives of Ventura and Oxnard Fire Departments as well as California State Firemen's Association. Each indicated that an influx of the range we specified would not perceptibly affect quality or timeliness of response to alarms. A response time of 2½ minutes is the stated objective of urban departments throughout the state and this is more a function of building type and distribution than minor increases in population.

SCHOOLS

In order to obtain data for assessing the current capacity of Ventura County Schools, Public Interest Economics-West conducted interviews with officials of relevant school districts. Two measures were used for calculating capacity, and Table 11 shows the results of each.

The first measure is the result of a comparison of current enrollment to state and/or locally-calculated capacity. The state capacity estimate is based on square footage area in schools. The local capacity figure is derived empirically by the school district. The net result, presented in column 3, reflects the degree of excess supply (positive value), or the degree of overcrowding (negative value).

Our second measure is the ratio of pupils to teachers. A statewide average is then presented for the elementary level (such an average is not calculated for secondary schools at the state level) and a reasonable estimate of current capital capacity is inferred therefrom.

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* Reported to PIE-West by the Peace Officers Research Association of California, November 1, 1976.

In addition to the empirical measures presented in Table 11, we have included a brief series of comments, Table 12, which further illustrates the current capacity of each district.

TABLE 11:
SELECTED VENTURA COUNTY SCHOOL DISTRICTS

SCHOOL DISTRICT	CAPACITY	ENROLLMENT FALL 1976	SURPLUS CAPACITY-ENROLLMENT	PUPILS/ TEACHER
CONEJO VALLEY UNIFIED				
Kindergarten-6	10,905	10,776	129	30
7-8	3,276	3,588	-312	30
9-12	5,300	6,241	-941	31
HUENEME ELEMENTARY				
Kindergarten-8	6,750	6,400	350	
	7,100*		700	28
OCEAN VIEW ELEMENTARY				
Kindergarten-8	2,250	2,100	150	24 (K-5) 28.95(K) 29.04(1-3)
OXNARD ELEMENTARY				
Kindergarten-8	10,050	9,824	226	33.95(4-6) 24.61(7-8)
PLEASANT VALLEY ELEMENTARY				
Kindergarten-8	5,600	5,400	200	27.8
OXNARD UNION HIGH				
9-12	10,500	11,281	-781	27.0(74/75)
SANTA PAULA ELEMENTARY				
Kindergarten-8	3,502	2,978	524	25.6
SANTA PAULA UNION HIGH				
9-12	2,000	1,300	700	27.3(75-76)
SIMI VALLEY UNIFIED				
Kindergarten-6	13,373*	12,022	1,351	31
7-9	5,806*	5,846	-40	32
10-12	5,103*	4,754	349	31.5
	4,300	4,754	-454	
VENTURA UNIFIED				
Kindergarten-6		8,777		
7-12		7,898		
STATE OF CALIFORNIA				
1-3				27.2/classroom
4-8				27.1
9-12				State does not calculate an average

* Figures calculated by the California State Department of Education. Conversations with District Superintendents suggest these figures may be unreasonably high.

TABLE 12:
COMMENTS OF SCHOOL DISTRICT REPRESENTATIVES

Conejo Valley - Phyllis Schatz of the Planning Office: All schools are using portables; a new high school is under construction and will open for the school year 1978-79.

Hueneme Elementary - Charles Slaughter, Superintendent: Operating within capacity; part of an expanding residential area; own a site that will probably be built on in six or seven years.

Ocean View Elementary - Robert D. Allen, Superintendent: Within capacity; expect to grow slowly, 35 students per year, unless there are zoning changes. If Petit housing tract is approved, it would result in an influx of 100 students and that number could be handled.

Oxnard Elementary - Norman Brekke, Superintendent: Crowded: running a twelve month year. Two recent bond issues have failed and the District is applying for funds from the Public Work Capital Development and Investment Act of 1976.

Oxnard Union High - Andy McEuen, Superintendent: Over capacity; voters turned down bonds in 1975 and 1976. Foresees double session and extended days. Projected high school enrollment in 1981 of 13,755 based on current elementary attendance and no move-ins.

Pleasant Valley Elementary - Charles Honn, Superintendent: Will reach capacity in a couple of years; have $300,000 remaining from last bond issue; may go to 12 month year.

Santa Paula Elementary - Dr. De La Rosa, Superintendent: Well within capacity; net 23 empty classrooms; expect to close a school.

Santa Paula Union High - Secretary to the Superintendent: Well within capacity; net increase of students over the last ten years approximately 100.

Simi Valley Unified - Edmund Richard, Director, School Facilities, Robert Allert, Property Manager: Elementary well within limits; 7-12 overcrowded, but that will ease in six years with declining enrollment in the elementary schools.

Ventura Unified - John C. Wolfe, Associate Superintendent: Considers the district to be at capacity; building a new elementary school; expect to build another high school within 5-10 years. No extended days or double sessions at present; one school on a 12-month year.

Although our results may be interpreted in a variety of ways, we feel they demonstrate several key points. First, that in the event of a relatively minor increasse in resident population, significant costs may be experienced by Simi Valley, Conejo Valley, and Oxnard Union High because they have no excess capacity. Further, that the marginal or incremental costs may be quite high when compared to each community's current tax base.

A more thorough evaluation of the probable patterns of residential preference by imported OCS employees would be necessary in order to refine our estimates. Local planning officials, presumably having conducted such studies, will be more fully equipped to assess the extent of the above-noted incremental costs upon their own community.

WASTEWATER TREATMENT

Interviews were conducted with officials of the Ventura County Regional Sanitation District, officials of local City Engineering Departments, and staff of the Ventura County Planning Department to determine the excess supply in the Ventura County wastewater treatment system.

Pursuant to Section 4700.00 of the California Health and Safety Code, the Ventura County Regional Sanitation District is currently implementing a county-wide plan, the "Sewerage Master Plan" of 1975. Under this plan, the District is acquiring all local plants in the County and, upon completion, will manage all plants as an integrated wastewater treatment system.

In Table 13, we present data on present use, present capacity, percentage excess capacity, and projected capacity for the year 2000, as calculated by the Regional District, for each facility in the county.

Assuming 100 gallons per capita per day, there exists excess capacity to handle over 300,000 new residents in Ventura County. It is not probable, however, that new residents would make housing location decisions so as to maximize use of existing capacity. As a result, existing excess capacity for new residents county wide is probably much less -- on the order of 150,000 to 200,000.

TABLE 13:
WASTEWATER TREATMENT PLANT CAPACITY
VENTURA COUNTY

FACILITY	PRESENT USE (1976)		PRESENT CAPACITY (1976)				FUTURE CAPACITY (2000)	
	MGD*	Equivalent Population	MGD**	Equivalent Population	Excess Capacity(MGD)	Excess% Capacity	MGD	Equivalent Population
Camarillo	2.70	27,000	4.75	47,500	2.05	43.2	8.00	80,000
Filmore	.67	6,700	0.75	7,500	.08	10.7	1.30	13,000
Oak View	1.65	16,500	1.50	15,000	-.15	-10.0	3.00	30,000
Oxnard	10.00	100,000	25.00	250,000	15.00	60.0	37.50	375,000
Piru	.09	900	.20	2,000	.11	55.0	.40	4,000
Santa Paula	2.00	20,000	2.50	25,000	.50	20.0	3.50	35,000
Simi Valley	5.50	55,000	7.00	70,000	1.50	21.4	14.00	140,000
Thousand Oaks	5.75	57,500	10.00	100,000	4.25	42.5	20.00	200,000
Ventura	7.00	70,000	14.00	140,000	7.00	50.0	14.00	140,000
Port Hueneme	3.75	37,5000	6.00	60,000	2.25	37.5		(no change)
							to be consolidated	
Moorpark	.40	4,000	1.00	10,000	.60	60.0	to be consolidated	
Montalvo	.12	1,200	0.25	2,500	.13	52.0	to be consolidated	
Saticoy	.10	1,000	0.86	8,600	.76	88.4	to be consolidated	
TOTAL	39.73	453,800	73.81	738,100	34.08		102.1	1,021,000

* Millions of gallons daily

** The most commonly accepted standard for usage is 100 gallons per capita day. Hence, the gallons were converted to equivalent population. Using this technique, non-residential usage is subsumed in equivalent residential usage.

SOURCES: Ventura County Regional Sanitation District, "Sewerage Master Plan," February 1975
Interviews with City, County and District Officials.

In those areas with the highest growth rates -- Simi Valley, Thousand Oaks, Oxnard -- there is substantial excess capacity. Only one community, Oak View, is at or in excess of its capacity, and a doubling of that facility's capacity is currently planned.

There is no evidence to suggest from these data that growth thresholds will be exceeded as a result of Lease Sale #35 activity in Ventura County. In the event that subsequent lease sales significantly affect county demographic patterns of the future, thresholds may be approached; yet given the small relative cost share borne by localities in treatment plant construction (12½ percent) it does not appear to be an area of major concern.

Tables 14 and 15 present a summary of selected public-sector effects including school enrollment, housing, population, and per capita local government expenditures for each of the study areas.

TABLE 14:
IMPORTED EMPLOYMENT, ORANGE AND LOS ANGELES COUNTIES

Year	(A) Average # Imported Employees	(B) Increase in Population	(C) Increase in School Enrollment	(D) Housing	(E) Local Government Expenditure ($000)
1976	257	694	139	129	618
1977	257	694	139	129	1108
1978	461	1245	249	231	1108
1979	461	1245	249	231	1108
1980	461	1245	249	231	1108
1981	461	1245	249	231	1108
1982	461	1245	249	231	1108
1983	461	1245	249	231	1108
1983	461	1245	249	231	1108
1984	221	597	119	111	531
1985	221	597	119	111	531

NOTE: Numbers in the columns were derived as follows: (A) is given from Table 6; (A) x 2.7 = (B); (B) x.20 = (C); (A) x .5 = (D); (B) x $890 = (E). The multiplier 2.7 refers to persons per dwelling unit as estimated in SCAG-76 Growth Forecast Policy (Southern California Association of Governments, Los Angeles; January, 1976). The multiplier .20 is drawn from "Active Enrollment in California Elementary and Secondary Public Schools, Fall, 1975" (California State Department of Education, 1974). The multiplier .5 is a residential relocation factor. The multiplier $890 is calculated from: a) Financial Transactions Concerning Cities of California; b) Financial Transactions Concerning Counties of California; c) Financial Transactions Concerning School Districts of California; and, d) Financial Transactions Concerning Special Districts in California, Office of the Controller, for 1974-1975.

TABLE 15:
IMPORTED EMPLOYMENT IMPACT, VENTURA COUNTY

Year	(A) Average No. Imported Employees	(B) Increase in Population	(C) Increase School Enrollment	(D) Housing	(E) Local Government Expenditures ($000)
1976	65	195	49	33	138
1977	65	195	49	33	138
1978	116	348	87	58	246
1979	116	348	87	58	246
1980	116	348	87	58	246
1981	116	348	87	58	246
1982	116	348	87	58	246
1983	116	348	87	58	256
1984	56	168	42	28	119
1985	56	168	42	28	119

NOTE: Numbers in columns were derived as follows: (A) is given from Table 6; (A) x 3.0 = (B); (B) x .25 = (C): (A) x .5 = (D); 2nd (B) x $707 = (E). The multiplier 3.0 refers to persons per dwelling united as estimated in SCAG-76 Growth Forecast Policy, (Southern California Association of Governments, Los Angeles: January 1976). The multiplier .25 is drawn from "Active Enrollment in California Elementary and Secondary Public Schools, Fall 1975" (California State Department of Education, 1974). The multiplier .5 is a residential relocation factor. The multiplier $707 is calculated from: a) Financial Transactions Concerning Cities of California; b) Financial Transactions Concerning Counties of California; c) Financial Transactions Concerning School Districts of California; and, d) Financial Transactions Concerning Special Districts in California, Office of the Controller, for 1974-1975.

TAXES AND TRANSFERS

Substantial flows of money result from Outer Continental Shelf oil and gas development. These flows arise in four forms:

1. increase in personal disposable income of residents within the study area(discussed earlier in the Economic Impacts Section);
2. changes in natural gas prices and gas supplies brought about by extraction of the resource;
3. the study area's share of national economic rent deriving from bonus and royalty payments; and,
4. state and local tax revenues less incremental costs of public services.

PETROLEUM PRODUCT PRICES

It is a well documented fact that savings associated with Outer Continental Shelf crude production will not be directly passed to the consumer. 12/ Even assuming a competitive domestic industry, free of direct price regulation, the price of OCS crude will not fall below the landed price of OPEC crude unless total domestic production throughout the U.S. would flood all foreign oil off the U.S. market. As a result, there is no consumer surplus in oil price to be derived from Southern California OCS production even if there are very high levels of production.

There is much current discussion of the impact of an anticipated glut of crude on the West Coast by 1979 when Alaskan crude will be reaching peak flow. It is important to emphasize that although supplies in excess of local demand may pass through southern California en route to Texas for refining, they will not affect the

market price. Put simply, no domestic producer is willing to sell oil for less than the landed price of foreign. Regional income deriving from OCS gas extraction, however, may increase.

REGIONAL SHARE OF NATIONAL RENT

Oil and gas operations on the Outer Continental Shelf are not currently taxable by state and local governments. The federal government has jurisdiction over OCS operations, and firms acquire rights to develop OCS lease tracts from the federal government in exchange for bonus and royalty payments.

A successful bidder for a tract receives a five-year lease, granting exclusive right to explore the tract and produce as much oil and gas as possible for as long as mineral production continues. The lease fixes the amount of annual rent ($3.00 per acre, due annually until production is initiated) and the amount of royalty (a percentage of the market value of the output). The royalty may be no less than 12½% and has been generally set at 16 2/3% for OCS development. The payments are intended to reflect a fair return to the public for the market value of the resource.

OCS bonus and royalty charges bring in significant revenues to the federal government. As reflected in Table 16, total royalty payments from 1970-1976 exceed $2.5 billion, with a per annum average of $429 million. As a frame of reference, Louisiana Coast operations paid $226 million in royalties and rents during 1970 while producing 338 million barrels. If, as projected, Lease Sale #35 peak production levels reach 75-100 million barrels per year, federal royalty and bonus revenues will reach $80 million per annum.

The benefits to residents of the study area from those federal receipts will arise either in the form of reduced federal income taxes or increased quantity and/or quality of federally financed public services.

TABLE 16:
FEDERAL BONUS AND ROYALTY RECEIPTS FROM
OUTER CONTINENTAL SHELF LANDS FOR 1970-1976
(Millions of dollars)

	Bonus	Royalty	Total
1970	944.8	283.5	1,228.3
1971	96.3	350.0	446.3
1972	2,251.3	363.6	2,614.9
1973	3, 91.0	401.1	3,492.1
1974	5,021.1	560.3	5,581.4
1975	1,088.2	615.5	1,703.7
1976	2,242.9	N.A.	---
TOTAL	14,735.9	2,574.0	15,066.7

Source: United States Department of the Interior

STATE AND LOCAL TAXES

The principal sources of OCS-related revenues to state and local governments are personal income taxes, property taxes, and sales taxes. Additional sources such as licenses, fees, and user charges are not sufficiently significant to include in the present analysis.

INDIVIDUAL INCOME TAXES. California's individual income tax will yield moderate sums over the life of the project. As shown in Table 17, the peak year total for both direct and indirect related wages and salaries will be $1.16 million. This is an upper-bound estimate in view of its implicit assumption that all OCS employment is new and that all employees will file California as their place of residence. Local units of government in California are not constitutionally empowered to impose income taxes. As a result, local residents will be limited to benefits derived from increased state income tax revenues -- either lower relative tax burdens or higher quality state services.

TABLE 17:
STATE INDIVIDUAL INCOME TAXES GENERATED BY
LEASE SALE NO. 35 - RELATED WAGES AND SALARIES
(millions of 1975 dollars)

YEAR	TOTAL EMPLOYMENT	TOTAL INCOME	INDIVIDUAL INCOME TAXES GENERATED
1976	976	18.17	.345
1977	1850	35.65	.677
1978	2450	47.45	.902
1979	2825	54.40	1.033
1980	3220	61.39	1.166
1981	2566	47.75	.907
1982	2278	41.99	.798
1983	2540	45.41	.863
1984	2400	42.15	.800
1985	2500	43.80	.832
1986	2300	39.80	.756
1987	1925	32.85	.624
1988	1650	28.00	.532
1989	1250	20.00	.380
.	.	.	.
.	.	.	.
.	.	.	.
1995	1250	20.00	.380
1996	1230	19.69	.374
.	.	.	.
.	.	.	.
.	.	.	.
2000	1230	19.69	.374
TOTAL	44,380	777.30	14.77

Data derived by multiplying total employment per year by average income per employee per year ($17,500) times the 1975 effective tax rate (.19) (State of California, Department of Finance).

The income tax data were derived by multiplying total employment per year by the average income per employee per year ($17,500) by the 1975 effective tax rate for that income bracket (.019).

SALES TAXES. Each of the counties in the study area is subject to 6% sales tax imposed by the State. The distribution of the revenues derived from the tax is as follows:

4 3/4 % -- State of California general revenues
1 % -- local general purpose revenues
¼ % -- local mass transportation

The 6 % rate has not changed since April 1974, at which time the state general revenue share increased from 3 3/4 % to 4 3/4 % of taxable sales.

Table 18 presents estimates of anticipated sales tax revenues derived from wages and salaries from Lease Sale #35. This table, as well as the property tax tables which follow, present estimates based on the average total income and employees per year. These average estimates are derived by summing the average total income columns of Ventura, Orange, and Los Angeles Counties in Table 6. We have limited our analysis to ten years since estimates beyond that period, using average data, are on very weak ground.

TABLE 18:
SALES TAX REVENUES GENERATED BY OCS #35 RELATED WAGES AND SALARIES IN LOS ANGELES, ORANGE AND VENTURA COUNTIES
(millions of 1975 dollars)

YEAR	TOTAL AVERAGE INCOME	DISPOSABLE INCOME	RETAIL SALES	TAXABLE SALES	SALES TAX REVENUES
1976	25.15	21.38	16.70	12.52	.7513
1977	25.15	21.38	16.70	12.52	.7513
1978	44.32	37.67	29.42	22.07	1.324
1979	46.66	39.66	30.98	23.23	1.394
1980	59.57	50.63	39.55	29.66	1.780
1981	59.57	50.63	39.55	29.66	1.780
1892	59.57	50.63	39.55	29.66	1.780
1983	59.57	50.63	39.55	29.66	1.780
1984	39.07	33.21	25.94	19.45	1.167
1985	39.07	33.21	25.94	19.45	1.167

The above sales tax data were derived by multiplying average total income for all counties in the study area by .85, the ratio of disposable income to average total income, to obtain personal disposable income. This result is then multiplied by 78.1, the average ratio of retail sales to wage and salary income in California from 1970 to 1975. This figure is then multiplied by .75, the value of the ratio of total taxable sales/total retail sales in California. This figure is then multiplied by .06, the sales tax in each of the counties in the study area.

Regarding the ratio of taxable sales/retail sales, note should be taken of the fact that the value of the ratio varies from county to county, because the composition of retail sales varies from county to county. In aggregating the three counties we used the unweighted average of the 1975 figures:

Los Angeles	.738	
Ventura	.680	X = .75
Orange	.736	

PROPERTY TAXES. Property taxes are the principal source of income to local governments. In 1975, over 85% of local revenues in California were drawn from property, with school districts being most heavily reliant upon them. Property tax revenues resulting from OCS development will be drawn from two sources:

1. residential property tax revenues resulting from the importation of OCS employees; and,
2. commercial and industrial tax revenues resulting from the construction and operation of onshore OCS related facilities.

In Table 19, we present estimates of annual property tax revenues resulting from the inmigration of new employees. Continuing our upper-bound approach, we have assumed that each new employee will form one new dwelling unit.

The data in Table 19 are derived by multiplying new employees by average annual income ($17,500), and multiplying this result by 14 in order to arrive at total net valuation, assuming each employee is willing to spend 25% of his income for housing. We then multiply this result by .25 (to obtain the State mandated assessed value) and finally, multiply this result by the relevant tax rates in the counties.

In addition to property tax revenues derived from newly developed housing for relocated OCS employees, revenues will also result from the construction of onshore facilities related to offshore development activities. Planning for onshore capital facilities, in the absence of certainty pertaining to the actual volume of reserves, is tenuous. We are able, however, to estimate an approximate range of capital value associated with facilities anticipated for the Port Hueneme and Long Beach areas.

TABLE 19:
RESIDENTIAL PROPERTY TAX REVENUES GENERATED AS A RESULT OF LEASE SALE #35
LOS ANGELES, ORANGE AND VENTURA COUNTIES
(millions of 1975 dollars)

Year	Average No. Imported Employees Relocating/year	Average Total Income of Imported Employees	Average Increase Residential Valuation	Assess Value	New Property Tax Receipts
Ventura					
1976	33	.57	2.28	.57	.063
1977	33	.57	2.28	.57	.063
1978	58	1.02	4.06	1.02	.113
1979	58	1.02	4.06	1.02	.113
1980	58	1.02	4.06	1.02	.113
1981	58	1.02	4.06	1.02	.113
1982	58	1.02	4.06	1.02	.113
1983	58	1.02	4.06	1.02	.113
1984	28	.49	1.96	.49	.055
1985	28	.49	1.96	.49	.055
					.914
Orange & Los Angeles					
1976	129	2.25	9.00	2.25	.252
1977	129	2.25	9.00	2.25	.252
1978	231	4,04	16.14	4.04	.452
1979	231	4.04	16.14	4.04	.452
1980	231	4.04	16.14	4.04	.452
1881	231	4.04	16.14	4.04	.452
1982	231	4.04	16.14	4.04	.452
1983	231	4.04	16.14	4.04	.452
1984	111	1.94	7.74	1.94	.217
1985	111	1.94	7.74	1.94	.217
					3.650

* Data for Table 19 were derived by multiplying average imported employees/year from Table 6 times 150, the accepted relocation factor, times the projected average annual income of $17,500 to get total income. Assuming the average family consumes housing valued at approximately four times current income* this will result in total valuation of new housing of total income of relocated employees times four. This result is then multiplied by .25, the statewide assessment ratio for real estate. Finally, this result is multiplied by the 1975 property tax rate (per thousand valuation) for each county. Ventura is 11.11, while for Orange and Los Angeles counties the average taken is 11.21.

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* Given the urban family budget studies of the Bureau of Labor Statistics, a $17,500 income earner will spend $4,375 annually for housing services. Using our rule of thumb, a $17,500 income earner will purchase a $70,000 home. This implies a 6.25% internal rate of return, which we find to be reasonable.

In Table 20, we present capital requirements for facilities that can reasonably be expected to be constructed in each study area. If we assume for each location the construction of one permanent service base, one gas processing plant, one surge tank farm, and two marine terminals, as well as one platform fabrication yard somewhere within the aggregate study area, we can project a range of capital valuation for the entire area from $130 to $160 million. In discussing these facilities it is important to point out the speculative nature of the assumption of a platform fabrication yard in the study area. None has been proposed as of this date.

Assuming a 25% assessed valuation and an average tax rate of $12.00 per hundred assessed value, the onshore facilities will yield between $3.88 and $4.80 million per annum in property taxes to the aggregate study area. To demonstrate the scale of these additions to the taxable base, it is noteworthy that the $160 million high estimate, if located totally within Ventura, would constitute only .022% of that county's taxable base.

TABLE 20:
ONSHORE FACILITIES RELATED TO OFFSHORE OIL AND GAS DEVELOPMENT
(1976 Dollars)

Permanent Service Base

1.	Breakwater	1,125,000
2.	Reclamation	200,000
3.	Dredging	200,000
4.	Road Access	50,000
5.	Berths for Vessels	1,125,000
	TOTAL	$2,700,000

Marine Terminal *	$50,000,000
Onshore Tank Farm **	$20,380,000
Gas Processing Plant ***	$26,000,000
Platform Fabrication Yard	$30-60,000,000

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* Fixed shoreside terminal designed for 250,000 barrels per day, and storage of 1 million barrels.
** For detail of typical cost breakdown, see Table 21.
***A 300 million cubic ft/day capacity plant.

Source: Onshore Facilities Related to Offshore Oil and Gas Development Factbook, New England River Basins Commission, 1976.

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TABLE 21:
INVESTMENT COST ESTIMATES FOR ONSHORE TANK FARMS *

	Shoreside Terminal	Mid-Depth Terminal
Total Storage Capacity	1,000,000	2,000,000
Crude Tank Configuration	4 x 250,000	2 x 250,000 3 x 500,000
Land Development	340	740
Storage Tanks	3,300	6,370
Tank Farm Piping	480	660
Piping to Refinery	12,290	14,260
Pumping Station	400	1,030
Drainage & Wastewater Treatment	200	220
Fire Protection	300	350
Electrical	300	400
Buildings & Miscellaneous	600	650
Subtotal	18,210	24,690
Mobilization/Demobilization	1,790	2,510
Total Construction Cost	20,000	27,200

* In thousands of 1974 dollars (all costs ± 25% because of non-specificity of site).

SOURCE: Arthur D. Little, Inc., and Frederic R. Harris, Inc., Petroleum Development in New England, Vol. II, 1975. p. IV-13.

EQUITY CONSIDERATIONS

With continued and increased levels of oil and gas development activity, cumulative effects in many forms may arise. Regional income and employment will rise, local public revenues will increase, costs of government operation will grow, and environmental damage will occur. From the perspective of residents and property owners within the study area, equity considerations arise -- namely, to what degree do the benefits of increased regional income and public revenue exceed public service and environmental costs? And, to the degree they fall short of doing so, at what level and in what form are residents compensated?

The Federal leasing system of bonus and royalty payments described previously is intended as a vehicle to provide the public with a fair return in exchange for the granting of sole resource development rights to a private firm. There is extensive debate in the literature, however, as to the adequacy of this system of compensation, and substantial evidence suggests that competition is currently less than optimal as a result. 13/

Examined independently, Lease Sale #35 does not appear to warrant additional compensation to residents on the basis of work conducted thus far, since the cost increases in public service will be minimal. However, environmental effects have not yet been measured, and it is possible that they may tip the balance for Lease Sale #35 so that costs exceed benefits. Further, in an aggressive leasing program, compensation may play a significant role.

The literature on equity strongly suggests that compensation is necessary where environmental damage is incurred by a specific population and that such compensation for a public or depletable externality does not impose market distortion. 14/

In the case of oil and gas development, the most efficient form of compensation to the public may be a tax on the profits of production. Although the law is somewhat unclear on the feasibility of legally instituting such a tax, the return to the public might be very high. Given the very high market value of the extracted resource and the fact that such a tax would impose no misallocations on the market, it is eligible for thorough consideration. The major pitfall of pursuing such a tax is the difficulty in identifying profits.

Alternatives exist, such as increasing existing royalty payments requiring the posting of performance bonds by private firms, or the setting aside of specific funds in escrow. In any case, the objective must be to provide those affected by the development with compensation equivalent to the discounted present value of net costs incurred. To date, no uniformly recognized measure for quantifying these costs has been developed, and indeed they are frequently of a non-monetary nature.

CONCLUSION

The development of Outer Continental Shelf oil and gas off the coast of southern California will not substantially alter the structural relationships or the overall volume of economic activities in the affected onshore communities. However, the impact on small and medium-size communities may, in the instance of a protracted and productive leasing program, be discernible. The effect upon larger communities, unless highly abnormal labor supply or housing preference patterns are evident, will not be perceptible.

Over the economic life of the project, 44,380 man-years of employment and $777 million in income will be produced within the three-county study area. These effects will be spread over 40 years, with 1980 reflecting peak levels of activity. Of the major phases involved in the development operation, the most labor-intensive and that which yields the highest annual income is exploratory drilling. During the peak year, exploratory activity will create 1550 jobs within the study area of which 1070 will be local employment. In terms of total man-hours over the life of the project, production operations yield the largest sum, comprising 25% of the total. Other development activities which constitute major percentages are support services and development drilling, comprising respectively 17% and 16% of total employment.

Of the two sub-areas examined, Ventura County, on average, will experience approximately 20% of the new employment and associated income, with the Orange/Los Angeles Counties sub-area receiving the remainder. During the peak year of the project, average total employment associated with Lease Sale #35 will reach 751 in Ventura County and 2,514 in Orange/Los Angeles. These employment levels will produce income flows of $13.45 and $46.12 million respectively. The levels of employment imported into the study area, approximately 464 workers per year on average, will be relatively inconsequential. As a result, the net effect upon public service within the affected communities will be very minor.

In Ventura County, the results of Lease Sale #35 fail to exceed specific growth thresholds that would require increased public service cost to

local governments or reduced service quality. Several high-growth areas such as Simi Valley, Thousand Oaks, and Oxnard are, however, nearing capacity levels in schools, and subsequent lease sales with attendant immigration will conceivably necessitate increased local expenditures.

As a result of new imported demand and a relatively fixed supply of housing and consumer durables, short-run price effects will be felt in the study area. In Los Angeles and Orange Counties, these effects will be very small. In Ventura County, however, a short run increase of 2% may be anticipated for housing, while prices of consumer durables, inclusive of kitchen appliances and automobiles, may increase 1.5%.

OCS development will result in increased housing development, higher retail sales, and higher general income levels in the affected counties. These higher levels of economic activity will result in increased levels of public revenues -- principally income, property, and sales tax revenues.

Including residential development as well as OCS onshore facilities construction, we anticipate increased annual revenues during peak production years of $1.52 million in Ventura County and $4.92 million in the Orange/ Los Angeles Counties area. Over the 1976-1985 period, cumulative increases in property tax revenues for the three counties will be approximately $530 million. This total represents approximately .04 % of anticipated revenues over the same ten year period.

The increase in State income tax revenues resulting from OCS activity will be relatively minor. During the peak year, net income will approach $1.16 million and a ten-year cumulative increase of $14.77 million may be anticipated. Sales tax deriving from increased levels of retail sales activity will peak at $1.78 million, and over the 1976-1985 period will yield a total of $13.67 million. The peak year flows of $1.16 million for income and $1.78 for sales represent less than .1 % of the aggregate yearly amount for the State. Peak year incremental flows of new tax money to the State of California will approximate $2.6 million while the local peak will exceed $6.0 million.

CUMULATIVE EFFECTS

As noted above, these regional economic effects will not alter structural relationships or significantly vary levels of economic activity. We hasten to emphasize, however, that effects deriving from a number of lease sales may accumulate and impose more substantial consequences. Such may result from the specific timing of the projects themselves or the scale of staggered development activity. Local officials should be very attentive to these effects on the horizon and be sensitive to their relationship to growth thresholds. In this respect, Lease Sale #48 and #53 should be thoroughly examined for such effects as soon as adequate estimates of reserves are published. Using the method described in this chapter, local planners should be capable of deriving incremental cost and revenue estimates for each sale.

ENVIRONMENTAL CONSIDERATIONS

One area requiring further research is the economic assessment of environmental impacts resulting from OCS Lease Sale #35. This analysis would be important in the event that environmental effects resulting from other regional lease sales are to be evaluated. Cumulative impacts stemming from Lease Sale #35 and #48 as well as those derived from the current development program within the Santa Barbara Channel, may be significant. The movement of Alaskan crude along the Southern California Coast will affect the environment.

In order to properly evaluate any possible environmental effects from Lease Sale #35, the following kinds of analyses should be conducted:

1. an evaluation of the probable physical effects in the event of an oil spill, using current data on probability estimates and resulting clean-up costs; and,
2. a presentation of baseline water and air quality data, for the regions under consideration, as well as estimates of percentage increases in pollutant load resulting from Lease Sale #35.

Given these considerations, the following kinds of effects should be assessed:

1. changes in the pattern of recreational usage resulting from the above air and water quality baseline changes, with an appropriate assessment of the costs borne by both consumers and resource owners;
2. costs incurred to both fishing and agriculture, with consideration given to the specific potential for crop damage and loss of fisheries;
3. changes in property assessments; and
4. evaluation of the effects of increased pollution on the health of individuals residing and/or working in the region.

When conducting this analysis, it is important to note that percentage increases in water and air pollution may be a poor measure of such environmental effects, since the first units of pollution may not be noticeable, while later units may become very significant. Thus, cumulative effects resulting from many lease sales could become very large. Furthermore, it is very difficult to compare pollution costs to other economic costs. Finally, since pollution reduces the quality of life for all individuals in the affected area, there is no dilution-effect when considering the effects upon a large versus small population.

Again, changes in traffic congestion and the landscape are not measured accurately by the use of percentages. Furthermore, if congestion is measured by travel-time, this type of effect can rise very rapidly as capacity is neared. In Los Angeles and Orange Counties, and perhaps in Ventura County, the imminence of these kinds of effects may not be obvious due to current levels. However, in the event that the cumulative environmental impacts of several lease sales are assessed, it is likely that many of the previously cited impacts may be large, and it is entirely possible that they may outweigh any easily measurable economic benefits to the region.

FOOTNOTES

1. U.S. Department of Commerce, Survey of Current Business, LVI (August 1976), pp. 26-27.

2. Governor's Office of Planning and Research, State of California, Onshore Impact of Offshore Southern California OCS Sale #35 (January 1976), pp. VIII-1 - 79.

3. Ibid., p. VIII-74.

4. Ibid., p. VIII-22.

5. Ibid., p. VIII-72.

6. Council on Environmental Quality, OCS Oil and Gas -- An Environmental Assessment, IV (April 1974).

7. Bureau of Land Management, U.S. Department of the Interior, Final Environmental Statement, Proposed 1975 OCS Oil and Gas General Lease Offshore Southern California (OCS Sale #35), 1975.

8. State of California, Employment Development Department, California Employment and Payrolls, January-March 1975, August 10, 1976.

9. H. S. Houthakker and Leslie D. Taylor, Consumer Demand in the United States, 1929-1970 (Cambridge: Harvard University Press), 1966.

10. Southern California Association of Governments, SCAG-76 Growth Forecast Policy (Los Angeles), January 1976.

11. Ibid.

12. J. W. Devanney, III, Georges Bank Petroleum and New England Regional Income (Cambridge: MIT Sea Grant Program), 1976.

13. For a cross-section of current thought on this topic, the following articles are recommended:

H. E. Leland, Optimal Risk Sharing and the Leasing of Natural Resources, with Application to Oil and Gas Leasing on the OCS, Working Paper #38, Institute of Business and Economic Research, Berkeley, California.

H. E. Leland, R. B. Norgaard, and S. R. Peason, Economic Analysis of OCS Leasing Policies, National Science Foundation, Office of Energy Research and Development Policy, September, 1974.

W. J. Mead, P. E. Sorenson, and R. O. Jones, "An Economic Analysis of the Performance of the Cash Bonus Bid Leasing System for OCS Oil and Gas Resources in the Gulf of Mexico," paper presented at the Southern Economic Association Annual Meeting, Atlanta, Georgia, November 1976.

14. W. J. Baumol and W. E. Oates, with contributions by V. M. Vawa and D. Bradford, The Theory of Environmental Policy: Externalities, Public Outlays, and the Quality of Life (Englewood Cliffs, New Jersey: Prentice-Hall), 1975.

APPENDIX 1

CONSIDERATIONS ON USING AN INPUT-OUTPUT MATRIX TO ASSESS REGIONAL ECONOMIC IMPACTS

Throughout the period of our analysis, we have discussed with individuals, departments, and agencies the merits of using an input/output matrix to assess regional economic effects of OCS development. In most instances, the specific model discussed has been the Curtis-Harris model which the Department of the Interior has used extensively to measure the economic effects of energy-related developments. The following discussion represents our thoughts concerning the merit of using an input/output matrix for this purpose, as well as some of the analytical weaknesses.

An input/output (I/O) matrix is one way to portray the relationships between different sectors once a study region has been defined. The rows of an I/O matrix demonstrate how the output of one sector is distributed among the other sectors, and the columns characterize the flow of inputs into one sector from other sectors. Such a portrayal is not an analytical model but a framework for collecting and integrating the movement between economic sectors. Under particular assumptions about production and markets, the matrix does, however, serve as an analytical tool, and the Curtis-Harris model is an example of a matrix used as such. As an analytical tool, the I/O matrix has been limited because of the cost of collecting data. In their present state of development, I/O matrices can have from 200 to 600 rows and/or columns and require over 1,000 observations for each study region each year. It would cost approximately $160,000, plus administrative expenses, to develop data for one year.

Given that OCS effects will occur over a period of years, and that to make accurate forecasts of the future, several years of historical data are required, we can estimate that an I/O matrix would cost about $500,000.

Further, transforming the I/O matrix from a framework to an analytical tool requires making assumptions which may or may not frustrate the goals of the study. As an analytical tool, the I/O matrix produces reliable forecasts in some, but not all, circumstances.

ASSUMPTIONS

In order to use the data of an I/O matrix analytically, the first assumption is that inputs used to make outputs combine in fixed proportions. This allows the analyst to state, for example, that if wages were 10% of total costs before an increase in production, then wages are 10% of total costs after such an increase. Since this assumption would require frequent revision in order to reflect the technological change highly characteristic of the oil industry, the reliability of I/O matrix forecasts about the effects of increasing production would be difficult to maintain.

A second assumption must be that there is no joint production, since the I/O matrix is not structured to cope with it. Joint production occurs if two or more outputs can be produced in varying proportions by a single production process. To the extent that OCS drilling produces both oil and gas, then I/O-based forecasts about the changes in the distribution channels are frustrated. For example, let us assume that in one day of drilling x bbl of oil and/or y cubic feet of gas can be recovered.

Since different processing and transportation facilities are required for these different commodities, and since x bbl of oil has a different monetary value than y cubic feet of gas, I/O forecasts will be unreliable.

A third assumption about the production process is that constant returns to scale prevail. This assumption means that if we wish to transport twice as many barrels of oil to an onshore processing facility, then we must double all transportation inputs. It is well known, however, that pipelines are subject to strong economies of scale. Thus, an I/O forecast would tend to overstate the effect of increasing the rate of resource extraction.

In addition to the above assumptions about technology, it is also necessary to make assumptions about the market characteristics through which the goods and services of a region or industry pass. This is necessitated because intersectoral flows are expressed best in terms of dollars rather than physical units. If markets are competitive, then prices adequately measure the value of goods and services. I/O models, however, will fail to give accurate forecasts if inflation has unevenly distorted money prices over time, or if there is a significant amount of non-market transactions, or a significant amount of transactions in markets that are not competitive.

The first of these problems -- inflation distortion -- can be overcome by using index numbers. The second is not easily remedied: non-market transactions and/or transactions in non-competitive markets must be included by imputation and adjustments. This not only makes the I/O forecast less dependable but can undermine its objectivity.

Other assumptions include the assertion that sectoral sales are equal to sectoral payments. This not only assumes that inventory levels are constant but also implies that a balance exists between development costs and production costs. A specific problem here is the case of growing sectors, where the level of capital investment is greater than revenues produced during the observed time period.

A final valuation problem concerns the assumption that must be made about the hard line of depreciation. Ideally, an I/O forecast is the net of any capital consumption allowance. Such an assumption, however, necessitates further assuming a standard rate of depreciation which may or may not conform to industry expectation and practice.

OTHER CONSIDERATIONS

As a general rule, the rigidities of the above assumptions are not so severe as to preclude entirely the use of I/O forecasting. Nevertheless, it is our opinion that the conclusions would be dependent on the assumptions to an excessive degree because: (1) the oil industry is characterized by technological change; (2) oil and gas are jointly produced; (3) pipelining is subject to economies of scale; and, (4) the oil industry is vertically integrated, growing, and known to experience rapid changes of inventory levels.

Furthermore, I/O models do not contain such policy variables as tax rates and subsidies. If the ultimate objective of a study is to provide information on which to base decisions, then the analysis should indicate not only potential problem areas, but also should indicate which variables may be adjusted so that a particular problem may be attenuated.

Finally, since I/O models explain and predict interactions between different sectors in a region, information would have been generated that was not germane to our purposes. Bluntly stated, expenditures would have been made for unnecessary information.

APPENDIX 2

INDUCED EFFECTS

For the purposes of the present study, induced income and employment are created by the spending and re-spending of OCS-related income in the study region.

Measuring induced effects is complicated by three interrelated spending patterns. First, not all OCS-related income will be spent; some will be saved. Second, of the OCS-related income that is spent, some will be spent outside the region. Finally, not all of the OCS-related income spent within the region will create more jobs. For convenience, we will represent the above considerations symbolically:

α = savings rate

$1-\alpha$ = rate of consumption

β = consumption outside region

$1-\beta$ = consumption inside region

γ = consumption that does not generate employment

$1-\gamma$ = consumption that does generate employment

Next, a mathematical expression is formed that represents the interaction of these variables. It is:

(Equation 1) $$M = \frac{(1-\alpha)(1-\beta)(1-\gamma)}{1-[(1-\alpha)(1-\beta)(1-\gamma)]}$$

A numerical value for the multiplier can now be obtained if we can determine values for α, β, and γ. α, the savings rate, is a relatively constant variable equal to .1. This means that about ten cents of every additional dollar received is saved. Called a leakage, β indicates the percentage of every dollar spent that leaves the region. The forces that influence the rate of leakage relate to the size of the region and the extent of industrialization. Large regions have smaller leakage rates than small regions, and industrialized urban regions have smaller leakage rates than rural regions.

Los Angeles and Orange Counties form a large and heavily industrialized region. β was assigned a value of .3. This means that 30 cents of every dollar spent leaves the Los Angeles/Orange area. Since Ventura County is smaller and less industrialized than Los Angeles/Orange, β was assigned a value of .5. γ indicates that portion of locally spent income which does not create employment. One quite reliable rule of thumb for estimating γ is to use the ratio of imported employment to total employment. For the Los Angeles/Orange region, this results in a value of .19. For Ventura County, where this ratio is not applicable, γ was arbitrarily assigned a value of .30. Summarizing, the estimates for α, β and γ for the two regions are:

	Ventura	Los Angeles/Orange
α	.10	.10
β	.50	.30
δ	.30	.19

Inserting these values into Equation 1 results in an employment multiplier for Los Angeles/Orange equal to about 1 and, for Ventura, .5. It can be seen that as either α, β, or δ rise, the multiplier will decrease, and hence, so will induced employment. It should also be emphasized that for relatively small regions, such as Ventura County, both the rate of leakages and the rate of demand not satisfied by domestic employment should be relatively large.

The above multiplier estimates may be compared to those in Table A, presented in OCS Sale #35. Since multiplier effects are shown in that table, the estimates corresponding to our analysis are 2.0 for the Los Angeles and the Orange Counties region, and 1.5 for the Ventura area. It can be seen that our estimates fall within the lower range of the multiplier spectrum, and that we do not anticipate heavy induced employment.

TABLE 1:
EXAMPLES OF PUBLISHED EMPLOYMENT MULTIPLIERS USED IN OCS STUDIES

	SOURCE	MULTIPLIER	COMMENTS
1.	BLM	1.6	Described as "high" in relation to peak employment
2.	OCZM	1.68	Based on U.S. Chamber of Commerce multiplier
3.	Woodward-Clyde	1.8	
4.	Resources Planning		
5.	Urban Pathfinders		
6.	Dames & Moore	2.2	
7.	Curtis Harris		
8.	Ultrasystems	3.0	For Los Angeles County
9.	Gulf South Research	3.1	
10.	Ventura County		
11.	Allied Contractors	4.0	Offshore:onshore ratio
12.	WOGA (H. Wright)		
13.	USGS	4.4	Jobs in Texas per crude-related job
14.	AFL-CIO, CIRB	6.8	Construction indsutry
15.	Gulf South Research	8.2	Prepared for the Louisiana Governor's Office

From: OCS Sale #35, Table II, p. VIII-32.

APPENDIX 3

EQUATIONS AND VARIABLES USED

Equations	Variables

Induced Employment and Income Impact

$$M = \frac{(1-\alpha)(1-\beta)(1-\gamma)}{(1-[1-\alpha][1-\beta][1-\gamma])}$$

α = savings rate
β = leakages outside region
γ = percentage of new domestic demand which will not be satisfied by new domestic employment

Price Impacts

Percent increase in prices = x/e

$x = \frac{\text{new income}}{\text{total income}}$

e = elasticity of demand

$$\frac{-dQ/dP}{Q/P}$$

Public Services

Assess if $x > y$

or $x < y$

$x = \frac{\text{new residents}}{\text{total residents}}$

y = % excess capacity

Taxes and Transfers

Calculated on basis of current income, sales, and property tax rates and property assessment ratios.

CHAPTER 19

FACILITIES PLANNING: EASING THE OFFSHORE/ONSHORE BIND

A primary concern of planning for offshore oil and gas in southern California is the apparent proliferation of onshore facilities occuring as a result of increased OCS activity. In the Santa Barbara Channel area there are 14 offshore platforms, 42 seafloor well completions and one manmade island; seven marine terminals for transshipment of crude oil; more than fifteen operating treatment and storage facilities; and, the necessary complement of crew staging and support facilities, pipelines, and pump stations. 1/ Estimates of additional facilities required to develop the Santa Barbara Channel indicate a potential for ten to 21 new platforms and/or ocean floor production systems; one to five marine terminals; and one to five treatment and storage facilities. 2/ From the Long Beach area through Newport Beach there are six offshore islands and two platforms, numerous slant-drilled wells from shore, nine wharfside petroleum terminals and one marine terminal, 11 operating treatment and storage facilities, and a wide variety of offshore-related industry and support facilities. 3/ Should San Pedro Bay federal leases be developed, two to nine platforms and ten to 60 miles of pipeline could be proposed for the Long Beach to Newport Beach area. 4/ In addition, the Outer Banks leases could include from two to 13 new platforms and up to 270 miles of offshore pipelines. 5/

Given current plans for Santa Barbara Channel, Lease Sale #35 and the proposed OCS Lease Sale #48, the demands placed on existing facilities and the need for new facilities can only increase. Yet because of the many petroleum companies involved, the numerous separate fields that could be developed, and the complex of existing facilities, there is great potential for unnecessary duplication. Planning on an area basis, by identifiable geographic entities, could avoid such duplication.

A common criticism of the OCS leasing process as practiced by the Department of the Interior in the past has been that it represents a "lease now, plan later" philosophy. 6/ In fact, the little planning that has occurred for offshore development has been on a well-by-well or platform-by-platform basis -- occasionally on a field-by-field basis, but never for a larger area. What planning there has been for onshore development has been accomplished as a stopgap reaction to development pressures from offshore. This piecemeal approach has resulted in the proliferation of facilities now evident along portions of the southern California coastline. Consideration of both the onshore and offshore facility requirements for OCS development over a larger area would lead to the logical design and siting of complete systems for producing, transporting, and processing crude oil and natural

gas, while simultaneously eliminating the unnecessary duplication. Systematic planning for offshore and onshore development together, however, has been conspicuously absent in the offshore leasing and development process. Conflicts between development requirements of offshore operators and prerogatives of onshore decision-makers have occurred as a result of this lack of planning, most notable being the Exxon Santa Ynez Unit controversy (see Appendix 5). In the absence of future planning, additional conflicts can be anticipated. In order to ease this offshore/onshore bind, we advocate three principal concepts: lease-area planning, unitization, and consolidation.

Lease-area planning as proposed here is a method for looking at large OCS areas with diverse leaseholders but with certain, common development opportunities and constraints. Unitization is a process whereby several leases overlying one prospect are managed by a single operator or committee. Consolidation refers to the sharing of onshore facilities, or the concentration of necessary OCS-related activities within a few selected areas.

Although the authority for area planning exists within the discretion of the Department of the Interior, it has not been undertaken offshore of southern California. 7/ Industry has voluntarily resorted to unitization and consolidation where there appeared a clear private-sector economic advantage to such joint undertakings. Where private-sector economic advantages may be lacking, the U.S. Geological Survey has the authority to require unitization when it is shown to be in the interests of conservation. 8/ California also believes that the consolidation of onshore facilities may be justified in the interests of conservation if the "costs" of environmental degradation resulting from any unnecessary duplication of facilities outweighs the benefits of such duplication. 9/

Of course, the feasibility of unitization or consolidation may be limited by other considerations: for example, critical concentrations of air pollutants, or tanker traffic congestion caused by intensified operations at certain locations, could be reason for strategically locating several small onshore facilities instead of one large one. Similarly, the timing of separate exploration, development, and production schedules may be incompatible, effectively limiting the ability of individual companies to unitize or consolidate. Nonetheless, by taking careful stock of the opportunities for coordinated development as they are perceived now and in the future, wasteful duplication of oil and gas facilities can be avoided.

If the authority to require unitization of federal leases lies solely with the USGS, why should California be concerned? The answer is simple: requirements for onshore support services and processing facilities are directly related to the number of offshore operations. When offshore activities are unitized, the oil and gas produced can more easily be linked to a few selected onshore sites. It is crucial, then, for onshore planners to be made aware of offshore plans and activities, and to participate in unitization decisions where appropriate.

The question remaining is: under what circumstances should unitization or consolidation be required as a matter of public policy when voluntary efforts (determined by private-sector economics) fail to achieve the desired results?

This chapter describes those circumstances and the principles for coordinating offshore and onshore development to ease the offshore/onshore bind. The following material is divided into three sections discussing lease-area planning, unitization,

and consolidation. These discussions provide guidance in making the choices for future OCS development presented in Chapter 21.

AREA PLANNING

Off southern California, leases have been sold in several geographically distinct areas: the Santa Barbara Channel, the three Outer Banks areas, and San Pedro Bay. Proposed Lease Sale #48 may offer new leases for sale adjacent to these existing leased areas plus three new areas along the Orange and San Diego County coastlines (hereafter referred to as the San Diego Coastline). The areas described in this section are shown in Figure 1.

These areas are unique on several levels. Each area is known to have several oil and gas prospects, with the exception of the Santa Barbara Island offshore area which only has one. Each area is the combination of many leases held by many different companies (with the exception of the Santa Barbara Island offshore area again, which only has one leaseholder). If we assume oil and gas are discovered and producible from one or more prospects in these areas, each is also unique from a development standpoint. Some of the factors distinguishing each area are distance from shore, available shoreside facilities, water depth, potential geologic hazards, environmental risks, and resource potential.

