DEVELOPMENT AND PRODUCTION PLAN

PLATFORM HARVEST PROJECT

PACIFIC OCS REGION
OFFSHORE SANTA BARBARA COUNTY

POINT ARGUELLO FIELD
LEASE NO. OCS P-0315
TRACT NO. 003 (OCS SALE NO. 48)
BLOCK NO. 55N-85W

TEXACO U.S.A., LEASE OPERATOR

AUGUST 1983

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SECTION I - OVERVIEW OF DEVELOPMENT AND PRODUCTION

As operator of Lease OCS P-0315, Texaco Inc. (Texaco) proposes to install a bottom-founded drilling and production platform (Platform Harvest) and subsea pipelines for the purpose of developing and producing oil and natural gas reserves from the Point Arguello field, located approximately 11 miles (17.7 km) west of Point Conception in the westernmost portion of the Santa Barbara Channel, California (Figures I-1 and I-2). Texaco's proposed facilities will be integrated fully with transportation, treating, and storage facilities that will be constructed by other operators. To minimize redundancy of effort, this Development and Production Plan (DPP) and its associated Environmental Report (Production) (ER(P)) provide detailed information concerning Texaco's proposed facilities only. Facilities to be constructed by other operators are described in a general fashion; the reader is referred to the appropriate DPP's and ER(P)'s for detailed information on these elements (e.g., Exxon Company, U.S.A., 1982; Chevron U.S.A. Inc., 1983).

Lease OCS P-0315 was acquired in Lease Sale No. 48 (29 June 1979) by a group consisting of Texaco (35% interest), Pennzoil Oil & Gas, Inc. (25%), Sun Exploration and Production Company (20%), and Koch Industries, Inc. (20%). The successful bid was $35,294,949.60, or $8267.50 per acre. Texaco was designated as the lease operator.

Exploration on the lease began in October 1981 (OCS P-0315 #1) and discovery of the Point Arguello field on the lease was announced in June 1982. Subsequent drilling confirmed the discovery (OCS P-0315 #2 and #3). The main productive zones in the discovery and confirmation wells occurred within an approximately 1000-ft (305-m) interval within the Miocene Monterey Formation at depths up to about 8300 ft (2530 m). Additional potentially productive zones are present at shallower depths. Exploratory drilling by Chevron on adjacent Leases OCS P-0316, P-0450, and P-0451 and Conoco's exploratory drilling on nearby Lease P-0320 has provided additional data to better define the overall areal extent of the Point Arguello field (Figure I-3).

Texaco's principal objective for the proposed Platform Harvest project is to produce oil and natural gas while receiving an equitable return on the invested capital. In accordance with the policies of the OCS Lands Act, as amended, Texaco has designed the proposed Platform Harvest project to minimize the potential for occurrence of significant adverse impacts on the human, marine, and coastal environments while providing for orderly energy resource development. Texaco believes that implementation of the proposed project is justified at the present time because it is consistent with overall state and national energy policies aimed at maximizing OCS energy resource production. To the extent that this reduces U.S. dependence on foreign energy sources, undesirable social and economic effects of that dependence can be avoided.

Texaco's proposed project will involve a new bottom-founded drilling and production platform (Platform Harvest). Produced fluids will be delivered via new subsea pipelines to Chevron's proposed Platform Hermosa where they will be commingled with fluids from other production facilities and transported to shore in common-carrier or shared pipelines. These pipelines will continue onshore to Chevron's proposed oil and gas treating facilities at Gaviota. After treating at Gaviota, product crude oil will be shipped by pipeline to proposed consolidated tank facilities in the Corral/Las Flores canyons area where it will be stored prior to being loaded into tankers at the proposed Las Flores (marine) Terminal. Alternatively, the crude oil could be transported via tanker or pipeline from Getty's Gaviota marine terminal or via a southern California coastal pipeline depending on the resolution of current planning issues related to coordination of regional offshore oil and gas development activities. Treated gas will be delivered to a regional transmission line located near the Gaviota treating facility. The overall systems flow and project schedule are shown on Figures I-4 and I-5. All facilities other than Platform Harvest and the pipelines to Platform Hermosa will be constructed and run by other operators.

As mentioned previously, additional exploration has been and is being conducted by Chevron and Conoco to determine the overall areal extent and commercial potential of the Point Arguello field. Depending on the results of these exploration programs, additional development could be proposed in the vicinity of Lease OCS P-0315. Should additional development be proposed, addenda to existing DPP's or additional DPP's would be submitted, as appropriate.

In accordance with Title 30, Code of Federal Regulations (CFR) 250.34 and Pacific Region OCS Order No. 8, this DPP for the Platform Harvest project is hereby submitted for approval. This document should be read in conjunction with the accompanying ER(P) for the project.

This DPP contains complete descriptions of the following aspects of the project:

- Geology
- Reservoir evaluation
- Platform site studies, engineering design, and installation
- Pipeline corridor studies, engineering design, and installation
- Drilling program, equipment, and procedures
- Offshore production facilities and systems flow
- Oil and gas treating facilities
- Product storage and transportation
- Termination and abandonment

Appendices to the main body of the DPP include:

- Proprietary geotechnical studies
- Detailed facilities and process flow diagrams
- Proprietary geologic and reservoir data
- Critical Operations and Curtailment Plan
- H_2S Contingency Plan
- Oil Spill Contingency Plan

The proprietary geotechnical studies, geologic and reservoir data, detailed facilities and engineering flow diagrams, and the Oil Spill Contingency Plan are submitted under separate cover.

Project engineering for the Platform Harvest project is in the intermediate stage. Some of the specific details concerning methods, processes, facilities, and equipment types, sizes, and capacities will not be determined until final design has been completed. Consequently, information contained in this DPP which relates to such detail will be subject to change based on continuing evaluation. Design changes will reflect inputs from the environmental review process as well as those from engineering and economic analyses to ensure that the Platform Harvest project is implemented in an environmentally sound manner.

REFERENCES

Chevron, U.S.A. Inc., 1983. Development and production plan, Point Arguello field, offshore Santa Barbara County, California.

Exxon Company, U.S.A., 1982. Development and production plan, Santa Ynez Unit development, Pacific OCS area, offshore Santa Barbara County, California, Santa Ynez Unit, Hondo, Pescado, and Sacate fields.

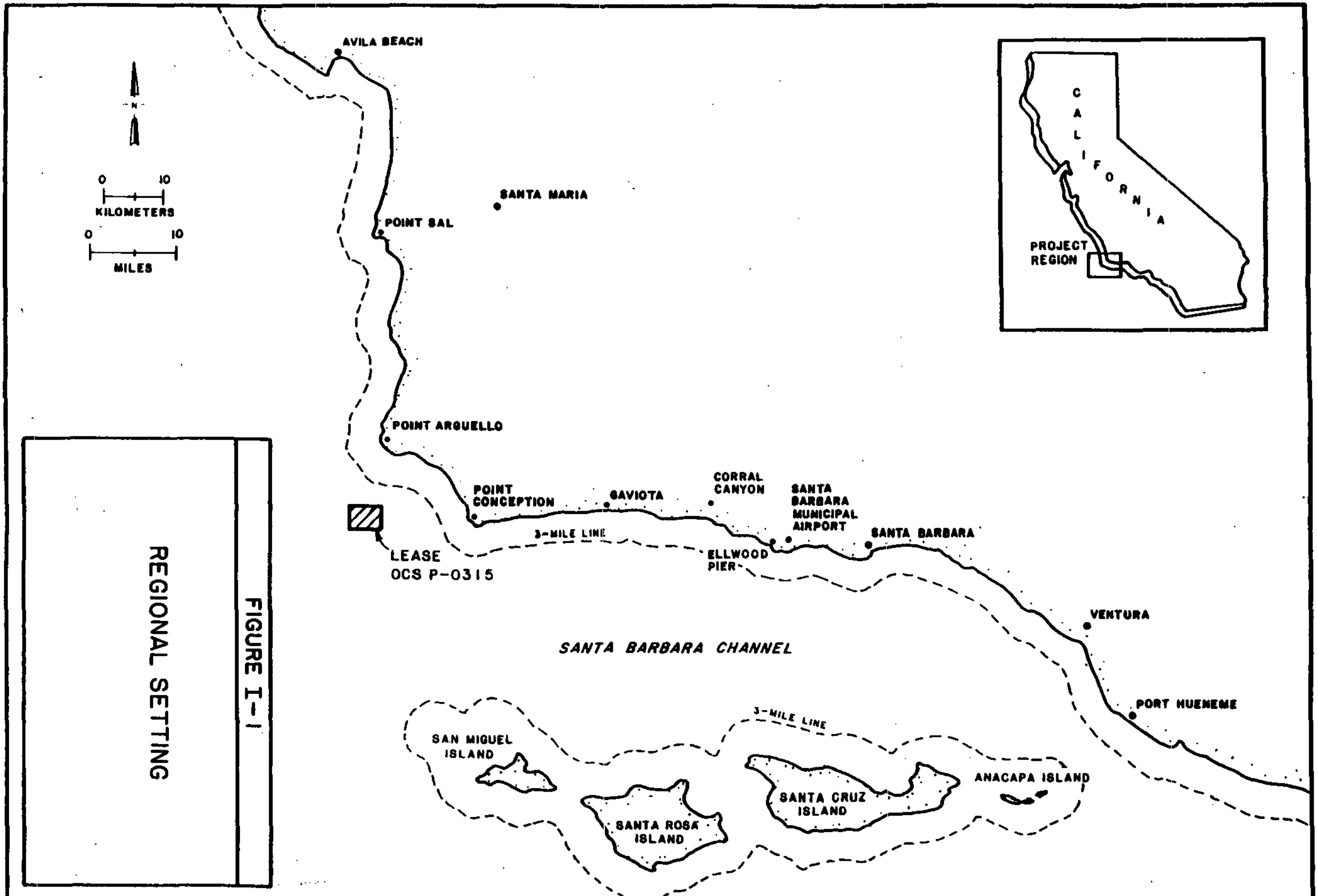

FIGURE I-1

REGIONAL SETTING

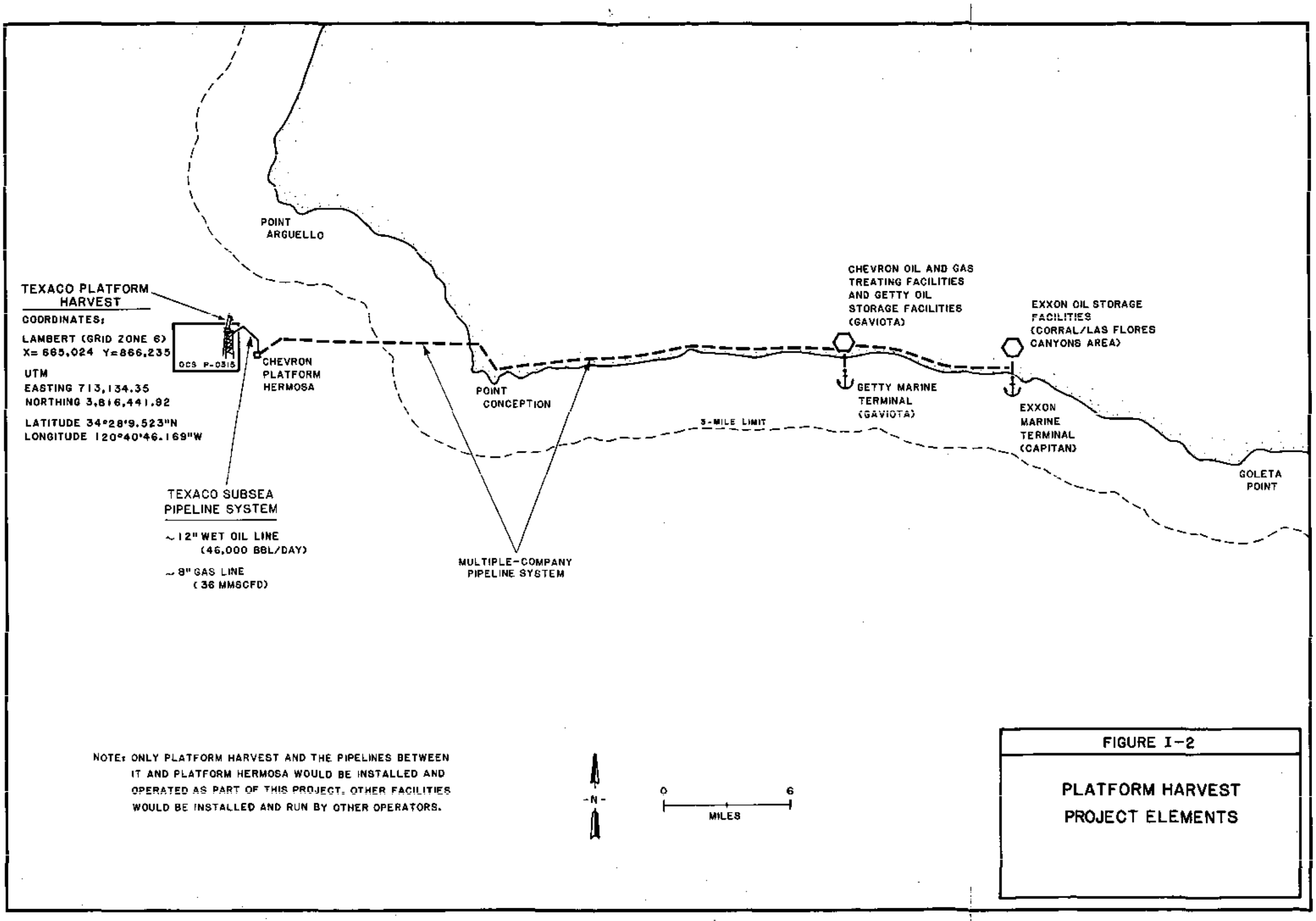

FIGURE I-2

PLATFORM HARVEST PROJECT ELEMENTS

Bottomhole Locations

Pursuant to the Freedom of Information Act (5 U.S.C. 552) and its implementing regulations (43 CFR Part 2) and as provided in 30 CFR 550.199(b), the information contained in this section is deleted from the public information copy of this submission.

Proprietary

Not for Public Release

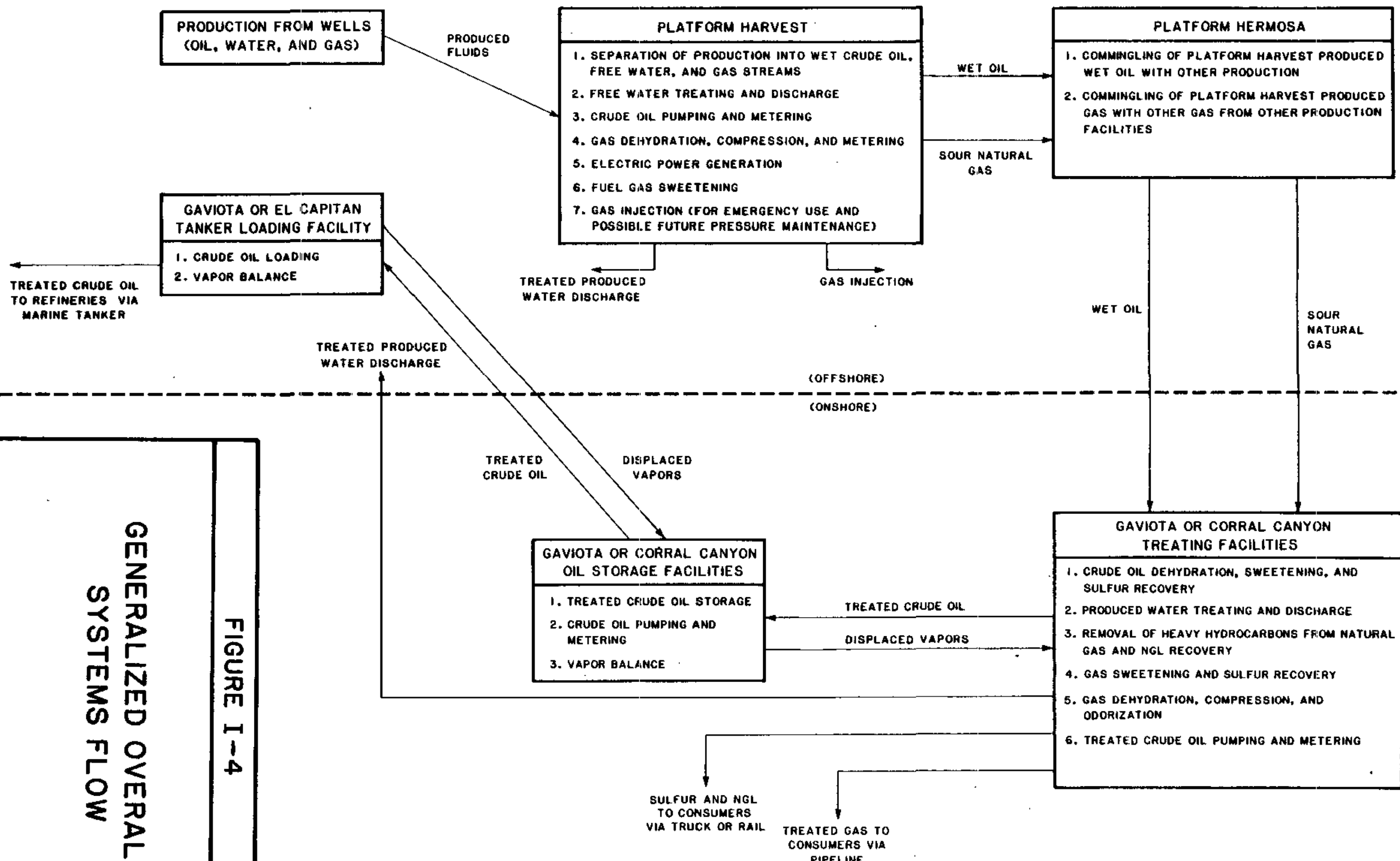

FIGURE I-4
GENERALIZED OVERALL SYSTEMS FLOW

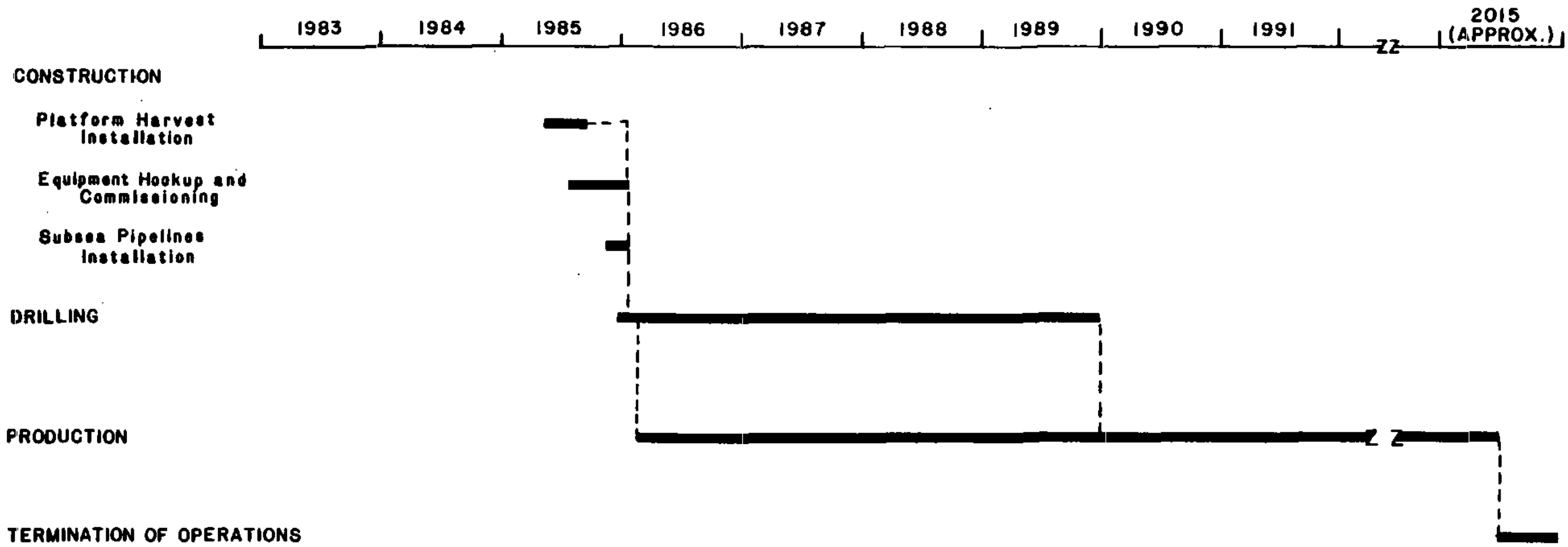

FIGURE I-5

PRELIMINARY SCHEDULE
PLATFORM HARVEST
PROJECT

Section II – Geology

Pursuant to the Freedom of Information Act (5 U.S.C. 552) and its implementing regulations (43 CFR Part 2) and as provided in 30 CFR 550.199(b), the information contained in this section is deleted from the public information copy of this submission.

Proprietary

Not for Public Release

Section III – Reservoir Evaluation

Pursuant to the Freedom of Information Act (5 U.S.C. 552) and its implementing regulations (43 CFR Part 2) and as provided in 30 CFR 550.199(b), the information contained in this section is deleted from the public information copy of this submission.

Proprietary

Not for Public Release

SECTION IV - PLATFORM HARVEST
SITE STUDIES, STRUCTURAL ENGINEERING DESIGN, AND INSTALLATION

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SECTION IV - PLATFORM HARVEST

SITE STUDIES, STRUCTURAL ENGINEERING DESIGN, AND INSTALLATION

4.1 INTRODUCTION

Platform Harvest will be designed, constructed, and installed in a manner to ensure safe and efficient performance of the structure. The principal design standards that will be followed are outlined in Section 4.2. The platform has been designed to accommodate expected levels of installation, operational, and environmental loading as determined by site-specific engineering studies. The methodologies used to develop geologic, geotechnical, seismic, oceanographic, and marine growth design criteria are summarized in Section 4.3. In Section 4.4, the platform structural design process is described and in Section 4.5 fabrication and assembly of the various components is summarized. Onsite installation of the platform is described in Section 4.6.

The information presented herein is of a summary nature suitable for public disclosure. Detailed design information is considered proprietary by Texaco and, consequently, is presented in Appendix A which may not be disclosed in whole or in part beyond the MMS without prior written authorization from Texaco.

4.2 APPLICABLE DESIGN STANDARDS - OCS ORDER NO. 8 AND API RP2A

Platform Harvest will be designed in accordance with applicable design standards including MMS Pacific Region OCS Order No. 8, API RP2A, and applicable American Institute of Steel Construction (AISC) guidelines.

OCS Order No. 8 states that all new fixed or bottom-founded platforms or other structures must be designed, fabricated, and installed in accordance with the applicable requirements of a MMS document entitled "Requirements for Verifying the Structural Integrity of OCS Platforms." This MMS document is the basis of the Platform Verification Program administered by the MMS. The program is designed to provide assurance that fixed or bottom-founded platforms located on the OCS have a high probability of surviving the environmental conditions to which they are likely to be exposed. The key element of the Platform Verification Program is the requirement for third-party verification of each major phase in platform development. The program defines procedures by which individuals or organizations may become certified verification agents (CVA) and identifies mandatory state-of-the-art performance standards which must be met. An important aspect of the verification program is the requirement for structural inspection immediately upon installation of a fixed structure.

The Platform Verification Program provides for the careful review of proposed offshore structures. It requires the submittal of a design verification plan and extensive platform design information (including general platform information, environmental and loading data, foundation design information, and structural design information) for CVA and MMS review and approval. A fabrication verification plan must also be submitted to a CVA and the MMS. The fabrication verification plan includes fabrication drawings and material specifications of all primary load-bearing members, and a summary description of: structural tolerances, welding procedures, fabrication standards, material quality control procedures, methods and extent of nondestructive examinations (NDE) for welds and materials, and other quality assurance procedures. CVA and MMS review of an installation plan including a description of the planned marine operations, contingencies considered, and a summary of routine inspections to be conducted is also required by the OCS Order No. 8 Platform Verification Program requirement.

API RP2A "Recommended Practices for Planning, Designing, and Constructing Offshore Platforms" contains a comprehensive set of industry guidelines pertaining to all phases of platform development. The various AISC guidelines pertain to a number of specialized operations, including such things as welding and weld integrity testing.

4.3 ENVIRONMENTAL DESIGN CRITIERIA

4.3.1 Geologic and Geotechnical Criteria

Data gathered during the exploration program conducted on Lease OCS P-0315 allowed definition of a commercial hydrocarbon accumulation extending northwesterly beneath the lease. The Platform Harvest location was initially selected to provide for adequate development of the hydrocarbon resource by directional drilling from a site with good foundation conditions in as shallow water as possible. Following this initial selection, regional and site-specific geologic and geotechnical studies were conducted by McClelland Engineers and

Woodward-Clyde Consultants (see REFERENCES section). These studies were conducted to assess geologic conditions and to develop geologic and geotechnical design criteria for the platform. The conclusion of the studies is that the proposed platform site presents no geologic or geotechnical problems with respect to design. Site-specific geologic conditions are described in Section 2.3 of this DPP and Section 3.a of the accompanying ER(P).

The platform foundation design criteria are based on soils information obtained by onsite borings and associated field and laboratory investigations conducted by Woodward-Clyde Consultants. The geotechnical laboratory testing program and the engineering analysis program were focused on soil shear strength characteristics, lateral pile responses, axial pile responses, pile installation responses, and the potential for soil liquefaction. Preliminary results from the offshore boring and laboratory testing programs indicate that soil conditions at the platform site are favorable for the proposed installation and that potential liquefaction and slumping in subsurface soils appear unlikely.

All boring logs, laboratory test results, and engineering reports will be included in the detailed platform design material to be submitted to the CVA in accordance with the Platform Verification Program. Platform foundation design criteria will satisfy API RP2A guidelines.

4.3.2 Seismic Criteria

The seismic design criteria are based on detailed evaluation of earthquake potential in the western portion of the Transverse Ranges Geomorphic Province and specifically account for regional and local geologic structure, regional and local active faulting, and local soil conditions. The design criteria were derived specifically for the Platform Harvest site. The platform design meets both strength and ductility requirements for earthquake loading.

Conformance with design strength requirements will assure resistance to levels of strong ground motion likely to occur during the platform's life without the platform sustaining any structural damage. The strength level design site motions were expressed in terms of a smoothed response spectrum and a suite of representative three-dimensional ground motion records. The response spectrum method of analysis was used to evaluate the platform's dynamic elastic response to earthquake ground motion.

Conformance with design ductility requirements will provide a platform/ foundation system that has sufficient energy absorption capacity such that the platform would not sustain any structural damage in the event of rare, intense ground shaking. Careful joint detailing and welding will be insured to guarantee that the structure performs as designed under earthquake loadings.

Woodward-Clyde Consultants' preliminary assessment of the seismic environment in the western Transverse Ranges area indicates that expected earthquake activity should not present any problems that preclude safe design, installation, and operation of Platform Harvest.

4.3.3 Wave, Current, and Wind Criteria

The oceanographic design criteria will provide for waves, currents, tides, and winds which may occur during the expected life of Platform Harvest. Existing oceanographic data have been reviewed to develop a preliminary planning assessment of these factors, and hindcast studies have been initiated to provide detailed site-specific information. Initial results of the oceanographic studies conducted by Oceanographic Services, Inc. indicate that oceanographic conditions in the western most portion of the Santa Barbara Channel will not preclude safe design, installation, and operation of Platform Harvest.

4.3.3.1 Waves

A numerical wave hindcast model which provides a directional wave spectrum has been used to determine design waves at the platform site during selected storm events. The model includes effects of: variation of the storm wind field in time and space; wave generation, propagation, and decay over a large grid extending westward into the Pacific; directional spreading; diffraction around headlands and through islands; and island sheltering. It was calibrated with existing data to ensure its accuracy and design wave heights were then determined for the platform site.

4.3.3.2 Currents

Two-dimensional numerical current models were used to assess wind-generated currents during the same storms for which wave conditions were generated. Existing current measurements were used to estimate expected values of background and tidal currents which were combined with the simulated storm currents to develop the maximum expected currents for the Platform Harvest site.

4.3.3.3 Wind

Representations of sustained wind fields during severe historical storms were developed based on available atmospheric pressure and wind velocity measurements. These winds were used with the design waves and currents to determine the maximum combined oceanographic load on the platform. In addition, extreme gusts (which may not be associated with extreme storm waves) were determined by extrapolating local wind speed statistics and used in designing deck facilities to withstand aerodynamic loads.

4.3.4 Marine Growth Criteria

A study of marine growth on existing Santa Barbara Channel platforms provided the basis for the marine growth design criteria.

4.4 PLATFORM STRUCTURAL DESIGN

Design of Platform Harvest was performed by Brown & Root and will be verified by a CVA pursuant to Pacific Area OCS Order No. 8. The design effort consisted primarily of stress analyses using established site-specific design criteria to evaluate structural responses to extreme oceanographic, installation, operational, fatigue, and earthquake loading conditions. A comprehensive detailing of design critiera, site conditions, design analyses, and structural designs for the platform will be provided as part of the verification process documentation. A conceptual description of the proposed platform follows.

Platform Harvest will be a conventional eight-leg, steel-template, pile-founded structure with 4 main decks and 50 well slots. General platform dimensions are given in Table IV-1. The jacket structure will be installed in approximately 670 feet (204 m) of water.

Preliminary elevation views of the Platform Harvest jacket are shown on Figure IV-1. The jacket structure will be comprised of eight main legs framed with diagonal and horizontal bracing. The structure will be secured to the ocean floor with main piles driven through its legs and welded and grouted to the jacket. Twenty skirt piles will be driven and connected to the jacket by grouting. The platform decks will provide adequate space and load carrying capability for simultaneous twin rig drilling and oil and gas production operations.

Various facilities will be installed on the platform, principally as pre-fabricated modules. These will include well drilling equipment; hydrocarbon production: separation, dehydration, compression, pumping, and metering equipment; power generation, fuel gas sweetening, waste heat recovery, and other utilities and service systems; monitoring and safety systems; permanent living quarters for platform personnel; boat landing facilities; and a helideck.

4.5 PLATFORM FABRICATION AND ASSEMBLY

The principal components of the platform will be fabricated and assembled at one or more suitable yards outside of the Santa Barbara Channel area and towed to the installation site by barge. The actual locations will not be determined until the fabrication and assembly contracts have been awarded.

4.6 PLATFORM INSTALLATION

4.6.1 Installation Procedures

No new or unusual platform installation procedures will be followed; complete details on the fabrication and installation of the platform will be provided as part of the verification documentation pursuant to Pacific Area OCS Order No. 8. Installation of the platform will require approximately 7 months including equipment hook-up. Major marine equipment required for installation will include a derrick vessel, the jacket launch barge, cargo barges, tug boats, supply boats, and crewboats.

General installation procedures are as follows:

Jacket tow and launch

Upon completion of fabrication, the jacket structure will be loaded onto a transport/launch barge and secured for tow from its assembly site to the Santa Barbara Channel. During this time, temporary buoy(s) will be placed at the platform site and a final subsea inspection of the site will be conducted if required. Upon arrival of the derrick and launch barges at the proposed platform site and prior to launch, all flood, vent and grout valves on the jacket will be inspected to ensure they are all closed; all jacket rigging and tow bridle(s) will be rechecked and corrected if needed; then most of the seafastenings will be cut, leaving a few tension braces. Next the launch barge will be ballasted down to the specified launch trim and all remaining seafastenings will be cut. Once completed, the jacket will be launched and floated horizontally in the water.

Jacket upending

Following launch the jacket will be positioned over its installation site as marked by the buoy(s) and upended to an upright attitude by flooding selected leg and skirt pile sleeve compartments. Final positioning and leveling will be made with the derrick barge and controlled leg flooding, respectively, within the specified tolerances. Once the jacket is positioned and level on the ocean floor, the remaining vent valves will be opened to complete flooding.

Pile installation

The eight main piles will be installed through the jacket legs in approximately 80-foot long welded segments. Upon reaching the mudline the piles will be driven to their design penetration of 225 feet below the mudline. Throughout this operation the jacket will be leveled by alternating driving between piles until both design penetration and level tolerances have been reached. At this time jacket pile connections will be installed and welded. The skirt piles will be installed through the skirt pile sleeves and driven to their design penetration of 235 feet (72 m) with the aid of a retrievable follower or underwater hammer. Both main and skirt pile will be continuously grouted to the jacket structure over their entire length above the mudline.

Deck setting

A two-piece deck will first be set and welded to the jacket top for support of the deck modules. The upper decks will be composed of 4 modules with production equipment preinstalled. The modules will be lifted by the derrick barge, set on top of the decks, and then welded into place. The flare boom, crew quarters, and other miscellaneous components will then be attached to the deck modules.

Equipment hookup and commissioning

After the deck modules have been set, offshore crews will make structural, piping, electrical, and instrumentation interconnections between modules. They will then test and commission all systems.

4.6.2 General Construction Information

Platform installation will entail use of standard offshore construction equipment. No special equipment is expected to be required. A list of typical equipment and its characteristics is contained in Table IV-2. The workforce will average about 130 persons per day, ranging from a low of about 50 to a high of approximately 240.

Logistics support will be provided from Port Hueneme, Santa Barbara Municipal Airport, and Ellwood Pier. Each of these facilities presently is engaged in providing support to OCS oil and gas operations. No modification of these facilities and no new facilities will be required for the Platform Harvest installation. However, Texaco plans to utilize a consolidated supply base if such a facility is developed to support western Santa Barbara Channel offshore operations. An overview description of proposed travel modes, routes, and frequencies for moving supplies and personnel to and from the platform site is presented in Table IV-3.

