SUPPLEMENTAL PLAN OF OPERATIONS

SANTA YNEZ UNIT

HUMBLE OIL & REFINING COMPANY

UNIT OPERATOR

INTRODUCTION

TABLE OF CONTENTS

INTRODUCTION

INTRODUCTION

1. SCOPE AND OBJECTIVES

The Santa Ynez Unit Area was designated by the Director, Geological Survey, on September 11, 1970, and the Unit Agreement became effective on November 12, 1970.

Section 6 provides in part that within twelve months after the effective date of the Unit Agreement, the Unit Operator shall submit for the Supervisor's approval an acceptable Supplemental Plan of Operations which shall provide for the development of actual production from the unitized area, including construction of the initial production system and such related facil ities as may be necessary for drilling wells, and for producing, metering, storing and transporting Unitized Substances from the Unit Area.

Pursuant to Section 6 of the Unit Agreement, this Supplemental Plan of Operations has been prepared. Detailed designs and specifications for the construction, installation, and operation of the initial system necessary for initiation of actual production from the Santa Ynez Unit are presented.

These detailed plans, specifications, and locations of wells and facilities are based on data and estimates derived from 16 exploratory penetrations (13 wells and 3 redrills in

(Revised)

the vicinity of the Hondo Prospect. These wells have discovered and partially defined various productive reservoirs. The complete definition of the extent and producing characteristics of the reservoirs will depend on the results of additional drilling, reservoir and geologic studies, and the initial drilling and production from the proposed structure.

Platform design and fabrication studies indicate that at least 24 months will be required to construct and install the initial platform after all government approvals are obtained. Usual practice would dictate that many of the facilities be sized and designed during the time that approvals are being obtained and the platform is being constructed to take advantage of additional data which might become available during this period. Thus many of the designs presented in this Plan have been developed more than two years in advance of the normal timing, and without benefit of data which could become available before construction commences.

It is Humble's intention to continue research, design, and planning of the Santa Ynez Unit operations, utilizing all data available up to the time of construction. This effort, or changed conditions resulting from additional data obtained prior to construction, may dictate modifications to the systems and equipment described in the Plan. Approval of modifications to the Plan will be obtained as the need arises.

The Supplemental Plan provides a specific plan of operations for initiation of production. Timing over which this portion of the Plan will be effective is contingent in part upon the time which will be required (1) to obtain all necessary Federal, State, County and other governmental permits, approvals, and rights-of-way, and (2) to construct the necessary facilities and drill the wells. It is estimated that approximately three years will be required to complete the initial phase. Long Range Plans for additional facilities have also been projected as requested and are presented in more general terms.

The initial phase of the Plan consists of constructing and installing an 850-foot drilling production platform with a capacity for 28 well conductors on OCS P-0188, drilling the first 10 producing wells, and installing production facilities, pipelines, treating and storage facilities, and marine loading facilities. (Figure 1). The drilling of additional necessary wells is part of the LONG RANGE PLANS section of this Plan, and more detailed descriptions of these will be the subject of future Supplemental Plans.

The individual facilities described in this Plan will be owned and operated by Humble Oil & Refining Company, the Unit Operator, or by various affiliated corporations such as Humble Pipe Line Company. The detailed designs for these proposed facilities have been developed by Humble and affiliates and by prominent consulting firms and contractors under

Humble's direction. Some recognized members of the academic community have also contributed to the designs and analyses, particularly the fixed platform. These designs are discussed in detail in subsequent sections of this Plan and many of the outside studies are included as Appendices.

The construction and installation of the proposed 850-foot platform and the drilling of 10 wells represent a significant step in the development of the Unit, from the standpoint of both effort and investment. Implementation of subsequent steps discussed in the LONG RANGE PLANS section of this Plan is dependent on the geologic and production performance information gained from the initial wells and on future developments of equipment and techniques.

2. SUMMARY

2.1 Geologic and Reservoir

[redacted]

(Revised)

Reservoir Evaluation Section

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

[redacted]

2.3 Development Drilling

Approximately 1800 acres of the Monterey Chert reservoir will be developed from the platform. The initial program consists of drilling 10 wells from the 28-well 850-foot platform. Wells will be directionally drilled with conventional platform rigs. Average measured well depth will be approximately 11,000 feet with an average maximum deviation of about 40° from vertical. Conductors and well courses will be selected to provide adequate distances between well bores. Each well will be surveyed while drilling, and well courses will be monitored. Previously drilled exploratory wells demonstrate that no abnormal pressures will be encountered. All operating practices, blowout prevention equipment, and casing and completion programs will meet or exceed applicable regulations. A well control training facility has been established on the West Coast. This facility is being used to provide extensive well control training for key Company and contract personnel.

2.4 Platform Production Facilities

Facilities on the platform have been designed to initially handle daily production rates of 60,000 barrels of oil, 25,000 barrels of water, and 28 million standard cubic feet of gas. Well fluids will undergo three-phase separation on the platform for the removal of entrained gas and free water. Before final separation the crude will be heated to remove vapors. Produced water will be cleaned to USGS standards for ocean disposal. Gas will be dehydrated, compressed and delivered to shore for sale. Provision for gas reinjection is provided. Produced fluids will be kept in closed vessels. To prevent vapor emissions to the atmosphere, vessels and tanks will be equipped with vapor recovery systems. The platform decks will be equipped with drains and sumps. Collected fluids from the sumps will be recycled through the treating system. A central control room equipped with microwave, radio, and telephone communication systems will provide overall surveillance and control of all platform systems.

Trained operators with responsibility for operation of the platform and associated production equipment will be present on the platform. Electric power will be provided by submerged cable from shore or will be generated on the platform. If power is from shore, standby generators will supply emergency power capable of operating all electrical equipment necessary for the maintenance of safe operations. Automatic and manual safety systems will shut down all or part of the platform in the event of any one of a variety of alarm conditions.

2.5 Pipelines

A 16-inch oil line and a 12-inch gas line will be installed to transport treated oil and gas to shore. Nominal capacity is 80,000 barrels of oil per day and 90,000 Mcf of gas per day. Pipeline routes have been surveyed in detail using side scan sonar, subbottom profiling, jet coring and sea floor diver investigations. Pipeline stability design is based upon extensive oceanographic studies of storm and current characteristics. Both lines will be buried through the surf zone out to a water depth of 200 feet (13,000 feet from shore). Both lines will be installed through reverse J-tube risers. Pipe will be pulled from the platform through the J-tubes into shallow water for connection to a section of line laid from shore. Both pipelines will be protected against external corrosion by pipe coatings and cathodic protection systems.

The oil and gas pipelines will be operated and regularly inspected in compliance with USGS and Department of Oil Transportation regulations. Relief valves and high-low pressure shutdowns are provided. The oil pipeline safety system includes volumetric comparison of fluid-in versus fluid-out. Instantaneous data communication is provided by a specially designed microwave system. Operating parameters will be displayed to controllers in a control room onshore. Displays will include telemetered pressure at each end of each line, compressor and shipping pump operations on the offshore platform, and valve lineup information. Controllers can shut down either line and stop the offshore compressors and pumps in the event of any out-of-limit condition.

2.6 Onshore Facilities

Onshore treating and storage facilities will be located on a 15-acre site in Corral Canyon. This site is near the existing Capitan Oil Field, approximately 20 miles west of the city of Santa Barbara. The natural terrain, assisted by landscaping, will screen the site from view from

Highway 101. The site is designed to be compatible with the surrounding area and to provide an area sufficient for future expansion to the capacity of the inlet pipelines. Facilities have been designed to handle an initial daily throughput of 40,000 barrels of oil, 28,000 Mcf of gas, and 10,000 barrels of water. Provisions have been made for expansion to pipeline capacity of 80,000 barrels of oil, 90,000 Mcf of gas, and 20,000 barrels of water.

Oil facilities will separate water from the inlet crude stream and direct the oil to two 110,000-barrel storage tanks. The oil will be loaded on marine barges or tankers through an existing marine terminal, which will be modified. Treating will be accomplished in a system totally closed to prevent vapor emissions. Special cone-roofed tanks with internal floating roofs and a vapor recovery system will minimize vapor evolution from the stored crude. All vessels and tanks will be equipped with vent, relief or blow-down lines routed to a vapor incinerator. Water will be cleaned and injected into subsurface formations.

Gas handling facilities will separate a butane-plus product from the inlet gas stream. Hydrogen sulfide will be reduced to marketable sulfur through a Claus unit with an IFP tail-gas cleanup unit. The removal process will have an efficiency of 99%. The remaining 1% will be incinerated so that no hydrogen sulfide is vented. Sulfur and the butane-plus product will be temporarily stored and then trucked from the site. Residue gas will be sold to a natural gas pipeline customer at the site.

2.7 Marine Terminal

The marine terminal now serving the Capitan Oil Field will be modified for the loading of Santa Ynez crude into tug/barges or tankers approximately 3/4 of a mile offshore. The pump station and central control room will be located in Corral Canyon adjacent to the 110,000-barrel storage tanks. The system is designed to load 25,000 barrels of oil per hour into vessels as large as 25,000 dwt. The vessels will be moored to a Single Anchor Leg Mooring System (SALM) in 80 feet of water. The SALM is designed to permit loading operations in seas of up to 10 feet and winds of up to 40 mph. Onshore and offshore portions of the loading line will be buried and will be protected against external corrosion by a sacrificial anode system and external coatings.

An integrated system of flow control, monitoring, and automatic shutdown is provided. Flow rates and pressures, cumulative volume pumped, and barge tank levels will be monitored continuously during loading. Barge and terminal personnel will be in direct communication. Safety valves are located at the SALM, at the shoreline, and at the pump stations, enabling segmental system block-off. Automatic shutdown is triggered by excessive total flow or by high pressure. The shutdown system can be manually activated at any time by the control room operator, and will be activated if communication with the barge is lost during loading operations.

2.8 Offshore Storage and Terminal

Included as part of this Supplemental Plan is a floating treating and storage facility which Humble will install and use if required to expedite the commencement of production or to test producing wells prior to constructing onshore facilities.

A floating vessel of approximately 28,000 dwt and a Single Anchor Leg Mooring System (SALM) would be installed adjacent to the proposed pipeline route to shore. Production facilities installed on the vessel would separate emulsified water from the crude, direct the crude oil to the vessel storage tanks, and clean the water to USGS standards for ocean disposal. Treated crude would be offloaded to shuttle barges or tankers for transport to market. Produced gas would be re-injected at the production platform and/or delivered to sales through onshore facilities.

The mooring system is designed to safely moor the storage vessel in seas of up to 20 feet and winds of up to 75 mph. If it appeared that the mooring design limit would be exceeded, production operations would be shut down and the vessel released from the mooring and taken to a sheltered port. Offloading operations would be limited to 8 to 10 foot significant wave-height seas. Operational weather can be anticipated 90 to 96% of the time on an annual basis. Production facilities have been designed to handle an initial production rate of 40,000 barrels of oil and 10,000 barrels of water per day. A safety shutdown system includes fire and gas detection devices and four safety valves on the SALM.

2.9 Product Transportation

The primary vessel used to transport Santa Ynez Unit crude will be a linked tug/barge unit of 25,000 dwt or less, or tankers of similar size. A linked tug/barge is comprised of a barge notched in the stern with a tug fitted into the notch. The two vessels are securely linked together and operate as a single unit. These units will incorporate totally segregated ballast systems. Clean ballast water will be picked up in the discharge port and discharged at the loading terminal. There will be no internal cross-connection of cargo and ballast compartments. Cargo tanks will be equipped with remote-reading tank gauges and high-level alarms. Remote shutdown of cargo pumps will be provided. Biological wastes will be retained in a shipboard holding tank and discharged into treatment facilities at the discharge ports.

Crude demand and marketing patterns indicate that while there will be some local demand, the primary market will be in the Los Angeles-Long Beach Harbor area. The units will transit between the loading and discharge points using the recommended traffic lanes while entering and leaving the Santa Barbara Channel. The units will be equipped with loran, high resolution radar, bridge-to-bridge radio, and a gyro compass. Humble's deck officers will have pilotage for the Los Angeles-Long Beach Harbor area. Loading, transit, and discharge operations will follow regulations established by the Coast Guard and by state authorities.

2.10 Operating and Contingency Plans

Equipment and systems have been designed to provide maximum protection of the environment through the use of the best available technology, stringent design criteria, and local fail-safe monitoring and shutdown devices. Guidelines for operating practices have been defined with the specific goals of maximizing personnel and equipment safety and eliminating environmental pollution. The operating and surveillance plans provide an integrated procedure for monitoring and surveillance of all components of the production system, from the wellbore to the point of delivery to the refiner. This system is intended to clearly define responsibilities and to provide contingency plans which can be readily implemented in the event of abnormal conditions.

In the event of an oil spill involving Humble-operated facilities or vessels, Humble has developed a plan of action aimed at immediately remedying the cause of the spill and initiating cleanup operations. Humble has established an emergency organization and communications network. General procedures for emergency operations have also been established. Humble's personnel will maintain responsibility and coordination of the cleanup effort and will be assisted by personnel and equipment of Clean Seas, Inc. Clean Seas, Inc. is a nonprofit corporation funded by fifteen member oil companies operating in the Santa Barbara Channel.

Humble is also a member of industry organizations having response capability for spills at the Los Angeles and San Francisco discharge points for Santa Ynez Unit crude. These organizations include the Petroleum Industry Coastal Emergency Cooperative (PICE) in the Los Angeles-Long Beach area and Clean Bays, Inc. in the San Francisco area. In the event of a spill involving Humble-operated facilities, these organizations would be available to assist with the cleanup.

2.11 Submerged Production System

A Submerged Production System is currently under development. This system will provide for drilling and operation of well clusters at locations compatible with development requirements. Well operations and monitoring, through-flowline well servicing, and well fluid processing will be accomplished with the aid of a nearby platform. Drilling and major workovers will be accomplished by a floating drill ship. A system for manned and/or remotely controlled maintenance of the installation will be provided. A three-well prototype system has been constructed. This unit is currently undergoing land testing under atmospheric conditions and will then be tested in a water-filled pit. When development and final land testing are complete, the unit will be evaluated by

TRANSMITTED BY LTR 9/6/72 SUPERCEDES FOLLOWING PAGE 20

means of a simulated production test on land, or installation offshore in an existing producing area. The evaluation program selected will depend on the results of current land testing as well as the timing of the initial platform installation. Following successful testing of the Submerged Production System, it will be used in conjunction with fixed platforms to develop additional areas of the Santa Ynez Unit.

2.12 Long Range Plans

Location and timing of future Unit development will be influenced by the results of the initial development program. Studies based on wells drilled in the Hondo Area indicate there are three to five billion barrels of oil in place in the Monterey with an API gravity of 10° and above. The percentage volume which can be recovered will become more definitive as additional data are gathered and production history is obtained. In addition to the 10° API crude, there are substantial volumes of oil in the Monterey with gravities of less than 10° API and significant volumes of both oil and gas in the Miocene, Oligocene, and Eocene sandstone reservoirs.

Future operations will consist of drilling 18 additional wells from the 850-foot platform for further development of the Monterey Zone and the means of a simulated production test on land, installation offshore in an existing producing area, and/or installation under the initial Santa Barbara Channel platform. The evaluation program selected will depend on the results of current land testing as well as the timing of the initial platform installation. Following successful testing of the Submerged Production System, it will be used in conjunction with fixed platforms to develop additional areas of the Santa Ynez Unit.

2.12 Long Range Plans

Location and timing of future Unit development will be influenced by the results of the initial development program. Studies based on wells drilled in the Hondo Area indicate there are three to five billion barrels of oil in place in the Monterey with an API gravity of 10° and above. The percentage volume which can be recovered will become more definitive as additional data are gathered and production history is obtained. In addition to the 10° API crude, there are substantial volumes of oil in the Monterey with gravities of less than 10° API and significant volumes of both oil and gas in the Miocene, Oligocene, and Eocene sandstone reservoirs.

Future operations will consist of drilling 18 additional wells from the 850-foot platform for further development of the Monterey Zone and the sandstone reservoirs. Following completion of the drilling program from the first platfrom, which serves approximately 1800 acres, two additional facilities will be required on OCS P-190 to complete development of the remaining 3300 acre western end of the Hondo reservoir. These facilities will be a fixed platform located in 900-1000 feet of water to develop the northern flank of the structure plus a Submerged Production System located in up to 1500 feet of water to develop the southern structural flank. A Submerged Production System may be used in place of the 900 to 1000 foot platform, making the total Hondo Field development the 850 foot platform and two Submerged Production Systems. Production from Submerged Production Systems would be pipelined to the initial 850 foot platform.

Other exploration within the Santa Ynez Unit but outside the Hondo Field area indicate other significant accumulations of oil and gas. The Pescado Area discovery, located about eight miles south-southwest of the Hondo Field, was announced after drilling OCS P-0182-1 well which tested gas with a high liquid content from 250 feet of Eocene sandstone. The well produced 800 barrels per day from Miocene and Oligocene sandstone reservoirs plus over 1000 barrels per day combined rate from 1400 feet of Monterey siliceous zone. Flank well OCS P-0183-1 also tested oil from the Monterey siliceous zone. Although additional drilling will be necessary prior to finalizing development plans, a fixed platform in 1000-1200 feet of water or a Submerged Production System in conjunction with a surface support structure will be given consideration.

Another high potential for production is the Sacate Area, nine miles west of Hondo Field. Well OCS P-0193-1 tested oil from Oligocene sandstone reservoirs that totaled over 2200 barrels per day. Also, well OCS P-0195-2 directly to the west and on the same trend tested over 1000 barrels per day from Eocene and Monterey reservoirs. These potential hydrocarbon reserves are in water depths of 700-900 feet. This water depth indicates probable platform development; however, the Submerged Production System will also be considered.

GEOLOGIC AND RESERVOIR

TABLE OF CONTENTS

GEOLOGIC AND RESERVOIR

Reservoir Evaluation Section

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

TABLE OF CONTENTS

ONSHORE FACILITIES

ONSHORE FACILITIES

ABSTRACT

This section describes the onshore treating and processing site to be located in Canada del Corral (Corral Canyon) approximately 20 miles west of the city of Santa Barbara and adjacent to the existing Capitan Oil Field and Marine Terminal. The approximately 15-acre site will contain facilities to treat the produced oil in order to remove the emulsified water, storage facilities for the oil, disposal facilities for the water, and facilities designed to process the produced gas for sale.