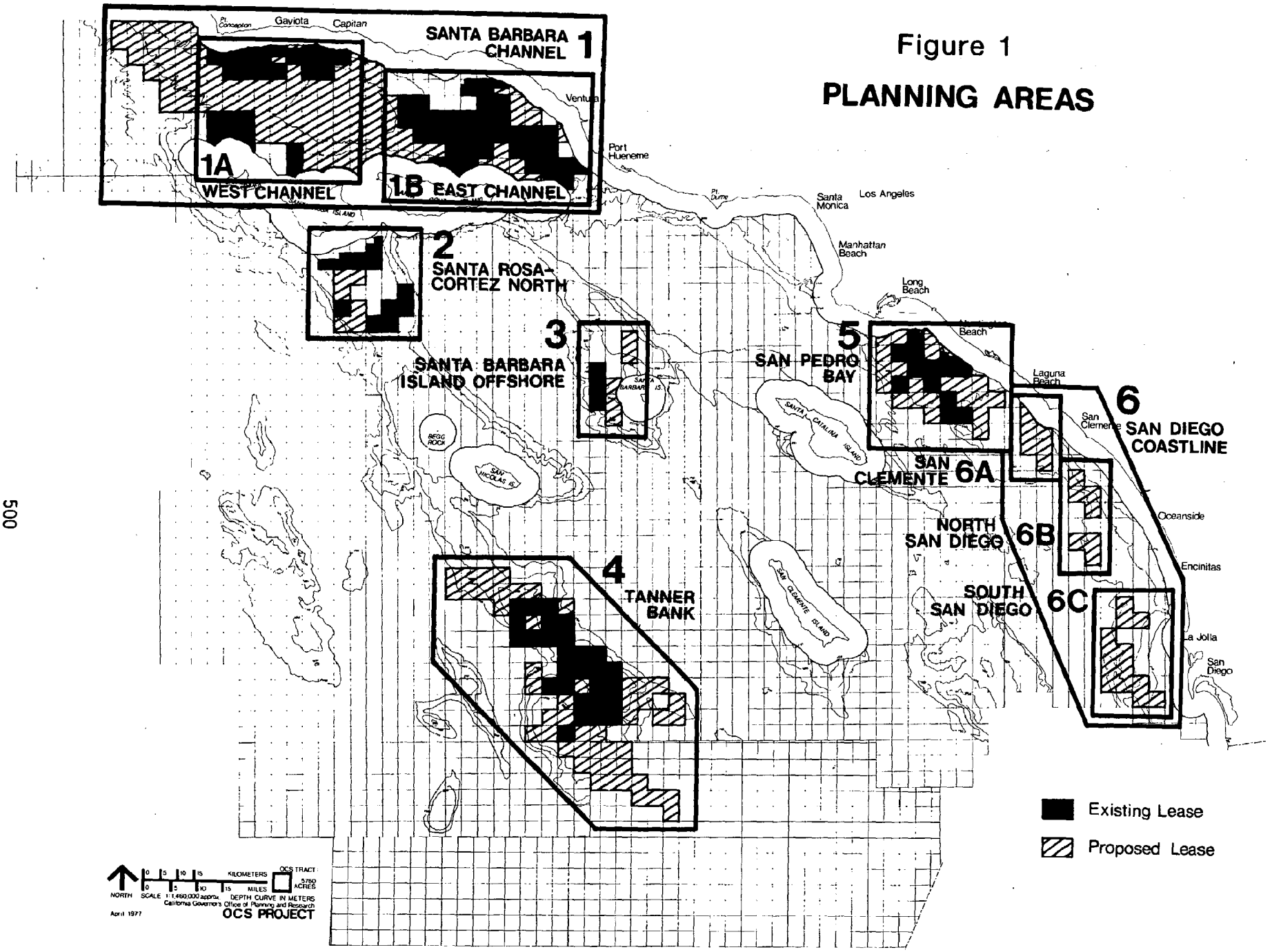
The number of separate producible prospects, the diversity of ownership, the geographic considerations and the obstacles to producing and delivering oil and gas present much the same challenges to each operator within a given area. The development options for each operator will also be similar because of the inherent constraints and opportunities of the lease area. Nonetheless, in the absence of clear direction from the managers of the OCS, each lease area may be developed in fragments and with duplication of essential facilities. The history of the Santa Barbara Channel indicates the likelihood of this fragmentation and its resultant redundancy in facilities. In the past, such redundancy has been caused by divergent development schedules, or simply for proprietary reasons. Regardless of the cause, duplication has increased the total development costs as well as the risk of oil spill accidents and the incidence of air pollution.

Fragmented development can also lead to losses in recoverable resources. For example, discoveries in the remote outer bank areas could be uneconomic to produce when considered individually; but when considered together, production may be feasible.

Avoiding the potential duplication of essential facilities and potential loss of recoverable resources is clearly an objective of the Department of the Interior under its charge to manage the OCS for the prevention of waste and the conservation of natural resources. 10/ Ideally, Interior should evaluate areas before they are leased to determine how best they could be developed (if at all) in light of environmental concerns, economic considerations, and physical constraints. Interior should then establish specific guidelines for developing an area of leases in a timely and coordinated manner and these guidelines should be made a part of lease stipulations attached to sale of OCS tracts. In practice, as for Lease Sale #35, Interior performs aggregate studies of the development potential of OCS tracts in terms of estimations of numbers of facilities required, persons employed and

Figure 1

PLANNING AREAS



environmental impacts of typical offshore operations for the lease sale area taken as a whole. 11/ This development potential and the projected impacts are based on estimates of undiscovered resources thought to be recoverable in the area.

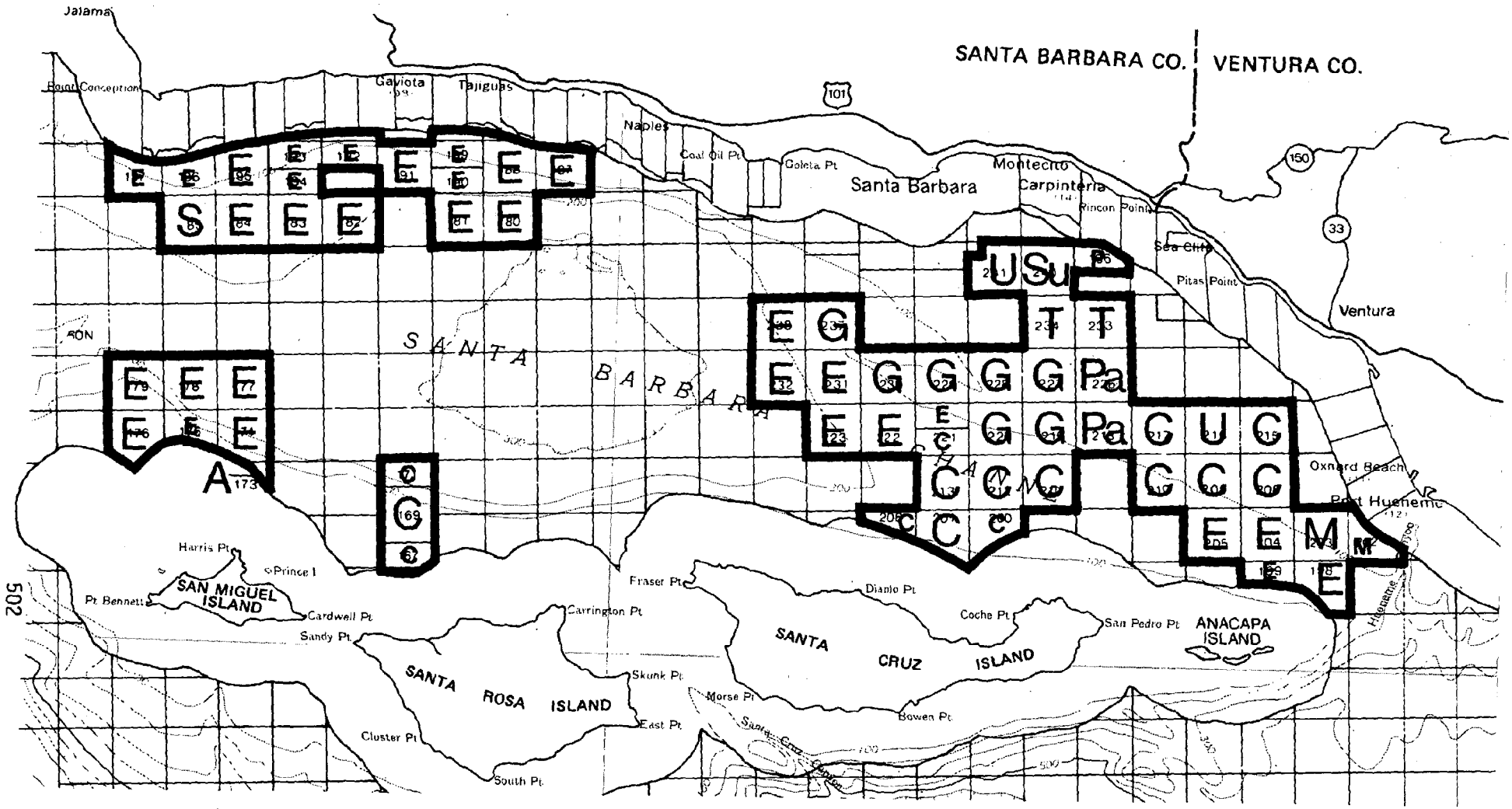
The questionable value of Interior's reliance on resource estimates determined from the extremely limited data available, in lieu of actual pre-sale exploration, is discussed in Chapters 13 and 14. The aggregate conclusions derived from Interior's analysis of development potential unfortunately provide no real insight into how a leased area could or should be developed or, more fundamentally, whether a given area should be offered for lease in the first place.

The alternative posed here, "lease-area planning," is intended to deal rationally with distinct offshore areas having in common certain development constraints and opportunities that will be faced by all operators in the area. The purpose is not to create another level of OCS management. We intend to deal specifically with the problems now facing the existing OCS leaseholders -- and the prospective leaseholders, should Lease Sale #48 be held -- and to avoid unnecessary duplication or possible loss of valuable resources. The objectives of lease-area planning, then, are to achieve the coordinated development of potential offshore resources, to eliminate unnecessary duplication of essential facilities, and to eliminate uncertainties of future development for each leased area. In a lease-area plan, agencies required to approve permits for various phases of development could define project-specific criteria and applicable regulations that would allow timely project approval. The results of lease-area planning would include timing parameters for exploration and development, requirements for unitization, and clearly defined transportation and processing options. Interior can still identify area planning problems for existing as well as proposed lease areas and develop solutions for each area. In the following, planning considerations identified by the OCS Project Staff for each area are outlined as an initial step in such a planning process.

COORDINATING DEVELOPMENT IN THE SANTA BARBARA CHANNEL

The Santa Barbara Channel planning area is shown as Area 1 on Figure 1. Of the 65 federal leases in the Channel, 41 are unitized into five units and the remaining leases are divided roughly into eight smaller areas. Figure 1 shows the Channel divided into two subareas for planning purposes. This separation is both logical and functional: leases to tracts in the west end of the Channel are held by the Exxon/Arco/Chevron consortium and are separated by deep water from the east end, where ownership is mixed. A total of nine different operators can be anticipated in the Channel. These operators are shown on Figure 2. Figure 3 shows functional operating areas in the Channel, based on ownership and current unit boundaries. A total of 14 separate areas are shown but it should be noted that this number could be reduced if some of the non-unitized leased tracts were ever to be subsumed by existing or future units. Table 1 summarizes the status and ownership of each area identified in Figure 3.

To summarize, the Santa Ynez, Pitas Point, Santa Clara, and proposed Hueneme Offshore Units are currently unitized after commercial discoveries have been credited within their boundaries. Union and Sun share a cooperative agreement for production from the competitive Dos Cuadras field reservoir, while Phillips produces from the federal portion of the Carpinteria Offshore field as a result of a federal drainage



OPERATORS:
SANTA BARBARA CHANNEL

Figure 2

- Leased Area
- A Arco
- C Chevron
- E Exxon
- G Gulf
- M Mobil
- Pa Pauley
- P Phillips
- Su Sun
- T Texaco
- U Union

NORTH
0 3 5 10 KILOMETERS
0 3 5 10 MILES
SCALE 1:500,000 DEPTH CURVE in FATHOMS
April 1977 California Governor's Office of Planning and Research
OCS PROJECT

OCS Tract
5760
ACRES

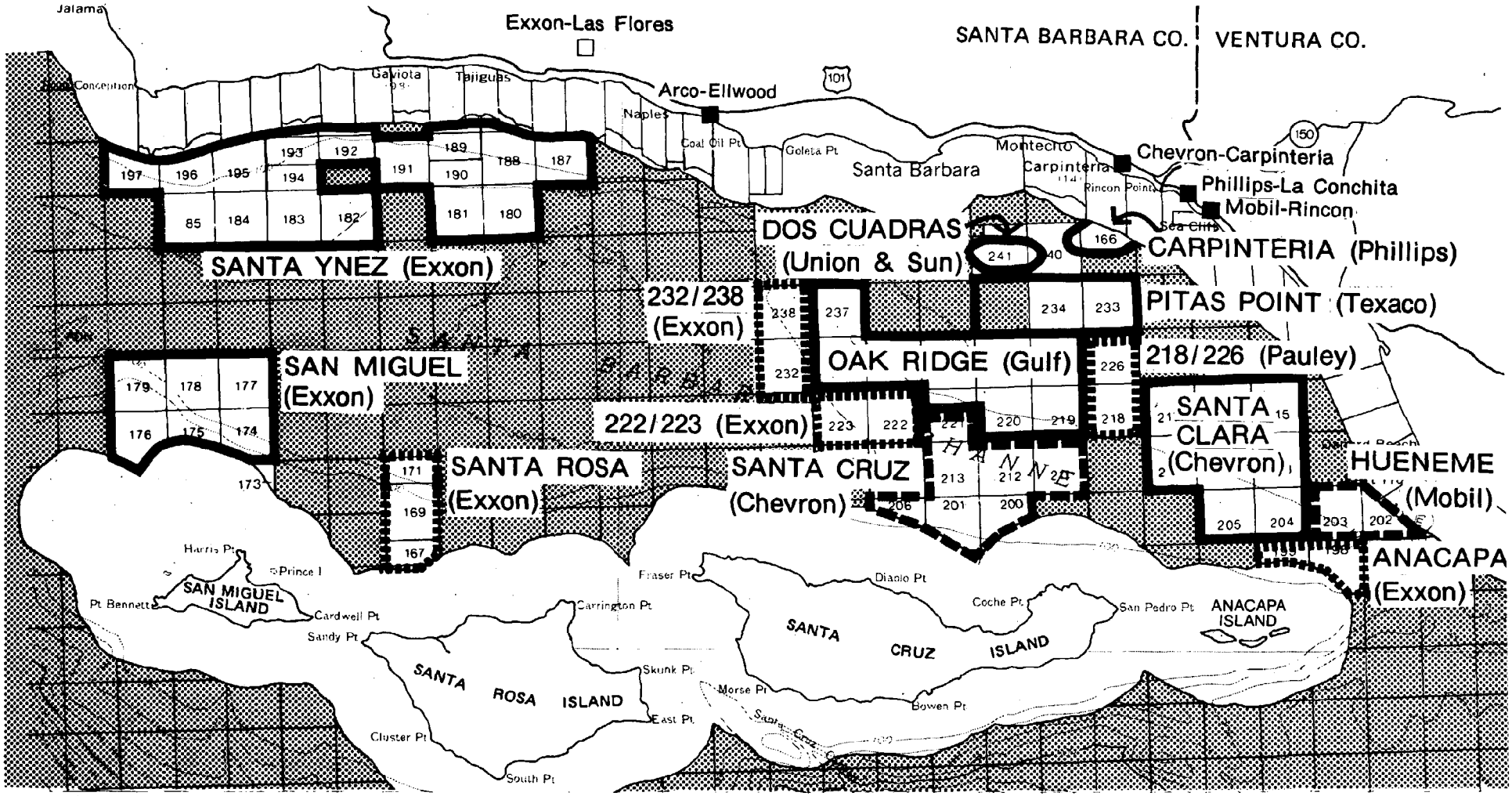


Figure 3

UNITS OR OPERATING AGREEMENTS: SANTA BARBARA CHANNEL

Existing
Proposed
Potential

Processing Plant:
■ Existing
□ Proposed

NORTH
0 3 5 10 KILOMETERS
0 3 5 10 MILES
SCALE 1:500,000 DEPTH CURVE in FATHOMS
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OCS Tract
5760
ACRES

Table 1:

OPERATING AREAS: SANTA BARBARA CHANNEL, APRIL, 1977 1/

Unit or Cooperative Agreement	Operator	Working Owners of Interest	Number of Leases	Effective Date	Phase	Production Start-Up Date	Date of Peak Production	Estimated Peak Rate Of Production	Processing Plant Site
EXISTING									
Carpinteria Field	Phillips (Houchin and Hogan)	Cities Service Continental Phillips	1	10/27/67	production	June 1968	Aug. 1969	27,899 BOPD 18,773 MCFD	Phillips-LaConchita
Dos Cuadras Field	Union ("A" and "B")	GTUM	1	05/06/68	production	Feb. 1969	Aug. 1970	60,097 BOPD 32,458 MCFD	Mobil-Rincon
	Sun (Hillhouse)	Sun Marathon Superior	1	08/21/69	production	July 1970	July 1971	30,420 BOPD 20,797 MCFD	Mobil-Rincon via Union Platform "A"
Pitas Point Unit	Texaco	GTUM	3	03/31/73	exploration (discovery credited)	—	—	—	2/
Oak Ridge Unit	Gulf	GTUM	8⅝	03/31/73	exploration	—	—	—	2/
Santa Clara Unit	Chevron	Chevron Exxon Arco Union	8	03/30/73	development	Sept. 1979	1982 or 1983	38,000 BOPD	3/
Santa Ynez Unit	Exxon	Exxon Chevron Shell	17	11/12/70	development (Hondo only)	Apr. 1978	1983-1985	60,000 BOPD 28,000 MCFD	4/
Hueneme Offshore	Mobil	Mobil Union	2		development	1979	1980	12,000 - 15,000 BOPD	2/
San Miguel	Exxon	Exxon Chevron Arco	6	1977	exploration	—	—	—	3/
PROPOSED									
Santa Cruz	Chevron	Chevron Exxon Arco	6½		exploration	—	—	—	
POTENTIAL									
OCS-P 171, 169 167	(?)	Exxon Chevron Arco	3		exploration	—	—	—	
Anacapa (OCS-P 198, 199)	Exxon	Exxon	2		exploration	—	—	—	
OCS-P 0222 and 0223	Exxon	Exxon	2		exploration	—	—	—	
OCS-P 0232 and 0238	Exxon	Exxon	2		exploration	—	—	—	
OCS-P 0226 and 0218	Pauley	Pauley Ashland Colorado J. M. Huber Husky Kewanee Midwest	2		exploration	—	—	—	
REMAINING									
OCS-P 173	Arco	Arco Chevron	1		—	—	—	—	

1/ Notes for Table 1 are derived from: (a) Final Environmental Statement, Oil and Gas Development in the Santa Barbara Channel..., March 4, 1976, USGS; (b) Hillary Oden, Acting Conservation Manager, Western Region, USGS, letter to Suzanne Reed, OPR, June 22, 1976; and (c) information communicated by representatives of petroleum companies involved in the respective areas to Allan Lind, OPR.

2/ Mobil-Rincon is the logical site for processing any new production from the Pitas Point and Oak Ridge Units and the Hueneme Offshore field because the operators and owners of interest in these areas also own interest in the Mobil-Rincon plant.

3/ Chevron considers the existing Mobil-Rincon facility or the Chevron-Carpinteria facility as equally viable options for processing new production from the Santa Clara Unit. The same options could be considered by Chevron if the proposed Santa Cruz Unit should prove productive.

4/ Las Flores Canyon has been approved by State and most local agencies as the appropriate location for a major new processing plant to be constructed. Exxon, however, is currently developing an offshore floating processing plant in lieu of this site.

sale. Of the 14 existing, proposed, and potential units or field operations, the Exxon/Chevron/Arco group would be the operator of eight, the Gulf/Texaco/Union/Mobil (GTUM) group would control four, and Phillips and Pauley would each operate one. 12/ These operating groups are described below.

The major issues to be addressed in planning for the Channel are the transportation of crude oil (tankers vs. pipelines), the consolidation of onshore facilities, with the concomitant removal of oil and obsolete onshore facilities, and the systematic exploration and development of the Channel. In order to deal effectively with these issues, all levels of government and industry will have to work together towards coordinating the timing, location, and scale of offshore and onshore development. 13/ We recommend that such a planning effort be carried out as a part of the environmental impact statement now being prepared by the Bureau of Land Management for Lease Sale #48.

EXXON/CHEVRON/ARCO

These three companies formed a consortium for bidding in the 1968 lease sale. Between them they acquired 49 of the 71 leases sold. They currently control 47 of the 65 active leases. At least one of these three companies is represented in ten of the 14 operating areas in the Channel, and between them they operate eight. They are not included in the Union/Sun operation of the Dos Cuadras field, the Phillips operation of the Carpinteria field, the Mobil operation of the Hueneme Offshore field, or the Pauley leases. Arco participates in three of the operating areas but is not an operator in the federal portion of the Channel. Chevron is the operator of the Santa Clara Unit and the designated operator of the proposed Santa Cruz unit, both in the eastern end of the Channel (area 1B on Figure 1). Operating these large units, Chevron could play an important role in shaping future development for that area of the Channel. Exxon is a designated operator in the west end of the Channel (area 1A on Figure 1) of the Santa Ynez Unit and the San Miguel Unit. Exxon's three pairs of tracts in the eastern block of leases could also influence a Channelwide area plan, should commercially recoverable oil and gas resources be discovered in these areas.

Tanker traffic within the Channel should also be a concern to this group. Of the 23 leases intersected by the designated Channel shipping lanes, 19 are operated by Exxon or Chevron. 14/

GULF/TEXACO/UNION/MOBIL (GTUM)

Tracts leased by GTUM are concentrated in the eastern end of the Channel (area 1B of Figure 1). GTUM members are the operators in four areas: the Dos Cuadras field, Union as operator; Pitas Point Unit, Texaco as operator; Oak Ridge Unit, Gulf as operator; and the Hueneme Offshore field, Mobil as operator. GTUM also owns 70% interest in the Mobil-Rincon complex, the largest processing plant serving Channel leases. This facility is presently capable of handling new production from the Dos Cuadras field when Platform "C" is completed, new production from the Carpinteria Offshore field if Platform Henry is installed, and new production from the Hueneme Offshore field if Mobil is allowed to proceed with its Plan of Development. 15/ Furthermore, the facility is capable of expansion with relatively slight modifications to accept production from other potential OCS sources such as the Pitas Point or Santa Clara Units. 16/ A more thorough review of this facility is presented later in this chapter.

From a Channelwide perspective, the GTUM group appears to be moving effectively

toward the goals of area planning and consolidation, but for full realization it will be necessary to phase future offshore development so as to require minimum expansion of the Mobil-Rincon facility. Development plans for Platforms C and Henry, and Hueneme Offshore and Santa Clara Units appear to be compatible with this strategy. Present uncertainties regarding the Oak Ridge and Pitas Point units, the proposed Santa Cruz Unit, the Pauley leases, and the Exxon leases make it difficult to predict levels of production for these areas and to anticipate when, if ever, oil and gas from those areas can be delivered to processing facilities. Nevertheless, decisions regarding changes in the operation of the Mobil-Rincon facility and pipeline linkages to the site must not ignore the possibility of production from these less defined areas.

PHILLIPS

Production from the Phillips portion of the Carpinteria Offshore field reached a peak in 1969 and has declined ever since. No production expansion is anticipated from the Phillips lease on the Carpinteria Offshore field; the remaining field life is estimated at eight to ten years. 17/ Sun's proposal to install Platform Henry near the Phillips lease may affect the remaining life of the field.

SUN

Current production for Sun is from Platform Hillhouse on the west side of Tract OCS-P 0240, delivered from the eastern extent of the Dos Cuadras field to Mobil-Rincon for processing, via Union's Platform A (see Figure 10 for a diagram of how production is transported in this area). Hillhouse peaked in 1971 and has declined ever since. In 1970 Sun proposed Platform Henry for the east side of 0240 to tap the western extent of the Carpinteria field, but the application was denied on environmental grounds. A similar application was again filed September 29, 1975, and is currently under review by USGS. Any decision on this application must consider: (1) the congestion of this area from the number of nearby platforms and the hazards they pose for the marine terminal operation directly onshore at Carpinteria; and, (2) the location of processing for the produced oil and gas.

PAULEY

Future development of the two leases operated by Pauley remains in doubt. Several wells have been drilled on each, but none has been credited as identifying a commercial discovery, although the operator describes some of the wells as "promising." 18/ Activity on these leases, along with the rest of the leases in the Channel, was suspended after the 1969 blowout. As a direct result of this suspension, Pauley sued the Department of the Interior claiming that the lease agreement had in fact been nullified by the Department. 19/ This case is still in the courts and its likely outcome is not now apparent. Since Pauley et al. have no other OCS leases nor processing capability in the Channel, it is possible that, if the leases are developed, transportation and processing would be consolidated with development plans of either the Oak Ridge or Santa Clara Units. Pauley has undertaken extensive exploration within their tracts along the same geologic trend which Chevron currently plans to develop in the Santa Clara Unit. 20/

COORDINATING DEVELOPMENT IN THE OCS 35 AREA

The area leased as a result of OCS Lease Sale #35 presents an entirely

different situation from the Santa Barbara Channel: the leases are new; relatively little geologic data exists to predict the possible occurrence of oil or gas; and, most tracts are quite remote. Insufficient data on geologic conditions increases the risks of encountering geologic hazards, and, with such little advance information available, financial risk in exploration and development will also be considerable. Due to these factors, mandatory unitization of oil and gas exploration should be considered from the outset in this area.

OUTER BANKS

Three general areas make up the Outer Bank portions of the OCS 35 Area: Santa Rosa-Cortes North, Santa Barbara Island, and the Tanner Banks (see Figure 1 for the location of these areas). The reader is reminded that these Outer Banks are considered among the most significant ecological resources offshore of southern California. Chapter 16 provides a detailed account of the ecological importance of these areas.

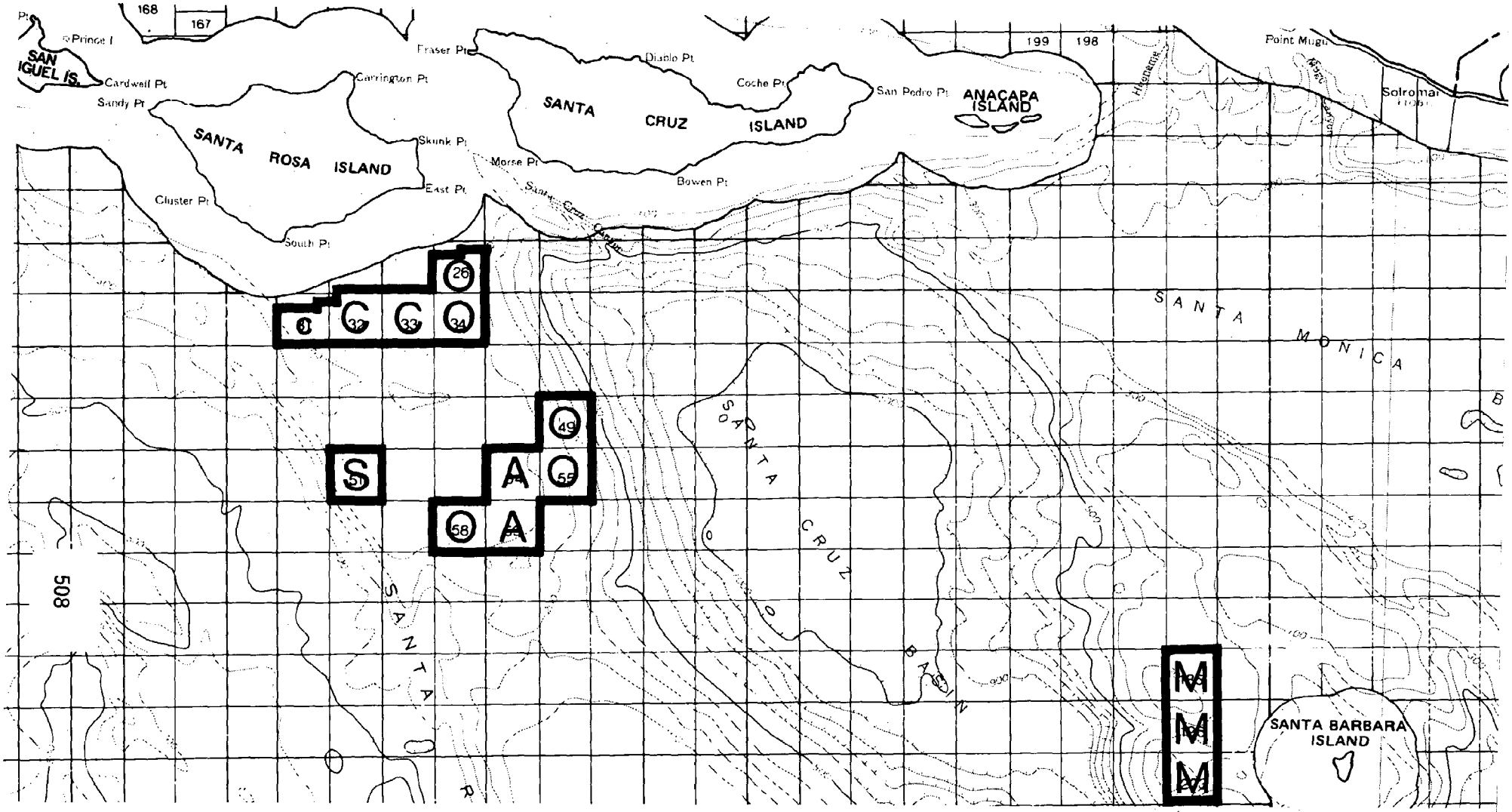
Distance from shore, as it affects transportation costs, will be a significant factor in determining how, where, and when (if ever) any of the leases in these areas will be developed. Certainly, transportation costs will be more than those expected for less remote leases in the Santa Barbara Channel or San Pedro Bay. The transportation alternatives to be considered will be pipelines and barges or tankers.

Another factor affecting the potential development of these areas will be the selection and design of processing sites and equipment. Several options may be considered: offshore floating or fixed-structure facilities, island locations, and sites along the Ventura County coastline. The number of operators involved, the timing of development, and the size of reserves discovered will determine the location and design of the necessary facilities. If the Outer Banks are developed in a piecemeal manner, the opportunity for consolidated development of these common facilities could be lost.

Figure 4 shows the location and likely operator for each tract in the Santa Rosa-Cortes North and Santa Barbara Island areas, while Figure 5 provides the same information for the Tanner Bank area. For the 29 leases in the Tanner Banks, seven different operators are expected to emerge for the purposes of exploration: Arco, Challenger, Exxon, Gulf, Marathon, Shell, and Texaco. Because of the distance involved in bringing oil and gas to shore, development and production may be feasible only with consolidation of transportation options.

In the Santa Rosa-Cortes Ridge North area, 11 leases are distributed among four different operators in three sub-areas. Any crude oil or natural gas discovered in this area could be transported to shore by pipelines in waters never exceeding 600 feet. If each sub-area is productive, three separate development plans could result.

Off Santa Barbara Island only three leases were sold. All three were acquired by one company (Mobil Oil), thus eliminating any coordination problems in this area at the present time. An expected problem in this area is whether or not sufficient resources exist to justify recovery and transportation costs, particularly in view of the threat their development represents to Santa Barbara Island and its environs. In Chapter 16, Santa Barbara Island is shown to be one of the most significant natural resources offshore of southern California.



OPERATORS: SANTA ROSA-CORTEZ NORTH AND SANTA BARBARA ISLAND

Figure 4

Leased Area
A Arco
C Chevron
M Mobil
O Oxoco
S Shell

NORTH
0 3 5 10 KILOMETERS
0 3 5 10 MILES
SCALE 1:500,000 DEPTH CURVE in FATHOMS
April 1977 California Governor's Office of Planning and Research
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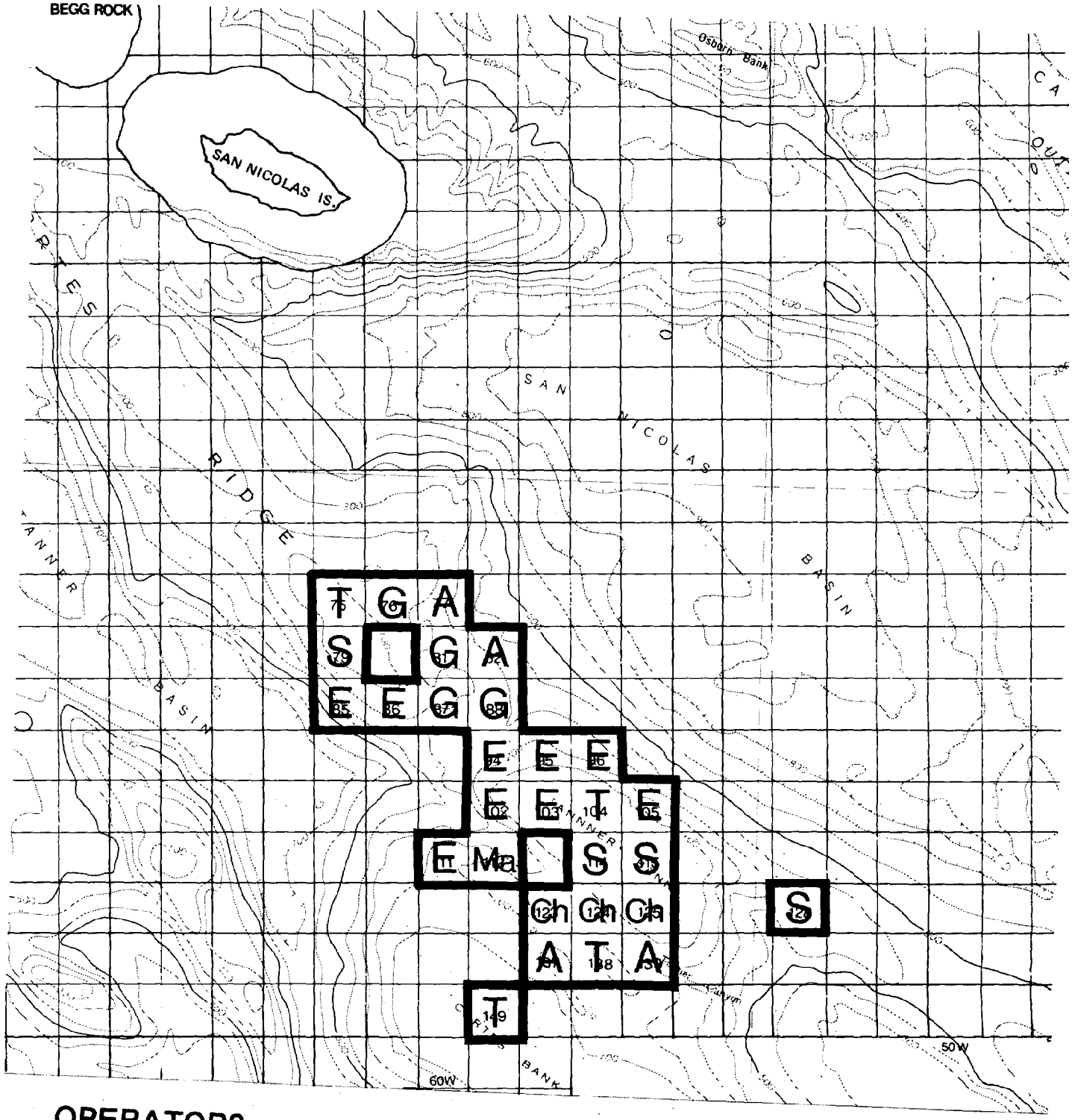
5760
ACRES



OPERATORS:
TANNER BANK

Figure 5

- ⊡ Leased Area
- A Arco
- Ch Challenger
- E Exxon
- G Gulf
- Ma Marathon
- S Shell
- T Texaco

NORTH
April 1977

0 3 5 10 KILOMETERS
0 3 5 10 MILES
SCALE 1:500,000 DEPTH CURVE in FATHOMS
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OCS Tract 5760 ACRES

SAN PEDRO BAY

Tracts offered, bid on, and leased as a result of Lease Sale #35 are shown on Figure 6 and as Planning Area 5 on Figure 1. A total of thirteen tracts were leased in a more-or-less checkerboard fashion. This pattern may hinder effective unitized operations if reservoirs are found to extend into the unleased spots of the checkerboard. Operators for the area include Chevron with four leases, Shell Oil with four leases, Gulf Oil Corporation with two leases, and Texaco Inc., Mobil Corporation, and Challenger Oil and Gas Company with one each. This ownership is shown on Figure 7.

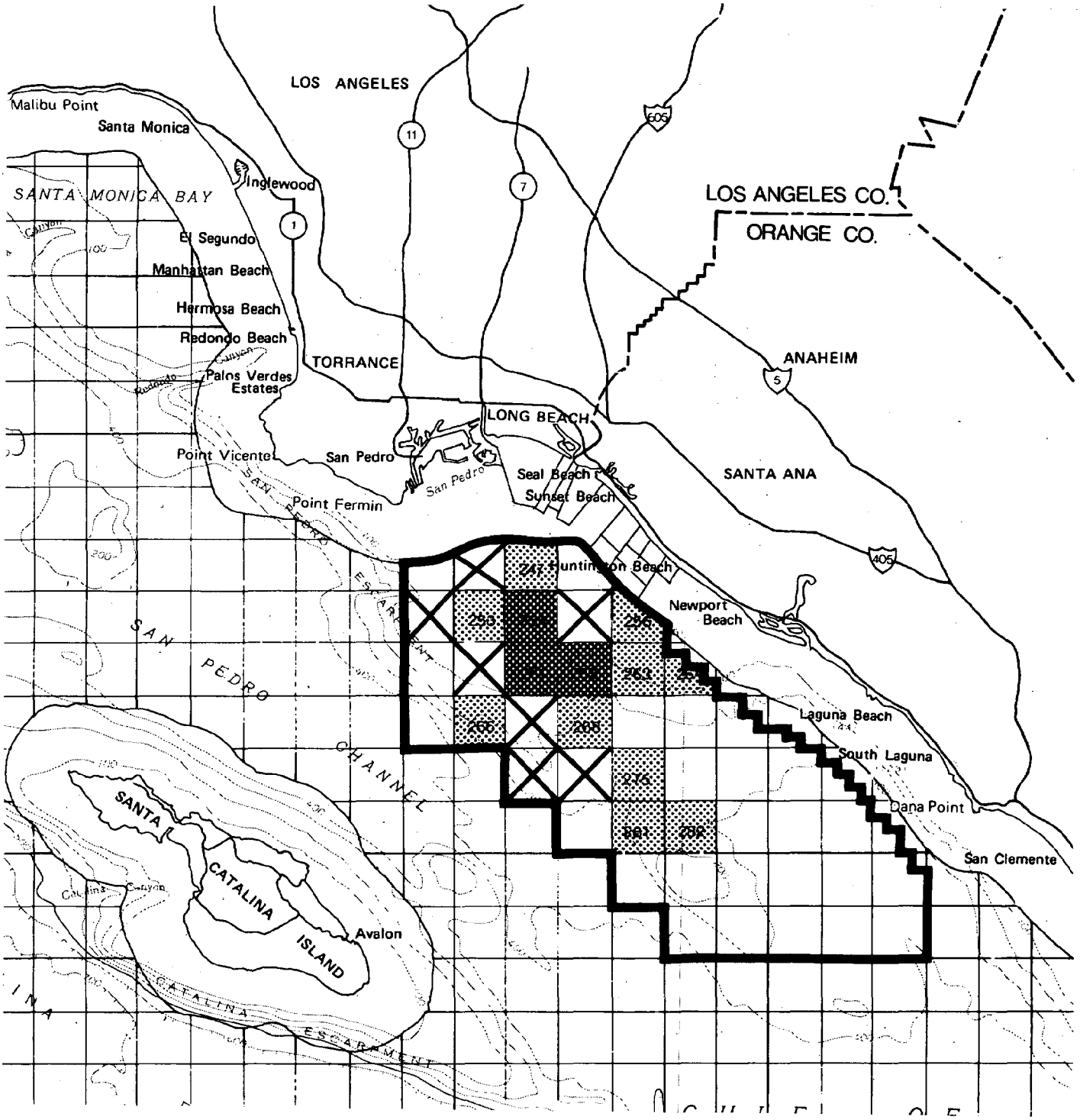
On November 5, 1975, the Acting Secretary of the Interior authorized an amendment to Lease Sale #35 stipulations requiring, in effect, that any commercially producible resources discovered in tracts 0254, 0261, and 0262 of San Pedro Bay, extending into other leased tracts, would be unitized. 21/ Conversely, any field discovered outside of 0254, 0261, and 0262 and proven to extend into one of the three tracts would automatically require unitization as well. This mandatory unitization was designed to eliminate potential conflicts arising from royalty differences between the 0254, 0261, and 0262 group at 33.3% and the royalty rate of 16.6% applied to any other adjoining leases that could result from Lease Sale #35. The Department of the Interior considered mandatory unitization in the San Pedro Bay area primarily because it was felt that the three high royalty leases involved were almost certain to overlie a productive prospect.

Exploration has begun in San Pedro Bay with both Chevron and Shell completing their first wells on four leases. Shell's first well on OCS-P 301 (Lease Tract 262) has been credited by USGS as a commercial discovery, and Shell has completed two additional delineation wells on that prospect. Of the 13 leases, only Challenger's lacks an exploratory drilling permit at the present time.

It is likely that Chevron or Shell, or both, will be principal operators in San Pedro Bay. The remaining leaseholders are overshadowed by the dominance of Chevron and Shell in leaseholding, not to mention their favorable location with respect to the major structures in the bay. These advantages may lead to the other leaseholders participating as subordinate participants in any units formed in the future. Encouraging full unitization of San Pedro Bay tracts, however, could maintain a controlled level of drilling activity in the bay and could result in a more systematic assessment of resource potential if exploration and development schedules are made a part of the unit agreements. Full unitization for exploration could also contribute to safer operations with regard to the vessel traffic separation scheme established by the Coast Guard. Like the Exxon/Chevron/Arco group in the Santa Barbara Channel, Chevron and Shell have the most to gain by controlled development since they operate six of the seven leases presently intersected by the vessel traffic lanes. The traffic separation scheme is shown on Figure 2 of Chapter 20.

COORDINATING OFFSHORE DEVELOPMENT FOR THE POTENTIAL LEASE SALE #48 AREA

The area tentatively to be offered for Lease Sale #48 is shown in Figure 4 of Chapter 22. Most tracts to be offered are contiguous with existing lease areas which have been described above. If Lease Sale #48 is held and leases are sold in these areas, lease-area plans must consider the effect these new leases will have on the timing of potential future development and estimated



LEASES AND ROYALTY RATES: SAN PEDRO BAY

Figure 6

- Area Offered
- 16.6% Royalty Lease
- 33.3% Royalty Lease
- Bid Rejected

NORTH
0 3 5 10 KILOMETERS
0 3 5 10 MILES
SCALE 1:500,000 DEPTH CURVE in FATHOMS
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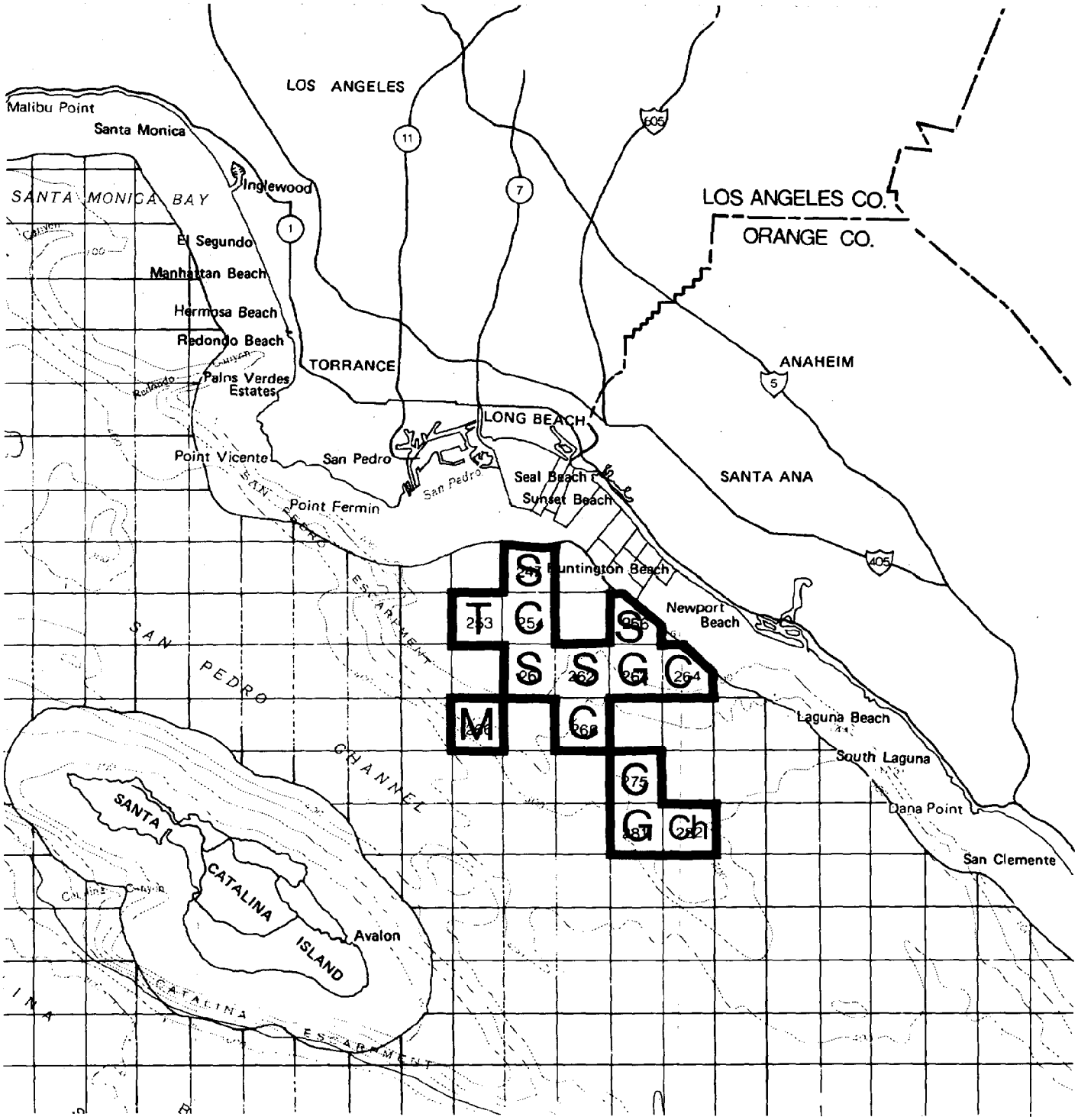

OPERATORS: SAN PEDRO BAY

Figure 7

- Leased Area
- Ch Challenger
- C Chevron
- G Gulf
- M Mobil
- S Shell
- T Texaco

NORTH
0 3 5 10 KILOMETERS
0 3 5 10 MILES
SCALE 1:500,000 DEPTH CURVE in FATHOMS
OCS Tract 5760 ACRES
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OCS PROJECT

volume of recoverable petroleum resources for the area studied. Tracts now tentatively to be offered for Lease Sale #48 but not contiguous to existing leased areas are found along the San Diego coastline. These tracts can be divided into three subareas as shown on Figure 1 within Planning Area 6.

A lease-area plan for Planning Area 6 should be undertaken as a part of the EIS now being prepared for that sale. For the tracts offered in the Outer Banks areas and San Pedro Bay, planning considerations will be the same as those discussed above for Lease Sale #35. For the tracts proposed to be offered in the Santa Barbara Channel and along the San Diego coastline, however, additional concerns will have to be considered.

The new tracts offered in the Santa Barbara Channel and to the west of the Channel included in Planning Area 1 represent the largest contiguous area of potential leases. Some of these tracts encounter water depths exceeding current state-of-the-art technology for development. Additionally, the westward extension of tracts past Point Conception encounter more severe weather conditions than are experienced in the naturally sheltered Channel. Finally, many of the new tracts conflict with the vessel traffic lanes passing through the Channel.

The new San Diego coastline tracts proposed to be offered in Lease Sale #48 represent the first-ever lease sale along this portion of California's coastline and the first-ever potential for oil and gas development in the San Diego region. Unlike the Santa Barbara Channel and San Pedro Bay, there has been no onshore or state tidelands development of oil and gas in this area. Lease-area planning for each subarea along this portion of coastline would have to take into account a wide range of impacts if leases are acquired here and production occurs. Of major importance to such plans will be visual and aesthetic effects, requirement for new industrial-type uses (oil and gas processing plants) in the coastal zone, pipeline corridor studies, and the possible requirement for marine terminals to load tankers or barges with crude oil for transshipment to the Los Angeles/Long Beach Harbors area.

UNITIZATION

Unitization occurs when companies owning leases in a given area or overlying a subsurface reservoir unify the ownership and control of the area or reservoir through a unitization agreement. Such agreements provide that a single company or committee will be the operator for exploration, development, and/or production of all the leases affected by the agreement. 22/ California's interest in unitization stems from the expectation that unitization can lead to the siting of only necessary onshore and offshore facilities and that they may be sited in the least environmentally sensitive areas.