Installation phase consumables will include such things as fuel, welding rod, oxygen, acetylene, fresh water, food, and miscellaneous personal items. Most of these items will be hauled from shore via supply boat. Fresh water will be obtained from desalinization units onboard the work vessels or hauled from shore during the later stages of platform installation.

Solid and liquid wastes which will be generated during platform installation are summarized in Table IV-4. Treatment and disposition of the wastes is also included.

Total cost for installation and hookup of proposed Platform Harvest (exclusive of fabrication costs) will be approximately 1.5 million dollars for Texaco company payroll, 15.6 million dollars for contracted installation labor/services; 35.4 million dollars for contracted hookup labor/services; 1.5 million dollars for purchased materials during installation; and 2.0 million dollars for purchased materials during hookup. The Texaco payroll will be 100 percent non-local during installation; 25 percent non-local, 75 percent local during hookup. Contracted labor and other services will be 100 percent non-local during installation; 100 percent local during hookup; purchased materials will be 100 percent local during installation and hookup. The use of non-local personnel and contract services for installation reflects the need for available qualified and specialized labor to complete the work.

(All engineering studies reports, boring logs, laboratory test results and similar information will be included in the detailed design material to be submitted to the CVA in accordance with the Platform Verification Program.)

REFERENCES

McClelland Engineers, Inc., 1983. Bottom topology and pipeline survey and engineering geological study, Hueso Platform "A", OCS P-0315, Point Arguello, offshore California, 10 March. Job Number 05820040.

Oceanographic Services, Inc., 1982. Point Conception measurement program, 21 May - 4 July 1982. October OSI #5471.

Woodward-Clyde Consultants, 1982a. Geological, seismological, and earthquake engineering studies, OCS Lease No. P-0315, Tract No. 48-003, Hueso prospect, offshore southern California. November.

Woodward-Clyde Consultants, 1982b. Soil characterization, OCS Lease No. P-0315, Tract No. 48-003, Hueso prospect, offshore southern California. November.

Woodward-Clyde Consultants, 1982c. Platform foundation engineering, OCS Lease No. P-0315, Tract No. 48-003, Hueso prospect, offshore southern California. November

Woodward-Clyde Consultants, 1983. Preliminary draft report, seismic exposure study, OCS Lease No. P-0315, Tract No. 48-003, Hueso prospect, offshore southern California. March.

TABLE IV-1

PLATFORM HARVEST DIMENSIONS

Platform Component	Elevation or (Height)[a]	Length[a]	Width[a]
Jacket	(703)	320[b]	200[b]
Boat landings and walkways	+20 MLLW	200	60
Subcellar deck	+47.5 MLLW	60	24
Cellar deck	+60 MLLW	240	100
Lower main deck	+87.3 MLLW	210	100
Upper main deck	+107.3 MLLW	210	100
Drilling/quarter deck	+124.3 MLLW	210	100
15,000-foot drilling rig mast	(139)	-	-
20,000-foot drilling rig mast	(142)	-	-

[a] All dimensions and elevations in feet.
[b] At base.

TABLE IV-2

PLATFORM INSTALLATION EQUIPMENT

Equipment Description	Number Required	Engine Type	Time on Job (Weeks)	Time in Service	Other
Survey Boat	1	2 @ 750-hp Diesel	1	60%	
Installation Barge	1				
Main Engine	1	Steam Boiler	11	100%	Average Load 2900 hp
Small Crane	1	75-hp Diesel	11	10%	
Jacket Tugs	2	5600-hp Diesel	2	20%	
Deck Tugs	4	2200-hp Diesel	2	20%	
Work Boat A		2 @ 1125-hp Diesel	28	40%	
Work Boat B		2 @ 1125-hp Diesel	16	40%	
Crew Boat A	1	3 @ 500-hp Diesel	18	40%	
Crew Boat B	1	3 @ 500-hp Diesel	13	40%	
Helicopter	1	2 @ 650-hp Turbines		90 Hrs	Fuel Usage 100 gal/hr.
Grouting Equipment	1	100-hp Diesel	1	50%	
Remote Control Vehicle	1	75-hp Diesel	1	25%	
Platform Equipment					
Temporary Generator	1	250-hp Diesel	10	30%	
Platform Generators	2	750-hp Diesel	14	50%	
Welding Machines	25	40-hp Diesel	15	30%	
Crane A	1	365-hp Diesel	18	20%	
Crane B	1	365-hp Diesel	18	10%	
Crane C	1	225-hp Diesel	18	10%	
Air Compressor	1	40-hp Diesel	10	30%	
Hydro Pump	1	15-hp Diesel	14	10%	

TABLE IV-3

PLATFORM INSTALLATION PERSONNEL AND SUPPLY TRANSPORT

	Supply Boat	Crew Boat	Helicopter
Activity	Movement of equipment and supplies	Movement of personnel; occasionally some light supply items	Movement of personnel; occasionally some light supply items
Route[a]	Most direct route to/from Port Hueneme	Most direct route to/from Ellwood Pier	Most direct route to/from Santa Barbara Municipal Airport
Frequency of round trips	4/week	1/day	3/week

[a] Assuming that Port Hueneme, Ellwood Pier, and Santa Barbara Municipal Airport are utilized. Texaco plans to use a consolidated industry supply base for support services if such a facility is constructed. In such case, the route will be as direct as possible between the base and Platform Harvest.

TABLE IV-4

PLATFORM INSTALLATION SOLID AND LIQUID WASTES

Project Element/Activity	Disposable Waste	Disposal Method	Disposal Frequency	Disposal Rate	Total Quantity
Platform Installation					
	Sanitary sewage	Discharge to ocean[a]	Daily	5,500 gpd	0.33 million gal
	Desalinization brine	Discharge to ocean	Daily	67,000 gpd	4.02 million gal
	Miscellaneous liquid wastes	Store in appropriate container and haul to shore	Weekly	0	0
	General refuse	Store in appropriate container and haul to shore	Weekly	0	0
Platform Equipment Hookup and Commissioning					
	Sanitary sewage	Discharge to ocean[a]	Daily	14,200 gpd	2.13 million gal
	Desalinization brine	Discharge to ocean	Daily	61,500 gpd	9.2 million gal
	Hydrostatic test water	Discharge to ocean	As needed	Variable	15,000 gal
	Miscellaneous liquid wastes	Store in appropriate containers and haul to shore	Weekly	0	0
	General refuse	Store in appropriate containers and haul to shore	Weekly	1000 lb/week	150,000 lb

[a] After treatment in a U.S. Coast Guard-approved unit.

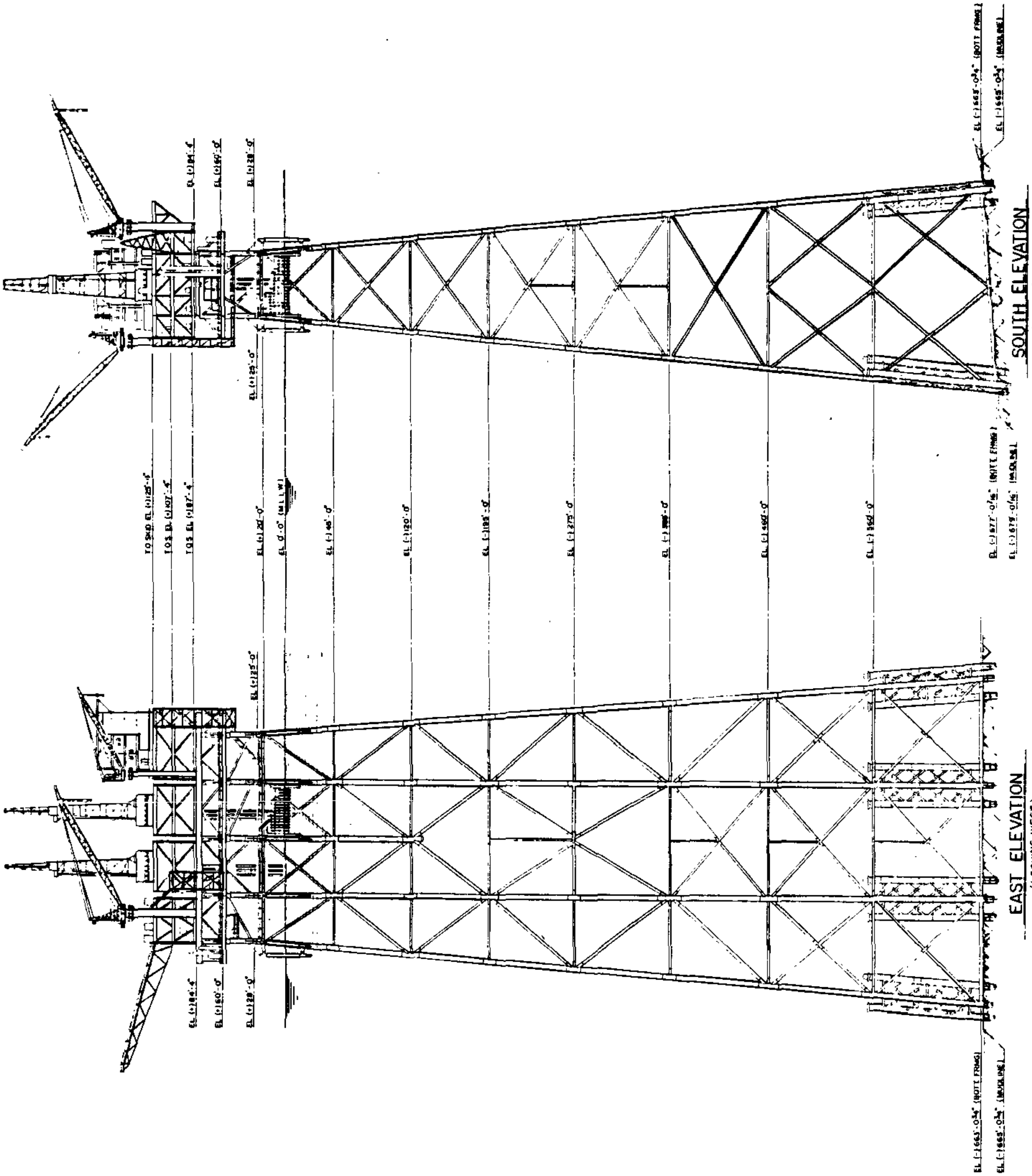

FIGURE IV-1

PRELIMINARY ELEVATION SCHEMATIC

SECTION V - PIPELINE CORRIDOR STUDIES,
ENGINEERING DESIGN, AND INSTALLATION

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SECTION V - PIPELINE CORRIDOR STUDIES, ENGINEERING DESIGN, AND INSTALLATION

5.1 INTRODUCTION

All transport of produced fluids between Platform Harvest and onshore treating and storage facilities at Gaviota and/or Corral/Las Flores canyons will be accomplished by Texaco subsea pipelines from Platform Harvest to Platform Hermosa, and consolidated multi-company pipelines from Chevron's Platform Hermosa to onshore facilities. Transport of treated crude oil will be accomplished by marine tankship, or by pipeline to Los Angeles or the San Joaquin Valley as discussed in Section IX, Product Storage and Transportation. Of the various pipelines that will be involved in transporting Platform Harvest produced fluids, only those between Platforms Harvest and Hermosa will be installed and operated by Texaco (Figure V-1). These pipelines are described in detail in this DPP; the pipelines that will be installed by other operators are described in the Chevron (1983) and Exxon (1982) DPP's.

Pipeline design standards, criteria, and the design process itself are outlined in Sections 5.2, 5.3, and 5.4. Fabrication and installation of the pipelines between Platforms Harvest and Hermosa are discussed in Sections 5.5 and 5.6.

5.2 DESIGN STANDARDS AND CODES

Texaco's proposed emulsion and gas pipelines will be designed, fabricated, installed, tested, operated, and inspected in accordance with the following design standards and codes:

- Liquid Petroleum Transportation Piping Systems, American National Standards Institute (ANSI) B31.4
- Gas Transmission and Distribution Piping Systems, American National Standards Institute (ANSI) B31.8
- Transportation of Liquids by Pipeline, Department of Transportation Regulation 49, Part 195

- Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, Department of Transportation Regulation 49, Part 192

- Recommended Practice for Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines, American Petroleum Institute Publication API RP 1111

- 30 CFR 256, Subpart N -- Grants of Pipeline Rights-of-Way on the OCS

5.3 PIPELINE DESIGN

Texaco's proposed pipelines from Platform Harvest to Platform Hermosa will be designed to ensure safe and efficient installation and operation in an environmentally sound manner. The pipelines will be installed along routes that have been studied carefully for potential hazards to ensure that the pipelines are safely installed and operated. Detailed design data will satisfy 30 CFR 256, Subpart N -- Grants of Pipeline Rights-of-Way on the OCS, as discussed in the following section.

5.3.1 Compliance with 30 CFR 256, Subpart N -- Grants of Pipeline Rights-of-Way on the OCS

All pipelines will be designed and maintained in accordance with the following:

- Texaco will be responsible for the installation of the following control devices on the wet oil and gas pipelines connected to Platform Harvest and will maintain records on Platform Harvest showing the present status and past history of each device, including dates and details of inspection, testing, repairing, adjustment, reinstallation or replacement.

  - The wet oil and gas pipelines leaving Platform Harvest receiving production from the platform will be equipped with a high-low pressure sensor to shut in the wells on the platform.

- The wet oil and gas pipelines will be equipped with a check valve at the platform to control backflow.

- The wet oil and gas pipelines crossing Platform Hermosa will be equipped with sensors to activate an automatic shut-in valve to be located in the upstream portion of the pipeline at or near the platform to avoid uncontrolled flow at the platform. This automatic shut-in valve will be connected to either the platform automatic and remote shut-in system or to an independent remote shut-in system.

- All oil pumps and gas compressors on Platform Harvest will be equipped with high-low pressure shut-in devices.

- The wet oil pipeline will have a metering system to provide a continuous volumetric comparison of input to the line at Platform Harvest with deliveries at the onshore treating facility. The system will include an alarm system and will be of adequate sensitivity to detect significant variations between input and discharge volumes.

• The wet oil and gas pipelines will be protected from loss of exterior metal that would endanger the strength and safety of the lines by methods such as protective coatings and cathodic protection.

• The wet oil and gas pipelines will be installed and maintained to be compatible with trawling operations and shipping.

• The wet oil and gas pipelines will be hydrostatically tested to at least 1.25 times the designed working pressure for a minimum of 2 hours prior to placing the lines in service.

• The oil and gas pipelines will be maintained in good operating condition at all times and the ocean surface above the pipeline will be inspected a minimum of once each week for indication of leakage using aircraft, floating equipment, or other means. Records of these inspections including the date, methods, and results of each inspection will be maintained by Texaco and submitted to the District Supervisor, Ventura District annually by April 1. Texaco will immediately notify the District Engineer of any pipeline leak and within 1 week will submit a report to him with respect to the cause, effect, and remedial action taken.

- The wet oil and gas pipelines will be designed and maintained for protection against water currents, storm scouring, soft bottoms, and other environmental factors.

- An external inspection of all pipelines by side scan sonar or other means acceptable to the Pacific OCS Regional Supervisor, Field Operations will be made at least once each year to identify all exposed portions of pipelines. All exposed portions of pipelines will then be inspected in detail by photographic or other means acceptable to the Regional Supervisor to determine if any hazards exist to the line or other users of the area. If a hazard is found to exist, appropriate corrective action will be taken. Records of these inspections including the date, methods, and results of each inspection, will be maintained by Texaco and submitted to the District Supervisor, Ventura District when the records become available.

Texaco will submit four copies of an OCS pipeline right-of-way application, each accompanied by the following:

- An index or vicinity map on an 8-inch by 10 1/2 inch sheet.

- A detailed map of a scale of at least 1" = 4,000', or such other scale as may be determined by the Regional Supervisor, Field Operations Office, Pacific OCS Region. The map will show:

  (1) A profile showing the pipes in relation to the water surface and the mudline, at the same horizontal scale.

  (2) Product to be transported and direction of flow for each pipeline.

(3) The initial and terminal points of the right-of-way located by x and y coordinates and by latitude and longitude.

(4) The owner-operator and designation of all structures (platforms, fixed structures, and artificial islands) or pipelines (existing or proposed) connected to or crossed by the subject right-of-way giving the x and y coordinates and latitude and longitude of each.

(5) The total distance and width of the right-of-way, and the diameter of the pipelines specified.

(6) A signed certificate of the engineer who made the map that the right-of-way is accurately represented upon the map and shall contain a notation that the design characteristics of the pipeline are in compliance with the United States Department of Transportation (DOT) regulations.

(7) Distances of the center line of the right-of-way and grid references for all turning points given either on the margin of the map or on an attached sheet or sheets with the courses referred to the true or grid meridian, either by deflection from a line of known bearing or by independent observation and calculated distances in feet and decimals.

• A schematic drawing showing all the safety equipment relating to the subject pipeline system to and including all input pressure source(s) or point(s) of containment for these sources; i.e., wells, pumps and compressors are considered points of pressure containment. The schematic will show the maximum input pressure of the source (wellhead -- shut-in in tubing pressure; pump or compressor -- maximum discharge pressure). For pressured vessels, the vessel's maximum working pressure will be indicated. All safety equipment will be shown downstream to and including the termination of the subject pipeline.

The following equipment and its location in the system will be shown: Pressure source(s) or point(s) of pressure containment identifying maximum input pressure(s), sensing devices with associated pressure lines, automatic fail-close valves, check valves, flanges, fittings, and volumetric metering system.

The schematic will be certified by an engineer and noted that the design characteristics of the pipeline are in compliance with DOT regulations.

- A statement of general information concerning each pipeline, including:

(1) Size, weight, and grade of the pipe.
(2) Type or types of corrosion protection.
(3) Description of protective coating.
(4) Bulk specific gravity of each line (with the line empty).
(5) Anticipated gravity or density of the product or products.
(6) Design working pressure and capacity.
(7) Maximum working pressure and capacity.
(8) Pipeline hydrostatic pressure and hold time.
(9) Size and location of pumps and prime movers.
(10) Pipeline burial depth and location.
(11) Drawing and design specification of pipeline crossings.
(12) Any other pertinent information as required by the MMS Pacific OCS Regional Supervisor, Field Operations.

Texaco will notify the Regional Supervisor when installation of the pipeline is completed and submit a drawing, in triplicate, showing the location of the line as installed, accompanied by all hydrostatic test data (the MMS District Supervisor, Ventura District will be notified in the advance of hydrostatic tests), including procedure, test pressure, hold time, and results. The drawing submitted will be accompanied by an engineer's signed certificate that the pipeline is accurately represented.

5.3.2 Mechanical Design

The wet oil and gas pipelines will be designed in accordance with the standards specified in Section 5.2 (above). These designs will include appropriate safety factors for the pipelines and pipeline risers. The lines will also be designed to withstand the maximum bending moment and the maximum local external hydrostatic pressure with the pipeline void of fluids.

Thermal, environmental, and other external loads will be analyzed to assure safe stress levels under all loading conditions for both pipelines and pipeline risers. Pipe wall thickness and steel strength will be determined based on the design analyses and on corrosion protection requirements.

5.3.3 Stability

The pipelines will be designed to resist significant horizontal and vertical deflection under the action of on-bottom steady currents, wave-induced oscillatory currents and earthquakes.

Earthquake motion design criteria will be consistent with the values used in the platform design. Stability will be accomplished wherever required via routing, increased submerged weight, trenching, anchoring, or combinations of these methods.

5.3.4 Corrosion Protection

The pipelines will be protected from external corrosion by a protective coating which will be supplemented with sacrificial anode type cathodic protection. The splash zone sections of the platform risers will have additional protection from the more severe mechanical and corrosive attack associated with this area. Design of protection from internal corrosion and other chemical degradation will be based on proper selection of pipe steel chemistry, pipe wall thickness and manufacturing processes. Injection of corrosion inhibitor chemicals will be used as needed to keep internal corrosion rates within acceptable limits.

5.4 DESIGN CRITERIA

Design criteria will be determined by the external environmental loads and the internal loads that the pipelines may experience over their operating life, including stresses induced during pipeline installation. Pipeline design will ensure that the level of stress imposed by these conditions will be accommodated within acceptable limits. All pipelines will be designed to withstand their maximum internal design operating pressure in accordance with the applicable standard specifications listed in Section 5.2.

Internal loads are a result of the chemical and physical characteristics of the transported fluid under operating conditions, including fluid composition, density and rheological parameters, flow rates, pressure, and temperature. Design flow rates are 46 MBD of wet oil and 36 MMSCFD of gas.

External environmental loads result from meteorological and oceanographic phenomena and the geologic and geotechnical characteristics of the sea bottom along the pipeline routes. Environmental forces include waves, currents, earthquake ground motion, and ambient pressure and temperature. Design parameters will account for significant wave height, period, and direction, bottom steady current velocity and direction, and earthquake wave velocities and periods. These criteria will be consistent with the values used in the platform design. Ambient external pressure is a function of water depth along the route. The maximum water depth that could be encountered in the pipeline system is approximately 670 feet. The design minimum value for ambient temperature will be approximately 45°F.

Stresses induced in the pipeline during installation are a function of construction methods and equipment, as well as the prevailing natural environment at the time and place of construction activities. The construction methods and specific equipment will be selected to assure that the pipelines are not overstressed during installation.

5.5 PIPE FABRICATION

Individual lengths of steel line pipe will be fabricated at an appropriate mill (or mills) outside of the Santa Barbara Channel area. The pipe segments will be transported by barge or rail to Port Hueneme or directly to the installation site. The pipe will then be loaded onto the pipeline lay barge or stockpiled at a staging area for makeup and installation.

5.6 PIPELINE INSTALLATION

Pipelines will be installed using the lay barge method. In the lay barge method, individual lengths of precoated pipe will be taken aboard a lay barge and stored on racks. The pipe joints will then be welded into a continuous string on a long, gently curved production ramp and the barge will be pulled forward one pipe length as each new joint is added. During pull up, the pipe string will pass down the ramp, onto a stinger, and to the ocean floor in an S-curve configuration. A simplified sketch of a lay barge is presented on Figure V-2. Deployment of the lay barge anchors will require a construction corridor approximately 12 times as wide as the local water depth. Pipelines will be laid in the approximate center of this corridor. Alternatively, the pipe segments could be welded together at an onshore site and towed offshore for installation.

Pipeline risers and connections between the riser and the pipeline will be installed by the conventional method through J-tubes which will be preinstalled on the platform jackets.

Connection of Texaco's pipelines to the pipeline system at Platform Hermosa will be accomplished on the platform deck. Continuous welded pipes will be pulled through J-tubes at the base of the platform jacket, and all fittings, valves, etc. will be on the platform deck. No fittings will be placed on the seafloor.

An average daily total of approximately 60 workers will be required to install the offshore pipelines. The estimated skills composition of the labor force is given in Table V-1. Work will be scheduled 7 days per week in two 12-hour shifts per day. Work crews will be berthed onboard the barges and work on a 2-weeks-on, 1-week-off basis. Installation of the pipelines will require approximately 7 weeks to complete.

The types of vessels and other equipment required for pipeline installation are listed in Table V-2. Materials and supplies will be delivered by truck to Port Hueneme or a consolidated industry supply base where they will be onloaded to supply boats. Truck deliveries will average two per day. Supply boat runs are expected to amount to four per week.

Waste products that will be generated during installation of the offshore pipelines are identified in Table V-3. Potable water will be supplied by desalinization equipment located on the lay barge or on the platform. Sanitary wastes will be processed by USCG-approved treatment units on the vessel. Ocean discharges will be made in compliance with a NPDES permit and will include treated sewage effluent and used hydrostatic test water. All other liquid wastes and general refuse will be collected and transported by supply boat to Port Hueneme or a consolidated industry supply base for onshore disposal at an approved facility.

5.7 PIPELINE CHARACTERISTICS

The Platform Harvest pipeline system will include two pipelines (one wet oil line and one gas line) between Platform Harvest and Platform Hermosa, along the route shown on Figure V-1. Detailed pipeline design is still underway and some of the characteristics presented here are subject to change. Each pipeline will be 17,000 feet long. The wet oil line will be a nominal 12-inch diameter pipeline designed for a maximum net internal working pressure of 2130 psig at 150°F. The maximum wet oil flow rate capacity of this line is estimated to be approximately 90,000 barrels of liquid per day, although anticipated volumes will be somewhat less. At peak Platform Harvest production (46,000 barrels per day), the calculated operating pressure of this pipeline is 1000 psig at 130°F.

The gas pipeline will be a nominal 8-inch diameter pipeline designed for a maximum net internal working pressure of 2130 psig at 150°F. The maximum gas flow rate capacity of this line is estimated to be 50 MMSCF per day. At peak Platform Harvest production 36 MMSCF per day will be transported by this pipeline. The calculated operating pressure of this pipeline with a 36 MMSCF per day throughput is 1000 psig at 110°F.

TABLE V-1

OFFSHORE PIPELINE INSTALLATION WORKFORCE

Job Skill	Workers per Shift	Shifts per Day	Hours per Shift	Work Days per Week
Supervisors	1-2	2	12	7
Texaco representatives	1-2	2	12	7
Welders and helpers	8-16	2	12	7
Riggers and laborers	8-16	2	12	7
Operating engineers	1-2	2	12	7
Quality control inspectors	1-2	2	12	7
Combined	20-40	2	12	7

TABLE V-2

OFFSHORE PIPELINE INSTALLATION EQUIPMENT

Equipment Type	Number Required	Engine Type	Time On Site (Weeks)	Percent of Time in Service
Lay barge				
(main engine)	1	Steam boiler	7	-[a]
(crane)	1	200-hp diesel	7	55
Lay barge tug	1	3500-hp diesel	7	25
Supply barge tug	1	2500-hp diesel	7	10
Supply boat	1	2 @ 1125-hp diesel	7	15
Helicopter	1	2 @ 650-hp turbine	-	-[b]

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[a] Average load 3200 hp
[b] 21 hours total time in service @ 100 gal fuel/hr

TABLE V-3

OFFSHORE PIPELINE INSTALLATION
WASTE MATERIALS

Type	Disposal Method	Disposal Frequency	Disposal Rate	Total Quantity
Sanitary sewage	Discharge to ocean after treatment in approved unit	Daily	8000 gpd	480,000 gal
Desalinization brine	Discharge to ocean	Daily	67,000 gpd	4.02 million gal
Hydrostatic test water	Discharge to ocean	As needed	Variable	85,000 gal
Miscellaneous liquid wastes	Store in appropriate containers and haul to shore	As needed	Variable	10 bbl
General refuse	Store in appropriate containers and haul to shore	As needed	Variable	7.5 tons

41.6/TV-3

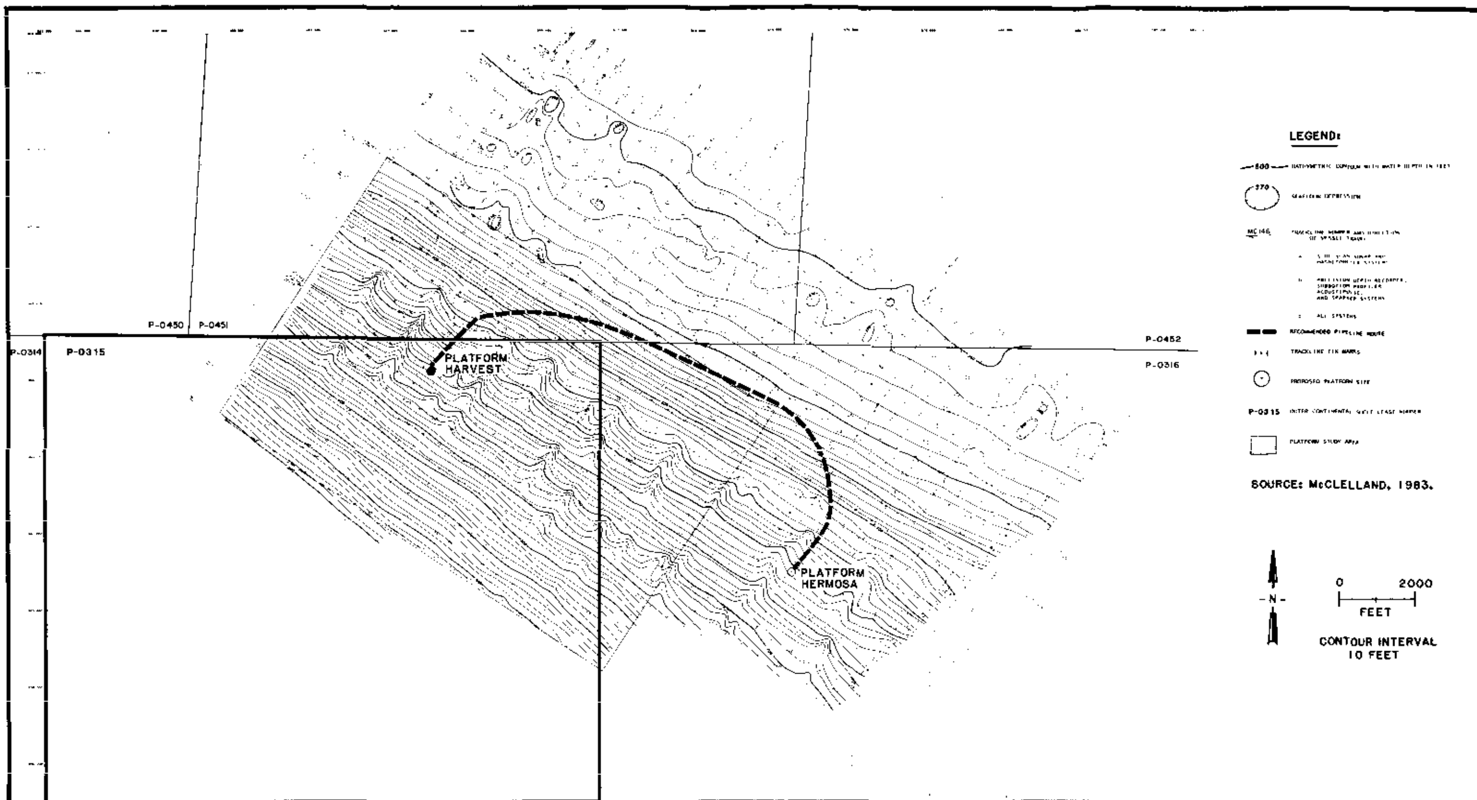


FIGURE V-1

PLATFORM HARVEST PROJECT PIPELINE SYSTEM

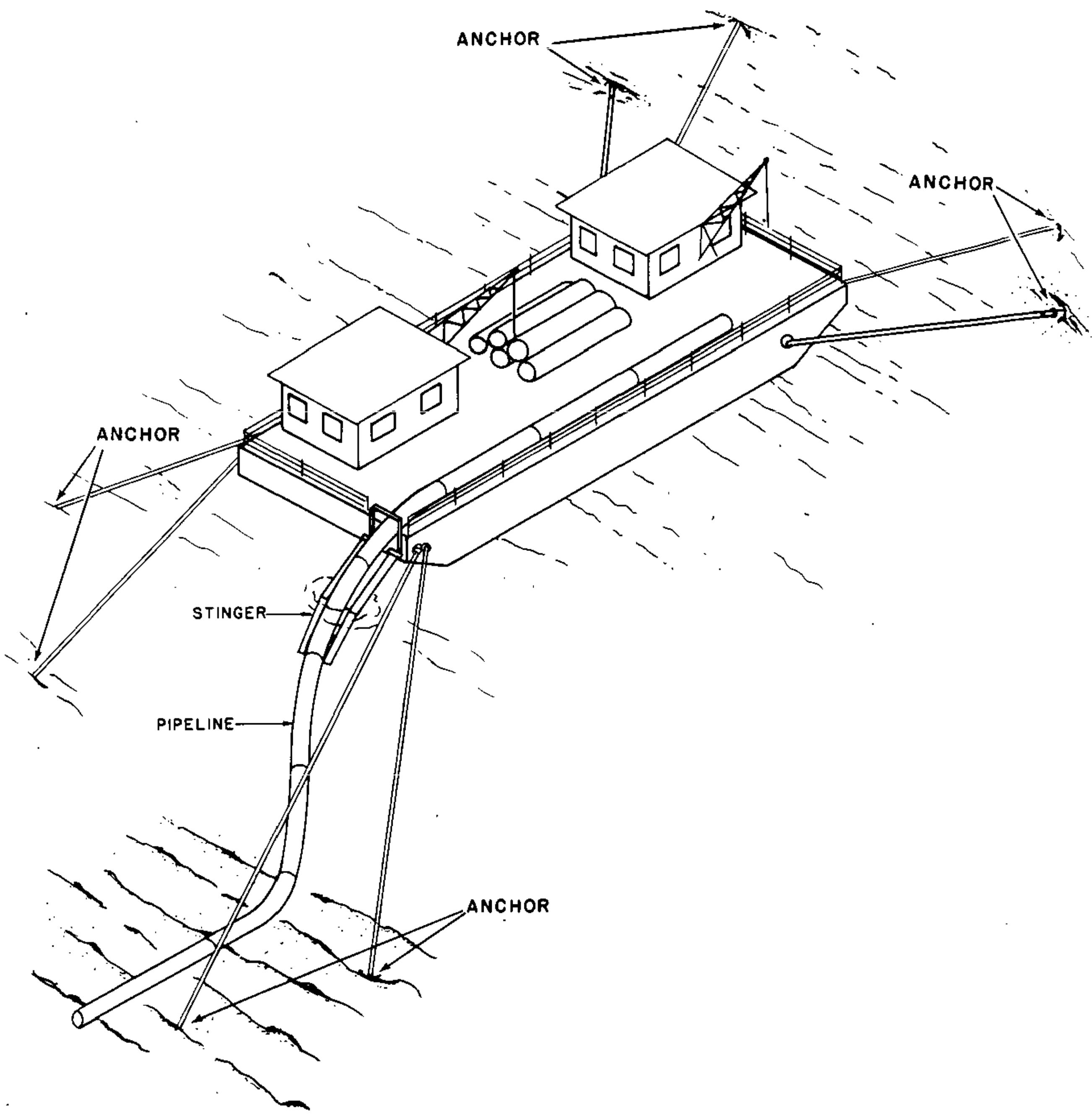
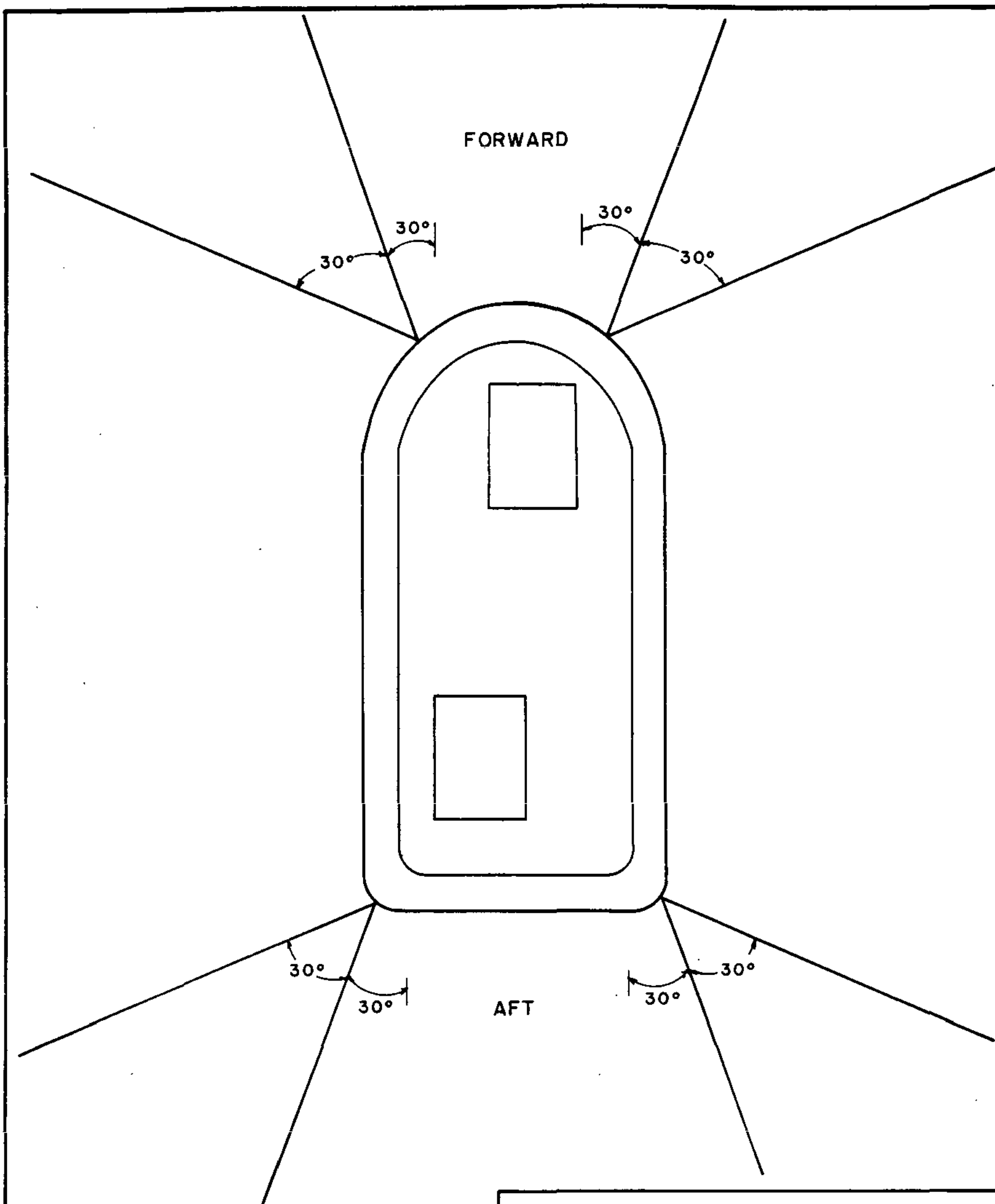


FIGURE V-2

TYPICAL LAY BARGE



ANCHOR LINE SCOPE IS APPROXIMATELY 6 TO 7 TIMES THE WATER DEPTH. FOR 670' WATER DEPTH, MAXIMUM LINE LENGTH APPROXIMATELY 4700' DEPENDING ON BOTTOM CONDITIONS AND ANCHOR TENSION.

