UNITED STATES
DEPARTMENT OF THE INTERIOR

FINAL
ENVIRONMENTAL STATEMENT
VOLUME I OF 3

OIL AND GAS DEVELOPMENT IN THE SANTA BARBARA CHANNEL OUTER CONTINENTAL SHELF OFF CALIFORNIA

U.S. DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

PREPARED BY THE
UNITED STATES GEOLOGICAL SURVEY
DEPARTMENT OF THE INTERIOR

V. E. McKelvey
(Director)

Summary

1. Oil and Gas development in the Santa Barbara Channel Outer Continental Shelf

(X) Administrative ( ) Legislative Action

2. Possible levels of oil and gas development in the Santa Barbara Channel. These are:

- Completely Develop Existing Producing Leases
- Explore and Develop All Existing Leases
  - Leased Areas with Discoveries
    - Santa Ynez Unit Discovery Area
    - Pitas Point Unit Discovery Area
    - Santa Clara Unit Discovery Area
    - Discovery Area Contained in Leases OCS-P 0202 and 0203
  - Leased Areas without Discoveries
- Lease, Explore and Develop Presently Unleased Areas

The Santa Barbara Channel, Outer Continental Shelf, reserves that could be developed by additional facilities and associated activities are estimated to be on the order of magnitude of 1 to 2 billion barrels of oil.

3. Oil and gas development in the Santa Barbara Channel, Outer Continental Shelf, poses a degree of pollution risk to the marine environment, adjacent shorelines, and at sites of onshore treating and processing facilities. The risk is related to adverse effects on the environment and other resource use which would result from accidental or recurrent spillage. This statement presents an evaluation of potential environmental impacts that result from oil and gas operations in the Santa Barbara Channel.

4. Administrative and energy alternatives are considered in section VIII.

5. Comments were requested from the following Governmental agencies (See section IX.B. for Agency comments):

FEDERAL

Environmental Protection Agency

Department of Commerce
- National Oceanic and Atmospheric Administration
  - National Marine Fisheries Service

Department of Defense
- Department of the Army
  - Corps of Engineers

Department of the Interior
- Bureau of Sport Fisheries and Wildlife
- Bureau of Land Management
- Office of Oil and Gas
- Bureau of Mines
- Bureau of Outdoor Recreation
- National Park Service

Department of Transportation
- United States Coast Guard
- Office of Pipeline Safety

STATE OF CALIFORNIA

State Clearinghouse
- Office of the Lieutenant Governor

Metropolitan Clearinghouses
- Santa Barbara County-Cities Area Planning Council
- Southern California Association of Governments

States Land Commission
- State Lands Division

Resources Agency
- Water Resources Control Board
- Department of Conservation
- Regional Water Quality Control Board, Central Coastal Region
- Department of Fish and Game
- Department of Water Resources
- Department of Parks and Recreation

California Coastal Zone Conservation Commission
- South Central Region
- South Coast Region

OTHER

County of Santa Barbara

County of Ventura

6. Draft statement made available to the Council on Environmental Quality and the public on June 6, 1975.

7. Final Statement made available to the Council on Environmental Quality and the Public on

CONVERSION FACTORS FOR READER INFORMATION

Gravity in degrees API (^{o}API) $= \frac{141.5}{\text{Sp. gr.}} - 131.5$ Example: Water = 10^{o} API

1 nautical or geographical mile = 6,076.12 feet = 1,852.00 meters

1 statute mile = 5,280 feet = 1,609.35 meters

1 knot = 1 nautical mile per hour = 1.151 statute miles per hour
= 1.69 feet per second (ft/sec)

1 cubic meter = 264.2 U. S. gallons = 35.31 cubic feet

1 cubic foot = 7.48 U. S. gallons

1 oilfield barrel = 42 U. S. gallons = 159 liters

Parts per million (ppm) = milligrams per liter (mg/L)

Parts per thousand (ppt) = milligrams per milliliter (mg/mL)
= grams/liter (g/L)

1 grain = 0.064798918 grams

1 grain per gallon (gpg) = 17.118 milligrams/liter (mg/L)
= 17.118 parts per million (ppm)

1 metric ton (M ton) = 1,000 kilograms = 2,204.62 pounds avoirdupois

1 U. S. standard pound avoirdupois = 453.592 grams

1 kilogram = 2.205 U. S. standard pounds avoirdupois

Weight of fresh water at 4^{o} C = 62.43 pounds per cubic foot
= 8.346 pounds per gallon

Average specific gravity of sea water = 1.025

Average weight of sea water at 4^{o} C = 63.99 pounds per cubic foot
= 8.555 pounds per gallon

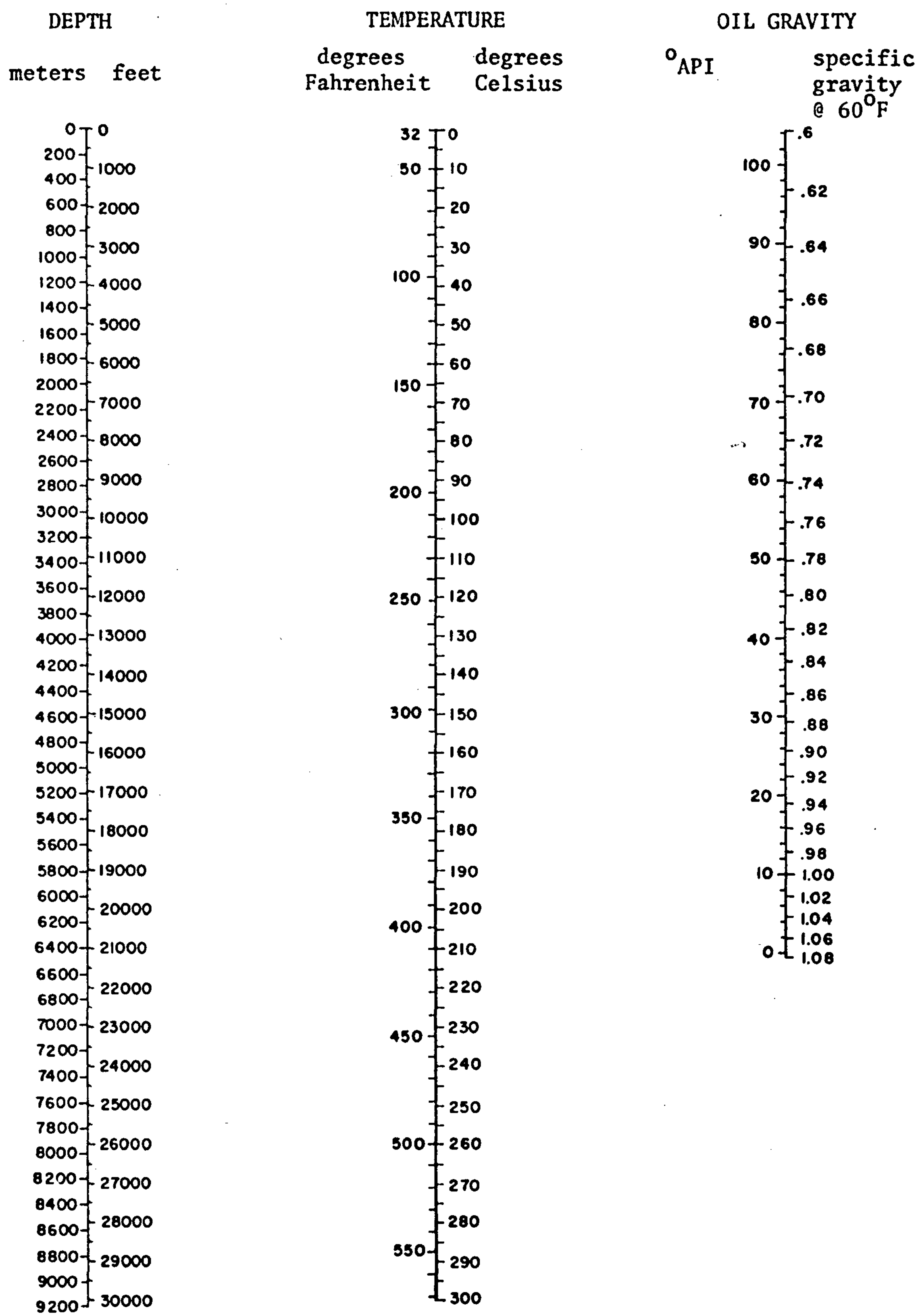
1 megawatt (MW) = 1,000,000 watts (W) = 1,340 horsepower (hp)

1 British Thermal Unit (BTU) = heat required to raise the temperature of one pound of water at its maximum density 1^{o} F.

1 horsepower (hp) = 42.418 BTU per minute = 746 watts

1 kilowatt-hour (kwh) = 1,000 watt-hours (wh)
= 1.341 horsepower-hours (hph)
= 3,413 BTU

CONVERSIONS



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ii. Introduction

I. Description of Potential Levels of Activities in Development of the Santa Barbara Channel OCS

II. Description of the Environment

PREFACE

In this environmental statement the Department of the Interior examines the potential impacts arising from oil and gas production in Federal OCS lands in the Santa Barbara Channel lying generally landward from the larger Channel Islands. More specifically, the area under consideration is OCS lands lying generally north of latitude 34°N, west of longitude 119°, and east of longitude 120°30'. Only a part of the OCS lands in the Channel has been leased by the Federal Government for oil and gas exploration and production. Of the lands so leased, only a few tracts had producing operations in progress on December 1, 1973. Considerable production is taking place in State waters and on adjacent onshore areas. In May 1974, the Department of the Interior issued its final environmental statement on a Proposed Plan of Development for the Santa Ynez Unit in the Channel. That Unit has only been partially explored to date. Three potential fields have been discovered; the Hondo field was proposed for development, while the Pescado and Sacates potential fields require further exploration to define their extent. In addition, some production history may be necessary before long-range Plans of Development can be submitted for approval. Four additional potential fields have been discovered in other areas of the Santa Barbara Channel (see figure 1 in the Introduction). These four potential fields require further exploration to define their extent. Reservoirs in the Federal OCS Dos Cuadras and Carpinteria fields are currently producing from three leases at the rate of 41,700 barrels of oil 43,900 barrels of water per day and 16,500 cubic feet of gas per day (August 1975). A total of 197 wells have been drilled on these leases. Proposals may be made in the future for other development of these three leases. Thirty-five Federally leased tracts had been proposed to the Congress for termination (HR-7500, HR-3177, and HR-3178). On November 16, 1973, the Department of the Interior recommended to the Chairman of the Committee on Interior and Insular Affairs, House of Representatives, that no action be taken on these measures. The Department's recommendation stated in part:

> "Our recommendation that none of the bills be enacted stems from our conviction that changing circumstances since the Administration proposal was formulated require that the Santa Barbara situation undergo thorough reconsideration including the preparation of a new environmental impact statement on all facets of oil production in the channel.---
>
> "The first new factor that has emerged since the Santa Barbara proposal was first formulated is an energy shortage of substantial proportions.---
>
> "The second new factor that has entered into the picture since 1969 is improved procedures and technology governing oil production in Outer Continental Shelf Lands.
>
> "The offshore regulations of the Geological Survey have been extensively revised to define more clearly the responsibility of lessees and the authority of the Survey's Regional Supervisor over OCS operations; to exercise tight control over drilling, production, and waste disposal; and to require equipment fully adequate for the safe conduct

> of operations. Much stress has been placed on the development of redundancy or "fail-safe" devices and procedures that provide for safety when another device or procedure has failed.---
>
> "Having considered these factors, we have determined that our Santa Barbara proposal should be reconsidered. One of the vehicles for doing this will be the National Environmental Policy Act. Signed into law by President Nixon on January 1, 1970, this Act established carefully thought-out procedures and policies which have governed all subsequent Federal decision-making having environmental ramifications. When the results of our study process are in, we will reexamine our proposal and communicate our decision to the Congress. Given the energy shortage that is now upon us, we believe that such a reexamination is strongly in the national interest. The differing approaches of HR-3177 and HR-3178 to the Santa Barbara situation will certainly be included in our reexamination; at this time, we recommend that no Santa Barbara bill be reenacted.---"

The Assistant Secretary for Energy and Minerals, Department of the Interior, had testified to the same effect on November 13, 1973, before the Subcommittee on Minerals Materials and Fuels, Committee of Interior and Insular Affairs, United States Senate, with respect to S. 1951 and S. 2339, bills dealing with oil and gas production in the Santa Barbara Channel. The Assistant Secretary noted that the Department's position was "that neither bill should be enacted at this time." The Department had proposed instead to undertake a thoroughgoing review of the Santa Barbara situation, including environmental impact statements on the ramification of developing the oil and gas in the Channel.

During the preparation of this statement the 93d Congress adjourned without acting on such energy reserve legislative bills. Subsequent court rulings (see section I.B.) determined that suspensions of the leases within the proposed energy reserve were no longer in effect after the 92d Congress adjourned, on October 18, 1972, without taking action on the legislation. (See Introduction p. ii-16 and section I.B. "Proposed National Energy Reserve" and section VIII.F.). Presently there are no Santa Barbara Channel Proposed Energy Reserve legislation before Congress. However, in the event such legislation should be submitted to Congress in the future, this statement could serve to evaluate such bills.

This environmental impact statement will consider the environmental impacts which could be associated with four possible future levels of development of oil and gas leases in the Santa Barbara Channel. The possible levels of development are as follows: (1) continue production from existing producing leases; (2) develop new production from existing leases on which oil and gas capable of being produced in paying quantities have been discovered; (3) explore and subsequently develop existing leases on which no discoveries have been made in the Santa Barbara Channel; (4) lease, explore and develop presently unleased acreage in the Outer Continental Shelf of the Santa Barbara Channel.

Other than the recently approved plan of development for the Santa Ynez Unit and routine on-going exploratory drilling programs, no formal applications were pending for development programs within the Santa Barbara Channel Outer Continental Shelf when this statement was published in draft form. However, subsequent to publication of the draft statement, the Pacific Area Oil and Gas Supervisor received a proposed Plan of Development (dated September 29, 1975) for the eastern portion of lease OCS-P 0240. The Plan consists of a request for the drilling of one or more exploratory evaluation wells and tentative approval for the installation of Platform Henry. This platform was previously proposed and denied. (See sections III.C.3. and III.C.3.a. for further discussion on this proposed platform). In addition, the Department can reasonably expect to receive requests for approval of exploration and development activities pursuant to rights established under leases issued in 1966 and 1968 in the Santa Barbara Channel. This environmental impact statement will provide an analysis of potential environmental impacts which could result from such activities and will be used by the Department in its review of such requests as may be submitted to it for approval in the future.

INTRODUCTION [1]

Santa Barbara Channel Region

The Santa Barbara Channel region includes the Santa Barbara Channel and adjacent land areas. The Channel is an elongate hydrographic feature off the southwest California coast about 110 miles northwest of Los Angeles and 280 miles southeast of San Francisco (figure 1). The Channel is bounded on the north and east by the shoreline of Santa Barbara and Ventura Counties, on the south by the Channel Islands of San Miguel, Santa Rosa, Santa Cruz, and Anacapa, and on the west by the open waters of the Pacific Ocean. The east-west length of the Channel is approximately 70 miles, the north-south width is 25 to 30 miles, and the total area is about 1,750 square miles.

Approximately 1,300 square miles or 74 percent of the Santa Barbara Channel is more than 3 nautical miles from shorelines of the mainland and Channel Islands, and is administered by the Federal Government.

On January 1, 1973, 351,877 acres, or about 40 percent of the Outer Continental Shelf portion of the Santa Barbara Channel was held by 69 oil and gas leases issued by the Bureau of Land Management, U. S. Department of the Interior.

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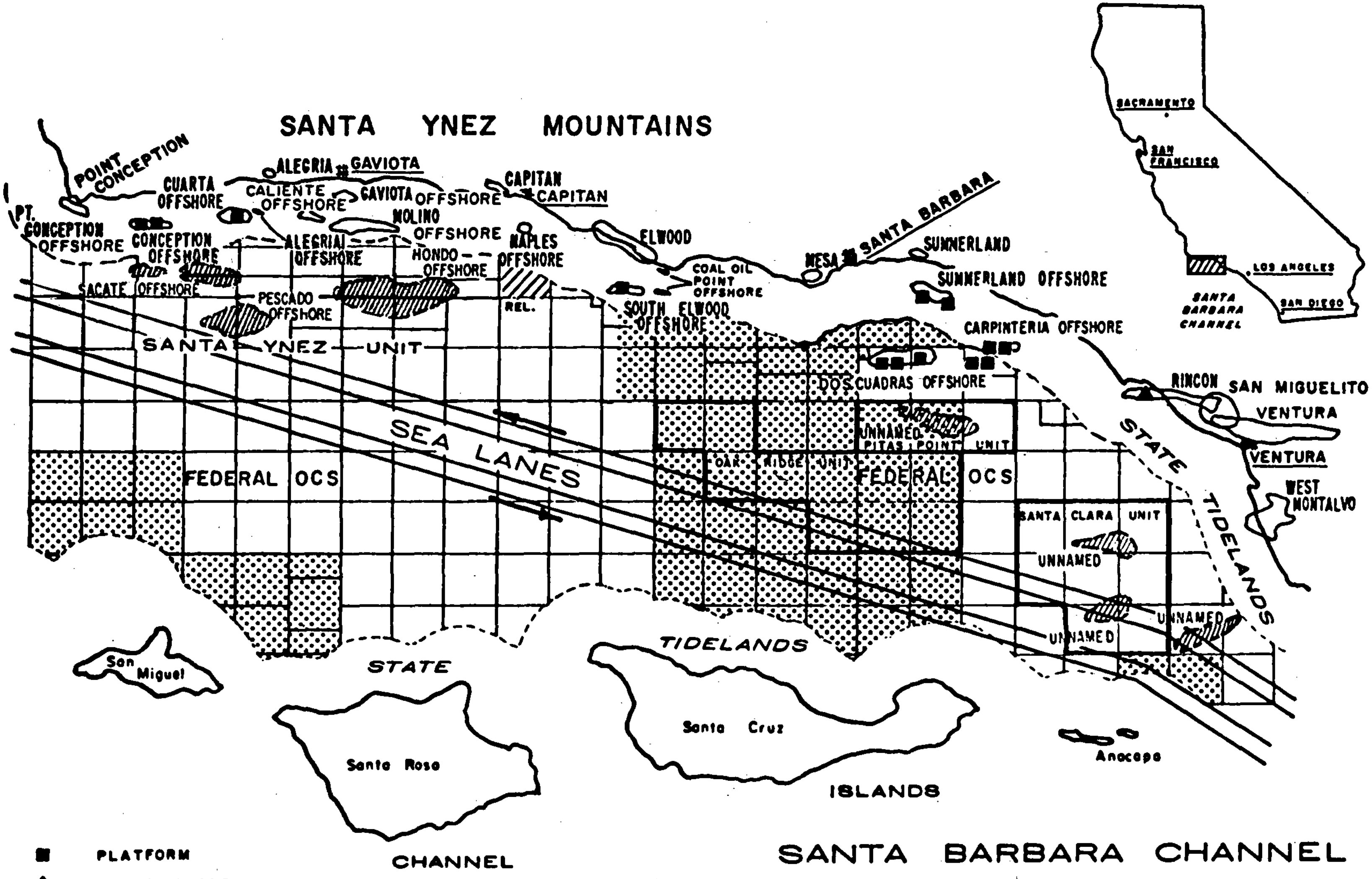
[1] The stratigraphic nomenclature used in this Statement is taken from many sources and may not conform entirely to Geological Survey usage.



PLATFORM

RINCON ISLAND

EXISTING OIL AND GAS FIELDS

POTENTIAL OIL AND GAS FIELDS

PROPOSED NATIONAL ENERGY RESERVE (35 LEASES)

CITIES AND TOWNS ARE UNDERLINED

SANTA BARBARA CHANNEL REGION

0 10 20 MILES

SCALE

FIGURE I

History of the Development of Oil and Gas in the Santa Barbara Channel Region

Production

Petroleum has been associated with human culture in the Santa Barbara Channel region for hundreds of years. Active natural seeps of tar, oil, and gas are present in and along the margins of the Channel (plate 1). Asphalt from these seeps was used in prehistoric times to hold points on weapons. (See Yerkes et al, 1969.)

At the present time, there are over 30 producing oil and gas fields in the Santa Barbara Channel region, and products from these fields are significant to the local economy. Offshore wells on State and Federal leases off California presently are producing 235,000 barrels of oil per day (January 1974). Offshore oil accounts for 25.6 percent of California's current output of 917,000 barrels of oil per day. Of offshore oil presently being produced, 186,000 barrels per day comes from State leases and 51,000 barrels per day comes from Federal OCS leases (January 1974).

Exploration and Development

State Lands

Oil was produced from shafts and tunnels in the Santa Barbara Channel region near Santa Paula as early as 1861. The first oil well in the region, and probably the first commercially successful well drilled in California, was completed in 1866 by the California Petroleum Company about 8 miles east of the town of Ojai. (See Yerkes et al, 1969.) Offshore oil development in the Santa Barbara Channel began in 1896 with the seaward extension of the Summerland oil field near the City of Santa Barbara.

In 1921 California introduced regulations governing offshore development. During 1929-31 and 1944-46 a number of small State tideland leases, located close to the shoreline, were granted to permit development of offshore portions of the Rincon, Capitan, and Elwood oil fields.

Shortly after World War II the State of California embarked on a program of offering large tideland leases which extended out to the 3-mile limit. In order to obtain knowledge of the geological conditions underlying these leases, several major oil companies began extensive geological and geophysical exploration programs in the waters of the Santa Barbara Channel. Information was obtained by coring surficial deposits, shallow and deep drilling, and seismic surveying. A peak in these exploration efforts was reached in the 1956-59 period. By this time, improved technology made it possible to drill to 7,500 feet below the ocean floor in water depths to 400 feet. (See Yerkes et al, 1969.)

Since the end of World War II, the State has awarded leases on 37 tideland parcels in the Santa Barbara Channel. Drilling on these leases has resulted in the discovery of eight offshore oil fields, four offshore gas fields, and the offshore extension of three onshore oil fields. State tidelands leases covering offshore portions of the Elwood field were awarded in 1946, 1964, and 1965. Parcels granted in 1952 and 1965 allowed the offshore development of the

West Montalvo oil field.

Development of the tidelands portion of the Rincon field underlying a lease granted by the State in 1955 was facilitated by the completion, in 1958, of Rincon Island located 2,800 feet offshore. The first successful seafloor completion of oil extraction facilities in California waters was in the offshore portion of the Rincon field in 1961. Since then, a total of 42 producing underwater completions have been installed in water depths up to 250 feet in the Santa Barbara Channel.

The first important postwar event in the offshore portion of the Santa Barbara Channel was discovery of the Summerland Offshore field in 1958 (figure 1). The first production from an offshore platform in California was from Platform Hazel in this field. Since then 12 additional platforms have been placed in State and Federal waters in the Santa Barbara Channel. Other offshore discoveries rapidly followed: Cuarta Offshore and Conception Offshore in 1959; Gaviota Offshore and Naples Offshore in 1960; Coal Oil Point Offshore in 1961; Alegria Offshore, Caliente Offshore, and Molino Offshore in 1962; Point Conception Offshore and South Elwood Offshore in 1965; and Carpinteria Offshore in 1966. (See table 1.)

There are seven platforms located in the State tidelands of the Santa Barbara Channel. The Summerland Offshore, Conception Offshore, and Carpinteria (State) Offshore fields each required two platforms while the Cuarta Offshore and South Elwood Offshore fields have required only one platform in each field to complete development (Fig. 1). Platform Harry, Conception Offshore Field, was removed July 1974.

TABLE 1

OIL AND GAS DISCOVERIES
STATE TIDELANDS, SANTA BARBARA CHANNEL 1946-1972

State Lease (PRC)	Date of Lease Award	Fields	Date of Discovery	Discovery/ Extension
208	1/18/46	Elwood		Extension
308	3/4/47	Coal Oil Point Offshore	8/61	Discovery
309	3/4/47			
735	6/30/52	West Montalvo		Extension
1466	8/29/55	Rincon		Extension
1824	1/10/57	Summerland Offshore	9/58	Discovery
2199	7/25/58	*Caliente Offshore	11/62	Discovery
		*Gaviota Offshore	8/60	Discovery
		*Molino Offshore	11/62	Discovery
2205	7/25/58	*Naples Offshore	9/60	Discovery
2206	7/25/58	Cuarta Offshore	4/59	Discovery
2207	7/25/58	Conception Offshore	11/59	Discovery
2198	10/14/58			
2725	5/4/61	Conception Offshore		Extension
2726	5/4/61	Conception Offshore		Extension
2793	10/26/61	Alegria Offshore	3/62	Discovery
2879	4/26/62	Pt. Conception Offshore	3/65	Discovery
2894	6/28/62	Caliente Offshore		Extension
2920	8/28/62	Molino Offshore		Extension
2955	10/20/62			
2933	10/25/62	Molino Offshore		Extension

* Gas field

TABLE 1 (Continued)

OIL AND GAS DISCOVERIES
STATE TIDELAND, SANTA BARBARA CHANNEL 1946-1972

State Lease (PRC)	Date of Lease Award	Fields	Date of Discovery	Discovery/ Extension
2991	2/28/63			
3004	4/25/63			
3120	4/29/64	Elwood		Extension
		South Elwood Offshore		Extension
3133	5/28/64	Carpinteria Offshore		Extension
3150	7/28/64	Carpinteria Offshore	2/66	Discovery
3184	9/24/64			
3242	4/8/65	Elwood		Extension
		South Elwood Offshore	8/65	Discovery
3314	7/2/65	West Montalvo		Extension
3403	11/18/65			
3498	6/15/66			
3499	6/15/66			
3503	6/28/66			
3945	5/23/68			
3946	5/23/68			
4000	8/28/68	Carpinteria Offshore		Extension
4001	8/28/68			
4002	8/28/68			
4031	8/28/68			

* Gas field

The Alegria Offshore, Coal Oil Point Offshore, Conception Offshore, Caliente Offshore, and Molino Offshore fields have been partially or completely developed with subsea completions. Platform Herman in the Conception Offshore field is being used as a production gathering and processing station for wells completed on the ocean floor. Two ocean-floor completions in the Coal Oil Point Offshore field produce through a 2-mile pipeline to shore.

Federal Offshore Lands

For a number of years, the boundary between the California State tidelands and the Federal Outer Continental Shelf in the Santa Barbara Channel was in dispute. This dispute was resolved by the United States Supreme Court, *United States* v. *California,* 381 U. S. 139 (1965), which decreed that areas of the Santa Barbara Channel lying seaward of 3 geographic miles from the California mainland and the Channel Islands would be under Federal jurisdiction. These lands are termed the Federal Outer Continental Shelf Lands (OCS). Before 1965 the State of California had permitted the drilling of approximately 250 core holes within the disputed Outer Continental Shelf area of the Channel. Because information obtained from these core holes was not generally available, some interested parties would have been at a disadvantage if leases had been offered on the OCS. In order to correct this inequity, additional core-hole drilling on unleased portions of the OCS of southern California was authorized by the Secretary of the Interior on November 3, 1965. Since the purpose of the authorization was to permit equal access of information to all interested parties, stipulations were included which insured that information from the Federally authorized core holes would be the same as that obtained from the State authorized core holes. A total of 53 Federally authorized twin core holes were drilled in the OCS portion of the Santa Barbara Channel between November 3, 1965, and February 6, 1968. These core holes were usually drilled as joint ventures involving several companies with appropriate exchanges of information.

Other activities undertaken by oil companies in the OCS portion of the Santa Barbara Channel between November 1965, and February 1968, included extensive geophysical surveys, ocean floor studies, and numerous bottom sampling programs.

Production of oil and gas from the State tidelands portion of the Carpinteria Offshore field, (State Lease PRC-3150), raised the probability that Federal OCS lands would be subject to drainage. To protect against this, the first Federal OCS lease in the Santa Barbara Channel, Lease OCS-P 0166, was offered for competitive bidding. A combine, consisting of Phillips Petroleum Company, Continental Oil Company, and Cities Service Oil Company, submitted the winning bid of $21,189,000.00. The lease was issued, effective January 1, 1967. Drilling on Lease OCS-P 0166 extended the Carpinteria Offshore field into Federal OCS lands. Two platforms have been placed on this lease to facilitate production.

Federal Ecological Preserve Established Seaward of State Sanctuary

The California state oil drilling sanctuary was established under the Cunningham - Shell Tideland Act, section 6871.2 of the Public Resources Code, in December 1955. The sanctuary, located seaward of Goleta Valley and the cities of Santa Barbara and Montecito, is 16 miles long and extends out to the three-mile limit. Oil production within the sanctuary is permitted only if the State Lands Commission finds that oil reserves within the sanctuary are being drained from land or water areas outside of the sanctuary.

In October 1966, the Federal government requested nominations of blocks of the Santa Barbara Channel OCS that should be offered for lease for petroleum development. The deadline for nominations, to be submitted to the Department of the Interior, Bureau of Land Management, was set at March 1, 1967.

On February 28, 1967 a group of County officials and representatives from the City of Carpinteria and City of Santa Barbara met with Assistant Secretary of the Interior, J. Cordell Moore in Washington. The purpose of this conference was to convey to Interior Department officials the concern of the people of Santa Barbara County that uncontrolled construction of oil production platforms would have a detrimental effect on the aesthetic values of the South Coast area, resulting in harm to the tourist, convention, and vacation industry, as well as affecting the desirability of this area from a residential standpoint. In addition, the delegation pointed out that unless the Federal government prohibited drilling near the sanctuary, the State might claim that wells on the Federal leases were draining oil pools in the State tidelands which would then permit the State to open up the tidelands to oil drilling. Such an action would negate the protection from close-in platforms which the sanctuary provides. The Assistant Secretary of the Interior agreed to study the peculiar problem of this coastal area and to make recommendations for safeguards in the Federal leases to protect the aesthetics, health and safety of the shoreline area and its residents.

On May 1, 1967 the Board of Supervisors adopted a resolution urging Congress to extend the 16-mile wide State tidelands sanctuary seaward over the Federal waters to the Channel Islands and asking the Department of the Interior to declare a year's moratorium on the award of Federal oil leases in the Channel.

On July 27, 1967, Assistant Secretary Moore, the State Lands Commission, and the Governor of California agreed that certain lands contiguous to the sanctuary would not be included in the lease sale. This area would extend two miles seaward of the State sanctuary and is shown as the Federal Ecological Preserve on plate I and figure ii-2.

The Buffer Zone to the Federal Ecological Preserve was established in March 1969 by the Secretary of the Interior, Walter J. Hickel. This area, contiguous to and seaward of the Federal Ecological Preserve, consists of several tracts for which no bids were received during the Santa Barbara Channel lease sale of February, 1968. The Buffer Zone and the Federal Ecological Preserve, collectively known as the Santa Barbara Channel Ecological Preserve, were withdrawn by the Secretary from all forms of deposition, including mineral leasing, and were reserved for scientific, recreational, and other similar uses as an ecological preserve (34 F.R. 5655-5656, March 26, 1969).

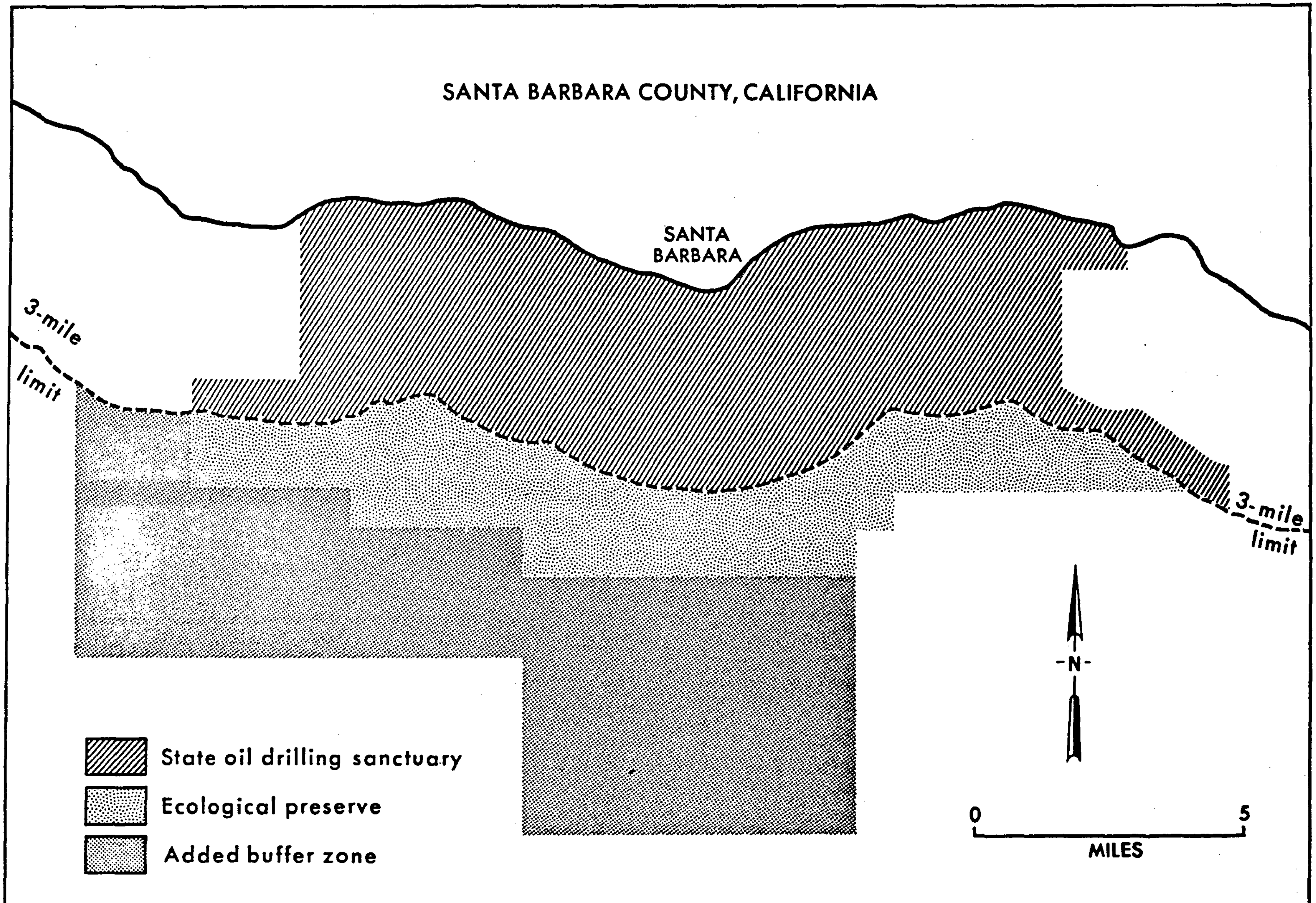


Figure 2

BUFFER ZONES - SANTA BARBARA CHANNEL

Santa Barbara Channel Major Federal OCS Lease Sale

On February 6, 1968, the Bureau of Land Management held a major OCS lease sale in the Santa Barbara Channel. Of 110 leases offered, bids were received on 75 and high bids were accepted on 71. The total bonus paid for these 71 leases was $602,719,261.60. Subsequent activities on these leases have resulted in the discovery of one producing oil field (Dos Cuadras Offshore) (figure 1). In addition, undeveloped oil and gas discoveries have been announced on 14 other leases on Federal OCS lands in the Santa Barbara Channel (table 2).

The Dos Cuadras Offshore field was discovered by exploratory drilling on Lease OCS-P 0241 on March 20, 1968. The field extends onto Lease OCS-P 0240. At present, development and production are being conducted from two platforms on Lease OCS-P 0241 and one platform on Lease OCS-P 0240. The results of exploration and development drilling on Federal OCS leases to date are summarized in table 2.

Indications of oil and gas have been found on other OCS leases in the Santa Barbara Channel but further evaluation is required to determine their significance.

Santa Barbara Channel Blowout and Oil Spill - 1969

On January 28, 1969, a blowout occurred in the fifth development well drilled from Platform A on Lease OCS-P 0241 in the Dos Cuadras Offshore field. Flow from the well was promptly controlled by activating blowout prevention equipment, but because of unusual geologic conditions, this action caused fluids from the deeper

TABLE 2

ANNOUNCED DISCOVERIES ON FEDERAL OCS LEASES IN THE SANTA BARBARA CHANNEL

OCS Lease	Field or Potential Field	Unit	Date of Discovery	Discovery/ Extension
OCS-P 0166	Carpinteria Offshore	---	---	Extension
OCS-P 0241	Dos Cuadras Offshore	---	3/20/68	Discovery
OCS-P 0234	Unnamed*	Pitas Point Unit	6/19/68	Discovery
OCS-P 0240	Dos Cuadras Offshore	---	7/24/68	Extension
OCS-P 0202	Unnamed*	---	6/19/69	Discovery
OCS-P 0188	Hondo Offshore*	Santa Ynez Unit	7/13/69	Discovery
OCS-P 0190	Hondo Offshore*	Santa Ynez Unit	7/20/69	Extension
OCS-P 0203	Unnamed*	---	8/19/69	Extension
OCS-P 0182	Pescado Offshore*	Santa Ynez Unit	5/2/70	Discovery
OCS-P 0194	Sacate Offshore*	Santa Ynez Unit	8/30/70	Discovery
OCS-P 0193	Sacate Offshore*	Santa Ynez Unit	9/22/70	Extension
OCS-P 0205	Unnamed*	Santa Clara Unit	11/22/70	Discovery
OCS-P 0216	Unnamed*	Santa Clara Unit	3/4/71	Discovery
OCS-P 0191	Hondo Offshore*	Santa Ynez Unit	3/8/71	Extension
OCS-P 0183	Pescado Offshore*	Santa Ynez Unit	5/31/71	Extension
OCS-P 0180	Hondo Offshore*	Santa Ynez Unit	10/4/71	Extension
OCS-P 0181	Hondo Offshore*	Santa Ynez Unit	12/21/71	Extension
OCS-P 0215	Unnamed*	Santa Clara Unit	8/21/73	Extension

*Potential Field

reservoirs to reach the ocean floor through fractures in shallow strata. According to U. S. Geological Survey estimates, approximately 10,000 barrels of oil escaped into the waters of the Santa Barbara Channel before the spill was brought under control. Other estimates ranged from 23,800 to 71,500 barrels, (President's Panel on Oil Spills, First Report), and 5,000 to 160,000 barrels (Resources Agency of California). The spill was brought under control 10 days later, on February 8, 1969, by forcing high density mud and cement down the wellbore and into the surrounding rock. Oil continued to seep from the ocean floor after the spill was controlled. Initially, the rate of seepage was approximately 30 barrels of oil per day, but the rate has since been diminished by cement grouting and production of the reservoirs. In addition, several ocean floor tents which trap and recover a portion of the oil, have been placed over the seeps. It is estimated that about 5 barrels of oil per day is released into ocean waters from these seeps at the present time. (See section III.L. and N. for discussion on the impact of this 1969 oil spill).

Federal Government Action

After the blowout and oil spill on Lease OCS-P 0241, the Secretary of the Interior ordered the suspension of all drilling and production on Federal leases in the Santa Barbara Channel. These suspensions affected only 6 leases on which drilling and production operations were in progress at the time. The DuBridge Panel, appointed by the President, and Department of the Interior Task Forces commenced scientific and engineering studies of the Channel.

The DuBridge Panel recommended that the producing reservoirs in the Dos Cuadras Offshore field should be depleted as rapidly as possible, consistent with safe practices. Additional drilling and production operations on Lease OCS-P 0241 were authorized in June 1969. The resulting fluid withdrawal decreased pressures in the reservoirs and thus diminished the amount of the oil reaching the ocean floor. In August 1969, a development platform was authorized for Lease OCS-P 0240 to facilitate pressure reduction in the eastern portion of the Dos Cuadras Offshore field.

In addition to the suspension of drilling and production operations on 6 leases in the Santa Barbara Channel, the Department initiated a safety clearance review of the remaining leases in the Santa Barbara Channel not then in a drilling or production status. Following a thorough review on a lease-by-lease basis, safety clearances were given and operations were permitted to proceed on these leases.

Several bills were introduced into Congress which would have terminated or suspended operations on some or all of the Federal OCS leases awarded at the February 6, 1968, lease sale. In 1970 an Administration bill was introduced which would have terminated the 20 contiguous leases seaward of a State sanctuary which lies seaward of the City of Santa Barbara. This bill was not passed by Congress. An identical bill, similar to, but more comprehensive than the 1970 bill, (H.R. 7991 and S. 1853, First Session, 92d Congress) was submitted in 1971 by the Administration. The latter legislation would have created a National Energy Reserve in the Santa Barbara Channel comprised of the 20 leases included in the 1970 bill, 13 additional leases north of San Miguel Island, 2 leases north of Anacapa Island as well as large unleased tracts which include most of the previously established Federal Buffer Zone and the Federal Ecological Preserve. The proposed 35-lease energy reserve covered about 180,000 acres of ocean area extending 3 to 20 miles offshore. Further similar legislation was introduced in the 93d Congress and was not passed (S. 1951 and S. 2339). No bills for establishing a National Energy Reserve in the Santa Barbara Channel presently exist before the 94th Congress. See Introduction figure 1 and plate 1 for location of the energy reserve that was proposed.

Congress acted on none and showed only slight interest in such legislation submitted by the Administration to the 91st, 92d and 93d Congresses to terminate 20 or 35 leases in the area proposed for a National Energy Reserve in the Santa Barbara Channel or in other legislative proposals introduced by members of Congress. Hearings were held in the 91st Congress on this legislation and again in the 93d Congress at which time the Administration announced it was withdrawing support for any legislation relating to these leases and was reevaluating its position in respect to oil and gas development in this area of the Santa Barbara Channel. This statement serves as a part of the reevaluation process and would serve to evaluate future legislative energy reserve proposals should such bills be submitted to Congress. (Refer to section I.B., Proposed National Energy Reserve, and to section VIII.F. for further discussion of proposed National Energy Reserve legislation).

Number of Wells Drilled After and Prior to the Platform A Blowout

Since the Platform A blowout in January, 1969 to date, (September 1975), approximately 173 platform development wells and 53 exploratory wells have been drilled on Federal OCS Santa Barbara Channel leases. The development wells were drilled on the three producing leases OCS-P 0166, OCS-P 0240, and OCS-P 0241; 32 of the 53 exploratory wells drilled were on Santa Ynez Unit leases.

Prior to the Platform A blowout, during 1967 and 1968, there were 24 platform development wells drilled (on lease OCS-P 0166) and 26 exploratory wells drilled on Federal OCS Santa Barbara Channel leases.

There have been a total of 197 platform development wells and 79 exploratory wells drilled on Federal OCS Santa Barbara Channel leases to date (September, 1975). There are 387 offshore Santa Barbara Channel wells presently on production, 201 on State leases and 186 on Federal OCS leases (November, 1975). There are 1,777 wells offshore California presently on production (March, 1975).

State Government Action

In February 1969, the California State Lands Commission revoked all existing offshore exploration drilling permits and imposed a moratorium on all new drilling on existing State tidelands leases. This action was taken because of the blowout and oil spill at Platform A on Federal Lease OCS-P 0241. The State Lands Commission stated that the basis for the moratorium was "the lagging state of technology in providing reliable oil containment and recovery techniques and devices."

On December 11, 1973, the State Lands Commission lifted the 5-year moratorium. The 3-member commission unanimously adopted a staff report indicating the oil industry has developed safety equipment and procedures that minimize the possibility of a major spill occurring and provide for effective cleanup in the event of a spill.

Agencies Responsible for Issuing and Regulating OCS Leases

Following the issuance of Federal OCS leases by the Bureau of Land Management, all subsequent operations are supervised by the Geological Survey. The Survey's Area Oil and Gas Supervisors enforce safety and pollution standards and operating regulations for exploration and development drilling, rates of production, and procedures for well abandonments. They also ensure that the lessees meet the specific terms of their leases, Federal Oil and Gas Regulations, and Geological Survey Outer Continental

Shelf Orders. All proposed facilities require Geological Survey approval of detailed applications prior to installation and operation. All proposed exploration and development plans submitted to the Geological Survey are also provided to other agencies that in turn provide comments and recommendations to the Geological Survey (see section IV.B.1. for a discussion of Secretarial Order 2974 which requires that the Bureau of Land Management and Fish and Wildlife Service make recommendations on such applications). For further discussion of Geological Survey responsibilities and regulations refer to section IV.A.1. and 2. EPA, Coast Guard, and Office of Pipeline Safety-DOT, also have regulatory responsibility. See section IV.A.1.

In considering such applications, each proposal would be carefully reviewed in light of this Channel-wide statement supplemented by site specific information, the technological state of the art, experience from current operations and any additional data collection. The Geological Survey would then proceed with an environmental assessment of the specific proposal and thereon base its determination as to the need for an additional environmental impact statement.

Unitization of Leases

Leaseholders may join together and apply for designation of a group of their leases as an area "logically subject to development under a unit, or cooperative agreement." If unitization is shown "to be necessary and advisable in the public interest," the Director of the Geological Survey may approve the agreement and designate an area as a unit under the terms of Title 30, of the Code of Federal Regulations, sections 250.50, 250.51 and Part 226.

Formation of a unit permits all leases within the unit to be explored and developed by a single operator using one plan of operations, rather than individually by a number of operators with varying plans of operation. Exploration and development of the entire unit with a single plan of operations increases ultimate recovery of oil and gas and at the same time eliminates wasteful operations and duplicate facilities. Thus, the purposes of unitization are to conserve resources and to minimize potential hazards.

REFERENCES

Code of Federal Regulations Title 30, Part 250, Part 226.

Conservation Committee of California Oil Producers, 1972, Annual review of California oil and gas production 1971.

Resources Agency of California, 1971, The offshore petroleum resource.

President's Panel on Spills (1st report), 1969, The oil spill problem: Washington, D. C., U. S. Government Printing Office.

Yerkes, R. F., H. C. Wagner and K. A. Yenne, 1969, Petroleum development in the region of the Santa Barbara Channel: U. S. Geological Survey Prof. Paper 679-B.

I. DESCRIPTION OF POTENTIAL LEVELS OF ACTIVITIES IN DEVELOPMENT OF THE SANTA BARBARA CHANNEL OCS

A. Purpose of the Environmental Impact Statement

The purpose of this Statement is to consider possible future levels of development of the Santa Barbara Channel OCS, and to identify and evaluate all probable and potential environmental impacts of such activities. This Statement is to serve as one of the bases for future decisions by the Secretary of the Interior and the U. S. Geological Survey regarding future OCS oil and gas operations in the Channel.

The four general possible levels of development are as follows: (1) continue production from existing producing leases; (2) develop new production from existing leases on which oil and gas capable of being produced in paying quantities have been discovered; (3) explore and subsequently develop existing leases on which no discoveries have been made in the Santa Barbara Channel; and (4) lease, explore and develop presently unleased acreage in the Outer Continental Shelf of the Santa Barbara Channel.

At this point it is considered convenient to summarize the probable basic activities and installations that would accompany differing levels of oil and gas operations in the Santa Barbara Channel Federal OCS area:

1. Exploratory Drilling

Exploratory drilling is the method for determining the presence of a hydrocarbon reservoir and to delineate its boundaries and characteristics. Offshore exploratory drilling is generally conducted from a floating vessel or from a mobile "jack-up" platform.

2. Installation of One or More Platforms

Platforms fixed to the ocean floor would probably be the principal facility used to directionally drill development wells for oil and gas production. The same platform, or a satellite platform, would probably be used to receive production, separate gas and oil, and perform the first stage of water separation. Platforms could be supplemented by subsea wells and production systems.

3. Construction of One or More Pipelines to Shore

Separate pipelines would normally be required to deliver oil and gas to shore for treating and temporary storage. In the event that offshore treating, storage, and loading facilities were constructed, an oil pipeline to shore would not be required. In such a case, it is probable that a gas line to shore would be necessary unless the gas were injected at the platform into subsurface horizons.

In existing, and future, operations, additional shorter pipelines are required to carry treated crude oil to offshore marine loading facilities for transportation by tanker to refineries. These short pipeline segments and marine loading terminals would not be necessary if additional onshore oil transmission pipelines were constructed from the Santa Barbara Channel area to refinery area such as Los Angeles - Long Beach.

If new onshore facilities were constructed, it is possible that an additional pipeline or lines, would be required to return separated formation water (brine) to the platform for subsurface injection into wells. However, the need for such return lines would depend on the method of brine separation, treatment and disposal.

4. Possible Construction of Offshore Treating and Storage Facilities

It is most likely that onshore treating, storage, and shipping facilities would be required and proposed. It is possible that existing onshore facilities could be used to handle the majority of future production, but this would depend on the quantity of production developed and the condition of such facilities at that time, among other factors. Expansion of existing facilities would probably be required to accommodate additional production. A possibility exists that treating and storage facilities could be constructed offshore. Treating facilities would require additional platform space, but storage would probably be in a nearby permanently moored vessel.

5. Possible Construction of Delivery Facilities

One possibility is that an onshore pipeline could be constructed to deliver oil from the channel area to a refinery center such as Los Angeles. Existing lines are operating at capacity.

Offshore loading facilities could be enlarged or increased in number. Such terminals could take the form of near shore facilities with piers, etc., or they could be completely offshore buoy installations where tankers would be accommodated, as is the present general practice.

There are numerous alternatives and variations for the basic facilities which would be required to handle production greater than currently produced from the Santa Barbara Channel area. Several of these are discussed later in this section.

As a minimum, all proposed OCS activities require USGS approval. Others require the approval of the Secretary of the Department of the Interior.

B. Present Status of Oil and Gas Operations in Federal Lands of the Santa Barbara Channel

The history of hydrocarbon development in the Santa Barbara Channel has been discussed in the introduction. However, it is believed that the current status of development in the OCS lands should be reviewed. Plate I should be referred to for orientation and locations of Units, leases and platforms.

There are two producing oil fields in the Federal OCS area, Dos Cuadras Offshore and Carpinteria Offshore. Part of the Carpinteria Offshore field lies within the California State tideland and submerged land area, with the remainder within Federal leases OCS-P 0166 and OCS-P 0240. All of the Dos Cuadras field is in the Federal OCS area on leases OCS-P 0240 and OCS-P 0241.

There are five producing platforms in operation on the Federal OCS area:[1]

- "Hogan" and "Houchin" in the Carpinteria Offshore field on lease OCS-P 0166 with Phillips Petroleum Company as the Operator. Phillips is presently drilling a deep test, with a proposed depth of 18,500 feet, from Platform Houchin.

- "Hillhouse" in the Dos Cuadras Offshore field on lease OCS-P 0240 with Sun Oil Company as the Operator.

- "A" and "B" in the Dos Cuadras Offshore field on lease OCS-P 0241 with Union Oil Company of California as the Operator.

Union applied for a permit to construct Platform "C" on lease OCS-P 0241 on September 9, 1968 and the request was approved by the Regional Supervisor on September 16, 1968. Union Oil Company completed fabrication of Platform C in February 1969, at the American Pipe and Construction Company's yard in Vancouver, Washington and planned to install it in March 1969. However, after the Platform A blowout, the Secretary of the Interior on April 4, 1969 withdrew the approval until further study could be made. The request was resubmitted on September 2, 1969 and after preparation and consideration of an environmental impact statement was denied approval by the Secretary of the Interior on September 20, 1971 on the grounds of environmental considerations. Platform C is presently stored at the Vancouver construction site. On September 24, 1971 Union, et al., brought suit against the Secretary, et al., alleging that the Secretary had no right to deny the petition on those grounds. The United States District Court found for the

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[1]There are 7 platforms in operation in Santa Barbara Channel State water leases. See plate 1 for the location of the 12 existing Santa Barbara Channel platforms (5 in Federal waters and 7 in State waters). Note that plate 1 shows 8 State platforms, however, in July 1974, Platform Harry was removed.

defendants on January 12, 1972. On February 24, 1975, the United States Court of Appeals for the 9th Circuit vacated the decision of the District Court and remanded the case for further proceedings.

Sun applied for a permit to construct Platform Henry on lease OCS-P 0240 on January 22, 1970. On September 20, 1971 after preparation and consideration of an environmental impact statement the Secretary of the Interior denied approval on the grounds of environmental considerations. On November 4, 1971 Sun, et al., filed suit in the United States Court of Claims alleging breach of the lease contract for OCS-P 0240. The suit is still being litigated.

present
Subsequent to the publication of this/Statement in draft form, Sun Oil Company submitted to the Geological Survey on September 29, 1975 a Plan of Development for the east side of lease OCS-P 0240. Sun submitted this Plan and a request for approval of a platform designated Henry to implement such Plan if information gained from the drilling of one or more exploratory wells, approval of which is also requested, establishes such a platform to be desirable.

Following are two paragraphs from Sun's letter transmitting this Plan of Development:

> "The attached Plan of Development and request for approval of the installation of Platform Henry and the drilling (and possible re-drilling) and testing of one or more exploratory wells are submitted without waiver of or prejudice to the rights and positions of Sun Oil Company, The Superior Oil Company and Marathon Oil Company in the above case, and said plaintiffs in that case shall have and continue to have the right to pursue all claims and causes of action alleged in such litigation. The approval of the attached Plan, the installation of Platform Henry, and the implementation of such Plan probably will mitigate or reduce the damages recoverable in the pending action. The extent of any such mitigation will remain a matter for determination in the Court of Claims.

"It must be emphasized that the Plan submitted includes interdependent parts but requests present approval for each part, i.e., (1) approval of a permit for the drilling (and possible re-drilling) and testing of one or more exploratory wells and (2) approval of a permit for installation of a self-contained drilling and production platform if deemed desirable in the light of the information gained from and results of said exploratory well or wells. Either part without the other would destroy the whole at this time. The exploratory well or wells are expected to provide information with respect to the producing capabilities, characteristics and state of depletion, if any, of the reservoirs on the east side of OCS-P 0240 sufficient to determine the feasibility of the installation of the drilling and production platform. Such information will be mere surplusage if implementation of the platform installation once decided upon is subject to delay attendant upon further permit approval as such delay would affect the determined feasibility. This is peculiarly so where, as here, it is believed that reservoir depletion under OCS-P 0240 has occurred and continues to occur by reason of production from lease OCS-P 0166."

Mobil Oil Corporation has submitted to the Geological Survey a preliminary notice, in brief letter form/ on March 15, 1974, of the possible future intent to install a platform on lease OCS-P 0202. Further exploratory drilling is required to determine the feasibility and optimum location of such a platform. This preliminary notice is being held in abeyance pending submission of more definite and more detailed information, and the completion of this statement. This tentative proposal, indefinite and lacking in detail, is not recognized by the Geological Survey as a formal application suitable for commencing serious evaluation and consideration.

See section III.C.3. for a detailed description and discussion of the three above-mentioned possible Santa Barbara Channel Platforms (C., Henry and the one for lease OCS-P 0202).

There are 186 producing oil wells on the five existing OCS platforms and the output is 41,700 barrels of oil per day and 43,800 barrels of water per day (August 1975). Oil production for the month of August 1975, from the three Santa Barbara Channel OCS Federal leases, was approximately 1.3 million barrels. The cumulative oil production from these three OCS leases, through August 1975, was approximately 136 million barrels. A portion of the produced water is pumped to shore for treatment and then pumped back to the platforms to be utilized in water injection projects. Water injection serves not only as a means of avoiding waste-water disposal to the sea, but also provides a method of reservoir pressure maintenance and thus results in greater ultimate oil recovery. A secondary, but important, effect of water injection is to minimize possible subsidence due to hydrocarbon withdrawal. This has been demonstrated in the Long Beach-Wilmington area.

Secondary recovery operations on the Federal leases in the Santa Barbara Channel can be summarized as follows. Pilot water injection operations are in progress in the Dos Cuadras field. These are preliminary to water flooding which has not yet been approved. The pilot water injection commenced in June 1971 and is presently being carried out on leases OCS-P 0240 and OCS-P 0241. Seven wells are presently (September 1975) injecting approximately 10,000 barrels per day of produced waste water. Water flooding of the Dos Cuadras field was recommended by the Du Bridge Committee, after the 1969, Platform A blowout, to minimize subsidence, to efficiently deplete the oil reservoir as rapidly as possible, and to immobilize the residual oil in place to prevent further oil seepage after abandonment of the field.

Produced waste water is also being injected into depleted portions of the oil producing sands of lease OCS-P 0166 of the Offshore Carpinteria field. This injection is solely for the purpose of waste salt-water disposal.

A portion of the produced water, after the oil is removed, is still released to sea, but as the water injection projects progress beyond the pilot stage, most, if not all, produced water might be re-injected to the reservoirs (see sections IV.A.1.c. and d. for discussion of produced waste-water disposal regulations). Plans for additional injection wells on Platforms "A", "B", and Hogan; and a system for Platform Houchin are being evaluated by the Geological Survey.

Only one of the production wells on the five platforms is still flowing under its own pressure. All wells on Platforms Hogan and Houchin and two on Platform Hillhouse are being produced by the gas-lift method. Submersible electric pumps and hydraulic pumps are other methods of lifting oil that are utilized.

There are no subsea completions in the Federal area of the Santa Barbara Channel, but this method has been widely used in some of the State lands. To date, 42 wells have ocean floor completions in the State Channel waters. Most of the oil from these subsea wells is produced by oceanfloor pipe to nearby platforms, but some gas wells produce to onshore treating facilities.

Presently (January 1976) there are two exploratory wells being drilled in the Santa Barbara Channel OCS from floating drilling vessels. The CUSS I is drilling on lease OCS-P 0217 in 350 feet of water. The Coral Sea is drilling on lease OCS-P 0212 in 910 feet of water. Permits for drilling new wells must be submitted to the District Engineer, Conservation Division, U. S. Geological Survey, for approval. Pressure maintenance programs utilizing water injection must also be submitted for approval. All operations are conducted in accordance with OCS Orders.

There are several potential fields in the Santa Barbara Channel OCS that have been credited by the Geological Survey with discoveries (i.e., evaluated as being capable of commercial production), but which have not been developed. With one exception they are included in Unit Areas. There is one unit in the Santa Barbara Channel OCS, the Oakridge Unit with Gulf Oil Corporation as the Operator, which to date has no discoveries. While some leases in this Unit have shown little potential for production, most of the Unit Area remains to be tested. This Unit is within the formally proposed National Energy Reserve, therefore both the Unit and formally proposed National Energy Reserve will be discussed below.

- <u>Oakridge Unit</u>

The Oakridge Unit agreement was approved by the Geological Survey on March 30, 1973, effective March 31, 1973. On March 31, 1973, all operations on the nine leases in the Oakridge Unit area were suspended for a period of 24 months. On April 18, 1973, all operations on the 35 leases included in the proposed National Energy Reserve (including the nine leases in the Oakridge Unit area) were suspended until January 2, 1975. Earlier, on April 21, 1971, operations on these 35 leases had been suspended until January 2, 1973.

The approved unit agreement requires that Gulf Oil Company - U.S.A., as Unit Operator, submit a Plan of Operations for approval by the Geological Survey.

The Plan of Operations submitted May 31, 1973, called for the drilling of two wells, one on lease OCS-P 0220 and the other on lease OCS-P 0227. Applications for permits to drill were submitted with the Plan of Operations. By letter dated November 7, 1974, Gulf requested that the March 31, 1973 suspension be lifted and that the Plan of Operations, including the two applications for permits to drill, be approved. Gulf also requested an extension of the period in which to commence drilling operations from six months, as provided in the Unit Agreement, to 15 months. Gulf further stated that it might be early 1976 before a drilling vessel would become available. In addition, the operator would be unable to make contract commitments until after the termination of the suspension order.

By letters to Gulf Oil Company - U. S., dated January 29 and 30, 1975, the Geological Survey, effective February 1, 1975:

- Terminated the suspension of operations on the Oakridge Unit leases.
- Approved the initial plan of operations to drill two exploratory wells to evaluate two geologic structures within the Unit Area, subject to the stipulations of applicable laws, regulations and OCS Orders. Applications to drill individual wells must be submitted to, and approved by, the District Engineer.
- Approved the request for an extension of the period in which to commence drilling operations from six months, as provided in the Unit Agreement, to 15 months due to the lack of availability of floating drilling vessels. The Oakridge Unit Operator is to commence drilling on the first unit well not later than 15 months after February 1, 1975.

The formally proposed National Energy Reserve was discussed earlier in the Introduction, however, inasmuch as the Oakridge Unit, as well as part of the Pitas Point Unit (discussed later), is within that Energy Reserve, a brief discussion of recent events relating to that Energy Reserve follows.

- <u>Formally Proposed National Energy Reserve</u>

See the discussion relating to the Energy Reserve in the Preface and Introduction and refer to figure 1 (in the Introduction) and plate 1 for the location.

Congress showed only slight interest in, and did not act on any, legislation submitted by the Administration to the 91st, 92d and 93d Congresses to terminate 20 or 35 leases in the area proposed for a National Energy Reserve. During the preparation of this statement the 93d Congress adjourned without acting on such legislation and presently there is no similar legislation pending before the 94th Congress. During hearings in the 93d Congress, the Department of Interior announced it was withdrawing support for any legislation relating to those leases and was reevaluating its position in respect to oil and gas development in the area of the Santa Barbara Channel. This environmental statement serves as a part of that evaluation process. To date (December 1975) there have been only nine exploratory wells drilled within the area that was proposed as a National Energy Reserve. Following is a brief chronological review of significant events relating to the formally proposed National Energy Reserve.

June 11, 1970: Legislation submitted to the 91st Congress to create a National Energy Reserve on 20 leases in the Santa Barbara Channel.

April 21, 1971: Legislation resubmitted to the 92d Congress and suspension ordered on 35 leases proposed for inclusion in a National Energy Reserve in the Santa Barbara Channel (suspension of operations until January 2, 1973).

August 3, 1971:	Gulf Oil Corporation et al., filed action in District Court for the Central District of California (Civil No. 71-1669-FCW) challenging the Secretary's authority to suspend operations on 35 leases pending consideration by Congress of the legislation for a National Energy Reserve.
June 21, 1972:	The District Court for the Central District of California held in "Gulf", supra, Civil No. 71-1669-FCW, that the Secretary's suspension of operations on 35 leases was not in the interest of Conservation as required by the Outer Continental Shelf Lands Act and hence was not a legal suspension. The Department of Justice filed an appeal with the Ninth Circuit Appeals Court.
April 18, 1973:	Legislation resubmitted to the 93d Congress to create a National Energy Reserve and terminate the 35 leases in the Channel. Suspension of operations on these 35 leases again ordered (suspension of operations until January 2, 1975).
November 3, 1973:	Assistant Secretary for Energy and Minerals of the Department of the Interior, Stephen Wakefield, testified before the Subcommittee on Minerals, Materials, and Fuels of the Committee of Interior and Insular Affairs, United States Senate, announcing that the Administration was recommending that no action be taken on legislation to create an Energy Reserve in the Santa Barbara Channel and that the Department was going to reevaluate the situation (see the Preface).
November 27, 1973:	The Ninth Circuit Court reversed the District Court ruling and judged that the Secretary's suspension of operations on the 35 leases was in the interest of Conservation and was valid.
March 25, 1974:	Upon rehearing, the Ninth Circuit Court modified its earlier opinion in "Gulf", supra, and found that suspension of operations was in the interest of Conservation but that the reason for the suspension terminated when the 92d Congress adjourned, on October 18, 1972, without taking action on the legislation. Thereafter, the Secretary's suspension was no longer in effect.
May 8, 1974:	The District Court for the Central District of California entered a judgment pursuant to the Ninth Circuit opinion which orders the Secretary "forthwith to take such action as is authorized under Outer Continental Shelf Lands Act and the regulations thereunder . . . promptly to act upon applications for

drilling permits submitted by plaintiffs respecting such leases, and to take such further action in accordance with said act and regulations as is necessary and proper to comply with the provisions of the leases." This order became final July 8, 1974.

November 7, 1974: On the basis of the May 8, 1974 District Court Order, Gulf Oil Company - U.S.A., by letter dated November 7, 1974, requested that the Geological Survey approve the Oak Ridge Unit Plan of Operations, including the two applications for permits to drill and that the suspension of operations on the Unit be lifted. (See the discussion under the preceding subhead titled "Oakridge Unit".)

January 29 & 30, 1975: By letters to Gulf dated January 29 and 30, 1975, the Geological Survey terminated the suspension of operations on the Oakridge Unit leases; approved the initial plan of operations to drill two exploratory wells and approved the Gulf request for an extension of the period in which to commence drilling from six months, as provided in the Unit Agreement, to 15 months.

- Potential Field Areas in the Santa Barbara Channel OCS

Following are the potential field areas in the Santa Barbara Channel OCS:

1. Pitas Point Unit Potential Field Area

Pitas Point Unit with Texaco, Inc. as the Operator was credited with a discovery on lease OCS-P 0234 in June, 1968. The potential field is unnamed. A portion of the Unit Area is within the once proposed National Energy Reserve (see plate 1).

2. Hueneme Offshore Potential Field Area within Leases OCS-P 0202 and P 0203

Non-unit, but the potential field is named Hueneme Offshore. Discoveries were made in lease OCS-P 0202 in June, 1969 and in lease OCS-P 0203 in August, 1969. Mobil Oil Corporation is the Lessee and Operator of both leases. An application dated March 15, 1974, in brief letter form, to construct a platform on lease OCS-P 0202 was submitted to the Geological

Survey. The application is being held in abeyance pending submittal of more definite detailed information, and the completion of this statement. The location of this proposed platform is shown on plate 1. The Operator has informed the Geological Survey that this location is very tentative pending further drilling. This tentative proposal is too indefinite and lacking in detail to be recognized by the Geological Survey as a formal application suitable for commencing serious evaluation and consideration. See section III.C.3.b. for more detail on this tentative proposed platform.

3. Santa Clara Unit Potential Field Areas

Santa Clara Unit with Standard Oil Company of California as the Operator contains the following potential fields:

- Unnamed field with a discovery made in lease OCS-P 0205 in November, 1970.
- Unnamed field with discoveries made in lease OCS-P 0216 in March, 1971 and in lease OCS-P 0215 in August, 1973. An application dated November 11, 1971, to construct a platform in lease OCS-P 0216 has been submitted by Union Oil Company of California.

The Operator informed the Geological Survey that this proposed and un-named platform location was tentative and subject to change pending additional drilling. Subsequent to receiving this application the Santa Clara Unit was approved on March 30, 1973. The Geological Survey has informed Union Oil Company of California that since lease OCS-P 0216 is now committed to the Santa Clara Unit, all future exploratory and development work must be submitted and considered for approval as a part of a plan of operations as provided by the Unit Agreement; and that no further actions will be taken on their application for preliminary approval to install the proposed platform on lease OCS-P 0216. Such submittal has not been accomplished as of January, 1976, and therefore, the Geological Survey does not consider it a valid pending application.

4. Santa Ynez Unit Potential Field Areas

a. Three Potential Field Areas

Santa Ynez Unit with Exxon Company as the Operator contains the following potential fields:

- Hondo Offshore field with discoveries made in lease OCS-P 0188 in July, 1969, in lease OCS-P 0190 in July, 1969, in lease OCS-P 0191 in March, 1971, in lease OCS-P 0180 in October, 1971, and in lease OCS-P 0181 in December, 1971. An application to construct a platform has been submitted for lease OCS-P 0188.
- Pescado Offshore field with discoveries made in lease OCS-P 0182 in May, 1970 and in lease OCS-P 0183 in May, 1971.
- Sacate Offshore field with discoveries made in lease OCS-P 0194 in August, 1970 and in lease OCS-P 0193 in September, 1970.

b. News Release Announcing the Approval of the Santa Ynez Unit Development Plan and the Secretary's Decision

On August 6, 1974, the Department of the Interior approved the proposed plan of development for the Santa Ynez Unit relating particularly to the Hondo Field. The Department of Interior news release announcing the decision and the Secretary's decision is reproduced and included in appendix I-1 at the end of this section (Section I).

C. Methods by Which Hydrocarbon Production from the Santa Barbara Channel OCS Could Be Obtained

Potential levels of development include:

- Developing existing producing leaseholds.
- Developing and producing oil and gas from discovered potential fields on existing leases.
- Discovering new oil and gas deposits on existing leases by exploratory drilling with subsequent development and production.
- Offering additional lands for lease, exploration and development.

As indicated above, the possibility of, and impacts resulting from, exploration and development in the unleased areas of the Santa Barbara Channel OCS will be considered in this Environmental Impact Statement. However, this possibility would require a Santa Barbara Channel OCS lease sale. In the event a lease sale is considered in the future, the Department of the Interior would make an assessment as to the need for an additional environmental impact statement on the sale and would otherwise meet all requirements of the National Environmental Policy Act of 1969.

D. Potential Activities

Development of the Santa Barbara Channel OCS could involve a variety of specific activities and related facilities. Activities discussed below are listed as nearly as possible in the chronological order they could be expected to occur in the development of production from an unexplored offshore area.

- Geophysical Exploration
- Geological Exploration
- Exploratory Drilling
- Development Drilling, Testing, and Completions

- Separation and Treating Facilities
- Gathering Systems and Pipelines
- Storage Facilities
- Delivery Facilities
- Production Stimulation and Secondary Recovery.

The following discussion will attempt not to duplicate material included in Appendices I-2 and I-3, titled respectively, "General Discussion of Oil Field Development" and "Background and History of Offshore Technology", which appear at the end of this section (Section I).

1. Geophysical Exploration

a. Industry

In order to locate potential hydrocarbon deposits, the oil industry must analyze the substructure of the Santa Barbara Channel area. The prime objective of the analysis is to locate geologic structures that are favorable for the accumulation of petroleum. A knowledge of the subsurface geologic environment is also necessary to detect near surface conditions, such as recent faulting or high pressure zones, which are potential hazards to exploration and production operations. Once hazardous conditions are identified, drilling programs are modified to assure safety of operations.

A considerable amount of geophysical exploration has been completed in the Channel Area. However, more could be expected, particularly if new areas were to be offered for lease. Any of the alternatives in section I.C., except confining activity to present production, would lead to a certain amount of geophysical surveying.

When lease sales are to be conducted, industry normally conducts regional geophysical surveys of an area of interest, prior to a call for nomination of lease sale tracts by the Department of the Interior. These surveys provide a network of modern state-of-the-art common depth point (CDP) seismic lines on approximately a 4-mile-by-4-mile grid spacing to provide data for reconnaissance mapping. In some cases an even closer 2-mile-by-2-mile line spacing may be used. If an oil company plans to submit lease tract nominations to the Department, then more detailed seismic data are collected and interpreted in order that potentially productive tracts may be identified.

In seismic exploration, a ship travels along a predetermined path, towing signal-generating and recording equipment. The signal generated by the energy source is a series of small amplitude sonic pulses that travel at thousands of feet per second through the water and sediments below, where they are reflected and refracted by the underlying strata. An array of sensitive hydrophones towed by the vessel detect incoming (returning) sonic waves which are recorded on magnetic tape. After extensive processing, these recordings are displayed in the form of vertical cross sections. These seismic profiles are interpreted to identify those areas in which the sediments are arched, faulted, and where they thicken or thin, and where reef structures occur. By assembling cross sections along traverses made in various directions, a three-dimensional picture can be constructed, indicating location, size, and form of geologic structures favorable for oil and gas accumulation. This information is normally displayed in the form of a series of subsurface structure contour maps.

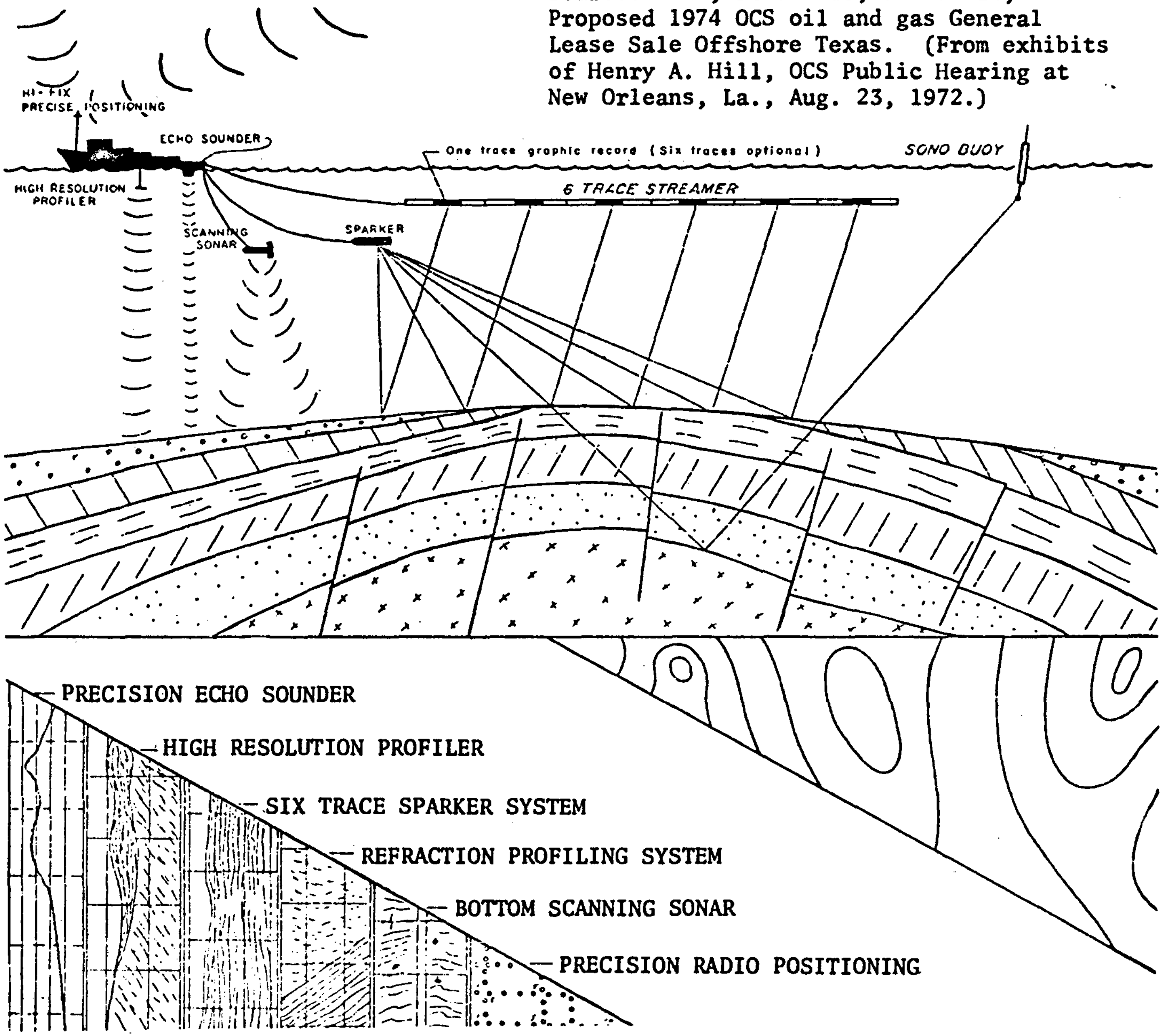
In early years of offshore exploration the energy source for the sonic wave was explosive charges detonated in the water layer. Because of the hazards associated with the use of explosives to the vessel, crew, and natural marine life, new equipment and methods have evolved within the last five years and now account for more than 95 percent of marine geophysical activity. In particular, the use of a vibrator system, sparkers, air guns, and gas guns now provide excellent seismic data, with no harmful effect on the marine environment.

In addition to the deep penetration CDP seismic reflection data, some companies purchase and interpret shallow penetration high resolution acoustic data to locate potential sea bottom or near bottom geologic hazards. A discussion of geologic hazards present in the area is presented in section II.B.7. Such hazards as shallow geologic structures, unstable bottom sediments, faults, and seeps may be predicted from these data and thus minimize any hazards to drilling operations and possible consequent dangers to the environment from pollution. These are used as guides to regulate platform and well locations as well as drilling procedures. A typical high resolution data acquisition system is illustrated in figure I-1.

The Santa Barbara Channel OCS has been extensively covered by company geophysical surveys conducted by industry and it is unlikely that any great amount of deep penetration surveys would be considered necessary in any development plan for the Channel. Individual operators, however, might consider that a small amount of tie-in lines would be required for development of unleased areas and/or further development of certain lease areas.

On the other hand, it can be expected that a considerable amount of shallow penetration, high resolution data, would be required if development of unleased areas is considered and if further development of leased areas (apart from that conducted on presently constructed platforms) is contemplated. To date, there has been relatively little work of this nature in the Channel area and this is a helpful tool in more closely determining potential hydrocarbon accumulations. In addition, present USGS stipulations require that

Figure I-1 Geophysical and Seismic Data Collecting
Source: BLM, Final EIS, FES-74-14, Proposed 1974 OCS oil and gas General Lease Sale Offshore Texas. (From exhibits of Henry A. Hill, OCS Public Hearing at New Orleans, La., Aug. 23, 1972.)



such surveys be taken at locations where the ocean floor is to be penetrated in order to avoid potentially hazardous locations.

b. U. S. Geological Survey

Regulations in existence on September 1974, do not require companies to submit their geophysical data to the USGS, except for a plat showing the location of the lines run and the total miles run during any particular survey.[1] An exception to this is that shallow, site-specific high resolution data is required by the Pacific Area Oil and Gas Supervisor before a permit for operations involving penetration of the ocean floor can be approved.

In order to provide needed geotechnical information the USGS has contracted for the collection of modern seismic reflection data on unleased areas. These data have provided definitive information for government use on the size, shape, and depth of structural features located in various areas. The structural information derived from seismic data has been used in selecting tracts offered for leasing and also demonstrated the relative merits of potential traps for oil and gas. The USGS has also acquired shallow, high resolution data.

Proposed Geological and Geophysical Exploration Regulations for the OCS are presently being considered which would require that all geophysical data be submitted to the Geological Survey (Federal Register, Vol. 39, No. 96, May 16, 1974).[1] These data are of value in determining the extent and volume of prospective hydrocarbon reservoirs and may be useful in pointing out possible hazardous zones which might be encountered during exploratory operations.

[1] In the Federal Register dated December 16, 1974 (39 FR 43562) and in the supplement to that notice dated August 27, 1975, the Acting Secretary gave notice that geophysical data would be provided to the Geological Survey in accordance with a permit agreement as an interim measure until the final publication of geological and geophysical regulations.

2. Geological Exploration

Geophysical data may be augmented by geologic data from outcrops on the sea bottom or near sea bottom. These geoscientific data are useful for age determination and regional stratigraphic correlation. Characteristics of origin and deposition may also be determined; that is, whether volcanic, igneous intrusive, sedimentary, etc. Information concerning possible source areas of sedimentary beds as well as the mechanical properties of the rocks (bearing strength, compressibility etc.) are determined from such geologic data.

Typical geological exploration operations could consist of:

a. Diver or Submersible Surveillance and Sampling

The use of divers or small submersibles for surveillance and sampling is generally reserved for special circumstances. Divers are limited by depth capabilities while both methods exhibit difficulty in penetrating sea floor muds in order to obtain significant samples. However, the use of side scan sonar from surface vessels as well as submersible vehicles have both been successful in mapping sea floor geomorphology.

b. Dart Sampling

This method is the one most commonly used for obtaining geological information in offshore operations since it is fast and relatively inexpensive. A weighted tube attached to wire line is dropped over the side, strikes the ocean floor and recovers from a few inches to a few feet of bottom samples depending on the tool design and bottom conditions. Some designs depend entirely on weight to penetrate the bottom while others utilize a hammer effect for additional penetration. The primary drawbacks to this type of sampling are failure to penetrate the overburden in many areas and, in many cases, lack of significant sample recovery.

The amount of dart sampling operations that may be undertaken in the Channel area would depend on the type of development program proposed. A considerable amount of sampling has been done in the Federal OCS area and, because one of the primary functions of sampling is to correlate geophysical surveys, the amount of future sampling that might be proposed would depend largely on the amount of seismic surveying proposed.

c. Shallow Coring and Soil Sampling

These operations are usually conducted with scaled down drilling equipment developed to operate on shipboard. Most of this work is limited to shallow depths below the ocean floor and is conducted under strict permitting procedures by the U. S. Geological Survey. The purpose of this work is not to encounter oil or gas, but simply to recover suitable samples for geological study. Locations for each sampling site are carefully selected on the basis of prior geophysical surveys to insure that the sites are in non-hazardous areas (areas free of seeps, geologic closures, acoustic voids, etc.).

Generally the operations are carried out in much the same manner as conventional drilling, the primary difference being that the only connection between the ocean floor and the drilling vessel is the drilling string. No riser pipe is used and therefore there is no return circulation of drilling fluid to the surface vessel. Drill cuttings and drilling fluid are circulated out the hole and deposited on the ocean floor. Sea water or a non-toxic salt water base mud that is not harmful to marine life is used as the drilling fluid.

Core samples are recovered through the hollow drill pipe using wire-line methods because once drilling is initiated the drill string cannot be recovered without losing the hole. Upon completion of drilling, permit stipulations require that the holes be plugged with cement to insure against the possibility of any seeps developing at a later date.

This type of operation is generally used where the other types of sample recovery, such as dart sampling, give inconclusive results or where information on underlying formations is required. Data on soil-bearing strength are of particular value when structures such as platforms are designed for emplacement on the ocean floor.

Present permit stipulations limit shallow coring for geological purposes to a depth of 500 feet below the ocean floor; however, if a competent formation has not been encountered, coring can be continued to a maximum total depth of 750 feet, except that no more than 50 feet of competent formation, below 500 feet, can be penetrated.

It is unlikely that any considerable program for shallow coring in the Santa Barbara Channel OCS would be proposed. A number of core holes, both shallow and deep, have been drilled and a number of exploratory wells have also been drilled throughout the Channel area. Figure I-2 indicates the density of these operations. The extent and quantity of future shallow coring operations that might be proposed would depend largely on the individual operator's requirements. However, the number of such programs are limited by USGS permit stipulations which require that all interested persons be allowed to participate in such programs and that duplicate locations are prohibited.

3. Exploratory Drilling

Drilling is the only presently known technique available to determine the presence of a hydrocarbon reservoir and to delineate its boundaries and characteristics. Drilling can be divided into two broad

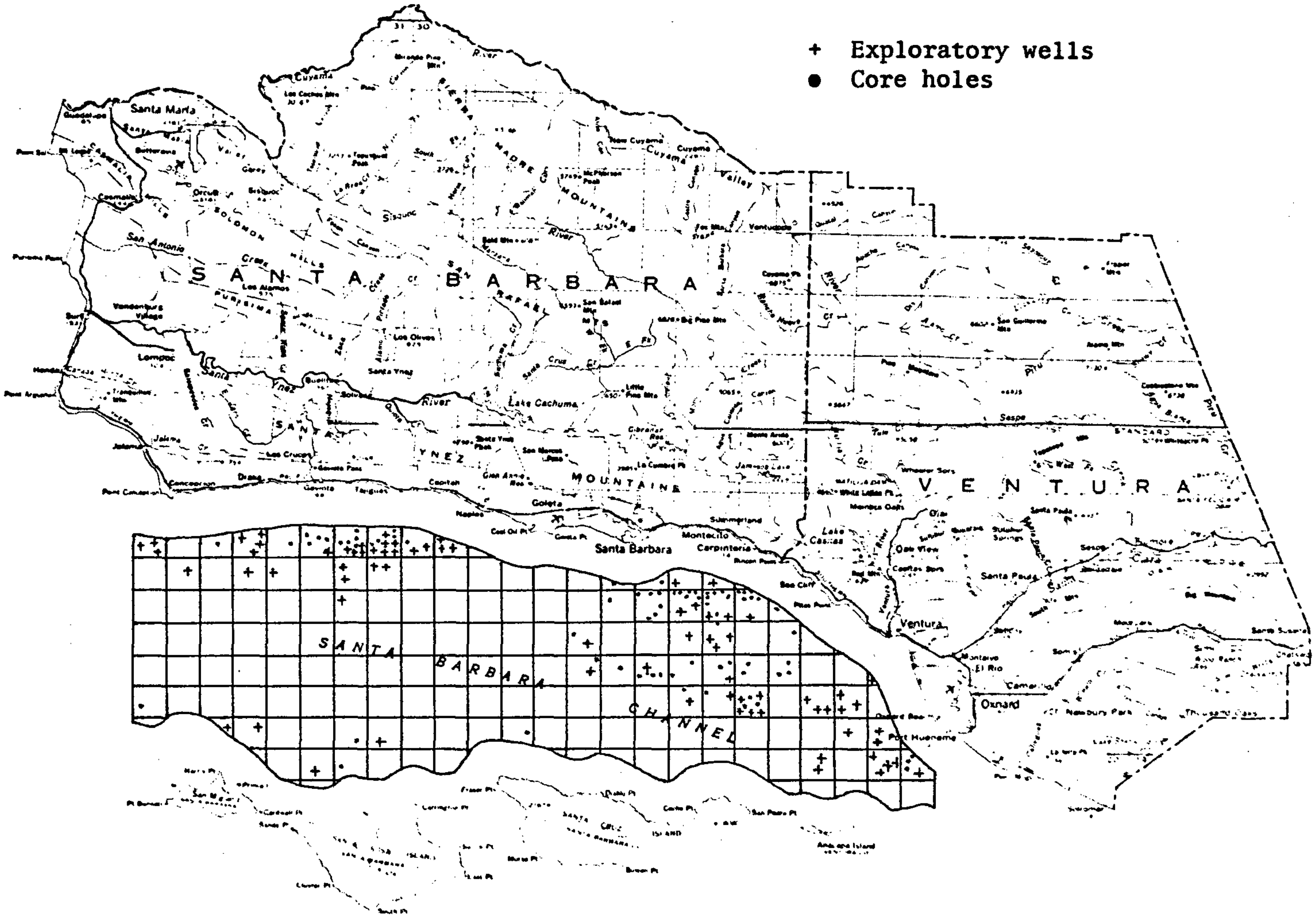


FIGURE I-2

CORE HOLES & EXPLORATORY WELLS DRILLED
IN THE FEDERAL OCS SANTA BARBARA CHANNEL

categories, i.e., (i) Exploratory drilling to discover a reservoir, to delineate its boundaries, and to determine its characteristics; (ii) Development drilling to most economically realize the potential of the reservoir.

The impact of exploratory drilling in the Santa Barbara Channel has been analyzed previously by the Department of the Interior in an Environmental Impact Statement issued July 1971. In addition, the impacts of platform drilling and drilling from floating vessels were considered in the Santa Ynez Unit Environmental Impact Statement issued in May 1974. These earlier evaluations have been reviewed, updated and included in this present statement. Figure I-2 shows exploratory wells drilled in the Channel.

Offshore exploratory drilling today is generally conducted from a floating vessel or from a mobile "jack-up" platform. The latter type platforms are of many configurations, but can most generally be compared to a barge on which all drilling equipment, as well as auxiliary facilities such as living quarters, helicopter deck, etc., are mounted. The platform may or may not be self-propelled. The platform is equipped with three or more legs suspended in "jacks" which serve to raise or lower the legs in a vertical direction. When moving the platform, the legs are elevated. On arrival at the drilling location, the legs are lowered to the bottom and the platform is elevated on the legs to a position above the water surface. The platform is then essentially a fixed platform and drilling is conducted in the same manner as from a fixed platform (see section I.D.3.h.). There is a further discussion of jack-up platforms in Appendix I-3, following Section I.

For these reasons, only floating vessel drilling will be discussed in this section. General features of a floating vessel drilling system are illustrated in figure I-3.

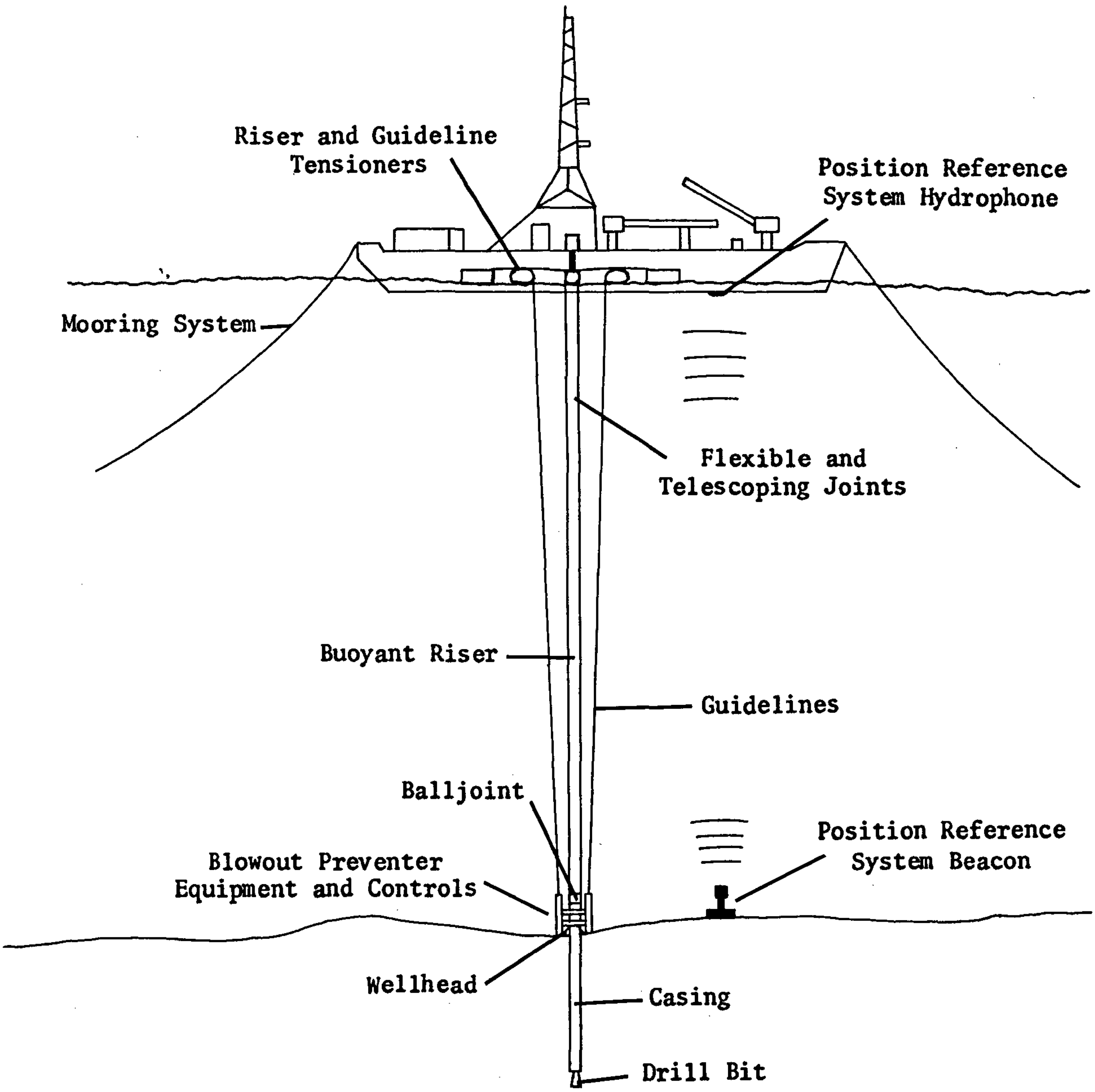


Figure I-3. Components of a Deepwater Exploratory Drilling System

Subsea completions discussed later in this section would also probably utilize floating vessel drilling.

a. Features of Floating Vessel Drilling

Whether drilling is conducted on land, a platform, or from a floating vessel, most of the requirements are similar. Drilling from a floating vessel, however, requires certain modifications in procedures and, in some cases, equipment modifications. Five areas of major differences in procedures can be identified for floating vessel drilling, they are:

(1) Movement of the Vessels from One Location to Another

Drillships move from one location to another under their own power. The older semi-submersible drilling vessels were moved by towing vessels. Most modern semi-submersibles have their own propulsion system, but may require assistance from towing vessels, especially on long moves, in order to save time.

(2) Mooring the Vessel

The mooring system is that system designed to hold the vessel on location against the forces of wind, waves, and current. Component parts include the mooring line winches, the mooring line, the anchor chair, the anchors, the pendants, the buoys, and all connecting links throughout the system. Mooring systems must not only provide satisfactory restoring force, but must also limit horizontal displacement. Moorings should be designed to limit vessel horizontal displacement to 10 percent of water depth.

Mooring systems normally consist of a combination wireline-chain system or a chain system. Wirelines are normally sized so that expected mooring loads never exceed one third of the wireline breaking strength.

In practice, chain-only mooring systems are used in water depths to about 1,000 feet. Combination cable and chain systems can be used to depths of about 2,000 feet. At depths over about 1,000 feet it is generally considered prudent to employ dynamic positioning in conjunction with a mooring system and at depths greater than 2,000 feet dynamic positioning is the only practical method of maintaining position. This positioning method is discussed below.

Reliable information on the relative position of the drilling vessel and the subsea wellhead is an important key to controlling horizontal displacement. Three types of monitoring devices are in use today. One type of vessel-position indicating system is based on acoustics. Vessel position is continuously monitored by triangulation methods using acoustic signals fed into shipboard computers; this position is visually displayed on a console which shows the location of the drilling vessel as to distance and direction of departure from the wellhead. The second type is the taut-line system. This system consists of a taut steel line stretched from the vessel to an anchoring point on the ocean floor and a dual-axis inclinometer to measure the slope of the line. The taut-line slope indicates vessel displacement in the horizontal plane. Both taut-line and acoustic position reference systems have been employed on drilling vessels in the Santa Barbara Channel. The third type of monitoring system is a riser angle sensor that will indicate the departure of the riser from vertical and, therefore, the horizontal displacement of the vessel from the wellhead location. The output from these monitoring systems is fed to a shipboard computer system and the output from the computer controls the tension in mooring system lines to maintain the vessel in position.

The more modern drilling vessels, both drillships and semi-submersibles, have in addition to the main fore and aft propulsion system, a "thruster" propulsion system. This system makes possible lateral, or sideways, movement of the vessel through screws or jets perpendicular to the fore and aft axis of the vessel. The combination of fore and aft, and lateral propulsion systems permits accurate positioning of the vessel in relation to a fixed point.

In practice, on location, the output of the thrusters and main propulsion system is computer controlled. The input to the computer is from the position monitoring system described above, the output from the computer controls the thrusters and main propulsion systems to maintain the vessel on position. In water depths from about 1,000 to 2,000 feet this dynamic positioning system is generally used in conjunction with a conventional mooring system.

In depths over 2,000 feet, the system can be used alone to maintain position.

Core holes were successfully drilled, and re-entered, by the Glomar Challenger in water depths up to 20,000 feet. Conventional cased wells have been successfully drilled and re-entered using this method, without the aid of divers, in waters up to 1,500 feet deep off southeast Asia.

Generally there are at least two positioning systems for redundance and of course the vessel can also be manually controlled to maintain position in case of failure of computer systems.

(3) Vessel Motion Compensation

Because of the flexibility of the drill string and due to the ball joints incorporated in the riser system (described in section I.D.3.b.(3), horizontal motion of the drilling vessel in relation to the ocean floor wellhead can be accepted up to at least 10 percent of the water depth.

One of the requirements for successful rotary drilling is to maintain a constant weight on the bit. Drilling from a floating vessel which moves up and down in relation to the ocean floor requires special methods to maintain a constant weight on the bit. The riser system is equipped with telescoping joints to permit vertical motion of the vessel. The bottom hole assembly of the drill string is also equipped with telescoping joints, called bumper subs, for the same purpose. Hydraulic or pneumatic vertical motion compensators have also been developed and are in use on many vessels. In one system the compensator is placed in the drill string below the traveling block. In another, the compensator is a part of the crown block, which is normally fixed in place at the top of the derrick, but in this system the crown block moves to compensate for vertical motion of the drilling vessel. Both systems maintain a constant drill string weight on the bit. Thus, as the vessel moves up and down, the drill string automatically maintains its position relative to the bottom. These compensators have been designed with as much as a 400,000-lb. capacity and a 14-foot stroke. Figure I-4 shows a typical hydraulic vertical motion compensator.

(4) Remote Location of Well Control Equipment

In floating vessel drilling, the wellhead and the blow-out preventer (BOP) stack are located on the ocean floor. Therefore, all of the functions normally carried out just below the drilling floor on land and platform drilled wells must be conducted by remote control.

Valves are remotely operated (hydraulically, pneumatically, or electrically) through lines run in conjunction with the guidance and riser systems (section I.D.3.b.(3)). Most of these valves are of the fail-to-close type which will automatically shut in the well should loss of control power occur. Kill and choke lines are also run with these systems to permit circulation in case the blowout preventers are closed.

Positioning systems to permit the installation of equipment in its proper alignment are generally mechanical and are discussed under guidance systems in section I.D.3.b.(3) and (4). Visual observation of these functions is made possible by underwater television systems which are in use on many vessels. A back-up system can be provided by divers or submersibles, but the trend is away from these methods as deeper water drilling is attempted.

(5) Weather and Oceanographic Influences on Operations

Drilling vessels are designed to be functional in all but the most severe weather conditions. Wells have been drilled in the

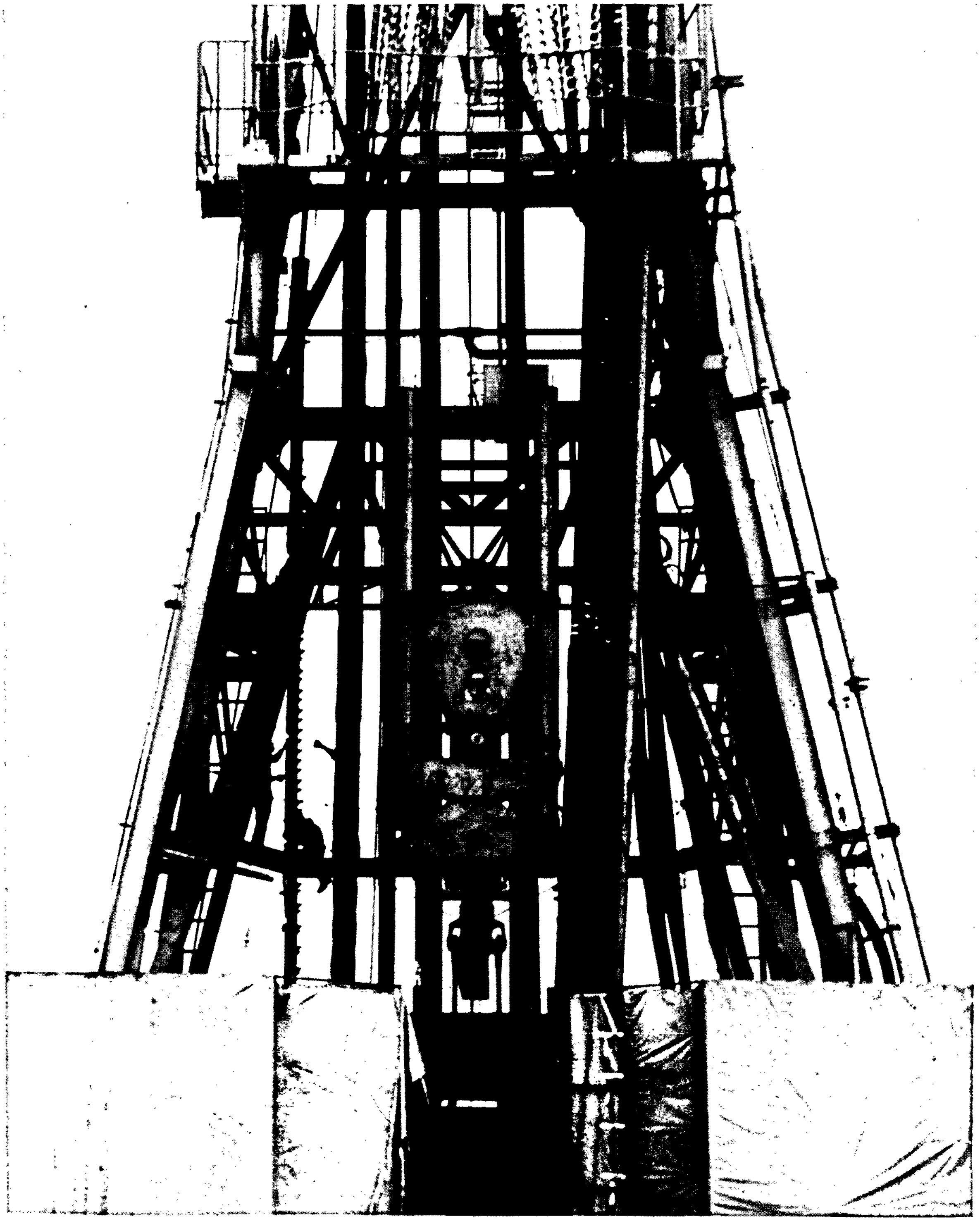


FIGURE I-4 VERTICAL MOTION COMPENSATOR

Source: VETCO OFFSHORE. INC

North Sea, with no down-time due to weather, when up to 14-foot significant waves were running. Vessels have remained on location under much more severe conditions, although drilling operations were suspended.

Recent observations from a modern semi-submersible drilling in the North Sea indicate the stability of these vessels in rough weather. During a storm period reaching 9 on the Beaufort Scale, with wave heights from 16 to 45 feet and 8 to 12 second wave periods, the vessel's heave ranged only from 1.5 to 7 feet.

In the event that conditions were severe enough to require that the vessel leave the location, the blowout preventers would be closed and the riser system retrieved by the vessel. When conditions permitted, the vessel would resume its location as before, re-run the riser system, and resume operations.

b. Drilling Equipment

In implementing a drilling program, a lease operator should focus on two objectives: (i) to conduct efficient drilling operations using advanced technology; and (ii) to conduct operations in a safe manner, with emphasis on maintaining well control and protecting the environment against accidental spills. The following discusses how floating drilling equipment components are selected, designed, and utilized to meet these objectives.

Floating drilling operations can be more easily described and understood by first separating the components into five categories, or systems, as follows:

- Drill Vessel
- Mooring System
- Drilling System
- Marine Well Control System
- Special Operating Techniques

(1) Drill Vessel

The term "drill vessel" is used here to refer to the vessel or hull from which drilling operations are conducted. There are two types of vessels utilized for the preponderance of deepwater drilling. One type is a conventional drillship where drilling is conducted through a vertical water-tight shaft (moon pool) built through the hull of the ship. The other type is a semi-submersible drilling platform with a structural configuration in which the main buoyancy members are located below wave action. Each of the types would be considered acceptable for drilling exploratory and submerged production system development wells in the Santa Barbara Channel (see Appendix I-3, subsection I.H.3).

Both hull types have exhibited favorable operating characteristics in the relatively mild environmental conditions of the Channel. Overall weather downtime averaged only about 2 percent while one operator conducted floating drilling operations in the Channel.

The semi-submersibles are large, advanced-design rigs that have better motion characteristics in rough seas than do ship types. The units can work in water depths to 1,000 feet and beyond. Vessels are being developed which have the capability to drill in over 3,000 feet of water.

(2) Mooring System

The mooring system was discussed in section I.D.3.a.(2) on Features of Floating Vessel Drilling.

(3) Drilling System

Components included in the drilling system are generally the same components found on most rotary rigs and are associated with all drilling operations whether on land or offshore. Those include the equipment for (i) hoisting the pipe, (ii) rotating the drill string, (iii) circulating the drilling fluid and (iv) the associated auxiliary facilities. Since these are common drilling components and not unique to floating vessel drilling, no description will be included here. Reference may be made to Appendix I-2 which discusses these components.

(a) Drilling Riser and Well Control Conduits

One part of the floating vessel drilling system that is unique to floating vessel drilling is the riser system. The riser itself is a large diameter pipe connected to the top of the blowout preventer stack by a hydraulic connector. All drilling operations after the conductor pipe is set are carried on through the riser and the primary function of the riser are to permit circulation of drilling mud and cuttings from the bottom of the hole to the drilling vessel, and to serve as a drill pipe guide.

The riser system includes ball joints or flex joints at the bottom and near the top to reduce bending moments caused by vessel movement in the horizontal plane. Horizontal movement is permissible to at least 10 percent of the water depth. In addition, the system includes telescoping or slip joints to permit vertical movement of the vessel. Figure I-5 shows a typical riser system and its relationship to other components of the drilling system.

The riser system is connected to the drilling vessel by riser tensioner lines designed to maintain proper tensioning of the riser. This is necessary to avoid overstress and buckling of the riser. In the later vessels proper tensioning of each line is controlled through a computer system.

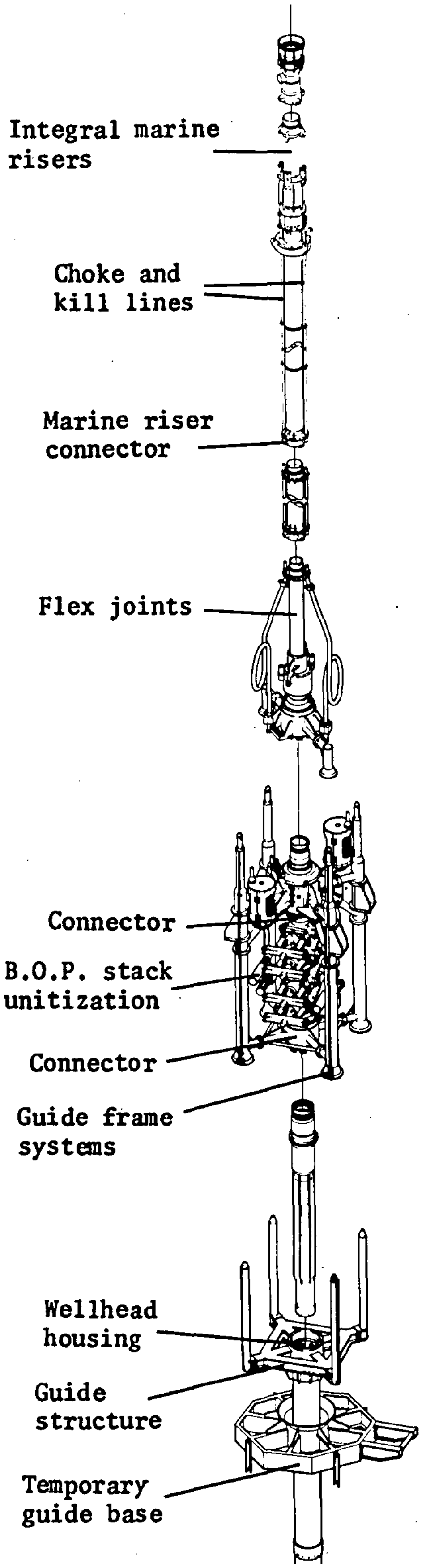
In deeper water, in order to diminish stress on the tensioner lines, buoyant riser joints or external float attachments are included in the riser string. It is possible to drill in water depths to about 1,500 feet without help, but in waters over 1,500 feet deep a buoyant riser system is a necessity.

Riser length has been one of the limiting factors in deepwater drilling, from the standpoint of strain on the tensioning system and on storage and handling facilities on the drilling vessel. However, Shell Oil Company is currently drilling a well in 2,150 feet of water off Gabon in western Africa.

Kill and choke lines are integral within the riser system to minimize running

Fig. I-5

MARINE WELL CONTROL
SYSTEM



MARINE RISER SYSTEM

The Marine Riser System functions to carry drilling fluid returns back to the drilling vessel. The Riser System incorporates a flexible joint at its lower extremity to isolate the blowout preventer and the wellhead from bending loads should the vessel move off location. A telescopic joint, located near the top, accommodates the vertical reciprocating motion of the vessel.

BLOWOUT PREVENTER STACK

Comprised of large diameter, high pressure valves, the Blowout Preventer provides the ability to securely control variation in well bore pressures during the drilling operation. Duplicate hydraulic control systems assure reliability of preventer operation at all times.

WELLHEAD ASSEMBLY

The wellhead assembly functions as a pressure vessel to which the casing strings are securely sealed as they are installed in the wellbore. The outer profile of the wellhead provides the means of attaching the blowout preventer stack.

GUIDANCE SYSTEM

The permanent guide base run with the conductor casing. The temporary guide base run on drill pipe. The guide bases incorporated in the assembly function as an anchor for guidelines extending from the drill vessel and provide initial support for the installation of the wellhead assembly.

Source: VETCO OFFSHORE, INC.

and pulling time. Connections of these lines to the BOP and manifolding are such that the lines can be operated as either kill or choke lines. Well control conduits are also run simultaneously with the riser system.

(b) Vertical Motion Compensation

The second part of the drilling system unique to floating drilling is the vertical motion compensation system. This was discussed in section I.D.3.a.(3).

(4) Marine Well Control System

The well control system is the composite of those components that provide for utilization and control of, and communication with, the subsea well during drilling operations. Major components of the system are:

- Guidance System
- Wellhead
- Well Casing
- Blowout Preventer Stack and Controls
- Drilling Riser

(a) Guidance System

A guidance system is one of the first ties made between the ocean floor and the drilling vessel. This consists of two or more wirelines attached to a fixed ocean floor structure and tensioned by hydraulic and/or pneumatic units on the vessel. These lines serve as guides for running the drill pipe, blowout preventer (BOP), riser system, and television camera if used.

A typical guide structure is shown in figure I-5. This structure is run and set on the drill string. Structural casing is set through the guide structure by drilling, driving, or jetting to a depth of about 100 feet. If drilled or jetted in place this casing is cemented in place with a quantity of cement sufficient to fill the annulus to the ocean floor. Conductor casing is then set and cemented in place through the structural casing to a depth of from 300 to 500 feet below the ocean floor. The wellhead casing hanger system is run with this casing string. The blowout preventer assembly and the riser systems are then installed and the actual drilling proceeds. Subsequent casing strings are run through the wellhead casing hanger system and seated as run.

The guidance system described above is typical, but various companies have adopted different methods that vary in details from the one described. Some systems make use of acoustic beacons to re-enter the sea floor assembly.