INTRODUCTION

Facilities for the final treatment and storage of Santa Ynez Unit crude, and for processing the gas for sale are required. The proposed location for these facilities is in Las Flores Canyon, a small tributary of Corral Canyon about one mile north of the existing Capitan Oil Field. It is more than one mile inland from the coastline. Use of this particular site is contingent upon Humble's ability to acquire the surface acreage. In the event that the acreage cannot be acquired, the treating facility will be located on another suitable site in Corral Canyon.

Produced oil and gas will be delivered to the site by separate pipelines from the offshore platform. Facilities will provide oil treating and storage and gas treating, including recovery of sulfur and other products from the gas stream. Production rates used in the design of the oil facilities are 40 Mb/d initially, with expansion capability to 80 Mb/d. Design gas rates are 28 MMcf/d initially, with expansion capability to 90 MMcf/d. Pipelines installed initially will be capable of handling the higher production rates; however, site facilities will be installed in two or more phases.

The treated oil will be loaded onto barges or tankers through an existing marine terminal now serving the Capitan Oil Field. The barges or tankers will transport the oil to California refineries. The treated gas will be delivered to a natural gas pipeline customer at the site.

1. SITE DEVELOPMENT PLAN

1.1 Design Criteria and Objectives

Major objectives in the development plan for the onshore site are:

(1) Locate, construct and maintain an aesthetically pleasing site in a manner that will minimize its impact on the environment and on the surrounding area, and provide for maximum safety and pollution control.

(2) Develop a site area of sufficient size to accomodate expansion of the oil and gas facilities with minimum additional disruption of the surroundings.

Some of the criteria used in selecting the site location and in planning its development include:

(1) Locate the site near existing oil facilities and use an existing marine terminal, as favored by the Santa Barbara Oil Facility Policy.

(2) Locate the site in an area remote from large population concentrations.

(3) Provide a site area of approximately 15 acres.

(4) Design major drainage facilities to accommodate a 100-year flood.

(5) Design stable cut and fill slopes, considering potential landslides, earthquakes and rainfall.

(6) Provide erosion control and fire protection measures by means of grading, drainage and landscape plantings.

1.2 Location of the Site

The proposed site is located within the drainage area of Canada del Corral, 10 miles west of Elwood and 10 miles east of Gaviota. Corral Canyon is on the southerly flank of the Santa Ynez Mountains and extends approximately five miles in a north-south direction from the mountain ridge to the Santa Barbara Channel. It is almost perpendicular to Highway 101, which traverses its seaward end. A small, normally dry canyon called Las Flores branches into Corral Canyon about one mile north of the shoreline.

As shown on the aerial photographs (Figures 1 & 2), the lower portion of Corral Canyon includes a lemon grove cultivated on 9.2 acres of the bottomlands north of U.S. Highway 101. The westerly portion of the Capitan Oil Field is situated within, and to the north of, this grove. The remainder of Corral Canyon is primarily used for cattle grazing.

Several different areas within Corral Canyon were investigated as possible sites for the oil and gas facilities. After investigating the advantages and disadvantages of each site, the one referred to as Site D in various reports, and in this Plan, was selected. This site is discussed in a report (coordinated by Humble) by Penfield & Smith entitled "Site Improvement Report, Onshore Facilities-Corral Canyon, Site D" (Appendix 4.4).

Site D is located within Las Flores Canyon several hundred feet upstream from its confluence with Corral Canyon (Figure 3). The high ridges and tall trees in the lower reaches of Corral Canyon tend to screen this site from view along Highway 101. The Los Padres National Forest occupies most of the Santa Ynez Mountains to the north of the site.

Geologic conditions in the lower two miles of Canada del Corral are discussed in an independent study by Geotechnical Consultants, Inc., entitled "Geotechnical Feasibility Investigation, Proposed Petroleum Treating and Storage Facility, Corral Canyon Site D, County of Santa Barbara, California" (Appendix 4.3). Site D was found to be a good location with respect to geological conditions. Two faults were noted in the canyon, but they are located a considerable distance from the site. These faults appear not only to be inactive at the present time, but probably have not been active for a span of millions of years (Appendix 4.3). Potential landslides in the vicinity of the site do not pose a serious hazard.

1.3 Layout of the Site

1.3.1 Earthwork

In general, the site will be constructed by excavating the Vaqueros and Rincon formations at the northerly end of the location to create a relatively level surface for the facilities. A site with an area of approximately 15 acres will be constructed. Some 500,000 cubic yards of excavated material will be used to fill and build up a level area within Las Flores Canyon. The fill will buttress the natural slopes on both sides of the canyon.

1.3.2 Drainage

Drainage will be conducted through most of the site in a closed conduit. The contributory drainage area for this culvert is approximately 680 acres. Using rainfall data from the County Flood Control Department, either a 96-inch concrete pipe culvert or a 7 x 8 foot concrete box culvert would accomodate a 100-year storm. Drainage from the slopes immediately adjacent to the site will be intercepted, conducted around the site and directed into Las Flores Creek by ditches and conventional storm drains.

1.3.3 Slopes

The south facing cut slope in the Vaqueros formation will have a maximum height of approximately 100 feet with an inclination of 2 horizontal to 1 vertical. The east facing cut slope in the Rincon formation will have a maximum height of approximately 130 feet with an inclination of 3 horizontal to 1 vertical. Maximum height of the compact fill will be approximately 50 feet, with side slope inclinations of 2 and 3 horizontal to 1 vertical. Benches and berms in the cut and fill slopes and keyways for the fill slopes will be provided as needed. Subdrains will be installed to collect and discharge water wherever it is encountered and wherever it is anticipated.

1.3.4 Fills

The compacted fill will be placed in accordance with the local grading ordinance. A minimum fill compaction of 90 percent, relative to the maximum dry density determined by standard testing methods, will be obtained. Cut materials will be excavated, placed in layers and compacted. No blasting will be required. Expansive soils will not be used in the top several feet of the fill. Instead, fills will be topped off with sandstone from the Vaqueros formation.

1.3.5 Roads and Pipelines

An access road with a sound structural roadbed, a minimum width of 20 feet, surfacing, and adequate drainage facilities will be constructed. Double 12' x 10' reinforced concrete box culverts will be provided if the road crosses Corral Creek.

Pipelines from the offshore production facilities will come to shore at the southerly end of an existing easement across the narrow coastal strip of land south of the Southern Pacific Railroad. The pipelines will extend north through a boring made under the railroad and U.S. Highway 101 and then follow the access road to the site. Other pipelines will carry treated oil and gas back down the canyon for transportation to market.

1.3.6 Water Supply and Utilities

Ground water will be used as the water supply for processing facilities, domestic needs, landscaping and fire fighting. The additional withdrawal of about 20 acre-feet per year from the water table will not adversely affect existing water uses or natural vegetation in Corral Canyon.

Electrical power and telephone lines exist in the area of the Capitan Oil Field, and service lines to the site will be installed underground along the same route as the pipelines.

Sewage will be disposed of by means of septic tanks and subsurface leaching. Percolation tests will be conducted in the area prior to final design of the disposal system. Approval of the County Health Department will be obtained.

1.3.7 Landscaping and Fire Protection

Landscape development will consist of an irrigation system, screen planting of large trees to conceal the facilities, erosion control planting, and naturalistic groupings of native shrubs and trees to blend in with the surrounding natural slope cover.

All native brush will be removed from within 50 feet of the road surrounding the facilities and will be replaced with fire resistant ground cover, trees and shrubs and watered by a sprinkler system. To allow the wetting down of an additional buffer zone in case of emergency, an additional water sprinkling system will be installed on the periphery of the planted area surrounding the site.

Screen planting at the narrow entrance to the facilities and intermediate screen planting at the storage tanks will consist of 25-foot tall Monterey and Aleppo pines, backed up by 5-gallon eucalyptus globules. Native shrubs will provide a lower, fill-in screen to augment the trees. All slopes will be stabilized by hydromulching with a slurry of water, mulch, and stabilizer, plus some seeds of drought-tolerant native flowering plants. The Uniform Fire Code and local codes have been used in the design of the site. Earth dikes, restricted to an average height of six feet above the interior grade, will surround the storage tanks. Layout of the facilities and roads will provide convenient access to the site in case of emergency. The main fire fighting system itself is discussed in Section 4.

1.3.8 Air Quality Studies

To establish a baseline for certain environmental factors, an independent preliminary field survey of Corral Canyon was made by Metronics Associates, Inc. Their report entitled "Preliminary Environmental Base Line Survey of Corral Canyon Site, Santa Barbara County, California" discusses the results of the study (Appendix 4.1).

A second Metronics study utilized air tracers to define the depth and trajectories of the canyon and coastline air flows. The report of this study, entitled "Airflow Tests at Santa Barbara, California," is found in Appendix 4.2.

The studies conducted by Metronics demonstrate that operations of the kind contemplated for this site will meet all applicable California air quality standards.

2. OIL FACILITIES

2.1 Design Criteria and Objectives

Objectives considered in design of the oil treating and storage facilities are as follows:

(1) Remove the water from the produced crude oil before transporting to market.

(2) Provide centralized control of facilities and automatic alarms and shutdowns on critical equipment and systems.

(3) Provide a vapor-free operation.

Criteria used in the design of the facilities include the following:

(1) Initial design crude oil rate: 40,000 b/d

With expansion capability to: 80,000 b/d

(2) Initial design water rate: 10,000 b/d

With expansion capability to: 20,000 b/d

(3) Produced crude oil properties:

Composition	Mol%
Methane	.08
Carbon Dioxide	.06
Ethane	.38
Hydrogen Sulfide	.08
Propane	1.67
i-Butane	.53
n-Butane	3.61
i-Pentane	.67
n-Pentane	.84
Hexanes	3.98
Heptanes	4.08
Octanes	4.59
Nonanes	3.61
Decanes	5.03
171 MWT Fraction	12.91
238 MWT Fraction	8.25
303 MWT Fraction	49.63
Total	100.00

Sulfur Content, maximum (including light mercaptans) 4 percent by weight

Specific Gravity @ 60°F 0,920 - 0.945

(4) Producted Water Properties:

Specific Gravity @ 60°F 1.019

Salinity 19,800 mg/liter (NaCl)

(5) Storage capacity for 5 day's production of treated oil and for 10,000 barrels of waste water.

2.2 Description of Major Equipment and Systems

2.2.1 Layout

Details of the oil facility are described in a report (coordinated by Humble) prepared by Stearns-Roger entitled "Engineering Study for Crude Oil Treating and Storage Facility, Santa Barbara Channel" and dated August, 1971 (Appendix 4.5).

The general layout of the oil treating and storage facilities is shown in Appendix 4.5 on Stearns-Roger Sheet No. 00-2-01 and on Figure 4. A block flow diagram of the facilities (Figure 5 and Sheet No. 00-1-01 in Appendix 4.5) shows the various major items of equipment, which are identified by letters and numbers. The use of this equipment is explained in following discussions of various subsystems.

2.2.2 Oil Handling and Storage

A mixture of emulsified crude oil and free brine is delivered from the offshore platform to the 10,000 barrel inlet crude surge tank (T-1) at the onshore site. After exchange of heat with the treated crude in the crude oil exchangers (E-1), the crude oil emulsion is fed to the electric treaters (S-1).

Each treater is operated at a pressure of 75 psia in order to prevent the formation of a vapor phase. The crude oil is degassed at atmospheric pressure prior to onshore treating at a temperature of 105-120°F to produce a crude oil vapor pressure of approximately 20 psia at 180°F. Therefore, at the treater operating pressure of approximately 75 psia, there will be no vapor evolution.

Crude oil leaving the treater is cooled by heat exchange with the crude feed in the crude oil exchanger (E-1). The crude is further cooled to 95°F storage temperature by the air cooler (A-2). The treated crude is then stored in the 110,000-barrel tanks (T-2) at atmospheric pressure. These storage tanks have a cone roof and an internal floating roof. Each tank is equipped with an atmospheric air breathing valve with vent vapors directed to the gas disposal system. In this system, no tank breathing vapors are emitted without passing through the incinerator (H-1)

The treater blow-off flows from the blow-off cooler (A-1) to the blow-off drum (V-1). Crude oil from the blow-off drum is then pumped to a rerun tank (T-3). The entire blow-off handling system is designed to prevent any release of vapors to the atmosphere in an emergency situation. Any vapors generated during blowoff will enter the crude treating vent gas disposal system.

Metering of the oil for sale is discussed in the MARINE TERMINAL Section.

2.2.3 Water Handling and Storage

Separated brine from the crude storage tank (T-1) and the electric treaters (S-1) flows to the 10,000 barrel dirty brine storage tank (T-4). Periodic drawoff of any accumulated free oil from this tank is accomplished by manipulation of oil skimming lines within the tank. The brine phase, having 200-300 ppm of total oil, is then pumped to the filter-coalescer (S-2). The coalesced oil flows to a settling basin (S-3) and the brine phase flows to the 1,000-barrel injection brine storage tank (T-6). Injection pumps (P-5) take suction from this tank and discharge into the injection line at 1,500 psig. The brine is then disposed of by subsurface injection.

Provision is made for high rate backwashing of the filter-coalescer with water from the dirty brine storage tank. Backwash brine pumps (P-8) and the 1,500-barrel backwash brine holding tank (T-5) are used for disposal of the backwash water. Backwash brine, coalesced oil, skimmed oil from the dirty brine storage tank and all streams which enter the closed drain system are fed to the settling basin (S-3). This is a covered basin operating under a gas blanket. Brine is pumped out of this basin to the dirty brine storage tank for reprocessing. Accumulated oil overflows an internal weir into an oil sump and is pumped to the rerun tank (T-3). Solids which accumulate at the bottom of the basin are periodically removed by a vacuum truck and trucked to solids disposal.

All tanks and vessels are closed and operated under a natural gas blanket. Vapors displaced during treating are released to a closed vent system and eventually pass through the vent vapor incinerator (H-1). All drains from tanks, vessels and pumps are piped to a closed drain system which discharges into the brine settling basin (S-3). This closed system eliminates the discharge of brines and sour crude oil into the surface storm drain system.

3. GAS FACILITIES

3.1 Design Criteria and Objectives

Objectives considered in the design of the gas treating facilities are as follows:

(1) Process the produced gas for sale by extracting butane and removing carbon dioxide and hydrogen sulfide.

(2) Provide centralized control of facilities and automatic alarms and shutdowns on critical equipment and systems.

(3) Provide for minimum vapor emission.

Criteria used in the design of the facilities include the following:

(1) Initial design gas volume: 28 MMscf/d
Expansion capability up to: 90 MMscf/d

(2) Inlet conditions:

Component	Initial Gas Mol%	Future Gas Mol%
Nitrogen	0.09	0.52
Hydrogen Sulfide	0.80	0.35
Carbon Dioxide	7.30	3.23
Methane	68.95	78.41
Ethane	9.19	8.27
Propane	8.17	5.64
i-Butane	0.94	0.74
n-Butane	3.66	2.11
i-Pentane	0.22	0.21
n-Pentane	0.28	0.21
Hexane	0.25	0.17
Heptane-plus	0.15	0.14
	100.00	100.00

Pressure: 915 psia

Temperature: 60°F

Mercaptan content: 500 ppm Initial

200 ppm Future

Heptane-plus characteristics:

Molecular weight: 100

Specific gravity: 0.732

(3) Residue gas specifications:

Delivery pressure, minimum	850 psia
Carbon dioxide, maximum:	3% by volume
Hydrogen sulfide, maximum:	1 grain/100 scf
Total sulfide, maximum:	20 grains/100 scf
Heating value, minimum:	1,000 btu/cf (gross saturated)

(4) Minimum of 3-days product storage and 5-days sulfur storage.

(5) Recover 99% of the inlet hydrogen sulfide as sulfur.

3.2 Description of Major Equipment and Systems

3.2.1 Layout

Details of the gas facility are described in a report (coordinated by Humble) prepared by Stearns-Roger entitled "Engineering Study for Gas Processing Facility, Santa Barbara Channel" and dated August, 1971 (Appendix 4.6).

The general layout of the gas facilities is shown on Stearns-Roger Sheet No. X00-2-01 in Appendix 4.6.

3.2.2 Gas Facilities Description

Block flow diagrams on Figure 6 and in Appendix 4.6 show the interconnection of the principal process units and their product rates, both for the initial and future phases of production. The hydrocarbon recovery and fractionation facilities are considerably expanded for the future plan along with their support systems, such as refrigeration. A brief summary of the specific process units follows, with volumes referenced to the initial design volume.

The inlet gas facilities are designed to provide stable flow of a single phase vapor to the gas treating plant. Major equipment includes an inlet separator (slug catcher), a low-pressure condensate separator and a heat exchange system to revaporize liquids condensed in the offshore gas line.

The initial gas treating facility is a single-train diethanolamine (DEA) plant designed to remove hydrogen sulfide and carbon dioxide from the inlet gas. DEA removes H_2S and CO_2 by reacting reversibly with these acid gases in a water solution. The H_2S and CO_2 absorbed chemically in the DEA solution are driven out of the solution by heating the DEA to a high temperature at low pressure. The exit streams from the DEA plant are sweet gas at high pressure and acid gas at low pressure. The circulation rate of the aqueous DEA solution is 412 gallons per minute when treating 28 MMcf/d of inlet gas. The acid gas rate to the sulfur plant is 3.4 MMcf/d. Major items of equipment required in this process are the high-pressure amine contactor, amine still, amine high pressure and booster pumps, and amine reboiler.

The sulfur recovery facilities are designed to convert 99% of the inlet H_2S in the DEA plant acid gas stream to liquid sulfur. Sulfur recovery will be 8.4 long tons per day containing 0.80 volume percent H_2S. The sulfur stream consists of a split flow, three converter Claus units and an IFP tail gas clean-up unit. The Claus unit converts H_2S to sulfur by a gas phase reaction over a dry bed catalyst. The IFP process is a proprietary method utilizing a liquid organic solvent and a catalyst to dissolve H_2S and SO_2 remaining in the Claus unit tail gas and to continue the reaction of H_2S

and SO_2 to sulfur. Gas from the IFP contactor flows to a forced-draft incinerator. There the remaining sulfur compounds are incinerated at 1000°F with 25 to 30% excess air prior to venting through a 100-foot high stack. Major items of equipment in the sulfur process are the SO_2 generator and waste heat boiler, the three section sulfur converter, sulfur condensers, sulfur pit, IFP contactor, and tail gas incinerator. The recovered molten sulfur will be transported from the site by truck.