FIGURE V-3

TYPICAL LAY BARGE ANCHOR PATTERN

SECTION VI - DRILLING PROGRAM, EQUIPMENT, AND PROCEDURES

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DRILLING PROGRAM, EQUIPMENT, AND PROCEDURES

6.1 INTRODUCTION

This section contains discussions of the drilling program to be conducted at Platform Harvest. Section 6.2 presents general information including drilling targets, regulatory requirements, logistics, supplies, and waste materials. Section 6.3 outlines compliance with OCS Orders. Sections 6.4 and 6.5 discuss the facilities and equipment used during the drilling phase of development. In Section 6.6 the drilling program and procedures are outlined. Also, discussions of the various safety systems and procedures that will be implemented during the drilling program are provided.

6.2 GENERAL INFORMATION

Texaco plans to produce hydrocarbons from intervals within the Monterey, Sisquoc, and Foxen formations at depths up to 8300 ft (2530 m) subsea. Texaco's primary consideration during all drilling operations will be safety to personnel and the environment. Drilling procedures, operational characteristics, pollution prevention systems, and safety systems will all be conducted or maintained in accordance with all applicable requirements, including MMS Pacific Region OCS Orders No. 2, 5, 6, and 7 (as discussed in Section 6.3), EPA NPDES permit conditions, and API standards.

Drilling times for individual wells will vary from about 41 to 97 days depending on depth to the producing horizon(s) and other factors such as the hardness of the rocks penetrated. The average drilling duration will be 67 days per well. The drilling program for Texaco's entire Point Arguello field development will last approximately 4 years.

Drilling activities will be conducted from two rigs on Platform Harvest in two 12-hour shifts, 24 hours per day, 7 days per week. Personnel associated with these activities will consist of approximately 24 drilling contractor crew members, 2 Texaco supervisors, and 18 service company workers per work week on the platform. Nearly all of these persons will be drawn from the Santa Barbara/Ventura/Los Angeles counties labor force. Personnel will live in quarters installed on the platform and work 7 consecutive days, then have 7 days off. The workers will be transported by crew boats on a weekly basis between Platform Harvest and Ellwood Pier in Goleta or a consolidated industry supply base; a total of up to 7 round trips will be required per week.

Required supplies and materials will include such things as tubular goods, drill bits, diesel fuel, mud materials, cement, mud and cement make-up water, completion fluids, food, and miscellaneous personal items. Most of these will be purchased in the Ventura County area and transported from Port Hueneme or a consolidated industry supply base to Platform Harvest by supply boat. Trips to Platform Harvest will total approximately 3 trips per week. Approximately 3 helicopter trips per week will be required for miscellaneous purposes.

Estimated total costs (in 1983 dollars) of the drilling program for Texaco's development of the Point Arguello field would be $58.5 million for labor and $124.8 million for purchased materials. Of these amounts, 100 and 75 percent, respectively, will accrue to residents or businesses of the Santa Barbara/Ventura/Los Angeles counties area.

Liquid and solid wastes which will be generated during Texaco's proposed drilling program are summarized in Table VI-1. The principal drilling wastes will be drill cuttings and excess water-based drilling muds. Drill cuttings are fragments of native subsurface rock material that are dislodged by the drill bit and carried to the surface by the circulating drilling mud. The cuttings are separated from the mud by high-speed, dual-screen shale-shakers, desanders, and desilters, after which the mud is reused to the extent feasible to minimize discharges. The separated cuttings will be washed with seawater to remove oil and grease and then discharged to the ocean in accordance with a NPDES permit. No free oil will be discharged. When oil-contaminated cuttings are produced, they will first be transported by supply boat or barge to Port Hueneme or a consolidated industry supply base, then transported by truck to an approved disposal site.

The muds which will be used during drilling operations will be composed principally of sea or fresh water, clays, barium sulfate, and organic polymers. Small amounts of other compounds, such as sodium hydroxide, lignite, lignosulfonates, and defoamers may also be added under certain circumstances. Examples of typical simple drilling mud compositions are given in Table VI-2. Specific mud types and volumes are discussed in Appendix A, Proprietary Data. If any oil-contaminated drilling muds are produced, they will first be transported by supply boat or barge to Port Hueneme or a consolidated industry supply base, then transported by truck to an approved disposal site. Used oil-free drilling muds will be discharged to the ocean in accordance with NPDES permit conditions.

Sanitary sewage will be treated on the platform in a packaged USCG-approved unit in which the sewage is macerated, chemically oxidized with chlorine, and then discharged to the ocean. All such ocean discharges will be made in accordance with NPDES permit conditions. General refuse generated during drilling activities will be collected and transported to shore via supply boat. Once onshore, these wastes will be disposed of at an approved location.

6.3 COMPLIANCE WITH OCS ORDERS

6.3.1 OCS Order No. 2 - Drilling Operations

Prior to commencing drilling, Texaco will file an Application for Permit to Drill with the MMS for approval.

6.3.1.1 General Requirements

Platform Harvest is designed to withstand the oceanographic and meteorological conditions for the Point Conception area. The information listed below will be submitted to the MMS:

- The rated capacity of all major drilling equipment
- Description of drilling safety systems
- Description of firefighting equipment

- Description of pollution-prevention equipment associated with the drilling operation

- Schematic diagrams of the drilling units

- A "Critical Operations and Curtailment Plan" (Appendix B of this document).

Prior to commencing drilling operations, Platform Harvest will be made available for a complete inspection by the MMS.

Texaco has conducted shallow geologic hazard surveys as required by the Supervisor. The results of these surveys and an analysis of the geological hazards have been furnished to the Deputy Conservation Manager, Offshore Operations. All data obtained from the surveys and all geophysical data relating to shallow hazards have been furnished to the Deputy Conservation Manager. Texaco has also collected oceanographic, meteorologic, and performance data and will submit the data to the Deputy Conservation Manager.

6.3.1.2 Well Casing and Cementing

All wells will be cased and cemented in accordance with the requirements of 30 CFR 250.41(a)(1). Casing design safety factors for collapse, tension, and burst are included in Appendix A. If there are indications of inadequate cementing (such as lost returns, cement channeling, or mechanical failure of equipment on the surface, intermediate, and production casing strings), Texaco will evaluate the adequacy of the cementing operations by pressure testing the casing shoe, running a cement bond log, running a temperature survey, or a combination thereof before continuing operations. If the evaluation indicates inadequate cementing, Texaco will recement or take other actions as approved by the MMS. Texaco will verify the adequacy of the remedial cementing operations as required by the MMS.

The design criteria for all wells will consider, all pertinent factors for well control, such as:

- Formation fracture gradients

- Formation pressure

- Anticipated surface pressure

- Casing setting depth.

These design criteria are presented in Appendix A.

Texaco will utilize appropriate drilling technology and state-of-the-art methods, such as drilling-rate evaluation, shale-density analysis, or other appropriate methods in order to enhance the evaluation of conditions of abnormal pressure and to minimize the potential for the well to flow or kick. All casing will be new pipe which meets or exceeds American Petroleum Institute (API) standards. If casing to be used is not fabricated to API standards, the yield strengths of the casing shall be included on the Application for Permit to Drill.

The proposed conductor and surface casing design and setting depths are based upon all engineering and geologic factors, including the presence or absence of hydrocarbons, anticipated pressures, and other potential hazards. These strings of casing will be set at the depths specified, subject to approved variation to permit the casing to be set in a competent bed, or through formations determined desirable to be isolated from the well by pipe for safer drilling operations; however, the conductor casing will be set immediately prior to drilling into formations known to contain oil or gas, or, if unknown, upon encountering such formations. These casing strings will be run and cemented prior to drilling below the specified setting depths. All casing setting depths are given in the casing program of Appendix A. Engineering and geologic data which are used to substantiate the proposed setting depths of the conductor and surface casings (such as estimated fracture gradients, pore pressures, shallow hazards, etc.) are also furnished in the proprietary appendix.

Conductor casing will be cemented with a quantity of cement sufficient to fill the calculated annular space back to the ocean floor. Since observation of cement returns is not feasible, an excess volume of cement will be used to assure fill to the ocean floor.

Surface casing will be cemented with a quantity of cement sufficient to fill the calculated annular space to the ocean floor. After drilling a maximum of 15 meters (49 feet) of new hole, a pressure integrity leak-off test will be conducted to obtain data to be used in estimating the formation fracture gradient and to test the integrity of the cement at the casing shoe. The results of this test and any subsequent tests of the formation will be recorded on the driller's report and used to determine the maximum allowable depth and mud weight to be used in the intermediate hole.

One string of intermediate casing will be set. The setting depth for intermediate casing will be based on the pressure tests of the exposed formation below the surface casing shoe or on subsequent pressure tests. After drilling a maximum of 15 meters (49 feet) of new hole, a pressure integrity leak-off test will be conducted to obtain data to be used in estimating the formation fracture gradient. The results of this test and any subsequent tests of the formation will be recorded on the driller's report and used to determine the depth and maximum mud weight to be used in the hole below the intermediate-casing string. A cementing procedure for the intermediate casing is presented in Appendix A.

Production casing will be set before completing the well for production. When a liner is used as production casing below intermediate casing, it will be lapped a minimum of 30 meters (98 feet) into the previous casing string and cemented as required for the production casing. Testing of the seal between the liner top and the next larger string will be conducted as in the case of intermediate liners and recorded on the driller's report. If the test indicates an improper seal, the top of the liner shall be squeeze cemented. A cementing procedure for the production casing is presented in Appendix A.

6.3.1.3 Pressure Testing of Casing

Prior to drilling the plug after cementing, all casing strings will be pressure-tested as indicated in the pressure summary of the proprietary appendices. If the pressure declines more than 10 percent in 30 minutes or if there is another indication of a leak, the casing will be recemented, repaired, or an additional casing string run, and the casing tested again. The above procedures will be repeated until a satisfactory test is obtained.

In the event of prolonged drill pipe operations which could cause damage to the casing, the casing will be pressure-tested, calipered, or otherwise evaluated, as approved by the MMS.

After cementing any of the above strings, drilling will not be resumed until there has been a time lapse of 8 hours for the conductor casing string or 12 hours for all other strings. All casing pressure tests will be recorded on the driller's report. In addition to the time lapse stated above, sufficient time will be allotted to allow the bottom 500 feet of annular cement fill, or total length of annular cement fill, if less, to attain a compressive strength of at least 500 psi before drilling resumes.

The typical performance data for the particular cement mix used in the well will be used to determine the time lapse required.

6.3.1.4 Directional Surveys

Wells are considered vertical if inclination does not exceed an average of 3 degrees from the vertical. Inclinational surveys will be obtained on all vertical wells at intervals not exceeding 500 feet during the normal course of drilling. Wells are considered directional if inclination exceeds an average of 3 degrees from the vertical. Directional surveys giving both inclination and azimuth will be obtained on all directional wells at intervals not exceeding 500 feet during the normal course of drilling and at intervals not exceeding 100 feet in all planned angle-change portions of the hole.

On both vertical and directional wells, directional surveys giving both inclination and azimuth will be obtained at intervals not exceeding 500 feet prior to, or upon, setting surface or intermediate casing, liners, and at total depth. Composite directional surveys will be filed with the MMS.

6.3.1.5 Blowout-Preventer Equipment

Blowout preventers and related well-control equipment will be installed, used, maintained, and tested in a manner necessary to assure well control. Blowout-preventer equipment will consist of an annular preventer and the specified number of ram-type preventers. The pipe rams will be of proper size to fit the tubulars in use. The working pressure of any blowout preventer will exceed the anticipated surface pressure to which it may be subjected.

Information submitted in the proprietary appendices includes the anticipated surface pressure and the criteria used to determine this pressure. All blowout-preventer systems will be equipped with:

- An hydraulic actuating system that provides sufficient accumulator capacity to supply 1.5 times the volume necessary to close all BOP equipment units with a minimum pressure of 200 psi above the precharge pressure. An accumulator backup system, supplied by a secondary power source independent from the primary power source, will be provided with sufficient capacity to close all blowout preventers and hold them closed. Locking devices will be provided on the ram-type preventers. The method of BOP actuation control will be hydraulic.

- One operable remote blowout-preventer-control station, in addition to the ones on the drilling floors will be in a readily accessible location away from the drilling floor for each drilling rig.

- A drilling spool with side outlets to provide for separate kill and choke lines.

- A kill line equipped with 2 kill-line valves will be provided. The master valve will be located adjacent to the BOP and will not normally be used for opening or closing on flowing fluid. The second valve will be located adjacent to the master valve and be used as the control valve.

- A fill-up line above the uppermost preventer.

* A choke manifold equipped in accordance with "API Recommended Practice for Blowout-Prevention Equipment Systems," API RP 53, first edition, February 1976, reissued February 1978, Section 3A and 3B, or subsequent revisions which the Pacific OCS Regional Supervisor, Field Operations has approved for use.

* Valves, pipes, flexible steel hoses, and other fittings upstream of, and including, the choke manifold will have a pressure rating at least equal to the anticipated surface pressure.

* A wellhead assembly with a working pressure at least equal to the anticipated surface pressure.

The following auxiliary equipment will be provided and maintained in operable condition at all times:

* A kelly cock will be installed below the swivel, and an essentially full-opening valve of such design that it can be run through blowout preventers will be installed at the bottom of the kelly. A wrench to fit each valve will be stored in a conspicuous location readily accessible to the drilling crew.

* An inside blowout preventer and an essentially full-opening drill string safety valve in the open position will be maintained on the rig floor at all times while drilling operations are being conducted. These valves will be maintained on the rig floor to fit all connections that are in the drill string.

* A safety valve will be available on the rig floor assembled with the proper connection to fit the casing string that is being run in the hole at the time.

The BOP program is presented in Section 6.6.6.

The diverter system will include a minimum of two 6-inch internal diameter lines and full-opening valves. The flowpath from the BOP to the branch point of diverter lines in new systems will have a minimum internal diameter of 6 inches.

When a tapered drill string is in use, the BOP stack will be equipped with one of the following pipe ram configurations:

- Two sets of pipe rams for the larger size string and one set for the smaller size string of drill pipe.

- Two sets of pipe rams for the larger size string and one set of variable bore pipe rams to fit both sizes of pipe.

- Two sets of variable bore pipe rams to fit both sizes of pipe.

- One set of pipe rams for the larger size string and one set of variable bore pipe rams to fit both sizes of pipe.

- One set of pipe rams for the larger size string, one set of pipe rams for the smaller pipe, and one set of variable bore pipe rams to fit both sizes of pipe.

Before drilling below the conductor casing string, the low-pressure blowout preventer stack will be installed. The diverter system will be equipped with remote-control valves in the main and diverter flow lines that can be operated from the control panel prior to shutting in the well. The diverter lines will vent in different directions to permit downwind diversion. A schematic diagram and operational procedure for the diverter system is presented in the proprietary appendices.

Before drilling below the surface and intermediate casing strings, the blowout-preventer system will consist of at least four remote-controlled, hydraulically operated blowout preventers including at least two equipped with pipe rams, one with blind rams, and one annular type. Prior to conducting high-pressure tests, all BOPS will be tested to a low pressure of 200 psi. All BOP tests will be recorded in the driller's report. A complete BOP testing procedure is presented in the proprietary appendices. BOP stacks will be tested as follows:

- When installed.

- Before drilling out after each string of casing has been set.

- At least once each week, and not exceeding 7 days between tests, alternating between control stations except when well operations prevent testing and remedial efforts are being performed. In such case, the tests will be conducted as soon as possible before normal operations resume, and the reason for postponing testing will be entered into the log. Testing shall be at staggered intervals to allow each drilling crew to operate the equipment. If either control system is not functional, further drilling operations will be suspended until that system is operational.

- Following repairs that require disconnecting a pressure seal in the assembly.

The following minimum-actuation frequencies will be practiced:

- Pipe Rams - Daily. In order to prevent damage to the rams, complete closure of the rams on drill pipe will be prevented, provided proper operation is indicated.

- Blind Rams - Once each trip while the drill pipe is out of the hole. If multiple trips are made, only one actuation per day will be conducted.

- Annular-Type Preventer - Once each week in conjunction with the pressure test.

- Control Stations - Once each trip from alternate control stations, while the drill pipe is out of the hole; however, not more than once each day if multiple trips are made. If either system is not functional, further drilling operations will be suspended until that system becomes operable.

- Choke manifold valves, kelly cocks, drill pipe safety valves - Weekly.

All BOP systems and associated equipment will be inspected and maintained in accordance with the manufacturer's recommended procedures. The BOP systems will be visually inspected at least once each day if the weather and sea conditions permit the inspection.

All drilling personnel will be indoctrinated in blowout-preventer drills and be familiar with the blowout-preventer equipment before starting work on the well. A blowout-preventer drill will be conducted for each drilling crew in accordance with the well-control drill requirements of the U.S. Geological Survey (USGS) Outer Continental Shelf Standard "Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Locations," No. T 1 (GSS-OCS-T 1). All BOP drills will be recorded in the driller's report.

6.3.1.6 Mud Program

The characteristics, use, and testing of drilling mud and the implementation of related drilling procedures will be designed to prevent the loss of well control. Sufficient quantities of mud materials will be maintained readily accessible for use at all times to assure well control. A complete summary of mud volume and quantities of mud materials vs. depth is presented in the proprietary appendices.

Before starting out of the hole with drill pipe, the mud will be properly conditioned. Proper conditioning requires either circulation with the drill pipe just off bottom to the extent that the annular volume is displaced, or proper documentation in the driller's report prior to pulling the drill pipe as follows:

- There was no indication of influx of formation fluids prior to starting to pull the drill pipe from the hole.

- The weight of the returning mud was essentially the same as the weight of the mud entering the hole. In the event that the returning mud was lighter than the entering mud by a weight differential equal to or greater than 0.2 pounds per gallon, the mud would be circulated until the annular volume is displaced, and the mud properties would be checked for the influx of gas or liquid.

- Other mud properties recorded on the daily drilling log are within the specified ranges required by the mud program.

When the mud in the hole is circulated, the driller's report will be so noted.

When coming out of the hole with drill pipe, the annulus will be filled with mud before the change in mud level decreases the hydrostatic pressure 75 psi or every 5 stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. The number of stands of drill pipe and drill collars that will be pulled prior to filling the hole and the equivalent mud volume will be calculated and posted. A device for measuring the amount of mud required to fill the hole will be utilized.

If there is an indication of swabbing or influx of formation fluids, the necessary safety devices and action will be employed to control the well. The mud will be circulated and conditioned, on or near bottom, unless well or mud conditions prevent running the drill pipe back to the bottom.

For each casing string, the maximum pressure to be contained under the blowout preventer, before controlling excess pressure by bleeding through the choke, will be posted near the driller's control console.

An operable gas separator will be installed in the mud system prior to commencement of drilling operations. The separator will be maintained for use throughout the drilling and completion of the well. The mud in the hole will be circulated or reverse-circulated prior to pulling the drill-stem test tools from the hole.

Mud-testing equipment will be maintained on the drilling rig at all times, and mud tests will be performed once each 12 hours, or more frequently, if conditions warrant. Such tests will be conducted in accordance with procedures outlined in "API Recommended Practice for Standard Procedure for Testing Drilling Fluids," API RP 13B. The results of the tests will be recorded and maintained at the drill site.

The following mud-system monitoring equipment will be installed with derrick floor indicators and used when mud returns are established and throughout subsequent drilling operations:

- Recording mud pit level indicator to determine mud pit volume gains and losses. This indicator will include both a visual and an audio warning device.

- Mud-volume measuring device for accurately determining mud volumes required to fill the hole on trips.

- Mud-return indicator to determine that returns essentially equal the pump discharge rate.

- Gas-detecting equipment to monitor the drilling mud returns, with indicators located in the mud-logging compartment or on the derrick floor. When the indicators are in the mud-logging compartment, there will be a means of immediate communication with the rig floor, and the equipment will be continually manned.

The proprietary appendices include a tabulation of well depth versus minimum quantities of mud material, including weighting material, to be maintained at the drill site to assure well control. Daily inventories of mud materials, including weighting material, will be recorded and maintained at the platform. Drilling operations will be suspended in the absence of minimum quantities of mud material specified in the table or as modified in the approved plan.

6.3.1.7 Supervision, Surveillance, and Training

A Texaco representative will provide onsite supervision of drilling operations on a 24-hour basis. From the time drilling operations are initiated and until the well is completed or abandoned, a member of the drilling crew or the toolpusher will maintain rig-floor surveillance continuously, unless the well is secured with blowout preventers, bridge plugs, storm packer, or cement plugs.

Texaco and drilling contractor personnel will be trained and qualified in accordance with the provisions of the MMS Outer Continental Shelf Standard "Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Locations," No. T 1 (GSS-OCS-T 1). Records will be maintained at the platform indicating specific training and refresher courses successfully completed, the dates of completion, and the names and dates of the courses.

6.3.1.8 Hydrogen Sulfide

The preventive measures and the operating practices set forth in MMS Outer Continental Shelf Standard "Safety Requirements for Drilling Operations in a Hydrogen Sulfide Environment," No. 1 (GSS-OCS-1) will be followed. Texaco is submitting with this DPP a Hydrogen Sulfide Plan to be followed whenever H_2S is present (Appendix C).

6.3.1.9 Critical Operations and Curtailment Plans

Certain operations performed in drilling are more critical than others with respect to well control, and for the prevention of fire, explosion, oil spills, and other discharges or emissions. Texaco is submitting with this DPP a Critical Operations and Curtailment Plan to be followed while conducting drilling operations (Appendix B).

6.3.1.10 Field Drilling Rules

Texaco will make an application for the establishment of field drilling rules. After field drilling rules have been established by the Pacific OCS Regional Supervisor, Field Operations, development wells will be drilled in accordance with these rules and the requirements of Order No. 2 which are not affected by such rules.

6.3.2 OCS Order No. 5 - Production Safety Systems

6.3.2.1 Drilling Rigs

6.3.2.1.1 Use of Best Available and Safest Technologies (BAST)

Texaco will continue the development of safety-system technology. As research and product improvement results in increased effectiveness of existing safety equipment or the development of new equipment systems, such equipment may be used and, if such technologies provide a significant cost effective incremental benefit to safety, health, or the environment, will be used if determined to be BAST.

The standards, codes, and practices referenced in OCS Order No. 5 will be conformed to. Specific equipment and procedures or systems not covered by standards, codes, or practices will be analyzed to determine if the failure of such would have a significant effect on safety, health, or the environment. If such are identified and until specific performance standards are developed or endorsed by the MMS, and as directed by the Supervisor on a case-by-case basis, Texaco will submit such information necessary to indicate the use of BAST, the alternatives considered to the specific equipment or procedures, and the rationale why one alternative technology was considered in place of another. This analysis will include a discussion of the costs involved in the use of such technology and the incremental benefits gained.

6.3.2.1.2 Electrical Equipment

The following will be applicable to all electrical equipment and systems:

- All engines with ignition systems will be equipped with a low-tension ignition system of a low-fire-hazard type and shall be designed and maintained to minimize the release of sufficient electrical energy to cause ignition of an external, combustible mixture.

- All electrical generators, motors, and lighting systems will be installed, protected, and maintained in accordance with the edition of the National Electrical Code and API RP 500B in effect at the time of approval.

- At the time of approval, wiring methods will conform to the National Electrical Code, 1978 Edition, or to the Institute of Electrical and Electronic Engineers (IEEE) "Recommended Practice for Electric Installation on Shipboard," IEEE Std. 45-1977, or subsequent revisions approved for use. Each conductor of a wire, a cable, or a bus bar will be made of copper.

- The elementary electrical schematic of the platform safety-shutdown system will be maintained on the platform. This schematic will indicate the control functions of all electrically actuated safety devices.

- Maintenance of these systems will be by personnel who are familiar with the construction and operation of the equipment and the hazards involved.

6.3.2.1.3 Welding Procedures

Texaco will file for approval by the District Supervisor a "Welding, Burning, and Hot Tapping Safe Practices and Procedures Plan." The plan will include the qualification standards or requirements for personnel and the methods by which Texaco will assure that only personnel meeting such standards or requirements are utilized. A copy of this plan will be available on the platform. The production supervisor will be thoroughly familiar with this plan.

All welding and burning equipment will be inspected prior to beginning any welding or burning. Welding machines located on the platform will be equipped with spark arrestors and drip pans. Welding leads will be completely insulated and in good condition; oxygen and acetylene bottles secured in a safe place; and hoses leak-free and equipped with proper fittings, gauges, and regulators.

Texaco will establish and so designate areas on the platform determined to be safe-welding areas pursuant to the National Fire Protection Association Bulletin "Cutting and Welding Processes," No. 51 B, 1976, or subsequent revisions approved for use. Approval for the use of such areas will be obtained from the MMS. These designated areas will be identified in the General Plan and a drawing showing the location of these areas will be maintained on the platform.

All welding or burning which cannot be done in an approved safe-welding area will be performed in compliance with the following procedures:

- Prior to the commencement of any welding or burning operation, Texaco's production supervisor will personally inspect the qualifications of the welder or welders to assure that they are properly qualified in accordance with the approved qualification standards or requirements for welders. The production supervisor and the welders will personally inspect the work area for potential fire and explosion hazards. After it has been determined that it is safe to proceed with the welding or burning operation, the production supervisor will issue a written authorization for the work.

- During all welding and burning operations, one or more persons will be designated as a Fire Watch. Persons assigned as a Fire Watch will have no other duties while actual welding or burning operations are in progress. If welding is done in an area which is not equipped with a gas detector, the Fire Watch will also maintain a continuous surveillance with a portable gas detector during welding.

- Prior to any welding or burning operation, the Fire Watch will have in his possession firefighting equipment in a usable condition. At the end of the welding operation, the equipment will be returned to a usable condition.

- No welding, other than approved hot tapping, will be done on piping, containers, tanks, or other vessels which have contained a flammable substance unless the contents have been rendered inert and determined to be safe for welding or burning by the production supervisor.

- If drilling, workover, or wireline operations are in progress on the platform, welding operations in other than approved safe-welding areas will not be conducted unless the well(s) where these operations are in progress contain noncombustible fluids and the entry of formation hydrocarbons into the wellbore is precluded.

- If welding or burning operations are conducted in the well-bay or production area, all producing wells will be shut in at the surface safety valve.

6.3.2.1.4 Employee Orientation and Motivation Programs

Texaco will make a planned, continuing effort to eliminate accidents due to human error. This effort will include the training of personnel in their functions. A program to achieve safe and pollution-free operations will be established. This program will include instructions in the provision of "API Recommended Practice Orientation Program for Personnel Going Offshore for the First Time," API RP T-1, January 1974, or subsequent revisions approved for use. "API Employee Motivation Programs for Safety and Prevention of Pollution in Offshore Operations," API Bulletin T-5, September 1974, or subsequent revisions approved for use will be used as a guide in developing employee safety and pollution-prevention motivation programs.

6.3.3 OCS Order No. 6 - Procedure for Completion of Oil and Gas Wells

6.3.3.1 Wellhead Equipment and Testing Procedures

All completed wells will be equipped with casingheads, wellhead fittings, valves, and connections with a rated working pressure equal to or greater than the surface shut-in pressure of the well. Two master valves will be installed on the tubing in wells with a surface pressure in excess of 5000 pounds per square inch. All wellhead connections will be assembled and tested, prior to installation, by a fluid pressure which shall be equal to 1.5 times the rated working pressure of the fitting to be installed.

Any wells showing sustained pressure on the casinghead, or leaking gas or oil between the production casing and the next larger casing string, will be tested in the following manner: The well will be killed with water or mud and pump pressure applied to the production casing string. Should the pressure at the casinghead reflect the applied pressure, corrective measures will be taken and the casing will again be tested in the same manner. This testing procedure will be used when the origin of the pressure cannot be determined otherwise.

6.3.4 OCS Order No. 7 - Pollution Prevention and Control

Texaco will prevent pollution of the ocean. Furthermore, by the disposal of waste materials into the ocean, Texaco will not create conditions which will adversely affect the public health, life, property, aquatic life, wildlife, recreation, navigation, commercial fishing, or other uses of the ocean.

6.3.4.1 Liquid Disposal

Texaco is submitting, as a part of this DPP, a detailed list of drilling-mud components including the common chemical or chemical trade name of each component, and a list of the drilling-mud additives anticipated for use in meeting special drilling requirements (see Appendix A). The disposal of drilling mud is subject to the Environmental Protection Agency's permitting procedures, pursuant to the Federal Water Pollution Control Act, as amended. Approval of the method of drilling-mud disposal into the ocean will be obtained from the District Supervisor.

All hydrocarbon-handling equipment for testing and production such as separators and tanks will be designed and operated to prevent pollution. Maintenance or repairs which are necessary to prevent pollution of the ocean will be undertaken immediately.