(b) Wellhead

Subsea wellhead equipment and casing programs are similar in most respects to the land counterparts. The equipment differs principally in that it incorporates provision for remote installation on the ocean floor. The primary function of the wellhead is to hang the casing strings and to serve as the base for the BOP stack. After the well is drilled, tested, and completed the wellhead assembly will serve as the base for the christmas tree assembly and any other subsea production equipment that may be installed.

(c) Well Casing

Formation pressures and fluids are isolated by setting and cementing steel casing strings as drilling progresses. The USGS approves casing programs submitted by lease operators which incorporate appropriate safety factors for maximum potential pressures. Casing setting depths comply with, or exceed, all applicable regulations. Pipe quality, dimensions, weights, grade, yield strengths, etc. are also regulated by the USGS. Cementing programs and practices are approved and regulated by the USGS. The Operator must comply with all OCS order casing requirements plus any other requirements the Oil and Gas Supervisor deems necessary.

(d) Blowout Preventer Stack

The blowout prevention equipment (BOPE) used in floating drilling operations is essentially the same as that described in Appendix I-2 for land drilling. The principal difference is that all the valves comprising the stack are run at one time as a unit and connected to the conductor casing with a hydraulic connector. The provisions to control the preventers are also more elaborate due to the remote location of the stack. Figure I-5 shows the relation of the underwater blowout preventer (BOP) stack to other elements of a floating vessel drilling system.

A more detailed discussion of the blowout prevention equipment and functions is given in section I.D.3.d.(3). Blowout preventers and other well control equipment must meet the Geological Survey requirements (see section IV.A.1.g.). This equipment is tested on a schedule set by prudent practice, but not less often than is specified in Geological Survey regulations (OCS Order No. 2).

(e) Drilling Riser and Well Control Conduits

The riser system was discussed in section I.D.3.b.(3)(a).

c. Safety Features of Marine Well Control System

The marine well control system of wellhead, BOP, controls and riser is the most vital component of the floating drilling system. It is also the most vulnerable. For this reason, the system must be designed as safe as possible compatible with the applicable safety features available to industry at the time and pursuant to Survey regulations (section IV.A.1.g.).

The following sections enumerate common operating procedures developed or established by industry organizations, OCS Operators or Geological Survey OCS Orders, for various components of well control systems:

(1) Maximum Reliability

- Pressure ratings in excess of those which may be encountered.
- Fail-safe design of all critical functions.
- Dual separate fail-safe valving on critical lines and outlets.
- Two blowout preventer (BOP) side outlets and manifolding such that kill and choke lines can be operated as either kill or choke lines.
- Adequate ocean floor storage of hydraulic power for cycling all critical functions in case of loss of surface connected power hose.
- Fast closure of blowout preventers (BOP) provided by ocean floor hydraulic power supply.
- Redundant control systems and pilot valves which can be retrieved individually and repaired without pulling BOP stack.
- Established operating practice to alternate use of control systems weekly to insure both are functional.
- Established practice to suspend operations when either control system is not functional, while conducting repairs.
- High level preventative maintenance such as sandblasting and magnafluxing riser joints, then repainting. Also, inspection for wear and testing functional capability of each piece prior to installation.
- Assembling, activating, and pressure testing each function of BOP on board vessel prior to installation.
- Functional testing of BOP daily and pressure testing weekly, or when changes are made.

(2) Well Closure in the Event of an Emergency

- Optimum ram closure around drill pipe to allow circulation of drilling fluid in the event of a well kick.
- BOP facilities to sustain emergency well control conditions over prolonged periods.
- Provision for hanging drill pipe on rams and moving drilling vessel off location.
- Capability to re-establish vessel on location, monitor and circulate well prior to reconnecting drill pipe.
- Provisions for alternate procedures should any of the foregoing fail.
- Drill with a float valve in the drill string to prevent reverse flow.
- Automatic locks on all ram-type preventers.
- All marine connectors through top of BOP stack designed to adequately handle full-well pressure.
- Annular preventer equipped with automatic closure or acoustically operated closure device in case of loss of control hoses.

(3) Completely Diverless Operation

- Provision for remote operation and remote recovery.
- Appropriate redundancy in all valves and controls.
- Provisions for latching and re-establishing guidelines.

(4) Simplified Installation

- Integration of choke and kill lines into marine riser to simplify simultaneous installation of riser and control lines.
- Run well control systems simultaneously with riser.
- Before landing BOP stack, install upper components (ball joint, telescoping joint and riser tensioning). This allows easy precision control in lowering last few feet with tensioning system.

d. Well Control

In sections 3.b.(4) and 3.c. above, the mechanical well control systems were discussed. However, well control is actually maintained through a variety of inter-related systems. The primary means of well control is the weighted column of drilling fluid (mud) in the hole. The weight of this column serves to control subsurface formation pressures and to prevent formation fluids from entering the well bore. The well casing is the secondary means of well control since, when casing is run and cemented through a formation, that formation is isolated from the well bore and from other formations. The blowout preventer system is the third means of well control and is designed to be used if the primary system fails.

(1) Drilling Fluid

During drilling the well bore is kept filled by circulating the drilling fluid (mud) through the drillstring, out the bit, and up to the surface through the annulus. The weight per volume of the drilling fluid (mud) can be controlled by the addition of weight material (barite) through a very wide range to give the desired hydrostatic pressure on bottom. This pressure is designed to be in excess of any natural formation pressure that may be encountered.

The pressure exerted by the mud column is a function of the mud weight and the height of the column. Should the formation pressure be allowed to exceed the pressure exerted by the column of drilling fluid, the column of mud would be forced up and out of the well and an uncontrolled flow of gas, oil, or water could ensue if proper control measures were not taken.

There are two ways in which the formation pressure may exceed the hydrostatic pressure of the mud column. The first, of course, is when the weight per volume of the mud is insufficient. The second is when the height of the column is allowed to decrease to the point where the hydrostatic pressure of the mud column is less than the formation pressure. Some formations contain highly permeable zones which will accept large quantities of the drilling fluid and result in "lost circulation". As the drilling fluid is lost to the formation, the height of the column will fall and a point may be reached where another formation will release formation fluid to the well bore.

When gas, or any formation fluid that is lighter than the drilling fluid, is allowed to enter the well bore, the weight per volume of the drilling fluid is decreased. The effect is cumulative; as formation fluid enters the well bore, the weight of the drilling fluid decreases thus allowing a continually increasing rate of formation fluid entry. Figure I-6 illustrates this process.

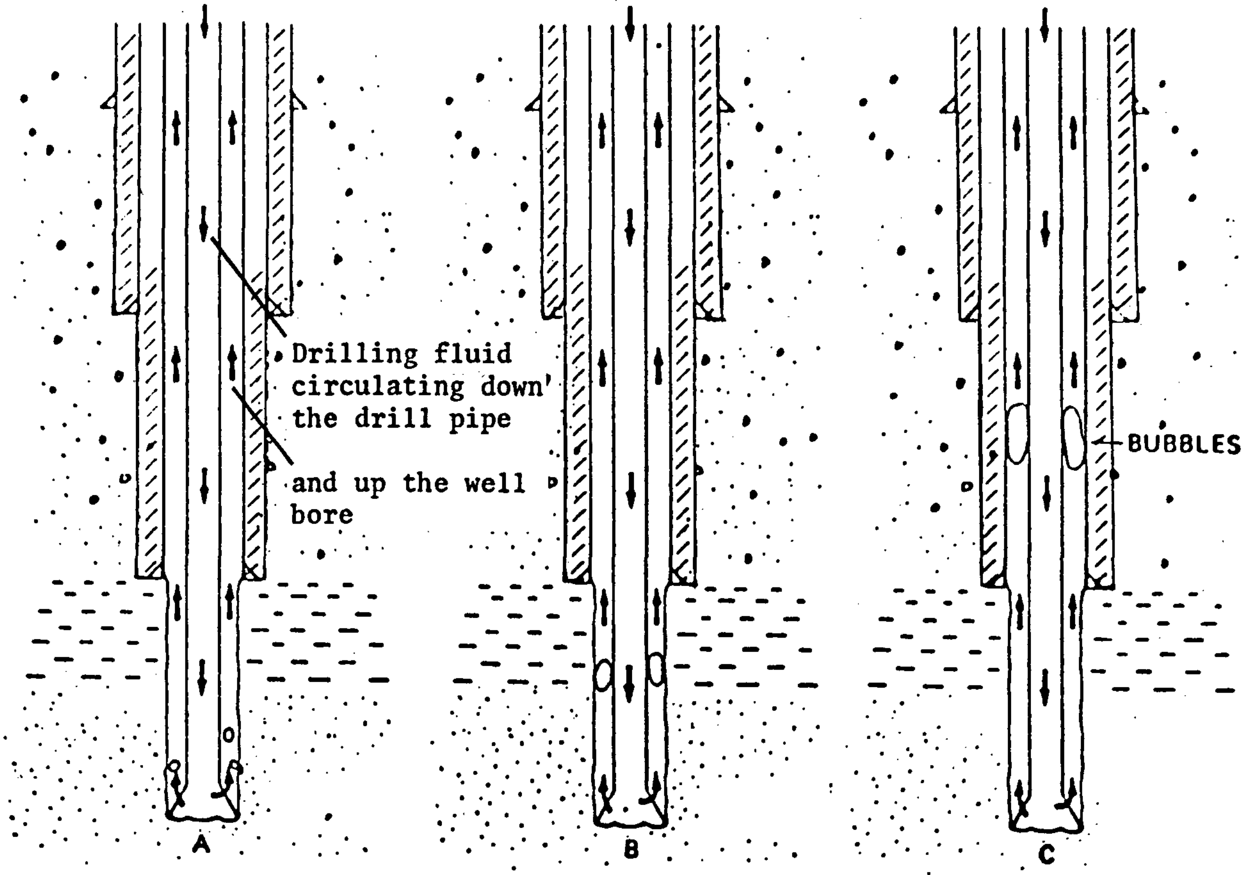
If formation fluid enters the well bore and a surface indication of some influx of formation fluid is observed, such an occurrence is called a kick. When even a slight kick occurs the operator uses the precautionary measure of circulating out through the choke with the blowout preventers closed.

Several methods are employed to ensure that the weight of the drilling fluid column is sufficient to control formation pressures and yet not so high as to risk lost circulation:

(a) Mud Program

The mud program is a very important part of the drilling program and is based on all available information on the area to be

FIGURE I-6 Gas Influx



A "kick" is a gas or liquid influx that reduces the hydrostatic head in the annulus. Here, the kick is a gas bubble (A). As it rises (B and C), it expands.

(Adopted from Panel on Operational Safety in Offshore Resource Development, "Outer Continental Shelf Resource Development Safety", Marine Board of National Academy of Engineering, December, 1972).

drilled. Mud weights are specified at the various depths to be drilled and changeover points are indicated where high pressure or loss-of-circulation zones can be expected. Naturally, in development drilling this program can be very detailed and based on known information. In exploratory drilling, the program must be based on general knowledge, inference, and experience. As an exploratory well is drilled, the mud program is adjusted to fit conditions as they are encountered. Mud programs are reviewed and approved by the USGS.

(b) Mud Monitoring and Control

- The Mud Engineer

  The drilling fluid (mud) engineer makes periodic mud property tests and prescribes the treatment required to obtain or maintain the desired properties.

- Mud Logging Equipment

  This equipment continuously monitors the mud system, recording mud properties, the presence of oil or gas in the mud system, and the lithologic properties of the formations. It also records other information such as the drilling rate, circulating mud pump pressure and weight on the drill bit. This information may indicate potentially dangerous situations and permits action to be taken before they develop. Mud logging equipment is required by the USGS as a stipulation to permits granted for drilling exploratory wells in offshore areas and by OCS Order 2 for development wells.

- Pit Volume Indicator

  The pit volume indicator indicates the total volume of drilling fluid in the system. If the volume of mud in the system decreases, there is a loss of fluid to the formation. An increase in the mud pit level indicates an inflow of formation fluid and thus the potential for a blowout. There is both an audio and a visual signal to indicate the level of mud in the sump.

- Fill-up Measuring System

  One of the critical periods in the drilling of a well is when the drillstring is removed from the hole. As the pipe is pulled from the hole, its equivalent volume must be replaced by mud to maintain the hydrostatic pressure on the formation. A calibrated fill-up tank is maintained for this purpose. As pipe is pulled, the quantity of mud required to replace its volume is metered. Any difference between pipe volume and replacement mud volume will indicate a potential hazardous situation.

- Mud Degasser

  Gas may enter the mud system as discussed above, or merely from the gas contained in the pores of the formation being crushed by the bit. The mud viscosity may prevent the release of small gas bubbles and thus there is a possibility of a continuing decrease in the mud weight per volume. A mud degasser is included in the mud system to remove any entrained gas from the mud before it returns to the mud pit. This prevents continued lightening of the mud and also prevents any hazardous gas buildup at the mud pit.

- Down-Hole Gas Influx Indicator

  A new method of indicating gas entry into the well-bore during drilling presently is being developed and tested. It essentially involves the use of a tool included in the drillstring that will trap a sample of the drilling fluid from the bottom of the hole. By lifting the drillstring, the chamber in which the sample is confined is enlarged, thereby reducing the pressure on the sample and allowing any entrapped gas to escape and expand. The energy resulting from gas expansion will be reflected on the surface weight indicator as a diminution of the work required to lift the drillstring. The time required for this operation is only about 30 seconds and the advantage is that gas entry can be detected immediately and at the point of entry. The other methods discussed above depend on surface indications that are delayed due to the time required to circulate fluid to the surface. This method is still in the development stage, but it may prove to be a very valuable tool in well control.

(2) Well Casing

Formation pressures and fluids are isolated by the setting and cementing of as many as five steel casing strings of successively smaller diameter. Each casing string is designed with appropriate safety factors for maximum potential pressures.

Casing setting depths must comply with Geological Survey regulations (see

IV.A.1.g.). Production casing and tubing that are subjected to corrosive oil and gas are made of quenched and tempered steel, with strengths and dimensions appropriate to this type of service. Well fluids are produced through an inner tubing string that isolates them from contact with the casing. In completed flowing wells, the production casing is further isolated from wellbore fluids and pressures by an annulus packer.

(3) Blowout Preventer Equipment

The blowout preventer installation is an emergency tool designed to be used in the event the primary means of well control, the drilling fluid, fails to control the well. It can be described as a large valve assembly attached to the top of the casing. In the event of an uncontrolled blow from the well, these valves can be closed to contain the blow. All drilling functions are conducted through the blowout preventers and the series of valves contained in the blowout assembly are designed to close in the well regardless of the operations being conducted.

Some of the valves are full closing, that is, they will shut in the well completely. Others will seal around any pipe in the hole and thereby close in the annular well space. One valve, called a shear blind ram, is designed so that it will shear through any pipe in the hole and close in the well.

The upper valve in the stack, an annular type, is designed to allow stripping operations. That is, pipe can be run or pulled through the valve while it is under pressure. In this way, circulation can be regained through the use of the pipe in the hole and the kill and choke lines.

The present USGS regulations require a minimum of four remotely controlled, hydraulically operated blowout preventers including at least one equipped with pipe rams, one with blind rams, and one bag (annular) type. In practice, subsea BOP's generally exceed this minimum and may consist of at least four ram types and one or two annular types.

The valves in the blowout preventer assembly are hydraulically operated and can be controlled from two or more locations and by alternate control systems. At least one of the component valves, usually the lower annular type preventer, is designed to close automatically if control pressure is lost.

The control fluid accumulator, or reservoir, is usually installed near the blowout preventer assembly, or stack, to provide minimum reaction time. In the case of offshore drilling from a floating vessel, the accumulator may be underwater or it may be on the surface vessel. Side outlets are provided in the blowout preventer body to permit circulation in case it is necessary to shut the preventers.

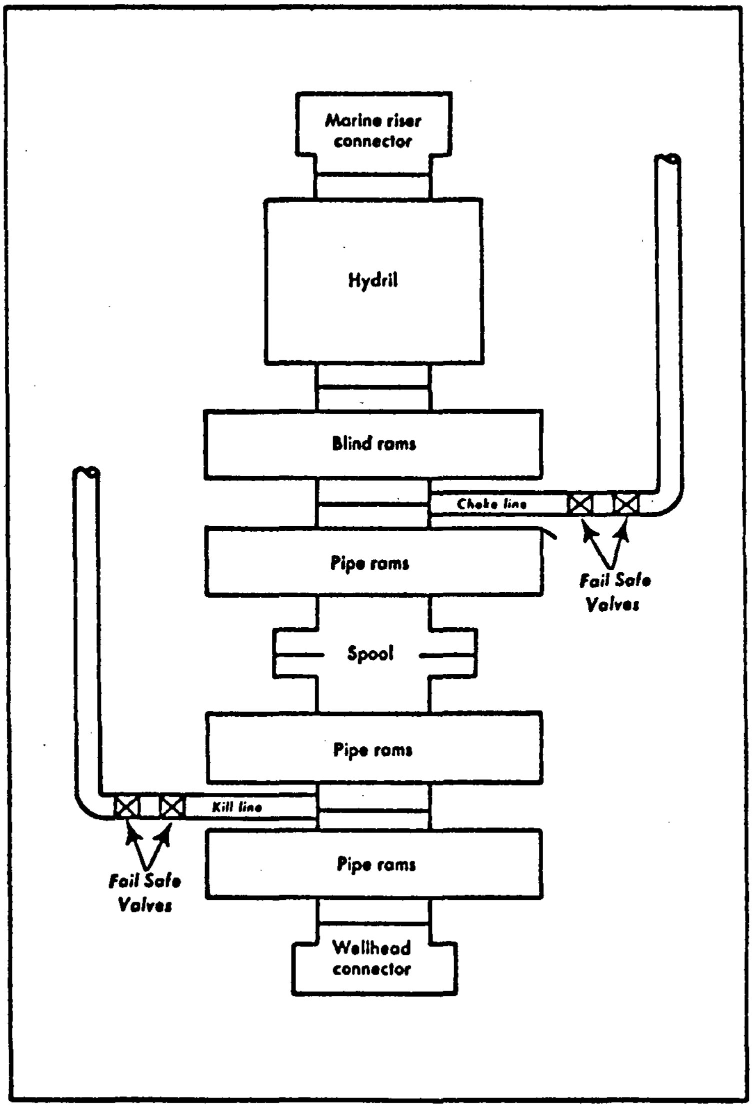
USGS regulations specify the minimum frequency of testing blowout prevention equipment as well as the testing range. These regulations also require crew training in the operation of this equipment.

Figure I-7 is a stylized version of a typical subsea BOP stack while figure I-8 shows one of the largest and heaviest assemblies in use at present.

(4) Additional Control Methods

Drill pipe safety devices are maintained in the drill string and on the derrick floor in conformance with USGS regulations.

FIGURE I-7 Stylized Subsea BOP Stack



L. M. Harris, *An Introduction to Deepwater Floating Drilling Operations* (Tulsa: Petroleum Publishing Co., 1972, p. 99. Used by permission.)

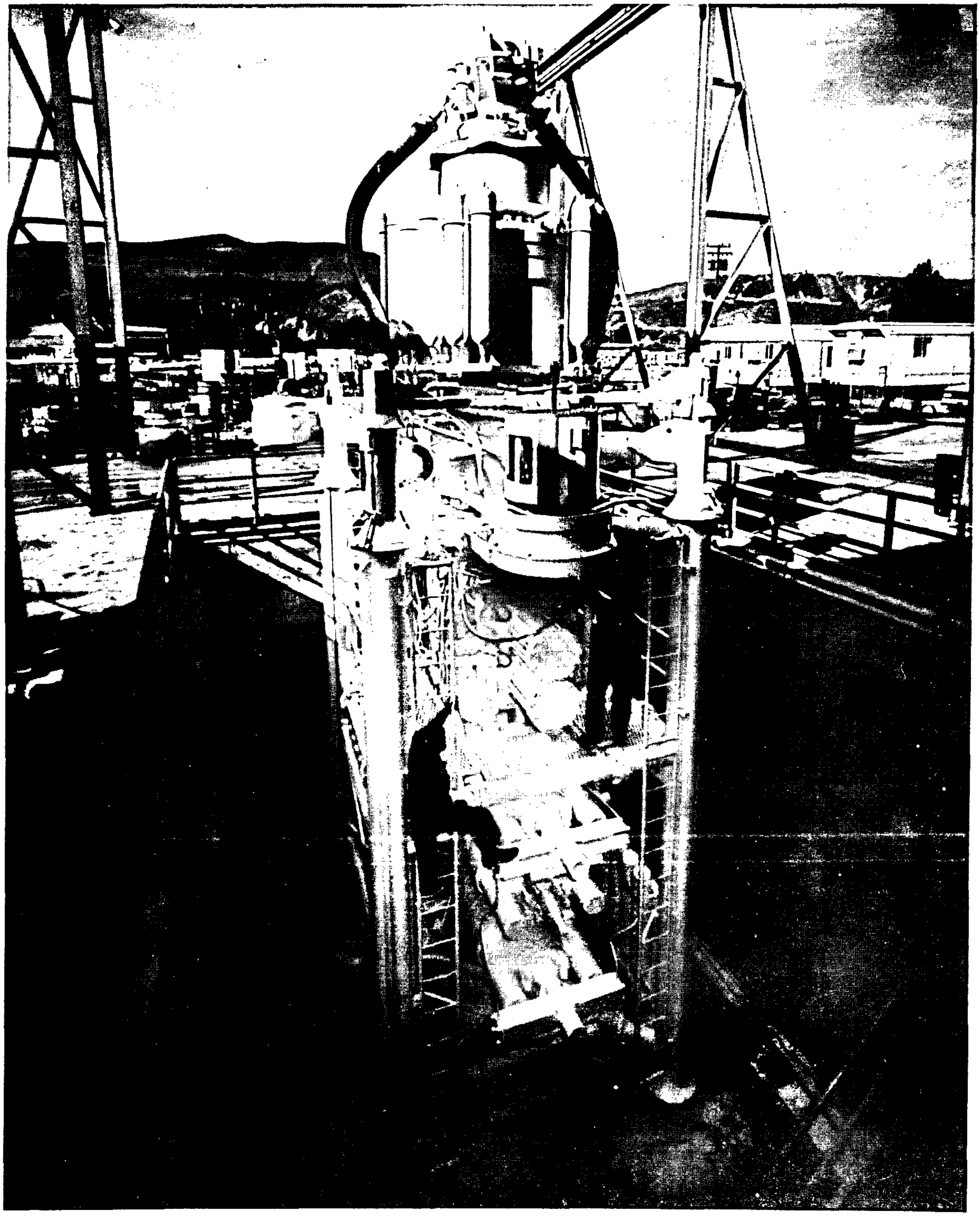


FIGURE I-8 SUBSEA BOP STACK

Assembly consists of, from the bottom:

(1) Wellhead Connector
(2) Triple Ram Preventer Unit
(3) Double Ram Preventer Unit
(4) Bag Type Preventer Unit
(5) Ball Flex Joint
(6) Marine Riser Connector

Source: VETCO Offshore, Inc.

(a) Full-Opening Drill String Safety Valve

This is maintained in the open position on the derrick floor for installation on the drill pipe to contain any unexpected flow from the well.

(b) Socket Type, Sealed Coupling with Full-Opening Safety Valve

This is also maintained on the derrick floor for situations where the well status prevents the use of a safety valve screwed on the drill pipe threads. The socket type, sealed coupling is capable of being dropped over exposed drill pipe and sealed.

(c) Back-Pressure Valve

A back pressure valve is maintained on the derrick floor for installation after the safety valve is installed. This valve prevents well bore fluids from flowing up the drill pipe, but will permit fluids to be pumped down the pipe.

(d) Kelly Cocks

Valves are installed at the top and bottom of the kelly to permit shutting off flow from the drill string while the kelly is in use. The two valves allow access regardless of the position of the kelly in regard to the rotary table. The kelly is a long steel forging which makes connection with the top joint of drill pipe in the drill string. The rotary table turns the kelly which turns the drill pipe and bit.

e. Pollution Control

On an industry wide basis, the more stringent regulations adopted by USGS since the Santa Barbara spill have significantly reduced the chances for an accident on the OCS that would result in pollution. Regulations and pollution prevention are discussed throughout section IV.

Pollution control equipment required to be employed in floating vessel drilling operations includes: a drill cuttings washing system to assure that no oil, or drill cuttings, sand, or other solids containing oil, is discharged into the sea (hauling of oil wet cuttings to shore for processing and disposal is utilized if more practicable); drain collectors and gutters to collect all feasible oil-contaminated rig-area washdown fluids; and tanks for storage of liquid waste water until treated for disposal or transferred to a shore facility for processing. Trash and waste material is accumulated in special containers, transported to shore and hauled to an approved refuse site. Biological wastes from the crew quarters are treated and disposed of in strict compliance with Geological Survey and Coast Guard regulations. Ocean dumping of waste materials, or debris is not permitted.

f. Fire Protection

Fire protection facilities are installed in accordance with U. S. Coast Guard regulations and OCS Orders, and periodically inspected as prescribed.

g. Community Facilities

The floating drilling vessel is usually equipped with a helicopter landing deck and alongside boat landings. Storage facilities are provided for diesel fuel, potable water and well drilling supplies. Crew quarters are provided. Electric power is generated onboard and auxiliary generators are maintained to provide emergency power. Continuous voice communications with nearby surface vessels and onshore are available via microwave, telephone, mobile radio, and marine radio systems. Emergency life support equipment, including gas masks, respiratory equipment, protective fire suits, life preservers and life rafts are stocked and maintained on-board to meet or exceed applicable U.S. Coast Guard regulations. The regulations of various agencies are discussed in section IV.A.1.

h. Drilling Operations

Drilling is normally conducted 24 hours per day, seven days per week, under the supervision of a lease operator drilling superintendent. Drilling personnel are normally transported to and from the drilling vessel by crew boats operating from nearby ports or by helicopter. Helicopter transportation is available for emergency conditions and to transport light loads of equipment and supplies during rough weather or at other times when rapid delivery is desired. Seagoing barges and/or large work boats are used to transport items such as drill pipe and well casing that are too heavy or too large for transport on crew and supply boats.

The generally mild weather conditions prevalent in the Santa Barbara Channel will not significantly affect drilling operations. Resupply operations can be conducted in seas of 8 to 10 feet or more; 10-foot seas are exceeded less than 1 percent of the time in a typical year and storage is provided for sufficient consumable supplies to maintain operations for at least one week regardless of weather. Santa Barbara Channel sea conditions are discussed in sections I.D.4.b.(2) and II.D.

To ensure that adequate provisions have been made for safety and well control, the mud, casing, and cementation programs for each well to be drilled must be approved by the Geological Survey before a drilling permit is issued.

Well control is stressed during all phases of drilling operations. Well control drills are conducted daily until each drilling crew is thoroughly trained, and thereafter at least once each week for each crew. A specific well control procedure is developed and posted as each successive casing string is set and whenever mud weights are changed. This procedure is immediately implemented in the event of any abnormal drilling condition. Other operating practices such as blowout preventer tests, casing pressure tests, waiting on cement time, and mud control practices must be in accordance with sound drilling practices and U.S. Geological Survey regulations.

Well control training is a basic part of routine crew training. Safety meetings and well control drills are held to insure proper response from each member of each crew. The frequency of drills and crew training is also specified in existing regulations.

i. Well Completion Operations

(1) Well Testing

Fluids from formations penetrated by wells are often brought to the surface in drill-stem tests to evaluate the possibility of oil and natural gas production. These fluids are collected in tanks at the surface; drilling mud is separated from the produced fluid, and if the formation fluid is oil it may be stored for later disposition. Gas is flared in specialized, high volume burners and if there is insufficient storage space, oil may also be flared.

If well tests show that commercial quantities of natural gas or oil have been found, it may be necessary to do several additional confirmation tests before the company is satisfied that the reserves will support installation of a production facility.

(2) Abandonment

If initial tests are dry, the well is usually plugged and abandoned. Cement plugs are set to confine formation fluids in their parent subsurface formations to prevent them from intermingling and to prevent flow to the surface. During plugging operations, well control equipment remains in use. When a well is abandoned, the casing is cut off at least 5 feet below the mud line, all obstructions are removed. In some cases, it may be necessary to drill several exploratory wells on each block before a lease is totally condemned.

Plugging and abandonment operations must be in conformance with Geological Survey regulations and such operations cannot be commenced prior to obtaining approval from the Geological Survey. The regulations specify acceptable alternate abandonment procedures for various well conditions, open hole, perforations, etc., and specify tests to ensure that formations are isolated and that the well is left in a safe condition.

(3) Producible Well Completions

If petroleum deposits prove to be commercial on a field basis, one of three courses of action in regard to an individual well may be followed:

- The exploratory well may be deemed expendable.

This may be because of the well's location in regard to the projected location of a production facility; because the operator is not prepared to undertake subsea completions; or because of some condition of the individual well, position on structure, mechanical condition, etc. In any case, the procedures would be the same as above for a dry-hole abandonment.

- The well may be considered useful as a future production well and be temporarily abandoned. In this case, the abandonment procedure would be the same as for a permanent abandonment as far as isolating the various intervals tested and/or left open, but other requirements of a permanent abandonment are relaxed. Annular space extending to the ocean floor may be left open, no cement surface plug is required, and the ocean floor need not be cleared. In lieu of the cement surface plug, a mechanical bridge plug is required to be set between 15 and 200 feet below the ocean floor. As in the case of a permanent abandonment, prior approval by the Geological Survey is required before commencing operations.

After the bridge plug is set, the wellhead is capped and left in condition for future entry when production activity commences. This results in the temporary existence of an underwater "stub". The Coast Guard District Commander requires that such stubs be marked by a buoy at the surface if located in 200 feet of water or less, and that the buoy be lighted if located in 85 feet of water or less.

When production facilities are ready and it is desired to put the well in production, a drilling vessel would be required and BOP's, controls and riser system would be reconnected as before. The temporary plugs would be drilled out and the completion would be made as described in section I.D.4.e.(2).

If at a later date it was decided to permanently abandon the well, a drilling vessel would also be required to re-enter the well, drill out the temporary plugs and proceed as for a dry-hole abandonment as described above.

- The well may be considered as a future production well and the well may be completed as described in section I.D.4.e.(2). while the drilling vessel is still on location. There may be certain modifications in the completion procedure insofar as the production wellhead assembly is concerned, depending on the operator's field development plan. That is, the complete production head assembly may be installed and the well left in a condition requiring only the connection of flow lines and the removal of the tubing plugs in order to produce. Or, perhaps only the lower portion of the production head assembly would be installed at this stage. This would leave the well closed in, requiring the installation of the upper portion of the production head assembly in addition to flow line connection and removal of the tubing plugs in order for the well to produce. The latter possibility would be particularly applicable if an encapsulated production system is planned, but could be used for other systems as well. The various subsea production systems are described in section I.D.6.

The selection of this option in well completion operations would be based on economic considerations. A smaller, and much less expensive, vessel could be used to complete the operations necessary to put the well on production. A drilling vessel would not be required since it would not be necessary to re-enter the well.

j. Contingency Plans

The most effective method of controlling pollution is to prevent it from occurring. Prevention is a primary objective of all Santa Barbara Channel operations, but the possibility of a pollution event always exists. Detailed containment and cleanup contingency plans have been prepared for Santa Barbara Channel drilling and production operations. Personnel would immediately activate the respective operator's Oil Spill Contingency Plan in the event of a spill or leak of oil or other pollutant. Small spills would be handled by the lease operator and supply boats in the area under the direction of the onboard lease operator supervisor. Larger spills would be handled by additional boats, equipment, and manpower under the direction of the lessee's Emergency Response Team. The Coast Guard Regional Contingency Plan would be activated if necessary. Contingency operations are directed toward the principal goals of reducing or eliminating the source of the spill and preventing oil from reaching the shore. Detailed contingency plans have also been prepared for severe weather conditions. National, Regional and Clean Seas, Inc. contingency plans are discussed in section IV.

4. Development Drilling

Offshore development drilling has normally been conducted from fixed bottom-founded, water surface-piercing platforms similar to those depicted in figures I-9 through I-12. If exploratory efforts are successful in proving a commercial hydrocarbon reserve, production operations are initiated by installing a platform to serve as a base for drilling development wells. A number of wells may be directionally drilled to develop a large area from a single platform. Platforms in the Santa Barbara Channel area may contain as many as 60 wells. The five existing Santa Barbara Channel OCS platforms are designed for 50 to 60 wells. Presently, 30 to 50 wells have been drilled from each platform.

Platforms have been installed in the Gulf of Mexico in water depths to 373 feet and Shell Oil Company has let contracts to build two jacket-type platforms for installation in 1,000-foot waters in the Gulf of Mexico. Industry experts state that the technical capability exists to extend platform operations to about 1,200 feet. Platforms are now being fabricated for installation in the North Sea in water depths to 500 feet and a platform is being constructed for installation in 850 feet of water in the Santa Ynez Unit in the Santa Barbara Channel.

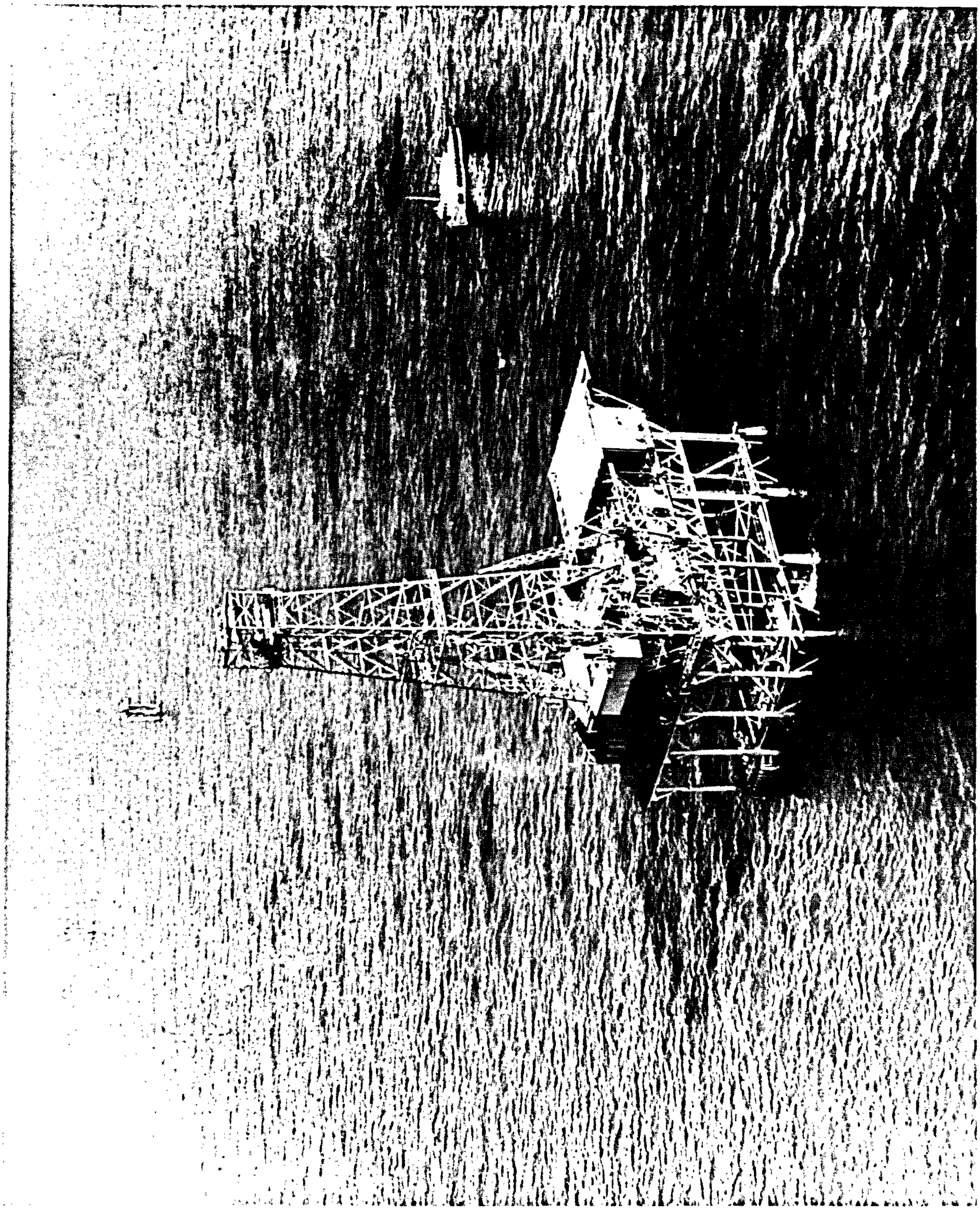


FIGURE I-9 SELF-CONTAINED FIXED PLATFORM

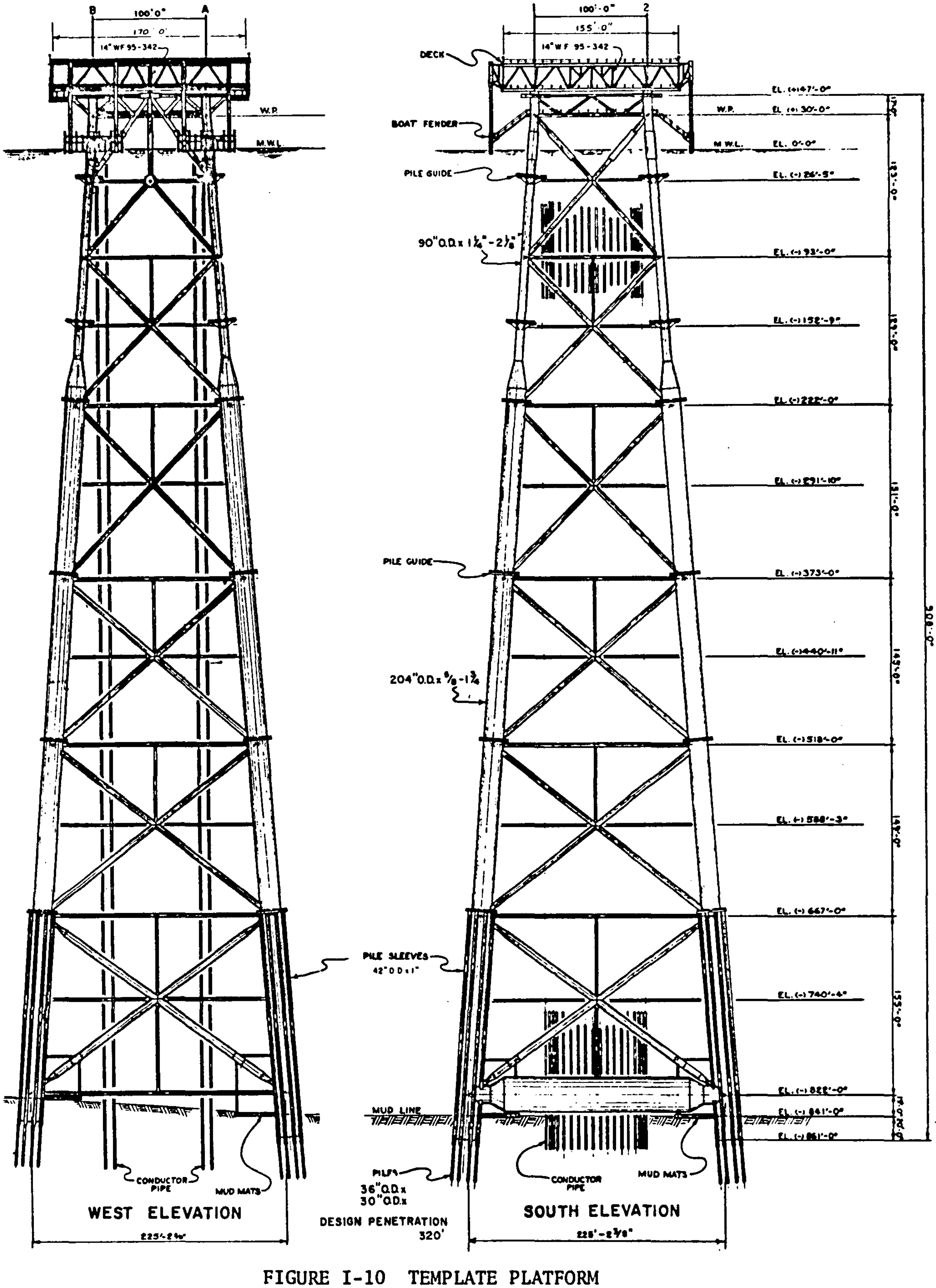


FIGURE I-10 TEMPLATE PLATFORM
Source: Exxon Company, U.S.A., 1971
Supplemental Plan of Operations,
Santa Ynez Unit

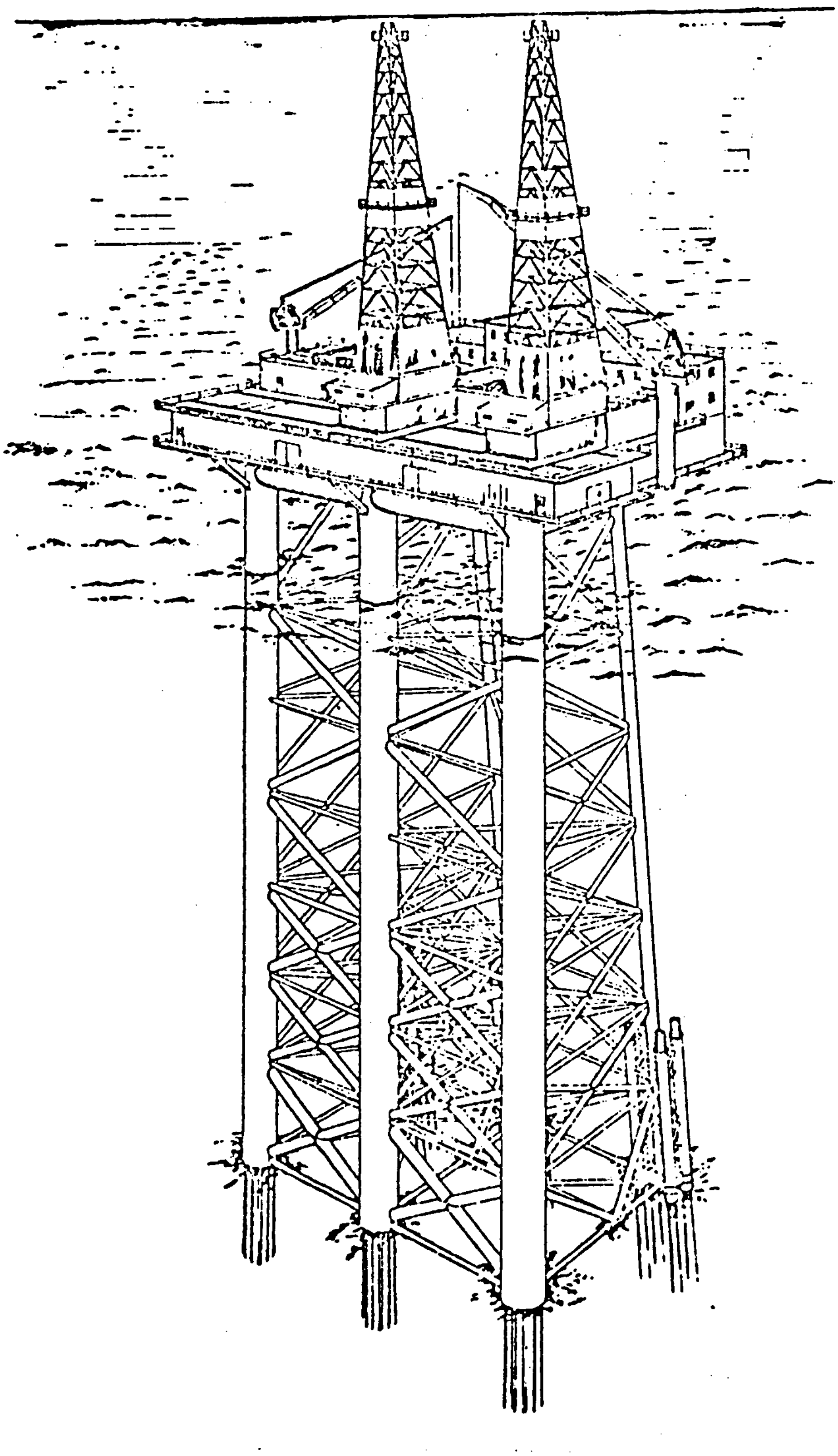
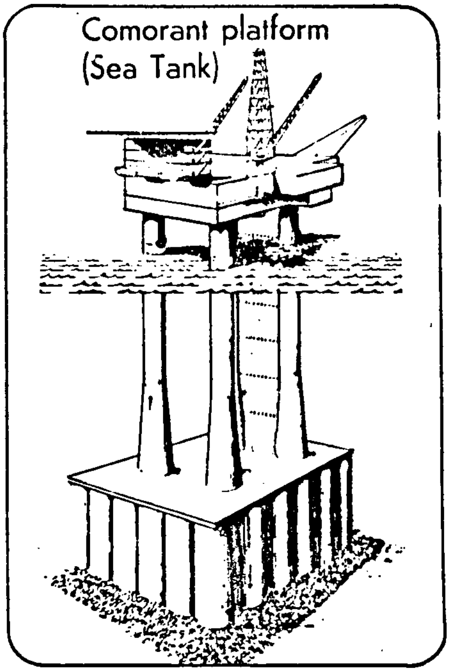
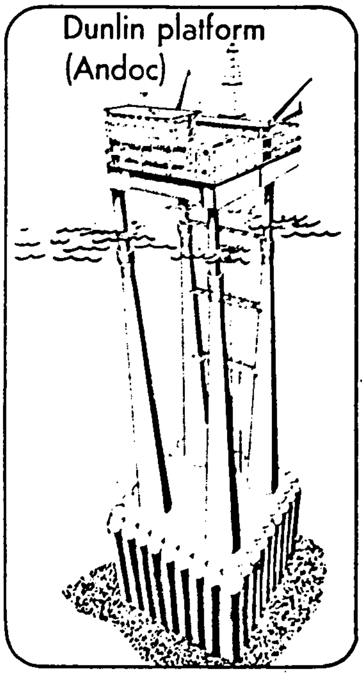


FIGURE I-11

TOWER/TEMPLATE PLATFORM



A



B

FIGURE I-12

A & B - GRAVITY TYPE STEEL & CONCRETE COMBINATION DRILLING, PRODUCTION & STORAGE PLATFORMS IN CONSTRUCTION FOR THE NORTH SEA.
From: Oil & Gas Journal, May 27, 1974, Vol. 72, No. 21, p. 34.

Development drilling could also be conducted from floating vessels or from mobile jack-up barges with wells completed on the ocean floor as discussed in section I.D.3.

a. Platform Fabrication and Installation

In shallow waters platforms are usually constructed by driving piling (wood, steel, or concrete) to resistance in the ocean floor. The platform proper is then constructed on the piling, or prefabricated on shore and installed on the piling.

In deeper waters the platform is prefabricated on shore, floated or barged to the location and sunk in place. Platforms may be constructed of steel or concrete. Several different basic designs have been developed, some are fastened to the sea floor by piling driven through templates on the platform proper (figure I-10), or through the legs (figure I-11), while others are supported on the sea floor by their own weight, (figure I-12). Some may be transported in sections to be assembled at the location before sinking in place and others may be completely prefabricated onshore. Equipment and facilities to be used on the platform are installed after the platform is placed.

Platforms may be designed purely as a drilling and workover platform or they may be designed as a combination drilling-production platform. Many of the fields in the Gulf of Mexico and in the North Sea are developed using a drilling platform for the development wells and a satellite platform for the production facilities. In deeper waters, particularly, the trend is toward combining platform functions since costs increase greatly with depth.

Recently, in the North Sea, a platform combining drilling and production functions with a 900,000 barrel storage capacity was set in place in the

Ekofisk field. This platform, which is essentially a giant group of concrete tanks, was prefabricated onshore, towed to the site and sunk in place. It is a gravity-type structure held in place by virtue of its geometry and weight.

The platforms shown in figures I-12a and I-12b are also gravity-type structures and are being constructed for installation in the North Sea in waters about 500 feet deep. Each platform is similar in size and construction methods and each will have a storage capability of about 900,000 barrels of oil in the base. They are scheduled for installation in 1976.

The Exxon platform, designed for use in 850 feet of water in the Santa Ynez Unit in the Santa Barbara Channel OCS was thoroughly discussed in the Santa Ynez Unit EIS. It will be a template-type platform, prefabricated onshore in two sections. The sections will be towed to a protected area near the installation site, joined together, then towed to the site and sunk in place.

Platform design depends on the projected use of the platform, the water depth, and the characteristics of the sea floor at the location. A thorough investigation of the sea floor conditions, including resolution, shallow penetration acoustic surveys and soil sample analyses, is required by the Oil and Gas Supervisor, Pacific Area, before a platform site and design is approved by the USGS. No technological limitation in platform installation in water depths to at least 1,200 feet is apparent at this time, according to industry experts.

Platform construction and installation would probably require from six to eighteen months, depending on the design. A probable prefabrication site for platforms in the Santa Barbara Channel would be in the Los Angeles Harbor area, a center of heavy industrial activity.

See section III.C.3. for a discussion on and description of Platform Henry that was proposed subsequent to the publication of this statement in draft form.

b. Platform Environmental Design Criteria

To insure that Santa Barbara Channel OCS platforms have adequate resistance to environmental forces and can fulfill their functional requirements, the structures and their foundations are designed to carry normal gravity and operating loads in conjunction with appropriate storm or earthquake induced forces. The latter forces are more critical in the Santa Barbara Channel. Earthquake and storm conditions in the Santa Barbara Channel area are described in section II.B.6. and II.D.

Inasmuch as the Santa Barbara Channel is a seismically active area, the design and location of platforms must take into account the probability that moderate- to large-magnitude shocks may occur during the life of the platform. Although earthquake criteria are the most important and the controlling design factor, wave load and severe storm design criteria are also important in the environmental design criteria.

The structure should be designed to:

- Withstand safely the most severe loads that might occur during the transport to location and during installation,
- Withstand safely the loads that might be caused by severe storm waves or maximum earthquakes anticipated in the area, and
- Perform the functions of a drilling and/or production facility.

(1) Earthquake Design Criteria

Proposed structures must be designed, based on the best technology available, to accommodate the seismic conditions within a given geographic area. The following general design requirements and criteria must be met:

- **Criterion 1**

  Structural damage must be avoided in the event of ground shaking for which there is a significant probability of occurrence during the life of the structure.

- **Criterion 2**

  Safety against collapse must be provided in the event of the strongest potential ground shaking (or ground shaking having an extremely small probability of occurrence); plastic straining and moderate yielding are permitted.

- **Criterion 3**

  The structure must have sufficient ductility to undergo plastic straining without loss of structural integrity. (This condition insures ductile behavior well into the yielding range).

Geological Survey regulations are presently being revised and will contain more specific design criteria guidelines and requirements.

Existing and presently proposed platforms on Federal leases in the Santa Barbara Channel have all been designed in accordance with the best technology for seismic design and structural analysis available, at the time of their initiation. In view of the continuing developments in the fields of earthquake seismology and seismic design, and the need to establish platform criteria in other areas of concern, the USGS is concluding negotiations and arrangements for the first step in establishing a system of third-party certification of platform design and for the development of various design criteria for OCS Platforms. In essence the system is to be patterned after the present British system now employed for the North Sea. (See section IV.B.10. for more details)

In addition to the design criteria, the location site is carefully investigated to ensure that potentially hazardous areas (areas with recently active faults, potential slide zones, incompetent bottom soil conditions, etc.) are avoided.

(2) Storm Design Criteria

Structural member stresses must remain within American Institute of Steel Construction (AISC) allowables for severe storms that have significant probability of occurrence during the life of the structure. For this criterion, AISC allowables are derived from Specifications for the Design, Fabrication and Erection of Structural Steel for Buildings, Seventh Edition, 1970.

Repetitive stresses arising from all storms occurring in the life of the structure must be sufficiently small as to preclude undesirable effects on the structure.

(a) Severe Storm

Standard engineering practices have led to platform designs for severe storms that have a probability of occurrence of one percent per year (a 100-year storm). This criterion was used for five existing OCS platforms and is presently acceptable storm design criteria. However, for the proposed Santa Ynez Unit platform, a severe storm crest elevation having a probability of exceedance of one-fourth of one percent per year (400-year storm) was used for analysis purposes. In designing this 850-foot water depth platform to meet desired earthquake criteria, it coincidentally met essentially all requirements for the 400-year storm.

The severe analysis crest elevation (400-year event) is derived from oceanographic analyses of historical meteorological data and statical treatment of these data. The resulting severe analysis conditions are as follows:

- Crest elevation above storm mean water level 28 ft. (wave height, crest to trough, 44 ft.)
- Storm tide, eight feet
- Storm wind velocity, 100 mph.

Oceanographic studies of meteorological data were performed by Oceanographic Services, Inc. (OSI). A copy of this report "Storm Wave Study, Santa Barbara Channel," is contained in the Santa Ynez Unit Operator's Supplemental Plan of Operations which was submitted to the Geological Survey for approval. This study includes a hindcast of the ten storms generating the most severe sea state at each of five locations in the Santa Barbara Channel for a historical period covering the years 1899 to 1968. Standard procedures are employed to derive the extreme crest elevation. See section II.D. for Santa Barbara Channel sea conditions.

(b) High-Cycle Repetitive Storm Stresses

Calculation of repetitive stresses from all storms to which a platform may be exposed during its lifetime requires integration of storm effects continuously with time. To make this integration practical, all sea states expected at a platform location, either frequently or as an extremely rare event, are classified into eight conditions of sea amplitude and dominant period.

(3) Other Design Conditions

During the 27-year history of oil operations in the Gulf of Mexico, industry has gained a good understanding of the physical forces acting on offshore platforms. Therefore platform design is a matter of selecting the optimum geometry and sizing structure members with appropriate safety factors to withstand maximum anticipated natural forces and operational loads. Appropriate design procedures are outlined in American Petroleum Institute (API) Recommended Practice RP 2A and various API specifications. Those guidelines were prepared to cover engineering design and operation of offshore structures and related equipment.

(a) Gravity Loads

Gravity loads for design must include all deck loads developed by the drilling and producing operations conducted on the platform as well as the dead weight of the platform itself.

(b) Piling Design and Soil Conditions

Foundation borings and detailed geological-geophysical studies will be made in order to assure that the selection of a location where sediments in which the piling is founded will be stable under the largest earthquake ground shaking expected in the Santa Barbara Channel during the lifetime of the structure and to provide data for design of adequate piling for the platform.

(c) Transportation and Installation

Platforms are designed to withstand the most severe loads that might occur during transportation and installation, and to have adequate stability. The design requirements insure structural integrity under dynamic wave loads that might occur during transportation, and under impact loads that might occur during either transportation or installation. Stability requirements insure safety under tow and during installation.

(d) Corrosion Control

Platforms are protected from corrosion by coatings above mean water level and by cathodic protection below mean water level.

(i) Protective Coating

The protective coating system used is an established concept and employs only standard materials used in accordance with conventional corrosion protection practices. It has been used successfully for over ten years in the Gulf of Mexico. Examples of protective coatings are used:

- Galvanizing - applied to all hardware, fencing, handrails, and grating.
- Sheathing - synthetic rubber and monel sheathing is applied to all members in the wave zone between ELEV (-) 8'-0" and ELEV (+) 16'-0".
- Painting - a 5-coat, 14-mil epoxy or vinyl system is applied to all surface areas above mean water level not protected by galvanizing or sheathing.

(ii) Cathodic Protection

The cathodic protection system employs standard materials used in accordance with conventional engineering practices. The system is a galvanic anode system that will provide 10 ma/sq. ft. of current density for surfaces in the water zone and 4 ma/sq. ft. current density for surfaces in the mud zone for approximately 20 years. Provision can be made to switch to an impressed current system for the remainder of platform life after depletion of the galvanic system.

(e) Specifications

In accepted engineering practice, various well-established specifications, codes and standards are incorporated into platform specifications in whole or in part, as applicable. Some examples of these specifications are listed below.

- American Institute of Steel Construction (AISC): Code of Standard Practice for Steel Building and Bridges. Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings.
- American Society for Testing and Materials (ASTM).
- American Welding Society (AWS).
- American Petroleum Institute (API).
- Steel Structures Painting Council (SSPC).
- U. S. Standards Institute (USSI).

(f) Platform Removal

Platform structures are designed to be removed at the end of their useful life. The platform wells would be plugged and abandoned, well conductors would be cut below the mudline and removed, and deck units and production equipment would be dismantled and removed. The platform pilings would then be cut below the mudline and the jacket refloated and removed.

(g) Beautification

Beautification studies have shown that under some conditions structures may be screened by the use of painted pattern designs that change their silhouette or by water spray techniques that reduce their visibility. However, the U.S. Coast Guard has expressed concern that camouflage techniques could increase the hazards to navigation. Since this is a prime consideration in platform location and design any such proposals would require very careful consideration.

c. Pollution Prevention and Control

Oil, gas, water, solid wastes, and biological wastes are carefully controlled to insure that untreated or hazardous substances are not discharged to the atmosphere or the ocean. Platforms have fire detection and fighting equipment, gas detecting equipment, and safety shut-in systems in all appropriate areas. Pollution prevention and control, safety procedures, and other regulations for platforms and other components are discussed in detail in section IV. Pollution prevention and safety procedures and equipment must be in compliance with all applicable regulations.

d. Community Facilities

Platforms would be equipped with a helicopter pad and boat moorings. Storage facilities would be provided for diesel fuel, potable water, and well stimulation chemicals. Crew quarters would be provided during the development drilling phase. Facilities and living quarters would be equipped and maintained in compliance with the Occupational Safety and Health Administration regulations.

Electrical power could be supplied by submarine cable from shore or power could be generated offshore. Auxiliary gas turbine or diesel generators are normally installed on the platform to provide emergency power. Microwave VHF/UHF mobile radio and marine frequency VHF marine radio communication systems would be installed to provide continuous voice communications with the onshore site and nearby surface vessels. Emergency life support equipment that meets or exceeds applicable U. S. Coast Guard regulations would be maintained on the platform. This include gas masks, respiratory equipment, protective fire suits, life preservers, and life rafts. The platform would be equipped with all of the navigation aids that are required or recommended by the U. S. Coast Guard.

e. Development Drilling Operations

As previously mentioned, development drilling could be conducted from fixed leg platforms, from floating vessels, or from mobile jack-up rigs, utilizing submerged production system completion techniques. Such wells could be drilled vertically and individually, that is on a selected spacing pattern, or they could be drilled directionally to cluster the wellheads in one location. Drilling techniques such as those already described in section I.D.3. would be followed in either event.

When drilling is conducted from a platform, the drilling rig, power plants, generators, living quarters, storage sheds and other components, constructed in modular form, are added to the platform, and production well drilling commences. The sequence of drilling operations for production wells is essentially the same as for exploratory wells.

Typical drilling system components for either platform or floating vessel use would be rated for drilling a 9-7/8 inch hole to 16,000 feet or more. The basic drilling equipment would include: a 142-foot, 1,000,000-pound class drilling derrick capable of withstanding 125 mph winds with 12,000 feet of 5-inch drill pipe racked in the derrick; a 1,500-input horsepower class draw works capable of efficiently hoisting loads from 16,000 feet; a 500-ton class matched hook, traveling block and crown block; a 1,000-horsepower drilling fluid pump and a 700-horsepower drilling fluid pump, both capable of operating at a pressure in excess of 2,500 psi; and a minimum 800-barrel drilling fluid treating system to include dual screen shale shakers, a desander, a desilter, a degasser, a 50-barrel mixing tank, and pumps and piping to provide drilling fluid treating flexibility.

All the functions and techniques described for floating vessel drilling in section I.D.3. are applicable to platform drilling with some exceptions. There is no need to compensate for vessel motion, well casing extends from the ocean floor to the platform and the wellhead and BOP equipment are located directly below the drilling floor, thus there is no need for riser pipe and well control functions are directly operable by drilling personnel. All of the safety features discussed for floating vessel drilling are also applicable to platform drilling and will not be repeated here.

Many platforms are designed so that the wellheads are on different levels, thus permitting a space saving staggered arrangement of the wellheads. This allows more wells to be drilled from the platform since the wellheads require considerably more space than the casing below the head.

The other features discussed under floating vessel drilling, such as pollution control, fire protection, community facilities, drilling operations, and contingency plans are also directly applicable to platform drilling.

One difference in platform drilling is in the well completion operations.

(1) Platform Well Completion Operations

If initial tests of a well are dry, the well could be plugged and abandoned as for wells drilled from a floating vessel. More likely, however, is that the well would be partially plugged back and then redrilled directionally to a more promising location.

Testing procedures would be similar to those discussed for floating vessel drilling.

When well tests indicate the well is productive, the production tubing string, or strings, is run. Well tubing is the smaller diameter pipe that is run inside the production casing string and that serves to carry well production to the surface. Tubing is generally within the range of 2 to 3½ inches I.D., depending on the wells' productive characteristics.

Tubing strings may vary in number from one to as many as three. Some wells have been completed with more than three strings, but with conventional casing and tubing installations, three is about the maximum number that sizing requirements will permit. The purpose of running multiple tubing strings is to permit simultaneous production from more than one reservoir. It is generally not good practice to commingle production from different reservoirs due to variations in pressure and other reservoir characteristics.

The tubing is suspended from the tubing hanger which is supported in the wellhead casing hanger. Generally, particularly in flowing wells, and always in multiple tubing string completions, tubing is run with a packer that is set in the casing above the productive interval. In this manner, each productive interval is separated from others and the casing, above the packer, is also isolated.

Testing procedures are conducted through the blowout preventers and tubing is also run with the BOP stack in place. When the tubing is run, the annular casing space is sealed by the tubing hanger. Temporary plugs are then set in the tubing and the BOP stack is removed. The wellhead control assembly (christmas tree) is then set in place and connected to the tubing. The temporary tubing plugs are removed through the christmas tree and the well is then in a state to produce.

Downhole completion procedures vary greatly depending on reservoir conditions. The simplest completion technique is to perforate the production casing opposite productive intervals with gun (bullet) or jet (shaped-charge) perforators. Where sand entry may be a problem, the production casing is usually set and cemented above the productive zone and a slotted or perforated liner is hung in the casing through the productive interval. The slot, or perforation, size depends on the grain size of the formation sand. Primary completion methods are discussed in Appendix I-2 (subsection I.G.4.).

In many fields in California the liner is gravel packed to prevent sand entry. After the production casing is run and cemented, the productive interval is underreamed. A special drilling tool, called an underreamer, that is capable of expanding the hole diameter, is run through the productive zone. When the hole size is increased, and checked by running a caliper log (a device to measure downhole diameters), the liner is run and hung in place. Gravel, sized according to formation sand grain size and distribution, is pumped down the drill string, through the liner float shoe at the bottom of the liner and up through the annular space between the liner and the wall of the hole. The quantity of gravel required is calculated to fill the annular space as determined by the caliper log. When the annular space is filled, excess gravel inside the liner and in the drill string is reversed out (pumping down through the casing and up through the drill string).

(2) Subsea Completions

Subsea completions differ from the above described normal surface completions only in that upon completion, the wellhead control assembly is situated on the sea floor. Completion operations are conducted through the riser pipe and the blowout preventers and the tubing is run and hung as before, and tubing plugs installed. The riser and BOP's are removed and the wellhead control assembly is run and connected.

After flowline connections are made, the tubing plugs are removed, safety valves are installed and the well is ready to produce.

There are two general types of subsea wellhead control assemblies, one is the "wet" completion where the control assembly is placed on the casing head and is exposed to the water. The valves and other controls in the assembly may be either diver operated, or controlled remotely from the surface. The other completion technique involves an encapsulated assembly that is fixed to the casing head and contains the wellhead control assembly. The capsule is equipped with an entry port that permits the connection of a personnel vehicle. Section I.D.6. describes subsea completion methods more fully.

5. Production Facilities

Generally, production facilities are considered to mean the equipment used to bring production to the surface, deliver it to a separation facility, and to separate the production into its component parts (oil, gas, and water).

a. Producing to the Surface

(1) Natural Flow Wells

Most wells in their initial completion stage will flow naturally to the surface. The reservoir pressure is sufficiently high to support the column of reservoir fluid in the production tubing and deliver it to the surface.

(2) Gas Lift Wells

When reservoir pressures are insufficient to lift production to the surface gas may be injected under pressure down the casing. A series of valves is located down the tubing string with each valve designed to open at a different pressure. As the gas enters the tubing string through a valve the column of fluid in the tubing is lightened and the reservoir pressure is enabled to bring the fluid to the surface. Gas lift is not practical in all wells and is generally a temporary stage, being practical only so long as reservoir pressure remains relatively high.

(3) Artificial Lift Wells

Almost all wells, at some stage in their productive lives, require artificial lift to bring production to the surface. The most common pumping method is a piston type pump run in or on the tubing and connected to the rod string run inside the tubing. The rod string is connected to the walking beam above the wellhead. Through a series of gears and levers power from a motor or engine is translated to up and down vertical motion of the walking beam. These pumping units are a common sight in most oil fields located on shore, but are not generally used for offshore production due to space limitations. Either submersible or hydraulic pumps are usually used in offshore applications. The submersible pump is an electrically operated rotary pump generally run on tubing, but some models can be suspended in the casing. The hydraulic pump is a piston type pump operated by hydraulic fluid pumped down the tubing or through a separate line run alongside the tubing. Either method requires little surface space and can be used in platform operations. Some models of the hydraulic pump can be placed or retrieved from the tubing string by pumping down or up the tubing and are particularly suitable for subsea applications.

b. Flow lines

Flow lines are the pipelines used to deliver production from the individual wells to a separation facility. In the case of wells drilled from a common platform, flow lines are practically non-existent. Production from each well is directed to a manifold consisting of a series of valves by which the production from all wells connected to the manifold can be commingled and sent to the production separation facility, or individual well production can be separately directed to a test separation facility.

For subsea completions the flow line could run from each well on the ocean floor to a production platform, and then up a riser to the separation and test manifold. The flow lines could also run to a subsea manifold for delivery in a common line to a separation facility or the wells could be directionally drilled from a common location to produce to a subsea manifold. Section I.D.6. describes various subsea systems.

Section I.D.7., "Transportation of Produced Oil and Gas", gives a description of the methods used to lay pipelines.

c. Separation Facilities

After production is brought to the surface it must be separated into its component parts of oil, gas and water. The production is introduced to a pressure vessel where the pressure is reduced and gas is liberated from the crude oil. These vessels are called separators and, where wellhead pressures are sufficiently high, there may be more than one separator connected in series to permit gas separation at decreasing pressures for increased efficiency. Generally a production station will have a production separator, or series of separators, where the production from all wells connected to the station is handled. In addition to the production separator, a test separator is available. Flow lines from all the wells connected to the station are connected to a manifold, a series of valves that allows the flow from each well to be connected to a common production line or to the test separator line. The test separator is used to gauge the production from each well periodically and determine its status.

Some separators are called three-phase separators and in addition to separating gas, also separate free water from the oil. In other cases, an additional pressure vessel called a free-water knockout is included in the flow pattern. These vessels have a series of chambers through which the crude oil-water mixture is directed with sufficient dwell time to permit water separation.

Often, water associated with crude oil forms an emulsion which is difficult to break down. Various methods including chemical, electrolytic, and the application of heat are used to break the emulsion and separate the water. As a rule these separation methods are not used on offshore installations due to space limitations, and after primary separation the mixture is pumped ashore for treatment.

After separation the gas is introduced to the gas pipeline for disposal, perhaps through compressors if necessary. Crude oil flows from the separators to a holding tank and from there is pumped to storage. The transfer pumps may be motor driven, but when gas pressures are sufficiently high they are commonly actuated by gas pressure. The gas, after use, is returned to the gas system.

Free water, if separated at the station, is treated to reduce the oil content to less than 50 ppm and sent to the water disposal line. It may be re-injected to the formation, disposed of in the sea, or piped to shore for disposal.

Present treating facilities in the Channel area reduce the oil and grease concentration to from 5 to 25 ppm. The variation in the oil and grease concentration reported by different operators for treated produced waste water is not completely due to the treatability of the waste water or the treatment method; it is partly due to the variation in analytical sample testing methods and sample preparation procedures. The Environmental Protection Agency and the Geological Survey recognize this problem and in the future one analytical method and sample preparation procedure will be used by all OCS operators.

With the increasingly stringent regulations concerning waste-water disposal, in the near future, a major portion of produced water may be returned to the formation rather than discharged to the ocean. In addition to the disposal of the water, this method would also aid in maintaining reservoir pressure and therefore in increasing ultimate production. (Section I.B. includes a discussion of the present status of water injection operations in the Santa Barbara Channel OCS and section I.D.10.c. discusses secondary recovery in general.) Sections II.G.2.d., III.C.2.b.(1)(c), and IV.A.1.c. and d. all cover water disposal in general and the regulations pertaining to water disposal.

As previously mentioned, production facilities may be included on the drilling platform or they may be installed on a separate, satellite platform. In either case, platform design, construction, and safety and pollution control features would be similar to those discussed under section I.D.4., Development Drilling.

d. Special Production System Safety Features

Produced fluids are controlled at the wellhead by control and safety devices including: dual master valves, a check valve, a fail-closed wing valve and a wellhead choke valve on flowing wells. Wellhead equipment is specifically designed for hydrogen sulfide service and maximum wellhead pressure. All components of the wellheads are designed to appropriate API specifications.

Tubing strings on flowing wells contain a subsurface safety valve. This valve is located at least 100 feet below the ocean floor and is designed to prevent flow from the well in the event of damage to the wellhead. These valves are surface-controlled, fail-closed safety valves that are hydraulically operated from a pressure system at the surface. A drop in hydraulic pressure, either intentional or accidental, will cause the valve to close, thereby shutting in the well.

Future subsurface safety valves will be selected on the basis of proven performances and reliability. The Geological Survey, National Academy of Engineers Marine Board, American Petroleum Institute (API) and private industry have formed various committees to improve oil and gas OCS operations. As to safety and anti-pollution, see section IV. for further discussion of the function of these committees. One of their projects is to improve standards, specifications and testing procedures for subsurface safety valves.

In the report "Energy under the Ocean: A Technology Assessment of Outer Continental Shelf Oil and Gas Operations," (University of Oklahoma Press, September 1973) the velocity-actuated subsurface valve was identified as a technological weakness. That report suggests that the replacement of these with the newer-type surface-actuated valves would resolve this problem. The following excerpt is from that report:

> *Downhole Safety Devices*. Although reliability data for velocity actuated downhole safety devices are limited, there are numerous indications of their inadequacy. For example, in recent major accidents in the Gulf of Mexico, 25 to 40 percent of them failed. The U. S. Geological Survey (USGS) now requires new wells to be equipped with a surface, rather than a velocity actuated, downhole safety device. However, this new requirement does not apply to wells presently producing until tubing has to be pulled for some other purpose, such as a workover, for example. This may not occur for several years, if ever.

> Until there is a reliable replacement for "storm chokes" that can be installed in most producing wells without pulling tubing, the "storm choke" will continue to be a problem. *Therefore, the "storm choke" must be made more reliable.*

It is recognized that certain Gulf Coast incidents reflect a poor subsurface safety valve performance record. However, most of these were velocity actuated valves and were in an area known for excessive sand production problems. Severe excessive sand production, as experienced in some Gulf of Mexico areas,has not been experienced in existing Santa Barbara Channel wells. There have been some instances of sand problems in the Channel, but the results have not been as severe as in the Gulf due to the difference in producing characteristics--the Channel wells generally exhibit lower volumes and pressures and therefore much lower velocities.

A few velocity actuated subsurface valves that were in the Santa Barbara Channel were replaced with surface controlled valves several years ago. All future Santa Barbara Channel subsurface safety valves will be the surface controlled type as required by the Pacific Area OCS Orders of June 1, 1971. (See section IV.A.1.g., "OCS Order No. 5", for further discussion on subsurface valve types.)

For these reasons, increased reliance can be placed on future Santa Barbara Channel OCS subsurface safety valves.

Sand monitoring devices can be installed in the flow lines near the wellhead on wells that may produce sand to indicate excessive sand production and thus alert operating personnel before damage to valves, connections, etc. can occur. These devices are a thin-walled, hollow steel tube inserted into the flow line perpendicular to the direction of flow. The production of sand will cut out the thin steel wall of the probe and expose the inside of the device to the flow line pressures. The probe may be used only as a monitoring device or it can be connected to a pilot valve that will actuate a safety valve to shut the well in until corrective measures can be taken.

All connections and equipment from wellhead to the separators are designed for maximum anticipated wellhead pressures. Separators and other pressure vessels are equipped with high and low level automatic shut down devices in case of oil surges to the gas system or gas flows to receiving tanks. All relief valves from pressure vessels are piped to a main vent scrubber and liquid from the scrubber is pumped to the receiving tanks. The receiving tanks are equipped with level control systems and vapors from these atmospheric pressure tanks is vented to a vapor recovery system to be returned to the gas system.

All well completion and production facilities must be designed pursuant to current regulations. The platform production facilities must be approved by the USGS before commencing operations. Equipment that would be used on future platforms in the Santa Barbara Channel Area would be similar to that being used safely in current operations, and would be installed and operated in accordance with safe practices accumulated from industry experience. This experience forms the basis of USGS requirements, which give the safe practices a regulatory mandate. Requirements specify multiple, redundant controls and safety devices including safety shut-in valves, high-low pressure pilots, high-low level controls, high-temperature shutdowns, gas detectors, shielded ignitions, fire prevention and detection equipment, and pressure relief systems. Drain and sump systems are also designed to collect any spillage that might occur on the platform.

6. Subsea Production Systems

As with all wells, the production from wells completed on the ocean floor must be collected, sent to a production facility, and at some point reach the surface in order that it may be utilized.

To date, the production facilities for subsea wells are generally located on a nearby platform. In this case the production facility itself, separators, etc., would be as described in section I.D.5.

Since there are so many possibilities regarding subsea production systems it is perhaps best to proceed logically from the well to the final disposition of the production.

a. Well Location

Wells can be drilled vertically from locations conforming to the spacing pattern of the subsea field. In this case flow lines are required from each well to a common point. This common point may be either a surface production facility, an ocean floor production and test manifold, or, possibly, a subsea production facility.

There are two principle drawbacks in developing a field in this manner:

- There is a practical limit to the length of flow line that can effectively be considered. Depending on the production characteristics, wellhead pressure and fluid viscosity in particular, there will be a pressure drop per unit length of line. In some cases this pressure drop could be such as to prevent production from reaching the central collecting point and certainly, as the reservoir pressure declines during the life of the field, problems will develop. With wells on artificial lift the flow line length could be critical.

  Depending on the type of well completion, the production tree in particular, flow line lengths are critical. If the well is to be maintained by divers and/or surface vessels, the flow line length may not be too important, but where maintenance is to be carried out by pump down, through flow line (TFL) tools, the length of flow line would be important. Also, if the well is to be remotely controlled, hydraulic lines and/or electric cables may be required to actuate well controls. These would normally parallel the flow line.

  Normally, subsea wells are drilled within three miles of the central collecting point and perhaps two miles is a more realistic limit.

- If conventionally moored vessels are used in field development, and later in field maintenance, the presence of a number of lines on the sea floor may hinder the use of anchors and increase the hazard of rupturing the lines.

Wells can be drilled directionally from a common site on the sea floor to bottom in widely-spaced locations to meet the needs of optimum field spacing. Generally, some type of base plate or template is employed to space well heads. These templates may be elaborate and combine functions other than wellhead spacing as described in sections I.D.6.d.(2), I.D.6.d.(3), and I.D.6.d.(4)., or the templates can be simple and merely replace the temporary guide base described in section I.D.3.b.(4).

This system is called the cluster concept for subsea completions and the wells can be conveniently connected to a common subsea test and production manifold. In this case only two lines carrying production are required, one to carry the total production from the cluster and the second to carry an individual well's production to a test facility. Depending on the field development plan, additional lines to handle well and manifold control functions may also parallel the flow lines.

b. Well Completion

Down hole completion procedures for subsea wells are as discussed in sections I.D.3.(i) and I.D.4.(e) and are carried on through the riser pipe and the blowout preventor stack. After tubing is hung and plugged, the BOP stack is removed and the wellhead is set and connected in place.

Wellhead equipment for subsea wells is functionally similar to the equipment described for platform wells and includes all the safety devices previously described.

The control equipment is necessarily modified in accordance with the type of basic control design - that is diver operated. remote control from the surface, control at atmospheric pressure in encapsulated well heads, etc.

(1) Diver Manipulated Production Tree

In the simplest form the subsea production tree can be the same as those used on land. The tree is installed by divers and manipulation of well controls would also require divers.

Figure I-13 shows a somewhat more sophisticated tree designed for subsea use. The tree is installed by divers who must also make up the flow line connections. The tree valves are controlled hydraulically from a remote point through hydraulic control lines. Four trees of this type were installed by Phillips Petroleum Company in the El Molino Field in the Santa Barbara Channel in 1963 in 200 feet of water.

(2) Diver Depth Capability

The problem with diver operated subsea systems is the diver depth capability. As of June, 1974, working dives were routinely carried out in water depths to 600 feet and they had been carried out in depths of 840 feet.[1] The U.S. Navy has, however conducted working dives on an experimental basis to depths of 1,010 feet off San Clemente Island, California, and experimental saturation chamber dives have been conducted to a simulated depth of 2,000 feet. The diving industry's depth capabilities have advanced rapidly over the past decade with the advent of saturation diving and through government and industry research and experimentation in the areas of breathing mixtures and diving physiology. Industry experts stated working dives were feasible to 1,000 feet, at state-of-the-art in June 1974.

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[1] See the discussion immediately following this paragraph for a recent extension of diver depth capabilities.

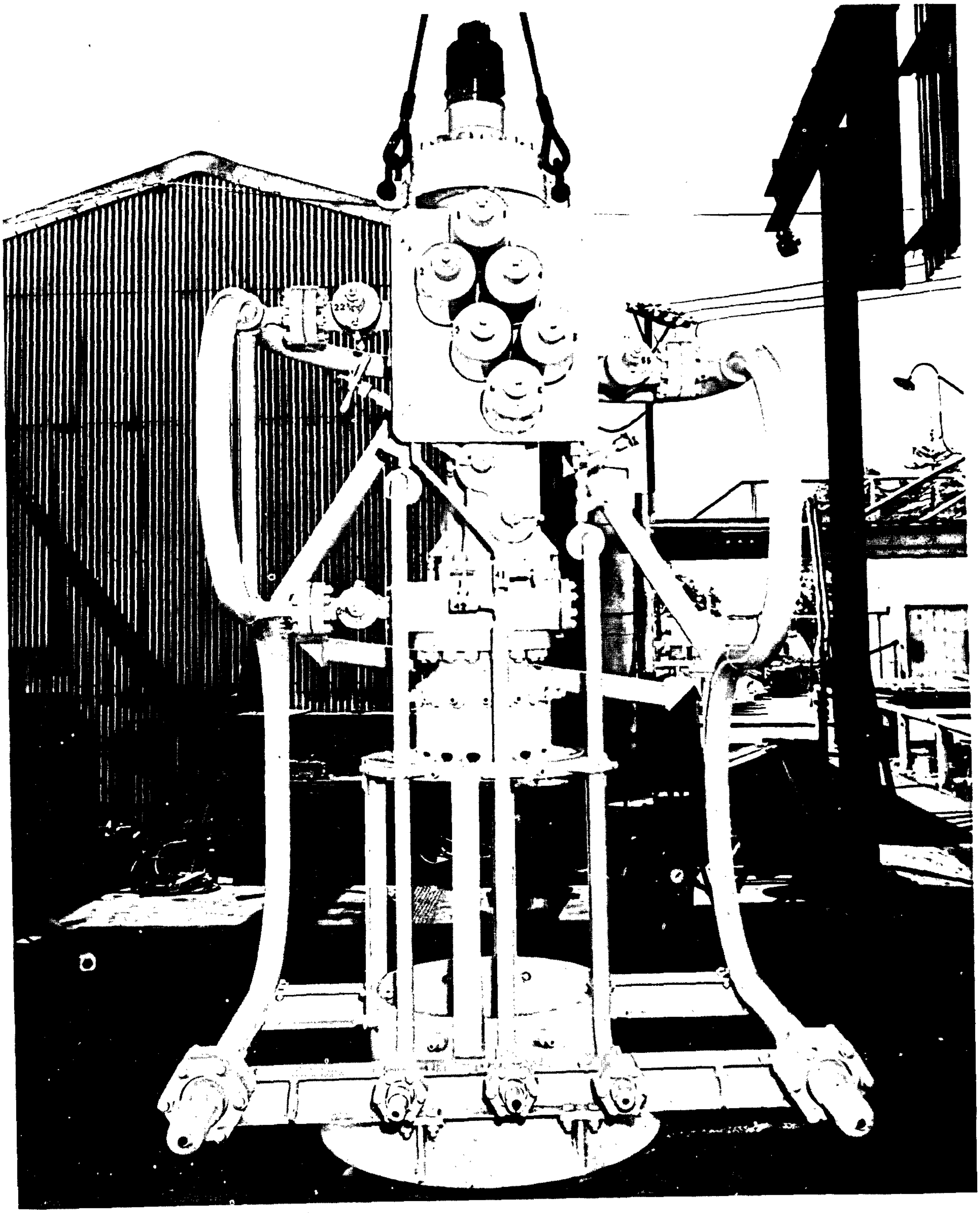


FIGURE I-13 DIVER INSTALLED AND OPERATED SUBSEA TREE

Source: VETCO Offshore, Inc.

To reflect the rapid advancement of deep water diving technology, two deep dives in June 1975 pushed the frontiers of diving beyond the 1,000 foot mark and have proven the technology exists for man to perform useful work in such water depths. The first dive was conducted by Comex, France, off Canada and the second series of dives was conducted by a joint project of the U. S. and Royal British Navies off Florida. The two dives are described in the following excerpts from Offshore Magazine (August 1975, Vol. 35, No. 9).

- Comex Dive

Comex carried out the world's deepest commercial saturation dive early in June 1975, working from the drilling vessel *Handrill*, offshore Labrador, Canada for a consortium headed by British Petroleum Canada. The dive, to a water depth of 1,069 feet, was for the purpose of recovering a blowout preventer stack and a control assembly that were left on the ocean floor by the *Handrill* during the previous season. Six divers (two teams of three divers each) were pressurized over a period of 24-hours to their living depth of 1,004 feet. Three of the divers descended to the stack in 1,069 feet of water and surveyed it by closed circuit TV both inside and outside of the diving bell. The diving bell was on the bottom for a total of four hours during which two of the divers each spent an hour working out of the bell. Their work included the removal of debris from the control assembly, disconnection of broken hydraulic hoses, reconnection of new hydraulic hoses, pressuring up of the control assembly and mechanical locking of the indicator pins.

The following morning the other three divers went back down to the stack with slings which were attached to the control assembly and was then successfully recovered to the surface. The water temperature was 0^{o} centigrade and the sea conditions were calm. The divers worked easily and were relaxed with respiration rates in the water between 10 and 15 per minute. The recovery operation was carried out in less than the scheduled time and clients, BP Canada, Chevron and Columbia Oil & Gas, were pleased with the operation. More time could have been spent working at this depth but there was nothing left for the divers to do. The divers underwent 139.5 hours of decompression after the dive. Comex uses a basic rule of 1 day decompression per 150 feet of dive. The company indicates that this operation represents a milestone in the history of commercial diving. It has pushed the frontiers beyond the 1,000 foot mark and has proven that the technology exists and that men are capable of doing useful, hard work deeper than 1,000 feet of water. Comex says it seems certain that in the near future men will be successfully working commercially in the sea at 1,500 feet of water. Comex also says that it is going to conduct an experimental dive before the end of the year to 1,450 feet. That dive will be conducted in one of the fjords offshore Norway.

- U.S. Navy and British Navy Dive

Also in June, in the Gulf of Mexico, a team of U.S. Navy and British Navy divers completed a dive to 1,148 feet. The dive took place about 80 miles southwest of Panama City, Florida, in the open sea.

Operating out of the *Mark I* Deep Diving System installed on board the diving tender YDT-16, the dive was conducted on June 3-6. Significant was the fact that three divers eclipsed the previous depth record of 1,010 feet on the same day, proving that man is capable of working at great ocean depth. In the deep dive system for 15 days, the divers spent close to 11 days in decompression. The divers began their deep saturation dive leaving the surface by way of the deck chambers to carry on multilevel dives to the 1,000 foot level. The personnel transfer capsule (PTC) was launched from the YDT to carry out open sea dives to 1,000 feet. A diver swam out of the PTC diving bell at a depth of 1,030 feet, thus passing the previous deepest U.S. Navy open sea dive of 1,010 feet. The same day the PTC hatches were closed and the PTC recovered. Again that day, the PTC entered the water. On reaching 1,000 feet, the PTC was pressurized and lowered to 1,130 feet. Pressure between the hatches was equalized and hatch seals broken. A diver entered the water and reported that in the glare of the 200-watt light he could see bottom about 20 feet below him. Another diver entered the water and checked his breathing rig with topside control and descended to the bottom. Depth was checked on the pressure gauge and a reading of 1,148 feet was logged, representing the deepest dive yet. The previous depth record was bettered three times by the three divers on this mission, on the same day.

(3) Remote Controlled, Hydraulically Manipulated Tree

Figure I-14 shows a later tree than that discussed in section I.D.6.b.(1). This tree is installed without diver assistance using the same techniques as those used to make up blowout preventer and riser pipe connections during drilling. All valves are controlled hydraulically, or electro-hydraulically where distance attenuates hydraulic response time, from a remote control point. All valves are also of the fail-to-close type, which means they will automatically shut in the well should loss of hydraulic pressure occur. Flow line connections can also be made from the surface using methods described in section I.D.7. Four of these trees are installed in 230 feet of water in the Ekofisk field in the North Sea operated by Phillips Petroleum Company.

The particular trees depicted in Figures I-13 and I-14 do not include facilities for through flow line (TFL) tools, but this is incorporated in the tree shown in figure I-15.

(4) Encapsulated Trees

An encapsulated tree is a conventional tree installed in a chamber that is maintained at atmospheric pressure and includes a means of access from a personnel vehicle. The personnel vehicle can be considered a diving bell with means of connection to the subsea chamber over the wellhead. In this manner, non-diving technical personnel have access to the wellhead controls and can perform all of the functions possible on a land well, including wire-line work.

Several systems have been developed, and they are discussed more fully in section I.D.6.d. One of these, the Lockheed system, was installed by Shell Oil Company in the Gulf of Mexico in September, 1972 in 375 feet of water. In

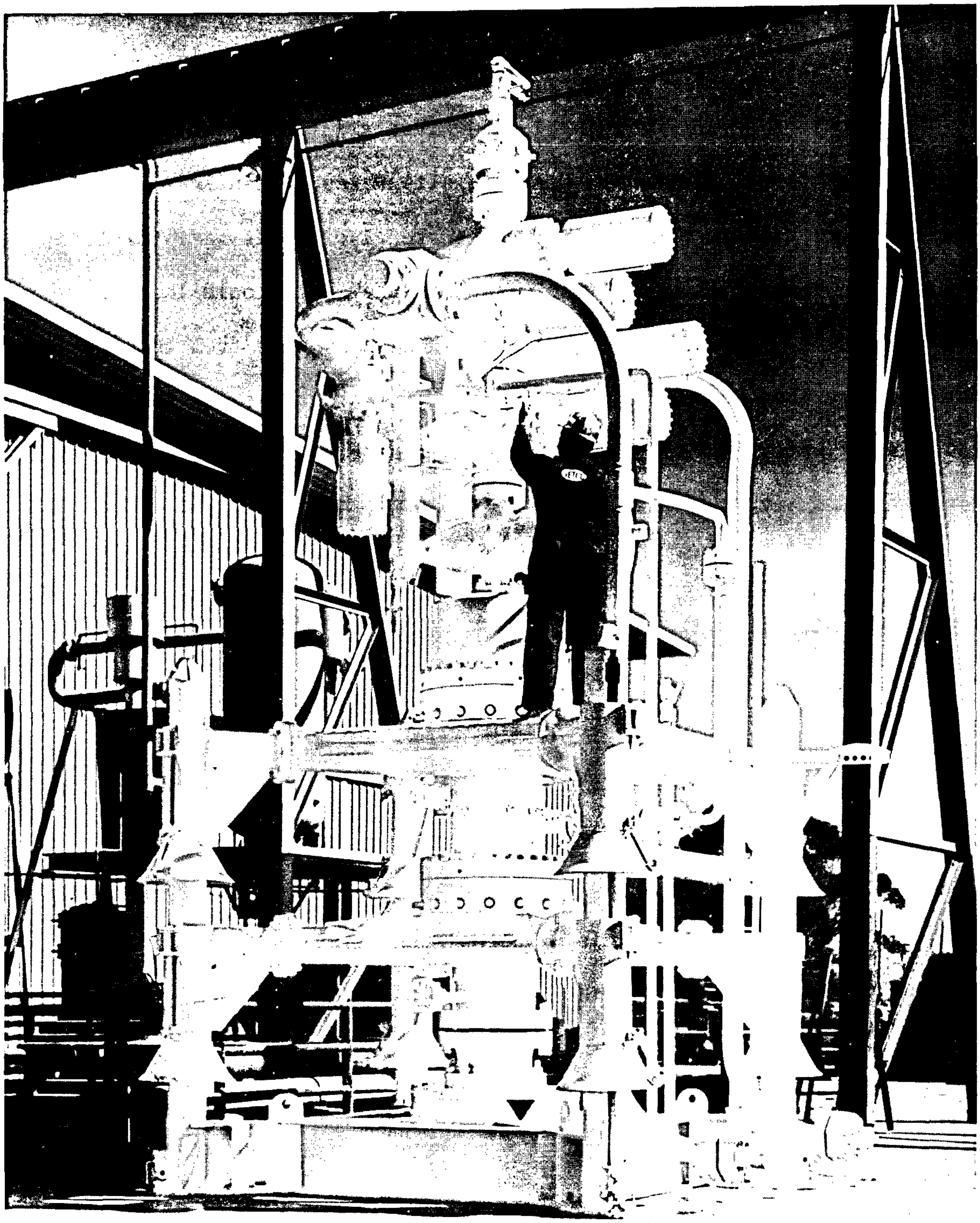


FIGURE I-14 TREE DESIGNED FOR USE IN EKOFISK FIELD (NORTH SEA) BY PHILLIPS PETROLEUM COMPANY. ALL VALVES ARE REMOTELY CONTROLLED. Source: VETCO Offshore, Inc.

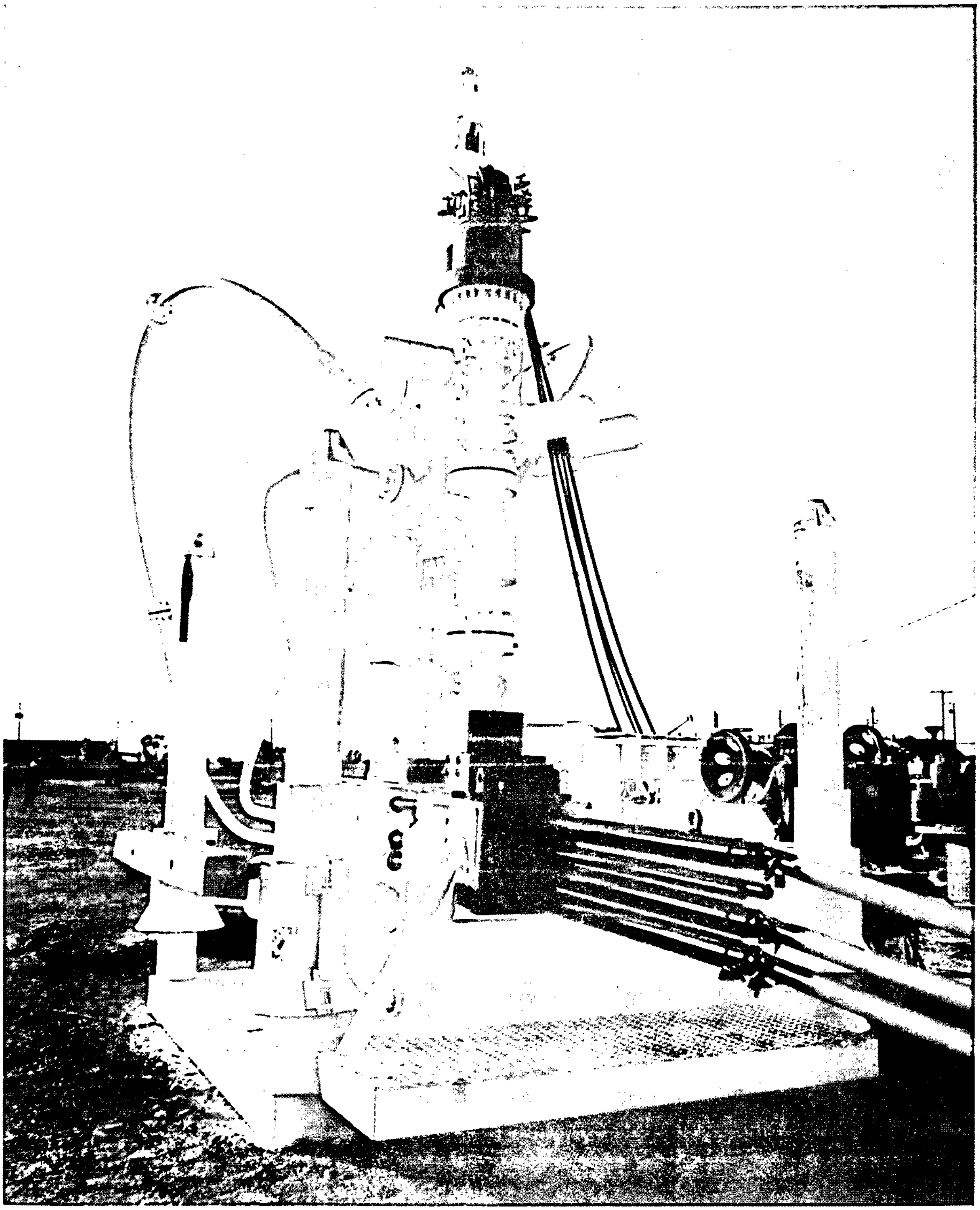


FIGURE I-15 TREE DESIGNED FOR USE BY SHELL OIL COMPANY IN THE GULF OF MEXICO. DESIGNED FOR INSTALLATION WITHOUT DIVER ASSISTANCE AND FOR REMOTE CONTROL OF ALL FUNCTIONS POSSIBLE ON A SURFACE INSTALLATION.

Source: VETCO Offshore, Inc.

1973 the well was successfully re-entered for routine maintenance.

This concept can be expanded to include a complete production system as discussed in section I.D.6.d. The advantage of course is that well work can be performed at surface conditions (atmospheric pressure) and that the work can be done using conventional oil field tools and techniques with no reliance on sophisticated remote control techniques. These systems are presently viable to at least 1,500 feet and even greater depths can be anticipated in the future.

c. Subsea Manifold

A subsea manifold would perform the same function as a manifold on a surface production installation. The purpose of this series of valves is to collect the production from several wells and combine it to a single stream for delivery to a separation facility. There must also be a means of segregating individual well production for metering and testing. This is accomplished by the series of valves included in the manifold.

The manifold, which can be operated hydraulically or electro-hydraulically from a remote control point can be "wet" or it can be encapsulated. These systems are described in section I.D.6.d. The value of such a system is to permit a cluster of subsea wells and avoid the number of flow lines required if wells were widely spaced.

d. Subsea Production Facilities

The ideal, from an aesthetic point of view, would be for an offshore oil field to have all production facilities located on the sea floor. This is within the realm of possibility and several systems have been designed and are being tested.

(1) Zakum Field

A subsea production system was installed in the Zakum field of Abu Dhabi Marine Areas Ltd. in the Arabian Gulf in 1970. The field is operated by British Petroleum and Cie. Francaise du Petroles. The system is electrically operated and diver maintained; the site is in 70 feet of water and was selected so as to be readily available for diver maintenance. The system includes all well controls, a gas-oil separator, and a gas driven generator for electrical power. The system is purely experimental, but it indicates what may be possible in the future.

(2) Exxon Submerged Production System (SPS)

This system has been proposed as a possibility for the development of the Santa Ynez Unit in the Santa Barbara Channel and was discussed in the Geological Survey's environmental impact statement covering this subject. Following the 1968 Channel OCS lease sale a need existed for a subsea production system capable of operating in water depths of 1500 to 2000 feet. This Exxon SPS development program was initiated to meet that need.

Exxon's submerged production system (SPS) has successfully completed land tests. The SPS is a cluster of subsea wells and associated production controlling, separating and pumping equipment mounted on a subsea template structure. The produced fluids are transported to surface processing facilities via pipelines to shore, to a platform or to a production riser which connects to a floating vessel. The subsea equipment is remotely controlled and monitored from the surface facilities by an electro-hydraulic supervisory control system. Pump-down tools are used to service wellbore equipment and a manipulator operated from the surface is used to replace components of the subsea equipment. All elements of the system have been designed and land tested. Work is in progress to perform an offshore test of the complete system.

The system essentially consists of a cluster of wells drilled through a seafloor template and connected through a manifold system. The manifold system is surrounded by a track on which a wellhead and manifold manipulator runs. The manipulator is controlled from the surface and can control all well control functions. Provision is also made for access to the annulus of each well. The manipulator maintenance system is shown in figure I-16 and the manifold schematic is given in figure I-17.

The submerged production system (SPS) provides both equipment and procedures which span the production requirements of a field from the time development drilling starts to field abandonment and from wellbore equipment at the completion interval to the processing equipment at the common carrier custody transfer point. The SPS is composed of eight functional subsystems as follows: 1) the drilling and completion subsystem, 2) the manifold subsystem, 3) the remote control subsystem, 4) the pump/separator, 5) the template subsystem, 6) the pipeline connection subsystem, 7) the production riser and floating facility subsystem and 8) the maintenance manipulator.

The final suite of land tests on a prototype, 3-well, subsea production manifold and a maintenance manipulator were performed in a water-filled pit where the underwater production equipment was automatically operated to control well streams simulating liquid, gas-liquid, and sand laden production. In this testing, the prototype equipment met or exceeded design specifications. In addition, the maintenance manipulator was deployed from a surface vessel to a mock-up installation in 425 feet of water to demonstrate its ability to land on its track which surrounds the underwater equipment. This development test, when coupled with the pit test, proved the manipulator to be capable of performing the maintenance tasks. Results of tests on the SPS wellbore equipment

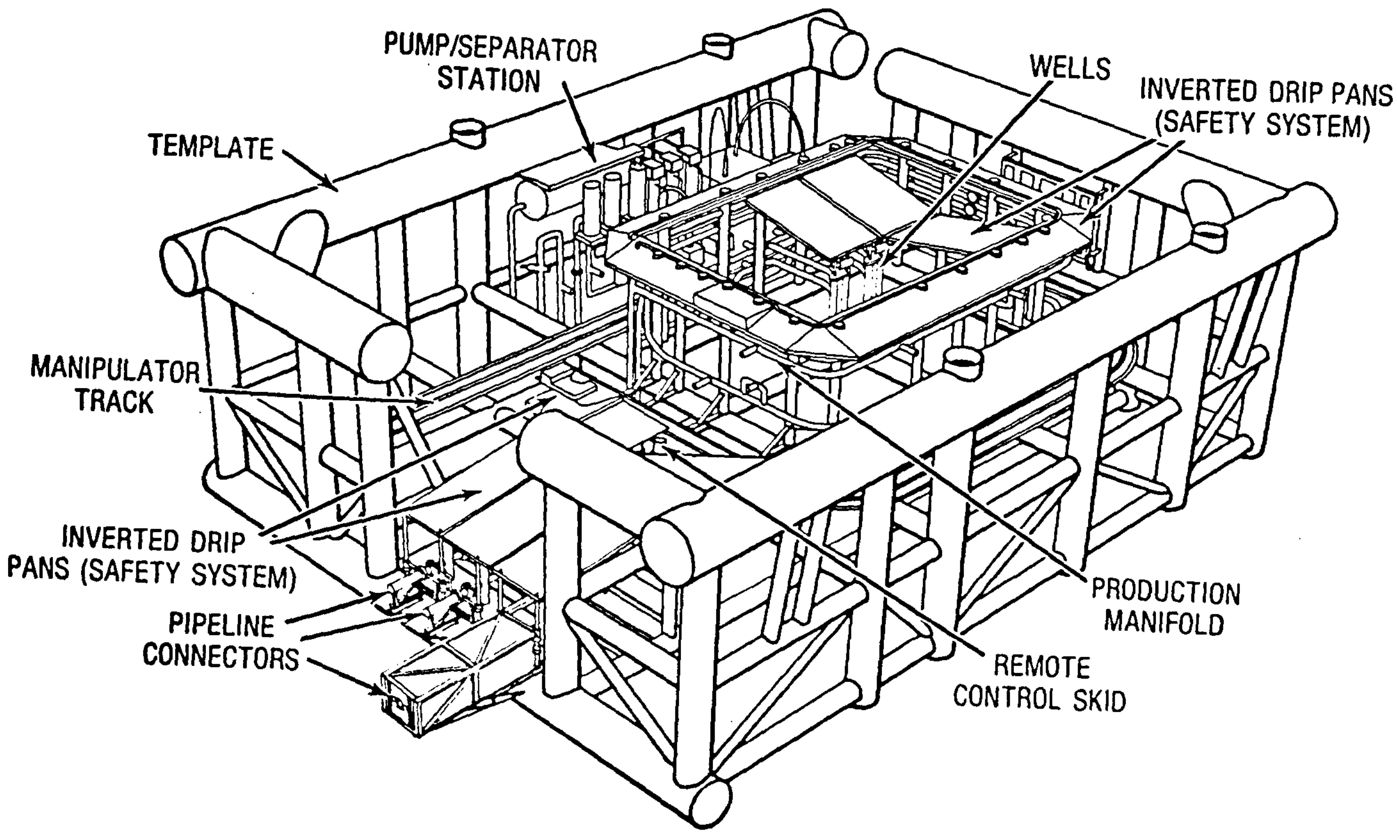


FIGURE I-16 EXXON SPS Manipulator System
Source: Exxon Company, U.S.A., 1971,
Supplemental Plan of Operations,
Santa Ynez Unit.

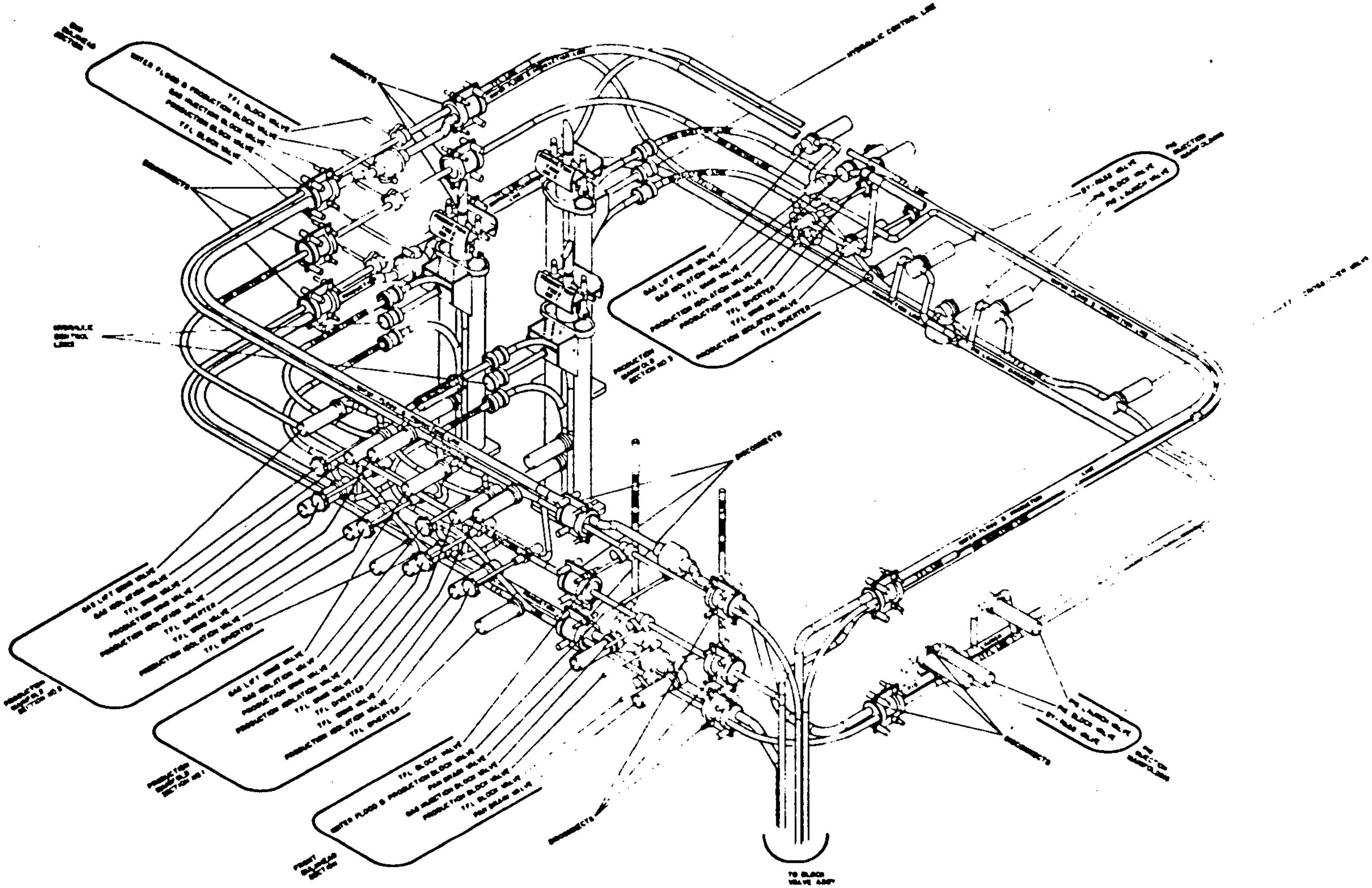


FIGURE I-17 EXXON SPS Production and Maintenance System
Source: Exxon Company, U.S.A, 1971, Supplemental Plan of Operations, Santa Ynez Unit.

and on a pre-prototype pump/separator subsystem have indicated the utility of these equipment subsystems in performing their functions. Tests simulating operating conditions have permitted an evaluation and selection of pressure swivels and hoses for the production riser. Land tests of line-up techniques and remote pipeline connectors have permitted the design of prototype pipeline connecting equipment needed for the SPS.

An offshore test of the Exxon SPS has commenced in the Gulf of Mexico off Louisiana. A prototype SPS was installed on the bottom of the Gulf of Mexico, 27 miles southeast of Grand Isle, Louisiana in 170 feet of water (October 1974). In the proposed offshore test, installation, production and maintenance operations in the Gulf of Mexico will be performed in a manner representative of producing a deepwater field with an SPS and the full-scale depth-capable equipment will be used. The purpose of the test is to evaluate the cost and performance of the equipment and techniques during installation, operation and maintenance activities. The results of extensive land testing indicate that the equipment functioned properly. This offshore test will provide data necessary to evaluate both equipment and procedures under actual production conditions.

The three-well prototype system installed in the Gulf of Mexico consists of a base skid (template) secured to the Gulf floor, replaceable subsea christmas-tree and valving assemblies, a gathering manifold, a subsea liquid separation vessel, and liquid transfer pumps. This assembly was installed in 1974 in 170 feet of water, in the West Delta Block 73 Field and two of the three wells have been drilled and completed. The 35,000-volt power cable for the pumps and the electrical communication cables have been installed and tested. Two eight-inch pipelines and three four and one-half inch multipurpose lines have been connected to the unit and pressure tested without the assistance of divers. Also to be tested is a submerged pipeline bundle and an articulated production riser assembly. Liquid production for the system will be looped to the head of the riser and then transmitted to a nearby platform where oil-water separation will be effected.

The subsea christmas tree will be installed for each well at an upper elevation on the template. Each christmas tree is designed to accommodate the production of the wall, fluid injection, pump-down tools, hydraulic control lines and reentry for conventional workover. Replacement of remote control pods or well control valves can be accomplished by use of a manipulator unit which is lowered from the surface to a curved track which encircles the unit. Once on the track, the manipulator can be remotely positioned with the aid of television cameras. Portions of the system undergoing replacement are isolated by manual isolation valves which are opened and closed by the manipulator.

(3) Lockheed Subsea Completion and Production System

Shell Oil Company and Lockheed Petroleum Services joined efforts to develop and field test an ocean-floor system for completing and producing wells. The system is based on the concept of housing more-or-less standard equipment in one-atmosphere chambers. The chambers can then be linked together with subsea pipelines to form a complete producing system. Servicing the equipment inside the chambers can be performed by experienced oilfield workers, transported to and from the chambers in a dry, one-atmosphere diving capsule.

The current joint program consists of three phases. Phase I, the subsea wellhead chamber, was successfully placed in operation in October 1972, on a Shell producing well in 375 feet of water. Phase II, the subsea manifold center, is scheduled for field trials in about 240 feet of water in the latter part of 1975. The third phase will consist of a subsea pumping station which is scheduled for startup in early 1976. It is anticipated that data from these tests will provide the sound basis necessary to project design and cost criteria for application in up to 3,000 feet of water.