The hydrocarbon recovery facilities are designed to remove butane from the treated inlet gas prior to final metering and delivery of residue gas to a gas transmission company. It is necessary to remove these liquids from the gas to prevent condensation in transmission and distribution lines. The facilities are designed to recover 960 b/d of a butane mix from 25.6 MMcf/d of treated gas. Residue gas from the hydrocarbon recovery unit will be 23.4 MMcf/d of completely conditioned gas meeting sale gas specifications. Liquids are removed through mechanical refrigeration of the inlet gas to 0°F followed by depropanization of the raw liquids. Principal items of equipment in the hydrocarbon recovery area include gas chilling heat exchangers, a depropanizer fractionator, a propane refrigeration unit, a glycol injection unit, a chiller separator, and a low pressure gas recompressor.

The butane product from the hydrocarbon recovery area will be stored in two 90,000-gallon pressurized storage vessels. Approximately four-days storage will be provided by the two vessels. Product will be shipped by trucks, and a loading rack, metering facilities and shipping pumps are provided.

The plant fuel gas system is designed to provide sweet fuel gas from in-plant sources. For start-up and emergency make-up, fuel gas will be taken from the sales gas pipeline.

Two flare headers, one high pressure and one low pressure, terminate at a vessel designed to remove any entrained liquids prior to burning the gas in a smokeless flare tip. Normal operation will require no flaring of gas and the smokeless flare tip is for upset safety release of pressurized vapors. Plant equipment operating near atmospheric pressure, including all drain sumps, will vent gas into the sulfur plant tail gas incinerator. Other plant systems described by Stearns-Roger include steam and water, drains, electric power, general plant utilities, fire protection, and emergency shutdown.

3.2.3 Environmental Quality Control

Disposition of the separated hydrogen sulfide is the major plant design specification for pollution control. By using both the Claus and IFP units, 99% of the hydrogen sulfide removed from the inlet gas will be recovered as liquid sulfur. The remaining 1% of unrecovered sulfur compounds will be incinerated to sulfur dioxide before being vented from a stack. No hydrogen sulfide will be vented. The normal emission of sulfur dioxide from the incinerator stack will be less than 12 lbs. per hour at an exit concentration of 370 ppm.

Additional design features include closed drain systems for blow-down of such items as liquid level control and incineration of resultant vapors, incineration of all acid streams released by safety relief valves, a smokeless emergency flare stack, exclusive use of sweet gas for process fuel, and vapor return for product loading.

Other aspects of the overall gas handling system will also serve to reduce the possibility of air pollutant emissions. The plant is provided with inlet block valves that may be activated by the plant operator to completely shut off flow of produced gas to the plant. The butane product is stored under pressure at a temperature of 105°F, eliminating the need for refrigeration to maintain a liquified product. Loss of the plant refrigeration system will not result in product flaring.

All waste waters from the plant process units will be collected in drain systems and delivered to the water injection unit at the crude oil facilities. The quantity of water used in the plant has been reduced to a very low level (1.5 gallons per minute) through the use of air cooling and direct-fired heaters.

4. FIRE PROTECTION SYSTEM

Separate, but interconnected, firewater loops will be provided for the oil facilities and the gas facilities. Both loops will draw water from a single 20,000 barrel fresh water storage tank located in the northeast corner of the gas facilities area. Two centrifugal pumps will provide pressure for the gas facilities and oil facilities areas. Both pumps will provide 125 psi discharge pressure, and either pump will be able to supply water to either loop. The locations of fire mains, hydrants, and other fire system elements are shown on Drawing No. 22070, Sheet No. 00-2-02 in Appendix 4.6, and Drawing No. 22071, Sheet No. 00-2-02 in Appendix 4.5.

The firewater loops are supplemented by foam generation facilities located to allow foam blanketing of the diked crude storage area. Numerous hand and wheeled dry chemical fire extinguishers will also be located throughout the site.

5. CENTRAL CONTROL AND EMERGENCY SYSTEMS

A central control room is provided to control the oil and gas facilities. Operating variables, such as pressures, temperatures, flow rates and levels from various units will be transmitted to the control room for display. The operator will have a complete current status picture before him and will be able to make necessary adjustments.

Alarms will call operator attention to abnormal conditions The alarm units are set to allow sufficient time to determine the proper action necessary to either diagnose the abnormality or to order the facility shut down. Emergency power in the event of a primary power failure is provided by a diesel generator and battery-inverter systems.

The system is designed to provide local equipment shutdowns while allowing as much as possible of the facility to remain in service. Although emergency shutdown can be initiated by the operator, certain units and individual pieces of equipment will also have their own safety shutdown systems. These will include flame failure shutdown systems on fired equipment, vibration shutdowns on fans for aerial coolers and low level pump shutdowns in suction vessels.

The emergency shutdown function is detailed on Stearns-Roger Drawing No. 22070, Sheet No. 00-1-25 in Appendix 4.6 (Figure 8) and on Drawing No. 22071, Sheet No. 00-1-15 in Appendix 4.5 (Figure 6). Listed on these sheets are the alarm units, the events causing shutdown and the actions taken during an emergency.

6. CONSTRUCTION OF FACILITIES

Construction of the oil and gas facilities is discussed in the previously referenced Stearns-Roger reports (Appendices 4.5 and 4.6). Preliminary project schedules indicate that approximately 7 months of field work with an average labor force of 85 men will be required for construction of the oil facilities, and that approximately 8 months of field work with an average labor force of 65 men will be required for the gas facilities. Efforts to minimize the environmental impact of construction work will include trash disposal in accordance with County rules, dust control measures, and procedures to minimize noise levels at surrounding property boundaries.

7. OPERATION OF FACILITIES

After construction of the facilities has been completed, all equipment will be subjected to comprehensive testing procedures. A carefully planned start-up procedure will be used to minimize plant upsets experienced during start-up operations. All significant process variables will be transmitted to the central control room where operating personnel will evaluate the plant performance, make necessary adjustments, and shutdown and bypass various units, or completely shutdown the entire plant through use of the emergency shutdown system.

Loading of liquid butane product will be required only during the day shift for five days per week. Sulfur loading should be required only one day per week. Emissions to the air will be limited to the products of combustion of 970 Mcf/d of sweet natural gas burned as plant fuel and 12 pounds per hour of sulfur dioxide from the incinerator. Except for normal rainfall or incidental landscape water, no water will be discharged to surface drainage.

Operating and contingency plans for the onshore site and facilities are discussed in detain in the OPERATING AND CONTINGENCY PLANS Section of this Report.

Figure 1
LOOKING WESTERLY ALONG SANTA BARBARA CHANNEL COASTLINE

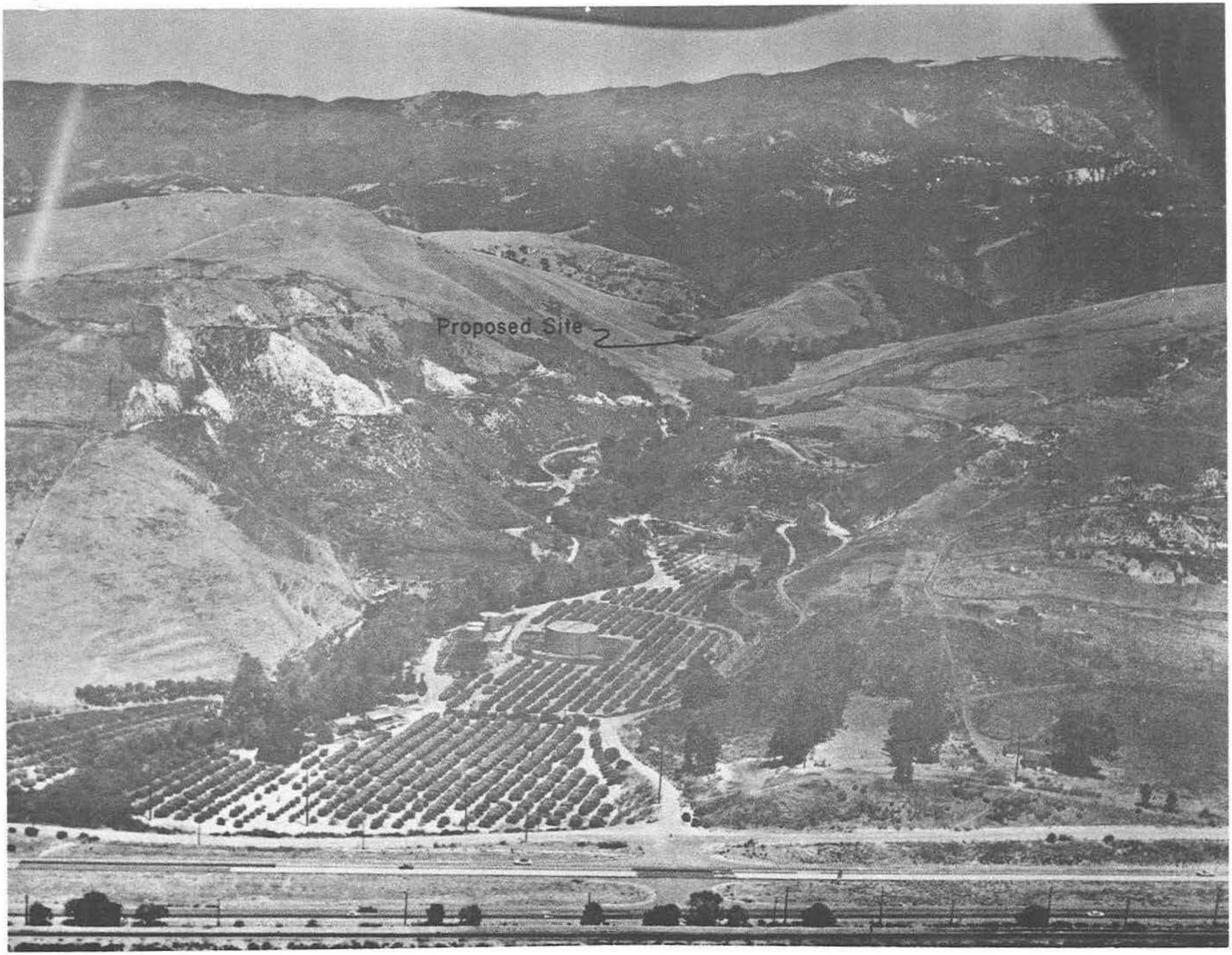
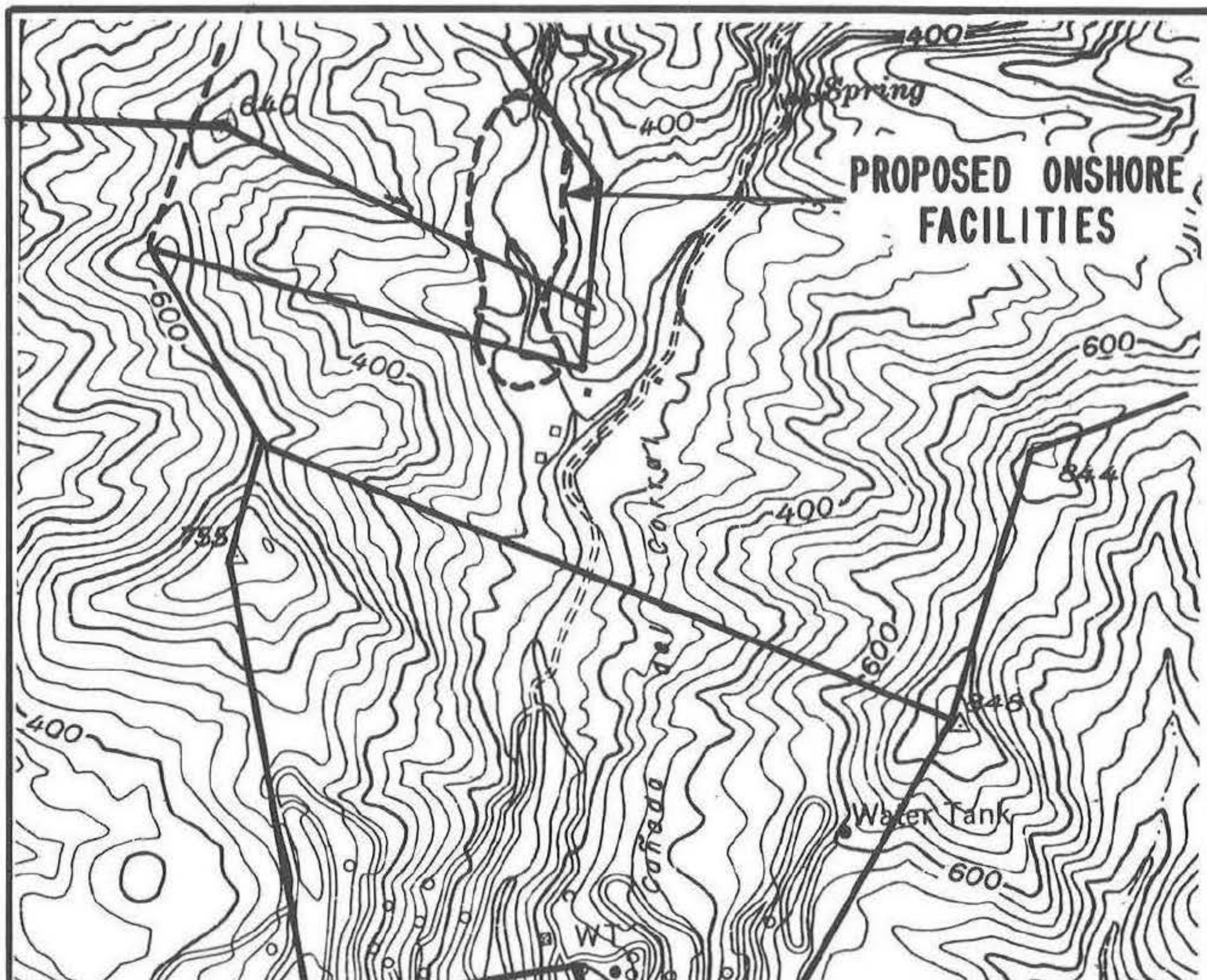


Figure 2

LOOKING NORTHERLY UP CANADA DEL CORRAL



SITE PLAN

SCALE

500' 0 500' 1000' 1500'