Curbs, gutters, drip pans, and drains will be installed in all deck areas in a manner necessary to collect all contaminants and piped to a properly designed, operated, and maintained sump system which will automatically maintain the oil at a level sufficient to prevent discharge of oil into OCS waters. Sump piles will not be used as a processing device to treat or skim liquids, but will be used to collect treated produced water, treated sand, liquids from drip pans and deck drains, and as a final trap for hydrocarbon liquids in the event of equipment upsets.

6.3.4.2 Solid Material Disposal

The disposal of drill cuttings, sand, and other well solids is subject to the Environmental Protection Agency's permitting procedures, pursuant to the Federal Water Pollution Control Act, as amended. All well solids which, if discharged, could result in discharge of free oil will be hauled to shore for disposal at an approved site. Approval of the method of disposal of drill cuttings, sand, and other well solids will be obtained from the District Supervisor.

Containers and other similar solid waste materials will not be disposed of into the ocean. Disposal of equiment into the ocean is prohibited except under emergency conditions. The location and description of any equipment disposed of into the ocean will be reported to the District Supervisor and to the U.S. Coast Guard.

6.3.4.3 Personnel, Inspections, and Reports

Texaco's personnel will be instructed in the techniques of equipment maintenance and operation for the prevention of pollution. Contractor personnel providing services offshore will be informed in writing, prior to executing contracts, of Texaco's obligations to prevent pollution and of the provisions of OCS Order No. 7.

All platform facilities will be inspected daily to determine if pollution is occurring. Maintenance or repairs which are necessary to prevent pollution of the ocean waters will be undertaken and performed immediately.

All spills of oil and liquid pollutants will be reported orally to the District Supervisor and confirmed in writing. All reports will include the cause, location, volume of spill, and action taken. Reports of spills of more than 5.0 cubic meters (31.5 barrels) will include information on the sea state, meteorologic conditions, size, and appearance of slick. All spills of oil and liquid pollutants will also be reported in accordance with the procedure contained in 33 CFR 153.203. Spills will be reported orally within the following time limits:

- Within 12 hours, if spills are 1.0 cubic meter (6.3 barrels) or less.

- Without delay, if spills are more than 1.0 cubic meter (6.3 barrels).

6.3.4.4 Pollution-Control Equipment and Materials and Oil Spill Contingency Plans

Texaco's Oil Spill Cleanup Manual, which has been submitted to the MMS for approval, contains a description of procedures, personnel, and equipment that will be used in reporting, cleanup, and prevention of the spread of any pollution resulting from an oil spill which might occur.

Pollution-control equipment and materials will be maintained by Texaco at Platform Harvest. The equipment will include a standby boat, containment booms, skimming apparatus, cleanup materials, chemical agents and other items needed for the existing climatic conditions, and will be available prior to the commencement of drilling and production operations. The equipment and materials will be inspected monthly and maintained in a state of readiness for use. The results of the inspections will be recorded and maintained at the site.

Texaco has submitted an Oil Spill Contingency Plan for approval by the Deputy Conservation Manager. The Oil Spill Contingency Plan will be reviewed annually. All modifications of the Oil Spill Contingency Plan and the results from the review of the plan will be submitted to the Pacific OCS Regional Supervisor, Field Operations, for approval. The Oil Spill Contingency Plan contains the following:

- Provisions to assure that full resource capability is known and can be committed during an oil spill, including the identification and inventory of applicable equipment, materials, and supplies which are available locally and regionally, both committed and uncommitted, and the time required for deployment of the equipment.

- Provisions for varying degrees of response effort depending on the severity of the oil spill.

- Provisions for identifying and protecting areas of special biological sensitivity.

- Establishment of procedures for the purpose of early detection and timely notification of an oil spill including a current list of names, telephone numbers, and addresses of the responsible persons and alternates on call to receive notification of an oil spill, and the names, telephone numbers, and addresses of regulatory organizations and agencies to be notified when an oil spill is discovered.

- Provisions for well-defined and specific actions to be taken after discovery and notification of an oil spill, including:

  (1) Specification of an oil spill response operating team consisting of trained, prepared, and available operating personnel.

  (2) Predesignation of an oil spill response coordinator who is charged with the responsibility and is delegated commensurate authority for directing and coordinating response operations.

  (3) A preplanned location for an oil spill response operations center and a reliable communications system for directing the coordinated overall response operations.

  (4) Provisions for disposal of recovered spill materials.

6.3.4.5 Drills and Training

Drills for familiarization with pollution-control equipment and operational procedures will be held at least once every 12 months. The personnel identified as the oil spill response operating team in the Contingency Plan will participate in these drills. The drills will be realistic and include deployment of equipment. A time schedule with a list of equipment to be deployed will be submitted to the Supervisor for approval. The drill schedule will provide sufficient advance notice to allow MMS personnel to witness any of the drills. Drills will be recorded, and the records will be made available to MMS personnel.

Texaco will ensure that training classes for familiarization with pollution-control equipment and operational procedures are provided for the oil spill response operating team. The supervisory personnel responsible for directing the oil spill response operations will receive oil spill control instruction suitable for all seasons. Texaco will retain course completion certificates or attendance records issued by the organization where the instruction was provided. These records will be available to any authorized representative of the MMS upon request.

6.3.4.6 Spill Control and Removal

Immediate corrective action will be taken in all cases where pollution has occurred. Corrective action taken under the Oil Spill Contingency Plan will be subject to modification when directed by the Supervisor. The primary jurisdiction to require corrective action to abate the source of pollution will remain with the Supervisor. The use of chemical agents or other additives will be permitted only after approval by the Supervisor.

6.4 DRILLING DECK AND WELL BAY LAYOUTS

This section discusses the major components that will comprise the drilling system to be installed on Platform Harvest. Platform Harvest will be a conventional steel jacket structure with 50 well slots. Drilling operations will be conducted using two electric drilling rigs. All drilling equipment and services will be provided on a contract basis, under supervision by Texaco.

A preliminary drilling deck layout is shown on Figure VI-1. The drilling rigs will be especially designed and/or adapted for use on offshore platforms. The drilling equipment will require overall compatibility with the drilling platform deck designs; however, the drilling contractor will have some flexibility in the final equipment layouts.

6.5 PLATFORM DRILLING EQUIPMENT

6.5.1 Rig Components

Characteristics of each of the two rigs to be used are given in Table VI-3.

6.5.2 Substructure

The substructure of each drilling rig will be capable of supporting the derricks and setback loads. It will be designed to provide unobstructed clearance for the blowout prevention equipment. The substructure will be supported on a skid-base, resting on elevated skidbeams. Each skidbase will be equipped with a hydraulic jacking system to allow transition along the direction of the well rows. Each subbase will also be equipped with hydraulic jacks to allow lateral skidding over the desired well. Mechanical restraint equipment will be provided to prevent substructure movement once positioned over the desired location.

6.5.3 Drilling Mud and Solids Control System

The mud system for each rig will be equipped with two 1600-hp 7 1/2-inch x 12-inch triplex single acting mud pumps and approximately 600 barrels of active mud tank capacity. Included with this system will be a mud mixing tank, trip tank, and a sand trap below the shale shaker. The solids control equipment will consist of double separating screens, mud cleaners, desilters, desanders, centrifuges and a degasser.

The shale shaker units will be equipped with a cuttings washing system to clean any oil-contaminated cuttings before disposal. No discharge of free oil resulting from the discharge of mud and cuttings will take place. Cuttings that cannot be adequately cleaned by washing will be diverted to a waste cuttings holding tank, to be transported to shore for disposal at an approved site.

Mud volumes will be closely monitored using a pit volume totalizer system, an incremental flow rate indicator, and a precision fill-up measurement system. These warning systems will have visual and audible alarm signals at the driller's console. A common bulk material handling system will be provided with 4000 ft^3 (113 m^3) storage capacity for clay and barite materials. Sacks of mud additives (chemicals, lost circulation material, etc.), needed on the platform will be stored on pallets near the rigs. Mud, barite, and gel volumes are given in Appendix A, Proprietary Data.

6.5.4 Cementing Unit

One Halliburton Type - FKD4 cementing unit driven by 2-8V-92 and 4-71 GM diesels, and 3000 ft^3 (85 m^3) bulk storage capacity will be provided for well cementing operations.

6.5.5 Electric Power Generators

Electric power necessary for drilling operations on Platform Harvest will be supplied by 5 turbine generators (main source) capable of supplying 11.5 MW of AC power. Two diesel reciprocating generators capable of producing 1.5 MW of power (total) will serve as a source of emergency power. Each rig will utilize a silicon controlled rectifier (SCR) system to convert alternating current to the direct current required by the drawworks, rotary table, mud pumps, and cementing unit motors. Transformers will convert the generated AC power to lower voltages, as necessary, for the AC equipment on the rig.

6.6 DRILLING OPERATIONS

6.6.1 Proposed Drilling Program

Texaco will have the capacity to drill 50 wells from Platform Harvest for the development of the Point Arguello field. Thirty-six wells are planned for oil production, 4 wells are for gas production, 2 wells are planned for gas injection, and 8 well slots are not committed at this time. The extra slots may be used for service wells or for additional oil or gas wells.

The surface and projected bottom hole locations of each proposed well to be drilled from Platform Harvest are listed in Appendix A, Proprietary Data.

6.6.2 Typical Drilling Procedures

Typical drilling procedures for the development wells are presented below. Each well will be directionally drilled using these general procedures supplemented and modified as necessary for the particular well program and anticipated drilling conditions. Individual drilling programs will be subject to approval by the MMS (a Permit to Drill is required) prior to commencement of drilling of each well.

(1) Rig up over designated slot number

(2) Drill a 30" hole to ±1130' KB (1000' VSS)

(3) Run and cement 24" conductor at ±1100' KB (300' BML)

(4) Install 21-1/4", 2000 psi BOPE

(5) Drill to ±1830' KB (1700' VSS) with a 22" hole opener strapped to a 17-1/2" bit

(6) Run and cement 18-5/8" casing at ±1800' KB (1670' VSS)

(7) Drill a 17-1/2" hole to ±3860' KB (3730' VSS)

(8) Run electric logs

(9) Run and cement 13 3/8" casing at 3830' KB (3700' VSS)

(10) Install 13-5/8", 5000 psi W.P. BOPE

(11) Drill a 12-1/4" hole to ±8680' KB (8550' VSS)

(12) Run electric logs

(13) Run and cement 9-5/8" casing at 8630' KB (8500' VSS)

(14) Run cased hole logs

(15) Perforate and complete well

(16) Install X-mas tree and move off.

It is estimated that drilling will require an average of about 67 days per well and completion an additional 7 days.

6.6.3 Casing Program

The typical planned casing program for development wells drilled from Platform Harvest to produce the Monterey (approximately 8300 ft (2530 m) subsea) will consist of a 24-inch conductor to ±1100' KB (1000' VSS), 18-5/8-inch surface casing to ±1800' KB (1670' VSS), 13-3/8 inch intermediate casing to ±3830 KB (3700' VSS), and 9-5/8 inch of production casing to ±8630' KB (8500' VSS) as shown in Figure VII-2. However, depending on anticipated depths of producing horizons, and on individual well completions, some changes to the above-mentioned casing program may occur.

This casing program assumes that a field rule would be issued precluding the installation of structural casing. The casing setting depths and cementing will be in accordance with MMS Pacific Region OCS Order No. 2 and/or field rules.

All casing will be designed to exceed anticipated burst and collapse pressures and tensile loads (presented in the proprietary appendices). Casing designs will include appropriate safety factors. Production casing, liner, and tubing subjected to sour service will be made of controlled hardness quenched and tempered steel.

6.6.4 Completion Procedures

Cemented and perforated casing (Figure VI-3) will be used when it is necessary to selectively produce an interval because of anticipated gas or water intrusion problems. When gas or water intrusion is not anticipated, slotted casing (Figure VI-4) may be used. The completion tubing string will be designed for natural flow but will allow for gas lift and/or conversion to electric downhole submersible pumps in the future.

All wells drilled will be completed in accordance with the applicable regulations of the MMS Pacific Region OCS Order No. 6 and/or field rules and will be subject to prior approval by the MMS.

6.6.5 Wellhead Equipment

All wellhead equipment will meet API specifications. The working pressure of each wellhead section will exceed the maximum anticipated pressure imposed on that section.

6.6.6 Blowout Prevention Equipment

Texaco will install the blowout prevention (BOP) system during the course of drilling each production well. A schematic of the BOP system is shown on Figures VI-5 and VI-6. The BOP program will consist of the following:

A. From ±1130' VDKB to ±3860' VDKB (1000' VSS to 3730' VSS)
   1 - 21-1/4" x 2000# W.P. Spherical Annular Preventor
   1 - 21-1/4" x 2000# W.P. Double gate
   1 - 21-1/4" x 2000# W.P. mud cross with 8" flange outlets and all necessary valves and piping for Class II hook-up
   1 - 21-1/4" x 2000# W.P. ram assemblies - blind
   1 - 21-1/4" x 2000# W.P. ram assemblies - 5"

B. From ±3860' VDKB to total depth
   1 - 13-5/8" x 5000# W.P. Spherical Annular Preventor, H_2S Trim
   1 - 13-5/8" x 5000# W.P. Single gate, H_2S trim
   1 - 13-5/8" x 5000# W.P. Double gate, H_2S trim

1 - 13-5/8" x 5000# W.P. x 24" mud cross with 4" flange outlets, check valve, hydraulic valve, and all necessary valves and piping for Class IV hook-up, H_2S trim

1 - 13-5/8" x 5000# W.P. set ram assemblies - blind with H_2S trim

1 - 13-5/8" x 5000# W.P. set ram assemblies - 3-1/2" with H_2S trim

1 - 13-5/8" x 5000# W.P. set ram assemblies - 5" with H_2S trim

1 - 13-5/8" x 5000# W.P. set ram assmeblies - 9-5/8" with H_2S trim

C. From 0' to total depth

3000# W.P. accumulator

3000# W.P. choke manifold with H_2S trim

One steel gate valve with H_2S trim, equal to the working pressure of blowout preventors installed adjacent to all blowout preventors or spool outlets.

In addition to the BOP system, the drilling program will be designed to control any high pressured zones through casing, mud and special procedure design. The casing will be designed with safety factors for the highest possible pressures due to a gas column to surface, hydrostatic pressures from the mud column, and tensile stress due to the weight of the casing. The mud program will be designed to have a hydrostatic pressure higher than formation pressure but lower than fracture pressure.

Special procedures such as formation integrity leak-off tests, BOPE pressure tests and maintaining barite supplies to weight up the mud will be conducted as appropriate to ensure the safety of the blowout prevention program.

Controls for operating the BOP systems will be located on the rig floors, at the accumulator units, and in a remote platform location. Operation and testing of the BOP equipment will be in accordance with MMS regulations and field rules. Test pressure data are provided in Appendix A, Proprietary Data.

6.6.7 Pollution Prevention

To prevent pollution from the drill cuttings, a cleaning and handling system will be installed for each drilling rig below the shale shakers.

Cuttings produced by drilling operations will be washed by this equipment prior to diposal in the ocean through the disposal caisson. Non-oil-contaminated approved muds will also be discharged to the ocean. No discharge of free oil will result from the disposal of muds and cuttings. Oil-soaked cuttings obtained when penetrating a hydrocarbon bearing zone and oily muds will be stored in metal bins until they can be taken to shore for disposal at an approved site.

A deck drainage system will collect deck and equipment runoff. Before disposal into the ocean, any oily material will be removed to levels specified by the NPDES permit conditions. All contaminated material will be transported to shore for disposal at an approved site.

Trash and garbage will be transported to shore for disposal. Containers will be constructed to prevent accidental loss onboard or enroute to the disposal site.

In the unlikely event that an oil spill should occur either through the drilling process or through fuel transfer between supply vessels and Platform Harvest, Texaco will immediately implement appropriate oil spill response procedures as outlined in its Oil Spill Contingency Plan (included as Appendix D to this document - separate volume).

6.6.8 Safety Features

The following safety features will be found on Platform Harvest.

6.6.8.1 Fire Detection and Alarm Systems

- Ultraviolet flame detectors installed at hazardous locations throughout the platform

- Ionization detectors installed in the control rooms, switchgear buildings, and crew quarters which would detect visible and invisible products of combustion

- Smoke detectors

- Fusible plug loops

6.6.8.2 Fire Suppression

- 1-1/2" (3.8 cm) hard rubber hose reels to provide coverage at any point on the platform with two hoses

- Fixed fog suppression with automatic area controls capable of wetting critical surfaces with a water density of not less than 0.25 gpm (gallons per minute) per square foot

- Two 250-gpm monitors on the main deck to cover the BOP stacks and the upper well bay area

- Dry chemical and Halon fire extinguishers at a number of locations throughout the platform

6.6.8.3 Hydrogen Sulfide Contingency Plan

The Hydrogen Sulfide Contingency Plan (Appendix C to this document) contains a detailed emergency plan to be followed when encountering formations that contain hydrogen sulfide while drilling wells. All appropriate offshore facilities will be equipped with H_2S monitors that will sound if potentially hazardous H_2S concentrations occurred in the ambient air.

6.6.8.4 Critical Operations and Curtailment Plan

The Critical Operations and Curtailment Plan (Appendix B to this document) describes the critical operations that are likely to be conducted and under what circumstances or conditions the critical operations would be curtailed.

6.5.8.5 Deck Drainage/Sump System

Drainage from the upper decks, drip pans in the rig substructure, and rig floor will gravitate to a waste tank located on the lower deck. Drainage from the lower deck areas will drain in a sump tank below the lower deck, from which the liquids will be pumped into the waste tank. Oily waste water from the waste tank will be sent to the production train for treating. Washed cuttings and oil free sediments from the waste tank will gravitate to the skim pile for ocean disposal in accordance with NPDES permit conditions.

6.6.8.6 Safety and Escape Equipment

The escape system will include assigned lifejackets for all individuals on Platform Harvest during drilling and production operations. Two survival capsules each capable of accommodating 54 persons and one survival capsule capable of accommodating 36 persons will be located at three easily accessible locations on the platform. Seriously injured personnel can be delivered to Goleta Valley Hospital by helicopter in approximately 30 minutes.

6.6.8.7 Safety Control System

Safety, anti-pollution, and control systems will be installed on all piping headers, machinery, and vessels. The systems will include a combination of electric and pneumatic controls. All automatic control valves will be designed to be fail-safe. Control devices will include the following:

1. High-low pressure alarm and shutdown sensors
2. High-low liquid level alarm and shutdown sensors
3. Flow safety valves
4. Pressure safety valves
5. Vibration sensors
6. High-low temperature alarm and shutdown sensors.

All of the above items will be designed and installed to facilitate testing. The devices will be tested for proper operation on an approved schedule.

All of the above safety devices will be interconnected through a central control panel. If a malfunction occurs, an alarm will be sounded; and if the condition is not immediately corrected, drilling operations will shut down. Shut-down will be accomplished by automatically closing the surface controlled subsurface safety valves and the surface controlled surface safety valves.

Produced fluid will continue to move off the platform through the pipeline until the equipment is automatically shut down by either low levels or low pressure. If the malfunction is pipeline-related, production would be shut in immediately and fluids would not be pumped off the platform.

TABLE VI-1

DISPOSABLE WASTES GENERATED DURING DRILLING

Disposable Waste	Treatment	Disposal Method	Disposal Frequency	Disposal Rate	Total Quantity[a]
Drill cuttings	Wash to remove oil and grease	Discharge to ocean	Continuously when actually drilling	0-300 ft^3/day[a]	17,000 ft^3/well (average)
Clean drilling mud	None necessary	Discharge to ocean	Daily	0-400 bbl/day	2400 bbl/well
Completion fluid	None necessary	Discharge to ocean	Once per well, mostly in one day	0-180 bbl/day[a]	180 bbl/day
Contaminated drilling mud	None necessary	Transport to shore and disposal at an approved site	Variable, as needed	0-20 bbl/day[a]	20 bbl/well
Cooling water	None necessary	Discharge to ocean	Continuous	120,000 bbl/day/ outfall (maximum)	240,000 bbl/day (maximum)
Deck drainage	Skim to remove oil and grease	Discharge water to ocean; deliver oil into production system	Daily discharge/ shore transport as needed	250 gpd	250 gpd
Sanitary sewage	Electro-catalytic unit	Discharge to ocean	Daily	3250 gpd	4700 bbl
Desalinization brine	None necessary	Discharge to ocean	Daily	123,100 gpd	1.07 million bbl
Acidic water	None necesary	Store in appropriate containers and haul to shore	As needed	Variable	50-200 bbl
General refuse	None necesary	Store in appropriate containers and haul to shore	Weekly	4,000 lb/wk	19 tons

[a] Per rig

TABLE VI-2

COMPOSITIONS OF TYPICAL SIMPLE DRILLING MUDS

Component	Concentration (mg/L)			
	Mud A[a]	Mud B[b]	Mud C[b]	Mud D[c]
Bentonite clay	7,125	57,000	57,000	85,000
Barium sulfate	135,000	228,000	170,000	230,000
Lignite	-	-	-	2,850
Lignosulfonate	12,500	14,250	11,400	2,850
Zinc carbonate	-	-	-	2,850[d]
Sodium hydroxide	9,400	2,850	2,850	1,425
Sodium biocarbonate	-	-	-	1,425[d]
Organic polymers	1,700	2,850	-	700
Sodium carbonate	-	-	3,000	-
Calcium hydroxide	-	-	-	700
Defoamer	150	-	-	300[d]
Detergent	-	-	-	300[d]
Water	As needed	As needed	As needed	As needed

[a] U.S. Department of Interior, Geological Survey, 1976, Final Environmental Statement Oil & Gas Development in the Santa Barbara Channel, Outer Continental Shelf, Off California. FES 76-13.
[b] U.S. Department of Interior, Bureau of Land Management, 1979, Final Environmental Statement - Proposed 1979 Outer Continental Shelf Oil and Gas Sale Offshore California
[c] Typical mud used during drilling at Exxon's Platform Hondo A
[d] Infrequently used component.

TABLE VI-3

DRILLING RIG CHARACTERISTICS

20,000-ft Rig	15,000-ft Rig
• Mast - cantilever mast or standard derrick, 43 m (142 ft) high with 6000 m (20,000 ft) drilling and 450 metric tons (500 tons) hook-load capabilities.	• Mast - cantilever mast or standard derrick 42 m (139 ft) high with 4572 m (15,000 ft) drilling and 386 metric tons (425 tons) hook-load capacities.
• Drawworks - single or double drum drilling hoist, nominal motor 1400-2000 HP.	• Drawworks - single or double drum drilling hoist, nominal motor 1400-2000 HP.
• Rotary table - 37-1/2" independent drive, 500 HP 2-gear transmission.	• Rotary table - 28-1/2", independent drive, 500 HP 2-gear transmission.
• Hook - minimum 500 tons capacity.	• Hook - minimum 425-ton capacity.
• Traveling block - minimum 500 tons capacity.	• Traveling block - minimum 425-ton capacity.
• Crown block - minimum 500 tons capacity.	• Crown block - minimum 425-ton capacity.
• Mud pumps - 2 x 1600 HP (minimum) 7-1/2" x 12" triple single acting mud pump.	• Mud pumps - 2 x 1600 HP (minimum) 7-1/2" x 12" triple single acting mud pumps.
• Solids control equipment - double separating screens, mud cleaners, desilters, desanders, centrifuge, degasser.	• Solids control equipment - double separating screen, mud cleaners, desilters, desanders, centrifuge, degasser.
• Mud tanks - volume active system 600 bbls.	• Mud tanks - volume active system 600 bbls.
• Choke manifold - 3000 psi W.P.	• Choke manifold - 3000 psi W.P.
• Cementing unit - Halliburton's FKD4 driven by 2 x 8V-92 and 4-71 GM.	• Cementing unit - Halliburton's FKD4 consisting of 2 x 8V-92 and 4-71 GM.
• Logging unit - driven by V3-78, 155 BHP @ 3300 RPM.	
• Cranes - 1-50 ton and 1-30 ton capacities.	• Cranes - 1-50 ton capacity.

TABLE VI-3 (concluded)

20,000-ft Rig	15,000-ft Rig
• Air tugger or hoist - 6000 lb. capacity.	• Air tuggers or hoists - 6000 lb. capacity.
• Drill string - 5" and 3-1/2" Grades E, G-105, S-135.	• Drill strings - 5" and 3-1/2" Grades E, G-105, S-135.
• Accumulator - 3000 psi W.P.	• Accumulator - 3000 psi WP.
• Air compressor - 150 psi (minimum) and air receiving bottles 2 x 400 gal.	• Air compressor - 150 psi (minimum) and air receiving bottles 2 x 400 gal.

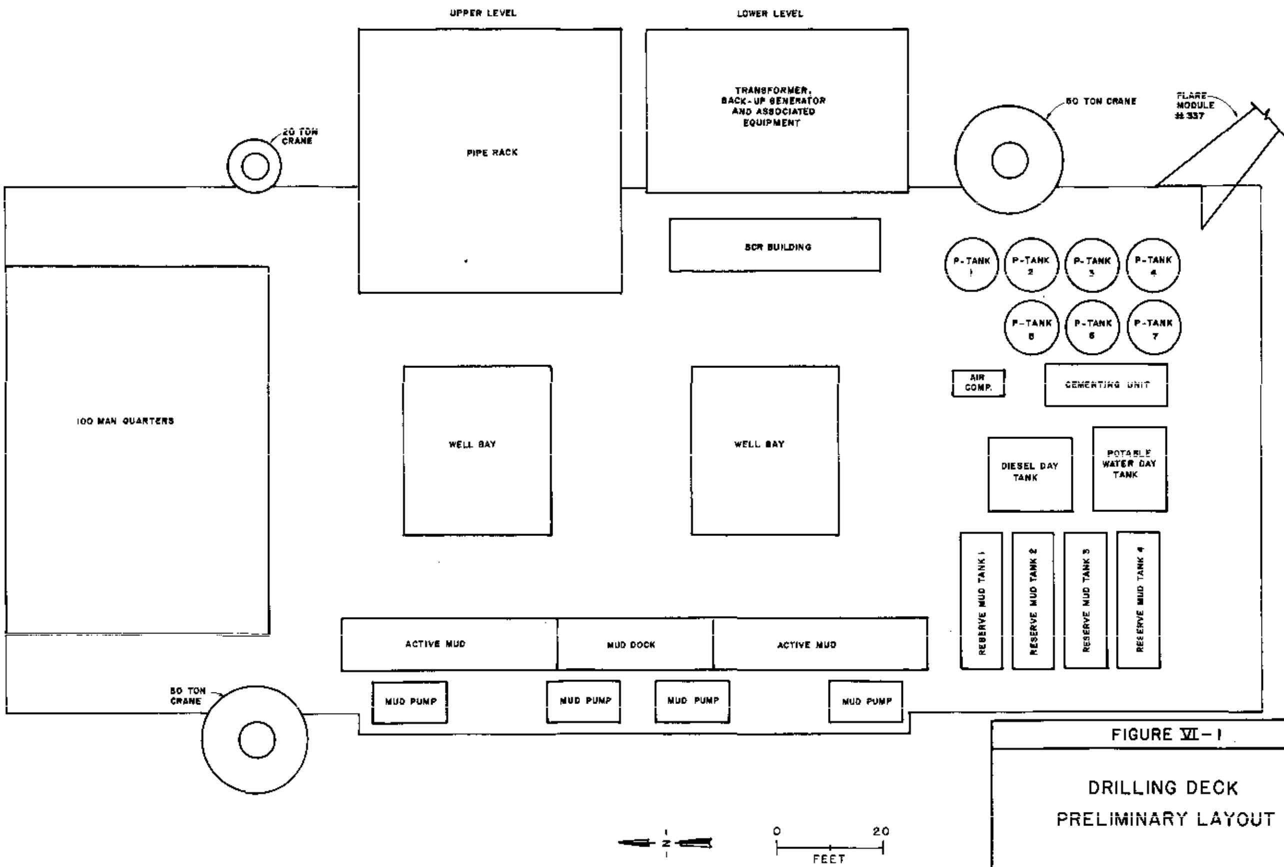
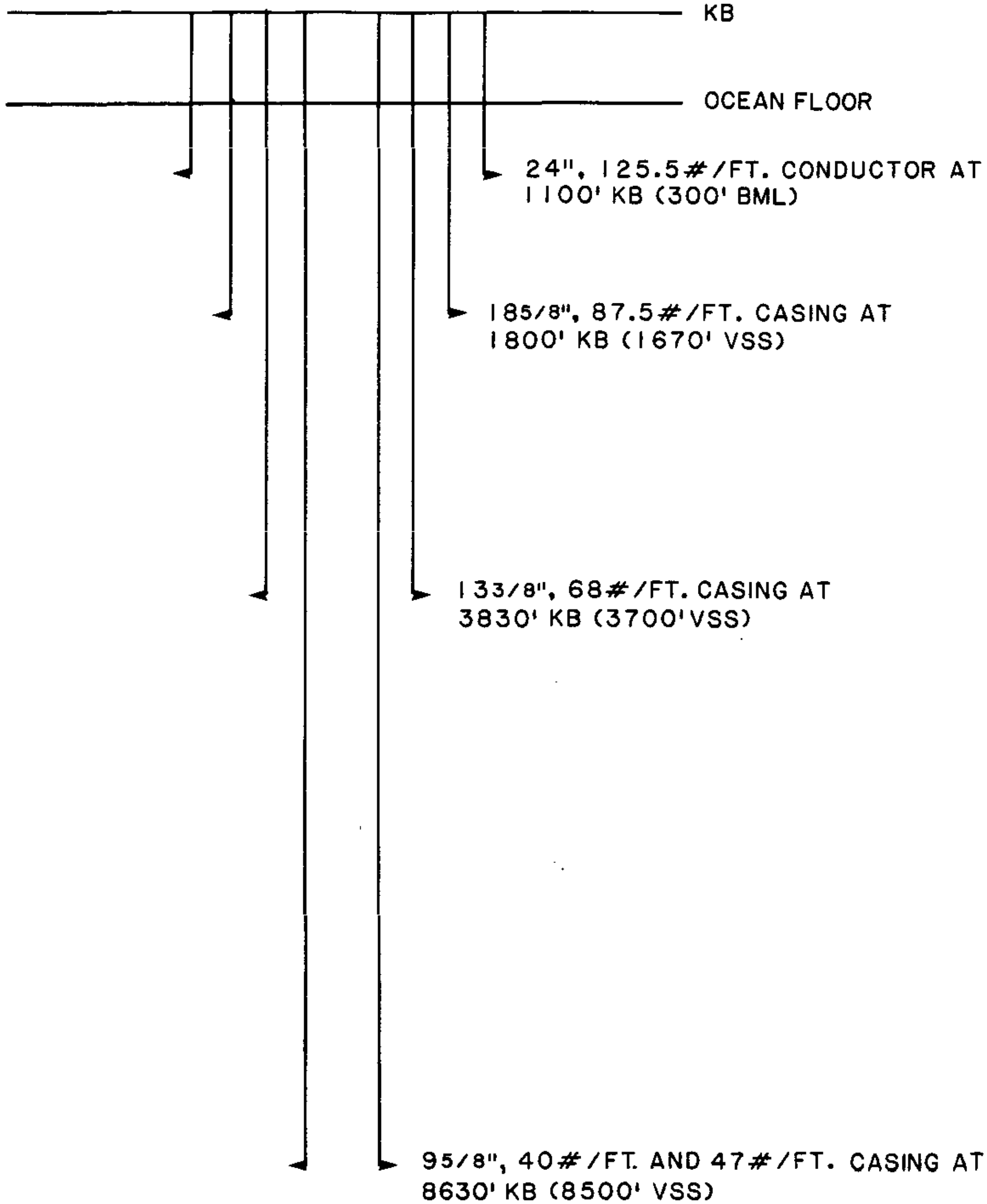


FIGURE VI-1

DRILLING DECK
PRELIMINARY LAYOUT



NOTE: ALL DEPTHS REFER TO KELLY BUSHING (KB) AND PRESENT VERTICAL DEPTH.