Shell and Lockheed have completed the first phase of their program with the completion of the first encapsulated (dry) subsea well, whereby men work in a normal pressure air environment to assemble christmas-tree and control components in a wellhead chamber on the ocean floor. The system is designed for 1,200-foot water depth and the first well was completed in 375 feet of water and has been producing since October 1972. The well is located in the Gulf of Mexico on lease OCS-G 1666, Main Pass Block 290 Field. Using the atmospheric diving system of Lockheed, Shell successfully reentered and performed maintenance in the atmospheric chamber of this well in September 1973.

The main purposes for the reentry were to locate and repair a leak in the hydraulic control system, observe condition of chamber and christmas-tree components after one year of operation, and provide diving experience for Shell personnel. Nine dives lasting a total of 67 hours were made. Nine Shell personnel and two USGS technicians made dives in addition to Lockheed crew members. Each dive carried four persons.

In the first year the well produced 263,000 barrels of oil and 83 million cubic feet of gas and was producing at a rate of 1,350 barrels per day and 450 thousand cubic feet per day from two oil zones. Maintenance and remedial experience has included three TFL (through-the-flowline) operations, where tools are pumped through the tubing, to service subsurface controls and acidize the lower zone, and the reentry into the WHC (wellhead Chamber) described above.

Shell Oil Company proposes by late 1975 to install a Subsea Manifold Center (SMC) and drill and complete two subsea wells in 240 feet of water in Eugene Island Block 331. The SMC is the second phase of the comprehensive program that Shell and Lockheed Petroleum Services, Ltd. have been working on since 1971.

The two subsea wells will be drilled and completed using techniques employed by Shell for previous subsea wells in the Gulf of Mexico. Production from these wells and one platform well will be routed to the SMC where the wells will be tested and production commingled prior to delivery through a common line to a nearby production platform.

The SMC is 12 feet in diameter and 30 feet long. It is a pressurized vessel built to provide a dry normal one-atmosphere environment.

Two examples of the Lockheed system for wellhead equipment are shown in figure I-18. The chambers shown are those permanently installed on the wellhead and the upper hatch indicates where the service capsule is attached. After the capsule is connected, the chamber below the capsule and above the entry hatch to the work chamber, is pumped dry and the atmosphere is tested prior to opening the hatches.

(4) SEAL Subsea Completion and Production System

Subsea Equipment Associates Limited (SEAL) has been principally funded by British Petroleum, Mobil Oil Company, Compagnie Francaise des Petroles, Westinghouse Electric Corporation, and Groupe Deep, the latter a consortium of European Contractors. Associate members of the group include Conoco, Sunoco, Phillips, ELF/ERAP, and Petrobras.

SEAL currently has under development three subsea oil and gas production systems. Two of the systems undergoing tests are designed for use in foreign fields where high production rates are prevalent. SEAL is also testing a subsea oil production system in the Gulf of Mexico which is designed primarily for

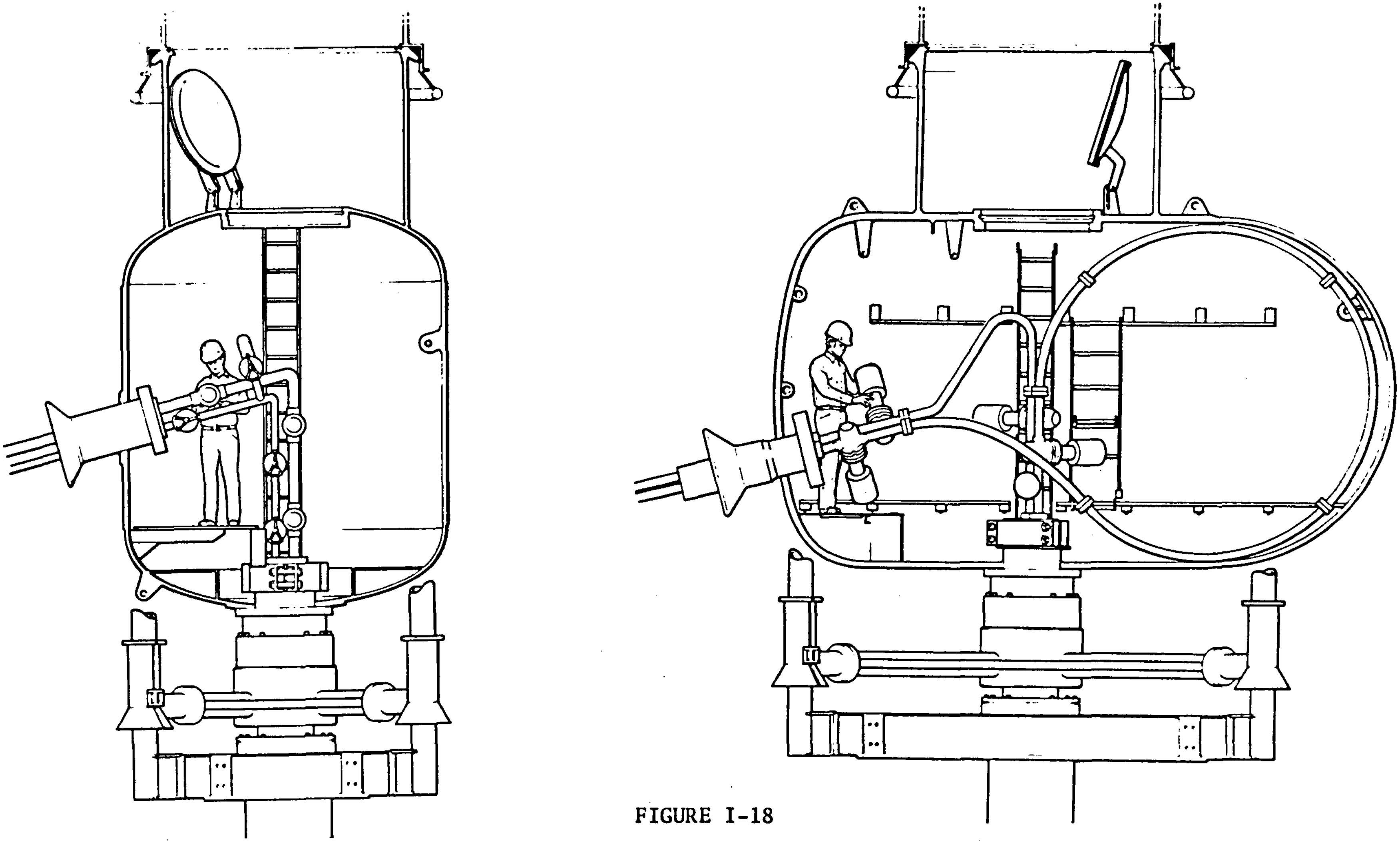


FIGURE I-18

LOCKHEED ONE-ATMOSPHERE SUBSEA COMPLETION SYSTEM

a. For wellhead installation where TFL tools are not required.

b. A wellhead cellar designed to enclose the TFL tubing loop.

Source: Lockheed Petroleum Services, Ltd. (Also presented at the Sixth Annual Offshore Technology Conference, Houston, Texas, May 6-8, 1974.)

utilization with large numbers of domestic low-production wells of less than 1,000 barrels per day which in turn generally require significant maintenance. Sun Oil Company is participating in the test project in the Gulf.

Essentially, the SEAL system is similar to the Shell-Lockheed system where working areas are enclosed in atmospheric chambers and access is available through personnel transfer capsules lowered from a surface vessel. Systems have been designed for individual well completions, cluster type well completions, a production manifold station, a subsea separation facility and a subsea pumping station.

As in other similar systems a base plate is hydraulically connected to the wellhead. For a multiple well system the base plate serves as a drilling template for directionally drilled wells and part of the structural piping is used in the manifolding system for the wells. The subsea work enclosure is then connected to the base structure and has provisions for personnel entry through a hatch from a personnel transfer chamber. The configuration of the work chamber can be varied depending on the water depth, number of wells associated, production rates, etc. The chamber provides a dry working environment on the ocean floor at atmospheric pressure.

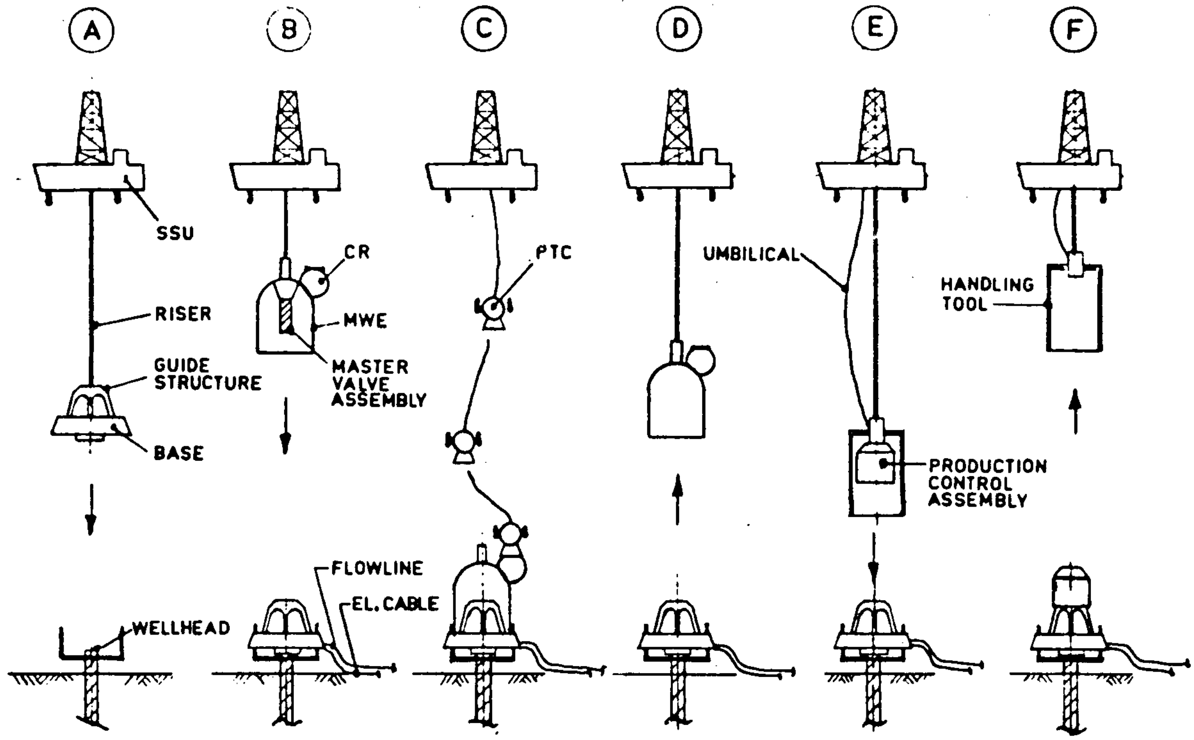
Phillips Petroleum Company is presently completing exploratory wells in the Ekofisk field in the North Sea in about 220 feet of water using this method. They are completing the well and connecting the base plate and lower master valve before releasing the drilling rig. The upper portion of the wellhead assembly (the work chamber and associated valves and piping, will be installed when production facilities are available. This installation can be made with a small support vessel without requiring the services of an expensive drilling vessel. Previously, exploratory wells were either abandoned, or temporarily abandoned. Abandonment represents a loss of considerable investment and if temporarily abandoned, a drilling vessel would be required to re-enter and complete the well.

In October of 1973, a series of tests involving the SEAL well completion system were started in the Gulf of Gabes, Tunisia. The first tests were in approximately 200 feet of water and the next step will be to test the system in about 575 feet of water in the same area. The system is designed to be used in waters over 1,500 feet in depth.

The vessel used in the Gulf of Gabes test was dynamically positioned using the "taut wire" system. The base plate was lowered on pipe and hydraulically connected to the well head, the master valve assembly was then lowered inside a manned work enclosure and manually connected by personnel within the MWE. The MWE was retrieved and remotely controlled production assembly (tree) was hydraulically connected to the master valve assembly. Since the MWE was lowered on drill pipe, wire line operations and well circulation could be conducted from the surface vessel. Figure I-19 shows the sequence of operations followed in these tests.

These tests are described in a paper, "Handling the SEAL Intermediate System for Subsea Wellhead Completions from the Support Vessel 'Tarabel'", by Mercier, Higler, Vine, and Darnborough of Subsea Equipment Associates, Ltd. The paper was presented at the 1974 Offshore Technical Conference in Houston, Texas. The paper is numbered OTC 1941.

Another test of the SEAL system is underway in the Gulf of Mexico. This involves a multi-well system and it is described in a paper titled "Subsea



A - Lower the seal base from the surface support unit (SSU) with internal guide structure attached to it onto wellhead.

B - Lower the master valve assembly inside the manned work enclosure (MWE). Attach flowline and electric cable to base.

C - Personnel transfer to MWE to attach master valve assembly to wellhead and connect flowline and electric cable to master valve assembly. (Atmospheric conditions inside MWE)

D - Raise the MWE leaving behind the master valve assembly.

E - Lower the production control assembly inside its handling tool and latch it to the master valve assembly.

F - Operate the master valves with the handling tool.
Operate the production control assembly from the support vessel (SSU).
Raise the handling tool.

FIGURE I-19

INSTALLATION SEQUENCE OF SEAL INTERMEDIATE SUBSEA WELLHEAD COMPLETION SYSTEM

Source: Subsea Equipment Associates, Ltd. (Also presented at the Sixth Annual Offshore Technology Conference, Houston, Texas, May 6-8, 1974)

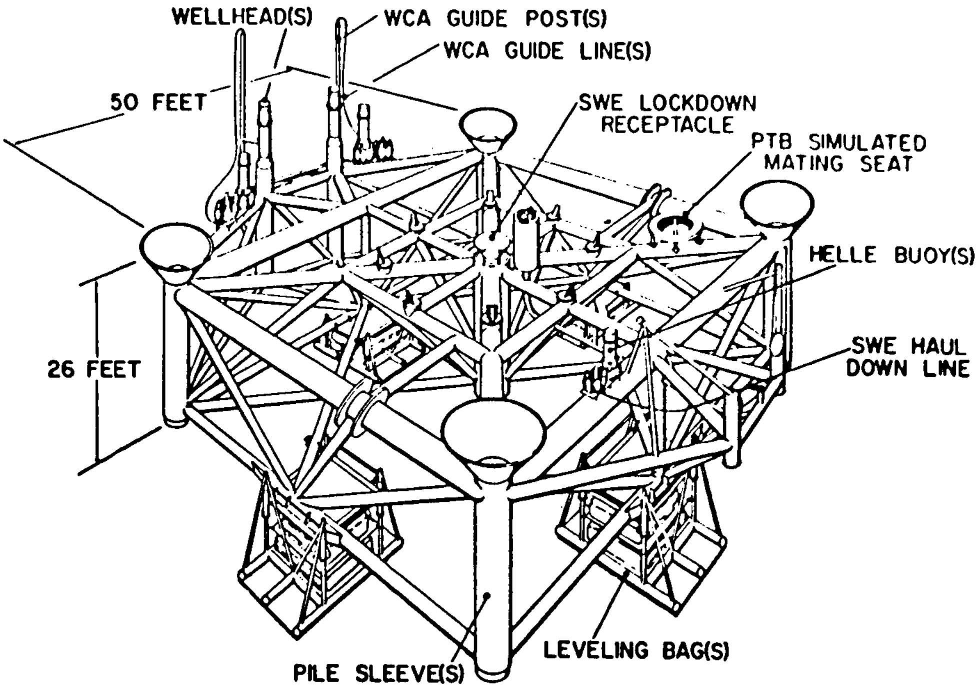
Manifold System" by Chatas and Richardson, Seal Petroleum Company. It is numbered OTC 1967 and was presented at the 1974 Offshore Technical Conference in Dallas, Texas.

Testing started by simulating field production on dry land in 1971 in Long Beach, California where the prototype was constructed. In 1972 the unit was transported to the Gulf of Mexico and installed in 247 feet of water near a Sun Oil Company production platform at Main Pass 293A. First tests were conducted by diverting production from wells on the platform through the manifold system. After processing the production was returned to the platform; additional drilling operations were started in December, 1973. Entrance into the production satellite is via a diving well designed to permit entry into the "shirt-sleeve" environment maintained in the chamber.

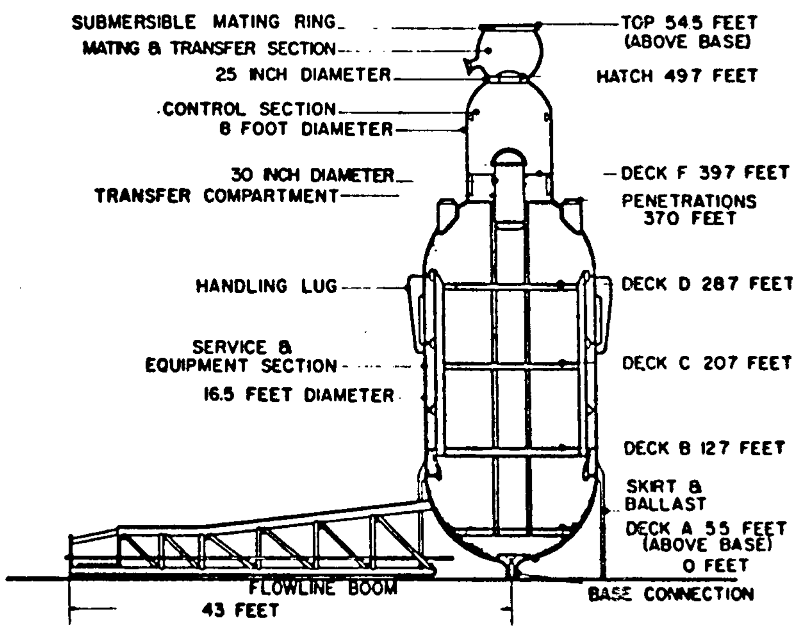
During the commissioning and check-out phase of the test, 56 entries by personnel were made into the subsea work enclosure (SWE). Most of these personnel were not divers, but regular oil company personnel and Geological Survey engineers and inspectors. Over 90 automatic operations of pump-down tools were performed, principally to remove paraffin deposits in the wells. These tools were pumped through the flow line network, to the platform, down the well and returned. The personnel transfer bell used in these tests is capable of transporting five men into the subsea structure.

The base of the SEAL Atmospheric System (SAS) and the subsea work enclosure (SWE) used in the Gulf of Mexico test are shown on figure I-20.

The SEAL Atmospheric System (SAS), which is being tested in the Gulf of Mexico, is based on the use of a large habitat type structure permanently installed on the sea floor to house oil field equipment. The SAS system incorporates



a. Base & wellhead connector assembly



b. Subsea work enclosure

FIGURE I-20 SEAL SUBSEA MANIFOLD SYSTEM

Source: Subsea Equipment Associates, Ltd. (Also presented at the Sixth Annual Offshore Technology Conference, Houston, Texas, May 6-8, 1974) a subsea manifold system in which various oil field production equipment can be installed depending on the application.

The three major elements being investigated in conjunction with the SAS Test Program are as follows: 1) the Subsea Work Enclosure (SWE), 2) The automatic production control system, and 3) automatic well maintenance system based on use of TFL (through-the-flowline) tests.

A common approach in the SEAL systems has been the use of trained oil field personnel on the sea floor. The maintenance personnel are transported from the surface to the subsea structure in a Personnel Transfer Bell. Test operations have proven conclusively that the vehicles are efficient and can be operated safely.

Future applications of this concept would be as a manifold center, a test separator center or a complete oil production system. In a similar manner to the other systems, men are transported to and from the Subsea Work Enclosure (SWE) through the use of a Personnel Transfer Bell. The men perform their duties at atmospheric pressure.

(5) Other Submerged Production Systems

Other submerged production systems are in the design or test stage. Deep Oil Technology, Inc., Transworld Drilling Company (a subsidiary of Kerr-McGee Corporation), and Standard Oil of California all have systems that have not yet been fully developed. The Transworld system is similar to the Lockheed and SEAL systems where an underwater work chamber at atmospheric pressure is utilized. The main difference is that wellheads would be maintained in a wet atmosphere except when work was actually in progress with the underwater work chamber in place. Construction is in progress on prototype models and the system is designed to be operable in water depths to at least 1,500 feet.

(6) Floating Production System

A possible production system where production from subsea wells is directed to a surface vessel containing separation equipment is more likely to be used in deep water where platform costs become prohibitive. A moored vessel could be connected to an underwater well manifold by a production riser. The vessel could be simply a separation facility and direct oil to a floating storage facility or the two functions could be combined. The vessel could be either a conventional ship type or a version of the semi-submersible hulls used in exploratory drilling. An adaptation of the semi-submersible type hull was tested off the coast of Scotland for a period of nearly two years from 1963 to 1965. This vessel was moored using the tension leg technique whereby anchor points were established by drilling in and cementing piles in the sea floor. The vessel was then connected to the anchor points by wire cables and by alternately taking in on the cables and flooding the buoyancy chambers, the vessel reached its predetermined buoyancy point with the buoyancy chamber about 80 feet below the surface. The water was then expelled from the buoyancy chamber leaving the wire cable "legs" in tension. Even in severe weather, the movement of the vessel was negligible since the only resistance offered to the sea was by the legs connecting the work platform to the buoyancy chamber which is itself below the depth affected by wave action. This test is described in OTC paper 2104, "The Design and Field Testing of the "Triton" Tension-Leg Fixed Platform and its Future Application For Petroleum Production and Processing in Deep Water," by R. David McDonald. This paper was presented at the 1974 Offshore Technical Conference in Dallas, Texas.

(7) Industry Assessment of the Current Status of Technology in Subsea Well Completion Techniques and Subsea Production Systems

By Notice in the Federal Register of January 27, 1975, the Department of the Interior requested from interested parties comments on the current status of subsea well completion techniques and subsea production systems. Comments were also requested as to the impacts from requiring subsea completions as a condition to granting some OCS leases.

As stated in the Notice, comments were to address all aspects of subsea operations, including the following:

- Water depth capabilities, depths at which subsea systems are economical (versus bottom-founded platforms).
- Cost of drilling, completing, and maintaining subsea wells.
- Flowline connections and servicing.
- Navigation for well location and reentry.
- Well maintenance and repairs.
- Subsea separation and storage
- Diving limitations.

Comments were received during the months of February and March, 1975 from twenty separate parties, including major oil companies, companies which market subsea systems equipment and/or components, and one United States governmental agency. The respondents did not agree in their assessments of the state-of-the-art in any of the seven specific aspects to which previous reference was made. These comments with attachments are available for reference in the Geological Survey Library, National Center, Reston, Virginia. Following is a brief summary of the information submitted by the companies as to the above aspects of subsea operations.

- <u>Water Depth Capabilities</u>

Technology is now available for installation and operation of "wet" subsea completions to a depth of 400 feet with diver assistance. However, platforms are necessary to provide support facilities. It is anticipated that this depth capability will be increased to 600 feet in the very near future.

The limiting factor in this operation at present is the capability for making flowline connections.

The use of manned diving capsules to perform this operation in encapsulated subsea completions at the present time has a water depth capability of 600 feet. Design and procedures have been developed to extend this capability to a depth of 1200 feet but practical experience is lacking.

It is anticipated that the use of encapsulated wellheads and manned diving chambers will further extend depth capability to 2000 feet in a time-frame of from 7 to 10 years.

In the case of subsea production systems, additional research and development and more field testing of critical subsea production components for water depths between 1000 and 2000 feet should be completed within the next 5 years. However, subsea systems independent of fixed platforms or other nearby surface facilities are not likely to become a reality until some type of subsea station capable of inputting energy into well streams can be perfected. There is no definite indication at this time as to when a reliable working station of this nature may be fully developed and implemented.

- Economic Feasibility of Subsea Systems

It is the consensus of the respondents that in water depths of up to 1000 feet platform systems are more economical than subsea systems.

It is indicated that subsea systems such as those using manned diving capsules and encapsulated trees may be competitive economically with fixed platforms in water depths of 200 to 700 feet, but in depths greater than 600 feet comparative economics would necessarily be employed on an individual basis.

In water depths ranging from 600 to 1200 feet it is suggested that different types of structures, such as the tension-leg platform, may replace conventional platforms more economically than subsea systems.

- Cost of Drilling, Completing and Maintaining Subsea Wells

Under existing conditions, platforms are required for production equipment support. These same platforms can be used for drilling most of the wells at a fraction of the cost of subsea completions.

The first major use of subsea completions will probably be to drain areas beyond the reach of directionally-drilled wells. In water depths to at least 500 feet, and possibly to 1000 feet depending on individual circumstances, subsea completions are economically justified only as peripheral or outpost wells to an established platform. As development moves into greater depths, the economics of subsea completions as compared to platform wells will shift in favor of underwater completions.

When platform depth limits are exceeded, the subsea completion may be the only alternative, even if they are connected to and controlled from some type of floating platform or vessel.

Under usual conditions, the cost of drilling, completing and maintaining a subsea well will be 2 to 3, or possibly more, times greater than that of a well drilled from a conventional platform. This is due primarily to higher costs of mobile rigs and the added cost of a flowline bundle between the subsea well and its surface facility.

The economic feasibility of drilling subsea wells cannot be determined by drilling and maintenance costs alone; the factor of reserves is very important. The cost of subsea completions may cause loss of reserves by early abandonment or prevent development of marginal properties.

- Flowline Connections and Servicing

The greatest depth at which a flowline has been connected to subsea well equipment is about 450 feet. Most connections have been made with diver assistance, but maintenance has been accomplished by the use of through flowline (TFL) tools.

Flowline connection and servicing appears to present the single most difficult barrier to subsea completions beyond diver depth. The mechanical complexity involved in remotely aligning, coupling, and high-pressure sealing of multiple pipe runs presents a significant problem in providing an economic and reliable system. It is anticipated that a period of 5 years will be needed to achieve this reliability.

Remote flowline connection capability has not been satisfactorily demonstrated, but several prototype systems are available and show potential for satisfying this requirement in water depths to 1500 feet. The "dry" system offers a promising approach by replacing the complexity of remote, "wet" mechanical functions with personnel within a subsea chamber to carry out the connections following a relatively simple pipe "pull-in" operation. However, the sole means of repairing these complex cable and pipe bundles under the current state-of-the-art technique is by removal and replacement of the malfunctioning equipment.

- Navigation for Well Location and Reentry

  The consensus of the respondents is that this operation does not present a problem for subsea systems. Precise positioning and navigation of mobile drilling rigs, construction barges, and maintenance vessels have been proven for any water depth or offshore location in an environment such as the Gulf of Mexico.

There is some indication that positioning and reentry procedures can be time-consuming and costly, especially in greater depths, which would warrant additional development and improvement of techniques and associated tool units.

- Well Maintenance and Repairs

  Divers can be successful in repairing and maintaining wellheads in depths up to 400 feet.

Through flowline (TFL) techniques have been successful in performing "in-tubing" maintenance in the Gulf of Mexico. Minor repairs to "wet" trees and control systems have been carried out by divers or remote manipulators.

Industry is developing refinements in the remote control of tool retrieval and manipulation techniques. Many wellhead components now require service with a diver or manned one-atmosphere chamber; therefore, depth capabilities are limited by either diver or vessel capability.

Subsea systems planned for depths beyond diver capability will require a back-up remotely-controlled manipulator or robot system.

Work requiring removal of tubing strings requires a drilling rig since flowlines must be disconnected and the wellhead completely removed.

For subsea wells requiring major repairs, economics may dictate early abandonment in some instances.

- Subsea Separation and Storage

Production from all current subsea completions is processed through facilities located either on fixed platforms or onshore.

Work done to date on subsea separation and production systems has primarily been in the area of developing concepts and prototype equipment. At present, the operating water depth of these systems is about 375 feet. This depth should be extended to about 1500 feet in 10 years.

Current state-of-the-art subsea separation is limited to experimental and developmental gas/liquid separation of relatively small volumes of fluids. Large volume separators have not been installed and tested and their application in subsea installations involves major problems requiring further research and development.

- Diving Limitations[1]

Diver-assisted subsea well installations are now practical in the water depth range of 250 to 300 feet. Between 300 and 400 feet conventional diving techniques begin to become ineffective as on-bottom time is limited to ½ hour or less.

[1] The diving depth limitations assessment and discussion under this heading is a summary of the situation as indicated in the February-March 1975 Company comments. See section I.D.6.b.(2), for an earlier discussion on recent extensions of diving depth capabilities. A working dive to recover a blowout preventer stack was performed at a water depth of 1,069 feet.

Current limitations on diving are to depths of less than 1000 feet with actual working dives on oil field projects to 840 feet. The diving industry has conducted experimental working dives to depths of 1000 to 1300 feet. At these depths the divers' work efficiency drops to 25-40%. Consequently, diving at these depths is now limited to observation service. Depths greater than 850 feet necessitate access by means of a manned or remote-controlled vehicle.

- Impact of Requirement for Subsea Completions as a Condition for Granting of Certain OCS Leases

It is unanimous among the respondents to the Departments Federal Register Notice request that a requirement of subsea completions as a condition for granting certain OCS leases would have adverse effects.

The most-repeated reason is additional costs resulting in delayed development of properties.

The second most-repeated reason is the adverse effects of regulation of technical decisions in determining the method of developing a property. It is indicated that the technology for deep water platforms is advancing as rapidly as subsea technology.

(8) Summary-Subsea Production Systems

The Shell-Lockheed the SEAL and the Exxon SPS Systems are undergoing operational tests as just described in the Gulf of Mexico at this time. The three systems have the capability for remote safety inspections as well as visual inspection in the underwater chambers. All submerged production systems must be approved for installation by the Geological Survey and must conform to regulations. As of January, 1976, no applications for other than test installation of any such system have been received by the Geological Survey.

Servicing and maintenance for the Shell-Lockheed and SEAL Systems are designed for operation in a similar manner, with experienced oil field workers being transported to the encapsulated wellhead chamber at the sea bottom. Diving capability may be required for special type maintenance outside the chambers.

Maintenance and service is to be performed on the EXXON System mechanically by remotely activating a manipulator, but diver capability may still be required.

It is likely that for the near future most subsea completions will be for single well completions similar to those on State leases in the Channel, and possibly some cluster type completions with a subsea manifold in locations which cannot be reached by drilling from a platform. Production from such completions would be directed to surface separation facilities. Perhaps in a few years a complete subsea production facility will be feasible, but it is not likely that their use will be widespread very soon.

Significant problems have been encountered and resolved during the evolution of subsea production systems and, prior to installation in water depths greater than 700 feet, further testing is required to improve and demonstrate the reliability of such systems. As early as 1962, subsea production systems were installed in more than 250 feet of water; however, investigation revealed that early deep-water installations were made prematurely when certain components were little beyond prototype state. The recent trend has been to install such subsea system components in shallow water for field testing until dependability can be ensured for use at greater depths (Ocean Industry, Subsea Production Systems - 1974). An example of this trend is the Exxon Submerged Production System installed in the Gulf of Mexico in 170 feet of water for several years of field testing prior to being considered for installation at greater depths such as in the Santa Barbara Channel, Santa Ynez Unit.

Prior to acting on a specific request to install a subsea production system in the Santa Barbara Channel, the Geological Survey would take into consideration the results of all testing, including several years of offshore subsea field operations and also diver depth capabilities. Since such systems are still largely experimental, a specific proposal would be carefully studied before granting approval and the need for additional environmental Statements would be determined by an environmental analysis of each proposal.

7. Transportation of Produced Oil and Gas

All of the hydrocarbons presently being produced in the Santa Barbara Channel OCS are transported from an offshore platform to onshore facilities by pipeline and it is anticipated that most future production would also be handled by pipeline to shore. The relatively short distance of potential OCS production from the coast makes it unlikely that expensive offshore storage and handling facilities would be contemplated in preference to onshore facilities. At the least a number of flow lines and gathering lines will be required. Unless expensive treating and reinjection platforms are constructed offshore, it is probable that lines to handle gas and water will also be necessary.

About the only feasible way to handle gas produced offshore is to move it by pipeline. In the early stages of the development of an oil field, small amounts of gas are sometimes vented or flared. However, wasteful avoidance venting or flaring is not permitted by the Geological Survey.

a. Offshore Pipelines

(1) Construction

Pipelines laid offshore are constructed and laid by several different methods, depending mainly on the size, location, intended use, and cost. One method, pipepulling, involves the use of barges and tugs to pull sections of welded pipe from an onshore launchway over the preselected right-of-way. These sections may either be dragged along the bottom or suspended by floats. There are at least three limitations to this system. First, an extensive section of shoreline, roughly perpendicular to the shore, must be available for the fabrication and launchway site. (Alternatively, it is possible although more costly to use a launching jetty constructed from the beach out over the water.) Second, the total length of pipeline that can be laid is limited. One company estimates the limit to be 100,000 feet for smaller diameter pipe. Third, the pipeline right-of-way must be essentially a straight line. The pipe pulling method is not used often for laying pipelines to OCS locations.

The second method, used in nearly all cases for large-diameter pipelines, involves the welding together of short sections of pipe on a barge as the barge simultaneously moves forward, and allowing the completed section of pipeline to sag downward and lay on the sea floor. This operation begins at the offshore location and proceeds toward the intended onshore terminal. The advantage of this system is that the pipeline right-of-way need not be straight, and any diameter of pipeline can be laid in this way. The main disadvantage is slow rate at which the laying proceeds.

The third method has become increasingly popular in the last decade for laying smaller-diameter pipelines and involves the use of a lay-barge equipped with a large reel or spool of coiled pipe. With the reel-pipelaying technique, segments of pipe are welded together onshore and the appropriate coatings are applied. Then the pipe is wound onto a large diameter reel which is mounted on a barge or other floating vessel. The vessel is then transported to the construction site. As the barge is towed along the right-of-way, the pipe is pulled off the reel through straightening equipment and continuous lengths of pipeline are laid on the sea floor. The reel method has several advantages. 1) With no welding and little crane work being done on the barge, the operation is much less susceptible to interruption by bad weather and high seas. A thicker-walled pipe can be used, eliminating the necessity of a concrete coating for negative buoyancy, increasing the pressure rating, and adding significant corrosion allowance. This method allows pipelaying to proceed at a much faster rate than other methods - up to 5,000-10,000 feet per hour.

The reel method has two principal disadvantages. First, economic considerations have so far limited the diameter of the pipe that can be laid to about 12 inches. Second, during pipe-handling operations, pipe coatings are subject to occasional damage, necessitating repairs and thus, slowing the rate of pipelaying.

One of the problems associated with marine pipelining is in making a connection to a platform. Deeper water of course increases the problem. Three methods in use are shown on figure I-21.

The tension method can be used in relatively shallow water with a riser installed on the platform during its construction. Risers are generally installed during platform construction. As shown in the figure, diver assistance would be required to make the connection between the riser and the pipeline. The riser may also be installed as the line is laid, but provisions to attach the riser to the platform underwater would be required for stability. Maintaining tension on the line controls bending stress as the line is raised or lowered.

Two other methods of making platform connections are shown and each are diverless operations. In the reverse J-tube method the pipe is lubricated and simultaneously pushed and pulled down the J-tube. When the pipe reaches

Fig. 4

Reverse J-tube method

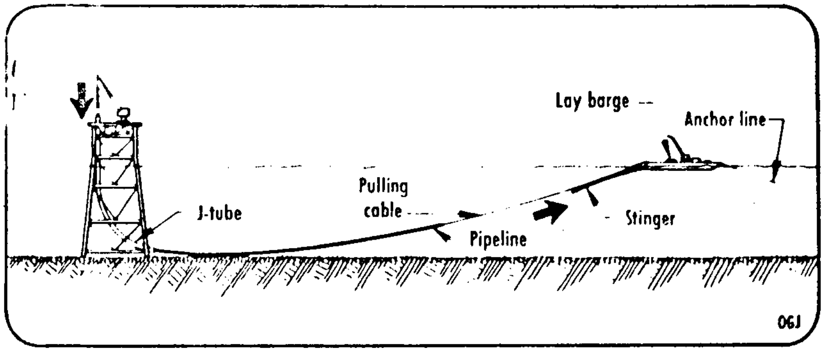


Fig. 5

Tension method

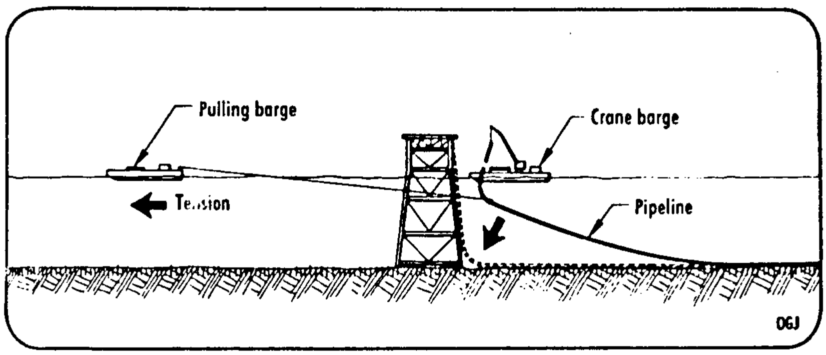


Fig. 6

Pulling method

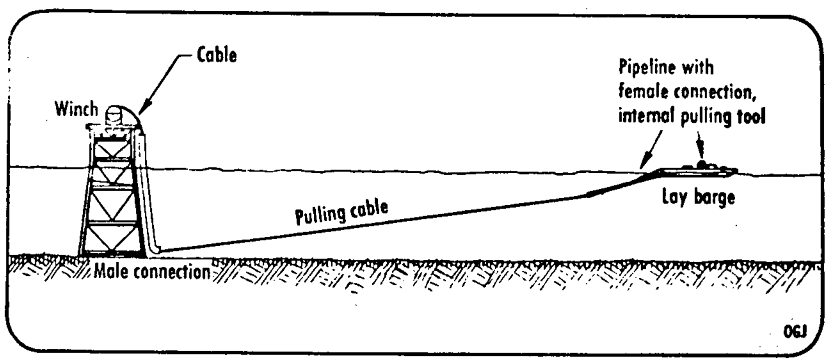


FIGURE I-21

SUBSEA PIPELINE RISER CONNECTION METHODS

From: Oil & Gas Journal, January 7, 1974,
Vol. 72, No. 1, p. 43.

the lay barge it can be connected to the next joint and pipelaying can continue in the normal manner. The pulling method involves pulling the pipeline from the lay barge to the platform. The pipe is fitted with a female connection and pulling tool and is pulled over a male connection on the riser. When the connection is made, the pulling tool is released and retrieved through the riser.

(2) Burial

Offshore pipelines may be buried for various reasons, but the most important is the safety of the line against damage. Such damage can be caused by many factors: anchors, fishing operations, currents, suspended lengths, etc. In water depths of less than 200 feet, present OCS administrative procedures require burial of the pipelines. The minimum depth of burial is 3 ft. except in shipping fairways and anchorage areas, where the minimum depth is 10 ft. Technology exists to bury pipelines in water depths of 600± ft., for cases where such action is deemed advisable. However, one of the most effective methods of protecting a pipeline from damage due to earthquakes, is to leave the portion in deeper waters on the ocean floor surface where it can maintain as much independent flexibility relative to the surface as possible.

Conventional dredging equipment can be used in shallow water, but it is practically impossible to lay a line in a previously prepared trench in deep water. For this reason marine pipelines are commonly burried after the line is laid.

Burial is usually affected by jetting sediment away from underneath the pipeline and allowing it to sink into the resulting trench. The equipment used in this operation consists of a work barge equipped with high volume/high pressure water pumps and air compressors. From the barge, a multiple-membered towline consisting of a strength member, water line, and air line extends downward to a U-shaped structure which straddles the pipelines and glides along it on rollers. Affixed to the U-shaped jetting device are several nozzles which direct water and air, under high pressure, ahead and below the pipeline. Sediments are blasted out of the narrow trench by the water jets, partially lifted by the air and deflected to the sides by various types of fins. The suspended sediments fall diffusely along either side of the trench. As the jetting device is pulled forward, the pipeline settles into the trench and is partially buried quite soon by the reworked sediment as it slips and settles back into the depression. Complete burial and restoration of original bottom contours may require additional time. In shallow waters, experience has shown that contour restoration is quite rapid, whereas in deeper waters, more than a year may be required. The jet method is most effective in fairly soft formations, but the use of extremely high pressure, high velocity jets make the system effective in most sea floor sediments.

Saipem SpA of Milan, Italy, a contractor, has developed an underwater trencher that operates over a pipeline and uses cutters operated by hydraulic motors. Four cutters are moved by four 80 horsepower hydraulic motors and the speeds can vary to suit different bottom conditions. A water jet system is used to clean the cutter blades and to move cuttings from the trench. The trencher was tested in the Mediterranean on a hard, stiff clay bottom with a shear strength of over 2,500-pounds per square foot. It trenched at a rate of 3.5 feet per minute making a ditch approximately 8 feet deep.

Even though a buried line is protected from fluid forces it is not necessarily stable. If it is too light, it will gradually work its way up through the soil and become exposed to the water forces. If it is too heavy, it will gradually sink in the soil and impose additional tensile stress in the line. Design procedures for determining the vertical stability of the line in sands and clays have been developed and are available in the industry.

Difficulties have been experienced in burying pipe in cohesionless sands. In this case the sand will often refill the jetted trench before the pipe can settle into it. Another method, fluidization of the sand, enables successful burial in this type of substrate. The powerful pumps used in the present jet systems involve such a tremendous quantity of water that it is estimated that the resulting mixture will contain an average of 1 part of solid material in 6 parts of water.

Pipelines laid to shore will be buried through the beach area, and shallow water approaches, and onshore to avoid exposure to beach erosion and to preserve aesthetic values. From this point the pipeline construction would be extended toward a storage facility or wharf facility, in turn leading to a processing facility, transport line, or refinery.

An alternative to burying the pipeline in inshore areas is to lay the pipe on the sea floor and securely anchor it in place with a cover of rip-rap (rock, concrete blocks, etc.).

Blasting may be utilized in lieu of other trenching methods in hard rock areas. The trench to bury the pipeline would be excavated by carefully placed explosive charges. This method would only be used in shallow waters where the pipeline could be placed after excavation.

(3) Pipeline Coating and Corrosion Protection

To prevent corrosion, offshore pipelines are carefully coated with such materials as epoxy compounds or thick asphaltic mastic. The coating is generally applied on shore before the pipe is delivered to the lay barge, but in some cases coating is done on the barge. In any event, as successive joints of pipe are added to the pipeline string the welded joint areas, normally left bare in the initial coating process, must be protected on the barge.

Lines are protected from electrolysis by both impressed-current systems and by sacrificial anodes (zinc is commonly used). Corrosion prevention measures are required by 49CFR Part 195.

If extra weight, or mechanical protection, is required, the pipe is also covered by a layer of dense concrete. This is applied over the corrosion protection material at an onshore location. The thickness of the coating depends on the weight required to sink the pipe and often weighting material is added to increase the density of the concrete. The concrete is generally jetted onto the pipe while the pipe is rotating and usually the concrete is reinforced by a wire cage around the pipe. In order to increase flexibility, the concrete may be partially sawn through at intervals along the pipe joint. Various curing methods are used to ensure that the concrete is completely set up prior to delivery to the lay barge.

(4) Present Capabilities in Offshore Pipeline Construction

The deepest underwater pipeline laid to date was in the Gulf of Gaeta off Italy in 524 feet of water. It was laid as a test line to develop deep water procedures and methods. Several lines have been constructed, are in construction, or will be started shortly in the North Sea at almost record depths. A 90-mile, 36-inch line will connect the Brent Field to the Shetland Islands in water more than 500 feet deep. A 276-mile, 36-inch line will connect the Ekofisk field to Emden, Germany. Also, a 10-inch line will be laid across the Strait of Messina connecting Italy with Sicily in late 1974. This line will be laid in water up to 1,180 feet deep. The strait is narrow, but deep and has a steep, rocky bottom. A second portion of this line will be laid from Algeria to Sicily in water depths of 1,640 feet.

One of the advances in pipelaying techniques is in lay-barge design. They are generally becoming larger in order to cope with the greater depths and greater loads to be expected. Most of the newer designs are of the semi-submersible hull type to reduce stresses due to vessel movement. Newer barges are being constructed with the capability of laying pipe in waters to 2,000 feet. Santa Fe International is constructing a reel ship capable of handling 24-inch pipe at 1-mile per hour at depths initially of 1,000 feet and ultimately 3,000-4,000 feet. Brown and Root, Incorporated has a new bury barge, now working in the North Sea, capable of working on waters to 600 feet with a trenching width adjustable from 4 to 12 feet and as deep as 10 feet on a single pass.

Repairs to pipelines to date are generally dependent, at least in part, on diver-assist methods and are therefore limited by diver capabilities (section I.D.6.b.(1)). But, a great deal of research and development is in progress, and is quite advanced, to develop diverless methods to make repairs in water as deep as 4,000 feet. Mechanical methods have already advanced to the point where repairs can be made without diver-assist except to observe and control operations. Esso Production Research, in conjunction with Hydrotech International and 16 other companies, has a two-year project underway. Shell Development Company has another program as does Saipem SpA of Milan, Italy. Other companies are also engaged in these projects.

b. Land Pipelines

Land pipelines to be laid in conjunction with increasing productive capacity from the Santa Barbara Channel Federal lands would probably be relatively minor, serving to deliver production to established onshore production facilities. Existing installed gas transmission line capacity for transporting gas from the Channel area is considered to be ample for any increased gas production.

The only possibility of onshore pipeline installation of any great magnitude would be if it were decided to transport crude oil from the Channel area to a distant refinery or loading site. If the site chosen was the Los Angeles area, rights-of-way exist, and are discussed in section III. There is also a possibility that an oil line or lines could be routed north, to either a proposed deepwater terminal at Morro Bay or to Monterey.

c. Operation and Maintenance

The safe operation and maintenance of a pipeline system requires several redundant monitoring systems to ensure the integrity of the line and detect leaks. The primary leak-detection system in use in the Santa Barbara Channel is a set of automatic pressure-sensing recorders on both ends of each pipeline system, and is essentially a safeguard to prevent the escape of large volumes of oil due to a catastrophic line break. These recorders are equipped with a built-in alarm system which either shuts down the flow automatically or sounds an alarm to alert personnel of an abnormal pressure level. In this way, a leak of substantial rate is detected immediately. This system is insensitive to leaks which do not produce a decrease in line pressure greater than 300-500 psi.

The second system of leak detection is the routine patrolling of the offshore pipeline routes by boat or aircraft, and onshore by wheeled vehicle or aircraft. A minimum patrolling frequency of intervals between inspections of transmission lines not exceeding 2 weeks is required by 49 CFR Part 195.412. This type of monitoring would result in the detection of all sizes of leaks. The Pacific Region OCS Orders require that oil pipelines (flow lines) from platforms to onshore facilities be inspected a minimum of once each week by aircraft or boat, but in actual practice is normally performed more often. The appeal of a system of regular pipeline patrolling is that it allows detection of small leaks and therefore complements the pressure-sensing system described above.

The third system for leak detection consists of a series of volume-recording flow meters, on either end of a pipeline system. Because nearly all crude oil moves from OCS areas to shore by common carrier lines, it must be metered in the offshore pipeline gathering system and again at the onshore pipeline terminal in order that each producer be properly credited for his share of the common stream. This flow monitoring system has been designed so that the flow sensors continually indicate net input and output in real time so that attendant personnel are able to discover a decrease in output and alert appropriate stations of the possibility of a leak. This type leak detection system is required for oil pipelines (flow lines) from OCS platforms to shore (OCS Order No. 9).

All major pipelines would include mainline block valves at intervals in order to allow isolation of segments of the pipeline. This is an industry standard and therefore "voluntary"; however, most companies operating pipelines subscribe to American National Standards Institute (ANSI) and would be expected to follow these recommendations. The pipeline requirements in OCS Order No. 9 apply only to pipelines (flow lines) from OCS platforms to shore. The Geological Survey would require any block valves deemed necessary for this type pipeline (flow line). The table below shows the relationship between the diameter of a pipeline and the volume contained per mile of line.

Length/Volume Relationship of
Line Pipe

Size (inches) ID	Length Required to Hold 1,000 bbl. (miles)	Barrels Per Mile of Line
2.067	45.6	22
4.026	12.0	83
6.026	5.3	189
8.071	3.0	334
10.020	1.9	515
12.090	1.3	750
24.000	0.3	2954

Such block valve systems, usually built on a pipeline connection platform, besides improving security in case of line breaks offer a means of access to the lines for repairs, for connection of additional lines, etc. An underwater-pipeline platform has been installed in 140 feet of water in the Gulf of Mexico by Transcontinental Gas Pipeline Company.

All pipelines to be installed will be designed in accordance with all applicable regulations; Department of Transportation, Army Corps of Engineers, California State Lands Commission, and Geological Survey regulations (OCS Order No. 9). The USGS will consider the design and installation methods before approving a permit to install any pipeline.

d. Barges

Production barges are occasionally used in offshore work, primarily for testing wells. In this case they are equipped with separation equipment and include facilities for oil storage. Their use is not anticipated in any future Santa Barbara Channel operations, however, since the newer drilling vessels and platforms are designed to fulfill this function.

Barges could be used as interim storage facilities for crude oil before pipelines or permanent storage facilities are installed. If used in this manner, procedures followed would be similar to those discussed in sections I.D.8.b. and I.D.9.

Another possible use for barges would be the transport of crude oil from the Channel area to a refinery center. In this case the crude oil to be transported would have water and gas removed. The maximum anticipated sizes for the vessels that would likely be used are 25,000 to 30,000 dwt. A 25,000 dwt tug/barge unit proposed for the Santa Ynez Unit would be approximately 500 feet long with a beam of 90 feet, a loaded draft of 31 feet, and a capacity of about 175,000 barrels. The 6,000 horse-power seagoing tug would have a length of about 150 feet, a beam of 40 feet, and a design draft of 21 feet. It is anticipated that Santa Barbara Channel crude oil would be delivered to one or more of the numerous refineries and terminals in the Los Angeles and Long Beach harbor area. Additional facilities may be required for handling the transport vessels for Santa Barbara Channel development.

All barges and equipment aboard would conform to applicable Coast Guard and Geological Survey regulations and would be equipped with segregated, clean ballast tanks.

e. Tankers

Tankers may be used to transport additional crude oil to refineries on the West Coast if the Channel area is further developed. The restrictions on the sizes of tankers which might be used depend on loading facility capability and depth of harbors near refineries. The use of tankers will be more likely if near-shore loading terminals utilizing the single point storage mooring buoys and vessels are used. Present coastwise tankers are in the 30,000/35,000 ton category and carry 200/230 m. bbls. of oil. No ballast is pumped overboard unless it is from segregated clean ballast tankers. Such vessels are equipped with containers on board to contain small spills involved in connecting and disconnecting loading hoses.

8. Treating and Storage Facilities

a. Onshore

As there are eight existing and one proposed new onshore treating and storage facility,/within about ½ mile of the shoreline, in the Channel area it is possible that they could be used, at least in initial stages, of further Santa Barbara Channel OCS development beyond that encompassed by the Santa Ynez Unit. It might become necessary to expand existing facilities and possibly construct new facilities. Most of these existing Channel area facilities do not presently handle Federal OCS production, but it is possible that, depending on agreement by the operators involved, State and County approval, and their mechanical condition, they could be so used in the future.

There are two onshore treating and storage facilities in the Carpinteria-Rincon area which handle the present Federal offshore production. The facilities presently have surplus capacity and could likely be expanded to handle additional production. A new facility has been proposed by Exxon, USA, for construction in Las Flores Canyon, a small side branch of Corral Canyon, to accommodate production from the Santa Ynez Unit. If significantly more production is realized in the Santa Barbara Channel, yet additional shore facilities and pipelines or enlargement of the existing facilities will have to be considered.

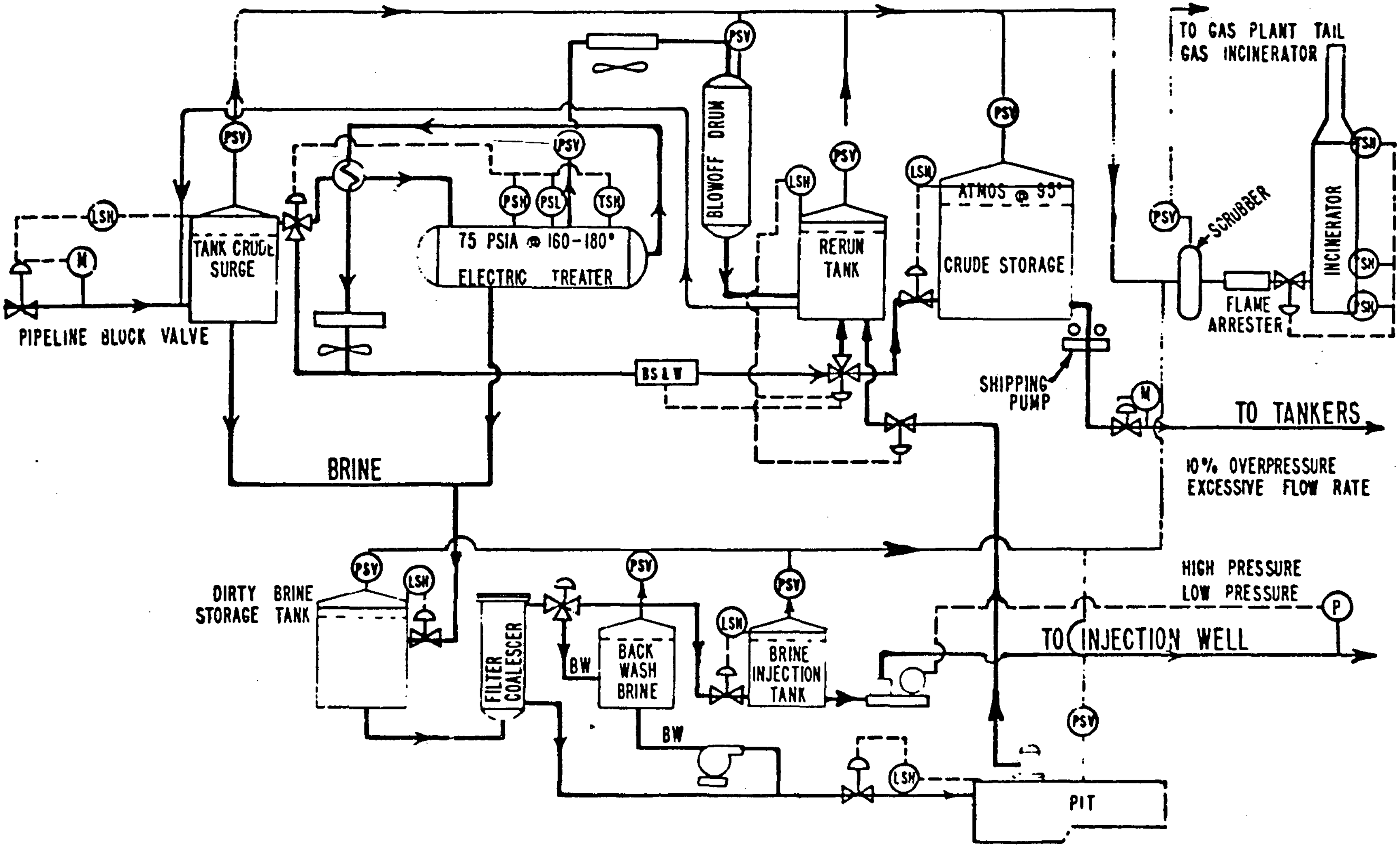
(1) Oil Handling

After initial separation at an offshore production facility an emulsified mixture of crude oil and salt water may be transported from an offshore platform to an inlet surge tank onshore through a pipeline. The produced oil and water would be treated by previously treated oil or another heating fluid in heat exchangers, and would then flow to electric treaters. The treaters would separate the oil and water, after which the oil would be returned to the heat exchangers to be cooled, and the water would be piped to a dirty-brine storage tank. The treated crude oil would be additionally cooled by an air cooler and then stored in tanks at atmospheric pressure. The oil would be pumped from the storage tanks through pipelines to a marine terminal for transport to market or through pipelines to market.

Treating of crude oil would be accomplished in a system totally closed to prevent vapor emissions. The crude oil would be degassed at atmospheric pressure (at the platform) prior to onshore treating. The onshore treater operating pressure would be approximately 75 psia and at a maximum operating temperature of 180^{o} F, there would be no vapor evolution. Special cone-roofed tanks, internal floating roofs and vapor recovery systems have been designed to minimize vapor evolution from the stored crude oil and prevent vapor emissions to the atmosphere. All vessels and tanks would be equipped with vent, relief, or blowdown lines routed to a vapor incinerator. (See figure I-22)

FIGURE I-22

OIL TREATING & STORAGE



WATER TREATING & DISPOSAL

(2) Water Handling

Separated salt water from the inlet surge tank and the electric treaters would flow to a dirty-brine storage tank. Free oil would be skimmed off in this tank, and the water would be pumped to a filter-coalescer or similar device. Coalesced oil would be drawn off to a settling basin. Present treating facilities in the Channel area reduce the oil concentration to from 5-25 ppm.

The produced water may be disposed of in three ways:

- The preferred method would be to return it to the reservoirs from which it was produced where it would aid in maintaining reservoir pressure. Pilot projects are already in progress on the Federal OCS and it is expected that these projects will be expanded so that all produced water will be reinjected. See sections I.B., I.D.10., and IV.A.1.d.
- Another possibility is that it could be disposed of in onshore waste water disposal wells under conditions approved by the State of California that ensure protection of water resources.
- A third possibility is to dispose of produced waste water in the sea. Disposal points could be near shore in State waters or offshore in Federal waters. Both State and Federal regulations concerning the quality of water disposed of in this manner are increasingly stringent to protect marine life. (See section IV.A.1.d.)

All three disposal methods would be in keeping with existing State and Federal Water Standards.

(3) Gas Handling

The design of gas treating facilities will depend on the gas produced and its content. A typical design is discussed below and is shown on figure I-23.

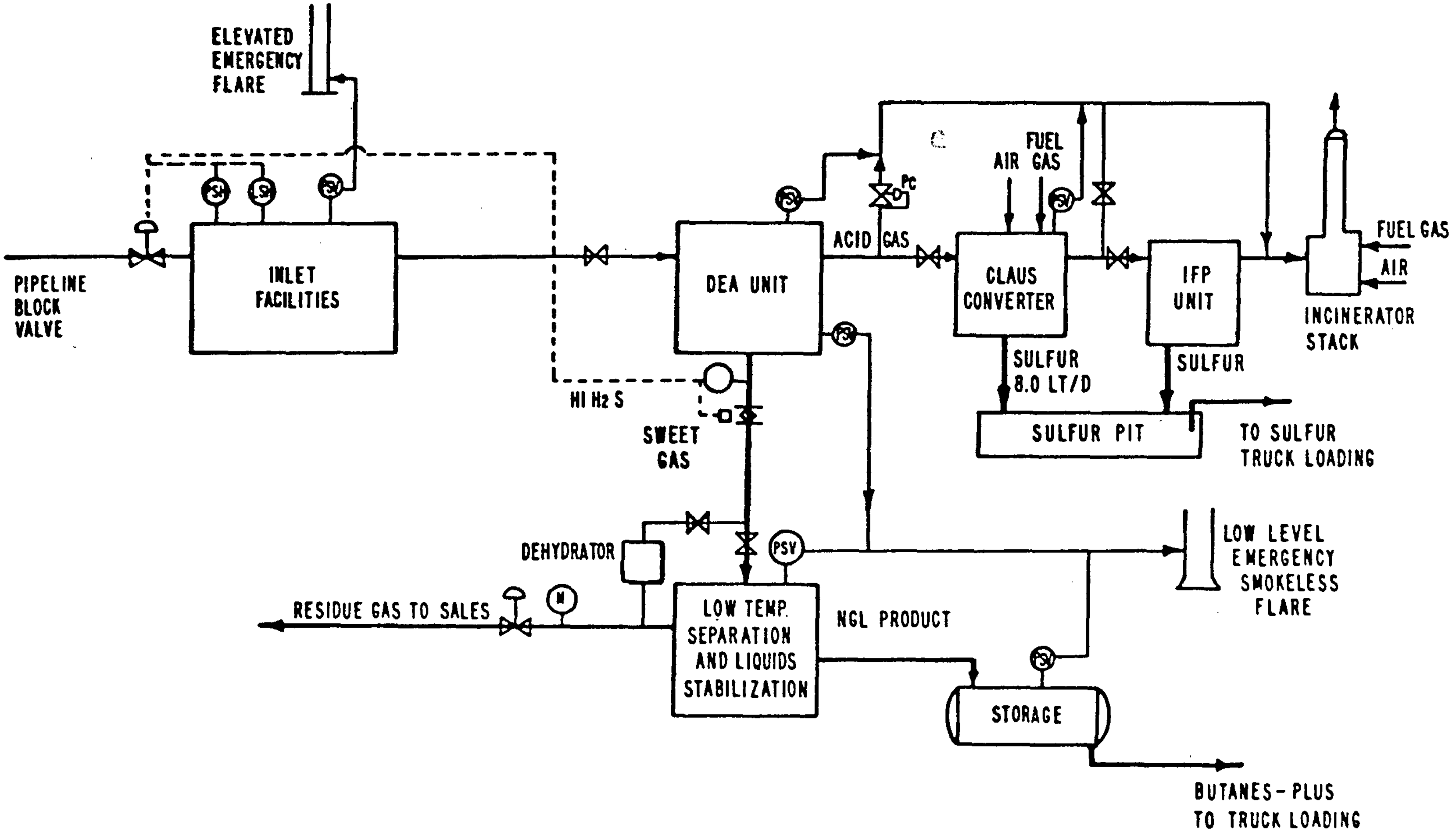


FIGURE I-23

TYPICAL GAS TREATING FACILITIES

Gas treating facilities can be designed to remove liquid hydrocarbons, carbon dioxide (CO_2), and if present, hydrogen sulfide (H_2S) from the produced natural gas. The gas would flow from the inlet facilities to a single-train diethanolamine (DEA) plant where hydrogen sulfide and carbon dioxide would be removed, if present. The H_2S and CO_2 would be absorbed chemically in the DEA solution. After the absorbed gasses are removed from the DEA solution by heating, they would flow to facilities which would convert the hydrogen sulfide to elemental sulfur. Tail gas facilities can be installed as necessary for final cleanup prior to gaseous impurities being incinerated. Sulfur could be stored until trucked to market. The low H_2S content gas from the DEA plant would flow to hydrocarbon recovery facilities which have been designed to remove butanes and heavier hydrocarbons from the gas stream prior to sale. These liquids would be removed by mechanical refrigeration of the inlet gas followed by depropanization of the raw liquids. The liquids would be stored under pressure until trucked to market. Residue gas would be sold to a gas pipeline company. The sulfur removal facilities (if H_2S content required such facilities) and vapor incinerator would be designed to comply with all applicable air quality regulations. Additional design features for environmental protection include provisions for recovering and incinerating any vapors that might be released while vessels are draining or blowing down or from the operation of safety relief valves. A smokeless emergency flare stack would be provided. Such facilities are designed to use low H_2S content gas for process fuel.

Crude oil from certain zones within the Santa Ynez Unit is expected to have a maximum H_2S content of 4 percent, whereas the crude oil from other zones in the Unit has a very low H_2S content. The H_2S content of all existing Santa Barbara OCS production is low (less than 0.1 percent).

Special instructions and contingency plan requirements for operations in an H_2S environment are being prepared by the Geological Survey for inclusion into OCS Order No. 2. As an interim measure pending amendment of OCS Order No. 2, the Geological Survey on August 26, 1974 issued a Notice to OCS Lessees and Operators containing these H_2S requirements.

(4) Sulfur and Gas Liquids

The butane-plus product separated from the inlet gas would be stored in horizontal, cylindrical tanks until it is pumped to truck loading facilities. Vapors from the truck loading operations would be returned to the storage tanks in a vapor return line.

Liquid sulfur from the sulfur recovery units would be similarly stored and removed from the site by truck.

(5) Central Control

A central control room would be provided to monitor and control the oil and gas facilities. Important operating variables would be transmitted to the central room for display. The Operator would have a complete current status picture before him and be able to make any necessary adjustments in flow patterns.

(6) Waste Handling and Watershed Protection

Biological wastes would be disposed of in existing sewer lines if available or, through septic tanks and by subsurface leaching in compliance with County Health Department standards. Trash and garbage from operations at the site would be stored in appropriate containers and transported by truck to existing disposal areas.

Surface runoff water would be handled in a proper manner to assure watershed protection. All drainage facilities would be inspected and approved by the appropriate (Santa Barbara or Ventura) County Flood Control Engineers.

Earthen dikes, designed to conform to the Uniform Fire Code and local codes, would be constructed around the crude storage tanks. These dikes would contain crude and product spills in the event of a tank rupture.

If due to an accident, equipment failure or other cause, oil from an onshore facility could reasonably be expected to be discharged into or upon the navigable waters of the United States or adjoining shorelines in harmful quantities, the facility would have to be designed and operated in compliance with the Environmental Protection Agency's regulations governing oil pollution prevention from non-transportation related onshore facilities (40 CFR, Part 112).

(7) Water Supply and Fire Protection Systems

Water supply wells would be required in the various onshore treating and storage areas to provide water for irrigation, fire-water storage, and sanitary uses, unless a municipal supply were available. Storage tanks would be required for fire-water storage. If hydrologic conditions were such that the drilling of and producing from water wells would be detrimental, water would have to be obtained elsewhere and transported to the onshore site, or another onshore facility site would have to be chosen.

Fire protection equipment would include separate but inter connected fire-water loops for the oil and gas facilities, foam generating equipment, and numerous hand and wheeled dry chemical fire extinguishers. Separate sprinkler systems could also be provided for wetting down a buffer zone on the periphery of the facilities.

The fresh water requirements for operation of an onshore facility are established to be about 20 acre-feet per year.

b. Offshore

(1) Treating Facilities

Treating facilities, whether installed onshore or offshore, require generally the same equipment and processing. Disposal of gas, in a practical manner, requires transport by pipeline to shore at some point, so it is doubtful if offshore gas-treating facilities would be considered. The installation of other treating facilities offshore would depend to a large extent on the nature of the production. For example, if produced water forms an emulsion with the crude oil that is difficult to break, it is doubtful that the use of expensive offshore space required for heater-treaters and/or electric dehydrators could be justified. Similarly, if produced water was to be reinjected, or disposed of to the sea, the size of the facility required to produce water of sufficient quality for either purpose would determine the practicality of an offshore facility.

A choice between offshore and onshore treating facilities would therefore be largely based on environmental and economic consideration. Factors influencing the decision would be water depth, platform cost versus pipeline cost, the type of platform (floating versus bottom founded), and the overall development procedure for the area. An important consideration in the development procedure would be the means of delivery of crude oil to a refinery; pipeline, offshore tanker loading, etc.

Any offshore treating facilities would necessarily be constructed and operated in conformance with all applicable regulations in a manner similar to drilling and production vessels or platforms. The necessary State and local approvals (i.e. Coastal Zone Commission) would be required for onshore facilities.

(2) Storage

At least in the initial stages of production from an offshore field, offshore storage may be provided by barges or tankers moored near a production facility and receiving the production from the facility. Mooring facilities could be simple, following normal vessel mooring procedures, or they could be more complex as discussed in section I.D.9. If permanent floating storage facilities were considered, these more elaborate procedures would undoubtedly be followed.

A possibility exists that offshore bottom-founded storage facilities could be used. As for treating facilities, the decision between onshore and offshore storage facilities would largely be determined by economics and the other considerations mentioned in section I.D.8.b.(1).

9. Offshore Loading Terminal

Offshore loading terminals are a possibility for shipping oil as they may be safer and more economical than onshore docking. They also permit the use of larger tankers, but larger tankers will probably not be a consideration in the Channel area since it is expected that all production will be utilized, if not locally, at least domestically. There are presently seven nearshore loading terminals in the Channel area. A significant increase in Channel production would require the consideration of adding new terminals or the modification of existing ones.

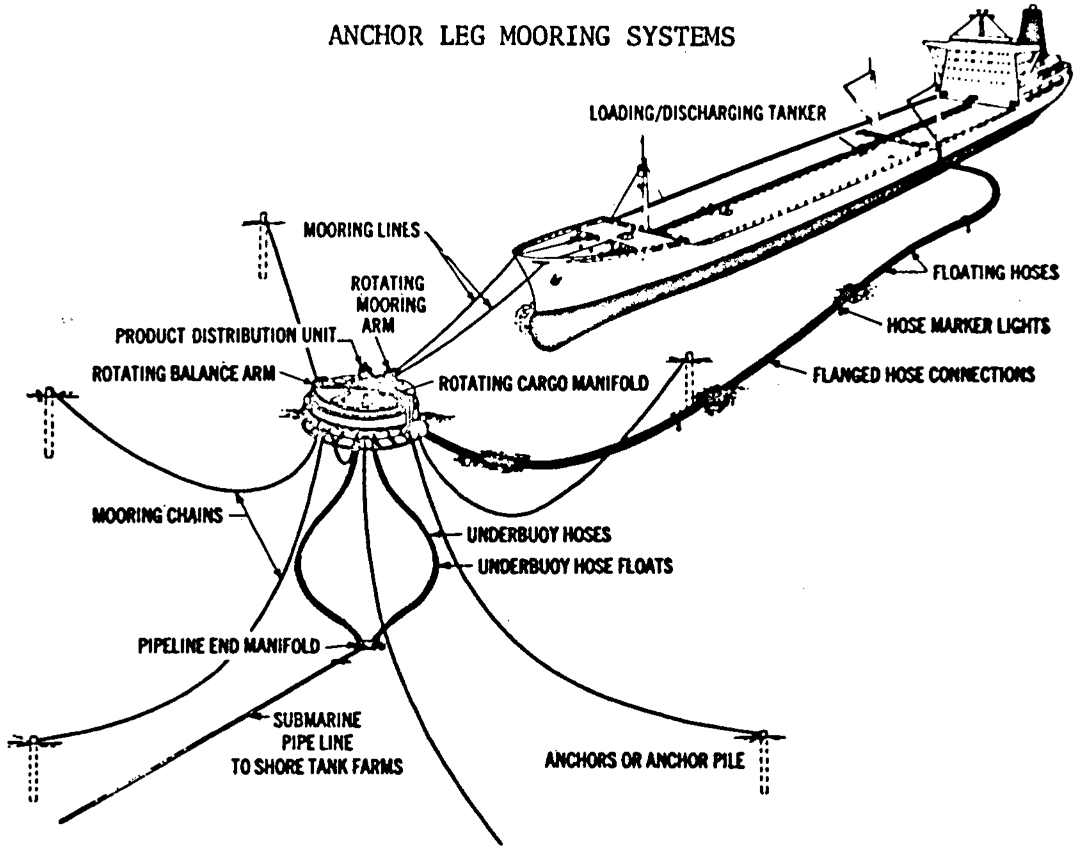
Several types of offshore loading terminals have been designed, some are under construction, and many are in operation throughout the world. Most of the newer systems consist of a single buoy to which the receiving vessel (tanker or barge) is moored. This allows the vessel to swing around the buoy according to wind and current effects. The buoy is securely anchored to the ocean floor using either a single anchor leg system or a catenary anchor leg system(multiple anchor chains). The anchor lines are fixed to structures driven or cemented in the ocean floor to prevent all but small lateral movement of the buoy. The delivery pipeline from the crude oil storage facility terminates below the buoy and a flexible delivery line from the pipeline runs either to the buoy or terminates in a floating hose system at the surface. If the flexible delivery line terminates at the buoy, the floating hose system runs from the buoy on the water surface. Examples are shown on figure I-24.

The receiving vessel picks up the floating hose and connects it to its receiving manifold. The proper valve sequence is completed and pumping starts from the storage facility. The single buoy mooring system is adequately provided with swivel joints, valves, and safety devices to provide for rotation of the vessel and hose system around the buoy and to prevent pollution.

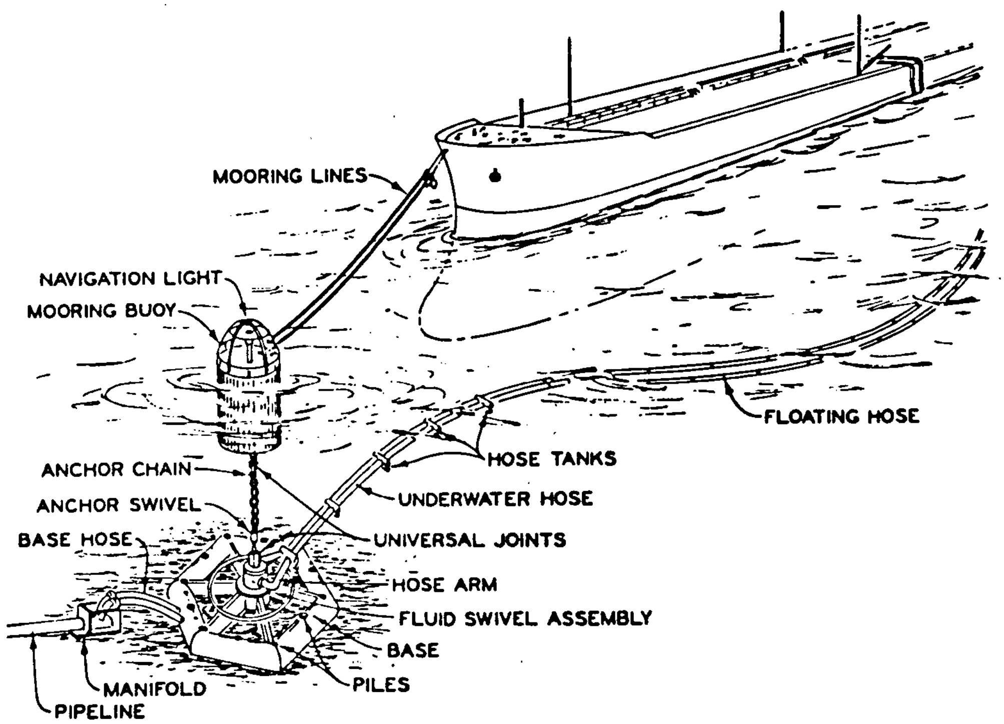
Several variations on the principles involved have been made. The newest system, especially designed for North Sea exposed locations, has been launched by Shell U. K. Exploration and Production Ltd. It is designed to float in 280 feet of water over the Auk field 186 miles east of Scotland and to be capable of loading in 12-foot waves and 20-30 mph winds. The buoy is 243 feet in height overall and will project 72 feet above the water. Production from the production station 6,500 feet away will travel through a 10-inch concrete coated pipeline terminating in a flexible armored rubber hose which lead to the bottom of the buoy. Steel piping in the

FIGURE I- 24

ANCHOR LEG MOORING SYSTEMS



A - Schematic of catenary anchor leg mooring (CALM) system.



B - Schematic of single anchor leg mooring (SALM) system.

Source: Seadock, Inc. (Also presented at the Sixth Annual Offshore Technology Conference, Houston, Texas, May 6 - 8, 1974) hull of the buoy will then carry the oil to a flexible hose delivery system. The surface portion of the buoy consists of a massive fender structure. The deck of the fender structure contains the delivery hose reels and handling system. The buoy contains a turntable system to which the vessel moors allowing it to remain in the same relative position to the buoy regardless of wind and wave direction. The buoy is topped by a helicopter landing deck and suspended from this deck are living quarters for maintenance men.

10. Enhancing Recovery from Oil Fields

Section I.C. discussed briefly the various general methods of obtaining production from the Federal OCS in the Santa Barbara Channel. Most of the possible potential activities required to do this have been described above in section I.D. The one topic that has not been covered is the possible increase in production from producing reservoirs by applying improved technology and equipment. This is a subject difficult to assess since it covers a very broad range of possibilities. Also, it is a field that is constantly changing, and in addition, any improvement derived would depend largely on reservoir characteristics and would probably require detailed studies to evaluate.

Appendix I-2, subsections I.G.1., 2., and 3., describe some of the methods of this nature used in general oil field practice. Their utility in offshore operations will be discussed below.

a. Mechanical Methods

Mechanical methods is probably a misnomer, but it conveniently describes methods used to improve rates of production, ultimate production and/or the economics of production without altering reservoir characteristics. These methods are constantly improving and a prudent operator will take advantage of new tools and procedures as they develop. All of these techniques are now in use in the Federal OCS. It is probable that improvement in present techniques would not involve radical changes in present procedures and none would require additional offshore installations. Improvement in the techniques, which will undoubtedly occur, will result in incremental increases in production rates and/or ultimate production. Some will improve the economics of production which will result in a longer economic life for the field and therefore result in higher ultimate production. Some possible areas in which improvements are most likely to occur (by no means a complete list) are given below:

- Drilling and Completion Fluids
- Clean-up Fluid
- Liner Design and Sand Control Techniques
- Artificial Lift Methods and Pump Design
- Wax and Scale Control
- Emulsion and Water Treatment

b. <u>Production Stimulation</u>

Stimulation techniques are used to improve reservoir characteristics, at least in areas surrounding the well bore, to improve production rates and increase ultimate production from the reservoir. In some cases these methods permit production from reservoir which would otherwise not be producible. Most of the stimulation methods require only one treatment, or periodic treatments, and would not require the installation of additional permanent installations. Whether or not any of these techniques are practical for a particular field depend on reservoir characteristics. The reservoirs now in production in the Federal area of the Santa Barbara Channel do not exhibit characteristics suitable for present stimulation techniques, but additional exploration may discover suitable reservoirs. Given the proper reservoir conditions any of the techniques given in Appendix I-2 would be practical for offshore use. A possible exception would be steaming techniques since: (i) steam generating equipment is sizable and would require platform space, although portable units are available and could be designed for vessel mounting; (ii) there may be excessive heat loss through the water leg portion of the well bore or through piping required to reach the wellhead.

c. Secondary Recovery Techniques

These techniques are discussed in Appendix I-2 and given the proper reservoir conditions most of them would be suitable for offshore applications. At present, a pilot water flood project is in progress in the Dos Cuadras field of the Federal OCS and it is expected to be expanded.

Any large scale injection project, particularly a gas injection project, may require additional offshore installations.

It is probable that pumps for water injection could be mounted on platforms in existence, but a large scale project might require additional platforms. Gas compression installations for gas injection would almost certainly require more platform space. It is also likely that, in either case, additional wells for use as injection and/or recovery wells might be necessary, however, depleted existing wells can be converted to injection wells.

Other secondary recovery methods now in use, except miscible fluid injection which is really a modification of either water or gas injection, are not likely to be used for offshore applications.

The advantage of secondary recovery techniques is, of course, to improve the utilization of natural resources. It can be expected that recovery of the oil in place can be increased by 25 to 30 percent over the recovery available by primary methods.

E. Estimation of the Number of Facilities Required in Implementing the Various Means of Developing the Santa Barbara Channel

- Minimization of the Number of 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 a proliferation of facilities in the area with duplication of efforts and little overall coordination. As a result, along portions of Highway 101 today, there is a series of oil production facilities; some are abandoned and some are in poor repair (none handle OCS production). This type of development detracts from the natural beauty of the area and is responsible for some of the local objections to further oil development of the Channel. There are, however, in the same vicinity, newer, better maintained facilities well-screened from view from the highway, i.e., the two onshore facilities handling OCS production and the one proposed for the Santa Ynez Unit OCS production.

As an alternative to this traditional piecemeal approach, future Federal and State oil development of the Santa Barbara Channel could be aimed at minimizing the number of facilities and their environmental impact. Accomplishment of these goals will require a better coordinated and unified approach among operators. All onshore facilities could be concentrated in two or three areas which are already industrially developed. The remaining existing oil production facilities could be phased out gradually and the terrain returned or restored to more compatible uses. The number of offshore platforms could be held to a minimum and subsea completions could be required whenever feasible.[1]

The precedent for such a coordinated production plan exists in the "unit concept". Under a unit agreement, no longer can operators work independently but they must work together to develop a "unit" or a group of adjacent leases. The unit concept has resulted in various economies of scale and thus has reduced total system costs.

Unitization also has reduced the environmental costs associated with development. Although each facility is larger than it otherwise would be, unitization has reduced the number of required facilities so much that the total environmental impact of development has been reduced. Because of the reduced number of required facilities, unitization has also allowed easier inspection of facilities and, it has allowed the operators to be more able to reduce adverse environmental impacts.

A second example of coordinated action by operators is in the area of response to oil spills. Oil spill containment and cleanup responsibility and costs in the Santa Barbara Channel are presently shared by all operators under the Clean Seas, Inc. organization.

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

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1 By notice in the Federal Register of January 27, 1975, (40 FR 4028) the Department of Interior requested comments as to the current status of technology in subsea production systems. Comments were also requested as to the impacts that would result from requiring subsea completions as a condition to granting some OCS leases. (See section I.D.6.)

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 those 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. The impacts that would result from the construction of a pipeline from the Ventura area to the Los Angeles-Long Beach area is discussed in section III.J.2.a.

- Possible Number of Facilities

The number of additional drilling and production facilities that might be installed in the Channel OCS depends on the means that may be utilized to develop the Channel. The four approaches as listed in the preface or combination thereof, tend to categorize possible levels of OCS activity: (1) development of existing producing leaseholds; (2) development of existing leaseholds on which a well has been declared capable of producing in paying quantities not presently developed; (3) exploration and development of existing leases on which no discoveries have been made; (4) offering additional lands for lease, exploration and development.

The operations and facilities that might result from these four possible levels of activity are discussed in the following subsections and concluding this discussion the possible facility requirements are summarized in table I-1. (See tables III-7 and III-8 for a hypothetical 40-year facility and activity projection)

1. Development of Existing Producing Leases

Development of existing producing leaseholds, OCS-P 0166, OCS-P 0240, and OCS-P 0241, which are in the Dos Cuadras and Carpinteria offshore fields, would necessitate few additional permanent facilities. Based upon the technical evaluation of the rejected application for Platform C and the pending application for Platform Henry, it is estimated that the two present onshore facilities could handle any additional production which might result from such platforms. Additional pipelines would not be required except for short segments tying into the existing pipelines. See pocket plate 1 for locations of the producing leases, the five existing producing platforms, and the two locations at which platforms Henry and C were originally proposed. No basis exists at the present time for anticipating any additional platforms on lease OCS-P 0166.

2. Development of Leased Areas with Discoveries

The number of mobile drilling rigs required to further explore these areas with discoveries would vary between three to five but the availability of the type rigs required was very limited as of December, 1975. It might take five or more years to build the rig fleet to full capability. It is premature to attempt to predict with reasonable accuracy the number and location of platforms that might be required for drilling and production. The number of such facilities can only be given in general ranges.

It is possible that most, if not all, production from all the presently known potential field areas, except for the Santa Ynez Unit area production, could be handled by existing onshore treating and storage facilities. The Mobil Rincon Facility is designed to accommodate considerable expansion. A major portion of the production to be handled by a common onshore facility could be gathered into one set of pipelines coming to shore.

The leased areas with discoveries (potential fields) are the Santa Ynez, Pitas Point, and Santa Clara Units and the discovery area in leases OCS-P 0202 and 0203 with Mobil as lease holder and operator of both leases. One unit, the Oak Ridge Unit, presently does not have a discovery within its boundaries. In each of these potential fields the Geological Survey has officially declared exploratory wells as discoveries capable of being produced in paying quantities, based on well test results. (See plate I for location of leased areas, units, and discovery areas; the discovery areas are shown as potential oil fields.)

- <u>Santa Ynez Unit Discovery Area</u>

The proposed general plan of development for this 17-lease, 83,037-acre unit is covered by the Environmental Impact Statement (FES-74-20) dated May 3, 1974. The proposed initial development, approved August 6, 1974, by the Department of the Interior (see appendix I-1 at the end of this section I), consists of: a platform in 850 feet of water, lease OCS-P 0188 on the Hondo potential field; an oil pipeline and gas pipeline from the platform to the onshore treating and storage facility; an onshore treating and storage facility; and modification of an existing marine tanker loading terminal. An offshore treating and storage terminal is included in the proposal as an alternative to the proposed onshore treating and storage facility. There would be need for this offshore facility only if the operator were not allowed to install the onshore facility. (See figure I-25 for the location

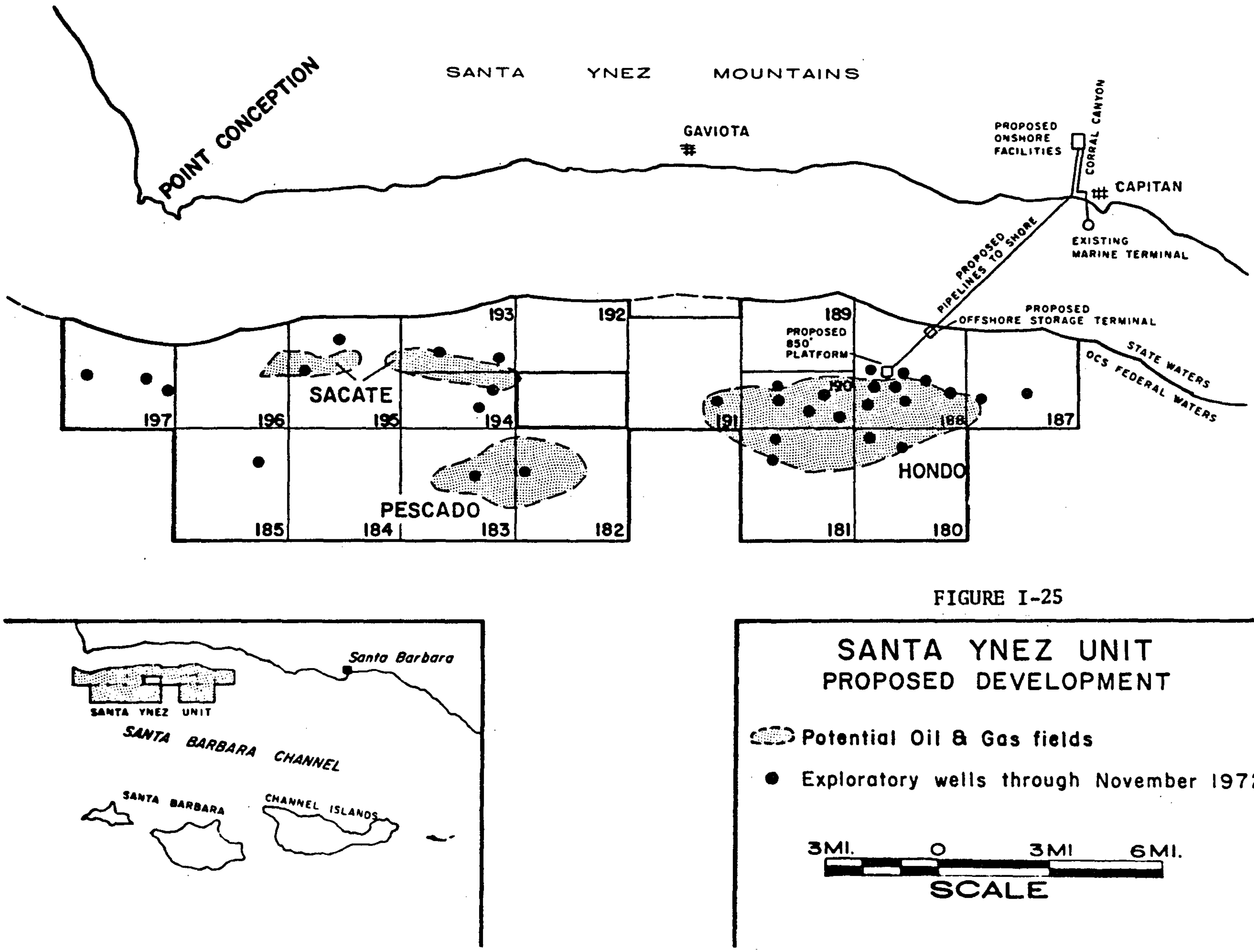

FIGURE I-25

SANTA YNEZ UNIT
PROPOSED DEVELOPMENT

Potential Oil & Gas fields

● Exploratory wells through November 1972

3MI. 0 3MI 6MI.
SCALE

of the proposed initial platform and related facilities.)

Further development of the Hondo potential field might consist of a platform or some type of submerged production system on lease OCS-P 0190. Production from this facility would be pipelined 1 to 2 miles to the initial 850-foot platform and then to the onshore treating and storage terminal via the pipelines that would already be installed for the initial platform. After installation and production from these two production facilities it might be determined that a third production facility would be required. This possible third production system might be a surface platform or a submerged production system.

Development plans in the Pescado potential field are dependent upon the results of additional exploratory drilling. It appears that Pescado development might consist of a platform or a submerged production system in conjunction with a surface support structure.

Development of potential hydrocarbons in the Sacate field is also dependent on the results of additional exploration drilling and it would appear that Sacate development might require one platform.

Other portions of the Santa Ynez Unit may prove to be productive after additional exploration drilling. Selection of the type of facility that would be used would be dependent upon the water depth and proximity to existing facilities.

The best estimate, based on currently available geologic data, is that three to five widely dispersed platforms would be required to develop the known potential fields within the Santa Ynez Unit. The platforms would probably be supplemented by one or more subsea production systems. Based on current data, the facilities proposed along with the initial proposed platform (pipelines to shore, onshore treating and storage facility, and the existing near-shore marine loading terminal to be modified) are designed for the capacity to handle the anticipated peak oil and gas production from the entire Santa Ynez Unit.

- Pitas Point Unit Discovery Area

Development of potential hydrocarbons in the area is dependent on the results of additional exploration drilling. The Unit Operator proposed to drill an 18,000-foot well on lease OCS-P 0234 several years ago. The drilling of this proposed deep well, although delayed for various reasons, would contribute greatly toward a better understanding of the requirements for the development of this discovery area.

It appears that one to two platforms with supporting submerged production systems and associated pipelines may be required to develop this potential field. It is probable that one of the existing onshore treating and storage facilities (i.e., Mobil's Rincon facility) could be expanded to handle Pitas Point Unit production.

- Santa Clara Unit Discovery Area

Present projections, although premature, since exploration is not completed, indicate a possibility of one to four platforms in the Santa Clara Unit area. In areas where oil reserves would not justify the cost of a platform or where shipping lanes are involved, satellite ocean bottom wells might be completed with flow lines extending to the nearest platform. The number of such satellite ocean bottom completion wells may range from zero to five per platform.

It is likely one set of pipelines to shore would transport the production to an existing onshore treating and storage facility or to a new onshore treating and storage facility that would probably be located between Port Hueneme and Ventura.

- Discovery Area Contained in Leases OCS-P 0202 and 0203 (Hueneme Offshore Field)

This discovery area is not unitized. Mobil, the lessee and operator of leases OCS-P 0202 and OCS-P 0203, has submitted a preliminary notice, in brief letter form, of a proposed platform on lease OCS-P 0202 (see plate I for proposed platform location). Further exploratory drilling is required to determine if another platform would be required to develop this potential field. The notice is being held in abeyance pending completion of the application and this Channel Environmental Statement. Submerged production systems might be used as a supplement to the proposed platform. The production would be pipelined to shore to an existing treating and storage facility or to a new treating and storage facility that would be located in Ventura County.

- Summary of Estimated Facility Requirements for Undeveloped Leased Areas with Discoveries

The total development of the undeveloped discovery areas might require six to twelve platforms with associated pipelines, one to three onshore treating and storage facilities, and zero to twelve submerged production systems.

3. Leased Areas without Discoveries

The Oak Ridge Unit and other leases are included in this category. Although a few leases have been fairly well disproven as potential sources for hydrocarbons, the majority of the leases are far from being completely explored and considerable exploratory drilling is required to determine the hydrocarbon potential of these leases. The number of mobile drilling rigs required to explore the leased areas without discoveries may vary from three to five. There are 36 OCS Channel leases on which no exploratory wells have been drilled; eight of these undrilled leases are in units on which discoveries have been made. An estimate of facilities, based on knowledge of and experience in the Channel, that might be required to develop possible discoveries is as follows: one to four platforms with associated pipe lines, zero to one onshore treating and storage facility, and zero to four submerged production systems.

4. Lease, Explore and Develop Presently Unleased Areas

It is most difficult to estimate on any rationale the number of new drilling and production facilities which may be required to explore and develop this unleased area (see plate 1 for location of unleased areas). The number of mobile drilling rigs required could range from three to five and the number of eventual platforms required could range from one to three, supported by zero to three submerged production systems (subsea completion systems). Additional pipe lines would be required and zero to one additional onshore facility may be required. Present onshore facilities in existence in State and Federal operations could be available.

A major portion of the unleased area is located in the deepest parts of the Channel and at water depths beyond present operating capabilities, and a part of it is in the Federal Ecological Preserve and the Federal Buffer Zone in which operations are not presently allowed (see plate 1 for the location of the deep water basin and Ecological Preserve in the unleased area). Although a part of the Federal Ecological Preserve area is considered geologically the most promising of the unleased area (section II.B.5.e.), the above estimate of one to three platforms to develop the presently unleased areas, is based on the assumption that the Ecological Preserve and Buffer Zone will remain excluded from development. If this platform estimate were to be based on the possibility that this area could be available for exploration and development, the estimate probably should be doubled to from two to six platforms. (See page ii-10 in the Introduction for a discussion as to the history and purpose of establishing this Federal Ecological Preserve and plate 1 for its location.)

5. Summary Tabulation of the Estimated Number of Possible Facilities at the Four Levels of Development

Following is a tabulation (table I-1) of the number of facilities estimated and discussed in 1, 2, 3 and 4 above. These estimates are based on geologic potential, past statistics (where applicable to the Santa Barbara Channel), published literature and Geological Survey engineering and geologic data. Admittedly, these estimates are preliminary and there are almost infinite combinations of possibilities that could substantially alter any of these broad ranges.

Refer to section I.F.1.c. for a summary of the existing Santa Barbara Channel oil and gas facilities.

See table III-7 and III-8 in section III.N. for a hypothetical case over a 40-year period as to the wells, platforms, production, revenues, and employment that might result from the potential levels of Channel development.

TABLE I-1

Estimated Number of Required Additional Facilities

Potential Levels of Development	Platforms		Onshore Facilities		Submerged Production Systems		Number of Pipelines to Shore		Miles of Offshore Pipelines		Exploratory Wells		Development Wells	
	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High
1. Completely develop Producing leases	2	2	0	0	0	2	0	0	5	8	0	5	30	50
2. Develop existing lease discoveries														
a. Santa Ynez Unit	3	5	1	1	0	5	1	1	5	20	10	20	60	140
b. Pitas Point Unit	1	2	0	0	0	2	0	1	3	7	2	10	20	50
c. Santa Clara Unit	1	3	0	1	0	3	0	1	10	15	5	15	20	60
d. Lease 0202 & 0203 discovery areas	1	2	0	1	0	2	0	1	4	10	2	5	20	40
Total of 2	6	12	1	3	0	12	1	4	22	53	19	50	120	290
3. Explore and develop leases without discoveries	1	4	0	1	0	4	0	1	5	30	15	60	20	100
Total of 1, 2, and 3 (all leased areas)	9	18	1	4	0	18	1	5	32	91	34	115	170	440
4.*Lease, explore, and develop unleased areas	1	3	0	1	0	3	0	1	5	20	15	50	20	80
Total of 1, 2, 3, and 4 (all leased and unleased areas	10	21	1	5	0	21	1	6	37	111	49	165	190	520

*These estimates given in 4. above for unleased areas do not include the estimated number of facilities required to develop potential reserves of the Ecological Preserve and Buffer Zone; if included the estimated ranges in 4. above probably should be at least doubled (i.e., the 1 to 3 estimated platform range would become 2 to 6).

Presently there are five OCS Santa Barbara Channel Platforms[1] and two pipeline bundles which transport the total OCS Production to two onshore treating and storage facilities. The oil is then transported to refineries by marine vessels and by a land pipeline (operating at capacity) to the Los Angeles - Long Beach refinery area.

It is estimated that the additional oil from further Santa Barbara Channel development, if transported to refineries by marine vessels, would increase marine traffic in the area by 5 to 10 percent. The maximum capacity of the barges or tankers would be approximately 175,000 barrels. However, if a new onshore pipeline from the Santa Barbara Channel area to a refinery area were built, the additional oil from further channel development, and most if not all the oil from existing Santa Barbara Channel development could be transported to refineries by land. This would result in a considerable decrease in marine traffic in the area. See section III.J.2.a. for further discussion on the existing pipeline to the Long Beach-Los Angeles area and the consideration for construction of an additional pipeline to this refinery area.

The majority of the above-estimated number of facilities would be installed within the next 10 to 15 years if operations were allowed to progress at a regular pace. The normal life of a platform would be 15 to 25 years, i.e., Platform Harry in State waters off Point Conception was removed in May, 1974 from the Channel after 14 years of productive life. The normal life of an oil field is 20 to 40 years. Certain Santa Barbara Channel existing platforms will be nearing the end of productive life within the next 10 years; therefore, several of the five existing platforms may be removed prior to the installation of the above total predicted additional platforms.

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[1] There are seven Santa Barbara Channel platforms in State water leases. See plate 1 for the location of the 12 existing Santa Barbara Channel Platforms (5 in Federal waters and 7 in State waters). Note plate 1 shows 8 State platforms, however, in May 1974, Platform Harry was abandoned and removed. Refer to section I.F.1.c. for a summary of existing Santa Barbara Channel oil and gas operations and facilities.

Inasmuch as the production from some existing platforms and fields will be greatly diminished within the next 5 to 10 years, and terminated within the next 10 to 15 years, existing onshore treating and storage facilities will have the capacity to handle a portion of the new production.

6. Estimated Production from Possible Levels of Development

Table I-2, which follows, reflects estimated production that might be obtained by 1) developing the existing producing leases, 2) developing the existing leases on which discoveries have been recognized, 3) exploring and developing leases without discoveries, and 4) offering additional areas for lease. (See table III-7 for a hypothetical 40-year production projection)

The table I-2 figures are only to give a rough estimate of how much oil might be produced as a result of the various levels of Santa Barbara Channel oil development. A detailed classification of table I-2 resource estimates, in accordance with Geological Survey nomenclature, immediately follows the table. These estimates are based on geologic potential and past statistics as to amount of in-place and recoverable hydrocarbons per square mile (volumetric method). No proprietary data were used in calculating these estimates. However, some task force members had access to and knowledge of proprietary geologic and engineering data from the Channel area as part of other activities and work assignments, i.e., hydrocarbon formation test information gained from exploratory wells. Reasonably accurate reserve estimates for even the discovery areas (potential field areas) can be calculated only after additional exploratory drilling and some production has taken place. Information gained from further drilling could alter these estimates extensively. The calculations of a Geological Survey OCS Evaluation Group were considered in the preparation of table I-1 estimates. This Geological Survey OCS Evaluation Group made some preliminary unpublished estimates dated February 1974, resulting in the following OCS Santa Barbara Channel oil reserve estimate summary:

	Recoverable Oil	Oil in Place
Low Estimate	1,230 million bbls.	4,920 million bbls.
High Estimate	1,875 million bbls.	7,500 million bbls.

TABLE I-2

Estimated Production from Possible Levels of Development

(A more detailed classification of table I-2 resource estimates is presented on the next page)

Potential Levels of Development	Recoverable Oil (in millions of barrels)			Gas (in billions of cubic feet)		
1. Complete development of producing leases (OCS-P 0166, 0240 and 0241)*	200	to	300	100	to	150
2. Develop existing lease discoveries (including the estimated 730 to 1,100 million barrels from the Santa Ynez Unit)	780	to	1,300	390	to	650
3. Explore and develop leases without discoveries	40	to	200	20	to	100
Total of 1, 2, and 3 (all leased areas)	1,020	to	1,800	510	to	900
4. Lease, explore, and develop unleased areas**	40	to	150	20	to	70
Total of 1, 2, 3, and 4 (all leased and unleased areas)	1,060	to	1,950	530	to	970

* "Complete development of producing leases" represents the total estimated recoverable oil from these three producing leases. Approximately 115 million barrels of this expected recoverable oil has already been produced as of September 1974.

** "Unleased areas" do not include the estimated undiscovered recoverable resources of the Ecological Preserve and Buffer Zone; if included, the estimated ranges in 4. above for unleased areas probably should be at least doubled, for a part of the Ecological Preserve area geologically shows considerable hydrocarbon potential. (i.e., the 40 to 150 million barrels of oil range would become 80 to 300). See page ii-10 in the Introduction for discussion on establishing the Preserve and Buffer Zone and plate 1 for location.

The 1,060 to 1,950 million bbls. estimated range of total recoverable oil from the Santa Barbara Channel OCS contained in this manuscript in table I-2 is in general accord with the above Evaluation Group Preliminary Estimate Summary.

Classification and Definition of Table I-2 Resource Estimates

To discuss resource potential, consistent terminology must be used. Through a joint effort of the Bureau of Mines and the Geological Survey, both bureau-level agencies in the Department of the Interior, nomenclature has been jointly adopted to clarify such terms as mineral resources and mineral reserves (USDI, 1974). The following resulting definitions of mineral resources and reserves are related to the degree of geologic knowledge and economic feasibility:

- A *mineral resource* is defined as a concentration of naturally occurring solid, liquid, or gaseous materials in or on the Earth's crust in such form that economic extraction of a commodity is currently or potentially feasible.
- A *mineral reserve* is that portion of the identified resource from which a usable mineral and energy commodity can be economically and legally extracted at the time of determination.
- *Identified resources* are specific bodies of mineral-bearing material whose location, quality, and quantity are known from geologic evidence supported by engineering measurements with respect to the demonstrated category.
- *Undiscovered resources* are unspecified bodies of mineral-bearing material surmised to exist on the basis of broad geologic knowledge and theory.
- *Measured reserves* are material for which estimates of the quality and quantity have been computed, within a margin of error of less than 20 percent, from analyses and measurements from closely spaced and geologically well-known samples sites.
- *Indicated reserves* are material for which estimates of the quality and quantity have been computed partly from sample analyses and measurements and partly from reasonable geologic projections.
- *Inferred reserves* are material in unexplored but identified deposits for which estimates of the quality and size are based on geologic evidence and projection.

The Table I-2 resource estimates for the four potential levels of development can be generally categorized as follows:

1. Complete development of producing leases - already produced reserves along with measured and indicated reserves.
2. Develop existing lease discoveries - indicated-inferred reserves.
3. Explore and develop leases without discoveries - undiscovered recoverable resources.
4. Lease, explore, and develop unleased areas - undiscovered recoverable resources.

F. Relationship of Potential Oil and Gas Activities to Other Projects in the Area

1. Ongoing Activities

a. General

The relationship of further development of oil and gas production from the Santa Barbara Channel to such other activities as shipping, commercial and sport fishing, kelp harvesting, recreation, transportation, tourism, agriculture, and mineral extraction are discussed in detail in sections II, III, and V.

b. Military Activities

Santa Barbara Channel oil and gas activities must be coordinated with all military (Navy and Air Force) activities in the area. Prior to the 1968 Santa Barbara Channel lease sale the Department of Interior conferred with the Air Force and Navy. Potential conflicts were considered and it was determined that oil and gas activities on the 110 proposed tracts (71 tracts were leased) could be coordinated with military activities. This mutual cooperation and coordination relationship has been successful with ongoing Santa Barbara Channel oil and gas, and military activities. See section II.F.6. for a description of military installations in the area.

The Navy conducts classified activities on San Miguel Island and just seaward of Santa Cruz Island. The Navy has conducted classified acoustic research projects in the Santa Barbara Channel and the Geological Survey supplied the Navy with all necessary information regarding oil and gas exploratory geophysical surveys conducted in order to avoid conflict with such military research programs. There are no submarine sea lanes or ammunition dumps in the Santa Barbara Channel.

Vandenburg Air Force Base on occasion launches missiles that pass over parts of the Santa Barbara Channel area. These overflights are limited primarily to the extreme western part of the Santa Barbara Channel. In October 1968, a detailed impact analysis was completed by Com-Consultants, Inc. The probability of platform damage resulting from missile overflight was determined to be extremely low.

See section IV.A.7. for further discussion of that missile overflight analysis and a description of missile overflight lease stipulations on certain leases.

The Point Mugu Naval Base also has a missile range, however, presently they are not firing missiles over the Santa Barbara Channel.

The Geological Survey informs all Santa Barbara Channel operators that they must coordinate their activities with the military. For example, following is an excerpt from a typical geological and geophysical permit issued by the Geological Survey:

> *The following agencies should be contacted regarding your survey:*
>
> 1. *A permit from the Army Corps of Engineers as to navigation is required and the local Commandant of the Coast Guard is to be contacted regarding operations involving loading and handling of explosives on ships, either by your company or your contractor.*
>
> 2. *You are requested to contact and cooperate with the Commander of the Third Fleet prior to commencing any offshore operations. This Command has a procedure for clearing areas for operations that under most circumstances will cause little or no delay in your work. Their address is: Commander, Third Fleet, Fleet Post Office, San Francisco, California 96610.*

In addition, if your survey is to be conducted in waters off southern California, you should contact:

3. *Commanding Officer, Fleet Air Control and Surveillance Facility, Naval Air Station, North Island, San Diego, California 92135. This office (FACSFAC) will provide charts defining Fleet operating areas and will advise the survey party of any hazardous operations which might affect survey vessels. They should be notified of when and where you will be conducting operations and will probably require daily ship-to-shore telephone calls for advice on survey locations and intentions.*

In the event your survey is to be conducted within the areas of the Pacific Missile Ranges off Point Mugu and/or Vandenburg Air Force Base (north of Point Conception) as shown on C&GS chart 5020, you should contact and cooperate with the appropriate Command. They should be notified of when and where you will be conducting operations and who they can contact in case of a schedule conflict. Their addresses are:

4. *Commander, Pacific Missile Range, Point Mugu Naval Base, Point Mugu, California 93042, Attention: Range Operations Officer (805-982-7545).*

5. *Commander, SAMTEC, Vandenburg Air Force Base, California 93437, Attention: R.O.S.F. (805-866-3603).*

The appropriate agencies to be contacted should be contacted sufficiently in advance of any operation to allow setting up a means of contact, coordination and cooperation, if required.

c. Existing Santa Barbara Channel Petroleum Operations

Further development would add to the existing petroleum operations and facilities. An estimate was presented earlier in table I-1 of the additional facilities required to further develop the Channel. Throughout this statement the existing Santa Barbara Channel area petroleum operations are described. Following are a series of cross-references for the purpose of locating the narrative, tables and figures that describe these existing petroleum facilities.

Cross-references

Introduction

In the Introduction the history of Santa Barbara Channel oil and gas development is presented, including the number of OCS exploratory and development wells drilled prior to and after the Platform A blowout. Figure 1 in the Introduction shows the existing and potential oil fields and existing petroleum facilities. Also plate 1 (in pocket) is referred to which is a Santa Barbara Channel area map showing offshore leases, existing and potential oil fields, existing petroleum facilities, and unit areas.

Section I

I.B. Present Status of Oil and Gas Operations

These existing OCS Santa Barbara Channel facilities and operations are described and accompanied by production statistics. Figure I-2 is a map showing location of core holes and exploratory wells drilled on the Santa Barbara Channel OCS.

I.E.5. Summary Tabulation of Estimated Number of Required Facilities

Under this heading, table I-1 contains estimates of the number of additional facilities required for the various means of further developing the Channel. Also enumerated are existing State and Federal Santa Barbara Channel platforms. Also here it is estimated that the additional production would result in a 5 to 10 percent increase in marine traffic unless a new onshore pipeline to a refinery area were built.

II.F.12 **Aesthetics**

A discussion of aesthetics as to oil structures in general is presented; also included is a discussion on public opinion toward oil and gas operations in the Santa Barbara Channel. Responses (in percent) are given to questions such as: "Would you say that present oil drilling in the Santa Barbara Channel is a serious problem, a problem, but not so serious; or not a problem at all?"

II.F.13 **Mineral Resources**

Oil and natural gas production data for Ventura and Santa Barbara Counties are given. Oil and gas onshore fields in the two counties is also presented and table II-54c gives the location and capacity of California petroleum refineries.

II.F.14.d. **Marine Transportation**

Shipping lanes are referred to on plate 1 and tables are referred to showing all offshore petroleum loading terminals.

II.F.14.e. **Oil and Gas Pipelines**

Oil and gas pipelines are described. Tables II-54d and II-54e list all State and Federal offshore platforms and State ocean floor completed wells, along with associated pipelines.

II.G.1. **Air Quality**

Tables II-57, 58 and 59 show emissions from existing petroleum production, refining and marketing.

II.G.2. Water Quality

d. Waste Discharges Related to Oil Production

(1) Existing Facilities and Discharges - General

The offshore production facilities in the Santa Barbara Channel are listed in table II-63 and their locations are shown in figure II-49. The tanker mooring facilities are described in table II-64 and their locations are shown in figure II-49. Discharges from various petroleum facilities onto the ocean are listed in table II-65. Locations of these discharge sources are shown in figure II-51. The above tables and figures describe and locate all existing Santa Barbara Channel platforms, pipelines, ocean floor wells, drilling and production islands and onshore treating and storage facilities.

(3) Waste Disposal at Santa Barbara Channel OCS Platforms

Under this heading is a detailed description of waste discharges (produced waste water, deck wash water and sewage effluent) from each of the five existing OCS platforms.

Section III

III.J.1 Marine Transport by Barge or Tanker

The number of ships that traverse the Santa Barbara Channel daily and yearly is given. It is estimated that further development might result in current ship traffic of 6,977 per year increasing to 7,350; approximately one additional ship traversing the Channel per day.

In summary there are 12 offshore platforms in the Santa Barbara Channel (5 Federal and 7 State). There are 10 onshore treating and storage facilities within ½ mile of the Santa Barbara Channel shoreline, 2 handle total OCS Federal production and 8 handle State onshore and offshore production. See table I-3 for a description of all existing treating and storage facilities within Santa Barbara and Ventura Counties. There are 20 Santa Barbara Channel offshore oil pipelines. These are pipelines from shore to tanker mooring facilities, pipelines from platforms to shore, and pipelines from ocean floor completed wells. The ocean floor wells are in State waters. Two of the oil pipelines are for the purpose of transporting the total OCS lease production to two onshore treating and storage facilities. There has been a total of 79 exploratory wells and 197 platform production wells (from the 5 platforms) drilled on Santa Barbara Channel OCS leases. There are presently 387 wells in production in the Santa Barbara Channel, 186 OCS Federal wells and 201 State wells (November, 1974).