Figure 3

ONSHORE SITE PLAN

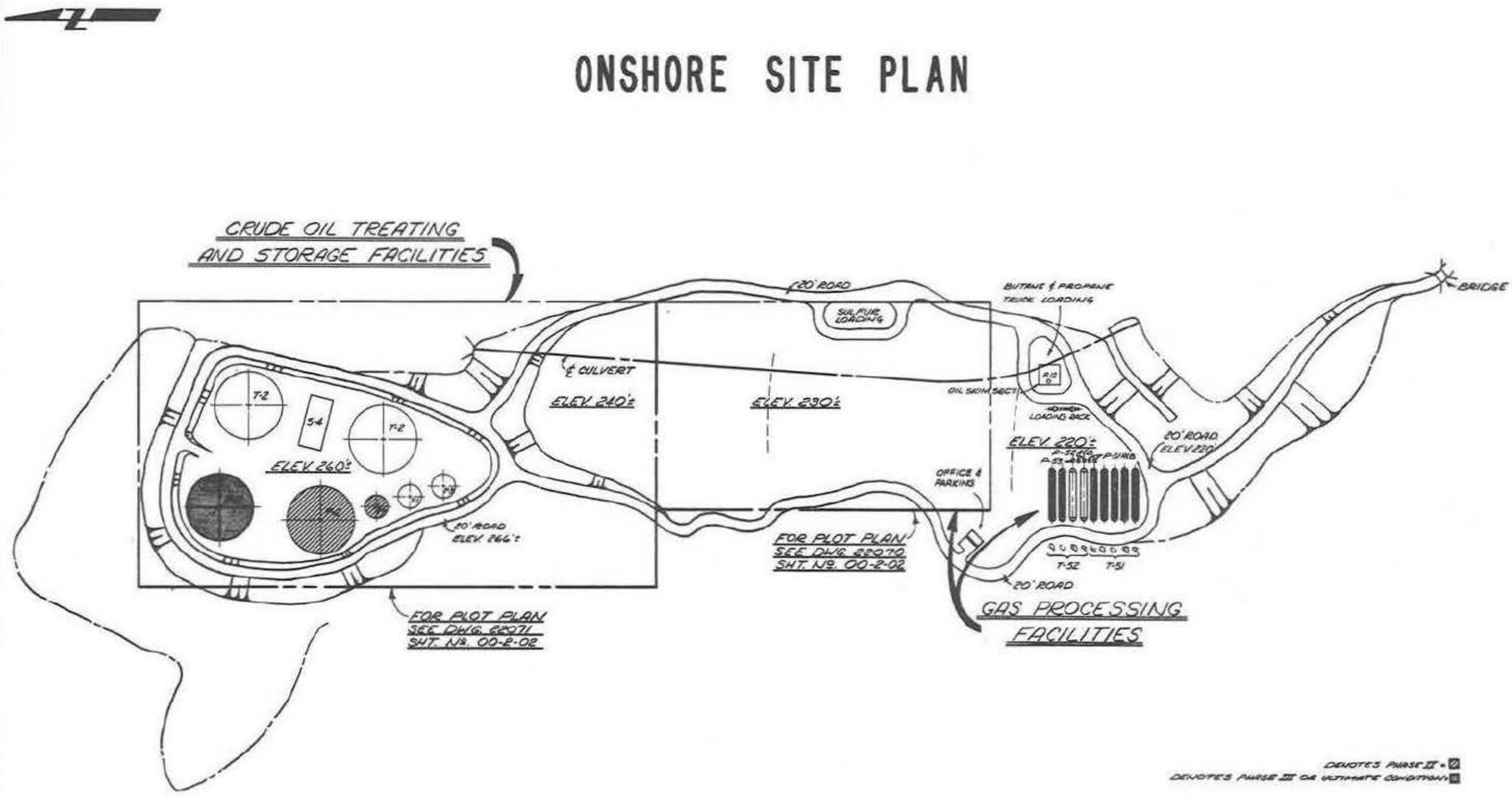


Figure 4

Ref. S-R DWG 22071 Sheet 00-2-01

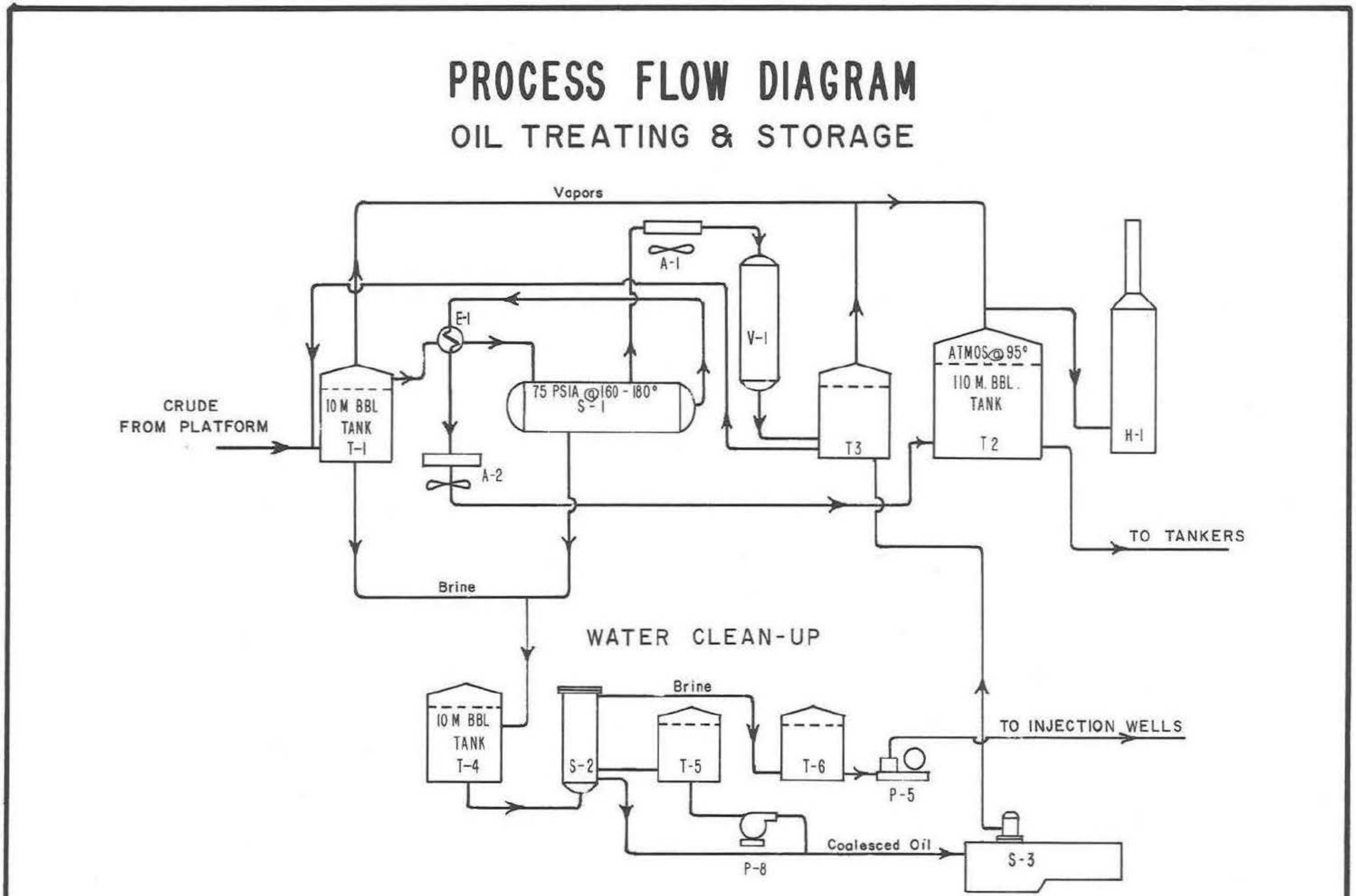

PROCESS FLOW DIAGRAM
OIL TREATING & STORAGE
Vapors
A-1
E-1
V-1
ATMOS @ 95°
110 M. BBL. TANK
T 2
H-1
CRUDE FROM PLATFORM
10 M BBL TANK T-1
75 PSIA @ 160 - 180°
S - 1
T3
A-2
TO TANKERS
Brine
WATER CLEAN-UP
Brine
10 M BBL TANK T-4
S-2
T-5
T-6
P-5
TO INJECTION WELLS
Coalesced Oil
P-8
S-3

Figure 5

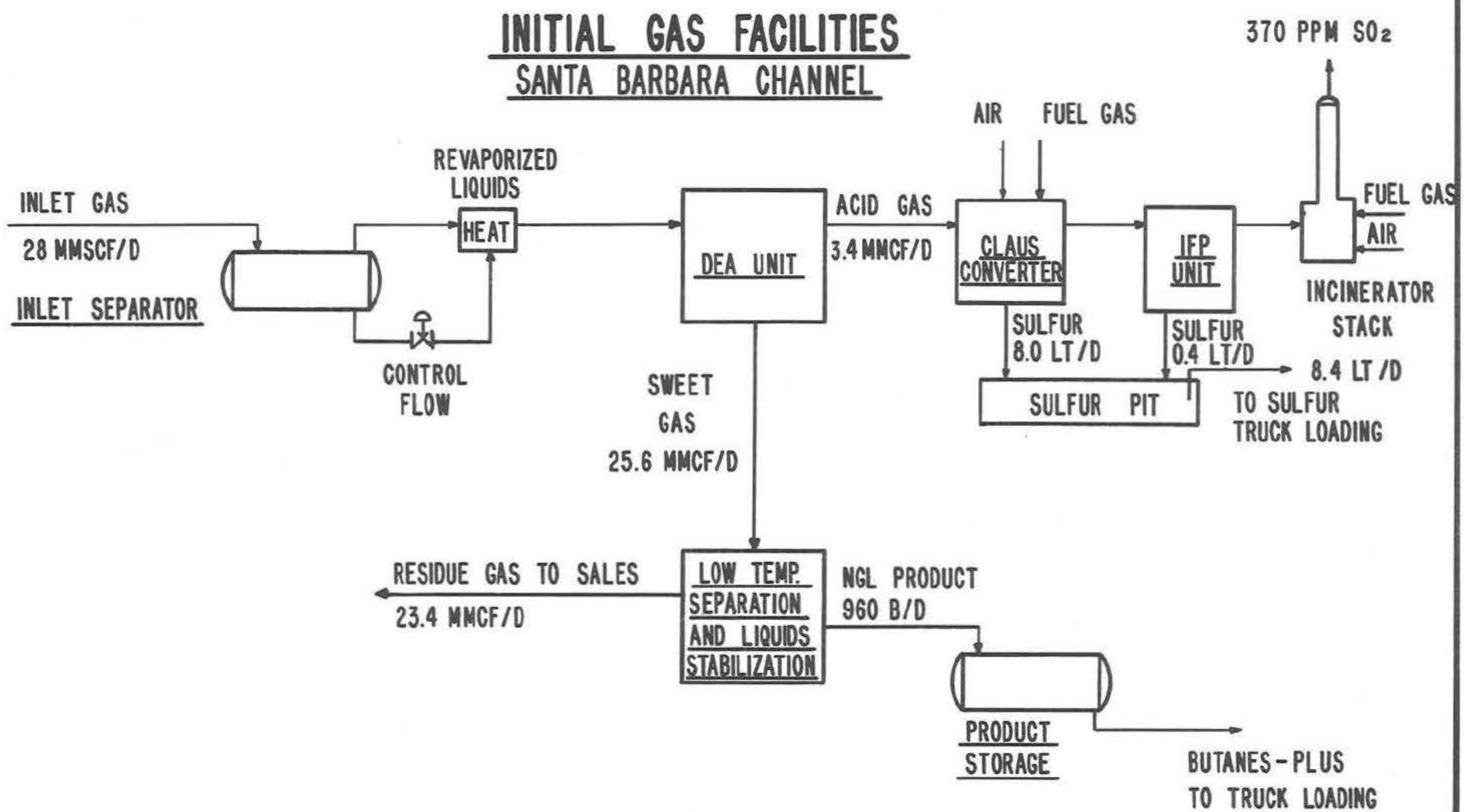

INITIAL GAS FACILITIES
SANTA BARBARA CHANNEL
INLET GAS
28 MMSCF/D
INLET SEPARATOR
REVAPORIZED LIQUIDS
HEAT
CONTROL FLOW
DEA UNIT
ACID GAS
3.4 MMCF/D
AIR
FUEL GAS
CLAUS CONVERTER
IFP UNIT
370 PPM SO2
FUEL GAS
AIR
INCINERATOR STACK
SULFUR 8.0 LT/D
SULFUR 0.4 LT/D
SULFUR PIT
8.4 LT/D
TO SULFUR TRUCK LOADING
SWEET GAS
25.6 MMCF/D
RESIDUE GAS TO SALES
23.4 MMCF/D
LOW TEMP. SEPARATION AND LIQUIDS STABILIZATION
NGL PRODUCT
960 B/D
PRODUCT STORAGE
BUTANES-PLUS TO TRUCK LOADING

Figure 6

FIGURE 7

SHUTDOWNS

EVENTS CAUSING SHUTDOWN	INITIATING DEVICE	ALARM	STOP CRUDE OIL TRANSFER PUMPS P-1	CLOSE FUEL GAS TO TREATERS S-1	CLOSE PILOT GAS TO TREATERS	STOP RERUN PUMP P-3	STOP CRUDE SHIPPING PUMPS	CLOSE FUEL GAS TO PLANT	CLOSE FUEL GAS TO VENT VAPOR INCIN. H-1	CLOSE PILOT GAS TO VENT VAPOR INCIN. H-1	CLOSE WTR. TREATING VENT TO H-1	CLOSE COMBUSTION AIR TO H-1	STOP CRUDE OIL TRANSFER PUMPS P-1
POWER FAILURE	BREAKER		X	X	X			X	X	X	X	X	
FIRE (MANUALLY TRIGGER ESD)	VISUAL		X	X	X			X					X
ESD MANUAL SWITCH	HS		X	X	X			X					X
LO/LO LEVEL - CRUDE SURGE TKS T-1	LS	YES	X	X									
FLAME FAILURE - TREATER S-1	BS	YES		X	X								
LO FLOW TO TREATER S-1	PS	YES		X									
HI STACK TEMP. - TREATER S-1	TS	YES		X	X								
LO/LO LEVEL RERUN TANK T-3	LS	YES				X							
LO/LO LEVEL STORAGE TANKS T-2	LS	YES					X						
HI STACK TEMP. - VENT VAPOR INCIN. H-1	TS	YES							X	X	X	X	
HI FURNACE TEMP. - VENT VAPOR INCIN. H-1	PS	YES							X	X	X	X	
FLAME FAILURE - VENT VAPOR INCIN. H-1	BS	YES							X	X	X	X	

ALARMS ONLY

FAULTS CAUSING ALARM	INITIATING DEVICE	ALARM
LOW LEVEL - CRUDE SURGE TKS T-1	LI	LAL
HI LEVEL - CRUDE SURGE TKS T-1	LI	LAH
HI LEVEL - BLOWOFF DRUM V-1	LS	LAH
TREATER BLOWOFF COOLER A-1	TS	TAH
HI LEVEL - RERUN TANK T-3	LI	LAH
LO LEVEL - RERUN TANK T-3	LI	LAL
HI LEVEL - STORAGE TANKS T-2	LI	LAH
LO LEVEL - STORAGE TANKS T-2	LI	LAL
HI LEVEL - DIRTY BRINE STG. T-4	LI	LAH
LO LEVEL - DIRTY BRINE STG. T-4	LI	LAL
HI LEVEL - BACKWASH BRINE TKS. T-5	LI	LAH
LO LEVEL - BACKWASH BRINE TKS. T-5	LL	LAL
HI LEVEL - INJECTION BRINE STG. T-6	PS	LAH
LO LEVEL - INJECTION BRINE STG. T-6	PS	LAL
HI LEVEL - FUEL GAS SCRUBBER V-4	LS	LAH
LO PRESSURE - INSTR. AIR SYSTEM	PS	PAL
HI LEVEL - SKIMMED OIL SUMP S-4	LS	LAH
LO PRESSURE - FUEL GAS TO H-1	PS	PAL
HI PRESSURE - INCIN. BURNER H-1	PS	PAH
HI BS&W - TREATED CRUDE	AX	AA
HI TURBIDITY - TREATED BRINE	AX	AA

DATE	BY	CHK	APPD	NO.	REFERENCE DRAWINGS

PRINT RECORD: DATE / FOR / REVISED / CUSTOMER / FIELD / INTRA CO.

ENG. RECORD		
DRAWN	H	
CHECKED		
MECH. CK.		
STRUCT. CK.		
ELECT. CK.		
PIPING CK.		
PROCESS	RMC	7/20/71

DRAWING STATUS				
DRAWING	ISSUE NO.			DATE
DEVELOPMENT	1	-	-	
PRELIMINARY ENGINEERING	4		6	8-25-71
APPROVED FOR CONSTRUCTION				
REVISED & APPROVED FOR CONSTRUCTION	REV. 0			

NOT APPROVED FOR CONSTRUCTION UNLESS SIGNED & DATED. DESTROY ALL PRINTS BEARING EARLIER DATE &/OR REVISION NO.

MECHANICAL FLOW DIAGRAM
EMERGENCY SHUTDOWN
SYSTEM
CRUDE OIL TREATING AND STORAGE FACILITY

HUMBLE OIL AND REFINING COMPANY
SBC, CALIFORNIA

SCALE: NONE

Stearns-Roger CORPORATION

ORDER NO. C-10140

DWG. NO. 22071

SHEET NO. 00-1-15

REV. 0

FIGURE 8

SHUTDOWNS

	No.	EVENTS CAUSING SHUTDOWN	INITIATING DEVICE	ALARM
	1	ELECTRICAL POWER FAILURE	BREAKER CONTACT	
	2	FIRE	MANUAL ESD SW.	ESD
	3	MANUAL ESD SWITCH	MANUAL	YES
INLET AND AMINE TREATING	4	HIGH INLET PRESSURE	PS	PAH
	5	HIGH H_2S	AT	XA
	6	HIGH LEVEL - SOUR GAS FINAL SEPARATOR V-3	LS	NONE
	7	LOW FLOW - AMINE TO H.P. CONTACTOR V-11A	PS	FAL
	8	LOW FLOW - AMINE TO AMINE STILL REBOILER H-11A	PS	FAL
	9	FLAME FAILURE - AMINE STILL REBOILER H-11A	BS	BA
	10	HIGH STACK TEMP. - AMINE STILL REBOILER H-11A	TS	TAH
	11	LOW LEVEL - AMINE STILL V-16A	LS	NONE
	12	HIGH LEVEL - AMINE SURGE TANK T-11	LS	NONE
SULFUR RECOVERY	13	LOW FLOW - ACID GAS TO HEATER H-23A	PS	FAL
	14	FLAME FAILURE - ACID GAS SIDE H-23A	BS	BA
	15	FLAME FAILURE - AIR SIDE H-23B	BS	BA
	16	HIGH STACK TEMP. - HEATER H-23 A&B	TS	TAH
	17	LOW FLOW - COMBUSTION AIR TO H-23B	PS	FAL
	18	COMBUSTION AIR BLOWER C-21 - DOWN		XA
	19	LOW LEVEL - 55# STEAM DRUM V-26	LS	NONE
	20	LOW LEVEL - WASTE HEAT BOILER B-21	LS	NONE
	21	FLAME FAILURE - SO_2 GENERATOR H-21A	BS	BA
	22	FLAME FAILURE - CONVERTER GAS REHEATER H-22A	BS	BA
	23	FLAME FAILURE - CONVERTER GAS REHEATER H-22B	BS	BA
	24	HIGH STACK TEMP. - CONVERTER GAS REHEATER H-22 A&B	TS	TAH
	25	FLAME FAILURE - TAIL GAS INCINERATOR H-24	BS	BA
H.C. RECOVERY	26	LOW FLOW - DEPROPANIZER BOTTOMS TO REBOILER E-42	PS	FAL
	27	HIGH STACK TEMP. - DEPROPANIZER REBOILER E-42	TS	TAH
	28	HIGH LEVEL - RECOMPRESSOR SUCTION SCRUBBER V-37	LS	LAH
REFRIGERATION SYSTEM	29	MANUAL SHUTDOWN - REFRIGERATION COMPRESSOR C-61	HS	XA
	30	HIGH PRESS. - DISCHARGE REFRIG. COMPR. C-61	PS	NONE
	31	MANUAL OPERATION - REFRIG. COMPR. INTERSTAGE INLET ROV	PS	NONE
	32	MANUAL OPERATION - REFRIG. COMPR. SUCTION ROV	PS	NONE
	33	LOW SUCTION PRESS. - REFRIG. COMPR. C-61	PS	NONE
	34	HIGH TEMP. - REFRIG. COMPR. C-61	TS	NONE
	35	HIGH LEVEL - PROPANE SUCTION SCRUBBER V-61	LS	NONE
	36	HIGH LEVEL - PROPANE INTERSTAGE SCRUBBER V-64	LS	NONE
UTILITY SYSTEM	37	FLAME FAILURE - STANDBY STEAM BOILER B-22	BS	NONE
	38	LOW DRUM LEVEL - STANDBY STEAM BOILER B-22	LS	NONE
	39	HIGH PRESS. - STANDBY STEAM BOILER B-22	PS	NONE