FIGURE VI-2

TYPICAL CASING PROGRAM

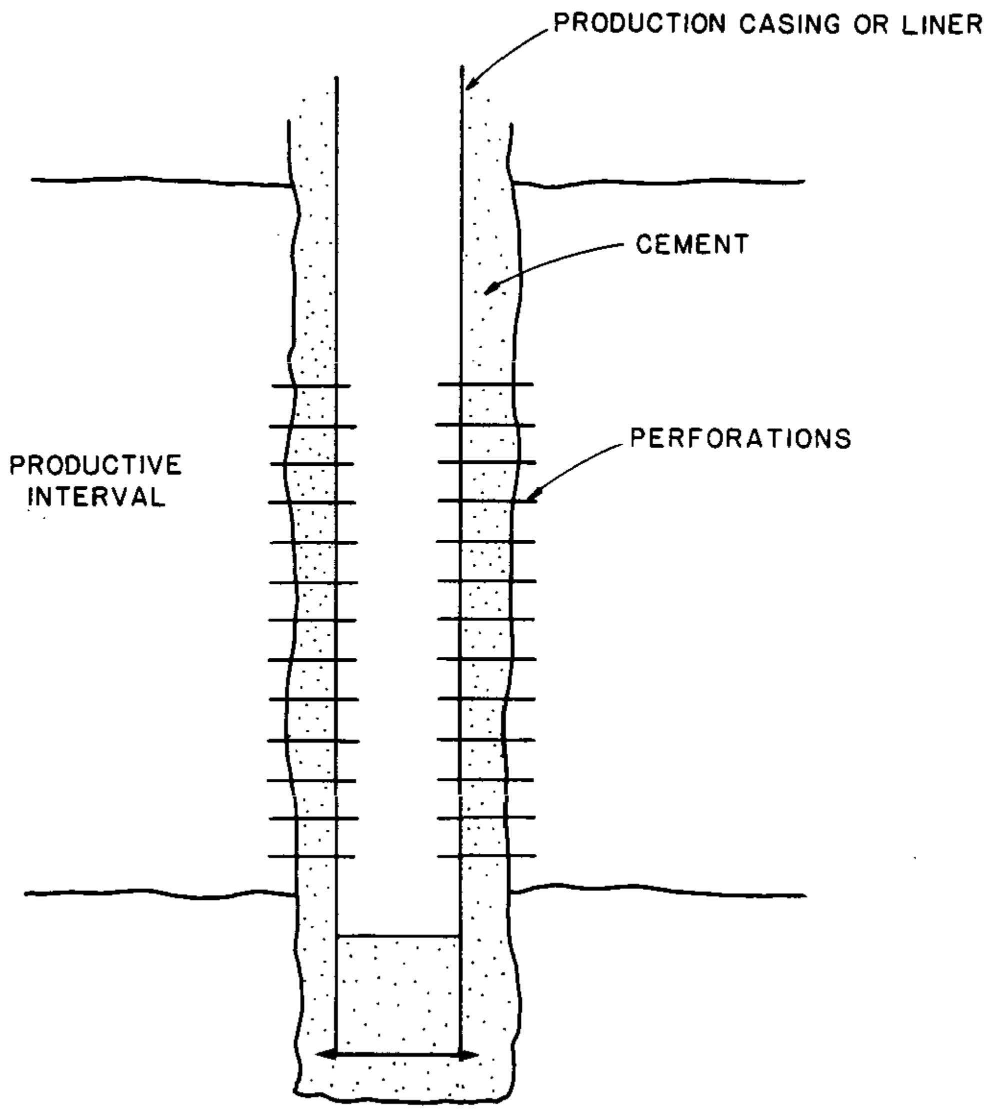


FIGURE VI-3

TYPICAL WELL COMPLETION CEMENTED AND PERFORATED CASING

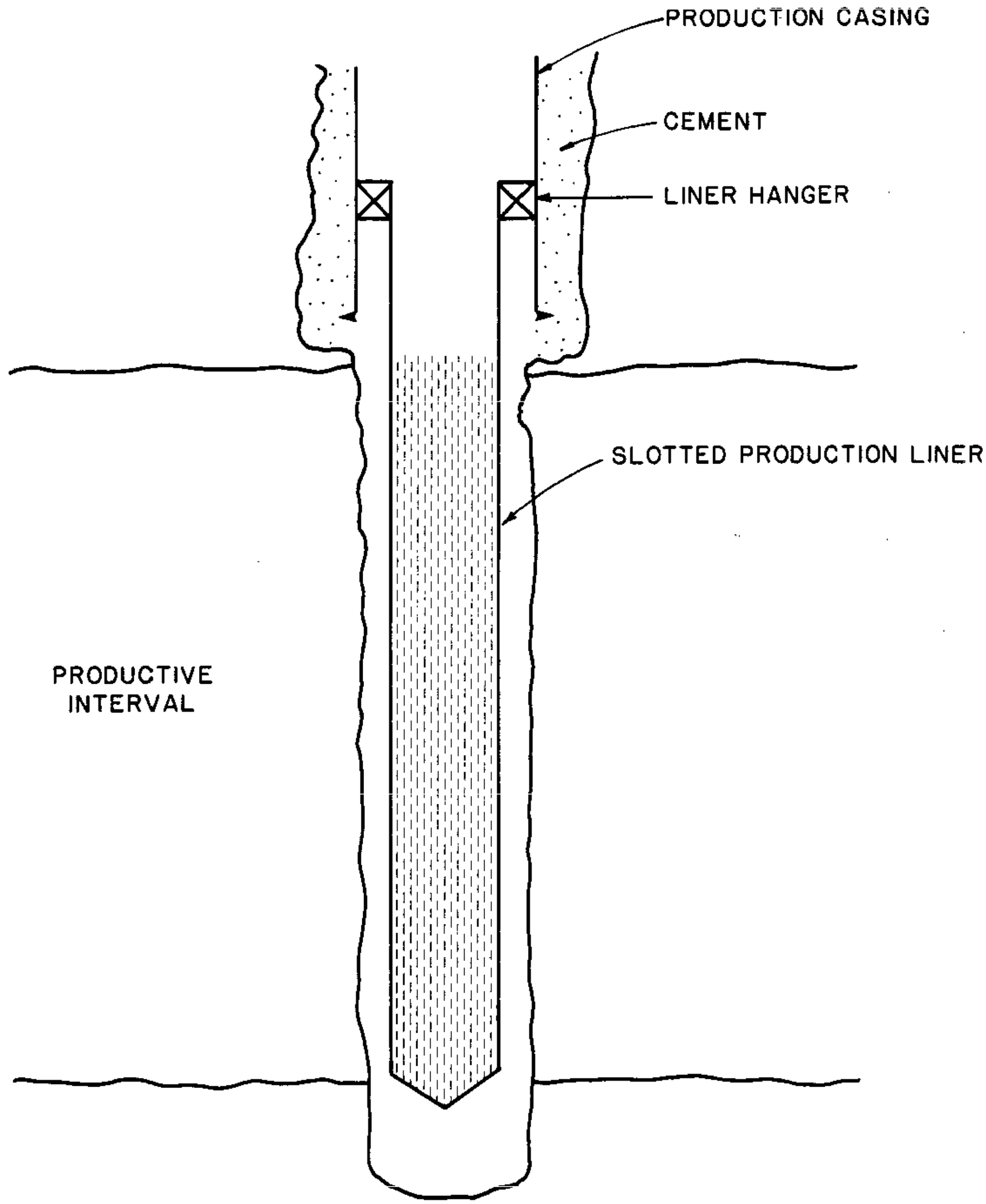
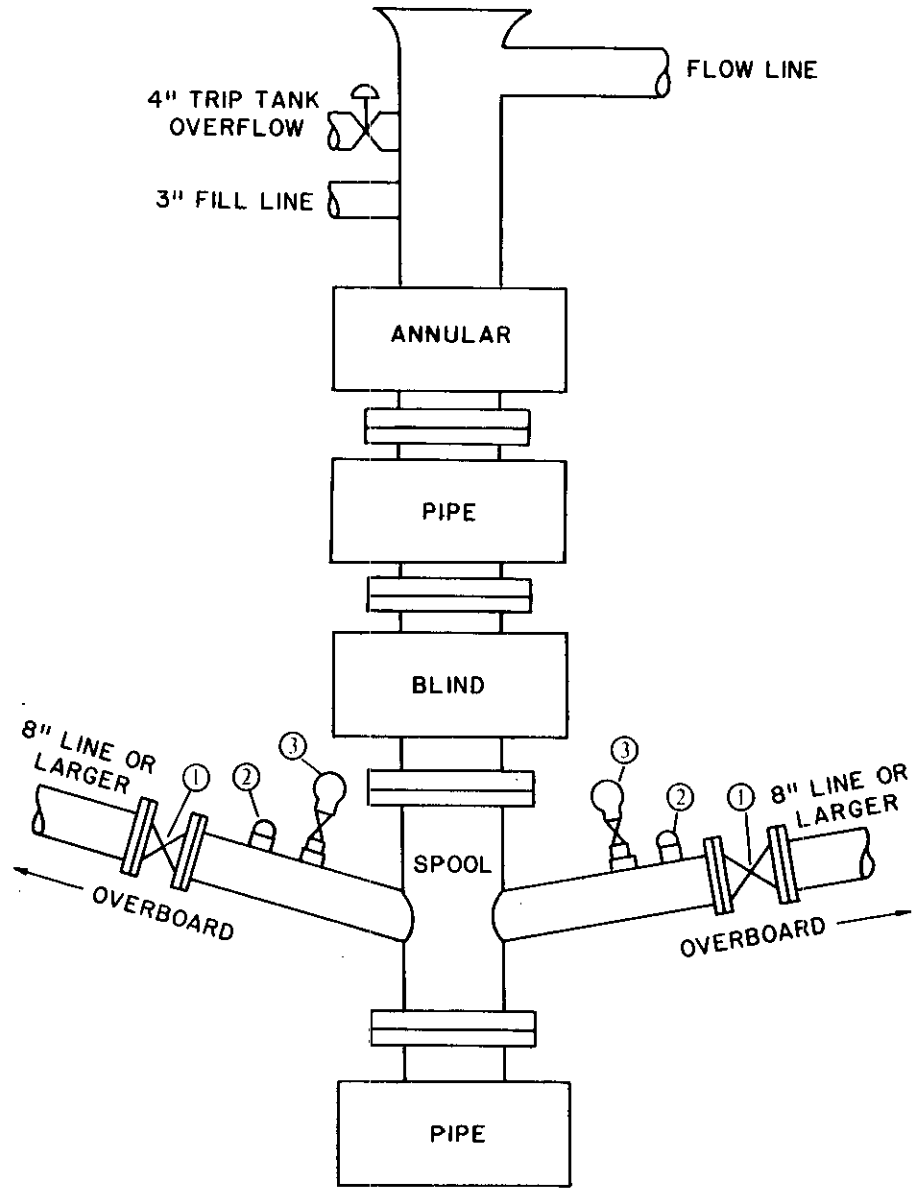


FIGURE VI-4

TYPICAL WELL COMPLETION
SLOTTED LINER

NOTES:

1. DIVERTER LINE, VALVES AND OTHER COMPONENTS WILL HAVE A 200 PSI MINIMUM WORKING PRESSURE.
2. DIVERTER LINE VALVES WILL BE OPERATED SO THAT ONE VALVE IS ALWAYS OPEN BEFORE AND WHILE THE ANNULAR IS CLOSED.
3. AN ALTERNATIVE ARRANGEMENT MAY BE USED CONSISTING OF A SINGLE DIVERTER LINE EXITING THE SPOOL AND ENTERING A TEE WITH TWO BRANCH LINES GOING OVERBOARD.
4. A KILL LINE (NOT SHOWN) WILL ENTER THE SPOOL.



LEGEND:

(1) 8" OR LARGER REMOTE CONTROLLED GATE VALVE

(2) BULL PLUG

(3) TAPPED BULL PLUG, VALVE AND PRESSURE GAUGE

FIGURE VI-5

DIVERTER SYSTEM

LEGEND:

1. HYDRAULIC GATE VALVE
2. 4" PLUG OR GATE VALVE
3. 4"x4"x2"x2" FLANGED CROSS
4. 2" PLUG OR GATE VALVE
5. HAND ADJUSTABLE CHOKE
6. 2" OR 4" PLUG OR GATE VALVE
7. HYDRAULIC CHOKE
8. PRESSURE GAUGE
9. BLIND FLANGE

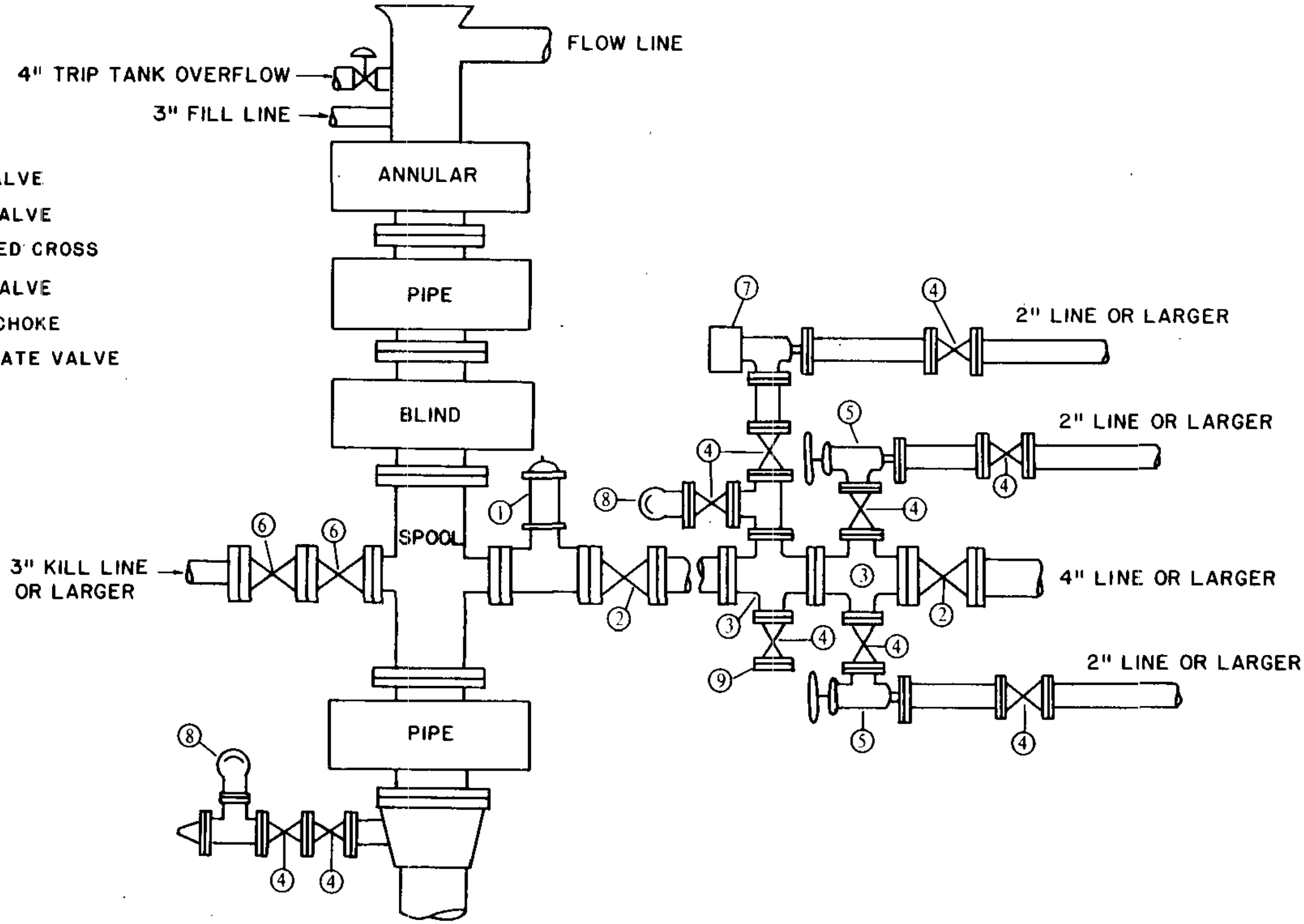


FIGURE VI-6

BLOWOUT PREVENTER STACK

SECTION VII - OFFSHORE PRODUCTION
FACILITIES AND SYSTEMS FLOW

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SECTION VII - OFFSHORE PRODUCTION FACILITIES AND SYSTEMS FLOW

7.1 INTRODUCTION AND OVERVIEW

Section VII contains descriptions of the offshore facilities and processing procedures associated with the proposed Platform Harvest Project. This section (7.1) contains an overview of production and processing steps, 7.2 contains a list of the design standards and codes that will apply to production facilities on the platform, and 7.3 contains descriptions of measures that will be implemented to comply with applicable OCS Orders. Process operations and support and utility systems, control and monitoring systems, safety measures, and environmental protection measures are contained in sections 7.4, 7.5, 7.6, and 7.7, respectively.

Oil and gas production at Platform Harvest are expected to peak at 46 MBD and 42 MMSCFD, respectively, both in 1988.

Free water will be separated from the crude oil/water mixture at the platform, treated, and discharged to the ocean. The wet oil will be delivered via a new subsea pipeline to Chevron's proposed Platform Hermosa where it will be commingled with produced fluids from other production facilities and transported via a common-carrier or shared pipeline to new onshore oil and gas treating facilities operated by Chevron at Gaviota. Produced gas will be dehydrated and compressed at Platform Harvest. A portion will be sweetened for use as fuel in gas-driven turbines installed on the platform for generating electricity. The remainder of the gas will be delivered via pipeline to Platform Hermosa and then to Gaviota. Figure VII-1 depicts the generalized overall systems flow. A simplified process flow diagram for the platform is presented on Figure VII-2.

7.2 DESIGN STANDARDS AND CODES

As discussed in Section IV, Platform Harvest has been designed in accordance with all applicable design standards, including MMS Pacific Region OCS Order No. 8 and API and American Institute of Steel Construction (AISC) guidelines. The following API Recommended Practices apply specifically to platform-installed production facilities.

- API RP2G: Recommended Practice for Production Facilities on Offshore Structures
- API RP14C: Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems on Offshore Production Platforms
- API RP14E: Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems
- API RP14F: Recommended Practice for Design and Installation of Electrical Systems for Offshore Production Platforms
- API RP14G: Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms
- API RP500B: Recommended Practice for Classification of Areas for Electrical Installation at Drilling Rigs and Production Facilities on Land and on Marine Fixed or Mobile Platforms.

In addition, the requirements of MMS Pacific Region OCS Order No. 5 and all other applicable regulations will be followed in the installation and operation of production safety systems. All designs for mechanical and electrical systems will be certified by registered professional engineers.

7.3 COMPLIANCE WITH OCS ORDER NO. 5 - PRODUCTION SAFETY SYSTEMS

7.3.1 Use of Best Available and Safest Technologies (BAST)

Texaco will continue the development of safety-system technology. As research and product improvement results in increased effectiveness of existing safety equipment or the development of new equipment systems, such equipment may be used.

Conformance to the standards, codes, and practices referenced in OCS Order No. 5 will be considered to be the application of BAST. Specific equipment and procedures or systems not covered by standards, codes, or practices will be analyzed to determine if the failure of such would have a significant effect on safety, health, or the environment. If such are identified, Texaco will submit such information necessary to indicate the use of BAST, the alternatives considered to the specific equipment or procedures, and the rationale why one alternative technology was considered in place of another. This analysis will include a discussion of the costs involved in the use of such technology and the incremental benefits gained.

7.3.2 Quality Assurance and Performance of Safety and Pollution-Prevention Equipment

Safety and Pollution-Prevention Equipment (SPPE) will conform to the following quality assurance standards or subsequent revisions approved for use.

- American National Standards Institute/American Society of Mechanical Engineers Standard "Quality Assurance and Certification of Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations," ANSI/ASME SPPE-1-1977, December 1977 (formerly ANSI/ASME-OCS-1-1977).

- American National Standards Institute/American Society of Mechanical Engineers Standard "Accreditation of Testing Laboratories for Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations," ANSI/ASME-SPPE-2-1977, December 1977 (formerly ANSI/ASME-OCS-2-1977).

7.3.3 Subsurface-Safety Devices

All tubing installations open to hydrocarbon-bearing zones will be equipped with either a surface-controlled subsurface-safety valve (SCSSV), a tubing plug, or a tubular/annular subsurface-safety device, unless, after application and justification, the well is determined to be incapable of flowing. The device will be installed at a depth of 100 feet or more below the ocean floor within 2 days after production is stabilized. The well will be attended in the immediate vicinity of the well so that emergency actions may be taken, if necessary, while the well is open to flow from a hydrocarbon-bearing zone, unless a subsurface-safety device is installed. All tubing installations will be equipped with a surface-controlled subsurface-safety device.

Surface-controlled subsurface-safety valves will conform to "American Petroleum Institute (API) Specification for Subsurface-Safety Valves," API Spec 14A, Fourth Edition, November 1979, or subsequent revisions approved for use. Subsurface-safety devices will be designed, adjusted, installed, and maintained to insure reliable operation. During testing and inspection procedures, the well will not be left unattended while open to production unless a properly operating subsurface-safety device has been installed in the well.

All tubing installations open to a hydrocarbon-bearing zone will be equipped with a surface-controlled subsurface-safety valve; the surface controls will be located on the platform.

Each surface-controlled subsurface-safety device will be tested in place for proper operation when installed or reinstalled and thereafter at intervals not exceeding 6 months. If the device does not operate properly, it will be removed, repaired, reinstalled or replaced, and tested to insure proper operation.

A tubing plug will be installed in lieu of, or in addition to, other subsurface-safety devices if a well is shut in for a period of 6 months. Tubing plugs will be set at a depth of 100 feet or more below the ocean floor. All tubing plugs installed will be of the pump-through type. All wells perforated and completed but not placed on production will be equipped with a subsurface-safety valve or tubing plug within 2 days after completion. A surface-controlled subsurface-safety valve of the pump-through type may be used as a pump-through tubing plug; in such case, the surface control will be rendered inoperative. A shut-in well which is equipped with a tubing plug will be inspected for leakage by opening the well to possible flow at intervals not exceeding 6 months. If a liquid leakage rate in excess of 400 cc/min or a gas leakage rate in excess of 15 cubic ft/min is observed, the plug will be removed, repaired, and reinstalled, or an additional tubing plug installed in lieu of removal and repair.

A surface-controlled subsurface-safety valve or an injection valve capable of preventing backflow will be installed in all wells placed in injection service, unless the well is incapable of flowing. Texaco will verify the no-flow condition of the well annually and submit an annual report certifying the no-flow status of the well.

Wireline- or pumpdown-retrievable subsurface-safety device may be removed, without further authorization or notice, for a routine operation which does not require the approval of a Sundry Notice and Report on Wells for a period not to exceed 15 days. The well will be identified by a sign on the wellhead stating that the subsurface-safety device has been removed. The removal of the subsurface-safety device will be noted in the records. The well will be attended in the immediate vicinity of the well so that emergency actions may be taken, if necessary, while the well is open to flow from a hydrocarbon-bearing zone until the subsurface-safety device is reinstalled. The well will not be open to flow while the subsurface-safety device is removed except when flowing the well is necessary for that particular operation.

All tubing installations in which a wireline- or pumpdown-retrievable subsurface-safety device is installed will be equipped with a landing nipple, with flow couplings or other protective equipment above and below, to provide for the setting of the subsurface-safety valve. The control system for all surface-controlled subsurface-safety valves will be an integral part of the platform Emergency Shutdown System (ESD) as defined in Appendix C, Section C1 of "API Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface-Safety Systems on Offshore Production Platforms," API RP 14C, Section Edition, January 1978, or subsequent revisions approved for use. In addition to the activation of the ESD system by manual action on the platform, the system may be activated by a signal from a remote location. Surface-controlled subsurface-safety valves will close in response to shut-in signals from the ESD system or the fire loop, or both.

All tubing installations open to hydrocarbon-bearing zones and capable of flowing in which the subsurface-safety device has been removed will be identified by a sign on the wellhead stating that the subsurface-safety device has been removed. A subsurface-safety device will be available for each well on the platform. In the event of an emergency this device will be properly installed as soon as possible with due consideration being given to personnel safety.

Texaco will maintain records for a minimum period of 5 years for each subsurface-safety device installed. These records will be maintained on the platform or in the nearest onshore field office for a minimum period of 2 years. The records may then be transferred from the platform to the onshore field office for the remaining 3 years of the 5-year retention period. These records shall be available for review by an authorized representative of the MMS. The records to be maintained shall contain verification of:

- The manufacturer's design, including make, model, and type. For subsurface-controlled valves, number of the spacers, size of beans, springs, and the pressure settings.

- The devices having been manufactured in accordance with the quality-assurance requirements of ANSI/ASME-SPPE-1 (formerly ANSI/ASME-OCS-1).

- The completion and return of the receiving report to the manufacturer as required by ANSI/ASME-SPPE-1.

- The record of all configuration modifications to the certified design.

- Installation at the required setting depth and in accordance with the manufacturer's instructions.

- The identity of the personnel who directed all installations and removals.

- The results of tests required by OCS Order No. 5, the dates of removals and reinstallations, and the reasons for removals and reinstallations.

- The completion and submission of failure reports and investigation reports required by paragraphs OE-2529 and OE-2670 of ANSI/ASME-SPPE-1.

Well completion reports and any subsequent reports of workover will include the manufacturer, the type, and the installed depth of the subsurface-safety devices.

7.3.4 Design, Installation, and Operation of Surface Production Safety Systems

All production facilities, including separators, compressors, heaters, coolers, and flowlines, will be designed, installed, and maintained in a manner which will facilitate an efficient, safe, and pollution-free operation.

The platform production facilities will be protected with a basic and ancillary surface-safety system designed, analyzed, tested, and maintained in operating condition in accordance with the provisions of API RP 14C, except Section A9, "Pipelines," which will be covered under OCS Order No. 9, and the additional requirements of Order No. 5.

All wellhead Surface-Safety Valves (SSV's) will conform to "API Specification for Wellhead Surface Safety Valves for Offshore Service," API Spec 14D, Second Edition, November 1977, as amended by Supplement 2, November 1978, or subsequent revisions approved for use. Prior to installation, Texaco will submit for approval to the District Supervisor information relative to design and installation features. Some of this information is submitted with this DPP. All information will be maintained at Texaco's onshore field engineering office. All approvals are subject to field verifications. This information will include:

- A schematic flow diagram showing size, capacity, and design working pressure of separators, storage tanks, compressors, pipeline pumps, and metering devices (see Appendix A).

- A schematic flow diagram (reference API RP 14C, example: figure E1; see Appendix A) and the related Safety Analysis Function Evaluation (SAFE) chart (reference API RP 14C, Subsection 4.3c; to be submitted at a later date). These diagrams and charts will be developed in accordance with the provisions of API RP 14C and the additional requirements of OCS Order No. 5.

- A schematic piping diagram showing the size and maximum-allowable working pressure with reference to welding specification(s) or code(s) used (see Appendix A). The maximum-allowable working pressures will be determined in accordance with "API Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems," API RP 14E, First Edition, August 1975, and Supplement 2, October 1977, or subsequent revisions approved for use.

- A diagram of the firefighting system (see Appendix A).

- Electrical system information including the following:

  - A plan of each platform deck outlining any nonrestricted area, i.e., areas which are unclassified with respect to electrical equipment installations and outlining areas in which potential ignition sources, other than electrical, are to be installed. The area outline will include the following information:

    (a) Any surrounding production or other hydrocarbon source and a description of the deck, overhead, and firewall (see Appendix A).

    (b) Location of generators, control rooms, panel boards, major cabling/conduit routes, and identification of the wiring method, including the identification of each wire and cable type that is utilized (see Appendix A).

  - Elementary electrical schematic of any platform safety-shutdown system with a functional legend (see Appendix A).

  - Classification of areas for electrical installations in accordance with the National Electrical Code, 1978 Edition, and with the "API Recommended Practice for Classification of Areas for Electrical Installations at Drilling Rigs and Production Facilities on Lands and on Marine Fixed and Mobile Platforms," API RP 500B, Second Edition, July 1973, or subsequent revisions approved for use.

- The design and schematics of the installation and maintenance of all fire and gas detection systems will include the following (see Appendix A).

  - Type, location, and number of detection heads.

  - Type and kind of alarm, including emergency equipment to be activated.

  - Method used for detection.

  - Method and frequency of calibration.

  - Name of organization to perform system inspection and calibration.

  - A functional block diagram of the detection system, including the electric power supply.

- Certification that the design for the mechanical and electrical systems to be installed were approved by registered professional engineers. After these systems are installed, Texaco will submit a statement to the District Supervisor certifying that the new installations conform to the approved designs.

7.3.5 Additional Safety and Pollution-Control Requirements

The following requirements modify or are in addition to those contained in API RP 14C.

7.3.5.1 Design, Installation, and Operation

Pressure vessels have been designed, and will be fabricated, stamped, and maintained in accordance with specific sections of the ASME Boiler and Pressure Vessel Code as listed below. The pressure vessels will conform to the July 1, 1977, edition of the Code or subsequent revisions approved for use.

- Pressure relief valves will be designed, installed, and maintained in accordance with applicable provisions of Sections I, IV, and VIII. The relief valves will conform to the valve-sizing and pressure-relieving requirements specified in these documents; however, the relief valves will be set no higher than the maximum-allowable working pressure of the vessel. All relief valves and vents will be piped in such a way as to prevent fluid from striking personnel or ignition sources.

- Texaco will determine, by the use of pressure recorders, the operating pressure ranges of all pressure-operated vessels in order to establish the pressure-sensor settings. Current pressure recorder charts will be maintained at the platform. The high-pressure shut-in sensor will be set no higher than 10 percent above the highest operating pressure of the vessel. This setting will also be sufficiently below the relief valve's set pressure to assure that the pressure source is shut in before the relief valve starts relieving. The low pressure shut-in sensor will activate no lower than 15 percent or 35 kilopascals (kPa) (5 psi), whichever is greater, below the lowest pressure in the operating range.

- All pressure or fired vessels will conform to the requirements stipulated in the edition of the ASME Boiler and Pressure Vessel Code, Sections I, IV, and VIII, as appropriate.

All flowlines will be equipped as follows:

- All flowlines from wells will be equipped with high- and low-pressure shut-in sensors located in accordance with Section A1 and Figure A1 of API RP 14C. Texaco will determine, by the use of pressure recorders, the operating pressure ranges of flowlines in order to establish pressure-sensor settings. Current pressure-recorder charts will be maintained at the platform.

- The high-pressure shut-in sensor(s) will be set no higher than 10 percent above the highest operating pressure of the line; but, in all cases, sufficiently below the maximum shut-in wellhead pressure or the gas-lift supply pressure to assure actuation of the surface-safety valve. The low-pressure shut-in sensor(s) will be set no lower than 10 percent or 35 kPa (5 psi), whichever is greater, below the lowest operating pressure of the line in which it is installed.

Pressure sensors will be of the automatic reset type. All of the automatic-reset types will have a nonautomatic-reset relay installed. All pressure sensors will be equipped to permit testing with an external pressure source.

The manually operated ESD valves will be quick-opening and nonrestricted to enable the rapid actuation of the shutdown system. On an emergency shutdown, the surface-controlled subsurface-safety valve (SCSSV) will close in not more than 2 minutes after the shut-in signal has closed the surface safety valve (SSV). Electro-pneumatic systems will meet the corresponding design and functional requirements as those which apply to pneumatic systems. A schematic of the ESD system which indicates the control functions of all safety devices will be maintained on the platform.

Engine exhausts will be equipped to comply with the insulation and personnel-protection requirements of API RP 14C, Section 4.2c(4). Exhaust piping from diesel engines will be equipped with spark arrestors.

A pressure relief system will be installed on the glycol regenerator, which will prevent overpressurization of all glycol-dehydration units. The discharge of the relief valve shall be vented in a nonhazardous manner. The glycol-dehydration unit will be properly maintained to prevent overpressurization of the unit.

Each gas compressor will be equipped with the following protective equipment:

* A PSH, a PSL, a PSV, and an LSH to protect each interstage and suction scrubber.

* An LSL to protect each interstage and suction scrubber, unless the fluid is dumped through a choke restriction to another pressure vessel. An LSL shut-in control(s) installed in interstage and suction scrubber(s) may be designed to actuate the automatic shutdown valve(s) (SDV's) installed in the scrubber dump line(s).

* A TSH on each compressor cylinder or other components as applicable.

* In addition to the provisions of API RP 14C, Subsection A8.3, PSH and PSL shut-in sensors and LSH shut-in controls protecting compressor suction and interstage scrubbers will be designed to actuate automatic SDV's located in each compressor suction and fuel gas line so that the compressor unit and the associated vessels can be isolated from all input sources.

  All automatic SDV's installed in compressor suction and fuel gas piping will also be actuated by the shutdown of the prime mover.

The firefighting system will conform to Subsection 5.2, "Fire Water Systems," of "API Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms," API RP 14G, First Edition, September 1978, or subsequent revisions approved for use.

A firewater system consisting of rigid pipe with firehose stations will be installed. The firewater system will be installed to provide needed protection in all areas where production-handling equipment is located. A fixed water-spray system will be installed in enclosed well-bay areas where hydrocarbon vapors may accumulate. Pump drivers will include diesel engines and electric motors. Fuel or power will be available for at least 30 minutes of pump driver run-time during platform shut-in time. A chemical fire-fighting system will be used also. A diagram of the firefighting system showing the location of all firefighting equipment will be posted in a prominent place on the platform.

Fire and gas detection systems will be installed as follows:

- Fire (flame, heat, or smoke) sensors will be used in all enclosed high-hazard areas. Gas sensors will be used in all inadequately ventilated, enclosed, high-hazard aras. Adequate ventilation is as defined in API RP 14C, Appendix C, paragraph C1.3b.

- All detection systems will be capable of continuous monitoring. Fire detection systems and portions of combustible gas detection systems related to the higher gas concentration levels will be of the manual-reset type. Combustible gas detection systems related to the lower gas concentration level will be of the automatic-reset type.

- An automatic gas-detection and alarm system will be installed in enclosed, continuously manned areas of the facility.

- Fire detection systems will be of an approved type, designed and installed in accordance with the National Fire Protection Association Standard for Automatic Fire Detectors, No. 72E, 1974, or subsequent revisions approved for use. Gas detection systems will be of an approved type, designed and installed in accordance with sections 9.1 and 9.2 of "API Recommended Practice For Design and Installation of Electrical Systems for Offshore Production Platforms," API RP 14F, First Edition July 1978, or subsequent revisions approved for use.

The following features will apply to all electrical equipment and systems:

- All engines with ignition systems will be equipped with a low-tension ignition system of a low-fire-hazard type and will be designed and maintained to minimize the release of sufficient electrical energy to cause ignition of an external, combustible mixture.

- All electrical generators, motors, and lighting systems will be installed, protected, and maintained in accordance with the edition of the National Electrical Code and API RP 500B in effect at the time of approval.