Table I-1 gives the estimated number of additional facilities required to implement the various means of further developing oil production in the Santa Barbara Channel. The following tabulation compares the estimated number of required additional facilities to the number of existing Santa Barbara Channel facilities.

	Existing Facilities	Estimated Required Additional Facilities
Platforms	12	10 to 21
Onshore Treating & Storage Facilities	10*	1 to 5
Number of Exploratory Wells (OCS)	79	49 to 165
Number of Production Wells (OCS)	197	190 to 520
Number of Offshore Pipelines to Shore	20	1 to 6
Miles of Offshore Pipelines	80 miles	37 to 111 miles

*Within approximately ½ mile of Santa Barbara Channel shoreline.

In section III (table III-17) calculations are made, based on certain stated assumptions to determine such impacts as:

TABLE I-3

ONSHORE OIL AND GAS PROCESSING AND SEPARATION
FACILITIES IN VENTURA AND SANTA BARBARA COUNTIES

CO.	FACILITY	OPERATOR	DESIGN		EXISTING		SURPLUS	AGE	EXPANSION POTENTIAL	REMARKS
			GROSS	NET	GROSS	NET				
S.B.	Pt. Concep.	Union Oil	5 MB/D		3 MB/D		2 MB/D	6 yrs.	Possible	2 acre site
S.B.	Ellwood P. F. (5 mi. N of Gol.)	Burmah	7000 BWPD	1000 BOPD 2000 MCFPD	4000 BWPD	100 BOPD 600 MCFPD	3000 BWPD 900 BOPD	30 yrs.	Yes	
S.B.	Ellwood M.T. (Coal Oil Pt.)	Burmah		20,000 BOPD		4000 BOPD	16,000 BOPD	40 yrs.	No	Could relocate at Dos Pueblos
S.B.	Dos Pueblos Marine Term.	Burmah		40,000 BOPD		0	-	-	Yes	In Planning Stage
S.B.	Ellwood	Arco		9600 BOPD 10,000 MCF		4,000 BOPD 0 MCF	5600 BOPD 10,000 MCF	9 yrs.	Yes	
S.B.	St. 2793 (Gaviota)	Arco		1000 BOPD 900 MCF		150 BOPD 300 MCF	850 BOPD 600 MCF	13 yrs.	No	
S.B.	St. 308-309 (Goleta)	Arco		1000 BOPD 2500 MCF		40 BOPD 130 MCF	960 BOPD 2370 MCF	14 yrs.	No	
V.	Rincon Island (Punta Gorda)	Arco		5000 BOPD 5000 MCF		700 BOPD 100 MCF	4300 BOPD 4900 MCF	17 yrs.	No	
V.	*La Conchita Near S.B. Co. Line So. of Carp.	Phillips		27,000 BOPD		4900 BOPD	22,100 BOPD	7 yrs.	Possible	16 acre site
S.B.	Tajiguas Shore N. of S.B.	Phillips		36,000 MCFD 1000 BNGB		4000 MCFD 65 BNGD	26,000 MCFD 935 BNGD	11 yrs.	No	5 acre site
S.B.	Molino (Gaviota)	Shell	34 MCFD		2 MCFD		32 MCFD gross	40 yrs.	No	
V.	Ventura	Shell	60 MCFD		6 MCFD		54 MCFD gross	50 yrs.	No	
S.B.	Capitan	Shell							No	Insignificant
S.B.	Las Flores	Mobil	8000	800	2950	215	585 B/D	36	Feasible	1-250 B, 2-2000 B, 1-3000 B, 1-3500 B
V.	Barnard	Mobil	3000 BD	500	800	160	340 B/D	43	No	1-200 BBL, 2-2000, 1-3000 BBL
V.	Ferguson	Mobil	3000	750	750	295	455 B/D	45	No	7-3000 BBL + 1-4000 BBL
V.	Notten	Mobil	1500	100	20	15	85 B/D	43	No	Using Barnard
V.	Padre	Mobil	2500	750	1000	515	185 B/D	41	No	2-2000 BBL, 2-3000 BBL, 1-8000 BBL
V.	*Rincon	Mobil	120,000	95,000 B/D	50,000 B/D	36,000 B/D	59,000 B/D	7	Yes	
S.B.	Gaviota Plan	Std. Oil Cal.		30,000 MCFD		1100 MCFD	28,900 MCFD	11 yrs.	No (recycle?)	Abandoning or remove poss.
S.B.	Carpinteria	Std. Oil Cal.		23,000 MCFD		11,900 MCFD	11,100 MCFD	13 yrs.	Yes	Could increase throughput
V.	West Montalvo	Std. Oil Cal.						20 yrs.		Not suitable for OCS oil

*These two onshore facilities handle the total existing Santa Barbara Channel OCS Production.

- Area required for offshore and onshore petroleum facilities.
- Amount of drilled cuttings deposited on ocean floor as a result of exploration and development wells (expressed in tons and in dimensions of cuttings mounds formed under platforms).
- Amount of drilling fluid (mud) lost to ocean from exploration and development wells.
- Quantity of produced waste water as a result of platform production (disposed of by either subsurface injection or discharge into the ocean).

2. Land Use Plans, Policies, and Controls for the Area

a. California Coastal Zone Commission

The California Coastal Zone Conservation Act was adopted by Initiative of the voters in November 1972. This Act created a Commission and six Regional Commissions which prepared a "Final" plan for the Coastal Zone (the area from three miles seaward of the coast and inland to the nearest mountain range or five miles, whichever is less), and submitted this plan to the Legislature December 1, 1975. See section II.G.2.b.(2) for additional information on Areas of Special Biological Significance. The information and views of State agencies and interest groups were considered by both the Regional and State Commissions in the preparation of findings and policies. Extensive hearings were held on each element of the plan. Findings and policies were adopted by the Commission after 20 public hearings were held from Crescent City to San Diego.

The Plan[1] requires California legislative approval.

[1]Copies of the California Coastal Zone Conservation Plan may be purchased from the Documents and Publications Branch, P.O. Box 20191, Sacramento, California 95820; price $4.50.

The State Commission recommended that most of the responsibility for implementing the comprehensive coastline plan be transferred to local governments. The State Commission reserved for itself power to overrule local governments in certain areas and asked the Legislature to create a permanent California Coastal Zone Conservation Commission, although under the Act the six Regional Commissions terminate at the end of 1976.

The four areas in which the Commission proposed to retain power to override local decisions are: (1) projects granted variances to the Coastal Plan by local entities, (2) approvals of large commercial or institutional projects, (3) construction within 100 feet of wetlands or coastal streams, on floodways, agricultural land, beaches or coastal bluffs, and (4) any energy project denied approval by local entities, provided the project serves more than local needs.

The California Coastal Plan (1975, 443 p.) contains 162 proposed policies and 44 recommendations. Many of these policies and recommendations would directly affect oil and gas operations on the Outer Continental Shelf. Acceptance of the Plan under the Coastal Zone Management Act requires approval by the California Legislature and subsequent review and approval by the Department of Commerce. The reader is referred to the Plan, as published, for detailed description of proposed policies and recommendations.

Among presentations of special interest in the text of the Plan are the text descriptions of the seven subregions of the South Central Coast Region and the annotated map graphics for these regions.

Topics in the Plan relevant to offshore activities include: national and public interest in the coastal zone, ecological planning principles, oil and toxic spills, coastal waters, estuaries, wetlands, coastal land environment, coastal streams and watershed management, natural habitat areas, air quality, geologic hazards, energy and the coast, and petroleum development.

Major Findings and Policy Recommendations on offshore petroleum development are summarized on p. 9 of the Plan:

> "OFFSHORE PETROLEUM DEVELOPMENT. Plan policies would allow offshore petroleum development, provided it is part of a clearly defined energy conservation and development program for the country or for the western states, provided stringent environmental safeguards are made part of the entire exploration and production schedule, and provided there is careful planning to minimize onshore impacts.
>
> The policies also recommend revising current Federal leasing practices to provide for withholding approval of offshore petroleum development until the offshore exploration has been sufficiently completed to determine the extent of the oil and gas available and the environmental impacts from extracting it."

The reader is referred to the complete volume for expanded treatment on this and other findings, policies and recommendations. (See section IV.A.1.h. for specific policies and recommendations on petroleum development.)

b. County Zoning and Land Use Planning

County and city zoning plans and ordinances would also apply to the location of onshore pipelines and facilities. A few examples from Santa Barbara County are cited. The Santa Barbara County General Plan adopted August 17, 1965 describes proposed land use plans in potential oil and gas facility areas. "The non-urban portion lying between Ellwood Wye and Gaviota Pass is proposed for agriculture, recreation, petroleum and open range land uses." (General Plan, p. 90) While land zoned "Beach Development" (BD) by Santa Barbara County, County Zoning Ordinance 661 provides that underground and underwater structures may be permitted in BD zones subject to the issuance of a conditional use permit. With respect to treatment facilities, the Santa Barbara County "Statement of Oil Policy Relative to the Location of On-Shore Oil Facilities" adopted April 12, 1967 provides that applications to construct oil and gas handling facilities shall be subject to the provisions of a specific ordinance under the "Planned Manufacturing" (PM) zone designation.

The Santa Barbara County "Oil Policy" includes other provisions, such as the preference that enlargement of existing facilities is normally preferred over the creation of new separate sites.

Similar plans and ordinances are in effect in Ventura County.

c. Marine Sanctuaries (National Oceanic and Atmospheric Administration)

Title 15 CFR Part 922 recognizes that certain areas of the ocean waters as far seaward as the Outer Continental Shelf, or other coastal waters need to be preserved or restored for their conservation, recreational, ecological or aesthetic values. (Federal Register, June 27, 1974: Vol. 39 No. 125.)

The Secretary of Commerce (Administrator NOAA) after consultation with designated officials and agencies may designate a marine sanctuary. Key provisions include: (1) multiple use will need to be examined on a case by case basis, and (2) the sanctuary will have a primary purpose to which other uses must be compatible.

If a preliminary review demonstrates the feasibility of a nomination, factual information will be gathered to obtain an understanding of: (1) animal and plant life, (2) geological features, (3) weather and oceanographic conditions and features, (4) present and potential recreational and economic uses, (5) present and potential adjacent land uses, and (6) laws and programs of Federal, State and local government that apply to the area. Following information analysis, a draft Environmental Impact Statement may be prepared and circulated for review in compliance with the National Environmental Policy Act of 1969 and implementing the Council on Environmental Quality guidelines.

3. Other Proposed Projects

a. Federal OCS Lease Sale Offshore Southern California (OCS Sale No. 35)

After preparation and Publication of a Final Environmental Impact Statement (FES No. 75-68, August 1975) the decision was made to hold OCS Lease Sale No. 35 offshore southern California. The Santa Monica Bay Area was withdrawn from the sale at the time the decision was announced. The Oil and Gas lease sale (OCS No. 35) was held on December 11, 1975 in Los Angeles, California. Following are the results of OCS Sale No. 35, offshore southern California.

Tracts Offered	231	Acreage Offered	1,258,189
Tracts Bid On	70	Acreage Bid On	384,540
Total Number Bids	166		
Tracts Bid Rejected	14	Acreage Rejected	74,491
Tracts Sold	56	Acreage Sold	310,049

Total Money Bid	$901,960,363.80	
Total High Bonus of Bid	$438,190,779.85	
Total High Bonus Accepted	$417,312,140.82	
Average of Total High Bonus Accepted per Acreage Sold	$ 1,345.96	
Highest Per Acre Bid	$ 18,260.05	
Total High Bonus Rejected	$ 20,878,639.03	
Highest Bonus Bid for Single Tract	$105,177,888.00	(Tract No. 254)
Annual Total Rentals	$ 930,147.00	

The reader is referred to FES 75-68 for a detailed consideration of potential impacts resulting from this OCS lease sale. However, the leased area is substantially less than that considered in the lease sale statement. (Santa Monica Bay area withdrawn from the sale and only 56, of the 231 tracts offered, were leased) Therefore, the estimated impacts in the lease sale statement must be adjusted accordingly. None of the sale 35 lease areas are within the Santa Barbara Channel.

Table I-4 provides estimates of the facilities, activities, production, and waste discharge volumes, for the four general sale 35 leased areas: 1) San Pedro, 2) Santa Rosa Cortes North, 3) Santa Rosa Cortes South and 4) Santa Barbara - Catalina. See figure I-25a for the locations of these four areas. This figure shows the original tracts offered and the tracts that were leased.

Oil and gas development of areas 2), 3) and 4) above could result in onshore treating and storage facilities along the Ventura and Santa Barbara County shoreline and also either pipelines or tankers traversing the Santa Barbara Channel. The Environmental Protection Agency had a study performed by Booz-Allen and Hamilton, Inc., dated July 3, 1975, titled "A Risk and Cost Analysis of Transporting Southern California OCS Oil". This study evaluates the risk of oil spills and the costs associated with alternative modes of transporting oil from sale 35 leased areas 2), 3) and 4) above. The reader is referred to this study for a presentation of the various oil and gas transportation alternatives for each of these areas.

TABLE I-4

Estimated Economic and Resource Data by OCS Sale No. 35 Leased Area

(These estimates are for the areas leased as a result of the December 11, 1975 OCS lease sale No. 35; none of the areas are within the Santa Barbara Channel, see figure I-25a for area locations.)

Economic and Resource Data	(1) San Pedro	Santa Rosa (2) Cortes North	Santa Rosa (3) Cortes South	Santa Barbara - (4) Catalina
Million Barrels of Oil	355-3,130	100-850	120-1,555	13-120
Billion Cubic Feet of Gas	301-3,500	240-2,800	310-3,580	20-240
Acreage Leased	67,409	58,320	167,040	17,280
Platforms	2-9	1-4	2-8	1-1
Wells	133-845	60-370	120-760	14-90
Miles of Pipeline	10-60	20-90	23-135	7-45
Annual Oil by Pipeline (MM BBL)	9-80	3-21	0-0	0-0
Annual Oil by Tanker (MM BBL)	0-0	0-0	3-27	.35-3
Drill Cuttings in 1000 Tons	75-480	33-210	70-430	8-50
Drilling Mud Discharged in 1000 bbls	30-190	15-80	26-165	3-20
Mud Additives Discharged in 1000 Tons	2.1-13	1-6	1.85-12	.2-1.4
Volume of Produced Brine (MM BBL)	355-3,130	100-850	120-1,555	13-120

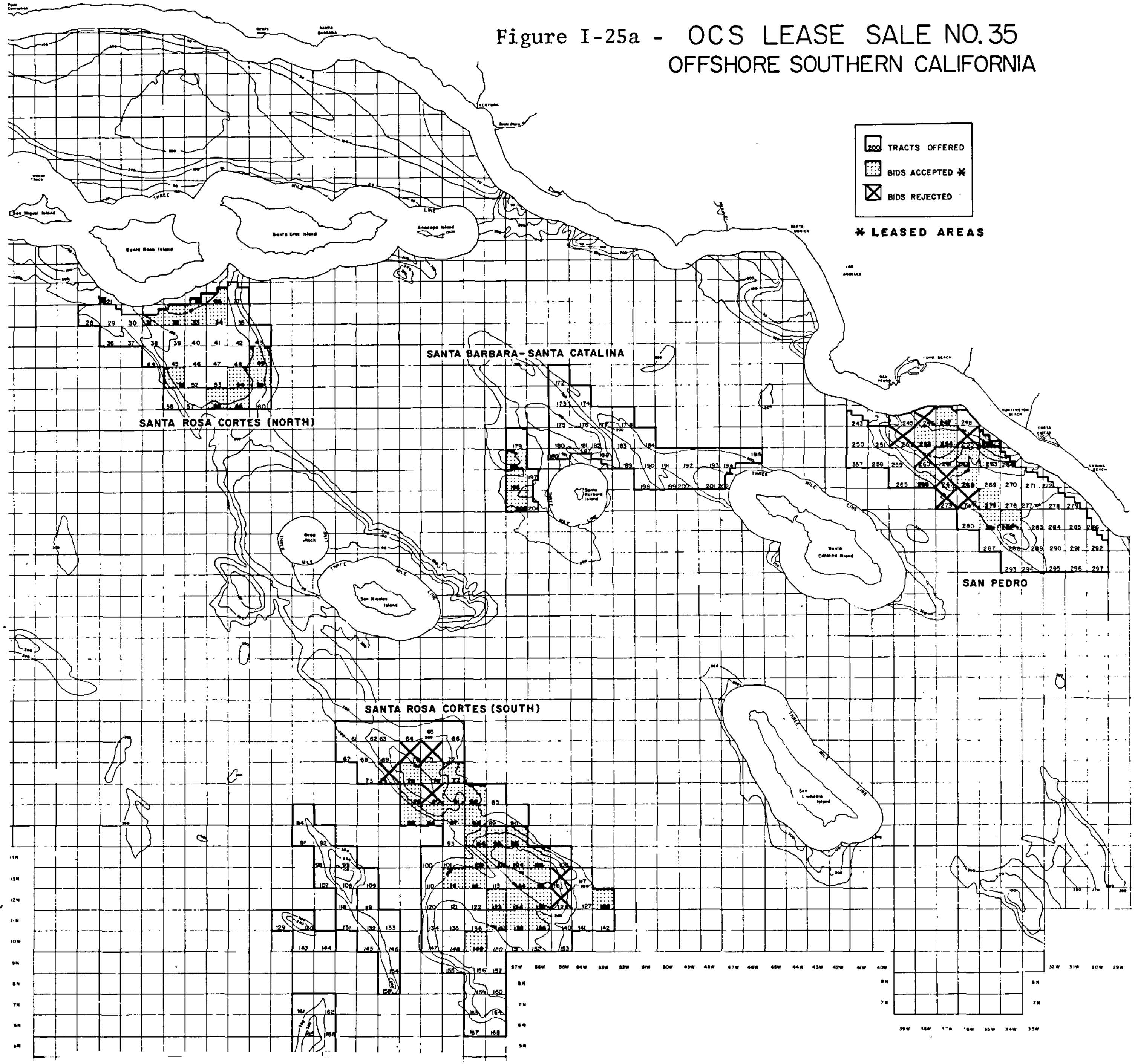

Figure I-25a - OCS LEASE SALE NO. 35 OFFSHORE SOUTHERN CALIFORNIA

b. Proposed Expansion of the OCS Leasing Program to 10-Million Acres

The Bureau of Land Management, Department of the Interior, prepared a draft environmental impact statement considering the expansion of the OCS oil and gas leasing program to 10-million acres. That draft statement was issued in October 1974, and public hearings were held in Alaska, California, and New Jersey in February 1975. The goal of 10 million acres was modified, by the Secretary of the Interior, in the latter part of 1974 to that of holding six lease sales per year rather than a specified leased acreage figure. This statement on increased OCS leasing considers 17 OCS areas, three of which are northern California, Santa Barbara Channel, and southern California. The southern California area is that area discussed in "a." above. The final impact statement was issued July 11, 1975, preceding publication of the final statement for southern California OCS sale no. 35.

c. Channel Islands National Park

Periodically, legislation has been introduced in Congress to establish Channel Islands National Park consisting of the islands of San

Miguel, Santa Rosa, Santa Cruz, Anacapa, and Santa Barbara. Anacapa and Santa Barbara Islands are presently designated as Channel Islands National Monuments; Santa Rosa and Santa Cruz are privately owned; and San Miguel is administered jointly by the U. S. Navy and the National Park Service.

The islands contain unique plant and animal life resulting from isolation from the mainland, a variety of marine fauna, rookeries of birds and marine mammals, and undisturbed examples of geological structures and processes.

The four Santa Barbara Islands have been nominated for status of Areas of Special Significance (discussed below and in sections II.E.1.c.(7) and II.G.2.b.(2)). For further significance of the Channel Islands see detailed discussion in section II.E.1.d., "Biology, Northern Channel Islands", and section II.E.2.b., "Channel Areas of Special Concern."

d. Parks and Beaches

Parks and beaches are listed in section II.F.5. Expansion or addition of some facilities is planned. National Park Service coastal themes are noted in section II.E.1. The latter, at present, have no legal status but may in the future.

e. Areas of Special Biological Significance

The State of California Water Resources Control Board has designated certain marine areas as Areas of Special Biological Significance (ASBS). The definitions and jurisdictional status of these are discussed in section II.G.2.b.(2).

ASBS designations in the Santa Barbara Channel are San Miguel, Santa Cruz, Santa Rosa and Anacapa Islands, as well as the mainland coast between Laguna Point and

Point Laterie. An extensive ongoing study is being conducted by the Coast Guard in order to better prepare them to make decisions such as order of protection and priority cleanup. This study involves such considerations as current patterns for any day of the year, weather, whale migration, water fowl migration and habits, and grunion running, to identify a few. A voluminous amount of data already has been accumulated. The U.S. Fish and Wildlife Service and the California Department of Fish and Game are furnishing the majority of this data. Additionally, other federal and state agencies are participating.

The U. S. Coast Guard has accumulated, and is continuing to accumulate, voluminous information on wind and water currents in the Santa Barbara Channel. Additionally, they plan to develop models to predict the behavior of various size spills at different locations and under several parameters of meteorological and oceanographic conditions. The results of the Coast Guard's work will be available to the On Scene Coordinator in the event of a spill.

A predictive model involving the numerous possible combinations of parameters has not yet been developed.

f. Increased Oil and Gas Activity in State Waters

On December 11, 1973, the California State Lands Commission voted unanimously to remove the moratorium on oil and gas development in State waters which they had imposed in 1969. Their resolution lifted the moratorium to the degree that development and exploratory drilling will be permitted from existing structures. They do not plan to issue any new leases, nor do they plan to permit exploratory drilling from mobile vessels. Additionally, permission will be granted on a well-by-well basis, but only after full compliance with the California Environmental Policy Act of 1970. This

Act requires submission, by the proponent, of an Environmental Impact Report (EIR) for each proposed action. Because the State leases in the Santa Barbara Channel are largely developed, the Geological Survey does not anticipate that the State Lands Commission's action will result in substantive additional activity in State waters.

At the above mentioned meeting, the State Lands Commission adopted new regulations covering DRILLING PROCEDURES, PRODUCTION PROCEDURES, and POLLUTION CONTROL AND RESTRICTIONS ON DRILLING AND PRODUCTION OPERATIONS. A detailed examination of their new regulations indicates that they are quite similar to the U. S. Geological Survey Pacific Areas OCS Orders of June 1, 1971. In some instances, the State regulations impose additional requirements on the State lease operators which are not presently imposed on Federal operators. The Geological Survey intends to incorporate such similar requirements as may be appropriate in the next revision of its Pacific Area OCS Orders. (For further discussion of Pacific Area OCS Orders see section IV.A.1.g.)

- Proposed Platform Holly Drilling Resumption

  The reader is referred to a Final Impact Report titled "Resumption of Drilling in the South Ellwood Offshore Oil Field from Platform Holly," dated November 1974, prepared for the State Lands Commission by Dames and Moore. This report was prepared pursuant to consideration by the State Lands Commission of a request by Atlantic Richfield Company to resume drilling operations on Platform Holly. The proposal is to drill 17 additional wells. (See pocket plate 1 for the location of Platform Holly)

g. Other Possible Activities - General Discussion

There are a number of other possible significant activities in the southern California area which, if implemented, could result in impacts on various environmental and socio-economic factors over and above those resulting from OCS oil and gas operations. These projects include: tanker delivery of Alaskan north slope oil: continued importation of foreign crude oil; delivery of liquefied natural gas (LNG); future OCS sales; deep-water ports; a proposed refinery and marine terminal near Carlsbad; and possible nuclear power plants along the coast.

Development of Alaska's north slope reserves could result in the arrival of 1,200,000 bbls of crude oil on the west coast by 1978, with an anticipated increase in delivery to a level of two million bpd by 1985. It is projected that 20 tankers with a deadweight tonnage of 1,390,000 tons and a turnaround time of 14.5 to 15.5 days will be required to transport the initial crude from Alaska to the Los Angeles area. Foreign imports, via tankers, from Indonesia are expected to continue because Indonesian oil has a lower sulfur content than domestic crude and is required for mixing with domestic crude for certain processing, and direct burning in boilers. Tanker transport of LNG from either domestic and/or foreign sources is proposed with terminal facilities planned for Point Conception, Oxnard, and Los Angeles harbor. Each of these proposed facilities would be capable of receiving LNG for a base load vaporization rate of 4 billion cubic feet of natural gas per day at full capacity. Possible future OCS sales No's. 48 and 53 presently scheduled for June 1977 and April 1978 respectively, would also affect the offshore California area.

The size and exact location of these possible sales is as yet unknown. Two deepwater ports are proposed for Los Angeles and Long Beach harbors to accommodate large oil tankers. One of these proposed ports could be used to offload Alaskan crude for pipeline transport to the mid-west. The proposed refinery and marine terminal near Carlsbad could be utilized to handle increased oil supplies resulting from the above-mentioned projects. Additional electrical power demands could also result in further development of previously proposed nuclear power plants along the southern California coast.

The projects involving tanker transport of crude oil would result in increased collision and spillage probabilities. The impacts of large spills would be similar to those described in section III of this EIS. However, the effects of chronic low level spillage, and the effect of possible reduced recovery time between major spills is as yet unknown, but could be more serious than large spills themselves.

The tanker transport of LNG would again increase shipping traffic and would tend to create even more congestion in port areas due to the fact that, for safety purposes, all other ship traffic within a harbor is halted while a loaded LNG ship is in the immediate area. Collision and resultant spillage of LNG would create a significant safety problem due to the highly flammable nature of LNG and the rapid spreading potential of the LNG plume cloud over water.

The above-mentioned tanker projects lead directly to the requirement for the proposed deepwater ports and marine loading terminals. These proposed port facilities would result in dredging operations and use of onshore lands. Dredging creates temporary impacts to water quality by increasing heavy metal and pesticide concentrations through resuspension of bottom sediments. Benthic organisms in the immediate vicinity of dredging are affected by both direct mechanical removal and loss through smothering. However, this impact is usually temporary and restricted to a small area. The combined effects of chronic low level oil pollution and the resuspension of heavy metals and other toxic elements, as a result of dredging, are also not well understood but could create significant impacts on food chains and productivity of the biotic community.

The onshore use of land for marine terminals would require only small portions of land, but because of the location along the coast, marshlands or other valuable areas could possibly be affected.

The onshore terminals and proposed refinery could also affect air quality during construction stages, and the refinery would emit odorous gases during its production life.

The possible future OCS sales would again increase the probability of oil pollution and might also create aesthetic impact due to offshore platform placement. Resultant pipelines which come onshore would remove various acreages of land for use as rights-of-way. This impact would vary considerably depending on the types of areas crossed. Industrial areas, roadways and other already developed areas would receive minor alteration. However, marshes or other unique areas could be significantly affected due to alteration in vegetation and drainage patterns.

The possible nuclear plants would remove certain acreages of land, could cause thermal pollution of nearby waters due to cooling water discharge, and would create radioactive waste products which have a high pollution potential.

On the positive side, the increased activity would help to create additional employment, directly and also indirectly, in the service and trade sectors. This would help to not only relieve any unemployment in the area, but also the resultant pressures applied to various government welfare agencies as a result. The positive economic benefits could be significant.

A study completed in June 1973 called "Environmental Assessment West Coast Deepwater Port Study" analyzed the potential development of 11 deepwater port sites through the use of approximately 40 scenarios and assessed the impacts from each. This study is referred to the reader for an insight into possible cumulative impacts in the southern California area. This study was completed by Battelle Pacific Northwest Laboratories for the U. S. Army Engineer District in San Francisco and summarized existing environmental conditions for potential deepwater port sites on the West Coast of the United States. Environmental assessments were also conducted relating to increased movement of conventionally sized oil tankers which would not necessitate deepwater port developments. These were compared with environmental changes which would result from the development of deepwater ports to handle larger but fewer oil tankers. Both development conditions were evaluated for projected crude oil demands on the West Coast in the years 1980 and 2000. The environmental analyses considered the impact of oil tanker operation (including oil spills), the construction and maintenance of navigation channels, and the construction and operation of terminals, pipelines, refineries and other support facilities on air quality, water quality, flora and fauna, aesthetics, recreation, and archeological and historical values. The assessments were presented in matrix form backed by brief narrative statements. Secondary effects of superport development such as impacts on land use, economics, transportation, social and political processes were not considered in this study.

Although the overall study conducted by the Corps of Engineers encompasses the entire West Coast, the scope of services conducted by Battelle-Northwest was limited to environmental assessments of potential deepwater port sites located in the vicinity of the existing West Coast refinery complexes in the Puget Sound, San Francisco Bay area and southern California regions.

In summary, the combined impacts possibly resulting from the possible levels of Santa Barbara Channel development, the sale 35 lease development (see section I.F.3.a.) and the above-mentioned projects could result in significant effects on the water quality and biota of the southern California coastal area. These cumulative impacts could be further compounded in areas presently under environmental stress from pollution due to agricultural run off, effluent discharges, natural oil seeps, and ocean dumping.

Therefore, it is imperative that all proposed projects be carefully analyzed as to their possible impacts, with particular attention given to the mitigating measures proposed by each, to reduce or elimimate cumulative impacts.

These projects for the most part are all still in the planning or proposal stages and as yet site-specific environmental impact statements, which would pinpoint the impacts of each project, have not been completed. Therefore, the specifics of the environmental and socio-economic impacts are not available and were only described in general terms.

DEPARTMENT of the INTERIOR

news release

OFFICE OF THE SECRETARY

For Immediate Release August 16, 1974

INTERIOR APPROVES DEVELOPMENT PLAN FOR SANTA YNEZ UNIT, CALIFORNIA

The Department of the Interior announced today approval of a plan for development of oil and gas that has been discovered on 83,000 acres of the Outer Continental Shelf about 20 miles northwest of Santa Barbara, California.

The decision, which was announced by Acting Secretary John C. Whitaker, means that subject to close inspection and supervision by the U.S. Geological Survey, unitized development can begin on a group of 17 tracts, known as the Santa Ynez unit, estimated to contain recoverable reserves of 750 million to 1.1 billion barrels of oil and 370 to 550 billion cubic feet of natural gas.

Leases for the tracts involved were awarded by the Department of the Interior in a competitive bid sale on February 6, 1968, to Exxon Company, U.S.A. (formerly Humble Oil and Refining Company), Standard Oil Company of California, and Shell Oil Company. The Director of the Geological Survey approved an agreement unitizing the 17 leases, with Exxon as unit operator, on November 12, 1970.

The approved development plan calls for construction of a self-contained drilling and production platform in 850 feet of water; 12-inch and 16-inch pipelines to shore; an onshore treating and storage facility; and modification of an existing marine floating terminal. An alternative plan, involving an offshore treating, storage and loading facility, also was approved if the onshore facilities are not accepted by the state and local officials who have ultimate authority over all construction onshore and within three miles of the shoreline.

Since the development plan was submitted for approval, the Interior Department has issued a 1,278-page draft environmental impact statement, published July 23, 1973; conducted three days of public hearings on October 2-4, 1973, in Santa Barbara, on the draft environmental impact statement; and issued an 1,849-page final environmental impact statement in three volumes, filed with the Council on Environmental Quality May 3, 1974.

In announcing his decision, Whitaker said "the engineering and technological capability exists for safe installation and operation of this platform in 850 feet of water," adding: "The increased forces which will operate on this platform as compared with platforms in lesser water depths are understood and have been accounted for in the design of the platform. The drilling and production operations are the same for a platform in this water depth as in lesser depths and will be subject to the same careful and rigorous regulation and inspection by the Geological Survey."

The Acting Secretary stressed that he believes an onshore treatment facility is preferable to the offshore facility for two basic reasons: (1) it involves less environmental risk, and (2) it will allow the production and marketing of natural gas contained in the Santa Ynez unit; if an offshore unit is utilized the gas will have to be reinjected into the reservoir.

Whitaker expressed the strong hope that the onshore site can be built, but he added that he is also convinced that an offshore facility can be safely built and operated. He said, "The strong national interest in producing this large discovery of oil requires approval of the offshore facility if the onshore facility cannot be built," but he said, "delay in approving the offshore alternative could result in delaying development of this much-needed resource.

"Every barrel of oil produced from this field will replace a barrel we would otherwise have to import from some other country, and this will help our economic and our foreign policy position," he said.

Dr. Whitaker pledged the Interior Department's continued cooperation with State and local agencies in planning and implementing actions which affect the California coastal zone, and the state's economic and environmental interests. The Department plans to obtain state and local input into the design of an environmental monitoring program for this area, which will, as Whitaker's decision makes clear, require the participation of the Santa Ynez unit operator.

x x x

Secretary's Decision on the Plan of Development
Santa Ynez Unit

Pursuant to the terms of the Santa Ynez Unit Agreement, approved by the United States Geological Survey on November 12, 1970, Exxon Company--U.S.A., the unit operator, submitted for approval on November 11, 1971, a supplemental plan of operations, (hereinafter referred to as the initial plan of development), for the Santa Ynez Unit. This initial plan of development has been the object of extensive technical and environmental analysis by the Geological Survey, the subject of a draft environmental impact statement published on July 23, 1973, three days of public hearings on October 2-4, 1973, and a final environmental impact statement made available to the Council on Environmental Quality on May 3, 1974. Based upon the discussion of the potential environmental impact as set forth in the environmental impact statement, a copy of which has been before me for my consideration in reaching this decision, and other factors before me for consideration, some of which are discussed here, I have determined that the initial plan of development should be approved as provided below.

On February 6, 1968, two years before enactment of the National Environmental Policy Act, the Department of the Interior conducted its first wildcat lease sale in the Santa Barbara Channel. Seventy-one leases were awarded. The eighteen leases in the area covered by the Santa Ynez Unit as originally formed were awarded to Exxon Company--U.S.A., formerly Humble Oil and Refining Company, Shell Oil Company, and Standard Oil Company of California. One lease within the unit was relinquished on October 2, 1972. The leases conveyed certain rights to the lessees subject to the limitations in the Outer Continental Shelf Lands Act and valid regulations issued pursuant thereto. Among the rights conveyed by the leases was the exclusive right to drill for, extract, remove and dispose of all oil and gas deposits on the lease and the right to construct or erect and to maintain platforms, pipelines and other works and structures necessary or convenient to full enjoyment of the lease rights.

Of necessity my decision with respect to this initial plan of development could not be made without considering the rights conveyed by these leases and the context of these leases within the history of oil and gas development on Federal and State lands in the Santa Barbara Channel. The relevant history after the sale of 1968 begins with the blowout of well A-21 on lease OCS-P 0241 on January 28, 1969. The Department took a number of steps in response to the causes and results of that accident so as to reduce to an absolute minimum the possibility that such an event could occur again. Drilling and production operations were suspended on six active leases and safety reviews were made of all other leases in the Santa Barbara Channel to determine if further operations could be conducted safely. Clearances were given on a lease-by-lease basis. The outer Continental Shelf operating regulations and orders were reviewed and revised as appropriate to strengthen operating requirements and provide for the absolute liability of the lessee for the cost of cleanup of any oil spill. In July 1967, Assistant Secretary Moore, the California State Lands Commission and the Governor of California agreed that certain lands contiguous to the State Santa Barbara Oil Sanctuary would withdraw from leasing, thereby creating a Federal Ecological Preserve to be *used for scientific, recreation, and other similar uses. In addition, a Federal Buffer Zone seaward of the Federal Ecological Preserve was created as an adjunct to it.*[1] *In 1970 the administration submitted legislation to the Congress for the purpose of terminating twenty existing leases immediately seaward of the State Santa Barbara Oil Sanctuary and the Federal Ecological Preserve and Buffer Zone. A National Energy Reserve would have replaced these twenty leases. In 1971 and 1973 similar legislation, but covering 35 leases, was submitted to Congress. In November 1973, during testimony on this and other legislation relating to the Santa Barbara Channel, subsequent to commencement of the oil embargo, the administration withdrew its support of its legislation and asked Congress not to act on any legislation relating to the Santa Barbara Channel. The administration announced that it was reconsidering its position with respect to oil and gas development in this area of the Santa Barbara Channel and would communicate to Congress its decision with respect to the administration's legislation and other legislation after the reevaluation was completed.*

In February 1969, the California State Lands Commission, reacting to the then recent blowout, revoked all existing offshore exploration drilling permits and imposed a moratorium on all new drilling on existing State tidelands leases. The Commission based its decision on what it found to be the lagging state of technology in providing reliable oil containment and recovery techniques and devices.

Given this historical background I was faced with a number of difficult issues in reaching a decision whether the initial plan of development submitted by Exxon Company, the unit operator, should be approved. Even though Exxon and others have drilled numerous exploratory wells in the deeper Channel waters, including the Santa Ynez Unit area, this is the first development plan submitted since the actions to reduce oil seeps following the 1969 blowout. One new production platform had been approved, but its approval was based in large part upon the recommendation of the DuBridge Committee whose report indicated a need for such a platform in order to reduce the pressures in the fractured Dos Cuadros reservoir.

Furthermore, approval of this initial plan of development would be made prior to completion of our reevaluation of oil and gas operations in the 35 lease area proposed for a National Energy Reserve and before completion of the Santa Barbara Channel exploration and development environmental impact statement currently being written to assess the impacts of oil and gas operations throughout the entire Santa Barbara Channel region. I was concerned that a decision to approve the initial plan of development could be misconstrued as a determination by the Department, prior to completion of the Santa Barbara Channel statement, that full scale operations should proceed throughout the entire Channel. The program decision option document prepared for my consideration in arriving at a decision, presented the alternative for my consideration of delaying action on this plan of development until the Santa Barbara Channel region impact statement was completed.

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[1] *These two sentences describing the formation of the Federal Ecological Preserve and the Federal Buffer Zone were ammended in order to be more complete. See the Introduction page ii-10 for more detail on the history of these areas.*

With respect to this issue, the Department has never imposed a moratorium on oil and gas development in the Santa Barbara Channel. Following the blowout of 1969 there were suspension orders issued and safety clearances required prior to permitting further exploration and development to proceed. This, however, never constituted a moratorium on oil and gas operations. The legislation submitted to terminate 35 leases and create a National Energy Reserve placed a temporary suspension on these leases pending consideration of the legislation by the Congress. It did not represent, however, a decision that these leases would never be developed should Congress fail to act on the legislation. Except for these interim measures taken by the Department, the Department's position has consistently been that development should proceed as usual in accordance with statutory and regulatory obligations imposed upon the Department and the lessees. Therefore, characterization of this present decision as anything other than an approval of a proposal for a significant production operation in a specific section of the Channel would be unwarranted. Clearly, it does not constitute a decision on full scale development of the Santa Barbara Channel.

In respect to our commitment to the Congress made in November 1973, when the administration withdrew support for its legislative proposal to create a National Energy Reserve, we were careful to point out at the time that our reevaluation was with respect to development of oil and gas resources on the 35 leases included in the legislation. This reevaluation was not intended to extend to other areas in the Santa Barbara Channel. The Department had been and remains opposed to other legislative proposals relating to the entire Santa Barbara Channel. With respect to the 35 leases in the administration's legislative proposal, we intend to honor our commitment to the Congress to advise them of our decision with respect to this legislation prior to taking any steps to approve development of these leases.

Recognizing that the Department had never written an impact statement on the entire Santa Barbara Channel, the statement presently in preparation was initiated in conjunction with our commitment to Congress to reevaluate the legislative proposal to create a National Energy Reserve. We decided that this statement to be of maximum value should encompass the entire Santa Barbara Channel rather than just the specific 35 leases. However, the statement was designed to analyze the environmental impacts which could result from exploration and development of leases and unleased lands for which no specific development proposals were pending before the Department. The Santa Ynez initial plan of development had been submitted to the Department long before initiation of the Santa Barbara Channel region environmental impact statement. Initiation of the Channel statement did not change the Department's intent that the Santa Ynez proposal would be analyzed through its own individual environmental impact statement and that a decision would be made with respect to that proposal independently of the Santa Barbara Channel impact statement.

Another issue which confronted me related to the attitude of the State of California toward oil and gas development within State territorial waters and development of the State's Coastal zone. The State Lands Commission on December 11, 1973, unanimously decided to lift the five year moratorium which it had imposed on oil and gas development in State tidelands. The moratorium was lifted to the degree that development and exploratory drilling will be *permitted from existing structures. No new leases are expected to be issued nor will exploratory drilling from mobile vessels be permitted. The Commission adopted a staff report indicating that the oil industry had developed safety equipment and procedures sufficient to minimize the possibility of a major oil spill occurring and to provide for effective cleanup in the event of a spill. To me this suggested that the State Lands Commission now felt that the risks involved with oil and gas operations were acceptable in light of the current state of technology and the need for energy.*

On the other hand, the California Coastal Zone Conservation Act became effective on February 1, 1973. That Act established the California Coastal Conservation Commission with the responsibility to supervise development of the coastal zone seaward to the outer limit of the State's jurisdiction and extending inland generally to the highest elevation of the nearest coastal mountain range. The Act requires the Commission to prepare, adopt and submit on or before December 1, 1975, to the State Legislature for its adoption and implementation a California Coastal Zone Conservation Plan. The Act provides that on or after February 1, 1973, any person wishing to initiate any development within the permit area, defined generally to be that area between the seaward limit of the jurisdiction of the State and 1000 yards landward from the mean high tide line of the sea, must obtain a permit authorizing such development from one of the regional commissions. There can be no question that the California Coastal Zone Conservation Plan and the implementation of the permit authority will have a bearing upon future plans for construction and maintenance of needed onshore facilities related to oil and gas development from federal OCS lands as well as from State territorial waters. Thus, an additional issue which I had to consider was whether a decision should be delayed with respect to the initial plan of development for the Santa Ynez Unit until completion of the California Coastal Zone Conservation Plan.

My decision to proceed at this time with approval of the plan of development for the Santa Ynez Unit, as provided below, was based on the following factors relating to the issue of the California Coastal Zone Conservation Plan. The Santa Ynez environmental impact statement contains a thorough assessment of the potential environmental, land use, and socio-economic impacts to the coastal zone area which could result from various aspects of this plan of development. The installation and operation of pipelines are discussed. The impact of the onshore storage and treatment facility upon the Las Flores Canyon and Corral Canyon are thoroughly treated and the near shore loading terminal for shipment of production to refineries is carefully analyzed. This analysis has been conducted in close cooperation and coordination with federal and State agencies as well as knowledgeable private sources having jurisdiction over, or information with respect to, this area of the coastal zone. The authority of the Coastal Zone Conservation Commission is discussed, as are county zoning and land use plans and other proposed federal and State projects in the area. The cooperation of this Department in the planning and implementation of facilities in the coastal zone will continue throughout the development of this project. In the final analysis it is clear that State agencies rather than the Federal Government must be looked to for approval of onshore facilities and pipelines and loading terminals within State territorial jurisdiction. Thus, my decision approves in concept facilities within State territorial waters and on State lands after consultation with State and local authorities, but it has no bearing upon the ultimate authority and responsibility of the

State for issuance of necessary permits for construction of these facilities.

Other issues which confronted me in reaching my decision on the initial plan of development related to specific aspects of the plan and some of its unusual features. The initial plan of development calls for installation of a drilling and production platform in 850 feet of water; water twice as deep as any in which a platform has been installed in the United States OCS previously. The integrity of this platform is critical due to the seismic problems presented by the incidence of earthquakes in, and in the vicinity of, the Santa Barbara Channel region. The initial plan of development includes an onshore treating and storage facility in the Las Flores Canyon off of Corral Canyon. This site would occupy about 15 acres approximately one mile inland from the coast. As an alternative to the onshore treating and storage facility, the initial plan of development proposes a floating vessel of approximately 28,000 dwt displacement and a single anchor leg mooring system to be used as an offshore treating and storage facility. This would be located 3.2 miles from the shore line in the northeastern portion of federal lease OCS-P 0188. The treated crude oil would be off-loaded to shuttle barges or tankers for transportation to market. Other features of the plan call for a 16 inch oil pipeline and a 12 inch gas pipeline to transport production from the platform to the onshore treating and storage facility. A 30 inch oil pipeline which reduces to 24 inches would transfer treated oil from the onshore facility to marine barges or tankers at a marine loading terminal located 3,500 feet offshore. A submerged production system (SPS) originally proposed by the unit operator has been withdrawn from further consideration by the unit operator pending testing and development of the SPS in the Gulf of Mexico.

The environmental impact statement on the proposed plan of development of the Unit, in a very careful and thorough analysis, discusses the technological feasibility and potential environmental impacts of these components of the initial plan of development. There is no question that environmental impacts will result from the day to day operations of the production system and that the potential for an oil spill can never be completely eliminated, even under the strict regulatory and inspection procedures now employed by the U. S. Geological Survey.

The impact statement does discuss the engineering requirements which must be satisfied by a platform in these water depths if it is to resist the wave, wind, and seismic forces which could occur during the life of the structure. I am satisfied from the discussion of these matters that the engineering and technological capability exists for safe installation and operation of this platform in 850 feet of water. The increased forces which will operate on this platform as compared with platforms in lesser water depths are understood and have been accounted for in the design of the platform. The drilling and production operations are the same for a platform in this water depth as in lesser depths and will be subject to the same careful and rigorous regulation and inspection by the Geological Survey.

I have compared the proposed design and operation of the onshore treating and storage facility with that of the proposed alternative offshore treating and storage facility. I find that based upon the operational limitations of the offshore treating and storage facility, and the potential for environmental harm from operations at that facility, that the onshore treating and storage *facility is the more desirable means for treatment of the oil and gas produced from the Santa Ynez Unit. The onshore facility is designed for expansion to accommodate the entire estimated production of oil and gas from the Santa Ynez Unit. In fact, this facility can be expanded to accommodate all production from the western portion of the Santa Barbara Channel without a great additional commitment of land. The offshore floating vessel's treatment and storage capacity limitations are such that additional offshore floating vessels or an alternative onshore facility might be needed for future production from other areas within the Santa Ynez Unit or outside the unit. Furthermore, the offshore facility would not be equipped to process gas produced from the unit, and the gas would have to be reinjected into the reservoir. The result would be that an estimated 370 to 550 billion cubic feet of recoverable gas would be lost to the local market, at least until some shoreside facility is approved.*

The continuous operation and integrity of the offshore floating facility would be adversely affected by high winds and waves. The impact statement points out that the mooring system has been designed to moor the fully loaded storage vessel safely in 20 foot high seas and 75 mph winds. If these design limitations are approached the vessel would be released from the mooring and taken to a sheltered port. Off-loading of the treated and stored oil could be conducted in 8 to 10 foot significant wave height seas. These limitations make it apparent that there may be instances during the course of a given year in which production operations would have to be halted on the platform so that the capabilities of the offshore treating and storage facility would not be over extended leading to possible polluting incidents.

Another feature making the offshore treating and storage facility less desirable is the fact that the production from the platform would have to be transferred onto the floating vessel and then transferred off the floating vessel to a shuttle barge or tanker for transport to market. The onshore treating facility on the other hand would require only one bulk transfer point for the production from a pipeline at the marine loading terminal to a shuttle barge or tanker.

I also considered the matter of aesthetics in determining that the onshore facility would be preferable. As pointed out in the environmental impact statement, the secluded location of the onshore facility and the extensive landscaping included in the plans for the facility will screen the facility from site from the coastal highway, U.S. 101, except for brief moments. During such moments only a few slender gas-handling vessels will be visible. This is a minimal aesthetic intrusion when compared to the offshore treating and storage facility, only 3.2 miles offshore, which would be visible constantly during clear weather from a broad expanse of coastline.

A further consideration that suggested to me a preference for the onshore facility is the potential environmental impact which would result should an oil spill of any consequence occur from either the onshore or offshore facility. A spill from the offshore facility could easily expand over a large area on the waters of the Santa Barbara Channel, contaminate kelp beds present between the proposed location for the offshore facility and the coast, and reach beaches which receive heavy recreational use. The damages which could result from such an offshore oil spill are well documented in the environmental impact statement.

On the other hand, the potential impact from an accident on the onshore facility appears to me to be considerably less. I agree with the analysis and conclusion reached in the impact statement that the possibility of an accident from an onshore facility resulting in major oil pollution of the marine environment is remote. A significant spill from the onshore facility which resulted in contamination of a segment of lower Corral Creek but did not reach the water would certainly result in detrimental impacts to the immediate local environment, but would not be nearly as harmful as a spill on the waters of the Channel. Furthermore, I am advised that the onshore treating and storage facility design and operation would be required to comply with the regulations of the Environmental Protection Agency, 40 CFR Part 112, which require the preparation and implementation of a Spill Prevention Control and Counter Measure Plan for non-transportation related onshore facilities. Effective preparation and implementation of such a plan should further minimize the risk of an oil spill reaching the waters of the Santa Barbara Channel. These factors have convinced me that the onshore facility is more desirable from the technological, environmental and aesthetic points of view than the suggested alternative offshore facility. For these reasons I have decided to approve both the onshore facility and the alternative offshore facility with the reservation specified hereinafter.

The other aspects of the plan of development such as the connecting pipelines and the near shore loading terminal to be employed in conjunction with the onshore storage and treatment facility are thoroughly treated in the environmental impact statement. These facilities raise no particular problems which are not adequately accounted for in their design and the regulatory mechanisms that will be employed to supervise their installation and continued operation. Under these conditions the potential environmental impacts resulting from their installation and operation are within acceptable limits.

Upon full consideration of the aforementioned issues, it remained my responsibility to balance the potential environmental damages associated with development against the anticipated benefits which could be expected to follow development of the Santa Ynez Unit.

The demand for energy in this country greatly exceeds the existing supply from domestic sources. If the Santa Ynez Unit is not developed the estimated 730 million to 1.1 billion barrels of recoverable oil and 370 billion to 550 billion cubic feet of recoverable gas underlying the unit would be unavailable to meet the Nation's energy demands. The State of California alone imports approximately one-third of its current requirements for petroleum products. Estimates by the Resources Agency of California indicate that imports must be increased to meet State needs in 1980.

In this period of double digit inflation, the substitution of domestic petroleum for imported petroleum could play a significant role in dampening inflationary pressures. Development which would reduce the outflow of funds for imported oil and the balance of payments deficit that may have an inflationary effect, and which can be implemented with appropriate safeguards for the environment, will benefit practically every U.S. citizen.

The Nation has learned in recent months the costs involved with relying heavily on foreign sources for oil and gas. Undeniably, excessive dependence on foreign *supply leaves the nation vulnerable to critical energy shortages in the event that these supplies are temporarily curtailed and to severe economic disruptions due to the expense of importing foreign energy sources. Additionally, the nation has observed the effect of higher energy prices on overall domestic prices.*

Based upon my review of the issues pertinent to this decision and the potential environmental impacts as discussed in the environmental impact statement I have concluded that the benefits flowing to the nation along with increased domestic supplies of oil and gas outweigh the adverse environmental impact which could result from my affirmative response to the proposal. This conclusion, for which I find ample support in the environmental impact statement and other material relating to supply and demand of energy in the United States, is consistent with the analyses and recommendations made by the Geological Survey and other members of my staff.

Therefore, I approve the initial plan of development for the Santa Ynez Unit as submitted by the unit operator with the following reservation: My approval of the alternative offshore floating treatment and storage facility may be withdrawn if, prior to construction of the offshore facility, I determine that the unit operator has not made diligent, good faith efforts, to obtain permission from the appropriate State agencies to construct and operate the onshore facility under reasonable terms and conditions. It is necessary to approve the offshore facility at this time and under these terms because delay in approving this facility could result in delaying development of the much needed resources of the Santa Ynez Unit.

It should be clear that my approval is limited to the initial plan of development, that is, the plan as it relates to development of the Hondo field by a platform to be installed in 850 feet of water, an oil and a gas pipeline to carry production to shore, an onshore treatment and storage facility, a pipeline to a near shore loading terminal, the near shore loading terminal, and the alternative offshore treatment and storage facility. My approval does not extend to other production facilities for the Hondo field, or development of the Pescado or Sacate fields. Subsequent supplemental plans of development are anticipated for these areas. Environmental assessments will be made for the supplemental plans and a decision will then be made as to the need for additional or supplemental impact statements. Following my approval of this initial plan of development the Geological Survey will review individual applications for the components of the plan in accordance with their normal procedures.

As an adjunct to this decision and in order to gain more scientific data on the impact of oil and gas operations upon the environment in the Santa Barbara Channel and elsewhere, I am initiating a study leading to the design of an environmental monitoring system to be used in the Southern California area including the Santa Barbara Channel. The Department will consult with appropriate federal agencies and California State and local agencies including the Coastal Zone Conservation Commission and the State Lands Commission, as well as knowledgeable private organizations and individuals, to determine the necessary scope and design of the monitoring system to be employed. At a minimum, federal lessees in the Santa Barbara Channel may anticipate the imposition of requirements in the future to monitor the impacts of their *operations upon the Channel environment through appropriate sampling procedures and other mechanisms. We hope this monitoring program will be designed and implemented prior to initiation of development drilling from the platform included in the unit operator's plan of development for the Santa Ynez Unit or development drilling from any other platform which may be approved in the future.*

/s/John C. Whitaker
Acting Secretary of the Interior

Date: August 16, 1974

APPENDIX I-2
(Subsection G)

GENERAL DISCUSSION OF OIL FIELD DEVELOPMENT

This subsection I-G and the following subsection I-H (included as Appendices I-2 and I-3) are not especially relevant to the main purpose of the Environmental Impact Statement, and do not apply to the Santa Barbara Channel only but they may serve to clarify some of the subjects discussed throughout the statement.

1. <u>Accumulation of Hydrocarbons</u>

Hydrocarbon, oil and/or gas, reservoirs are formed when the proper combination of conditions are present. Without going into the initial formation of hydrocarbons, it is sufficient to say that there must be a porous bed of rock to contain the hydrocarbons.

Most sedimentary rocks are porous, that is, they have open spaces between the mineral grains that compose the rock. Igneous and metamorphic rocks may also be porous, but this is usually a secondary type of porosity caused by fracturing of the rock that is a result of movement in the earth's crust.

A second requirement for a reservoir rock to be producible is that the rock must be permeable. This refers to the quality of interconnection between pore spaces so that fluids are free to move from one space to another. Shales for example are composed of very fine-grained sediments and while they have porosity, the pore spaces are not interconnected and fluid in the rock is trapped in the pore spaces; therefore the shale is said to have low permeability.

Fluids in the hydrocarbon reservoir rock may consist of saline water and oil or gas and often consists of all three. Gas, being the lightest of the three fluids, will naturally migrate to the highest obtainable position in the reservoir rock. Oil, being lighter than water will rise above the water.

The third requirement for a reservoir is that an impermeable rock be above the reservoir rock to confine the reservoir fluid.

The fourth requirement is that the reservoir rocks be formed into a trap to collect and retain the reservoir fluid. Some common trap types are shown in figure I-26., and are discussed below.

a. Structural Traps

Forces within the earth may uplift sections of the earth's crust to form folds, anticlines, and domes that may serve as traps for hydrocarbons. Oil and gas may collect in the higher sections of these folds with water possibly present in the lower sections. This type of trap is responsible for most of the hydrocarbon accumulations thus far discovered.

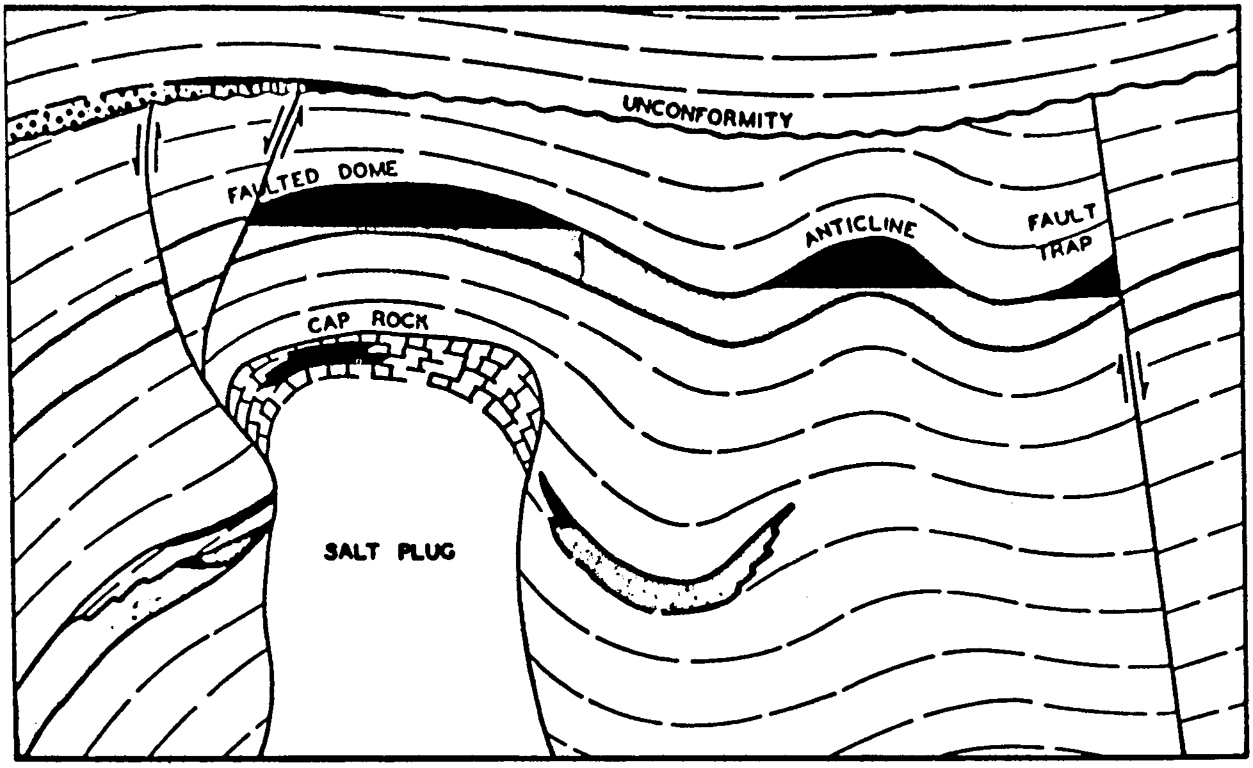
b. Fault Traps

A fault is a break resulting from a displacement in the earth's crust. When the movement along a fault results in an impermeable bed opposite a porous and permeable bed, a seal results. When this happens hydrocarbons may move up the permeable bed until they reach the fault, where they are confined.

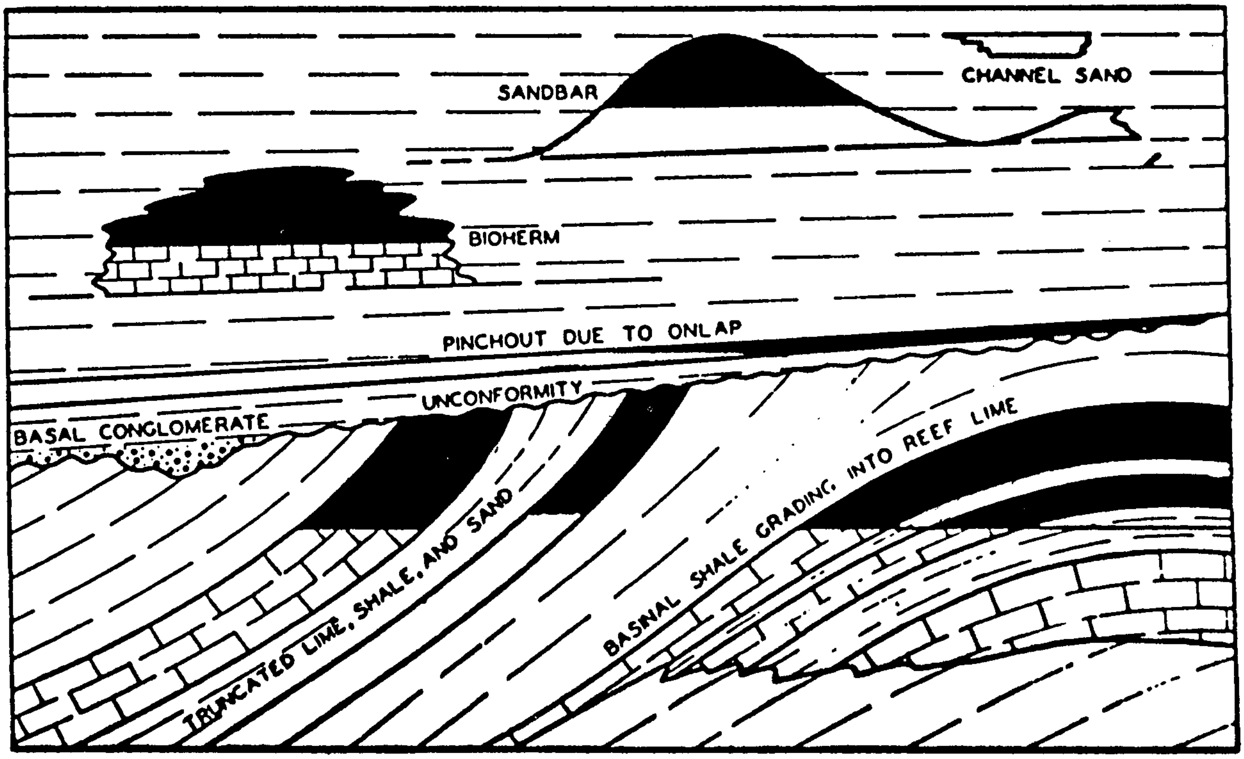
c. Stratigraphic Traps

The sedimentary beds that generally comprise the reservoirs for hydrocarbon collection may be deposited under very widely diverse conditions. The resulting beds can vary greatly in grain size, porosity, texture and thickness. These differences can result in a suitable trap for confining hydrocarbons.

FIGURE I-26



Common types of structural traps



Common types of stratigraphic traps

Source: Petroleum Extension Service,
The University of Texas at Austin,
and others, 1973, p. 5-6.

Many of the California oil fields consist of more than one reservoir bed and many consist of a number of hydrocarbon accumulations collected in every type of trap described.

2. Searching for Hydrocarbons

a. Surface Geology

The earliest searches for hydrocarbon deposits were based on features observable at the surface: seeps, outcrops, etc. The geologist would map the data obtainable at the surface: composition, age, dip, strike, etc. In this manner an interpretation of the probable subsurface structural features could be obtained.

b. Subsurface Geology

This information can be obtained from wells drilled for various purposes or from core holes drilled specifically to sample the geologic formations. The information collected is similar to that obtained from surface inspection. Various types of instrumental exploratory equipment may be run in wells and core holes which differentiate the various types of deposits penetrated as to depth, thickness, physical character, and probable fluid content. These can then be correlated to give a structural interpretation of the area. Cores, are collected with a type of hollow drill bit that allows a sample of the formation being penetrated to enter through the bit and be retained in a core catcher in the drill string above the bit. These may be obtained from conventional exploratory or development wells, or from wells drilled solely for this information. The cores are examined for composition, presence of hydrocarbons, porosity and permeability characteristics, and fossil content. The fossil content is especially important in determining the age of the formations penetrated and in identifying and correlating formations in an area. The microfossils, formanifera, were single cell animals that lived in the sea and developed a shell. As they died, they settled to the bottom and were buried in the ocean floor sediments. There were many species, each with characteristic qualities that permits their identification with a certain geologic era. Thus the geologist or paleontologist can correlate the probable subsurface structures.

c. Geophysical Exploration

Geophysical methods are the most commonly used preliminary exploration methods in use today. There are several types, but basically they all involve a means of obtaining a response that will reflect subsurface structural features.

(1) Magnetometer and Gravity Surveys

These surveys are generally used to map regional structural features. The magnetometer is used to measure the magnetic intensity beneath the instrument and are most useful in reflecting basement (the igneous or metamorphic rock underlying sedimentary formations) features that may control overlying structures. The gravity survey measures the gravitational intensity of the rock underlying the surface. Any structural change or either dense or light rock will result in a change of gravitational force from that of the sediments surrounding the structure.

(2) Seismic Surveys

Seismic surveys are used to map localized subsurface structural surveys. A seismic (sonic or vibrational) pulse is directed through the earth and the return echoes from the various formations below the surface are recorded by detectors. The depth of penetration of these pulses is determined by the frequency of the impulse and can vary from a few hundred feet to several thousand feet. Generally, various types of surveys are run through an area to obtain information on shallow as well as deep-seated structures.

The surveys are along traverses over the earth's surface with impulses being generated at intervals along the lines. By assembling the data from traverses run in various directions, a three-dimensional picture reflecting the subsurface structural features in an area can be constructed.

In earlier years the energy source for the seismic pulse was an explosive charge detonated in a pre-drilled hole or in the sea. Now, however, vibrator systems, air and gas guns, and sparkers are used, particularly in marine exploration, that provide excellent seismic data without harm to marine life.

3. Drilling for Hydrocarbons

In spite of the many exploration methods in use today, their utility is limited to exposing the possible presence of a hydrocarbon accumulation. The only method of definitely ascertaining the presence of producible hydrocarbons is by drilling.

Drilling may be accomplished by two methods. The older of the two is the cable tool method which involved the use of percussion tools that were repeatedly lifted and dropped on the end of a steel cable to penetrate the sub-surface strata. This method is still in use in some areas for special purposes, and still is widely used in the water-well industry. However, the general method of drilling in the oil industry, particularly offshore, is the rotary method.

a. Rotary Drilling

This drilling method involves the use of a considerable amount of equipment, including, in part, a derrick, draw works, mud pumps, drill pipe and bits. Figure I-27 illustrates a typical set-up.

The drill string, which consists of bit, drill collars, drill pipe, kelly, and swivel is suspended from the traveling block, which in turn is suspended by wire cables from the crown block at the top of the derrick. The cables are connected to the draw works which serves to raise and lower the drill string. The drill string passes through the rotary table on the derrick floor and the kelly, an angular joint (generally square in cross-section) fits in an appropriate slot in the table to give rotational movement to the drill string. The rotary table is also powered from the draw works.

As drilling is continued, additional joints of drill pipe are added to the drill string below the kelly joint. The entire drill string is hollow and attached to the swivel above the kelly joint is a flexible mud line. This line is connected to the mud pump which draws the drilling fluid, or mud, from the mudsump. The drilling fluid is especially composed to obtain the particular chemical and physical properties required for each well.

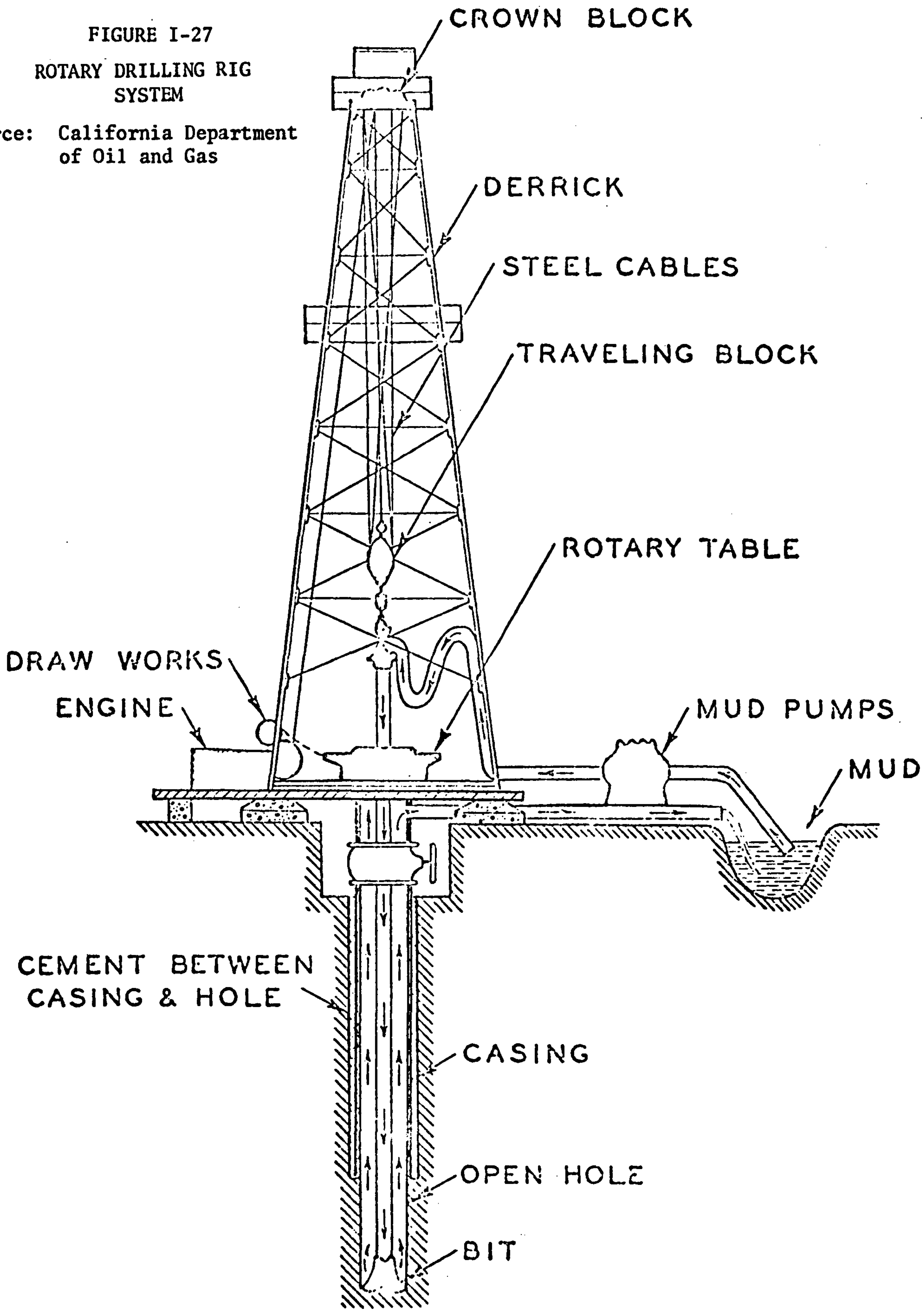
(1) The Drilling Fluid

The drilling fluid, or drilling mud, is pumped down the drill string and out through the bit. The fluid, jetting through the bit, picks up the drill cuttings and carries them up the hole through the annulus to the surface. The mud return line, from the well surface, carries the fluid to the shale shaker. This is a vibrating screen that retains the cuttings, but allows the fluid to pass through and be returned to the mud sump. A generalized mud system is shown in figure I-28.

FIGURE I-27

ROTARY DRILLING RIG SYSTEM

Source: California Department of Oil and Gas



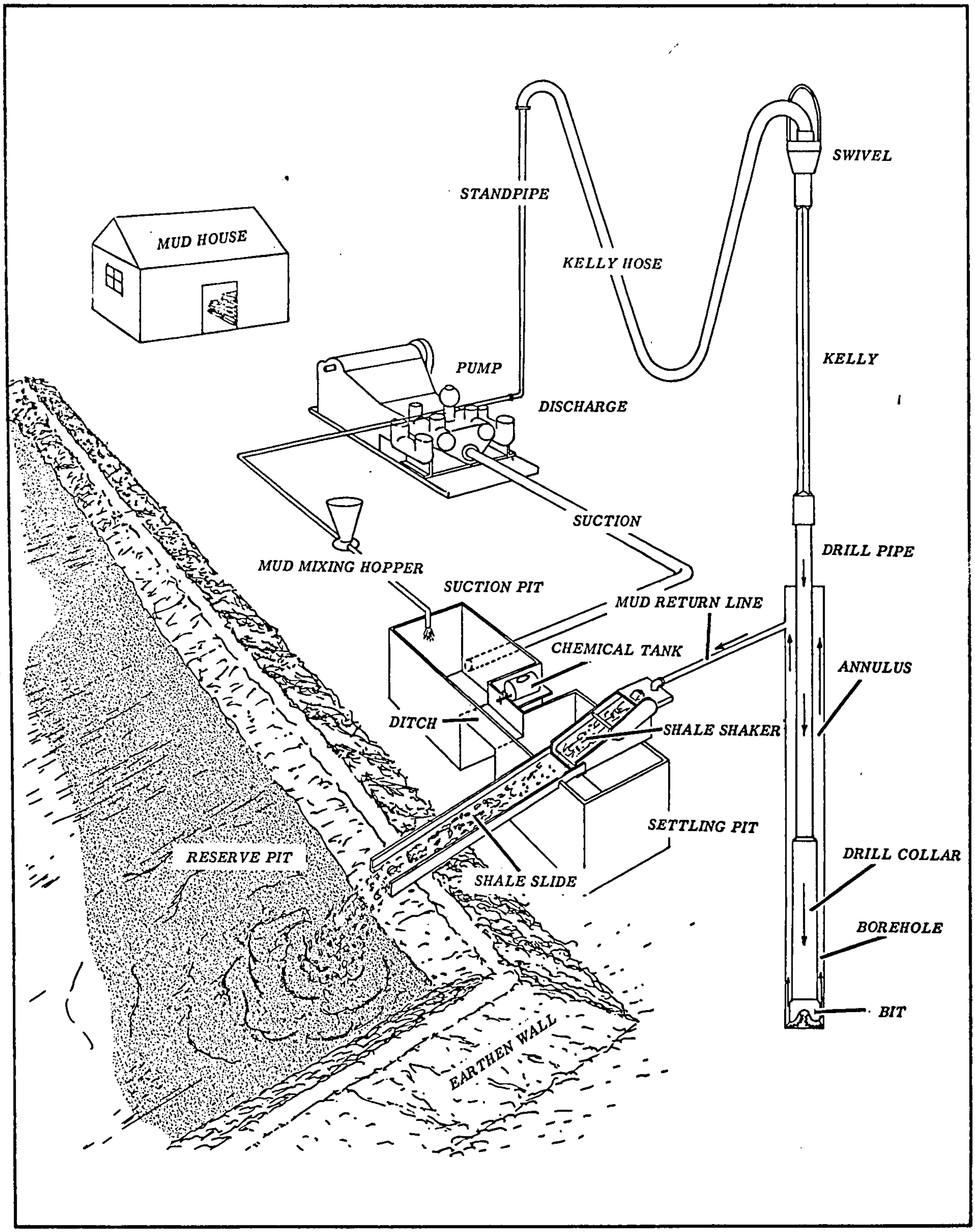


FIGURE I-28

ROTARY RIG FLUID CIRCULATION AND MUD TREATING SYSTEM

Source: Petroleum Extension Service, The University of Texas at Austin, and others, 1973, p. 31.

The drilling fluid is one of the most important components of the rotary drilling system. In addition to carrying the drill cuttings to the surface, it performs other necessary functions. The weight of the column of fluid in the hole is controlled by additives to support the sides of the uncased hole and prevents caving. The weight also prevents the entry of fluid from any porous formation penetrated.

(2) Directional Drilling

Holes may be drilled vertically, as is the usual case, but in cases where the drilling equipment cannot be placed directly over the desired bottom hole location, the well can be deflected both vertically and horizontally to reach the exact location desired. Many wells, particularly in California, have been drilled from shore locations at the ocean's edge to extend out under the sea. Some of these wells have been deflected as much as 70 degrees from the vertical.

(3) Casing

When drilling commences, the first string of casing, or large diameter pipe, is set from the surface to a shallow depth. Depending on the area, this depth may be as little as 300 feet to more than 500 feet. The hole to accommodate this casing may be drilled by the drilling rig or by a lighter rig moved in prior to the drilling rig. The first string, commonly called the conductor pipe is then set on bottom and is cemented from total depth to the surface. The purpose of this casing string is primarily to provide a means of circulating the drilling fluid in subsequent drilling and returning it to the mud pit and to provide a base for the blowout prevention equipment (discussed below in section I.G.3.a.(4)).

After cementing the conductor pipe, the well is then drilled to a depth, depending on the area, below the lowest fresh water zones, but above any potentially productive hydrocarbon zones. A second string of casing, called the surface casing, is then run to bottom and is cemented from the bottom with the cement extending through the open hole and through the annulus between the conductor pipe and the surface string to the surface.

Drilling is then continued to the desired total depth and the final string of casing is cemented. The last casing string is called the production string. In some areas there may be only three casing strings run. In other areas additional strings of casing, called intermediate strings, are run for various reasons. All of the casing run after the surface string may extend from the bottom to the surface, or some may extend from bottom to a point within the next higher string. In the event they do not extend to the surface they are called liners. Casing run after the surface string may also be cemented from bottom to surface or to some point within the next higher string. In the case of liners the cement extends from the bottom to the top of the liner. Usually, at least one of the casing strings run after the surface casing extends to the surface and is cemented to the surface. Most regulatory agencies have regulations concerning the number of casing strings required, setting depth, and cementing procedures.

The number of casing strings run depends on many factors, the type of formations encountered, pressures in the formation, depth of well, etc. As the number of casing strings is increased the strength and security of the well is increased, but each successive string must be smaller in diameter than the preceding string so a carefully considered casing program must be developed prior to drilling. Figure I-29 shows a typical arrangement of casing strings.

(4) Blowout Prevention Equipment

This equipment is set on the conductor pipe and all subsequent drilling operations are conducted through the BOP's, or blowout preventers. They are a series of valves, generally remotely operated and hydraulically or pneumatically controlled. In case the primary well control system, the drilling fluid, fails to prevent a hazardous situation from

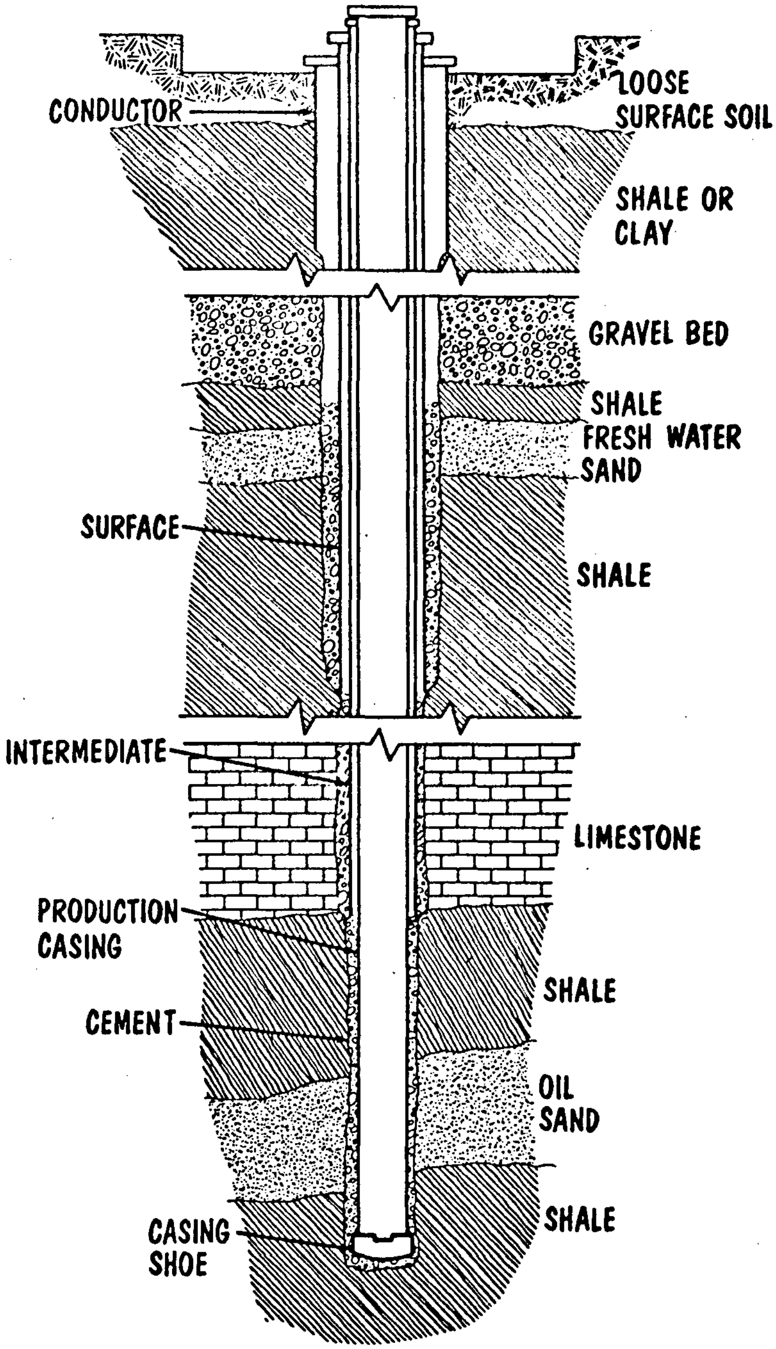


FIGURE I-29

CASING STRINGS AND PIPE USED IN AN OIL WELL

Source: Petroleum Extension Service, The University of Texas at Austin, and others, 1973, p. 48.

developing, this equipment can be actuated to shut-in the well.

There are basically two types of valves. One is an inflatable bag type that will expand around any pipe in the hole and shut off the annular space. The second is a ram type that when actuated will shut off the entire hole. A pipe ram preventer is one that will seal around a particular size pipe in the hole. Another of these types is called a shear blind ram which can shear through drill pipe in the hole and seal in the well. Figure I-30 shows simplified versions of blowout preventer types and figure I-31 shows a typical BOP arrangement for land drilling.

4. Well Completion Methods

When a well encounters productive horizons, it must be completed to make it possible to recover the hydrocarbons. Since there are many types of reservoirs with widely varying characteristics, there are many types of completion procedures.

In the simplest methods, the production casing is cemented above the productive zone and the well is completed open hole. In another method, the production string of casing is set and cemented through the productive zone. The casing is the perforated opposite the productive intervals. Perforating is accomplished in various ways, but generally by bullets (fired from a perforating gun run in on wire line) or by jets. If this casing string extends to the surface it is called production casing, if it does not extent to the surface it is called a blank liner.

In another method, used generally in areas where the producing zone is unconsolidated or friable, the production string is set and cemented above the producing horizon. A production liner is then hung in the production casing and extends through the productive interval. This liner may be

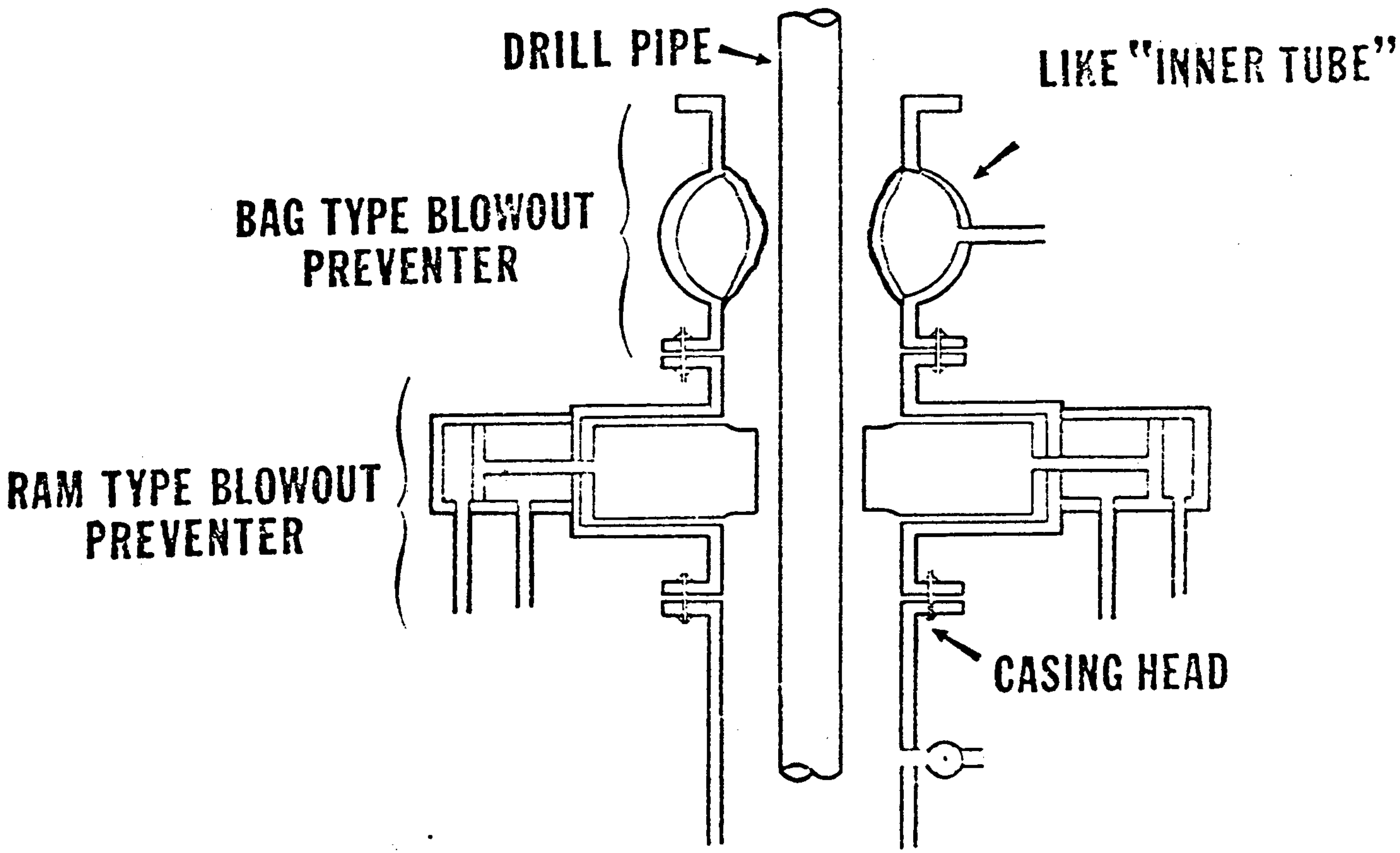
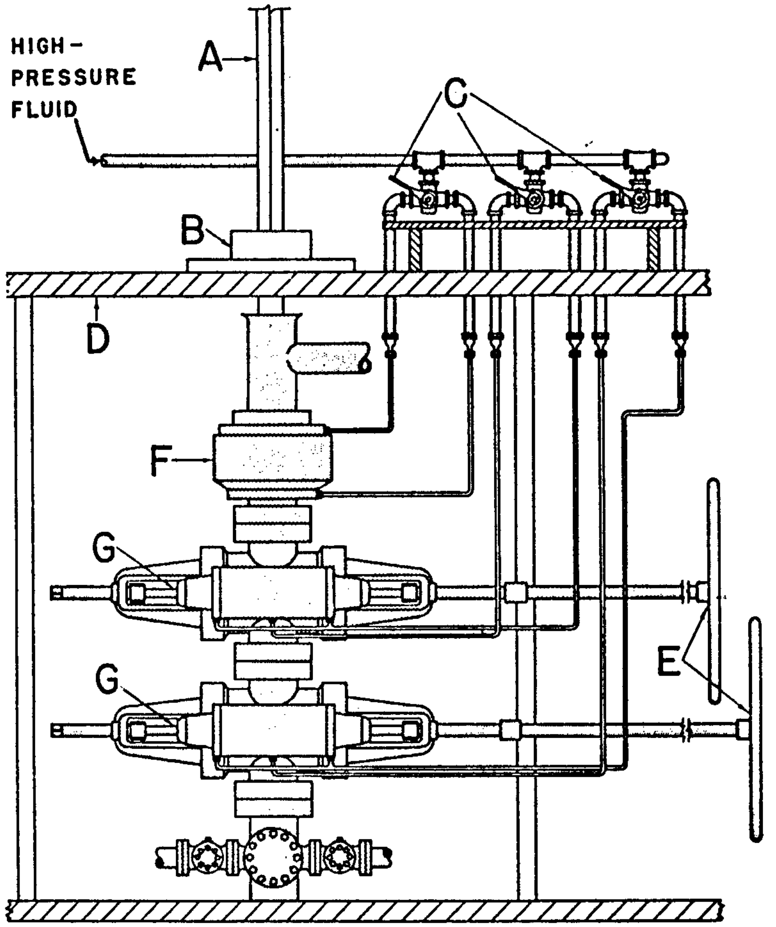


FIGURE I-30

BAG TYPE AND RAM TYPE BLOWOUT PREVENTERS

FIGURE I-31
TYPICAL BLOWOUT PREVENTER STACK ARRANGEMENT



Source: Petroleum Extension Service, The University of Texas at Austin, and others, 1957, p. 45.

KEY

A = Kelly
B = Rotary table
C = Hydraulic controls on derrick floor
D = Derrick floor
E = Manually operated controls on side of substructure
F = Top preventer, which contains large rubber element capable of sealing around any tool protruding through casing head
G = Pipe rams, which close off hole

pre-perforated, slotted, wire-wrapped, or it may be gravel-packed. In the latter case, gravel is placed in the annulus between the liner and the open hole. This type of completion, with many variations, is common in many areas of California. Figure I-32 shows these completion methods.

When the well is capable of production, the tubing is run and hung from the tubing head below the blowout preventers. The tubing is the string of pipe through which the well will produce to the surface. A plug is set in the tubing and the blowout preventers are removed. The well head, a series of surface valves to control subsequent production is then installed, the tubing plug is removed and the well is ready to be brought into production. The tubing strings may be single or multiple. In most flowing wells the tubing is isolated from the production casing by a packer set above the producing formation.

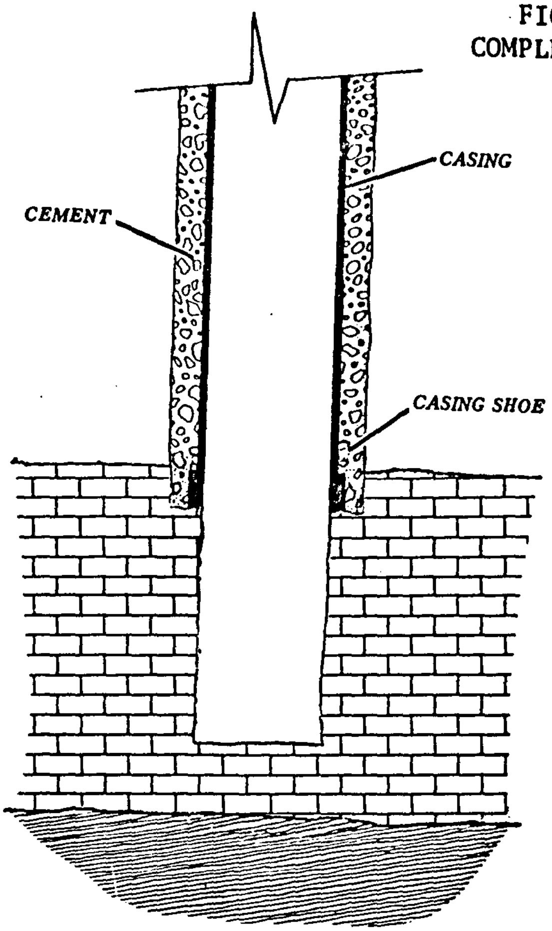
5. Production Methods

Many wells, particularly early in the life of a reservoir, will produce from their own pressure. These are called natural flow wells.

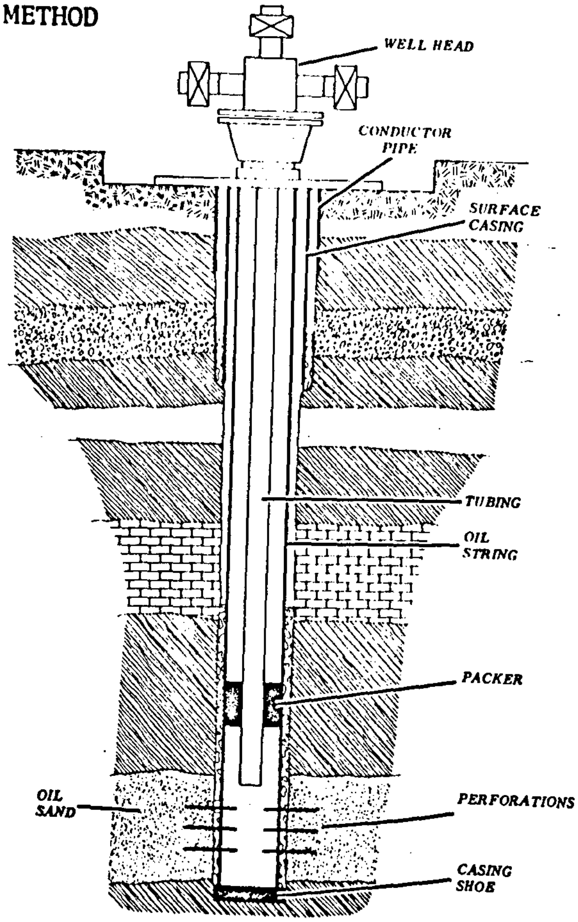
Other wells (and most wells at some time in their life) will require artificial lift to bring oil to the surface. One method is called gas lift. In this method, gas is pumped down the annulus and enters the tubing through a series of valves and commingles with oil in the tubing. This lightens the weight of the fluid column in the tubing and allows the reservoir pressure to produce the oil to the surface.

A second form of artificial lift is used when the reservoir pressure is not sufficient to produce oil to the surface. Various types of sub-surface pumps run into the tubing lift the oil to the surface. The most common type of pumping system is the familiar rod pump. The pump is run in or on

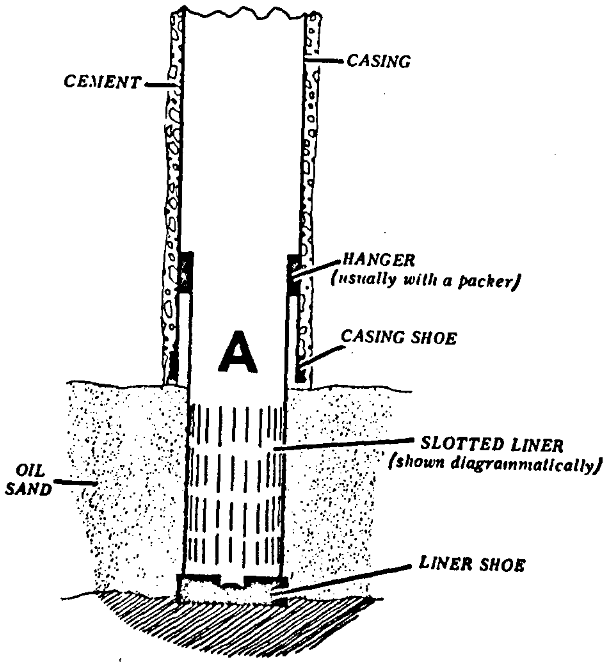
FIGURE I-32
COMPLETION METHOD



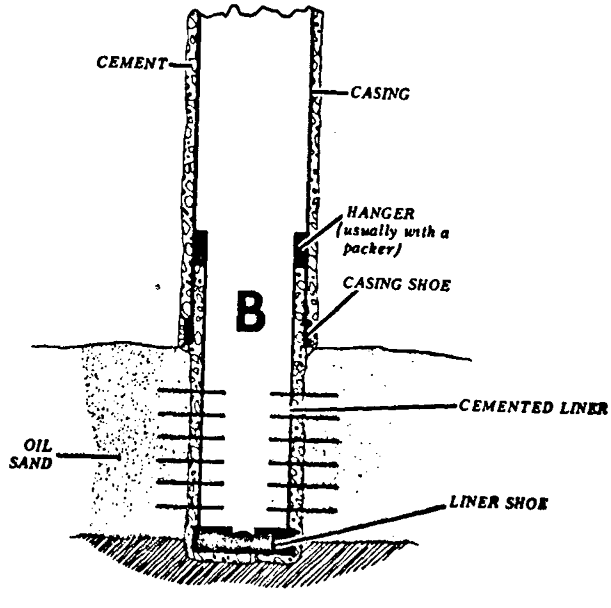
Open-hole completion.



Perforated casing completion.



Slotted liner completion.



Perforated liner completion.

Source: Petroleum Extension Service, The University of Texas at Austin, and others, 1973, p. 64-65.

the tubing and is actuated by rods (lengths of metal bars) that extend from the pump to the surface and connected at the surface to a walking beam. The beam is mounted on a pivot supported by a pedestal. The other end of the beam is actuated by a motor through a series of linkages to give the familiar up and down motion to the rod string. More recent pump developments include electrically operated submersible pumps and down-hole hydraulic pumps.

Whatever the means of production, the production is directed through a flow line connected from the well head to a production station. The first stage in the production station is generally a separator where gas and oil are separated. The gas then flows to a gas pipe line for delivery to a gas facility. The oil may flow or be pumped to a treating facility (for water removal, etc.), to a collecting tank, or to an oil pipeline.

6. Improvement of Production Rate and Recovery

a. Application of Improved Technology and Equipment

Improved technology and equipment is a subject difficult to evaluate since it covers a very broad range of possibilities. Also it is a field that is constantly changing and, in addition, any improvement derived from improved technology or equipment would depend to a large extent on the reservoir characteristics.

Some methods of productive improvement that can be considered are:

(1) Drilling Fluid and Completion Fluid Design

The quality and composition of the fluid used in drilling through the productive zone and the fluid used during the completion phase of the well are very important in determining the productive capability of the well as compared to the potential productive capability of the well.

Some reservoir rocks may contain quantities of clay that swell on contact with water and reduce the permeability, or clays may wash out reducing the competency of the reservoir rock, or water in the interstitial spaces can itself reduce permeability to oil, or emulsions can be formed in the reservoir to reduce permeability, or the filter cake formed on the face of the well bore can partially block production--there are many possibilities, each dependent on reservoir characteristics and the fluids introduced.

(2) Clean-up Fluid Design

Several types of fluids have been designed to repair damage around the well bore after completion and after extended production. The type depends on the character of damage and the intent in their use is to restore reservoir permeability to its original state. Mud-acids are used to remove particles left after completion or deposited after a period of production. Various detergent type fluids are used to break down emulsions and clean up the formation around the well bore. Various petroleum-based products such as diesel fuel are used for the same purpose. Aluminum hydroxide may be used to reduce clay swelling that results in reduced permeability. Many other chemicals are used for other purposes, such as scale buildup on liners.

(3) Liner Design and Sand Control Techniques

Many of the shallower reservoirs in California are composed of sandstones in various degrees of competency. The production of sand with the reservoir fluid leads to a great many problems: the well itself can plug up and therefore require frequent cleanouts in order to be able to produce; sand traveling with the production fluid can cut out production equipment downstream from the well; and, most seriously, sand caving in the vicinity of the well bore can reduce permeability in the peripheral zone, the most critical area, to the point where the well may not be able to produce. Normally, therefore, the ideal completion technique is to leave the area around the well bore in an essentially undisturbed state during the productive life of the well.

Several liner designs have been used in an attempt to attain this ideal. Slotted liners, where the slot size is determined by the sand grain size and distribution have been developed. Other liner designs, such as wire-wrapped and gravel pre-packed have also been designed to solve this problem. One of the more successful solutions has been to run the liner and then gravel-pack the annular space between the liner and the well bore.

Several other sand control methods have also been devised for sand control. Generally they involve injecting a sand consolidation fluid in the area around the well bore. Various types of plastic compounds that are injected as a fluid and later set up as a honeycombed solid are used for this purpose. Other methods involve injecting various chemicals for the same purpose.

(4) Pumping Methods and Pump Improvement

The familiar rod pumps actuated by a walking beam are still used on land and in some offshore areas, but they are not too practical for offshore application, especially in deeper water where platform space is at a premium. Platform construction is too expensive to allow for space taken up by the large pumping units.

When pumping is required on offshore wells, and for special applications on land, the usual choice is between a down-hole submersible pump and a hydraulic pump. The former is an electrically operated rotary pump characterized by high volume delivery while the latter is a hydraulically operated piston pump.

The original submersible pumps were run on tubing, but models have been developed to be run on wire line. Besides high volume capability the only surface requirement is an electrical source. These pumps are especially suitable in wells with high water cuts, such as fields with water injection, where a large volume of fluid with a relatively low percentage of oil can be economically lifted. A primary problem is scale control, due to produced water, and this problem can be solved by proper chemical treatment.

There are several variations of the hydraulic pump, but basically it is a piston-type pump actuated by a power fluid pumped down the tubing or through a power line run in conjunction with the tubing. Some pumps are run on the tubing, others are pumped down the tubing and are retrieved by reversing the flow direction. The latter quality is a big advantage in offshore situations since no extra equipment is required to service the pump. A surface pump and power source is required for the power fluid, but the space required is relatively small. Originally one problem was that their efficiency was greatly diminished by even low quantities of gas produced with the oil, but this problem has been largely solved by improved design.

In some hydraulic pump designs the power fluid is returned to the surface commingled with the production fluid. This offers an additional advantage where production is heavy and viscous and a lighter oil is available for power fluid. Commingling decreases viscosity and specific gravity of the produced fluid and increases pump efficiency.

(5) Wax and Scale Control

Accumulations of wax or scale can seriously limit a well's productivity. Waxy deposits are a problem where oil has certain characteristics. Deposits are generally a result of a decreasing temperature up the hole and deposits can create a problem in the tubing or further along in the production flow pattern. Both mechanical and chemical methods are used to remove these deposits.

Scale is generally deposited from chemicals included in the water produced with the oil. It can severely limit production through liner slots and also create high losses in pump efficiency. Treatment is usually chemical and depends on the characteristics of the scale deposit. The chemical is usually injected continuously, or in batches, down the casing, but occasionally elaborate cleanout measures are required.

(6) Emulsion Control

Many reservoirs, with the proper combination of characteristics between oil and water, temperature, etc., produce an emulsion that is extremely difficult to break down. However, this is largely a question of economics, since, given the proper equipment (heat and/or electrolytic sources) and chemical treating facilities, most emulsions can be broken down. If treatment were required on an offshore platform the problem of space could be the most important factor.

These are only some examples of methods that may be used to increase production from wells through improved technology and equipment; there are undoubtedly many other methods such as improving completion techniques in shutting off gas and/or water, improving cementation methods, improving wireline techniques and tools, improving clean-out methods, etc. In general, none of these methods, nor those discussed above, will improve the potential, ultimate production from a reservoir. They may help to reach this potential and they may also help to improve the rate of production. They may simply improve the economics of production and therefore increase the ultimate production from a reservoir that may economically be reached. In many cases improved technology will result in obtaining part of the potential that would otherwise not be recoverable.

b. Applying Production Stimulation Techniques to Existing Production

Stimulation techniques are those which improve the existing, natural, productive capability of the reservoir and therefore increase the ultimate recovery that can be obtained from the reservoir. Most of these techniques are based on increasing the natural permeability of the reservoir. Several methods have been designed, and used, among which are:

(1) Acidizing

This is probably one of the oldest stimulation techniques and is generally most effective in limestone reservoirs or in sandstone reservoirs with a calcareous type of cemention. Basically, the acid dissolves a portion of the reservoir rock and thereby increases permeability. In other types of formations, special acids (hydrofluoric and various mixtures) have been used with varying degrees of success.

(2) Fracturing

This stimulation technique involves pumping a fluid, under high pressure, down the well bore to the productive formation. When the pressure exceeds the fracture pressure of the formation, the rock ruptures. Generally, a propping agent is introduced with the injected fluid after the fracture is induced. The propping agency may be one or more of a variety of materials: sand, walnut hulls, glass or metal beads, etc. The propping agent serves to hold the fracture open when the injection pressure is removed. The fracturing fluid may be water or oil, gelled mixtures of either, or other fluids. The type used is dependent on all characteristics of the reservoir, as is the selection of propping agent.

(3) Steaming

Unlike the above examples of stimulation, this technique is not based on improved rock permeability. It is generally used in reservoirs containing low gravity and high viscosity crude oil. The purpose is to heat the oil and thereby reduce the viscosity. The method used is called "huff and puff" and consist of injecting steam for a period of a few days to increase reservoir temperature. The well is then returned to production until the temperature, and therefore production, declines and the process is repeated. Three principal factors determine the productive capability of a reservoir, the pressure drop across the reservoir, the permeability, and the viscosity of the produced fluid.

All of these methods, while not applicable to all reservoirs, will result in higher ultimate recovery and, in many cases, can permit production from reservoirs otherwise not producible.

c. Secondary Recovery Techniques

As a reservoir goes through the primary stage of production the reservoir pressure steadily declines and the production rate declines. Eventually a point is reached at which the reservoir will no longer produce, or at least a point will be reached at which it can no longer be economically produced. When this point is reached, none of the methods previously discussed will help to increase production and generally there is a considerable amount of oil left in the reservoir.

(1) Reservoir Drive Mechanisms

Several methods have been devised to continue production from a reservoir past the point at which it would normally be capable of producing. When these methods are used fairly early in the productive life of the reservoir, the technique is called pressure maintenance. When these methods are used late in the life of the reservoir the technique is called secondary recovery. Whatever the terminology, the purpose of the technique is to maintain, or restore, the reservoir pressure as long as possible at a level that will permit continued production.

All the methods used involve the injection of fluid to replace fluid extracted from the reservoir and thus maintain or restore reservoir pressure.

The method selected will depend on the original reservoir energy source, or, drive mechanism. Basically, reservoirs can be divided into three general types depending on the drive mechanism.

(a) <u>Gas Cap Reservoir</u>

In many reservoirs there is an accumulation of gas above the oil which is called a gas cap. When a well is completed to the oil zone and the pressure is reduced, the gas cap expands driving the oil to the well.

(b) <u>Solution Gas Drive</u>

Other reservoirs have no gas cap originally in place. However, there is always gas, in varying quantities dependent on the oil characteristics and the temperature and pressure of the reservoir, dissolved in the oil. As the pressure in the reservoir around the well bore is reduced, gas will come out of solution and as it expands will drive the oil to the well bore.

(c) <u>Water Drive</u>

Other reservoirs have an accumulation of water below the oil zone. If the structure is such that the reservoir formation folds up from below the water-oil contact the difference in hydrostatic pressure will maintain a pressure on the oil zone as oil is produced. When the water-leg, or aquifer, continues to the surface at some point, the water will be continually replaced and result in an artesian type drive as oil is produced. Even though water is considered to be practically incompressible, where the volume of water is large in comparison to the volume of oil, the relatively low expansibility of water can become significant. As oil is withdrawn, water will expand to occupy the space vacated by oil and in turn will be replaced by water from the contiguous surrounding water zone.

While examples of each type of reservoir do exist, most reservoirs consist of a combination of these mechanisms, at least at some point during development. The method of secondary recovery technique to be used will depend on a careful consideration of the reservoir drive mechanism and the method selected will be the one calculated to result in the greatest benefit. To be most effective, the reservoir as a whole must be considered and injection well patterns must be designed to give maximum results.

(2) Gas Injection

Generally gas injected to a reservoir is gas that has been produced from the reservoir, treated to remove hydrocarbon liquid components, and then compressed and re-injected as dry gas. Each time the gas passes through the reservoir the dry gas will pick up liquid components which are in turn removed and the dry gas is again returned to the reservoir. This process is called cycling and may not be considered as secondary recovery, but it does decrease the rate of reservoir pressure decline and therefore increases recovery.

In addition to produced gas, gas from outside sources may also be injected.

Due to the increased volumes involved, the rate of reservoir pressure decline can be reduced substantially.

(3) Water Flooding

Water injection is by far the most common, and successful, secondary recovery method in use in the United States. Ideally the quantity of water injected is that required to replace the volume of liquid withdrawn from the reservoir. However, unless injection is started early in the life of the field this may not be practical. But, as water is injected a front develops that picks up and drives the oil ahead to the producing wells. The water injected must be selected and is usually treated so as to minimize harmful effects on the reservoir. Produced water is re-injected and can be augmented by water from other sources.

(4) Miscible Fluid Injection

Miscible fluid injection is really a modification of the primary fluid injection methods discussed above. For example, in a gas injection project, a slug of propane or other light, liquifiable hydrocarbon that is miscible with both oil and gas is injected ahead of the gas. A liquid front or bank is thus established between the oil and gas that serves to drive the oil to the producing wells. This results in a greater recovery efficiency and leaves less oil behind in the reservoir. Similarly, in water injection projects, slugs of glycol and other alcohols, kerosene or diesel oil, and various detergents may be injected ahead of the water for the same reason.

While not exactly a miscible fluid process another method of improving sweep efficiency is sometimes used in water injection projects. Since the permeability characteristics of most reservoirs are not uniform throughout the reservoir, fingering can result. The water injected will follow the path of least resistance leaving behind oil in the less permeable zones. Slugs of various gelling agents will be injected which will penetrate the higher permeability zones and reduce their permeability. On resumption of water flooding, the originally low permeability zones will be flooded and a more regular front can be maintained to improve sweep efficiency.

(5) Thermal Recovery

The primary method of thermal recovery today is steam injection. It is similar to the stimulation method described in sec. I.G.6.b.(3) but differs in that the steam is not injected in the producing well, but is continually injected in a steam injection well. It is also similar to a water flood in that the steam will heat the reservoir rock and fluid and condense to form a bank driving the oil to the producing wells. It is primarily used in reservoirs with low gravity, high viscosity oil and is not as widely used as the "huff and puff" technique discussed under section I.G.6. b.(3).

(6) In-Situ Combustion

This process, also called fire-flooding, involves ignition of the reservoir fluid. This is accomplished by injecting air, or oxygen bearing gas, into the reservoir to the point where it will spontaneously ignite or it may be ignited by other means. A combustion front will develop that travels from the injection well toward the producing wells driving oil in front of it. Extremely high recoveries have resulted where the proper conditions were present. It is primarily used in reservoirs with low gravity oil and can be used in reservoirs with low permeability. Combustion consumes but a small portion of the oil in place. The heat increases the oil gravity in place and reduces the viscosity, gas produced ahead of the front creates pressure to drive the oil.

(7) Tertiary Recovery Methods

Tertiary recovery methods are generally, to date, those employed as secondary recovery methods. After the primary recovery process is complete, a secondary method can be used to recover additional oil. If sufficient oil is retained in place and a feasible method can be devised, production can be continued through a third phase.