AUTHORITY FOR UNITIZATION

The Outer Continental Shelf Lands Act authorizes the Secretary of the Interior, in the interest of conservation and the prevention of waste, to provide for unitization, pooling, and drilling agreements. 23/ The courts have broadly interpreted the conservation of the natural resources of the OCS to include "marine life,

recreational potential, and aesthetic values, as well as the reserves of gas and oil." 24/ As delegated under the Act, unitization can be required by the Conservation Manager of the regional USGS Office under OCS Operating Order #11. The basic premise behind the authority to require unitization is that, without cooperation, each lease owner of separate tracts overlying a common subsurface reservoir would attempt to recover all that can be profitably and legally produced from his lease, regardless of whether or not his operations serve to optimize economic recovery from the entire reservoir: "It has been long recognized that the unitized operation of all or part of an oil or gas pool as if under one lease is usually the most effective and efficient way to produce petroleum." 25/

Unitization has been identified in numerous environmental planning documents, including the California Coastal Plan, and in federal environmental impact statements as a practical tool for controlling offshore development. The Final Environmental Statement for Lease Sale #35 acknowledges that "mandatory unitization could contribute to more efficient development of discovered resources; contribute to optimum placement of collection, storage, and transportation facilities; and would ... present only one comprehensive development plan for each producing field. Thus, reviewing agencies would be able to view the aggregate situation, including potential cumulative effects of development activities, without the need to review numerous, possibly conflicting plans." 26/

BENEFITS OF UNITIZATION

The objectives of unitization are to conserve resources, to cut the costs of developing a field or reservoir, and to protect lessees' rights. Unitization can achieve these objectives because:

1. it allows exploration and development programs to be based on the nature of the oil and gas prospects, rather than on lease boundaries and ownership considerations, which are basically irrelevant to the task of locating and producing commercial deposits of oil and gas;

2. it increases overall recovery from reservoirs by facilitating use of the most efficient "natural drive" and secondary recovery methods, eliminating less efficient competitive practices that would otherwise occur; and,

3. it eliminates facilities not vital to exploration or development of leases, resulting in financial savings to industry from fewer administrative permits required, plus savings to onshore communities in terms of more efficient land use.

In a draft policy paper on unitization, Herman Enzer of the Policy Development Branch of the Department of the Interior notes:

> In order to get some idea of the magnitudes in savings possible through unitization, 38 non-unitized fields in the Gulf of Mexico with diverse leaseholders were examined. It is estimated that of the 170 production platforms located in the fields, 79, or 46%, would have been unnecessary under unitization.... Considering all possible savings in costs, it is estimated that a unit plan would reduce the cost of a barrel of oil [for this area] by 20 to 40% as compared to independent production. 27/

Although Enzer later discounts this 20% to 40% range of savings by half, because of the then recent adoption of OCS Order #11 establishing utilization as a priority

objective for OCS development, the conclusion remains basically the same: unitization will reduce the number of required facilities and can ultimately increase total production. A recently completed unit agreement reported in industry journals further illustrates the benefits of unitization by the example of a 50-year-old, 600-well field in West Texas, the Yates field. This unit agreement, bringing together 12 oil companies (Marathon, Amoco, Chevron, Cities Service, Continental, Exxon, Getty, Gulf, Phillips, Shell, Sohio, and Union of California) resulted in doubling the maximum efficient recovery rate to 100,000 B/D. The ultimate recovery of the field was effectively increased by 200 million barrels (from 1.75 billion to 1.95 billion barrels). 28/ In evaluating the effects of unitization, a review panel found that "anticipated additional recovery will more than offset the cost of the program." 29/

By comparison, it is arguable that the Carpinteria Offshore field, straddling the state/federal offshore boundary near Carpinteria, illustrates the duplication that often results from a competitively developed field. Figure 8 shows the Carpinteria field and related development.

The Carpinteria offshore field underlies three leases operated by three separate companies: Chevron, Phillips, and Sun. Chevron and Phillips are currently producing their portions of the field, and Sun probably would be also if a platform proposed by them in 1970 had been approved. Had Sun obtained permission to install its platform, a total of five platforms would be located on the field: Chevron's portion of the field is developed with platforms Hope and Heidi; Phillips has developed its portion with platforms Houchin and Hogan; and Sun proposed to install Platform Henry on its portion. Chevron has had 66 wells producing at one time, and 59 are now in operation. 30/ Phillips has had 60 wells producing, of which 48 remain in operation. 31/ Sun's proposal was for a 30-well platform. 32/ In addition, Chevron has approval to drill 20 new wells supplementing the 59 now in existence. 33/ As can be seen from Figure 8, the three companies would have had three separate pipeline transmission systems delivering their oil and gas to three separate onshore processing plants. Chevron transships crude oil to refineries via its marine terminal at Carpinteria; Phillips crude is pipelined directly to Los Angeles refineries or tankered from another marine terminal at Ventura; and, Sun's production would have had the same options as Phillips. 34/ Thus, in the absence of unitization, this field might have been developed with some 169 producing wells (79 for Chevron, 60 for Phillips, and 30 for Sun) from five production platforms dependent on three sets of pipelines to shore, three processing plants, and two marine terminals. Under a unitization agreement, several of these production or transportation systems would have been eliminated. At a minimum, all production could have been transported to a single shoresite processing plant by a single set of pipelines. It is also possible that the field could have been developed by fewer production stations located more strategically (for example, four instead of five), or possibly by fewer surface structures augmented by satellite production systems on the ocean floor (water depths over the Carpinteria field are relatively shallow). Further, unitization would have optimized the number and location of wells rather than allowing these matters to be determined by arbitrary lease boundaries. Finally, the competitive methods of producing the field may well have lowered the ultimate volume of recoverable oil. 35/

VOLUNTARY V. MANDATORY UNITIZATION

According to Enzer, only 260 leases of a total of 1266 in U.S. OCS waters were unitized in March of 1974. 36/ Enzer also notes that less than 4% of non-producing OCS leases (i.e., those in the exploratory phase of OCS development)

in the U.S. are in units combining diverse ownerships, and less than 20% of leases currently in production are unitized. 37/ This may be due to the fact that "the vast majority of producing leases in the Gulf are characterized by small salt domes and listric pools which are often contained within one lease." 38/ The size of these pools does not preclude the unitization of leases for the purpose of consolidating transportation of crude oil and natural gas to shore, yet the sharing of pipelines in the Gulf is the exception rather than the rule. In other words, despite the apparent economies and actual increased benefits from unitization, the vast majority of OCS tracts are not being unitized nor are offshore pipelines being consolidated. Furthermore, units are generally not formed until after initial exploration and delineation wells have been completed. Because voluntary unitization has not resulted in a significant number of units, especially in the exploratory phase of resource recovery, Enzer's study group concluded that the department should pursue mandatory unitization of frontier areas. He specifically identified the southern California Outer Banks for mandatory unitization and recommended that additional consideration be given to the Santa Barbara Channel, which must also be considered a frontier area. As a part of that study, Exxon submitted a suggested outline for implementing such a program. The outlined program was designed to expedite the leasing and exploration of frontier areas. Because it presents a clear and concise case for mandatory unitization, we have included it in its entirety, with comments by Enzer, as Appendix A to this chapter.

In response to our draft findings and recommendations, industry representatives, without exception, opposed mandatory unitization, some equating it with "regulatory extremism," alleging that it would prolong rather than expedite exploration and development, and that it would not alter environmental risks. A typical response is that of Chevron: "The amount of drilling and the number of platforms and facilities are not governed by mandatory political maneuvers; they relate to, and develop from, the geology, physical geometry of the oil field(s) and the dictates of inviolable economic factors." 39/

We do not agree with this position. As noted in the preceding section describing the Carpinteria offshore field, the amount of drilling and the number of platforms and facilities were clearly not governed by the geology or physical geometry of the oil fields but rather by the absence of governmental coordination and industry cooperation. We strongly agree, however, that geology and reservoir geometry be taken into consideration in forming units and so advocate in our findings and recommendations.

The position taken by Chevron and others also raises a classic economic debate: are private sector economic factors really inviolable? 40/ To be certain, industry repeatedly asserts that (a) their economics are not to be violated and (b) that such governmental intervention, as a policy of mandatory unitization, flies in the face of the free enterprise system. As discussed in Chapter 18, some economists believe that the petroleum industry is oligopolistic in nature, rather than a simple marketplace phenomenon, and that in fact the very market place in which they do business is not the unfettered haven where free enterprise exists inviolate. We assume that economic determinants to development choices are not, in the final analysis, absolute, especially when certain costs -- environmental, social, or other -- are not calculable. Rather, we assume that economic determinants are ultimately negotiable. Further, we conclude that mandatory unitization in especially sensitive environmental regions such as the Outer Banks, or heavily used areas such as San Pedro Bay, is essential to minimizing these incalculable costs to other resources the public has declared inviolable.

Our findings relative to unitization offshore of southern California indicate that mandatory unitization in the Santa Barbara Channel is essentially a moot point as 53 of the 65 existing leases are already unitized or incorporated in development plans or proposals for unitization. Of the remaining 12, ten are controlled by the Exxon/Arco/Chevron consortium, and two are controlled by Pauley, an independent (see "Coordinating Offshore Development in the Santa Barbara Channel" below). With respect to tracts leased as a result of Lease Sale #35, we conclude that planning for the coordination of exploration, production, and transportation on an area-by-area basis (lease-area planning) should precede unitization. This area planning stage would identify the location and extent of the most promising geologic structures and the strategies for developing each area. Geologic structures found to underlie leases of diverse ownership would be scheduled for unitization of further exploration and development where feasible. Lease-area planning is described in greater detail earlier in this chapter.

It should be noted here that the privileges of unitization can be abused. Once a group of leases is unitized, a showing of "diligent and good faith efforts" must be made to preserve the unit past the initial term of the leases in the unit (five years). The determination of good faith efforts is left to the discretion of the USGS Area Supervisor. Since under unitization all leases in a unit are treated more or less as if they were one, the drilling of one or more wells on one lease may be construed as satisfying this good-faith requirement for all leases in the unit, thereby extending the term of all the unitized leases. Hence, unitization may be used as a lease-holding device, permitting offshore operators to defer the exploration and possible development of certain leases until it is in their interest to explore them. For example, in the Santa Ynez Unit four leased tracts have never been explored, there are no current plans to explore them, and there has been no effort on the part of the Department of the Interior to cause these areas to be explored.

PROCESS OF UNITIZATION

OCS activities may be unitized at any stage of development. The principal steps required for establishing unitized operations are: (a) the designation of a Unit Area by the Director, USGS; (b) submission of a unit agreement for approval by the USGS Oil and Gas Supervisor having jurisdiction over the area being unitized; and, (c) submission of plans of operation as may be specified in the approved unit agreement or as need may arise. A unit plan combines the unit agreement and operating plan(s).

DESIGNATION OF A UNIT AREA. A unit area may be defined as the submerged lands recognized as logically subject to consolidated exploration, development, and operations for the production of oil and gas without regard to separate leaseholdings. 41/ The Conservation Manager of the USGS Regional OCS Office is authorized to require unitization of offshore leases when a determination has been made that "conservation will be best served by unitization of a competitive reservoir." 42/ This authority has not been exercised in southern California, as all existing and proposed units to date have been voluntary. However, mandatory unitization has been provided for in lease stipulations for three tracts in San Pedro Bay. In this instance, the operators of these leases must unitize as a condition of approval of a development plan. The stipulation provides for mandatory unitization only if a discovery is made and the reservoir is found to underlie two or more leases.

Perhaps unique to southern California has been the designation of unit areas containing more than one structure. 43/ Typically, a unit area boundary is

governed by the geographic extent of a single reservoir or specific geological volume. 44/ However, in the instances of multiple-structure units, e.g., Santa Ynez and Santa Clara Units, consideration of administrative and operational factors may have determined the unit area configurations.

UNIT AGREEMENTS. Unit agreements contain set requirements to be met by the operator for the development of a specified field or reservoir. Unit agreements also establish the working relationship between the unit operator and the USGS. A unit agreement may contain the following:

1. a description of the area to be unitized;

2. provision for expansion or contraction of the area;

3. designation of the operator and provision for its successor;

4. requirement for a unit operating agreement detailing a method of reimbursement to the operator for costs and expenses and an allocation to all working-interest owners of the benefits accruing from operations, and any other agreements they may agree upon;

5. provision that the unit agreement prevails in any inconsistency with a unit operating agreement;

6. delegation of exclusive rights, privileges, and duties of the parties to the agreement to the operator, subject to the terms and conditions of an approved Plan of Operation;

7. requirement that a Plan of Operation be submitted for approval by the Supervisor providing for exploration or development or both. The plan shall be as complete and adequate as the Supervisor determines necessary for timely exploration or development or both. The plan must also ensure environmental protection and conservation of the oil and gas or other natural resources of the unit area;

8. requirement that prior to production, Participation Area(s) be submitted for approval by the Supervisor to allocate percentages of unitized substances to each tract, thereby governing allocation of future production;

9. provision that "all unitized substances ... shall be deemed to be produced equally on an acreage basis from the several tracts of unitized land within the participating area.... For the purpose of determining royalty ... each tract of unitized land shall have allocated to it such percentage of the production from the participating area as the number of acres of unitized land in said participating area... ";

10. provision for the right of any lessee to relinquish any interests committed to the unitized area;

11. specific rental and minimum royalty payments and schedules;

12. a specific method by which land not entitled to inclusion in a Participation Area may be automatically eliminated from the unit agreement;

13. the effective date and term of the agreement (five-year terms are standard) with provisions for term extension and termination; and,

14. right of the unit operator to appear before the Department of the Interior for and on behalf of any and all interests affected by the agreement. 45/

The unit agreement does not elucidate the relationship between owners of interest in the unitized area. That function is reserved for a unit operating agreement, identified as "any agreement entered into by and between the unit operator and the working-interest owners for the development and production of oil and gas from the unitized area with an allocation of costs and benefits on a basis defined in said agreement." 46/ The USGS requires preparation of such agreements but is not authorized to approve or disapprove their conditions.

In its standardized form and purpose, the unit agreement is of little help to state and local planners in anticipating onshore impacts. What may be of greater use to planners concerned with onshore impacts are Plans of Operations -- which may also be required by an approved unit agreement.

PLANS OF OPERATION. There are two basic types of plans of operation (PO): plan of exploration (POE), and plan of development (POD). POEs are usually for one or, at most, a few exploratory well(s). They describe the location, drilling procedures to be used, and precautions to be undertaken during the operation. A POE is generally quite brief -- sometimes only a few pages. If exploration beyond the initial POE is merited, the lease holder may submit supplemental POEs for additional wells. These supplemental plans may be used to confirm or deny discoveries or to delineate the extent of a reservoir.

PODs are prepared by offshore operators who have decided to develop a reservoir (discovered through a POE). Usually an initial POD is submitted to the USGS Oil and Gas Supervisor for his approval, to be followed by a supplemental, more detailed POD. The initial POD presents an overview of the project, including summaries of geotechnical review data for the operating area, field history and reservoir data, drilling plans, platform facilities, offshore pipelines, onshore facilities, contingency plans, and other relevant material. The initial POD may be less than 100 pages and would probably contain schematic or prototypical drawings of the proposed facilities. Following approval of the initial POD, a supplemental POD may be prepared. Supplemental PODs present the same material mentioned above, but in great detail. For example, the Exxon Supplemental Plan of Operations, Santa Ynez Unit consisted of seven volumes, each over four inches thick and when combined weighing 56 pounds. Additional PODs may be submitted as circumstances demand.

Plans of Operation are generally regarded as proprietary because they often describe oil and gas potential in the area; therefore, they have been generally unavailable to the public. When such plans are available, they provide the first real insight to state and local planners of the potential onshore and offshore effects of specific OCS development. Of particular importance is the fact that the plans bind the operator: "the failure of the unit operator to timely drill any of the wells provided for in a plan of operation approved under this Article X or to timely submit a plan of operation for approval by the supervisor or in any other way to timely comply with the requirements of this (unit) agreement, shall, ... result in automatic termination of this agreement...." 47/

Upon approval of a plan of operation by the USGS, and the nature and scale of operation anticipated, unitization may require environmental impact assessments and permits before actual operations can begin. Necessary documents may include federal EISs, state and local EIRs, local general plan and zoning amendments, and federal, state, and local building permits and authority-to-construct certification.

The Santa Ynez Unit illustrates perhaps the extreme case wherein nearly six years elapsed between designating the unit area (September 11, 1970) and securing a final approval (July, 1976) from the Secretary of the Interior, notwithstanding continuing litigation. 48/

It should be noted that in the case of the Santa Ynez Unit Development Plan, state and local officials were not involved in the project until 1974, after the massive supplemental POD was completed and a draft EIS prepared. By this time the development plan was a fait accompli, in effect disallowing a critical review of underlying assumptions. Further, discussions of alternatives, such as the onshore pipeline or consolidation with other operations, were not comprehensive. It is possible that the permitting process for Exxon encountered numerous delays because state and local views were scarcely considered in the early stages of the plan's formulation.

COORDINATING ONSHORE DEVELOPMENT

The principal strategy considered for coordinating onshore development along southern California's coastline is "consolidation." This strategy involves the sharing of existing or new facilities or the concentration of two or more activities at the same location. Consolidation occurs when two or more companies use the same site or facilities for development, transportation, processing, or storage functions, rather than each company constructing and operating a facility for its own needs only.

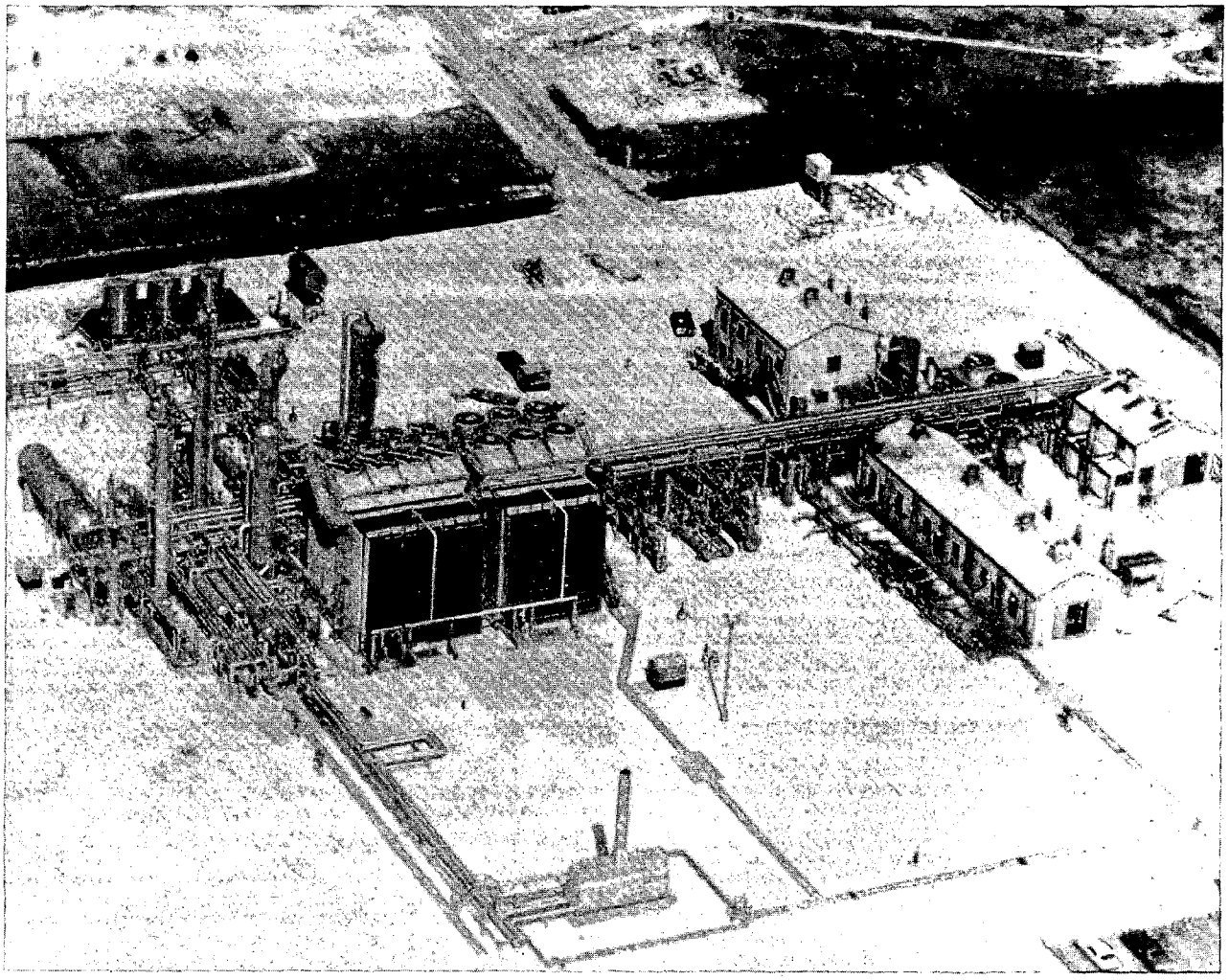
A policy supporting consolidation of offshore oil-related facilities is generally believed preferable because consolidation implicitly represents a reduction in the number of facilities required to recover offshore petroleum resources, which in turn represents a proportionate reduction in the number of situations wherein oil spills or air pollution would be likely to result. Consolidation also requires less energy and consumes less land. Building fewer facilities also saves money for the petroleum industry and thereby may save consumers' money. Various consolidation policies are included at the end of this chapter as Appendix 8.

Of critical concern to this process is the potential and unnecessary duplication of oil and gas processing facilities. Of equal concern are the alternative modes of transporting processed crude oil. Processing facilities and transportation alternatives have been the target of consolidation efforts to date and are the focus of this discussion because they constitute the major sources of land use impacts and potential pollution.

Express policies of the California Coastal Act of 1976 and of Santa Barbara County recommend that facilities related to offshore petroleum exploration and production be consolidated wherever feasible. The petroleum industry has occasionally agreed to consolidation after a clear public agency directive to do so. Ventura County has had some success with this, while Santa Barbara County and Coastal Commission efforts to require consolidation have thus far been resisted. In comparison, Scotland has successfully directed industry to consolidate pipeline facilities, onshore sites, and tanker terminals needed for North Sea operation. Industry resistance to consolidation is variously based on concern that:

1. some consolidation strategies might increase capital costs, thereby making small scale, marginal ventures uneconomic;

Onshore gas processing plant
(photo courtesy of Exxon).



2. the information exchange and inter-company cooperation that must attend planning for consolidated facilities may lead to loss of competitive advantage and violation of antitrust laws;

3. the uncertainty of information regarding the petroleum resource on their own leases already sufficiently complicates facilities planning without adding the uncertainties of other companies' production prospects and actual production volumes;

4. flexibility in production and marketing strategies will be impaired by facilities that must be designed and operated to meet the needs of other companies as well; and,

5. physical properties of oil and gas produced from different reservoirs might make the respective substances incompatible and preclude use of common facilities.

Our findings indicate that, contrary to industry's beliefs, company cooperation required for consolidation will not ordinarily jeopardize technical patents and proprietary information. Further, necessary inter-company planning efforts will not ordinarily be subject to antitrust action. We also find that no physical properties of offshore petroleum resources prevent commingling.

Admittedly, inter-company planning for consolidated facilities is complicated by the great latitude leaseholders are allowed in proceeding toward development. And in some instances consolidation of facilities may raise environmental problems more serious than those it solves: the increased activities at a single site could, for example, result in violation of air pollution standards at the consolidated site, when no such violations would have resulted at smaller, dispersed sites.

Economic analysis of consolidation options by public decisionmakers is also complicated by:

1. incomplete information about the producible petroleum resource;

2. incomplete information regarding the investment and marketing strategies of the individual companies potentially involved; and,

3. inadequate analytical tools for measuring the economic value to society of environmental improvement, mitigation of adverse environmental effects, or elimination of the risks of environmental damage.

For practical reasons, this analysis of consolidation is limited to offshore production stations; pipelines between production stations and processing facilities, processing and related storage facilities; transportation of oil and gas between processing facilities and customers or refineries; and, staging areas for crew and supply boat activities. Refineries and related facilities are specifically excluded because existing California refineries do not depend on California offshore oil for their location or design.

To establish a clear set of conditions under which consolidation should be required as a matter of public policy, several examples of currently consolidated operations and the proposed Exxon/Arco/Aminoil consolidation in Santa Barbara County were analyzed and are described below. The key issues raised by these examples are discussed in question-and-answer form following these descriptions.

EXAMPLES OF CONSOLIDATION

Consolidation of offshore oil-related facilities to date has occurred largely as a result of private industry economics. 49/ Where the sharing of a facility such as a marine terminal is shown to be more economical than developing a separate new facility, industry has demonstrated a willingness to pursue this alternative. Generally, this has occurred where total combined production throughput has been relatively small. An example of this is the Getty Marine terminal at Gaviota. Likewise, several offshore-related onshore oil facilities become concentrated at one location as a result of advantages such as compatible zoning and surrounding land uses. Generally, where production from individual operations is relatively high, industry lacks incentive to share common facilities. Key examples illustrating these principles and the incentives and disincentives that led to them are described below. See Figures 8, 9, and 10 for the general location of these sites.

GETTY-GAVIOTA 50/

Approximately 30 miles west of the City of Santa Barbara and one mile east of Gaviota, Getty Oil Company owns a 98-acre parcel fronting the ocean and extending inland approximately 1,000 yards. The site, shown in Figure 10, is presently used by Getty, Chevron Company USA, Arco, and Douglas Oil. Prior to 1973, Texaco also used portions of the site (Douglas was not then involved). All activities are concentrated on an 11-acre portion of the parcel which is bisected by Pacific Coast Highway (101) and separated from the ocean and low coastal bluffs by the Southern Pacific Railroad.

Present operations at the site include gas processing by Chevron; small scale oil and gas processing by Arco; crude oil storage leased by Douglas Oil as a reserve for future use in their northern Santa Barbara County refinery; and Getty's truck loading rack, storage, pumping, and heating equipment related to its offshore marine terminal.

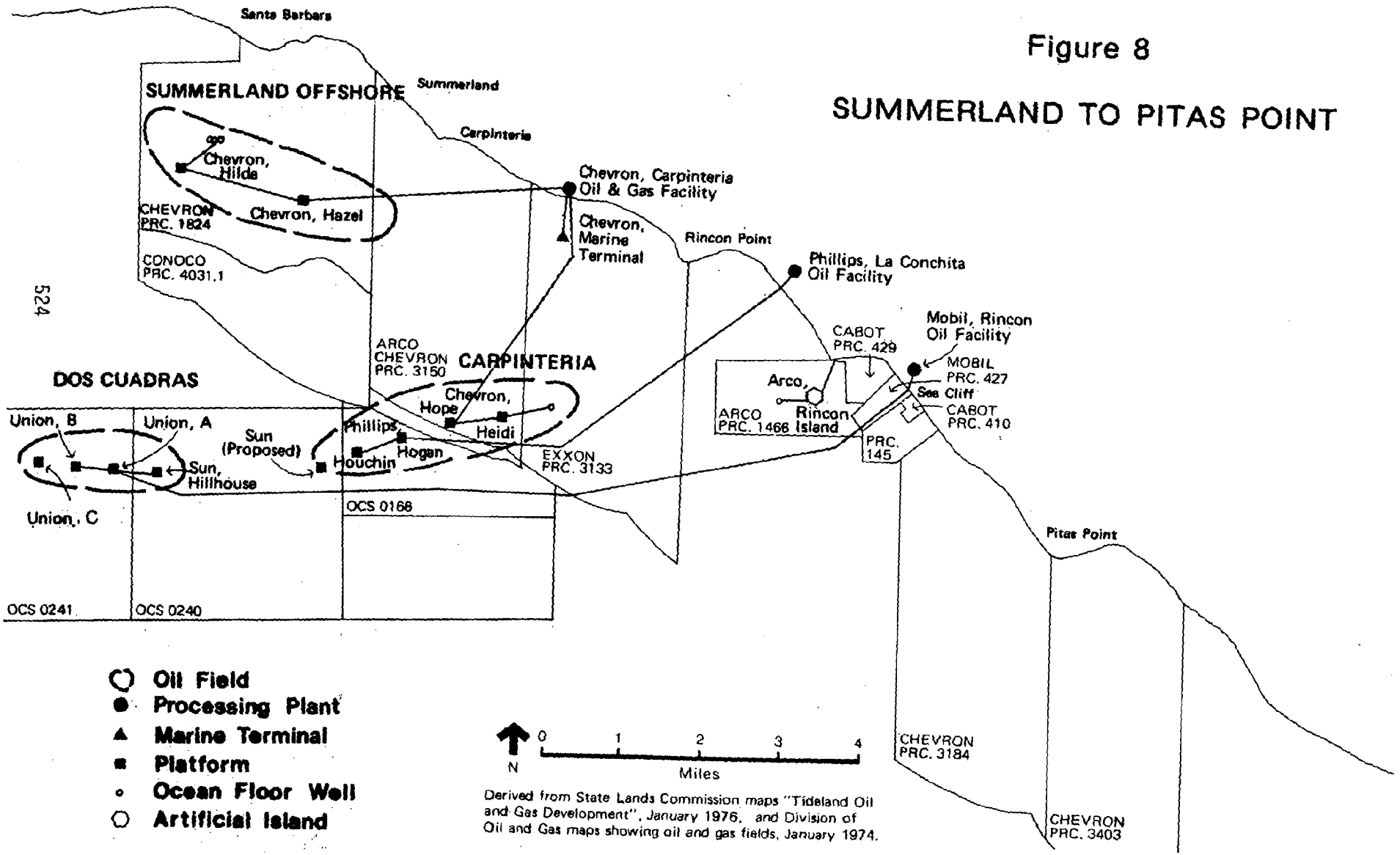
Chevron processes gas from its offshore wells in state leases 2894.1 and 2199.1 directly offshore the Gaviota site and from three onshore wells located on the bluffs. The processing site is north of the highway, across from the main storage and marine terminal operations. Chevron's processed product (natural gasoline) is pipelined to a storage tank in the main storage area which is in turn linked to the submarine pipelines serving the offshore marine terminal. Produced dry gas is sold into the Southern California Gas Company pipeline which crosses the site, and produced propane is trucked from the site.

Arco has one well 1.5 miles offshore producing oil and gas from the Alegria offshore field (state lease 2793.1). The well is connected to Arco's processing facility at Getty-Gaviota to the north by a 4.5-mile submarine pipeline. Treated gas is sold to an onsite gas pipeline company; produced oil is stored for trucking through Getty's truck-loading rack. When Texaco stored crude oil at Getty-Gaviota, Arco would commingle its treated crude with Texaco's for shipment via Getty's marine terminal.

Douglas Oil currently leases two 80,000-barrel storage tanks from Getty for storage of crude oil to be used in the Douglas refinery at Santa Maria. The crude is produced near Santa Maria and trucked to this storage site for future use or exchanges with other potential users.

Figure 8

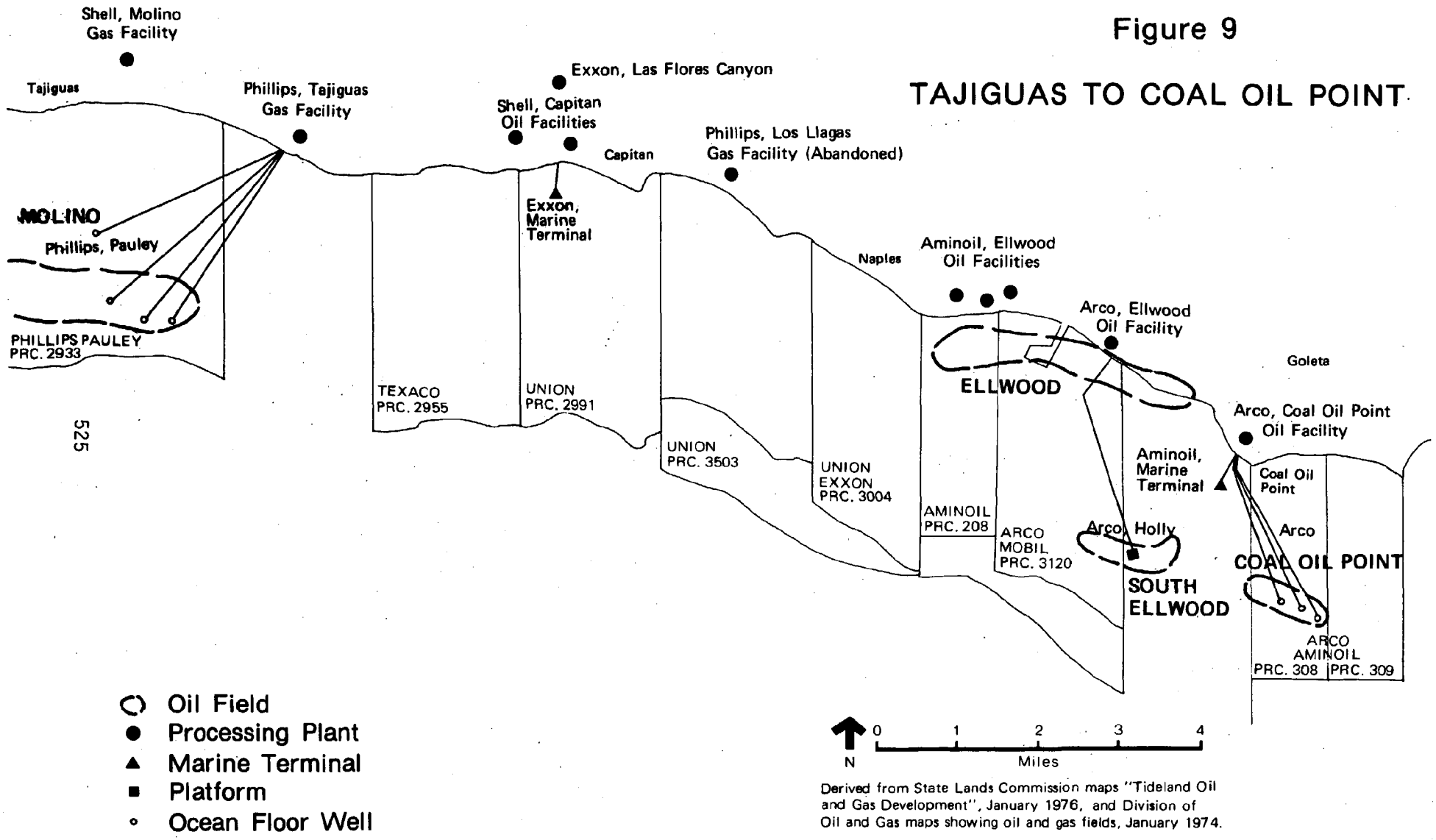
SUMMERLAND TO PITAS POINT



Derived from State Lands Commission maps "Tideland Oil and Gas Development", January 1976, and Division of Oil and Gas maps showing oil and gas fields, January 1974.

Figure 9

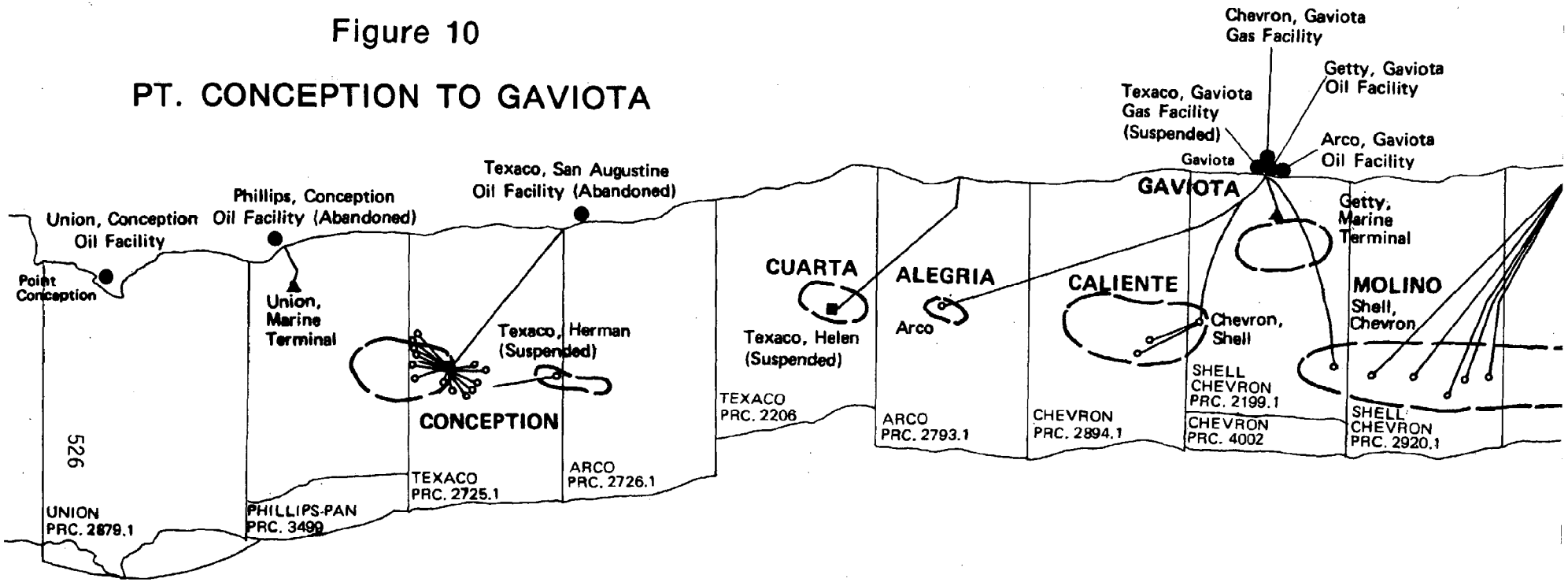
TAJIGUAS TO COAL OIL POINT



Derived from State Lands Commission maps "Tideland Oil and Gas Development", January 1976, and Division of Oil and Gas maps showing oil and gas fields, January 1974.

Figure 10

PT. CONCEPTION TO GAVIOTA



- Oil Field
- Processing Plant
- Marine Terminal
- Platform
- Ocean Floor Well

N

0 1 2 3 4

Miles

Derived from State Lands Commission maps "Tideland Oil and Gas Development", January 1976,, and Division of Oil and Gas maps showing oil and gas fields, January 1974.

The Getty facilities at Gaviota were designed initially as a transshipment point for its own production from the north-county Zaca Creek field. Crude is trucked to the site, transferred via the truck-loading rack to one of Getty's storage tanks (one 80,000-barrel tank and one 35,000-barrel storage tank, formerly Texaco's). Since the Zaca Creek crude is extremely "heavy," Getty has integrated into the marine terminal loading system a heating unit to maintain the crude at a temperature that allows it to flow readily. In the early life of the Zaca Creek field, Getty considered constructing a pipeline to the Gaviota site, but production volumes were never large enough to justify such a pipeline.

With excess capacity resulting from lower-than-expected production from Zaca Creek, the marine terminal operations began to attract the interest of other companies needing a transshipment point. Texaco, Arco, and Chevron each saw advantages in contracting for the marine terminal services and developing facilities onsite. As Getty's throughput declined and Texaco abandoned its interests in the site, additional surplus storage became available for Douglas Oil. Getty was also attracted to this consolidation of offshore petroleum-related activities: since space was available, tanker scheduling presented no problem, and more significantly, rental rates were favorable to Getty's local economics. Fortunately, the relative compactness of operations minimizes the amount of land area affected by industrial facilities.

EXXON/ARCO/AMINOIL 51/

The first real test of mandated consolidation by a public agency is demonstrated in the proposed consolidation of Exxon, Arco, and Aminoil oil companies in Santa Barbara County. Exxon proposed a new onshore separation and treatment facility at Las Flores Canyon, a marine terminal directly offshore, and related facilities onshore to serve Platform Hondo, now being placed in federal waters. Exxon's processing plant and marine terminal are designed to handle approximately 80,000 B/D 90MMCF/D. Arco had initially sought approval for the drilling of new wells from the existing Platform Holly but not for the necessary improvements onshore to handle the expected increased production of natural gas. A permit for this initial proposal was denied by the Coastal Commission pending completion of a more comprehensive application, including consideration of necessary onshore facilities to accommodate total anticipated increased production of 20,000 B/D and 22 MMCF/D. Aminoil has proposed a new marine terminal operation at Dos Pueblos Canyon, including related onshore pipelines, marine pipelines, and mooring facilities in state waters, to replace its presently obsolete terminal operations at Coal Oil Point. Aminoil's proposed operation is designed for "storing and transporting (via coastal tankers) oil at an anticipated production level of 20,000 B/D" which, for all practical purposes, wholly depends on Arco's anticipated production of 20,000 B/D. 52/ See Figure 9 for the location of these projects.

The plans of these companies are well suited for a consolidation analysis since the applications are concurrent. Both Exxon and Aminoil have proposed new marine terminals and storage facilities within seven miles of each other; both Exxon and Arco are proposing onshore processing plants for oil and gas; timing of development for the three proposals is compatible; and, the three proposed development sites are within reasonable distances of each other.

The feasibility of various consolidation opportunities among these three companies is currently under review by Santa Barbara County, which has required Arco and Aminoil to evaluate their options through the EIR process. Pending the outcome of these and other studies, the County Board of Supervisors passed a resolution in 1975 recommending that a permit Arco had applied for from the State Coastal Commission "be withheld until the issue of consolidation of the South Coast oil processing facilities is resolved." 53/ At that time, Arco's permit application was for the drilling of 17 new wells from the existing Platform Holly in state waters. The application did not include a request for the development of new onshore facilities that would be required in order to accommodate the anticipated increased throughput upon completion of the 17 new wells. On the basis of this and other factors, the Coastal Commission denied the permit to Arco. In adopting the denial resolution, the Commission noted that:

> ... piecemeal approach to energy production is not consistent with Coastal Act requirements for the orderly, balanced use of coastal resources consistent with sound conservation principles.
>
> Given the increased risk of oil spills from the drilling and production of these 17 new wells, approval of this project, independent of clear proposals for consolidating onshore treatment facilities that will also provide natural gas, would be contrary to the mandates of the Coastal Act....a complete application -- for offshore petroleum production and necessary onshore facilities, consolidated with others of a similar type... -- would be consistent with the Coastal Act and would thus be approved. 54/

Upon appeal to the State Supreme Court, however, the Commission's jurisdiction over this application was ruled invalid because of vested rights Arco had accumulated prior to passage of Proposition 20, the Coastal Act of 1972. Arco has, however, again returned to the Coastal Commission for a permit, this time for expansion of the existing onshore processing plant to accommodate the anticipated production. See Chapter 21 for a discussion of this current proposal.

Subsequent to the Arco decision, the State Coastal Commission also reviewed Exxon's application for development of a marine terminal in state waters, pipelines and electrical cables connecting an offshore platform with an onshore processing plant, an electrical generating plant to provide power for the offshore platform, and miscellaneous appurtenances. A Commission resolution granting a permit to Exxon Corporation included the following:

> The permittee agrees to accept oil and/or natural gas produced from the South Ellwood Oil field...to process, to the extent of its excess capacity or to the extent of added capacity authorized by any additional permits or entitlements of use, said oil and/or natural gas..., and to permit the use of its proposed offshore marine terminal and/or common carrier (public utility) pipeline for the shipment of such oil. 55/

The Commission staff noted in the resolution that:

> There has been agreement [between representatives of Exxon and the Commission staff] on many conditions of approval, most notably those involving consolidation of petroleum processing facilities for other companies of the proposed Exxon site in Las Flores Canyon. 56/

A major feature of the Coastal Commission permit to Exxon was temporary approval of the marine terminal (five years) and a requirement that Exxon explore

the feasibility of constructing an onshore pipeline, in lieu of a permanent marine terminal, to transport crude oil from the Las Flores Canyon processing facility to the Los Angeles area or other alternative destination for refining. The feasibility of the pipeline would ultimately be determined by an appropriate state agency on the basis of:

1. a preliminary design study prepared by Exxon;

2. an Environmental Impact Report;

3. the status of government approvals and right-of-way acquisitions; and,

4. the determination of the economic feasibility of the pipeline, based on the projected cost of the pipeline, the amount of oil Exxon plans to transport from the Santa Ynez Unit, the production of other companies anticipated to be transported through the pipeline, a fair rate of return to the pipeline owner or operator, a tariff reasonable to the users of the pipeline, the market price of crude oil, and other relevant considerations.

Exxon rejected this approach for determining pipeline feasibility, thereby rejecting the entire permit. Earlier, Exxon had submitted criteria of its own for determining feasibility, effectively setting a dollar limit on Exxon's involvement and a minimum throughput to the pipeline by other producers, essentially placing Exxon in the position of determining ultimate pipeline feasibility. The Coastal Commission could not accept this method of determination because, in the opinion of the Attorney General's Office, the Coastal Act of 1972 explicitly prohibited the Commission from making a determination based on such criteria.

In light of the Commission's resolution regarding Exxon and the potential Arco consolidation, Aminoil's marine terminal proposal is placed in jeopardy. If Arco and Exxon proceed with consolidation, there would be no need for a new Aminoil marine terminal. A key question remaining in this situation is the transport mode to be ultimately implemented: the OCS offshore option, the nearshore marine terminal, or the onshore pipeline. Should appropriate governmental authorities determine that consolidation of Arco and Exxon activities is in fact economically and environmentally undesirable and the companies are allowed to pursue their separate plans, Aminoil's marine terminal proposal becomes more viable. Then, of course, the applicability of a consolidation policy to Arco and Aminoil would be raised.

The possible consolidation of Exxon, Arco, and Aminoil was entertained by industry reluctantly, at best. Exxon's position is stated as follows: "Under the free enterprise system, a condition requiring consolidation is basically unnecessary because there is economic incentive to make unused capacity available to others." 57/ This gets to the crucial issue of consolidation: in the absence of private industry economic incentive, should public economics be brought to bear on land-use decisions? The unwillingness of Exxon and Arco to enter into a consolidation agreement is based on a lack of private industry economic incentive: each company was pursuing a generally self-sufficient operation. Proceeding on their own separare development schedules, Arco and Exxon were hardly aware of the potential sharing or inter-company utilization of common facilities. At the insistence of Santa Barbara County staff, and later the Coastal Commission, these opportunities were discussed by the two companies, resulting in a general agreement that at least the marine terminal solution can be shared. Analysis by county staff based on data provided by the two companies, however, indicates that Exxon

and Arco crude production is basically compatible and that the Las Flores processing and storage capacity can be adjusted at a reasonable cost to accommodate currently estimated crude production peaks and volumes of both companies combined.

The proposed pipeline between Las Flores Canyon and the Los Angeles refinery area (or alternative destination) is to date the most ambitious proposal for a consolidated facility in southern California. The pipeline could potentially serve as the primary mode of transporting all Channel production to refineries, eliminating up to 200 Channel-originated trips a year. Considering that Exxon owns interest in 42 of the 65 Santa Barbara Channel leases (clearly the largest investor in the Channel), it would seem logical for Exxon to take a lead as industry's representative in working with government toward Channelwide planning goals. The proposed pipeline is Channelwide in significance and, to a degree, comparable to the Alaskan pipeline, which involves many companies in both construction and operation.

If Exxon, Arco, or Santa Barbara County had perceived the potential consolidation at the Las Flores site or for a Santa Barbara-to-Los Angeles pipeline earlier in the permit review process, there might have been less resistance to the idea of concentrating separation, treatment, and storage activities for the two companies at the one site. This lack of coordination clearly points out the need for Channelwide planning to provide adequate guidance to sound resource management in the future.

CHEVRON-CARPINTERIA 58/

Chevron operates an onshore processing plant, a crew and supply boat staging area, and a marine terminal within the City of Carpinteria to service production from the Summerland Offshore and Carpinteria Offshore fields. The Summerland field is produced through Chevron's platforms Hilda and Hazel; production delivered to the processing plant from the Carpinteria field is by way of Chevron's platforms Hope and Heidi. The Summerland field is entirely within state waters while the Carpinteria field extends into federal waters from the state lease where the field was originally discovered.

Chevron maintains two essentially separate and parallel oil handling systems, one for each producing field. The two oil-handling systems permit Chevron to process the two crudes separately and simultaneously for independent metering of throughput. The treated and dewatered crudes are then stored on site in Chevron's 217,000-barrel tank (note that commingling does not occur in this tank: the crudes are fed into the tank at different elevations, and an interface between the crudes maintains itself without significant blending). When enough processed oil is accumulated from one field or the other, that portion of the tank is drained off via pipelines to the offshore marine terminal for transport by tanker.

According to the draft EIR for the resumption of drilling from Chevron's platforms, the majority of recent tanker deliveries have been to the Chevron refinery at El Segundo. 59/ The marine terminal is also used for unloading tankers delivering gasoline and diesel fuel to a Chevron-owned but spearately operated bulk plant adjacent to the processing plant site. Considering the possibility of an onshore pipeline with the purpose of delivering Santa Barbara Channel crude oil to refinery market areas, the operation of this marine terminal could become dependent on offloading products only since the loading of crude oil would no longer be required.

In contrast to the parallel oil-processing equipment, gas from the four platforms is essentially commingled and treated in one system. At each platform, natural gas is separated from the produced liquids, "scrubbed," and compressed at a low pressure to go ashore in a pipeline serving each pair of platforms from the respective fields. The onshore gas separation and treatment equipment removes additional water from the gas and separates natural gasoline, liquid petroleum products, and dry gas. Some gas is used by Chevron for energy purposes on-site and at the platforms; the remainder is sold. The main reason why only one processing system is required for gas when two are required for oil at this site is that once natural gas is separated into its component parts, desulfurized, and dehydrated, there are no distinguishing characteristics affecting its value.

The significance of the Chevron-Carpinteria operation is that it illustrates the difficulties pertaining to commingling produced oil for onshore processing. Regardless of whether the crudes are "compatible" or not, the method of valuation for the purposes of determining the state's royalty, and the value industry receives from crude characteristics (gravity, sulfur content, others) encourage the development of separate-but-parallel systems, especially when the crudes differ significantly in economic value. In Chevron's case, Carpinteria Offshore oil (gravity: 25° API) sells for around $5.00/barrel while Summerland Offshore oil (gravity: 35° API) is now selling for around $10.00/barrel. Chevron naturally prefers not to commingle the different priced crudes from a market standpoint -- and for taxation reasons as well, since it would complicate the accounting system for determining state royalty.

The sharing of crew and supply boat activity by Chevron, Union, Sun, and Phillips demonstrates industry's knack for getting together even when the mutual benefit is marginal. The flexible scheduling of boat use and the proximity of the other platforms to Chevron's are two factors facilitating this cooperation.