- Wiring methods shall conform to the National Electrical Code, 1978 Edition, or to the Institute of Electrical and Electronic Engineers (IEEE) "Recommended Practice for Electric Installation on Shipboard," IEEE Std. 45-1977, or subsequent revisions approved for use. Each conductor of a wire, a cable, or a bus bar will be made of copper.

- The elementary electrical schematic of the platform safety-shutdown system will be maintained on the platform. This schematic will indicate the control functions of all electrically actuated safety devices.

- Maintenance of these systems will be by personnel who are familiar with the construction and operation of the equipment and the hazards involved.

No sand production is expected; consequently, an erosion control program will not be required.

7.3.5.2 General Platform Operations

Surface- or subsurface-safety devices will not be bypassed or blocked out of service unless they are temporarily out of service for startup, maintenance, or testing procedures. Only the minimum number of safety devices necessary for the operation will be taken out of service. Personnel will monitor the bypassed or blocked-out functions. Any surface- or subsurface-safety device which is temporarily out of service will be flagged.

All open-ended lines connected to producing facilities will be plugged or blind-flanged, except those lines designed to be open-ended, such as flare or vent lines.

7.3.5.3 Simultaneous Platform Operations

Prior to conducting activities simultaneously with production operations which could increase the possibility of occurrence of undesirable events, such as harm to personnel or to the environment or damage to equipment, a "General Plan for Conducting Simultaneous Operations" will be filed for approval with the District Supervisor. This plan will be modified and updated by supplemental plans when actual simultaneous operations are scheduled which are significantly different from those covered in the General Plan. The plan will include:

- A narrative description of operations.

- Procedures for the mitigation of potentially undesirable events including:

  - Guidelines which Texaco will follow to assure coordination and control of simultaneous activities.

  - The identity of the person having overall responsibility at the site for the safety of platform operations.

The "Supplemental Plan for Conducting Simultaneous Operations" will include:

- A floor plan of each platform deck indicating critical areas of simultaneous activities.

- An outline of additional safety measures for simultaneous operations.

- Specification of added or special equipment or procedural conditions imposed when simultaneous activities are in progress.

7.3.5.4 Welding and Burning Practices and Procedures

All offshore welding and burning will be minimized by onshore fabrication when feasible. Texaco will file for approval by the District Supervisor a "Welding, Burning, and Hot Tapping Safe Practices and Procedures Plan." The plan will include the qualification standards or requirements for personnel and the methods by which Texaco will assure that only personnel meeting such standards or requirements are utilized. A copy of this plan will be available on the platform. All welding supervisors will be thoroughly familiar with this plan. All welding and burning equipment will be inspected prior to beginning any welding or burning. Welding machines located on Platform Harvest will be equipped with spark arrestors and drip pans. Welding leads will be completely insulated and in good condition; oxygen and acetylene bottles secured in a safe place; and hoses leak-free and equipped with proper fittings, gauges, and regulators.

Texaco will establish and so designate areas on the platform determined to be safe-welding areas pursuant to the National Fire Protection Association Bulletin "Cutting and Welding Processes," No. 51B, 1976, or subsequent revisions approved for use. Approval for the use of such areas will be obtained from the District Supervisor. These designated areas will be identified in the General Plan and a drawing showing the location of these areas will be maintained on the platform.

All welding or burning which cannot be done in an approved safe-welding area will be performed in compliance with the procedures outlined below:

- Prior to the commencement of any welding or burning operation on a structure, Texaco's production supervisor will personally inspect the qualifications of the welder or welders to assure that they are properly qualified in accordance with the approved qualification standards or requirements for welders. The production supervisor and the welders will personally inspect the work area for potential fire and explosion hazards. After it has been determined that it is safe to proceed with the welding or burning operation, the production supervisor will issue a written authorization for the work.

- During all welding and burning operations, one or more persons will be designated as a Fire Watch. Persons assigned as a Fire Watch will have no other duties while actual welding or burning operations are in progress. If welding is to be done in an area which is not equipped with a gas detector, the Fire Watch will also maintain a continuous surveillance with a portable gas detector during welding.

- Prior to any welding or burning operation, the Fire Watch will have in his possession firefighting equipment in a usable condition. At the end of the welding operation, the equipment will be returned to a usable condition.

- No welding, other than approved hot tapping, will be done on piping, containers, tanks, or other vessels which have contained a flammable substance unless the contents have been rendered inert and determined to be safe for welding or burning by the production supervisor.

- If drilling, workover, or wireline operations are in progress on the platform, welding operations in other than approved safe-welding areas will not be conducted unless the well(s) where these operations are in progress contain noncombustible fluids and the entry of formation hydrocarbons into the wellbore is precluded.

- If welding or burning operations are conducted in the well-bay or production area, all producing wells will be shut in at the surface-safety valve.

7.3.5.5 Safety Device Testing

The safety-system devices will be tested at the intervals specified below or more frequently if operating conditions warrant. Testing will be in accordance with API RP 14C, Appendix D, and the following:

- All PSV's will be tested for operation at least once every 12 months. These valves will be either bench-tested or equipped to permit testing with an external pressure source.

- All pressure sensors-high/low (PSHL) will be tested at least once each calendar month, but at no time will more than 6 weeks elapse between tests.

- All SSV's will be tested for operation and for leakage at least once each calendar month, but at no time will more than 6 weeks elapse between tests. The SSV's will be tested for operation in accordance with the test procedure specified in API RP 14C, appendix D, section D4, Table D2, subsection L, and tested for leakage in accordance with subsection M. If the valve does not operate properly or any fluid flow is observed in step 3 of the leakage test, the valve will be repaired or replaced.

- All flowline FSV's will be checked for leakage at least once each calendar month, but at no time will more than 6 weeks elapse between tests. The FSV's will be tested for leakage in accordance with the test procedure specified in API RP 14C, Appendix D, section D4, table D2, subsection D. If the leakage measured in step 6 exceeds a liquid flow of 400 cc/min or a gas flow of 15 cubic ft/min, the FSV's will be repaired or replaced.

- All LSH and LSL controls will be tested at least once each calendar month, but at no time will more than 6 weeks elapse between tests. These tests will be conducted by raising and lowering the liquid level across the level-control detector.

- All automatic inlet SDV's which are actuated by a sensor on a vessel or a compressor will be tested for operation at least once each calendar month, but at no time will more than 6 weeks elapse between tests.

- All SDV's located in liquid-discharge lines and actuated by vessel low-level sensors will be tested for operation once each calendar month, but at no time will more than 6 weeks elapse between tests.

- All pumps for firewater systems will be inspected and test-operated weekly.

- All fire (flame, heat, or smoke) and gas detection systems will be tested for operation and recalibrated every 6 months.

- Texaco will notify the MMS when ready to conduct a preproduction test and inspection of the integrated safety system. Texaco will also notify the MMS upon commencement of production in order that a post-production test and inspection of the integrated system may be conducted.

- All TSH devices on fired components will be tested at least once every 12 months.

- The ESD system will be tested for operation at least once each calendar month but at no time will more than 6 weeks elapse between tests. The test may be conducted by closing at least one SSV from each of the ESD stations.

7.3.5.6 Records

Texaco will maintain records for a minimum period of 5 years for each surface-safety device installed. These records shall be maintained on the platform for a minimum period of 2 years. The records may then be transferred to the onshore field office for the remaining 3 years of the 5-year retention period. These records will be available for review by any authorized representative of the MMS. The records will show the present status and history of each device, including dates and details of installation, inspection, testing, repairing, adjustments, and reinstallation.

Records for surface-safety valves and associated actuators which require compliance with paragraph 2 will contain additional information showing verification of:

- The devices having been manufactured in accordance with the quality assurance requirements of ANSI/ASME-SPPE-1 (formerly ANSI/ASME-OCS-1).

- The completion and return of the receiving report to the manufacturer as required by ANSI/ASME-SPPE-1.

* The completion and submission of all failure reports required by paragraph 6 and all investigation reports required by paragraphs OE-2529 and OE-2670 of ANSI/ASME-SPPE-1.

7.3.5.7 Safety Device Training

Texaco will ensure that all personnel engaged in installing, inspecting, testing, and maintaining these safety devices have been qualified under a program as recommended by "API Recommended Practice for Qualification Programs for Offshore Production Personnel Who Work With Anti-Pollution Safety Devices," API RP T-2, revised October 1975, or subsequent revisions approved for use. Documented evidence of the qualifications of individuals performing these functions will be maintained on the platform. Any on-the-job trainees working with safety devices will be directly supervised by a qualified person.

7.3.6 Crane Operations

Cranes will be operated and maintained to ensure the safety of facility operations in accordance with the provisions of "API Recommended Practice for Operation and Maintenance of Offshore Cranes," API RP 2D, October 1972, or subsequent revisions approved for use. Records of inspection, testing, maintenance, and crane operators qualified in accordance with the provisions of API RP 2D will be kept on the platform for a period of 2 years. "API Specification for Offshore Cranes," API Specification 2C, February 1972, or subsequent revisions will be used as a guideline for selection of cranes.

7.3.7 Employee Orientation and Motivation Programs for Personnel Working Offshore

Texaco will make a planned, continuing effort to eliminate accidents due to human error. This effort will include the training of personnel in their functions. A program to achieve safe and pollution-free operations will be established. This program will include instructions in the provision of "API Recommended Practice Orientation Program for Personnel Going Offshore for the First Time," API RP T-1, January 1974, or subsequent revisions approved for use. "API Employee Motivation Programs for Safety and Prevention of Pollution in Offshore Operations," API Bulletin T-5, September 1974, or subsequent revisions approved for use will be used as a guide in developing employee safety and pollution-prevention motivation programs.

7.4 PROPOSED PLATFORM FACILITIES

7.4.1 Production Systems

7.4.1.1 Wellbay Manifolds

Platform Harvest initially will have 42 wells with an additional 8 slots reserved for possible future use. Thirty-six wells will initially be completed as Monterey/Sisquoc producers, 4 as shallow gas producers from the Foxen sands, and 2 will be used for gas injection in the event that produced gas could not be transported off-platform for any reason and for possible future pressure maintenance. Each well will be equipped with a valve and manifold to allow connection to either a production separator, test separator, sweet gas separator or well cleanup separator. A gas lift manifold will also be connected to each well's production casing. Table VII-1 provides a list of major production equipment to be installed on Platform Harvest.

7.4.1.2 Production/Separation

Platform Harvest will be equipped with two primary oil and gas separation trains in parallel. Each train will have a heater, a three-phase separator, and a production surge tank. The produced fluid will be heated to about 130°F and sent to the separator operating at 40 psig. Gas will flow to the first stage of compression, wet oil to the production surge tank, and free water to the oily water coalescer. Two three-phase test separators and heaters will also be provided and equipped with gas, free water, and net oil meters. Each well will be tested when it is first completed and at least once per quarter thereafter as required by OCS Order No. 11.

A well cleanup separator initially will be used for each well until the well flows sufficiently for use of the normal production separators. This separator will be able to handle the relatively large volumes of mud and water produced as the well comes on-stream.

7.4.1.3 Shipping and Metering

All oil and gas measurements required to ascertain volumes will be in accordance with the standard practices, procedures, and specifications used in the industry. Metering is discussed in greater detail in section 7.5.4. Wet oil from surge tanks will be boosted to pipeline pressure by pumping. The maximum normal operating pressure for the wet oil shipping pumps will be 1200 psig.

7.4.1.4 Gas Compression

Gas compression to 1180 psig will be accomplished in three stages. Additional compression will be required initially to provide lifting capability for the wells. This compression will be provided by gas turbine driven centrifugal compressor units located on the lower level of module 336. Each stage of compression will be equipped with suction scrubbers, discharge coolers, and controllers to handle varying production rates.

7.4.1.5 Fuel Gas

Fuel gas will be provided by sweetening gas from the third stage compressor suction and/or sweet gas wells. An amine solution will be used for sweetening. Non-condensible vapors from the acid gas containing H_2S and CO_2 will flow to the second stage of compression and be diluted with the natural gas stream. Sweetened gas will be scrubbed for liquid removal, filtered, and heated before entering the fuel gas system. Fuel gas will be used as turbine fuel and as makeup into the low pressure buffer gas system.

7.4.1.6 Artificial Lift

Gas lifting will be the primary means of artificial lift used to maintain Monterey well productivity.

7.4.1.7 Power Generation

Electricity will be generated on Platform Harvest by five gas turbine-driven generators. Two diesel reciprocating generators will be installed for emergency situations.

7.4.1.8 Process Heating

A heating oil system will be used for production and test separator heat exchangers, water desalinators, glycol reboiler, and sweetening unit regeneration. The heat source for the heating oil will be waste heat recovered from the turbine drivers for the electric generators.

7.4.1.9 Water Treating

Free water will be treated for removal of oil and other solids and then discharged to the ocean at a total rate of approximately 30,000 bbl/day.

7.4.2 Support and Utilities Systems

Platform Harvest will be equipped with the support and utility systems described below.

7.4.2.1 Compressor Air

Air compressors will provide compressed air at a pressure of 100 psig. A desiccant absorber will dehydrate a portion of this air for use as instrument air. The remainder will be used as service air.

7.4.2.2 Potable and Deionized Water

Fresh water will be produced by two distillation units at a rate of 1260 gallons/hour and will be held in a storage tank. A portion of the water will be demineralized and used in the turbines for NO_x control. Part of the water will be sterilized with sodium hypochlorite for use as potable water.

7.4.2.3 Diesel Fuel

Diesel fuel will be stored in the pedestal columns which support the three deck cranes and in the drill rig storage tanks. Pumps will transfer fuel as needed for logging and cementing, platform cranes, secondary fuel for turbine generators, engine driven fire water pump, and standby emergency power generation.

7.4.2.4 Vent and Flare System

Platform Harvest will be equipped with three relief header systems: high pressure, low pressure, and atmospheric. All relief valves set at 50 psig or higher pressure will be relieved through the high pressure flare system. Relief valves set below 50 psig will be connected to the low pressure flare system. Vapors from equipment that cannot be included feasibly in the vapor recovery system, such as the skim piles, will be vented to the atmosphere through an atmospheric vent equipped with a flame arrestor. All relief headers will flow through respective scrubbers out to flare burner tips located at the end of an extended boom off the edge of the platform. The vent outlet will be located approximately halfway along the boom.

7.4.2.5 Drain Systems

A closed drain system for all volatile hydrocarbons under pressure and an open drain system for the non-volatile fluids will be collected in a production drain sump and then pumped back to the production separators.

Rainwater, spillage, washdown, and firewater will be collected through deck drains and disposed to a skim pile.

7.4.2.6 Heating Oil

A circulating heating oil system will be employed to provide heat to the process heat exchangers. The system will consist of a heating oil expansion tank, circulation pumps, supply and return headers, and a heat source. The heat source will be waste heat recovered from the turbines generating electrical power.

7.4.2.7 Sewage Treatment

Approximately 6500 gallons per day of sanitary wastes will be generated. This will be treated by an Omni-Pure electrocatalytic unit and discharged to the ocean. Effluent will meet U.S. Coast Guard and NPDES requirements.

7.4.2.8 Chemical Injection

Numerous small storage tanks and metering pumps will be provided for injection of corrosion inhibitors, emulsion breakers, antifoam agents, and methanol into the process streams.

7.4.2.9 Central Hydraulic Unit

Four centrally located hydraulic supply pump units will be used to provide high pressure hydraulic fluid to the emergency subsurface safety shutdown valves. This will be a closed loop system with spent fluid returning to a pump suction reservoir.

7.4.2.10 Lighting

General platform lighting levels will meet or exceed standards set forth by the Illuminating Engineering Society for safety and efficiency of visual operations. Outdoor lighting will be by high pressure sodium lights, whereas indoor lighting will come from fluorescent fixtures. Battery powered emergency egress lighting will also be provided.

7.4.2.11 Communications

Platform Harvest will be equipped with hard-wired speakers and handsets as well as hand-held portable radios for intra-platform operational communications.

The platform will also be equipped with a radio system for external communication with boats, nearby platforms, and onshore facilities.

7.4.2.12 Personnel Quarters

Sleeping accommodations, a galley, restrooms, a washroom, a recreation room, repair shops, and supervisor offices will be located in a building on the drilling deck.

7.4.2.13 Corrosion Control

Corrosion of equipment and piping will be minimized through the use of internal and external coatings, corrosion inhibitor chemicals, and careful selection of materials.

7.4.2.14 Gas Dehydration

Gas leaving the compression system will be dehydrated in a triethylene glycol contacting system. Dehydrated gas will be scrubbed and will then flow to sales or gas lift. Removed water will leave the unit as steam and be condensed by a cooler. Glycol will be continuously regenerated.

7.4.2.15 Solid and Liquid Waste Disposal

Solid waste will be collected in large enclosed metal containers and hauled to shore for disposal at an approved onshore dump site.

Spent amine will occasionally be removed from the sweetening process because of degradation and buildup of impurities.

7.5 CONTROL AND MONITORING SYSTEMS

The following types of systems will be used to control and monitor the operation of general process equipment on Platform Harvest.

7.5.1 Process Controls

Closed loop analog proportional controllers will be used to control process temperatures, pressures, flow rates, and liquid levels. Variables requiring routine operation will be handled from the control room. Non-routine operations will be controlled in the vicinity of the specific process.

7.5.2 Alarms

Alarms will be activated in the control room in the event that process control variables exceed operating limits. Alarms will consist of horns and flashing lights.

7.5.3 Shutdown Systems

Safety shutdown equipment will be available in order to respond to emergency conditions and will be applied using MMS Pacific Region OCS Order No. 5 and API RP 14C as guidelines. The following will be supplied:

- high/low pressure sensors
- high temperature sensors
- high/low liquid level sensors
- pressure safety (relief) valves
- high/low flow sensors
- automatic emergency shutdown system
- manual emergency shutdown system
- surface and surface-controlled subsurface well safety valves, one of each per producing well
- equipment isolation shutdown valves

7.5.4 Oil and Gas Metering

Oil volumes measured at Platform Harvest will be considered absolute and be the basis for royalty payment and sales. The shipping and metering system will consist of the surge tanks, meters, meter prover, and a net oil computer with a basic sediment and water (BS&W) probe and a mechanical sampler. As the wet oil stream flows through the BS&W probe, a capacitance measurement will be continually read. The change in capacitance of a coaxial cell is a sensitive indicator of the water content of a wet oil stream. The water volume signal and the volume pulses from the pipeline meters will be combined in the net oil computer to determine net oil and water volumes in the wet oil stream. After specified volumes of flow pass, the mechanical samplers will take a wet oil sample which will be periodically analyzed to verify computer operation for allocation purposes and to determine crude characteristics.

Each test separator will be three-phase and will have meters for gas, free water, and wet oil. Each separator will have a net oil computer which accepts input from the wet oil and water meters and the BS&W probe to provide total water and net oil volume accumulations and rate data.

All gas measurements will utilize orifice type meters which have static, differential, and temperature transmitters tied into a local electronic metering unit. A local mechanical static and differential recorder will be placed on the sales gas meter as a contingency against electronic meter outage. Gas metering will be done in accordance with the specifications contained in the American Gas Association publication "Orifice Metering of Natural Gas, Gas Measurement Report Number 3."

7.5.5 Leak Detection Monitoring

For pipeline leak detection monitoring purposes, the platform wet oil metering systems will transmit volume pulses to a comparator located at the outlet where a leak detection counter will provide a continuous volumetric comparison of inputs to the line with deliveries. The system will include an alarm which would be triggered by a preset difference in detected volumes.

7.6 SAFETY MEASURES

Appropriate safety systems, equipment, and features will be installed on Platform Harvest and incorporated into operations practices.

7.6.1 Safety Standards

U.S. Coast Guard requirements under 33 CFR 67 and 33 CFR Subchapter N will be met. These requirements concern personnel quarters, personnel safety, means of escape, lifesaving, fire detection, fire control, fire extinguishers, navigation lights, obstruction lights, and sound signals to be used on fixed structures in navigable waters.

Requirements for detection and control of combustible gases and hydrogen sulfide established in Pacific Region OCS Order No. 5 will be adhered to.

7.6.2 Hazard Detection and Warning Systems

Continous fire monitoring sensors will be placed in high-hazard areas throughout Platform Harvest. These will be connected to visual and audible alarms in the control room. Fire sensors will include smoke/ionization detectors, manual fire alarm stations, ultraviolet detectors, and fusible plug systems that will activate automatic fire extinguishing equipment in the immediate vicinity.

The gas detection system will be design in accordance with the following parameters:

- At 20 percent of the lower explosive limit (LEL) of gas, the detectors will initiate a warning alarm, locally and at the central alarm panel.

- At the second level, 60 percent LEL, the gas detectors will:

  - initiate a general alarm at the central alarm panel,

  - initiate emergency shutdown,

  - actuate the Halon 1301 system, if provided, when detection is within an enclosed area, and shut down the air handling system in that building,

  - actuate the water spray deluge system for the platform deck area detected and shut down air handling systems for the control building and switchgear building.

Toxic gas detectors will be arranged throughout the platform to detect hydrogen sulfide at two levels. At the low level concentration of 10 ppm of H_2S, the detector will initiate a warning alarm at the central alarm panel. At the high level concentration of 20 ppm, the detector will initiate a general alarm and emergency shutdown.

7.6.3 Firefighting Equipment and Systems

Platform Harvest's production deck will be equipped with three firewater pumps. One will have an electric motor and two will be diesel driven. Each pump would be rated at 3000 gpm at 320 feet total dynamic head. Certain process equipment containing combustible fuels will be covered by an automatic deluge system.

Each gas turbine driver will have an automatic fire extinguishing system. Numerous portable and semi-portable dry chemical or CO_2 fire extinguishers will be placed on Platform Harvest in accordance with the requirements of 33 CFR 145.

7.6.4 Escape and Lifesaving Equipment

Platform Harvest will be equipped with U.S. Coast Guard-approved escape capsules or lifeboats, plus an adequate number of life preservers, ring life buoys, first aid kits, litters, and other lifesaving appliances as required by 33 CFR 144.

7.6.5 Emergency Power and Lighting

Emergency AC power for lighting, communications equipment, hazard detection systems, quarters, controls, and minor utility systems will be provided by two diesel engine driven generators.

Battery-powered emergency lighting units will be installed in several areas of the platform to illuminate critical escape or facility black-start work areas.

Battery chargers and battery systems will be provided for aids to navigation, communications, general alarm systems, generator startings, and electrical switchgear control.

7.6.6 Aids to Navigation

Platform Harvest will be equipped with Class A obstruction lights and fog signals as required by 33 CFR 67. Steady as well as flashing red lights will be used to illuminate the flare and crane booms and drilling derricks. Lights and one amber flashing beam will be used to illuminate the heliport when in use.

7.7 ENVIRONMENTAL PROTECTION MEASURES

The following measures will be taken to minimize platform air emissions and discharge of oil to the surrounding area.

7.7.1 Waste Heat Recovery Process

Platform Harvest's heating requirements will include those for reducing emulsion viscosity, sweetening unit regeneration, glycol reboiler, and water desalinators. As much of this heat as possible will be supplied by waste heat recovered from exhaust from turbines used for electricity generation. The use of waste heat conserves fuel and correspondingly reduces emissions from the burning of fuel.

7.7.2 Spill Prevention and Containment

Platform Harvest will be designed to prevent the discharge of oils into the ocean during routine operations. Platform decks will be enclosed with a toe plate to prevent drainage from going overboard. Onboard spilled fluids and washdown water will drain to skim piles for oil/water/solids separation. Oil will be skimmed from the surface and pumped to the wet oil system and clean wastewater will be discharged to the ocean.

Process bleed valves and drains will be routed to a sump for collection and pumped back to the wet oil or free water system. Gas and liquid relief valves will be part of a closed system with gas routed to the flare and liquids ultimately entering the wet oil system.

Texaco has developed an Oil Spill Contingency Plan for Platform Harvest. This plan describes the measures which will be taken in the event of an oil spill. The plan also describes the personnel and equipment available to implement spill containment and cleanup procedures.

7.7.3 Gas Turbine NO_x Reduction Equipment

Water injection type NO_x reduction equipment will be installed on all turbines on Platform Harvest. The equipment will be designed to reduce NO_x levels to a minimum of 50 percent of uncontrolled levels.

7.7.4 Operational Contingency Plans

Platform equipment will be fueled with produced gas and excess gas will be transported to shore via pipeline for further processing and sales. Gas injection facilities to be installed for possible use at a future date could be used to reinject gas if the gas pipeline system or the gas treating facilities were inoperative for some reason. The gas pipeline and onshore treatment facilities could be used to handle all the excess gas if injection facilities failed. Simultaneous failure of both the gas reinjection system and the onshore treating facilities is unlikely.

Additionally, a great deal of redundant excess capacity has been designed into the platform equipment to minimize process downtime and therefore minimize flaring episodes. A few of these design features are listed below:

- The platform process train is designed to handle up to 81,300 bbl liquid per day, whereas the peak production rate anticipated is 56,000 bbl liquid per day.

- Two independent separation trains, each capable of handling 40,650 bbl liquid per day provide 100 percent redundancy during all but the peak production years of 1988 and 1989.

- Fuel gas may be provided by sweet gas (Foxen sand) wells, or by sweetening produced sour gas, or, diesel fuel could be used as a second backup for power generation in the unlikely event that no produced gas was available.

- Five turbine-generator sets are provided, while four are sufficient to meet the maximum power requirements.

- Three turbine-compressor sets are provided, allowing one spare during all but the peak production year of 1988.

7.7.5 Other Measures

Internal combustion engines will be equipped with catalytic converters and tanks will be equipped with a vapor recovery system to reduce air emissions.

TABLE VII-1

MAJOR PLATFORM PRODUCTION EQUIPMENT

Equipment	Number
Wellbay manifold	2
Production/separation heater	2
Three-phase production separator	2
Production surge tank	2
Test separator	2
Test heater	2
Sweet gas separator	1
Gas turbine driven compressor	3
Gas turbine driven generator	5
Diesel generator	2
Amine contact column	1
Glycol contact column	1
Air compressor	1
Desalinization distillation column	2
Flare boom	1
Heating oil surge tank	1
Gas lift compressor	1
Central hydraulic unit	4
Firewater pump	3
Cooling water pump	3
Oily water coalescer	2
Flotation unit	1
Skim pile	2
Vapor recovery compressor	2

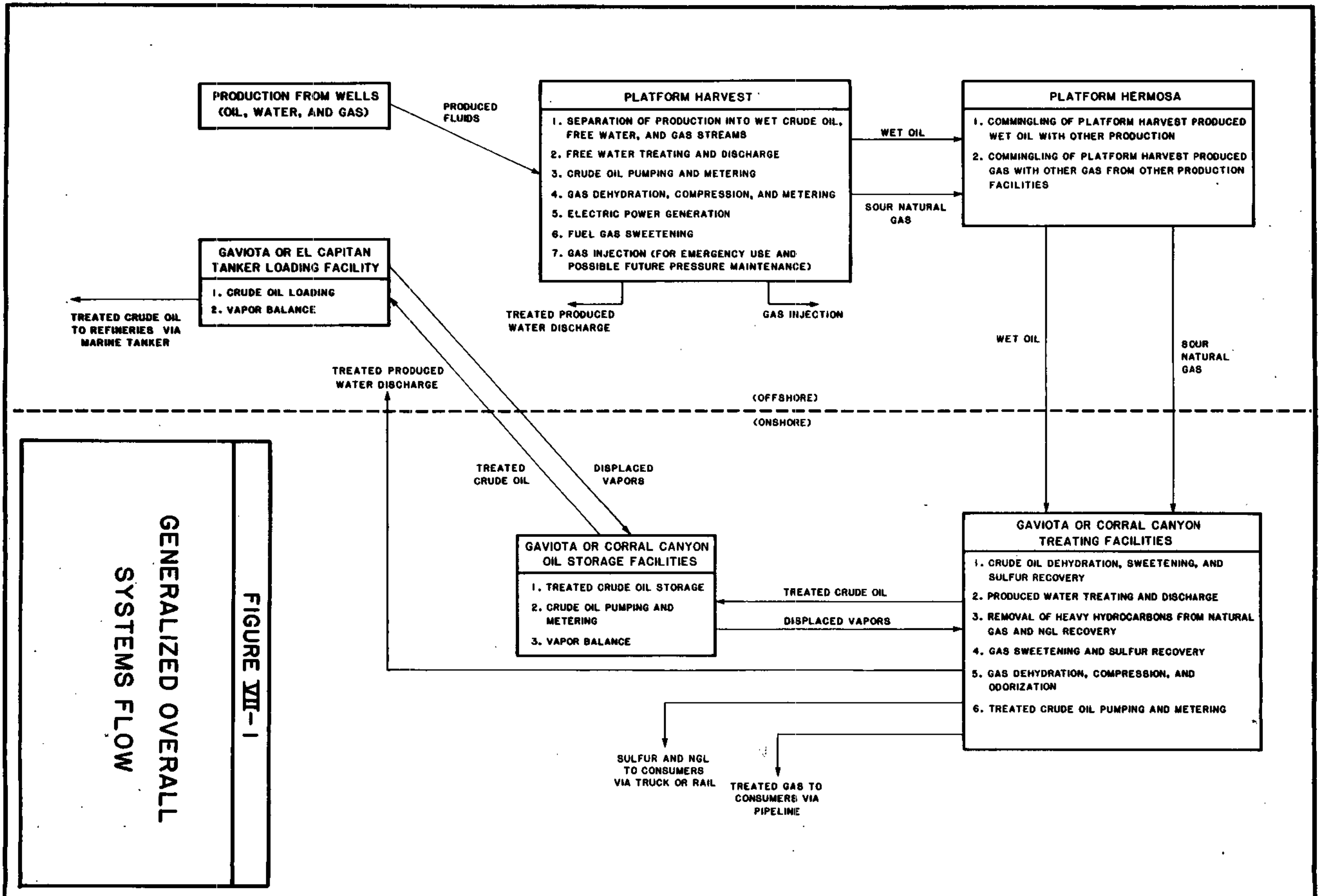
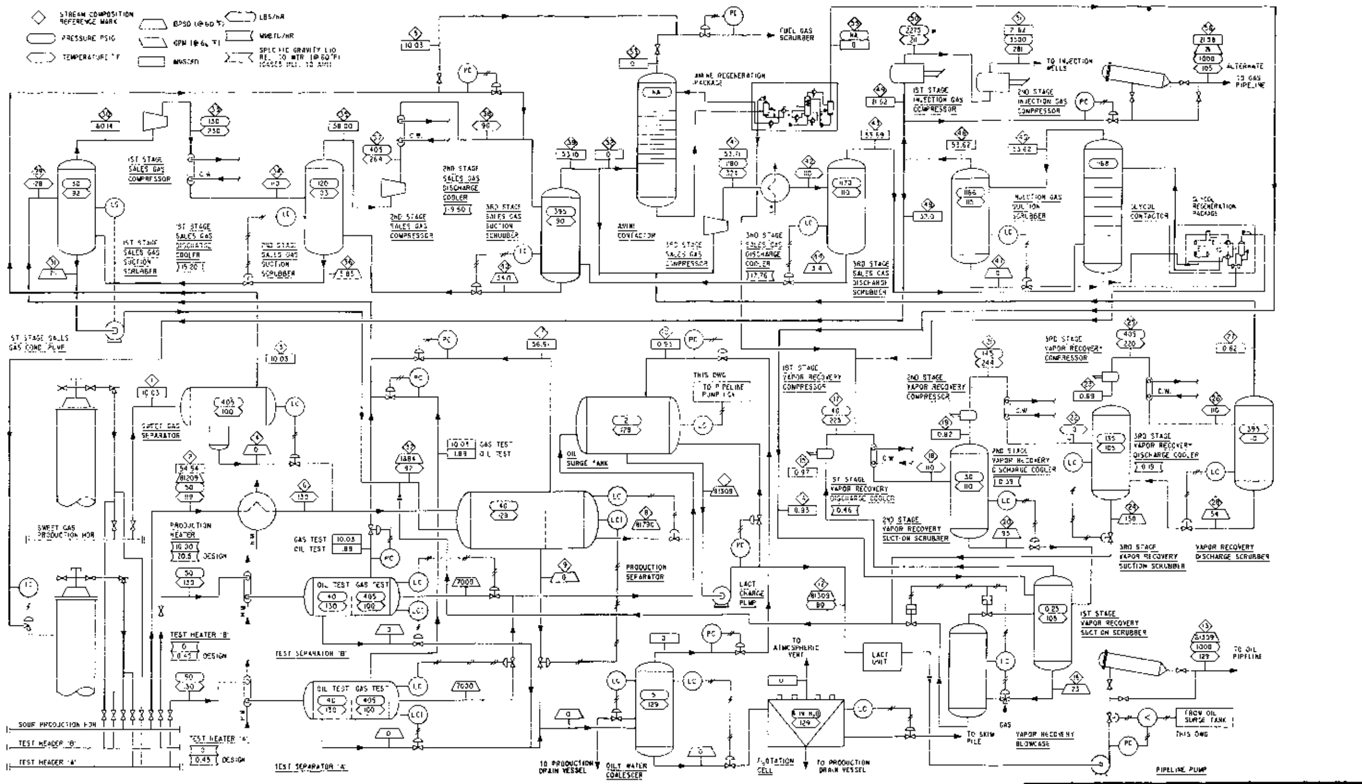


FIGURE VIII-1
GENERALIZED OVERALL SYSTEMS FLOW



NOTE: THIS DIAGRAM IS BASED ON ONE OF SEVERAL PRELIMINARY DESIGN CASES AND IS PRESENTED FOR EQUIPMENT ILLUSTRATION ONLY. ACTUAL FLOW RATES THROUGH THE SYSTEM WILL VARY DURING PLATFORM OPERATION.