(8) Potential Recoveries through Secondary Means

The potential recovery from an oil reservoir by primary recovery methods can vary widely depending on reservoir characteristics. It may be as low as 5 percent of the oil in place to as much as 80 percent under ideal conditions. The average recovery is probably between 20 and 30 percent.

Gas injection methods can increase primary recovery by an additional 25 to 50 percent of the oil in place.

Water injection may increase primary recovery by an average of about 30 percent.

Miscible fluid injection may recover as much as 45 to 70 percent of the original oil in place.

Thermal recovery (steam injection) is very efficient and can result in recoveries as high as 50 percent or more of the oil in place. Since, in many cases, practically none of the oil could be recovered by primary means this is an impressive figure.

In-situ combustion appears to be the most efficient process of all and recoveries above 80 percent of the oil in place have been obtained. However, it, like miscible fluid injection, is still in an experimental change and procedures and methods are in a developing stage.

As previously mentioned, these methods are limited in application to compatible reservoirs. For example: water injection requires a reservoir with fairly high permeability, but more important, relatively uniform permeability; thermal and in-situ combustion methods have so far been limited to shallow reservoirs, etc.

APPENDIX I-3
(Subsection H)

BACKGROUND AND HISTORY OF OFFSHORE TECHNOLOGY

This subsection is not especially essential to the main purpose and needs of the Environmental Impact Statement and does not relate solely to the Santa Barbara Channel (therefore it is included as an Appendix at the end of section I), but it may serve to clarify some of the subjects discussed throughout the Statement.

Offshore development was originally conducted in much the same manner as onshore development. Because of the differences in operational requirements environmental quality considerations, particularly as the search for oil progressed to deeper and deeper water and the distance from shore increased, various new methods of accomplishing the basic requirements for oil field development under these conditions were devised.

Offshore technology, as related to the drilling and production of oil wells, has progressed a great deal since the earliest offshore wells were completed off southern California and in the relatively calm and shallow waters of the Caspian Sea and Lake Maracaibo. Offshore production was initiated in Summerland, California, in 1896, when a well was completed under the Santa Barbara Channel from a pier extending from the beach. However, probably the most significant major advances in technology, as related to the present state of the art, began about 35 years ago when oil drilling began in the Gulf of Mexico.

1. Early Offshore Wells

The first offshore wells were drilled from wooden piers extending from shore. In the early 1920's, single well platforms, usually close to shore and in shallow waters, were constructed on wooden piling driven to resistance in the sea bottom. All the drilling equipment, materials and supplies were contained on the platforms.

Production, or collecting, stations were built on separate, but similar, platforms and the platforms were connected by walkways also supported on piling. Flow lines were led along the walkways to the production station. Since most operations were close to shore another walkway would be built connecting the installation to shore and carrying the pipeline to shore.

These operations were common in Lake Maracaibo and in the southern California area such operations were conducted in the 1920's and even earlier at Summerland, Elwood and Rincon in the Santa Barbara Channel area.

The first advance came in the 1920's when drilling tenders began to be used. Platforms were constructed as before, a derrick would be erected on the platform and the drilling equipment: drawworks, rotary, engines, etc. would be installed. A tender barge would then be moored to the platform. The barge would carry mud and supplies, the mixing and sump tanks, mud pumps and required pipe. In this manner the platform size and cost was reduced. Figure I-33 shows a modern tender-assisted fixed offshore drilling platform.

All the operations required to drill, complete, and produce the wells were the same as for an onshore well. The only difference was that the conductor casing and subsequent casing strings extended above the sea floor to a point below the drilling platform. The principal problems at this point in time were not connected with drilling and producing, but with platform construction.

As the search for oil progressed to deeper water the first change in procedure was that pipelines were laid on the sea floor and connected to the platforms

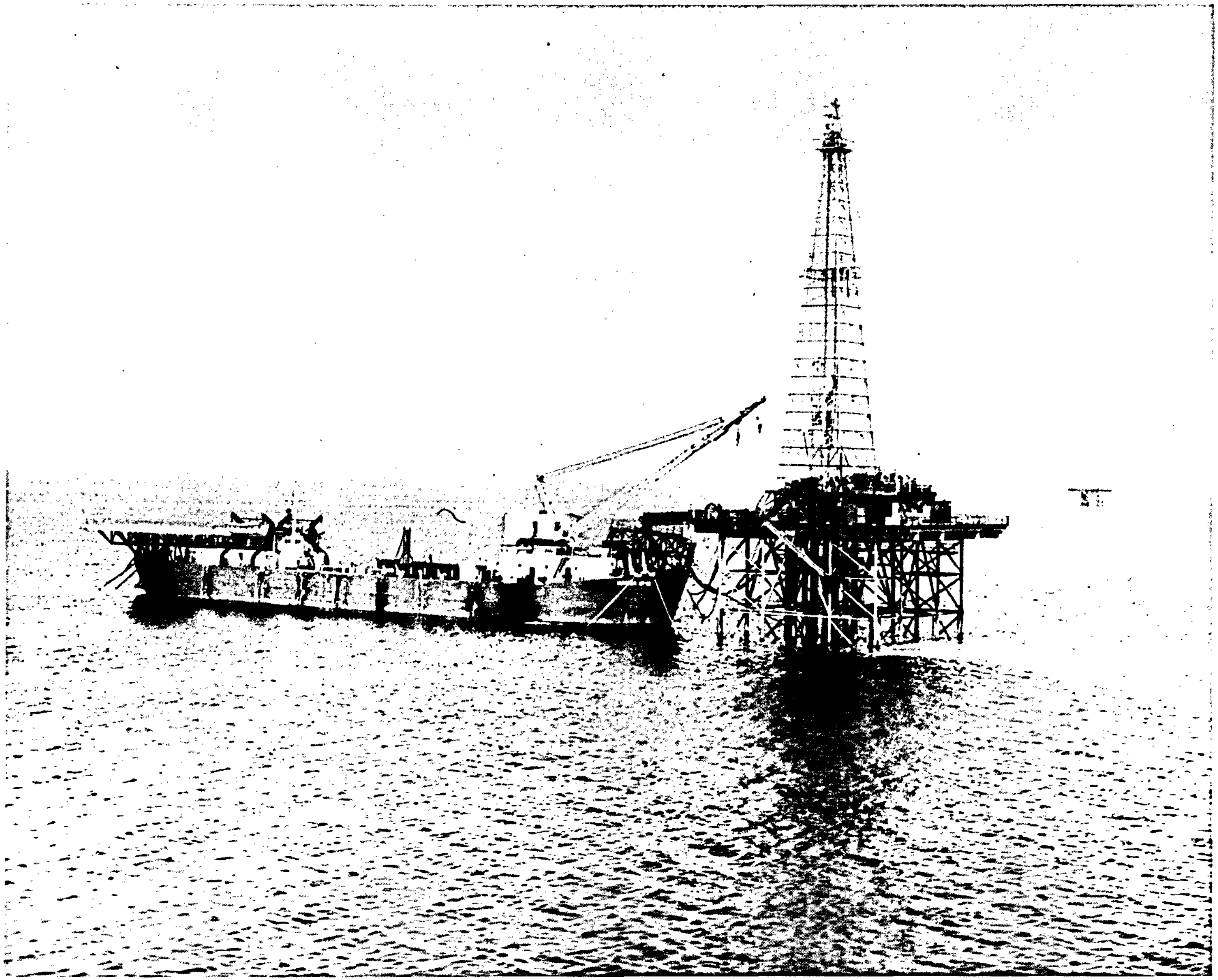


FIGURE I-33 TENDER ASSISTED FIXED DRILLING PLATFORM by risers. This change was due to the increasing cost of driving piles as the water depth increased. For the same reason, multiple well platforms where several wells were directionally drilled from a common platform began to be used.

During this period, improvements were made in many phases of the technology. Pile construction methods were improved as were the driving techniques. The first concrete piling was used in Lake Maracaibo and in 1940 the first application of steel piling was used in the Gulf Coast area. Pipe laying procedures were improved and pipes were coated, both for protection and for the necessity to reduce their buoyancy as water depth and pipe sizes increased. In 1934 the first underwater pipeline burying machine was used in Galveston Bay. Cathodic protection measures began to be used to protect pipe from corrosion. To reduce costs, drilling equipment was split into modular units so that the units could be placed on the platforms in single lifts, without the expensive rig-up time and derrick construction time previously required. Drilling techniques also improved, but were still primarily developed on the same lines as those used on land. In 1933 a notable advance in offshore technology was made with the first offshore geophysical surveys carried on by boat in Galveston Bay.

2. Mobile Drilling Platforms

As the platform costs increased it was recognized that exploratory drilling costs could be substantially decreased if the drilling platform were movable. In the case of a dry hole, the cost of a permanent platform is essentially unrecoverable and in fact represents an additional expense for removal.

The first movable platforms designed for offshore work were barges designed to be moved to the location and sunk in place to rest on the bottom and provide a stable drilling platform. These were first used in the shallow waters off Louisiana in 1933 and some are still in use. Naturally their utility is severely limited by the water depth.

In the early 1950's jack-up drilling platforms were developed where the drilling equipment, derrick or mast and draw works were mounted on a floating platform. The platform was equipped with "legs", three or more, which were connected to "jacks", by means of which the legs could be raised or lowered. On arrival at the location, the platform was moored in position and the legs lowered to the sea floor. Then, as the legs took the weight, the platform was raised the required distance above the water surface. A tender barge was then moored to the jack-up and drilling proceeded as from a permanent platform.

If the well was successful, a permanent well platform was constructed at the site after the jack-up departed. This platform could be constructed much less expensively than a permanent drilling platform since it was not designed to carry the load of the drilling equipment. In case additional work, requiring drilling equipment, was necessary at a later date, the jack-up rig could be moved in over the small production platform.

Although jack-up rigs similar to those described above are still in use, later models have been designed and are in use. Some have much larger platforms with all drilling equipment and supplies, including mud and pipe, carried aboard. Some of these rigs are also self-propelled. Most of these larger rigs have crews' quarters and facilities, as well as heliports. Figure I-34 shows a transition type jack-up, constructed in 1957 for use in

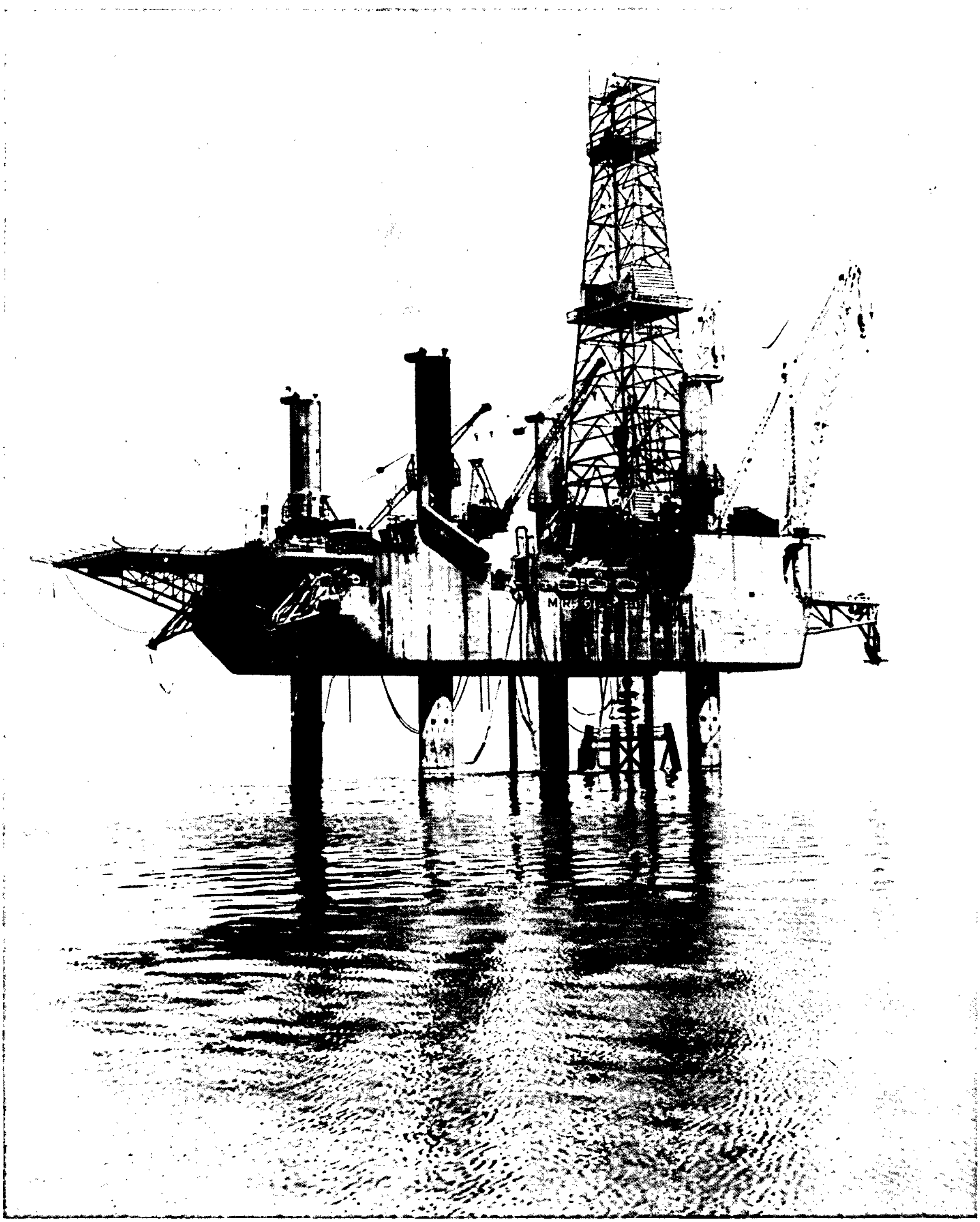


FIGURE I-34 FOUR LEG JACK-UP MOBILE DRILLING PLATFORM

180 feet of water.

There are certain limitations in the use of jack-ups. As water depths increase, the supporting legs must be heavier and the power required to elevate and lower the platforms increases rapidly. It is obvious that at some point the cost will make the jack-up uneconomic. Jack-ups have been designed, and are in use, for water depths to 400 feet, and more, but newer models are generally being designed and built for maximum water depths of about 350 feet. The bottom supported rigs are moved from one location to another with the legs raised and are most vulnerable to damage or loss while in transit. Drilling operations from the mobile, bottom supported, platforms are still essentially the same as for fixed platform drilling.

3. Floating Drilling Platforms

a. Drill Ships

For drilling in deeper waters, drillships and barges were designed. These, beginning about 1950, were conventional hulls with drilling conducted from a platform over the side or stern, or through a well cut through the hull. Later models are designed and built on hulls expressly designed for the purpose.

Earlier drilling was conducted with the vessel moored in place by an anchoring system with the tension on the anchor lines keeping the vessel in place. In most of the later models position keeping is aided by the use of "thrusters" (jets or propellers acting in different directions). The thrusters are actuated by a signal sent from a computer system which receives its input from either, or both, of two systems: (i) the angle of displacement from vertical of a line attached from the vessel to the bottom; or (ii) a sonar signal measuring the position of the vessel relative to a sonar beacon fixed in place on the ocean floor. More recently, such vessels have been designed with computer controlled, dynamic, positioning equipment designed to keep the vessel in place without the use of anchor systems.

The earlier use of this type vessel was restricted to drilling and coring uncased holes, with no returns, for geological information. In this case the vessel need be on a particular location only a short time since drilling depths below the ocean floor are relatively shallow. Later, these vessels were used to drill regular cased wells with returns to the surface as in drilling on shore or from fixed platforms.

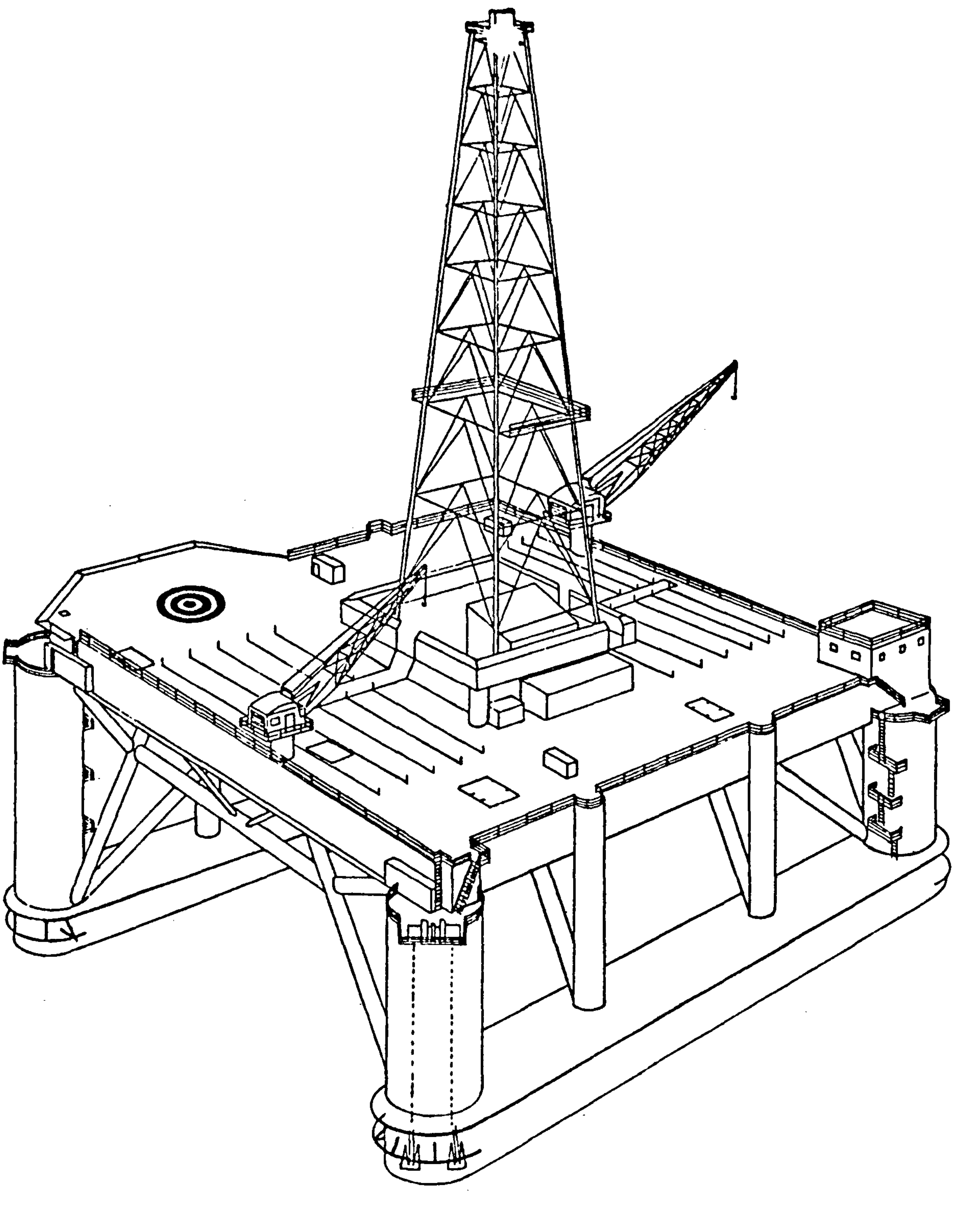
b. Semi-Submersibles

By 1963 the first semi-submersible floating drilling platform was completed. These differ from conventional drilling ships in that the drilling platform is supported on legs extending from buoyant pontoons or chambers. When moving from one location to another, the buoyancy chambers are evacuated to give maximum buoyancy and the vessel is supported by them. On arrival at location, the chambers are flooded to partial buoyancy sufficient to support the platform the required elevation above the ocean surface. The advantage of this design is that the center of gravity is lowered and the buoyancy chambers are below the surface of the water. This minimizes the response to wave forces and stabilizes the motion of the drill string and working floor. Figure I-35 shows one version of a semi-submersible, built in 1972 for use in water depths of 600 feet and with a drilling depth capability of 25,000 feet.

The first semi-submersibles were designed to be moved from location to location using towing vessels, but later designs are self-propelled. These vessels are held in place at the drilling site using the same systems as the drill ships and the drilling techniques are the same for each type of vessel.

FIGURE I-35

SEMI-SUBMERSIBLE DRILLING PLATFORM



Source: Western Oil and Gas Association,
Outline of Anticipated OCS Platforms

There are differences of opinion as to which type of floating vessel is the better. Each has its advantages, but it is generally agreed that the semi-submersible is the more stable platform and it is preferred for use in areas where storms and rough seas are prevalent. The primary advantage of the drillship is its mobility and it may be preferred where exploratory locations are far apart, particularly if the area is not in a severe weather zone. The drillship is also generally somewhat less expensive than the semi-submersible.

c. Floating Drilling Techniques for Cased Holes

With this type of drilling a whole new drilling technology was required and developed. It is still in a formative phase with changes developing so rapidly that statements about techniques may be outmoded as soon as they are made.

After arriving on location a drilling template equipped with guidelines, is set on the sea floor. This serves as a guide for subsequent drilling operations. Conductor casing is set and cemented through the template and the blowout preventor stack is connected at the sea floor. Up to this time there are no returns to the surface from drilling. A riser pipe is connected to the blowout preventor stack and extends to the drilling vessel to permit returns to the vessel during subsequent drilling operations. If the well is completed for production, the wellhead is also placed on the ocean floor.

Earlier drilling of cased wells from floating vessels required the use of divers, but more recent systems do not require divers. Some systems use television as an aid in performing the various operations, others are mechanical. All controls are actuated by remote control from the drilling vessel, electrically, hydraulically or pneumatically.

It should also be mentioned that adequate tools are available to directionally drill from a floating vessel, controlling both wellbore angle and direction. The technique used is the same as that used on land or platform wells. Five of the exploratory wells drilled in the Federal area of the Santa Barbara Channel by floating vessels were plugged back and directionally drilled to new objectives with maximum wellbore angles ranging from 24 to 38 degrees.

It is of interest to note that cores (from uncased holes with no returns to the surface) have been recovered in water depths of over 20,000 feet. Such core holes have also been successfully re-entered after tripping the pipe with the vessel dynamically positioned. Cased holes have been successfully drilled in water depths down to 1,400 feet. A well drilled and completed (left in condition to be re-entered) by the Shell Oil Company off Borneo in 1,170 feet of water was successfully re-entered without the use of divers. Also, Shell has successfully drilled a cased hole in 2,150 feet of water off Gabon.

d. Subsea Completions

Originally, and generally to date, floating vessels were primarily used to drill exploratory wells, with the wells considered to be expendable. After testing, the exploratory wells were abandoned and development wells were drilled from fixed platforms. Drilling from a fixed platform has a number of advantages, the primary one being that wells can be drilled as from shore locations with all valves and connections at the surface. However, there is a practical depth limit for fixed platforms. Costs increase geometrically with depth and it is generally conceded that presently a maximum depth limit of about 1,200 feet approaches this limit.

Exploratory sites, while understandably not always located at the most desirable spots for maximum reservoir drainage, are expensive to drill and saving the wells for future use in field development would represent a significant economic advantage. For this reason many exploratory wells are now only temporarily abandoned with provisions left for the well to be re-entered at a later date for a subsea completion. Or wells may be completed after testing as a subsea completion.

Several different sorts of subsea completion systems have been developed. The simplest is the so-called "wet" completion, where the wellhead valves and connections are located on the ocean floor. Valves can be manipulated and connections can be made by divers or by remote mechanical control from the surface. Some systems use television to perform these functions, others use purely mechanical methods. These systems have been extensively tested, usually in fairly shallow water, to date, and their practicality has been proven.

Shell Oil Company has successfully completed several wells in the Molino gas field in the Santa Barbara Channel at depths of up to 275 feet. Phillips Oil Company has completed wells at depths of 230 feet in their Ekofisk field in the North Sea. These completions were made with the use of divers. Many other similar completions have been made in other parts of the world including the Gulf Coast and the Persian Gulf.

The earlier subsea completion systems required the use of a surface vessel and, in some cases, divers, to perform any down hole maintenance. Now, systems have been devised to use pump down tools in conjunction with wire-line methods to perform many functions. With these tools, the only time a surface vessel would be required would be to perform major down hole work such as a workover.

Since diver capabilities are limited by water depth, other procedures, involving protective capsules or hemispheres over the wellheads and other production equipment are being developed by Shell, Exxon, and other companies. Those procedures involve the use of an entry lock on the protective capsule and a second personnel vehicle that can be lowered to the capsule, attached to the entry lock and permit personnel to work at atmospheric pressure. Extensive surface tests of these systems have been conducted to demonstrate their feasibility. In September, 1972, Shell installed such a subsea completion on a well in the Gulf of Mexico in 375 feet of water. In September of 1973 the well was successfully re-entered for routine maintenance. Shortly it is expected that field tests will be initiated for multi-well manifold systems and complete production systems.

Diver operated facilities have a depth limitation due to diver capability. Routine dives are presently made to about 600 feet with a potential capability of about 1,000 feet. Systems using surface remote control of operations and the capsule system have a present probable technical limitation of about 2,000 feet.

e. Production Facilities

Generally, production facilities for these wells are either onshore or on nearby platforms. However, a diver operated complete production facility including separators and transfer pumps is in operation in the Arabian Gulf in 70 feet of water. The facility is operated by the British Petroleum Company and the Compagnie Francaise de Petrole.

As mentioned above, field tests are expected shortly for protective capsule systems over multi-well manifolds and complete production facilities that will permit work under water at atmospheric pressure.

4. Present Trends in Offshore Production

In the earlier days of development drilling, the wells were drilled from a drilling platform. The well's production was then delivered to a nearby production platform that contained the required production facilities such as separators, treaters, gauging facilities, temporary holding tanks, transfer pumps, etc.

However, with increasing water depths and rising costs of platform construction, many platforms are now used for both drilling and for production facilities. Most platforms have more than one deck each of which may be used for various purposes. For example, one deck may be used for drilling. Wellheads are generally located below the drilling deck and in the case of a platform from which many wells are directionally drilled there may be more than one level containing the wellheads. This permits a staggered wellhead arrangement and thus increases the number of wells permitted in the horizontal space occupied by the platform. Production facilities, crews accommodations, etc. may be located on one or more additional levels.

These platforms and, in general, most deepwater platforms are pre-fabricated, from steel, on shore and floated to the location and sunk in place. Most of the platforms are fixed to the sea floor by piling, but some are fixed by gravity. More recently, structures of concrete have been developed.

Storage facilities for offshore wells have in the past generally been located onshore. But with increasing distances from shore, especially in the North Sea, offshore storage facilities have been constructed or are in construction. The Ekofisk field in the North Sea has a 900,000 barrel concrete storage facility on the ocean floor in 230 feet of water. This particular installation is a combination drilling, production and storage facility with a 216-

mile long, 34-inch oil line coated and buried from 3 to 10 feet below the ocean floor at a maximum depth of 312 feet. A second pipeline for gas is also connected to this platform. It is 36 inches in diameter, 249 miles long, and is also buried. Each line has two intermediate booster platforms. Several other similar platforms are either in construction or planned in the North Sea. One is presently under construction for the Brent field in 460 feet of water.

At several locations temporary and permanent storage facilities have been used consisting of a tanker or barges moored in a location to receive production for transshipment to conventional tankers.

Pipelines have been successfully laid and connected in 524 feet of water in the Gulf of Gaeta and a line is contracted for to be laid from Algeria to Sicily and thence to Italy in water depths up to 1,500 feet. A technical capability exists to lay lines in water depths of up to at least 4,000 feet at the present time.

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II. DESCRIPTION OF THE ENVIRONMENT

A. Geography and Geomorphology

The Santa Barbara Channel is an elongate marine feature located off the southwest California coast approximately 110 miles northwest of Los Angeles and 280 miles southeast of San Francisco. The Channel is bounded on the north and east by the mainland shoreline of Santa Barbara and Ventura Counties, on the south by the Channel Islands (San Miguel, Santa Rosa, Santa Cruz, and Anacapa), and on the west by the open waters of the Pacific Ocean. The east-west length of the Channel is approximately 70 miles, the north-south width is 25 to 30 miles, and the total area is about 1,750 square miles. (See figures II-1 and 2) Approximately 1,300 square miles or 74 percent of the Santa Barbara Channel is located more than 3 miles from shorelines of the mainland and Channel Islands and therefore is administered by the Federal Government. On January 1, 1973, 351,877 acres (about 550 square miles), or about 40 percent of the Outer Continental Shelf portion of the Santa Barbara Channel, were held by 69 oil and gas leases issued by the Federal Government.

The Santa Barbara Channel lies within the western part of the Transverse Ranges physiographic province of southern California, in which the major features characteristically trend east-west (figure II-2). In the vicinity of the Channel, the Santa Ynez Mountains form the northern margin of the province; the Santa Monica Mountains and the chain of the Channel Islands form the southern margin. In the Santa Ynez Mountains, peak elevations increase eastward from about 1,500 feet near Point Conception to 6,400 feet north of the city of Ojai in the east. The crest is generally between 3,000 and 4,000 feet. In the Santa Monica Mountains, the crest is generally at about 2,000 feet, and only a few peaks are over 3,000 feet. Maximum

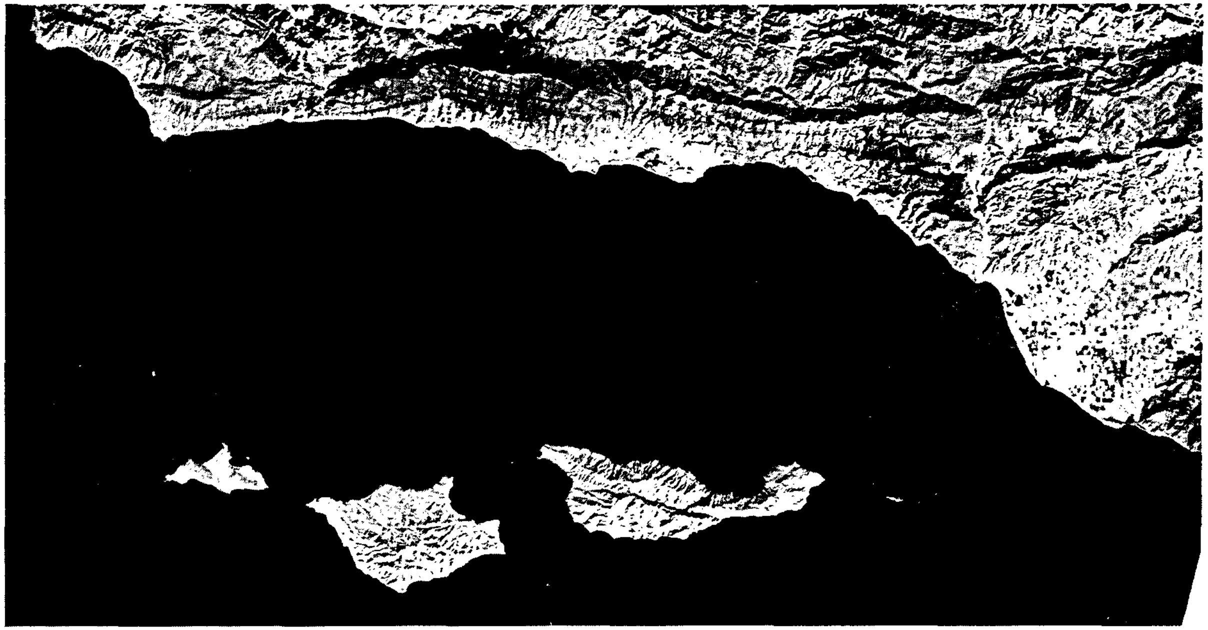

Figure II-1 Earth Resources Technology Satellite (ERTS) image of Santa Barbara Channel region (scale, 1:1,000,000)

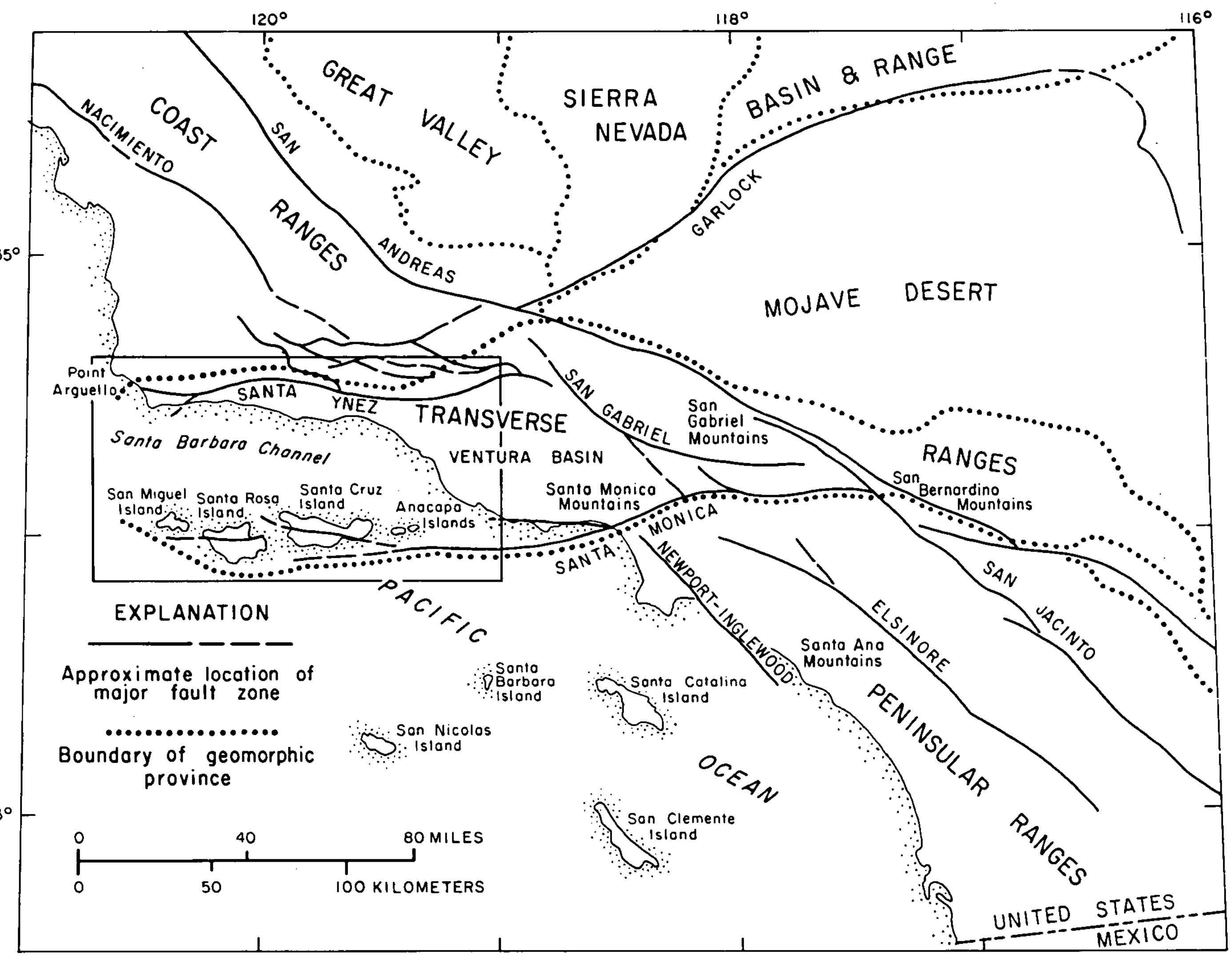

Figure II-2 Index map showing relation of Santa Barbara Channel region to major faults and physiographic provinces of southern California elevations on the islands are: Anacapa, 930 feet; Santa Cruz, 2,434 feet; Santa Rosa, 1,515 feet; and San Miguel, 831 feet. The Channel occupies the submerged lowland between the Channel Islands chain and the Santa Ynez Mountains. West of San Miguel Island and Point Conception the Channel is open to the eastern Pacific Ocean. On the east it shoals gradually to the shoreline of the Oxnard Plain. Onshore, east of the Oxnard Plain, the central region bounded by the Santa Monica Mountains and the Santa Ynez Mountains is dominated by east-west ridges and hills rising to elevations of as much as 2,200 feet and generally above 500 feet.

Along the north shore of the Santa Barbara Channel west of Santa Barbara, a narrow marine terrace slopes gently southward from the foothills of the Santa Ynez Mountains to a sea cliff, 50 to 100 feet high, beneath which there is generally a narrow sand or gravel beach (figure II-3). In the vicinity of the city of Santa Barbara, the coastal terrace widens to about 5 miles, and between Santa Barbara and Ventura the terrace is discontinuous, and the width is generally less than about 2 miles. The terrace, coastal plain, and sea cliff are cut by numerous small streams which drain the Santa Ynez Mountains. Many of these streams flow only during the rainy season, but large boulders attest to episodes of torrential floodflow or mudflow in many of these drainages.

The east shore of the Channel is dominated by wide, straight, sandy beaches that stretch for about 20 miles from Ventura to Point Mugu, and from which the Oxnard Plain rises gradually for about 10 miles inland. From the eastern end of the plain, alluvial valleys extend several miles further east up the drainages of the Santa Clara River, Arroyo Las Posas, and Arroyo Santa Rosa.

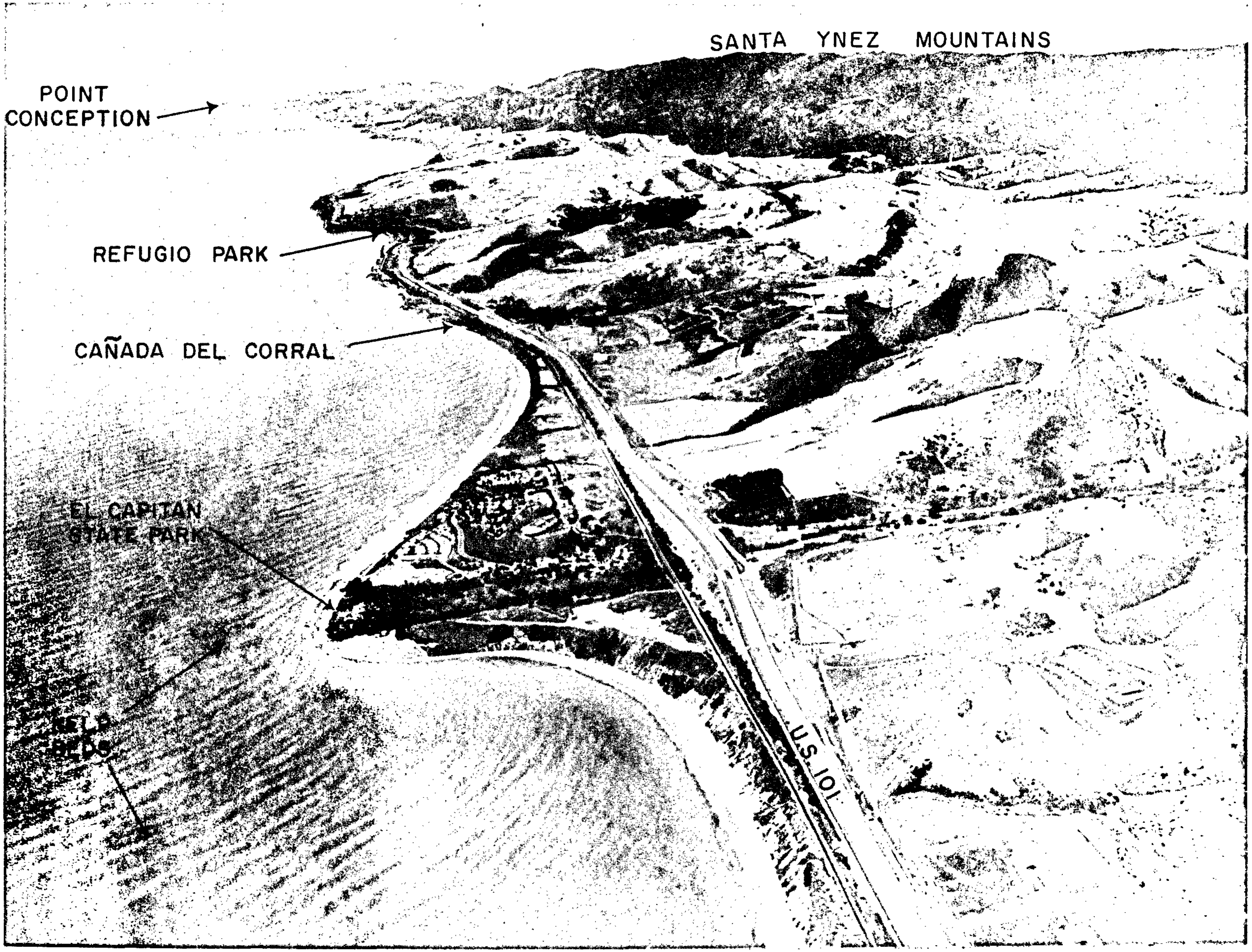

Figure II-3 Aerial View Looking West From El Capitan to Point Conception

On the south, the Channel Islands form an east-west-trending chain about 68 miles long (from Anacapa Island on the east to Richardson Rock on the west), beginning about 13 miles offshore at the east end of Anacapa Island. The islands range in length from 4½ miles (Anacapa) to 23½ miles (Santa Cruz), with hilly to mountainous terrain, characterized by sea cliffs, rocky headlands, and pebble beaches. Sandy beaches are found along some of the more sheltered shorelines.

The Santa Barbara Basin and the Channel Islands Platform are the two major physiographic features that express the continuation of the east-west trend of the Transverse Ranges province offshore onto the Continental Shelf. However, the subsea topographic trends of the Santa Barbara Basin, and of the southwestern margin of the Channel Islands Platform, are more nearly west-northwest than east-west, and trend even more northwesterly at the west end. West of the meridian of Point Arguello, the trends of the Transverse Ranges are not as clearly defined as their eastern counterparts, and it is possible that the province does not extend westward to the edge of the Outer Continental Shelf.

The Santa Barbara Basin, 625 m (2,000 feet) deep in the Central Deep, is bounded on the north by the Goleta and Oxnard Slopes, some 100 m (300 feet) high in most places, and on the south by the Channel Islands Slope, which is roughly comparable in height (figure II-4).The Goleta Slope marks the break between the basin and the Mainland Shelf, a submarine terrace that parallels the coastline and extends 4-5 km (3-4 miles) offshore from Point Conception to Santa Barbara. South of Santa Barbara, the shelf widens and is crossed by the east-west-trending Dos Cuadras Ridge. Southeast of the ridge, the shelf extends as much as 20 km (12 miles) from shore. The section

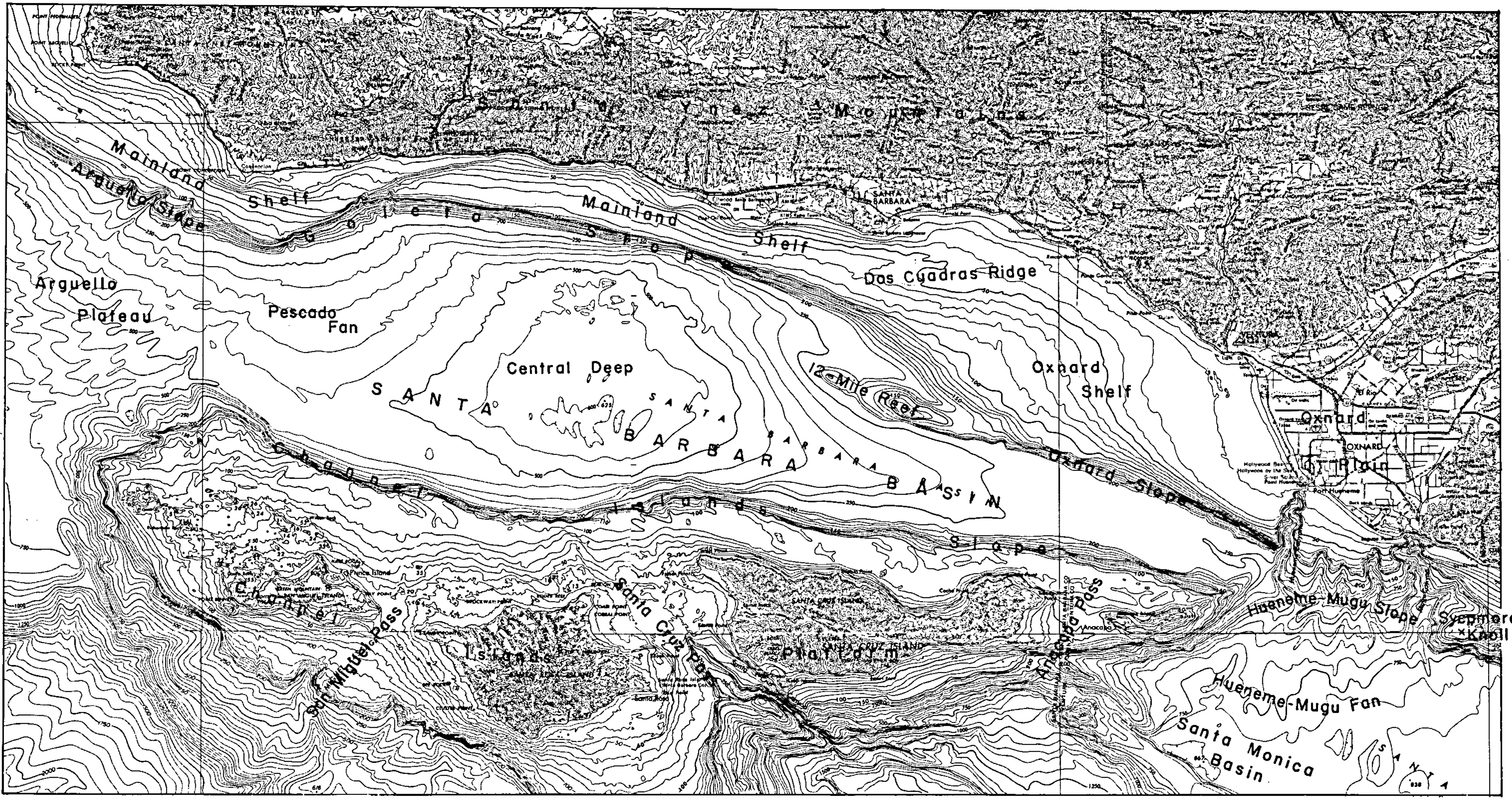

Figure II-4 MAP SHOWING PHYSIOGRAPHIC FEATURES OF THE SANTA BARBARA CHANNEL REGION.

of shelf lying offshore from the Oxnard Plain is called the Oxnard Shelf. The eastern end of this platform is dissected by a series of south-trending submarine canyons, largest of which are Hueneme and Mugu Canyons. These canyons terminate in the northern end of the Santa Monica Basin. The northwest-trending Santa Monica Basin lies south of the eastern end of the Santa Barbara Basin and east of the north-northwest-trending Santa Cruz Basin, which abuts the south-central margin of the Channel Islands Platform. The western part of the Santa Barbara Basin is constricted by a large submarine fan, the Pescado. To the west, the fan merges with the Arguello Plateau, which extends from the Arguello Slope at the edge of the Mainland Shelf some 50 km (30 miles) westward to the Continental Slope.

The four Channel Islands rise from what appears to be a single platform surrounded by a nearly continuous convex slope break at a depth of from about 90 m to about 130 m. The platform, some 127 km (80 miles) in length, parallels the trend of the Santa Barbara Basin. Three passes, San Miguel, Santa Cruz, and Anacapa, from west to east, respectively, separate the islands. All have water depths of less than 50 m. Santa Cruz Pass connects with the Santa Cruz Basin via a deep southeast-trending submarine canyon.

B. Geology

1. Introduction

The geologic setting of the Santa Barbara Channel region provides indications of several sorts of environmental impact that may be anticipated:

- Location of those parts of the Channel area where additional petroleum production seems most likely.
- Geologic processes that may result in adverse environmental impact because of potential hazards to development and production wells and platforms.
- Geologic processes that may result in adverse environmental impact because of potential hazards to transportation, storage, and processing installations.
- Oil and gas production activities may trigger or accelerate geologic processes that could be potentially hazardous.

a. Geologic Map Data

The geology is fairly well known for onshore parts of the Santa Barbara Channel region such as the mountainous uplands, the subsurface bedrock of producing oil fields, and the shallow (ground water) subsurface of the important agricultural area of the Oxnard Plain. Offshore, the geology is much less completely known; areas in the vicinity of producing oil fields have been studied most intensively, and areas of shallow water are generally better known than areas of deeper water. Offshore areas away from productive oil fields are generally known only from acoustic subbottom profiles, supplemented by dart cores, dredge hauls, and sparse information from a few exploratory drill holes. Generally, detailed geologic information obtained by oil companies during exploration is proprietary and is not available to supplement published or U.S. Geological Survey manuscript information except by special permission or where supplied to support detailed proposals for development of specific lease areas (e.g., the Santa Ynez Unit EIS).[1] Consequently, most of the geologic information shown in the offshore area of the geologic map (plate 2) was compiled for this report from recent work in the area by the Office of Marine Geology, U.S. Geological Survey.

The geologic map (plate 2) was compiled chiefly from the Los Angeles (Jennings and Strand, 1969) and Santa Maria (Jennings, 1959) quadrangles of the Geologic Map of California, for the generalized onshore geology. The offshore geology was compiled from the work of Wolf and Wagner (in preparation), Greene, Wolf, and Blom (in preparation), and preliminary manuscript maps of Wolf and Arne Junger prepared from acoustic profiles, dart cores, and dredge hauls made in 1973 by the USGS ship *G. B. Kelez*. Paleontologic determinations for this cruise were made by J. D. Bukry and R. E. Arnal, and lithologic correlations by J. G. Vedder. Navigation for the *Kelez's* cruise was by radar ranging from onshore transponders, and is accurate to within ±30 feet (10 m) for each shot point. Shot points were spaced at 1,000-foot intervals, and for the most of the shelf areas the lines were spaced 1 mile apart. Acoustic profiles include both high-resolution (uniboom) and deep-penetration (high-energy sparker) instruments for subbottom profiles; in addition, a hull-mounted transducer delineated fine bathymetric detail. The high-energy sparker system is generally capable of resolution of lithologic units 20 to 30 feet thick, to nominal penetration depths of 1,000 to 1,500 feet, but the first 60 feet below the sea floor is generally obscured

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[1] It should be noted that oil companies have cooperated in making proprietary information available to the Geological Survey, where such information was needed for regulatory purposes and in considering applications for specific proposals.

because of the length of the output pulse. The high-resolution system generally obscures only the upper 1 to 2 feet of sediment because of output pulse length and can generally resolve units as thin as 6 inches to 1 foot at places. It can penetrate sediment thicknesses of 200 to 300 feet, decreasing to 50 to 150 feet in deeper water.

Any review of the geology of the Santa Barbara Channel region must include some consideration of the detail in which different parts of the region have been examined, and the completeness and detail of various kinds of geophysical investigations. Although the onshore geology has been mapped (in most places in more than reconnaissance detail), the depositional and structural history is so complex that there is a continuing need for new evidence and for continual reexamination and refinement of detail to evaluate new geologic interpretations or reevaluate old ones.

Although the Santa Barbara Channel has been the site of some of the world's most intensive marine geologic studies, especially by companies exploring for oil, the offshore geology is incompletely portrayed on published maps, even at a reconnaissance scale of 1:250,000, except for a few oil fields where subsurface data are available. The marine geologic studies necessary to depict the offshore area with the detail and accuracy of that presently available in much of the onshore area are in their infancy. The accuracy with which individual acoustic profiles can be interpreted to depict the distribution of actual geologic units depends upon the quality and quantity of stratigraphic control by physical sampling of the strata, and upon the complexity of the geologic structure. The accuracy and completeness with which maps can be constructed from series of profiles is, in addition, dependent upon the spacing between individual lines. The offshore geology depicted on plate 2 is based on parallel lines about 1 mile apart for most of the shelf and platform areas, supplemented by ¼-mile spacing of lines over the Dos Cuadras area. In the deeper parts of the Santa Barbara Basin, profiles are spaced from 15 to 25 miles apart. More information and a more refined understanding of the offshore geology can be expected from continuing research programs.

Seismologic studies directed toward the identification delineation of active faults and fault zones are presently capable only of reconnaissance-scale resolution; neither the station density nor the length of record are available to specify which faults are the most active. From the present record it is possible to formulate some judgments about the various geologic processes that are most likely to be of concern in evaluating environmental impact, and about the general parts of the region most likely to be affected; but their specific impact on specific areas generally cannot be evaluated without additional detailed geologic and seismologic information.

2. Stratigraphy

Strata in the Santa Barbara Channel region range in age from Early Cretaceous to Holocene and overlie, or are faulted against, basement rocks that are chiefly pre-Cretaceous in age (plate 5). The Cretaceous succession is 20,000 to 30,000 feet thick in places, and the Cenozoic succession may be as much as 30,000 to 40,000 feet thick in the northeastern part of the Channel. These thicknesses have been calculated on the assumption that those measured in outcrops on basin flanks are similar along basin axes where they are deeply buried by younger strata. Interpretations of the stratigraphy of the Santa Barbara Channel area are made even more speculative by the possibility of large-scale lateral displacement on east-west-trending faults. For example, there was probably about 55 miles of left-lateral movement on the Malibu Coast fault in late middle Miocene time (Yerkes and

Campbell, 1971). Sedimentological evidence has also given rise to speculations that the pre-Miocene rocks of San Miguel, Santa Rosa, and Santa Cruz Islands have moved tens of miles westward or northwestward relative to those north of the Channel (Howell and others, 1973; Yeats and others, 1974). If the rocks of the northern and southern parts were originally deposited long distances from one another and were later brought more closely together by tectonic displacements, then the character of the pre-Miocene rocks beneath the Channel cannot be estimated by simple interpolation between the outcrops on the edges of the Channel.

a. Basement Rocks

The basement rocks of the Santa Barbara Channel and surrounding areas consist of two distinct assemblages, correlatives of the Western and Eastern Bedrock Complexes of Woodford and others (1954). Rocks of the Franciscan assemblage and the Catalina Schist belong to the Western Bedrock Complex. Franciscan rocks crop out in the Santa Ynez fault zone and to the north of it, and Catalina Schist occurs to the southeast, south of the Malibu Coast fault. Catalina Schist is also reported in dredge hauls from some areas south of the Channel Islands. The metamorphic and igneous rocks exposed on Santa Cruz Island appear to belong to the Eastern Bedrock Complex as represented further east by the basement terrains of the San Gabriel Mountains and eastern Santa Monica Mountains; however, they do show some evidence of a different genesis (Hill, 1974).

The Franciscan is composed of graywacke, shale, chert, and mafic volcanic rocks. Some of the rocks have been severely deformed and metamorphosed under high pressure-low temperature conditions. The most highly metamorphosed rocks are the blueschists that characterize the Catalina Schist. In central and northern California, the Franciscan rocks are known to range in age from Jurassic to Cretaceous (Bailey and others, 1964), and perhaps even early Tertiary (Berkland and others, 1972). In the Santa Barbara Channel region, the basement rocks are generally in fault contact with strata that are older than middle Miocene, and in places, middle Miocene and younger strata lie unconformably on basement rocks. The oldest rocks mapped as depositionally overlying the Franciscan rocks in the area just north of the Santa Ynez Mountains are of early Cretaceous age (Dibblee, 1966); this relationship is anomalous, for elsewhere in the region the oldest strata reported to overlie Franciscan rocks depositionally are of Eocene age (Nelson, 1925), though Upper Cretaceous rocks in the western Santa Ynez

Mountains contain Franciscan detritus (Gibson, 1973).

The crystalline rocks of Santa Cruz Island include the Santa Cruz Island Schist, which consists largely of chloritic schist, the Alamos Tonalite, which is a quartz-diorite that intrudes the Santa Cruz Island Schist, and the Willows Diorite, which is in fault contact with the Santa Cruz Island Schist. The Willows Diorite has been dated radiometrically as Late Jurassic, and the other rock units are thought to be older (Weaver, 1969).

Present knowledge is insufficient to locate the crystalline basement rocks of Santa Cruz Island and the Franciscan rocks exposed in the Santa Ynez Mountains to the north. The possibility that Franciscan-type basement occurs at least locally under the Santa Barbara Channel is suggested by Miocene strata of the Channel Islands that contain blueschist boulders thought to be derived from nearby sources to the north (Yeats, 1970).

b. Cretaceous Rocks

The distribution of Cretaceous sedimentary rocks under Santa Barbara Channel is unknown except for their reported penetration in exploratory wells near the middle of the Channel north of Santa Cruz Island (Vedder and others, 1969, p. 2) and on the Channel Islands Platform about 3 miles north of San Miguel Island (Weaver, 1969, p. 14); no information on the thickness and character of the Cretaceous rocks penetrated in these wells is available. Cretaceous beds crop out in several places around the margins of the Channel, but in none of the outcrops close to the Channel is the base of the sequence exposed; therefore, only minimum thicknesses can be estimated. The closest point at which a reasonably complete section is exposed is north of the Santa Ynez fault, where 20,000 to 30,000 feet of Cretaceous beds (possibly including some Late Jurassic beds at the base) are exposed.

The incomplete exposures around the margins of the Channel suggest that very thick Lower and Upper Cretaceous sequences are present in the Channel area. Thick Lower Cretaceous beds (Espada Formation of Dibblee, 1950) crop out only north of the Santa Ynez fault; although they are not exposed to the south, they are presumed to be present in the subsurface along the south flank of the Santa Ynez Range. The Lower Cretaceous rocks are overlain by Upper Cretaceous rocks north of the Santa Ynez fault, and thick Upper Cretaceous beds (Jalama Formation of Dibblee, 1950) are exposed in numerous but fragmentary outcrops along both the north and south sides of the Santa Ynez fault. Thick Upper Cretaceous beds lie directly on Eastern Basement Complex rocks in the Santa Monica Mountains east of the Channel, and the base of the Upper Cretaceous section is not exposed in the Simi Hills or on San Miguel Island. Upper Cretaceous rocks have been penetrated in wells on the Oxnard Plain east of the Channel (Nagle and Parker, 1971) and on Santa Cruz Island, both north and south of the Santa Cruz Island fault (Weaver, 1969, p. 14). The thickness of the Upper Cretaceous sequence is probably more than 5,000 feet in all these areas except north of the Santa Ynez fault in the area west of the longitude of Santa Barbara, where the Upper Cretaceous sequence locally pinches out or becomes very thin, and where Lower Cretaceous rocks are overlain by Eocene rocks (Dibblee, 1950; Dibblee, 1966; Gibson, 1973a).

The Cretaceous rocks, wherever exposed in the Channel region, consist of interbedded mudstones, sandstones, siltstones, and, in places, conglomerates. Most of the rocks have a deep marine aspect, and studies in a few areas

(Colburn, 1973; Fisher and Mattinson, 1968; Rust, 1966) suggest that most of the sands and conglomerates were deposited by turbidity currents (bottom-seeking currents that flow because of their high densities resulting from large concentrations of suspended sediment) or by related gravitational mass-transport mechanisms. Paleocurrent data suggest that the pattern of sediment transport was complex but that most of the currents flowed to the west or north (Colburn, 1971; Rust, 1966).

Small amounts of oil have been produced from Cretaceous rocks in the eastern Ventura basin, where the reserves are reportedly less than 2 million barrels (Nagle and Parker, 1971, p. 259). Although no Cretaceous rocks in the Santa Barbara Channel area produce oil or gas, they have been little tested, and some geologists (Curran, Hall, and Herron, 1971; Nagle and Parker, 1971) consider them worthy of further evaluation. The top of the Cretaceous section in OCS areas is to be expected at depths ranging from a few thousand feet on the Channel Islands Platform to as much as 40,000 feet at the eastern shoreline of the Channel near Ventura.

c. Paleocene and Eocene Rocks

Like the Cretaceous rocks, the Lower Tertiary rocks beneath Santa Barbara Channel are poorly known, and their distribution, thickness, and character can be described only from exposures around the edges of the Channel. Paleocene and Eocene rocks are treated together here because they are lithologically similar, difficult to distinguish, and form a continuous sequence in many parts of the Channel area. They rest depositionally on Cretaceous rocks or, where these pinch out north of the Santa Ynez fault, on basement rocks. The Paleocene and Eocene strata are similar to the Upper Cretaceous strata and seem to have formed in a similar depositional setting.

- Paleocene Rocks

Paleocene rocks are exposed east of the Channel area in the Simi Hills and Santa Monica Mountains. They also crop out on San Miguel and Santa Cruz Islands and probably on nearby parts of the Channel Island Platform. Recent paleontologic studies indicate that beds of Paleocene age are also present in the western Santa Ynez Mountains (Gibson, 1972, 1973b) and perhaps are present in the central and eastern Santa Ynez Mountains (Stauffer, 1967; Nagle and Parker, 1971), although the faunal evidence there is inconclusive. Paleocene beds are missing north and east of the Santa Ynez fault and in the western Santa Ynez Mountains. (Dibblee, 1966; Chipping, 1972.)

Paleocene rocks reach their maximum thickness, 3,000 feet or more, in a belt trending north-south to northwest-southeast across the eastern Ventura basin and Santa Monica Mountains (Nagle and Parker, 1971), and the section thins westward to about 1,000 feet on the Oxnard Plain (Dosch and Mitchell, 1964; Nagle and Parker, 1971). The thickness on the Channel Islands is poorly known because of incomplete exposures and structural complexities but is about 1,600 feet on San Miguel Island (Vedder and others, 1969; Weaver, 1969). In the western Santa Ynez Mountains the Paleocene section is, at most, about 700 feet thick but thins northward (Gibson, 1972, 1973). If Paleocene strata are present in the central and eastern Santa Ynez Mountains, they are less than 500 feet thick (Stauffer, 1967; Nagle and Parker, 1971).

The Paleocene succession consists mostly of mudstones, sandstones, siltstones, and in places, conglomerates. These rocks in the Ventura basin and

Santa Monica Mountains are commonly called the Martinez Formation; the lower part of the overlying Santa Susana Shale in this area is also Paleocene (Nagle and Parker, 1971). On the Channel Islands the Paleocene rocks have been referred to as the Pozo Formation by Weaver and others (1969). The lower part of the Anita Shale forms the Paleocene section in the western Santa Ynez Mountains (Gibson, 1972, 1973b), and farther east in the Santa Ynez Mountains the possible Paleocene beds form the basal part of the Juncal Formation (Stauffer, 1967; Nagle and Parker, 1971). To the north, the base of the Juncal Formation is Eocene in age (Buckry, Brabb, and Vedder, 1973). The depositional framework of the Paleocene clastic deposits is poorly known; by analogy with the underlying Cretaceous and overlying Eocene beds, a source to the east seems likely. The thin but paleontologically complete section of shales and siltstones at the western end of the Santa Ynez Mountains described by Gibson (1972, 1973b) suggests slow, continuous deposition in deep water far from the source area.

Thin layers and lenses of limestone, much of it distinctively algal, occur locally in the Paleocene-Eocene sequence. Algal limestone occurs in undivided Paleocene or Eocene beds (possibly basal Eocene) in the eastern Santa Monica Mountains (Yerkes and others, 1973). Similar limestone occurs at the base of the Paleocene beds in the western Santa Ynez Mountains (Gibson, 1972, 1973b). The most widespread occurrence of such limestone is north of the Santa Ynez fault, where the Sierra Blanca limestone of Eocene age rests depositionally on Franciscan basement rocks, Lower Cretaceous beds, or Upper Cretaceous beds (Dibblee, 1966). The algal limestones are thought to have been deposited on shallow-water algal banks (Schroeter, 1972). Where they form the base of the Paleocene or Eocene marine sequence, they represent the initial deposits in what was probably a gradually deepening basin. The algal limestones of the Santa Monica Mountains define a north-south trending isobath for a west-facing shoreline, while those of the Santa Ynez Mountains probably define an east-west trending, south-facing topographic high (Gibson, 1972; Schroeter, 1972).

Paleocene strata have produced only small amounts of oil in the Ventura basin, and none in the Santa Barbara basin. Recoverable reserves in known fields in the Ventura basin are less than 5 million barrels (Nagle and Parker, 1971). However, the occurrence of some rocks having reservoir qualities suggests the possibility of additional significant discoveries (Curran, Hall, and Herron, 1971; Nagle and Parker, 1971).

- <u>Eocene Rocks</u>

Eocene rocks are widely distributed around the edges of Santa Barbara Channel. They crop out in a continuous belt along the Santa Ynez Mountains north of the Channel, in the Simi Hills and Santa Monica Mountains east of the Channel, and on Santa Cruz, Santa Rosa, and San Miguel Islands and nearby parts of the Channel Islands Platform. Eocene rocks have been penetrated in oil wells on the Oxnard Plain east of the Channel and both onshore and offshore along the northern edge of the Channel.

The Eocene succession reaches its maximum thickness, about 17,000 feet, near the eastern end of the outcrop belt along the south side of Santa Ynez fault. The section gradually thins westward along this outcrop belt to only 2,000 to 3,000 feet near Point Conception. Thinning of the section southward across the Ventura basin takes place in a short distance, and only 1,000 to 3,000 feet of Eocene strata are found in the Simi Hills, western Santa Monica Mountains, and under the Oxnard Plain (Nagle and Parker, 1971). In the area to the north, between the Little Pine fault and the Santa Ynez fault, and west of the longitude of Santa Barbara, the Eocene beds thin greatly in a short distance northward and locally pinch out, leaving Oligocene or Miocene rocks resting on Cretaceous rocks. The Eocene succession on the Channel Islands is of moderate thickness, about 2,400 feet on Santa Cruz Island where the thickness is most reliably measured (Weaver and others, 1969). The Eocene sequence on Santa Rosa Island is over 4,400 feet thick, and on San Miguel Island the Eocene sequence is more than 2,900 feet thick (Weaver and others, 1969).

The Eocene succession in the Santa Barbara Channel area consists largely of sandstone, mudstone, siltstone, and, in places, conglomerate. Algal limestone occurs locally at the base of the succession. The succession has been divided into several relatively persistent formations in the Santa Ynez Mountains. In ascending order these are the Sierra Blanca Limestone, Juncal Formation (or Anita Shale in the western part), Matilija Sandstone, Cozy Dell Shale, and Coldwater Sandstone (or Sacate Formation in the western part) (Vedder, Wagner, and Schoellhamer, 1969; Vedder, 1972). In the Simi Hills and under the Oxnard Plain, beds of Eocene age form the upper part of the Santa Susana Shale and the overlying Llajas Formation. The Eocene rocks on the Channel Islands have been studied most recently by Weaver and others (1969). Their nomenclature on Santa Cruz Island is, in ascending order, Canada Formation, Jolla Vieja Formation, and Cozy Dell Shale. On San Miguel Island, they do not differentiate the Canada Formation from the underlying Pozo Formation, of Paleocene age, and the South Point Formation is the only other named Eocene unit present.

The Eocene rocks in the Santa Ynez Mountains can be grouped into two similar sequences, the lower consisting of the Juncal Formation and Matilija

Sandstone, the upper consisting of the Cozy Dell Shale, Coldwater Sandstone, and overlying Oligocene beds (van de Camp and others, 1973). The lower parts of both sequences consist of mudstones and thin sandstones deposited in deep water by turbidity currents. These beds grade upward into thick-bedded, medium- to coarse-grained sandstones deposited by turbidity currents or related mechanisms, and these in turn grade upward into shallow-water sandstones (Stauffer, 1967a; Link, 1972; O'Brien, 1972; van de Camp and others, 1973). The sands were deposited by currents flowing westward to southward or even southeastward (Stauffer, 1967a, 1967b; Link, 1972; O'Brien, 1972; and Fischer, 1973).

The Eocene sandstones of the Simi Hills and Santa Monica Mountains contain sedimentary structures indicating deposition by currents flowing to the northwest; at least some of these sandstones were deposited by turbidity currents (Yeats and others, 1972, p. 296). The Eocene rocks of the Channel Islands have faunas that at least in part are suggestive of deposition in a deep marine environment (Weaver and others, 1969), and the sedimentary structures of the sandstones suggest deposition by turbidity currents or related types of flow (Yeats and others, 1974). Paleocurrent data from Santa Cruz Island suggest flow to the southwest, data from Santa Rosa Island suggests flow to the northwest, and data from San Miguel Island suggests flow to the northwest and northeast (Yeats and others, 1974). Some of the Eocene conglomerates of the Channel Islands contain pebbles and cobbles of distinctive metatuffs that resemble those found in the early Tertiary section of the Peninsular Ranges of southern California; these clasts have been cited as evidence for large-scale lateral displacement of the Channel Island rocks from an original location far to the south and east of their present location (Howell and others, 1973; Yeats and others, 1974).

Eocene rocks have yielded moderate quantities of oil in the Ventura basin but only small quantities so far in the Santa Barbara Channel area. The ultimate recoverable reserves in known fields in the Ventura basin are between 11 million and 15 million barrels of oil (Nagle and Parker, 1971). The entire Eocene section has been penetrated at very few points in the Channel area, and some geologists consider the Eocene rocks to be favorable for future exploration (Curran, Hall, and Herron, 1971; Nagle and Parker, 1971).

d. Oligocene Rocks

A continuous belt of Oligocene rocks is exposed along the southern flank of the Santa Ynez Mountains and several outcrop areas are present in the Ventura basin and Santa Monica Mountains. Oligocene rocks also crop out on Santa Rosa Island, and may crop out locally on the sea floor of the Channel Islands Platform. Correlative beds have been penetrated in drill holes on the Oxnard Plain, on the mainland shelf and onshore along the northern edge of Santa Barbara Channel, and on northern Santa Cruz Island and in the Channel offshore from that island (Weaver and others, 1969, p. 47).

A maximum thickness of about 7,000 feet of nonmarine beds (the Sespe Formation) dominantly of Oligocene age has been penetrated in the subsurface of the central Ventura basin (Nagle and Parker, 1971). In the eastern part of the outcrop belt along the Santa Ynez Mountains, the equivalent section is nearly as thick, 3,500 to 6,000 feet. The sequence gradually thins to the west along this outcrop belt and is only about 1,700 feet thick near Point Conception. To the north of the Santa Ynez fault the Oligocene section thins and locally pinches out a few miles from the fault, so that Lower

Miocene or younger rocks rest on Eocene or older rocks. Oligocene rocks have been penetrated in wells in northern Santa Barbara Channel as much as 5 to 8 miles south of the outcrop belt and are similar in thickness and character to the nearest exposed rocks. On the Oxnard Plain, a short distance southwest of its point of maximum known thickness, the Oligocene rocks have been locally removed by Miocene erosion (Dosch and Mitchell, 1964; Nagle and Parker, 1971). Oligocene rocks of moderate thickness are present, however, in the Santa Monica Mountains farther to the southeast. The Oligicene section on Santa Rosa Island has a maximum thickness of 570 feet (Weaver and others, 1969). On San Miguel and Santa Cruz Islands, where Oligocene rocks are absent or very thin, Lower Miocene beds rest on Eocene beds (Weaver and others, 1969).

The Oligocene rocks are unique in the stratigraphic section of the Santa Barbara Channel area because of their variegated colors, including shades of red and green, and largely nonmarine origin. The nonmarine part of the Oligocene sequence, the Sespe Formation, consists of sandstones, conglomerates, mudstones, and siltstones that are thought to have been deposited on coalescing alluvial fans (McCracken, 1971, 1972). Paleocurrent data indicate that the nonmarine beds north of the Channel were deposited by streams that flowed southward to westward, while those exposed on the south flank of the Ventura basin, in the Santa Monica Mountains, and on Santa Rosa Island were deposited by streams that flowed to the north and west (McCracken, 1971, 1972; Weaver and others, 1969, p. 47; Yeats and others, 1974).

Marine Oligocene beds (possibly including some Eocene beds at the base) have been found only in the western part of the Santa Ynez Mountains and in adjacent offshore areas. These beds have been named, in ascending order, the

Gaviota and Alegria Formations, and consist of sandstone and mudstone deposited mostly in shallow water (O'Brien, 1972). They intertongue eastward into the nonmarine Sespe Formation. The marine-nonmarine boundary migrated westward during the regression that continued through Oligocene time, so that marine beds near the base of the Oligocene sequence extend as far east as Goleta, but the youngest marine Oligocene beds extend only as far east as Gaviota, about 22 miles west of Goleta.

Both the marine and nonmarine Oligocene beds have produced moderate amounts of oil and gas along the north side of Santa Barbara Channel, and the nonmarine Sespe Formation in the Ventura basin has produced large amounts of oil. Ultimate recoverable reserves in Oligocene reservoirs of known fields of the Ventura basin are 240 million barrels of oil (Nagle and Parker, 1971 p. 267). In the Santa Barbara Channel region production from Oligocene beds is usually not reported separately from production from the overlying Vaqueros Sandstone (lower Miocene), but Oligocene production has been less than Vaqueros production where production figures from the two units have been separated (Yerkes, Wagner, and Yenne, 1969).

e. Miocene Rocks

(1) Lower Part

The lower part of the Miocene succession forms a continuous outcrop belt along the northern edge of Santa Barbara Channel. Scattered outcrops occur north of the Santa Ynez fault, but the unit is locally absent and the middle part of the Miocene succession rests on Oligocene and older beds in parts of that area. To the east of the channel, the lower part of the Miocene succession crops out at several places in the Ventura basin, in the Santa Monica Mountains, and on Santa Cruz, Santa Rosa, and San Miguel Islands. Lower Miocene beds have been penetrated in a number of oil wells along the northern edge of Santa Barbara Channel and on the Oxnard Plain just east of the Channel. They have also been penetrated in drill holes on northern Santa Cruz Island and on the south flank of the Montalvo Trend (Twelve-Mile Reef) in the middle of the Channel (Weaver and Meyer, 1969).

In most parts of the channel area, the lower part of the Miocene succession has been divided into two formations, the basal Vaqueros Formation, which consists mainly of sandstone, and the overlying Rincon Shale. In the Santa Monica Mountains only the Vaqueros Formation is recognized in the lower part of the Miocene section (Campbell, Yerkes, and Wentworth, 1966), whereas on San Miguel Island only the Rincon Formation is recognized (Weaver and Doerner, 1969).

In the outcrop belt north of the channel, the Vaqueros Formation ranges from 25 to 600 feet thick, and the Rincon Shale thickens eastward from as little as 850 feet near Point Conception to as much as 2500 feet near Ventura. In drill holes as much as 7 miles south of the outcrop belt, the thicknesses of these formations is similar to those in the outcrop belt (Cordova, 1972; California Division of Oil and Gas, 1961, 1969; U.S. Geological Survey, 1974). In scattered outcrops a few miles north of the Santa Ynez fault both units locally pinch out.

Lower Miocene rocks are locally very thin or absent beneath the Oxnard Plain east of the channel and south of the Oak Ridge fault, where they appear to have been thinned by erosion prior to the deposition of the middle Miocene Conejo Volcanics. To the south and east, in the Santa Monica Mountains, the Vaqueros, together with pre-Conejo middle Miocene strata (the Lower Topanga Formation of Durrell, 1954), thicken to a section that is as much as 6,000 feet thick.

On Santa Cruz Island south of the Santa Cruz Island fault, the Vaqueros Formation is about 800 feet thick and the Rincon Shale is 250 feet thick (Bereskin and Edwards, 1969). On Santa Rosa Island, the Vaqueros is 400 to 600 feet thick, and the Rincon is 400 to 2,400 feet thick (Avila and Weaver, 1969). On San Miguel Island, the Rincon is 1260 feet thick in a single measured section (Weaver and Doerner, 1969).

The Vaqueros Formation consists of sandstone with subordinate conglomerate, siltstone, and mudstone. The sandstone is commonly thick-bedded, cross-bedded, well-sorted, and porous. A shallow marine origin is indicated by the sedimentary structures and preserved fauna of the formation. A west-facing, north-trending shoreline passing through the Santa Monica Mountains and Simi Hills is recognized (Yerkes and Campbell, 1971).

The Rincon Shale consists of claystone, mudstone, siltstone, and subordinate sandstone. Some beds are bentonitic (containing altered volcanic ash), and dolomitic concretions are common. The formation is rich in organic matter and may have furnished much of the oil found in adjacent reservoir rocks such as the Vaqueros Formation (Curran, Hall, and Herron, 1971). The foraminiferal fauna of the Rincon Shale is indicative of deposition in water depths ranging from those found on the continental shelf to those found on the continental slope, with the shallower depths being more common in the southern part of the area, around the present Channel Islands (Avila and Weaver, 1969; Bereskin and Edwards, 1969; Edwards, 1971, 1972; Patet,1972; Weaver and Doerner, 1969).

The sequence from the base of the Vaqueros Formation to the top of the Rincon Shale was deposited during a transgression and deepening of the sea.

The base of the Miocene beds is marked by an unconformity, at least in some places, and indicates the maximum retreat of the seas following the Eocene-Oligocene regression and preceding the early Miocene transgression.

(2) Miocene Volcanic Rocks

Volcanic rocks and associated volcaniclastic sedimentary rocks of Miocene age form a significant part of the rock sequence in the Santa Ynez Mountains northwest of Point Conception, on the Channel Islands, and in the western Santa Monica Mountains. Volcanic rocks crop out on the sea floor around Anacapa Island and elsewhere on the Channel Islands Platform (Scholl, 1960; Greene/1974, written commun.). The volcanic rocks northwest of Point Conception have been named the "Tranquillon Volcanics" (Dibblee, 1950). The older of two sequences of volcanic rocks on the Channel Islands has been named the "San Miguel Volcanics"; it occurs on San Miguel and Santa Rosa Islands (Avila and Weaver, 1969; Weaver and Doerner, 1969). The Tranquillon and San Miguel extrusive volcanic rocks occur, stratigraphically, at the base of the middle Miocene succession. The younger sequence of volcanic rocks on the Channel Islands is best developed on northern Santa Cruz Island, where it has been named the "Santa Cruz Island Volcanics" (Nolf and Nolf, 1969). Equivalent volcanic rocks occur on Anacapa Island (Scholl, 1960). Volcaniclastic rocks on southern Santa Cruz Island have been named the Blanca Formation (Weaver and others, 1969). Other volcaniclastic rocks on Santa Cruz, Santa Rosa, and San Miguel Islands have been named the Beechers Bay Member of the Monterey Formation (Avila and Weaver, 1969; Bereskin and Edwards, 1969; Weaver and Doerner, 1969). The volcanic rocks in the western Santa Monica Mountains have been called the "Conejo Volcanics" (Vedder, Wagner, and Schoellhamer, 1969). These Conejo Volcanics and the younger volcanic rocks on the Channel Islands correlate with the middle part of the middle Miocene succession.

The Tranquillon Volcanics northwest of the channel are of rhyolitic composition and reach a maximum thickness of about 1,200 feet (Dibblee, 1950). The San Miguel Volcanics, which consist of basaltic and dacitic flow rocks, fine- to coarse-grained volcaniclastic rocks, and associated intrusive volcanic rocks, reach a thickness of at least 1,520 feet (Weaver and Doerner, 1969). The Santa Cruz Island Volcanics, which consist mainly of andesitic flow rocks and volcaniclastic rocks, reach an estimated maximum thickness of 8,000 feet (Nolf and Nolf, 1969). The Blanca Formation of southern Santa Cruz Island consists of fine- to coarse-grained volcaniclastic rocks of rhyolitic, dacitic, andesitic, and basaltic composition and attains a maximum thickness of at least 3,900 feet (Weaver and others, 1969). The "Conejo Volcanics" of the western Santa Monica Mountains are of basaltic and andesitic composition and are locally more than 15,000 feet thick (Campbell, Yerkes, and Wentworth, 1966; Vedder, Wagner, and Schoellhamer, 1969). The volcanic rocks thin northward and although they may extend from the Channel Islands nearly as far northward as the Twelve-Mile Reef, they probably do not occur in the northern part of the Channel.

(3) Middle Part

The middle part of the Miocene succession is widespread in the Santa Barbara Channel area. In fact, this sequence probably mantled nearly the entire area at the time when deposition of the next younger unit started; only in parts of the Simi Hills and eastern Santa Monica Mountains does the upper part of the Miocene succession lie directly on rocks older than middle Miocene. The middle part of the Miocene succession crops out in a belt along the north edge of the Santa Barbara Channel, at numerous localities in the Ventura basin east of the channel, and on the Channel Islands. This unit forms the sea floor, or occurs beneath a thin cover of Holocene unconsolidated sediments, on parts of the mainland shelf along the north edge of the channel, and on parts of the Channel Islands Platform. Throughout most of the channel area, the middle Miocene succession is known as the Monterey Shale, but in the Santa Monica Mountains, where the sedimentary strata are separated into upper and lower parts by the intervening Conejo Volcanics, the sequence is called Topanga Formation.

The Monterey Shale varies from 1,200 to 2,300 feet in thickness in the outcrop belt along the north edge of Santa Barbara Channel. Similar thicknesses of Monterey Shale have been penetrated in wells as much as 7 miles south of the outcrop belt (California Division Oil and Gas, 1961, 1969; Cordova, 1972; U. S. Geological Survey, 1974). Wells in the Oxnard oil field east of the Channel indicate that the Monterey Shale is 1,300 feet thick along the northern edge of the field but thins and pinches out to the south as the middle Miocene volcanic rocks increase in thickness (Dosch and Mitchell, 1964). The total thickness of the Monterey in the Channel Islands is not known, as the contact with overlying upper Miocene beds is nowhere exposed, but is at least 2,000 feet on Santa Rosa Island (Avila and Weaver, 1964) and at least 1,600 feet on northern Santa Cruz Island (Weaver and Meyer, 1969).

The Monterey Shale is composed of shale with subordinate sandstone, siltstone, chert, dolomite, limestone, and volcanic tuff altered to bentonite. Much of the shale is siliceous, diatomaceous, tuffaceous, phosphatic, or bituminous. The Beechers Bay Member of the Monterey on the Channel Islands is composed of volcaniclastic sandstones, conglomerates, breccias, siltstones, and shales. The foraminiferal faunas in most parts of the Monterey Shale on the Islands suggest deposition in water depths ranging from those on outer continental shelves to those on continental slopes (Avila and Weaver, 1969; Bereskin and Edwards, 1969; Patet, 1972; Weaver and Doerner, 1969). Many of the sandstones of the Beechers Bay Member of the Montery Formation have sedimentary structures indicative of deposition by turbidity currents (Bereskin and Edwards, 1969).

A distinctive sedimentary breccia (San Onofre Breccia) is included here with the middle part of the Miocene succession, even though it is partly of Saucesian (early Miocene) age (Bereskin and Edwards, 1969). The San Onofre is exposed on Santa Rosa Island and on Santa Cruz Island where it overlies the Rincon Shale, underlies the Beechers Bay Member of the Monterey Shale or the volcaniclastic Blanca Formation, and ranges from about 100 to 1,560 feet thick (Bereskin and Edwards, 1969; Weaver and others, 1969). Beds resembling the San Onofre also occur in the lower part of the volcanic sequence on Anacapa Island (Scholl, 1960) and on the Channel Island Platform north of Santa Rosa Island (Yeats, 1970). A thickness of about 1,070 feet of San Onofre has been penetrated in a drill hole on northern Santa Cruz Island, and rock fragments resembling those of the San Onofre Breccia have been found in Rincon mudstones penetrated in a drill hole on the south flank of the Montalvo Trend (Twelve-Mile Reef) in the middle of the channel (Weaver and Meyer, 1969; Yeats, 1970). The San Onofre also crops out along the south flank of the Santa Monica Mountains south of the Malibu Coast fault. There, the distinctive clasts are found in sedimentary breccias and conglomerates interbedded with mudstone, shale, and volcanic rocks ranging in age from Saucesian (lower Miocene) to upper Mohnian (upper Miocene).

The San Onofre Breccia consists of breccia, conglomerate, sandstone, and mudstone. The breccia is distinctive because of its blueschist clasts, some of them of boulder size, derived from the Catalina Schist. A coarsening of clast size to the northeast suggests that the breccia exposed on southern Santa Cruz Island was derived from that direction (Bereskin and Edwards, 1969). The coarse-grain size of the breccia suggests that it was deposited as talus or by debris flows near the source area of high relief. The breccia was probably deposited in marine water (Bereskin and Edwards, 1969).

The high concentrations of organic matter in the Monterey Shale suggest that it has been a source rock for much petroleum in the area. Although sandstone reservoir rocks are not common in the Monterey Shale in most areas, they do occur locally, as in the northwestern part of the Channel, and some cherty beds have porosity due to fracturing and recrystallization of the chert (Curran, Hall, and Herran, 1971; U. S. Geological Survey, 1974).

Middle Miocene strata have not yielded significant production of oil or gas in the Channel region as yet, but tests in the Hondo Offshore area of the Santa Ynez Unit indicate that they contain the principal potential producing horizons of that area. The reservoirs tested include both fractured siliceous shale and chert of the upper part of the Monterey Formation and sandstones found in the lower part of the formation. In addition, operators in the South Ellwood Offshore Oilfield have recently established production from Monterey strata, and have proposed a program for resumption of drilling from Platform Holly (California State Tidelands) to develop as many as 30 wells to recover oil and gas from that target reservoir (Dames and Moore, 1974).

(4) Upper Part

The upper part of the Miocene succession crops out along the northern edge of Santa Barbara Channel, both onshore and on the mainland shelf, and at various localities in the Ventura basin and northeastern Santa Monica Mountains. Beds on Santa Rosa Island formerly thought to be of late Miocene age are now recognized as middle Miocene (Avila and Weaver, 1969), but the upper part of the Miocene succession does crop out on parts of the Channel Island Platform (plate 3). In the area along the north edge of the Channel, the upper part of the Miocene succession is known as the Sisquoc Formation, while in the Ventura basin the unit has been variously known as the "Santa Margarita" or Modelo Formation.

The thickness of the Sisquoc Formation is as much as 3,200 feet along the northern edge of the Channel. In the Hondo offshore potential field in the northwestern part of the Channel, the thickness is about 2,200 feet (U.S. Geological Survey, 1974), and in the Ventura area northeast of the Channel the thickness is 1,700 to 1,800 feet. In the vicinity of Santa Barbara, the Sisquoc and underlying Miocene units were locally eroded before upper Pliocene or lower Pleistocene beds were deposited (Dibblee, 1966). On the Oxnard Plain east of the Channel, the "Santa Margarita Formation" is about 1,000 feet thick in the West Montalvo oil field (Hardoin, 1961) but pinches out to the southeast and is absent in the Oxnard oil field (Dosch and Mitchell, 1964).

The Sisquoc Formation and equivalent stratigraphic units in the Channel area consist of diatomaceous mudstone, claystone, siltstone, and sandstone. The sandstone is generally a minor constituent, but increases in abundance eastward. These rocks were deposited after a middle Miocene episode of volcanism and deformation. By the end of Miocene time, a strong east-west structural grain had formed, and Pliocene deposition consisted, to a large degree, of the infilling of the topographic basins formed by this Miocene deformation. It is uncertain whether the upper Miocene rocks should be considered the basal unit of this basinal fill; perhaps they are best thought of as a transitional unit deposited during the final stages of the deformation that produced the basinal framework.

Upper Miocene strata have not yielded significant oil or gas production in the Santa Barbara Channel region. Onshore, to the east, in the Ventura Basin, sandstone becomes a more important part of the upper Miocene succession and Nagle and Parker (1971) estimate that about 15 percent of the recoverable reserves in that area are in Upper Miocene strata.

f. Lower and Upper Pliocene Rocks

The Pliocene rocks in the Santa Barbara Channel area have been divided into a lower part, the "Repetto Formation", and an upper part, the "Pico Formation". However, the two formations have no striking lithologic differences, both being composed of interbedded sandstone, siltstone, mudstone, and conglomerate in proportions that vary vertically and laterally, and the two formations will be discussed together here.

Pliocene rocks crop out on the outer part of the mainland shelf of the Santa Barbara Channel from Point Conception to east of Carpinteria, where the outcrop belt continues eastward, crossing the inner shelf and shoreline and extending along the northern flank of the Ventura basin. Small remnants of upper Pliocene rocks occur north of the main outcrop belt along the coast near Goleta, suggesting that the Pliocene rocks may once have extended north of the present outcrop belt, but their original extent was probably not much greater than their present extent. Other outcrops of Pliocene rocks occur along anticlines within the Ventura basin. In the deep part of the Ventura basin, on the Oxnard Shelf, and in the Santa Barbara Basin to the west, the Pliocene rocks are overlain by thick Pleistocene and Holocene deposits. These younger beds generally extend southward beyond the edge of the Pliocene beds, whose southern edge can be located only by well data and seismic studies. Well data indicate that the Pliocene beds pinch out in the subsurface of the Oxnard Plain south of the Oxnard oil field (Dosch and Mitchell, 1964), and seismic profiles suggest that the south edge of the Pliocene deposits extends southwestward across the Oxnard Shelf and thence along a line parallel with and a few miles south of Twelve-Mile Reef (see B-B[1], pl. 2). Farther west, where the topographic expression of Twelve-Mile Reef dies out and Santa Barbara Basin widens, the Pliocene beds apparently extend southward to the base of the steep slope forming the north edge of the Channel Islands Platform (see A-A[1], pl. 2). Pliocene beds do not occur on the Channel Islands, except in one small remnant on Santa Cruz Island (Weaver and Meyer, 1969). They may occur locally on the Channel Islands Platform, but dart-core samples indicate that they are not widespread.

The Pliocene deposits are extremely thick along the axis of the Ventura basin, perhaps exceeding 15,000 feet between the Ventura anticline and the Oakridge fault (Nagle and Parker, 1971). The Pliocene beds are much thinner immediately south of the Oakridge fault, totaling about 7,000 feet in the West Montalvo oil field (Hardoin, 1961), and they thin gradually to the southeast across the Oxnard Plain, ranging from 3,500 to 500 feet in the Oxnard oil field (Dosch and Mitchell, 1964). Similar southward thinning is indicated by seismic profiles in the area south of Twelve-Mile Reef.

Where the Pliocene beds crop out on the mainland shelf along the northern edge of the Channel, they have been thinned by post-Pliocene erosion; for example, in the Dos Cuadras field the entire upper Pliocene sequence has been removed by erosion along the crest of the anticline (McCulloh, 1969). Farther offshore, where the Pliocene beds are overlain conformably by

Pleistocene deposits, the Pliocene sequence gradually thins westward. At least 6,000 feet of Pliocene beds have been found by drilling in mid-channel south of Santa Barbara (Curran, Hall, and Herron, 1971). The axis of maximum thickness of Pliocene and younger deposits apparently curves northwestward at the western end of Santa Barbara Channel, and these deposits are very thin on the Arguello Plateau west of the Channel (von Huene, 1969).

Most of the Pliocene sandstones, siltstones, mudstones, and conglomerates were deposited in deep marine water. The sedimentary structures of the sandstone beds indicate that most were deposited by turbidity currents (Crowell and others, 1966; Davis, 1971; Thomson, 1971). The percentage of sand in the sequence decreases to the west and the water depth in which deposition occurred increased to the west, indicating that most of the sand was supplied from eastern sources; some sand was supplied from the north flank of the basin, but relatively little was supplied from the south flank (Davis, 1971; Nagle and Parker, 1971). Most of the sand deposition was concentrated along the east-west trending axis of the basin, and the northern and southern flanks of the basin are characterized by lesser percentages of sand (Curran, Hall, and Herron, 1971; Davis, 1971; Nagle and Parker, 1971).

The depositional trough, during Pliocene time, was steep-sided and had a very gently dipping floor. The basic form of the basin was established by the beginning of Pliocene time, but further subsidence and down-faulting of the central trough continued during Pliocene time. Deposition was rapid enough to exceed the rate of subsidence, so that water depths gradually decreased during Pliocene time. In conjunction with the shallowing, the younger beds overlapped the older beds and extended into areas where they were deposited on Miocene rocks. The topography on this basinal surface of Miocene rocks was locally steep and irregular, resembling the present continental slope, as indicated by well data (Yeats, 1965) and seismic profiles (plate 3).

Curran and others (1971, p. 203) note that Pliocene reservoirs in nine oil fields in the Ventura Basin have yielded nearly one billion barrels of oil. About 67 percent of the estimated ultimate recoverable reserves of the Ventura Basin are in Pliocene strata (possibly including some Pleistocene beds) according to figures published by Nagle and Parker (1971, p. 296).

g. Pleistocene Deposits

The stratigraphic nomenclature and age relations of the strata overlying the Pliocene "Pico Formation" have not yet been agreed upon by geologists. The terminology used here follows that of Greene, Wolf, and Blom (written commun.), who recognize, in ascending order: the Santa Barbara Formation, of latest Pliocene and early Pleistocene age; the San Pedro Formation of early Pleistocene age; unnamed beds of late Pleistocene age; and unnamed beds of Holocene age.

Some basal beds are reportedly oil-saturated in some areas, where the oil has apparently migrated up from below; however, none of the Pleistocene strata contain indigenous hydrocarbons and they are not believed to have a significant potential (Curran and others, 1971, p. 204).

(1) Lower Pleistocene and Upper Pliocene Strata; The Santa Barbara Formation

The Santa Barbara Formation (late Pliocene and early Pleistocene) was named from outcrops in a series of small down-faulted basins along the northern edge of the channel in the vicinity of Santa Barbara (Dibblee, 1966). Southward-dipping beds probably correlative with the type Santa Barbara Formation crop out along the northern flank of the Ventura basin and extend westward across the mainland shelf, where they may be covered by a thin layer of Holocene sediment. West of the longitude of Santa Barbara, these beds are restricted to the outer edge of the mainland shelf. South of their outcrop belt, these beds extend in the subsurface over large parts of the Oxnard Plain, the adjacent Oxnard Shelf, and deeper parts of the Santa Barbara Channel. Drill-hole and seismic data show that they wedge out beneath the San Pedro Formation in the southeastern part of the Oxnard Plain and Oxnard Shelf and near the southern edge of the deep central basin of Santa Barbara Channel.

The Santa Barbara Formation consists of mudstone, siltstone, sandstone, and conglomerate. The formation attains a maximum thickness of about 2,500 feet on the Oxnard Shelf and probably thins gradually to the west. In the Channel area the formation is of marine origin, but farther eastward, in the Ventura basin, the Pleistocene beds are nonmarine. The Santa Barbara Formation rests conformably on the Pliocene Pico Formation and represents a continuation of the basin filling that began in Pliocene time. In the vicinity of Santa Barbara, the basal part of the Santa Barbara Formation is Pliocene in age. Like the Pliocene beds, the younger beds of the Santa Barbara Formation extend progressively farther southward, lapping onto the surface of Miocene rocks that forms the southern edge of the basin (plate 2). The fact that the Santa Barbara Formation rests unconformably on rocks as old as Oligocene in outcrops near Santa Barbara suggests that a similar onlapping relationship existed on the north edge of the basin, but the nature and position of the northern edge of the basin are poorly known because of mid-Pleistocene deformation and resultant erosion.

A buried terrace deposit that may be equivalent in age to the Santa Barbara Formation was found beneath the southern edge of Santa

Barbara Basin north of Anacapa Island (plate 3, line 99; Greene, Wolf, and Blom, written commun.). This terrace deposit formed at the former edge of the Channel Island Platform and is composed of northward-dipping beds that prograded northward into deeper water, forming a wedge of sediment as much as 375 feet thick. After this deposition, the outer edge of the platform and the adjacent terrace deposit were warped downward and then were covered by beds thought to belong to the San Pedro Formation and by younger Pleistocene beds.

Another very small outlier of rocks probably correlative with the Santa Barbara Formation occurs on northeastern Santa Cruz Island (Weaver and Meyer, 1969).

(2) Lower Pleistocene Strata; The San Pedro Formation

The distribution of the San Pedro Formation (early Pleistocene) is very similar to that of the underlying Santa Barbara Formation. Near Santa Barbara, the Casitas Formation (Dibblee, 1966), overlies the Santa Barbara Formation. The Casitas Formation consists of nonmarine sandstones and conglomerates and is probably equivalent to the San Pedro Formation.

The San Pedro Formation in the Oxnard Plain area consists of marine and nonmarine mudstone, sandstone, siltstone, and conglomerate. Farther west in Santa Barbara Channel the unit is probably entirely marine. The maximum thickness is about 1,500 feet on the Oxnard Shelf, and the unit apparently thins considerably in the deeper parts of the basin. Although the contact between the San Pedro Formation and the underlying Santa Barbara Formation is unconformable on parts of the Oxnard Plain, the contact is conformable in the vicinity of Ventura, and the San Pedro Formation marks a later stage in the essentially continuous filling of the basin formed in Miocene time. Seismic profiling across the Oxnard Shelf has shown that the San Pedro Formation is characterized by a complex internal structure (Greene, Wolf, and Blom, written commun.). A three-fold division of the formation is evident from the seismic profiles (plate 2): a thin sequence of flat-lying topset beds that were deposited on a shallow shelf; a thick sequence of beds dipping 10° to 20° southwestward that were deposited on a prograding slope; and a thin sequence of flat-lying bottomset beds that were deposited in a deep marine basin. By the end of San Pedro deposition, the slope had built out nearly to the present position of the slope separating the mainland shelf from the deeper Santa Barbara Basin. If, as seems likely, a similar basinal topography was present during Pliocene and earlier Pleistocene time, the slope must have been located farther east in the Ventura basin.

(3) Upper Pleistocene Deposits

Upper Pleistocene deposits occur in various settings in the Santa Barbara Channel area. Marine and nonmarine sands and gravels form terraces at heights of as much as 700 feet on the slopes rimming the Channel. Marine and nonmarine sands, gravels, and clays are widespread and as much as 700 feet thick on the Oxnard Plain. These beds extend into the adjacent Oxnard Shelf, where they are as thick as 200 feet and form a sequence of basinward-dipping beds that prograded over the flat top of the underlying San Pedro Formation (Greene, Wolf, and Blom, written commun.). Upper Pleistocene clays and silts blanket the slope that separates the mainland shelf west of Santa Barbara from the deep central basin of the Channel. Here, the upper Pleistocene deposits thicken from about 100 feet at the top of the slope to 1,100 feet at the base of the slope (U.S. Geological Survey, 1973). An unknown thickness of upper Pleistocene deposits is presumed to underlie all the deeper parts of the Channel.

h. Holocene Deposits

Holocene deposits form the sea floor throughout most of the deeper parts of Santa Barbara Channel; they are absent in parts of Mugu and Hueneme Submarine Canyons and are absent or very thin on large parts of the shallow shelves adjoining the Channel Islands and the mainland.

The Holocene shelf deposits are thickest on the Oxnard Shelf, reaching a maximum thickness of about 200 feet (Greene, Wolf, and Blom, written commun.). These deposits consist of clay, silt, and sand that are largely marine in the shelf areas but which grade into alluvial deposits on the Oxnard Plain. On the mainland shelf west of Santa Barbara, the Holocene deposits are locally as much as 125 feet thick; these deposits consist of an upper layer that is 5 or 6 feet thick and is composed of fine-grained sand, silt, and clay, and a lower layer that is composed of coarser material, mainly sand (U.S. Geological Survey, 1973). The Holocene deposits at the base of the slope separating the mainland shelf from the deeper basin are about 60 feet thick and consist of clay and silt (U.S. Geological Survey, 1973).

The character of the surficial shelf sediments is well known as the result of numerous grab samples collected from the area (Stevenson, Uchupi, and Gorsline, 1959; Emery, 1960; Wimberley, 1963; Allan Hancock Foundation, 1965). The nearshore area from shore to a depth about 30 feet is underlain largely by sand. On the deeper parts of the shelves along the north edge of the Channel and adjoining the Channel Islands, the surficial sediment ranges from sand and gravel to silt and clay. The distribution of sediment types is irregular in most areas due to the relict nature of much of the sediment, the influence of local, topographic irregularities of the shelf surface, and the effects of complex current patterns. On the Oxnard Shelf the distribution of sediment types is more regular; the sediment in that area grades from sand in the near shore area to mud on the outer shelf as a result of the abundant supply of sediment from the Santa Clara River.

The bottom sediments of the Central Deep have been examined by Hulsemann and Emery (1961) and Fleischer (1972) and found to be predominantly hemi-pelagic silt and clay muds containing varying amounts of organic detritus. These deposits may be as much as several hundred feet thick (plate 3). On the Pescado Fan, which was examined by Duncan and others (1971), the bottom sediments consist of interbedded sand, gravel, silt and clay. The thicknesses of individual beds and the proportions of the various sediment types can be expected to change abruptly over short distances because fans are generally regarded as having a complex history of development and abandonment of numerous channel systems controlling sediment distribution. Such a history seems borne out by the relatively poor penetration and lack of reflector continuity found in these strata (see line 7-21, plate 3).

The rates of deposition and erosion of sediment vary with location within the Channel. Seasonal erosion and redeposition of sand on the beaches causes changes in vertical level amounting to several feet (Kolpack, 1971). Some sections of beach are undergoing permanent erosion (Emery, 1960). Sediment discharged by the Santa Clara River during major floods can form layers of sediment more than 15 cm thick on the inner part of the Oxnard Shelf; this sediment is later eroded by wave and current action and redeposited over wider areas of the shelf and deep basin (Drake, Kolpack, and Fischer, 1972).

The average rate of deposition in the deep central basin of Santa Barbara basin is about 2 mm per year (Fleischer, 1972; Hulsemann, 1961).

3. Structural Geology

a. Regional Setting

The Santa Barbara Channel is the seaway that occupies the submerged western part of the Transverse Ranges province of southern California. Throughout that province, the major folds and faults generally trend east-west (figure II-2), as do the metamorphic fabric of pre-Cretaceous basement rocks, and the fabric and petrochemical trends of the late Mesozoic batholithic rocks of the province (Baird and others, 1974). In some parts of the province, east-west structural trends may have controlled the orientation of sedimentary deposits of early Tertiary age. For example, thick Eocene sandstones in the Santa Ynez Mountains may have accumulated in south-flowing fans from an east-west-trending high area to the north (Stauffer, 1965). In other parts of the province (for example, the Santa Monica Mountains-Simi Hills area), northerly trends may be inferred for the shorelines and isobaths of sedimentary environments of Late Cretaceous through early middle Miocene age (Yerkes and Campbell, 1971) and east-west structures controlling depositional environments are not clearly evident prior to late middle Miocene time. Also about late middle Miocene time the Ventura Basin, whose Paleogene ancestry is indistinct, became an important basin of deposition. Great thicknesses of marine sediments accumulated in this rapidly subsiding narrow trough from late Miocene through early Pleistocene time. These basin strata have been folded and faulted along east-west structural trends by north-south compressive stresses, beginning in mid-Pleistocene time. Tectonic deformation continues to the present, as indicated by the historic seismicity of the region, geodetic measurements of differential vertical movement, and the evidence of deformed Holocene beds and geomorphic features (section II.B.6.).

b. Relation of the Santa Barbara Basin to the Ventura Basin

The strata and structure of the Santa Barbara Channel region are continuous with those of the Ventura Basin area, onshore to the east; however, there are significant topographic and structural differences between the two "basins". The Santa Barbara Basin may not have become a discrete depositional feature until Pleistocene time, about the time when the sedimentary fill of the Ventura Basin was being deformed by folds and faults along the axial trend of the depositional Ventura basin. This axial shift is suggested by comparisons of thickness of equivalent sequences from both onshore data and the cross-channel seismic lines (see, for example, lines 99 and 621, plate 3). Generally, the Pliocene and early Pleistocene deposits of the Santa Barbara Channel region seem to be distributed in accord with east-west Ventura Basin trends. The axial part of the late Miocene to middle Pleistocene Ventura Basin is marked by the thickest accumulations of deposits of those ages and lies to the north and northeast of the axis of the present-day topographic and depositional basin, Santa Barbara Basin. The southern flank of the pre-early Pleistocene Ventura Basin is marked by a wedge-edge of the thick Pliocene and late Miocene strata that has been noted in the subsurface onshore (Paschall and others, 1956), and can be found in nearly all the seismic profiles across the Channel (plate 3). In the western two-thirds of the Channel, the alignment of the subsurface southern wedge-edge is approximately along the present line of greatest bathymetric depth. South of the 12-Mile Reef, it continues due east and crosses the shoreline near Port Hueneme, whereas the Santa Barbara Basin axis trends more south of east. Some comparisons of thicknesses for lower Pleistocene deposits suggest a shift southward in the axial part of the depositional trough at or before about middle Pleistocene time. (Figure II-5.)

Unlike the Santa Barbara Basin, which is a present-day topographic and depositional basin, the Ventura Basin is no longer a basin of active marine deposition. The axial deep of the late Miocene-Pliocene depositional Ventura Basin apparently trended eastward from the area now marked by the Ventura Avenue anticline, inland along the valley of the Santa Clara River. To the west, the Rincon-Dos Cuadras-Hondo trend of folds and faults seems to be alined with the offshore continuation of the old depositional trough. The deformed strata underlie the wave-planed mainland shelf and its adjacent slope along the north aide of the Santa Barbara Channel. The sedimentary strata that filled the Ventura Basin have been folded, faulted, and eroded since middle Pleistocene time. In contrast to the east-west trend of the old Ventura Basin, the axial trend of the Santa Barbara Basin is

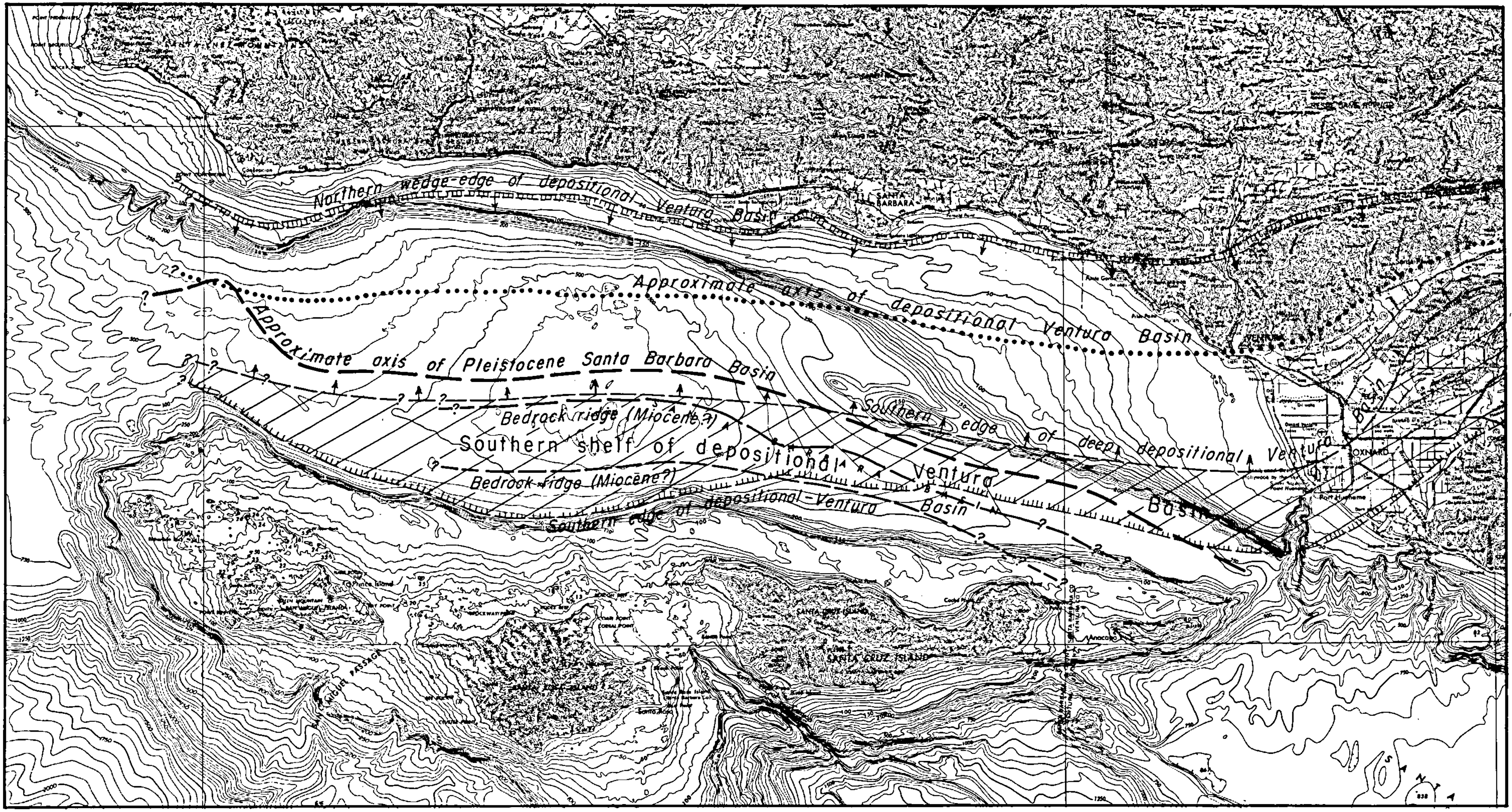

Figure II-5 MAP SHOWING RELATION OF THE SANTA BARBARA BASIN TO THE VENTURA BASIN west-northwest and transects the south flank of the older Ventura Basin at a low but distinctly crosscutting angle. Only the northern part of the Central Deep of the Holocene Santa Barbara Basin lies close enough to the western projection of the older axis to serve as a credible remnant of the depositional Ventura Basin. There, however, thick Holocene and Pleistocene deposits conceal whatever older sedimentary deposits may be present, and questions about its origin as a western remnant of the Ventura Basin must remain open.

c. Relation of the Channel Islands and the Santa Monica Mountains

The Channel Islands appear to be a topographic western continuation of the Santa Monica Mountains; however, several significant equivocations should be offered: a) The only demonstrated structural continuities are late Miocene and younger; b) some Paleogene strata of the Islands appear to represent depositional facies as proximal as those of the central part, rather than the western end, of the Santa Monica Mountains (Yeats, 1968); c) the sedimentary facies associated with the middle Miocene volcanic rocks on the Islands are significantly different from those associated with the Conejo Volcanics of the northern flank of the Santa Monica Mountains, and more nearly similar to the strata associated with the volcanic rocks found south of the Malibu Coast fault along the southern flank of the Santa Monica Mountains. Yeats (1968; 1970) has postulated that the Channel Islands are a "rafted" block of crustal material that was formerly adjacent to the Santa Ana Mountains, far to the east. More recently, Howell and others (1974) have suggested that several blocks, each including one of the present islands, were moved relatively northwestward by right-lateral faulting in the Continental Borderland, from original positions offshore between San Diego and Long Beach.