MOBIL-RINCON

"Mobil-Rincon" derives its name from its operator, Mobil, and its location, the Rincon coastline. The facility processes production from the Santa Barbara Channel federal leases 241 and 240. The site has been identified as having significant capability for accommodating future OCS production by this study and in the Santa Barbara Channel FES by the USGS. Lease 241 is operated by Union Oil Corporation; current production is from Platforms A and B, with Platform C scheduled for production by late 1977. Lease 240 is operated by Sun Oil Corporation, producing through Platform Houchin. Leases 241 and 240 overlie the Dos Cuadras field, currently the largest of two OCS producing fields off southern California. The peak rate of production for the Dos Cuadras field was approximately 81,000 B/D and approximately 40,000 MCF/D in 1971. Current production from the Dos Cuadras field is approximately 30,000 B/D and 13,000 MCF/D.

Mobil-Rincon covers approximately 140 acres on a terrace along the coastal bluffs of Ventura County, approximately 3.4 miles southeast of the Ventura-Santa Barbara county line at Rincon Point, and 1.2 miles due south of Rincon Mountain. The site covers level to gently rolling topography bounded by increasingly steeper land to the north and east, and exceedingly steep bluffs to the south and west. Of the 140 acres, 20 on the north are reserved as a buffer zone, as a result of permit conditions issued by Ventura County, leaving 120 acres developable. Approximately 32 acres are currently developed for the processing plant and a 268,000-barrel storage tank owned by the Ventura Pipeline

Company (see below for a description of this operation). An estimated five of the 32 acres are available for expansion without grade preparation. An additional ten acres adjacent to the processing plant are graded to a uniform gradual slope and could be utilized with minimal grade modifications. The remaining 78 acres are in a relatively natural state of rolling grass and brush-covered terrain. The operations of the bluff-top site depend on a pump station and offshore-to-onshore transfer equipment at the base of the bluffs.

The Mobil-Rincon facility, including the land, equipment, access road, pump station, and offshore-to-onshore equipment, is presently owned by Gulf, Mobil, Union, and Texaco (the GTUM group) and Sun, Marathon, and Superior (the Sun group). The GTUM group purchased the site in 1968 in anticipation of OCS production they expected as a result of the leases acquired in the February 1968 Channel lease sale. The Sun group bought in to the operation in 1969 and collectively hold 30% interest in the facility. The Mobil-Rincon facility is operated by the Mobil Corporation.

The Ventura Pipeline Company owns a pipeline connecting the Phillips-La Conchita processing plant on the north to the 268,000-barrel storage tank at Mobil-Rincon and a pipeline continuing south to several transfer points near the City of Ventura. The Ventura Pipeline Company also owns the storage tank at Mobil-Rincon. The pipeline company consists of the GTUM group, the Sun group, the owners of Phillips-La Conchita (Phillips Petroleum, Cities Service Oil Company, Continental Oil Company), Arco, and Chanslor Western. The company is operated by the Mobil West Coast Pipeline Company, a subsidiary of Mobil Corporation.

The significance of the Mobil-Rincon facility lies in its advance planning and the degree of industry cooperation. Recognizing at the very outset of the Santa Barbara Channel development that the GTUM group could be responsible for as many as four offshore units that could begin production at various times, the operators designed a facility with considerable expansion potential at a site that was compatible with local land use policies. The system design anticipated crudes of differing characteristics and therefore allowed for commingling managed through a complex accounting system. This accounting system has facilitated the cooperative joint-venturing of GTUM with Sun Oil, an entirely separate producer, and will facilitate the entry into the system of several additional units, such as Pitas Point, Hueneme Offshore, Oak Ridge, and Santa Clara. Further consolidation is achieved by the GTUM group in its Ventura Pipeline Company agreement, which has been expanded to include three other operating groups.

ISSUES RAISED BY CONSOLIDATION

A number of significant issues concerning the validity of consolidation were mentioned earlier. The following paragraphs illustrate in greater detail some of the consequences that might result from adopting consolidation as a public policy.

1. Will technical patents and proprietary information necessarily be jeopardized by the sharing of production facilities?

No. Generally, new facilities use the most modern technology available, and new innovations are quickly assimilated industry-wide. Technological innovations protected by patents were never identified by industry representatives as a constraint to consolidation of existing or proposed facilities. The cutting edge of technological innovation in the petroleum industry is in the exploration and refining phases of resource exploitation, not in the development and production

phases. Even if high technology were present in shared facilities, the "sharing" rarely if ever poses a security problem. The common practice used in sharing facilities is for the partners to contract for services, with one partner acting as operator. The non-operating partners then limit their concern to volumes of throughput and leave the means of handling the oil and gas up to the operator. Proprietary information such as exploration results, long-range planning strategies of individual companies, or oil and gas volumes moving into various markets is rarely if ever developed at production facilities, although the raw data for such information may come from such facilities, and hence would not be exposed to competitors.

2. Will industry violate antitrust laws through the cooperation implicit in agency-initiated or approved consolidation proposals?

Not by this type of working agreement alone. Numerous cooperative agreements existing in offshore-related petroleum development in southern California have operated for years with federal, state, and local approval and have never been challenged in court. Antitrust concerns become meaningful when the actions of companies have the effect of defrauding the public or competitors through control of the market -- not when they collaborate for the purposes of increased efficiencies or public benefit. Like most states, California statutes provide in effect that cooperative agreements implicit in consolidation or unitization proposals, when approved by a regulatory agency of the state, shall not be construed to violate the state antitrust laws.

3. What costs or benefits result from commingling crude oil? When is crude oil "incompatible?"

No physical properties of offshore petroleum resources literally prevent commingling. The commingling of crudes can occur at a gathering point of pipelines from several production stations; at the inlet tank to a processing facility; at treatment stage; at the storage tank awaiting shipment to a refinery; or in the tanker or pipeline carrying the crude to the refinery. Commingling of production is specifically provided for in the federal regulations governing OCS operations: "...the [Area Oil and Gas] supervisor may authorize the lessee to move production from the lease to a central point for purposes of treating, measuring, and storing, and in moving such production, the lessee may commingle the production from different wells, leases, pools, and fields, and with production of other operators." 61/ Oil companies tend to consider crude oil to be "incompatible" when accounting problems occur.

Accounting problems involve keeping track of the percentage owned by each company of the commingled production; the financial investment by each involved company in the exploration and development of the producing field(s); the proper allocation of actual production costs; and the allocation of royalty payments accruing from each lease involved. It also involves projecting market allocation strategies for the anticipated production. From a strictly administrative point of view, crude oils become incompatible when the costs of setting up an adequate accounting system exceed the calculated benefits of commingling. The "costs" may be purely administrative or they may reflect inter-company competition. The costs of setting up an adequate accounting system are not a substantial or significant economic constraint to commingling when compared to the investment typically required to produce offshore oil or the ultimate value of the oil produced. Nonetheless, industry sometimes views the economic incentives to commingling as inadequate to overbalance the accounting problems. An example is the Chevron-Carpinteria

case, which contrasts with the Mobil-Rincon case, where the incentives were effective.

The combination of unlike crudes always results in the averaging of respective characteristics in proportion to the volumes mixed: gravity, sulfur content, and viscosity are the critical factors. If the crudes are identical, there will be no loss or gain involved. If the crudes differ significantly, the combined product will represent an average value. The main consequence of commingling crude oils, from the producer's standpoint, is the difference in price a refiner will pay for it; the price varies according to the demand for types of crude. Also affecting the producer's decision to commingle is the effect it will have on the royalty paid to the State Lands Commission or USGS, depending on whether it is in state or federal waters. Both the State Lands Commission and USGS apply their royalty charges to the lease from which the production originates and base their royalty on the value or amount of crude produced from a given lease after water and gas have been separated. The value of the crude is determined by the oil's gravity, sulfur content, and viscosity, factors that vary over the life of a producing field. Water content must be less than 3% by volume (generally, to reduce the water content to this percentage requires an elaborate processing facility not easily accommodated at an offshore production platform). If production remained constant from various leases and the crudes were identical, it would not be difficult to determine how much oil is being produced from which lease, as well as the quality of the respective oils if they are commingled before reaching a metering station. The problem would be worsened if a producing field spanned state and federal waters because the methods of computing royalty rates differ.

4. If facilities are to be shared or consolidated, how can equitable use, liability, and access be guaranteed? What phasing problems would occur?

When two companies approach the idea of sharing a new facility to produce, transport, or process petroleum resources of identical volumes, characteristics, and production schedules, there are few or no problems in making the necessary arrangements. But these circumstances have been virtually non-existent in the recent past. More commonly, two or more companies are not ready to enter production simultaneously, their ultimate volumes and rates of production vary significantly, their facility requirements may vary, and their risks of environmental damage differ appreciably. One product may be extracted at a high pressure, or it may be more volatile, more aromatic, more viscous, or higher in sulfur content than the other. Each of these factors could warrant specialized attention not required by the other product. Potential equity problems occur when the participants in a proposed shared facility begin to allocate the expenses of developing a system that must serve the specialized needs of two or more production plans. Since volume and rate of production vary dramatically over time, the degree of use of certain facilities would likewise vary, resulting in differences of opinion as to the responsibility for facility operation and any associated liability.

Another potential equity problem exists when new production begins and the producer is obligated by a governmental agency to unitize or consolidate with an existing operation in the interests of conservation. Proverbially, the existing operator has the new producer over a barrel: it can charge the producer for access to the established system ostensibly to defray the costs of developing the original facility, even if it is already paid for.

In order to reach an equitable way to share facilities, public agencies such as USGS should more clearly mandate procedures for establishing reasonable joint-venture conditions. For such mandates to be entirely effective, greater coordination -- perhaps joint advisory boards -- should exist between state and federal agencies to better integrate the necessary onshore components to offshore production operations. Together, state and federal agencies could introduce guidelines for joint ventures that would identify formulas for cooperative agreements considering the various equity, liability, and access questions that could be raised.

Phasing in and out of production poses another distinct problem for facility planners. Not until fairly late in the development design stages can industry predict with any reasonable degree of certainty the rate of production over time, including the variable water-to-oil ratio which often becomes a critical factor in facility design. Although companies begin together (i.e., are awarded leases at the same time), they explore, develop and produce on extremely variant schedules, and the possibility of subsequent lease sales in the same area almost certainly guarantees different start-up times. With companies operating under such diverse schedules, and with the vast uncertainties as to how much oil and gas might actually be found and where, the design of facilities to accommodate more than one user generally transcends the planning capabilities of individual companies.

A potential solution to these problems lies again with public agencies. USGS, the State Lands Commission, the Division of Oil and Gas, or the Coastal Commissions should take the initiative jointly, forming a clearinghouse for offshore petroleum production planning. For understandable proprietary and competitive reasons, industry has not demonstrated an interest in tackling the complexities of equity or phasing problems, especially to facilitate consolidation. Yet, if consolidation reduces initial costs to industry, especially to the smaller independents, as well as serving public goals of minimizing the effects of offshore oil, then it would seem to be in the public interest that governmental agencies provide this clearinghouse.

5. If consolidation were required, what economic hardships would be suffered by industry? What economic gains would be enjoyed by industry?

Whether consolidation consists of the concentration of several facilities or activities at the same site, or the sharing of one facility by two or more companies, industry need not suffer economically. All apparent inequities can be eliminated in a carefully considered consolidation by means of compensation and compromise. For example, some market flexibility could be lost and certain scheduling prerogatives of individual companies could be hindered, but at the same time operational efficiencies would accrue from a consolidated facility. Fewer employees would be required and capital investment could be reduced since fewer facilities would be built; and fewer administrative delays affecting oil development would take place.

6. At what stage in the resource development process should consolidation be considered?

Preliminary production planning by industry begins with identifying the best means of recovering the resource, i.e., platforms and ocean floor wells. Following preliminary planning, an operator prepares a development plan which will describe the production system, schedule the phasing of development and production, and identify alternatives for transporting and processing produced resources. This stage, which takes place often from one to three years before production begins,

is the logical point to consider the potential for consolidating anticipated production with other proposals or existing facilities. If state agencies are to take a greater role in coordinating offshore development, they should be made aware of development planning by industry: review of development plans will be crucial to this task. In the preparation of such plans, it would also be wise for industry to consult with state and local agencies to identify potential sites for onshore activities compatible with local and regional land use planning goals.

7. If consolidation results in fewer facilities, what effect will this have on local job markets? Local services? Local tax base? Local land use planning?

Offshore oil production is basically a capital-intensive industry and not a high employer of local labor. Depending on what is consolidated, potential new jobs will be reduced. Current offshore petroleum-related jobs are fairly secure at this time and likely future production from the Santa Barbara Channel and the southern California borderlands area can only result in more jobs, though perhaps fewer than if consolidation were not anticipated. Although taxes generated by offshore-related development are quite helpful to local communities, the relative effect of petroleum-related jobs is virtually negligible in all large cities.

Some public service agencies operate more efficiently when consolidated facilities exist. Consolidation reduces the number of facilities requiring periodic visits or surveillance by units of the fire and police departments, the petroleum administrator's office, the local Air Pollution Control Districts, and many others. Offshore oil-related labor, even cumulatively, will be relatively insignificant and hence would probably not contribute inordinate demands on additional services such as hospitals, schools, garbage collection, etc.

Local taxes will be affected to the degree that consolidation represents the construction of one fairly large facility instead of two or more smaller-sized facilities. These theoretical tax losses to the local economy, however, must be related to the reduction in infrastructural costs resulting from the favorable land use planning facilitated by a consolidation policy. By concentrating or minimizing the number of new or existing facilities for offshore oil and gas production, the land that might have been converted to offshore-related facilities would remain available for some other coastal-related development. The effect of consolidation on land use planning is potentially beneficial provided local government, with the aid of state agencies as necessary, adequately plans and zones for consolidated offshore-related facilities.

8. If consolidation of processing plants results in fewer but larger facilities, what effect will this have on ship or truck traffic?

Processing plants with larger throughput capacities will require more frequent transfers of produced oil, gas, gas by-products (butane, propane, natural gasoline), and sulfur compounds. It is possible that the number of tanker movements could be reduced by the use of larger tankers if offshore marine terminals related to the expanded processing plants can handle the deeper draft ships. Tank trucks, however, appear to have reached maximum size and hence their use is directly dependent on the volume of substances to be moved.

Tanker or tank truck congestion is a critical problem that must be addressed in any facility consolidation plan because of potential environmental risks. Since truck movement of produced by-products seems unavoidable, the selection of

future sites for increased processing activity should thoroughly consider highway access problems and conflicts. An increasingly serious problem is the use of tankers servicing consolidated processing plants. Serious consideration should be given to pipeline alternatives for either transporting treated crude to marine terminals in less hazardous circumstances or directly to the refineries. Site-specific studies will be needed to evaluate the potential risks of truck or tanker movement, as no simple rule exists for determining excessive congestion.

9. If consolidation of processing plants results in fewer but larger facilities, what effect will this have on oil spill risks?

Oil spill risk is more or less a function of the frequency with which oil is transferred (from platform to pipeline to processing plant to storage tank to tanker or pipeline) although most major oil spills are known to be the result of human error. If consolidation results in increased throughput and larger but fewer tankers, potential oil spill risk is reduced, although spill size may be larger.

10. If consolidation of processing plants results in fewer but larger facilities, what effect will this have on cumulative air quality?

Given the present state-of-the-art, it is virtually impossible to eliminate hydrocarbon vapor emissions from loading crude oil into tank ships or at various junctions within a processing plant. Numerous records of fugitive emissions aboard tankers, at marine terminals, and at processing plants have been made. The net result has been to demonstrate that air quality is a critical concern for offshore petroleum planning.

A crucial issue facing a consolidation policy is the effect a consolidated (concentrated) solution would have on air quality versus the dispersion of facilities which now exist. Consolidation could result in creating a "hot spot" of air pollutants with potentially severe local effects whereas dispersion of facilities would result in distributing pollutants over a wider area. Two facilities, however, will have twice as many outlets for fugitive emissions as one, resulting in the possibility of a net increase in regional air pollution. Again, no handy guidelines exist for choosing between consolidation or dispersion.

11. If consolidation results in fewer but larger facilities, what changes in potential fire hazard can be expected?

Fire hazard is a function of the amount of volatile material on hand. Fire risk is determined by the number of times the material is transferred from one vessel to another. The hazards of fire at a consolidated facility may be greater than at a smaller facility, but the risk will be smaller because it is easier to monitor one facility than two or more.

12. If consolidation results in fewer but larger facilities, what changes in potential visual impacts can be expected?

Visual impacts are a function of the degree of visibility of a facility and the amount of contrast it represents with respect to its surrounding environment. Visual impacts are primarily a siting problem. Generally speaking, where scenic values are highly regarded, consolidation of onshore facilities at sites that are well screened from public viewing points may significantly reduce much of the public opposition to onshore industry activities.

CONCLUSIONS AND RECOMMENDATIONS

"Oil and gas development shall be permitted ... if ... new or expanded facilities related to such development are consolidated to the maximum extent feasible and legally permissible, unless consolidation will have adverse environmental consequences ..." (the California Coastal Act of 1976).

An obvious pitfall of consolidation policy will be in determining the degree of consolidation considered "feasible" and "economically feasible." The Coastal Act of 1976 reduces the definition of feasible to "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors." 62/ A policy advocating consolidation must also recognize relationships to environmental and economic goals of local and regional governments as they would affect offshore-related development, as well as industry prerogatives regarding facility siting. But the most difficult obstacle facing the application of a consolidation policy is the consideration of fluctuations in production and variations in start-up, peak, and tail-off stages of an offshore field's productive life. These are variables not easily accounted for in a broad policy statement. In the final analysis, the policy statements must be backed up by responsible decisionmaking that can piece together the sometimes divergent, competitive, and temporal variables affecting the siting and design of petroleum facilities.

COSTS AND BENEFITS OF CONSOLIDATION

The costs and benefits of consolidation are not readily quantifiable: there are as many permutations of potential consolidated operations as there are offshore lease holders, commercially producible fields, and onshore processing facilities. Of the examples described, consolidation of offshore-related activities occurred both voluntarily and in compliance with government stipulations; in no instance was it indicated that consolidation adversely affected the economic viability of the overall resource recovery process. In fact, the sharing of facilities, such as at Gaviota, contributed materially to the operation's solvency. However, the ultimate desirability of consolidation, as well as its feasibility, will have to be determined on a case-by-case basis, since factors such as air pollution may conflict with other basic environmental goals. A summation of some of the benefits and costs is outlined below.

BENEFITS OF CONSOLIDATION

1. Consolidated onshore processing plants may initially require longer underwater and land pipelines between processing sites and offshore production stations.

2. Air pollution hot spots may occur.

3. Unless commingling, royalty, and "compatibility" problems can be worked out, a consolidation requirement may simply result in two parallel systems side by side.

4. Accounting problems of a consolidation proposal may lead to legal and financial problems between petroleum companies or between a governmental unit and a petroleum company. This could produce delays in the resource development process.

5. Assignment of liability for oil spills, air pollution, etc., is complicated.

RECOMMENDATIONS

1. Institutional arrangements should be designed to insure the coordinated and planned development of offshore resources with the least environmental damage possible, both offshore and onshore. Possible institutional organization could include a local government advisory board made up of representatives from southern California governments, with authority to advise a responsible state or state/federal agency in negotiating with and overseeing petroleum industry activities. The express objective would be to minimize onshore impacts through the coordinated and planned development of new, possibly consolidated facilities and the expansion or abandonment of existing facilities.

2. Detailed studies should be done to determine practical applications of a consolidation policy in the following situations:

a. to clarify the remaining options open to the Exxon/Arco/Aminoil proposed consolidation;

b. to identify and recommend appropriate options for onshore delivery and transportation modes for production from the Santa Clara Unit, Hueneme Offshore field, Pitas Point Unit, Oak Ridge Unit, and San Miguel Unit;

c. to develop a Channelwide production scenario with emphasis on the identification of potential landfalls for all production and the alternative transportation modes for subsequent shipment to market;

d. to develop a schematic production and transportation scenario for the existing lease areas from OCS Lease Sale #35; and,

e. to identify and recommend appropriate options for onshore delivery and transportation modes for the San Pedro Bay unit(s).

FOOTNOTES

1. See Appendix 3 at end of this report for a complete inventory of petroleum-related facilities in the coastal zone.

2. See generally, pages I-163 to I-177 of Volume 1 of United States Department of the Interior, Geological Survey, Final Environmental Statement -- Oil and Gas Development in the Santa Barbara Channel Outer Continental Shelf Off California, 1976. This section does not include marine terminals.

3. See footnote 1.

4. United States Department of the Interior, Bureau of Land Management, Final Environmental Statement -- Proposed 1975 Outer Continental Shelf Oil and Gas General Lease Sale Offshore Southern California (OCS Sale #35), 1975, p. I-183.

5. Ibid., p. I-183.

6. "Lease now, plan later" is a common theme through much of the comments received on the OCS Sale #35 EIS (see Volume 5). This theme was a part of a suit brought by the State Attorney General (Complaint, California v. Kleppe, Civ. No. 75-1943 [D.C., filed November 1975]). This theme was also apparent in the suit which overturned Lease Sale #40 on the east coast (NRDC v. Secretary of the Interior, No. 76C 1229 [E.D.N.Y., February 17, 1977]).

7. The OCS Lands Act confers broad discretionary powers on the Secretary of the Interior in carrying out the general mandate of the Act. To "manage the OCS for the prevention of waste and the conservation of natural resources," the Secretary has authorized the conducting of pipeline corridor studies by BLM for offshore leased areas. Notably, none have been undertaken offshore of southern California.

8. Outer Continental Shelf Lands Act of August 7, 1953, 67 Stat. 462; 43 U.S.C. 133(a)(1), Section 5(a)(1).

9. California Coastal Act of 1976, PRC, Section 30262.

10. 30 C.F.R. 250.1 and 250.11.

11. See for example, Volume 2, pp. 384-400 of Final Environmental Statement -- Proposed 1975 Outer Continental Shelf Oil and Gas General Lease Sale Offshore Southern California (OCS Sale #35), 1975, by the Bureau of Land Management, Department of Labor.

12. If Exxon's four leases in the middle of the Channel were combined with the Oak Ridge Unit, the number of total operating areas would be reduced to 12, and the Exxon/Chevron/Arco group would be the operator of six.

13. In a letter dated July 21, 1976, from Ronald Coleman, Assistant Secretary, Program and Development, Department of the Interior, to Melvin Lane, Chairman, California Coastal Zone Conservation Commission, informing the Commission of the Secretary's decision to allow Exxon to proceed with their "offshore alternative," Mr. Coleman states:

> ...We are greatly concerned over the cumulative impact of OCS development on the coastal resources of California. We believe that we share an objective

with the State of California of getting the Santa Barbara Channel Oil into use by our citizens at the least possible cost, where such cost is reckoned as both environmental cost and cost of economic resources. In this spirit, let me urge the State to undertake a Channel-wide study of the likely scenarios for development of both the state and federal leases and an evaluation of alternative arrangements for handling the oil produced.

Although we concur with the need for such a study, we respectfully disagree with the strategy for preparing it. The Department of the Interior should take a major role in preparing the study, including the funding of it, because they are the landlord of the offshore area to be planned for.

14. See Plate 1: Map Showing Oil and Gas Fields...Final Environmental Statement -- Oil and Gas Development in the Santa Barbara Channel Outer Continental Shelf Off California, 1976, Geological Survey, Department of the Interior.

15. Personal communication to Allan Lind, from R. M. Voils, Western Producing Area Projects Manager, Mobil Oil Corporation, July 28, 1976.

16. Ibid.

17. Personal communication to Allan Lind, from B. C. Peister, Area Supervisor, Phillips Petroleum, July 28, 1976.

18. Letter, dated April 12, 1977, from James B. Anderson, Vice President, Exploration, Pauley Petroleum, Inc., to Allan Lind, OCS Project.

19. U.S. Court of Claims Docket #197-69.

20. Anderson letter, April 12, 1977, op. cit.

21. United States Department of the Interior, Bureau of Land Management, Outer Continental Shelf Off Southern California Oil and Gas Lease Sale #35 Amendment of Sale Notice, November 5, 1975.

22. 30 C.F.R. Part 226, "Unit or Cooperative Agreements."

23. Outer Continental Shelf Lands Act of August 7, 1953, (67 Stat. 462), Section 5 (a)(1).

24. Union v. Morton (1975) 512 F 2d 743, 749, citing Gulf v. Morton (1973) 493 F 2d 141.

25. H. Enzer, "Unitization of Offshore Oil and Gas Operations, Draft," Department of the Interior, Mineral Policy Development Branch, 1974, p. 1.

26. United States Department of the Interior, Bureau of Land Management, Final Environemntal Statement -- OCS Sale #35, 1975, Vol. 2, p. 756.

27. Enzer, op. cit., pp. 49-50.

28. The Oil Daily, July 1, 1976.

29. The Oil and Gas Journal, May 31, 1976, p. 41.

30. Letter dated June 22, 1976, form Hillary A. Oden, Acting Conservation Manager, Western Region, Geological Survey, United States Department of the Interior to the Office of Planning and Research.

31. Ibid.

32. United States Department of the Interior, Geological Survey, Final Environmental Statement -- Santa Barbara Channel, 1976, Volume 2, p. III-43. The most recent design for Platform Henry, submitted in 1975, calls for only 21 wells instead of the original 30.

33. Final approval for this project was obtained by Chevron from the State Lands Commission, September 30, 1976, Sacramento, California. No permit is required from the Coastal Commission.

34. See Chapter 21 for a detailed description of Sun's proposal and its options. In brief, when Sun installed Platform Houchin, they applied for permits to construct a new processing plant on vacant land adjacent to Phillips-La Conchita. This proposal was rejected by Ventura County, resulting in Sun acquiring interest in, and arranging for processing by, the Mobil-Rincon processing plant. Sun's proposal for Henry is to pass produced crude oil and natural gas to Platform Hillhouse for processing and then deliver it to Mobil-Rincon via existing pipelines for sale and transshipment to refineries.

35. During the time that Sun Oil has been in court, from 1969 to the present, some drainage of the Sun portion of the Carpinteria field may have occurred as a result of the continued operation of the Phillips platforms. Sun representatives have indicated to the Office of Planning and Research that if the drainage is significant, it may no longer be economic for them to develop their portion of the reservoir. Sun is currently evaluating an exploratory well to determine the extent of drainage if any. If Sun does not develop its portion of the reservoir, because of the alleged drainage, whatever crude oil that might have been recoverable may be lost. It is not reasonable to expect continued drainage by Phillips platforms to recover the more distant deposits of petroleum in the field.

36. Enzer, op. cit., pp. 29-30.

37. Ibid., p. 30.

38. Letter dated October 7, 1976, from Tom Hudson and others, Chevron USA, Inc., to the Office of Planning and Research.

39. Letter dated March 11, 1977, from T. A. Hudson and others, Chevron USA, Inc., to the Office of Planning and Research, p. 11.

40. Inviolable: "not to be violated, not to be profaned or injured; sacred, ...indestructible...," Webster's New World Dictionary, William Collins & World Publishing company, New York, 1974.

41. Adapted from Unit Agreement for the Development and Operation of the Santa Clara Unit Area, Channel Islands Area, Outer Continental Shelf, Offshore California, Standard Oil Company of California, 1973, p. 2.

42. United States Department of the Interior, Geological Survey, Conservation Division, Pacific Area, OCS Order No. 11, Effective May 1, 1975, Oil and Gas

Production Rates, Prevention of Waste, and Protection of Correlative Rights, Paragraph 16, C.

43. Both the Santa Ynez Unit and the Santa Clara Units encompass two or more structures. The Santa Ynez Unit contains the Hondo field, now being developed, as well as the Pescado and Sacate fields. There has been speculation that a fourth field exists within the Unit further to the west. This field first appeared on a map published in 1969 by the Geological Survey titled, "Map Showing Oil and Gas Fields, Leased Areas, and Seeps in the Santa Barbara Channel Region" (Interior -- Geological Survey, Washington, D.C. -- 1969 -- G70137). On subsequent maps of the same title published by the Geological Survey in 1973, 1974, and 1975, this unnamed field no longer appeared. On a map published by Exxon Company, USA, in 1975, however, this phantom field has reappeared.

44. Personal communication to Allan Lind, from Maury Adams, Staff Petroleum Engineer in charge of offshore operations, Pacific Area, United States Geological Survey, August 19, 1976.

45. Standard Oil Company of California, Unit Operating Agreement for the Development and Operation of the Santa Clara Unit ..., March 30, 1973.

46. Ibid., p. 3.

47. Ibid., p. 10.

48. Exxon Company, USA, "Chronology of Exxon's Efforts to Develop the Santa Ynez Unit," 1976. (An information leaflet, one page.)

49. Personal communication with representatives from Getty, Mobil, Phillips, Chevron, and Arco; various dates between July 1, 1976, and August 18, 1976.

50. The Getty-Gaviota discussion is based primarily on an on-site interview by Allan Lind, with E. W. Mathisen, Operating Superintendent, Pipeline District, Getty Oil Company, July 8, 1976.

51. This analysis is based on personal communication to Allan Lind by Darrell Warner, Exxon Company USA; Jack Hundley, Arco; Coastal Commission staff and the records of pertinent Coastal Commission hearings; Santa Barbara County staff; and the various EIRs published to date on the three separate projects.

52. Dames and Moore, Draft EIR, Proposed Dos Pueblos Marine Terminal, 1976, pp. II-1, II-5.

53. Minutes, Hearing of the Board of Supervisors of the County of Santa Barbara, State of California, September 2, 1975.

54. Appeal No. 163-75 (Platform Holly), California Coastal Zone Conservation Commission, October 1, 1975.

55. Appeal No. 216-75 (Exxon), California Coastal Zone Conservation Commission, March 3, 1976.

56. Ibid.

57. Exxon Corporation, "Issue Analysis (Appeal No. 216-75) for the California Coastal Zone Corporation," October 14, 1975.

58. Analysis based on personal communication, John Herring, Chevron Company, USA; and Draft EIR, Resumption of Drilling ... From Standard Oil Company of California Platforms, Woodward-Clyde Consultants, March 1976.

59. Woodward-Clyde Consultants, Ibid., p. I-21. The report indicates that 24 out of the previous 27 tanker calls, or 88.8%, involved deliveries to Chevron's El Segundo refinery; the balance had as their final destination Chevron's Richmond refinery in the Bay area. This ratio of deliveries to southern vs. northern California refineries is thought to be indicative of the transportation economics for crude oil produced in the Santa Barbara Channel.

60. Analysis based on site visit and personal communication to Allan Lind, by Richard Voils, Western Producing Area Projects Manager, Mobil Corporation, July 28, 1976.

61. Title 30 -- Chapter II, C.F.R. Part 250.68.

62. PRC, Division 20. California Coastal Act, section 30108.

APPENDIX A

According to Enzer, the following plan was suggested to a Department of Interior study group by Exxon in 1974 as one alternative for future exploratory operations in OCS frontier areas. The objective was to maximize the rate at which frontier areas could be leased and explored within projected industry equipment limitations. According to West Coast Exxon representatives, this plan does not represent an official position of Exxon Company, USA.

OUTLINE OF A MANDATORY UNITIZATION PLAN

1. Industry would nominate tracts for sale as they do now. However, they would also be required to submit an outline of the major structures in the area.

2. The Department then selects tracts for sale and designates exploration units which conform to the major structures. A complicated faulted structure may be partitioned into several units.

3. As a condition of the sale, the Department would stipulate that all tracts purchased in each unit will automatically be part of an exploratory unit. The operators would submit a unified exploration plan to the USGS, which will be reviewed with the objective of minimizing the number of exploratory wells required to evaluate the structure.

4. The lease owners would then agree on an operator to drill the exploratory wells at the specified depths and locations. After the initial drilling program was completed, the operators, with agreement by the USGS supervisor, would have the options of dissolving the unit, conducting further exploration of the unit, or moving into a development phase on either an individual lease basis or on a unit basis. At this point some of the operators would have the option of dropping out of the unit and letting the remaining operators continue as a subunit.

The main operating features of the plan are:

a. the Department would stipulate in advance that the costs of the exploration program would be shared on a surface acreage basis;

b. the agreement would provide that a lessee may be relieved of an obligation to participate in the initial exploration program by assignment of his lease to other operators in the unit or surrender of the lease if none of the remaining operators accepts an assignment;

c. as long as the operators are diligently pursuing exploratory or development operations under an approved plan, the leases would be held beyond the primary term;

d. the Department would specify a maximum time for submission of the detailed exploratory plan by the operators;

e. the unit agreement should permit an operator who feels that his tract has not been adequately evaluated to drill a non-consent well at his own expense without forcing him out of the unit; and,

f. lease owners should be allowed to negotiate participation in production based on an oil and gas in-place factor under their respective tracts with adjustments for the difference in the value between oil and gas.

The plan is said to have the following advantages:

a. it requires no change in legislation. Its mandatory unit features insure that exploratory plans will be designed to evaluate entire structures rather than individual leases. This will tend to optimize the number of exploratory wells drilled. However, it also provides industry sufficient flexibility to insure that the structures will be fully and adequately evaluated;

b. it achieves about the same efficiencies as leasing large blocks or entire structures without forcing smaller companies to compete for large blocks; and,

c. while it does not mandate unitization of development and production, it will tend to strongly encourage this.

The plan is recommended for use in frontier areas, such as the Atlantic, Gulf of Alaska, and California Outer Banks. It is not recommended for drainage acreage or where leases already exist as in the Gulf of Mexico and Santa Barbara Channel.

EVALUATION OF THE BENEFITS

After being asked to be more specific as to the potential savings in rig years such a plan might entail, the sponsoring company provided the following examples.

Consider a prospect which underlies ten tracts. Exploratory drilling requirements are estimated assuming first that a hypothetical discovery with eight tracts having productive results, and second that the entire structure is dry. Obviously, the number of wells required to evaluate a structure adequately is highly dependent on its geologic conditions. However, some average data are available. The National Petroleum Council (U.S. Energy Outlook: Oil and Gas Availability, 1973, p. 363) states that between 1954 and 1970 an average of 2.4 exploratory wells per tract of 5,000 acres were drilled in offshore regions. This is an average for dry and productive tracts. The average is heavily influenced by the offshore Louisiana area with its relatively shallow water, low drilling costs, and large number of piercement salt dome prospects. A somewhat reduced exploratory density should be expected in high-cost frontier areas.

Table A1 compares the drilling requirements for the ten-tract prospect assuming eight tracts productive under individual lease and unit operation.

If all ten tracts are purchased by ten separate operators and no data are shared or joint wells drilled, an estimated 24 wells or 2.4 per tract would be required to define the discovery and select platform sites. This would require 2.6 rig years over an estimated four-year period, and cost industry about $38 million.

TABLE A1:
TEN TRACTS -- EIGHT PRODUCTIVE

	WELLS (1)	RIG YEARS (2)	INDUSTRY COST MM$ (3)	ESTIMATED TIME FOR EXPLORATION PHASE
INDIVIDUAL LEASES TEN OPERATORS	24	2.6	38.4	4 years
FRONTIER AREA UNITIZATION	15	1.6	23.3	2 years
SAVINGS	9 (38%)	1.0 (38%)	15.1	2 years

(1) Taking the historical average of 2.4 wells as above average for future frontier exploration.
(2) Based on 40-day, 12,000-foot wells.
(3) Based on $1.6 million/well.

Under the mandatory exploration plan, it is estimated that only 15 wells would be required, one per tract plus five additional wells on the eight productive tracts to define initial platform sites. This results in about a 40% saving in wells and rig years, and completion of the exploratory phase in an estimated two years at a $15 million saving to industry.

Table A2 compares the exploratory requirements for this same prospect assuming it is dry.

TABLE A2:
TEN TRACTS -- ALL DRY

	WELLS (1)	RIG YEARS (2)	INDUSTRY COST MM$ (3)	ESTIMATED TIME FOR EXPLORATION PHASE
INDIVIDUAL LEASES TEN OPERATORS	15	1.6	24.0	2.5 years
FRONTIER AREA UNITIZATION	10	1.1	15.5	1.5 years
SAVINGS	5 (33%)	.5 (33%)	8.5	1.0 years

(1) Taking 1.5 wells per tract as below the average for future frontier exploration.
(2) Based on 40-day, 12,000-foot wells.
(3) Based on $1.6 million/well.

Under individual lease exploration, an estimated minimum of 1.5 wells per tract or a total of 15 would be required. Under mandatory exploration, about 30% fewer wells and rig years are required, resulting in an $8.5 million saving to industry.

It should be emphasized that the above analysis represents a judgment of what savings could be achieved under hypothetical conditions. Actual results will be highly influenced by geologic conditions, leasing patterns, and economic factors. For example, if the initial wells indicated an economically marginal field rather than a clear-cut success or failure, a greater number of exploratory wells might be necessary. However, the relative saving of 30-40% under the frontier area leasing plan is likely to be representative of a wide range of conditions.*

* This last paragraph represents the view of the sponsor of the plan. No applicable published or unpublished statistics could be found to check the estimates by the sponsor of the plan (Enzer, 1974, pp. 10-15).

APPENDIX B

The Coastal Plan considers consolidation in Policy 83c, "Consolidate Drilling, Production, and Processing Sites":

> Petroleum-related facilities and operations shall be consolidated (i.e., drilling, production, separation facilities, and support sites shall be unitized -- developed and operated as a unit by a single company or group of companies for the benefit of all interested companies -- or shall be shared) to the maximum extent feasible and legally permissible, unless such consolidation will have adverse environmental consequences and will not significantly reduce the number of producing wells, support facilities or sites required to produce the reservoir economically and with minimal environmental impacts.... The unitization or consolidation requirements shall apply to (1) all types of offshore platforms; (2) submerged production systems; (3) onshore drilling and production facilities; (4) pipelines; (5) separation, treatment, and storage facilities; (6) transfer terminals related to petroleum production; (7) rights-of-way for transporting produced oil and gas; (8) equipment lay-down areas; and (9) port facilities to supply and service offshore platforms.

The Coastal Act of 1976 provides for consolidation under Section 30262:

> Oil and gas development shall be permitted in accordance with Section 30260, if the following concerns are met:
>
> (a) The development is performed safely and consistent with the geologic conditions of the well site.
>
> (b) New or expanded facilities related to such development are consolidated to the maximum extent feasible and legally permissible, unless consolidation will have adverse environmental consequences and will not significantly reduce the number of producing wells, support facilities, or sites required to produce the reservoir economically and with minimal environmental impacts.

Similarly, the Santa Barbara County Planning Commission advocates as a matter of policy their preference for consolidation:

> Consolidation of facilities on existing sites or on adjacent land will be favored as an alternative to the establishment of new separate sites. 63/

The Department of Interior similarly acknowledges the need for and benefits derived from coordinated planning that could result in fewer facilities:

> In the past the development of oil production facilities in the Santa Barbara Channel (as in most other areas) has been for each lessee (or group of lessees) to develop its own production facilities, pipelines, treatment and storage facilities, and product transportation facilities. This piecemeal approach has had the advantages of versatility, ease of modification, and avoidance of joint-interest projects which are often criticized. It has, however, resulted in proliferation of facilities in the area with duplication of efforts and little overall coordination.
>
> Thus an alternative to the traditional piecemeal development is the coordinated development of all oil production in the Santa Barbara Channel. Such coordination may result in increased costs and increased environmental impact in specific cases due, for example, to the longer pipelines or larger facilities

required, but it would result in lower total economic and environmental costs.

Coordination of efforts and minimization of the number of facilities can be expected to reduce costs (economic and/or environmental) in the areas of pollution monitoring and product transportation. For example, if all production facilities were concentrated in a few centers, this would contribute toward the economic feasibility of building a single large pipeline from these centers to the existing refinery complex in Long Beach. Such a pipeline would result in lower transportation costs (if the volume of oil were sufficient) and would eliminate the danger of oil spills during marine loading, transportation and unloading of product. 64/

FOOTNOTES, APPENDIX B

63. Santa Barbara Planning Commission, "Statement of Policy Relative to the Location of On-Shore Oil Facilities," April 12, 1976.

64. Final Environemntal Statement, Oil and Gas Development in the Santa Barbara Channel..., USGS, Department of the Interior, pp. I-153 to 155, March 4, 1976.

CHAPTER 20

TRANSPORTATION: CROSSING THE WATERS

The means by which OCS oil and gas are transported from production site to treatment and refining facilities is, along with planning for and locating essential facilities, clearly a major determinant of environmental risks and degradation. OCS tracts are currently selected for lease without adequate consideration of whether production from the tract can be safely and economically transported in a manner that minimizes environmental risks. In declaring leases of a recent Atlantic OCS lean sale null and void, federal Judge Jack Weinstein held the opinion that the Interior Secretary had failed to consider the environmental effect of specific, probable pipeline routes from the OCS and had failed to consider the possible results of particular tract selection on the feasibility and siting of pipelines.

Commitments to clean air and the preservation of the marine habitat do not exclude development of the OCS. But the urgency for development of our energy resources should not preclude these concerns. Because of these concerns and because the technology is available and economics would justify such a course, pipeline transport is in theory preferable to marine vessel transport, and should be given thorough consideration.

California's concern over transportation issues has focused on the development of the Santa Ynez Unit by Exxon. An analysis of the capital and environmental costs associated with transportation alternatives available to Exxon appears in Appendix 5 of this report. The following chapter is a generic discussion of how oil and gas are transported, factors affecting the mode of transportation selected, and the benefits and limitations of transportation alternatives. The final part of the chapter discusses the transportation of oil and gas produced from areas other than the southern California OCS and the potential for conflict with future OCS development. This chapter, combined with the preceding Chapter 19, "Facilities Planning," are the building blocks upon which Chapter 21," Development Scenarios," is based.

TRANSPORTATION REQUIREMENTS OF OFFSHORE CRUDE OIL AND NATURAL GAS

The fluids produced from offshore wells contain a mixture of crude oil, water, and dissolved and/or associated gas. They may also contain amounts of hydrogen sulfide, carbon dioxide, and other impurities such as sand. Most existing California OCS platforms, including those in State waters, are equipped for primary gas-oil separation and water removal. The crude produced at the platform must be transferred to a treatment facility to remove emulsified water, gas, and impurities such as sulfur. Natural gas separated from the produced fluids goes to a scrubber on the platform to remove additional liquids. The gas is then sent to a low-pressure compressor where a certain amount of gasoline and LPG (liquid petroleum gas) drop out. For further removal of water, natural gasoline, LPG, and impurities, the gas is transferred to a separate treatment facility. In southern California, crude oil and gas have always been pipelined to onshore processing sites. Only recently have offshore treatment facilities been proposed.

After crude oil and gas are processed, they must be transferred to refineries or to a gas company distribution system. In some instances, a certain portion of the dehydrated gas is returned to the platform for reinjection to maintain reservoir pressure, or retained at the treatment facility as fuel.

ECONOMIC DETERMINANTS OF OIL AND GAS TRANSPORTATION NEEDS

The kinds of transportation available for oil consist of barging or tankering and pipelining. Those for gas are pipelining and LNG operations. The factors considered in selecting the most economically appropriate form of transportation will also affect the location (offshore vs. onshore) of treatment facilities, if new facilities are required. These factors include:

1. size and projected life of the oil field;
2. market value of the oil and gas;
3. rate of production;
4. amount of capital investment required for development;
5. operating costs of the system;
6. distance from the field to the receiving point on land;
7. water depths; and,
8. topography of the ocean floor. 1/

The last three factors involve engineering as well as economic considerations, and they influence the route of a pipeline. Pipeline developers seek the route providing the best combination of least distance from production to onshore treatment facilities, shallowest water, and least hazardous terrain.

Another important consideration is the distance between reservoirs and their distribution within a tract. This distance determines the feasibility of installing gathering lines from platforms to a common trunk line which then carries production to treatment facilities. Gathering lines become more practical the closer production platforms are to one another and the farther they are from shore. Generally, sites close to shore yet spread out laterally have individual pipelines to shore. In such a case it would be more costly to gather the lines into a trunk line.

The size and projected life of the oil fields and their rate of production are major parameters used for development scenarios. They ultimately decide the economic feasibility of the transportation mode to be used. Finally, the amount of capital investment required for development and the operating costs of the system are directly affected by the physical properties of the crude oil. For a discussion of the capital, operational, and environmental costs associated with tankers and pipelines, the reader is referred to the Santa Ynez controversy in Appendix 5.

OIL CHARACTERISTICS AS DETERMINANTS OF TRANSPORTATION MODES

Crude oil characteristics impose constraints on whichever form of transportation is used. These characteristics include specific gravity, viscosity, pour point, wax point, and sulfur content. 2/

Specific gravity is the ratio of the weight of the petroleum product to the weight of an equal volume of water. The specific gravity, or weight of the oil, is a factor in pumping requirements. Crude oil is often described in American Petroleum Institute (API) degrees, ranging from light crude, 40° API rating, to heavy viscous crude, 14° API.

Viscosity measures the resistance of a fluid to flow: highly viscous fluids resist movement through a pipeline. Viscosity of the oil governs the diameter and thickness of pipe, in turn establishing the material and laying costs and fixing the size and number of pumping stations. The viscosity of crude oil can be reduced by heating or diluting it with less viscous petroleum products such as natural gasoline.

Pour point and wax point characterize increasing oil viscosity. The pour point of an oil is the lowest temperature at which oil will flow. The wax point is the temperature at which gas within the crude oil begins to "cloud" and "crystallize."

Sulfur content in crude oil occurs both as compounds (sulfide, sulfates, etc.) and as hydrogen sulfide (H_2S) gas. Each of these have an impact on the disposition and processing of crudes but at different points in the total process. Sulfur compounds are undesirable in oil and must be reduced to acceptable levels for a refinery; hence the choice of destinations for the crude is limited by refinery desulfurization capabilities.

The presence of H_2S gas in crude oil directly influences the technical design and material of a pipeline. Crude oil containing as much as 0.05 cubic feet of H_2S per 1000 gallons, is classified as "sour" and, when combined with water, forms a corrosive fluid which results in the embrittlement of very hard or high strength steels. Pipelines of relatively low strength steels are thus used to carry sour crude. 3/ Commingling high sulfur and low sulfur oil reduces the chances of pipeline corrosion, allowing for the shipment of sour crude without changes in the design or operation of the pipeline system. H_2S gas is often removed from the crude oil at the production site prior to transfer to processing facilities. "Sweet" natural gas is used to absorb the H_2S through direct contact. Platform treatment reduces H_2S in oil (or gas) to levels acceptable for pipeline transshipment, but further stripping at a processing plant is required before shipping companies will accept sour crude for tanker transport.

TRANSPORTATION FROM PRODUCTION TO PROCESSING SITE

Processing plants are located as close as possible to production areas to reduce transportation costs. The costs of transporting unprocessed crude oil by tanker to processing sites is normally prohibitive because the purchaser pays for shipment of emulsified waste water and other impurities as well as the crude oil. Where the transportation costs become too high or if onshore processing facilities are unavailable, oil producers have proposed offshore processing plants, with the transshipment of the processed crude to refineries by tanker (see, for example, Santa Ynez Unit and Santa Clara Unit development proposals).

The choice of whether to process offshore or onshore involves the consideration of many factors, a major one being economics. Platform processing requires fewer and smaller diameter pipelines to shore than onshore processing since the waste water is not shipped to shore with the oil and then shipped back to the platform for reinjection onto the reservoir. Platform space, while expensive, may still be less costly than onshore processing, and it may be the only option if an onshore site is not available. 4/ But while operating costs of offshore processing -- because of more effective use of manpower already on the platform -- may be lower than onshore processing for southern California OCS production, offshore processing, storage, and loading operations remain undesirable because the risks of oil entering the marine environment are greatly increased and because of air quality considerations. Navigational safety may also be reduced by additional unnecessary fixed structures in the OCS.

PROCESSING PLANT TO REFINERY

Fluctuations in crude oil production and demand argue for flexible delivery systems between processing plants and refineries. Under ideal conditions, both producer and refiner prefer a pipeline network. Direct pipelines are preferable because the throughput can be regulated, eliminating the use of tankers and tanker-related storage requirements at the processing end. A pipeline network can also link several processing plants with one or more refineries to allow selective delivery of different crudes or blends of crude as market demand requires. Refineries are always located close to market areas because of higher transportation costs past the refining stage.

NATURAL GAS TRANSPORTATION

All natural gas produced on the southern California OCS must be transported by pipeline from production sites to processing plants for treatment and separation. Where processing sites are not available or the quantities of gas produced are too small to justify a pipeline, natural gas is flared or reinjected into the underlying reservoir. Offshore processing of natural gas discoveries in southern California waters has not proved economically feasible under current technology.

Natural gas is transported to gas companies by pipeline or, in liquefied form, by cryogenic tankships or tank trucks. A vaporization plant receives the liquefied gas, vaporizes it with heat from ocean water, then compresses the gas to a high pressure for entry into the utilities transmission lines.

Liquefaction involves an energy loss and, therefore, is practical and profitable only when large natural gas fields are separated from potential pipeline corridors and at extreme distances (thousands of miles) from customers. Southern California OCS leases are not remote, given this context, nor are the expected quantities of natural gas of a scope to justify the costs of such an operation offshore. Pipelines connecting all leased areas off southern California to mainland gas company transmission lines appear to be feasible given the advances in pipelaying technology projected for the next five years.

A remote possibility exists for a floating liquefied natural gas plant located along the Tanner-Cortes Ridge. Pipelines, connecting both the North and South areas, could run along the ridge to the facility where the produced gas would be treated and liquefied. In order for a floating LNG facility to be economically feasible the combined gas production from both the North and South areas would have to total 400 million cubic feet per day. Alternatively, volumes of natural gas too small to be pipelined ashore or liquefied, can be converted to methanol at a floating gas plant, stored in a moored barge, and then taken to port by transit tankers. Industry experts have concluded that a production rate of 35 million cubic feet per day offshore production of liquefied petroleum gases is a realistic concept. 4a/

POPCO

The Pacific Offshore Pipeline Company (POPCO), a wholly owned subsidiary of Pacific Lighting Company, has proposed an innovative idea: buy as much OCS natural gas as possible directly at the platform and construct the gathering system itself as a Federal Power Commission (FPC) regulated pipeline company. This would obviate the cost of transporting the gas from the platform to an onshore processing plant, while construction of one integrated pipeline collection system would theoretically be cheaper than numerous spaghetti lines. Gas reserves thought too small to be produced by different operators within a lease area because of transportation costs, could be economically transported under POPCO's proposed gathering system, increasing the supply of natural gas to southern California.