FIGURE VII-2

PLATFORM HARVEST
GENERAL PROCESS FLOW

SECTION VIII - OIL AND GAS TREATING FACILITIES

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SECTION VIII - OIL AND GAS TREATING FACILITIES

8.1 INTRODUCTION

Oil/water emulsion and natural gas produced at Platform Harvest will be transported via subsea and onshore pipelines to onshore treating facilities operated by other companies. All treating at such facilities will be conducted on a contractual basis. Texaco will not be responsible for the construction and operation of the treating facilities; however, for completeness, those facilities that likely could treat hydrocarbon fluids produced at Platform Harvest are discussed briefly in this DPP. Full descriptions of these existing or proposed facilities can be found in the DPP's submitted by Chevron (1983) and Exxon (1982).

Texaco's present plans call for oil and gas treating to take place at new consolidated facilities (proposed by Chevron) located near Gaviota (Figures VIII-1 and VIII-2). Alternatively, treating could take place at the POPCO/Exxon (or other) consolidated facilities to be located in the Corral/Las Flores canyons area (Figures VIII-1 and VIII-3). These facilities are described briefly in Sections 8.2 and 8.3; the general oil and gas treating processes which could occur at either area are described in Sections 8.4 and 8.5. Specific details concerning the actual facilities and process flows can be found in the Chevron and Exxon DPP's.

Texaco plans to continue its participation in joint government and industry planning of consolidated onshore processing facilities. Because the details of the consolidated facility design and location are currently being developed by these cooperative efforts, the descriptions presented in this section are preliminary.

8.2 CHEVRON GAVIOTA TREATING FACILITIES

Chevron's treating facilities will be located on land near Gaviota (Figure VIII-2). Several oil and gas industry facilities are present in the vicinity including ones for oil and gas treating, oil storage, and marine terminalling. Although the various facilities have experienced a relatively low level of activity in recent years, the potential for development of major discoveries in the western Santa Barbara Channel and the Santa Maria Basin has spurred interest in establishing a major consolidated facility at Gaviota. Chevron's proposed treating facilities will be fully integrated with existing and/or proposed storage and transportation facilities for maximum efficiency.

Chevron's development plans include construction of new oil treating facilities on a small parcel of land north of U.S. Highway 101. Chevron will also recondition its existing gas treating facility and/or construct new gas treating facilities on a site adjacent to the proposed oil treating facilities. Texaco's current development plans include treating of Platform Harvest oil and gas at Chevron's proposed Gaviota facilities. Brief descriptions of these facilities are presented in Section 8.4.

8.3 CORRAL/LAS FLORES CANYONS AREA TREATING FACILITIES

POPCO is presently completing construction of a 30-MMSCFD gas treating facility in Las Flores Canyon on land owned by Exxon (Figure VIII-3). This facility initially will treat gas produced at Exxon's Platform Hondo A located near the eastern end of the Santa Ynez Unit (SYU). As part of its SYU Development plan, Exxon has proposed to expand the Las Flores Canyon gas treating facilities to approximately 90 or 135 MMSCFD. Future ownership of the expanded facilities is uncertain at this time. Exxon also proposes to construct oil treating facilities on a site adjacent to the east. Area for construction of additional facilities will also be provided by Exxon. Texaco does not currently plan to utilize the Corral/Las Flores canyons area facilities for treatment of oil and gas from Platform Harvest. However, brief descriptions of the treating operations are presented in Section 8.5.

8.4 CHEVRON GAVIOTA OIL AND GAS TREATING OPERATIONS

8.4.1 Introduction

Oil dehydration, gas sweetening, oil pumping, and gas compression facilities are proposed to be installed by Chevron at the Gaviota site. Initial Chevron facilities will require approximately 11 acres of land. Additional areas will be reserved to expand facilities as required to handle production that might be discovered and require processing at Gaviota such as that from Texaco's Platform Harvest. Initially, gas may be processed for commercial sale at Chevron's existing Gaviota gas plant at Gaviota which has a capacity of 30

MMSCFD. Depending upon the reservoir data developed with additional drilling, this plant may be expanded or replaced with a new plant.

8.4.2 Overview

A preliminary process flow diagram and plot plan for the Gaviota facility are shown in Figures VIII-4 and VIII-2. The facility will be built in phases and will be designed to permit expansion with minimum disruption to existing equipment when plant additions are required. Oil dehydration equipment and gas compressors will be installed in stages as production increases. The facilities will be designed to heat and dehydrate 170,000 BPD of oil in an emulsion (200,000 barrels of fluid per day) and to sweeten 120 million standard cubic feet per day (120 MMSCFD) of sour gas. Up to 37,000 BPD of waste water will be cleaned for disposal through a new ocean outfall line. Space will be provided and the design will accommodate expansion to accommodate future hydrocarbons.

8.4.2.1 Oil Dehydration and Shipping

8.4.2.1.1 Inlet

Crude oil emulsion and free water will enter the Gaviota facility from a pipeline and pass through an inlet metering station. The volume of fluid reaching Gaviota will be continuously compared with that recorded by each of the offshore platform shipping meters. Differences exceeding preset limits will trigger alarms and appropriate response measures will be initiated.

Fluid leaving the meter will enter a free water knock out (FWKO) vessel where free water will be removed and sent to the water cleaning plant. A pressure control valve located between the inlet and FWKO will direct a portion of the incoming production to the re-run tank if vessel pressure exceeds a pre-set value. The crude emulsion from the re-run tank will then be pumped into the system downstream of the control valve when operating conditions permit.

8.4.2.1.2 Oil Dehydration

Oil dehydration is a process of removing water from the oil emulsion using a combination of heat, settling time, emulsion breaking chemicals, and an electrostatic field. This process is started within the FWKO vessels and continues within the treating vessels.

Emulsion heating will occur in heat exchangers that utilize waste heat from a cogeneration power plant that will supply electrical power to the onshore facility. The emulsion will flow through another bank of heat exchangers using a heating medium from boilers or fired heaters. In addition, excess heat from oil and water streams leaving the treaters will be transferred to the incoming emulsion stream. The oil/water mix will then flow to the dehydration vessel.

Electrostatic grids located in the processing section of each treating vessel cause droplets of water suspended in the oil stream to coalesce and then settle to the bottom of the treater. Dehydrated oil will pass through a dry oil/wet oil heat exchanger to preheat the incoming crude.

Produced water extracted during dehydration will be mixed with the stream entering the FWKO or flow through heat exchangers to conserve energy. The water from the FWKO and dehydrators will flow to the produced water treating facility.

8.4.2.1.3 Oil Shipping

Dehydrated oil will leave the dehydration system with a water content of less than 3 percent. Before entering the shipping pump surge tanks, the crude stream will pass through a monitor to ensure that it meets pipeline specifications; crude that does not will be sent to the re-run tank and will be pumped through the treating vessels again.

8.4.2.2 Waste Water Handling

Waste water removed during oil and gas dehydration, and water from the sump tank will be stored in a 5000 barrel oily water tank. From this tank, waste water will be processed to meet current requirements for discharge to the ocean through a proposed new ocean outfall line in accordance with a NPDES permit.

Liquids and suspended solids removed during water treating will be collected in the sump tank. Oil from the sump tank will be pumped to the dirty oil tank and water will be pumped to the oily water tank. Solids will be hauled away and disposed of at an appropriate dump site.

8.4.2.3 Gas Handling

8.4.2.3.1 General Process

Gas will be dehydrated offshore prior to entering submarine pipelines. Upon reaching Gaviota, the gas stream will pass through liquid slug catchers and to a H_2S removal unit. Gas from the process will supply sweet fuel to the heaters (if utilized), turbine generator sets, and gas blanket system.

Gas that has gone through the H_2S removal unit will pick up water in the process; therefore, additional dehydration will be required. After dehydration, the gas will be processed in the low temperature separator to remove natural gas liquids. After natural gas liquids are removed, the gas will be compressed and enter the utility gas line. Natural gas liquids will be placed in storage tanks for transportation by tanker trucks or railroad tank cars.

The H_2S removal unit will produce sulfur as a by-product. This material will be sold or taken to an appropriate disposal site periodically by rail and/or truck.

8.5 CORRAL/LAS FLORES CANYON OIL AND GAS TREATING OPERATIONS

8.5.1 Oil Treating

Crude oil will be treated at new oil treating facilities located in the Corral/Las Flores canyons area. The primary functions of the facilities will be to separate produced water from the crude oil and to reduce the H_2S content of the oil to less than 10 ppm by weight. Storage and pumping facilities will be provided for oil and produced water. Separated produced water will be treated to remove any remaining oil and suspended solids and then pumped to an offshore outfall for disposal in accordance with a NPDES permit.

The oil treating facilities will receive crude oil emulsion via pipeline from offshore platforms and process the incoming stream as illustrated on Figure VIII-5. The incoming crude oil/water emulsion will first undergo separation in a knockout vessel. The separated water will pass to the produced water treating facilities, while the outgoing emulsion stream will be preheated and then fed to a chem-electric treater where the oil/water emulsion will be further separated using heat, chemicals, and an electrostatic field. Water separated by this process will flow to the water treating system.

After leaving the chem-electric treater, the crude oil will be reheated and countercurrently contacted with sweet natural gas to remove most sulfur and light hydrocarbon compounds. The sour gas will be compressed and sent to the gas treating facilities. Sour water produced in this operation will be routed to a water treating system; the stabilized crude will be pumped to storage.

Bulk storage tanks will be installed at the oil treating facilities site to hold treated crude oil for shipment. These will be cone roof tanks connected to a vapor recovery system.

The produced water treating facilities will use gas flotation and filter systems to remove suspended solids and residual oil. The treated produced water will be disposed of by discharge to the ocean in accordance with a NPDES permit.

Auxiliary systems at the oil treating and storage facilities will include a blanket gas system, a vapor recovery system, and a relief flare system. Recovered vapors from the vapor recovery system will be routed to the gas treating facilities. The relief system will provide emergency flaring in the event of an upset condition.

8.5.2 Gas Treating

The gas treating facilities in Las Flores Canyon would be expanded to either 90 or 135 MMSCFD approximate capacity. However, the basic processing scheme would not differ from that of the existing 30-MMSCFD facility.

The purpose of the gas treating facilities is to upgrade produced gas to meet sales specifications. This entails heavy hydrocarbon and sulfur removal and recovery, dehydration of the gas, and compression and odorization. Figure VIII-6 shows the gas treating facilities process flow scheme.

The produced gas will be transported via pipeline to the gas treating facilities from offshore platforms. The initial treating step will involve heavy hydrocarbon separation using a refrigeration system. Hydrocarbon liquids will be separated from lighter components (primarily methane and ethane) and sent to pressurized storage tanks as NGL. The NGL will then be trucked away for sale. The separated sour gas will flow to a gas sweetening unit where it will be contacted with a solvent which absorbs acid components from the gas in a counter-current regenerative process.

After the acid gases have been removed in the sweetening unit, the natural gas will be dehydrated using a TEG countercurrent absorption/regeneration system. Sweet natural gas leaving the TEG system will be compressed, odorized, and sent to the existing natural gas transmission system.

Sulfur compounds removed from the produced gas will be concentrated into an acid gas stream in the gas sweetening unit; the acid gas stream then will be sent to the SRU. Treated acid gas leaving the SRU will be sent to a tail gas treating unit for removal of residual sulfur. This sulfur will be temporarily stored at the site and then trucked away for sale in the southern California area.

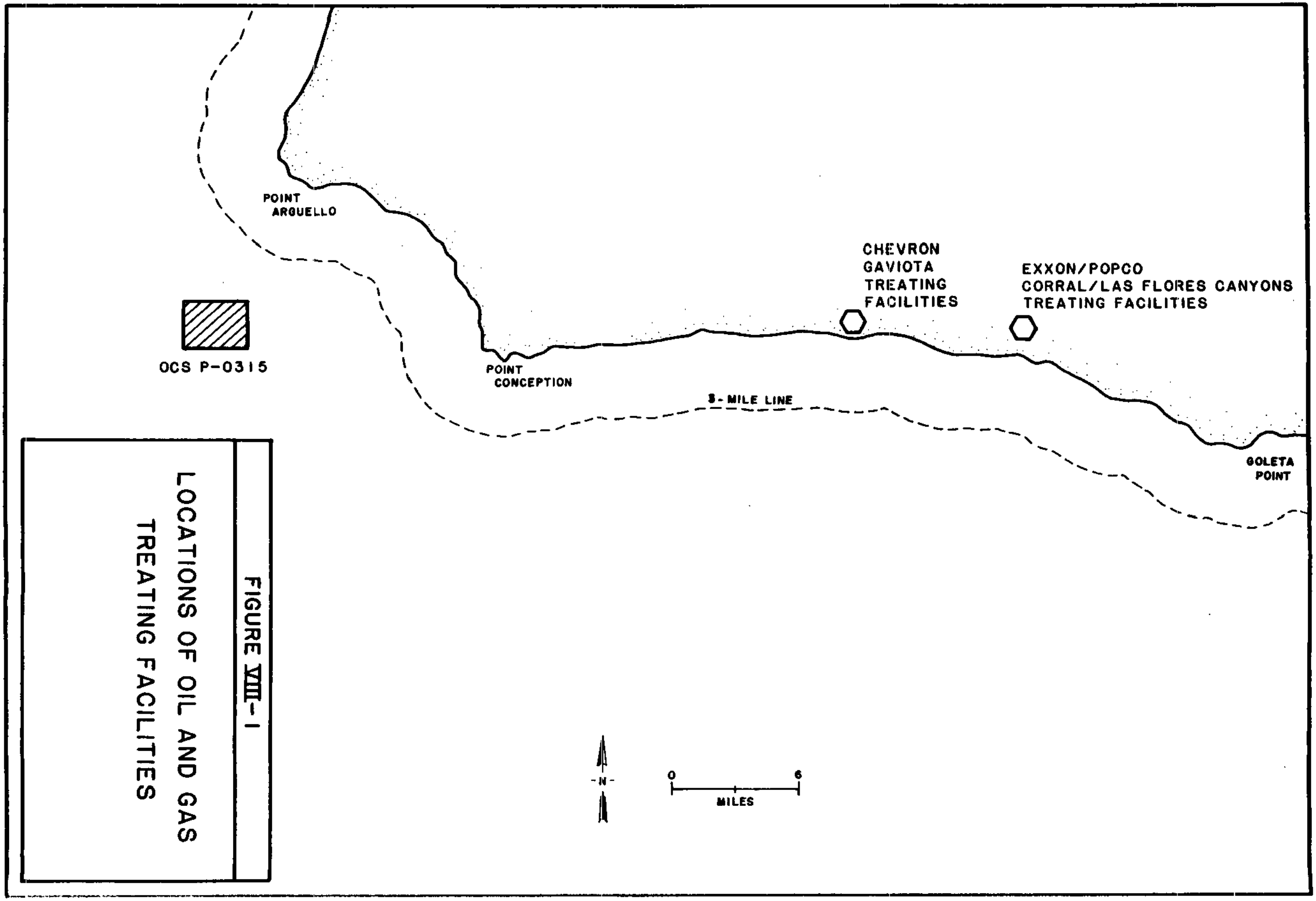
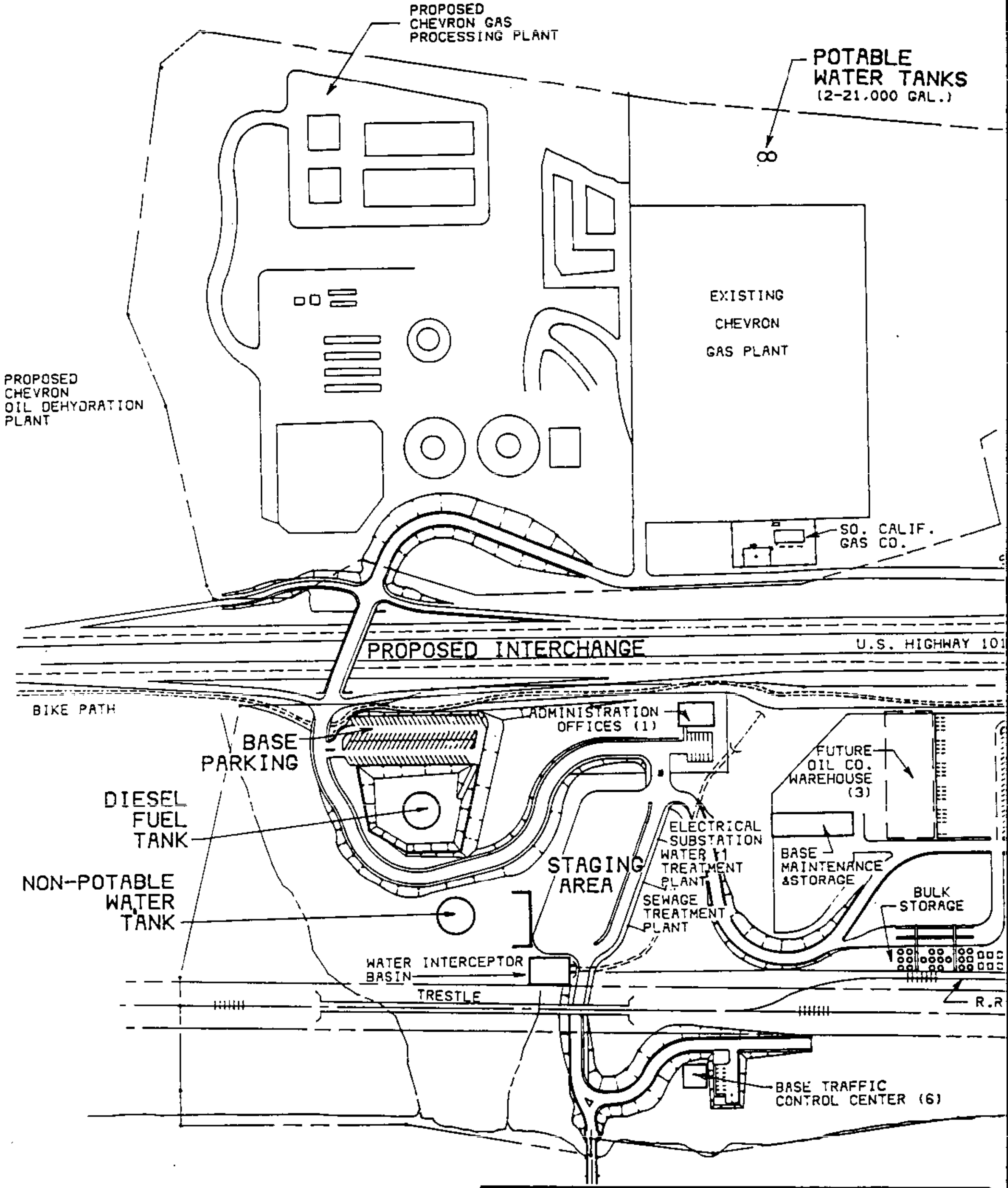


FIGURE VIII-1

LOCATIONS OF OIL AND GAS TREATING FACILITIES



SOURCE: GETTY, 1983.

FIGURE VIII-2

PROPOSED SITE PLAN–
CHEVRON GAVIOTA FACILITIES

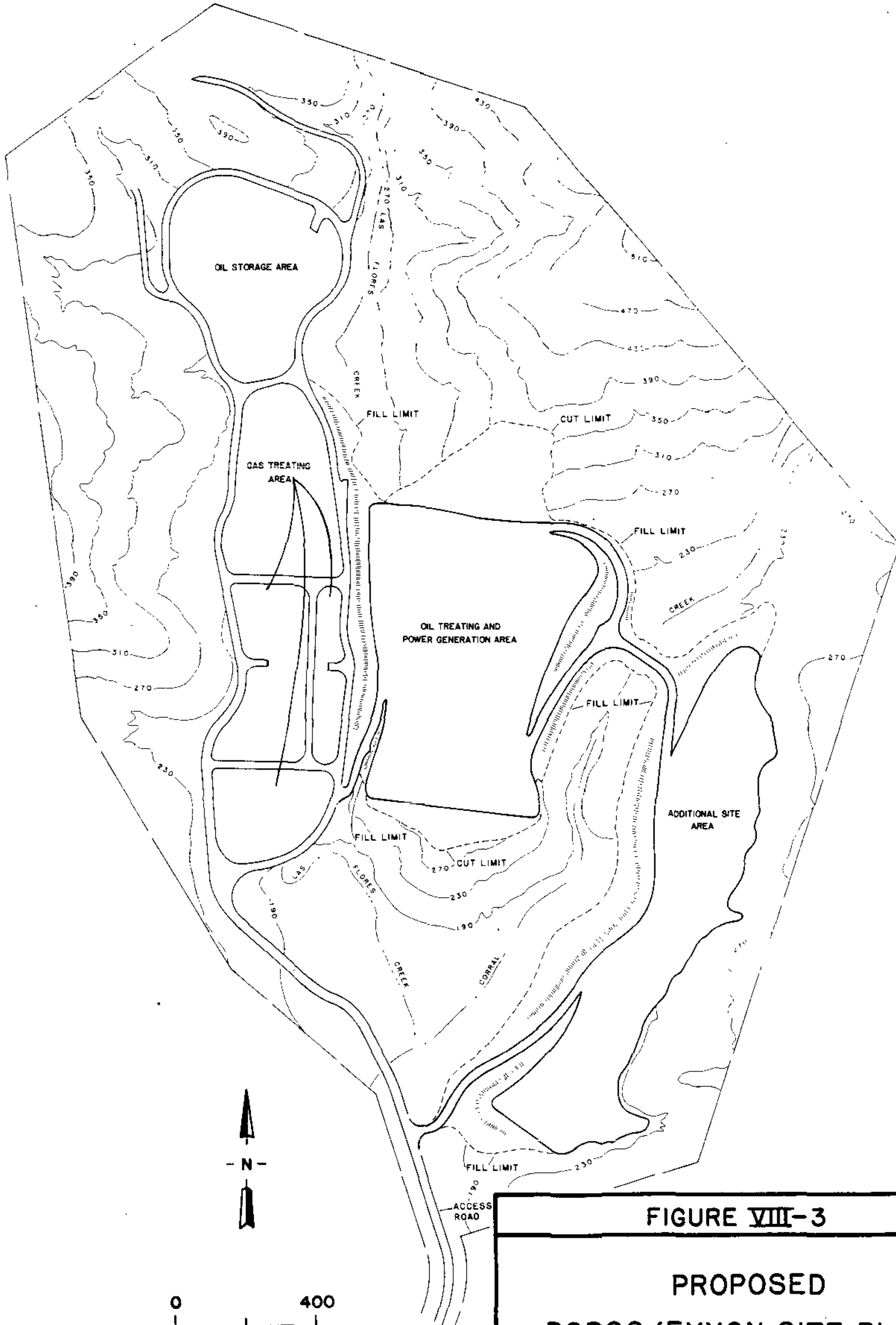


FIGURE VIII-3

PROPOSED POPCO/EXXON SITE PLAN– CORRAL/LAS FLORES CANYONS AREA

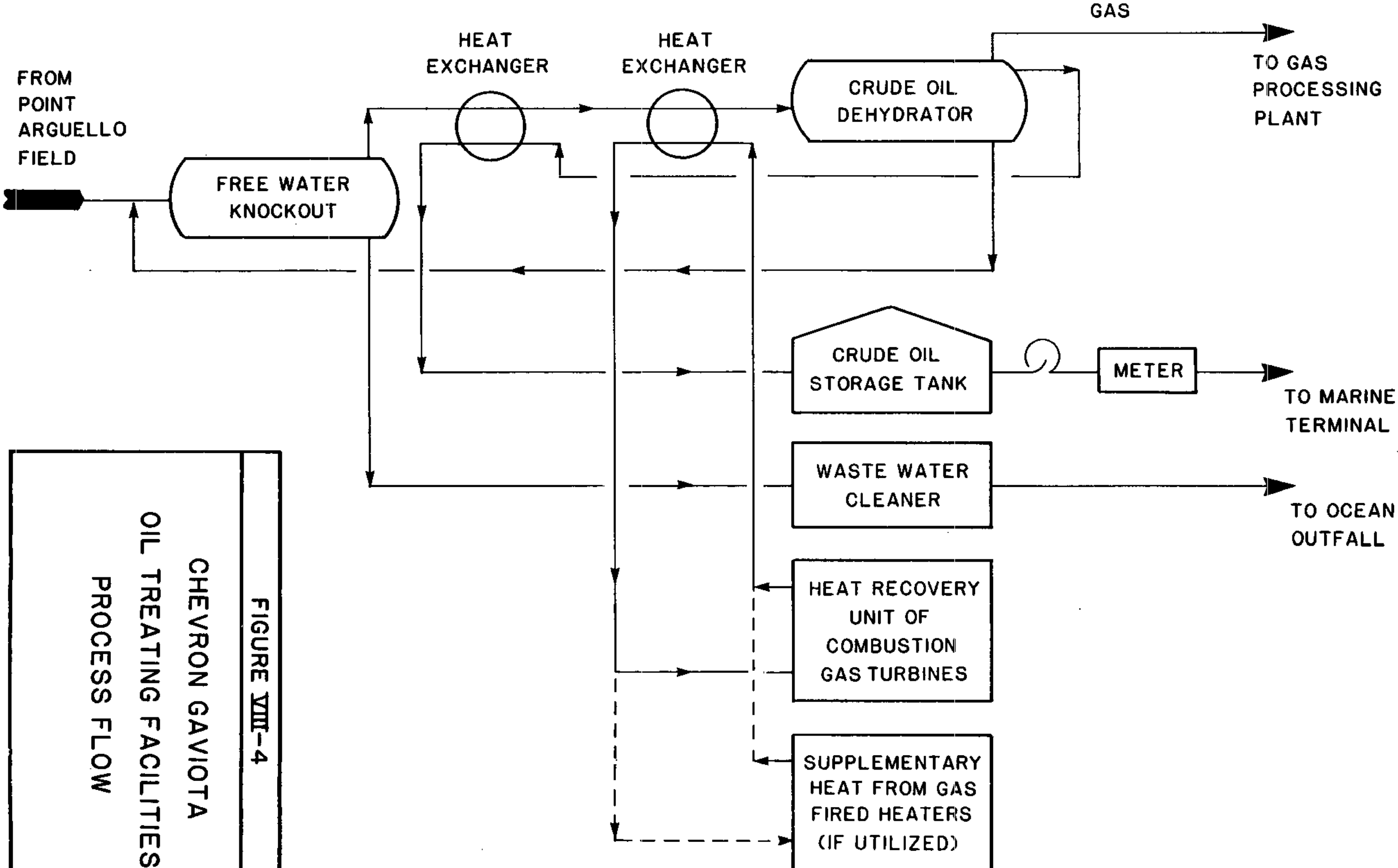


FIGURE VIII-4

CHEVRON GAVIOTA
OIL TREATING FACILITIES
PROCESS FLOW

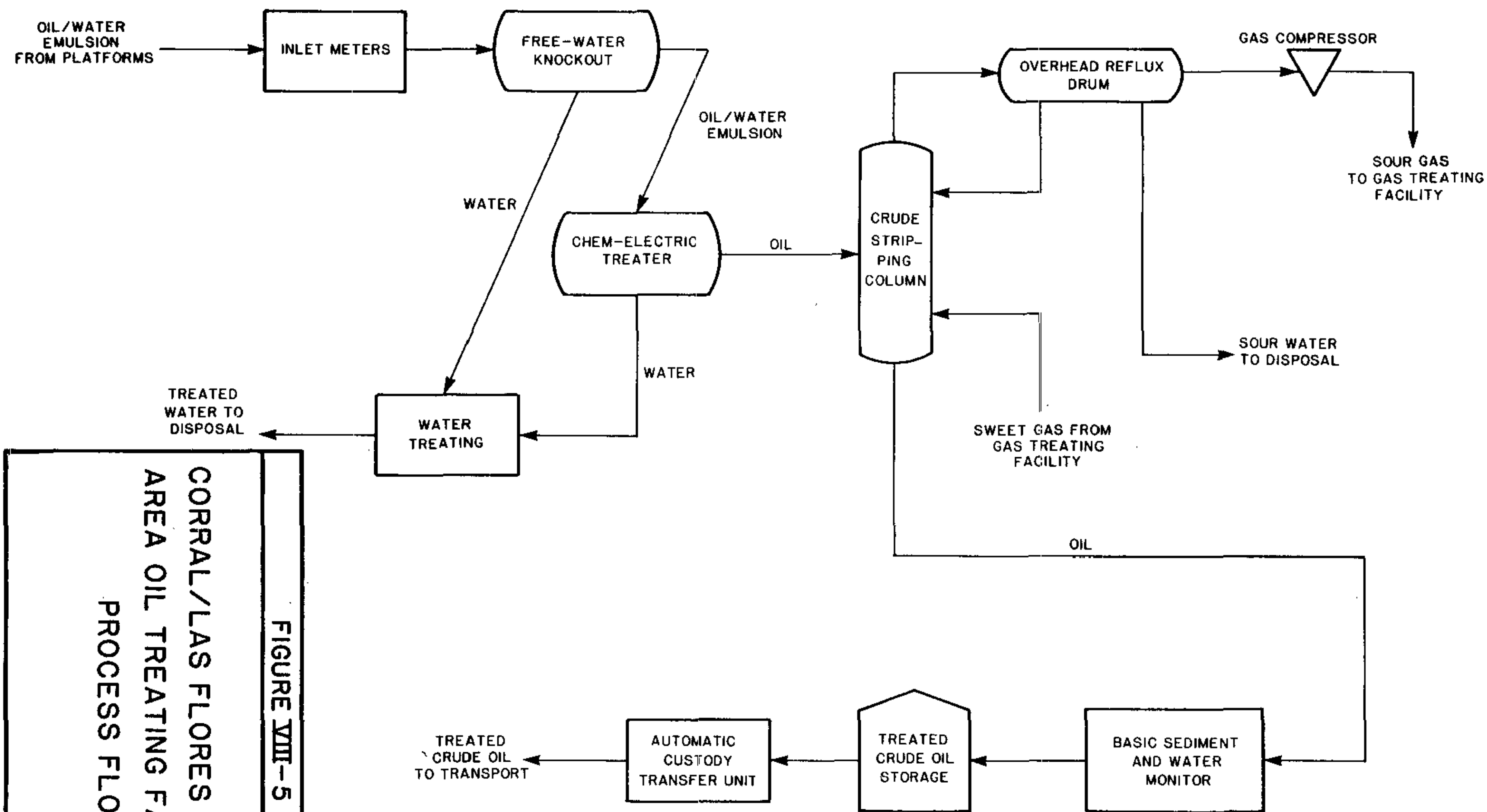


FIGURE VIII-5
CORRAL/LAS FLORES CANYONS AREA OIL TREATING FACILITIES PROCESS FLOW

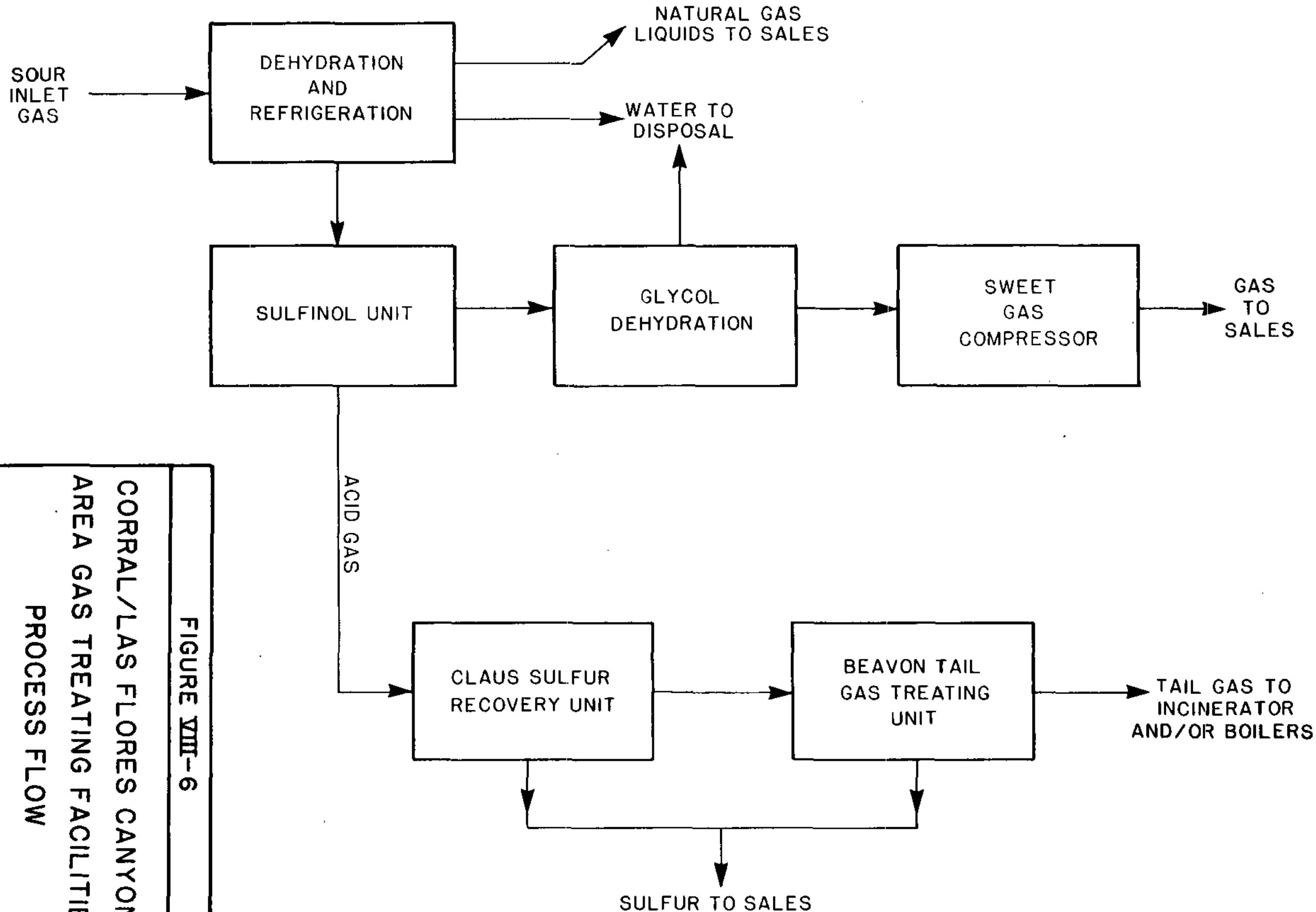


FIGURE VIII-6
CORRAL/LAS FLORES CANYONS AREA GAS TREATING FACILITIES PROCESS FLOW

SECTION IX - PRODUCT STORAGE AND TRANSPORTATION

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SECTION IX - PRODUCT STORAGE AND TRANSPORTATION

9.1 INTRODUCTION

This section presents an overview of the facilities and operations involved in storing and transporting the marketable products from Texaco's Platform Harvest Project. Texaco will neither own (although it might participate as a joint-venture partner) nor operate any of the storage or transportation facilities discussed herein except for tankers which may be owned and operated by Texaco. All other facilities will be installed and operated by other companies.