In any case, the present position of the Channel Islands is anomalous with respect to the most likely source areas and depositional environments of their basement rocks and Paleogene strata, and their relationship to the Santa Monica Mountains is more complex than the present topography may indicate.

d. Prominent Structural Features

Many of the prominent structural features of the Santa Barbara Channel have been described in the report by Vedder and others (1969), from which the following has been modified by the addition of some new seismic and sample data from 1973 cruises by the U.S. Geological Survey, and data supplied in the Santa Ynez Unit Environmental Impact Statement.

(1) Santa Ynez Fault

The Santa Ynez fault extends from east of the map area (plate 2) to the vicinity of Gaviota Pass, where it bifurcates into a west-trending northern branch and a southwest-trending southern branch. East of the bifurcation, the fault generally dips steeply to the south, and the south side apparently has been raised 5,000 to 10,000 feet relative to the north side. The net slip on the fault has not been determined because of complex stratigraphic and structural relations, but some geologists suggest that it is a major active fault zone along which there has been left-lateral oblique slip (Page and others, 1951; Dibblee, 1966). It is a convenient natural feature to use as the northern boundary of the Santa Barbara Channel region.

(2) Santa Ynez Mountains

The structure of the Santa Ynez Mountains between the Santa Ynez fault and the Channel is, in general, a steeply south-dipping homocline, which incorporates Cretaceous to Miocene rocks west of Santa Barbara and includes strata as young as Pleistocene east of Santa Barbara. In the area north of Carpinteria, an overturned syncline and a faulted anticline disrupt the homoclinal nature of the structure (Lian, 1954), and a faulted syncline complicates the pattern at Santa Barbara. On the north side of the mountains northwest of Santa Barbara, a reversal in dip forms an anticline against the Santa Ynez fault.

(3) Mainland Coast

Along the mainland coast of the Channel the younger and less competent late Cenozoic rocks are cut by many faults that generally trend parallel to the range front. The strata have been folded into complex anticlines and synclines that vary in size from a few inches to prominent folds, such as the Ventura anticline which is nearly 17 miles long and about 4 miles wide. Other, less prominent anticlines are present in the areas of Summerland, Montecito, Mesa of Santa Barbara, Goleta, Capitan and Elwood. Numerous small folds are evident along the sea cliffs and on wave-cut platforms when the tide is low.

(4) Rincon Trend and Adjacent Structures

The Rincon anticlinal trend is one of the most prominent in the Santa Barbara Channel (plate 2). It extends westward from the Rincon oil field through the Carpinteria Offshore and Dos Cuadras Offshore fields, into the Federal Ecological Preserve, where it becomes discontinuous, partly because of faulting. Further to the west, the same or an en echelon structure appears to continue into the Hondo Offshore area. At its eastern end, the Rincon trend appears to be bounded by the Pitas Point fault on the south and the Red Mountain thrust fault on the north. It extends eastward onshore to include the Ventura Avenue anticline. Several faults within the block parallel the anticlinal trend and displace the axial part of the anticline upward. North of the Red Mountain fault is a parallel structural zone containing several smaller, en-echelon structures, approximately parallel to the Rincon trend to the south, on which are located the Summerland Offshore, Summerland, and Mesa oil fields. Although the continuity through the Santa Barbara-Coal Oil Point area is disturbed and uncertain, a western equivalent of this zone of structural trends seems to be represented by the Ellwood-Molino-Conception Offshore alignment of oil fields. In general, the Rincon anticlinal trend seems to lie on about the same line as the axis of the deep basin of late Miocene to late Pliocene sedimentation; and the less-well-defined trend that lies parallel to and north of the Rincon trend approximates the alinement of the northern wedge-edge of the Pliocene depositional basin.

(5) Montalvo Trend and 12-Mile Reef

The Montalvo anticlinal trend extends westward from the offshore part of the West Montalvo oil field, west of Oxnard, for about 20 miles. The broad anticlinal structure is bounded by normal faults that appear to diminish in displacement westward. Its continuation west of the longitude of Santa Barbara is uncertain, and related adjacent structures on the north and south seem to converge westward.

Another prominent anticlinal structure lies a few miles south of the western part of the Montalvo trend and en echelon with it. It has been traced for more than 20 miles westward and west-northwestward from the southwest part of the Oxnard Shelf to the Central Deep, where its further continuation is concealed by thick Holocene and Pleistocene sediments. The structure appears to control the form of 12-Mile Reef, on top of which folded, eroded

Pliocene strata are exposed on the sea floor (plate 3).

(6) Channel Islands Platform

The structure of the Channel Islands Platform, the north side of which lies beneath the waters of the Santa Barbara Channel, is probably as complex as that exposed on the Islands themselves. Folds and faults are discernible in the seismic profiles, and those structures have trends that generally parallel the structures to the north. Faults with a west or northwest trend are the dominant structural features, and the fault-bounded anticlines and synclines on Santa Rosa and Santa Cruz Islands have similar trends. Santa Rosa and Santa Cruz Islands are cut by median faults that have strong topographic expression. Each divides its respective island into dissimilar geologic parts; both faults are believed to have components of left-lateral displacement. The submerged saddle between Santa Rosa and Santa Cruz Islands appears to be controlled by a zone of northwest-trending faults and folds (plate 2), having a pattern suggestive of right-lateral drag. However, the northwest-trending zone appears to merge westward with the continuation of the Santa Cruz Island fault, of probable left-lateral displacement, and it may be that the pattern originated in response to a complex displacement involving left-lateral slip and local northeast-southwest compression.

Neogene strata form only a thin cover over basement, Cretaceous, and Paleogene rocks that were subjected to middle Miocene deformation, accompanied by volcanic activity. The Pliocene to early Pleistocene strata of the Ventura Basin are represented on the platform only by discontinuous shallow marine deposits suggesting the area was part of a shallow platform along the southern margin of the Ventura Basin.

The north-facing slope separating the Channel Islands Platform from the deep part of the Santa Barbara Basin appears to be controlled by a zone of faults that, in many places, are overlapped by terrace and slope sediments, so that the slope angle is controlled by depositional repose (plate 3).

(7) The Southern Frontal Fault System

The west-trending Santa Monica fault, which marks the northern edge of the deep part of the Santa Monica basin, appears to form the southern boundary of Transverse Ranges structural trends to the southeast of the Santa Barbara Channel (figure II-2). It is probably a north-over-south reverse fault like many exposed onshore to the north of it, along the southern flank of the Santa Monica Mountains, and it may extend westward beneath the sea south of Santa Cruz Island. The data available at the present time are insufficient to evaluate whether it may extend further west, across the ridge south of Santa Rosa Island, or if it joins or is truncated by the fault system that trends north-westward through the pass between Santa Cruz and Santa Rosa Islands. The Malibu Coast fault, which lies along the southern flank of the Santa Monica Mountains is onshore in the central part of that range, where it trends generally westward and dips northward, in some places at low angles. Although the present outcrop relations demonstrate only north-over-south reverse displacement, the fault juxtaposes completely dissimilar basement and younger rocks, and it was probably a surface of large-scale left-lateral displacement during the late-middle Miocene to late Pliocene episode of deformation. Its western continuation has not been identified in available seismic profiles, apparently because acoustic basement lies on both sides. If it continues due west or north of west, it passes through the Santa Barbara Channel to the north of the Channel Islands. If the western continuation passes to the south of the Islands, it must make a sharp bend to the south to cross the Hueneme-Mugu slope.

The present data are inadequate to distinguish between these possibilities.

e. Structural Evolution of the Santa Barbara Channel Region

The structural evolution of the region is complex and difficult to reconstruct--partly because the distribution of the basement rocks is so poorly known. There seem to have been three principal episodes of deformation, each one associated with a different stress field, since Early Cretaceous time: 1) middle Cretaceous--right-lateral displacement on east-west faults along the northern boundary of the Transverse Ranges province, probably associated with rotation of blocks; 2) late middle Miocene to late Pliocene--regional extension (normal faulting) between blocks that now form the north and south boundary ranges of the western Transverse Ranges, and left-lateral slip at the southern boundary of the province; and 3) late Pliocene to Holocene--regional compression between the same blocks resulting in reverse dip-slip, either alone or in oblique left-lateral combination. Between the middle Cretaceous and late-middle Miocene episodes, deformation was relatively slight; although the thick Paleocene and Eocene sections of the Santa Ynez Range indicate significant early Tertiary uplift to the north, most of the area to the south was undergoing a relatively quiet cycle of transgression, regression, and transgression across generally north to northwest-trending shorelines. Both of the first two episodes of deformation were apparently associated with large-scale lateral slip on faults with general east-west trends. The latest episode superimposed compressional deformation on a terrane that already contained a strong east-west orientation for many planes of weakness, many of which were reactivated in segments of varying length.

The total structural relief on the basement rocks of the Santa Barbara

Channel region is estimated by Vedder and others (1969) to be on the order of 60,000 feet (18,500 m). However, the distribution of basement rocks is known from only a few outcrops marginal to or some distance outside of the Channel region, and type of basement and depths to it in the basins are unknown. Two or more basement terranes are probably structurally juxtaposed in areas covered by younger sedimentary rocks. If, as postulated by several workers (King, 1959; Hamilton and Myers, 1966; Ernst and others, 1970; Yeats, 1968; Suppe, 1970), a paired metamorphic belt--Franciscan-Catalina Schist terrane on the west, "Sierran type" metamorphic and granitic rocks on the east--lay continuously along the western margin of North America by late Mesozoic time, the present basement rock distribution and fabric in the Transverse Ranges province is anomalous and must be the result of large-scale fault disruption (and probably rotation) in post-Early Cretaceous time, perhaps as early as middle Cretaceous. Such large-scale disruption is also suggested by the absence in the Transverse Ranges of a clear analog of the Coast Ranges thrust, as recognized by Bailey, Blake, and Jones (1970) in central and northern California.

The rapid subsidence of the Ventura Basin, the western end of which continues offshore into part of the area now occupied by the Santa Barbara Channel, probably reflects an episode of regional north-south crustal extension by normal faulting (see Campbell, 1973), associated with large left-lateral displacement on the Malibu Coast fault to the south (Campbell and Yerkes, 1971). The subsequent deformation, possibly beginning as early as late Pliocene, and continuing to the present, reflects regional north-south compression--reverse faults dipping inward from the outboard flanks of the province (the Santa Ynez and Santa Monica faults), and reverse faults dipping outward, away from the center of the thick late Cenozoic sediment accumulation (the Oak Ridge and San Cayetano-Red Mountain systems). The effects of compressional stress may diminish somewhat to the west (by giving way to right-lateral shear effects), as suggested by the northwestward bending of the structural trends west of Point Conception and San Miguel Island (plate 2), and the change from east-west to northwest trends for contours of Bouguer gravity anomalies in the western end of the Channel (plate 6).[1] The lack of clearly evident strong east-west structural trends crossing the continental shelf and slope further to the west suggests that the western end of the Transverse Ranges province may lie at or near the western end of the Santa Barbara Channel (Von Huene, 1969).

This complex history makes interpreting the deep structures of the Ventura and Santa Barbara Basins extremely difficult because faults that offset the relatively shallow Pliocene and Pleistocene strata may not have the same amount or kind of displacement where they cut the older strata below. Moreover, because there may have been large lateral displacement of pre-late Miocene strata along faults now concealed by younger strata along the axial trend of the Pliocene Ventura Basin, correlations of older strata from the mainland, on the north, to the islands, on the south, are more speculative than might be assumed.

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[1] The present compressional stress field is inferred to be a consequence of: 1) northwestward right-lateral slip between major crustal plates along the San Andreas fault, and 2) the constraint on northwestward displacement imposed by the west-northwest-trending segment of the San Andreas as it crosses the Transverse Ranges Province. The resultant compression, where relieved along pre-exising east-west planes of weakness, can be expected to show as reverse left-lateral (oblique) slip. Where the pre-existing planes of weakness take on a northwest orientation, the dominant response may be right-lateral shear.

4. Hydrology

a. General Description

Water-supply conditions vary considerably in the southern coastal area of Ventura and Santa Barbara Counties. In Ventura County water demand is met by local supplies and imported water. The local water supplies are obtained from surface reservoir storage and ground-water extraction. Water is imported to the city of Oxnard by the Calleguas Municipal Water District, a member of the Metropolitan Water District of southern California. Additional imported water became available with the completion of the State Water Project. The Ventura County Flood Control District has contracted for a maximum annual entitlement of 20,000 acre-feet.

In Santa Barbara County, the south coastal area for many years relied on local ground-water resources to meet its water needs. As the demand for water increased, the city of Santa Barbara developed the water in the upper reaches of the Santa Ynez River by constructing Gibralter Dam and Reservoir. This was followed by Montecito County Water District's construction of Juncal Dam and Jameson Lake, located a short distance upstream from the Gibralter Reservoir. The water supplies from these two reservoirs were conveyed to the south coastal area in tunnels constructed through the Santa Ynez Mountains.

In 1953, the U.S. Bureau of Reclamation completed the Cachuma Project for diversion of substantial quantities of Santa Ynez River water into the south coast area. Major project features include the 205,000 acre-feet capacity Cachuma Reservoir, the Tecolote Tunnel through the Santa Ynez Mountains, and the South Coast Conduit. South coastal area users of Cachuma water include the city of Santa Barbara and the Carpinteria, Goleta, Montecito and Summerland County Water Districts. These agencies encompass virtually all of the developed lands in the south coastal area of Santa Barbara County.

Santa Barbara County has contracted for water from the State Water Project but the construction of the "Coastal Stub" portion of the Coastal Branch of the California Aqueduct that will serve the area has been postponed. State Project water was originally scheduled for delivery in 1980 (Bookman and Edmonston, 1970). The present delivery schedule is uncertain.

Possible overdraft conditions in the Carpinteria ground-water basin have been the subject of a recent study by Geotechnical Services Inc. for the Carpinteria County Water District. According to Mr. J. Gonzales, President of Geotechnical Services, Inc. (oral communication, 1975), the report in preparation will state that there is no overdraft in the Carpinteria basin at the present time. An adjudication of water rights is pending for the Goleta ground-water basin because of an existing water shortage. Any major expansion of existing facilities or location of new crude-oil treatment or storage facilities in these areas may not be feasible until imported water becomes available.

b. Surface Water

Many small southward-flowing streams drain the south coastal area of Santa Barbara County west of Ellwood. During most of the time, the flow in the streams is small or intermittent, but during and shortly after periods of heavy precipitation, the streams may be swollen with runoff. The low or base flow is supplied mainly or entirely by ground-water discharge.

East of Ellwood the south coastal area near Goleta is a broad, flat alluvial plain bordered on the south by the coastline and on the north by foothills and terraces, above which rise the Santa Ynez Mountains. Ten major creeks drain into a slough lying south of the town of Goleta. They all flow intermittently upon entering the alluvial plain.

Seven main creeks carry runoff from the Santa Barbara-Montecito area. The gradient of these creeks, where they flow across consolidated rocks, is about 800 feet per mile. The gradients decrease where the stream courses cross areas underlain by alluvium, but even there the gradients are steep--about 200 feet per mile. The stream gradients conform closely to the general land-surface gradients across the low-lying areas. Several of the creeks are perennial in their upper reaches, but all are intermittent where they cross the alluvium.

Five main creeks drain into the eastern part of the alluvial plain in the Carpinteria area. These creeks are usually perennial almost to the edge of the consolidated rocks and are intermittent in their courses across the alluvium. The cover of the upper watershed in this area is almost entirely made up of brush with a high fire hazard during the dry season.

In Ventura County the Ventura and the Santa Clara Rivers and Calleguas Creek drain into the Santa Barbara Channel. The drainage area of the Ventura River comprises 188 square miles. Elevations in the drainage area vary from a maximum of 6,003 feet above sea level at Monte Arido in the northwestern extremity of the watershed to sea level at the mouth of the river. The 45-year average discharge of the Ventura River at Ventura is 40,790 acre-feet per year and the maximum discharge for the period of record is 58,000 ft^3/s (U.S. Geological Survey, 1972). Present realty developments are concentrated in the small alluvial valleys and adjacent hills south and east of the confluence of Matilija and North Fork Matilija Creeks, which are the principal tributaries of the Ventura River.

The Santa Clara River drains an area of 1,612 square miles above the gaging station at Montalvo. The river flows generally southwestward from its headwaters in Los Angeles County, at elevations in excess of 5,000 feet, to the

Pacific Ocean near Oxnard. Its principal tributaries are Sespe Creek with a drainage area of 251 square miles above the gage near Fillmore and Piru Creek with a drainage area of 437 square miles above the gage near Piru, both of which flow eastward and then southward to join the main stream near the towns of Fillmore and Piru, respectively. Another important tributary, Santa Paula Creek, drains an area of 40 square miles southwest of the Sespe Creek watershed and, flowing generally south, joins the Santa Clara River at the town of Santa Paula. Urban and agricultural developments are found along the Santa Clara River bottomlands and on the broad coastal plain at its mouth. Most of the drainage area of Sespe, Piru, and Santa Paula Creeks are sparsely-settled national forest lands. The 28-year average discharge of the Santa Clara River at Montalvo is 81,140 acre-feet per year, and the maximum discharge for the period of record is 165,000 ft^3/s (U.S. Geological Survey, 1972).

The headwaters of Calleguas Creek and its principal tributary, Conejo Creek, originate in the Santa Susana and Santa Monica Mountains at elevations in excess of 3,000 feet. The drainage area, poorly defined in the lower reaches of the stream, comprises about 331 square miles (California State Water Resources Board, 1953). Oak Ridge, a relatively narrow elongated range of hills extending in an east-west direction, separates the Calleguas Creek watershed from that of the Santa Clara River on the north. The watershed is defined by the Santa Susana Mountains on the east and by the Santa Monica Mountains on the south. The system drains generally in a southwestward direction, and discharges into the ocean through Mugu Lagoon about 7½ miles southeasterly of Port Hueneme. The drainage area is characterized by a more moderate relief than that of the Ventura and Santa Clara River watersheds, and most of the area lies below 1,000 feet in elevation. Present urban and agricultural developments are restricted to the relatively small alluvial valleys and adjacent hills throughout the area, and on the coastal plain in the lowermost reaches of Calleguas Creek. From intermittent records the 24-year average annual runoff of Calleguas Creek is estimated to be 17,000 acre-feet.

c. Ground Water

In the ground-water basins along the Santa Barbara and Ventura County coastal areas adjacent to the Santa Barbara Channel there are areas where fresh water ground-water bodies or aquifers extend seaward and crop out on the ocean floor. The ground-water level or head of water in an aquifer along the coast, in relation to sea level, is the controlling factor that determines whether seawater intrusion or submarine springs will occur. If the head of water in the aquifer is above sea level, ground-water movement will be seaward; if the head is below sea level, seawater intrusion into the aquifer may occur if there is no subsurface physical barrier to its landward movement.

(1) Onshore Aquifers

- Point Conception-Elwood Area

Along the Santa Barbara County coast between Point Conception and Elwood most of the ground water occurs in the consolidated rocks of Miocene age. The water is in fractures in siliceous shale and in intergranular spaces in partly cemented sandstone. In the outcrop area the consolidated rocks contain ground-water under water table conditions. Down-dip, however, beneath confining beds of nearly impermeable materials, the water is under artesian pressure. Fresh water aquifers in this area have a very limited offshore extension.

The California Department of Water Resources (1958) listed the Gaviota Basin, Cemetario Basin, Tajiguas Basin, Cañada del Refugio Basin, Cañada del Corral Basin, Las Varas Basin, and Bell Canyon Basin as "areas of suspected sea-water intrusion and areas of over 100 ppm chloride." Intensive pumping of wells near the shore in the permeable alluvium of these stream valleys or in areas of highly fractured Monterey Shale could induce seawater intrusion which would result in eventual contamination of the ground water. However, the majority of wells in this part of the coastal area are far enough inland so that they tap aquifers of the sandstone unit that are stratigraphically below but topographically above the Rincon Shale of the shale unit (Miller and Rapp, 1968). These wells probably are protected from seawater intrusion by the nearly impermeable shale and mudstone of the Rincon Shale. If the older aquifers are in hydraulic contact with the ocean in some area offshore, prolonged pumping from them could induce seawater to move landward beneath the overlying shale unit.

- Elwood-Rincon Point Area

In the coastal area between Elwood and Rincon Point ground water occurs in the interstices of the unconsolidated deposits of the alluvium, Casitas and Santa Barbara Formations, and in sandstone and fractured shale. Between Elwood and Santa Barbara the unconsolidated water-bearing deposits are truncated on the south by consolidated rocks uplifted by faults. Thus, the unconsolidated deposits along this area of the coast are almost completely separated from the ocean by strata of consolidated rocks.

Pumping of ground water from wells in a coastal area may cause seawater to move inland into the aquifers. In the area between Elwood and Santa Barbara, with minor local exceptions, intrusion of seawater probably does not pose a serious threat. Along the coast to the east, between Santa Barbara and Montecito, east-west trending faults just offshore seem to act as effective barriers to seawater intrusion along the southern margin of the aquifers (Muir, 1968). Fresh water-bearing deposits that comprise the deep water body in the Carpinteria area may be in contact with the ocean (Evenson and others, 1962) but to date no deterioration in the water quality has been observed in the wells along the coast, in spite of periods of landward gradient of the water table. This would suggest that subsurface offshore stratigraphic and structural features may be such that the deep water body in this area is effectively sealed from seawater intrusion.

- Rincon Point-Ventura Area

Along the Ventura County coast, between Rincon Point and the city of Ventura, the principal aquifers occur in the late Quaternary alluvium of the Ventura River and in the "San Pedro Formation" which flanks and underlies the alluvium near the mouth of the river (Calif. State Water Resources Board, 1953). There are few wells in this area, and there is no record of seawater intrusion. Ground-water outflow to the ocean through the alluvium probably occurs during periods of high ground-water levels.

- Ventura-Point Mugu Area

In the area between the city of Ventura and Point Mugu, two ground-water basins with offshore extensions border the coast: Mound basin between Ventura and the Santa Clara River and the Oxnard plain basin between the Santa Clara River and Point Mugu. In Mound basin deposits of late Pleistocene age overlie the "San Pedro Formation." The deposits are divided into two distinct parts: an upper, tight clayey zone, 200 to 400 feet thick; and a lower water-bearing zone, primarily sand and gravel, 100 to more than 300 feet thick (Mann and Associates, 1958). The thickness and continuity of the aquifers in the "San Pedro Formation" are not well known because of the lack of well data. Ground-water outflow to the ocean occurs through the gravel in the upper Pleistocene deposits. There is no record of seawater intrusion in this basin.

The Oxnard plain basin contains five principal water-bearing zones designated the Oxnard, Mugu, Hueneme, Fox Canyon, and Grimes Canyon aquifers (Calif. Department of Water Resources, 1965, 1970). The Oxnard aquifer in this basin is a thick layer of coarse, gravelly deposits. Beneath Port Hueneme where seawater intrusion has occurred the aquifer is about 250 feet thick. The confinement of the Oxnard aquifer beneath the Oxnard plain basin is caused by the "clay cap," which consists of many silty and clayey layers with interbedded lenses of sand. The effective upslope edge of the "clay cap" has not been defined, but beginning with the thin clay lenses north of Oxnard, the "clay cap" becomes thicker and less permeable toward the ocean; the clayey layer overlying the Oxnard aquifer near the sea is 100 feet or more thick.

Between the base of the Oxnard aquifer and the unconformity, which marks the top of the "San Pedro Formation," is a section, perhaps 200 feet thick, of clay, sand and gravel as yet not extensively explored or tested by water wells.

In the Point Mugu area there is a widespread gravel zone between depths of 350 and 420 feet named the Mugu aquifer. Northward toward Saticoy the Mugu aquifer becomes less permeable and apparently is replaced by a series of alternating thin sand and clay beds. Near Point Mugu, however, especially to the north of the Pacific Missile Range there is extensive pumping from this aquifer.

The Hueneme aquifer is separated from the overlying Mugu aquifer by a clay layer. The fine- to coarse-grained sediments of the Hueneme aquifer are about 100 feet thick within the city of Port Hueneme and about 300 feet thick north of the city of Oxnard (Calif. Department of Water Resources, 1970).

The Fox Canyon aquifer comprises the predominantly sand and gravel basal zone of the "San Pedro Formation" of early Pleistocene age. At the time of deposition the Fox Canyon sand and gravel were saturated with sea water. As shown by the contained fossil remains, the upper layers of the "San Pedro Formation" were deposited in a non-marine environment.

The "San Pedro Formation" and Fox Canyon aquifer underlie almost all the coastal part of the area. From the Santa Clara River south the Fox Canyon aquifer extends continuously to the vicinity of the Santa Monica Mountains, underlying nearly all the Oxnard plain, the western part of the Rancho las Posas area, the Camarillo Hills, and Pleasant Valley.

The base of the Fox Canyon aquifer is quite readily determined because the thick shale of the Santa Barbara Formation underlies the basal gravel in most places, but in parts of Pleasant Valley and elsewhere the top of the Santa Barbara Formation contains a thick gravel zone referred to as the Grimes Canyon aquifer. Over much of its area of occurrence the Grimes Canyon aquifer has an extensive hydraulic connection with the Fox Canyon aquifer.

In contrast with the generally recognized base of the Fox Canyon aquifer there seems to have been no consistent interpretation for the top. Whereas the sand and gravel layers near the base are traceable over an extensive area, the upper sand and gravel layers are less continuous, appearing as lenses in various stratigraphic positions. Nevertheless, there are commonly one or more thick sand zones (as much as 100 feet) above the more continuous permeable layers.

As noted above, the main sand and gravel layers in the lower part of the Fox Canyon aquifer have a high degree of continuity, and water movement is relatively unrestricted. Higher in the "San Pedro Formation" the water-bearing zones are less continuous and would have less opportunity for recharge. Similarly, they are less subject to seawater intrusion. There generally is very limited interconnection among these sand lenses. Many of the lenses, however, have been interconnected recently by water wells that are perforated in several zones.

In addition to restrictions imposed by lenticular deposition, underground flow in the Fox Canyon and upper "San Pedro" aquifers is retarded by several faults.

The Grimes Canyon aquifer is separated from the overlying Fox Canyon aquifer by a layer of fine-grained sand and silt. Within the Oxnard basin the areal extent of the two aquifers is approximately the same (Calif. Department of Water Resources, 1970). Few water wells penetrate the Grimes Canyon aquifer; for this reason, information concerning this unit has been derived mostly from oil well electric logs. These logs indicate that the aquifer consists of fine- to coarse-grained materials.

- Northern Channel Islands

On the Channel Islands bordering the Santa Barbara Channel, which include San Miguel, Santa Rosa, Santa Cruz, and Anacapa, no detailed ground-water studies have been made. On Anacapa Island there is a single small spring but no wells or fresh-water aquifers are known to exist. On San Miguel Island there is one abandoned well and 14 small springs (Weaver, D.W., oral commun., 1974). The well is near an old abandoned ranch house and the well water when sampled had a reported chloride ion concentration of 1,848 Mg/L (milligrams per liter).

Limited information from oil exploration holes indicates that fresh water occurs to depths of several hundred feet or more below sea level in the volcanic rocks on Santa Cruz Island and in the Miocene sedimentary rocks on Santa Rosa Island. No evidence is available on any subsurface extension into the Channel of these fresh-water bodies. There are a few water wells on Santa Rosa and Santa Cruz Islands, but the wells are privately owned and data on them are not available. On eastern Santa Cruz Island an oil exploration hole has been perforated opposite the Miocene volcanics and converted to a water well. The depth of the perforations and the quantity and quality of the water produced are not known.

(2) Offshore Aquifers

Offshore extensions of the fresh water aquifers occur seaward of both the Mound and Oxnard plain ground-water basins. A detailed marine geophysical survey was made in this area in the summer of 1970 as a joint effort by the U.S. Geological Survey and the State of California Department of Water Resources.

- <u>Mound Ground-water Basin Extension</u>

The results of the survey show (Green, written commun., 1974) that the aquifers in the Mound basin appear to extend offshore for more than 14 miles, with a width of about 5 miles. The thickest section of fresh water-bearing deposits is near the Oak Ridge fault (figure II-6). The deposits thin and wedge out to the north. The western limit is not known because it was not within the surveyed area.

- <u>Oxnard Plain Ground-water Basin Extension</u>

The offshore extension of the aquifers of the Oxnard basin lies south of the Oak Ridge fault and west of Mugu Canyon. It is possible that the deeper fresh water-bearing deposits may extend southwestward, west of Hueneme Canyon, to Anacapa Ridge. Beneath the Hueneme-Mugu shelf it is difficult to determine the offshore limits of the aquifers because of a zone of seismic incoherency. Most likely their extent is limited by the northern slope of the Santa Monica basin. The eastern limit of the fresh water-bearing deposits seems to be about two miles east of Mugu Canyon, where it thins and wedges out against Miocene rocks that crop out on the sea floor.

The offshore extension of the fresh water-bearing deposits of the Mound and Oxnard plain ground-water basins is estimated to have an areal extent of more than 475 square miles (Green, written commun., 1974). The average thickness of probable fresh water-bearing deposits offshore ranges from 1,200 feet on the shelf areas to about 800 feet in the Santa Barbara basin. Thicknesses of the total offshore sediments of Quaternary age that lie above rocks of Pliocene or older age (figure II-6) agree fairly well when equated with onshore depths to the effective base of fresh water, which

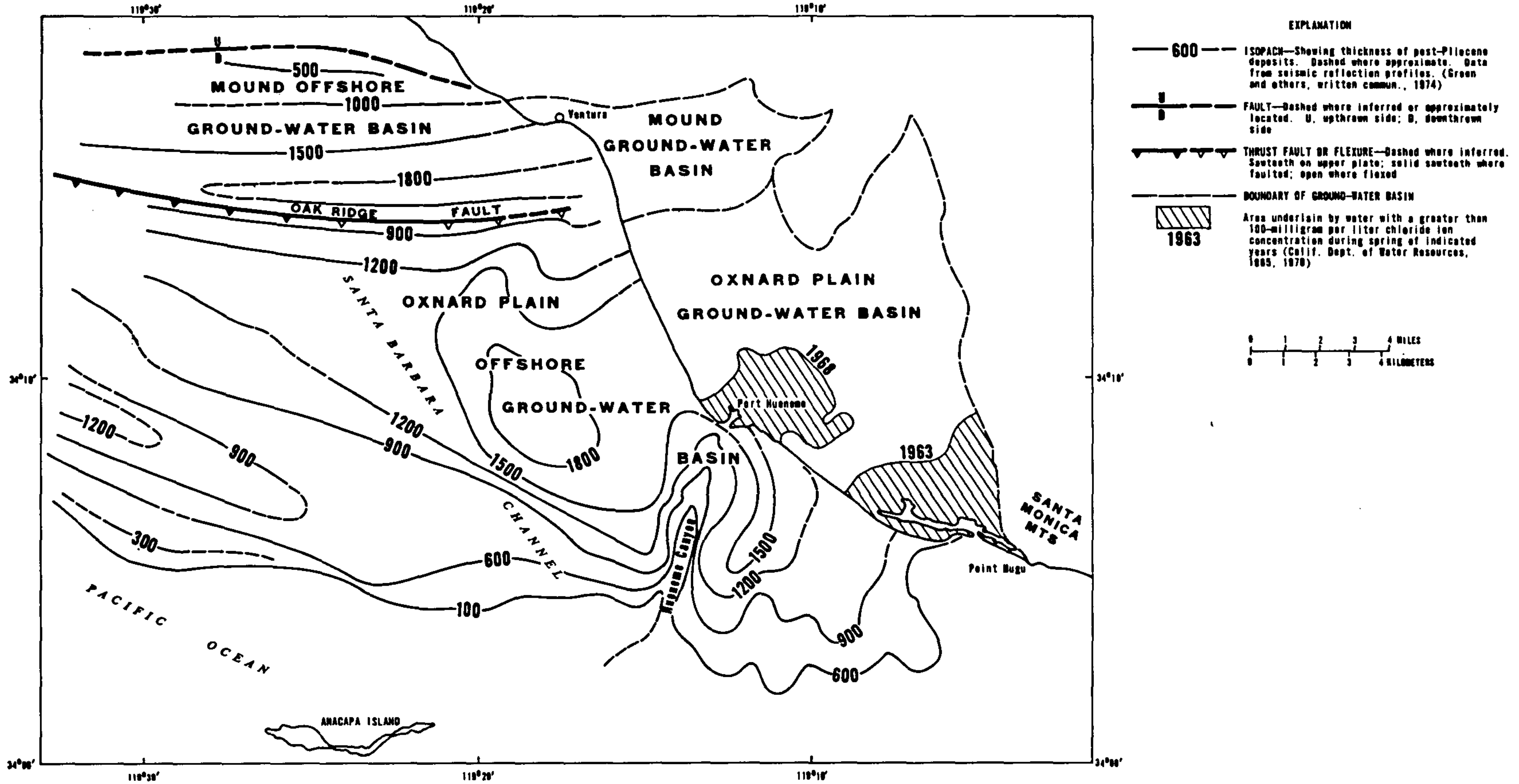


FIGURE II-6 Thickness of offshore post-Pliocene deposits.

essentially is the onshore thickness of water-bearing deposits as mapped by the Ventura County Flood Control District and the California Department of Water Resources (written commun., 1973).

(3) Seawater Intrusion

The present known major areas of seawater intrusion are limited to the Port Hueneme and Point Mugu areas of the Oxnard plain ground-water basin (figure II-6). Seawater intrusion was initiated in these areas during the dry years of the early 1930's when water-level altitudes were lowered as much as 5 feet below sea level along parts of the coastal plain. At that time wells located opposite the heads of Mugu and Hueneme submarine canyons began to yield water that indicated possible seawater intrusion.

- Port Hueneme Area

Active seawater intrusion near Port Hueneme was first recorded in 1950 (California Department of Water Resources, 1965). By 1952 the chloride in water samples from wells located opposite the head of Hueneme submarine canyon exceeded 250 Mg/L, the maximum recommended chloride ion concentration for most uses (U.S. Public Health Service, 1962). Seawater is occurring principally in the Oxnard aquifer. The most recent water-quality survey of the area made by the California Department of Water Resources in 1968 showed that 4,800 acres near Port Hueneme was underlain by water that contained chloride in excess of 100 Mg/L (California Department of Water Resources, 1970).

- Point Mugu Area

In the Point Mugu area, two wells were constructed in 1949 by perforating the well casing in both the Oxnard and

Mugu aquifers, placing a packer and seal between the aquifers, and providing for the separate airlift pumping of each aquifer (California Department of Water Resources, 1965). The water produced, presumably from both aquifers, increased progressively from around 300 Mg/L chloride ion concentration when drilled to greater than 8,000 Mg/L in 1954. However, recognition of actual seawater intrusion in either the Oxnard or the Mugu aquifers was uncertain because of possible deterioration of the pumping mechanism. Definite evidence of active seawater intrusion in the Point Mugu area became apparent about 1958. By spring 1965 about 5,700 acres in the Point Mugu area were underlain by water that contained chloride in excess of 100 Mg/L (Calif. Department of Water Resources, 1967).

- <u>Santa Barbara Area</u>

Water levels in wells near the coast in the Santa Barbara area declined to below sea level between 1960 and 1969. Sea water apparently intruded as the water levels declined. The intrusion was not extensive and seems to have been limited to the shallow deposits directly adjacent to the coast. Only wells less than 50 feet deep and deep wells that were constructed without sealing off the near-surface water-bearing zones were affected. The rather limited data that are available suggest that no direct horizontal migration of sea water has occurred at depth into the main aquifers (Muir, 1968). The possibility that horizontal migration could occur seems remote because there is no direct connection between the deeper water-bearing zones and the ocean. Consolidated rocks of Tertiary age have been uplifted on the south side of an offshore fault, and these serve as an effective salt-water barrier.

5. Areas of Potential for Oil and Gas Production

Some parts of the Santa Barbara Channel OCS have proven production and, as a result of intensive investigations by private companies, nearby targets for exploration and development may be inferred from geological and geophysical evidence. In part of the area, however, information about the stratigraphy, lithologic character and deformational history of rocks underlying the Channel is so scarce and unevenly distributed that any evaluation of ultimate petroleum potential must be regarded as conjectural. In parts of the Channel inferences about the distribution of strata that might have served as source beds for petroleum, or about rock types that could be potential reservoirs, are based largely on information about presumably analogous regions onshore.

a. Stratigraphic Associations

Production data tabulated by Curran and others (1971), with the addition of data through 1972 for the Dos Cuadras Offshore field (70,753,156 bbl. since the 1968 discovery), clearly indicate that well over 80 percent of the total production from the Channel region has come from Pliocene strata. Onshore to the east the relations are similar, with about 67 percent of the estimated recoverable reserves in Pliocene strata (possibly including some Pleistocene), 15 percent in upper Miocene strata, about 14 percent in Sespe (nonmarine Oligocene) reservoirs, and the remainder in small pools scattered through the middle Miocene, lower Miocene, Eocene, Paleocene, and Upper Cretaceous strata (Nagle and Parker, 1971). Older Tertiary strata have yielded important production in the Channel region in the near offshore of the north coast and the coast south of Ventura, as well as onshore along the north coast and inland, to the east. Marine sandstone beds of Oligocene and early

Miocene age have also been productive of oil and gas, particularly in the area west of the Ellwood field. There has been only minimal production from Eocene strata, mostly from the Capitan field, west of Santa Barbara, and shows of oil have been reported in Eocene beds drilled on the Channel Islands. Except for South Ellwood, the middle and upper miocene strata have not yielded significant production in the Channel region as yet, but tests in the Hondo Offshore area of the Santa Ynez Unit indicate that they contain the principal potential producing horizons of that area. Pliocene strata are thin and discontinuous on the Channel Islands Platform, and the shows of oil reported from exploration there are mostly in lower Miocene marine (Vaqueros Formation) and Oligocene nonmarine (Sespe Formation) strata.

b. Structural Associations

Five oilfields along the Rincon anticlinal trend form a nearly continuous giant field--Dos Cuadras Offshore, Carpinteria Offshore, Rincon, San Miguelito, and Ventura (figure II-7)--which, together with a relatively small portion of the production from the West Montalvo field, account for all of the production from Pliocene strata of the Channel region. The strata and structure extend westward from the Dos Cuadras Offshore field into the Federal Ecological Preserve and the Federal Buffer Zone, in which development is prohibited. Although no single structural feature has a demonstrated continuity through the gap south of the Coal Oil Point-Capitan part of the coast, the 5-mile trend lies along the western projection of the Rincon trend, and may reflect a general westerly continuation of that structural zone. The Hondo Offshore area lies near the east end of the 5-Mile trend, and to the west the trend appears to continue toward the Sacate Offshore area of the Santa Ynez Unit, with a spur to the southwest forming the anticlinal structure of the Pescado Offshore area (figure II-8).

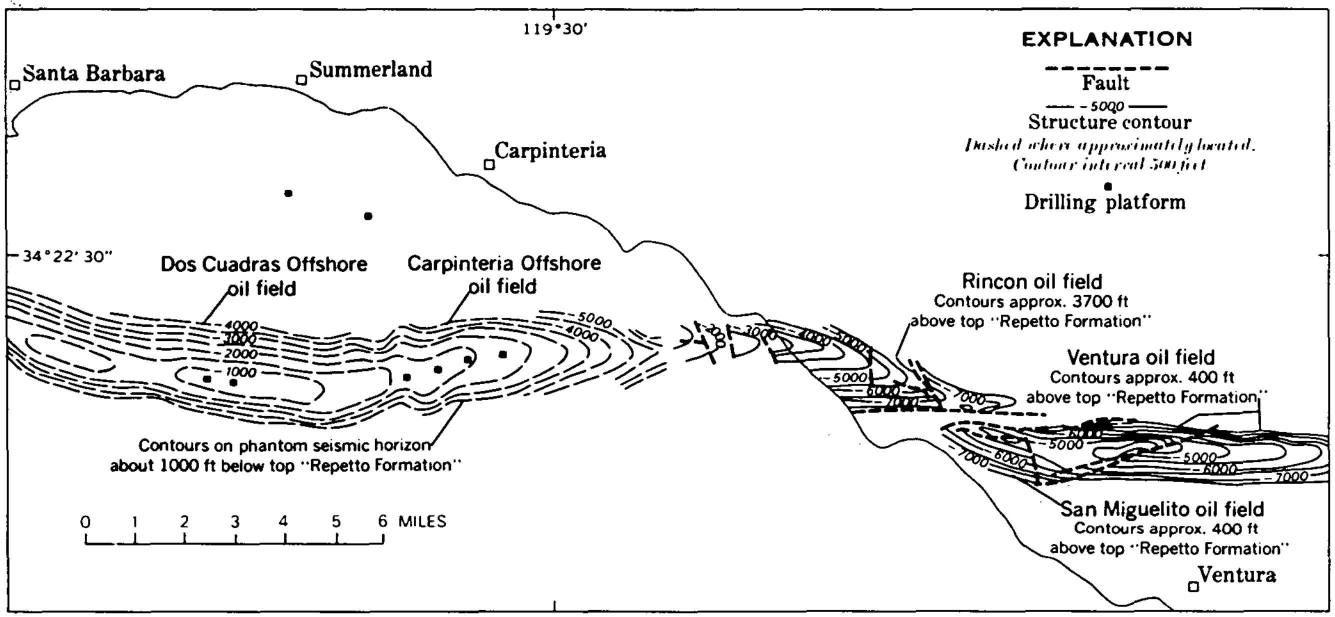


Figure II-7. Schematic structure contour map of the Rincon trend. (from Vedder and others, 1969)

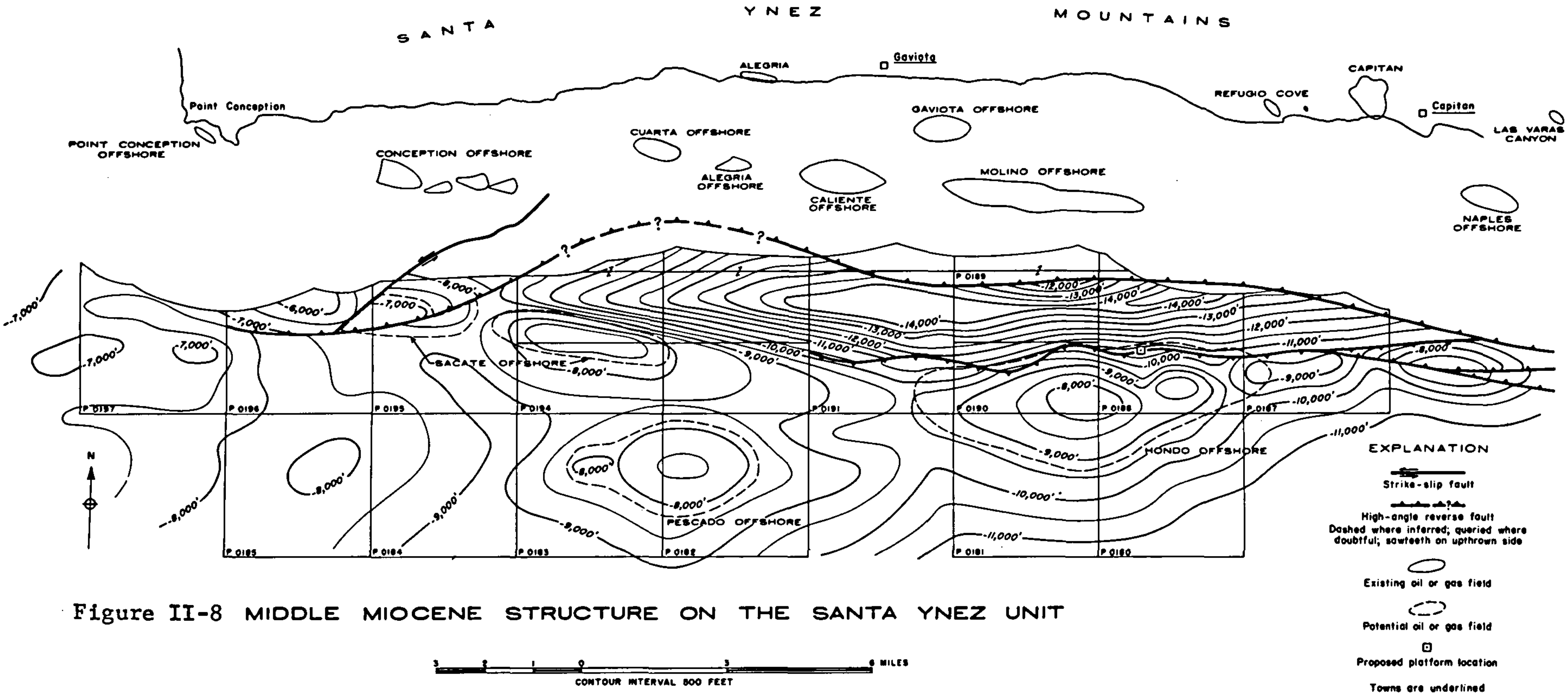


Figure II-8 MIDDLE MIOCENE STRUCTURE ON THE SANTA YNEZ UNIT

Drill stem tests in the Hondo, Pescado, and Sacate Offshore areas have indicated a potential for commercial production Santa Ynez Unit - Final Environmental Statement 74-20, 1974 (SYU-EIS).

c. Production from Existing Producing Leaseholds

The only existing OCS leaseholds presently producing in the region are on the Dos Cuadras and Carpinteria Offshore fields. Both fields are on the Rincon anticlinal trend and most of the production to date has been from Pliocene strata. It is entirely possible that deeper exploration from the existing platforms will disclose oil-bearing rocks in the underlying Miocene and older strata. However, none of the fields on the Rincon trend had reported production from older strata as of 1970 (Curran and others, 1971), and deep test holes will be necessary before the potential can be estimated on a rational basis.

Platforms C and Henry were proposed for recovering oil from the various layers of the presently producing Repetto formation in the western portion of the Dos Cuadras field and the northeast part of the Carpinteria Offshore field respectively. (See sections I.B. and III.C.3.)

d. Existing Leaseholds Not Presently Producing

Three potentially commercial fields have been delineated in the Santa Ynez Unit and the unit operator has presented plans for proceeding with the development (Plate 1). An environmental impact statement was prepared and on August 6, 1974, the Department of Interior approved the proposed initial development of the Hondo Field (see section I.B.4. and Appendix I-1 at the end of section I.).

Three potential oil fields have been reported in the southeastern part of the

Channel region, two in the Santa Clara Unit area and one on leases OCS-P 0202 and P 0203 (plate 1). The unnamed potential oil field in leases OCS-P 0216 and P 0215, in the Santa Clara Unit area appears to lie along a faulted continuation of the 12-Mile Reef anticlinal trend, but the geologic details of all three of the discoveries are proprietary to the leaseholders, and the published information is too scanty to provide an evaluation of their geologic settings. As a first approximation, they may be in settings similar to that of the Oxnard field onshore, where the most important reservoir strata are in the nonmarine Oligocene (Sespe Formation) and the structure is that of a faulted homocline (Dosch and Mitchell, 1964). Although the potential of these discoveries is poorly known at the present time, it is possible that commercial production from the Channel region could be increased by authorizing development of these areas. In each of the potential fields, (shown on plate 1) the Geological Survey has officially declared exploratory wells as discoveries of oil capable of producing in paying quantities. These determinations of discovery are based on well test results and are in accordance with OCS Order Number 4.

Another potential oilfield has been reported along the Pitas Point anticlinal trend, south of the Dos Cuadras Offshore and Carpinteria Offshore fields, in the Pitas Point Unit area (plate 1). Here, too, geologic details are proprietary to the leaseholders and published information is too scanty to provide an evaluation; however, line 621 (plate 3) and cross-section (plate 2) cross the area. They indicate the presence of a thick section of upper Pliocene strata, presumably underlain by the lower Pliocene and upper Miocene beds of the Ventura Basin. The inferred geologic structure (section B-B', plate 2) indicates a small subsidiary anticline on the generally south-dipping south flank of the Rincon anticline; the Pitas Point fault might also provide part of the updip closure. Petroleum production from the Channel region could perhaps be increased by authorizing development of this area.

There is little but general geologic data by which to evaluate those leaseholds on which no discoveries have been reported. According to Curran and others (1971, p. 205), several anticlinal trends on and adjacent to the Channel Islands have been tested by a few wells north of the central faults on Santa Cruz and Santa Rosa Islands (these reports do not separate State lands from Federal OCS). The results are reported as "interesting shows," but commercial production was not established. Offshore structures near the islands have been explored to limited depths by 28 coreholes and two exploratory wells, with inconclusive results (Curran and others, 1971, p. 205). Curran and others (1971, p. 211) report "disappointing results" from drilling in deep water on the Pitas Point trend, the Montalvo trend, and in two areas near San Miguel Island, although some encouraging shows of oil and gas were found. Existing leaseholds where potential commercial discoveries have not already been reported must await further exploration before it can be determined whether they could contribute significantly to Santa Barbara Channel production.

e. OCS Areas Not Presently Leased

Within the Santa Barbara Channel region, the largest continuous areas not presently leased are (plate 1): 1) the Central Deep--chiefly the area enclosed by the minus 500-meter depth contour; 2) the lower part of the Pescado Fan--north of the western sill of the Santa Barbara Basin and west of the Central Deep; 3) the parts of the Channel Islands Slope and Channel Islands Platform that lie north of the west half of Santa Cruz Island and eastern and central Santa Rosa Island; 4) the Hueneme-Mugu Slope and Fan; and 5) the Federal Ecological Preserve and Federal Buffer Zone. There are also a few smaller areas, of one to about four parcels in size, west of Ventura and northeast of Santa Cruz Island.

Very little is known about the Central Deep. The very thick Holocene and Pleistocene deposits there are generally flat-lying, and the thickness and structure of potential oil-bearing strata below them are unknown (line 670 et seq., plate 2). Projection of known structural trends from adjacent areas where they are, perhaps, better known suggests that the upper Miocene to upper Pliocene deposits of the Ventura Basin are likely to be thinner on the south side than on the north, and that the known anticlinal trends--Pitas Point, Montalvo, and 12-Mile Reef--of the eastern part of the area appear to converge northwestward toward the northern part of the Central Deep. No exploratory drilling has been reported in these deep waters, and, probably, considerable technological advance would be required to exploit any discoveries that might be made. Any contribution of this area to increased petroleum production in the region must await both further exploration and developments of deep-water drilling and production technology.

The lower part of the Pescado Fan is similarly unknown. Fan deposits conceal the relations of older strata and their structures on the acoustic profiles. In addition, although not as deep as the Central Deep to the east, the unleased area is generally below the 350-meter depth contour. No exploratory drilling has been reported. There are no adjacent areas from which structures and strata of known petroleum potential can be projected. Any potential for this area to contribute to increased petroleum production in the region has yet to be discovered.

On the Channel Islands Platform and the slope adjacent to the north, the deep-water upper Miocene to upper Pliocene strata, so thick and productive in the north, are represented only by thin, discontinuous, relatively shallow-water strata. Anticlinal structures are known, but exploratory drilling in the area described by Curran and others (1971, p. 205), which presumably refers to both leased and unleased parcels, was inconclusive, resulting only in "interesting shows." Future exploration in these areas may result in significant discoveries; however, the geologic setting does not encourage hopes for discovery of large, prolific fields such as those of the Rincon trend.

The Hueneme-Mugu slope has been investigated by Greene and others (in preparation), who show the sea floor to be largely unconsolidated Pleistocene and Holocene deposits lying directly on middle Miocene volcanic rocks and pre-volcanic sedimentary rocks (Vaqueros and Topanga Formations, undifferentiated) that have been intruded by diabase. To the south, where the slope gives way to the fan, thick Holocene and Pleistocene fan deposits conceal any underlying older strata and structure. Presumably, middle Miocene (Monterey Formation) beds, such as those present on Sycamore Knoll to the east, are present at some depth beneath parts of the fan, but probably not where water depths are shallower than 400 meters. Although a small amount of oil has been produced from volcanic rock reservoirs onshore (Conejo and Oxnard fields), such beds are not generally desirable exploration targets. Presumably, the Sespe Formation (nonmarine Oligocene) underlies the pre-volcanic middle and lower Miocene strata at greater depth, and it has been an important reservoir in the Oxnard and West Montalvo fields to the north, even where intruded by volcanic dikes (which have reportedly provided local closure; Nagle and Parker, 1971, p. 284). In the area of the Hueneme-Mugu Slope, however, the potential for petroleum production from the Sespe is completely unknown, and evaluation must await deeper exploration. The potential for petroleum in the Hueneme-Mugu Fan area is also problematical; although the middle Miocene strata that are presumed to underlie the fan are believed to be similar to beds that have yielded some oil in the Oxnard field from fractured shale, there has been no published report of "shows" from exploratory holes drilled in the same formation along shallower parts offshore of the Malibu Coast to the east.

Although development for petroleum is prohibited there, any evaluation of the petroleum potential for the region would be incomplete without noting that the geologic settings of the Federal Ecological Preserve and the Federal Buffer Zone (see plate 1) indicate a larger potential than that of any other unleased area. The Pliocene strata and anticlinal structure of the Rincon trend extend into and across the preserve. In addition, parallel anticlinal trends in the same strata, including the northwestern part of the 12-Mile Reef anticlinal structure, enter the southern part of the Ecological Preserve-Buffer Zone area.

The unleased parcels west of Ventura and northeast of Santa Cruz Island are presumed to have been evaluated by exploring oil companies prior to the 1968 lease sale and found to have insufficient potential for commercial petroleum production. These are, of course, large areas that include strata and structural settings like those that have been productive elsewhere nearby, or like those where nearby exploration has indicated discoveries. Further exploration, therefore, may yet disclose significant potential for production. However, it is probable that the potential is less than that for adjacent parcels for which companies believed the evidence justified purchase.

6. Earthquake Activity in the Santa Barbara Channel Region

a. Introduction

The contemporary seismic setting of the Santa Barbara Channel region in relation to the rest of southern California is indicated by the distribution of recent large earthquakes (figure II-9). During the past 60 years, 24 earthquakes of local magnitude 6 (Richter Scale unless otherwise specified) or larger have occurred in southern California. Six of these are of direct interest because they either 1) originated in the Channel region, 2) originated in the same structural province (western Transverse Ranges) and in association with displacements and ground motions similar to those expected from earthquakes originating in the Channel region, or 3) originated in adjacent structural provinces and had sufficient intensity to cause damage in the Channel region. The six are: Santa Barbara earthquake of 1925 (magnitude 6.3) Point Arguello earthquake of 1927 (magnitude 7.5; not shown on figure II-9), Santa Barbara earthquake of 1941 (magnitude 6), Kern County earthquake of 1952 (magnitude 7.7), San Fernando earthquake of 1971 (magnitude 6.4), and Point Mugu earthquake of 1973 (magnitude 6).

The seismic history before installation of seismographs in the 1920's appears in various reports describing earthquake effects (Townley and Allen, 1939; Richter, 1958). Reliable accounts of California earthquakes date from about 1800. The earliest reports are found in notes of Spanish explorers and early settlers and in the records of the Franciscan Mission. Since 1932 instrumentally recorded earthquakes throughout southern California have been reported by the Seismological Laboratory of the California Institute of Technology. Results from the Caltech seismograph network have been analyzed by Allen and others (1965), who related earthquake data for the period from 1934 to 1963 to the regional geologic structures in southern California. Sylvester and others (1970) studied the earthquake swarm that occurred in the Santa Barbara Channel during the period from June 26 to August 3, 1968, and discussed their results with respect to the seismic history of the Channel and hydrocarbon exploration and withdrawal.

An offshore oil well blowout on January 28, 1969, drew national attention to oil pollution and provided the impetus for preparing a report on the geology, petroleum development, and seismicity of the Santa Barbara Channel region (U.S. Geological Survey, 1969). In that report, Hamilton and others reviewed the seismicity and its possible associated effects on the region and noted that the limitations of the existing seismic network precluded

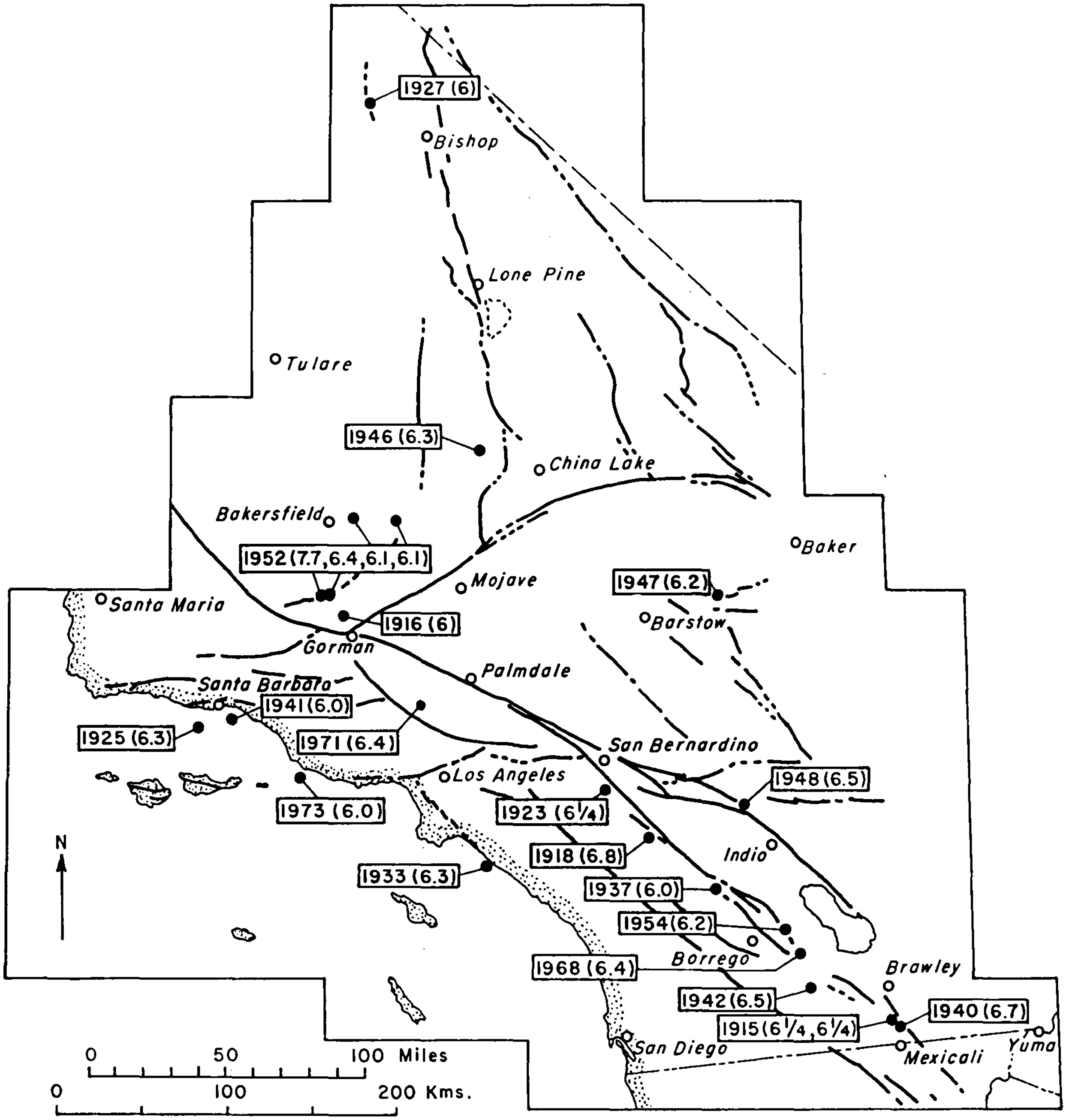


Figure II-9 Earthquakes of magnitude 6 and greater in southern California since 1912. Modified from Allen and others, (1965) identification of individual active faults within the Channel.

In order to improve earthquake monitoring, a new network of seismograph stations surrounding the Santa Barbara Channel was established by the U.S. Geological Survey in late 1969. Lee and Vedder (1973) reported the earthquakes located by this network for the period from January 1, 1970 to December 31, 1971, and showed that the earthquake activity appears to be spatially related to recognized faults in the region. On February 21, 1973, a moderate-sized earthquake (magnitude 6.0) occurred in the vicinity of Point Mugu at the eastern end of the Santa Barbara Channel. Ellsworth and others (1973) reported the seismological investigations of this earthquake sequence and noted that the complex fault zone associated with the southern boundary of the Transverse Ranges poses a significant earthquake hazard.

The present report relies heavily on published works by Hamilton and others (1969), Lee and Vedder (1973), and Ellsworth and others (1973) and, in addition, on the unpublished earthquake data of the Santa Barbara Channel region for 1972 and 1973 (Ellsworth, written communication, 1974). The accuracy and detail of earthquake records in the Santa Barbara Channel region have increased in uneven steps since the first written account. These improvements have been stimulated by the increasing population and advances in instrumentation. Consequently, the most accurate and detailed data are available for only the last few years of the approximately 170 years of continuous historic record.

Eaton and others (1970a, 1970b) demonstrated that accurate and detailed studies of small earthquakes can identify active faults and their nature of movement. For example, the installation of a densely spaced network of seismographs in the San Francisco Bay area by the U.S. Geological Survey has made possible precise hypocenter determinations of over 10,000 earthquakes in the past five years. These results show clear associations between mapped faults and earthquake distribution, even in areas where faults are relatively closely spaced (see, e.g., Brown and Lee, 1971). No such densely spaced network exists in the Santa Barbara Channel region. There, the most detailed resolution of presently available data can only define general zones of earthquake activity, as will be described later (section II.B.6.e.). Further refinement will require installation of a suitably dense network of seismographs and a longer period of record.

The existing geologic and seismologic data support the conclusion that the Santa Barbara Channel region is seismically active, and that an event of magnitude 7.5 occurring somewhere in the channel region should be regarded as the "maximum credible earthquake" (see footnote p. II-126). The seismic activity implies contemporary fault movement at depth, and the region also shows geologic evidence of Holocene fault displacement and geodetic evidence of contemporary differential vertical movement. The present data are insufficient to discriminate among different parts of the region as to where a maximum credible earthquake might occur; therefore, for design purposes, all portions of the Channel region must be regarded as susceptible to that maximum. For more detailed seismic evaluations of specific sites or parts of the region (which might lower the seismic hazard reduction requirements at particular sites), more extensive geologic and geophysical investigations must be made. In certain instances design specifications for less than the maximum expectable earthquake may be justified based on detailed geologic and geophysical investigations conducted for that particular platform site.

b. Destructive Earthquakes in the Channel Region

A summary of earthquakes that affected the Santa Barbara Channel is useful in evaluating the earthquake hazards. Hamilton and others (1969) have compiled a list of significant felt earthquakes from published literature for the period from 1800 to 1952. This list, revised and extended to 1973, is presented here (table II-1). Some of the destructive earthquakes listed in this table are described in more detail below; their locations are shown in figure II-10.

(1) Santa Barbara Channel Earthquake of 1812

The earliest known destructive earthquake to affect the Santa Barbara Channel region occurred on December 21, 1812. It destroyed Purisima Mission (about 10 miles--16 km-- northeast of Point Arguello), damaged missions at San Fernando, San Buenaventura, Santa Barbara, and Santa Ynez, and produced a tsunami in the Santa Barbara Channel (Richter, 1958, p.466). The high-water mark of this tsunami was estimated to have been as much as 50 feet near Gaviota. A recent detailed study (Marine Advisors, Inc., 1965) of historic records, however, concludes that such accounts are unsubstantiated and cannot be accepted at face value. Several asphalt (crude oil) springs reportedly began to flow at places inland from the coast, and a burning oil spring near Rincon Point was enlarged. In the area of Santa Barbara the destruction had a Rossi-Forel intensity of IX to X. The reported damage and other effects resemble those accompanying other California earthquakes of magnitude 7.

TABLE II-1

List of Significant Felt Earthquakes in the Santa Barbara Channel Region, 1800 to 1973 [1]

Year	Month and day	Local Time	Maximum R.F. intensity [2]	Magnitude	General Location of Maximum Intensity Area and (or) Epicentral Area	R.F. Intensity [2] Santa Barbara Area	Remarks
1800---	11-22	1330	VIII	---------	Southern California---	VIII(?)	Heavy damage at San Diego, San Juan Capistrano
				---------	----do----------------	VIII	Light damage at Santa Barbara Mission. Probably same earthquake as above, but no date given for Santa Barbara observation.
1812---	May	---------	I -III(?)	---------	----do----------------	---------	Unconfirmed southern California "swarm" activity lasting 4.5(?) months.
	10-8 to 11-18	---------	I - IX(?)	---------	San Juan Capistrano---	---------	Shocks for 40 days (Probably a swarm on coast or offshore faults near Mission San Juan Capistrano). Especially hard shock on October 21.
	12-8	Morning	IX	---------	----do----------------	---------	Mission San Juan Capistrano destroyed with loss of 30-45 lives; 28 buried in rubble from collapse of massive stone church walls. Possible seaquake damaged Spanish ship at anchor 38 miles from Santa Barbara.
	12-21	1030	X	--------	Santa Barbara and Purisima Concepcion Missions	IX - X	Santa Barbara and Purisima Concepcion Missions destroyed (adobe construction). Santa Ynez Mission heavily damaged. Tsunami broke along Santa Barbara coast; wave height unknown, but runup possibly as high as 30-50 feet at some points between Santa Barbara and Gaviota according to unconfirmed reports. Several "asphaltum springs" formed in the mountains.

See footnotes at end of table

TABLE II-1 (Continued)

Year	Month and day	Local Time	Maximum R.F. Intensity 2/	Magnitude	General Location of Maximum Intensity Area and (or) Epicentral Area	R.F. Intensity 2/ Santa Barbara Area	Remarks
1815---	1-18 to 1-30	---------	I - III(?)	---------	Santa Barbara-----------	I - III (?)	Several small shocks felt (probably swarm of microearthquakes).
	7-8 to 7-9	---------	I - III(?)	---------	----do------------------	I - III (?)	Six felt shocks (probably swarm of microearthquakes).
1852---	11-27 to 11-30	---------	IX - X	---------	Northern Ventura County-	---------	(Probably on either San Andreas or Big Pine fault 40-50 miles northeast of Santa Barbara.)
1853---	1-29	---------	---------	---------	Santa Barbara-----------	---------	(Probably a local slight shock.)
	3-1	---------	V(?)	---------	San Louis Obispo--------	V(?)	Felt in Santa Barbara.
1854---	4-20 to 5-31	---------	VI	---------	Santa Barbara-----------	VI	(Probable earthquake swarm) Sea waves generated during largest shock of series on May 31 at 4:50am and many people were alarmed. The large shocks seem to have terminated the series.
1855---	6-25	1400	V	---------	----do------------------	V	Also felt strongly in Santa Maria.
	7-10	2015	IX	---------	Los Angeles-------------	V	Tsunamis broke on coast at Point San Juan (Dana Point) which indicates possible movement of offshore fault.
1857---	1-8	---------	VII(?)-VIII	---------	Santa Barbara-----------	VII-VIII	Several slight shocks and one severe shock. Many other southern California shocks. This entry perhaps results from confused accounts of the following entry.

See footnotes at end of table

TABLE II-1 (Continued)

Year	Month and Day	Local Time	Maximum R.F. Intensity 2/	Magnitude	General Location of Maximum Intensity Area and (or) Epicentral Area	R.F. Intensity 2/ Santa Barbara Area	Remarks
1857---	1-9	---------	IX - X	---------	Fort Tejon--------------	VIII	Roof of Mission at San Buenaventura (Ventura) fell in. All houses in Santa Barbara damaged according to unconfirmed reports. Several new springs formed near Santa Barbara. One of California's greatest earthquakes centered 50 miles east-northeast of Santa Barbara on San Andreas fault.
	3-4	1500	V	---------	Santa Barbara-----------	V	Severe shock felt in Santa Barbara and Montecito.
1860---	4-16	1930	---------	---------	Fort Tejon--------------	III(?)	Felt in Santa Barbara.
1862---	---------	---------	VIII(?)	---------	Goleta------------------	VII(?)	Livestock frightened; trees swayed; people stood with difficulty.
1872---	3-26	0230	X	---------	Owens Valley------------	V(?)	Probably the greatest earthquake in California's recorded history. Shock felt over nearly all California and Nevada and parts of Utah and Arizona, possibly also over northern part of Mexico. Many widely distributed aftershocks within Inyo County also felt throughout large areas.
1875---	12-21	---------	---------	---------	Santa Barbara-----------	---------	(Probably a local slight shock)
1877---	6-23	2350	III -IV(?)	--------	----do------------------	III-IV(?)	Three shocks; also felt in Bakersfield.
1878---	1-8	---------	---------	---------	----do------------------	III(?)	(Probably a local slight shock)

See footnotes at end of table

TABLE II-1 (Continued)

Year	Month and Day	Local Time	Maximum R.F. Intensity 2/	Magnitude	General Location of Maximum Intensity Area and (or) Epicentral Area	R.F. Intensity 2/ Santa Barbara Area	Remarks
1880---	4-12	0440	V	--------	Los Angeles-------------	IV(?)	Severe effects along San Gabriel River. Also felt at Riverside(?) and had about same intensity at Ventura.
	4-12	0803	V	---------	Ventura County----------	IV(?)	Probably a severe shock in vicinity of San Buenaventura (Ventura and lands to northeast).
	11-12	2230	---------	---------	Santa Barbara-----------	III(?)	(Probably a local slight shock)
1881---	8-30	1900	III	---------	----do------------------	III	Two slight shocks.
1883---	9-5	0430	VI	---------	Ventura-----------------	V(?)	Strong Shock felt from Santa Barbara to Los Angeles.
	9-13	1430	IV	---------	Santa Barbara-----------	IV	Small quake lasting 5 seconds.
1884---	8-2 to 8-4	---------	III	---------	----do------------------	III(?)	A few very slight shocks felt.
1885---	4-7	0200	III	---------	----do------------------	III(?)	Also felt at Ventura and possibly at Bakersfield.
	6-14	0314	V	---------	Ventura-----------------	IV(?)	A moderate earthquake felt also at Los Angeles.
	7-9	0120 to 0815	V	---------	Santa Barbara-----------	V	A limited swarm of five moderate earthquakes. Felt shocks were of long duration, awakened most sleepers.

See footnotes at end of table

TABLE II-1 (Continued)

Year	Month and day	Local Time	Maximum R.F. Intensity 2/	Magnitude	General Location of Maximum Intensity Area and (or) Epicentral Area	R.F. Intensity 2/ Santa Barbara Area	Remarks
1890---	(?)	---------	VI(?)	---------	Santa Barbara-----------	V(?)	"Quite a heavy shock."
1893---	4-4	1140	VIII - IX	---------	Pico Canyon-------------	V(?)	An intense local shock centered near Newhall, 35 miles north of Los Angeles. Strongly felt at Ventura San Bernardino, and Mojave. Felt only lightly at Los Angeles and Santa Ana.
	5-18	1635	VII(?)	---------	Ventura-----------------	VI(?)	Widely felt shock, most severe southeast of Ventura. Felt from San Diego to Lompoc and inland to San Bernardino No damage reports. Possible submarine origin off Ventura coast.
	6-1	0400	VII(?)	---------	Santa Barbara-----------	VII(?)	Considerably heavier than event on May 18, 1893. Also felt in Ventura and Ojai. Followed by light aftershocks.
1894---	7-29	2112	VII	---------	Southern California-----	V(?)	Widely felt earthquake, most severe at Mojave and Los Angeles.
1895---	7-26	1610	III(?)	---------	Santa Barbara-----------	III(?)	Local slight shock.
	12-23	.2130	III(?)	---------	----do------------------	III(?)	Local slight shock.
1897---	6-24 to 7-19	---------	III(?)	---------	Santa Barbara and Vicinity	III(?)	A few light shocks and two strong shocks.

See footnotes at end of table

TABLE II-1 (Continued)

Year	Month and Day	Local Time	Maximum R.F. Intensity 2/	Magnitude	General Location of Maximum Intensity Area and (or) Epicentral Area	R.F. Intensity 2/ Santa Barbara Area	Remarks
1898---	5-29 to 6-3	---------	V	---------	Santa Ynez Valley-------	III(?)	One light and one heavy shock felt in Santa Barbara and vicinity. Heavy shaking at 2200 on June 3 felt throughout Santa Ynez Valley. Heaviest shock for some years at Santa Barbara.
1902---	2-7 to 2-9	---------	VI(?)	---------	Santa Barbara-----------	VI(?)	One light shock February 7 followed by moderate shock on February 9 causing general alarm but no reported damage.
	7-21	---------	III(?)	---------	Pine Crest--------------	---------	(Probably slight local shock near Pine Crest, Santa Barbara County)
	7-27	2257	VIII - IX	---------	Los Alamos--------------	III(?)	Severe local shock probably centered near Los Alamos, 35 miles west-northwest of Santa Barbara. Considerable local damage at Lompoc and Los Alamos. No damage reported at Santa Barbara.
	7-27 to 8-14	---------	VIII - IX	---------	Los Alamos, Santa Barbara, Lompoc, Santa Maria and San Louis Obispo	VII(?)	Unusual widespread swarm of felt shocks attaining local intensities as high as R.F. IX. Several events felt at Santa Barbara but no reports of damage there. Heaviest intensities and most frequent reports concentrated at Los Alamos, 45 miles west-northwest of Santa Barbarbara. Shocks probably originated on various western extensions and branches of Santa Ynez fault zone. Heavy shocks near Los Alamos on July 31 preceded by 5 days of frequent minor shocks; drove nearly the entire population away.

See footnotes at end of table

TABLE II-1 (Continued)

Year	Month and Day	Local Time	Maximum R.F. Intensity 2/	Magnitude	General Location of Maximum Intensity Area and (or) Epicentral Area	R.F. Intensity 2/ Santa Barbara Area	Remarks
1902---	9-10	2130	V	---------	Los Alamos-------------	III(?)	Severe shock preceded by days of light shocks
	10-21	---------	IV(?)	---------	----do-----------------	II(?)	Three shocks, the first quite severe. No damage reports. Felt in Lompoc.
	12-12	---------	VIII	---------	----do-----------------	III(?)	All of north Santa Barbara County shaken by severe quakes. Light damage at Los Alamos and Santa Maria. Felt at Lompoc, San Luus Obispo, and Santa Barbara.
1904---	10-14	---------	III(?)	---------	Ventura----------------	---------	(Probably slight local shock)
	10-15	---------	IV(?)	---------	Los Angeles------------	III(?)	Light shock probably centered near Los Angeles. Felt at Santa Barbara and Sierra Madre.
	10-20	---------	III(?)	---------	Ventura----------------	---------	(Probably slight local shock at Snedden Ranch near Ventura)
1905---	3-18	2040	VI	---------	Bakersfield------------	II(?)	Shocks were heaviest at McKittrick and Sunset oil fields. Flow of oil wells was increased. Shock felt at Nordhoff (Ojai), in Ventura County 25 miles east of Santa Barbara.
1907---	7-3	0108	III(?)	---------	Ojai-------------------	II(?)	Slight local shock near Ojai felt at Santa Barbara.
	7-28	2110	II(?)	---------	Pine Crest-------------	---------	Slight local shock.

See footnotes at end of table

TABLE II-1 (Continued)

Year	Month and Day	Local Time	Maximum R.F. Intensity 2/	Magnitude	General Location of Maximum Intensity Area and (or) Epicentral Area	R.F. Intensity 2/ Santa Barbara Area	Remarks
1907---	August	---------	III(?)	---------	Pine Crest--------------	II(?)	"Slight earthquake felt on same day and hour as at Santa Barbara City."
	9-19	1745	VII - VIII	---------	San Bernardino----------	III(?)	Large shock probably centered near San Bernardino, but felt throughout most of southern California. Light shaking at Montecito, near Santa Barbara.
	12-27	0115	III(?)	---------	Santa Barbara-----------	III(?)	A light local shock also felt at Ventura and Ojai.
1909---	1-23	0658	III(?)	--------	----do------------------	III(?)	A light local shock also felt at Pine Crest.
	7-2	2330(?)	III(?)	---------	----do------------------	III(?)	A sharp local shock also felt at Montecito.
	7-2 to 7-31	---------	IV	---------	----do------------------	II - IV(?)	Several slight to moderate shocks felt in Santa Barbara area. One heavy shock July 16, also felt at Los Angeles.
1910---	5-15	0747	VII-VIII	---------	Riverside County--------	II(?)	Widely felt earthquake in southern California. (Probably slight at Ventura and Santa Barbara)
	November	---------	III(?)	---------	Santa Barbara-----------	III(?)	Two slight quakes.
1911---	3-28	2025	V - VI	---------	San Miguel Island	III(?)	Moderate quake centered near San Miguel Island, Santa Barbara County. Felt slightly at Santa Barbara.

See footnotes at end of table

TABLE II-1 (Continued)

Year	Month and Day	Local Time	Maximum R.F. Intensity 2/	Magnitude	General Location of Maximum Intensity Area and (or) Epicentral Area	R.F. Intensity 2/ Santa Barbara Area	Remarks
1911---	5-10	0500 to 0540	IV(?)	---------	Oxnard	II(?)	Three light shocks centered near Oxnard, Ventura County. Felt slightly at Los Angeles and at Ojai.
1918---	12-14	0200	IV	---------	San Miguel Island-------	II(?)	(Probably slight local event)
	4-21	1432	IX - X	---------	San Jacinto-------------	II - III(?)	Strong shock felt over wide area of southern California and western Arizona. Very slightly felt at Los Olivos, Santa Barbara County, 30 miles northwest of Santa Barbara.
1919---	1-25	1429	V	---------	Tejon Pass--------------	II	Sharp quake near Tejon Pass, felt at Ojai, Ventura, Bakersfield, and Maricopa with intensity of III to IV. Weak but perceptible at Santa Barbara and Los Angeles.
	2-16	0757	VII	---------	San Andreas fault south of Maricopa	II(?)	Strong shock felt over wide area. Intensity was IV at San Luis Obispo and Los Angeles. Los Olivos and Ojai reported intensities III and V respectively.
	8-26	0412	V+ (?)	---------	Santa Barbara County----	V(?)	Generally felt at Santa Barbara and from San Luis Obispo to Ojai. No damage reported.
1920---	6-18	0208	VIII(?)	---------	Los Angeles region	III(?)	Sharp quake, felt also on Santa Catalina Island. (Reports seem to indicate an origin on submarine fault in San Pedro Channel.)

See footnotes at end of table

TABLE II-1 (Continued)

Year	Month and Day	Local Time	Maximum R.F. Intensity 2/	Magnitude	General Location of Maximum Intensity Area and (or) Epicentral Area	R.F. Intensity 2/ Santa Barbara Area	Remarks
1920---	6-21	1848	VIII-IX	---------	Inglewood, Los Angeles County	II(?)	High intensity of VIII to IX near the source in small area of the western part of Inglewood. Barely felt at Ventura.
1924---	12-30	---------	IV(?)	---------	Santa Barbara-----------	IV(?)	Two "sharp, heavy blows."
1925---	1-28	0930	IV	---------	Ojai--------------------	II(?)	Two slight shocks.
	6-29	0642	IX	6.3	Santa Barbara-----------	IX	Strong, destructive local earthquake practically destroyed the business section of Santa Barbara. Felt from Watsonville on the northwest to Santa Ana on the southeast and inland to Mojave.
	6-29 to 10-9	---------	---------	---------	Santa Barbara and Ventura Counties	---------	Forty-two earthquake reports from Santa Barbara area. Most of these were aftershocks associated with the event of June 29. About 32 reports from Santa Barbara alone yield a count of 10 strong aftershocks. Only the aftershocks of some special significance will be listed separately.
	7-3	0838	VII(?)	---------	Santa Barbara------------	VII(?)	Also felt at Pasadena, III; Ojai, III; and Ventura IV(?).
	7-3	1021	VII(?)	---------	----do------------------	VII(?)	Sharp and heavy. Instrumental records indicate this was strongest Santa Barbara aftershock.

See footnotes at end of table

TABLE II-1 (Continued)

Year	Month and Day	Local Time	Maximum R.F. Intensity 2/	Magnitude	General Location of Maximum Intensity Area and (or) Epicentral Area	R.F. Intensity 2/ Santa Barbara Area	Remarks
1925--	7-5	0400 to 2300	II - III(?)	---------	Santa Barbara-----------	II - III(?)	Eleven-shock swarm of felt tremors. A thermograph instrument recorded almost continuous vibrations between 7 and 10 am.
	7-6 to 7-9	---------	---------	---------	----do------------------	---------	Continued activity during aftershock sequence.
	7-30	---------	IV(?)	---------	Santa Barbara, Ventura, and vicinity	IV(?)	Several felt earthquakes.
	8-12	---------	V	---------	Ojai--------------------	III(?)	Abrupt bumping also felt at Ventura, III(?).
	8-13	---------	III(?)	---------	Santa Barbara-----------	III(?)	(Several light shocks)
	10-30	---------	III(?)	---------	----do------------------	III(?)	"Little jolt," followed by sharp shock. Second event felt at Ventura also.
1926---	1-12	0215	IV	---------	Ojai--------------------	III(?)	Abrupt bumping, awakened many sleepers. Felt at Santa Barbara.
	2-18	1018	VI+	---------	Origin at sea southwest of Ventura	VI(?)	Windows broken at Santa Barbara school, water pipe broken in roundhouse. Felt along coast from San Luis Obispo on northwest to south of Santa Ana, a distance of 200 miles. No mention of tsunami.
	5-3	0553	VI(?)	---------	Origin at sea southwest of Port Hueneme, Ventura County	III(?)	Felt at San Luis Obispo, 100 miles to northwest. Ventura intensity VI(?). Slight tremor at Santa Barbara. No mention of tsunami.

See footnotes at end of table

TABLE II-1 (Continued)

Year	Month and Day	Local Time	Maximum R.F. Intensity 2/	Magnitude	General Location of Maximum Intensity Area and (or) Epicentral Area	R.F. Intensity 2/ Santa Barbara Area	Remarks
1926---	5-14	1000(?)	IV+ (?)	---------	Ojai--------------------	III(?)	Also felt as slight shock at Santa Barbara
	6-24	0730	V	---------	Santa Barbara-----------	V	Two shocks, like sharp blows, felt by all; pendulum clocks stopped.
	6-27	1730	IV	---------	Ventura-----------------	---------	Two shocks, abrupt; bumping; felt by many.
	6-29	1521	VII - VIII	---------	Santa Barbara-----------	VII - VIII	Shock from possible offshore fault exactly one year following destructive 1925 earthquake. Child killed by falling chimney. Glass broken, cracks in walls enlarged; surf agitated violently (probably due to seaquake, possible due to small tsunami). Felt from Los Angeles to Buellton, 30 miles west-northwest from Santa Barbara, where shock was felt by all; plaster was cracked.
	7-3	1500	II	---------	----do-----------------	II	Four slight shocks within 20-minute period. Felt by very few.
	7-6	0945	V	---------	----do-----------------	V	Three shocks felt by many. Buildings swayed.
	8-6	0942	IV	---------	Santa Barbara region---	IV	Sharp quake at Santa Barbara, also felt at Ojai and Ventura.

See footnotes at end of table

TABLE II-1 (Continued)

Year	Month and Day	Local Time	Maximum R.F. Intensity 2/	Magnitude	General Location of Maximum Intensity Area and (or) Epicentral Area	R.F. Intensity 2/ Santa Barbara Area	Remarks
1926---	8-8	2012	V +(?)	---------	Santa Barbara-----------	V+ (?)	Shook dishes from shelves and caused noticeable swinging of chandeliers.
	9-28	0949	V(?)	---------	Ventura----------------	IV(?)	Located at sea southwest of Ventura. Felt at Santa Barbara and Ojai also.
	12-19(?) to 12-20 (?)	---------	III+	---------	----do-----------------	II(?)	Two slight shocks one hour and 40 minutes apart.
1927---	5-15(?)	0320	V +	---------	----do-----------------	III(?)	Pronounced shock which cracked windows in Ventura. Probably originated on offshore fault south of Port Hueneme.
	8-4	0424	VI+	---------	Santa Monica Bay--------	IV(?)	Origin located offshore. Felt from Ventura to Anaheim on Coast and to San Bernardino.
	8-26	0440	V +(?)	---------	Santa Barbara-----------	V+ (?)	Two sharp shocks, causing much alarm. Also felt at Ventura.
	11-4	0300 to 0330	V(?)	---------	Point Arguello, Lompoc--	II(?)	Four shocks preceding strong event at 0551.
	11-4	0551	IX - X (?)	7.5	At sea west of Point Arguello	VI - VII	Largest earthquake in California following 1906 San Francisco event until July 21, 1952 (7.7). Much stronger shock than 1925 Santa Barbara event. Seaquakes generated during some larger aftershocks. Small tsunami broke along coast at Surf and Port San Luis. Tsunami also recorded on tide gages at San Diego and Santa Barbara. Felt from Morgan Hill on northwest to

See footnotes at end of table

TABLE II-1 (Continued)

Year	Month and Day	Local Time	Maximum R. F. Intensity 2/	Magnitude	General Location of Maximum Intensity Area and (or) Epicentral Area	R.F. Intensity 2/ Santa Barbara Area	Remarks
							Whittier on southeast. Many after-shocks, including some destructive tremors, occurred through December 31, 1927, and later.
1927---	11-18	1932	VI - VII	---------	Santa Maria------------	IV(?)	
1930---	8-5	0325	VIII	---------	Santa Barbara-----------	VIII	
1933---	3-10	1754	IX+	6.3	Long Beach--------------	III(?)	An event of moderate magnitude similar to Santa Barbara 1925 quake, but $40 million in damages and 115 lives lost because of proximity to heavily populated area with many poorly constructed buildings and poor foundation conditions.
1941---	6-30	2351	VII - IX	5.9	Santa Barbara----------	VIII	Most damaging earthquake since 1925, with origin in Santa Barbara Channel area. Total damage about $100,000. Many structures affected had been damaged in 1925 and not adequately repaired.
1945---	4-1	1543	IV	5.4	Santa Rosa Island------	IV	Felt along coastal area from Santa Maria, south through Santa Barbara and Ventura to Simi.
1949---	8-27	0652	VI	4.9	Near Point Conception--	V	Felt in coastal region of San Luis Obispo and Santa Barbara Counties. Strong effects at Arlight and Lompoc.

See footnotes at end of table

TABLE II-1 (Continued)

Year	Month and Day	Local Time	Maximum R.F. Intensity 2/	Magnitude	General Location of Maximum Intensity Area and (or) Epicentral Area	R.F. Intensity 2/ Santa Barbara Area	Remarks
1952---	7-21	0352	X	7.7	Kern County-------------	VIII(?)	Largest earthquake in the continental United States since 1906. Strongly felt along southern California coast, including Santa Barbara area. Centered about 60 miles northeast of Santa Barbara. Caused damage to buildings in Santa Barbara with losses estimated at $400,000.
1954---	8-26	0548	VI(?)	4.8	Near Anacapa Island-----	VI(?)	People awakened by short, sharp shock at Santa Barbara. No damage other than plaster was shaken.
1957---	3-18	1056	VI	4.7	South of Oxnard---------	III(?)	Felt over 3000 square miles of southern California. Minor damage occurred at Oxnard, Port Hueneme, and Ventura.
1958---	3-13	2125	VI	4.7	Off Carpinteria---------	V	Felt over 5000 square miles of Santa Barbara coast area. Slight damage in Carpinteria.
1962---	9-16	1012	V	4.0	Near Santa Barbara------	V	Felt principally in Santa Barbara County.
1968---	7-4	1645	VI(?)	5.2	Santa Barbara Channel---	VI	Largest shock of an earthquake swarm (from June 26 to Aug. 3) . Felt over 8000 square miles. Minor damage sustained at Goleta, Carpinteria and Santa Barbara. Many shocks of this swarm also felt over wide area.

See footnotes at end of table

TABLE II-1 (Continued)

Year	Month and Day	Local Time	Maximum R.F. Intensity 2/	Magnitude	General Location of Maximum Intensity Area and (or) Epicentral Area	R.F. Intensity 2/ Santa Barbara Area	Remarks
1971---	2-9	0600	IX-X	6.6	14 km NNE of San Fernando	V	Felt throughout southern California, Nevada, Arizona, northern Mexico. Due to proximity to populated areas, 64 lives lost and tangible damage amounted to $553 million. Nearly 25,000 buildings damaged, several newly constructed hospitals severely damaged, one old hospital collapsed, 5 highway overpasses collapsed, 7 additional overpasses damaged, 5 dams damaged. Many aftershocks.
1973---	2-21	0646	VII	6.0	Point Mugu-------------	IV - VII	Felt throughout much of southern California. Preliminary estimate of damage $1 million. Some major structural damage in Oxnard, but most damage minor. No deaths, injuries minor.
1973---	8-6	1629	VI(?)	4.8	Near Anacapa Island----	VI(?)	

1/ The primary source for the information presented is the Catalog of Townley and Allen (1939); data after 1928 have been compiled from various sources, especially the annual issues of "U.S. Earthquakes." Question-mark entries are used for original queried entries or where present author entered an interpretation based on incomplete data. Remarks enclosed in parentheses are interpretations drawn from incomplete accounts.

TABLE II-1 (Continued)

2/ The most commonly used form of the Rossi-Forel (R.F.) scale reads as follows (Richter, 1958):

I. Microseismic shock.—Recorded by a single seismograph or by seismographs of the same model, but not by several seismographs of different kinds; the shock felt by an experienced observer.

II. Extremely feeble shock.—Recorded by several seismographs of different kinds; felt by a small number of persons at rest.

III. Very feeble shock.—Felt by several persons at rest; strong enough for the direction or duration to be appreciable.

IV. Feeble shock.--Felt by persons in motion; disturbance of movable objects, doors, windows, cracking of ceilings.

V. Shock of moderate intensity.--Felt generally by everyone; disturbance of furniture and beds, ringing of some bells.

VI. Fairly strong shock.--General awakening of those asleep, general ringing of bells, oscillation of chandeliers, stopping of clocks, visible agitation of trees and shrubs, some startled persons leaving their dwellings.

VII. Strong shock.--Overthrow of movable objects, fall of plaster, ringing of church bells, general panic but no damage to buildings.

VIII. Very strong shock.--Fall of chimneys, cracks in the walls of buildings

IX. Extremely strong shock.--Partial or total destruction of some buildings.

X. Shock of extreme intensity.--Great disaster, ruins, disturbance of the strata, fissures in the ground, rock-falls from mountains.

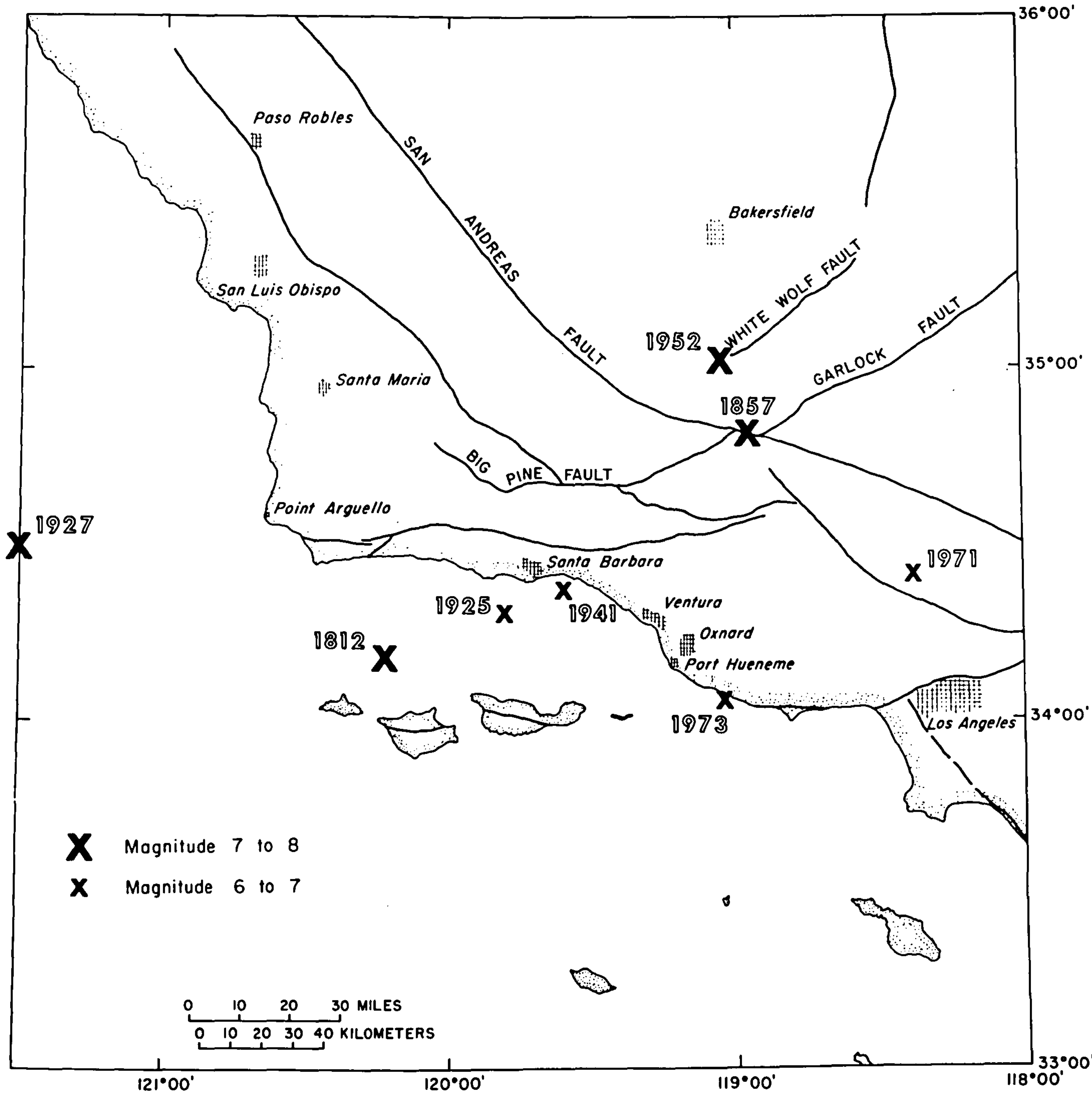


Figure II-10 Selected strong earthquakes that have affected the Santa Barbara Channel region as discussed in the text. Not all strong earthquakes in the figure area are shown. Please see table II-1 for a more complete list of strong earthquakes that have affected the Channel region.

(2) Santa Barbara Channel Earthquake of 1925

An earthquake on June 29, 1925, caused widespread damage in coastal communities from Pismo Beach on the northwest, through Santa Barbara, to Ventura on the east. Twenty people were killed. Almost the entire business section of Santa Barbara was destroyed or rendered unsafe. The damage was estimated at $6 million, not including damage to residences. Mission Santa Barbara was again heavily damaged. Two bell towers were partly destroyed, the front facade collapsed, and some older interior adobe walls failed. Nunn (1925) reported that crude oil was extruded through beach sand at several points along the Santa Barbara coast at approximately the same time as a series of slight foreshocks began, about three hours before the main earthquake. The epicenter of this magnitude 6.3 earthquake was probably less than 10 miles (16 km) west of Santa Barbara in the vicinity of the Elwood oilfield at the coast (Richter, 1958, p. 534).

(3) Santa Barbara Channel Earthquake of 1941

A moderate-sized earthquake occurred on June 30, 1941 (Neumann, 1943, p. 10). Its magnitude was nearly 6 and its epicenter was located in the Channel about five miles (8 km) south of the coastline between Santa Barbara and Carpinteria. The total damage to communities along the Santa Barbara coast was estimated at $100,000. This earthquake was felt over an area of 20,000 square miles in southern California. Maximum intensities of VIII were reported at Carpinteria and Santa Barbara. Outstanding effects of this earthquake included a small landslide which covered the railroad and reached the coast highway about 20 miles (32 km) east of Santa Barbara and the snapping off of many street lamps in Santa Barbara. Strong-motion seismograph records were obtained at Santa Barbara, Hollywood, Los Angeles, Vernon, and Long Beach. The maximum horizontal ground acceleration recorded at the Santa Barbara station was 0.18 g at a distance of about 10 miles (16 km) from the inferred epicenter. Examination of this record by Neumann (1943, p.37) indicated that the maximum ground acceleration might have exceeded 0.18 g because the instrument might have been triggered after the maximum acceleration occurred.

(4) Point Mugu Earthquake of 1973

A magnitude 6.0 earthquake centered near Point Mugu shook the Santa Barbara Channel region on February 21, 1973. The focal depth was about 10 miles (17 km). Although the earthquake was felt over a wide area of southern California--as far away as San Luis Obispo, Bakersfield, Barstow, Indio, and San Diego--there were no deaths and injuries were minor. The maximum horizontal acceleration recorded was 0.13 g at Port Hueneme, approximately 16 miles (26 km) from the focus. Damage has been unofficially estimated at $1 million. Structural damage was confined to old unreinforced masonry structures. While most of the structural damage was minor, several buildings in the city of Oxnard were severely damaged. Damage to newer, earthquake-resistant buildings was mostly confined to suspended ceilings, light fixtures, partitions, and windows (Takahashi and Schneite, 1973).

Operators of all Santa Barbara Channel OCS oil and gas leases were required by the U.S. Geological Survey to report damage to platforms, wells, pipelines, and onshore treating and storage facilities caused by this earthquake. No damage was reported. This is not surprising because the nearest OCS platforms (in the Dos Cuadras and Carpinteria offshore fields) are over 30 miles (48 km) from the earthquake epicenter.

c. <u>Nearby Destructive Earthquakes That Affected the Channel Region</u>

Several destructive earthquakes have affected the Santa Barbara Channel region even though they originated outside the Channel region. These must also be considered in earthquake-hazard evaluations. These events are briefly described here, and their locations are also shown in figure II-10.

(1) <u>Fort Tejon Earthquake of 1857</u>

A distant earthquake strongly shook the northern part of the Santa Barbara Channel on January 9, 1857 (Wood, 1955). Its epicenter was on the San Andreas fault near Fort Tejon, about 50 miles (80 km) northeast of Santa Barbara. The surface faulting that accompanied this earthquake was not mapped at the time, but contemporary accounts and recent geologic studies (Wallace, 1968; Vedder and Wallace, 1970) demonstrate substantial right-lateral displacement on a fault break at least 150 miles (240 km) long. The effects of this earthquake are comparable to those of more recent earthquakes greater than magnitude 8. Early descriptions indicate that all the houses in Santa Barbara were damaged (Wood, 1955) and that shaking in the Santa Clara River Valley east of Ventura was severe. Differential subsidence occurred in the river bed, and long cracks formed from which water jetted to heights of 6 feet.

(2) <u>Point Arguello Earthquake of 1927</u>

A major earthquake occurred on November 4, 1927, northwest of the Channel off Point Arguello (Byerly, 1930). This shock, with a magnitude of 7.5, ranks as the second largest California earthquake since the San Francisco earthquake of 1906. Effects were most pronounced at Surf and Honda, just north of Point Arguello, where people were thrown from their beds, the concrete highway was cracked, a railroad bridge was damaged, and several hundred thousand cubic feet of sand was shaken down from a beach cliff. Buildings were damaged along the coast from Cambria, about 80 miles (128 km) north of Point Arguello, to Gaviota, 28 miles (45 km) to the east. A tsunami was generated by the main event, and seismic disturbances from the main shock and some of its stronger aftershocks were felt in ships at sea. The tsunami was observed at Surf and Pismo Beach, 10 and 40 miles (16 and 64 km) respectively, north of Point Arguello. The wave was at least 6 feet high and resembled a large storm wave. At Port San Luis (Avila) near Pismo Beach, a 5-foot wave was followed by one hour of water agitation. Tide-gage records at San Francisco and San Diego confirm this tsunami.

(3) Kern County Earthquake of 1952

A major earthquake (magnitude 7.7), the largest in California since 1906, shook southern California on July 21, 1952. This was earthquake/centered about 60 miles (96 km) northeast of Santa Barbara and rupture occurred along the White Wolf fault. The main shock was followed by numerous aftershocks, three of which had magnitudes greater than 6. It was strongly felt along the southern California coast, including the Santa Barbara area. Building damage in Santa Barbara was estimated to be $400,000 (Steinbrugge and Moran, 1954).

(4) San Fernando Earthquake of 1971

A distant earthquake, magnitude 6.4, shook the Santa Barbara Channel on February 9, 1971 (U.S. Geological Survey, 1971). The epicenter was about 10 miles (16 km) northeast of the city of San Fernando or about 60 miles (96 km) east of Santa Barbara, and the hypocenter was 8 miles (13 km) beneath the surface. A discontinuous fault scarp was formed in the vicinity of the cities of San Fernando and Sylmar. Sixty-four persons died, and tangible damage was estimated at $553 million. Nearly 25,000 buildings were damaged or destroyed, five highway overpasses collapsed and seven others were damaged, four hospitals were severely damaged or destroyed, and five dams sustained major damage.

Oil and gas installations in the Los Angeles area largely escaped severe damage from the San Fernando earthquake (Oil and Gas Journal, 1971). Only one small refinery (5,500 barrels/day) is located near the earthquake epicenter (about 11 miles or 18 km). It was forced to shut down temporarily because of damage to storage tanks and pipelines. A number of oil fields in the earthquake area shut down immediately after the quake but were returned to production within a day or two. Damage to gas lines was limited to an area of 4 square miles in the northeast corner of the San Fernando Valley.

Operators of all Federal public and acquired land leases in Los Angeles and Ventura Counties were required by the U.S. Geological Survey to report damages resulting from the San Fernando earthquake. Some Federal leases are within 10 miles (16 km) of the epicenter. There was no significant damage to the production facilities or producing wells on the 20 Federal leases on which reports were received. Geological Survey personnel inspected all of these leases. Several of the leases had some earthslides, but the slides caused no damage. The total damage on Government leases was minor and was estimated at about $6,000; about half of this was damage to roads.

The relatively light damage sustained by petroleum production and refinery facilities was most probably due to the geographic relationship of those facilities to the earthquake fault break. Although the Newhall refinery is almost the same distance from the epicenter as the most heavily damaged areas, the latter were located along and near the surface fault break. The greatest structural damage was concentrated along the surface rupture, in areas of locally amplified seismic shaking and in tectonically deformed areas in the thrust plate above the faults that ruptured the surface (U.S. Geological Survey, 1971, p. 75). Thus, the San Fernando earthquake clearly demonstrates the importance of recognizing the location of active fault scarps and the tectonic nature of movement on a fault system.

d. Regional Seismicity Based on Caltech Data (1932-71)

Instrumental investigations of earthquakes in southern California began in the 1920's. By the summer of 1927, four stations with Wood-Anderson torsion seismometers were recording continuously in southern California. Routine and systematic epicentral determinations began in 1932 with seven stations reporting. The number of stations has increased gradually over the years, with over 40 stations operating at present. The distribution of the Caltech seismograph stations is shown in figure II-11. Because the Santa Barbara Channel region is not surrounded by the Caltech seismograph stations, instrumental determinations of earthquake epicenters in the Channel area are relatively poor. This situation was improved in late 1969 with the installation of the USGS Santa Barbara Channel network of seismograph stations, as discussed in the next section.

In 1972, Caltech provided the USGS with a copy of the magnetic tape containing their earthquake catalog for southern California from 1932 to 1971. They have since published their catalog for the period from 1932 to 1972 (Hileman and others, 1973). Earthquake epicenters in the Santa Barbara Channel region were extracted from the Caltech catalog and plotted in

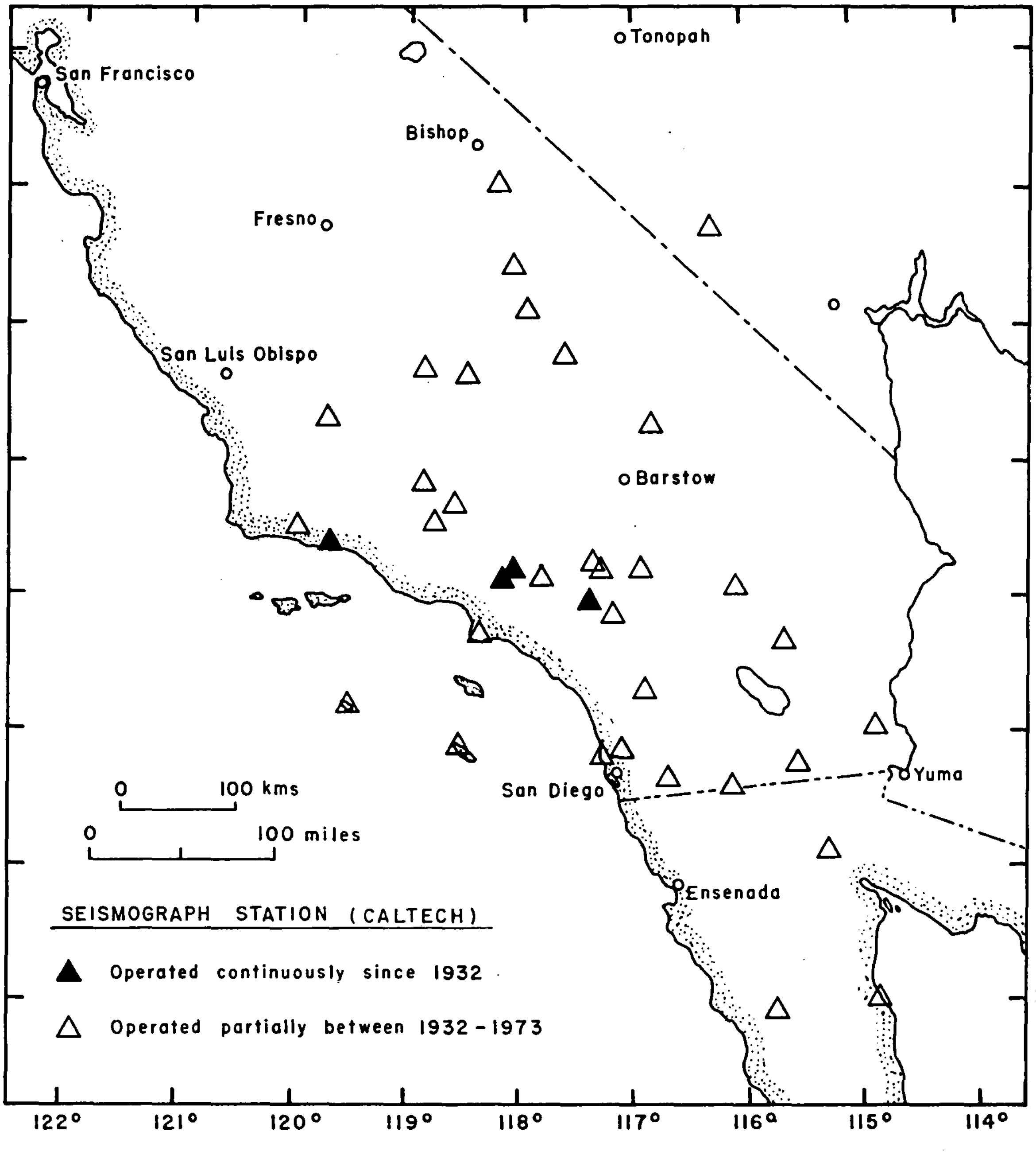


Figure II-11 Location of Caltech's seismograph stations figure II-12. This figure shows that earthquake activity has been concentrated in the eastern part of the Channel and is not obviously related to mapped faults.

In late 1968, an earthquake swarm began in the center of the Santa Barbara Channel approximately midway between Santa Barbara and the eastern end of Santa Cruz Island. Sylvester and others (1970) studied this earthquake sequence using the Caltech seismograph network, supplemented during part of the swarm by additional portable instruments. They found no apparent correlation between the swarm activity and recognized faults in the area.

Lee and Vedder (1973) compared earthquake locations reported by Caltech for 1970 and 1971 with locations for the same events computed using the local USGS network. Their analysis showed location discrepancies of as much as 24 miles (39 km) between the two sets of solutions. Independent estimates of one epicentral location error of the USGS network solutions indicate a relative location error of less than 3 miles (5 km) (Lee and Vedder, 1973). Thus, the apparent lack of correlation between the epicenters in figure II-12 and the mapped faults may arise from inaccurate determinations of earthquake epicenters.