HIOS

A similar gathering system is currently under construction in the Gulf of Mexico to tap gas reserves in the High Island area off Texas. The High Island Offshore System (HIOS) will extend 150 miles offshore and have an expected delivery capacity of 988 MMCF/D of gas. Through expansion and additional compressor facilities, the HIOS system ultimately could handle two BCF/D. Unlike POPCO, HIOS is a cooperative of five natural gas pipeline and supply companies. HIOS, however, will carry gas for other companies having interests in nearby gas reserves. In addition to the lateral lines being installed to 35 existing or planned platforms, double side-taps are being placed at intervals along the 67-mile main trunkline. They will allow access for future natural gas production if new discoveries are made, as appears likely. Gathering lines to the trunkline will be constructed separately from HIOS and will be handled by the major owner of each line, with generally two or more partners involved. 5/

PIPELINES AND PIPELAYING

COST OF CONSTRUCTING CRUDE OIL PIPELINES

Based on the actual costs of existing onshore pipelines, the costs of pipe and installation usually constitute over 70% of the investment required to construct an onshore pipeline. Other average costs for onshore pipelines are: land (.3%), right-of-way (2.3%), pipe equipment (8.7%), storage tanks (5.2%), delivery facilities (.7%), and miscellaneous appurtenances (1.3%). 6/ Table 1 gives the range of pipeline construction cost per mile in 1975 for various diameters. In highly urbanized areas of southern California, onshore pipeline costs will differ somewhat from these estimates.

As can be seen from Table 2, offshore pipelines may cost two to ten times as much as same-diameter onshore pipelines, depending on the distance and the water depths encountered, the latter being the chief consideration. As depth increases, pipelines require thicker walls for added strength and reduced buoyancy. An increase of 3/32" in the thickness of the wall of a 30-inch, bare, high-strength pipe raises the costs some $50,000 per mile, or about $90,000 per mile with a 1/8-inch increase in wall thickness on a 40-inch line. Also more sophisticated and expensive pipelaying equipment is required in deeper waters, with consequent increases in installation costs. 7/

TABLE 1:
ONSHORE PIPELINE CONSTRUCTION COSTS/MILE FOR 1975

DIAMETER (INCHES)	RANGE LOW	RANGE HIGH
12	$ 44,909	$ 52,249
16	45,001	121,922
20	101,674	155,982
24	130,939	139,833
30	179,445	414,866

Source: "Pipeline Economics," Oil and Gas Journal, August 18, 1975, pp. 64-82.

TABLE 2:
COMPARISON OF SELECTED ONSHORE AND OFFSHORE PIPELINE CONSTRUCTION COSTS/MILE

ONSHORE				OFFSHORE			
DIAMETER (INCHES)	LENGTH (MILES)	COST/MILE	YEAR BUILT	DIAMETER (INCHES)	LENGTH (MILES)	COST/MILE	YEAR BUILT
10	10.3	$ 59,938	1974	10	10	$531,472	1972
12	6.5	44,909	1973	12	5.1	346,999	1973
16	17.3	50,625	1974	16	16.5	202,184	1973
24	30.7	139,833	1972	24	32.5	306,546	1972

Source: "Pipeline Economics," Oil and Gas Journal, August 18, 1975, 64-82.

FLEXIBILITY IN PIPELINE CAPACITY

The throughput, or capacity, of an existing natural gas or crude oil pipeline is limited to the maximum allowable working stress of the pipeline walls, fittings, and valves. In some cases, capacity can be increased by replacing an existing pump with a larger one or by adding new pumps on the line. A line is normally designed to handle an initial throughput but with capability for increased capacity by the later addition of more pumping stations, as required.

The factors to be considered in designing flexibility into a pipeline are the diameter of the pipe, its thickness and quality (which set the maximum safe pressure), and the spacing and number of pumping stations. For example, a 36-inch crude oil pipeline once proposed by Socal between Estero Bay and Richmond was designed to accommodate throughput rates of 340,000, 420,000, or 570,000 barrels per day, depending on whether two, four, or five pumping stations were put into operation.

The viscosities of fluids to be pumped through the line present another variable for determining the thickness of pipe wall and the horsepower requirements of the pump. Crudes with different viscosities move through pipelines differently; a pipeline designed to accommodate the maximum throughput of a highly viscous crude could conceivably manage an even greater throughput of a less viscous fluid, either by batching or by commingling crudes of varying viscosities. Heaters can also be added to a pipeline to reduce viscosity and increase flow.

Every pipeline has a maximum throughput, and some pipelines do indeed reach design capacity in terms of the number of pumping stations, heating plants, and throughput. If peak production rates are expected to be quite high, it may be more economical to build a second parallel line than to attempt to design for a later increase in the number of pumps and heaters. Ultimately, pipeline capacity is a function of the characteristics of the crude.

PIPELAYING CAPABILITIES

The principal problems of offshore pipelines are water depth and pipe size (diameter and wall thickness). The greater the depth, the thicker the wall must be to resist the bending stresses placed on the pipe. The thicker-walled pipe, however, adds weight and thus increases the bending stresses. Pipe diameter is a

function of throughput. Large finds of recoverable reserves require larger pipe diameters, and this also increases bending stresses on the pipe.

Dramatic improvements in offshore pipelaying technology have helped in overcoming the previously imposed limits of water depth and pipe size. Depths of 200 feet were once considered the upper limit for laying a pipeline of any size. Recently, however, a barge (Brown and Roots Bar 347) has been constructed capable of laying a 36-inch pipe in water 1,100 feet deep. 8/

The maximum depth of pipelines currently in operation is 600 feet (in the North Sea); this depth will be increased to 850 feet when Exxon completes platform Hondo in the Santa Barbara Channel. Experimental pipelines have been installed at depths of 1,000 and 1,200 feet. A pipelaying ship designed with a capability to lay pipe at a 3,000-foot depth is currently under construction. 9/

The greatest depth within any leased tract off southern California is 2,500 feet. Gathering lines linking all leases and central gathering stations would encounter no greater depths, while gathering stations themselves can be located in depths of less than 850 feet for all OCS lease areas. Trunklines connecting the gathering stations with the mainland can avoid depths greater than 1,600 feet.

Proposed tracts for Lease Sale #48 in the southern California OCS, however, would involve depths approaching 6,000 feet. Shell Pipeline Research and Development Laboratory is conducting investigations into pipelining in depths to 3,000 feet and is looking into the feasibility of extending this capability to 6,000 feet. 10/ The trend of recent developments in pipelaying equipment and the goals being set by industry-sponsored research programs indicate that all leased areas off southern California can be serviced by on-bottom pipeline within five years.

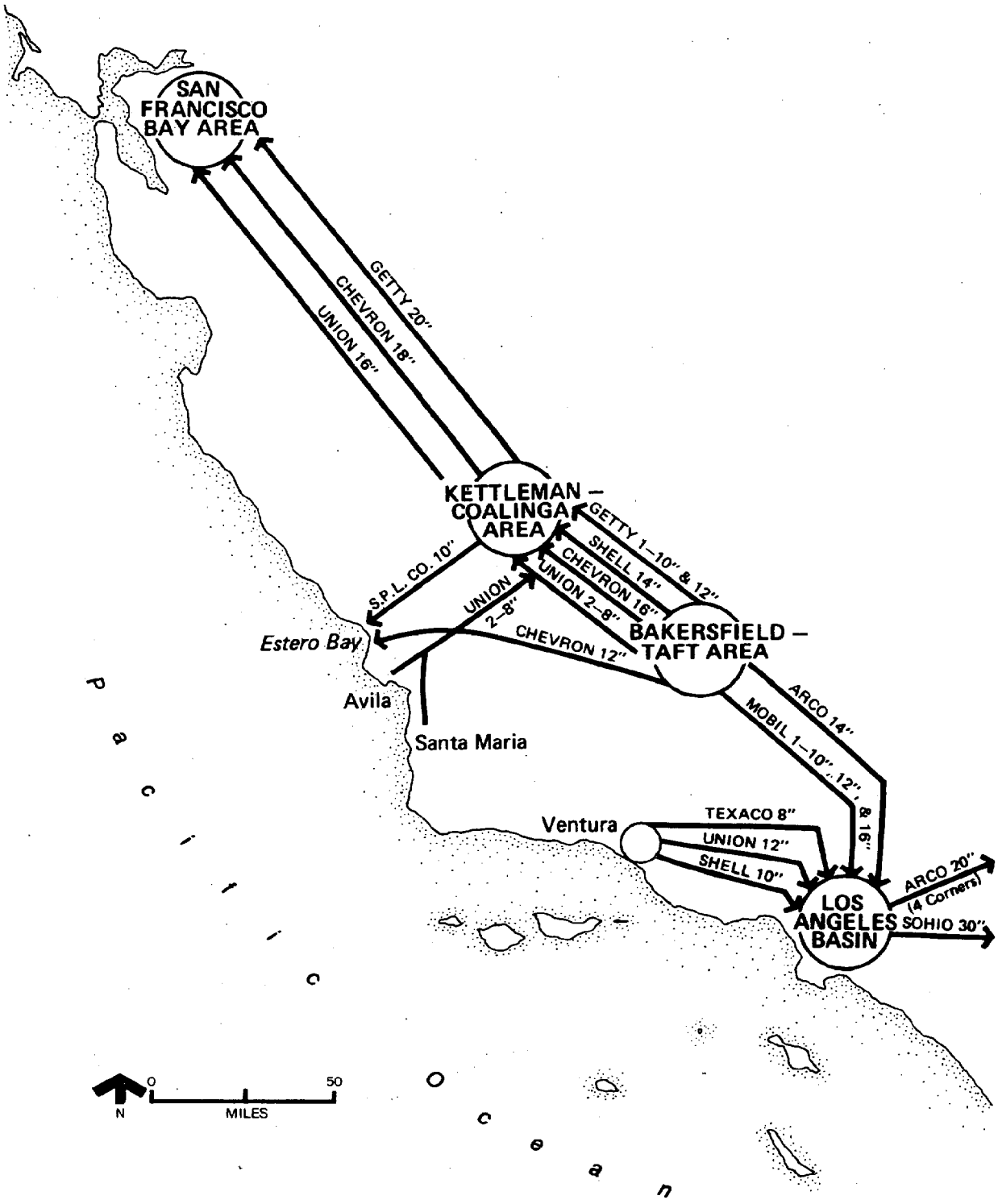
CALIFORNIA'S ONSHORE CRUDE OIL PIPELINE SYSTEM

Little is known about the crude oil pipeline network in California; no public agency has mapped all the crude oil pipelines, let alone determined their ownership, current throughput, surplus capacities, costs, or conditions of use. Some information has become available in these areas as a result of the Joint Industry/Government Working Group's efforts to determine the feasibility of land pipeline transportation of Santa Barbara Channel and Elk Hills crude oil production to replace tanker operations.

Figure 1 shows the known main pipelines distributing crude oil to the state's three refinery centers -- the San Francisco Bay Area, the San Joaquin Valley, and the Los Angeles Basin. This crude oil transportation system is comprised of six major pipeline corridors:

1. the lower San Joaquin Valley to Los Angeles Basin;
2. the valley to the San Francisco Bay region;
3. the Ventura area to the L.A. Basin;
4. a highly integrated and complex network (over 1,000 separate pipelines) in the L.A. Basin moving local production and crude delivered from the San Joaquin Valley, Ventura, Los Angeles, and Long Beach Harbors to the various refineries in the basin;

Figure 1


SAN FRANCISCO BAY AREA
GETTY 20"
CHEVRON 18"
UNION 16"
KETTLEMAN – COALINGA AREA
GETTY 1–10" & 12"
SHELL 14"
CHEVRON 16"
UNION 2–8"
S.P.L. CO. 10"
UNION 2–8"
CHEVRON 12"
BAKERSFIELD – TAFT AREA
ARCO 14"
MOBIL 1–10", 12", & 16"
Estero Bay
Avila
Santa Maria
Ventura
TEXACO 8"
UNION 12"
SHELL 10"
LOS ANGELES BASIN
ARCO 20" (4 Corners)
SOHIO 30"
Pacific Ocean
N
0
50
MILES

5. the central California coast (Estero Bay and Avila Beach) to the San Joaquin Valley, permitting shipment to or from the coast and to the bay region from Estero Bay; and,

6. the Four Corners Pipeline, the only designated common carrier line in California, linking the Los Angeles Basin with the Four Corners area.

In addition, at each producing area there are numerous gathering lines connected to the main trunklines.

Table 3 was compiled from information supplied by trunk line operators in response to a memo from the Joint Industry/Government Working Group chairman requesting data regarding the physical properties of the pipelines and crude oil being transferred. Excess capacity within each of the lines listed in Table 3 will determine the feasibility of alternate inland routes for crude oil transportation of southern California OCS and/or Elk Hills production.

TABLE 3:
PRESENT AND POSSIBLE PIPELINE CAPACITIES*

SAN JOAQUIN VALLEY TO THE SAN FRANCISCO BAY AREA

COMPANY AND SIZE		PRESENT CAPACITY BBLS/DAY	MAXIMUM CAPACITY BBLS/DAY
Chevron	18"	83,000	96,000
Getty	20"	105,000	200,000
Union	16"	59,500	70,000
		247,500	366,000
SAN JOAQUIN VALLEY TO LOS ANGELES BASIN			
Arco	14"	68,000	95,000
Mobil	10"	50,000	50,000
		118,000	145,000
SAN JOAQUIN VALLEY TO AVILA			
Union	two 8"	48,000**	48,000**
SAN JOAQUIN VALLEY TO ESTERO BAY			
Chevron	12"	60,000	60,000
TOTAL		473,500	619,000

*Capacities are based on crude oils produced in the San Joaquin Valley having gravities varying from 14^{0} API (heated) to 25^{0} API (unheated).

**Approximate; exact figures not available.

Source: Letter from John Messer, State Lands Division, to Al Reynolds, Chairman, Joint Industry/Government Working Group, regarding Pipeline Strategy Report -- San Joaquin Valley Trunkline Capacities and Production Trends, April 14, 1977.

Table 4 summarizes the apparent present surplus capacity of trunk lines leaving the San Joaquin Valley. Estimates of the maximum surplus capacity that may be developed with additional pump and heater stations to accommodate viscosity and pressure limitations of the existing lines show that the present surplus capacity of 70,500 B/D can be expanded to 216,000 B/D. These figures are based on the assumption that San Joaquin Valley production (except the Elk Hills fields) will stay at the present rate.

TABLE 4:
AVAILABILITY OF SURPLUS PIPELINE CAPACITY

	BBLS/DAY
a. Current crude oil production in the San Joaquin Valley, including Elk Hills	525,000
b. Current crude oil consumed by San Joaquin Valley refineries	122,000
c. Crude oil leaving by pipeline (a. minus b.)	403,000
d. Present pipeline capacity	473,000
e. Present surplus capacity (d. minus c.)	70,000
f. Maximum pipeline capacity	619,000
g. Maximum surplus capacity (f. minus c.)	216,000

Source: Letter from John Messer, State Lands Division, to Al Reynolds, Chairman, Joint Industry/Government Working Group, regarding Pipeline Strategy Report -- San Joaquin Valley Trunkline Capacities and Production Trends, April 14, 1977.

CALIFORNIA'S ONSHORE PIPELINES ARE PRIVATE

Once crude oil is brought ashore and treated, it is delivered to refinery centers by either pipelines or tankers. California is exceptional among oil-producing states in that all but one of the onshore crude oil pipelines in the state are privately owned and nearly all are operated by major integrated companies. Integrated companies maintain control of their oil from the time it leaves the ground until it is sold as a refined product.

Crude oil carried in private onshore pipelines, however, is not necessarily produced by the parent company owning the lines, nor is it used in that company's refineries. Essentially these pipelines are operated like common carriers, but the pipeline company purchases the crude oil from the producing company at one end of the line, carries it to the other end, and then resells it (possibly to the initial owner or to a competitor). Operators of private pipelines thereby avoid common carrier status in that they transport their own crude oil. This poses certain limitations on the flow of offshore crude oil or any crude oil in that private pipeline owners regulate the costs of the crude oil moving through them and can control access as well.

The major oil companies in California prefer private ownership of crude oil pipelines because it gives them an added measure of control over crude oil marketing. Transportation costs charged by common carrier oil pipeline companies are regulated by the Interstate Commerce Commission (ICC). Tariffs for privately owned crude oil pipelines are not regulated, allowing the pipeline company to set its own price for purchasing crude and reselling it.

In a report of the Joint Committee on Public Domain on "Crude Oil Pipelines in California" (October 1974) the private carrier pipeline system was described as functioning in clear defiance of the State constitution. The report went on to say:

> The major oil companies control the California crude oil market by their ownership and control of the crude oil pipelines. This control artificially depresses prices paid to independent producers and restricts the supply of crude oil to the independent refiners. Starving the independent refiners inhibits competition at the retail products level and results in too-high prices at the gasoline pump. 11/

All attempts by the Legislature and the Public Utilities Commission to eliminate the control private pipeline companies exert over independent producers and refiners have failed.

A common carrier pipeline is desirable to carry OCS production from the Santa Barbara Channel area to Los Angeles refineries because all companies would be guaranteed access at a regulated price. Transmission costs would be competitive with other means of transporting crude oil, if not cheaper. Although common carrier pipelines are desirable, they are not absolutely essential. Channel producers could form a private pipeline consortium that would build and operate a pipeline in the same manner as a common carrier pipeline, and with some assurance given that future producers not part of the original consortium would be allowed access. A common carrier pipeline, however, would eliminate the many problems encountered in trying to get private producers to cooperate and enter into a pipeline agreement. The problem of anti-trust allegations would be avoided as well.

SOUTHERN CALIFORNIA'S ONSHORE NATURAL GAS PIPELINE SYSTEM

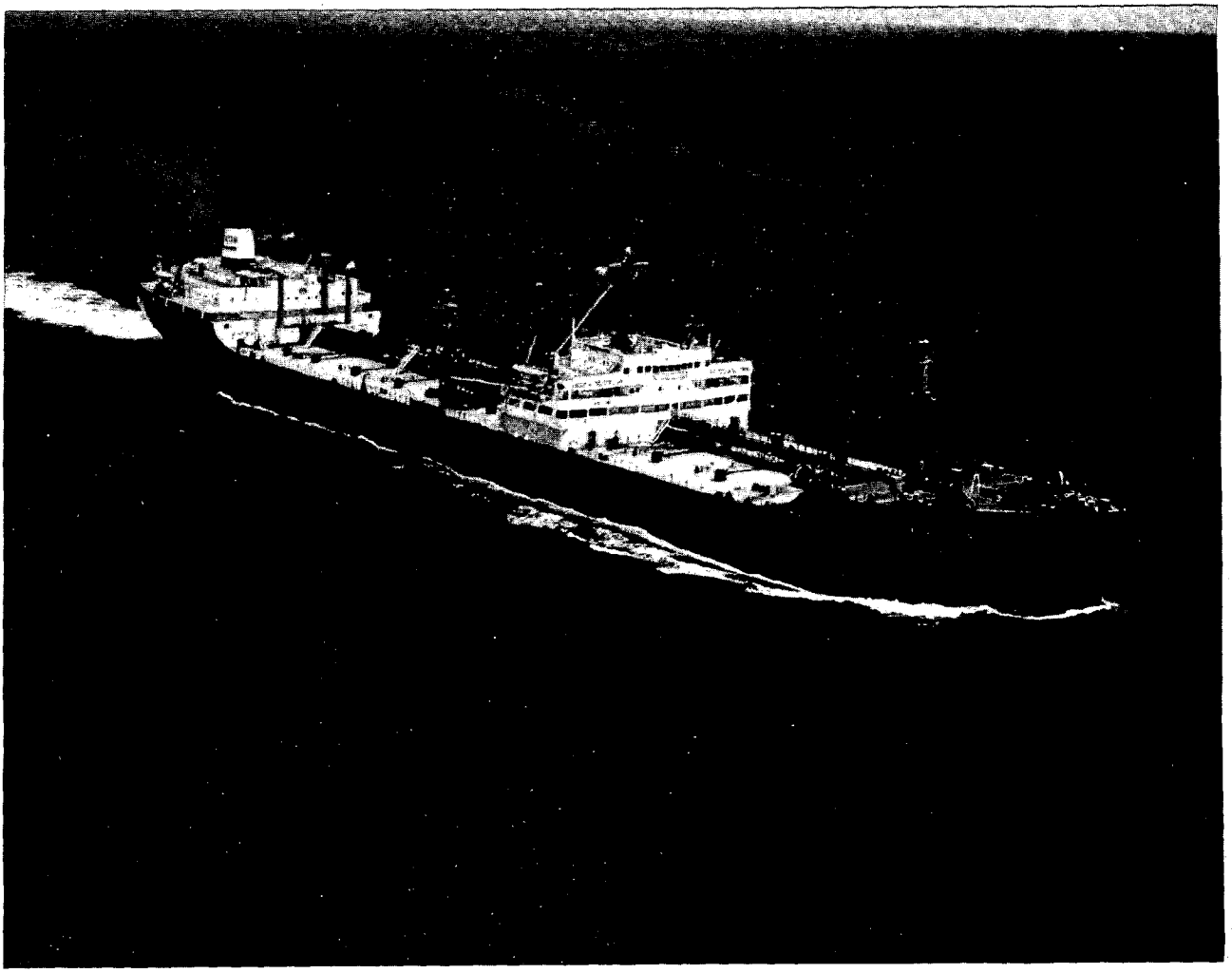
Natural gas pipelines are regulated by the State Public Utilities Commission and are well documented. Several natural gas companies serve the southern California coastline from Point conception to San Diego. Natural gas transmission and trunk lines operated by the various gas companies are within five miles of any landfall between Point Conception and the Mexican border. Engineering feasibility studies may be required before OCS natural gas could be transshipped through these lines, although many of them are known to have the capacity to carry OCS natural gas production. New pipelines may be required if existing lines are not capable of further increases in throughput.

MARINE TRANSPORT

Crude oil produced from the Long Beach-to-Huntington Beach offshore area is delivered to Los Angeles refineries by pipeline, while that produced from the Santa Barbara Channel is delivered to refineries by tankers or barges as well as by pipelines. Tankers are loaded at marine terminals located within the Channel, and the crude is then taken to refineries in Los Angeles or the San Francisco Bay area. The largest terminals are at Ventura and are operated by Getty and Union.

Three pipelines also directly connect ventura with Los Angeles refineries (see Figure 1). A ten-inch pipeline, owned by Shell Oil Company, has an estimated throughput capacity of 51,000 B/D. Union operates an eight-inch line, with an

Exxon Baltimore, a 48,000 DWT tanker suitable for the Alaskan trade as well as coastwise traffic for transporting southern California offshore production. A tanker of approximately this size is proposed to be used by Exxon as an offshore storage and terminal (OS&T) facility for the Santa Ynez Unit (see Chapter 22). (Photo courtesy of Exxon Company, USA.)



18,000 B/D capacity, from Ventura to Torrey Canyon from which point a 12-inch line with an estimated 48,000 B/D capacity extends to Los Angeles. Texaco operates an eight-inch line running east to Fillmore, then south to Newhall, just above Los Angeles, where it connects with other pipelines. The Ventura-to-Fillmore section has an 18,000 B/D capacity, and the Fillmore-to-Newhall line, 33,000 B/D. 12/

A 22-inch pipeline operated by Mobil brings crude oil from treatment facilities south of Rincon Point into the Ventura Marina where it ties in with the Shell and Texaco pipelines. The Mobil 22-inch line is capable of carrying 170,000 B/D. The total capacity of all the lines running out of Ventura to Los Angeles is only 87,000 B/D. When the lines are operating at maximum capacity, tankers are used to deliver crude from Channel producing areas north of Rincon Point and from the marine terminals at Ventura. Tankers are also used between the Channel and San Francisco Bay area refineries because the two areas are not now linked by pipelines.

VESSEL TRAFFIC PATTERNS IN SOUTHERN CALIFORNIA

The majority of foreign and domestic merchant vessel traffic in southern California is confined to legally established vessel traffic lanes from Point Conception to south of the Los Angeles and Long Beach Harbors complex. A study in progress by the U.S. Coast Guard Research and Development Center indicates that traffic within the lanes in the Santa Barbara Channel is as follows:

	Northbound	Southbound
Between Point Conception and Port Hueneme 13/	6.6 Vessels/Day	6.0 Vessels/Day

A common traffic pattern for handling crude oil production in the Channel area has evolved. A tanker originating in Los Angeles, Long Beach, or El Segundo moves via the northbound lane to the Channel, leaving the lane to make calls at the Channel marine terminals, and returns by way of the southbound lane to the Harbors or El Segundo for offloading.

From Port Hueneme to the Los Angeles/Long Beach Harbors, traffic within the shipping lanes increases sharply with the influx of vessels of foreign origin and destinations entering or leaving midway between Port Hueneme and Los Angeles/Long Beach Harbors. Estimates of vessel traffic within this area were compiled by Tetra Tech, Inc., from unpublished data supplied by both the U.S. Coast Guard and the Army Corps of Engineers for the year 1975. 14/ The following numbers include vessel movement to and from the four marine terminals at El Segundo and the Los Angeles/Long Beach Harbors.

	Northbound	Southbound
Between Port Hueneme and Los Angeles/Long Beach Harbors	12 Vessels/Day	10.6 Vessels/Day

Tetra Tech's data for traffic within the Santa Barbara Channel for 1975 showed 6.2 vessels/day northbound and 4.8 vessels day southbound. Comparing these figures with current data supplied by the Coast Guard for the Santa Barbara Channel shows an increase of 6.5% in northbound traffic and 25% in southbound traffic since 1975. Assuming

a similar increase over the same period for traffic between Port Hueneme and Los Angeles/Long Beach, estimated vessel traffic for 1977 would be as follows:

	Northbound	Southbound
Between Port Hueneme and Los Angeles/Long Beach Harbors	12.8 Vessels/Day	13.2 Vessels/Day

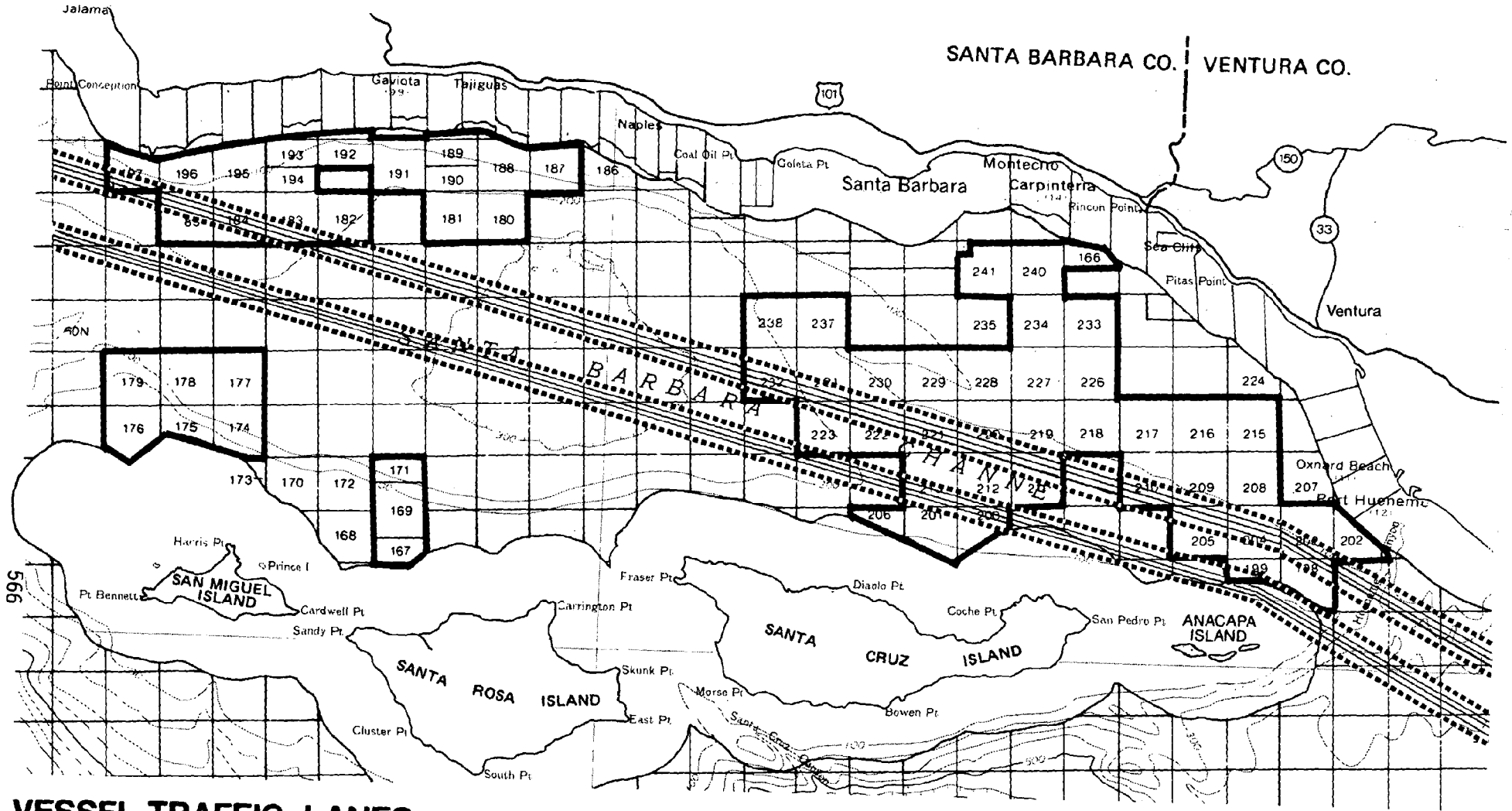
PROJECTED VESSEL TRAFFIC INCREASES CAUSED BY SOUTHERN CALIFORNIA OFFSHORE CRUDE OIL PRODUCTION

If an onshore pipeline is not constructed to deliver Santa Barbara Channel production, as many as 40 new round trips per month can be expected by 1980. New production from South Elwood, Summerland, and Carpinteria offshore fields could add seven round trips per month (assuming development as projected in the related EIRs). The Santa Ynez Unit could add 11 round trips per month (assuming 60,000 B/D ultimate production and an average cargo size of 175,000 barrels). New production from Platforms C and Henry could add five round trips per month from the Union marine terminal at Ventura (assuming all new production is transshipped through that terminal); and new production from the Santa Clara and Hueneme Units could add ten round trips per month. The peak round trip estimates occur at different times between 1979 and 1983 and therefore do not add up to the estimated total of 40 round trips projected to occur in 1980. If pipeline options are not constructed for the Outer Banks areas, an additional 40 round trips per month, or 1.3 round trips per day, for all three areas could occur in 1983, assuming 150,000 B/D are produced from the Outer Banks.

NAVIGATIONAL SAFETY

In the late 1960s and early 1970s the Coast Guard, the Army Corps of Engineers, the Department of the Interior, the U.S. Navy, and shipping and offshore oil interests joined together in developing an effective Vessel Traffic Separation Scheme (VTSS) in certain areas off the California coast to provide a safe and unobstructed navigation route for deep-draft vessels. By separating vessel traffic and allocating the sea space needed for safe entry and exit of vessels at busy ports, the risk of collisions and environmental damage could be minimized. Vessel traffic schemes were established for San Francisco, Santa Barbara Channel, Santa Monica Basin, western approaches to Los Angeles/Long Beach Harbors, and most recently the southern approaches to Los Angeles/Long Beach Harbors through the Gulf of Santa Catalina.

The Pacific Merchant Shipping Association (PMSA) has expressed deep concern over the need to keep the vessel traffic lanes clear of oil drilling structures. In the Santa Barbara Channel, 20 of the 65 active leases are intersected by the designated shipping lanes; and seven of the 13 San Pedro Bay leases intersect the shipping lanes on the southern approach to Los Angeles/Long Beach Harbors (see Figures 2 and 3). Most commercial vessels entering or leaving San Pedro Bay use these lanes. In 1976 the U.S. Coast Guard recorded an average of five vessels per day northbound and 3.5 vessels per day southbound through the traffic lanes in the Gulf of Santa Catalina. These estimates refer to passenger or cargo vessels, tankers, seagoing barges, and Navy vessels with drafts more than 18 feet; they do not include smaller barges, commercial or sport fishing boats, pleasure boats, tugs, research vessels, Coast Guard vessels, or the Catalina ferry. Over 600 of these smaller vessels traverse the waters between Los Angeles and Santa Catalina daily.



VESSEL TRAFFIC LANES:
SANTA BARBARA CHANNEL

Figure 2

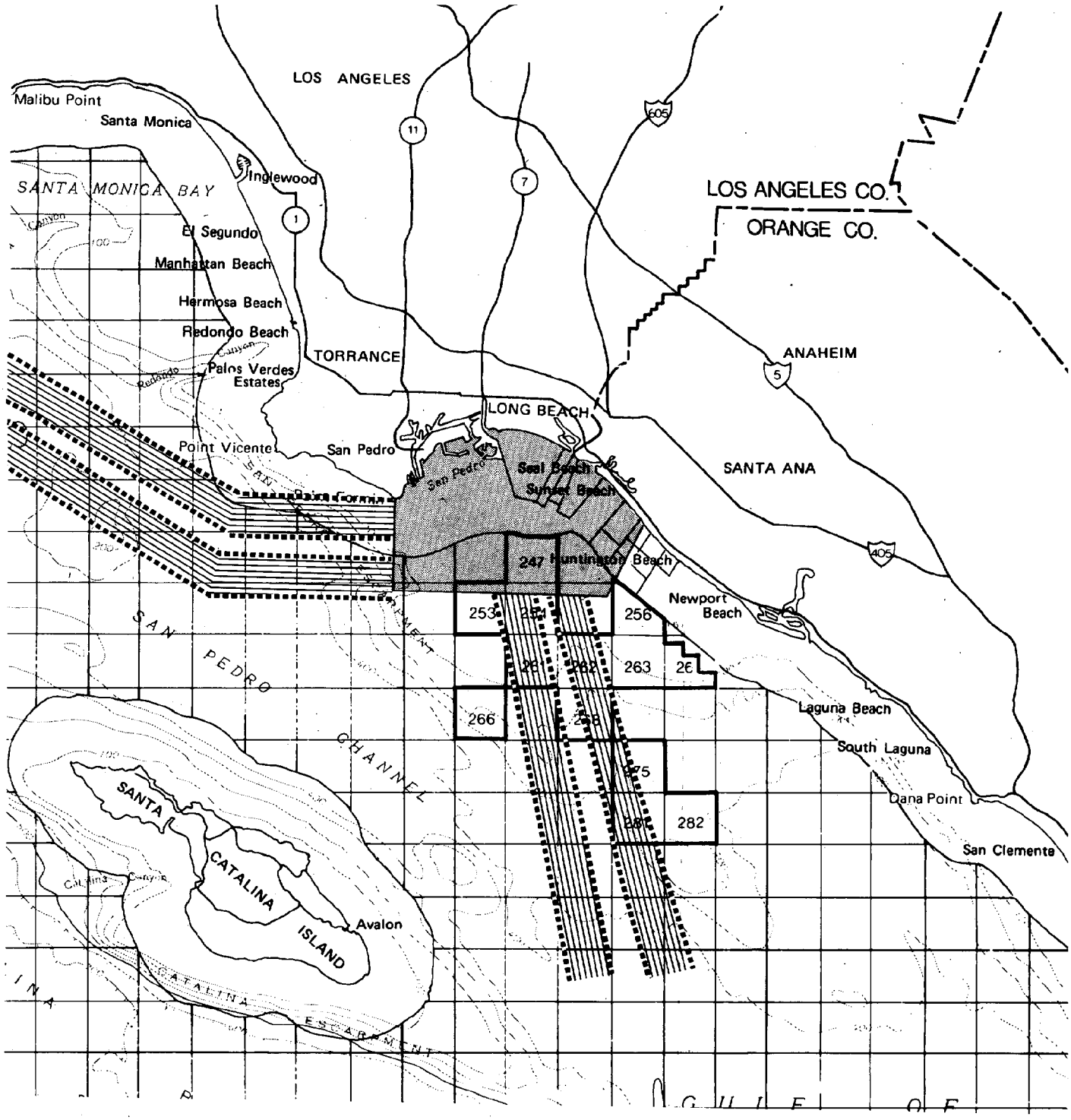
Leased Area

Vessel Traffic Lane

0 3 5 10 KILOMETERS
0 3 5 10 MILES
NORTH SCALE 1:500,000 DEPTH CURVE in FATHOMS
April 1977 California Governor's Office of Planning and Research

OCS Tract 5760 ACRES

OCS PROJECT



VESSEL TRAFFIC LANES: SAN PEDRO BAY

Figure 3

Leased Area

Vessel Traffic Lane

Precautionary Zone

NORTH

0 3 5 10 KILOMETERS

0 3 5 10 MILES

SCALE 1:500,000 DEPTH CURVE in FATHOMS

OCS Tract 5760 ACRES

April 1977 California Governor's Office of Planning and Research

OCS PROJECT

The approach to Los Angeles/Long Beach Harbors was difficult even before oil drilling structures posed new hazards from high traffic density and to sudden fog common at various times throughout the year. Statistics for tanker collisions show that 80% occur in coastal or harbor regions, and 82% occur when visibility is poor. 15/ The only recorded collision involving a tanker in the Santa Barbara Channel occurred in heavy fog just after midnight. These conditions, together with the potential for collisions between commercial and public vessels and oil structures, formed the motivating force behind the development of traffic lanes.

The ships that will be used in the near future for transporting crude oil and LNG to California ports will be much larger, faster, and less maneuverable than vessels currently operating off the coast. Energy-related vessel traffic will be a larger component of vessel congestion as well. These developments greatly compound the need for clear traffic lanes.

The Army Corps of Engineers is responsible for the issuance of drilling permits on the OCS. At the request of the Bureau of Land Management, the Corps issued drilling permits for the seven leases in the San Pedro Bay intersecting the southern approach to the Los Angeles/Long Beach Harbor, although the area had already been set aside, with approval of the U.S. Coast Guard, for vessel traffic. The Corps has ignored warnings from the Pacific Merchant Shipping Association that drilling in these parcels could present a navigational hazard. It is PSMA's position that indiscriminate drilling in waters necessary for safe passage of vessels would undermine the entire concept of traffic lanes and open the door to further encroachment of critical sea space near congested traffic routes off California's coast. Encroachment also places the shipowner in a precarious position regarding his liability in the event of a collision with oil drilling vessels, barges, or permanent structures. There are no recorded ship-platform accidents for the California OCS. However, during the period from July 1, 1962, through June 30, 1971, the Coast Guard recorded 24 incidents of collisions between vessels and fixed platforms in the Gulf of Mexico. Eight of these accidents involved vessels over 1,000 gross tons. 16/

Moving the VTSS is not the solution to avoiding collisions. Use of the VTSS is recommended, not required; the present scheme, however, reflects customary and historic routes for vessels approaching and leaving southern California harbors. Any move of the scheme in the Gulf of Santa Catalina would interfere with the recreational boating traffic between the mainland and Santa Catalina. Exploratory and development facilities resulting from future lease sales will have the possibility of interfering with the VTSS no matter where it is located.

The Coast Guard has urged the Corps to establish a safety fairway across the Santa Catalina VTSS (southern approach to the Los Angeles/Long Beach Harbors). Safety fairway designation would prohibit the installation of any fixed structures in the vessel traffic lanes, including platforms or movable drilling rigs. Such a move would not preclude production from oil and gas reserves in OCS tracts intersecting a safety fairway, since slant drilling operations could be used. Standard Oil of California and Shell Oil have encountered oil-bearing sands in their San Pedro Bay tracts within the Santa Catalina VTSS, at depths below 2,900 feet. If other San Pedro Bay prospects lie at equivalent depths, then all tracts could be explored from a drilling vessel lying outside the 5,280-foot-wide traffic lanes, using slant drilling at an angle of less than 45 degrees. Such slant drilling operations are well within the oil industry's present capability.

The Corps has issued a public notice (Federal Register, Vol. 41, No. 198, October 12, 1976) establishing rules and regulations for permits for exploratory drilling operations in the Pacific Ocean at the Gulf of Santa Catalina. The proposed regulation would establish an eight-nautical mile buffer between an exploratory

vessel in a lane and the nearest fixed structure in the same direction of traffic, and a 3,000-yard buffer in all other directions. There are no restrictions proposed on the siting of exploratory vessels in the separation zone between the lanes. This can only be regarded as a gesture by the Corps and a rather small one since it applies only to exploratory drilling in the Gulf of Santa Catalina. The entire process of establishing regulations would have to be repeated for guidelines applicable to fixed production platforms, and for areas other than the Gulf of Santa Catalina. It may be years before such final regulations are adopted. In the interim, the efficacy of the Vessel Traffic Separation Schemes in the Santa Barbara Channel and Gulf of Santa Catalina will have been seriously impaired by fixed production platforms.

ENVIRONMENTAL RISKS: TANKERS VS. PIPELINES

Statistical comparisons between tankers and pipelines, in terms of oil spill probability, consistently favor the use of pipelines for transporting southern California OCS production. Oil spill potential is believed to be a function of the opportunities for spills to occur; the opportunities are clearly greater for tankers. Tankers and barges distribute oil to the marine environment in several ways: oil discharges from bilge pumping, ballasting operations, tank cleaning, dry docking, terminal operations, and fallout from exhaust stacks. Aside from these normal operations and accidental releases of cargo and bunker fuel, tankers and barges are exposed to numerous risks that result in oil spills. For example, incidents can occur as a result of structural failures, rammings, groundings, collisions, breakdowns, fires, or explosions. Each vessel operating off the southern California coast faces the probability of one or more of these occurrences. Additionally, and perhaps most significantly, the loading and unloading of tankers and barges increases the handling of crude, further raising the number of opportunities for a spill. Finally, tankers or barges depend more heavily on storage facilities because of their periodicity, than do pipelines. This storage requirement is another source of oil spill potential as well.

Marine transport of OCS production involves numerous opportunities for mishap and disaster that are multiplied with each tanker or barge visit over the entire lifetime of a producing area. In contrast, pipelines present a singular, albeit constant, risk. Throughout the history of pipeline usage for crude oil and natural gas transport, both on and offshore, the incidence of pipeline leaks resulting from structural failure or installation errors is almost nil. Most pipeline accidents are directly attributable to external damage or rare and infrequent natural phenomena.

Prior to 1970, several pipelines in the Gulf of Mexico were damaged by anchors, resulting in large quantities of spilled oil. Since then the Bureau of Land Management has required all new pipelines be buried in at least three feet of cover in areas less than 200 feet deep. Where pipelines cross shipping fairways and anchorages, they must be buried at least 10 feet. The Office of Pipelines Safety (OPS) has required that pipelines be coated with tightly bonded, moisture-impervious material to prevent corrosion. OPS regulations also require continuous line pressure monitoring with some type of communication system (a built-in alarm or automatic shut-down system), and regular inspection of the pipeline route for leaks and other irregularities.

Most spill factors for pipelines are derived from historical OCS spill data, a large portion of which comes from OCS operations in the Gulf of Mexico. Such factors, therefore, have limited applicability for future OCS development in the Pacific in that they do not reflect the improvements mentioned above. Had the present regulations governing pipeline design and placement been enforced at the beginning of offshore pipelaying, spill factors for pipelines would be significantly lower than those currently based on historical performance.

Other studies often use worldwide data for selected years to determine spill factors for tankers. This too results in artificially high spill projections for future OCS transportation activities, depending on the sample years selected. Tanker casualties in one year could be either abnormally high or low as a single spill like the Torrey Canyon can distort the statistical distribution of spill magnitude. Spill factors from such years do not reflect the vessel traffic situation encountered over the production lifetime of an area.

In its critiques on the Bureau of Land Management's Draft EISs for Lease Sale #35, Oil and Gas Development in the Santa Barbara Channel OCS, Dames & Moore cited several studies based on worldwide data which placed the emission rate for tankers between 127 ppm to 165 ppm of the total oil carried. These studies also indicated that open-ocean spills (beyond 50 miles) tend to be over three times as large as those in coastal areas (within 50 miles of land). Most of the open-ocean spills resulted from structural failures caused by extreme sea and weather conditions. 17/ Dames & Moore therefore felt that because conditions off the southern California coast were not comparable to those in many parts of the open ocean, an appropriate spill factor for the southern California OCS should be based on casualties within 50 miles of land. The following table compares the Dames & Moore spill factors with those presented in a report by the Council of Environmental Quality.

TABLE 5:
BARRELS SPILLED PER MILLION BARRELS HANDLED WITHIN 50 MILES OF LAND

SPILL SOURCE	CEQ	DAMES & MOORE
Tankers	160	88
Pipelines	110	13

CEQ's rates were derived from historical data and therefore lack assumptions about improved technology and stricter regulations. Their high emission rate for pipelines stems from those accidents which occurred in the Gulf of Mexico. Tanker emission rates were derived with no distinction being made between spills in the open-ocean and coastal waters. Dames & Moore's rates incorporated these considerations and therefore are lower than CEQ's. With these allowances, pipelines are safer to use by almost a factor of 7.

Surface transport of crude oil is necessary and acceptable over great distances. But to use tankers and barges as shuttlecrafts for transporting local production to separation and treatment facilities, and to refineries, is to risk environmental harm unnecessarily. This is especially true when pipelines are technically and economically feasible. Future OCS leasing policy should enhance the economic advantages of pipeline transportation through tract selection and permit conditions. The cost of pipeline transport is at a minimum when the pipeline operates continuously at full capacity. Permit conditions can be used to coordinate the development of lease areas, optimizing the operating costs of a pipeline. Proper tract selection is important as well to insure that the amount of recoverable reserves within a lease area is sufficient to justify the use of pipelines.

EXTERNALITIES: ALASKA, ELK HILLS, AND INDONESIA

The future transshipment of Alaskan oil and LNG, Indonesian LNG, and possibly of Elk Hills oil could significantly increase the amount of tanker vessel traffic passing through the Santa Barbara Channel and off the southern California coast, depending on the final destinations approved for each proposal. Marine traffic resulting from southern California OCS development will have to merge into existing traffic flow and contend with the increasing likelihood of vessel collision. The following discussion gives the projected traffic volumes that can be expected if onshore receiving terminals for handling Alaskan oil and LNG and Indonesian LNG are built as planned, and if Elk Hills oil is delivered to Port Hueneme.

ALASKAN OIL

Six companies share in the crude oil produced at Prudhoe Bay -- Exxon, Arco, Union, Phillips, Mobil, and Standard Oil Company of Ohio (Sohio). Sohio has a 54% ownership of the crude produced, Exxon and Arco each have 20%, and Mobil and Phillips have approximately 3% each. Sohio alone has submitted plans for disposition of the oil in California. The Arco fleet will serve the company's 96,000 B/D refinery at Cherry Point, Washington, then move south to the Los Angeles Basin. Shell, which owns a small percentage of Prudhoe Bay crude, plans to move its share to Shell refineries at Martinez in the San Francisco area and Wilmington in the Los Angeles area. Mobil also plans to bring crude from Valdez to Los Angeles, where the company has a refinery at nearby Torrance. 18/ Given the lack of information about the transport of oil from Valdez to California ports by the other Alaskan interests and conclusions about additional tanker traffic off southern California would be merely speculative.

Sohio proposes to bring 700,000 B/D of Alaskan crude oil to Long Beach. The projected tanker fleet is a mix of four 80,000 DWT, three 120,000 DWT, and four 165,000 DWT ships. The crude would be offloaded at a proposed common carrier, deepwater tanker terminal in the Port of Long Beach. From the terminal the crude would move through a new onshore common-carrier storage surge facility developed by Sohio, then be transported to Midland, Texas, by a proposed common carrier pipeline. If the proposed Alaskan crude oil terminal is constructed in Long Beach Harbor, all of the Alaskan tanker traffic between Long Beach and Valdez will pass through the Santa Barbara Channel.

The 11 Sohio vessels alone will be making a total of 267.3 port calls per year at Long Beach. Should the flow of crude through the Alaskan pipeline be doubled, Sohio expects to increase its southbound tanker volume to 1,200,000 B/D and add six 165,000 DWT ships to its fleet. Thus by 1982 a Sohio tanker fleet of 17 ships could be making 408 annual trips moving between Valdez and Long Beach. 19/

ELK HILLS OIL

The Naval Petroleum Reserves Production Act of 1976 authorized the development of certain national petroleum reserves. The act specifically directs the Secretary of the Navy to acquire or construct by April of 1979 the facilities needed to ship not less than 350,000 B/D of crude oil from the Naval Petroleum Reserve at Elk Hills in the San Joaquin Valley to unspecified marketing terminals. Several transportation options are being considered:

1. Elk Hills to Port Hueneme via pipeline with further distribution by tanker;

2. a crude oil pipeline from Elk HIlls to connect with either a Getty, Union, or Chevron pipeline at Coalinga, using excess capacity as available;

3. Elk Hills to Redlands via pipeline connecting to a 42-inch portion of the proposed Sohio pipeline; and

4. a railroad/truck tank car system for transport to appropriate marketing facilities. 20/

The most desirable route from a marketing standpoint appears to be the Redlands connection to Sohio's proposed west-east pipeline. If the Sohio line cannot be completed by the 1979 date, to which the Navy is committed, it might be necessary to build a pipeline from Elk Hills to Port Hueneme. The Navy presently holds an option on an Arco 20-inch gas pipeline extending from the Southern California Edison Mandalay Beach steam plant near Ventura to the Cuyama Valley. The Navy would have to convert the line to carry crude oil and then build two connecting 20-inch pipelines -- one from Cuyama to Elk Hills, the other from Ventura to a tank farm to be built at Port Hueneme.

The Navy wharf facilities at Port Hueneme are limited to 35,000 DWT tankers or smaller because of the maximum harbor draft of 35 feet. Dredging would lower the harbor depth, increasing the maximum draft vessel that could be accommodated. If 35,000 DWT tankers are used, it has been estimated that an average of one tanker every 19 hours would be loading to transport 200,000 B/B through Port Hueneme. 21/ The use of larger tankers would, of course, reduce the number of visits. Alternately, if production rates of 350,000 B/D are not achieved (as considered likely), the number of tanker visits will be less. If Elk Hills production is delivered to Port Hueneme, vessel traffic through the Santa Barbara Channel, and from Port Hueneme to the Los Angeles/Long Beach Harbors will increase.