ITEMS SHUT DOWN

INLET AND AMINE TREATING	1	CLOSE - INLET BLOCK VALVE
	2	CLOSE - CONTRACTOR OUTLET BLOCK VALVE
	3	STOP - H.P. AMINE PUMPS P-12
	4	CLOSE - FUEL GAS TO AMINE STILL REBOILER H-11A
	5	CLOSE - PILOT GAS TO AMINE STILL REBOILER H-11A
	6	STOP - AMINE REBOILER PUMPS P-14
	7	CLOSE - AMINE STILL LCV-
SULFUR RECOVERY	8	CLOSE - ACID GAS VALVE TO H-23A
	9	CLOSE - ACID GAS TO CONVERTER V-22
	10	CLOSE - FUEL GAS TO ACID GAS SIDE H-23A
	11	CLOSE - PILOT GAS TO ACID GAS SIDE H-23A
	12	CLOSE - FUEL GAS TO AIR SIDE H-23B
	13	CLOSE - PILOT GAS TO AIR SIDE H-23B
	14	STOP - COMBUSTION AIR BLOWERS C-21
	15	CLOSE - FUEL GAS TO SO_2 GENERATOR H-21
	16	CLOSE - PILOT GAS TO SO_2 GENERATOR H-21
	17	SHUTDOWN - SO_2 GENERATOR H-21
	18	CLOSE - FUEL GAS TO H-22A
	19	CLOSE - PILOT GAS TO H-22A
	20	CLOSE - FUEL GAS TO H-22B
	21	CLOSE - PILOT GAS TO H-22B
	22	CLOSE - FUEL GAS TO INCINERATOR H-24
	23	CLOSE - PILOT GAS TO INCINERATOR H-24
REFRIG. SYSTEM	24	CLOSE - RESIDUE GAS TO SALES ROV
	25	STOP - DEPROPANIZER BOTTOMS CIRC. PUMP P-44
	26	CLOSE/VENT - HOT GAS INLET TO E-42
	27	SHUTDOWN - RECOMPRESSORS C-32
H.C. RECOVERY	28	SHUTDOWN - REFRIGERATION COMPRESSOR C-61
	29	CLOSE - FUEL GAS TO C-61
	30	CLOSE - REFRIG. COMPR. SUCTION ROV
	31	CLOSE - REFRIG. COMPR. INTERSTAGE ROV
UTILITY SYSTEM	32	CLOSE - FUEL GAS TO BOILER B-22

MECHANICAL FLOW DIAGRAM EMERGENCY SHUTDOWN SYSTEM GAS PROCESSING STUDY	DWG. NO. 22070
HUMBLE OIL AND REFINING COMPANY SBC, CALIFORNIA	SHEET NO. 00-1-25
SCALE NONE — Stearns-Roger — ORDER NO. 5-41100	REV △

ALARM ONLY

	No.	FAULT CAUSING ALARM	INITIATING DEVICE	ALARM
INLET	1	HIGH LEVEL - INLET SEPARATOR V-2	LIC	LAH
	2	LOW LEVEL - INLET SEPARATOR V-2	LIC	LAL
	3	HIGH LEVEL - SOUR GAS FINAL SEPARATOR V-3	PS	LAH
	4	START - DUMP LIQUID PUMP P-1	LS	XA
	5	HIGH LEVEL - L.P. CONDENSATE SEPARATOR V-4	LS	LAH
AMINE TREATING	6	HIGH H_2S - CONTACTOR OUTLET	AR	AA
	7	LOW LEVEL - TREATED GAS SCRUBBER V-12	LI	LAL
	8	HIGH/LOW LEVEL - H.P. AMINE CONTACTOR V-11A	LI	LAHL
	9	HIGH/LOW LEVEL - AMINE VENT TANK V-13A	LIC	LAHL
	10	HIGH DIFF PRESS. - H.P. AMINE CONTACTOR V-11A	dPR	dPAH
	11	LOW LEVEL - AMINE STILL V-16A	LI	LAL
	12	HIGH LEVEL - AMINE STILL REFLUX ACCUMULATER V-17A	LI	LAH
	13	HIGH/LOW LEVEL - AMINE SURGE TANK T-11	LI	LAHL
SULFUR RECOVERY	14	HIGH LEVEL - SULFUR UNIT INLET SCRUBBER V-21	LS	LAH
	15	HIGH LEVEL - TAIL GAS CLEANUP UNIT U-2	PS	LAH
	16	LOW LEVEL - TAIL GAS CLEANUP UNIT U-2	PS	LAL
	17	SHUTDOWN - CONVERTER GAS REHEATERS H-22 A&B		XA
	18	HIGH TEMP. - INCINERATOR H-24	TS	TAH
	19	LOW TEMP. - INCINERATOR H-24	TS	TAL
	20	HIGH LEVEL - WASTE HEAT BOILER B-21	PS	LAH
	21	LOW LEVEL - WASTE HEAT BOILER B-21	PS	LAL
	22	HIGH LEVEL - 55# STEAM DRUM V-26	PS	LAH
	23	LOW LEVEL - 55# STEAM DRUM V-26	PS	LAL
H.C. RECOVERY	24	HIGH LEVEL - DEPROPANIZER V-47	PS	LAH
	25	LOW LEVEL - DEPROPANIZER V-47	PS	LAL
	26	HIGH LEVEL - DEPROPANIZER REFLUX DRUM V-48	LI	LAH
	27	HIGH/LOW LEVEL - CHILLER SEPARATOR V-31	LI	LAHL
GLYCOL SYSTEM	28	LOW PRESS. - GLYCOL TO PROCESS	PS	PAL
REFRIGERATION SYSTEM	29	TROUBLE - PROPANE REFRIG. COMPRESSOR C-61	COMPR. PANEL	XA
	30	SHUTDOWN - PROPANE REFRIG. COMPRESSOR C-61	COMPR. PANEL	XA
	31	LOW FLOW - DISCHARGE REFRIG. COMPRESSOR C-61	FRC	FAL
	32	HIGH LEVEL - PROPANE SUCTION SCRUBBER V-61	LS	LAH
	33	HIGH LEVEL - PROPANE INTERSTAGE SCRUBBER V-64	LS	LAH
UTILITIES & STORAGE	34	LOW LEVEL - D.A. HEATER W-22	LI	LAL
	35	LOW PRESS. - INSTRUMENT AIR SYSTEM	PS	PAL
	36	HIGH LEVEL - H.P. FUEL GAS SCRUBBER V-77	LS	LAH
	37	HIGH LEVEL - L.P. FUEL GAS SCRUBBER V-78	LS	LAH
	38	HIGH LEVEL - FLARE SEPARATOR V-8	LS	LAH
	39	HIGH LEVEL - BUTANE PLUS STORAGE TANK T-52 A&B	LS	LAH

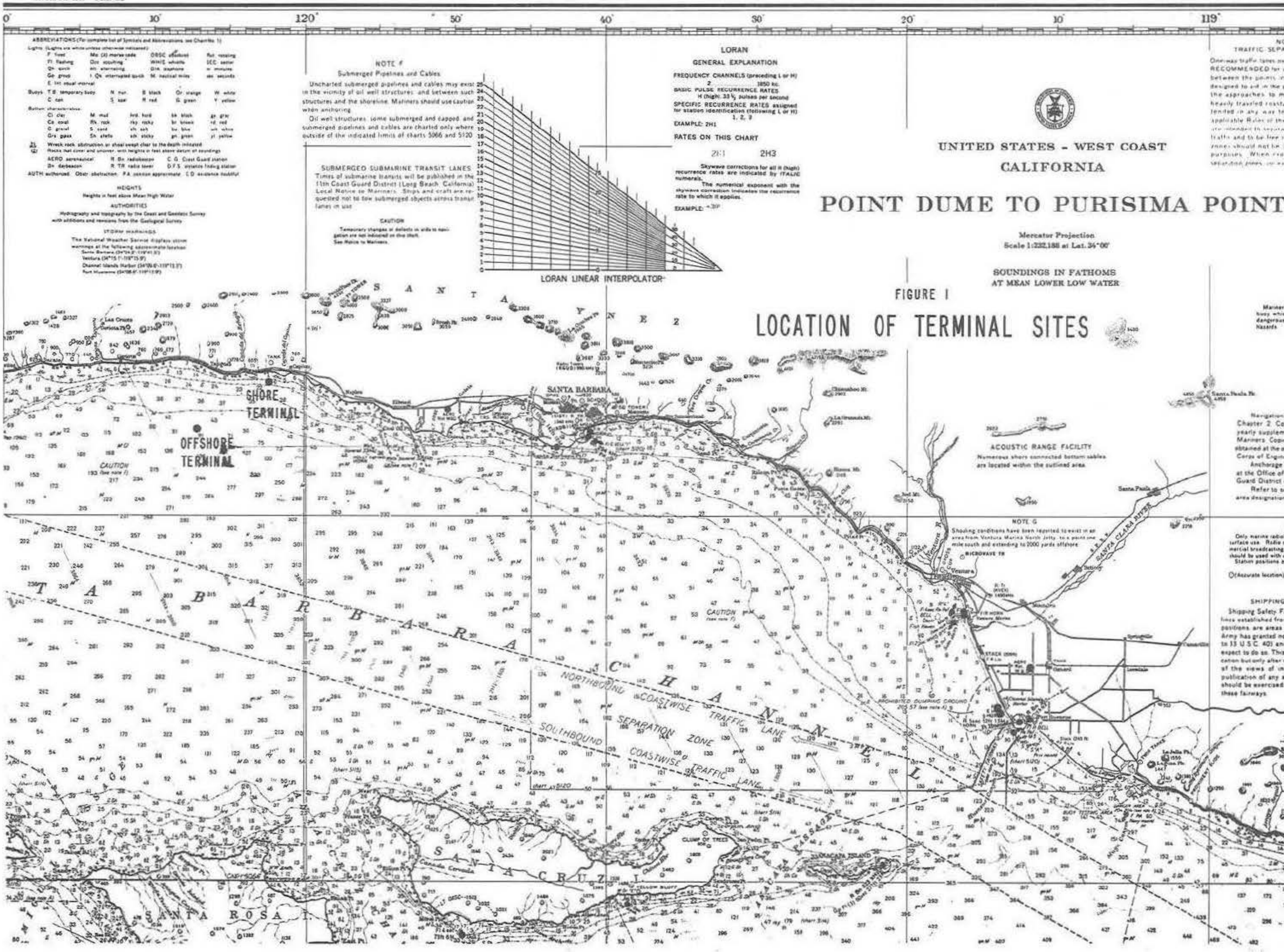
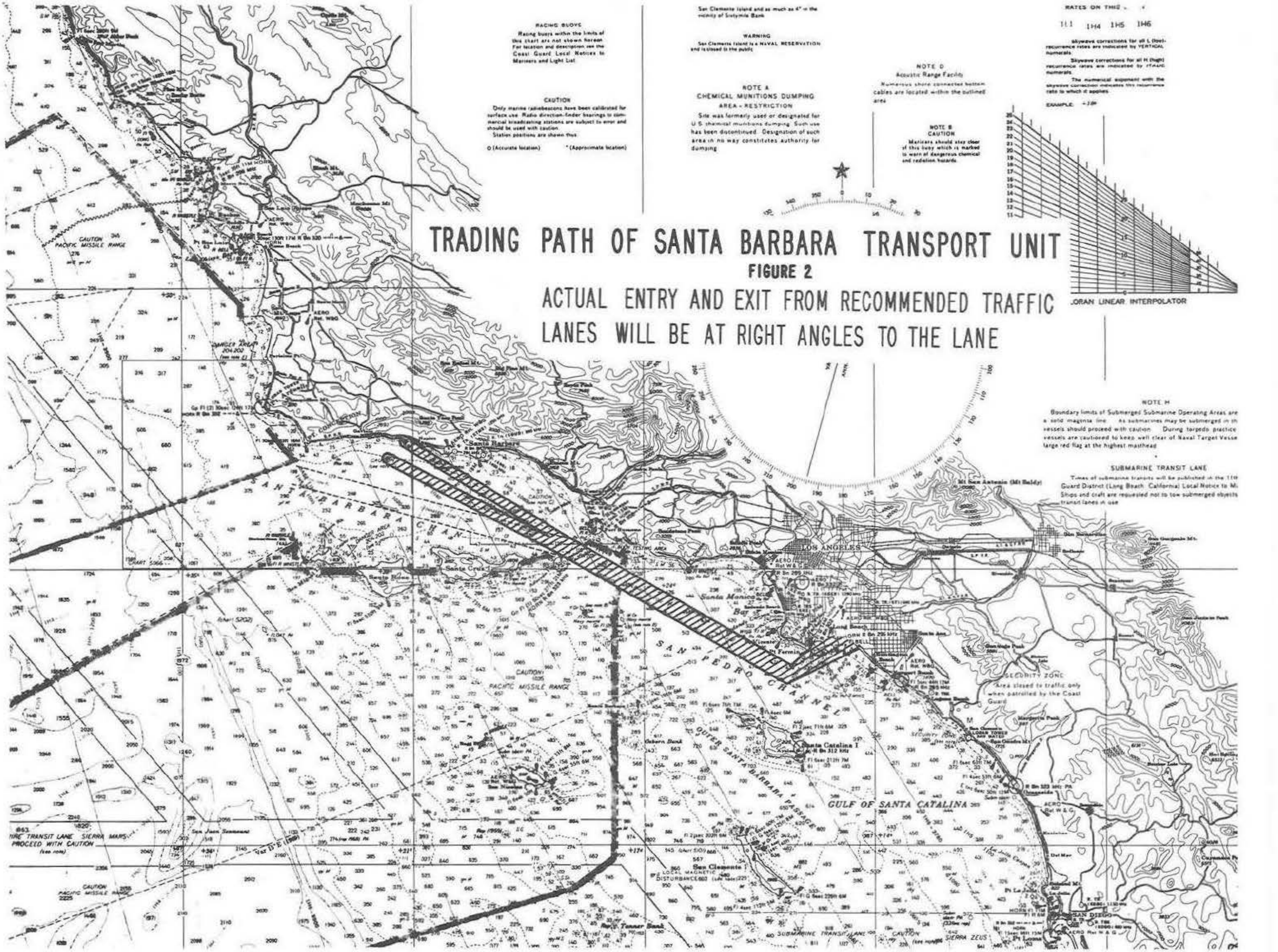


FIGURE I
LOCATION OF TERMINAL SITES



TRADING PATH OF SANTA BARBARA TRANSPORT UNIT

FIGURE 2

ACTUAL ENTRY AND EXIT FROM RECOMMENDED TRAFFIC LANES WILL BE AT RIGHT ANGLES TO THE LANE

TYPICAL TUG/BARGE UNIT IN LINKED MODE

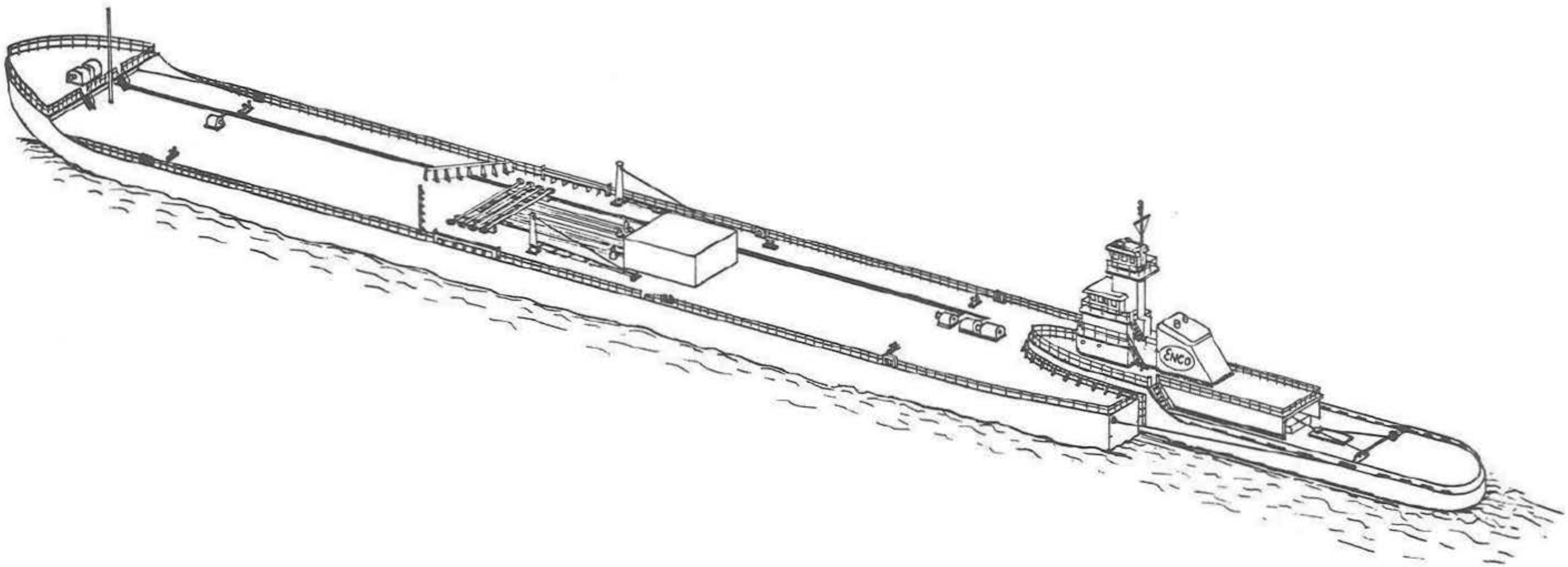


Figure 3

TABLE OF CONTENTS

SUBMERGED PRODUCTION SYSTEM

SUBMERGED PRODUCTION SYSTEM

ABSTRACT

A Submerged Production System (SPS) is being developed by Humble to augment the capabilities of fixed platforms for the production of oil and gas in the Santa Ynez Unit. The SPS consists of clustered subsea wells, a drilling template and a production gathering manifold. The wells will be drilled with a floating rig and connected to the manifold with a subsea wellhead assembly. Main production control valves will be located on the manifold, accessible for replacement maintenance by a special purpose manipulator. The manipulator will also have the ability to replace modules containing control equipment.

The SPS will be linked to a surface control station on a fixed platform with a pipeline and electric power and communication cables.

A full-scale 3-well prototype of the SPS has been fabricated and is currently undergoing dry land testing at Ventura, California. Following successful land testing, the SPS will be tested in a water-filled pit. The need for further testing will depend on the results of land and pit testing.

1. GENERAL DESCRIPTION

The SPS is flexible and provides a wide range of capabilities. Drilling and completion are carried out with the subsea template and manifold in place. Production gathering is accomplished by the subsea manifold, which includes remote monitoring and safety control features. In conjunction with a surface support facility, the SPS provides for oil and gas production, gas lifting, individual well flow tests, and chemical injection.