Although the distribution of Caltech's seismograph stations is not favorable for precise location of earthquakes in the Santa Barbara Channel region, the Caltech catalog provides over 40 years of continuous instrumental record of earthquake activity there. These data are extremely valuable in establishing the level of earthquake activity in the Channel region.

e. Regional Seismicity Based on USGS Data (1970-73)

In late 1969, the U.S. Geological Survey established a telemetered network of seismograph stations surrounding the Santa Barbara

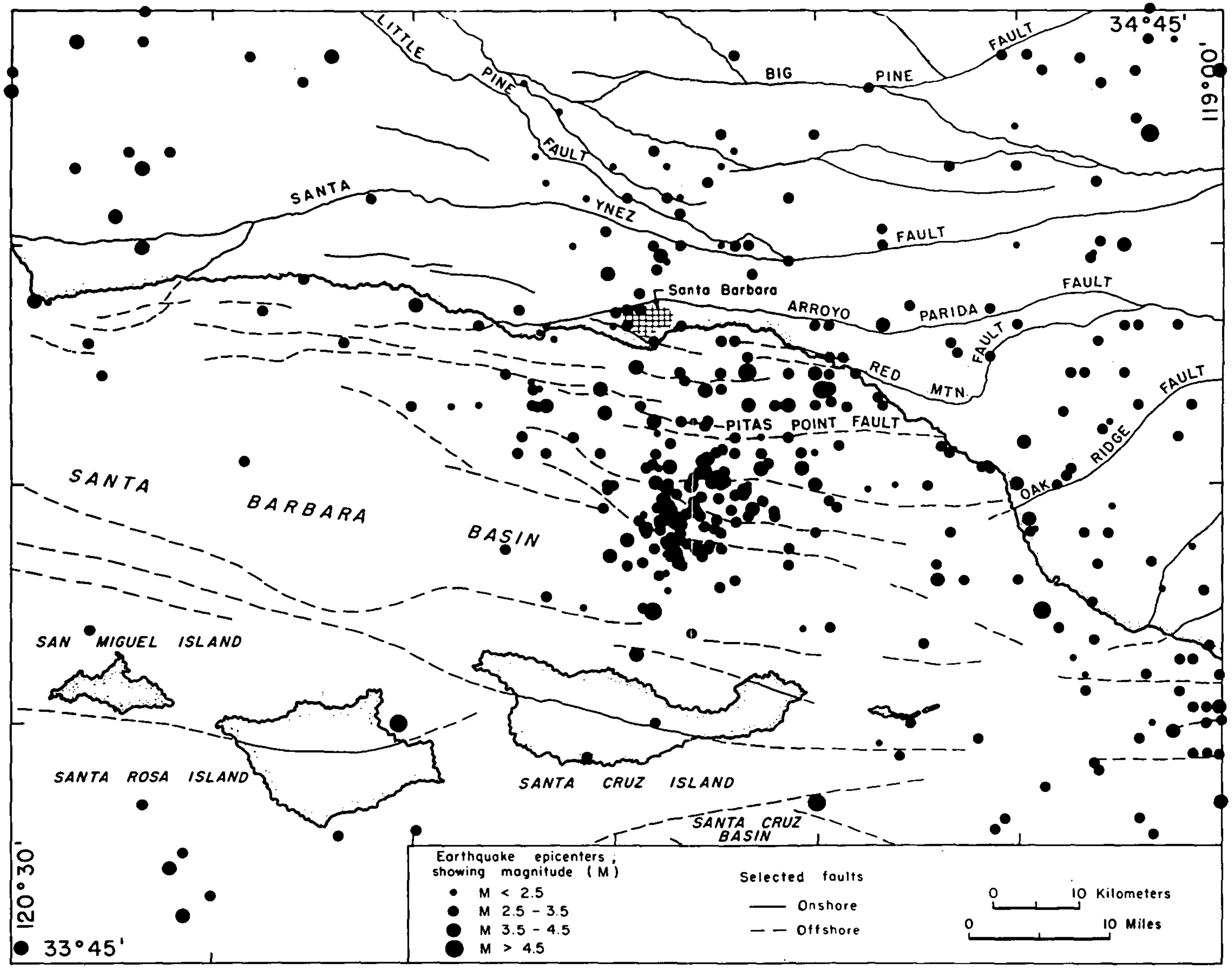


Figure II-1[illegible]. Earthquake epicenters in the Santa Barbara Channel region from 1932 to 1971 as determined by Caltech

Channel. The purpose of this network was to improve earthquake monitoring there so that active faults could be identified. Experience with local seismograph networks elsewhere in California has proven the value of small, local, earthquake data, both for the identification of active faults and as an aid in understanding the contemporary tectonic environment of the region (Eaton and others, 1970a, 1970b; Brown and Lee, 1971; and Wesson and others, 1973). The distribution of the USGS stations as well as others that provide information applicable to the Santa Barbara Channel is shown in figure II-13. Results of the USGS data for 1970-71 have been published (Lee and Vedder, 1973), and those for 1972-1973 have been incorporated here (Ellsworth, written communication, 1974). Earthquake locations in the Santa Barbara Channel region for the 4-year period 1970-73 are plotted in figure II-14.

The accuracy of earthquake locations depends on several factors: 1) The geographic distribution of the seismograph stations relative to the epicenter; 2) the proximity of the stations to the epicenter; 3) knowledge of the crustal velocity structure between the epicenter and the stations; and 4) the number of stations recording a given event. Lee and Vedder (1973) estimated that the accuracy of the USGS earthquake locations is about 3 miles (5 km) in the Santa Barbara Channel region. Their estimate was supported by the fact that they were able to locate several offshore explosions near Santa Cruz Island to within 3 miles (5 km) of their true positions.

The focal depths determined for events with nearby stations and the range of computed focal depths within the Channel indicate that most of the earthquakes occur at relatively shallow depths--from near the surface to about 10 miles (16 km) deep. Such shallow focal depths are consistent with values determined for earthquakes in central California, where the USGS operates a much denser network of seismograph stations; however, focal depths

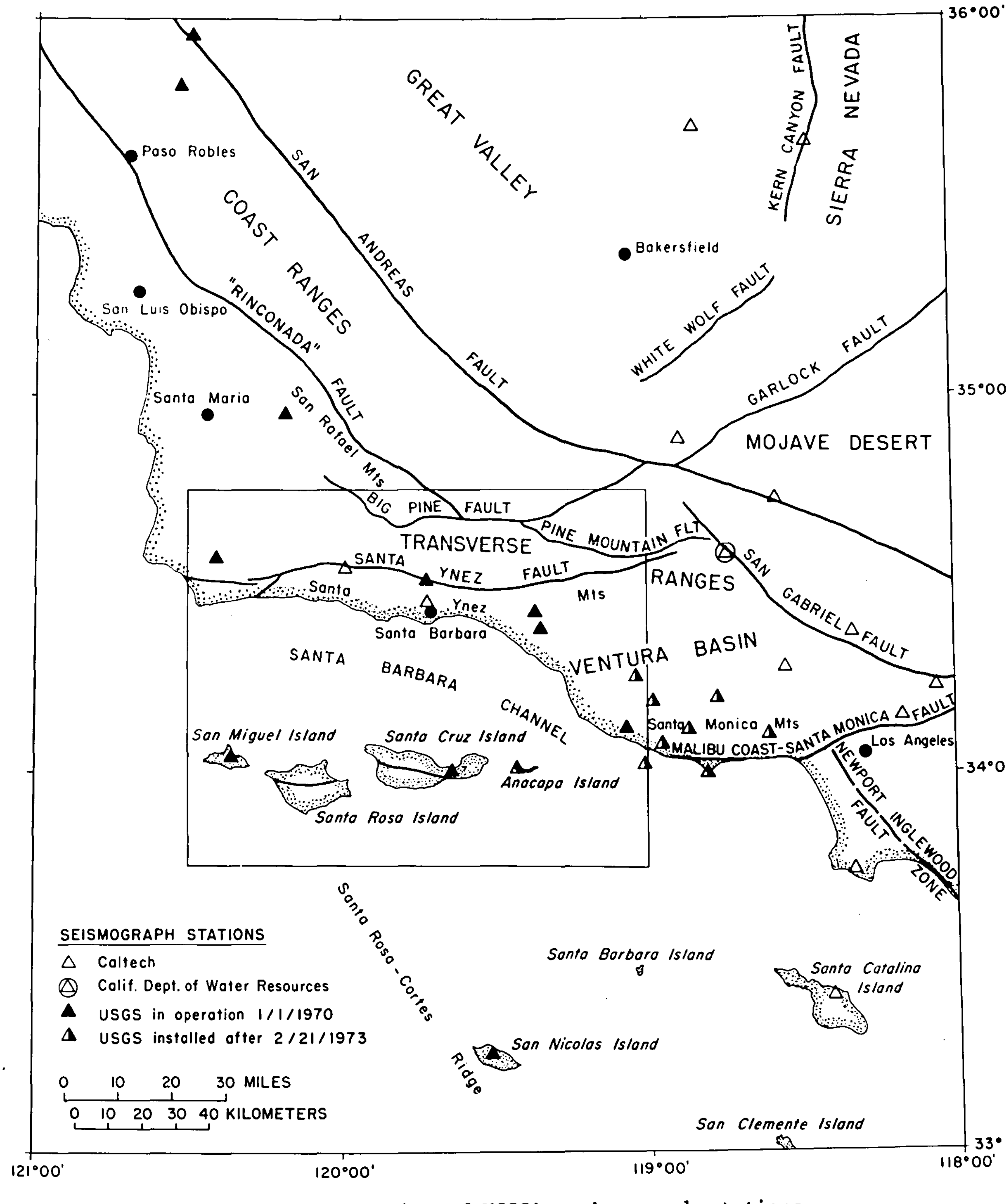


Figure II-13 Location of USGS's seismograph stations

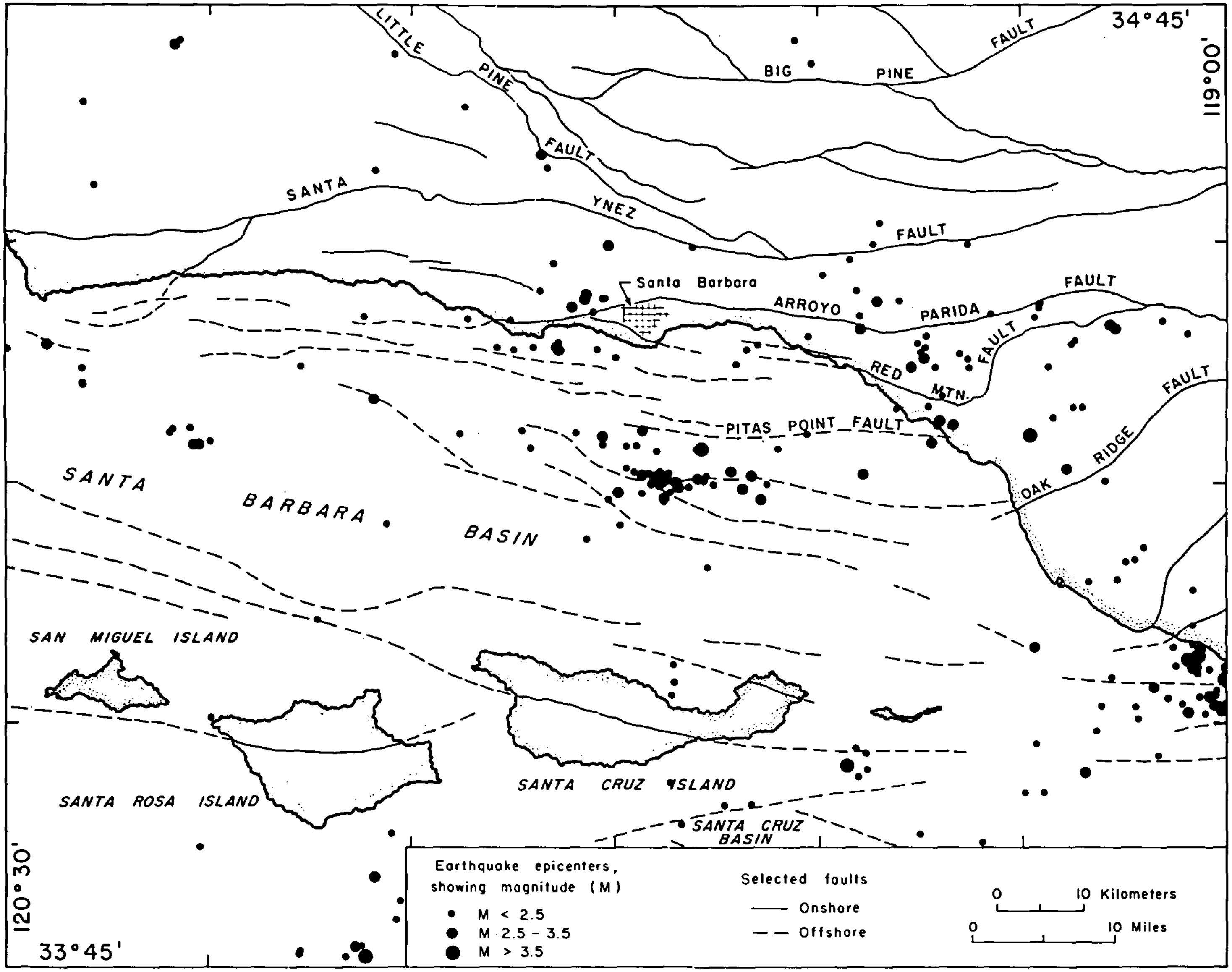


Figure II-14 Earthquake epicenters in the Santa Barbara Channel region from 1970 to 1973 as determined by USGS for earthquakes in the Santa Barbara Channel region cannot be as accurately determined because of the relatively wide station spacing. Accurate determination of the depth of focus requires at least one seismograph station within a few miles of the epicenter. There are now (January, 1976) seven ocean-bottom seismograph stations in the Santa Barbara Channel, all but one in a tight array over the Dos Cuadras field; however, the record is short because installation was completed in December, 1975.

Most of the earthquake epicenters in figure II-14 may be loosely grouped into three east-west-trending sets: 1) along the southern front of the Transverse Ranges province--a complex fault zone which includes seaward extensions of the Santa Monica fault, the Malibu Coast fault, and the Santa Cruz Island fault; 2) along the north-central part of the Santa Barbara Basin, including the Pitas Point fault, Oak Ridge fault, and several unnamed east-west-trending faults inferred from acoustic profiling; 3) along the Santa Barbara coast and parallel to the coast to the east, including the Red Mountain fault, Arroyo Parida fault, Santa Ynez fault, and several unnamed faults 3 to 6 miles (5 to 10 km) offshore. Significant earthquake activity outside of the Santa Barbara Channel was also detected south of Santa Rosa Island and seaward of Point Arguello.

Many of the faults within the Transverse Ranges province that have evidence of Holocene or late Quaternary displacement, including most of the faults in groups 1 and 3 defined above, are reverse faults. Because the fault planes of most of these faults are not vertical, dipping into the crust to depths in excess of 6 miles (10 km), and because the earthquake locations have relatively large uncertainties associated with them, only in a few isolated instances can specific faults be identified as active on the basis of local earthquakes alone. Rather, the pattern of seismicity evident in figure II-14 indicates the presence of three broad, seismically active zones, each of which may consist of one or many active faults.

The Malibu Coast fault, the Santa Monica fault, and the Santa Cruz Island fault are parts of the complex fault system that lies along the southern boundary of the Transverse Ranges in the Channel region. This fault system, together with its extension to the east, forms a complex zone which has undergone crustal shortening by north-over-south reverse slip and left-lateral strike slip in Pliocene through Holocene time. Data from the 1973 Point Mugu earthquake sequence, the magnitude 4.8 earthquake of August 6, 1973, located 4 miles (7 km) southwest of Anacapa Island, and USGS seismograph stations located in the western Santa Monica Mountains show that the contemporary seismicity is not restricted to a simple fault surface. Fault-plane solutions for individual earthquakes within this zone vary in type from north-south reverse slip to horizontal strike slip (figure II-15). The fault-plane solution of the Anacapa Island earthquake of 1973, located along the inferred eastward extension of the Santa Cruz Island fault, is in excellent agreement with the geologic evidence of left-lateral strike slip on this fault. In contrast, fault movement in the 1973 Point Mugu earthquake was inferred to be chiefly north-over-south reverse slip. Aftershocks of this earthquake indicate a complex pattern of deformation in a zone lying between the inferred north-dipping projections of the Malibu Coast and Santa Monica faults (Ellsworth and others, 1973). It is noteworthy that the focal depths of the two largest shocks during the past four years of seismic monitoring were deeper than had previously been assumed for earthquakes in California. They indicate that active faulting extends to a depth of at least 10 miles (17 km) along the southern frontal fault system.

The distribution of epicenters within the north-central part of the Santa

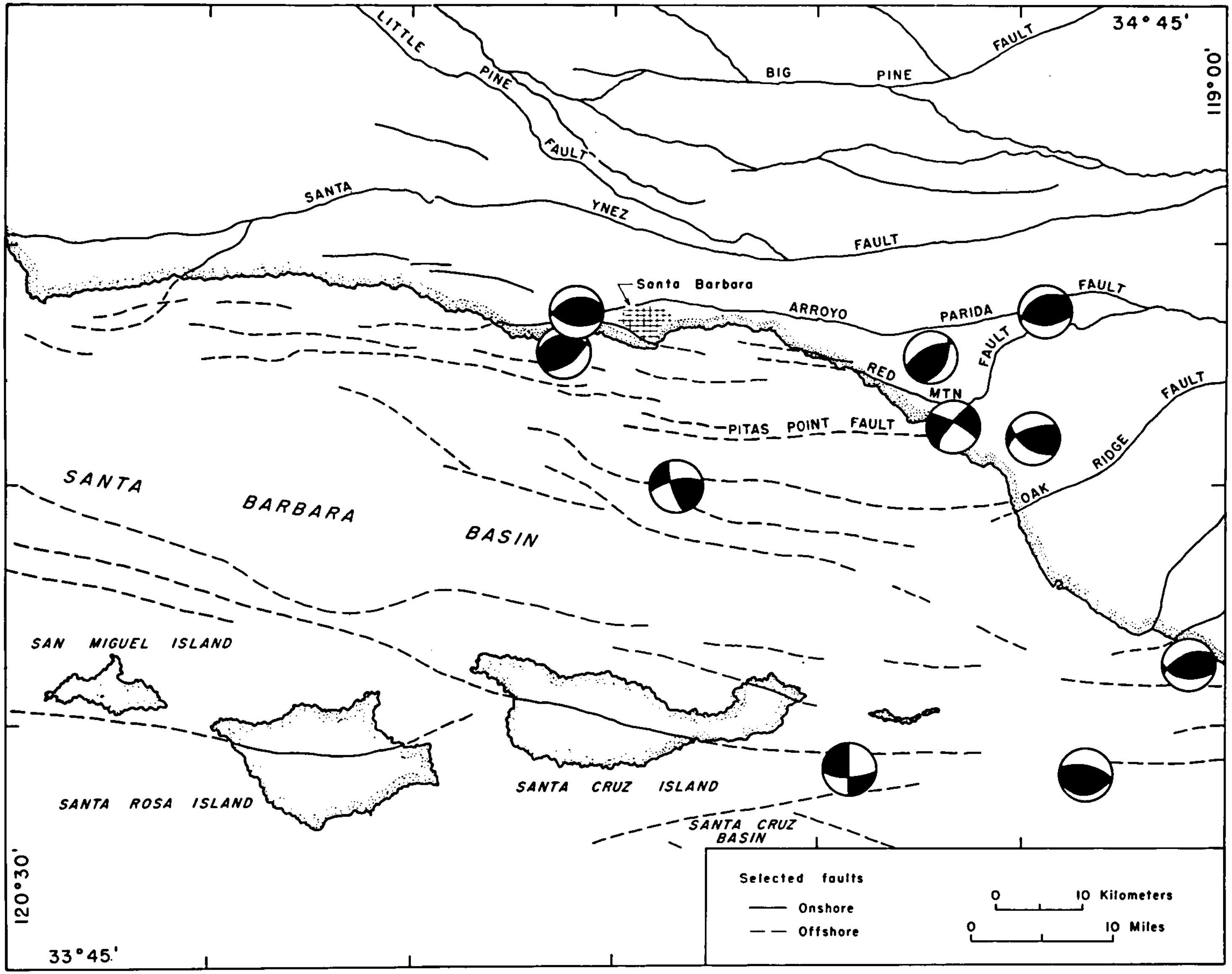


Figure II-15 Focal mechanisms of earthquakes in the Santa Barbara Channel region

Barbara Channel may be attributable to activity on several subparallel fault strands. A composite fault-plane solution for 10 earthquakes that occurred on May 7, 1971, in a small cluster located on the inferred offshore fault west of the Oak Ridge fault (figure II-15), was obtained by Lee and Vedder (1973). They suggested a fault plane which strikes N 77°E, dips about 70°N, and indicates left-lateral strike slip motion. This solution agrees favorably with some of the known and inferred fault orientations and movement directions in the region. However, it does not fit the south-dipping and reverse-slip relations observed along the Oak Ridge fault onshore to the east.

Along the Santa Barbara coast, earthquake activity lies within a broad zone comparable in width to that of the southern frontal fault zone. In the area between Ventura and Santa Barbara, the seismicity lies well north of the seaward projection of the north-dipping Red Mountain fault and is separated from the activity farther to the south by an aseismic corridor about 6 miles (10 km) wide. The fault-plane solution for the magnitude 3.4 earthquake of March 29, 1973, located about 3 miles (5 km) west of Santa Barbara and a composite fault-plane solution for two events in April 1972 located 6 miles (10 km) southwest of Santa Barbara indicate thrust faulting. The north-dipping nodal plane for both solutions strikes about N 83°E and dips 40°N in the former case and 34°N in the latter. North-dipping thrust displacement is consistent with the sense of late Quaternary displacement along the Red Mountain fault though its continuation to and west of Santa Barbara has not been clearly delineated on present maps.

The north-dipping Red Mountain fault has displaced a Holocene soil zone and the trace shows physiographic evidence of recent movement. Comparison among four sets of first-order leveling circuits which cross the fault scarp 5 miles (3 km) north of Ventura shows a marked elevation change across the fault (Buchanan and others, 1973). The sense of elevation change across this fault scarp and also along another circuit which crosses the Red Mountain fault west of Ventura is consistent with the recent displacements on this fault. The small earthquakes located to the north of this fault in 1970-73 could be directly associated with this fault. The fault-plane solution for the magnitude 3.4 event on September 4, 1973, located 7 miles (12 km) northwest of Ventura, and a composite fault-plane solution for four events occurring on August 24 through September 13, 1973, at Ojai agree with the north-over-south reverse slip on the Red Mountain fault. However, when the foci are projected to the surface along the inferred northwest-dipping fault planes, they intersect the ground surface well to the south of the Red Mountain fault. Thus, the earthquake activity detected in the Ventura region may be associated with faults whose activity is not recognized from geologic evidence.

Active faulting within the Santa Clara River Valley-Oxnard-Ventura area also is suggested by the epicenter distribution in figure II-14. A magnitude 3.6 earthquake of August 26, 1970, located east of Ventura, has a fault-plane solution corresponding to right-oblique reverse slip. In contrast, the composite solution for three magnitude 3 events with epicenters within the Ventura oil field and relatively shallow focal depths indicates right-lateral strike slip on steeply dipping surfaces. Although this composite fault-plane solution differs markedly from the other events shown in figure II-15, the inferred axis of maximum compression is nearly horizontal and in a north-south direction, as was found for nearly every other solution.

The level of seismicity in the western half of the Santa Barbara Channel region during the four years covered by the USGS network was significantly lower than the level in the eastern half of the Channel. As a result, the available data suggest only a crude relationship between contemporary seismicity and geologic structures. Contemporary activity in the western part of the Channel lies principally along the central axis of the basin where the water is deep and the geologic structure relatively poorly known.

f. Recent Structural Deformation

An indication of long-term seismic activity is provided by data on the amount, rate, and nature of crustal deformation at the earth's surface. Accurate dating of the deformation of young rock units and such features as terraces, drainages, or other geomorphic markers yields a useful and reliable extension of written and instrumental earthquake records. Many of the latest fault movements in the Santa Barbara Channel region and adjacent parts of the Transverse Ranges province involve reverse dip-slip, although some of the larger faults, such as the Santa Ynez, Big Pine, and Malibu Coast, may have had major left-lateral components of movement in the geologic past.

The Santa Ynez fault zone, which trends westward for about 82 miles (130 km) along the northern margin of the Transverse Ranges (figure II-13), exhibits some physiographic evidence that suggests recent movements, and it has been considered an active tectonic feature (Page and others, 1951).

The Big Pine fault, a major left-lateral fault with oblique slip near its western end, may have had measurable movement during historic time. The southern California earthquakes of November 1852 were possibly accompanied by surface rupture along the fault trace for about 30 miles (48 km) in Lockwood Valley, about 40 miles (64 km) northeast of Santa Barbara (Townley and Allen, 1939). The exact trend and location of the surface faulting are unknown, but geologic evidence and contemporary reports indicate that it may have been along the Big Pine fault. Independent evidence of very recent movement along the fault includes possible scarplets that cut Quaternary terrace deposits and apparent left-lateral offset of stream channels (Vedder and Brown, 1968).

Faulting and local warping associated with the Malibu Coast fault have deformed upper Pleistocene marine-terrace platforms and their deposits at seven known localities along a 20-mile segment of the fault bordering the south side of the Santa Monica Mountains (Yerkes and Wentworth, 1965). No surface faulting was observed after the Point Mugu earthquake of February 21, 1973. However, numerous rock falls, cracks and fissures, and sand boils caused by the shaking of unconsolidated ground were observed in the Point Mugu area.

Deformation of very young rock units and recent topographic surfaces in the eastern part of the Channel region has long been recognized. In the Ventura anticline, lower Pleistocene strata form the upper part of a sedimentary sequence that is more than 40,000 feet thick. These lower Pleistocene beds dip 35° to 60° on the south flank of the anticline, and because they conformably overlie older rocks, they provide clear evidence that the structure has been formed since early Pleistocene time. At Loon Point, 6 miles (10 km) east of Santa Barbara, upper Pleistocene alluvial fan deposits are tilted and cut by a northeast-trending thrust fault that offsets the base of the oldest fan by at least 400 feet (Lian, 1954). This faulting may have continued into Holocene time. Faulted terrace deposits are well exposed about 2 miles (3 km) southeast of Carpinteria, where highway cuts reveal a southwest-dipping (40°) reverse fault that juxtaposes upper Pleistocene marine terrace deposits and highly deformed Tertiary sandstone and siltstone. This fault may also cut the present topographic surface; presumably it has moved during Holocene time.

A study directed toward determining the recency of faulting in coastal southern California is being conducted by the U.S. Geological Survey (J.I. Ziony and others, written communication, 1974). Preliminary results from this study of faults occurring onshore in the northwest part of the Santa Barbara Channel region are summarized in table II-2 . Age determinations for the parameters listed in table II-2 were not available for many faults that have been mapped in the area.

Several west-trending faults have been mapped offshore in the northeast part of the Channel, and sub-bottom profiles show that they extend at least several hundred feet beneath the sea floor. Some of the faults in the vicinity of Dos Cuadras field appear to cut very young bottom sediments (McCulloh, 1969; p. 32).

The fault scarps indicate Holocene tectonic activity, some of which may have been accompanied by historic earthquakes felt in the Santa Barbara Channel region. At least two earthquakes of magnitude 6 or larger have occurred in this region of the Channel; both could have caused surface faulting.

g. Expectable Earthquakes and Design Considerations

In designing earthquake-resistant structures at a given site, it is necessary to know the most severe ground motions at the site from earthquakes expected to occur within the lifetime of the structures. The existing geologic and seismic data in the Santa Barbara Channel region can be used

TABLE II-2

RECENCY OF FAULTING ONSHORE IN THE NORTHWEST PORTION OF THE SANTA BARBARA CHANNEL REGION
(Adapted from Ziony, and others, personal communication, 1974)

Fault or Faulted Area	Fault Age Class	Youngest Known Rock Unit Displaced by Fault/Faults (Maximum Limit on Age of latest Displacement)	Probable Age of Fault-Produced Topography (Maximum Limit on Age of latest Displacement)	Oldest Known Unfaulted Rock Unit which is Deposited or Intruded into Fault (Minimum Limit on Age of Latest Displacement)
"Main" Santa Ynez Fault				
(West of Gaviota)	Late Cenozoic	5 to 12 Million Years		11,000 to 500,000 Years
(East of Gaviota)	Late Quaternary	5 to 12 Million Years		
South Branch of Santa Ynez Fault	Late Quaternary	11,000 to 500,000 Years		
Near Capitan	Late Quaternary to Late Cenozoic	11,000 to 5 Million Years		11,000 to 500,000 Years
Near Coal Oil Point	Late Quaternary to Quaternary	11,000 to 5 Million Years	11,000 to 500,000 Years	
Between Santa Barbara and Coal Oil Point	Late Quaternary to Quaternary	11,000 to 3 Million Years	11,000 to 500,000 Years	11,000 to 500,000 Years

to estimate the maximum credible earthquake in the region and the accompanying expectable ground motions. If the earthquake rate of the past 50 years is representative of the average level of activity, a magnitude 6 earthquake can be expected in the region about every 20 years. However, the instrumental record is inadequate to specify the expected ground motions on a site-by-site basis, or where such events might occur. While moderate-sized earthquakes are definitely known to have occurred in the region and are to be expected to occur in the coming decades, the history of large earthquakes and the time interval between their recurrence is less certain because the instrumental record is too short.

The largest earthquake known to have occurred in the Channel in the past 170 years is the earthquake of 1812. A magnitude of 7 to 7.5 is suggested for this earthquake by the documented effects of the strong shaking. Both the geographic extent and the intensity of the shaking are comparable to other California earthquakes of magnitude 7 to 7.5. Empirical data on the length of surface rupture for earthquakes in this magnitude interval range from 6 miles (10 km) to 60 miles (100 km) (Bonilla and Buchanan, 1970). Through-going fault structures 60 miles and more in length certainly exist in the Santa Barbara Channel region.

Although no events of magnitude 7.5 are definitely known in the Channel, two events of about that magnitude have occurred on the periphery of the Channel region in the past 47 years. These were the magnitude 7.5 event of 1927, located near the western end of the Channel and the magnitude 7.7 event of

1952, located to the northeast of the Channel region. Both earthquakes had substantial vertical displacement, as is also characteristic of recent fault movement in the Santa Barbara Channel region. In addition, the 1952 shock, like the 1971 San Fernando earthquake, resulted from horizontal compression with an orientation parallel to the contemporary axis of maximum compression in the Channel. It is therefore likely that the stress necessary for the generation of a magnitude 7.5 earthquake is attainable in the Channel region. It is noteworthy that the White Wolf fault, which generated the 1952 Kern County earthquake, was unrecognized as a contemporary earthquake hazard prior to the earthquake (Oakeshott, 1955).

These considerations suggest that, for design purposes in the Santa Barbara Channel region, a magnitude 7.5 earthquake should be adopted as the maximum credible earthquake.[1] No particular fault or fault system can be ignored as a potential surface of origin for a local earthquake of such magnitude unless it is demonstrably inactive, demonstrably not a branch of one of the known or inferred major faults of the region, and until detailed examinations provide clear evidence that it is an unlikely surface for the origin of an earthquake of such magnitude.

Strong ground motions for several local earthquakes have been recorded at two accelerograph sites in the Santa Barbara Channel region. Peak acceleration values of 0.18 g recorded at Santa Barbara from the June 30, 1941 earthquake, and of 0.13 g recorded at Port Hueneme from the February 21, 1973 Point Mugu earthquake, have been cited above. In addition a maximum horizontal acceleration of 0.18 g was recorded at Port Hueneme, an epicentral distance of about 5 miles (8 km), for the magnitude 4.7 earthquake of March 18, 1954 (Housner and Hudson, 1958). These three values agree well with acceleration values recorded at comparable distances from earthquakes of similar magnitude (figure II-16).

1. For clarification of the term "maximum credible earthquake" see Coulter and others, 1973, p.46

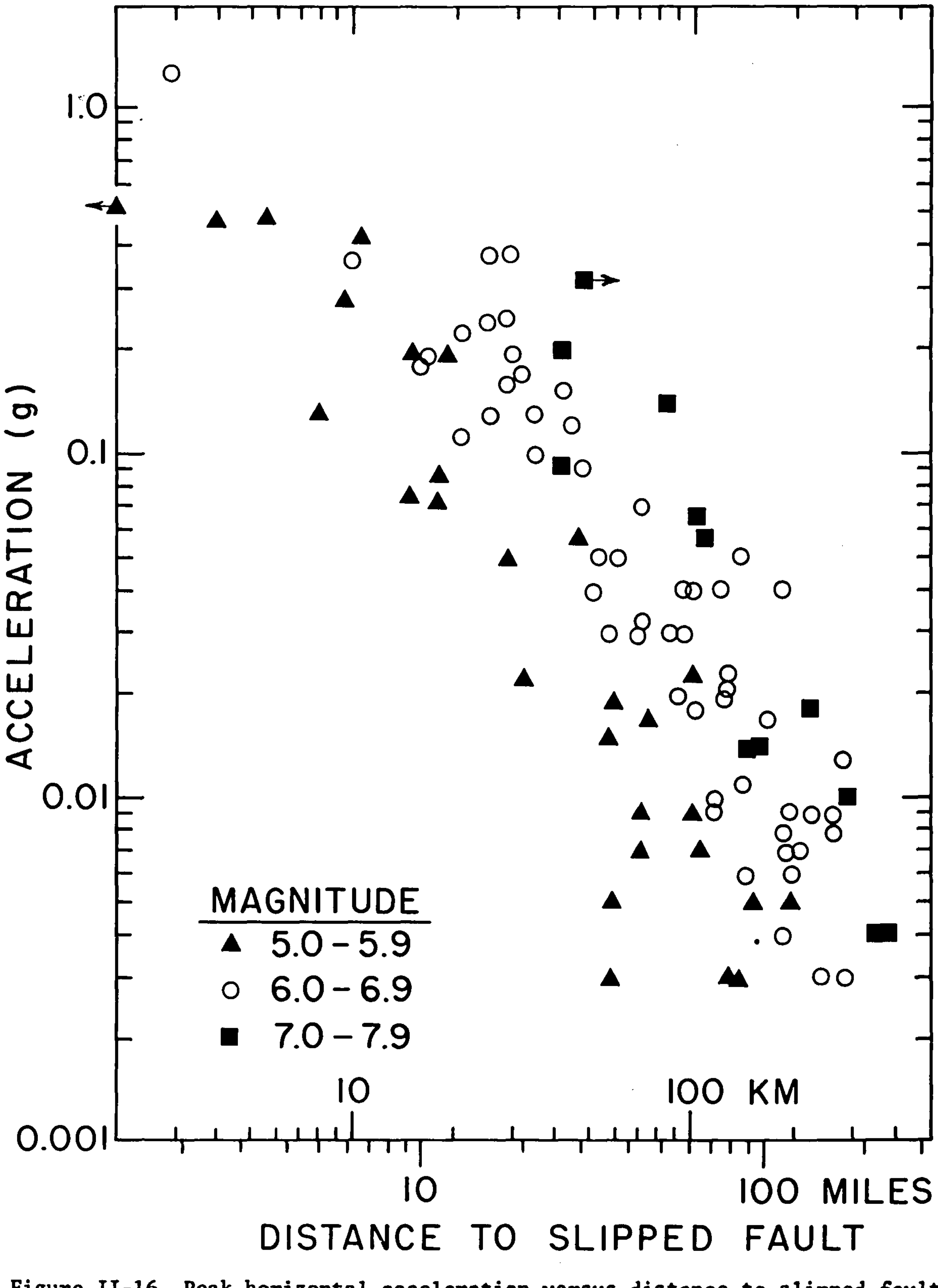


Figure II-16 Peak horizontal acceleration versus distance to slipped fault as a function of magnitude. Modified from Page and others (1972)

The data in figure II-16 show the peak horizontal acceleration at bedrock sites versus the distance to the causative fault for three magnitude intervals. The majority of the data are for California earthquakes. Only events for which the distance to the slipped fault is known to a few miles have been used. These data clearly show the strong dependence of the peak acceleration on the distance to the earthquake rupture surface and on the earthquake magnitude. Other dynamic ground motion parameters, such as the peak horizontal velocity, also show the same dual dependence on distance and magnitude (Page and others, 1972).

Ground motion parameters for bedrock sites near the epicenter of a magnitude 7.5 earthquake based on the above data are: a peak horizontal acceleration greater than 1.0 g (980 cm/sec^2) and a peak horizontal velocity greater than 125 cm/sec. The duration of strong shaking (time interval between first and last peaks of absolute acceleration greater than 0.05 g) predicted for the maximum expectable earthquake[1] is in excess of 40 sec. These values are largely extrapolated values from smaller earthquakes and from earthquakes of comparable magnitude observed further from the causative fault. Revision of these current best estimates may be necessary as more empirical data close-in to large earthquakes are collected. Corresponding near-fault horizontal ground motions for a magnitude 6.5 earthquake, based on instrumental data, are: peak absolute acceleration 0.9 g, peak absolute velocity 100 cm/sec, and duration 17 sec (Page and others, 1972).
It should be emphasized that the ground motion parameters suggested here are based on instrumental data, and that estimates of intensity of near-fault ground motion for shocks larger than magnitude 6 are extrapolated from data obtained at larger distances or near-fault data from smaller shocks. The expectable ground motion values reflect the expected response of strong-motion

[1]For the purpose of this report, the term "maximum expectable earthquake", introduced by Wesson and others, 1974, can be considered equivalent to the term "maximum credible earthquake" as defined by Coulter and others, 1973.

instruments at bedrock sites not affected by the presence of structures. They may not be the maximum possible as, for example, Trifunac and Brady (1975) have postulated maximum acceleration as high as 4.5 g (90 percent confidence level) at the epicenter of a magnitude 7.5 earthquake. Moreover, they contain no factor relating to the nature or importance of the structure being designed. However, as Trifunac and Brady (1975, p. 51) also conclude: "...from the practical earthquake engineering point of view, high acceleration amplitudes should not necessarily be associated with a proportionally higher destructive potential. An extended duration of strong ground motion and high acceleration amplitudes characterize destructive earthquake shaking, while one or several high-frequency high-acceleration peaks may, in fact, constitute only minor excitation because of the short duration involved and may lead to only moderate or small impulses when applied to a structural system."

In addition to ground motion parameters, the capacity of a structure to resist deformation by earthquake stresses also depends on characteristics of the structure that are dictated by other considerations. For example, the height of a drilling platform, which is dictated by water depth, is the principle factor in determining the natural period of the structure which, in turn, determines the expected stresses on upper parts of the structure from shaking at the base. Other factors, such as stresses generated by storm waves, or those that are imposed on a structure during construction in a shipyard, transportation to an offshore site, and fixing it in place, require design for resistance to deformation by horizontal stresses that may add to the capability to resist damage from earthquake shaking after the platform is emplaced. Therefore, a complete analysis of platforms designed using nominally lower values for horizontal bedrock acceleration may determine that they can resist significant damage from shaking by much greater ground motion.

The reader will note that the maximum acceleration for the suggested 7.5-magnitude earthquake is higher than the horizontal accelerations of 0.2 g and 0.50 g, which are listed as the "ground accelerations" for which design spectra were computed for the platform described in the environmental impact statement for the Santa Ynez Unit (FES 74-20); moreover, it is also higher than the design coefficient of 0.15 g for code design of existing platforms in the Channel OCS. These differences do not necessarily imply that structures designed and built using the lower values cannot resist destruction by the ground motions suggested in this report as those expected to accompany a magnitude 7.5 earthquake. The existing structures and designs can only be evaluated within the context of the entire design procedure for each platform. For example, according to H. W. Coulter, U. S. Geological Survey (1974, oral communication), there was a computation made for Platform C in 1969 that indicated it should withstand ground accelerations of as much as 2.0 g, even though the coefficient reputedly used in the design for horizontal acceleration due to earthquake shaking was 0.15 g. As a further example, Jennings (1975, p. 3) testified that "...the 0.25 g and 0.50 g design spectra, combined with the other portions of the recommended design criteria for the Santa Ynez platform and the conservative manner in which the recommendations have been implemented, have produced a platform which has the calculated capacity to resist without danger of collapse ground motions with peak values equal to those which they /DES 75-35/ recommend."

The existing Santa Barbara Channel OCS platforms incorporated the best up-to-date design criteria available at the time. Because data gathering is continuous and because the determinations of ground motion parameters is a rapidly advancing field of technology, the Geological Survey has initiated the establishment of a system of third-party certification of platform design and for the development of various design criteria for OCS platforms. In essence the system is to be patterned after the present British system now employed for the North Sea development (refer to section I.D.4.b.(1) and section IV.B.10.).

Estimation of the earthquake risk in the Santa Barbara Channel region depends on 1) the location of a given site relative to specific active faults; 2) the magnitude of expectable earthquakes on these specific faults; and 3) the occurrence rate of damaging earthquakes. As noted above, the instrumental record indicates that a magnitude 6 earthquake can be expected about every 20 years, on the average (based on the 1925, 1941 and 1973 events). However, since only one large earthquake has occurred in the Channel region since 1800, it is not possible to estimate the occurrence rate of large earthquakes in this manner. Two methods which have been employed elsewhere to estimate the occurrence rate of large events are 1) a statistical method based on properties of the nature of small earthquake activity, and 2) determination of the rate of movement on specific faults by detailed geochronology or by strain-rate measurement.

The level of small earthquake activity has been used by Allen and others (1965) to estimate recurrence intervals for southern California. They estimate the interval between magnitude 8.0 earthquakes in the region to be 52 years, on the average, from the 1934 and 1963 earthquake record. This frequency of large earthquakes roughly corresponds to the average period between the 1812 Santa Barbara Channel earthquake, the 1857 Fort Tejon earthquake, the 1872 Owens Valley earthquake, and the 1892 Baja California earthquake (Allen and others, 1965). Southern California, however, has experienced no earthquakes larger than magnitude 7.7 in the past 82 years. Division of southern California into geologic provinces yields somewhat ambiguous results for recurrence intervals. The interval between magnitude 8.0 events on the San Andreas fault was found to be 18,300 years--a value which is probably two orders of magnitude in error. Allen and others (1965) conclude it can be misleading to extrapolate from a short (29-year, in their case) seismic record for areas smaller than 4 x 10^3 square miles (10^4 km^2).

For the sake of completeness, the occurrence rate of magnitude 7.5 and 6 earthquakes has been estimated from 40 years of data from Caltech (in Hileman and others, 1973) and 2 years of USGS data (in Lee and Vedder, 1973). Using the cumulative frequency of events versus magnitude relations shown by Lee and Vedder (1973), recurrence intervals of 3,950 years for magnitude 7.5 events and 105 years for magnitude 6 events are indicated by the Caltech data. The results for the USGS data are 7,180 years and 205 years, respectively. These values underestimate the observed occurrence rate for magnitude 6 events (24 ± 8 years) by a factor of from 4 to 8, indicating large uncertainties in the intervals estimated for magnitude 7.5 events. It is misleading, therefore, to estimate the recurrence rate of large earthquakes from small earthquakes recorded over a relatively short time interval (40 years, in this case).

A more useful technique for estimating the occurrence rate of large earthquakes on specific faults is by determination of the rate of movement on the fault. The fault-slip rate can be determined in at least three different ways: 1) by measuring the offset of geologic markers of known age cut by the fault; 2) by dating of individual slip events by geochronologic techniques; and 3) by determining the rate of strain accumulation across the fault. The first two techniques require detailed geologic investigations and fortuitous geologic circumstances. They have been successfully applied in only a few places, none of which are in the Santa Barbara Channel. The third technique requires a decade or more of precise geodetic measurements.

For example, although geodetic data collected in the Santa Barbara Channel region are limited in scope, first-order leveling circuits observed over the past 51 years indicate relative vertical movement rates across the Red Mountain fault north of Ventura and along the coast near Rincon Point that are compatible with the geologic evidence for recency of faulting (Buchanan and others, 1973). Between 1934 and 1968, the region north of the fault rose as a block 0.83 feet (0.26 metre), an average rate of 30 inches per 100 years (0.76 metres per 100 years). Assuming that this vertical displacement rate represents a steady, continuing strain accumulation, the recurrence interval for a vertical offset of 39 inches (1 metre) is 132 years. The release of such a strain accumulation could be aseismic (by fault creep), or accompanied by one or more earthquakes. If released during a single earthquake, its expected magnitude would be about 6.0 or greater. This limited evidence on the rate of vertical strain accumulation in the Santa Barbara Channel region is consistent with an occurrence rate of about 250 years for magnitude 7.5 earthquake events (following the method of Wallace, 1970). Because no earthquake approaching that magnitude has occurred in the Channel region in the 162-year period since the major Santa Barbara Channel earthquake of December 21, 1812 (magnitude estimated at 7 or greater), a magnitude 7.5 earthquake should be considered a credible event during the commercial life of oil production from the region, even if that commercial life is limited to a few tens of years.

No geodetic determinations of horizontal strain (by repeated surveys comparable to the leveling circuits) are presently on record; therefore, the estimate of the recurrence rate cannot now be refined further from that yielded by the leveling circuits. Until more geologic work is done on specific faults, especially those beneath the Channel waters, and until the crustal strain rates are reasonably well known, it will be difficult to give a more reliable long-range forecast of the probability of a magnitude 7.5 earthquake.

h. Man-made Earthquakes

Not all of the potential earthquake hazard in the Santa Barbara Channel region is due to natural, tectonic earthquakes. A part of the earthquake risk is due to the possibility of triggering earthquakes in the course of normal oil-field operations. Earthquakes have accompanied subsidence due to fluid withdrawal (Frame, 1952; Kovach, 1974; and Yerkes and Castle, 1975) and been triggered by the injection of fluid into natural faults at several localities in the U. S. (Evans, 1966; Healy and others, 1968; Raleigh, 1972; Raleigh and others, 1972). There is as yet no evidence that earthquakes have been so triggered in the Santa Barbara Channel region; however, investigations of small shallow earthquakes in the Ventura and San Miguelito oilfields are currently under way (R. F. Yerkes, U.S.G.S., 1-15-76, oral communication).

The best-documented association of earthquakes with reservoir fluid withdrawal is reported from the Wilmington oil field, where four shallow earthquakes occurred between December 14, 1947 and September 24, 1951, in association with subsurface displacements that damaged well casings, prior to the beginning of fluid injection in 1955 (Frame, 1952; Kovach, 1974). The earthquakes apparently were generated on shallow subsurface faults by sudden movements that relieved horizontal shear stresses induced by differential subsidence over the producing oil field. The earthquakes were small (magnitude 2.4 to 3.3 estimated by Kovach, 1974) and damage to surface installations was light, expressed chiefly in the bending of formerly straight railroad tracks and pipelines, and confined to the immediate vicinity of the oil field (Frame, 1952).

Fluid, usually water, may be injected into an oil reservoir in order to increase oil production once the initial reservoir pressure is depleted. In some cases, the pressure increase due to injection will trigger earthquakes. The causal link between the elevation of fluid pressure in a reservoir and earthquakes was first suggested by Evans (1966) as an explanation for anomalous earthquake activity in the Denver, Colorado, area. Evans linked the earthquake activity to a deep waste disposal well at the U. S. Army Rocky Mountain Arsenal.

Healy and others (1968) reported the U. S. Geological Survey's investigation of these earthquakes and demonstrated a causal link between the earthquakes and fluid injection activity at the disposal well. The Rocky Mountain Arsenal disposal well penetrated an inactive fault zone at depth. The effective strength of the fault was reduced owing to an increase in pore pressure which allowed the ambient shear stresses to cause sliding. In this earthquake sequence, earthquakes as large as magnitude 5.5 were triggered as a result of the injection activity.

The theory relating the fluid pressure in the fault zone to the shear stress level required for frictional sliding has been advanced by Hubbert and Rubey (1959) and applied to the Denver earthquakes by Healy and others (1968). According to this theory, the shear stress τ acting on the fault plane needed to initiate movement of the fault is related to the frictional strength of the fault by $\tau = S+\mu(\sigma - P)$ where

S = cohesive strength of the fault

μ = static coefficient of friction

σ = normal stress across the fault

P = fluid pore pressure.

This physical model of the failure condition for a fault is based on the results of both laboratory (e.g., Mogi, 1972) and field experiments (e.g., Raleigh and others, 1972). The pore pressure necessary for initiation of earthquake activity in the Rangely, Colorado, oil field has successfully been predicted by this theory and knowledge of the other four parameters (Raleigh and others, 1972).

Accidental triggering of fault displacement in an operating offshore oil field in the Santa Barbara Channel region represents an environmental hazard because even small displacements on short fault segments -- displacements of the size associated with small earthquakes, magnitude 3.5 and less -- could shear well casings in the subsurface or even break to the sea floor. Such displacements might seal off a well. On the other hand, they could result in leakage of deep reservoir fluids to the sea floor or to shallow strata where hydraulic fracturing might result. Therefore, it is desirable to know the values of the parameters cited above in order to establish rational guidelines on bottom-hole pressures, and thus greatly reduce the possibility of inadvertently triggering displacement.

Rock samples taken from cores of wells in the Channel region and covering a satisfactorily wide range of rock types should provide an adequate data set for determining μ and S. The values for these parameters can be measured by established laboratory techniques.

Measurement of the in-situ stresses is somewhat more difficult but should be possible on a routine basis by using the hydrofracture technique described by Haimson and Fairhurst (1970).

Monitoring of pressures in the initial stages of fluid injection for secondary recovery, as is being done for the Dos Cuadras field (Adams, 1973), would provide a useful check on the calculated pressure level for safe operation. Initiation of small earthquakes near the injection wells would indicate that the injection pressure was probably too high. It is likely that, in this case, the pressure could be lowered to a safe level before serious damage resulted.
In December, 1976, the Geological Survey installed an array of seven seismographs on the sea floor in the vicinity of the Dos Cuadras field. The spacing and location of the instruments is such as to locate and identify the foci of small, shallow earthquakes in the vicinity of the producing reservoir, that might occur in association with fluid injection operations, and distinguish those from the regional tectonic seismic activity. At this time (January, 1976) the record is too short to provide significant results.

7. Geologic Conditions and Processes Having a Potential for Hazard ("Geologic Hazards")

Several geologic conditions and processes are indigenous to the Santa Barbara Channel region that might affect, directly or indirectly, petroleum development and production facilities in ways that could create adverse environmental impact. The conditions and processes of greatest concern are those that could result in a large oil spill in the waters of the Channel and attendant conditions that could delay control and cleanup or make them ineffective.

In addition to the geologic conditions and processes that could affect development and production facilities, the production of oil and gas and attendant operations may have a potential for triggering or accelerating geologic processes that could, directly or indirectly, have adverse environmental impact. For example: reservoir fluid withdrawal can cause subsidence, in turn causing associated fault rupture; or, fluid injection into a reservoir (usually for purposes of secondary recovery or prevention of subsidence) can trigger local earthquakes (Raleigh, 1972), generated when increased fluid pressures reduce resistence to shear and permit displacements on otherwise "locked" faults.

The potential for damage from different kinds of natural processes and events varies from area to area; thus, it is not possible to specify all possible site conditions in a report of regional scale, and all potential sites should be examined in detail as a preliminary to planning and design of any structures to be placed on them. For example, potential for liquefaction is more likely to be found on the Oxnard Plain, the Oxnard Shelf, and, perhaps, on parts of the Pescado Fan (see figure II-4) and subaerial landslide conditions (including mudflows) are more likely in the southern foothills of the Santa Ynez Range. On the other hand, alluvial sands in the lower reaches of some of the foothill streams may have a potential for local liquefaction, and landslides of some kinds can occur on very low slopes such as those found on the Oxnard Plain.

Development and production facilities of the OCS affect the offshore area only (except where a spill into Channel waters creates a slick that migrates inshore); however, any consideration of transportation, storage, and processing installations necessarily involves onshore support facilities. Unless such facilities are located entirely outside the Channel region, the potential for adverse impact from damage to these facilities by onshore geologic hazards must also be considered.

a. Reservoir Fluids and Pressures

As described by McCulloh (1969, p. 38-40), blowouts are generally associated with reservoir fluids that are saturated with gas (at an equilibrium depending on the pressure and temperature in the reservoir) which, if subjected to a sudden reduction in pressure (such as by penetration by a bore hole open to the lower pressures at shallower depths), tends to expand, becoming less dense and more buoyant as it rises to regions of still lower pressure. This is the mechansim of the "solution gas drive" that can cause reservoir fluids to flow freely at the wellhead from reservoirs under hydrostatic "normal" pressure at depth. If confining pressure is further reduced to or below the saturation pressure, the solution boils and gaseous hydrocarbons of low density may be released in large volumes. Uncontrolled expansion of solution gas, caused by sudden accidental lowering of pressure in a well bore, can result in a blowout of explosive violence. If the upward flow is confined to the bore hole casing, it can be controlled or stopped by valves ("blowout preventers"). However, if the upward flow is exposed to shallower strata at depths where the lithostatic pressure (as an upper limit) is lower than the fluid pressure on the solution from the deep reservoir, hydraulic fracturing of the shallow strata may occur, permitting flow to the sea floor through fractures in the strata in the vicinity of the bore hole. Flow to the surface under such conditions could be very difficult to bring under control, as it was in the case of the 1969 blowout of well A-21 in the Dos Cuadras field. The condition is intensified where the deep reservoir is under "abnormal" initial pressure (pressure above hydrostatic), not only because the greater pressure differential may not be anticipated during drilling, but also because the volume of gas dissolved in the oil may be greater. More stringent casing regulations imposed after the 1969 oil spill and more frequent inspections by Geological Survey have reduced the chances of a subsurface blowout behind casing such as the above-mentioned 1969 blowout.

The reservoir conditions are generally well known for the producing fields on existing leases (see McCulloh, 1969) and have been reported from drill stem tests in the potential fields of the Santa Ynez Unit (SYU-EIS). Drill stem test information for the other known potential field areas is available to the Geological Survey for regulatory purposes. Elsewhere in the Channel region, these parameters are not generally known, either for existing leaseholds or for unleased areas. In general, it seems that formation gas is a ubiquitous associate of the oils of the Santa Barbara Channel region. With the sole exception of one reservoir at the Lion Mountain field, gas has been produced with the oils of all the fields of the region (see Yerkes and others, 1969, table 1). Solution gas drive is reported in parts of many fields of the region (see various volumes, California Division Oil and Gas, Summary of Operations), and at least one blowout (with fire) occurred at an onshore well in the McGrath area of the West Montalvo field in 1946 (Hardoin, 1961, p. 45). Abnormal pressures (greater than hydrostatic) are known at depth in the fields of the Rincon trend (McCulloh, 1969, figure 11, p. 38) but are generally not common in California oilfields. Clearly, geologic conditions and processes that might contribute to a blowout must be carefully ascertained for every site of proposed drilling. The above-described geologic conditions and processes generally describe almost every oil producing area of the world and are well understood by industry. The fluid expansion process and reservoir energy release is the natural mechanism by which oil fields are produced; uncontrolled, it could cause a blowout.

b. Earthquake Shaking

Because severe earthquakes can be expected to occur in the Santa Barbara Channel region (see section II.B.6. - Earthquake Activity ...), the structures associated with oilfield development and production must be capable of withstanding the expectable ground motions at their sites without serious failure such as might result in adverse environmental impact. The existing geologic and seismic data in the Santa Barbara Channel region are inadequate to specify expected ground motions on a site-by-site basis. At best, they support an estimate for the maximum credible earthquake in the Channel region and the expectable accompanying ground motions. Section II.B.6. of this report discusses the rationale for suggesting a magnitude of 7.5 for such an earthquake. Peak horizontal accelerations near the epicenter of such an earthquake may exceed 1.0 g, and the peak horizontal velocity may exceed 125 cm/sec. The duration of shaking could be in excess of 40 sec. Ground motions of such intensity and duration could damage platforms and pipelines offshore, as well as onshore pipelines, storage tanks, and treatment facilities. It is also likely that an earthquake of that magnitude would cause considerable damage to the neighboring onshore communities, which unless anticipated and planned for, could disrupt control and repair operations, and delay cleanup of any oil spill that might result. Because no part of the Channel is far from one or another of the major faults, and because the seismicity of individual faults cannot be resolved from among the many nearby faults by the present seismograph net, the hazard should probably be considered to be uniformly distributed throughout the region, even though the instrumental record of small earthquakes indicates a greater frequency on the north-central, east-central, and southeastern parts of the Channel (figures II-14 and II-15). However, in certain instances, detailed geophysical and geological investigations for a specific platform site may suggest that a lower seismic hazard exists for that particular site and design specification requirements could be safely adjusted accordingly.

c. Fault Rupture

Evidence for Holocene tectonic activity is not restricted to the instrumental record of seismic shaking (which is inferred to be caused by fault movement at depth). Fault scarps in very young bottom sediments in the Channel and tilting and faulting of Pleistocene strata provide geologic indicators (see section II.B.3.e. and plate 3) of very young displacement, some possibly associated with historic earthquakes felt in the Santa Barbara Channel region. Repeat surveys of precise leveling lines have demonstrated historic tilting and differential elevations of crustal blocks. Fault rupture of the sea floor, or the ground surface onshore, is a potential hazard to production facilities and ancillary installations. The condition most likely to result in an uncontrolled oil spill could be the rupture, at relatively shallow depth, of well casing in such a manner that shallow strata were exposed to fluids rising in the bore hole by solution gas drive from a deep reservoir. If the pressure on the fluid hydrocarbon exceeded that needed to cause hydraulic fracturing of the shallow strata, uncontrolled flow to the sea floor could result. Fault rupture could also cause failures in the integrity of pipelines, tanks, and treatment facilities. However, spills that might result should be readily controlled by valves or dikes, and uncontrolled release to the environment should be minimal. Careful geologic investigation of pipeline routes and sites for storage and treatment facilities should provide the basis for avoiding faults with a potential for surface rupture, or for design and engineering to prevent damage and/or control spills in the event that ground rupture should occur.

d. Seismic Sea Waves

Seismic sea waves originate from subsea earthquakes, submarine volcanic eruptions, or large submarine landslides. They may be generated a long distance from an affected area where the cause of the wave may not be felt or known. Seiches are similar, but smaller, low-energy waves that form in smaller bodies of water such as lakes, bays, reservoirs and storage tanks. In deep water, seismic sea waves generally have low crest and long wavelength; shoreline areas and coastal waterways are the areas where they are most destructive. A seismic sea wave associated with the earthquake of December 21, 1812, broke along the Santa Barbara coast. Although Marine Advisors, Inc. (1965) concludes that the accounts are unsubstantiated, reports that onshore runup may have been as high as 30 to 50 feet above sea level at some points between Santa Barbara and Gaviota cannot be ignored in evaluating the potential effects of tsunamis of local origin. Such events pose a potential for hazard to shoreline installations, where damage could result in a spill of oil. However, seismic sea waves are very rare and the possibility of damage to platforms is extremely remote.

A recent study by the U. S. Army Waterways Experiment Station (Houston and Garcia, 1974) gives estimates of runup for 100-year (R_{100}) and 500-year (R_{500}) tsunamis for selected parts of the coast of the Channel. The estimates for R_{100} range from 5.0 ft at Oxnard (but as much as 10.1 ft in the harbor at Port Hueneme) to 10.5 ft at Ventura, and for R_{500} range from 11.0 ft at Santa Barbara to 21.7 ft at Ventura. These estimates, however, are only for tsunamis of distant origin because the equations used to simulate and propogate tsunamis probably do not provide an adequate description of near-source processes. For near origins, Houston and Garcia (1974, p. A3, A4) conclude that: "The probability of a destructive, locally generated tsunami occurring in southern California is not considered very great. ..." However, that conclusion is candidly based (ibid) on the interpretation that northwest-trending strike-slip faults (inefficient generators of tsunamis) predominate throughout the southern California Borderland, and clearly does not consider the tsunami-generating potential of east-west-trending oblique-slip faults in the Channel.

e. Liquefaction

Liquefaction is the transformation of a granular material from a solid state into a liquefied state as a consequence of increased pore-water pressures (Youd, 1973). Three types of ground failures have been identified as associated with liquefaction--flow landslides, landslides with limited displacement, and quick-condition failures (loss of bearing capacity). In addition, ejection of water and sediment in the form of sand "boils" has been a source of damage associated with liquefaction during earthquakes. The transient effects of seismic shaking can trigger liquefaction in layers or lenses of saturated sands in flat-lying unconsolidated strata, which can lead to landslides by lateral spreading at very low gradients, or to quick-condition failures including loss of bearing capacity and buoyant rise of buried tanks. Flow failures in saturated slope soils may be triggered by earthquake shaking, or by rainfall of high intensity (see section II.B.7.f., Subaerial Landslides). All of these phenomena pose potential hazards to structures, both offshore and onshore, that are founded on unconsolidated Holocene strata, or that lie below soil-covered slopes. The thick Holocene deposits of the Oxnard Plain, the Oxnard Shelf, the Central Deep, and the Pescado Fan are areas where these phenomena may be of most concern;

however, small areas of alluvial fill in stream valleys in the mountains and coastal plains, and unconsolidated shelf and slope deposits offshore, may locally contain the essential conditions for failure by liquefaction. Careful geologic examination of sites can identify potential liquefaction conditions, and such sites can generally be avoided, or modified to mitigate the hazard.

f. Landsliding, Subaerial

The term "landslide" covers a wide range of kinds of downslope gravitational movement, ranging from rockfalls and soil falls from undercut sea cliffs, through massive failures by rotational slumping and lateral spreading, to debris slides, debris flows, and mudflows. The severity of the problem in any one area depends on the slope and local bedrock and soil conditions (including moisture content, vegetation, orientation of anisotropic geologic features, and other factors). Although most landslides and landslide-prone areas can be identified by geologic studies, only a small part of the area subject to landslide damage has been mapped in sufficient detail to be of use in selection of sites for construction. The only part of the Channel region that has been the subject of systematic study for such purposes is the southern Ventura County area (Evans and Gray, 1971).

Nearly all kinds of landslides are found in the onshore parts of the Santa Barbara Channel region. The mountainous areas are subject to rockfalls, rotational slumps, debris slides, soil slips, debris flows, and mudflows. Rockfalls and soilfalls occur along the coastal bluffs. A tendency for some lateral spreading is suggested for parts of the Oxnard Plain by lurch cracks noted after the Point Mugu earthquake of 1973 and for parts of the Santa Clara River valley where extensive "lurching" effects were reported during the 1857 earthquake at Fort Tejon.

The proposed development of any site for petroleum storage, treatment, or transportation facilities should include detailed engineering geology studies, and landslide and landslide-prone areas should be engineered to avoid or correct all problems of slope stability. Geologic and engineering reports should be reviewed for adequacy by qualified professionals, and qualified local government grading inspectors should inspect various stages of the development to insure that all work necessary to prevent future landslide problems is being done.

g. Landsliding, Submarine

Submarine landslides have been mapped in the Santa Ynez Unit (SYU-EIS) originating on the slope between the Mainland Shelf and the Central Deep (figures II-17 and 18) and on the upper part of the Hueneme-Mugu slope (figure II-4 section II.A.). In addition, disturbed bedding at the foot of the Channel Islands Slope, overlain by flat-lying younger deposits, suggests a possible landslide of major proportions (see line 670, plate 3). Elsewhere along the Goleta, Oxnard, and Channel Islands Slopes, there are indications that depositional slopes of unconsolidated sediment layers are steeper near the top than further down on the slope, and therefore appear to be in a potentially unstable condition (plate 2). Landslides in such submarine settings could be triggered by earthquake shaking.

A large submarine landslide in the Santa Barbara basin could cause a seismic sea wave and its attendant potential for hazard to oilfield operations. In addition, if a large landslide occurred where its movement caused the shearing-off of a flowing well or group of wells, it could result in the transmission of pressures to the shallow strata in excess of those required for hydraulic fracturing, thus creating the potential for uncontrolled flow of petroleum to the sea floor. It may be possible to mitigate that potential hazard by placing subsurface safety valves in the bore holes.

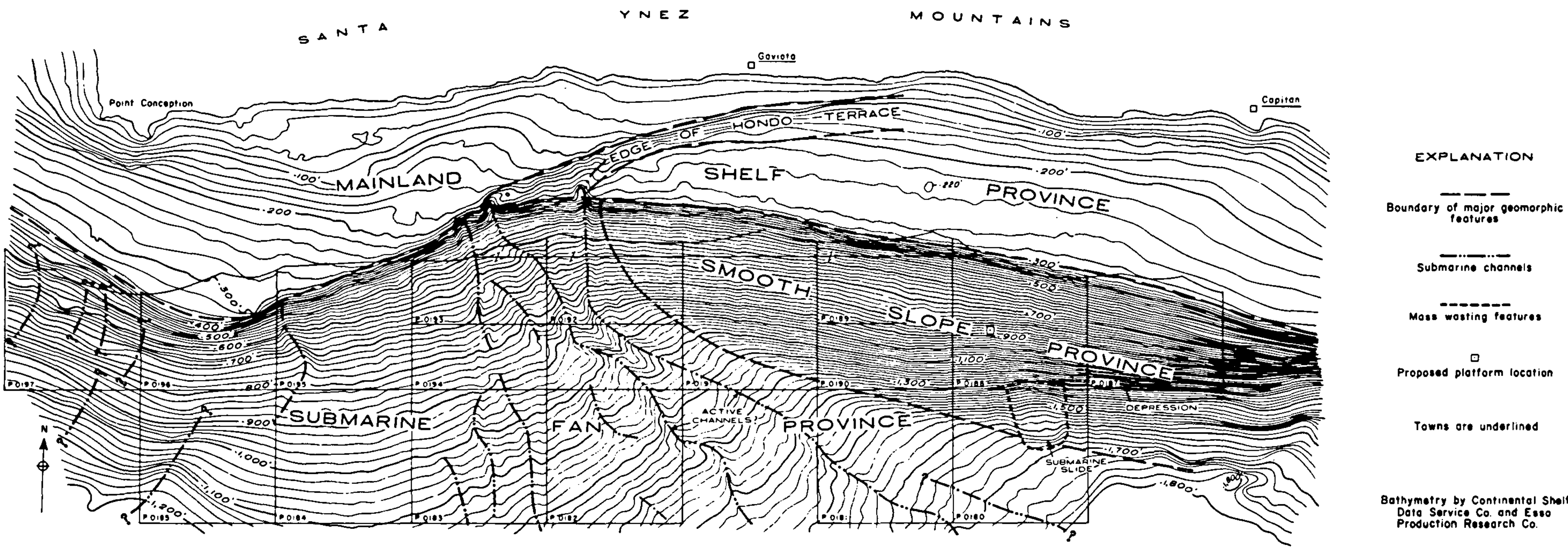


Figure II-17 BATHYMETRIC AND GEOMORPHIC FEATURES IN THE VICINITY OF THE SANTA YNEZ UNIT

CONTOUR INTERVAL 20 FEET

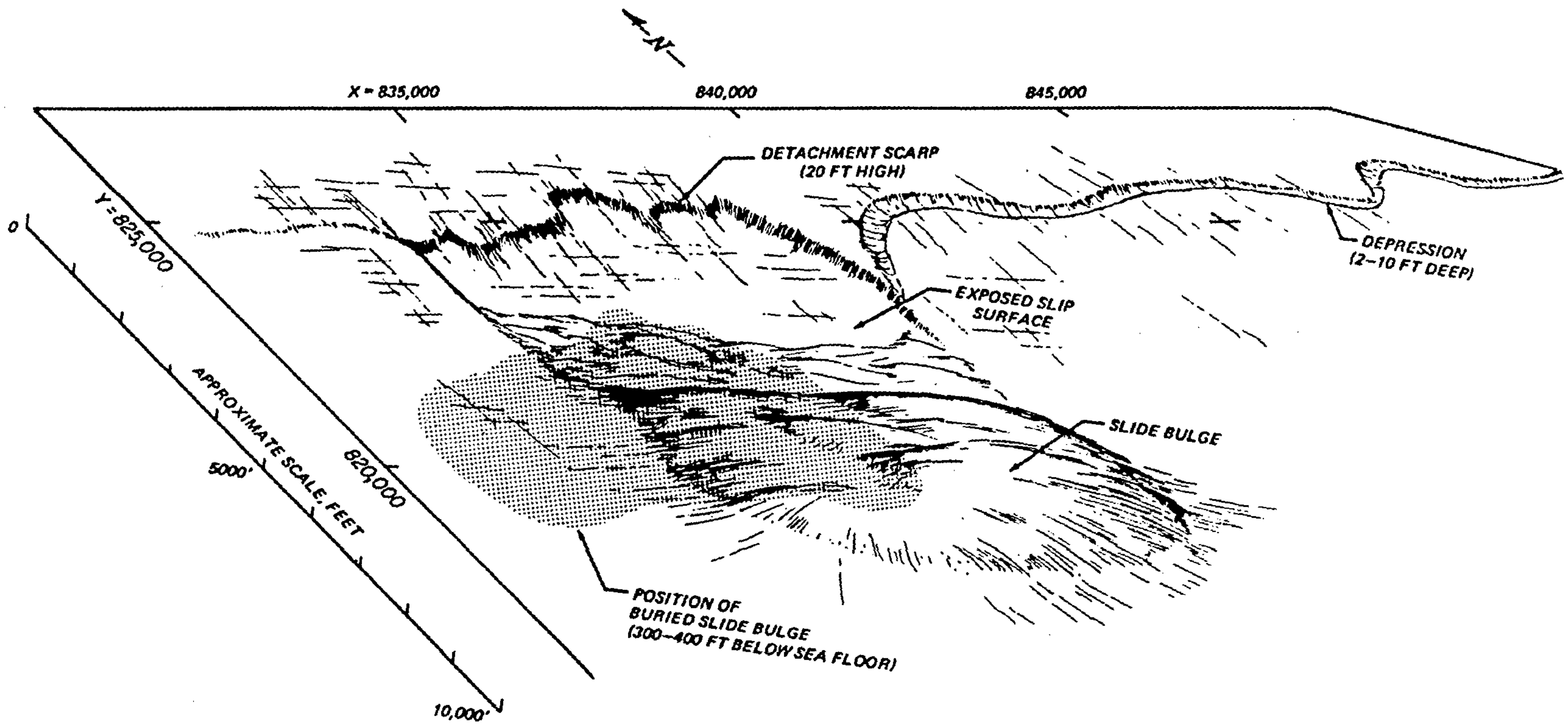


Figure II - 18 Diagrammatic sketch of submarine slide area.
Scale and coordinate positions are approximate.
(Duncan and others, 1971)

h. Surface Deformation and Earthquakes Associated with Oil and Gas Production

Subsidence is a common form of surface deformation associated with production of oil and gas in California fields. Yerkes and Castle (1969) list 22 California oil and gas fields with measured differential subsidence, three with measured horizontal displacement, and five with faulting of the ground surface. Their list does not include the Ventura and Rincon fields, which have been shown in subsequent investigations (Buchanan and others, 1973) to have localized subsidence over their producing areas, the largest increment being 0.54 feet (0.17 m) over the Ventura field between 1934 and 1960. Differential subsidence can be accompanied by centripetally directed horizontal displacements, and Yerkes and Castle (1969, p.60) cite the Inglewood and Wilmington fields of southern California as good examples. Subsidence-associated surface faulting has been observed in five California oilfields (Yerkes and Castle, 1969, table 1). Surface faulting may develop suddenly and is, therefore, potentially more damaging to structures on the surface than the subsidence itself or the associated horizontal displacements. Most of the subsidence-associated faults reported are high-angle and normal, peripheral to the subsidence bowls and downthrown on the oilfield side; however, low-angle reverse faulting in the zone of compression central to the subsidence bowl, has been recognized in one field (Yerkes and Castle, 1969, p. 61). Small earthquakes may be generated by sudden fault displacements associated with subsidence (Frame, 1952; Kovach, 1974).

Maintenance of "optimum" pressures by means of water injection may be effective in limiting and controlling the amount of subsidence in some fields; however, water injection can upset pressure balances in some reservoirs and must be done with great care and forethought (McCulloh, 1969, p. 45, 46). In addition, there is a significant risk of triggering shallow earthquakes by the injection of fluid under pressure, as described in section II.B.6. of this report.

i. Flooding and Erosion

Floods in the Santa Barbara Channel region are generally associated with prolonged heavy rainfall from individual storms that cross the region during the winter rainy season--approximately October through March. Past flooding has been severe along the Santa Clara River (and its tributaries), the Ventura River, Calleguas Creek, and many of the short, steep, south-flowing streams that drain the southern flanks of the Santa Ynez Range directly to the coast. In many of the short steep drainages, mudflows and debris flows are common associates of the storm water runoff, which may, at times, become mudfloods. Sites of onshore storage and treatment facilities and routes of pipelines should be selected so as to avoid or correct conditions that would allow flood damage of the sort that might cause an oil spill.

Stream erosion is most commonly associated with floods in the Channel region because most of the streams have little or no flow except during periods of runoff from heavy rainstorms. The chief hazard is from undercutting of banks of main streams, and from rilling, gullying, and sheetwash of slopes. Sites of onshore storage and treatment facilities and routes of pipelines should be selected or protected so as to prevent damage of the sort that might cause an oil spill.

Beach erosion is also most likely during the winter stormy season. High waves commonly accompany major rainstorms in the region, although they also occur as the local manifestations of distant storms. Large amounts of beach sand are removed and redeposited during a storm, and high waves may undercut and erode sea cliffs that are protected from breaking waves by the beach at other times. These processes pose potential hazards to pipelines crossing the beach and installations near cliff edges.

j. Expansive Soils

Expansive soils may present a problem for some onshore facilities. According to a summary map prepared for the California Division of Mines and Geology Urban Geology Master Plan (Alfors and others, 1973, p. 34), the predominant soil types of the Oxnard Plain and the coastal plain between Rincon Point and El Capitan have "high" expansiveness ratings, and the remainder of the area has "moderate" or "low" ratings. Routine engineering site examination and foundation soil sampling and testing techniques used in site selection preclude the construction of facilities where flooding, erosion, or expansive soils would be hazards.

8. Natural Hydrocarbon Seeps

Natural hydrocarbon seeps, asphalt deposits, and tar mounds have long been known in the Santa Barbara Channel region. The occurrence, character, and distribution of the seeps offshore of Coal Oil Point and Point Conception have recently been summarized by Fischer and Stevenson (1973), who mapped over 900 individual occurrences of hydrocarbons within a seven-square mile area off Coal Oil Point. Of that total, about 250 are active gas or gas-oil seeps and the remainder are inactive seeps, shallow zones of oil- and tar-saturated sands of unconsolidated deposits or fractured shale of bedrock units. Because offshore seep activity is variable--locally, some seep activity has apparently been stimulated by earthquakes, and declining seep activity in some areas has been attributed to petroleum production (Fischer and Stevenson, 1973)--and because of the dispersing effects of waves and currents, estimates of the rate at which natural seeps introduce fluid hydrocarbons into the Channel waters are necessarily crude. Allen and others (1970), however, conclude that the natural seeps in the Coal Oil Point area of the Channel introduce an average of 50 to 70 barrels of oil per day into the Channel waters, and that the variations in seepage activity ranged from a low of about 10 barrels per day to maxima in excess of 100 barrels per day. The area of the Coal Oil Point seeps is only one of many areas of seepage in the Channel, but it is generally thought to be the most prolific, and tar deposition on beaches in the Coal Oil Point area is at least 100 times greater than on any other beach from Point Conception to the Mexican border (Allen and others, 1970, p. 975).

Natural hydrocarbon seeps are located along geologic structural trends. Fischer and Stevenson (1973) note that about 75 percent of the seeps mapped in their study areas occurred within 2,000 feet of a mapped anticlinal axis or a fault. Seeps also appeared to be restricted to those areas where the cover of Late Quaternary unconsolidated deposits is less than 15 feet thick (Fischer and Stevenson, 1973).

Increasing rates of production of oil and gas from wells along the Rincon-South Elwood anticlinal trend between 1946 and 1972 has apparently been responsible for correlative decline in activity of natural seeps, suggesting that production from depth has reduced pressure on near-surface oil-bearing strata (Fischer and Stevenson, 1973). On the other hand earthquake activity in the area, whether tectonic in origin or triggered by oil field operations, could result in increased seepage from the natural sea floor vents.
(See also II.G.2.e. and III.L.1.)

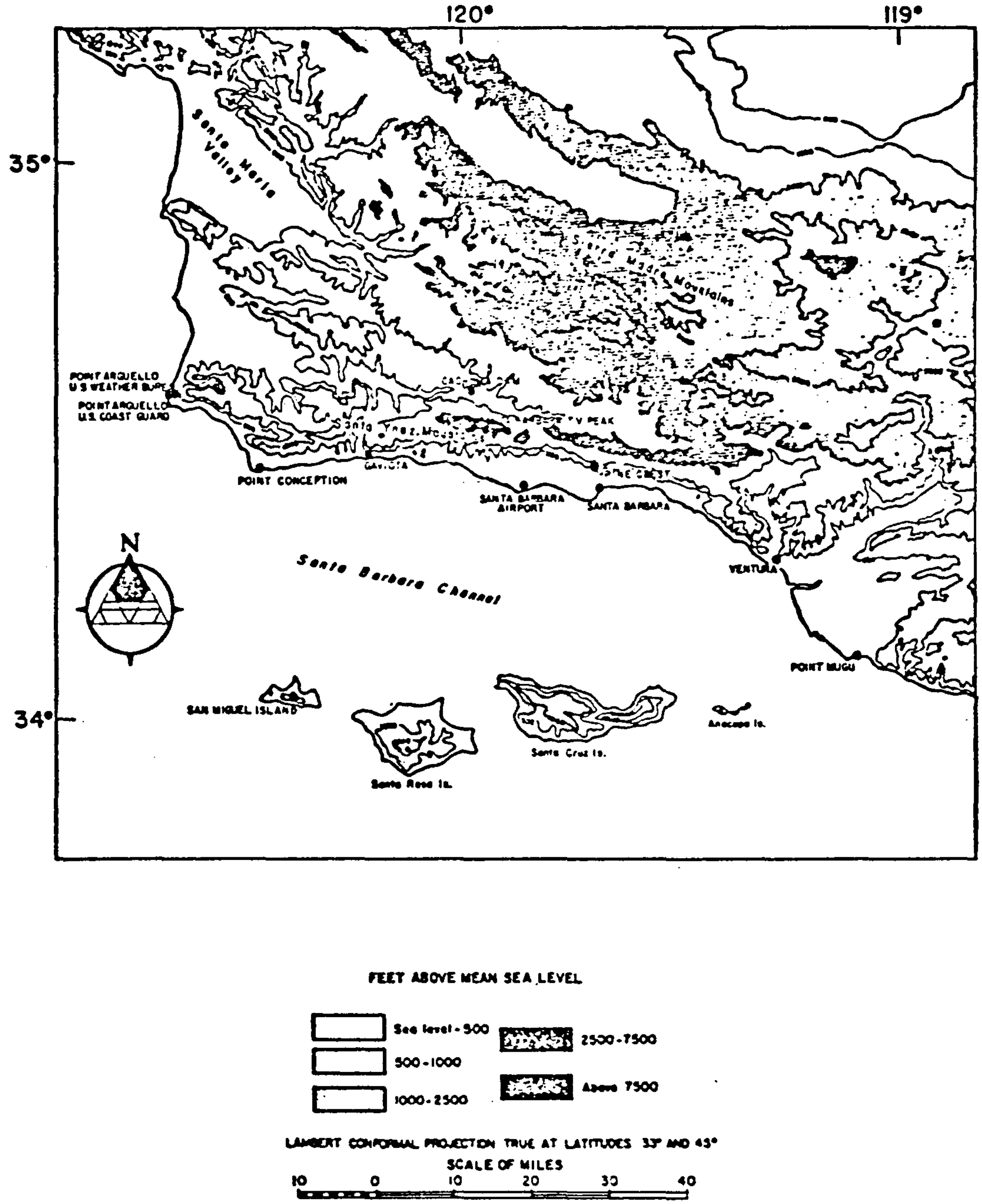
C. Meteorology

Portions of this section were excerpted from the Final Environmental Impact Report - Resumption of Drilling Operations in the South Ellwood Offshore Oil Field from Platform Holly, prepared by Dames and Moore for the California State Lands Commission, November 1974.

1. General Weather Summary

The climate of coastal southern California and of the Santa Barbara Channel in particular is classified as a Mediterranean type and is characterized by warm, dry summers and mild, wet winters. This climate is controlled primarily by the position and intensity of the semi-permanent Pacific High pressure system over the ocean to the west, thermal contrasts between land and adjacent ocean, and geographic factors. The latter include the change in the orientation of the coastline from northwest-southeast to east-west at Point Conception, and topographic features such as the east-west trend of the Santa Ynez Mountains along the coast (figure II-18a). The summers are mostly dry because a semi-permanent high pressure area covers the eastern North Pacific Ocean and deflects eastwardly moving storms to the north. During the winter months this Pacific high migrates southward and weakens, allowing occasional frontal systems to move through southern California. The climate then is mild, with many days of bright sunshine normally separated by brief periods of rain.

In spring as the North Pacific high moves northward and strengthens, the winter rains come to an end. With the increasing solar radiation the coastal areas and deserts begin to warm but by late spring the deserts have warmed considerably more than the coastal areas. A thermal low pressure area forms over the deserts and causes a flow of air from the Pacific in over the coastal waters and across the coast. As this air passes over the



GEOGRAPHIC FEATURES AND STATION LOCATIONS

Source: DeMarrais, G.A., *et al*, 1965

DAMES & MOORE

FIGURE II-18a

relatively cool coastal waters it cools and forms a layer of cool air known as the "Marine Layer." Since warmer air lies above the Marine Layer, a temperature inversion is formed and tends to suppress vertical movements of air.

As the Marine Layer moves over the coastal waters it picks up water vapor by evaporation. Fog or low stratus clouds form and are common during the late spring and summer. The inversion is strongest at night and thus the coastal fog and low clouds are most common during the night and early morning hours. Daytime heating causes the inversion to weaken and allows the clouds to dissipate or burn off. Thus, afternoons are generally sunny in summer.

By the beginning of fall, the deserts begin to cool and the thermal low weakens. The coastal low clouds and fog are then at a minimum, and the best weather of the year occurs along the coast. During the fall, southern California also experiences occasional "Santa Ana" conditions when a high pressure system forms over inland areas and a low pressure system over the Southern California Bight. During Santa Ana conditions warm, dry air blows down from the interior deserts through the mountain passes to the coast, raising temperatures, lowering humidities, and creating fire danger in the coastal and mountain areas (Aldrich, 1966). By late fall, the Pacific high has migrated southward, and once again the winter rains begin.

2. Storms

a. Extratropical Storms

Most winter storms that affect the Santa Barbara area move southeastward from the northeast Pacific. However, the most intense extratropical storms develop between Hawaii and the California coast (Aldrich, 1966). On the average, one or two such storms influence the Santa Barbara

Channel region each year. These storms, because of their southerly position and intensity, often produce large westerly ocean swells and waves which can move into the Santa Barbara Channel between Point Conception and San Miguel Island.

b. Tropical Storms

During the summer and early fall, tropical cyclones frequently move northwestward off the west coast of Mexico. Very few have reached as far north as southern California, but several of the tropical storms each year may generate southerly swells that affect sections of the southern California coast that are exposed to the south, such as the Santa Barbara Channel (Aldrich, 1966; Chevron Oil Field Research Company, 1972).

c. Thunderstorms

The coastal areas of the Pacific States normally have the smallest number of thunderstorms per year in the entire United States. Normally only two or three thunderstorms occur per year in the Santa Barbara Channel region. From 1949 to 1968 never more than five thunderstorms were reported in any year by the weather station at Point Mugu, California. Thunderstorms occur most frequently during the late summer and early fall months and during the middle and late winter months, but they can occur at any time of the year (Rosenthal, 1972).

d. Funnel Clouds

Only one or two tornadoes (funnel clouds reaching the ground) are reported in California a year. Tornadoes occurring in California are much smaller and weaker than those that occur in the Midwest and as a consequence do little more than damage trees and light buildings (Aldrich, 1972; Elford, 1970). Funnel clouds have been reported only 7 times in history at Point Mugu, with only 1 touching the surface (Rosenthal, 1972).

e. Snow and Freezing Precipitation

Snow falls each year in the coastal mountains above about 4,000 feet but is rare at sea level. The last general snow fall at sea level occurred in January 1949, with Point Mugu and other coastal stations reporting 1 to 2 inches (Rosenthal, 1972). Freezing temperatures occasionally occur during the winter months in the coastal sections but seldom, if ever, offshore. Practically speaking, there is virtually no chance of freezing precipitation occurring offshore, and the chance of such an occurrence along the coast is so slight that its consideration is unnecessary.

3. Temperatures

Mean daily temperatures over the Santa Barbara Channel range from the low 50's in the winter to the middle 60's in the late summer. At Santa Barbara Airport during January the mean maximum temperature is 64^{o} F and the mean minimum is 39^{o} F. The highest monthly mean maximum temperature at Santa Barbara Airport occurs during September, when it reaches 75^{o} F. The mean minimum temperature for July and August at this location is 56^{o} F and for September, 55^{o} F. The highest and lowest temperatures recorded at Santa Barbara Airport for the 19-year period ending in 1960 are 101^{o} F and 26^{o} F respectively. Extremes of 115^{o} F and 20^{o} F were recorded at the Santa Barbara City weather station during a 64-year period ending in 1969 (Environmental Science Services Administration, 1969). Marked temperature discontinuities occur throughout the region and are related to the interplay of marine and continental controls. San Miguel Island displays the lower maxima, the higher minima, the narrower temperature range, and the late summer maximum temperature typical of a marine climate compared to a continental one. Compare, for example, San Miguel with Cachuma Dam (table II-2a). The latter station is located in the interior Santa Ynez

TABLE II-2a - TEMPERATURES IN THE CHANNEL AREA

	J	F	M	A	M	J	J	A	S	O	N	D	Annual	Extreme	Range
Daily Mean Maximum															
San Miguel Island	59	58	60	60	60	62	64	65	66	67	64	61	62	102	11
Point Arguello U.S.C.G.	60	61	61	61	63	65	67	68	71	69	67	62	65	104	14
Point Mugu	62	63	62	63	65	67	70	71	72	70	68	64	66	104	15
Santa Barbara Airport	64	64	66	67	70	72	74	74	75	72	70	66	70	101	22
Santa Barbara	65	66	68	70	72	74	78	78	79	76	73	67	72	108	23
Cachuma Dam	64	66	668	72	75	83	91	90	89	82	73	68	77	112	34
Daily Mean Minimum															
San Miguel Island	49	49	49	49	50	52	53	54	55	55	52	49	51	31	
Point Arguello U.S.C.G.	47	48	48	49	50	51	53	53	55	54	52	49	51	30	
Point Mugu	44	45	45	48	51	54	57	57	57	53	49	46	51	27	
Santa Barbara Airport	39	42	44	48	50	53	56	56	55	50	44	41	48	26	
Santa Barbara	40	42	44	48	50	53	57	57	55	51	44	42	49	20	
Cachuma Dam	36	37	39	43	45	47	49	49	50	46	41	38	43	22	
Temperature Extremes, 1941-1960															
Santa Barbara Airport Maximum	86	85	87	94	95	96	101	94	99	99	96	89	101		
Santa Barbara Airport Minimum	26	31	31	33	39	41	45	43	42	37	30	28	26		
Days Temperature ≥ 90°F and ≤ 32°F															
Days equal/greater than 90°F	0	0	0	+	+	1	+	+	1	1	+	0	3		
Days equal/less than 32°F	2	+	+	0	0	0	0	0	0	0	+	2	4		

__ maximum or minimum temperature

+ less than 0.5

Bureau 1^64· Rosenthal, 1972.

Valley. Point Arguello and Point Mugu are situated on the west-facing coast north and south, respectively, of Santa Barbara. Both display temperatures only slightly less marine-dominated than San Miguel Island.

Santa Barbara and Santa Barbara Airport on the south-facing coast between the ocean and the south slopes of the Santa Ynez range experience higher maximum temperatures, lower minimum temperatures, and more continental influence than the coastal stations discussed above. Cold air drainage off the mountain slopes is a common feature during the winter. At Santa Barbara Airport, the highest mean maximum temperature (75^{o} F) occurs in September and the lowest mean minimum temperature (39^{o} F) occurs in January. Temperatures at Santa Barbara are slightly warmer.

Although temperature extremes of 101^{o} F and 26^{o} F occurred at the Airport over a 19-year period, the station experiences relatively few days with maximum temperatures above 90^{o} F or minimum temperatures below 32^{o} F.

It is inferred that temperatures experienced in the Channel are reasonably approximated by those at the Santa Barbara Airport. Minimum temperatures may be slightly lower in some canyons, if cold air flowing down the canyons spills over the dikes caused by the highway and railroad embankments. The near-shore waters are expected to be characterized by cooler maximum temperatures and warmer minimum temperatures, at least during winter, than the adjacent land areas. Marked temperature discontinuities occur less than a mile inland from the Airport.

4. Rainfall

Rainfall occurs mainly in the winter, with nearly 90 percent of the mean annual total falling from November through April inclusively. The annual mean precipitation for Santa Barbara Airport from 1941 to 1960 was

14.15 inches. The wettest month is January, with a mean of 3.32 inches. The 3-month mean for June, July and August combined totals only 0.08 inches (Environmental Science Services Administration). San Miguel Island for the years 1894 through 1921 had a recorded mean annual rainfall of 13.77 inches, with a January mean of 3.42 inches (U. S. Weather Bureau, 1934). Point Mugu's mean annual rainfall from 1946 to 1971 was 10.56 inches, with a January mean of 2.57 inches (Rosenthal, 1972). The following table titled "Precipitation in the Channel Area" provides rainfall data for the various portions under study. (Table II-2b)

5. Humidity

Relative humidities along the coast of southern California are moderate to high throughout the entire year except for brief periods of dry northerly winds. The highest mean maximum relative humidity occurs during the early morning hours of the summer months because of the summer low cloudiness and fog. The mean maximum relative humidity for July and August at Point Mugu for the period 1952 through 1964 was 96 percent. Lowest humidities occur during periods of strong northerly or northeasterly Santa Ana winds in the late fall and winter. Humidities below 10 percent have been recorded along the coast during Santa Ana wind conditions (Rosenthal, 1972).

6. Winds

Due to the distribution of atmospheric pressure over coastal California, the prevailing winds are from the northwest and blow generally parallel to the coastline. The Coast Range of mountains also parallels the coast and further constrains the wind to follow the coastline.

Exceptions to this general pattern are the Santa Ynez and the Topa Mountains

TABLE II-2b - PRECIPITATION IN THE CHANNEL AREA

Average Annual Precipitation, by Months

	J	F	M	A	M	J	J	A	S	O	N	D	Annual
Santa Barbara TV Peak	7.33	7.13	3.46	4.43	1.20	.04	T*	.01	.20	.32	2.48	6.39	32.99
Pine Crest	7.62	4.97	5.14	1.24	.96	.16	.04	.02*	1.05	1.08	1.07	2.84	26.79
Santa Barbara	5.07	3.04	2.12	2.22	.42	.05	T*	.01	.03	.22	1.83	2.59	17.60
Santa Barbara Airport	4.35	2.65	1.95	1.98	.29	.01	T*	.01	.06	.16	1.59	2.50	15.55
San Miguel Island	3.39	2.92	2.82	.69	.37	.15	.03*	.04	.42	.57	.83	2.06	14.26

Precipitation Extremes, by Months, 1931-1960

Santa Barbara	maximum	13.89	10.49	11.71	5.50	2.11	1.00	.81	.70	.41	1.86	6.57	9.84	41.48
	minimum	0	0	0	.03	0	0	0	0	0	0	0	.04	3.99

Average Annual Snowfall, by Months

Santa Barbara TV Peak	1.9	T	.4	.4	T	0	0	0	0	0	.1	T	2.8
Santa Barbara	0	T	0	0	0	0	0	0	0	0	0	0	T

____ maximum

* minimum

Sources: Elford, et al, 1965; U.S. Dept. Commerce, Weather Bureau 1964 which lie transverse to the normal trend and which shelter the Southern California Bight and the Santa Barbara Channel from the prevailing winds. The eastern end of the Channel is more sheltered and thus winds there are weaker and more variable than are the winds at the western end of the Channel. The waters offshore of Point Conception and San Miguel Island are openly exposed to the prevailing winds and have long been known to mariners as a region of strong winds. Climatological summaries of marine winds (U. S. Navy, 1971) show that the winds off Point Conception are greater than 34 knots 1 to 4 percent of the time in all months except June whereas areas near the head of the Southern California Bight have such wind speeds less than 0.5 percent of the time.

Generally, however, winds over the Santa Barbara Channel are relatively weak and very strong winds infrequent. A storm that would occur only once every 100 years has been calculated to have a wind of 65 knots (Oceanographic Services, Inc., 1969).

The strongest winds observed in the Santa Barbara Channel can occur from 2 different mechanisms. Strong frontal passages can cause strong general winds of 25 to 35 knots with locally higher gusts. Strong winds much more localized in nature are the Santa Ana winds caused by a building of high pressure over the great Basin of the western United States. In these situations, strong, gusty, northeasterly winds funnel down the canyons, and areas opposite a northeast-southwest canyon may have 20 to 50 knot winds, while adjacent areas not exposed to such a canyon may have winds of only 5 knots at the same time.

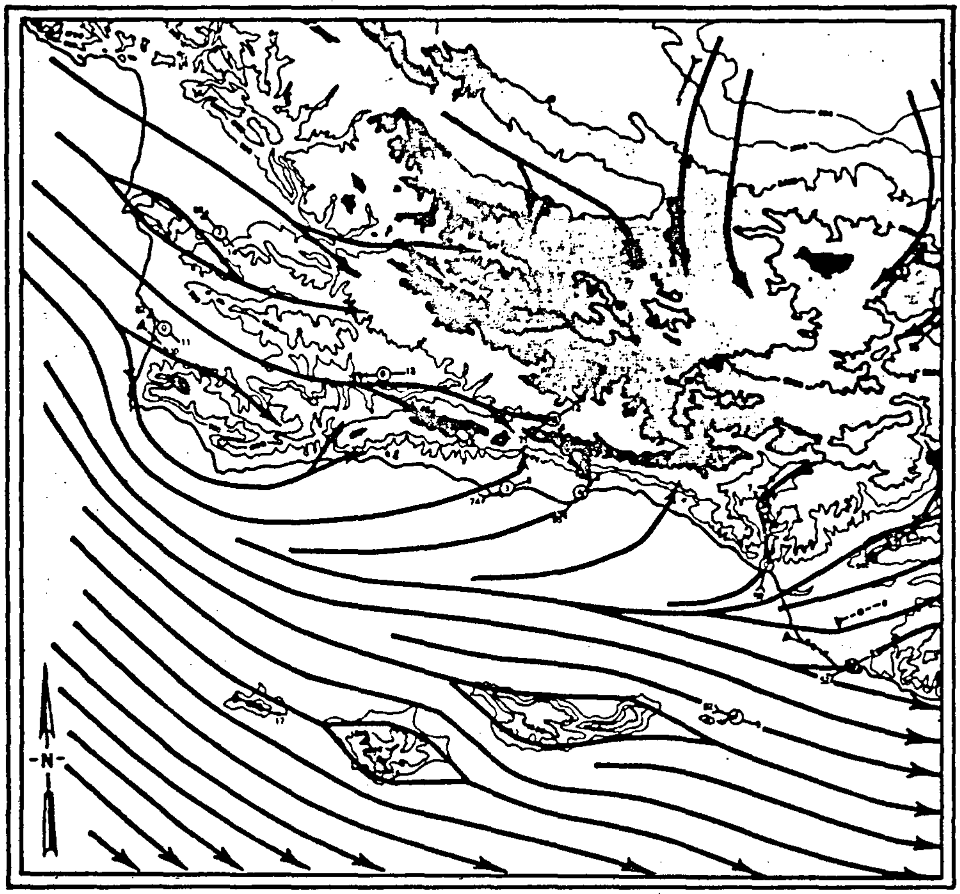
Due to heating of the land surface during the day and to its subsequent cooling at night, there is a daily alternation of wind, along the California coast. The typical wind pattern in the Santa Barbara Channel is an onshore wind (sea breeze) in the afternoon and evening hours and an offshore wind (land breeze) during the night and early morning hours (Aldrich, 1966). The sea breeze is much stronger than the land breeze, with the strongest afternoon wind occurring during the summer months.

The streamline analyses shown in figures II-18b and II-18c depict the typical horizontal transport of air over the region during day and night in the winter and summer seasons. These analyses are based on available data and the consensus of twelve independent analyses. Inferences, interpolations, and extrapolations were necessary in some areas, especially over the ocean, because of minimal data. The most common wind direction, percent frequency of wind from the most common and two adjacent directions, mean wind speed, and percent frequency of calms are shown at selected stations, including Santa Barbara Airport.

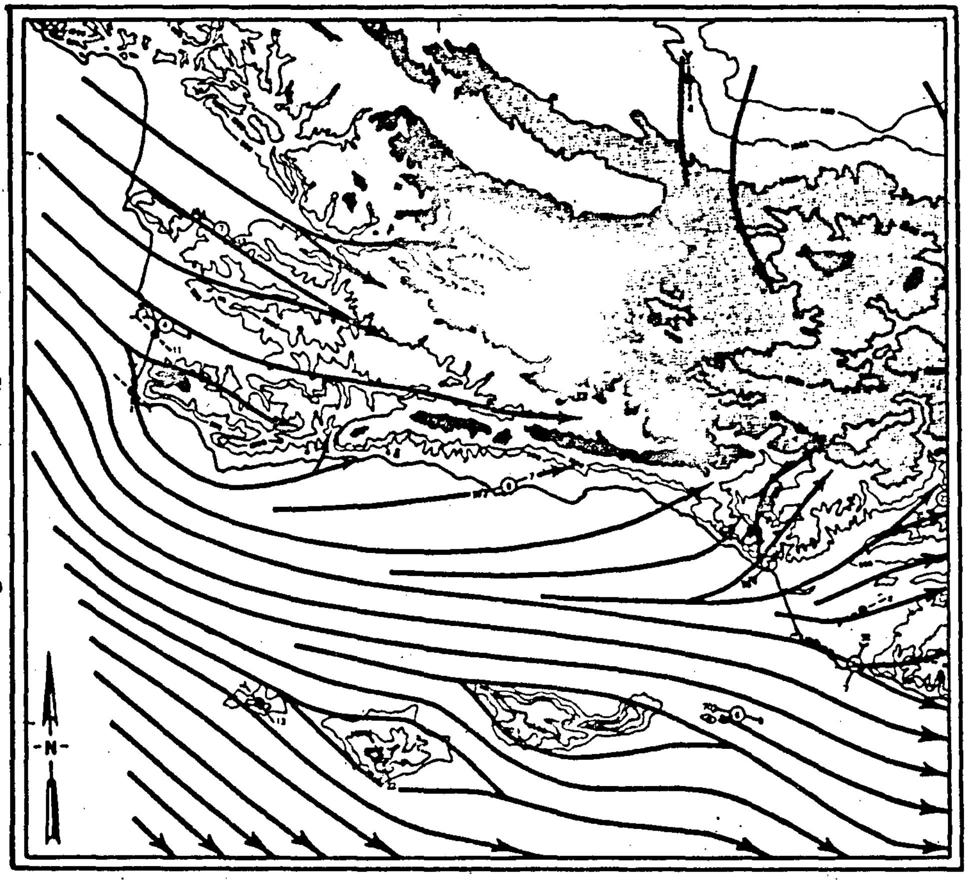
Northwesterly air flow associated with the Pacific High is significantly modified by its interaction with terrain and local winds generated in response to thermal contrasts between land and ocean. The land-sea breeze is especially important in this respect. However, during the day, the sea breeze is complemented by upslope and valley winds in many areas, including that of the site. At night the land breeze, downslope, and mountain winds also complement one another.

The significant features of the day-time streamline charts are as follows: (1) northwest flow incident upon the west-facing coastline turns counter-clockwise in passage around Point Arguello/Point Conception and takes a more westerly direction; (2) flow is relatively strong near Point Arguello/Point Conception, in mid-channel, and in the vicinity of the Islands;

DAYTIME AIR FLOW DURING SUMMER AND WINTER, SANTA BARBARA CHANNEL



JULY
1200-1800
PST



JAN.
1200-1700
PST

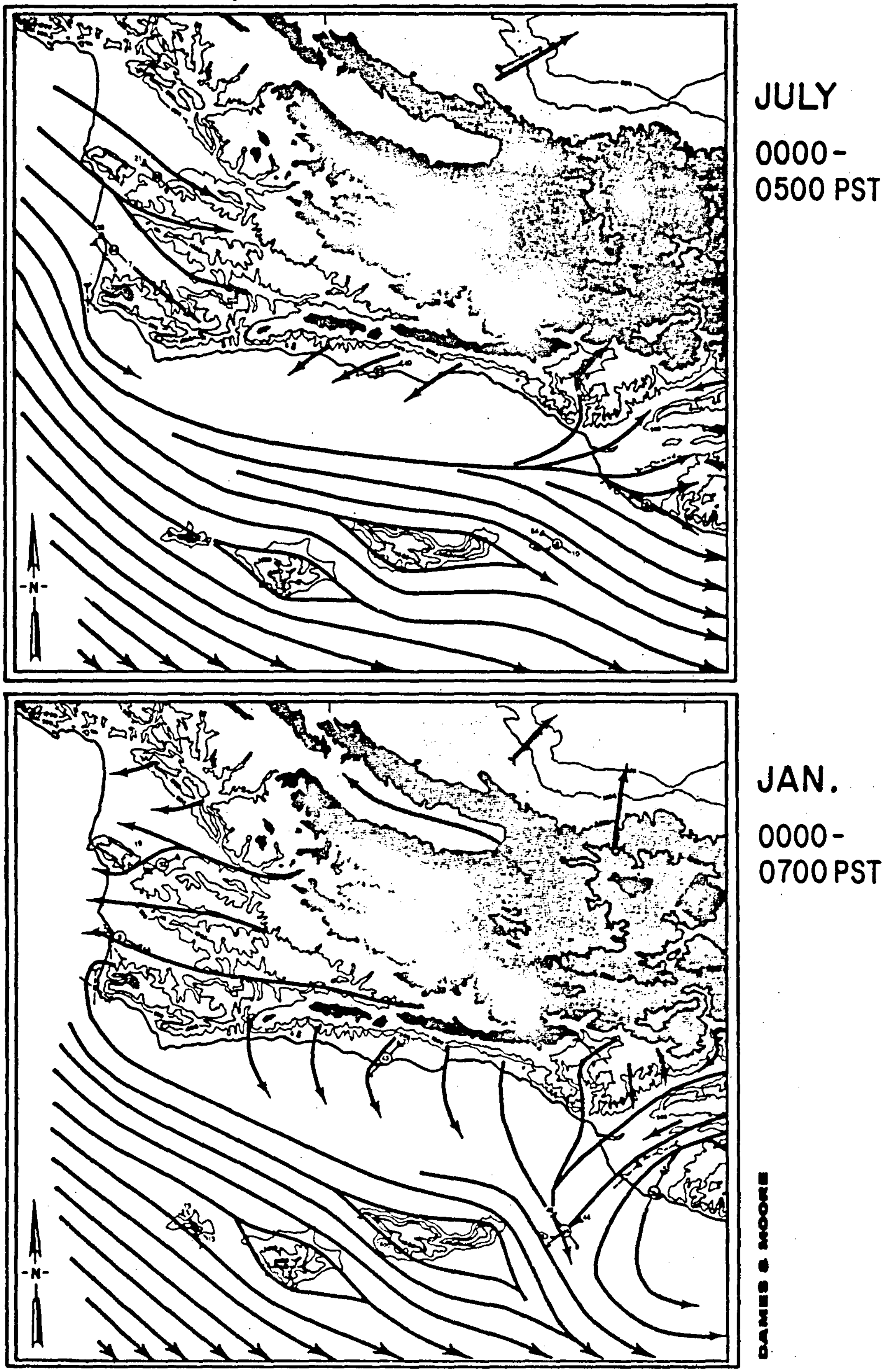
Source: DeMarrais, G.A., *et al*, 1965.

for scale and legend - see Explanation Sheet

DAMES & MOORE

FIGURE II-18b

NIGHTTIME AIR FLOW DURING SUMMER AND WINTER, SANTA BARBARA CHANNEL



Source: DeMarrais, G.A., *et al*, 1965

for scale and legend - see Explanation Sheet

DAMES & MOORE

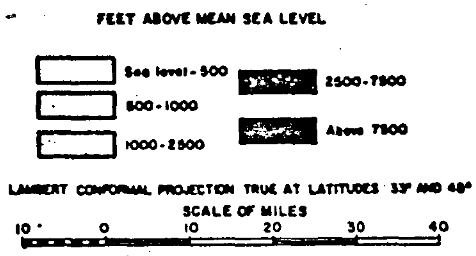
FIGURE II-18c

SYMBOL	EXPLANATION SHEET
	Solid shaft=based on 100 or more observations
	Discontinuous shaft=based on opinion of qualified observer or less than 100 observations
	Solid tail=one direction accounted for more than half of all directions in the 3-direction sector; shaft oriented with that direction
	Open tail=most frequent winds centered along shaft orientation
45 8	Number at tail=percent frequency of most frequent three adjacent directions
71 9	Number at head=average speed (mph)
16 11	Number in large circle on shaft=percent frequency of calms
C C	Letter C on shaft=calms occurred frequently
	No large circle on shaft=calms not counted
86	Number in large circle (no shaft)=calms prevailed; no percent of three adjacent directions totaled 10
41	More than one direction shown=frequency of other directions within 5 percent of primary direction sector shown by solid tail
#	Occurred less than 0.5 percent of time

DAMES & MOORE

Note: Arrows are drawn through station circle and fly with the wind; i.e., wind blows from tail of arrow to head.

Source:
De Marrais, G.A.,
et al, 1965



LEGEND FOR FIGURES II-18-B AND C

(3) flow around the Santa Ynez range and the Islands is typical of that around such obstructions; (4) there is considerable horizontal divergence in the northern Channel region where the direction becomes more southerly and weaker flow is experienced; (5) horizontal flow of air over the ocean merges with that over land; and (6) prevailing wind directions have higher percent frequencies and the associated mean speeds are higher during summer than winter. The last feature results from the weakening of thermal contrasts (sea breeze) and decreased influence of the Pacific High during winter. Shifting winds during extratropical storms raise the percent frequencies of the less frequent directions.

The significant features of the night-time charts are as follows: (1) the movement of air over the ocean is not very different than it is during the day, except near the coast;(2) the night-time flow in coastal areas is very complicated (areas of horizontal convergence are shown in the streamline analysis as blank areas to which streamlines approach from opposing directions); (3) the areas of horizontal convergence are not necessarily stationary, but can be areas where winds come together and shift with time; (4) from Point Conception to Ventura during summer, the convergence zone exists somewhere between the coast and 15 miles offshore; (5) in winter the land breeze attains its greatest development and the convergence zone is further offshore; and, (6) mountain and downslope winds are well-developed throughout the region.

In order to give reasonable approximation to wind conditions in the area, the wind regime at Santa Barbara Airport is presented in table II-2c. This table shows the percentage frequency of wind direction and mean speed by direction associated with the predominant land and sea breezes (and the transitions between them) during each season. The mid-month of each season

TABLE II-2c

PERCENT FREQUENCY OF WIND DIRECTIONS (UPPER NUMBER IN EACH ENTRY) AND AVERAGE SPEED IN M.P.H. (LOWER NUMBER). *INDICATES LESS THAN 0.5 PERCENT. SANTA BARBARA, CALIFORNIA, PERIOD OF RECORD 1949-53[1]

Regime (Hours)	Direction[2]																Calm
	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW*	NNW	
JULY																	
Night-time (0100-0600)	2	5	15	7	16	5	4	1	1	*	1	1	1	1	1	1	39
	3	3	4	5	5	6	5	4	3	3	2	3	3	2	2	2	
Transition (0700-1100)	*	*	1	1	3	2	19	17	17	8	13	4	1		*	*	13
	2	4	2	4	4	5	6	6	6	6	6	6	4		3	2	
Daytime (1200-1700)					*	1	5	3	7	5	35	37	5	*			2
					2	5	6	5	6	6	8	9	8	6			
Transition (1800-0000)	*	1	10	6	20	8	9	3	3	2	6	7	5	*	*	*	20
	2	3	3	5	6	5	4	4	3	3	4	5	6	2	2	2	
OCTOBER																	
Night-time (0100-0700)	6	6	13	1	4	1	1	*	1	*	1	1	2	1	3	2	58
	3	3	3	4	5	6	6	3	3	2	3	3	4	5	5	4	
Transition (0800-1000)	1	1	2	1	2	2	20	11	12	2	11	3	2	*	1		30
	2	3	3	3	4	8	6	5	5	5	6	7	6	8	8		
Daytime (1100-1600)	*	*	*		1	1	12	9	12	5	25	20	9	1	*	*	4
	11	12	3		7	7	7	6	5	6	7	9	10	15	16	14	
Transition (1700-0000)	5	3	12	3	7	3	3	2	1	1	3	4	5	2	3	1	41
	4	3	3	4	5	5	5	4	4	3	4	5	6	6	7	7	
JANUARY																	
Night-time (1900-0800)	8	5	16	4	6	1	2	1	*	*	1	1	4	3	5	4	40
	4	3	3	4	6	7	8	7	4	3	4	7	7	7	6	6	
Transition (0900-1100)	2	*	2	3	8	4	14	6	8	3	7	4	5	3	3	2	2
	6	2	4	5	6	9	6	6	5	5	5	7	7	9	8	13	
Daytime (1200-1600)	1	*	1	*	5	5	11	8	9	3	15	14	12	4	4	2	
	9	7	6	4	8	8	6	5	5	5	6	7	9	13	11	10	
Transition (1700-1800)	11	5	8	2	8	1	4	1	1	1	2	3	16	3	8	4	2
	4	4	4	3	6	10	6	4	9	4	3	4	6	8	6	3	
APRIL																	
Night-time (2300-0600)	7	4	14	5	10	3	3	1	1	1	2	2	4	2	3	3	3
	5	4	3	5	5	6	5	4	4	3	4	4	5	6	7	7	
Transition (0700-1100)	1	*	3	2	5	4	18	12	10	5	11	7	5	2	2	1	1
	4	8	3	5	6	8	7	6	6	5	6	7	7	12	6	7	
Daytime (1200-1700)	*		*		2	2	9	7	7	5	19	25	14	3	2	2	
	11		3		8	10	7	6	6	6	7	9	11	14	7	12	
Transition (1800-2200)	4	3	8	3	9	5	6	2	2	1	5	6	9	4	6	2	2
	6	3	4	5	5	7	4	5	2	3	4	5	5	8	8	10	

Notes: [1]After De Marrais et al., 1965.