L N G : A L A S K A , I N D O N E S I A

Three major proposals to transport LNG by cryogenic tanker to southern California for regasification and distribution are currently being considered. Two proposals concern the transportation of the natural gas recovered from Alaska. The El Paso/Alaska System proposal would deliver LNG to a loading and receiving terminal to be built at Point Conception, located at the northern end of the Santa Barbara Channel. The Pacific Alaska LNG Company proposes to deliver its LNG to a receiving terminal in the Los Angeles Harbor. The third source of LNG to southern California involves a proposal by the Pacific Indonesia LNG Company to import LNG from Indonesia to Oxnard.

Each of the three regasification facilities would be constructed and operated by the Western LNG Terminal Company, with a design capacity of four BCF per day. Use of the three proposed facilities is to occur in phases until design capacity is reached. The El Paso/Alaska receiving terminal at Point Conception would expect 308 annual visits from cryogenic tankers. Annual visits to the LNG facility at Oxnard would start at 75, and at 52 for the Los Angeles site. At design capacity, each LNG terminal would receive between 425 and 565 tanker visits annually. 22/

Clearly, if all the LNG proposals were approved and operating at design capacity by 1981, future vessel traffic patterns off the southern California coast and within the Santa Barbara Channel would become seriously congested. Again, if LNG terminals were constructed at Oxnard and/or Los Angeles Harbor, all LNG deliveries from Alaska and Indonesia would be by way of the Santa Barbara Channel. If only one LNG terminal is constructed and placed at Point Conception, the Channel itself will not experience increased vessel traffic from the importation of LNG.

Given the maximum projection for vessel traffic from each of the sources discussed above, the following table summarizes the number of daily trips that could be expected.

TABLE 6:

SOURCE	ROUNDTRIPS PER DAY	REMARKS
Crude oil from Valdez to Long Beach	1.1	Assumes 1,200,000 B/D and mean tanker size of 136,825
Elk Hills oil from Port Hueneme to Los Angeles/ Long Beach Harbors, or San Francisco	1.3	Assumes 200,000 B/D and average tanker size of 35,000 DWT
LNG from Alaska and Indonesia to Point Conception, Los Angeles/ Long Beach, and Oxnard	3.5 - 4.6	Assumes each facility is operating at design capacity of 4 BCF per day

While the possibility of all the above scenarios developing to maximum capacity may seem remote, the fact that vessel traffic off the southern California coast will substantially increase by the year 1981 as a result of energy-related developments is irrefutable. Measures have been taken to protect the southern California coast from unnecessary environmental risks associated with an increase in vessel traffic. The Commander of the Eleventh Coast Guard District, R. I. Price, requested that the U.S. Army Corps of Engineers designate as a Safety Fairway the Traffic Separation Scheme between Point Conception and Point Fermin, thus excluding encroachment by oil production platforms into shipping lanes. The Coast Guard has also recommended a helicopter surveillance of the Santa Barbara Channel to police adherence by all vessels to prescribed traffic lanes. Attention has also focused on the feasibility of consolidating LNG operations. A consolidated LNG facility would help to reduce traffic within the Santa Barbara Channel only if it were located at Point Conception or at a location north of there.

FOOTNOTES

1. California State Lands Commission, State Lands Division, Oil and Gas Development, Santa Barbara Channel -- Southern California OCS, September 1976, Sec. III, p. 1.

2. Ibid., p. 2.

3. Ibid., p. 5.

4. Letter from L. P. Haxby, Shell Oil Company, to Richard Hammond and Suzanne Reed, March 11, 1977.

4a. The Oil Daily, June 2, 1977, "Offshore Methanol, LNG Production is Predicted."

5. Leonard Leblanc, "HIOS Contractors Shoot for November 1 Start-Up," Offshore, February 1977, 43-47.

6. Robert C. Ewing, "Pipeline Economics," The Oil and Gas Journal, August 23, 1976, 80.

7. Douglas Bynum, Jr., "Here's a quick, easy method to design a system for higher efficiency," Offshore, February 1977, 82.

8. Robert C. Earing, "Subsea pipeliners' know-how gets the job done," The Oil and Gas Journal, January 3, 1977, 48.

9. U.S. Department of the Interior, Pipelines and Outer Continental Shelf Oil and Gas Production, October 27, 1976, p. 3.

10. Booz-Allen & Hamilton, A Risk and Cost Analysis of Transporting Southern California Outer Continental Shelf Oil, for the U.S. Environmental Protection Agency, July 3, 1975, p. II-6.

11. Joint Committee on Public Domain, Ken Cory, Chairman, Crude Oil Pipelines in California, October 1976.

12. Ibid., pp. 56-57.

13. Letter from R. I. Price, Rear Admiral, U.S. Coast Guard Commander, to Richard Hammond, March 22, 1977.

14. Tetra Tech, Inc., Environmental Assessment Report, Crude Oil Transportation System: Valdez, Alaska to Long Beach, California, Appendix B, Oil Spill Analysis, p. B-7.

15. Margaret Cashman, "Tankers will be safer in the future," Ocean Industry, March 1975, 44.

16. U.S. Department of the Interior, Bureau of Land Management, Final Environmental Statement, Proposed 1975 Outer Continental Shelf Oil and Gas General Lease Sale Offshore Southern California (OCS Sale No. 35), Vol. 2, p. 77.

17. Ibid., Vol. 3, p. 639.

18. Howard M. Wilson, "Beefed-up tanker fleets readied for North Slope oil," The Oil and Gas Journal, June 14, 1976, 25.

19. The Port of Long Beach and the California Public Utilities Commission, Draft, Environmental Impact Report, Sohio West Coast to Mid-Continent Pipeline Project, Vol. 3, Part 3, Sec. I, p. 5.

20. Ibid., Vol. 3, Part 2, Sec. III, pp. 158-159.

21. URS Company, Draft Environmental Impact Statement, Crude Oil Transport Alternates From Naval Petroleum Reserve No. 1 Tupman, California, Part Two Elk Hills/Port Hueneme Conveyance System, for the Department of the Navy, Naval Petroleum and Oil Shale Reserves, Washington D.C., 18 April 1977, Sec. 1, p. 25.

22. California State Lands Commission, California and the Disposition of Alaskan Oil and Gas -- A Working Paper, June 1976, Ch. VI, pp. 5-11.

CHAPTER 21

DEVELOPMENT SCENARIOS: WORKS IN PROGRESS

As a guide to the potential range of effects and of possible onshore facilities, this chapter describes the timing and extent of OCS-related development on existing leases and in areas that may be leased as a result of Proposed Lease Sale #48. The choices for OCS development appear here as scenarios describing activities that could take place, from the point of lease sale through exploration, development, production, processing, and transportation of crude oil and natural gas. The scenarios present choices for OCS development because continued OCS development off southern California is inevitable: two platforms have been installed within the last year; two development plans are currently being prepared; as many as eight exploratory vessels have been working at one time; over one billion dollars has been spent to acquire the offshore leases; and, over 200 million dollars has been spent exploring and developing these leases. The possibility of buying back these leases is remote at best: four times under the Nixon Administration attempts were made in Congress to buy back certain leases in the Santa Barbara Channel and each time they failed. It would be naive to believe that future OCS development on existing leased tracts can be prevented, but it is equally naive to believe that such development will automatically meet local and State concerns for environmental protection expressed in this and numerous other documents. These scenarios, therefore, are seen as a way of integrating many otherwise separate projects in order to avoid unnecessary environmental risks.

Use of scenarios which anticipate potential conflicts in the process of estimating the scope of future development permits OCS proposals to be evaluated from a broad perspective; individual projects need not be considered as if each were an isolated event. Thus, the scenarios presented here are to be seen as illustrative, depicting a set of reasonable options for future OCS development that fit within a broader framework of feasible offshore and onshore opportunities. When these choices are considered as a whole, transportation and processing options emerge as the major opportunities for lessening environmental impacts and for reducing costs -- both the production costs of industry and the infrastructural costs of the coastal communities involved.

These descriptive scenarios are, however, necessarily limited by the amount of available information and by the unpredictability of numerous variables affecting OCS activities -- for example, the supply of exploratory vessels; the availability of production platforms; delays caused by moratorium, governmental regulation, or litigation; corporate decisionmaking on capital expenditures in a given area;

the need to balance regional energy supply and demand; etc. A hypothetical scenario demonstrating the sequence of exploration and development and the inherent difficulties in predicting this sequence with precision is described in the passage below, quoting a letter to the Office of Planning and Research from an industry representative. The field unit under discussion in the letter encompasses more than one prospect and drew considerable interest at the time of the Channel lease sale. The industry spokesman writes:

> Let us assume than an evidently commercial discovery is made at or above the 9,000-foot required depth. Our next obligation would be as soon as possible to file for the approval of the USGS a second exploratory plan of operation as provided in Sec. 10.1 of the Unit Agreement. This plan could conceivably require the drilling of two to four or five wells to delineate the producing structure and to assure ourselves of the number and type of platforms required and amount of capital necessary. Following the delineation of the field which would, if the wells were successful, obviously be an accelerated drilling program using one or perhaps more than one drilling vessel, we would submit a plan of operation for the development of this proven sector of the unit. The plan of development would be a rather comprehensive one calling for the construction and emplacement of a platform or platforms. It is to be hoped that by that time the environmental impact procedure would be somewhat narrowed from what it is today, so that instead of opening the subject to consideration of matters that already have been largely resolved in the Santa Barbara Channel area, these hearings would involve only the alternatives of handling production and processing of the oil and the associated impacts to be borne by the outlying communities as the result of such a volume of additional oil. After the conclusion of the NEPA procedure, a contract for the construction of platforms would be let for the reason that the size and sophistication of such platforms would not be known at any earlier time. After platforms had then been constructed and placed on location, then only would development drilling begin.
>
> Under any circumstances, it does not appear that production could be initiated in less than four (4) years from the date of discovery, and it is realized that in making this estimate there would have to be some emergency or urgency for the resolution of the many questions involved in such a short time. A more realistic estimate would, no doubt, be five (5) years after the date of discovery that production could begin. Again, after production commences, it would take an appreciable time before say 50 or 60 wells could be completed if the oil-bearing structure indeed proved to be that large. The production curve would probably peak at or about the time the field became fully developed. 1/

Recognizing the limits to and the inherent difficulties in predicting the timing and extent of future OCS-related development, this chapter adopts a conservative view towards the changes that could take place. That is, speculation for areas having proven recoverable reserves is presented with considerably more specificity than for those areas of relatively unknown potential. Rates of production (assuming reasonable time sequences for development) have been projected

only for those discoveries having estimates for recoverable reserves. Other discoveries are described in terms of possible range of production.

The scenarios are generally presented in a descending order of degree of reliability, those with most information available appearing first. They are also grouped into four categories: those for fields already in production; those for leases with discoveries but not yet in production; those for leases without discoveries; and, unleased areas that may be offered in Lease Sale #48. The fields or areas reviewed are as follows:

Fields in production
1. Carpinteria Offshore
2. Dos Cuadras

Leased areas with discoveries (but no production)
3. Santa Ynez Unit
4. Hueneme Offshore
5. Santa Clara Unit
6. Pitas Point Unit
7. San Pedro Bay

Leased areas without discoveries
8. Oak Ridge Unit
9. San Miguel Unit
10. Santa Cruz Leases
11. Outer Banks

Unleased areas that may be offered in Lease Sale #48
12. Santa Barbara Channel
13. San Pedro Bay
14. San Diego Coast
15. Outer Banks

The summary below predicts OCS development for the next several decades. Most readers concerned with southern California OCS development in general should find this summary adequate for their purposes, while the scenario section that follows the Summary is provided primarily for corroborative detail and for decisionmakers who must ultimately piece together the many separate developments into a logical whole. To those who would read the scenarios in their entirety, we caution with the words of our editor who wrote after reviewing an earlier draft: "I accept that this extended analysis is basic to the report, a necessary pro forma exercise. But it must also be accepted that few, if any, will read through what is inevitably a tedious recital, Byzantine in complexity and redundant in concept." 2/.

In addition to the summary below, all of the development choices -- and the recommendations of this report regarding those choices -- are capsulized in Chapter 11. Appendix 2 of this report provides a detailed explanation of how production rates and estimates of recoverable oil and gas were derived. Finally, Appendix 3 provides extensive information on each of the existing facilities in the scenarios.

SUMMARY

Provided on the following pages are several figures that graphically illustrate the principal findings and conclusions of the scenario studies.

Figure 1 shows all existing leases off southern California, with estimates of economically recoverable resources for each leased area. To qualify these estimates properly, the reader is referred to Chapter 14 wherein sources, methods of derivation, and reliability of the numbers are discussed. Here, we must stress that these estimates are, for the most part, of undiscovered resources (with the partial exception of the Santa Barbara Channel) and should not be taken literally as oil and gas waiting for the right moment to come ashore. Rather, these resources must still be discovered within the geographic areas suspected of containing them. Once discovered, they must be further explored, delineated, and tested to determine if they can be economically recovered. Finally, those discoveries found to be economical must pass the tests of regulatory authorities concerned with the safety of offshore operations before these resources can be produced. The importance of Figure 1 is to provide a sense for the volumes of potentially recoverable resources in each leased area.

In Figure 2 we show routes for pipelines that combine the best fit between least distance, shallowest water, and available onshore facilities for transporting crude oil and natural gas to shore. Chapter 20 discusses OCS pipeline routing criteria and state-of-the-art laying capability that were influential in defining these routes. Although these pipelines would follow the shallowest paths possible, they cannot avoid water depths in some areas that exceed current state-of-the-art capability. However, based on significant developments in the last several years, we conclude that pipelaying capability for the routes shown in Figure 2 can be achieved in the next five years -- the same time required to discover, explore, and, if feasible, develop the undiscovered resources offshore.

Since the Santa Barbara Channel is likely to be most heavily developed in the near future, Figure 3 shows clearly the pipeline route that will be required if that area is to reduce air pollution and the risks of oil spills associated with tankering. These pipeline routes again combine the same criteria mentioned above. They also conform more closely to the location of existing discoveries, with the exceptions of the San Miguel, Oak Ridge, and Santa Cruz areas where no discoveries have been made yet. The offshore pipeline routes for the east end of the Channel are not restricted by water depths and could be laid today if the various discoveries are found to be economical. The route linking Hueneme and Santa Clara is now being evaluated by the operators of those two areas.

For the west end of the Channel, beyond Hondo, water depths reach a maximum depth of around 1500' between the San Miguel and Pescado areas. A shallower route to shore from the San Miguel area would be possible if a pipeline were laid to the eastern end of the Channel, but the distance travelled would be triple that required for the route shown.

Figure 4 shows the location of existing, proposed, and possible OCS-related facilities in the Santa Barbara Channel. This display is useful for identifying

Figure 1

ESTIMATED RECOVERABLE RESERVES

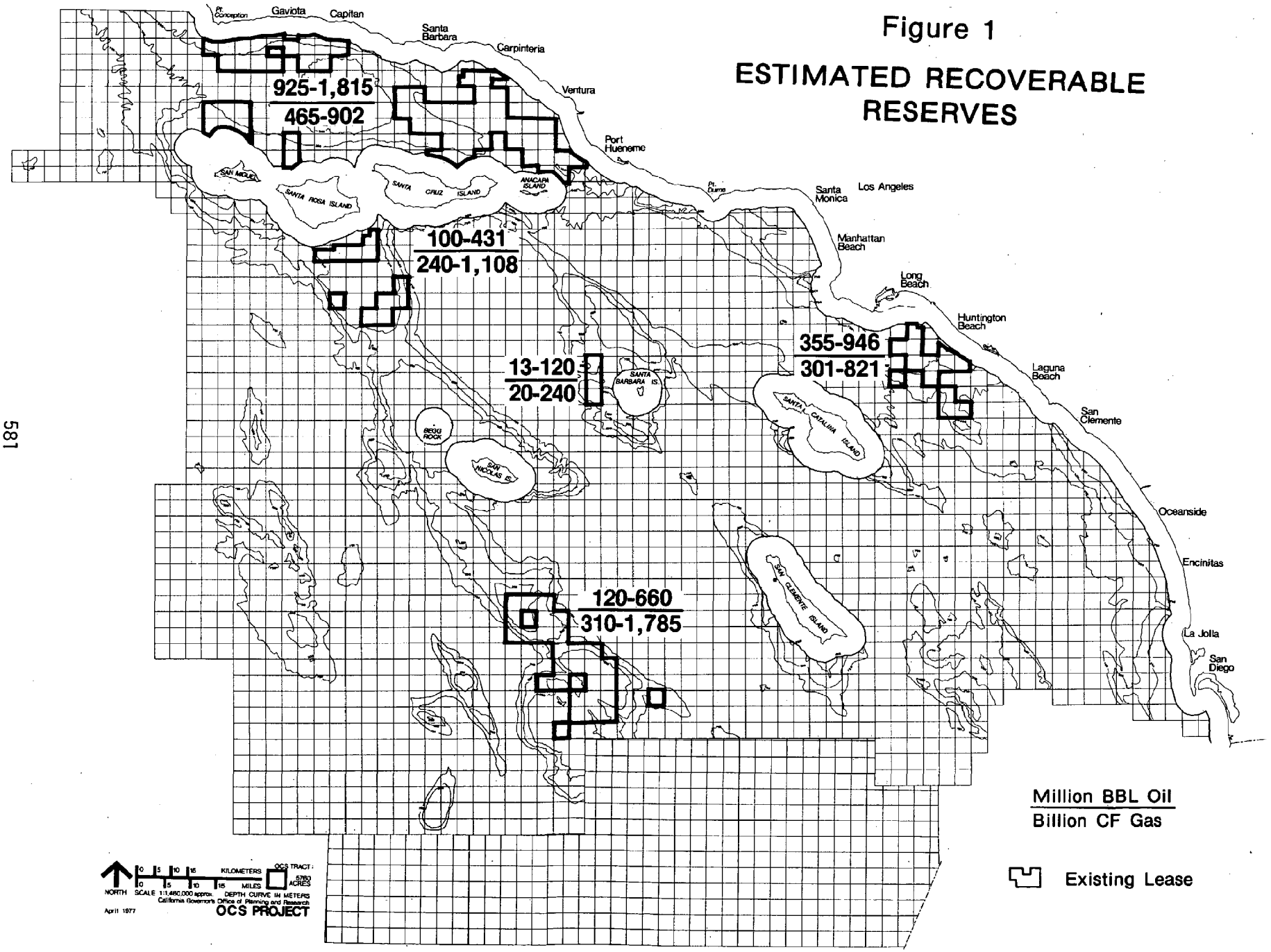
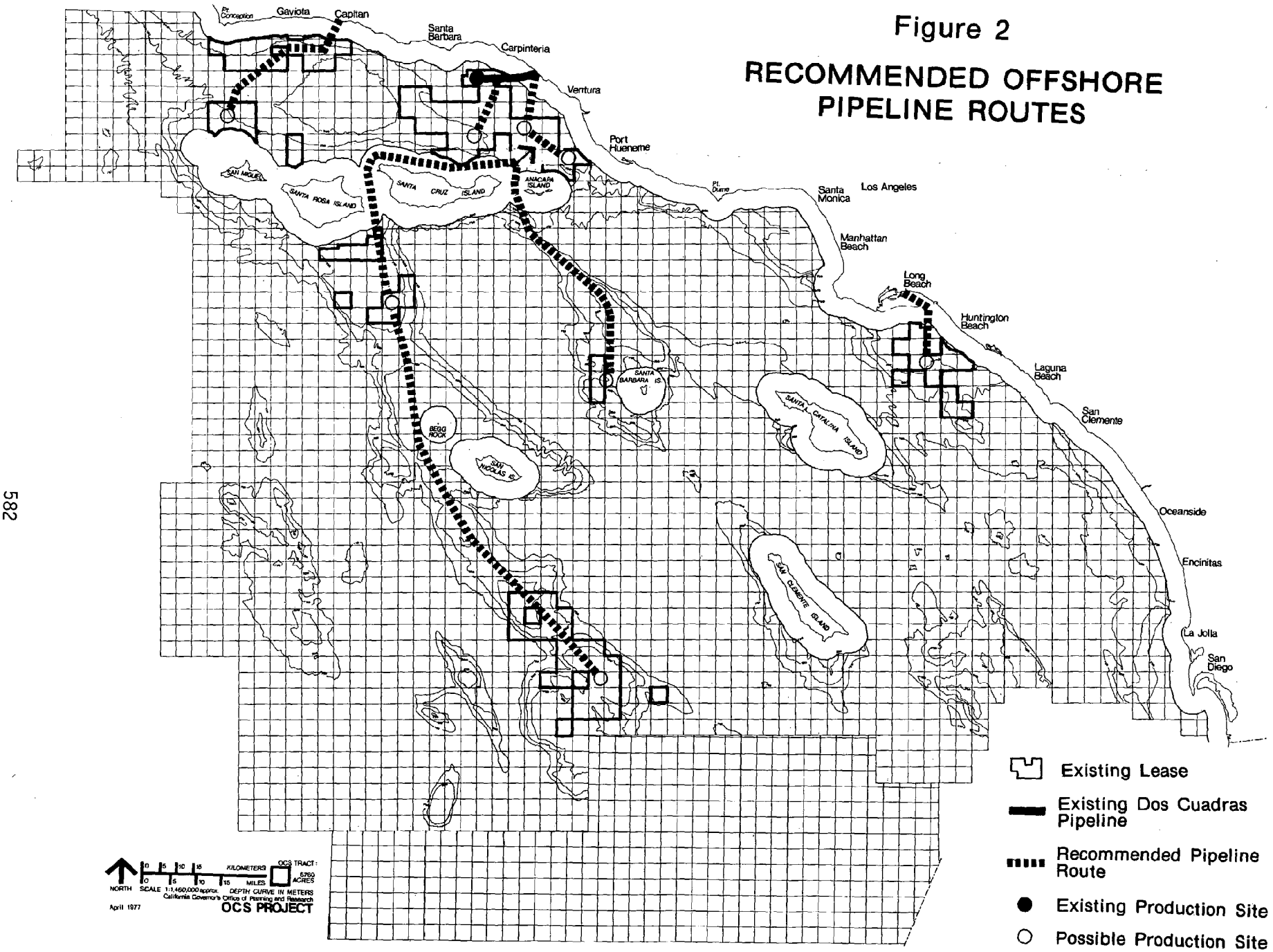
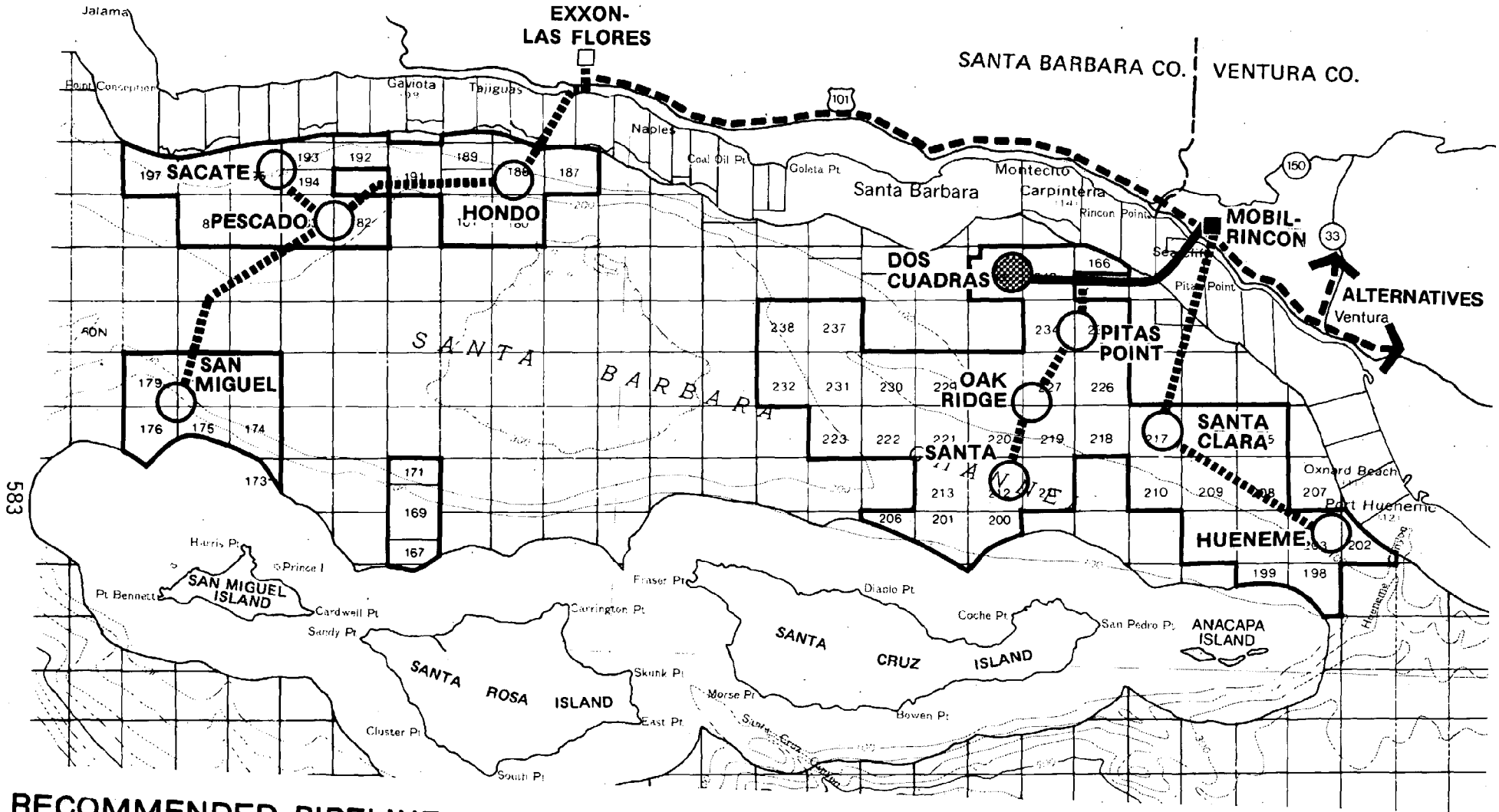


Figure 2

RECOMMENDED OFFSHORE PIPELINE ROUTES



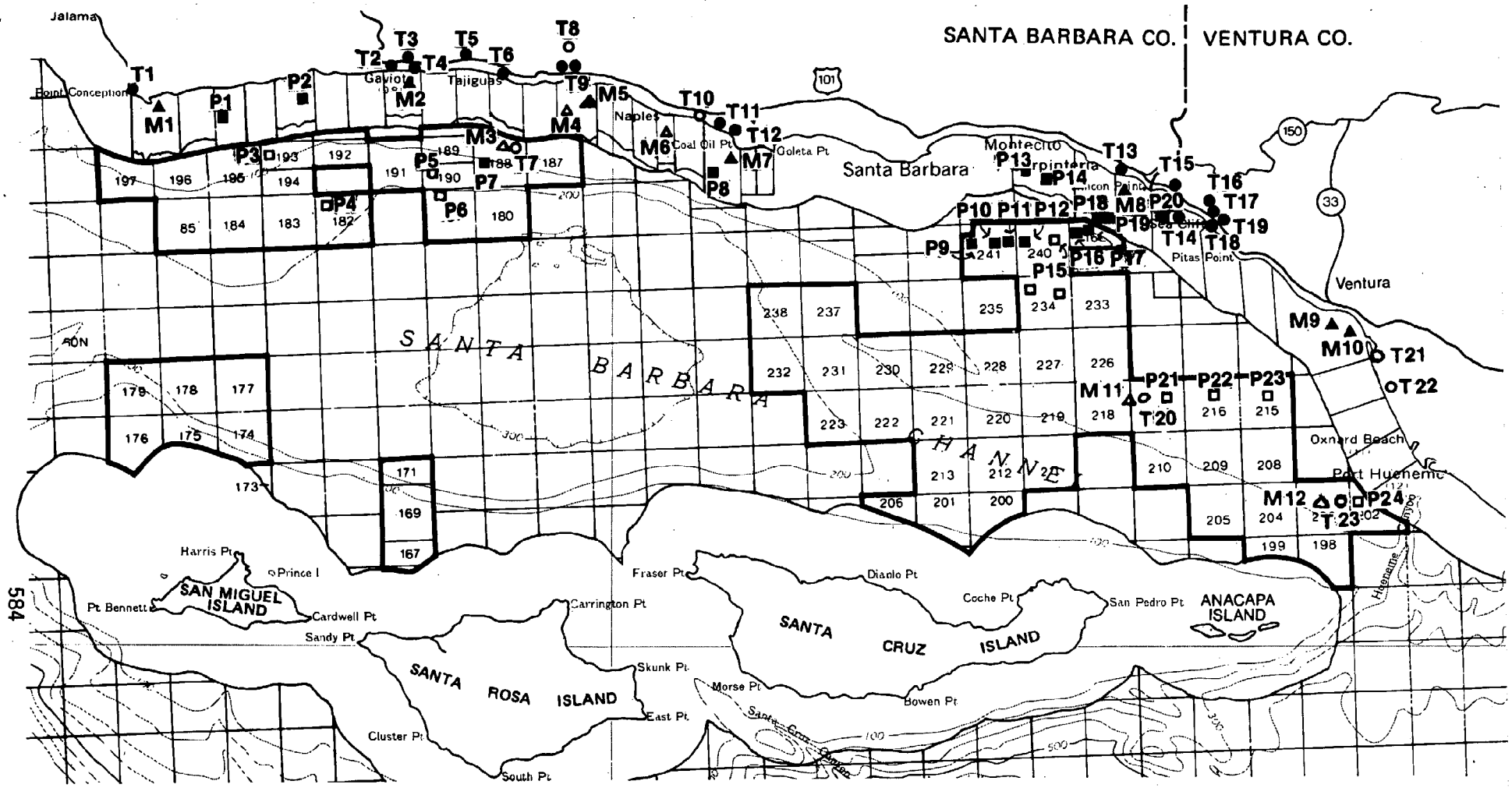


RECOMMENDED PIPELINE ROUTES: SANTA BARBARA CHANNEL

Figure 3

- Leased Area
- Recommended Offshore Pipeline Route
- Recommended Onshore Pipeline Route
- Existing Dos Cuadras Pipeline
- Existing Mobil Processing Plant
- Proposed Exxon Processing Plant
- Existing Production Site
- Possible Production Site

NORTH
0 3 5 10 KILOMETERS
0 3 5 10 MILES
SCALE 1:500,000 DEPTH CURVE in FATHOMS
April 1977 California Governor's Office of Planning and Research
OCS Tract 5760 ACRES
OCS PROJECT



OCS - RELATED FACILITIES: SANTA BARBARA CHANNEL

Figure 4

- Leased Area
- ■ Existing Platform
- □ Proposed or Possible Platform
- ● Existing Processing Plant
- ○ Proposed or Possible Processing Plant
- ▲ Existing Marine Terminal
- △ Proposed or Possible Marine Terminal

NORTH
0 3 5 10 KILOMETERS
0 3 5 10 MILES
OCS Tract 5760 ACRES
SCALE 1:500,000 DEPTH CURVE in FATHOMS
April 1977 California Governor's Office of Planning and Research
OCS PROJECT

at a glance those areas most likely to be affected by offshore oil and gas development in the near future. Note, however, that some "proposed or possible" facilities represent alternatives: not all of these will be constructed. Similarly, not all possibilities can be anticipated: platforms for the Pitas Point Unit, Oak Ridge Unit, San Miguel Unit, the Santa Cruz leases, and the Anacapa leases are not illustrated because information about these areas is insufficient for projecting possible development. Finally, not all facilities shown are involved in the scenarios: State tideland platforms and related facilities are not discussed; they are shown primarily for reference. Below, we list all facilities by name and cross reference those that are discussed in the scenarios. Additional information on each of the existing facilities is provided in Appendix 3 of this report.

PLATFORMS

P1:	Herman	(existing, State tidelands)
P2:	Helen	(existing, State tidelands)
P3:	"Sacate"	(possible, see Santa Ynez Unit scenario)
P4:	"Pescado"	(possible, see Santa Ynez Unit scenario)
P5:	"Hondo C"	(possible, see Santa Ynez Unit scenario)
P6:	"Hondo B"	(possible, see Santa Ynez Unit scenario)
P7:	Hondo A	(existing, see Santa Ynez Unit scenario)
P8:	Holly	(existing, State tidelands)
P9:	Dos Cuadras C	(existing, see Dos Cuadras scenario)
P10:	Dos Cuadras B	(existing, see Dos Cuadras scenario)
P11:	Dos Cuadras A	(existing, see Dos Cuadras scenario)
P12:	Hillhouse	(existing, see Dos Cuadras scenario)
P13:	Hilda	(existing, State tidelands)
P14:	Hazel	(existing, State tidelands)
P15:	"Henry"	(proposed, see Carpinteria scenario)
P16:	Houchin	(existing, see Carpinteria scenario)
P17:	Hogan	(existing, see Carpinteria scenario)
P18:	Hope	(existing, see Carpinteria scenario)
P19:	Heidi	(existing, see Carpinteria scenario)
P20:	Rincon Island	(existing, State tidelands)
P21:	"Santa Clara A"	(proposed, see Santa Clara Unit scenario)
P22:	"Santa Clara B"	(possible, see Santa Clara Unit scenario)
P23:	"Santa Clara C"	(possible, see Santa Clara Unit scenario)
P24:	"Hueneme"	(proposed, see Hueneme scenario)

MARINE TERMINALS

M1:	Union/Cojo Bay	(existing, tidelands-related)
M2:	Getty/Gaviota	(existing, tidelands-related)
M3:	Exxon/OS&T	(alternative, see Santa Ynez Unit scenario)
M4:	"Exxon/El Capitan"	(proposed, see Santa Ynez Unit scenario)
M5:	Exxon/El Capitan	(existing, see Santa Ynez Unit scenario)
M6:	"Aminoil/Naples"	(proposed, see Santa Ynez Unit scenario)
M7:	Aminoil/Elwood	(existing, see Santa Ynez Unit scenario)
M8:	Chevron/Carpinteria	(existing, see Santa Clara Unit scenario)
M9:	Getty/Ventura	(existing, see Dos Cuadras scenario)
M10:	Union/Ventura	(existing, see Dos Cuadras scenario)
M11:	"Chevron/OS&T"	(possible, see Santa Clara Unit scenario)
M12:	"Mobil/OS&T"	(possible, see Hueneme scenario)

PROCESSING PLANTS (Treatment and Storage Facilities)

T1:	Union/Pt. Conception	(existing, tidelands-related)
T2:	Texaco/Gaviota	(existing, tidelands-related)
T3:	Chevron/Gaviota	(existing, tidelands-related)
T4:	Arco/Gaviota	(existing, tidelands-related)
T5:	Phillips/Tajiguas	(existing, tidelands-related)
T6:	Shell/Molino	(existing, tidelands-related)
T7:	"Exxon/OS&T"	(alternative, see Santa Ynez Unit scenario)
T8:	"Exxon/Las Flores"	(proposed, see Santa Ynez Unit scenario)
T9:	Shell/Corral Canyon	(existing, see Santa Ynez Unit scenario)
T10:	Arco/Elwood	(proposed, tidelands-related)
T11:	Aminoil/Elwood	(existing, tidelands-related)
T12:	Arco/Coal Oil Point	(existing, tidelands-related)
T13:	Chevron/Carpinteria	(existing, see Santa Clara Unit scenario)
T14:	Rincon Island	(existing, tidelands-related)
T15:	Phillips/La Conchita	(existing, see Carpinteria scenario)
T16:	Mobil/Rincon	(existing, see Dos Cuadras scenario)
T17:	Mobil/Sea Cliff	(existing, tidelands-related)
T18:	Cabot/Sea Cliff	(existing, tidelands-related)
T19:	Chansler-Western/Sea Cliff	(existing, tidelands-related)
T20:	Chevron/OS&T	(possible, see Santa Clara Unit scenario)
T21:	"Outer Banks/Ventura"	(possible, see Outer Banks scenario)
T22:	"Mobil/Mandalay:	(possible, see Hueneme scenario)
T23:	"Mobil/OS&T"	(possible, see Hueneme scenario)

Figure 5 shows the timing and sequence of exploration, development, and production projected for the scenarios, including the installation of individual platforms where information is available. What should be immediately apparent from this graph is the widely divergent schedules under which different areas of the OCS have been developed. Similarly, it should be clear that the greatest amount of OCS development is yet to occur.

Figure 6 returns to the Santa Barbara Channel again to illustrate the potential rates of production based on existing development plans only. The significance of the Santa Ynez Unit to Channelwide planning for increased levels of OCS development is conspicuous. Yet, as is discussed in the scenario, a great deal of uncertainty remains regarding the total magnitude of the Santa Ynez Unit contribution to future production. The graph clearly shows the differences that result from assuming different numbers for total recoverable reserves: 419 MMB being derived from Exxon-supplied information, 730 MMB and 1,100 MMB being a range of recoverable crude oil estimated by the Geological Survey.

THE SCENARIOS

FIELDS IN PRODUCTION

Production in the federal OCS is presently limited to two fields: Carpinteria and Dos Cuadras, located along the same geologic formation known as the Rincon trend, off the coast of Santa Barbara County. Figure 10 of Chapter 19 shows the location of these two fields together with production facilities, those already in place, and those proposed for development.

FIGURE 5:
TIMING AND SEQUENCE OF SOUTHERN CALIFORNIA OCS DEVELOPMENT

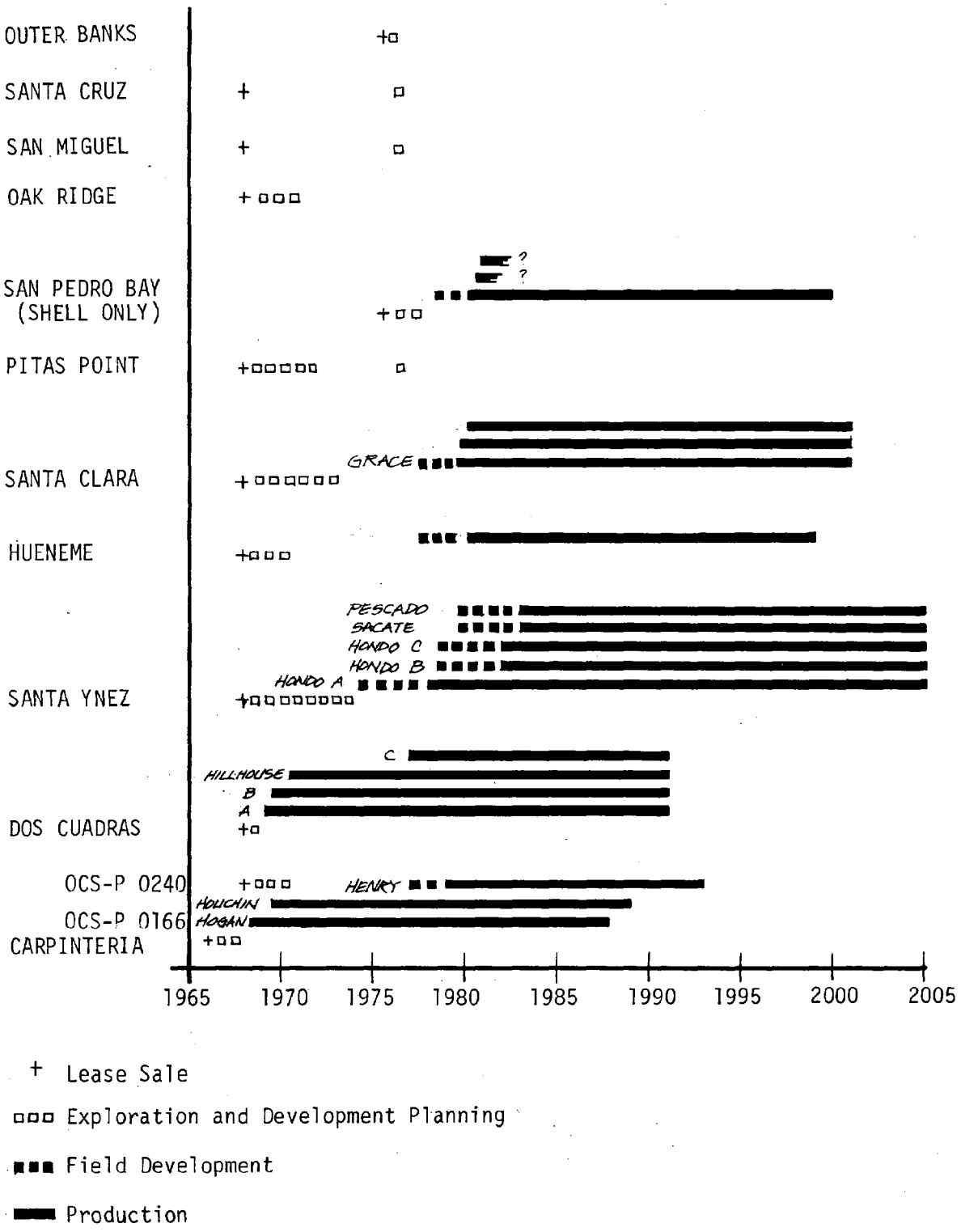
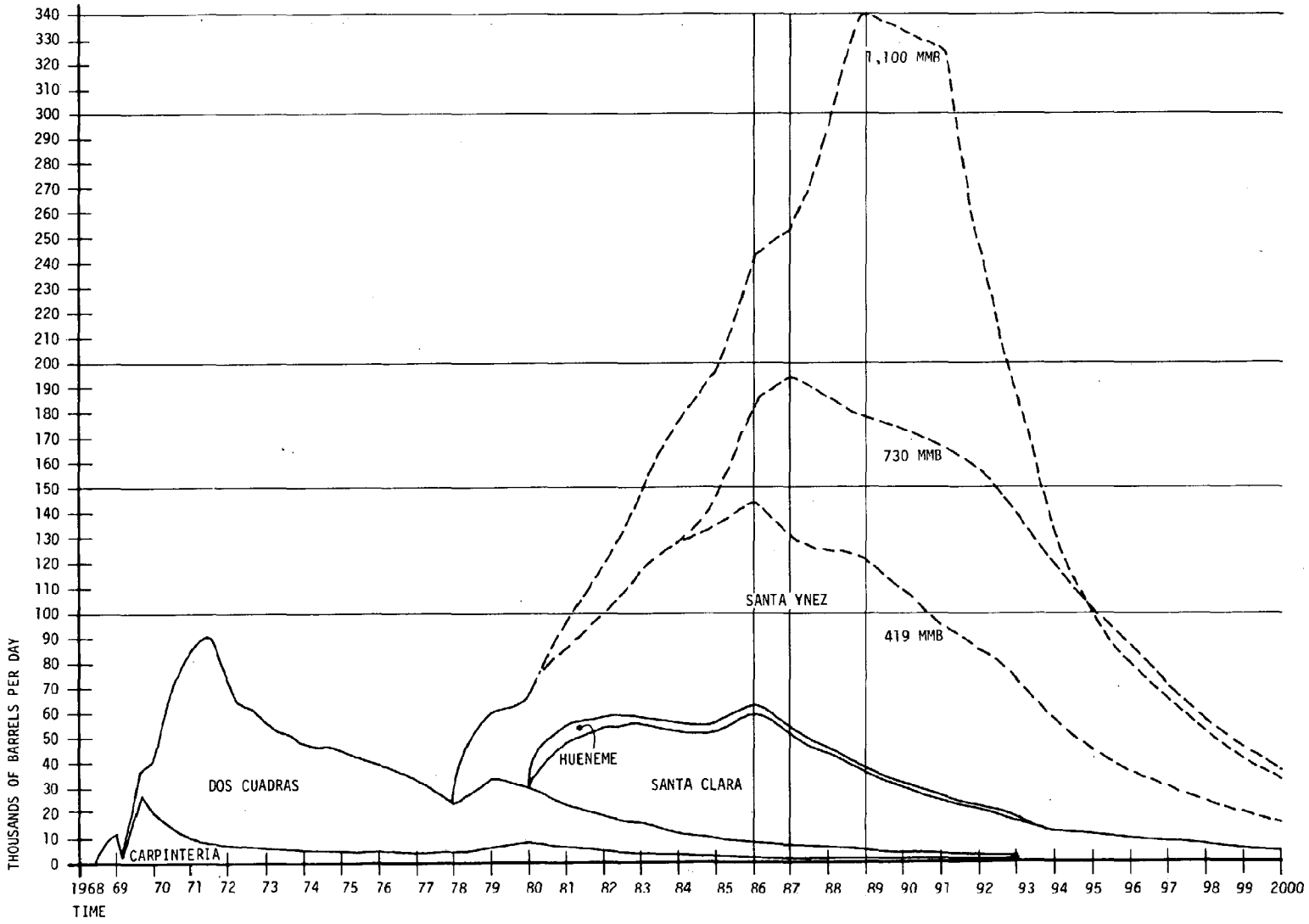


FIGURE 6:
SANTA BARBARA CHANNEL FEDERAL OCS CRUDE OIL PRODUCTION FORECAST



CARPINTERIA

Operators:	Phillips, Sun
Prospect:	Carpinteria
Exploration:	Phillips completed; Sun currently evaluating 1976 well
Development:	Phillips completed; Sun evaluating
Production:	Phillips started in 1968; Sun earliest projected for 1979
Production Systems:	Phillips' Houchin and Hogan, 1968; Sun proposed "Henry"
Processing:	Phillips/La Conchita for Phillips; Sun proposes processing at their Platform Hillhouse on Dos Cuadras field, then to Mobil/Rincon
Transportation:	onshore pipeline and tanker options available to both.

The Carpinteria field straddles the boundary line between state and federal waters. Initial production from the field occurred in state waters from Platforms Hope and Heidi on a State tidelands lease granted to Standard Oil of California and Arco in 1966. When structural analysis of geologic conditions indicated that this field extended into federal waters, the Department of the Interior authorized a drainage sale of adjacent federal OCS submerged lands. A consortium of Phillips Petroleum, Continental Oil, and Cities Service were high bidders on December 15, 1966, for the acreage offered as Lease OCS-P-0166. Phillips became the designated operator of 0166 for development phases. In 1960, a major lease sale was held in the Santa Barbara Channel. Adjoining submerged lands to 0166 were leased as OCS-P-0240 to a consortium made up of Sun Oil Company, Marathon Oil Company, Sunray DX, and the Superior Oil Company. Exploration on 0240 in 1969 confirmed an extension of the Carpinteria offshore field into it.

EXPLORATION. Exploration on 0166 was completed with six core holes drilled in 1967. By 1968, development plans for the lease were completed and two platforms were installed. Subsequent exploration by Sun, the adjoining tract operator, confirmed an extension of the Carpinteria field into OCS-P-0240. It is yet unknown whether oil and gas from this extension is economically recoverable.

DEVELOPMENT. The Carpinteria field is developed with two production platforms in state waters and two in federal waters. No apparent effort was made during field development to accommodate field unitization, either by the companies involved or by state and federal regulatory agencies. It is unclear whether or not unitization would have actually increased ultimate recoverable reserves; however, it can be demonstrated that unitization would have eliminated the cost of some pipelines to shore and possibly the Phillips processing facility. 3/

PRODUCTION. The federal portion of the Carpinteria field began to produce in June 1968 and peaked in August 1969 at 27,899 barrels of oil per day. It currently produces about 4,500 barrels of oil, 2,280 MCF of gas and about 9,000 barrels of water per day. The peak number of producing wells for the two platforms was sixty in February 1970; the current number of producing wells is forty-eight. 4/ The remaining productive life of the two platforms is estimated to be eight to ten years.

TRANSPORTATION. Production from the Phillips platforms goes to shore for

treatment and separation by way of two ten-inch diameter pipelines for oil and one twelve-inch diameter pipeline for gas, each approximately 6.15 miles long. Phillips operates the pipelines and pumping equipment, designed to handle around 42,000 barrels of fluid (15,000 water and 27,000 oil) and 22,500 MCF of gas per day. After processing, surplus gas is sold to the Pacific Lighting Company which operates a pipeline adjacent to the onshore facility, while oil is transferred to a 55,000 barrel storage tank operated by a Phillips pipeline company. This pipeline company connects with the Ventura Pipeline Company (described in the scenario for Dos Cuadras production) to transport the oil through a 30-inch pipeline to the Ventura area, where additional pipelines and two marine terminals link with refining areas.

PROCESSING. Federal Carpinteria production is processed at the Phillips-La Conchita treatment and separation plant, located at the foot of coastal bluffs along Ventura County's Rincon coastline some 1.5 miles west of Rincon Point. The site covers approximately 16 acres, 11 of which are occupied. The remaining four vacant acres were proposed for development by Sun Oil in 1969. 6/

The Phillips-La Conchita processing plant was originally designed to treat around 27,000 barrels of oil, 15,000 barrels of water and 22,500 MCF of gas per day. Current design has reduced gas handling capability to 11,000 MCF/D and wastewater disposal to around 9,000 B/D. The original design for disposing of treated wastewater relied on an ocean outfall. Since present regulations prohibit this method of disposal, Phillips converted a six-inch freshwater line, formerly connecting the platforms with an onshore water system, into a wastewater return line. At the platform, the wastewater is disposed of by injecting it into already-depleted areas of the Carpinteria field.