Stringent design criteria have been adhered to throughout the development of the SPS. All materials and equipment used in the system have been carefully selected for pressure and depth ratings. Metal-to-metal seals have been used throughout. Local fail-safe controls are utilized, and all subsystems have been designed to eliminate environmental pollution.

A working, full-scale Submerged Production System has been completely fabricated. This "prototype" utilizes subsystems, components, and materials that would be used in actual field production. The prototype was designed and built for tubingless well completions; however, the basic concept and most subsystems would be applicable to casing-tubing completions.

2. SUBSYSTEMS AND MAJOR EQUIPMENT

The Submerged Production System in its present configuration has been under development for three and one-half years; however, many of the basic concepts and techniques used originated in the late 1950's and were used in actual underwater completions as early as the mid-1960's. Prominent designers and vendors of subsea systems and equipment have served as consultants to Humble in the development of the SPS, and the system incorporates a substantial amount of electronics, reliability and systems technology developed for aerospace operations by government and private contractors.

2.1 Template and Manifold

The template consists of a heavy tubular framing network containing the production manifold and manipulator track sections. The template is installed prior to drilling, and the wells are drilled through it. A heavy, anchor-deflecting support device surrounds the template, which is supported by pilings set in the sea floor. Figure 1 is a photo of the 3-well prototype model.

Figure 2 illustrates the prototype manifold used to gather produced fluid. The manifold is made up of separate 8-1/2 foot module sections for each well. Besides providing connection points for production tubing, the manifold allows pumpdown tool circulation for wellbore work on tubingless completions.

The replaceable manifold sections are interconnected with large damage control bulkheads. The bulkheads are designed to reduce the extent of any manifold damage that might occur. Manifold sections can be replaced and reconnected by a rig or derrick barge.

Manifold lines include two 3000 psi w.p. lines for production and injection, a 1500 psi w.p. line for gas lift, and for tubingless completions, two 5000 psi w.p. lines for well tests, well killing, chemical injection, and pumpdown tool work.

Each completion string contains a hydraulically operated subsurface safety valve below the mudline, a hydraulically operated master valve in the wellhead, and a hydraulically operated wing valve in the manifold. The valves are held open by hydraulic pressure and close automatically by spring action whenever hydraulic pressure is lost or removed. The manifold valves, complete with metal seals and a hydraulic operator, are in a single replaceable unit. The wing valves, located in the manifold to facilitate maintenance, are the principal operating valves for control of production, gas lift, and pumpdown tools. All connections in the manifold are by metal-to-metal seals or are welded.

2.2 Drilling and Completion System

Submerged Production System drilling is carried out in the same manner as typical floating drilling. Figure 3 is a photo of a special, unitized Christmas tree for tubingless (no casing) completions. The wellhead Christmas tree assembly is connected to both the casing and manifold with metal-to-metal seals using the special, retrievable, rig-operated hydraulic tool shown in Figure 4. Provision has been made for both vertical reentry and through-flowline pumpdown tool access into the wellbore.

Well completion, using either a rig or pumpdown tools for a tubingless well, is made with the wellhead assembly in place. Through-flowline pumpdown tools for perforating, cementing, paraffin removal, choke change outs and gas lift valve replacements have been designed and tested.

The downhole assembly for a typical tubingless well consists of a slip type tubing hanger-connector and a set of hydraulically operated fail-safe ball valves. The subsurface valves are operated by the template hydraulic system.

2.3 Electro-Hydraulic Controls

The electro-hydraulic controls provide for remote control of manifold and wellhead production functions. A control command originates at a surface station, is transmitted by a subsea cable, and is decoded by a subsea electronic logic unit. A command can either interrogate pressure and temperature sensors or operate solenoids on hydraulic pilot valves.

For purposes of reliability and ease of maintenance, the controls have been designed to operate through the use of a number of individual modules. The well control module, located at each well, houses the pilot valves and the electronic controls used for activating the manifold valves and operating the sensors associated with each well. Another module is used to control equipment for launching pigs and valves for isolating the hydraulic distribution sections. The subtemplate control module distributes hydraulic fluid and contains the safety system electronics which activate shutdown devices. The pump module contains the hydraulic pump used for pressurizing the hydraulic fluid accumulator.

The principal reason for using the individual modules is to improve SPS reliability. To enhance the performance of this control and monitoring equipment, strict quality control was maintained, and extensive test screenings and test operations were carried out during fabrication. Clean, controlled atmosphere work areas were used for assembly. The result of the above precautions is a relatively high calculated mean time between failures of two years for the electro-hydraulic equipment on a cluster of up to 20 wells.

2.4 Manipulator Maintenance System

The manipulator maintenance system performs two operations. It provides for the replacement of production valves and makes and breaks two-bolt clamp flange connections. This permits the replacement of manifold hardware, supporting equipment skids, and the manifold itself. Figure 5 shows the manipulator located on the three-well model track. Two work tools (end effectors) are provided for the manipulator. One is used to remove and install valves. The other is used to make and break two-bolt clamp connections. The manipulator can be remotely controlled through the use of television cameras, or can be operated by a man inside the atmospheric pressure bell.

A typical maintenance operation begins by taking the manipulator to the work location with a surface vessel equipped with a gantry crane handling system. The remote controls are utilized to order a pop-up buoy with a guide line to the surface. The guide line is threaded through a winch on the manipulator. The manipulator, which floats, is lowered into the water, and winches itself down to the template track. Once on the track, an anchor is picked up by the manipulator, making it negatively buoyant.

A hydraulic drive system provides locomotion for the manipulator as it moves to the location of a part to be replaced. Manual isolation valves on either side of a problem valve are closed by the manipulator before the valve is replaced. The valve is removed from the manifold and stored on a rack on the manipulator carriage. A new part is removed from the rack, installed in the manifold, and pressure tested. The manipulator then returns to the landing area, installs a new pop-up buoy, releases the anchor, and winches itself to the surface, where it is picked up. The guide line is then released and the system returned to its ready state.

2.5 Safety and Pollution Control

Sensors on the SPS continuously monitor manifold pressure, hydrocarbon accumulation in the inverted spill pans, and the status of the safety system batteries. Shutdown occurs automatically if an out-of-limits condition is found.

Any hydrocarbons trapped by the inverted spill pans, forming an umbrella over the SPS, cause shutdown of sections of the SPS. Continued accumulations of hydrocarbons will shut down the entire SPS.

Proven equipment with good performance history is used throughout. Humble has made every effort to minimize the use of new equipment, and has utilized off-the-shelf material wherever possible. New developments in metal-to-metal seals and special underwater electrical cable connectors were incorporated to improve reliability of the SPS. The major engineering effort has been directed at system configuration, equipment selection and packaging, and system reliability.

3. PROTOTYPE TESTING AND QUALIFICATION PROGRAM

3.1 Land Test

Fabrication of a full-scale, working prototype SPS has been completed. The assembly has been placed in a concrete test pit in Ventura, California, and is currently undergoing dry land testing (Figure 6). Functional tests of the wellhead assembly have been completed and the automatic alignment system for installing the assembly has proven successful. Other dry tests will include checking for interchangeability of parts, proper tolerances, and physical strength. The electronic controls have been tested separately and are being integrated with the hydraulic system for further testing. Full-scale flow tests will be performed and all operational sequences and troubleshooting procedures will be tested.

At the successful completion of the dry tests, the pit will be flooded, and all operational tests will be repeated underwater.

3.2 Offshore Test

All SPS subsystems except the manipulator deployment will be tested onshore. Depending upon test results, it may be desirable to test the SPS in actual offshore production operations. This could be accomplished by installing the system in an area of existing offshore production, or by installing it in the structure of the proposed 850 foot platform. The preferred test method will be determined upon completion of the onshore tests, when timing of the proposed platform installation is better defined.

4. SYSTEM INSTALLATION AND OPERATION FOR FULL-SCALE USE

The SPS would be completely tested in the fabrication yard and debugged before being barged offshore. It would be launched from the barge in a manner similar to the way jacket platforms are launched. The SPS would float until it is lowered to the ocean floor by controlled flooding.

In the normal mode of production operation, all remote control electrical units are in a passive "listening" state, with electronic components powered down. Wells are maintained on stream with hydraulic pressure holding the valves open. Normal operations such as pressure build-up testing, hydraulic distribution line purging and selection of hydraulic fluid filters are instituted by surface commands.

As an example of a normal operation, consider shutting in a well for a pressure build-up test. First, a command is entered into a surface controller to close the production wing valve on the particular well. This command is then transmitted down the cable and received by the subsea template control module, which recognizes the well address and turns on the line containing the desired well control module, thus ending the passive listening state. Upon receipt of the command, the well control module's electronics decode it and energize the solenoid operated hydraulic pilot valve of the production wing valve. The pilot valve closes, releasing hydraulic pressure from the wing valve operator, shutting in the well. Next, the wellhead pressure transducer is activated by a surface command. An analog signal from the well transducer can be monitored by the surface controls, and a pressure build-up recorded.

Safety shut-in operations occur when some part of the system malfunctions. The shut-ins are automatic and require no manual initiation from the surface.

Maintenance operations consist of wellbore maintenance and manifold equipment maintenance. For tubingless completions, wellbore work is performed with pumpdown tools. The work can also be performed with a floating rig, using the vertical access provided by the wellhead assembly.

Wellbore work on conventional completions would be performed with a floating rig. The manipulator is employed for manifold equipment maintenance. No repair work is performed subsea and only equipment replacement is carried out by the manipulator.

MODEL OF 3-WELL PROTOTYPE SPS

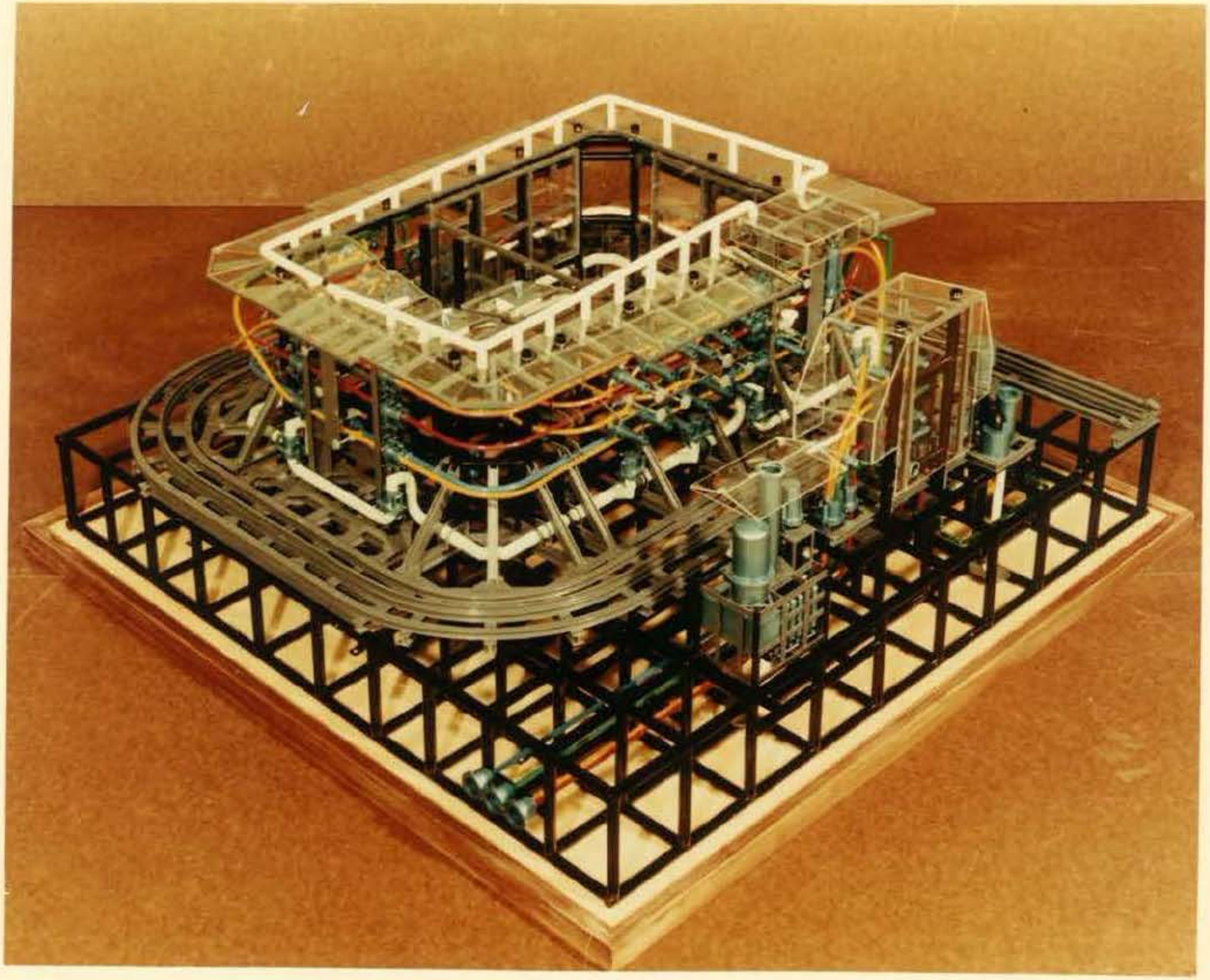
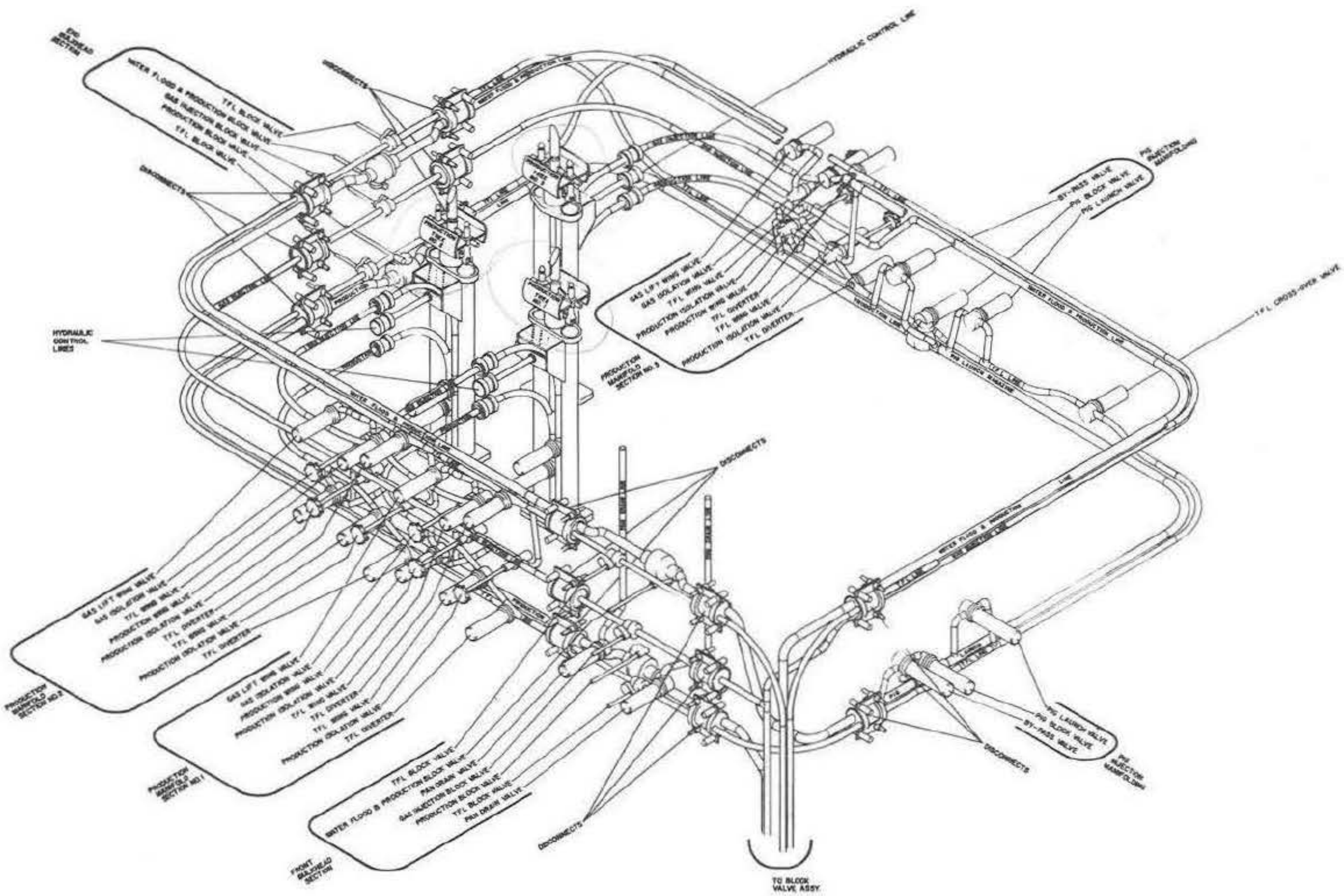