[2]Records are biased to the eight main directions.

is taken as representing the entire season.

During daylight hours, the southwest-west southwest sea breeze has its maximum frequency during summer. A marked secondary maximum between south and southeast occurs during other seasons. Wind speeds average 8-11 mph during the afternoon. At night, northeasterly drainage winds predominate during the clear winter months, but, with the arrival of low clouds and fog during spring and summer, the direction shifts more to the east. Wind speeds average about 3-5 mph during the night.

There is greater exposure to winds at nearshore waters of the Channel area than at the Airport. Wind speeds are expected to be higher in those areas. The daytime wind direction at Platform Holly, for example, is probably slightly more westerly than at the Airport.

Cold air drainage, especially during winter, is a common occurrence in the canyons which cross the shore. The highway and railroad embankments represent dams which could obstruct this flow. Holly, again for example, is probably close enough to shore to experience the night-time land breeze on some winter nights, but no actual data exist to substantiate this. The high number of calms reported at the Airport are explainable in part with respect to the wind speed threshold (2-3 mph) of the cup anemometer and observation procedure. It is expected that 1 or 2 mph winds usually occur over the nearshore waters when calms are reported at the Airport.

The land-sea breeze regime is expected to occur on about 70% of the days during the year. A common land-sea breeze cycle is as follows: The wind begins to increase from the southeast during mid-morning, swinging through the south into the southwest by late morning or early afternoon; then decreasing and becoming light and variable in the late evening, followed by late night and early morning drainage flow from the northeast, especially during the winter. During summer, wind at night is from the east or southeast.

The Santa Barbara area often experiences warm, dry northerly winds induced by local pressure gradients. These winds are associated with a slight inland intrusion of the Pacific High and are typically gusty and quite strong below coastal canyons. These warm, dry winds occur throughout the year but have their highest frequency of occurrence in the spring. Further west near Gaviota, these warm, dry north to northwest winds blow with great persistence throughout the summer. Typically, they progress eastward from Point Conception during the afternoon. The extent of this eastward progression varies depending upon the broader scale meteorological situation. The normal sea breeze regime is interrupted by these localized gradient winds on about 10% to 15% of the days during the year.

The most potentially damaging winds to hit the area are the pre-frontal southeasters. These storms may be expected to occur on about 15 to 20 days from October through April. Wind speeds are usually less than 30 mph, but on an average of once every two years 50 mphs winds may be expected in exposed coastal locations. The most common duration of the southeaster is from 6 to 9 hours. Under certain conditions, with a quasi-stationary front or low pressure center to the west, it may persist for up to three days.

Reinforced by winds aloft, post-frontal westerly winds may also be quite strong. These winds are not likely to persist more than a day before shifting into the northwest and then to the north. Strong west to northwest winds are most frequent in April and May, when intense low pressure centers commonly form in the region of southern Nevada.

The mountain ranges to the north and east afford the Santa Barbara area protection from the northeasterly Santa Ana winds which are often so devastating south of Santa Barbara. Under such conditions the Santa Barbara area will experience: 1) southeasterly winds up to 20 mph for extreme Santa Anas; 2) light, variable winds associated with moderate Santa Anas; or, 3) normal sea breeze conditions with mild Santa Anas.

Estimated extreme wind speeds for given recurrence intervals are shown in table II-2d. These values are 30-ft. (above surface) winds and are derived from charts and methods in Thom (1968). Commonly used factors of 1.3, 0.77, 0.70, and 0.65 were employed to determine the maximum instantaneous gust, one-hour, three-hour, and six-hour values, respectively, from the one-minute wind speed. Thom's charts are based on airport wind data, and do not take into account special topographic effects. Therefore, the values in table II-2d are considered conservative estimates for exposures such as ocean bluffs and canyons (where air is subjected to channeling and lifting), and near-shore waters where long unobstructed fetches are encountered. One-minute wind speeds may be as much as 30 mph higher in such locations.

7. Inversions

The Pacific High is strongest in the summer. Subsiding air from this high causes the air aloft to be warm and dry. An inversion forms between this air and the cool marine air which is trapped below (Aldrich, 1966). The mean summer height of the base of the inversion is 800 feet near the Santa Barbara coastline and around 1,000 feet near Santa Cruz and Santa Rosa Islands. The diurnal variation of the height of the inversion base is about 200 to 300 feet, with the minimum height usually occurring in

TABLE II-2d

ESTIMATED EXTREME WINDS (MPH) FOR GIVEN RECURRENCE INTERVALS, SANTA BARBARA AREA

(after Thom, 1968)

Recurrence Interval (years)	Maximum Instantaneous Gust	1 Minute	1 Hour	3 Hours	6 Hours
2	46	35	27	24	23
10	66	51	39	36	33
25	66	51	39	36	33
50	87	67	52	47	44
100	103	79	61	55	51

the afternoon. The inversion is weaker in the winter and is occasionally completely absent (Edinger, 1971).

Beneath the inversion layer natural particles of air pollutants are trapped and cannot mix with the air above. This causes haze to normally exist in the cool marine air (Aldrich, 1966). The haze becomes thicker as the inversion level becomes lower since there is less air to mix with the air particles.

The subsidence temperature inversion occurs throughout the year, but is most frequent from late spring to early fall. It is often accompanied by coastal fog or low clouds. During the winter clear skies and radiational cooling of the surface layer of air produce strong surface-based inversions. Although no upper air meteorological soundings are available at the Santa Barbara Airport, published statistics from the former weather station near Point Arguello are available and have been used to approximate frequencies in the area (table II-2e).

From June through September, the inversion is at its highest level and persists throughout the day nearly 100% of the time. Aircraft soundings taken during the summer of 1966 indicate that the mean height of the inversion base along the coast of southern California during the morning is at its lowest in the Santa Barbara Channel. (Edinger and Wurtele, 1971) Moreover, the mean depth of the marine layer in the Channel area is decreased by about 200 feet from the morning to afternoon (i.e., the inversion base lowered). Comparing these results with Point Arguello soundings indicates a very close agreement between the Channel area in general and Point Arguello on the morning inversion base height (a difference of less than 50 feet).

There is no wintertime inversion climatology available for the area.

TABLE II-2e

PERCENT FREQUENCY OF TEMPERATURE INVERSIONS
AND AVERAGE BASE HEIGHTS AT POINT ARGUELLO, CALIFORNIA

MONTH	OBSERVATION TIME (PST)	TOTAL OBSERVATIONS	INVERSION BASE HEIGHT: SURFACE* PERCENT FREQUENCY	≤2500 FT. PERCENT FREQUENCY	≤2500 FT. AVERAGE HEIGHT	≤5000 FT. PERCENT FREQUENCY	≤5000 FT. AVERAG HEIGHT
JAN	0400	93	89	90	374	92	453
	1600	93	22	48	869	57	1274
FEB	0400	84	75	82	494	88	711
	1600	85	6	41	1095	60	1912
MAR	0400	93	57	72	654	87	1099
	1600	93	4	62	1139	74	1513
APR	0400	58	50	84	866	91	980
	1600	60	12	73	1054	80	1247
MAY	0400	62	29	74	1108	90	1469
	1600	61	0	77	1491	88	1743
JUNE	0400	61	20	87	1267	98	1445
	1600	59	5	92	1387	100	1517
JULY	0400	93	33	99	1050	100	1066
	1600	92	9	98	1118	100	1153
AUG	0400	93	28	97	1134	100	1199
	1600	93	2	96	1258	99	1353
SEPT	0400	89	40	90	1016	94	1131
	1600	90	6	91	1232	96	1349
OCT	0400	93	65	90	734	98	907
	1600	93	10	86	1091	92	1208
NOV	0400	90	76	89	542	93	698
	1600	90	17	72	1049	82	1414
DEC	0400	93	84	87	414	88	468
	1600	92	22	56	880	74	1474

*Station Elevation 369 ft MSL

However, it is likely that there is similarity to the Point Arguello morning soundings, with surface inversions existing about 90% of the time. In the afternoon, surface inversions exist only about 20% of the time at Point Arguello with no low level inversion about 30% to 40% of the time. Little difference in this trend is expected in the general Channel area.

A five year compilation of monthly and annual frequencies of Pasquill's stability classes for Santa Barbara Airport is presented in table II-2f. These classes are a function of solar elevation and standard meteorological measurements of wind speed and cloud cover. They represent a first order estimate of the statistical distribution of the low level air mass stability. Since the dispersion of routinely and accidentally released gases from the additional OCS development would be confined primarily to the marine layer below the inversion, the Pasquill distribution is considered to be a reasonable approximation of the atmospheric conditions in the area.

On an annual basis, it is seen that the neutral condition (D) is the most prevalent (34.8%) followed by the stable condition (F) (32.4%). These would be associated with the day-time sea breeze condition and night-time land breeze condition, respectively, with direction of air mass flow as described earlier. The other conditions occur with significantly less frequency and may be considered primarily as transitional. Significant differences should be expected a short distance inland from the Airport. There, one would expect the B and C categories to occur more frequently than the D category; that is, that the afternoon conditions would become more unstable. Over the near-shore waters, conditions are expected to be more stable with the frequency of E and F categories increasing mostly at the expense of D. No significant difference is likely in the night-time F stability frequency.

TABLE II- 2f

MONTHLY AND ANNUAL FREQUENCIES OF STABILITY CLASSES

(5-Year Averages for 1960-1964)

STABILITY CLASS

Month	A - %	B - %	C - %	D - %	E - %	F - %
January	0.05	6.8	13.4	25.6	7.0	47.1
February	0.7	7.4	14.3	32.5	9.4	35.7
March	0.4	7.7	13.0	36.7	9.9	32.3
April	0.9	10.4	16.3	33.7	9.1	29.5
May	1.0	9.7	18.2	33.4	10.1	27.7
June	1.0	9.5	15.4	47.2	6.2	20.6
July	0.6	12.7	18.9	36.5	9.2	22.1
August	0.3	10.7	17.3	36.8	9.4	25.5
September	0.3	7.6	17.0	38.1	7.6	29.4
October	0.1	6.4	15.5	36.5	7.8	33.7
November	0.1	4.6	13.4	35.2	8.8	37.8
December	0.0	5.1	15.1	25.6	6.5	47.7
Annual	0.5	8.2	15.7	34.8	8.4	32.4

A - Very unstable

B - Unstable

C - Slightly unstable

D - Neutral

E - Slightly stable

F - Stable to very stable

(after NOAA, no date)

8. Fog

During the summer, heavy fogs are a common occurrence in the Santa Barbara Channel and envelop the main shore channel and islands. The fogs are most common during the mornings and early afternoons and often are caused by radiation cooling of the air at night and consequent condensation. During the afternoons, heating of the air and the sea breezes commonly dissipate the fog. Fogs occur mostly during periods of calm or light winds and are generally dissipated by strong northwesterly winds.

9. Visibility

Haze and costal fog in the Santa Barbara Channel often combine to restrict visibility, particularly in summer. Table II-3 displays the monthly frequency of visibility of 2 nautical miles or less in the Southern California Bight and table II-4 lists the monthly frequencies of visibilities of various distances for 3 areas of the Santa Barbara Channel.

As is seen by table II-4 the minimum visibilities occur during the summer period from June through October. The eastern portion of the Channel has a greater incidence of low visibilities than do the central or western portions. For example, the visibilities during the summer months of July, August, and September are less than 5 miles only 8 to 23 percent of the time in the central and western portions of the Channel while they are less than 5 miles 42 to 55 percent of the time in the eastern portion.

TABLE II-3

Monthly percentage frequency of visibilities of 2 nautical miles or less, summarized by ½ degree quadrangles. Data taken from Climatological Study, Southern California Operating Area, U. S. Navy, 1971. (Hyphen means fewer than 5 observations of visibility).

	121W		120W		119W		118W	117W
35N	.0 6.5	.0 -						Jan Jul
	10.8 7.2	- -						Feb Aug
	4.0 10.7	.0 -						Mar Sep
	4.8 9.0	- .0						Apr Oct
	9.0 8.2	- -						May Nov
	8.5 4.0	- -						Jun Dec
	1.4 5.5	3.7 12.6	.0 7.5	2.4 20.4	- -	- -		
	4.7 6.8	2.8 7.2	.0 5.4	8.5 24.3	- -	.0 -		
	3.7 2.9	.0 10.8	7.0 10.3	7.4 20.8	- .0	- -		
	2.0 2.4	.0 8.9	.0 4.3	17.2 27.1	.0 -	.0 20.0		
	7.6 3.1	2.0 .0	2.4 1.7	13.3 9.9	.0 .0	- 16.7		
	5.0 3.1	9.4 5.3	7.2 2.3	11.5 3.7	- 11.1	- -		
34N	1.4 4.0	1.2 4.2	.0 3.7	.0 .0	8.4 1.1	14.7 11.3	2.6 6.3	
	7.6 1.2	6.0 3.7	6.0 .0	2.2 2.4	3.0 2.0	6.4 4.9	.0 5.0	
	1.0 3.3	2.7 7.0	2.6 9.1	3.2 9.4	3.4 6.6	7.5 10.7	.0 .0	
	6.8 6.6	.0 5.1	2.4 11.5	3.1 10.9	5.6 4.1	10.4 16.6	4.2 10.7	
	2.4 3.3	3.0 6.0	1.2 7.8	2.2 4.1	.0 6.5	0.5 11.0	14.2 11.8	
	1.0 3.0	5.6 6.3	4.7 4.7	1.2 4.5	2.7 9.0	7.5 8.8	13.4 7.8	
	6.8 1.8	1.2 4.4	4.0 1.9	2.2 2.1	4.7 0.9	3.4 2.0	4.1 4.5	4.0 2.3
	5.8 .0	2.6 3.9	6.3 6.2	6.1 2.4	3.4 2.4	3.2 2.0	5.0 5.7	4.1 2.4
	.0 .0	1.2 .0	.0 0.5	1.4 .0	2.1 0.8	2.5 2.4	4.1 12.5	3.4 27.7
	.0 .0	5.0 3.3	1.8 3.2	3.6 2.0	3.0 3.6	2.8 6.2	4.1 14.2	5.2 12.0
	1.9 5.8	2.1 2.5	2.5 4.3	3.3 6.4	1.9 2.1	1.0 3.1	5.2 5.5	.0 14.8
	.0 .0	.0 5.1	5.2 5.7	2.1 2.2	2.4 2.4	2.2 4.5	3.0 4.9	.8 7.4
33N	3.0 4.8	2.0 1.5	3.8 2.3	3.5 2.1	2.2 1.4	2.8 1.3	4.4 1.7	6.3 2.4
	5.4 .0	.0 6.3	2.3 3.0	3.9 3.2	1.6 1.4	3.6 1.5	3.5 1.3	5.6 2.7
	2.6 .0	.0 .0	.0 .0	1.8 .0	2.3 .0	3.1 0.7	2.1 1.1	7.7 7.5
	3.8 .0	2.9 2.4	0.7 0.8	2.4 3.2	2.7 1.6	1.5 3.0	2.3 4.3	3.4 12.4
	.0 3.8	.0 7.2	1.8 1.8	3.6 0.8	1.4 3.2	.6 2.6	.6 2.4	2.1 7.9
	3.4 .0	1.6 6.8	4.2 0.9	2.8 7.9	1.4 4.6	2.4 4.0	2.2 6.1	4.8 13.1

TABLE II-4

Monthly percentage frequencies of various ranges of visibility in nautical miles for three areas of the Santa Barbara Channel. Based on data in Climatological Study, Southern California Operating Area, U. S. Navy, 1971.

EASTERN PORTION (34.0 - 34.5°N, 119.0 - 119.5°W)

Visibility (Nautical Miles)	January	February	March	April	May	June	July	August	September	October	November	December
Less than 0.5	0.2	2.6	2.4	4.2	1.9	1.0	4.7	6.5	9.1	7.9	3.5	0.6
Less than 1	0.9	4.1	3.8	8.0	5.5	5.4	9.7	11.5	13.3	15.1	5.6	1.5
Less than 2	2.4	8.5	7.4	17.2	13.3	11.5	20.4	24.3	20.8	27.1	9.9	3.7
Less than 5	8.0	16.5	20.1	33.9	26.7	28.6	51.9	55.7	42.5	54.1	28.1	12.3
Less than 10	49.4	56.8	59.3	74.2	67.3	84.1	91.8	93.8	88.9	87.5	64.1	49.5
10 or greater	50.6	43.2	40.7	25.8	32.7	15.9	8.2	6.2	11.1	12.5	35.9	50.5
Number Observations	585	886	1091	1066	1083	902	1055	953	973	992	719	545

CENTRAL PORTION (34.0 - 34.5°N, 119.5 - 120.0°W)

	January	February	March	April	May	June	July	August	September	October	November	December
Less than 0.5	.0	.0	4.7	.0	.0	3.6	1.9	2.7	6.9	.0	1.7	.0
Less than 1	.0	.0	4.7	.0	2.4	5.4	3.8	5.4	8.6	4.3	1.7	2.3
Less than 2	.0	.0	7.0	.0	2.4	7.2	7.5	5.4	10.3	4.3	1.7	2.3
Less than 5	4.3	.0	9.3	5.5	4.8	21.5	13.1	8.1	20.6	19.2	5.1	9.1
Less than 10	15.2	22.0	23.3	29.1	31.6	53.6	48.1	29.7	48.3	61.7	24.1	43.2
10 or greater	84.8	78.0	76.7	70.9	68.3	46.4	51.9	70.3	51.7	38.3	75.9	56.8
Number Observations	46	50	43	55	41	56	54	37	58	47	58	44

WESTERN PORTION (34.0 - 34.5°N, 120.0 - 120.5°W)

	January	February	March	April	May	June	July	August	September	October	November	December
Less than 0.5	.0	1.4	.0	.0	2.0	4.7	4.7	3.6	4.3	5.3	.0	5.3
Less than 1	3.7	1.4	.0	.0	2.0	4.7	11.0	5.4	6.5	7.1	.0	5.3
Less than 2	3.7	2.8	.0	.0	2.0	9.4	12.6	7.2	10.8	8.9	.0	5.3
Less than 5	11.1	7.0	.0	4.8	8.0	11.0	23.5	16.1	15.1	12.4	1.3	7.9
Less than 10	40.7	18.1	12.8	27.0	36.0	48.4	62.5	58.9	52.2	56.1	21.2	21.1
10 or greater	59.3	81.9	87.2	73.0	64.0	51.6	37.5	41.1	47.8	43.9	78.8	78.9
Number Observations	54	72	47	63	50	64	64	56	46	57	80	38

D. Oceanography

The Santa Barbara Channel is located in the "Southern California Bight", an open embayment of the Pacific bounded on the north by Point Conception, California, and on the south by Cape Colnett, Baja California. The Bight extends offshore to the California Current, a broad, southerly flowing current along the California coast.

1. Physical Oceanographic Features of the Southern California Bight[1]

The currents in a coastal region such as the Southern California Bight can be thought of as being caused by four separate factors:

- The internal forces related to the distribution of mass and momentum of the water,
- The external forces caused by the wind acting directly on the water surface,
- The external forces produced by the tides, and
- The forces caused by surface and internal waves.

The first of these forces creates the so-called geostrophic currents and is due to variations in the distribution of mass within the water. Since distribution of the mass of the water is related to the distribution of density of the water which in turn is related to the distribution of water temperature and salinity, measurements of temperature and salinity can be used to infer the geostrophic currents of an area. Such maps of geostrophic

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[1] Much of the material of this section was abstracted from Southern California Coastal Water Research Project, 1972, The ecology of the Southern California Bight: Implications for water-quality management. Southern California Coastal Water Research Project (SCCWRP) is a unit organized by five government agencies; Ventura County, the city of San Diego, the city of Los Angeles, the Sanitation District of Orange County and the Sanitation District of Los Angeles County.

currents are often used to represent the average current pattern of an area since the distribution of internal mass takes a finite time to adjust to fluctuations in external or driving forces.

The second type of currents--the wind driven currents--may be ephemeral due to the rapid fluctuations of the wind speed and direction. The wind acts at the ocean surface and causes the uppermost few centimeters of water to move at 2 or 3 percent of the wind speed in the direction of the wind. Due to frictional drag and to the Coriolis force (caused by the earth's rotation), the deeper water moves slower than the surface water and in a direction to the right of the wind. The motion is transferred further down the water column and generates a current profile known as the Ekman Spiral. The integrated effect of this process is to create an "Ekman" drift or average transport of the surface waters at about a 90° angle to the right of the wind. This process is of interest along the coast of California since the prevailing northwest winds present during the spring, summer, and early autumn flow parallel to the coast and transport the surface water away from the coast. This forces the colder, deeper water to well up along the shore. Since the upwelled water is rich in nutrients it can support high organic productivity in the area. Upwelling also modifies the distribution of mass of the water which in turn helps to maintain the California current geostrophically.

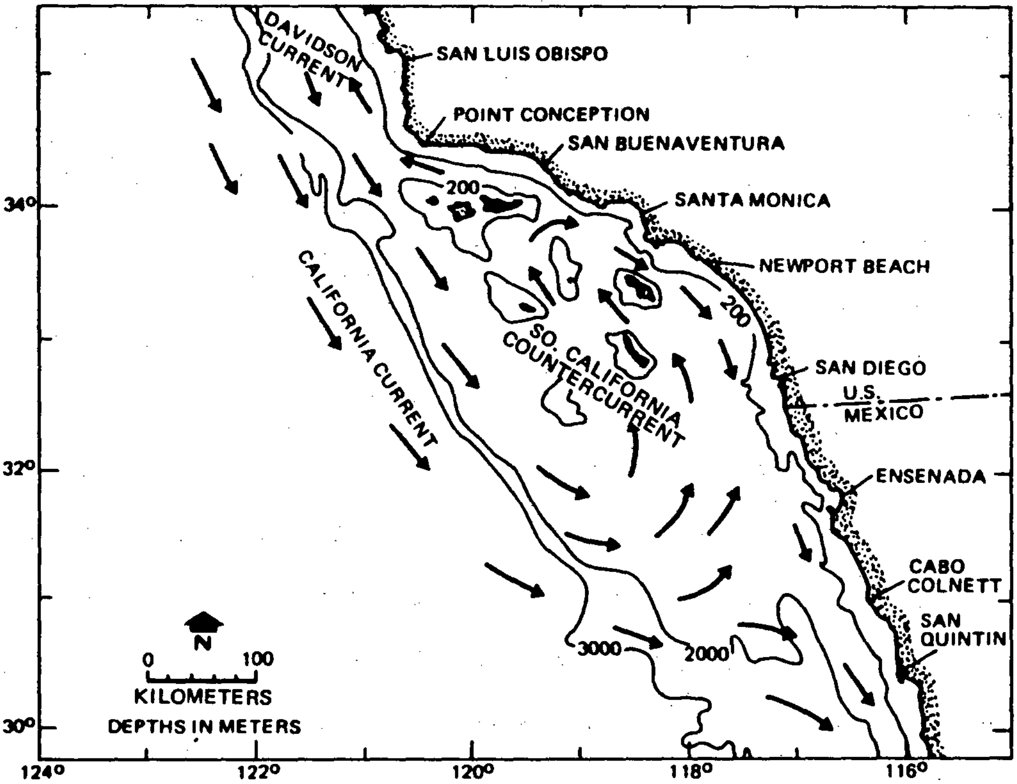
The third type of current-producing forces--the tidal forces--are produced by a balance of the gravitational attractions of earth, moon, and sun and the various centrifugal forces produced by their motions. Although the lunar and solar tides produce rhythmic tidal currents, small-scale features such as variations of the coastline and irregularities of the sea bottom can cause tidal currents to be very complex.

The fourth type of forces that produce local currents are the surface and internal wave forces. Water transports due to surface waves cause such features as rip currents and longshore currents. Longshore currents are confined primarily to the surf zone and move essentially parallel to the shoreline. They are generated by surface waves breaking at an angle to the shoreline. To compensate for shoreward water transport by the waves, seaward return flow, including rip currents, exist. Internal waves are gravity waves moving on the internal density structure in the water. They have many of the same characteristics as surface gravity waves but normally have greater amplitudes and lower speeds. Internal waves are created by a variety of processes and may travel for great distances. They may cause very complex currents and interactions when they enter shallow water in coastal areas such as the Southern California Bight. The effects of internal waves in coastal areas are poorly understood but their principal effect is to produce small-scale random and unpredictable variations in local currents.

2. Mean Current Patterns

The prevailing westerly winds over much of the North Pacific Ocean drive the surface water across the Pacific towards the North American continent. When the water impinges on the continental land mass, it diverges and flows north as the Gulf of Alaska Gyre and south as the California current. Along the California coast the prevailing coastal winds are from the northwest and tend to maintain the surface flow nearly parallel to the coast (figure II-19). Because the water is of northern origin and because of upwelling of cold water along the coast, the waters of the California current are colder than those offshore. Heating of the surface water as the current moves south reduces the density of the surface water and isolates it from the deeper, colder waters. The deeper waters move in a

FIGURE II-19



Surface Circulation (0–100 m) in the Southern California Bight. (Arrows Indicate Approximate Direction of Flow). From Jones 1971, Fig. 1.

From SCCWRP, 1972, Figure 3-14, p. 38

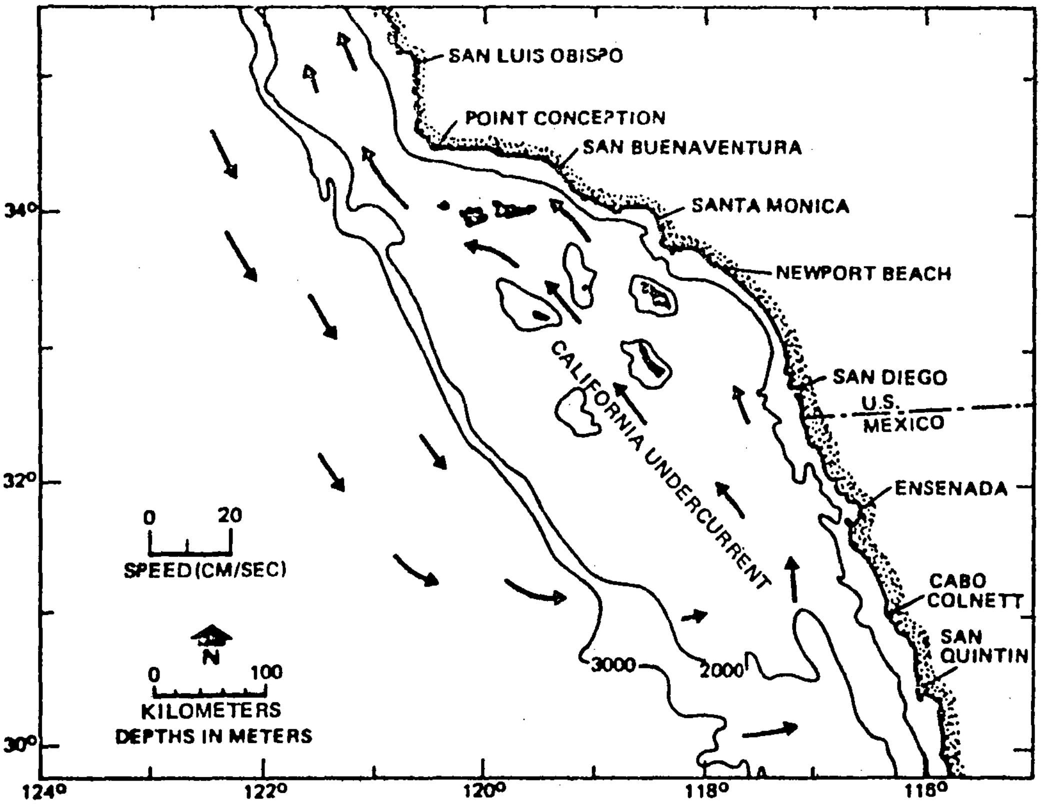
northerly direction as the California undercurrent. Near Point Conception the undercurrent lies over the continental shelf at depths greater than about 150 meters depth. Farther offshore, off the edge of the continental shelf, deep currents are weak and move in a southerly direction (figure II-20).

During the winter the prevailing northwest winds along the California coast relax and may even reverse direction. The relaxation slows the California current and allows a northerly inshore flow, the Davidson current, to develop. According to Reid (1965) surface currents north of Point Conception within 150 kilometers of the coast often flow northwestward along the coast from November through February and southeastward during the remainder of the year. Although measurements are few, the Davidson current may be a surface expression of the California undercurrent as has been suggested by Wooster and Jones (1970) and Jones (1971).

As the California current flows southerly along the edge of the continental shelf, it passes Point Conception where the shoreline swings sharply to the east while the edge of the continental shelf continues on southerly (figure II-19). The California current follows the edge of the shelf past Point Conception until it is off northern Baja California before it swings shoreward. Off Ensenada the shoreward flow diverges--one arm flowing north as the southern California countercurrent and the other arm continuing on southward.

In the Southern California Bight the California current and southern California countercurrent form the Southern California Eddy. The circulation in the Eddy is complex and variable due to the interactions of the various currents with the many islands and bottom irregularities. The circulation of the Eddy is usually well developed in summer and autumn and

FIGURE II-20



Mean Geostrophic Flow at 200 m Depth in the Southern California Bight (Arrows Show Direction and Magnitude of Flow). From Jones 1971, Fig. 11.

From SCCWRP, 1972, Figure 3-17, p. 42

weak (and occasionally absent) in winter and spring.

The oceanography of the California current has been described by many authors but the classical description is by Reid, Roden, and Wyllie in 1958. Reid (1965) described the waters near Point Conception and Point Arguello. SCCWRP (1972) has presented seasonal charts of the currents and surface temperatures in the Southern California Bight (figure II-21).

3. Currents Within the Santa Barbara Channel

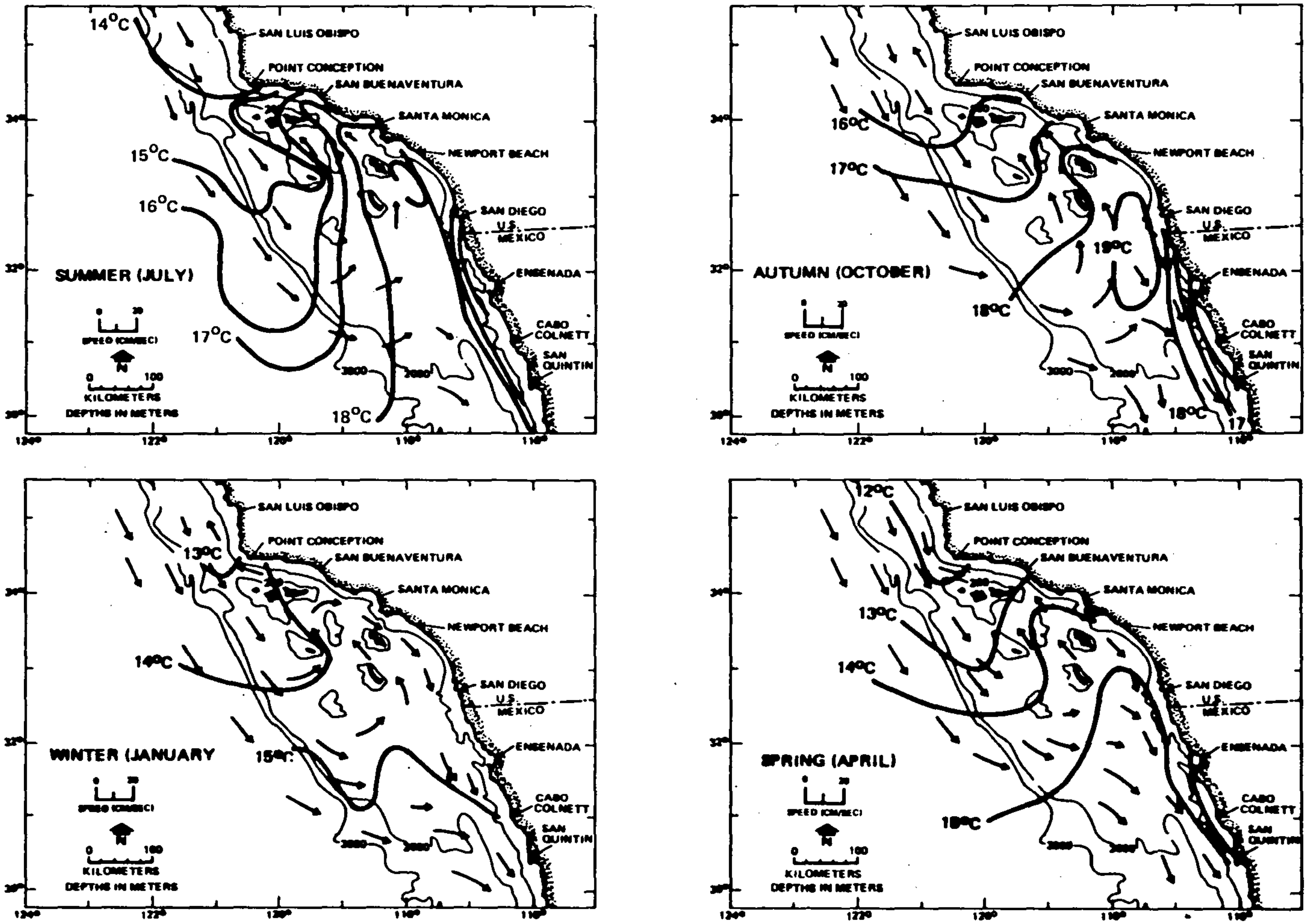
The Santa Barbara Channel is that portion of the Southern California Bight bounded on the north by the mainland and on the south by the chain of San Miguel, Santa Rosa, Santa Cruz, and Anacapa Islands. Figure II-22 is a bathymetric chart of the Santa Barbara Channel for orientation.

a. Surface Currents

The surface currents in the Santa Barbara Channel form a gyre with westward flows along the mainland coast and eastward flows along the north shore of the Channel Islands. At the western end of the Channel the circulation may be erratic and variable but will not necessarily be weak. This area is affected by the strong winds off Point Conception and is complicated by the interactions of the California current, the Davidson current, and the gyral currents in the Santa Barbara Channel.

Kolpack (1971, pp. 90-180) has summarized the oceanography of the Santa Barbara Channel, based on a review of available published oceanographic data, hydrographic recording and sampling stations. Surface current patterns were derived primarily from a "drift card" survey; wherever possible related parameters such as temperature, isotherms, salinity, oxygen content, nutrient

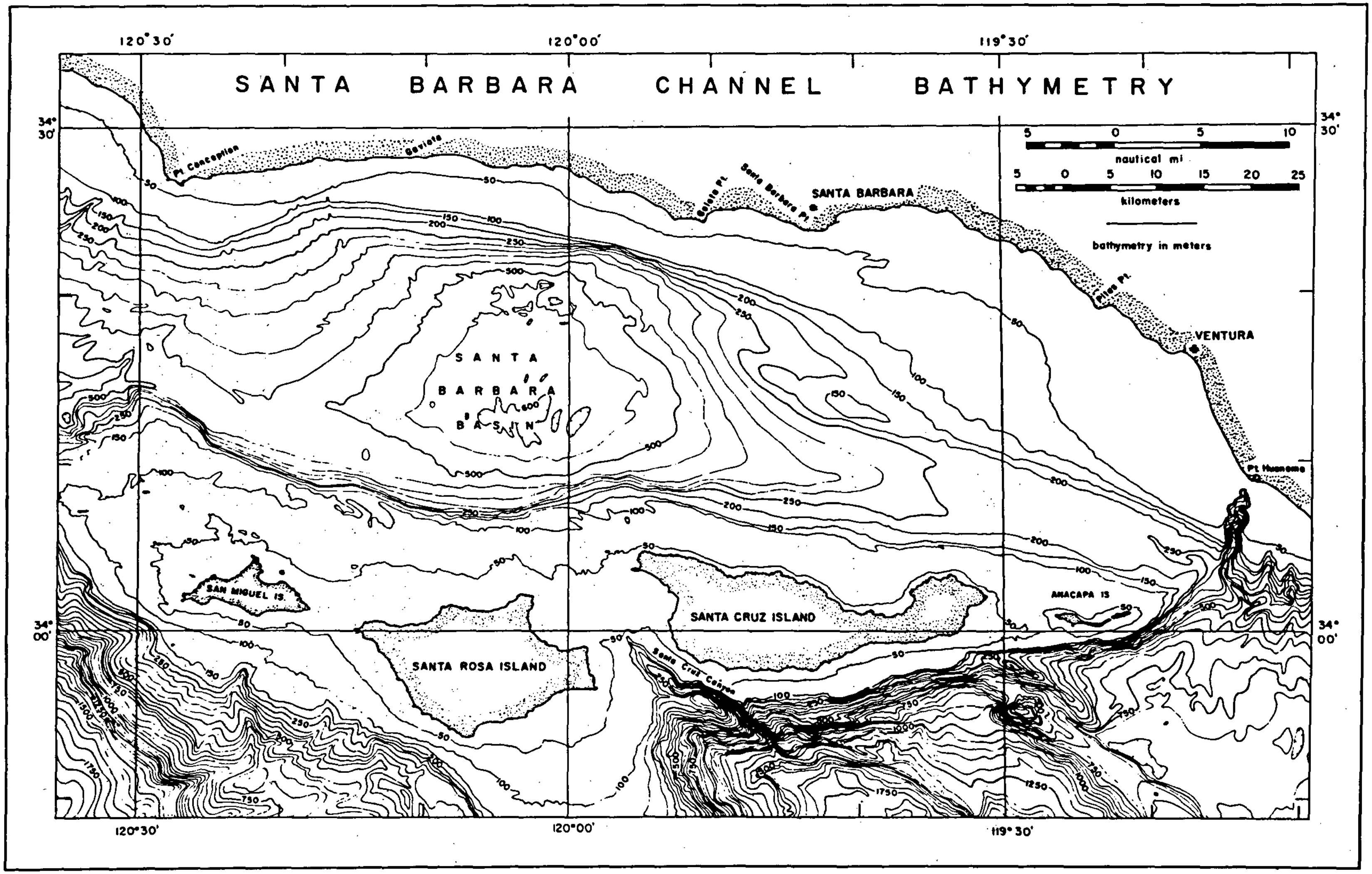
FIGURE II-21



Average Geostrophic Surface Flow (Arrows) and Surface Isotherms (Degrees C) in the Southern California Bight.
From Jones 1971, Figs. 5-8.

From SCCWRP, 1972, Figure 3-15, p. 39

FIGURE II-22



From Kolpack, 1971, Figure 1, p. 182

content, and turbidity, were utilized in interpretation of surface current patterns.

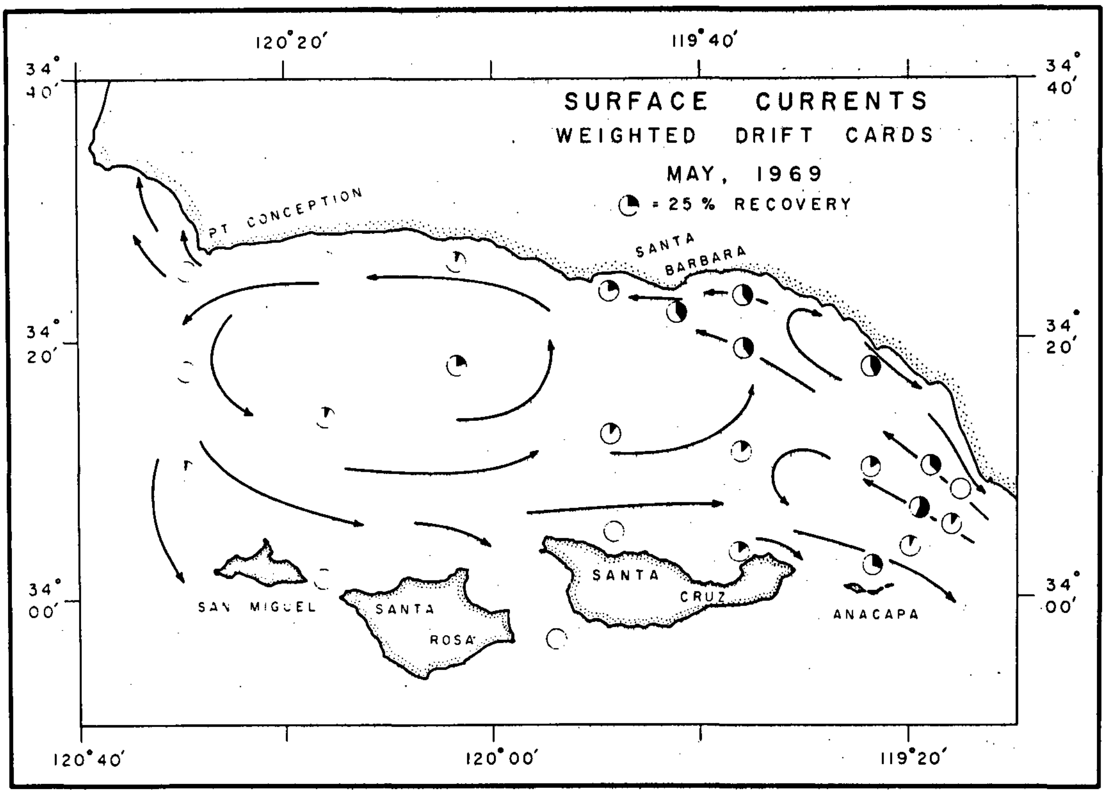
Kolpack states:

> "The surface water circulation pattern in Santa Barbara Channel consists essentially of a counter-clockwise cell in the western half of the channel and a northwesterly flowing current in the eastern part of the channel. The western cell is driven by a current entering the channel from the northwest. Convergence of these currents results in a complex pattern of eddies in the area between Santa Barbara and Santa Cruz Island. Other eddies along the eastern margin of the channel are produced by deflections resulting from current impingement near Santa Barbara and Ventura. Surface water temperature, salinity, and nutrient values all reflect the same circulation pattern."

A series of surface current charts (based primarily on drift card data) are presented by Kolpack for intervals between May 1969 and February 1970. Figures II-23 through II-26 are reproduced as examples (May 1969, August 1969, December 1969, and February 1970).

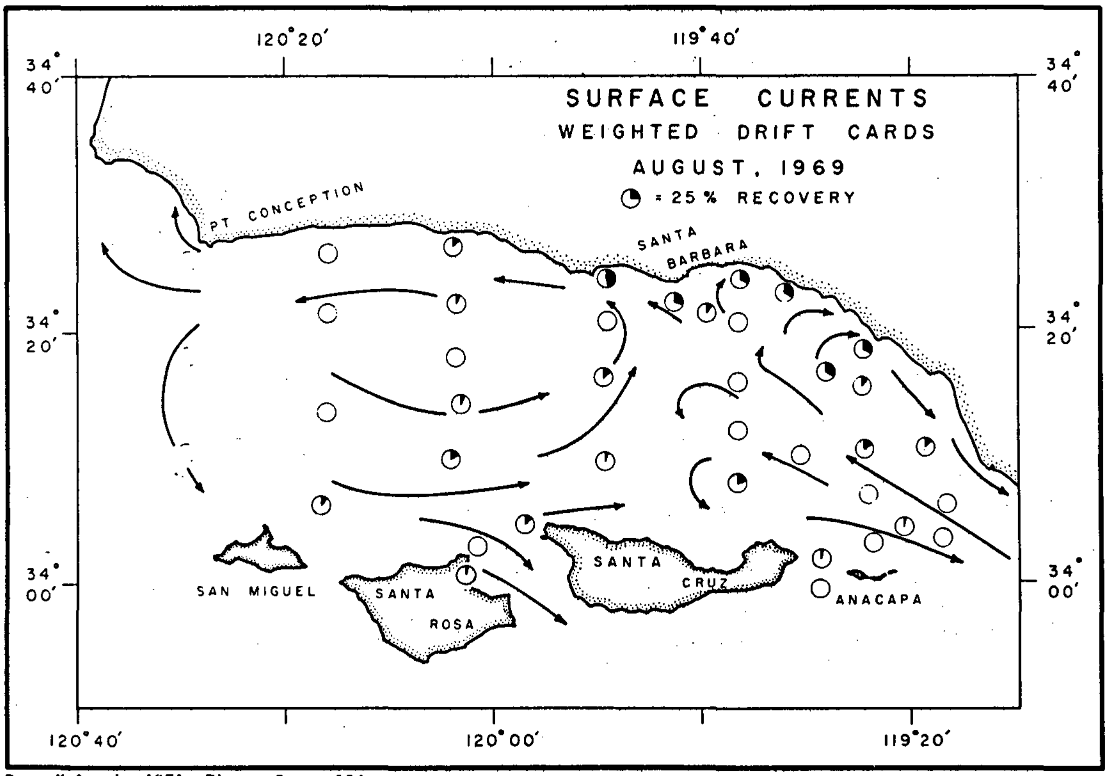
Few measurements have been made of speeds of surface currents in the Santa Barbara Channel. One available source, however, is the observations of ship drift made by merchant and naval ships. These measurements are made by assuming that all of the error between the predicted position of a ship made by dead reckoning and the ship's actual position after traversing a certain course can be attributed to surface current after corrections for windage are made. Monthly values of surface current speeds in the Santa Barbara Channel by ship drift are given in table II-5 . As is seen by the table, currents are generally weaker in summer than winter -- typical values are 0.3 to 0.6 knots in summer and 0.5 to 0.7 knots in winter. The currents are variable in direction but are most variable in summer in the eastern portion of the channel. This is in agreement with Kolpack's observations of numerous eddies in the eastern portion in summer.

FIGURE II-23



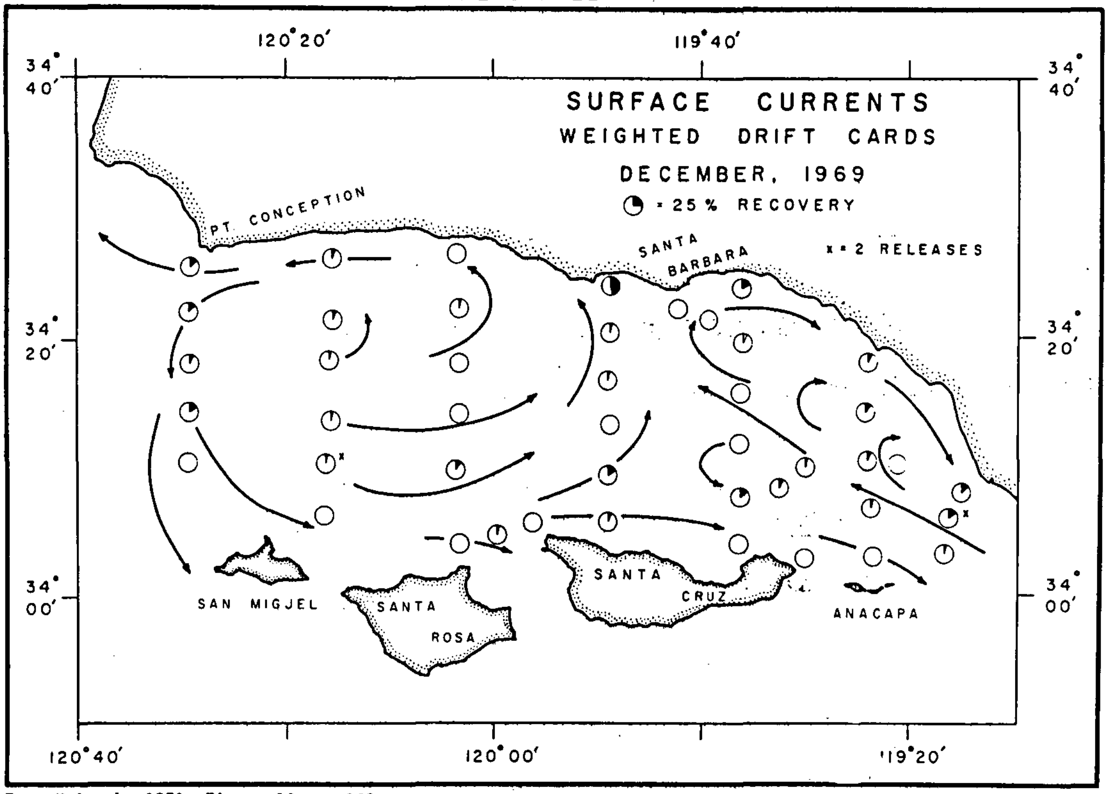
From Kolpack, 1971, Figure 4, p. 100

FIGURE II-24



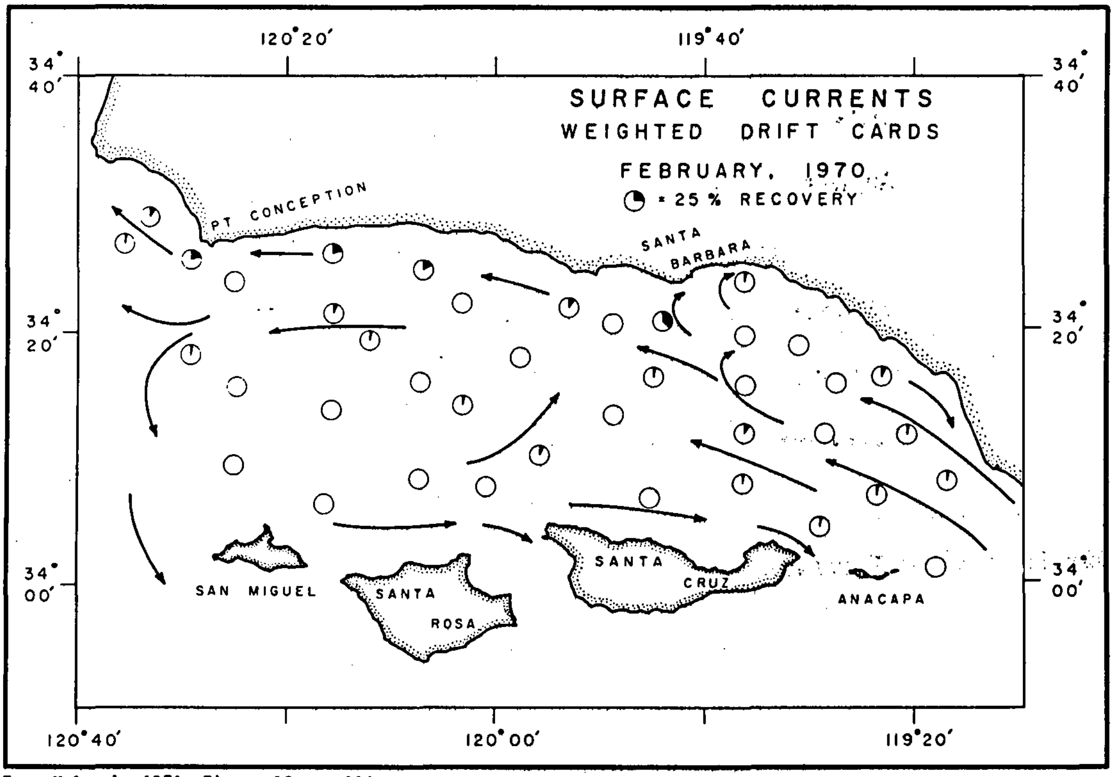
From Kolpack, 1971, Figure 9, p. 104

FIGURE II-25



From Kolpack, 1971, Figure 10, p. 109

FIGURE II-26



From Kolpack, 1971, Figure 18, p. 114

TABLE II-5

MONTHLY OBSERVATIONS OF SURFACE CURRENT SPEED
IN THE SANTA BARBARA CHANNEL

(From graphical presentations in Naval Weather Service Command (1971)).

MONTH	EASTERN PORTION SPEED[1]	EASTERN PORTION DIRECTION[2]	WESTERN PORTION SPEED[1]	WESTERN PORTION DIRECTION[2]
January	0.7	W	0.5	SSE
February	0.6	W	0.5	SW
March	0.5	E(or W[3])	0.6	SE
April	0.7	ESE(or WNW[3])	0.7	SE
May	0.5	ESE(or WNW[3])	0.5	SE
June	0.5	E(or W[3])	0.6	SSW
July	0.4	ESE(or WNW[3])	0.3	W
August	0.5	WSW(or SE[3])	0.6	W
September	0.7	W	0.4	SE(or NW[3])
October	0.4	ESE or WNW	0.3	S
November	0.7	W	0.5	WNW
December	0.7	W	0.5	W(or SE)

[1] One knot = 51.3 cm/sec.

[2] Prevailing current direction.

[3] Secondary current direction.

b. Subsurface Currents

Subsurface currents in coastal waters such as the Santa Barbara Channel are primarily related to the tides and bottom topography of the basin. They are only secondarily related to the winds, except perhaps when strong winds have been blowing for more than a few hours or where the water is not stratified (SCCWRP, 1971). Subsurface currents usually have a lower speed than the surface currents. The differences in speed and direction between surface and subsurface currents are greatest in summer when thermal stratification is most pronounced (SCCWRP, 1971).

The net circulation of the Santa Barbara Channel is determined by the long-term average of the subsurface currents which are in turn determined by the shape of the basin and by the dimensions of the passages connecting the channel with adjacent waters. Kolpack (1971, p. 181) summarized the net circulation of the Santa Barbara Channel as follows:

> "Inflow and outflow of basin water occurs predominantly through the southeast Anacapa-Oxnard passage and the western opening between Point Conception and San Miguel Island. Subsurface circulation is restricted by sill depths of 230 meters at the southeastern margin and 475 meters at the western margin of the basin. The Channel Island ridge forms an effective barrier to all flow below about 40 meters. Emery (1960), on the basis of the physical and chemical characteristics of the basin water, demonstrated that water below the deepest sill is derived from open sea water at the level of, or somewhat deeper than, that sill. Therefore, the deep water of Santa Barbara Basin (below about 500 meters) is replenished by water from the low oxygen zone (400-600m) in the North Pacific. Emery and Rittenberg, (1952) and Rittenberg, Emery, and Orr, (1955), based on consideration of nutrient regeneration, determined that complete deep basin recharge must occur in less than 2 years. More recent information indicates that basin recharge probably occurs on a yearly basis."

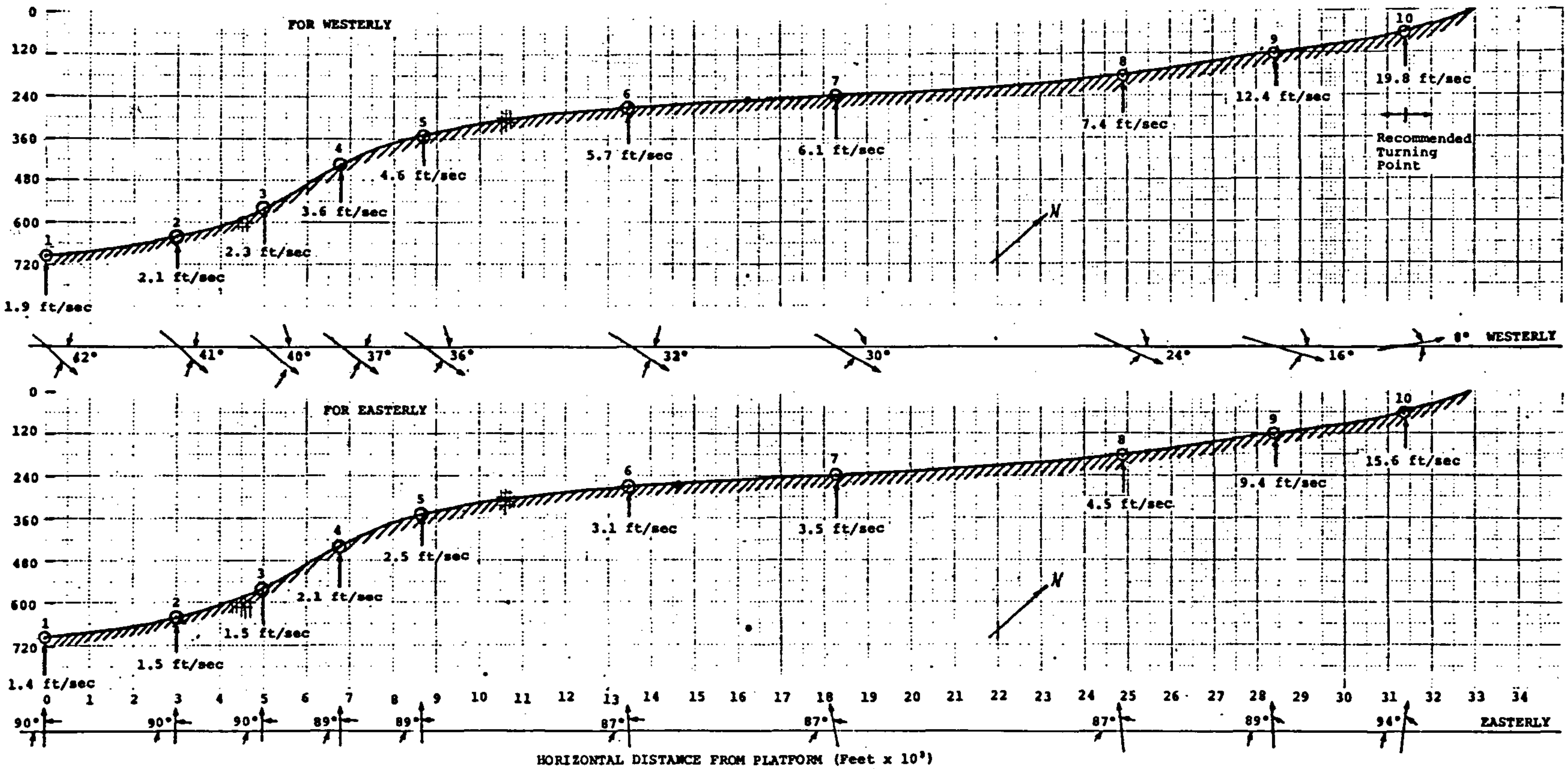
Kolpack (1971, p. 342) suggests that the northeasterly flowing subsurface current in the easterly portion of the Santa Barbara Channel (earlier called the California undercurrent) is deflected into a westerly flow by the seafloor ridge south of Santa Barbara (figure II-22).

The maximum possible or extreme values of subsurface currents in the Santa Barbara Channel are of interest in relation to the design and safety of subsurface oil production facilities. Unfortunately, few observations of subsurface currents are available and many of these were made during periods of relatively light winds and thus are biased towards low wind speeds.

No subsurface current measurements in the Santa Barbara Channel are available for long periods of time. Because actual measurements are not available, it is necessary to use what historical data are available to reconstruct a time series of predicted values for as long a period as possible. Such a study was made along the route of a proposed pipeline from the shore near San Refugio State Beach to a point 5.1 miles to the southwest, (Oceanographic Services, Inc., 1971). The historical data used included historical meteorological maps from the U. S. Weather Bureau and California Institute of Technology and published articles on severe storm conditions from Los Angeles and Santa Barbara newspapers. From these sources it was possible to identify severe storm conditions during the period 1905 to 1970. Based on these data OSI predicted the average wave height of the highest 1 percent of all waves occurring in a 100-year storm, the maximum tidal current to be expected, and the maximum wave-induced longshore current. The vector sums of these currents are shown in figure II-27 for various points along that proposed pipeline.

FIGURE II-27

PREDICTED BOTTOM CURRENTS



From Oceanographic Services, Inc., June 1971, Figure 7: Report No. 222-2A

The currents shown in figure II-27 range from 0.8 knots (1.4 ft/sec) in deep water at depths of 700 feet to 11.7 knots (19.8 ft/sec) near shore at depths of 60 feet.

Except for the area near Point Conception, the Santa Barbara Channel is protected from swells generated by distant storms by the Channel Islands. Ocean swells coming only from the west (directions 260 to 280°) can enter the Channel itself.

The Naval Weather Service Command (1971) has summarized climatological data on surface waves in the Santa Barbara Channel for the period of 1949 to 1970, with the exception of swell data which were generally available only from 1963 to 1970.

Table II-6 summarizes monthly frequencies of occurrence of waves of various heights and periods for the western portion of the Santa Barbara Channel. Waves in the central and eastern portions of the channel are generally less than those of the western portion.

Riffenburgh (1973) studied the distribution of bottom currents along the California coastline in connection with a proposed undersea aqueduct from northern to southern California. The currents were based on empirical extrapolations of a mathematical model of tidal currents. Riffenburgh found that bottom currents depend primarily on the configuration of the ocean bottom and continental shelf and do not necessarily decrease with increasing depth. In the Santa Barbara Channel, Riffenburgh predicted that bottom currents might be large and of potential danger to undersea constructions in three areas: 1) in the immediate vicinity of Point Conception; 2) on top of and along the slope north of the submerged

TABLE II-6

MONTHLY PERCENTAGE FREQUENCY OF OCCURRENCE OF WAVES OF VARIOUS HEIGHTS, AND PERIODS IN THE SANTA BARBARA CHANNEL.

Taken from Naval Weather Service Command, 1971

Data listed are for Naval Weather Service Command, Quadrangle 8 (34^{o} 00' to 34^{o} 30' north latitude; 120^{o} 00' to 120^{o} 30' west longtitude). Wave data (1949-1970) for these tables were selected as the higher of sea or swell when both were reported. If heights were equal, the longer period was chosen. Wave period is in seconds.

Month	Period	Frequency of waves 2 feet	6 feet	9 feet	12 feet
January (48 observations)	less than 6	8.3	.0	.0	.0
	6-7	8.3	4.2	.0	.0
	8-9	14.6	6.3	.0	.0
	greater than 9	6.3	4.2	.0	.0
February (65 observations)	less than 6	20.0	1.5	1.5	.0
	6-7	10.8	1.5	.0	.0
	8-9	15.4	7.7	1.5	.0
	greater than 9	15.4	10.8	.0	.0
March (40 observations)	less than 6	25.0	2.5	2.5	.0
	6-7	32.5	7.5	2.5	.0
	8-9	5.0	2.5	2.5	.0
	greater than 9	7.5	7.5	7.5	.0
April (48 observations)	less than 6	35.4	4.2	.0	.0
	6-7	20.8	6.3	.0	.0
	8-9	8.3	6.3	.0	.0
	greater than 9	4.2	2.1	2.1	2.1
May (38 observations)	less than 6	28.9	5.3	.0	.0
	6-7	26.3	7.9	5.3	2.6
	8-9	13.2	7.9	5.3	.0
	greater than 9	5.2	.0	.0	.0

TABLE II-6 Continued

Month	Period	Frequency of waves 2 feet	6 feet	9 feet	12 feet
June (56 observations)	less than 6	21.4	3.6	.0	.0
	6-7	16.1	3.6	1.8	1.8
	8-9	7.1	3.6	.0	.0
	greater than 9	.0	.0	.0	.0
July (58 observations)	less than 6	29.3	.0	.0	.0
	6-7	8.6	1.7	.0	.0
	8-9	5.2	1.7	.0	.0
	greater than 9	5.2	.0	.0	.0
August (47 observations)	less than 6	17.0	.0	.0	.0
	6-7	23.4	4.3	.0	.0
	8-9	4.3	.0	.0	.0
	greater than 9	.0	.0	.0	.0
September (35 observations)	less than 6	17.1	2.9	.0	.0
	6-7	28.6	5.7	.0	.0
	8-9	11.4	5.7	.0	.0
	greater than 9	2.9	.0	.0	.0
October (46 observations)	less than 6	34.8	4.3	2.2	.0
	6-7	19.6	4.3	.0	.0
	8-9	2.2	.0	.0	.0
	greater than 9	4.3	.0	.0	.0
November (69 observations)	less than 6	18.8	.0	.0	.0
	6-7	15.9	2.9	1.4	.0
	8-9	5.8	2.9	1.4	.0
	greater than 9	1.4	.0	.0	.0
December (31 observations)	less than 6	22.6	6.5	.0	.0
	6-7	19.4	6.5	3.2	.0
	8-9	6.5	3.2	.0	.0
	greater than 9	9.6	3.2	.0	.0

peninsula extending west into the Santa Barbara Basin from a point midway between Santa Barbara Point and the east end of Santa Cruz Island; and 3) along the slope extending southeast from the submerged peninsula and into the heads of Hueneme and Mugu Canyons (see Riffenburgh, pages 71-75).

4. Surface Waves

Surface waves are commonly thought of as being the combination of short period waves (seas) generated by local winds and longer period waves (swell) generated by distant storms. Surface wave conditions in the Santa Barbara Channel are relatively mild due to the few storms passing through the area and to the protection from the prevailing northwesterly winds provided by the Santa Ynez Mountains. The waters along the northern and eastern shores of the Channel are most protected while the waters near the Channel Islands and especially the area west of San Miguel Island have no protection and thus rough seas are common in these areas. Heavy seas are also encountered near canyons during Santa Ana winds and during northerly gales in winter.

The user of these climatological data is cautioned by the Naval Weather Service that ". . . it must be borne in mind that maritime meteorological data are available only from observations taken by ships in passage. Since mariners tend to avoid areas of bad weather, our samples may be somewhat biased to good weather conditions."

5. Severe Storm Wave Data

Prediction of the largest storm waves that might be expected in the Santa Barbara Channel are of interest for safety of operations. Riffenburgh (1973) presented data (table II-7) on the extreme wave conditions that might be expected in a 100 year period for five

TABLE II-7

Greatest extreme wave periods, lengths, and heights likely to be observed in a 100 year period for selected locations in the Santa Barbara Channel. Taken from Riffenburgh, 1973.

As an example of the usage of this table, the first entry can be read as: "We may be 80 percent confident that the greatest wave period which will occur in the next 100 years will not be greater than 18.5 seconds, the greatest wave height in the deep sea will not exceed 8.8 m., the greatest wave length over water of 200 m. depth will not exceed 527 m., and the greatest wave height over water of 200 m. depth will not exceed 8.5 m."

Latitude 34° 22′ Longitude 120° 30′
Approximate location: Pt. Conception

Confidence Bound (Probability)	Period, sec	Deep Sea Height, m	200-m Depth		100-m Depth		50-m Depth		20-m Depth	
			Length, m	Height, m	Length, m	Height, m	Length, m	Height, m	Length, m	Height, m
0.80	18.5	8.8	527	8.5	468	8.0	370	8.2	249	9.4
0.85	18.8	8.8	540	8.6	477	8.1	376	8.3	253	9.6
0.90	19.1	8.9	560	8.6	491	8.2	385	8.4	258	9.8
0.95	19.8	9.1	592	8.7	513	8.3	400	8.7	268	14.9
0.96	19.9	9.2	602	8.8	520	8.4	404	8.7	273	15.0
0.97	20.2	9.2	615	8.8	528	8.4	410	8.8	278	15.2
0.98	20.5	9.3	634	8.9	541	8.5	418	9.0	286	15.5
0.99	21.1	9.5	664	9.0	562	8.7	432	9.2	299	15.9
0.995	21.7	9.6	696	9.1	582	8.8	446	9.4	313	16.3
0.999	23.0	10.0	768	9.3	630	9.2	478	9.9	346	17.3

TABLE II-7 (Continued)

Latitude 34° 22′   Longitude 120° 05′
Approximate location: East of Pt. Conception

Confidence Bound (Probability)	Period, sec	Deep Sea Height, m	200-m Depth		100-m Depth		50-m Depth		20-m Depth	
			Length, m	Height, m	Length, m	Height, m	Length, m	Height, m	Length, m	Height, m
0.80	20.7	7.0	644	6.7	548	6.4	423	6.8	281	7.9
0.85	21.2	7.1	667	6.7	563	6.5	433	6.9	287	8.1
0.90	21.7	7.2	698	6.8	584	6.6	447	7.0	296	8.3
0.95	22.7	7.4	751	6.9	619	6.8	470	7.3	313	13.7
0.96	23.0	7.4	767	6.9	630	6.8	478	7.4	319	13.8
0.97	23.4	7.5	789	6.9	644	6.9	487	7.5	328	14.0
0.98	24.0	7.6	818	7.0	663	7.0	500	7.6	341	14.3
0.99	24.9	7.7	868	7.1	696	7.2	522	7.9	362	14.8
0.995	25.9	7.9	918	7.2	729	7.4	544	8.2	383	15.3
0.999	28.1	8.3	1031	7.6	804	7.9	595	8.8	435	16.4

TABLE II-7 (Continued)

Latitude 34° 17′   Longitude 119° 45′
Approximate location: Santa Barbara

Confidence Bound (Probability)	Period, sec	Deep Sea Height, m	200-m Depth		100-m Depth		50-m Depth		20-m Depth	
			Length, m	Height, m	Length, m	Height, m	Length, m	Height, m	Length, m	Height, m
0.80	17.4	6.6	470	6.5	427	6.1	343	6.2	233	7.0
0.85	17.7	6.7	483	6.5	437	6.1	350	6.2	237	7.1
0.90	18.0	6.7	501	6.6	449	6.2	358	6.3	242	7.2
0.95	18.6	6.8	530	6.6	470	6.2	371	6.4	250	7.3
0.96	18.8	6.8	539	6.6	477	6.3	376	6.4	253	7.4
0.97	19.0	6.9	551	6.6	485	6.3	381	6.5	256	7.5
0.98	19.3	6.9	568	6.7	497	6.3	389	6.6	261	7.6
0.99	19.9	7.0	598	6.7	517	6.4	402	6.7	269	7.8
0.995	20.4	7.1	627	6.8	536	6.5	415	6.8	276	8.0
0.999	21.7	7.3	694	6.9	581	6.7	445	7.1	295	8.2

TABLE II-7 (Continued)

Latitude 34° 10′ Longitude 120° 20′
Approximate location: San Miguel Island

Confidence Bound (Probability)	Period, sec	Deep Sea Height, m	200-m Depth		100-m Depth		50-m Depth		20-m Depth	
			Length, m	Height, m	Length, m	Height, m	Length, m	Height, m	Length, m	Height, m
0.80	17.4	7.5	466	7.4	425	6.9	342	7.0	232	7.9
0.85	17.6	7.6	479	7.4	434	7.0	348	7.0	236	8.0
0.90	18.0	7.7	497	7.5	447	7.0	356	7.2	241	8.2
0.95	18.5	7.8	527	7.6	468	7.2	370	7.3	249	8.4
0.96	18.7	7.9	536	7.6	474	7.2	374	7.4	252	8.5
0.97	18.9	7.9	548	7.7	483	7.3	380	7.5	255	8.6
0.98	19.3	8.0	565	7.7	495	7.3	388	7.6	260	8.8
0.99	19.8	8.2	595	7.8	515	7.5	401	7.8	268	9.0
0.995	20.4	8.3	624	7.9	534	7.6	414	8.0	276	9.3
0.999	21.6	8.7	692	8.2	580	8.0	444	8.4	303	15.0

TABLE II-7 (Continued)

Latitude 34°05′ Longitude 119°40′
Approximate location: Santa Cruz Island

Confidence Bound (Probability)	Period, sec	Deep Sea Height, m	200-m Depth		100-m Depth		50-m Depth		20-m Depth	
			Length, m	Height, m	Length, m	Height, m	Length, m	Height, m	Length, m	Height, m
0.80	17.0	9.8	449	9.7	412	9.1	333	9.1	227	10.3
0.85	17.2	9.9	460	9.8	419	9.2	338	9.2	230	10.4
0.90	17.5	10.1	473	9.9	430	9.3	345	9.4	234	10.6
0.95	18.0	10.3	497	10.0	447	9.4	356	9.6	241	11.0
0.96	18.1	10.4	505	10.1	452	9.5	360	9.7	243	15.6
0.97	18.3	10.4	515	10.2	459	9.6	364	9.8	247	15.8
0.98	18.6	10.6	529	10.3	469	9.7	371	9.9	253	16.1
0.99	19.0	10.8	552	10.4	485	9.9	382	10.2	264	16.5
0.995	19.5	11.0	576	10.6	502	10.0	392	10.4	275	17.0
0.999	20.5	11.5	631	10.9	539	10.5	417	11.0	300	18.0

locations in the Santa Barbara Channel. For these same locations he also presented data (table II-8) on the greatest expected bottom surge currents that would be associated with these extreme waves.

Of the five locations used, the largest waves are expected near Point Conception and the Channel Islands and the lesser extreme waves at the points along the north shore of the Channel east of Point Conception and near Santa Barbara.

A report by Oceanographic Services, Inc., March 1969, titled "Storm wave study, Santa Barbara Channel" derived seven storm wave characteristics at five study locations in the Santa Barbara Channel. Significant wave-height-period-direction is presented for ten storms between March 1905 and February 1963. Additionally presented for the Santa Barbara Channel are relative wave heights for: a southwest swell, a westerly swell, and a west and northwest sea and swell.

Oceanographic Services, Inc., (OSI) June 1971, prepared a "Study of ocean currents affecting proposed pipeline in Santa Barbara Channel, easterly route". This study, mentioned previously in connection with subsurface currents, used available historical records to hindcast severe storm conditions for the 65-year period 1905 to 1970. Table II-9 presents the hindcast wave directions, significant height, and period at a location east of Point Conception in the Santa Ynez Unit of the Santa Barbara Channel. The study showed that, at the location of the pipeline, large waves would come from only two directions or "windows". One, from the southeast (design direction of 123°) are those waves generated locally in the Santa Barbara Channel. These waves are of short period (9 seconds) and it is estimated that 80 percent of the significant waves generated by a 100-year storm would

TABLE II-8

Maximum expected bottom surge velocities by depth over the next 100 years at locations in the Santa Barbara Channel. Taken from Riffenburgh, 1973. As an example of the usage of this table, the first entry can be read as: "We may be 80 percent confident that the greatest bottom surge velocity which will occur in the next 100 years at the location near Point Conception at 200 m. will not be greater than 13.4 cm./sec."

Latitude 34°22' Longitude 120°30'
Approximate location: Point Conception

Confidence Bound (Probability)	Depth,m			
	200	100	50	20
0.80	13.4	38.1	73.0	152.4
0.85	14.1	39.1	74.4	154.8
0.90	15.1	40.4	76.2	158.3
0.95	16.8	42.5	79.2	241.3
0.96	17.4	43.2	80.2	242.3
0.97	18.0	44.0	81.4	243.4
0.98	19.0	45.2	83.1	245.0
0.99	20.6	47.2	86.1	247.7
0.995	22.2	49.2	89.0	250.3
0.999	25.7	53.7	95.9	256.5

TABLE II-8 (Continued)

Latitude $34^{o}22'$ Longitude $120^{o}05'$
Approximate location: East of Point Conception

Confidence Bound (Probability)	Depth,m			
	200	100	50	20
0.80	14.7	34.4	63.1	129.9
0.85	15.5	35.4	64.6	132.7
0.90	16.6	36.8	66.6	136.5
0.95	18.4	39.1	70.0	224.6
0.96	19.0	39.8	71.1	225.7
0.97	19.7	40.7	72.5	227.1
0.98	20.7	42.0	74.4	229.0
0.99	22.3	44.1	77.7	232.3
0.995	23.9	46.2	81.1	235.5
0.999	27.4	51.1	88.8	242.7

Latitude $34^{o}17'$ Longitude $119^{o}45'$
Approximate location: Santa Barbara

Confidence Bound (Probability)	Depth,m			
	200	100	50	20
0.80	8.1	26.7	52.9	111.3
0.85	8.6	27.3	53.8	112.8
0.90	9.3	28.2	54.9	114.9
0.95	10.5	29.7	56.8	118.5
0.96	10.9	30.2	57.5	119.6
0.97	11.4	30.7	58.2	121.1
0.98	12.0	31.5	59.3	123.1
0.99	13.2	32.9	61.2	126.6
0.995	14.3	34.2	63.0	129.9
0.999	16.7	37.2	67.3	138.0

TABLE II-8 (Continued)

Latitude 34°10' Longitude 120°20'
Approximate location: San Miguel Island

Confidence Bound (Probability)	Depth,m			
	200	100	50	20
0.80	9.0	30.0	59.8	125.8
0.85	9.6	30.9	60.9	128.0
0.90	10.5	32.1	62.5	130.9
0.95	12.0	34.0	65.2	135.9
0.96	12.4	34.6	66.0	137.5
0.97	13.0	35.4	67.1	139.6
0.98	13.8	36.4	68.6	142.5
0.99	15.3	38.2	71.2	147.4
0.995	16.6	40.0	73.8	152.2
0.999	19.8	44.1	79.9	239.0

Latitude 34°05' Longitude 119°40'
Approximate location: Santa Cruz Island

Confidence Bound (Probability)	Depth,m			
	200	100	50	20
0.80	10.9	38.3	77.2	163.2
0.85	11.6	39.3	78.7	165.9
0.90	12.5	40.7	80.6	169.6
0.95	14.1	43.1	83.9	175.7
0.96	14.6	43.8	84.9	250.7
0.97	15.3	44.7	86.3	252.2
0.98	16.2	46.0	88.2	254.2
0.99	17.8	48.3	91.4	257.6
0.995	19.5	50.5	94.6	260.8
0.999	23.3	55.5	102.2	267.8

TABLE II-9

SEVERE STORM WAVE DATA NEAR NORTHERN
SHORE OF SANTA BARBARA CHANNEL EAST OF POINT CONCEPTION

(From Oceanographic Services, Inc., March 1971)

	Date	θ (degrees true)	H_s (significant height, feet)	T_s (period, sec)
Westerly	Feb. 1963	215	20.0	13
	Feb. 1959	240	13.5	12
	Apr. 1958	270	14.5	11
	Apr. 1958	270	17.0	15
	Apr. 1958	270	18.0	15
	Feb. 1941	270	12.0	10
	Feb. 1941	240	17.0	9
	Dec. 1916	270	15.0	12
	Feb. 1915	240	18.5	10
	Feb. 1915	270	14.0	11
	Jan. 1914	245	15.5	13
	Jan. 1914	270	12.0	11
	Mar. 1912	220	11.0	9
	Mar. 1905	240	20.5	14
Southeasterly	Feb. 1963	110	10.0	8
	Feb. 1959	110	16.0	8
	Feb. 1941	110	17.0	8
	Dec. 1927	120	17.0	9
	Feb. 1915	135	13.5	9
	Jan. 1914	135	10.0	8
	Mar. 1905	110	18.0	9

be between 17 and 18 feet high. The other window is from the west (design direction of 260°) and includes those waves generated by storms in the open Pacific Ocean. These waves have a longer period (15 seconds) and are higher than the southeasterly waves--OSI estimated that 90 percent of the significant waves generated by a 100-year storm would be between 20 and 22 feet high.

6. Tsunamis[1]

The term tidal wave, which is often used to describe long period water gravity waves associated with submarine seismic disturbances, is now seldom used as such waves are unrelated to the tides. Instead the Japanese word tsunami is usually used instead.

Tsunamis are generated by movement of the ocean bottom associated with earthquakes and have a principal period that is related to the magnitude of the earthquake, the diameter of the rupture area, and the water depth. The greater the magnitude of the earthquake, the longer the period. Also the greater the focal depth of the earthquake, the less the magnitude of the tsunami.

Once generated, tsunamis travel at great speed and decay slowly, thus reaching great distances. During transit the waves approximately follow great circle paths although they can be refracted by bathymetry. When the waves reach the edge of a continental shelf, tsunami waves begin to interact with the bottom, to decrease in wave length and increase in amplitude. Because of their long wavelengths tsunamis are unaffected by the small details of

[1] Much of the material of this section was abstracted from E. E. Welday in California Division of Mines and Geology, 1971, Comprehensive ocean area plan: Appendix V, Volume 1, pp. 59-78.

the bathymetry but instead are affected by the average trend of the coastline. Storm waves if present locally may increase the wave height of the tsunami and allow resultant waves to reach an impact on structures not designed to withstand them.

There is a possibility of tsunami damage to shallow water structures and onshore facilities in the Santa Barbara Channel from both distant and local earthquakes. To quote Welday (1971):

> "A review of the World Seismicity Map compiled from ESSA, C&GS epicenter data 1961-1967 indicates that most of the shallow offshore epicenters during 1961-1967 were concentrated near the Pacific trench systems. The areas off Alaska, Kamchatka, Japan, Mexico and Peru-Chile have had most of the seismic activity. An epicenter map of California 1934-1969 suggests the offshore areas most likely to be troublesome would be the Santa Barbara Channel, the San Pedro Channel, off Point Arguello and off Cape Mendocino and the Blanco fracture zone. The probability of vertical displacement in these areas is unknown, however some waves were generated by bottom displacement during the 1927 earthquake at Point Arguello. In the same vicinity, the 1812 earthquake was accompanied by a tsunami.
>
> "It is concluded that a tsunami from the Aleutians, the Gulf of Alaska or Kamchatka is probable, perhaps a 20 year event. A local tsunami due to vertical displacement of the sea floor (such as occurred in the Gulf of Alaska in 1964 or off Chile in 1960) is less likely, but probable at a longer recurrence interval."

A tsunami wave originating in the Aleutians or Gulf of Alaska would probably not refract around Point Conception and enter the Santa Barbara Channel to any great extent. Similarly, waves impinging on the Santa Barbara Channel from the Southern Hemisphere would be partially damped by the basin and island topography of the continental shelf to the south of the Channel. Waves from the west, however, might be expected to enter the Channel and possibly cause damage.

Riffenburgh (1973) studied the probability of tsunami damage on the proposed California undersea aqueduct. He found that the tsunami danger in the Southern California Bight would be small. He predicted that water velocities at San Diego would be only about one third of those found farther north near Crecent City. At the latitude of the Santa Barbara Channel, Riffenburgh predicted that the horizontal water particle velocity caused by an extreme tsunami would vary from about 0.29 knots (14.04 cm./sec) at 200 m. depth to about 1.5 knots (78.97 cm./sec) at 20 m. depth.

7. Water Characteristics

The physical and chemical characteristics of coastal waters vary more rapidly in time and space than do waters farther offshore due to the larger number of processes occurring inshore and to complex interactions between the processes.

a. Temperature

Temperature fluctuations in inshore areas are caused by heating and cooling by the atmosphere, by advection of water of different temperature in from other areas, by upwelling of colder waters from below, and by mixing of warm surface waters with the cold deeper waters. The water in the Southern California Bight stratifies in summer with a thermocline present at 20- to 30-meters depth during the months May to October. Figure II-28 presents contours of water temperature data for a location in the Southern California Bight; figure II-28 presents water temperature profiles in the Santa Barbara Channel.

b. Salinity

Salinity fluctuations in inshore areas are caused by precipitation and evaporation at the sea surface, by runoff of fresh water

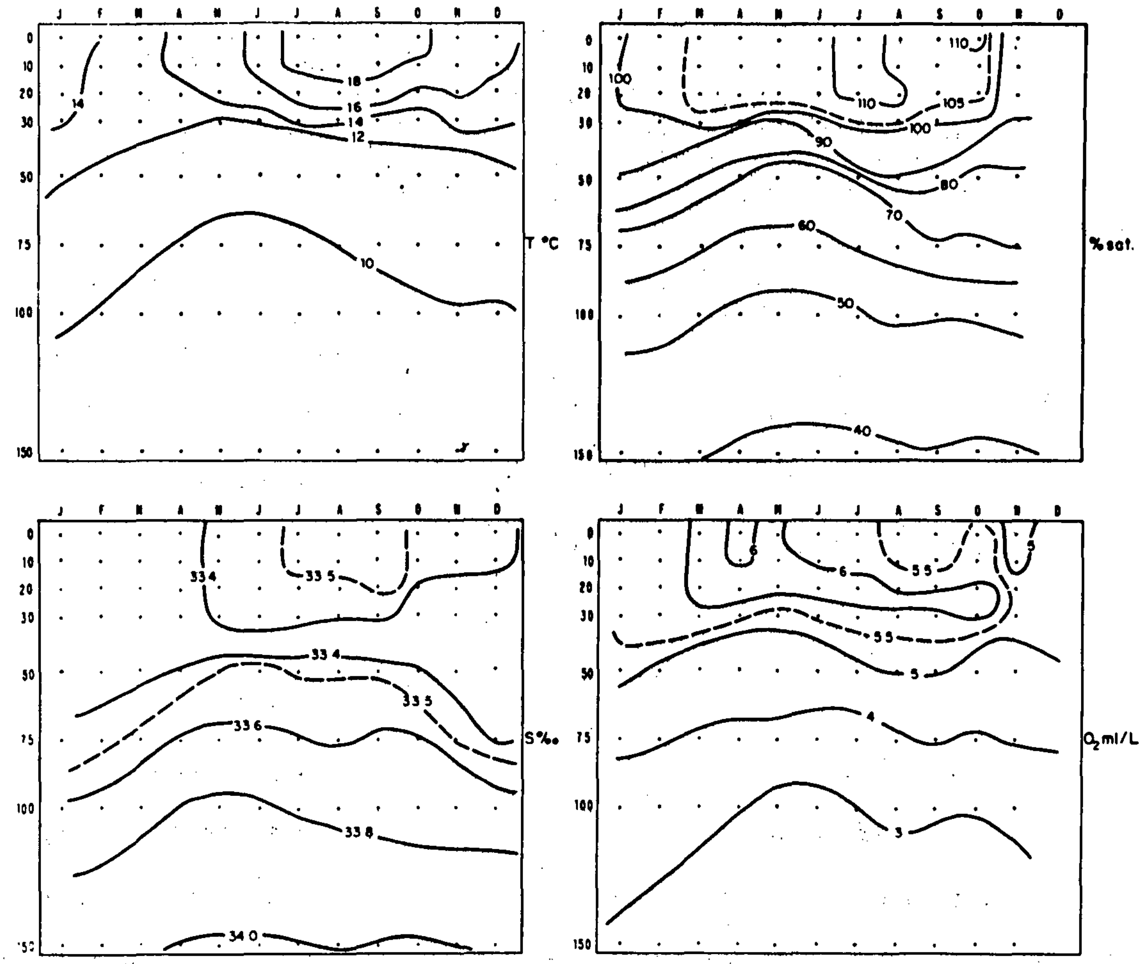


FIGURE II-28

TYPICAL OCEANOGRAPHIC CONDITIONS AT A LOCATION IN THE SOUTHERN CALIFORNIA BIGHT BY SEASONS

(From Reid, 1965, Figure 32)

Average seasonal variation of temperature, salinity, dissolved oxygen and percent of saturation of dissolved oxygen in the upper 150 m between Santa Catalina and San Clemente Islands (33° 12' N, 118° 24' W) in the period 1950-1953.

from adjacent land areas, by advection of water of different salinity in from other areas, by upwelling of water from below, and by mixing. Salinity data are shown in figures II-28 and II-29; salinity is expressed in units of parts per thousand (0/00).

c. Density

The density of sea water is a function of both the temperature and salinity of the water. Although the relationship is non-linear density increases as temperature decreases and as salinity increases. Since in the Southern California Bight temperature decreases and salinity increases with increasing depth, both act in concert to increase density with depth. The variation of density with depth in the Southern California Bight divides the water into a shallow surface, wind-mixed layer of 10- to 50-meters thickness and the thick, deep bottom layer. Typical profiles of density in the Santa Barbara Channel are shown in figure II-29.

d. Hydrogen Ion Concentration

The concentration of hydrogen ion is measured on the pH scale (where a pH of 1 is very acidic, 7 is chemically neutral, and 14 is very alkaline). Within the coastal waters from Point Conception to the Mexican border, the hydrogen ion concentration ranged from a minimum of pH 7.5 to a maximum of 8.6; the mean was 8.1. Most determinations between 7.6 and 7.8 were from samples at 200 to 300 feet. (Allan Hancock Foundation, 1965, p. 92).

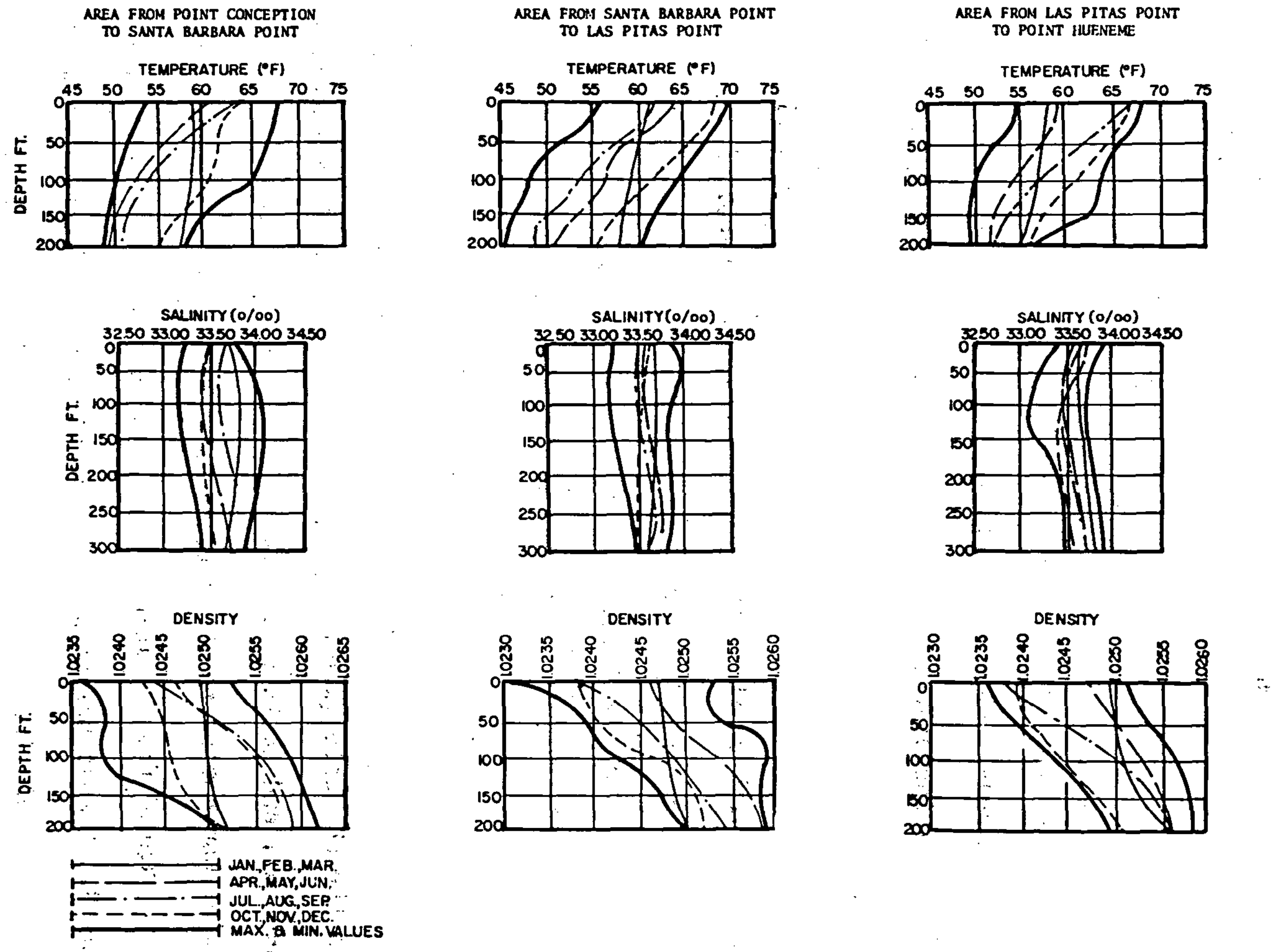
e. Dissolved Oxygen

Oxygen is a product of plant photosynthesis, and in turn is used by plants and animals in their metabolic processes. In addition to photosynthesis by marine flora, the distribution of dissolved oxygen is

FIGURE II-29

MEAN TEMPERATURE, SALINITY, AND DENSITY

(From Allan Hancock Foundation, 1965, Figures 3.3A, 3.3B, pp. 58-59.)



influenced by free exchange with the overlying atmosphere, turbulent mixing of the upper ocean layers by winds, tides, and currents.

At the surface, the water of the Southern California Bight is nearly always saturated with dissolved oxygen. Values at times can reach 140 percent of saturation. A decrease of dissolved oxygen occurs with depth, but mean values near 60 m usually do not fall below 4 mg/L, which is about 50 percent of saturation and may not provide adequate protection for certain forms of marine life.[1] Dissolved oxygen data for the Southern California Bight and Santa Barbara Channel are presented in figures II-28 and II-30.

In deeper waters and, particularly, in several of the isolated basins of the Southern California Bight, including the Santa Barbara Basin, oxygen values are extremely low. Decomposable organic material is present in such high quantities in the waters and sediments of these nearshore basins that dissolved oxygen values below the sill depths are in the order of 0.3 to 0.4 mg/L, and may fall as low as 0.1 mg/L. (Southern California Coastal Water Research Project, 1972).

f. Inorganic Nutrients

Phytoplankton growth is dependent on an adequate supply of three essential nutrients: nitrogen, phosphorous, and silica. The primary sources of supply of these nutrients are upwelling of deep waters, advection, and discharge from land sources (rivers and industrial and domestic sewerage). The primary process depleting the concentration of nutrients in the surface waters is rapid uptake by phytoplankton and consequent removal of the phytoplankton by predation or by sinking. As a

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[1] (The State Water Resources Control Plan - Ocean Waters allows only a ten percent depression in the naturally occurring oxygen level.)

FIGURE II-30

MEAN VERTICAL DISTRIBUTION OF OXYGEN BY SEASONS, DISSOLVED OXYGEN (mg/L)
(From Allan Hancock Foundation, 1965, Figure 3.8A, p.70)

POINT CONCEPTION TO
SANTA BARBARA POINT

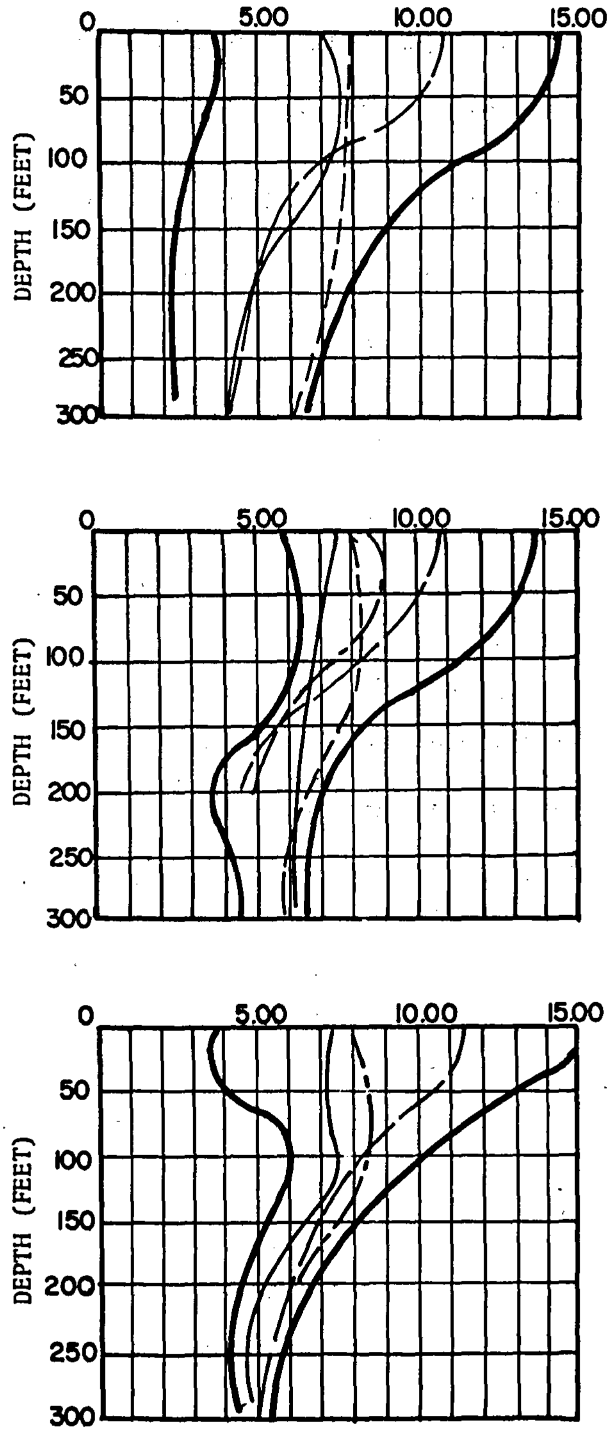
(AREA I)

SANTA BARBARA POINT
TO LAS PITAS POINT

(AREA IIa)

LAS PITAS POINT
TO POINT HUENEME

(AREA IIb)



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— — —— APR., MAY, JUNE
—·—·— JUL., AUG., SEP.
—·——— OCT., NOV., DEC.
━━━━ MAX. & MIN. VALUES

result, only low concentrations of nutrients are normally found in surface waters, except in local source areas.

"The common inorganic nitrogenous nutrients are nitrate, nitrite, and ammonia. In natural sea water, nitrate is the dominant of these three forms. Nitrite is usually an intermediate form appearing either as nitrate is reduced to ammonia or in the reverse process, as ammonia is oxidized to nitrate. Ammonia is normally present only in small concentrations in natural waters, although in nitrogen-deficient waters it may be the dominant form of the nitrogenous nutrients.

"The Hancock Foundation surveys found nitrate concentrations in surface waters ranging from 0.01 to 0.16 mg/L over the study area.[1]

Surface concentrations in the spring months were somewhat higher than those found during the fall and winter months. Nitrate concentrations were significantly higher at 90 m depth, where the mean values ranged from approximately 0.2 to 0.4 mg/L." (Fron SCCWRP, 1972, p. 123).

Upwelling of deep waters is considered to be the primary process that brings nutrient-rich waters to the surface in the California Current region. The surface concentrations of phosphorous are highest during the summer months when upwelling is greatest (figure II-31). Typical values of phosphate and silicate for the Santa Barbara Channel are shown in table II-10.

g. Trace Metals

"Although trace materials such as metals are difficult to measure and are therefore less well-known, many are as essential to

[1] (Point Conception to the Mexican Border).

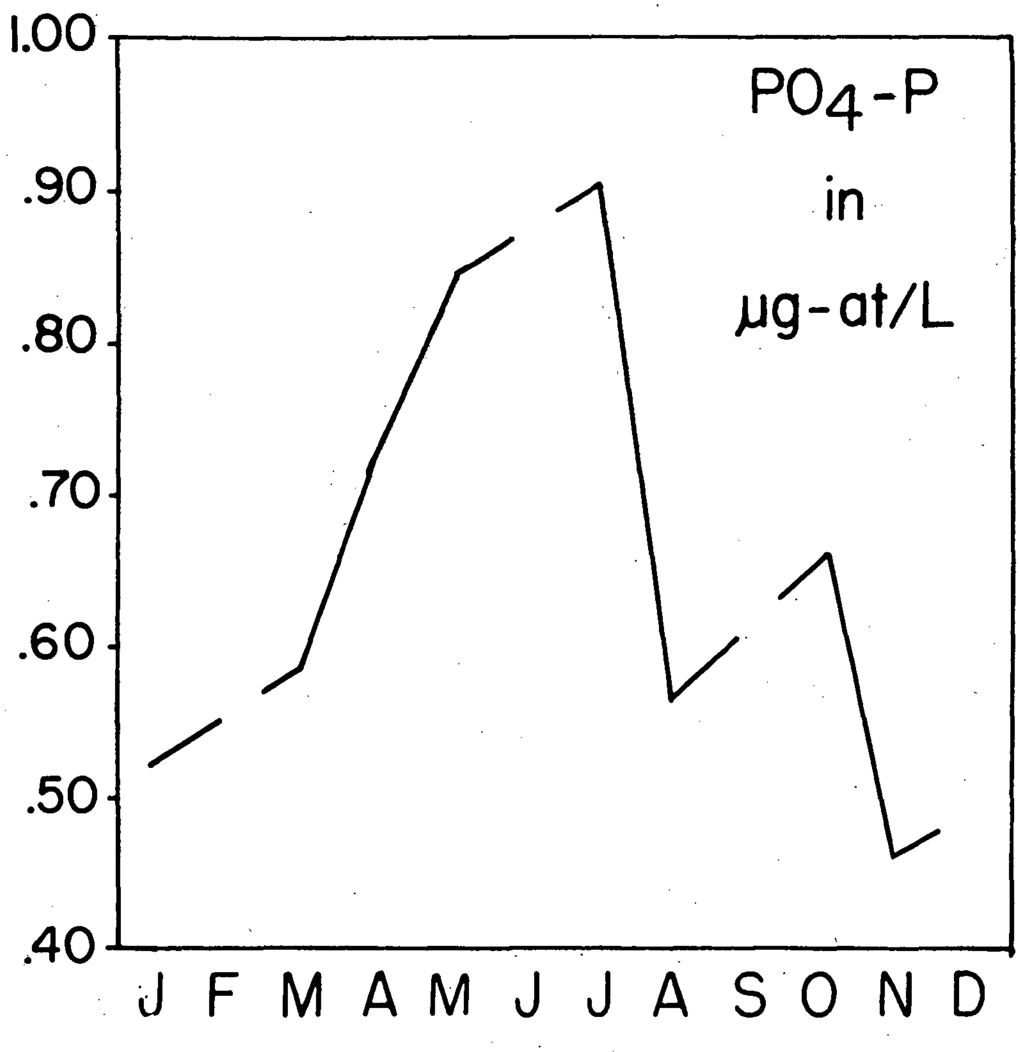

FIGURE II-31

TYPICAL PHOSPHATE-PHOSPHORUS CONCENTRATIONS AT A LOCATION OFF POINT ARGUELLO BY SEASONS

(From Reid, 1965, Figure 33)

Average phosphate-phosphorus (ug-at/L) at the sea surface at a position 18 miles southwest of Point Arguello, from data collected in various years between 1949 and 1964.

TABLE II-10

MINIMUM AND MAXIMUM PHOSPHATE (PO_4)
AND SILICATE (SiO_2)

(From Allan Hancock Foundation, 1965, p. 82)

Area	Depth	Range (mg/L) PO_4[1]	SiO_2
Point Conception to Santa Barbara Point	0	0.01-0.08	0.10- 1.40
	50	.01- .19	.12- 1.80
	100	.03- .20	.08- 2.41
	200	.05- .19	.36- 2.58
	300	.09- .20	.85- 2.38
Santa Barbara Point to Las Pitas Point	0	0.01-0.20	tr. - 1.14
	50	.01- .13	tr. - 1.23
	100	.01- .16	tr. - 0.95
	200	.08- .19	.32- 1.11
	300	.13- .21	.72- 1.67
Las Pitas Point to Point Hueneme	0	0.02-0.13	0.28- 1.88
	50	.02- .14	.25- 1.68
	100	.04- .18	.22- 2.02
	200	.08- .19	.86- 2.64
	300	.11- .23	1.43-(2.85)*

* Estimated.

[1] Values rounded to two decimal places by U. S. Geological Survey.

biological productivity as are the better known nutrients such as phosphate, nitrate, and silica. Examples of physiologically essential metals are copper, cobalt, zinc, iron, manganese, boron, molybdenum, and selenium. Yet these same trace elements, which are essential to a healthy physiological state, are toxic in certain concentrations to some organisms and may also be concentrated and/or transformed to a state toxic to organisms high in the food web. As trace metals are present in waste discharges, it is essential to learn the effects, if any, that they have on local and regional marine waters.[1]

"It is difficult to ascertain general concentration levels for trace metals in sea water. The difficulty arises from two sources. First, the sea water concentrations of these constituents are usually near the limit of detection by analytical techniques, and contamination of samples during collection and analysis is common. Second, there is usually uncertainty as to the physical/chemical state of the constituent, and analysis is difficult.

"The variability resulting from these factors is superimposed on the natural variability of concentrations in the waters. Total concentrations and the state of trace materials in coastal waters can be expected to vary significantly from those in offshore waters. Similarly, concentrations in surface waters and in deep ocean water should differ significantly. Other factors, such as heavy rains, storm runoff in the coastal waters, upwelling of subsurface water, or extensive alterations in plankton population should produce

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[1] U.S. Geological Survey notation: Studies are cited in Southern California Coastal Water Research Project, 1972, pp. 125-129. These pertain to Los Angeles waste water outfalls and world-wide data and are not directly applicable to the Santa Barbara Channel.

additional differences" (Southern California Coastal Water Research Project, 1972, p. 125).

h. Light and Water Transparency

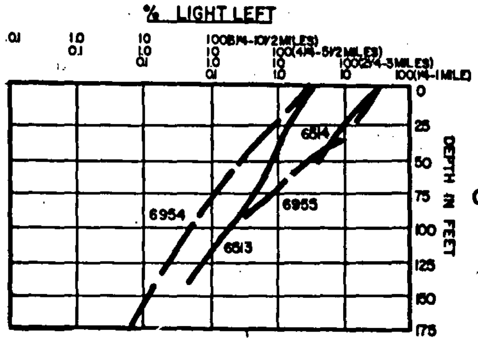
Light is important biologically because it provides the energy source for all photosynthesis and ultimately all biological activity. Because the intensity of available light diminishes with increasing depth, light levels strongly affect the vertical distribution and migrations of plankton and of the vertical zonation of attached marine plants such as kelp. A commonly used criterion of water transparency is the greatest depth at which a white metal disc, 30 cm in diameter (Secchi disc) can be seen from the surface. The depth to which light is useful for photosynthesis has been estimated at about 2.5 times the Secchi disc depth. Along the California coast, the mean visual transparency varies from less than 6 m to more than 15 m; lower values occur close to shore. Within one mile of the coast, visual transparencies of less than 6 m are common opposite alluvial land plains; transparencies of 6 to 12 m are more typical off rocky shores.

The attenuation of light through water is expressed as a diffuse extinction coefficient, which relates the light remaining at a depth to the incident light. Extinction coefficient data are obtained by a variety of photometric instruments. Extinction coefficients along the southern California coast are in the range of 0.08 to 0.40 per meter (Southern California Coastal Water Research Project, 1972, pp. 128, 130). Figure II-32 presents percentage of light remaining-versus-depth for several locations and seasons within the Santa Barbara Channel. The extinction coefficient is sensitive to the quantity and size of suspended living and non-living particles in the water, and to the kind and quantity of dissolved organic

FIGURE II-32

LIGHT EXTINCTION CURVES AND VISUAL TRANSPARENCIES--FALL AND SPRING SEASONS
(From Allan Hancock Foundation, 1965, Figure 3.41A, p. 117)

GAVIOTA SHELF

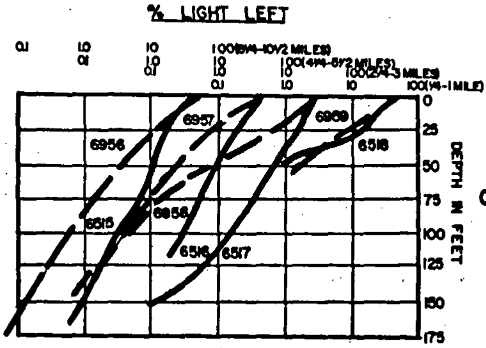


CRUISE 394-FALL (solid line)

CRUISE 411-SPRING (dashed line)

CRUISE	STATION	K	D	S
394	6513	0.089	62	2 1/4
	6514	0.130	39	1/4
411	6954	0.189	28	2 1/2
	6955	0.228	18	1/2

SANTA BARBARA SHELF

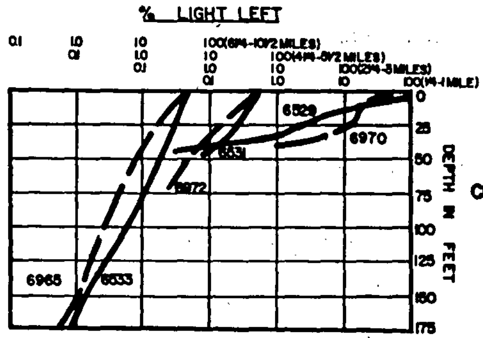


CRUISE 394-FALL (solid line)

CRUISE 411-SPRING (dashed line)

CRUISE	STATION	K	D	S
394	6515	0.060	68	6 1/4
	6516	0.100	61	4 1/4
	6517	0.113	35	2 1/4
	6518	0.248	26	1/2
411	6956	0.160	33	6 1/2
	6957	0.197	23	4 1/4
	6958	0.180	15	2 1/2
	6959	0.204	17	1/2

VENTURA SHELF

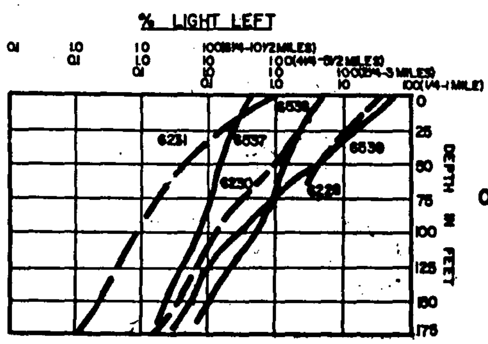


CRUISE 394-FALL (solid line)

CRUISE 411-SPRING (dashed line)

CRUISE	STATION	K	D	S
394	6529	0.551	8	3/4
	6531	0.124	33	5
	6533	0.077	70	8 1/2
411	6970	0.298	10	3/4
	6972	0.145	20	4 1/2
	6965	0.097	25	8 1/2

POINT MUGU SHELF



CRUISE 394-FALL (solid line)

CRUISE 376-SPRING (dashed line)

CRUISE	STATION	K	D	S
394	6537	0.065	65	5
	6538	0.083	65	3
	6539	0.140	27	1
376	6231	0.116	33	5
	6230	0.139	35	3
	6228	0.257	27	1

K = mean extinction coefficient of light between a dpeth of five feet and that at which the Secchi disc disappeared

D = Secchi disc depth in feet

S = distance of the station from shore in miles substances. These in turn are dependent on the intensity of life processes and sediment load, both of which increase in coastal areas.

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