Current production is at 4,500 B/D oil, 9,000 barrels of water and 2,280 MCF of gas per day. These production levels allow a surplus treating capacity estimated at 22,500 B/D oil and 8,800 MCF of gas per day. Phillip's personnel indicate that to process any new oil and gas including significant quantities of water would require new wastewater disposal pipelines. 7/

FUTURE DEVELOPMENT FOR THE CARPINTERIA FIELD. Sun completed four exploratory wells in the vicinity of the Carpinteria extension by 1970, when it submitted a development plan to USGS. That plan requested permission to drill up to three additional exploratory wells and to install Platform Henry approximately 1½ miles west of Platform Houchin, should the results favor further development. This request, along with an application to install Platform C on the Dos Cuadras field (see a discussion of this proposal in the Dos Cuadras scenario), was the subject of a federal Environmental Impact Statement in 1973. The Secretary of Interior denied approval of both platforms on environmental grounds in that year. Following the decision, both applicants initiated lawsuits against the Department of the Interior. In September 1976, Union vs. Morton [(1975) 512 F.2d 743] was settled in favor of Union, with the stipulation that USGS quickly provide all necessary permits for installing Platform C. Further, as a factor in settling Santa Barbara County, et al. vs. Kleppe (Civil Action No. 76-0245-MML), the County agreed not to seek further legal action that would impede or delay the development plans for Platforms C and Henry. Sun's suit against Interior is still pending before the United States Court of Claims. Proposed findings of fact and conclusions of law have been filed with the court, but no hearing date has been set. 8/

With approval of Platform C as a precedent, it appears likely that the development plan for Henry will also be approved. USGS has estimated probable

reserves of 12.75 MMB oil and 8.66 BCF gas to be recoverable by Henry. 9/ We assume that Sun installs Platform Henry on 0240 in 1978, that production begins in 1979, peaks in 1980 at 8,000 B/D oil and 4,000 MCF/D gas, and declines thereafter. The peak oil rate and the gas/oil ratio (GOR) are extrapolated from the production history of tract 0166. Productive life of the new platform is assumed to be 15 years. Production life for Houchin and Hogan is estimated to last until 1986 by Phillips; but, if Henry is installed and required to use Phillips facilities, it would be fair to assume Houchin and Hogan would stay in operation past their anticipated economic life.

TIMING FOR FUTURE ACTIVITIES ON THE CARPINTERIA FIELD. If approval of the development plan for the exploratory wells and Platform Henry is obtained by the end of 1977, exploration may begin by mid-1978 and conclude in early 1979. A commitment for Platform Henry to be installed would be made in late 1978 and begin in mid-1979. Under these assumptions, development drilling and initial production could occur in 1980.

Transportation and processing options include linking by way of a half-mile pipeline with Phillip's Platform Houchin to bring oil and gas ashore at Phillips-La Conchita; or linking by way of a two-mile pipeline with Sun's Platform Hillhouse on the Dos Cuadras field to bring oil and gas ashore at Mobil-Rincon. Sun prefers the latter option for several reasons. First, Platform Hillhouse is designed to separate completely crude oil, water, and natural gas to "pipeline quality" standards. By directing its Carpinteria production to Hillhouse, Sun would save the expense of purchasing processing capability from Phillips at La Conchita. Second, Sun is part owner and is entitled to a portion of the available surplus capacity in both the pipelines from Dos Cuadras to Mobil-Rincon and in the Mobil-Rincon facility itself. Sun's share of surplus capacity exceeds the projected peak rates of production for Platform Henry and hence would permit use of these facilities without additional costs above the current throughput rate charged for operating them. Third, and most important to Sun, the preferred option simply avoids the complicated process of setting up joint-use agreements with another company, in this case, Phillips.

The Phillips option has two advantages: it reduces the length of pipeline required to deliver crude oil and natural gas to a processing site; and it reserves surplus capacity at Mobil-Rincon for other future production. A disadvantage of the Phillips option would be the extended life required of Phillips-La Conchita. Production from Henry could sustain operation of the plant to the year 1993, or seven years past its current life expectancy, thus delaying the recycling of this site to other coastal-related uses.

DOS CUADRAS

Operators:	Union, Sun
Prospect:	Dos Cuadras
Exploration:	Complete
Development:	Complete, with possible addition of satellite, ocean-floor wells
Production:	Begun 1969
Production Systems:	Union Platforms A, B, C; Platform Hillhouse
Processing:	Mobil/Rincon
Transportation:	Onshore pipeline to Ventura, pipeline and tanker options from Ventura to refineries

The Dos Cuadras field was discovered in Lease OCS-P-0241 in 1968 by the

leaseholders -- Gulf, Texaco, Union, and Mobil (GTUM), with Union as tract operator. Further exploration in 1968 by Sun demonstrated an extension of this field into OCS-P-0240, held by Sun, Marathon, and Superior, with Sun as operator. Exploration activities ceased in late 1968 when platform installation began.

DEVELOPMENT. The development plans for the field require three platforms for the GTUM portion and one platform for the Sun portion. Union installed Platforms A and B by February of 1969 with intent to install Platform C in March of that year. Sun's plans called for installing Platform Hillhouse in late 1969. Platforms A, B, C, and Hillhouse are currently in place and producing, although permission to install Platform C was delayed until recently (described below). No further development for the Dos Cuadras field is contemplated beyond the possible addition of a few satellite, ocean-floor wells.

PRODUCTION. Production for the Dos Cuadras field began at the time of the 1969 blowout, peaked in 1971 at 81,000 B/D oil from A, B, and Hillhouse, and currently amounts to about 34,500 B/D oil and 11,300 MCF/D gas. The peak number of producing wells was 129 in 1973 and is currently 122. 10/

TRANSPORTATION. Transportation of production to shore for treatment and separation is facilitated by commingling production at Platform A, then pumping to shore through two 12-inch pipelines approximately 11 miles long. The pipelines and related pumps, operated by Union Oil, are designed to handle approximately 96,000 B/D oil and 60,000 MCF/D gas. Once ashore, production is pumped to the Mobil-Rincon processing site at an elevation of approximately 500' through a 20-inch oil pipeline and a 20-inch gas pipeline. After processing, gas enters a Pacific Lighting Company gas line on-site; and custody of oil automatically transfers to the Ventura Pipeline Company. 11/

The Ventura Pipeline Company was formed to own and operate a pipeline connecting the Phillips-La Conchita processing plant on the north to a 268,000-barrel storage tank at Mobil-Rincon and a pipeline continuing south to the City of Ventura. The Ventura Pipeline Company also owns the storage tank at Mobil-Rincon. The company consists of the GTUM group, the Sun group, the owners of Phillips-La Conchita (Phillips Petroleum, Cities Service Oil Co., Continental Oil Co.), Arco, and Chanslor Western. It is operated by the Mobil West Coast Pipeline Company, a subsidiary of Mobil Corporation.

In Ventura, the pipeline diverts oil to any of two marine terminals and three pipelines capable of delivering production to refining areas. 12/ Two of the pipelines from Ventura to Los Angeles are owned by GTUM members (Texaco and Union). One marine terminal is also owned and operated by Union Oil. This terminal, Union/Ventura, is capable of loading crude oil at a rate of 10,000 barrels per hour through a 20-inch line and 6,400 barrels per hour through a 10-inch line. The 20-inch line is used about 33 times per year, lifting 200,000 barrels per tanker visit. It is not clear how much of Dos Cuadras production uses this particular marine terminal; however, a typical month's loading of 645,000 barrels total (3 X 200,000 + 45,000) is significantly less than the one million barrels per month currently being produced.

PROCESSING. Processing of Dos Cuadras production takes place at Mobil/Rincon, a treatment and separation plant owned jointly by GTUM (with four equal shares at 17½%) and the Sun group (with shares totaling 30%). 13/ This site is located on a terrace along the coastal bluffs of Ventura County, approximately 3.4 miles southeast of the Ventura County-Santa Barbara County line at Rincon Point, and 1.2 miles

due south of Rincon Mountain. Of the 140 acres, 20 on the north are reserved as a buffer zone. The processing plant and a 268,000-barrel storage tank owned by the Ventura Pipeline Company occupy about 32 acres. An estimated five of the 32 acres are available for expansion with no grade preparation necessary. An additional ten acres adjacent to the processing plant could be used, with minimal grade modifications. The remaining 78 acres are in a relatively natural state of rolling grass and brush-covered terrain, including some very steep bluffs.

The processing facility is designed to handle 96,000 B/D oil, 60,000 MCF/D gas, and 50,000 barrels of wastewater per day. Inadequate pipelines, however, limit the disposal of wastewater to 14,000 barrels of water daily. Accomodation of new production without increasing wastewater disposal will necessitate disposing of nearly all produced water at the producing site. 14/

FUTURE DEVELOPMENT FOR THE DOS CUADRAS FIELD. Union Oil applied for and received approval for Platform C in September 1968, anticipating installation in March 1969. When the Platform A blowout occurred in February 1969, installation was delayed. In April 1969, the Secretary of the Interior withdrew the earlier approval. Subsequent reapplication, EIS review, and legal action resulted in further delays for Platform C. The Secretary finally approved Platform C on June 14, 1976, contingent on the U.S. District Court approval of the settlement of the suit between Union and others against the Secretary. On August 31, 1976, the District Court entered an order of judgment approving the settlement. 15/ Platform C was subsequently installed in February 1977.

TIMING OF FUTURE ACTIVITIES ON THE DOS CUADRAS FIELD. The Court decision affecting Platform C requires USGS to provide Union Oil with all necessary permits to install and commence production without further delay. Therefore, we project new production from Platform C to begin in 1977, peak in 1979 at 6,900 B/D oil and 2,400 MCF/D gas, and decline thereafter. 16/ The peak oil rate is speculative; the GOR is extrapolated from Dos Cuadras production history; and productive lifetime of the new platform is assumed to be 15 years.

Platform C production will require a new pipeline segment, approximately 1.5 miles in length, linking it with Platform A, thereby allowing new production to flow through the existing 12-inch pipelines to the Mobil-Rincon processing plant. No alternatives for Platform C production are proposed since the project as described has been essentially approved.

LEASED AREAS WITH DISCOVERIES (BUT NO PRODUCTION)

In addition to the two currently productive fields described above, eight additional fields in the federal OCS have been discovered and are in various stages of exploration or development. The eight fields and their initial discovery dates are the following: Pitas Point Offshore, 6/19/68; Hueneme Offshore, 6/19/69; Hondo Offshore, 7/13/69; Pescado Offshore, 5/2/70; Sacate Offshore, 8/30/70; the Santa Clara south field, 11/22/70, and north field, 3/4/71; and the unnamed San Pedro Bay field, July 1976. 17/ All of these are in the Santa Barbara Channel except the San Pedro Bay discovery. The five- to seven-year interval between field discovery and development is not typical of field development but rather is a result of federal moratoriums in effect between 1969 and 1975.

Of the eight fields, three occur in the Santa Ynez Unit, one in the Hueneme

Offshore area, two in the Santa Clara Unit, one in the Pitas Point Unit, and one in San Pedro Bay.

SANTA YNEZ UNIT

Operator:	Exxon
Prospects:	Hondo, Pescado, Sacate, P-0197
Exploration:	Complete for Hondo, more proposed for remainder of unit
Development:	Hondo plan filed 1973, initial platform in place, two additional systems contemplated for Hondo, one system each contemplated for Sacate and Pescado (total of five for unit)
Production:	Mid-1978
Production Systems:	Hondo Platform A in 850' water, Hondo B and C, Sacate, and Pescado require deep-water technology (ocean-floor or compliant tower systems)
Processing:	Exxon/Las Flores Canyon proposed alternate offshore storage and terminal (OS&T) now under construction
Transportation:	Tankers proposed

The Santa Ynez Unit is estimated to contain more oil and gas than any other discovery in the Channel. 18/ It presently consists of 17 leases acquired in the 1968 Santa Barbara Channel lease sale. Exxon, the designated operator, controls 92% of the working interest in the unit, with the remaining interest held by Standard Oil of California and Shell. The unit is currently credited with the Hondo, Sacate, and Pescado field discoveries. In 1969, USGS also showed a discovery in lease 0197 on an official Santa Barbara Channel OCS map. 19/ Subsequent revisions to this map in 1973, 1974, and 1975 omitted this discovery; however, in 1976 Exxon produced a map that again showed this phantom field in lease 0197. 20/

EXPLORATION. Exploration of the unit began in 1968, and 32 exploratory wells have been completed to date. Exploration of the Hondo prospect has led Exxon to submit a development plan for that portion of the unit; however, Exxon estimates that four to six additional wells will be needed on the Sacate and Pescado prospects before development commitments can be made. 21/

DEVELOPMENT. Exxon's plan for the Hondo prospect calls for constructing a 28-well platform in 850 feet of water on the east end of the field. This platform will be augmented later by two additional facilities to develop the western 3,300 acres of the prospect. Quoting from Exxon:

> These facilities will be a fixed platform, located in 900-1,000 feet of water to develop the northern flank of the structure, plus a Submerged Production System located in up to 1,500 feet of water to develop the southern structural flank. A Submerged Production System may be used in place of the 900 to 1,000 foot platform, making the total Hondo Field development the 850 foot platform and two Submerged Production Systems. Production from Submerged Production Systems would be pipelined to the initial 850 foot platform. 22/

The initial Hondo platform was installed in December 1976. The first wells

are to be drilled in late 1977 with production from the platform expected in April 1978. Installation of the additional production systems is projected for 1982. Exxon expects that complete development of the Hondo prospect (with the two additional production systems) will result in a peak flow of 60,000 B/D oil and 90,000 MCF/D of sales gas, with ultimate recovery of 240-250 MMB of oil and 360 to 375 BCF of sales gas. 23/

Development of the Sacate and Pescado fields depends on further exploration and flow tests on the Hondo prospect. Exxon representatives have indicated that no decision to develop Sacate and Pescado will be made before 1979. Exxon states that, "Although additional drilling will be necessary prior to finalizing development plans, a fixed platform in 1,000 to 1,200 feet of water or a Submerged Production System in conjunction with a surface support structure will be given consideration" for the Pescado area; another platform is probable for the Sacate area. 24/ Allowing three years for the design, fabrication, and assembly of the required production facilities, and about one year for development drilling and pipelaying to connect these production systems with processing facilities, production could probably begin in 1983. Design specifications of the proposed Las Flores Canyon processing plant are for a peak flow of 80,000 B/D oil, with GOR close to 1,100. 25/ Under these circumstances, ultimate recovery would be around 419 MMB of oil, assuming a typical OCS field performance and a productive lifetime for the unit of 30 years.

TRANSPORTATION. Transportation of Santa Ynez Unit production is one of the most controversial issues currently facing public agencies concerned with OCS development. Exxon proposed to transport all production to shore for treatment and separation of liquids and gas, sell the gas to a natural-gas company at the edge of the onshore site, and transport the processed crude to refineries via a new marine terminal. This facility would be designed to store up to 440,000 barrels of oil. Assuming peak production of 80,000 B/D, a minimum of one tanker visit every five days would be required.

A permit granted by the California Coastal Commission for the onshore processing plant and the marine terminal, imposed a condition that the marine terminal be used on an interim basis to transport the crude oil pending the outcome of a feasibility study for a pipeline to refineries in the Los Angeles Basin or other suitable destination. Exxon chose not to accept this condition and is currently constructing a floating offshore storage and terminal (OS&T) facility in federal waters capable of separating fluids and gas, but not capable of treating the produced gas or transporting it to a gas company. As a consequence, the natural gas would be reinjected into the Hondo reservoir. The OS&T could treat up to 60,000 B/D oil and store up to 200,000 barrels. This production rate would necessitate at least one tanker visit every three days during peak production.

Much of the controversy over the transportation of Santa Ynez Unit production focuses on the economic feasibility of the pipeline, a factor directly dependent on pipeline throughput. It is therefore apparent that production forecasts are a critical determinant to transportation options for Santa Ynez Unit crude oil. It is equally apparent, after reviewing published reserve estimates, that production scenarios derived from information provided by Exxon may be overly conservative.

Earlier production scenarios for the unit have accepted certain parameters Exxon and the Department of the Interior considered accurate. 26/

These parameters include: (1) unit life of around 30 years; (2) peak production of about 80,000 B/D oil and 90,000 MCF/D gas, assuming a normal production curve; and, (3) total oil in place of from three to five billion barrels. Discrepancies occur when projections of recoverable reserves are considered: USGS estimates recoverable oil at 730 million to 1.1 billion barrels with a GOR of 500; the Oil and Gas Journal published an estimate of one billion barrels; and, Exxon estimates recoverable oil at 400 to 500 billion barrels with a sales gas GOR of 1500.

A major inconsistency between production forecasts and recoverable reserves now seems apparent. After Exxon released more information, the following production scenario was derived: initial production from Platform Hondo would begin in 1978, supplemented by production from the Submerged Production Systems on the Hondo prospect in 1982; total Hondo production would peak in 1985 at 60,000 B/D oil; and total recoverable reserves after 25 years (to the year 2002) would be 243 MMB of oil and 365 BCF of gas (if gas were brought to shore). Further extrapolation of Exxon-provided information indicates potential production from Sacate and Pescado would begin in 1983; peak in 1985 with a resulting increase in total Santa Ynez Unit peak production of oil to 80,000 B/D oil; and recovering after 25 years (to 2006) around 176 MMB of oil (and 264 BCF of gas) for a unit total recoverable reserve of 419 MMB of oil and 628 BCF of gas.

The difference of 300 to 700 million barrels of oil between the Exxon-derived scenario and the recoverable reserve estimates of USGS has not been resolved during the course of this study despite requests to both Exxon and USGS for clarification. Among the more plausible explanations are: (1) Exxon finds new recoverable reserves at regular intervals which were not calculated in its 419 MMB figure, thereby either sustaining the 80,000 B/D oil peak rate of production; or, (2) the 419 MMB figure reflects primary recovery only, and with enhanced recovery techniques the 730 million to 1.1 billion barrel range would be achieved. If the USGS low-range of recoverable reserves is attained, a level of production reaching or exceeding 80,000 B/D oil and 90,000 MCF/D gas could exist for up to 20 years, significantly affecting the economics of transporting processed crude to refining areas. It is also conceivable that Santa Ynez Unit production rates could reach as high as 200,000 to 300,000 B/D oil or 200 to 300 MB/D oil if a normal production curve over 30 years was applied to recoverable reserves of 730 million to 1.1 billion barrels of oil respectively. For a further discussion of Santa Ynez production rates see Appendix 2.

PROCESSING. The Santa Ynez production may be processed offshore through use of an OS&T or, provided the differences between Exxon and the Coastal Commission can be worked out, onshore. The onshore site, a portion of a 1,500-acre parcel owned by Exxon, is in Las Flores Canyon, about 20 miles west of Santa Barbara and about 1 1/2 miles inland from the coast. The plant site covers about 15 acres of land to be terraced and cut from canyon walls. In order to get permission from the county to develop this site, Exxon had to secure a zone change and general plan amendment. The new zoning affects a total of 66 acres, including the 15-acre plant site, and extends into nearby Corral Canyon, suggesting that if expansion were necessary, new equipment could be accommodated somewhere on the remaining 51 acres. By contrast, expansion of the offshore alternative is not physically possible on the OS&T anticipated. Should increased production occur, the existing OS&T would have to be replaced by a larger one or an additional OS&T would be required.

FUTURE DEVELOPMENT FOR THE SANTA YNEZ UNIT. The only development certain for

the Santa Ynez Unit is Platform Hondo. Exxon has also projected a need for two Submerged Production System's (SPS), intended to operate in 900 to 1,500 feet of water as satellites to the initial Hondo platform. Additional production facilities for the Sacate and Pescado prospects are also contemplated in the Santa Ynez development plan but are much more speculative at this time. The Sacate Prospect is within reach of conventional platform production operations while Pescado will require other deepwater technology.

Exxon has recently begun testing a guyed tower for production in deep-water tracts such as Pescado. According to Exxon, "the guyed tower system may offer an economically attractive alternative to conventional platforms for use in water depths from 600 to 1,000 feet and an alternative to submerged production systems from 1,000 to 2,000 foot depths." 27/ This appears to be a logical substitute for the 1,000 to 1,200 foot platform or an SPS plus a surface support facility that was originally considered.

Exxon proposes to link the five offshore facilities with a pipeline network tied together at the initial Hondo platform. All production would then be commingled and transferred by pipeline to the onshore facility or to the OS&T.

TIMING FOR FUTURE ACTIVITIES ON THE SANTA YNEZ UNIT. Platform Hondo will probably begin development drilling in late 1977, possibly beginning production by April 1978. Considering the uncertainties caused by the lawsuits affecting the Santa Ynez Unit, all timing forecasts beyond these dates are hypothetical. The earliest possible settlement of pending cases could occur in the summer or fall of 1977, affecting exploration and development phases minimally, possibly delaying production and processing by at least one year. Assuming no significant delays, the second and third Hondo production systems could be set in place and begin development drilling in 1981, with production starting in 1982.

Installation of the initial OS&T is scheduled for 1978, but pending court actions may delay this proposal, and hence all production. Should the Las Flores Canyon site be developed, construction time is estimated at two years, beginning no earlier than six months following final court settlement. In no case is construction likely to begin before 1978.

Further exploration of the Sacate and Pescado prospects will probably require six wells and may take place before 1979. 28/ If development proceeds for Sacate and Pescado, we assume a three-year interval for design, fabrication, and assembly of production components. Production facility installation would occur in 1982, development drilling would be completed in 1983, and initial production would occur in the same year.

Forecasts of production throughput for Santa Ynez Unit facilities are shown in Tables 4 and 5 of Appendix 2. These tables assume the earliest possible settlement of pending court cases and construction of the Las Flores Canyon facility, with interim use of the OS&T until the onshore facility is completed.

HUENEME OFFSHORE

Operator:	Mobil
Prospect:	Hueneme
Exploration:	complete
Development:	proposed plan filed 1976
Production:	1980
Production System:	one conventional platform

Processing:	Two alternatives: (a) Mobil/Rincon (b) new facility at Mandalay Beach
Transportation:	onshore pipeline to Ventura, tanker and pipeline options from there

The Hueneme Offshore field is located approximately three miles west of Port Hueneme in Ventura County. The field lies in OCS-P-0202 and -0203, both acquired in the 1968 lease sale by Mobil Oil and Union Oil jointly. Mobil is the designated operator of both tracts and has submitted a development plan for the field to USGS. 29/

EXPLORATION. Exploration of the Hueneme field is essentially complete, with nine wells drilled to date. No additional exploration activity is anticipated. 30/

DEVELOPMENT. Development of the Hueneme field as described in the plan of development proposes installing one platform in waters around 100 feet deep with up to ten producing wells. 31/ One rig would be used for all drilling, and all producing wells would be drilled before any crude oil and natural gas would be allowed to flow.

PRODUCTION. The Hueneme field is estimated to peak near 10,000 B/D oil and 200 MCF/D gas in the first year of production and to decline steadily thereafter, with field life anticipated at around 20 years. 32/ These figures suggest total recoverable reserves of around 20 MMB of oil and 4 BCF of gas.

TRANSPORTATION. Options for transportation include several pipeline alternatives and barging. Barging is considered the least economic, to be used only as a last resort, according to the unit operator. Pipeline alternatives vary, depending on location of the processing site and on the possibility of combining Hueneme production with production from the nearby Santa Clara Unit.

A limiting factor to transporting the Hueneme crude oil is its viscosity. Because the oil is unusually dense, much of the emulsified water which would ordinarily be removed at the platform may be left with the oil to improve pipeline flow. 33/ After processing, the crude would most likely proceed to refineries via the marine terminal operated by Union at Ventura, or through one of the pipelines connecting Ventura with the Los Angeles area.

Gas produced from the Hueneme field would be used for energy requirements of the platform and would not be transported to shore.

PROCESSING. Mobil intends to process Hueneme field crude oil at the existing Mobil-Rincon facility or at a new facility at Mandalay Beach. Surplus capacity at Mobil-Rincon can accommodate this projected crude oil production, but to do so may approach or exceed the present wastewater disposal capability of the plant. On the other hand, development of a new facility at Mandalay Beach may be too costly for Hueneme production alone, although sharing such a facility with Santa Clara Unit operators appears significantly more feasible. 34/

FUTURE DEVELOPMENT FOR THE HUENEME FIELD. If the Proposed Plan of Development for Hueneme is approved as described, the one platform and a crude oil pipeline to Mobil-Rincon would be constructed. The pipeline could deliver crude directly to Mobil-Rincon or it could link with the existing pipelines delivering Dos Cuadras production to the Mobil-Rincon plant. The former, direct pipeline, is preferable because it is the shorter route and avoids the complications and attendent risks of joining with an existing submarine line.

TIMING FOR FUTURE ACTIVITIES ON THE HUENEME FIELD. If the plan is reviewed in a timely manner, a decision could be reached in late 1977. If approved, construction plans would follow immediately. Allowing three years for design, fabrication, and assembly, development drilling and pipelaying could begin in 1980 with production beginning at the end of that year.

SANTA CLARA UNIT

Operator:	Chevron
Prospects:	Santa Clara (north field), south field (unnamed)
Exploration:	north field 60% complete, south field less complete
Development:	proposed plan for north field filed 1976
Production:	1980
Production Systems:	163 conventional platforms for north field, unspecified for south field
Processing:	four alternatives: (a) Chevron/Carpinteria; (b) Mobil/Rincon; (c) new facility at Mandalay Beach; (d) OS&T
Transportation:	tankers proposed

The Santa Clara Unit includes eight tracts in the Santa Barbara Channel, leased in 1968. Tract ownership is divided among Standard Oil of California, Chevron, Exxon, Arco and Union, with Chevron as the designated operator. Exploration began in 1968 and two potential fields were discovered by 1971. Union oil submitted an application to USGS in 1971 to construct a Platform "Herb" on its lease overlying the northern field; however, no action was taken and in 1973 the eight tracts were unitized. With unitization, the Union proposal could not be considered apart from a plan of operations for the unit. 35/ Chevron is now preparing a Plan of Development for the unit.

EXPLORATION. Exploration for the eight-tract area has so far resulted in nine wells, the earliest started in 1968, the most recent in 1976. Further exploration projected by unit operators includes up to "two evaluation wells in 1977 and possibly three more at a later date" for the north field, and an unspecified program for the south field. 36/

DEVELOPMENT. Development activity to date consists of preparing engineering designs for an initial platform and preparing a Plan of Development. The proposed plan calls for developing the northern field with an initial platform to be installed on Lease OCS-P-0216. Two additional platforms will be installed on -0217 and -0215 if justified by flow tests from the first platform. Northern field development would require 46 to 116 wells drilled from the one to three platforms. Depending on further exploration of the southern structure, development of this field would be completed by additional satellite production systems. 37/

PRODUCTION. Production from the unit is projected by the participants to begin in 1981 and peak in 1982 or 1983. For the northern field, the participants estimate proved reserves for the initial platform at 35 MMB of oil and 35 BCF of gas, with another 73 MMB of oil and 93 BCF of gas should additional two platforms prove feasible. The southerly field may contain reserves of 70 MMB of oil and 113 BCF of gas; however, the unit operator has less confidence in these latter estimates because they are based on insufficient data. 38/

Under the single-platform scenario, Chevron projects a peak rate of production at 16,000 B/D oil and 16,000 MCF/D gas for the year 1982. Assuming the three-platform scenario, Chevron projects a peak rate of production at 38,000 B/D oil and 45,600 MCF/D of gas. With both north and south fields producing, we project a peak rate of production at 51,300 B/D oil and 72,800 MCF/D gas in 1986. 39/

TRANSPORTATION. Transportation of production to a processing site would be by pipeline. Four alternative destinations are under consideration: three are onshore and one is offshore (similar to Exxon's OS&T for the Santa Ynez Unit). The processing location will influence the method of transporting crude to refineries, since only one site (Mobil-Rincon) is currently accessible by pipeline to refineries. Chevron identifies Mobil-Rincon as a preferred site for processing but states that it "plans to transship the crude by tanker to either/or both El Segundo or Richmond refineries." 40/

PROCESSING. Processing could be achieved through one of four options: (1) using the existing Mobil-Rincon facility; (2) using Chevron's existing facility at Carpinteria; (3) installing a new facility in the Ventura-Oxnard area; and, (4) processing offshore. Unit participants have shown some preference for the Mobil-Rincon facility because "it is the most cost-effective,...enables Santa Clara and Hueneme Unit to unitize a common subsea pipeline from platforms to shore, ...best conforms to zoning and land use requirements,...[and has] minimal environmental and social impact." 41/ Chevron, however, also considers the Carpinteria option attractive, and for this reason has not made a decision yet on which plant will be finally selected.

Mobil-Rincon is capable of absorbing new production from the Santa Clara Unit. Neither oil nor gas treating capacities will be exceeded. Since the unit operator intends to remove emulsified water from produced fluids to reach pipeline quality standards (three percent water by volume) at the platform(s), wastewater disposal limitations should not be exceeded as well. 42/

FUTURE DEVELOPMENT FOR THE SANTA CLARA UNIT. If Chevron's Proposed Plan of Development is approved substantially as is, as many as three platforms would be constructed and connected by pipelines to one of four alternative processing sites, including one offshore. In view of the potential volume and timing of production that could occur in the Santa Barbara Channel, it appears reasonable that Santa Clara Unit production be pipelined to shore for processing at Mobil-Rincon. This processing solution is preferable because it involves the use of surplus capacity at an existing facility, with a minimum amount of offshore pipeline. The Carpinteria option would involve some expansion of that facility under full northern field development. The Carpinteria option is less desirable than the Mobil-Rincon option because, in the present situation, Carpinteria is dependent on marine transport for delivering crude oil to refineries. The Ventura-Oxnard solution is undesirable because it involves constructing a new oil and gas facility near areas designated for recreational use and conservation in local and state coastal management plans. It would also require construction of a new pipeline through fragile coastal environments (Mandalay dunes, Ventura River estuary) to connect the processing plant with crude oil transportation facilities in Ventura. The offshore alternative is considered unacceptable because of the increased oil-spill risks posed by offshore storage and transfer operations over onshore operations.

The Mobil-Rincon processing option would also promote unitization of an offshore pipeline to serve both the Santa Clara and Hueneme production operations. Mobil-Rincon is already linked by existing pipelines to the Ventura area where

transporting processed crude to the Los Angeles basin could be accomplished by existing pipelines, provided surplus throughput were made available. In the absence of pipeline transportation to refineries, Santa Clara production could create a need for some three additional tanker loadings per month from existing marine terminals during peak production in 1983.

TIMING FOR FUTURE ACTIVITIES IN THE SANTA CLARA UNIT. If Chevron's Proposed Plan of Development is approved substantially as unit participants describe it, the timing of future activities may occur as follows: two exploratory wells drilled on the northern field in 1977; three additional exploratory wells drilled in 1978 or 1979; and, initial platform installed in 1979. Platform design was begun in mid-1976, with fabrication and assembly for the initial platform projected to be completed by 1979. If the field justifies three platforms, the second and third could be installed in two-month intervals following the initial platform. The first production wells could be in operation by late 1979, with peak production in 1983. The productive life for the three platforms is estimated to be around 22 years.

PITAS POINT

Operator:	Texaco
Prospect:	Pitas Point
Exploration:	Continuing
Development:	Plans (if any) not available
Production:	1982
Production Systems:	One to two conventional platforms plus supporting ocean-floor systems
Processing:	Mobil-Rincon (probable)
Transportation:	Same as Dos Cuadras

The Pitas Point Unit, still in the exploratory stage, consists of three tracts located ten miles offshore from Santa Barbara. Two tracts are leased to the GTUM group with Texaco as operator for both. The third tract was leased to Exxon, but that lease has been allowed to expire.

EXPLORATION. Far less is known about Pitas Point development potential than any of the preceding fields described. Texaco's two initial exploratory wells were inconclusive and a third well has been recently completed. 43/ Each of the three wells have looked for potential reservoirs at depths greater than 15,000 feet, deeper than any other potential reservoirs now being considered for development in the Channel. Knowledge gained from the recent exploration could indicate whether the field is commercially productive or not. Further exploration beyond this well could also be required.

DEVELOPMENT. Development of the Pitas Point Unit depends on further evaluation of exploration results. Yet the potential development of this area commands more than a casual interest if the bonus paid for a lease is any indicator: the lease to OCS-P-0234 was acquired for $56,378 million, second only in the 1968 Channel lease sale to the $61,418 million paid for the nearby OCS-P-0241 in which the Dos Cuadras field is being produced.

PRODUCTION. Production of the field is difficult to predict since no information has been published or volunteered by Texaco on recoverable reserves or production rates. 44/ The only published information on the unit is the perhaps optimistic commentary in a recent trade journal that "one to two new platforms with supporting submerged production systems" could be positioned on the field if the

current well being drilled is successful. 45/

TRANSPORTATION. If the discovery is found to be commercial, oil and gas would be pipelined to shore for processing. GTUM facilities would logically be considered first in formulating transportation and processing options. Existing GTUM facilities in the area include the Union-operated Dos Cuadras field, platforms, the pair of twelve-inch pipelines connecting these platforms with the onshore Mobil-Rincon processing plant, the Mobil-operated pipeline from Rincon to Ventura, the Union/Ventura marine terminal, and the Union and Texaco pipelines that connect Ventura to Los Angeles. Production from Pitas Point could flow through a four-mile pipeline to Platform A, which already serves as a gathering platform, and then through the existing pipelines to shore. Alternatively, a new ten-mile pipeline could be laid directly to Mobil-Rincon. Past Mobil-Rincon the transportation options are the same as described in the Dos Cuadras scenario.

PROCESSING. Mobil-Rincon is likely to be proposed as the processing facility, with an offshore alternative reserved in the event onshore processing is not possible. Assuming production is initiated in 1981, Pitas Point oil and gas processed through Mobil-Rincon could exceed current design capacity after 1982. We estimate that any expansion required to accommodate this increase in production could be accommodated within the already-developed 14 acres of the 140-acre site.

FUTURE DEVELOPMENT FOR THE PITAS POINT UNIT. If Texaco's evaluation of recent exploration proves the field to be commercial, development plans could begin to be formulated soon. Considering the depth and size of the field we conclude that two platforms positioned in OCS-P-0234 are plausible. Further, it would be logical for Pitas Point production to be processed at Mobil-Rincon. In order to get to Mobil-Rincon, we conclude that the existing Dos Cuadras-to-Mobil-Rincon pipelines should be used because of significant available surplus capacity (in excess of 60,000 B/D oil and 80,000 MCF/D gas in the 1980s). This option is preferred over that of constructing a new pipeline directly to shore. Note, however, that increased throughput at Mobil-Rincon resulting from Pitas Point production could necessitate expansion of that facility in the mid-1980s.

TIMING OF FUTURE ACTIVITIES IN THE PITAS POINT UNIT. If Texaco's recent exploratory well is successful, we assume that an additional two to three confirmation wells would be required and could be undertaken in 1977-78. Allowing three years for platform design, fabrication, and assembly, the two platforms could be installed in 1981, with initial production by 1982.

SAN PEDRO BAY

Operators:	Chevron, Shell, Gulf, Texaco, Mobil, Challenger
Prospects:	One confirmed discovery, several others to be explored
Exploration:	Continuing
Development:	Shell currently evaluating
Production:	1980s
Production Systems:	None specified yet, conventional platforms preferred by companies
Processing:	Onshore options available, Shell has suggested fixed offshore structure
Transportation:	Onshore pipelines

Tracts leased in San Pedro Bay are thought to contain the best prospects offered in Lease Sale #35. Since the lease sale in December 1975, industry has applied for exploratory drilling permits on 12 of the 13 leases. Exploration began in July 1976; 15 wells have been completed as of May 1977. From these initial wells, cautious reports on one discovery have been made and at least one estimate for recoverable reserves has been suggested. 46/

Ownerships in the federal OCS of San Pedro Bay include bidding groups led by Shell, Chevron, Gulf, Texaco, Mobil, and Challenger Oil. Shell and Chevron are the designated operators for four tracts each; Gulf operates two; and, the remaining three group leaders each operate one lease. Lease ownership is shown on Figure 7 of Chapter 19.

EXPLORATION. Shell has drilled eight wells on its four leases in San Pedro Bay as of May 1977. Chevron has drilled another seven, all in one tract. At least some of these wells have reported oil-bearing sands with some apparent commercial potential. Fourteen of the wells are on the same structure. Four other structures within the bounds of existing leases remain to be explored.

DEVELOPMENT. Development planning for San Pedro Bay is likely to begin this year when Chevron and Shell complete their separate evaluations of the wells they have drilled. A possible plan of development for the current discovery area (tracts 254, 261, and 262 on Figure 7, Chapter 19) could be ready for review by the Department of the Interior by 1978. Production equipment, depending on its availability, regulatory approvals, and industry incentive, could be installed anytime between 1978 and 1980.

The initial reservoir has been found in depths less than 4,000 feet below the ocean floor by drilling vessels operating in 175 to 659 feet of water. The water depths suggest that if Chevron and Shell proceed with development plans, conventional fixed platforms may be proposed. Based on the geographic extent of the prospect, its relative shallowness, and the location of the exploratory wells drilled to date, we predict that up to four platforms would be proposed by Chevron and Shell.

Further development in San Pedro Bay will depend on additional exploration, since several other prospects have yet to be explored. For total development, USGS estimated San Pedro Bay could justify two to nine platforms.

PRODUCTION. Production estimates for San Pedro Bay are extremely limited. Based on USGS estimates, current leases in San Pedro Bay are capable of economically recovering 355 to 946 MMB of oil with a GOR of 850. 47/ According to two independent petroleum analysts, the Shell discovery is estimated to contain 300-400 MMB recoverable oil. 48/ Based on typical offshore field performance, the current discovery then could be expected to peak around 80,000 B/D oil and, using USGS's GOR of 850, we would expect 70,000 MCF/D gas to be produced as well. If we assume 946 MMB oil and 821 BCF gas are recoverable, it is likely this volume will be produced from several prospects. Since individual field peaks would probably be staggered, we project an area-wide peak level of production at around 160,000 B/D oil and 140,000 MCF/D gas. Area-wide average daily production would be around 60,000 barrels of oil and 50,000 MCF of gas.

TRANSPORTATION. Transportation by pipeline is likely to be favored by industry because of the field's proximity to the well-developed Los Angeles Basin

pipeline network serving the many refineries in Los Angeles County. Since all the OCS designated operators in San Pedro Bay, except for Challenger, own nearby oil and gas facilities, onshore processing plant sites are also likely to be available. In particular, Gulf and Chevron already have processing plants, and own suitable, undeveloped land in Huntington Beach.

Facilities in the harbor areas owned or operated by San Pedro Bay leaseholders include: Union* Oil Refinery, Wilmington; Union Oil Bulk Terminal in the Outer Los Angeles Harbor, San Pedro; Mobil Oil marine terminal and storage facilities on Terminal Island; Chevron marine terminal and storage in San Pedro; Shell Oil marine terminal and storage at Slip 1, Wilmington; Gulf Oil marine terminal and storage on Terminal Island; Texaco marine terminal near Channel 2 in Long Beach; and, the THUMS operation (Texaco, Humble (Exxon), Union, Mobil, and Shell) for the Long Beach Unit on Pier J, Long Beach. Chevron, Shell, Texaco, Mobil, and Gulf have refineries in other parts of the Los Angeles Basin (see maps in Appendix 3 for a location of these refineries).

An extensive pipeline network connects the harbor areas with refineries throughout the Los Angeles area. Huntington Beach is also linked to refineries by pipelines. Either location could satisfy processing requirements while facilitating pipeline transportation to local refineries.

PROCESSING. Since Chevron and Shell will most likely be required to unitize operations on Leases 254, 261, and 262, where they are now delineating the current discovery, they will need one processing site for this area. This site could be in the harbor areas or Huntington Beach or offshore. We conclude on the basis of total estimated recoverable reserves, San Pedro Bay OCS tracts will not require more than one additional treatment and separation site.

FUTURE DEVELOPMENT FOR THE SAN PEDRO BAY OCS AREA. If the recent discovery on leases 254, 261, and 262 is as productive as some indicators suggest, four platforms could be proposed, with pipelines connecting them to an onshore processing plant in Huntington Beach or Long Beach Harbor. Additional development is likely to occur, but its extent is unknown. USGS has suggested that up to five additional platforms could be required.

Partly because of congestion problems caused by ship traffic in the San Pedro Bay area, the State of California requested that this area not be leased by the federal government and that structures not be permitted in the vessel traffic separation scheme (VTSS) 49/ The Department of the Interior has not accepted similar recommendations by the State for denial of drilling permits in the shipping lanes: exploration has taken place and development would appear to be inevitable.

In order to minimize risks involved in developing this area, we propose that industry substantially complete exploration of all prospects in San Pedro Bay before proceeding with any development. After weighing all potentially recoverable reserves against the attendant risks of recovery, the operators should prepare a development plan which coordinates timing and location of all facilities and minimizes the number of surface production systems in the Bay. We further recommend that any production that must be located within the VTSS be submerged, ocean-floor systems.

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*Union is a joint-owner of one lease with Chevron.

Onshore processing should also be considered in the area-wide plan. Possibilities include converting existing facilities used for onshore production, expanding the THUMS operation, and constructing new facilities. Design of the new processing plans should accommodate the projected throughput for the 0254/0261/0262 discovery and should also evaluate the feasibility of expanding throughput capacity to handle additional San Pedro Bay OCS production. If an initial plant could not feasibly accommodate this total production, a second plant might be justified.

TIMING FOR FUTURE ACTIVITIES IN THE SAN PEDRO BAY OCS AREA. We project up to four drilling rigs to drill approximately twelve exploratory wells will be present in 1977. In 1978, this could be reduced to two drilling rigs completing another five to six exploratory wells. Unless development of the entire area is planned simultaneously, there is strong likelihood of an incremental buildup, possibly with as many as nine platforms by the early 1980s.

LEASED AREAS WITHOUT DISCOVERIES

Leased areas without discoveries include 36 tracts in the Santa Barbara Channel, 43 tracts in the Outer Banks areas, and 10 tracts in San Pedro Bay. In the Santa Barbara Channel, exploration without discovery has resulted in some tracts being quit-claimed, while others are still being evaluated. In the Outer Banks, exploration has just begun.

Exploration for all of these areas has accelerated in 1977. Of the 43 tracts comprising the Outer Bank leased areas, 31 have received permits for exploration from the Corps of Engineers. Of the Santa Barbara Channel's 36 leases without discovery, 12 have received drilling permits following approval of the Santa Barbara Channel EIS in 1976. Additional exploratory drilling permits in both areas can be anticipated.

In formulating scenarios for leased areas without discoveries, the only assumptions we have relate to undiscovered recoverable reserves and to the number of production systems possibly required.

For the Santa Barbara Channel USGS estimates that 40 to 200 MMB oil and 20 to 100 BCF gas could be recovered in leased areas without discoveries. The areas include the Oak Ridge Unit, the San Miguel Unit, the Santa Cruz leases, the Anacapa leases, the Pauley leases, leases east of San Miguel, and four mid-Channel tracts owned by Exxon. These areas are shown on Figure 3 of Chapter 19. For these 36 leases, $221,439,971 was paid, slightly more than one-third of the amount paid for all 71 leases sold in the 1968 Channel sale. Since no area-specific information is available, assumptions regarding the location and size of undiscovered recoverable resources in the Channel are not possible.

Even less is known about the Outer Bank areas than leased areas without discoveries in the Santa Barbara Channel, the latter areas having benefited from several years of exploration and production in nearby leases. Each Outer Bank area is located in geologic provinces not associated with the Channel or San Pedro Bay and, until recently, none had been explored by deep wells. The first exploratory drilling has just begun in the Santa Rosa-Cortes South (Tanner Banks) area.

If and when recoverable reserves are discovered in the Outer Banks, a critical factor in determining the magnitude and nature of effects onshore will be the

transportation method used to bring production to shore. An analysis of transportation costs of pipeline vs. surface transport for southern California OCS oil concludes that: "For the Santa Rosa-Cortes North site, the shallow water pipeline is the least costly alternative at both the high and low-estimates of reserves.... For the Santa Barbara-Santa Catalina site, the pipeline alternative is clearly the most cost-effective alternative at both the low and high-estimates of reserves. For the Santa Rosa-Cortes South site, which is the farthest site from shore, the tanker is the most cost-effective alternative at both the low and high-estimates of reserves." 50/ The analysis also states: "Pipelines are safer by a factor of seven in the case of Santa Rosa-Cortes (North)...by a factor of five in the case of Santa Barbara-Santa Catalina...by a factor of 6.5 in the case of Santa Rosa-Cortes (South)." 51/

Figure 7 shows the various pipeline and tanker routes considered by Booz-Allen. This analysis was prepared before the lease sale was held and without knowing which tracts would actually be leased. The analysis does not sufficiently compare the following alternatives or evaluate several important considerations: it does not compare the effects of sharing the pipelaying costs for produced oil with the pipelaying costs for produced gas if the two pipelines were laid together; it does not evaluate the risks of oil spills from storage facilities required by tankers; the pipeline routes used do not follow the shallowest routes possible; a pipeline route between Santa Barbara Island leases and Ventura County is not considered; each pipeline is assumed independent of the others; it is not clear to what extent, if at all, offshore treatment and separation was considered; the environmental costs of tankering vs. pipelining are not considered.

In light of the uncertainties regarding optimum transportation and processing of Outer Banks production, and the potential risks and unnecessary costs attendant with incremental and disjointed development, it should be clear that a thorough exploration program for each of the Outer Banks should precede any planning for production, transportation, and processing in these areas. If recoverable reserves within the limits estimated for the respective areas are confirmed, an offshore pipeline system could be designed to avoid water depths exceeding 1,350 feet. The combined length of the primary trunklines would be approximately 200 miles (see Figure 2).

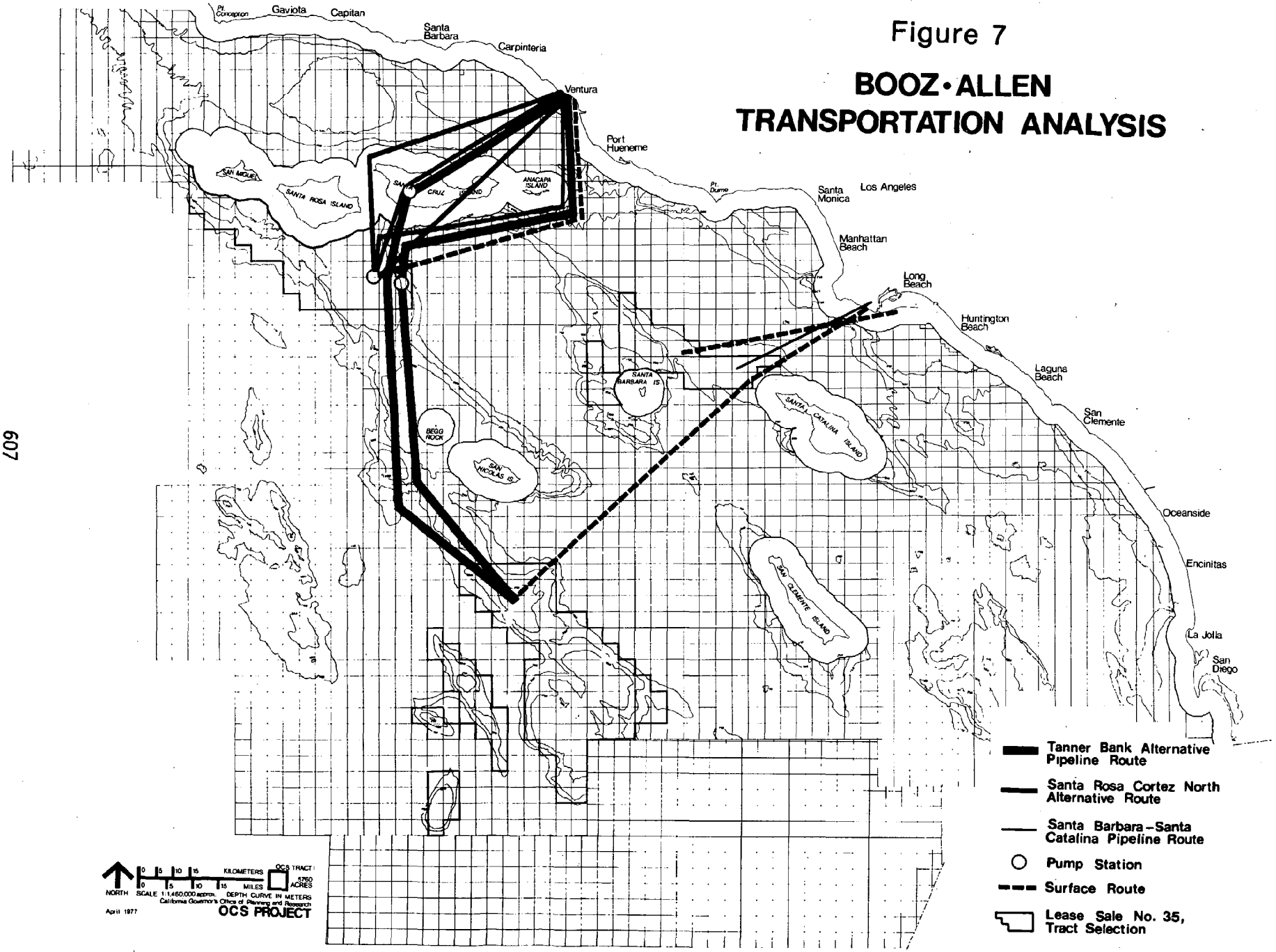
UNLEASED AREAS THAT COULD BE OFFERED IN LEASE SALE #48

In the following chapter we discuss in greater detail the prospects of Lease Sale #48 for southern California. Although this sale has been deleted from the current schedule for offshore leasing, there is still a strong possibility it will be offered by 1980. The Department of the Interior is continuing its efforts to prepare an EIS for this sale and has tentatively selected tracts to be offered. These tracts were selected on the basis of public and private-sector nominations -- many of which conflict. Notably, the Santa Barbara Channel received the most positive nominations and the most negative. San Pedro Bay and the San Diego Coast were each heavily nominated both positively and negatively, as well. The locations of positive, negative, and tentatively selected tracts for Lease Sale #48 are shown in Figures 2, 3, and 4 of Chapter 22. In the "Lease-Area Planning" section of Chapter 19 we outline some of the concerns that need to be addressed by the Department of the Interior before and after any of these areas are offered for lease.

In the following few paragraphs we reiterate some of the concerns identified

Figure 7

BOOZ·ALLEN TRANSPORTATION ANALYSIS



in Chapter 19 and postulate a range of new development that could occur as a result of leasing these areas. These projections can be viewed only as extremely speculative by their nature as they are based on suppositions regarding a very uncertain lease sale proposed for a very uncertain future.