Section 9.2 contains discussions of treated crude oil storage and transport. Four separate alternatives are described, each of which would involve facilities which have not been constructed. Texaco's proposed plan calls for transporting its treated crude oil via the proposed consolidated Las Flores (marine) Terminal. Alternatives to this plan include marine transport via Getty's proposed upgraded marine terminal at Gaviota; overland transport to the Los Angeles area via a possible southern California coastal pipeline; and overland transport to the southern San Joaquin Valley via Getty's proposed new pipeline.

Texaco recognizes the considerable interest that has been expressed in developing a consolidated crude oil transportation system for the western Santa Barbara Channel and Santa Maria Basin areas. Texaco has participated actively in numerous working groups for the purpose of investigating the feasibility of consolidation proposals such as the southern California coastal pipeline and consolidated marine terminals. Texaco fully intends to continue its participation in this planning process and is prepared to commit its Platform Harvest production to any consolidated transportation system which is feasible for Texaco's use in terms of economic, operational, marketing, and environmental considerations.

Sections 9.3 and 9.4 contain discussions of natural gas transport and sulfur and NGL transport, respectively.

9.2 CRUDE OIL TRANSPORTATION

The projects described in this section are all in the very early or intermediate stages of planning and engineering, and so their design characteristics will be subject to change based on continuing engineering, environmental, and economic analyses, as well as in response to public and regulatory agency permitting concerns. Consequently, the descriptions presented herein should be regarded as preliminary. For up-to-date information concerning these projects as their designs evolve, interested persons should contact the principal public agencies involved:

- Las Flores Terminal - Santa Barbara County Department of Resource Management, California State Lands Commission
- Getty Gaviota Marine Terminal - Santa Barbara County Department of Resource Management, California State Lands Commission
- Southern California Coastal Pipeline - Santa Barbara County Department of Resource Management
- Getty San Joaquin Valley Pipeline - Santa Barbara County Department of Resource Management.

9.2.1 Las Flores Terminal

Texaco is an active member of an industry steering group which is currently developing plans for implementing a consolidated marine terminal proposal and which will apply for necessary permits and approvals to cover this expansion. Texaco intends to continue its participation in the group and will utilize a consolidated marine terminal should such a facility be installed.

The objective of the Las Flores terminal is to provide onshore storage and marine loading facilities, capable of storing field production and of loading approximately 350,000 barrels per day of treated crude oil. The terminal will incorporate a closed system to transfer vapors displaced from the tankers to the onshore tank farm and have provisions for handling ballast water from marine vessels.

9.2.1.1 Description of Major Components

9.2.1.1.1 Oil Storage Facilities

The oil storage facilities associated with the Las Flores terminal ultimately will consist of five nominal 500,000-barrel tanks. All tanks will be cone roofed and will be equipped with breathing valves connected to the tank vapor blanketing system of Exxon's nearby onshore oil treating facilities. In addition, all tanks will be equipped with protective devices to prevent over or under pressuring or overfilling of the tanks.

9.2.1.1.2 Pump and Meter Station

The pumps and meter station associated with the terminal will be located near the oil storage area. The treated oil will flow by gravity from the oil storage tanks to the pump suction. The pump station will include pumps rated for a total flow of up to approximately 45,000 barrels per hour. Flow from the pump station will be metered in an automatic custody transfer (ACT) meter battery, including proving facilities.

9.2.1.1.3 Pipelines

Three pipelines will be installed from the onshore facilities to each of the two single anchor leg moorings (SALM). These pipelines will be for crude oil, ballast water, and marine vessel vapor balance. In addition to the three major pipelines, a service bundle consisting of two small-diameter hydraulic lines and one small diameter gas supply pipeline will be installed. The hydraulic lines will permit automatic operation of the subsea manifold valves on the crude oil transfer and marine vessel vapor balance lines. The gas supply line will permit operation of a subsea pigging station associated with the vapor balance line.

9.2.1.1.4 Single Anchor Leg Moorings

Two SALM's will be installed offshore capable of accommodating marine vessels of up to approximately 300,000 deadweight tons (DWT). The locations of the SALM's will be based on required maneuvering area and underkeel clearance requirements and the location of nearby kelp beds.

The SALM's will be designed to withstand the maximum operating loads induced by moored marine vessels and to withstand survival conditions based on a 100-year design storm with no vessel moored.

The major components of each SALM are:

- A mooring base founded on piles or a gravity type structure designed to withstand the maximum expected horizontal and vertical loads

- A three product fluid swivel assembly near the mooring base to allow simultaneous transfer of crude oil, displaced marine vessel vapors, and ballast water.

- A mooring buoy attached to the mooring base in a manner which allows full and continuous 360-degree rotation. A radar reflector and a beacon light will be mounted atop the mooring buoy for navigational safety

- A synthetic hawser with chafing chains attached at the mooring buoy and marine vessel ends. The hawser will be attached to the mooring buoy and will extend into the water, with a messenger line attached at the vessel end to aid in mooring operations. Floats will be attached to the mooring line and chafing chain as necessary.

- Three hoses for crude oil, ballast water, and marine vessel vapor transfer between the three product swivel assembly and the vessel. At the water surface, the hoses will lie freely with messenger lines attached to aid in mooring operations.

A schematic drawing of Exxon's proposed SALM is presented as Figure X-1. The SALM's used in the Las Flores Terminal are expected to be very similar.

9.2.1.1.5 Vapor Balance System

The Las Flores terminal will be equipped with a closed system to transfer vapors displaced from tankers during crude oil loading. The displaced vapors will be transferred to the onshore tanks by a shore-mounted compressor and will enter the tank vapor blanketing system and a closed balanced system will be maintained. Thus, inclusion of the vapor balance system in the marine terminal design will not only prevent any uncontrolled marine vessel vapor emissions, but will also minimize vessel modifications by locating the required equipment onshore. All marine vessels in dedicated service to the marine terminal will be compatible with the crude loading and vapor balance systems.

9.2.1.2 Marine Terminal Operations

Up to 350 MBD of crude oil would be pumped from the onshore storage tanks through the SALM's to marine vessels during loading operations. A VBL will be provided to convey hydrocarbon vapors displaced from the vessel cargo holds to the onshore treating facilities.

Physical and operational characteristics of marine vessels representative of those that could be used for transport of Platform Harvest crude oil are given in Table IX-1.

9.2.1.3 Implementation of the Las Flores Terminal

These facilities are planned to be implemented in a phased fashion, with the second SALM and a portion of the tankage being installed sometime after the initial facilities, in response to increasing production rates.

The steering committee is currently evaluating various concepts of the relationship of the Las Flores Terminal facilities to the facilities proposed by Exxon as part of the SYU Development. The two basic plans would involve either full integration of all Corral/Las Flores canyons area facilities or, alternatively, limited functional integration of the two sets of facilities; several intermediate concepts are also being considered in an attempt to take advantage of the favorable aspects of each of the two basic approaches.

9.2.2 Getty Proposed Upgraded Gaviota Marine Terminal

Getty Trading and Transportation Company is proposing to phase out their existing 5-point mooring marine terminal and construct a modern marine terminal as an integral part of their Consolidated Coastal Facility. The basic elements of the new marine terminal will be offshore berthing facilities for the simultaneous loading of two deep draft tankers, piping and vapor return systems, and an onshore crude oil storage tank farm.

9.2.2.1 Marine Terminal Design Requirements

The proposed Getty Gaviota marine terminal has been designed based on a number of assumptions with respect to tanker operations and user procedures. These design and operational assumptions are described in the following paragraphs.

The tanker fleet assumed by Getty to service the marine terminal is based on a projection of the U.S. flag tanker fleet for 1986, with emphasis on smaller-DWT tankers. The fleet assumed ranged in size from 31,000 DWT to 52,500 DWT, based on the size distribution in the project fleet. The average size tanker assumed was 48,600 DWT, carrying a cargo lot of 355,600 barrels. Table IX-2 lists the tanker fleet assumed by Getty; no specific user-supplied information was used in generating this fleet.

Getty anticipates that the vast majority of all tanker calls at the proposed marine terminal will be by tankers in dedicated service to movement of oil from the terminal to specific destinations. The tankers may be owned or time-chartered by the users of the facility. One-time ("spot") sales of oil by the facility users, with the oil picked up by one-time-calling tankers at the Gaviota marine terminal, are not expected.

The Getty Gaviota marine terminal is being designed to accommodate tankers ranging in size from 30,000 to 300,000 DWT. The terminal is expected, however, mostly to service tankers in the 50,000 DWT range. On the average, this size DWT tanker, which has a capacity of approximately 365,000 barrels and an average pumping rate of 30,000 barrels an hour, could be loaded in 12 hours.

The berth and mooring facilities proposed for the Getty Gaviota marine terminal were designed for the prevailing oceanographic and meteorological conditions, and for the extreme (100-year occurrence) winds and waves.

9.2.2.2 Marine Terminal Tanker Berth Alternatives

Getty has prepared three tanker berth design alternatives based on an analysis of the relative advantages and disadvantages of each from an operational, safety, and environmental protection point of view. The alternative Getty is calling the "preferred project" is the development of the Single Anchor Leg Mooring (SALM) Tanker Berths. Two other alternative designs being given consideration are Alternative 1: Fixed Pier Tanker Berths, and Alternative 2: Tanker Berths at a Sea Island.

9.2.2.2.1 Single Anchor Leg Mooring

The preferred tanker berth design is a Single Anchor Leg Mooring (SALM) buoy. Two SALMs are proposed to provide two tanker berths. The SALM's will be located 9500 feet offshore, in 240 feet of water. At this depth and location the SALM's can be used by tankers between 30,000 and 300,000 DWT.

The SALM's will be designed to withstand the maximum operating loads induced by moored tankers in winds of 50 mph, and to withstand survival conditions based on a 100-year design storm with no tanker moored. Descriptions of the major components of the SALM tanker berth design are basically the same as those presented in Section 9.2.1.1.4.

Two major pipelines will be installed from shore to each SALM. These two pipelines will be for crude oil and tanker vapor recovery system and will be 40 inches and 18 inches in diameter, respectively. In addition to the two major pipelines, a service bundle consisting of two 2 inch hydraulic lines and one 2 inch gas supply pipeline will be installed. The hydraulic lines will permit automatic operation of the subsea manifold valves on the crude oil transfer and tanker vapor recovery lines. The gas supply line will permit operation of a subsea pigging station associated with the vapor recovery line.

The preferred SALM alternative will be equipped with a closed system to recover vapors displaced from the tanker during crude oil loading. The vapors displaced by the loading of crude oil will be compressed by a tanker-mounted motor driven transfer compressor.

From the tankers, the compressed vapors will travel to the onshore facilities via the SALM's and submarine pipelines. There they will enter the tank vapor blanketing system at the onshore tank storage facilities. Thus, the inclusion of the vapor recovery system in the marine terminal design will prevent the release of any marine tanker vapor emissions. With the SALM alternative, all tankers in dedicated service to the Getty Gaviota marine terminal will be equipped with vapor recovery systems and compressors compatible with the marine terminal system.

9.2.2.2.2 Fixed Pier Tanker Berth

The Fixed Pier tanker berth consists of two fixed platforms, located approximately 5000 feet from shore in 140 feet of water. The fixed platforms, providing two tanker berths, are connected to the end of a supply boat pier by a two-lane roadway trestle which would be approximately 4000 feet in length.

The platforms will be equipped with hydraulically operated steel loading arms, vapor return compressors, firefighting equipment, oil spill response equipment, cargo control rooms, and other items. Breasting dolphins to resist lateral movement of the tanker against the pier and mooring dolphins to which the tanker is secured with cables will be constructed on both sides of the platforms. The connecting trestle, in addition to the roadway, will support the piping and conduits.

The tanker berthing platforms will be supported on 42-inch diameter steel piles braced with 24-inch batter piles. The decks will be poured-in-place concrete with curbs.

A compressor for the displaced cargo tank vapors will be located in one corner of the pier, to provide the pressure to move the inert gas and hydrocarbon vapors from the pier to the shore tanks. The ability to locate the compressor on the pier, and properly capture displaced vapors from any and all tankers using the terminal, is one of the principal advantages of the Fixed Pier.

The two-lane roadway trestle, which connects the Fixed Pier tanker berths to the supply boat pier, will provide access for maintenance vehicles, trucks delivering stores to the ships, and shuttle buses for personnel transfer. The trestle will be constructed of pre-stressed concrete piles, and poured-in-place concrete pile caps. Pre-stressed girders, topped with poured-in-place concrete decking and curbs will span from one bent to the next to form the roadway.

A number of pipelines and conduits will go to each Fixed Pier tanker berth:

- 40 inch crude line
- 18 inch vapor return line
- 4 inch foam concentrate (fire fighting) line
- 12 inch fire water line
- 4 inch power conduit
- 2 inch communications conduit
- 3 inch oily water/surface runoff drainage return
- 3 inch vapor pressure relief line
- 4 inch diesel line
- 2 inch control conduit.

As the inert gas and hydrocarbon vapors are displaced from the tanker cargo tanks during loading, it is necessary to compress the vapors in order to pump them through the return without the overpressure in the ship's cargo tanks exceeding safe limits. The compressor on the pier will pressure the vapors, and pump them through an 18 inch vapor return line. With this system, no venting of cargo tank hydrocarbons will result.

9.2.2.2.3 Sea Island

A second tanker berth design alternative is the "Sea Island." The Sea Island design consists of the same two tanker mooring and loading platforms of the Fixed Pier design and in the same location, but the trestle/ roadway connecting the supply boat pier to the tanker loading platform is not present. Submerged pipelines will connect the Sea Island tanker loading platform with the supply boat pier.

At the tanker loading platform, the berthing of the tankers, construction of breasting and mooring dolphins, and design of the cargo control house, vapor return compressor, fire-fighting equipment, oil spill response equipment, etc.

will be the same as that described for the Fixed Pier. Since the Sea Island design alternative does not include the access roadway, all crew and stores transfered to the tanker would be by boat or barge. Return of displaced vapors and tanker fueling would be by subsea pipeline as in the preferred SALM design.

Pipelines to the Sea Island tanker loading platform will be carried from shore on the supply boat pier, and from the end of that pier the pipelines will be submerged, traveling along the ocean floor to the Sea Island loading platform. The number, size, and functions of the pipelines will be approximately the same as those described for the Fixed Pier.

Recovery of hydrocarbon and inert gas vapors displaced from the ship's cargo tanks during loading at the Sea Island will be done in the same way as with the Fixed Pier alternative. A compressor on the Sea Island loading platforms will pump the displaced vapors through the vapor return lines into the vapor blanketing system of the shore tanks.

9.2.2.3 Crude Oil Storage

A crude oil storage tank farm is an essential element of the Getty Gaviota Consolidated Coastal Facility. The tank farm will be located north of Highway 101 and east of the present Getty Gaviota site on the 84-acre Gervais Fee property. The site is on an elevated plateau between 135 and 190 feet above sea level at a minimum of 20 feet above Highway 101.

There are presently three existing storage tanks located on the Getty Gaviota property south of Highway 101. The three tanks will be relocated by Getty to the Gervais Fee property tank farm site to receive crude by truck from various production areas.

Two new storage tanks with a capacity of 500,000 barrels will be constructed initially at the new tank farm providing a storage capacity of 1,000,000 barrels of processed crude. An additional two to three tanks of similar size and capacity are scheduled for future construction as needs require. Thus, total storage capacity could be as much as 2,500,000 barrels.

Crude arriving from offshore platforms via pipelines will be processed by either Exxon (Las Flores), Chevron (Gaviota), or Arco (Ellwood) at their proposed oil processing facilities. Crude leaving the processing facilities will be pipelined to the Getty Gaviota tank farm for transhipment.

9.2.3 Southern California Coastal Pipeline

For several years, state and local agencies have considered the possibility of transporting all western Santa Barbara Channel crude oil to market via an onshore pipeline to the Los Angeles basin. In 1977, the Santa Barbara County Joint Industry/Government Pipeline Working Group was formed with the objective of investigating pipeline feasibility. The focus of the group was principally on engineering and economic feasibility of a pipeline. This group was subsequently supplanted by the Petroleum Transportation Committee, whose attention has primarily been directed toward pipeline economic feasibility considerations. A third group, the Coastal Pipeline Study Steering Committee (principally industry with some state representation), was formed in 1981. This group has been conducting engineering, economic, and environmental planning investigations relative to pipeline feasibility.

In all cases, these groups that have been or are studying pipeline feasibility considerations have reached no substantive or final conclusions on the economic and environmental feasibility of a pipeline. Instead, studies completed generally recommend that further investigations are needed either to develop better information or to explore considerations that were previously unknown or unanticipated (e.g., refinery retrofits and permitting feasibility).

9.2.4 Getty Gaviota to San Joaquin Valley Pipeline

Getty Trading and Transportation Company proposes, as a component of the Getty Gaviota Consolidated Coastal Facility, to construct and operate a pipeline connection from Gaviota to the San Joaquin Valley refinery/transportation network with a capacity range of 100,000 to 400,000 BPD.

Getty's proposed corridor for the pipeline will commence at the existing Gaviota marine terminal facility. The proposed corridor will utilize existing rights-of-way north through Gaviota Pass and continue north into the Cat Canyon area. The corridor will cross the Sisquoc River and enter the Los Padres National Forest at La Brea Canyon and exit the National Forest into the Cuyama Valley. At this point, the corridor will generally parallel State Highway 166 into Kern County and terminate in the southern San Joaquin Valley.

The proposed pipeline will be 20 to 30 inches in diameter. The exact diameter of the pipe will be determined at a later date when projected volumes become more defined. Initially there will be two pump stations. One pump station will be located at the Gaviota Marine Terminal facility and the second pump station near the southwest boundary of the Los Padres National Forest. A third pump station will be constructed in the Cuyama Valley when future increased volumes of oil become available from producers.

The pipeline is expected to be in essentially continuous operation. Its capacity will provide a pumping rate of up to 400,000 BPD, although the long-term average will be significantly below that level. With a single pipeline, and the possibility of several grades of crude oil requiring segregation, batching procedures will be used. The minimum batch size, to prevent unacceptable intermixing and to allow reception at the San Joaquin Valley end, will be about 50,000 barrels.

9.3 NATURAL GAS TRANSPORT

Treated natural gas will be transported via a new or existing pipeline from Chevron's Gaviota treating facility to a nearby utility company regional transmission pipeline. This regional pipeline is part of the overall southern California distribution network.

9.4 SULFUR AND NGL TRANSPORT

Sulfur and NGL recovered during gas treating operations will be transported by truck or rail to markets in the southern California area. Approximately 15 truck trips per day or 20 rail car trips per week will be required for transporting the total volumes.

TABLE IX-1

PHYSICAL AND OPERATIONAL CHARACTERISTICS OF TYPICAL TANKSHIPS

	30,000-DWT Class	40,000-DWT Class	60,000-DWT Class
Capacity (barrels)	210,000	280,000	420,000
Length (feet)	648	715	770
Beam (feet)	82	93	111
Loaded draft (feet)	35	37	40
Loading time (hours)	10	10	12
Peak calls per year (peak production year 1988)	80	60	40
Median number of calls per year	18	13	9

TABLE IX-2

TANKER FLEET MIX (ASSUMED) FOR THE GETTY GAVIOTA FACILITY

Tanker Size (DWT)	Percent of Fleet
31,000	2
37,500	32
42,500	5
47,500	10
52,500	34
57,500	2
62,500	2
67,500	5
72,500	7
73,000-300,000	1

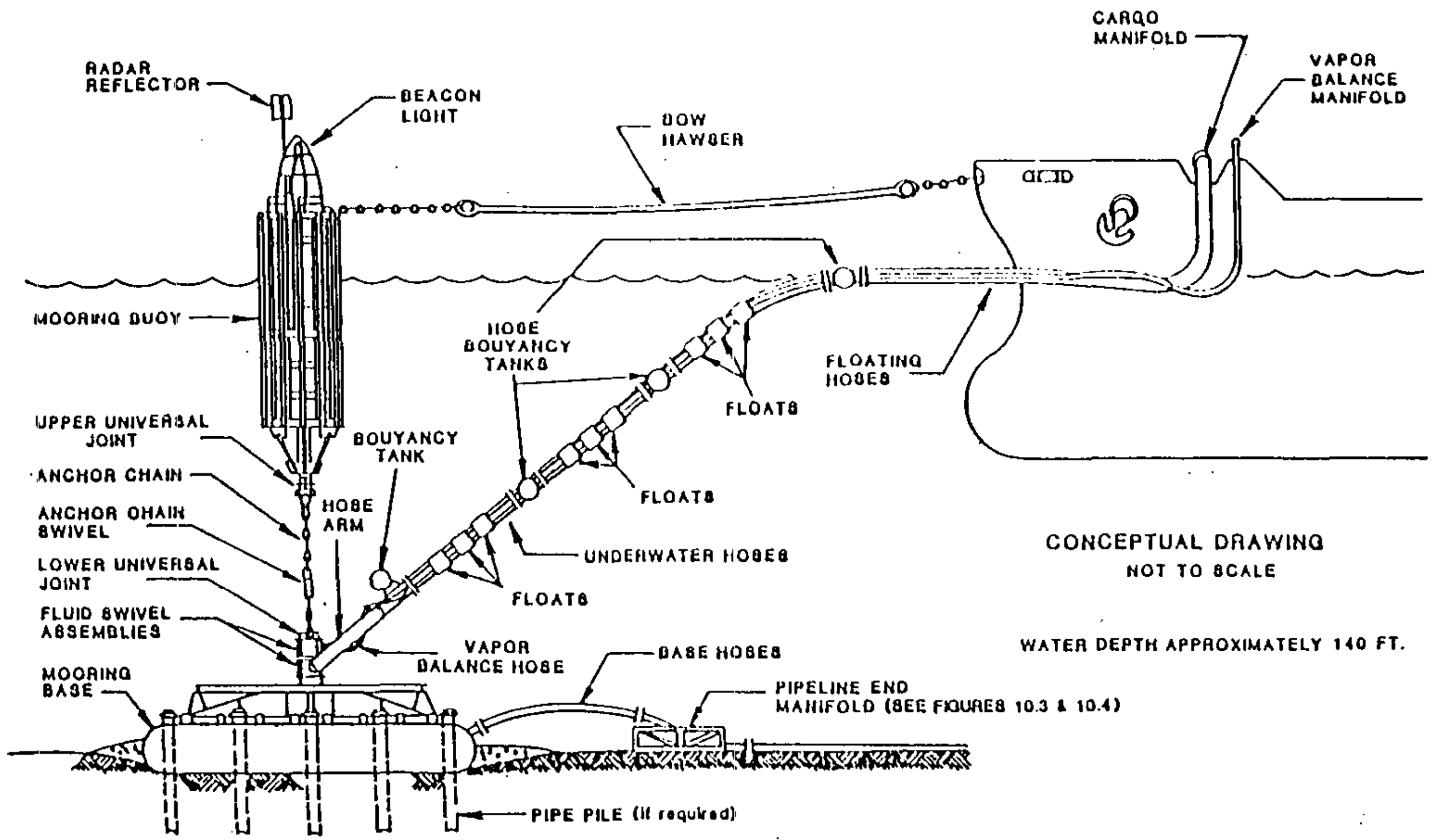
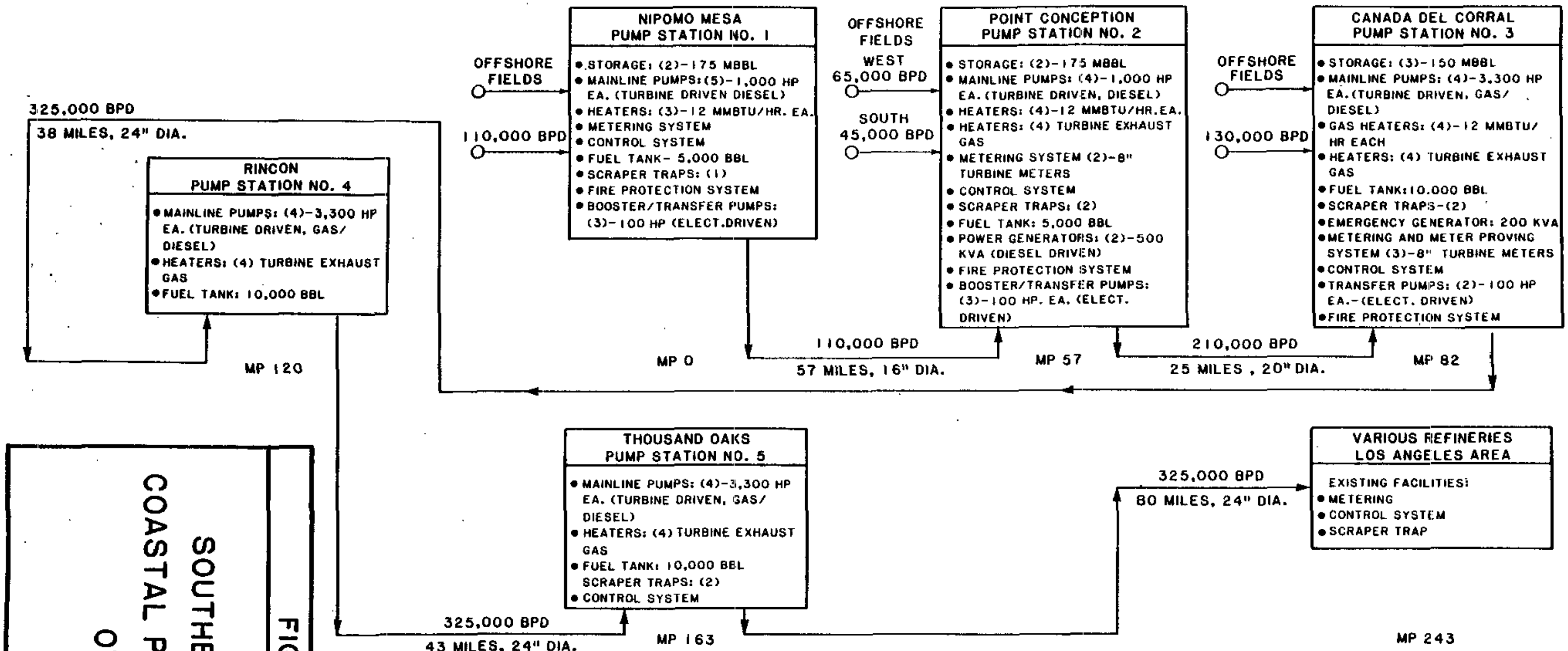


FIGURE IX-1

SCHEMATIC DRAWING OF EXXON'S PROPOSED SALM



NOTES:

1. INDICATED THROUGHPUTS ARE MAXIMUM.
2. PRODUCTION INPUT PEAKS IN DIFFERENT YEARS, THEREFORE SYSTEM THROUGHPUT CANNOT BE SUMMED.

FIGURE IX-2

SOUTHERN CALIFORNIA COASTAL PIPELINE FACILITIES OVERVIEW

SECTION X - TERMINATION AND ABANDONMENT

Upon cessation of production from Platform Harvest, all wells will be plugged and abandoned. Well control equipment equivalent to that used during drilling operations will be used during abandonment. Plugging and abandonment operations will be performed in conformance with MMS regulations (OCS Order No. 3) as discussed below, or in accordance with other regulations applicable at the time. The regulations for plugging and abandonment identify acceptable alternate abandonment procedures for various well conditions and specify tests to ensure that formations are isolated and that the well bores are left in safe condition.

Texaco will submit for approval a Form 9-331, Sundry Notices and Reports on Wells, containing the following information:

Notice of Intention to Abandon a Well. A detailed statement of the proposed work for abandonment of any well. For all wells, the statement will describe the proposed work (including by depths, the kind, location, and lengths of plugs) and plans for circulating mud, cementing, shooting, testing, and removing casing, and other pertinent information. The statement as to a producible well will set forth the reasons for abandonment, the amount and date of last production, and complete data from the last well test.

Subsequent Report of Abandonment. A detailed report of the manner in which the abandonment or plugging work was accomplished, including the nature and quantities of materials used in the plugging and the location and extent, by depths, of casing left in the well, and the volume of mud fluid used. If an attempt is made to cut and pull any casing string, a description of the methods used and results obtained will be included.

In uncased portions of wells, cement plugs will be spaced to extend 100 feet below the bottom to 100 feet above the top of any oil, gas, and fresh-water zones so as to isolate them in the strata in which they are found and to prevent them from escaping into other strata or the surface. The placement of additional cement plugs to prevent the migration of formation fluids in the well bore may be required by the MMS.

Where there is an open hole below the casing, a cement plug will be placed in the deepest casing string in accordance with "a" or "b" below. In the event lost circulation conditions have been experienced or are anticipated, a permanent-type bridge plug may be placed in accordance with "c" below:

a. A cement plug set by the displacement method so as to extend a minimum of 100 feet above and 100 feet below the casing shoe.

b. A cement retainer with effective back-pressure control set not less than 50 feet nor more than 100 feet above the casing shoe, with a cement plug calculated to extend at least 100 feet below the casing shoe and 50 feet above the retainer.

c. A permanent-type bridge plug set within 150 feet above the casing shoe with 50 feet of cement on top of the bridge plug. This bridge plug will be tested prior to placing subsequent plugs.

A cement plug will be set by the displacement method opposite all open perforations (perforations not squeezed with cement) extending a minimum of 100 feet above and 100 feet below the perforated interval or down to a casing plug, whichever is less. In lieu of setting a cement plug by the displacement method, the following two methods may be used, provided the perforations are isolated from the hole below:

a. A cement retainer with effective back-pressure control set not less than 50 feet nor more than 100 feet above the top of the perforated interval with a cement plug calculated to extend at least 100 feet below the bottom of the perforated interval and 50 feet above the retainer.

b. A permanent-type bridge plug set within 150 feet above the top of the perforated interval with 50 feet of cement on top of the bridge plug.

If casing is cut and recovered leaving a stub, one of the following methods will be used to plug the casing stub.

Stub Termination Inside Casing String. A stub terminating inside a casing string will be plugged by one of the following methods:

a. A cement plug set so as to extend 100 feet above and 100 feet below the stub.

b. A cement retainer set 50 feet above the stub with a volume of cement equivalent to 150 feet squeezed below the retainer and with an additional 50 feet placed above the retainer.

c. A permanent bridge plug set 50 feet above the stub and capped with 50 feet of cement.

Stub Termination Below Casing String. If the stub is below the next larger string, plugging will be accomplished in accordance with requirements for open holes described previously.

Any annular space communicating with any open hole and extending to the ocean floor will be plugged with cement. A cement plug at least 150 feet in length, with the top of the plug 150 feet or less below the ocean floor, will be placed in the smallest string of casing which extends to the ocean floor. The setting and location of the first plug below the surface plug will be verified by one of the following methods:

a. By placing a minimum pipe weight of 15,000 pounds on the cement plug, cement retainer, or bridge plug. The cement placed above the bridge plug or retainer need not be tested.

b. By testing the plug with a minimum pump pressure of 1,000 psi with no more than a 10-percent pressure drop during a 15-minute period.

Each of the respective intervals of the hole between the various plugs will be filled with mud fluid of sufficient density to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling the intervals between the plugs.

All casing, wellhead equipment, and piling will be removed to a depth of at least 5 meters (16 feet) below the ocean floor, or to a depth approved by the District Supervisor after a review of data on the ocean bottom conditions. Texaco will verify that the location has been cleared of all obstructions.

All equipment will be removed from the platform. The decks will be dismantled and transported to shore or an offshore site for disposal, salvage, or re-use. Jacket legs and pilings will be cut off at least 5 m (16 ft) below the mud line. The jacket will then be cut into sections for transportation to shore or to an approved offshore site where it may be disposed, salvaged, or made ready for re-use.

Any obstructions in the platform area will be removed from the ocean floor. The offshore pipelines will be purged and abandoned in place.