Figure 1



SPS PRODUCTION AND INJECTION MANIFOLD

Figure 2

PROTOTYPE CHRISTMAS TREE

FIGURE 3

TREE RUNNING TOOL

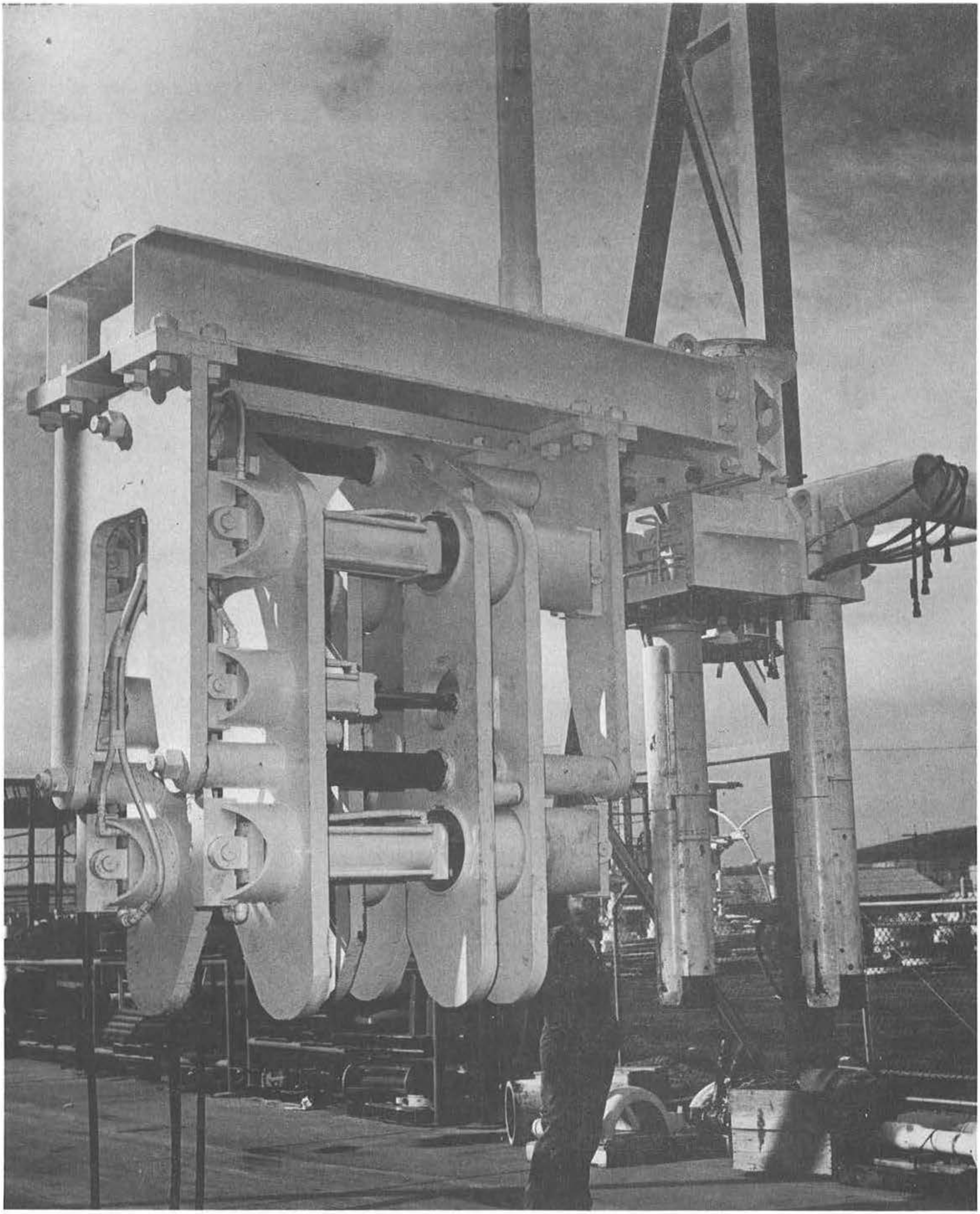


FIGURE 4

MANIPULATOR MAINTENANCE SYSTEM 3-WELL MANIFOLD

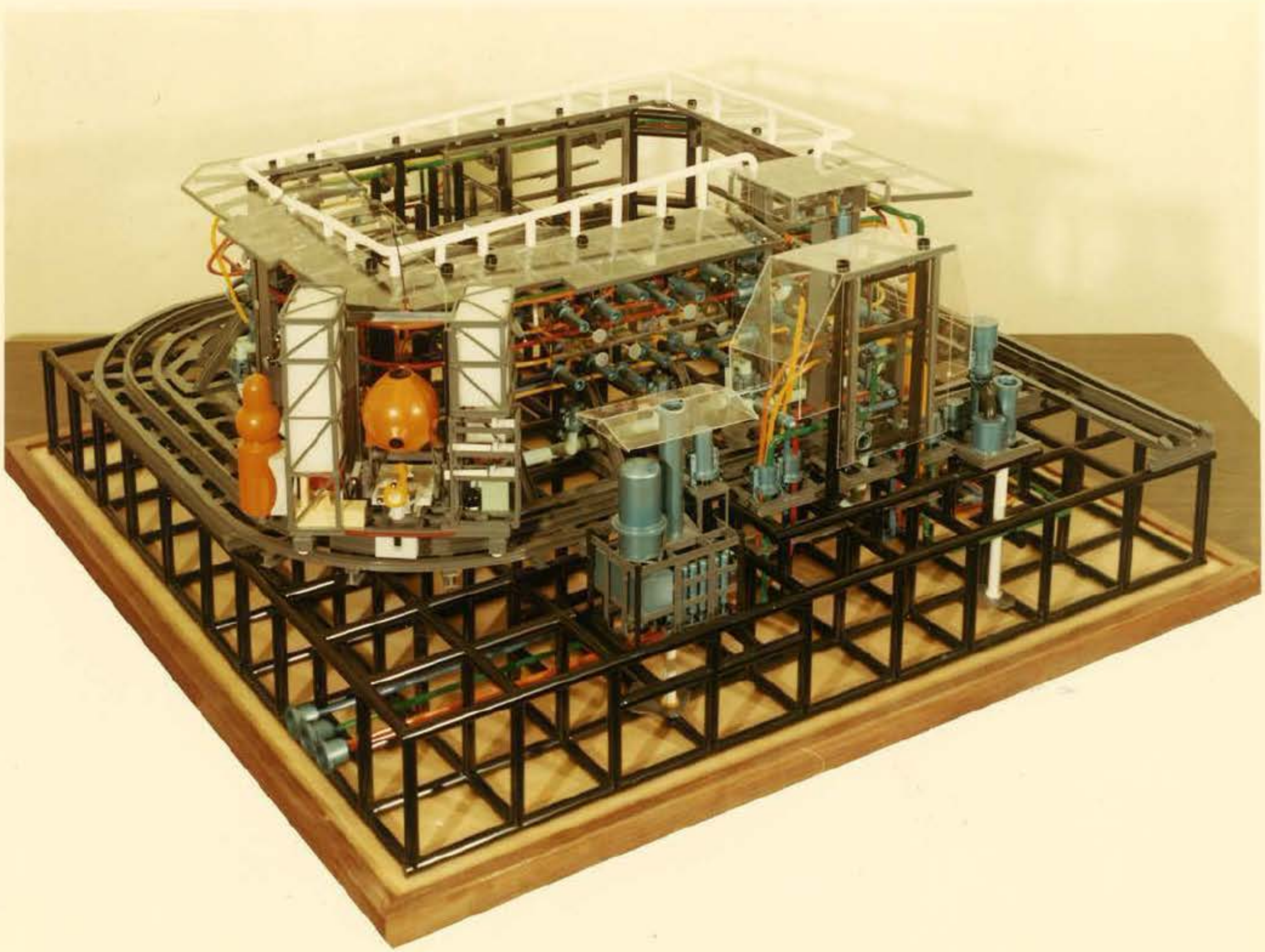


Figure 5

SPS TEST SITE

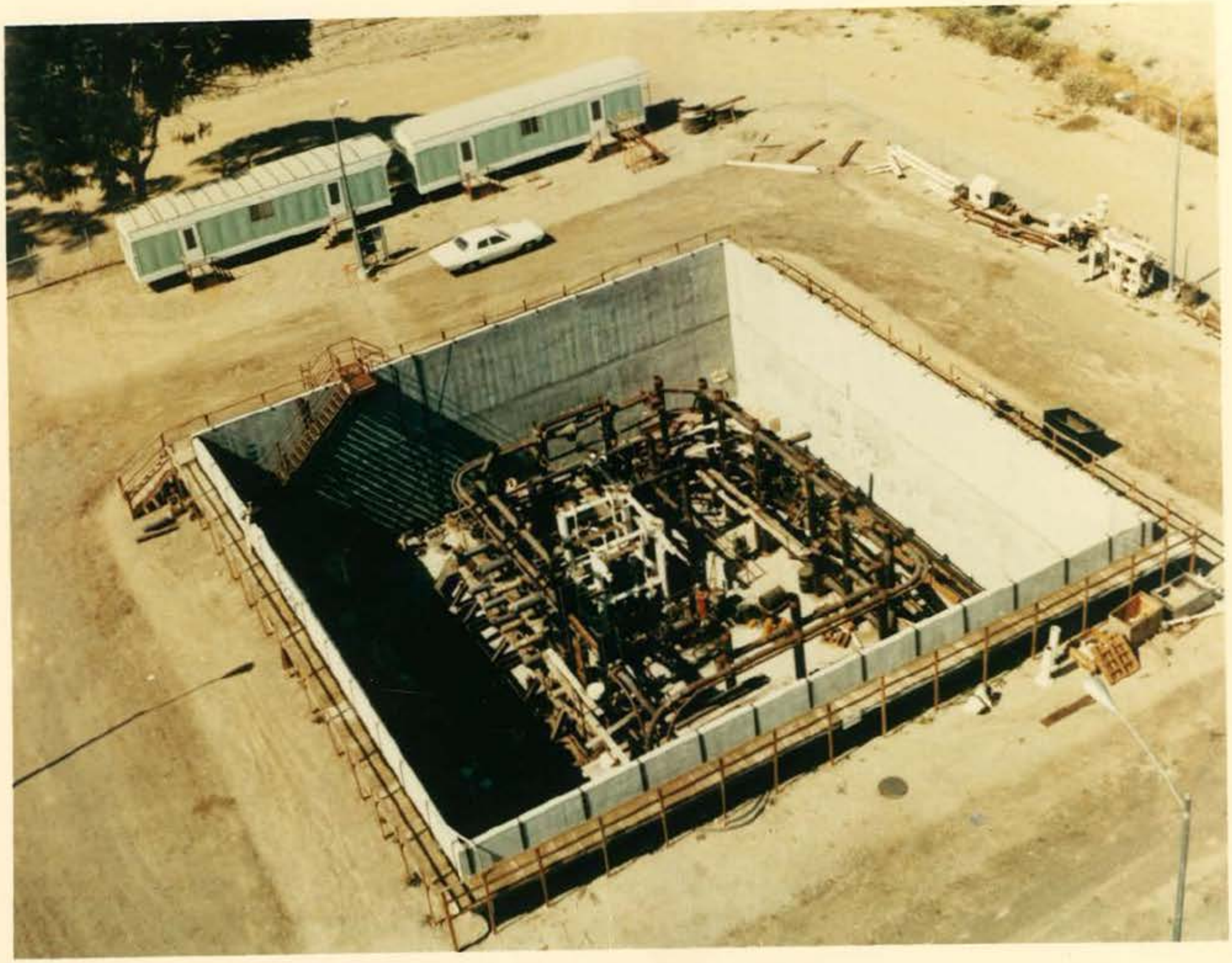


Figure 6

PLATFORM

TABLE OF CONTENTS

PLATFORM

PLATFORM

ABSTRACT

This section discusses the design, construction, and installation of the initial platform proposed for installation in 850 feet of water on OCS P-0188. This platform will provide a foundation for the drilling of the development wells and for the offshore production facilities.

The platform will be located at (coordinates) x=832,517, y=830,859 in Lease OCS P-0188. A map showing the location of the structure is given in Figure 1.

INTRODUCTION

This section describes design, construction, and installation of the bottom-founded fixed platform that forms the foundation for the drilling rig and production equipment required for development of the reservoir. The structure is designed (1) to withstand safely the most severe loads that might occur during the transport to location and during installation, (2) to withstand safely the loads that might be caused by severe storm waves or maximum earthquakes anticipated in the area, and (3) to perform the functions of a drilling and production facility.

Elevation views of the platform are given in Figures 2 and 3, and drawing series HQE215 - 1 through 13 in Appendix 1.4 which gives details of the structure. Eight main legs framed with X and diagonal bracing and appropriate geometric bracing comprise the basic structure. This bracing system provides a high level of redundancy and adds substantially to the safety of the platform under severe earthquake or wave loads. The structure is secured to the bottom with 20 piles. These piles are securely attached to the legs and the pile guide sleeves by welding and grouting. Piling extend into the ocean floor 340 feet to provide a secure foundation for the platform. The deck of the platform provides sufficient space and load carrying capacity for drilling equipment, attendant production facilities, and has a capacity of up to 28 well conductors.

The following paragraphs (1) describe the design criteria and/or conditions for earthquake, wave, gravity, and operating loads; (2) describe analyses and results of analyses used to show that the platform meets these criteria, and (3) describe construction, installation, and related analyses of the platform. The design earthquake and storm conditions used herein are conservative. The conservative approach is considered justified and appropriate for the initial platform in this water depth and in this location; however, these design conditions are not proposed as design standards for general use.

1. DESIGN CRITERIA AND OBJECTIVES - EARTHQUAKE, WAVE, AND GRAVITY LOADS

To insure that the platform has adequate resistance to environmental forces and can fulfill its functional requirements, the structure and its foundation are designed to carry normal gravity and operating loads in conjunction with appropriate earthquake or storm induced forces.

Sections 1.1 through 2.4, following, describe design criteria, design conditions, gravity and operating loads, analysis procedures, and results.

1.1 Earthquake-Induced Loads

1.1.1 Earthquake Design Criteria

The location of the Santa Ynez Unit requires that the structure be designed for an earthquake environment appropriate for that seismic region. The following design requirements and criteria have been satisfied in the design.

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

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

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

1.1.2 Earthquake Design Conditions

For criteria 1 and 2 above, the "design spectra", which describe the response of a structure to earthquakes, are those recommended by Dr. G.W. Housner and Dr. P.C. Jennings of the California Institute of Technology. Their report "Earthquake-Resistant Design of Drilling Tower in the Santa Barbara Channel" (Appendix 1.1), describes in detail the response spectra and the general approach to earthquake-resistant design used in the design of the structure.

For criterion 1, which requires design to avoid structural damage, a design spectrum scaled to reflect a ground acceleration of 0.25 g (Figure 4) is used. This level of acceleration has a recurrence interval of about 250 years at a typical site in Southern California (recurrence interval derived from Table III Appendix 1.1).

For criterion 2, which requires design for safety against collapse, a design spectrum scaled to reflect a ground acceleration of 0.5 g is used (Figure 5). This level of acceleration approximates the maximum potential ground shaking that can occur near a causative fault (Appendix 1.1).

To insure fulfillment of criterion 3 the structure is designed to accommodate without collapse deformations 2.0 times those resulting from the application of criterion 1, or 1.25 times the deformation resulting from the application of criterion 2, whichever is the larger.

To account for the three-dimensional character of earthquake motion, the vertical component and the two horizontal components are considered to act simultaneously.

For design purposes, the horizontal ground motion in a secondary direction is taken to be 0.8 times that in a primary direction. This value of 0.8 was developed from transient analyses of platform models in which the input ground motion consisted of two non-identical horizontal components of ground motion of equal spectral intensity. The effect of non-synchronization in time of the peak responses demonstrated by the transient analyses is accounted for in the modal design analyses by the 0.8 factor applied to the spectral intensity for the secondary direction.

The vertical component of earthquake ground motion is assumed to act simultaneously with the horizontal motion described above. For criterion 1 the vertical design spectrum is scaled to one-half of the horizontal spectrum for the primary direction, (Figure 4), and for criterion 2 a factor of one-third is used on the design spectrum for strongest potential shaking (Figure 5).

The structure's design is adequate to meet all of the above criteria.

After design for the conditions described above, the response of the structure to appropriate transient ground shaking is calculated to give additional measures of expected performance. For this particular case, ground shaking measured at Pacoima Dam during the San Fernando Valley earthquake of February 9, 1971 was used.

1.2 Wave Loads

1.2.1 Wave Load Design Criteria

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

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

1.2.2 Wave Load Design Conditions

1.2.2.1 Severe Storm:

Standard engineering practices have led to platform designs for severe storms that have a probability of exceedance of 1 percent per year (a 100-year storm). For the proposed platform, a severe storm crest elevation having a probability of exceedance of one-fourth of 1 percent per year (400-year storm) is used for analysis purposes.

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

Crest elevation above storm mean water level, 28 ft (wave height, crest to trough, 44 ft)
Storm tide, 8 feet
Storm wind velocity, 100 MPH

Oceanographic studies of meteorological data were performed by Oceanographic Services, Inc. (OSI). A copy of their report, "Storm Wave Study, Santa Barbara Channel", is attached (Appendix 6.2). This study includes a hindcast of the ten storms generating the most severe seastates at each of five locations in the Santa Barbara Channel for a historical period covering the years 1899 to 1968.

(Revised)

The proposed platform location is nearest to their Site 2 as indicated on the map shown in Figure 6. Accordingly, selection of the severe storm wave is based primarily on their report for this location.

Standard statistical procedures are employed to derive the extreme crest elevation from the OSI hindcast. A root-mean-square (rms) combination of sea and swell is made for cases in which the seastate at the proposed location included both locally generated seas and swell. (Because these components do not necessarily arrive from the same direction, the rms combination overestimates appropriate design waves). Severe storms hindcasted by OSI are fitted to a log normal probability distribution for additional analysis. Likelihood of occurrence of storms from this log normal distribution in a given year is considered to follow a Poisson distribution. Likelihood of occurrence for given wave crest elevations for a specific seastate is calculated with procedures described by Longuet-Higgins ("On the Statistical Distribution of the Heights of Sea Waves", M. S. Longuet-Higgins, Sears Foundation for Marine Research, Volume IX, 1952, No. 3). The resulting log normal distribution of severe storms, Poisson distribution for annual occurrence, and crest statistics referenced above, permit calculation of the crest elevation that has the very rare one-fourth of 1 percent per year.

Analyses of dynamic response of the platform require specification of the distribution of energy in the seastate as well as the size of the design wave. For purposes of analysis, the spectral shape reported by Robinson, Brannon, and Kattawar ("Storm Wave Characteristics", R. J. Robinson, H. R. Brannon, Jr., and G. W. Kattawar, Society of Petroleum Engineers Journal, March, 1967, pp 87-98) is used in the dynamic calculations. This power spectrum contains relatively more energy in the shorter period ranges than do commonly used analytic forms. Accordingly, stresses are somewhat larger than those expected to occur at the specific location.

1.2.2.2 High-Cycle Repetitive Storm Stresses

Calculation of repetitive stresses from all storms to which the platform may be exposed during its lifetime requires integration of storm effects continuously with time. To make this integration practical, all seastates expected at the platform location, either frequently or as an extremely rare event, are classified into eight conditions of sea amplitude and dominant period. The seastates are derived from the OSI Severe Storm Study (Appendix 6.2) and the National Marine Consultants report on

"Wave Statistics for Seven Deepwater Stations Along the California Coast" (Appendix 6.1). National Marine Consultants' Station 6 is considered to be most appropriate in establishing expected seastates at the platform location. Because this station has a greater exposure than the proposed platform location, the seastates used for repetitive stress analyses are more severe than those likely to be encountered.