SANTA BARBARA CHANNEL LEASE SALE #48 NOMINATIONS

The unleased area of the Santa Barbara Channel federal OCS represents approximately 95 tracts. At the time of the 1968 lease sale, 44 of these tracts were not offered, primarily because of excessive water depths, while the rest were offered but did not receive bids or the offers received were rejected. The Call for Nominations for the Proposed Lease Sale #48 resulted in all available tracts in the Channel being nominated. Tentatively, BLM has selected 76 tracts in the Channel, plus an additional 33 tracts to the west of Pt. Conception for inclusion in Lease Sale #48. The combined total of 109 tracts is almost identical in number to the 110 tracts offered in the 1968 lease sale. In that sale, 75 tracts received offers, and of these, 71 were accepted.

Of the 109 tracts that may be offered in Lease Sale #48, two-thirds are located in water depths exceeding the capability of conventional fixed-structure platforms. If these tracts are leased and subsequently proved to contain economically recoverable resources, we project that they will be developed with ocean-floor production systems such as Exxon's Submerged Production System proposed for the Santa Ynez Unit. Such systems are preferable to surface structures that would otherwise pose potential navigational risks in the Channel.

SAN PEDRO BAY LEASE SALE #48 NOMINATIONS

BLM has tentatively selected 22 tracts in San Pedro Bay for Lease Sale #48. All 22 were offered in Lease Sale #35 but either received no bids (15 of the 22) or received bids that were rejected by BLM as being too low (7 of the 22).

Assuming these tracts are offered, we would expect that less than half of them will be leased. If leased, their exploration would coincide with the first development and production operations that we projected for existing San Pedro Bay leases that resulted from Lease Sale #35 (i.e., 1980). If these newly leased tracts are found to contain economically recoverable oil and gas, we assume new production facilities would be required but supporting onshore development could be kept to a minimum if that which is developed for the Lease Sale #35 tracts were made available.

OUTER BANKS LEASE SALE #48 NOMINATIONS

For the three Outer Bank areas, BLM has selected 60 tracts for inclusion in proposed Lease Sale #48. Most of these tracts were offered in Lease Sale #35 but were not bid on or received bids that were rejected by BLM as being too low.

Exploration to date in the Tanner Banks has produced discouraging results leading some leaseholders to cancel already-planned exploration programs. Because of the very sparse information available on the Outer Banks, all that can be said about future development resulting from Lease Sale #48 is that the chances for any development at all may simply increase.

SAN DIEGO COAST LEASE SALE #48 NOMINATIONS

Although the San Diego coast offshore area was eligible for nominations in Lease Sale #35, no tract received a nomination at that time. As a result of the Call for Nominations for Lease Sale #48, however, positive nominations were received uniformly from Point Fermin to the Mexican border, extending seaward up to 25 miles beyond the three-mile offshore limit of state-federal jurisdiction. BLM has selected approximately 27 tracts from Dana Point to the international boundary for tentative inclusion on Lease Sale #48. Most of these tracts are in deep water; and we judge that only two tracts could possibly be developed from conventional, fixed-structure platforms (both would be in the 900-foot range). The remainder of the tracts would require deepwater technology such as compliant towers or ocean floor production systems.

If Lease Sale #48 is held and this area is offered, it would initiate the first OCS-related activities along this stretch of coastline. There is presently no onshore or state tidelands oil and gas development in this area, and the only existing petroleum-related activities include San Diego Gas and Electric's marine terminal operation at Carlsbad for offloading fuel oil and a pipeline from the Los Angeles area delivering jet fuels and other refined products to the Navy and other users in the San Diego area. If San Diego coast offshore leases prove to contain economically recoverable resources, it is likely that onshore industrial uses, including processing plants, supply bases, and crew staging areas, will be required to support them. We project that from one to five processing plants and from one to three crew staging and support bases could be required. The location and scale of development will depend on the location and amount of recoverable reserves and other variables, including environmental regulation. If natural gas is discovered, it can be sold directly into major gas transmission lines that parallel the coastline, and relatively little new construction may result. If crude oil is discovered, it will require either the construction of a new pipeline to the Los Angeles basin or one or more marine terminals to permit barging or tankering to the same area.

FOOTNOTES

1. M. R. J. Wyllie, Vice President, West Coast Division, Gulf Energy and Minerals Company -- U.S., letter to Bill Deller, Office of Planning and Research (OPR), October, 27, 1976.

2. R. B. Read, Editor, letter to Allan Lind, OPR, May 1, 1977.

3. See "Unitization" in Chapter 19 for an elaboration on this point.

4. Hillary A. Oden, Acting Conservation Manager, Western Region, Geological Survey, letter to Office of Planning and Research, Attention: Suzanne Reed, June 22, 1976.

5. Personal communication from Ben C. Piester, District Superintendent, Phillips Petroleum Company, to Allan Lind, OPR, July 7, 1976.

6. Personal communication from Maurice V. Adams, Staff Petroleum Engineer, Geological Survey, to Allan Lind, OPR, August 4, 1976. Sun's proposal was to build an onshore processing plant to handle production from the soon-to-be-installed Platform Hillhouse on the Dos Cuadras Offshore field. Sun was denied a permit to construct this facility by the Ventura County Board of Supervisors who encouraged Sun to consolidate its production requirements with Union, operating another portion of the Dos Cuadras field, and to consolidate its processing requirements at the existing Mobil/Rincon plant where Dos Cuadras production was already being handled. Sun eventually carried out these suggestions.

7. Piester, op. cit.

8. Hillary A. Oden, letter to Suzanne Reed, OPR, October 6, 1976.

9. Ibid.

10. Oden, op. cit.

11. Personal communication from Richard Voils, Projects Engineer, Mobil Corporation, to Allan Lind, OPR, July 28, 1976.

12. Ibid.

13. Wyllie, op. cit.

14. Voils, op. cit.

15. Oden, op. cit.

16. See Appendix 2 for production rate estimates made by OPR staff from data supplied by the various offshore operators.

17. Discovery dates for all but the San Pedro field are from Final Environmental Statement, Oil and Gas Development in the Santa Barbara Channel Outer Continental Shelf Off California, U.S. Department of the Interior, Geological Survey, I, 1976, pp. ii-14. The San Pedro Bay discovery was reported in Offshore Magazine (August, 1976), 120.

18. See Chapter 14 and Appendix 2 for further discussion of Santa Ynez Unit resource potential.

19. From a map titled "Map Showing Oil and Gas Fields, Leased Areas, and Seeps in the Santa Barbara Channel Region," Scale 1:250,000. Department of Interior, Geological Survey, Washington, D.C., 1969, G70137. Map is also noted as Plate 2, Professional Paper 679.

20. "Southern California Offshore Lease Map With Oil & Gas Fields," Exxon Company, USA, April 1, 1976.

21. Personal communication from Darrell Warner, Division Operations Manager, Western Division, Production Department, Exxon Company, U.S.A., to Trevor O'Neill, OPR, August 29, 1976.

22. Exxon Company, U.S.A., Supplemental Plan of Operations Santa Ynez Unit, I (Introduction), revised, c. 1973, p. 21.

23. These numbers assume a GOR of 1500 for sales gas. See Appendix 2 for further details. Numbers based on personal communication from Darrell Warner, Exxon, to Trevor O'Neill, October 27, 1976.

24. Exxon Company, U.S.A., op. cit., I, p. 22.

25. Since the design of this facility, Exxon has raised its estimate of the GOR to 2500, with 1500 being sales gas. We would assume that, if the Las Flores Canyon plant is constructed, certain modifications to the original design may be necessary.

26. Exxon's Supplemental Plan of Operations, Interior's FES, Santa Barbara Channel, and Interior's FES, Santa Ynez Unit (1974), agree on the parameters listed.

27. Offshore Magazine, Volume 36, No. 8 (July 1976), 55.

28. Warner, op. cit., August 29, 1976.

29. W. D. Fritz, Acting Producing Manager, Los Angeles Producing Area, Mobil Oil Corporation, letter to David Calfee, OPR, October 21, 1976.

30. Personal communication from W. D. Fritz to OCS Project staff, October 18, 1976.

31. Ibid.

32. Ibid.

33. Ibid.

34. Ibid.

35. Oden, op. cit., June 22, 1976.

36. Personal communication from Thomas A. Hudson, Supervisor of Offshore Planning, Western Operations, Chevron Company, USA, to OCS Project staff, September 28, 1976.

37. See Appendix 2, Table 3.

38. Hudson, op. cit., September 28, 1976.

39. Ibid.

40. Ibid.

41. Ibid.

42. Ibid.

43. Offshore Magazine, October, 1976.

44. Questionnaires regarding such information were sent to all major OCS operators, and each responded except Texaco. Texaco informed OPR that it was unable to respond to the questionnaire for reasons they chose not to explain.

45. Offshore Magazine, Volume 36, No. 11 (October 1976), 115.

46. Los Angeles Times, October 20, 1976.

47. See Chapter 14.

48. L.A. Times, loc. cit.

49. See, for example, letter from Preble Stolz, Director, OPR, to BLM, October 14, 1975; letter from Bill Press, Director, OPR, to Bill Brant, Pacific OCS Manager, BLM, September 14, 1976.

50. Booz-Allen & Hamilton, Inc., A Risk and Cost Analysis of Transporting Southern California Outer Continental Shelf Oil, July 3, 1975, pp. 3-5.

51. Ibid., p. 5.

CHAPTER 22

LEASE SALE #48: BEGINNING AGAIN

BACKGROUND

CALL FOR NOMINATIONS

On July 16, 1976, seven months after completing southern California OCS Lease Sale #35, the Bureau of Land Management issued a Call for Nominations for southern California Lease Sale #48. 1/ The area covered by the Call included the offshore southern California area already considered in OCS Lease Sale #35, plus the Santa Barbara Channel. In all, 2,400 tracts encompassing 13.2 million acres between Point Conception and the Mexican border were tentatively proposed for inclusion in the sale (see Figure 1), scheduled to take place in March, 1978.

In response to the Call for Nominations, California State and local governments submitted "negative nominations" opposing leasing in specified offshore areas, based primarily on concerns over:

1. air quality impacts;
2. oil spill risks;
3. threat to areas of special biological significance and ecological importance;
4. conflicts with navigation;
5. lack of adequate information concerning the extent of oil and gas resources or potential for damage to environmental, recreational, and aesthetic resources;
6. cumulative effects of OCS development combined with a number of other major energy activities proposed for the California coast;
7. lack of adequate assurance that OCS exploration and development would be conducted in a manner consistent with California's Coastal Zone Management Program; and,
8. need for amendment of the OCS Lands Act, in order to provide adequate environmental safeguards and a greater role for state and local governments in leasing and development decisions. 2/

Tracts recommended for exclusion from the OCS Lease Sale #48 area included:

1. all tracts excluded for environmental and geologic reasons from Lease Sale #35, including:

a. Santa Monica Bay;
b. tracts south of San Miguel Island;
c. portions of tracts adjoining state jurisdiction offshore of the Palos Verdes Peninsula, Long Beach, and all of Orange County; and,
d. four tracts in the Outer Banks areas designated as tracts with high geologic hazard;

2. all tracts located within three miles of the three-mile state tidelands boundary;
3. all unleased tracts in the San Pedro Bay;
4. all tracts intersected by vessel traffic lanes and separation zones; and,
5. all tracts wholly or partially overlying bank areas of recognized ecological value.

These negatively nominated areas are shown in Figure 2.

Representatives of several local governments whose coastal areas would be potentially affected by Lease Sale #48 also submitted negative nominations and expressed views on tract selection for consideration by BLM.

The County and City of Santa Barbara recommended deletion of all tracts in the Santa Barbara Channel and surrounding the Channel Islands. 3/ Supervisor Hayes, of the County of Los Angeles, recommended extending the Santa Monica Bay exclusion area and deleting all tracts surrounding Santa Catalina Island and lying between the Island and the mainland. 4/

The City of Newport Beach, in Orange County, registered its opposition to any further leasing of offshore southern California until technological advances significantly reduce the risks to recreational resources inherent in OCS development. 5/

The County of San Diego recommended deletion of all tracts within approximately fifty miles of the Los Angeles, Orange, and San Diego County coastlines. 6/ A similar recommendation was submitted (November 19, 1976) by the Comprehensive Planning Organization of the San Diego Region 7/ and by the San Diego Coast Regional Commission. 8/ In addition, San Diego's Mayor Wilson negatively nominated tracts within the Thirty- and Forty-Mile Bank areas off San Diego. 9/

Many of the areas identified by state and local government as particularly sensitive to oil and gas development correspond with tracts specified as high-interest areas by industry. Seventeen oil companies positively nominated 970 tracts totalling over five million acres. 10/ Those areas receiving greatest industry response were in the Santa Barbara Channel, offshore San Diego, San Pedro Bay, and the Outer Banks (see Figure 3).

TRACT SELECTION

In October, 1976, the Pacific Coast office of BLM held an "environmental briefing" for state and local representatives, in which highly generalized and dated information concerning the proposed lease area was presented orally. In late November, the Pacific Coast BLM office invited state representatives to attend a meeting on December 2, 1976, to discuss tract selection recommendations for Lease Sale #48. 11/ Local representatives were notified of the meeting by telephone the day before it took place. At the meeting, the information was presented verbally, in summary fashion. BLM refused to provide state and local government representa-

Figure 1

LEASE SALE 48: CALL FOR NOMINATIONS AREA

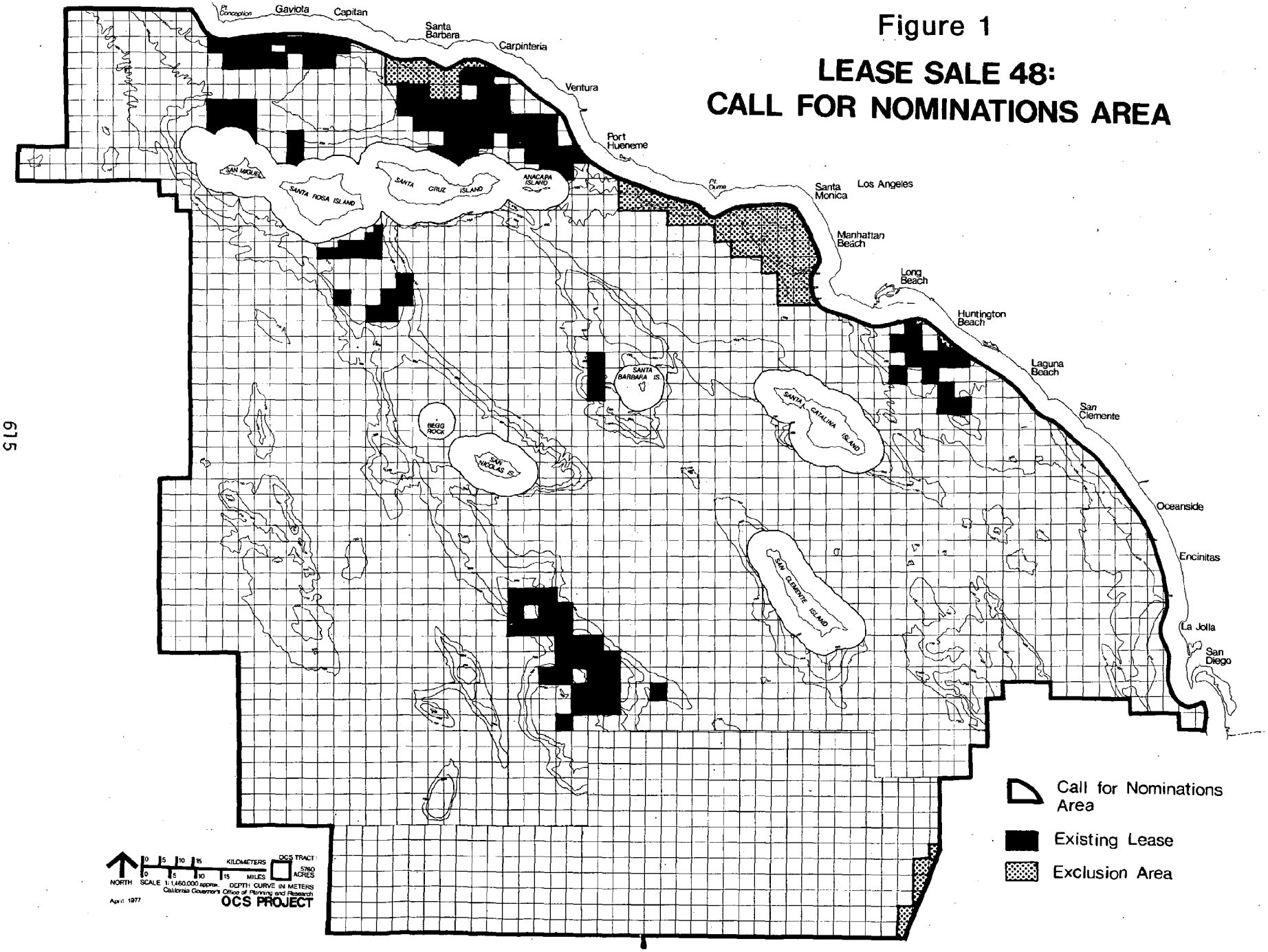


Figure 2

LEASE SALE 48: GENERALIZED POSITIVE NOMINATIONS

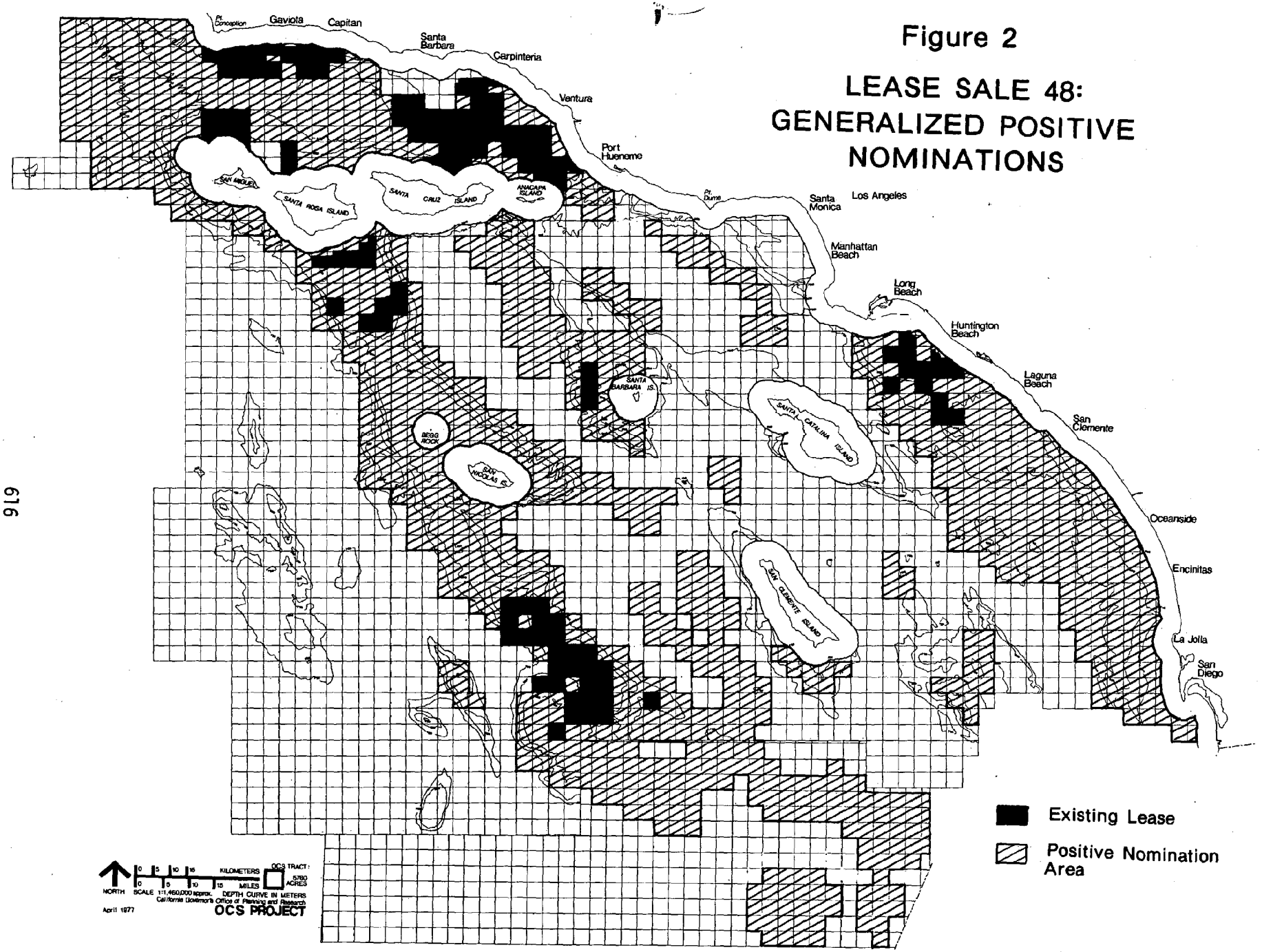
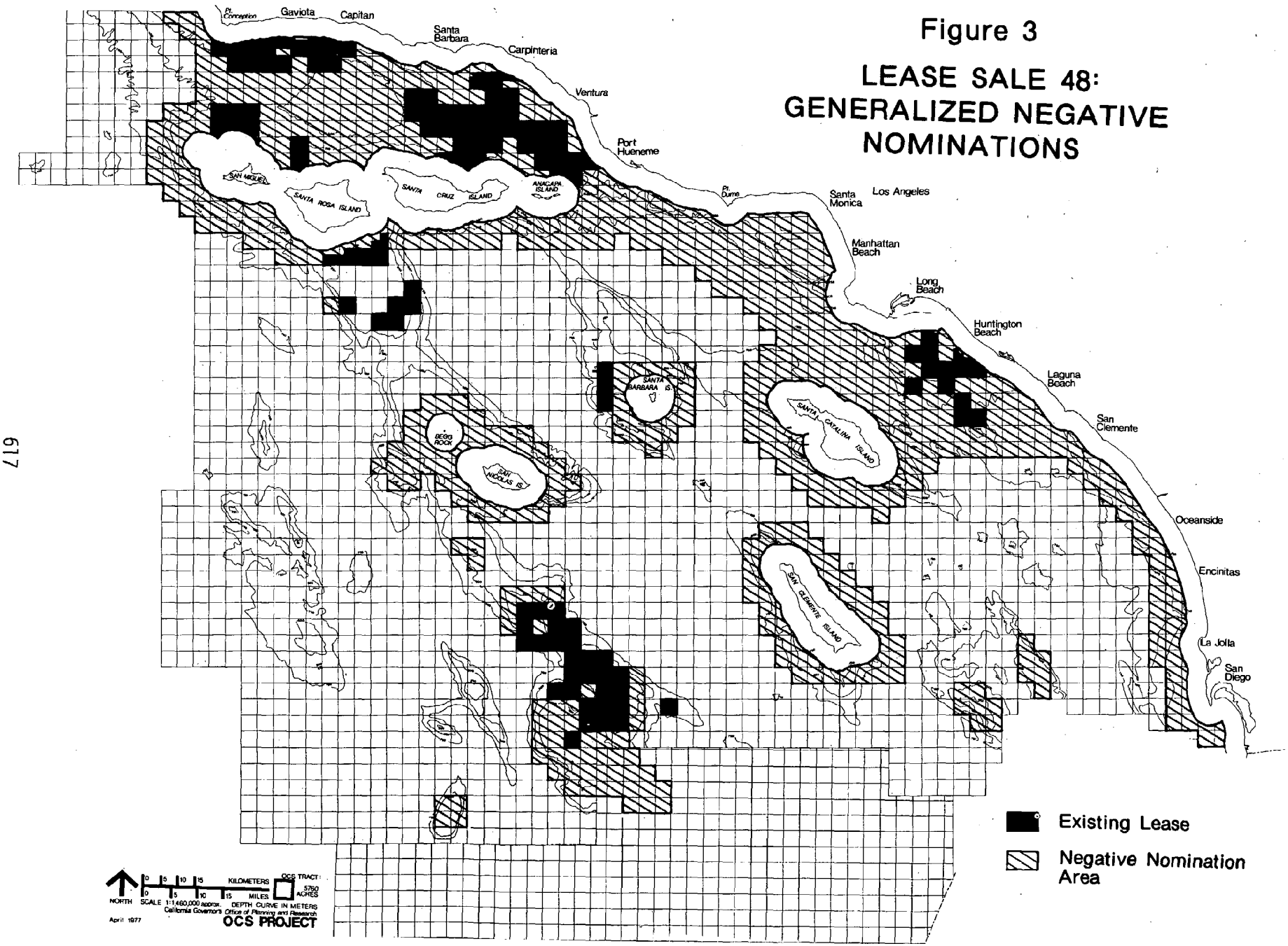


Figure 3

LEASE SALE 48: GENERALIZED NEGATIVE NOMINATIONS



tives with the Pacific Coast office's written tract selection recommendations prepared for the Washington offices of BLM and USGS in spite of two written requests from the State. 12, 13/

State and local government representatives were invited to attend a tract selection meeting in Washington, D.C., scheduled for two weeks after the Pacific Coast office presentation. 14/ However, lacking written recommendations to which they could respond substantively, California state and local governments were ill-prepared to participate. The State responded in writing, reiterating previously expressed concerns and pointing out that a majority of the federal agencies providing BLM with resource reports on the Lease Sale #48 area had raised concerns similar to those of California state and local governments. 15/

The Director of the Department of the Interior's Bureau of Outdoor Recreation (BOR) characterized the southern California coastal and offshore area as "one of the best known and most heavily used recreation and resort destinations in the United States." Describing the entire southern California coastal and offshore area as a recreational resource of "special significance," BOR emphasized that the "special significance intensifies around the Channel Islands, inshore waters, shoreline, estuaries, and accessible stretches of coast in the vicinity of population centers and resort destinations." 16/

The National Marine Fisheries Service, 17/ the Fish and Wildlife Service, 18/ and the Marine Mammal Commission 19/ characterized the southern California bays, wetlands, estuaries, and offshore rocks and waters as important habitats for commercial and sport fish, marine birds, and marine mammals. Many species of birds and mammals found in these areas are rare or endangered, including the brown pelican and seven species of cetaceans. Each of these agencies emphasized the especially unique qualities and sensitivity of the Santa Barbara Channel marine species habitats. Fish and Wildlife reaffirmed its view, as expressed in response to Lease Sale #35, that an

> ...ecological buffer zone should be established around all the Channel Islands, especially San Miguel Island and Santa Barbara Island, in order to protect them from the possible adverse effects of OCS leasing and development.

The Marine Mammal Commission recommended that further leasing in the Channel be delayed until environmental baseline studies are completed and a better understanding of the potential for OCS activities to affect marine mammal population adversely is reached. The Commission also recommended that the three-mile buffer zone afforded by state territorial waters around San Miguel, Santa Rosa, and most of Santa Cruz islands be augmented by a three-mile federal buffer zone in order to protect pinniped and cetacean habitats.

The Environmental Protection Agency recommended that the entire Santa Barbara Channel be deleted from the lease sale because of the "hazardous potential" for adverse effects from OCS leasing and development. 20/ The National Park Service expressed its desire to protect cultural resources of the southern California offshore area, especially the 33 archeological sites, including nine possible early village sites known to exist off the southern California coast. 21/

On January 18, 1977, BLM announced the selection of 217 tracts to be examined in the OCS Lease Sale #48 Environmental Impact Statement. 22/ Although some of

the tracts negatively nominated by California state and local government were excluded from consideration, the apparent reason for this was lack of industry interest. On the other hand, the entire Santa Barbara Channel, for which state, local, and federal opposition to leasing is the greatest, was selected (see Figure 4).

ENVIRONMENTAL IMPACT STATEMENT

The Bureau of Land Management began to prepare the Lease Sale #48 Environmental Impact Statement in early 1977 by contacting state and local representatives to invite participation in drafting the Lease Sale #48 Environmental Impact Statement. 23/ The draft EIS was scheduled for publication in late 1977, with the final EIS scheduled for publication early next year just prior to the March, 1978, lease sale date. Local and state government representatives responded with recommendations as to how their participation might be structured. 24, 25/ This response included requests for:

1. the Department's budget for Lease Sale #48, including allocation for staff and contractual services among various subject areas, and,
2. financial assistance to local governments in order to support independent review and analysis of the EIS.

In addition, this response recommended that:

1. an Executive Summary of the EIS be prepared and widely distributed;
2. the EIS consider in detail energy alternatives to OCS development and indicate the actual effect on the energy supplies of deleting various tract offerings such as the Santa Barbara Channel or the area immediately offshore San Diego;
3. BLM use a more suitable method for analyzing economic impact at the subregional level than is currently planned, and that such analysis consider the economic effects of deteriorated air quality and oil spills;
4. BLM place considerable emphasis on oil spill impact analysis and reconsider whether the EIS is using the most suitable trajectory model available;
5. BLM reconsider its proposed air quality impact assessment in light of the need for better data and more time to develop a credible and useful analysis; and,
6. the EIS address in detail potential conflicts between military operations based on the southern California coast and OCS development.

Because the City of San Diego also filed suit against the lease sale, the Department was hesitant to respond in writing to local government requests for information on the EIS.

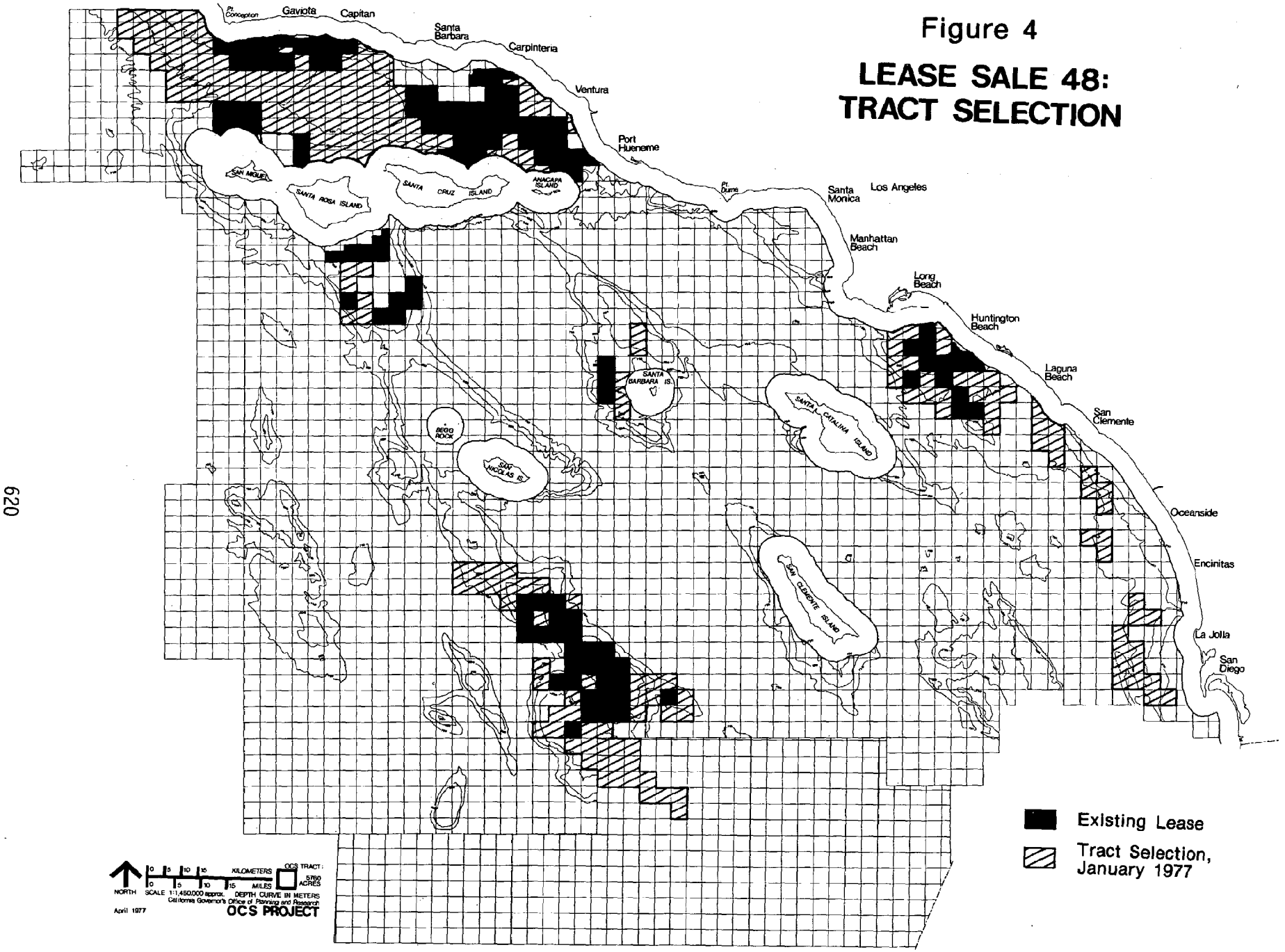
RELATIONSHIP TO LEASE SALE #35 AND THE NATIONAL OCS LEASING SCHEDULE

State and local concerns over Lease Sale #48 are similar to those expressed over Lease Sale #35, which is now the subject of litigation between the State of California and the Department of the Interior. Responding to some of these concerns in 1975, the Department of the Interior stated its intention to:

1. resolve confusion over regulation of OCS drilling in shipping lanes in order to minimize threats to navigation; 27/ and,
2. commence pipeline corridor studies in cooperation with state and local

Figure 4

LEASE SALE 48: TRACT SELECTION



governments, once a commercial discovery of oil was made in the Lease Sale #35 area. The studies would be part of a national planning process that would ultimately eliminate a proliferation of tanker traffic and OCS-related facilities and operations, thereby minimizing threats to navigation and harmful onshore effects. 28/

More than a year later, regulations governing drilling activities in the shipping lanes have been proposed but not made final. 29/ Meanwhile, exploratory rigs have been drilling in shipping lanes for the past six months. Furthermore, although commercial discoveries of oil have been made on OCS Lease Sale #35 tracts in the San Pedro Bay, the BLM has not initiated a cooperative effort with state and local governments to conduct the promised pipeline corridor studies.

Lease Sale #48 was scheduled by the previous Administration as part of an ill-considered accelerated leasing program. This program was arbitrarily formulated without the benefit of a cohesive national energy policy that would enable a rational examination of OCS development's role in meeting national energy needs. The new Administration indicated its intention to review the schedule in light of this deficiency. 30/

Under the previous Administration, the Department had reduced the original ten-million-acre-per-year leasing goal 31/, and the schedule for opening all frontiers to leasing by 1978 was extended to 1980. 32/ However, the Department still lacks an adequate data base and sufficient staff to produce reliable resource estimates. In addition, inadequacies in federal leasing policy and baseline studies noted in Chapter 13 still plague the Department's OCS leasing program. Many of these inadequacies would be corrected through enactment of currently pending legislation to amend the Outer Continental Shelf Lands Act.

CONCLUSION

Well into 1977 it was not clear to what degree the Interior Department would respond to State and local government concerns over Lease Sale #48. Representatives of the State met with Department of Interior officials, appointed by the new Administration on February 28, 1977, to request that Lease Sale #48 be postponed until:

1. the Department of the Interior fully reconsidered the National OCS Leasing Schedule in the context of developing a national energy policy;
2. amendments to the Outer Continental Shelf Lands Act, providing additional environmental safeguards and an enhanced role for the states in leasing and development decisions, have been enacted;
3. California received necessary assurances that OCS leasing and development will be conducted in a manner consistent with the State's Coastal Zone Management Program;
4. more reliable petroleum resource and geologic data, resulting from current southern California OCS exploration activities, became available;
5. adequate plans for the disposition of the impending West Coast crude oil surplus, to which additional OCS leasing and development will contribute, have been made; and,
6. the issue of potential conflicts between OCS exploration and development and vessel navigation has been adequately resolved.

On May 17, 1977, California and all coastal states received a clear signal from

Secretary of the Interior, Cecil D. Andrus, that the new Administration would be more sensitive to state and local concerns in the OCS leasing and development process. Secretary Andrus replaced Secretary Kleppe's OCS Leasing Schedule with a newly-revised OCS Planning Schedule covering sales to be held through the end of 1978. Lease Sale #48, originally scheduled by Kleppe for March, 1978, was removed from the schedule of 1978 sales.

The Secretary also announced his intention to issue a schedule in August to cover sales for the 1979-1980 period in which Lease Sale #48 might be included. Describing the new schedule, Secretary Andrus said:

> The principal goal of the program continues to be the increased production of oil and gas from U.S. offshore areas.... Completion of development in known areas, along with a steady exploration and development pattern in frontier areas (including Alaska), are the twin thrusts of the program. There remains a critical need to develop the Nation's overall oil and gas resources as a part of the President's National Energy Plan.
>
> What is substantially different is the manner in which the program will be carried out in relation to the states, local government, and the general public. While expecting that every region will support and contribute to the program, I intend to recognize fully the distinct social, economic, technological, cultural, and environmental elements with each individual region and sale.
>
> The emphasis will be on working with the states and others to resolve key issues associated with sales or the opening of new regions. I believe this objective can be accomplished most effectively by providing adequate time in the planning process for resolving conflicts and involving coastal states in a significant manner. 33/

California state officials and local governments are relieved that the new Secretary's assessment of Lease Sale #48 apparently resulted in conclusions similar to their own, that Lease Sale #48 was scheduled precipitously and, as such, was destined to proceed based on inadequate environmental and oil and gas resource information. However, no state should be required to rely on the uncertainties of an OCS leasing and management policy that may change from Administration to Administration. Nor should the petroleum industry be expected to operate in an atmosphere of political uncertainty.

It is important to continue all efforts to achieve mandated reforms in the OCS leasing and development process through enactment of the OCS Lands Act Amendments. Insofar as Lease Sale #48 is concerned, the Bureau of Land Management's Pacific Coast Office will continue to prepare the Environmental Impact Statement for OCS Lease Sale #48 using an extended schedule for completion of the draft.

California state and local governments must avail themselves of the extended time to assure accurate and complete consideration of the effects of Lease Sale #48 on the southern California environment. Only active and persistent state and local government involvement will assure an Environmental Impact Statement suitable for informed decision making on Lease Sale #48.

FOOTNOTES

1. Federal Register, July 16, 1976.

2. Letter from Bill Press, Director, Governor's Office of Planning and Research, to George Turcott, Associate Director, Bureau of Land Management, September 14, 1976.

3. Letter from Santa Barbara County Board of Supervisors to George Turcott, Associate Director, Bureau of Land Management, December 6, 1976, Resolution of Santa Barbara City Council, September 7, 1976.

4. Letter from Los Angeles County Supervisor James Hayes to George Turcott, Associate Director, Bureau of Land Management, September 3, 1976.

5. Letter from Newport Beach City Council to George Turcott, Associate Director, Bureau of Land Management, July 28, 1976.

6. Letter from San Diego County Board of Supervisors to George Turcott, Associate Director, Bureau of Land Management, November 16, 1976.

7. Letter from Comprehensive Planning Organization of the San Diego Region to George Turcott, Associate Director, Bureau of Land Management, November 19, 1976.

8. Letter from Malcolm A. Love, Chairman, San Diego Coast Regional Commission to Melvin B. Lane, Chairman, California Coastal Zone Conservation Commission, November 3, 1976.

9. Letter from Mayor Pete Wilson, San Diego, to Secretary of Interior Thomas Kleppe, August 6, 1976.

10. Press release, "Seventeen Companies Nominate Five Million Acres for Proposed Oil and Gas Lease Sale (OCS #48) Offshore Southern California," U.S. Department of the Interior, Bureau of Land Management, October 6, 1976.

11. Letter from William Grant, Manager, U.S. Department of the Interior, Bureau of Land Management, Pacific OCS Office, to Suzanne Reed, OCS Project Manager, Governor's Office of Planning and Research, November 26, 1976.

12. Letter from Suzanne Reed, OCS Project Manager, Governor's Office of Planning and Research to William Grant, Manager, Department of the Interior, Bureau of Land Management, Pacific Coast Office, October 25, 1976.

13. Letter from Bill Press, Director, Governor's Office of Planning and Research, to Ronald Coleman, Assistant Secretary of Interior for Program Development and Budget, November 15, 1976.

14. Telegram from Frank Edwards, Assistant Director, Bureau of Land Management, to Governor Edmund G. Brown, Jr., California, January 17, 1977.

15. Letter from Bill Press, Director, Governor's Office of Planning and Research, to Curtis J. Berklund, Director, U.S. Department of the Interior, Bureau of Land Management, January 5, 1977.

16. Memorandum from Director, Bureau of Outdoor Recreation, to Director, U.S. Department of the Interior, Bureau of Land Management, June 3, 1976.

17. Letter from Robert M. White, Administrator, National Oceanic and Atmospheric Administration, to Curtis Berklund, Director, U.S. Department of the Interior, Bureau of Land Management, June 7, 1976.

18. Memorandum from Allan Hirsch, Director, U.S. Department of the Interior, Fish and Wildlife Service, to Director, Bureau of Land Management, June 25, 1976.

19. Letter from John R. Twiss, Jr., Executive Director, Marine Mammal Commission, to Curtis Berklund, Director, U.S. Department of the Interior, Bureau of Land Management, September 8, 1976.

20. Letter from Rebecca Hanmer, Director, Environmental Protection Agency, Office of Federal Activities, to Curtis J. Berklund, Director, U.S. Department of the Interior, Bureau of Land Management, May 19, 1976.

21. Memorandum from R. Rodgers, Assistant Secretary for Fish and Wildlife and Parks, National Park Service, to Director, Bureau of Land Management, May 17, 1976.

22. Press release, "Interior Makes Tract List Available for Possible Southern California Offshore Sale (OCS #48)," U.S. Department of the Interior, Bureau of Land Management, January 18, 1977.

23. Letter from Harold Martin, Acting Manager, U.S. Department of the Interior, Bureau of Land Management to Bill Press, Director, Governor's Office of Planning and Research, February 10, 1977.

24. Letter from Arthur Letter, Director for Intergovernmental Relations, Comprehensive Planning Organization, to Bill Grant, Manager, U.S. Department of the Interior, Bureau of Land Management, Pacific OCS Office, March 22, 1977.

25. Letter from Bill Press, Director, Governor's Office of Planning and Research, to Bill Grant, Manager, U.S. Department of the Interior, Bureau of Land Management, Pacific Coast OCS Office, April 4, 1977.

26. County of San Diego, et al. v. Cecil Andrus, et al., USDC SD (No. 77-0236-N), filed April 14, 1977.

27. Bureau of Land Management, Final Environmental Statement: Proposed 1975 Outer Continental Shelf Oil and Gas General Lease Sale Offshore Southern California (OCS Sale No. 35), U.S. Department of the Interior, vol. 3, p. 93.

28. Ibid., vol. 2, p. 538.

29. Secretary of the Interior, Cecil Andrus, Testimony before the House Interior and Insular Affairs Committee, February 1, 1977.

30. U.S. General Accounting Office, op. cit., p. 59.

31. Federal Register, October 21, 1976.

32. Press release, "Revised Outer Continental Shelf Oil and Gas Planning Schedule is Released," U.S. Department of the Interior, Bureau of Land Management, January 12, 1977.

33. Press release, "Revised OCS Planning Schedule Announced," U.S. Department of the Interior, Bureau of Land Management, May 17, 1977.

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LEGEND

SENSITIVE RESOURCES INVENTORY


Pinniped Rookery &
Major Hauling Out Site


Marine Bird Rookery


Wetland


Rocky Intertidal


Kelp Bed

Sandy Beach

Area of Special
Biological Significance

State Oil & Gas Sanctuary

Ecological Reserve &
Marine Life Refuge

Estuarine Sanctuary

Three Mile Line

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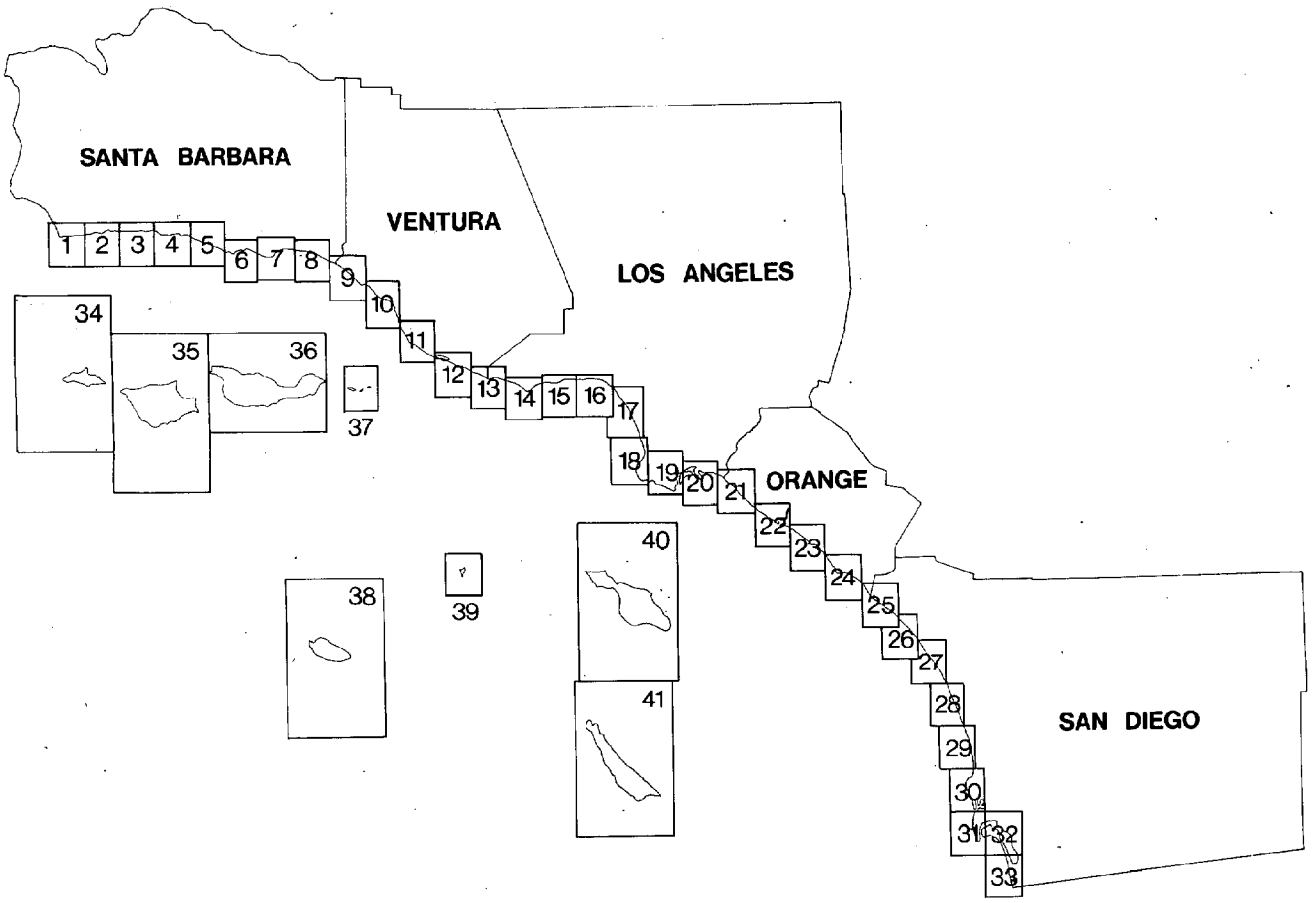
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INVENTORY MAPS
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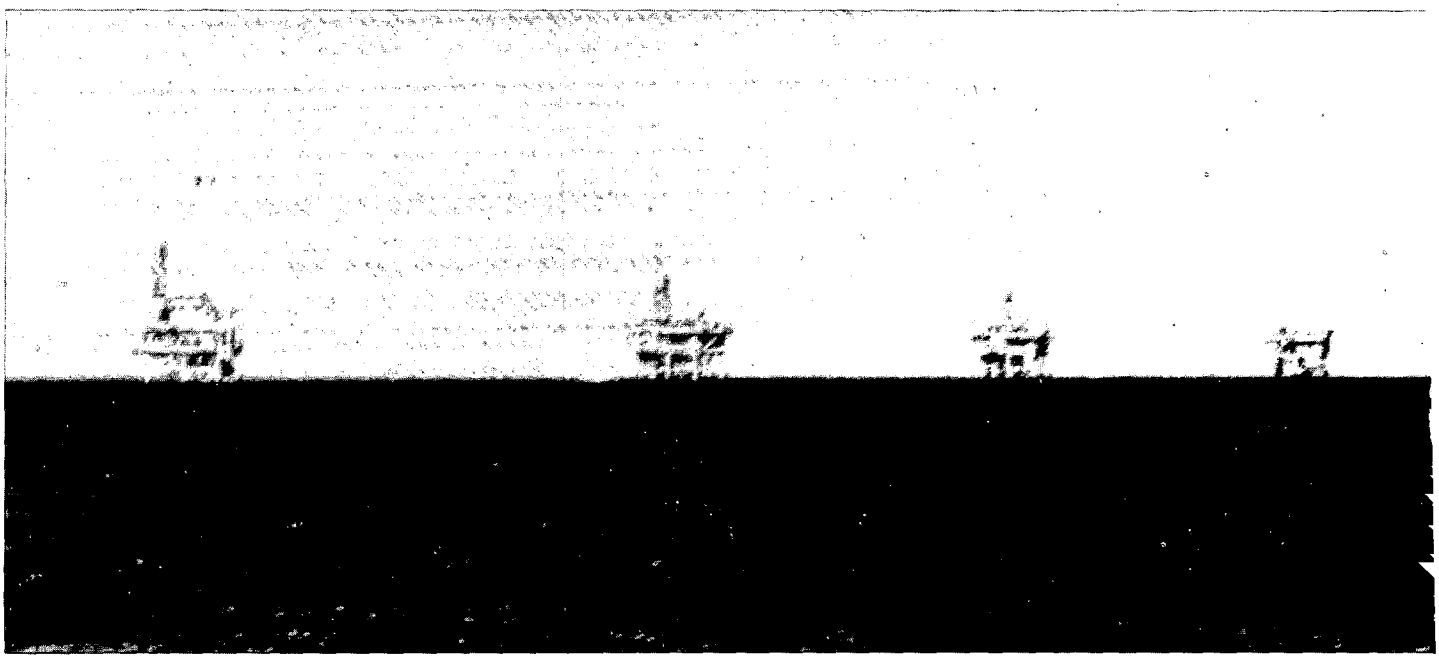

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