1.3 Gravity Loads

Gravity loads for design include all deck loads developed by the drilling and producing operations conducted on the platform and the dead weight of the platform itself. These loads are listed in Tables I and II.

2. ANALYSIS OF WAVE AND EARTHQUAKE DYNAMIC RESPONSE

Satisfaction of the earthquake and wave design criteria requires use of dynamic response analyses in design of the platform. Sections 2.1, 2.2, and 2.3, following, describe the mathematical models and methods used for these analyses. Results of analyses are given in Section 2.4.

2.1 Model for Analysis

A three-dimensional, 42 degree-of-freedom (two translational and one rotational degrees of freedom at each level) mathematical model is developed using the lumped mass idealization illustrated schematically in Figure 7 (W. C. Hurty and Moshe F. Rubenstein, Dynamics of Structures, Prentice Hall, Inc., 1965). Masses are lumped at the framing levels and the stiffness characteristics are defined in terms of deflections of the framing levels.

An equivalent linear representation of the nonlinear behavior of the pile foundation is used. Linear springs are selected after an extensive study of the nonlinear load deformation characteristics of the foundation (Matlock, Hudson, "Correlations for Design of Laterally Loaded Piles in Soft Clay", Paper 4T02, Journal of the Soil Mechanics and Foundation Division, Proceedings, ASCE, March, 1966).

The dynamic mass of the structure used includes the steel mass, the mass of the contained water, and the added hydrodynamic or virtual mass which must be considered when a body accelerates through a fluid. The amount of virtual mass is developed using classical hydrodynamic theory (Lamb, H., Hydrodynamics, The University Press, 1932) and is in all cases equal to or slightly greater than the mass of the displaced water.

2.2 Response to Earthquakes

Two analysis methods are utilized in developing and analyzing the proposed design. They are the transient method, that utilizes earthquake ground motion records, and the spectral modal analysis method, that utilizes earthquake response spectra.

Spectral modal analyses are used in implementation of the earthquake criteria 1 and 2 given in Section 1.1.1. These analyses give the prediction of the earthquake response of the structure in each of its several bending and torsional modes. The total response is obtained by combining the contributions from the several modes in accordance with the Naval Research Laboratory (NRL) method (NRL Report 6002, November 15, 1967). The NRL method, in the judgment of Humble, results in more consistent and accurate predictions of the actual transient response that other commonly used modal combination methods.

Transient analyses of the response of several platforms to measured and artificially generated ground motion records have been made to verify adequacy of the modal analysis procedure. Other transient analyses which consider nonlinear effects have been used to verify adequacy of the pile-foundation model used in the design analysis.

Piecewise linear calculations are carried out to assure that the structure has sufficient ductility to meet earthquake criterion 3 given in

Section 1.1.1. By replacing yielding structural elements with the proper reactions as the loads are increased, the nonlinear elastoplastic behavior of the structure is approximated.

Damping is assumed to be uniform in all modes of vibration. For elastic response (criterion 1) a value of 3.5 percent of critical damping is used and for elastoplastic response (criterion 2), a value of 6.5 percent of critical damping is used. These values differ slightly from those suggested in Housner and Jennings' report (Appendix 1.1) and are derived for the specific structure, foundation conditions, and anticipated level of response.

2.3 Response to Waves

Dynamic analyses of the structure are performed for both the severe storm waves and those for the frequent storms to demonstrate structural adequacy. For severe storms, transient analyses are used in which the time response of the structure to a wave profile containing the specific design wave is calculated. For the frequent, operational storm causing repetitive stresses, structural response spectra are computed in the frequency domain. These response spectra are analyzed with statistical procedures that account for some nonlinearity in response to waves in order to obtain the expected repetitive stresses. Damping for all analyses is taken to be 2 percent.

2.4 Results of Analyses

2.4.1 Earthquake Loading

The proposed platform is designed and analyzed using three-dimensional models and analysis methods. For comparison purposes only, typical shears and moments related to the principal direction are shown in Figure 8. Dominance of the earthquake criteria over wave criteria is apparent in results shown in Figure 8. The earthquake criteria are even more dominant when the three-dimensional loading is considered.

Quasi-static loading patterns consistent with the results of the dynamic response analyses are imposed on the three-dimensional space frame structural model, along with gravity loads, and a structural analysis is performed. The axial and bending stresses are calculated for each member, and these are compared to the allowable stresses calculated in accordance with AISC Specifications for the Design, Fabrication, and Erection of Structural Steel for Buildings, Seventh Edition, 1970, with a factor of safety of 1.0.

The results of the analysis are shown in Figure 9. The combined stress proportionality factors range from a value of 0.05 to 0.70 which indicates the actual stress is well within the allowable stress.

Maximum deflections calculated for ground shaking appropriate for criteria 1 and 2 (cf. 1.1.2) occur parallel to the short platform dimension and are shown in Figure 10. For deflections shown, the structure remains elastic for criterion 1 and elastoplastic for criterion 2, thus fulfilling each.

The results of piecewise linear analyses, plotted in Figure 11, show that the elastoplastic behavior of the structure fulfills criterion 3. Deformations plotted are differential deflections between deck and base of the platform in the long platform dimension; this is the most severe loading direction for criterion 3. In fact, the structure remains ductile substantially beyond the minimum requirements of criteria 3.

A transient analysis was made for the ground shaking measured at Pacoima Dam during the February 9, 1971 earthquake in the San Fernando Valley. This record was selected, not because it is representative of a design condition, but because it contains the largest measured earthquake induced ground accelerations. In this analysis the structure remains ductile and thus would not collapse under this severe condition.

2.4.2 Wave Loading

Stress in the most highly stressed member under the loads from the severe design is within AISC allowable. For repetitive loading from frequent storms, maximum stress for over one million cycles was less than 2 ksi. These stresses are well below allowable levels.

3. PILING DESIGN AND SOIL CONDITIONS

Foundation borings and detailed geological-geophysical studies were made (1) to assure choice of a location where sediments in which the piling is founded will be stable under the largest earthquake ground shaking expected in the Santa Barbara Channel during the lifetime of the structure and (2) to provide data for design of adequate piling for the platform. A description of soil conditions shown by the geological-geophysical studies, and of piling design, follows in Sections 3.1 and 3.2, respectively.

3.1 Soil Conditions from Geological-Geophysical Study

The Santa Ynez Unit has been surveyed in detail using modern continuous seismic profiling (3000 joule arcer), high-frequency echosounding (3.5kHz sub-bottom profiler), and side scan sonar techniques (Appendix 1.2). The survey included

1590 line miles of arcer and echosounder data and 577 line miles of side scan sonar data. In addition to core holes drilled for soil engineering tests, 19 core holes were drilled for supplementary lithologic and paleontologic control. Spacing of north-south profiles in the proposed platform site area is 500 feet, with 2000-feet spacing of east-west tie lines. Positioning of profiles was performed with a precision, high-frequency radio-positioning system.

A detailed description of the near-surface geology of the Santa Ynez Unit is contained in Appendix 1.3, along with maps showing profile locations, bathymetry, percent slope, structural geology, and thicknesses of major stratigraphic units. Methods of interpretation are also summarized.

The proposed platform site area in Federal Lease Tract OCS P-0188, at a nominal water depth of 850 feet, is situated approximately halfway down the smooth basin slope from the edge of the mainland shelf. It lies on a gently sloping (approximately 7% slope or 4°) portion of the sea floor where there are no small-scale topographic irregularities or channels. In the unconsolidated surface sediment, there is no evidence of surface faulting, fracturing or failure.

Predominantly fine-grained sediments (silty clay and clayey silt) have been accumulating at this locality with little or no interruption in deposition for at least the past 80,000 years. Although rates of sedimentation have varied with changes in sea level during Pleistocene periods of high and low sea level, there is no evidence that sea level changes or tectonic activity have produced conditions of submarine erosion or subaerial exposure. This portion of the margin of the Santa Barbara Basin has not experienced recent, local tectonic uplift and has been the site of passive accumulation of sediments during the late Pleistocene, and probably since the end of the major mid-Pleistocene orogenic activity that produced the present basin topography.

Sediments encountered in borings at or near the platform site comprise the upper portion of a late Pleistocene-Holocene wedge that thickens to at least 1000 feet near the southern boundary of Federal Lease Tract OCS P-0188 and thins to a few feet near the outer edge of the mainland shelf. The minimum thickness of the wedge at the proposed platform site is 450 feet.

The proposed platform site lies in an area of uniformly southward-dipping sediments in which dips are no greater than 6° (10.5% slope) in the upper 1000 feet. The nearest subsurface faulting recognized in the upper 1000 feet of sediment lies 3500 feet to the southeast of the site. This faulting, near the base of the basin slope, is part of an east-west trending zone of reverse and normal faults with small vertical displacement of the sea floor. On the margin of the Santa Barbara Channel there are numerous folds and faults. None of the problems associated with such structures are anticipated in the homoclinal area of the proposed platform site where such structures are not present.

Submarine slides involving unconsolidated sediments and rotational slumps of semi-consolidated blocks are absent in the Santa Ynez Unit except for a shallow submarine slide in water depths greater than 1200 feet near the boundary between Federal Lease Tracts OCS P-0180 and P-0188. Although a submarine slide mass is present in Federal Lease Tract OCS P-0180 and slides and rotational slump blocks exist to the east outside the Santa Ynez Unit, conditions near the proposed site in OCS P-0188 are not conducive to near-surface slope failure. In contrast to those conditions in OCS P-0188, the submarine slide in OCS P-0180 occurred in an area of steeper slope and greater thickness of the stratigraphic unit involved in the slide.

Additional data collected after completion of Appendix 1.3 indicate that rotational slumps of large size occur east of Federal Least Tract OCS P-0187 (5-1/2 miles east of the proposed platform site), but do not occur within the Santa Ynez Unit boundaries. The large slump blocks to the east have formed on slopes as steep at 26% (14.5°). These slopes are three times as steep as those at the proposed platform site, and twice as steep as the maximum slopes observed within the Santa Ynez Unit. The slumps east of the Santa Ynez Unit are probably related to major basin-bounding fault zones where the Pleistocene-Holocene sediment wedge is thin. Conditions conducive to this type of failure are not present within the Unit boundaries.

On the basis of the studies summarized above, we conclude that sediments in which the platform will be founded at the proposed location will be stable under the largest earthquake ground shaking expected in the Santa Barbara Channel during the lifetime of the structure. This conclusion is based on:

(1) absence of slides in sediments younger than 80,000 years at or near the platform site, which indicates that these sediments have

remained stable under all earthquakes affecting the area during deposition and up to the present.

(2) absence of near-surface faulting, fracture, or failures in sediments at or near the platform location.

(3) absence at or near the platform site of the combination of geological conditions associated with slides that have been identified in the Santa Barbara Channel.

3.2 Pile Design

3.2.1 Soil Description

The soil condition for pile design at the site of the platform is described in the report, Soil and Foundation Investigation, Lease OCS P-0188, Boring 188EE, Santa Barbara Channel, by McClelland Engineers, Inc. This report is Appendix E of Specifications for Construction of a Self-Contained Platform for Drilling and Producing Operations, Santa Barbara Channel (Appendix 1.5). For the soil study reported, continuous 2-1/2 inch OD samples were taken for the first 50 feet and two-foot long samples were taken at 10-foot intervals thereafter to the final penetration of 350 feet. Conventional tests, including water content, unit dry weight, liquid and plastic limit tests and 7 types of shear tests were made to determine soil properties for use in pile design.

In general, the soil is slightly over-consolidated silty clay. Its strength increases from 200 psf at the mudline to 5500 psf at 350-foot penetration.

3.2.2 Criteria

The piles are designed to carry normal gravity and operating loads in conjunction with appropriate earthquake or storm forces as described in Section 1.

3.2.3 Design

Since the early 1960's laterally loaded piles for offshore structures have generally been designed by methods developed by Professors Matlock and Reese of the University of Texas. By field test correlations, Matlock developed discrete nonlinear springs to represent the response of a pile being moved laterally through soil. BMCOL, a computer program developed by Matlock for the finite-difference solution of laterally-loaded piles in nonlinear soil, is used to solve for the deflection, the bending moment, and the shear in a pile for given pilehead conditions. (Matlock, 1970; Matlock and Reese, 1961).

The axially-loaded pile analysis is carried out in two steps. The required pile penetration is computed according to current skin friction and point bearing techniques, and the axial load-deformation is calculated using computer program PX4CI developed by Professor Coyle of Texas A & M University for the solution of axially-loaded piles in nonlinear soil. (Coyle and Reese, 1966).

The fundamental assumption for pile design is that the dynamic loading of a pile is similar to the static loading. The difference in resulting pile stresses has been found to be negligible for the range of parameters important to Humble's design. The peak dynamic response of the entire pile may be analyzed by imposing the peak pilehead dynamic response on a detailed static model of the pile-soil system. Matlock's BMCOL program is used to determine the pile response to lateral and rotational pile cap deflection while Coyle's PX4CI program is used to predict the pile response to axial pilehead deflection. The peak dynamic pilehead response results from the loading pattern predicted by a three-dimensional dynamic response model. This loading pattern, which accounts for bi-directionality and torsion, is imposed on the linear static three dimensional structural analysis program, FRAN. In the FRAN model, the foundation is idealized by a set of linear springs resulting from the linearization technique outlined in Section 2.1. The results of the structural analysis specify the pilehead response at each of the twenty piles.

Given the pilehead response, the total stress distribution in the pile can be computed and compared with the allowable stress in the following manner: The bending moment in the pile is obtained using the Matlock program with the appropriate lateral deflection from FRAN. The resulting combined bending and axial stress is then compared with the allowable stress appropriate for the criterion being considered.

Earthquake forces rather than storm forces control the design of the piles. The maximum combined stress in the piles for earthquake criterion 1 is 39.1 ksi which, being well below the pile yield stress of 50.0 ksi, is acceptable. For earthquake criterion 2, the maximum plastic moment ratio (the ratio of actual moment in the pile to the maximum allowable moment for the given axial load without fully yielding the pile cross section) is 0.82. Since this ratio is less than 1.0, the pile is not fully yielded and is therefore acceptable.

The pile penetrations are determined using McClelland's latest capacity-prediction techniques for tubular piles in soft clay (Vijayvergiya and Focht, 1972).

Each of the 20 piles is made up of two components, an outer pile extending to a penetration of 130 feet below the mudline, and a smaller-diameter insert pile extending to a penetration of 340 feet for main piles and 250 feet for skirt

(Revised)

piles. The main piles consist of 48-inch outer piles and 42-inch inserts while the skirt piles consist of 54-inch outer piles and 48-inch inserts. The inability of existing pile driving equipment to drive 48-inch or 54-inch piles to the total required penetration requires the use of a two-part pile. The outer main pile is driven to its required penetration through a 54-inch OD jacket leg while the outer skirt pile is driven through a 63-inch skirt pile sleeve located near the bottom of the platform. The annulus between the outer pile and jacket leg or skirt pile sleeve is then filled with grout, which forms the link between the pile and the platform. Following this, an insert pile is installed inside the outer pile by conventional oil field drilling and grouting techniques. The grout bonds the insert pile to the outer pile and also bonds the composite pile to the soil, allowing distribution of horizontal and vertical reactions to the soil.

4. CONSTRUCTION AND INSTALLATION

4.1 Fabrication and Installation

Although the proposed platform is larger than any built to date, construction techniques are conventional. From conception prospective contractors have participated in and contributed to the design concepts that effect fabrication and installation.

To implement this project, a contractor or contractors will develop an assembly yard, fabricate and assemble the structure, barge transport it from the assembly yard to the erection site, and make the installation.

The principal components of an offshore platform are the deck, the jacket, and the piling. Each of these components can be fabricated as a single unit or as multiple units. The decision as to how a platform is fabricated onshore depends upon the projected availability of construction equipment to handle the components offshore. Decks and piling have historically been subdivided to facilitate transportation and handling and until the development of the launch barge in the early 1960's, jackets were generally composed of a number of small units or templets. Launch barges have since permitted the installation of single jackets approaching 400 feet in length and 5000 tons in weight. In the mid 1960s the multiple templet concept made a comeback in the form of platforms with two or more large templets or jackets. This concept provided large platforms capable of twin rig drilling and simultaneous production.

The 850 foot platform proposed for installation in the Santa Ynez Unit is an extension of the proven jacket platform concept. Because of launch barge length limitations, the 850-foot jacket will be loaded, transported, and launched in two separate units; then connected in sheltered waters of the Channel, towed to the erection site, and installed by lowering the structure to the ocean floor where it is secured by piling. This basic procedure has been employed on over 90% of the offshore platforms built to date.

The in-water structural connection of the two jacket units will be by full strength butt welding of the eight jacket legs from inside, using water-tight chambers formed within each leg to provide a welder habitat. (See Drawing HQE-215-12 of Appendix 1.4).

4.1.1 Fabrication and Installation - Plans and Specifications

(1) Appendix 1.4 is Drawing Series HQE-215-1 through 15 which describes in some detail the proposed platform.

(2) Appendix 1.5 is Specifications for Construction of a Self-Contained Platform for Drilling and Producing Operations, Santa Barbara Channel which describes in detail the work to be undertaken, the quality that is expected, and the materials that are permitted.

4.1.2 Platform Design - Transportation and Installation

The platform is designed (1) to withstand the most severe loads that might occur during transportation and installation, and (2) to have adequate stability. The design requirements insure structural integrity under dynamic wave loads that might occur during transportation, and under impact loads that might occur during either transportation or installation. Stability requirements insure safety under tow and during installation.

4.1.3 Model Testing - Transportation and Installation

The test results from previous model studies indicate that in-water performance can be predicted analytically and that structures of this size can be safely towed and accurately set at a precise location in the open sea.

A model of the 850 foot platform was constructed. This is a highly effective training device to familiarize Humble and contract personnel responsible for platform installation with the floating, flooding, response and uprighting characteristics of installation. It also provides an additional means of verification of calculations and previous experience in the areas of in-water flotation, stability, relative motion, and the up-ending sequence.

4.1.4 Hydrostatic Design - Installation

All platform members subject to hydrostatic loading are designed to withstand these pressures in accordance with procedures outlined in the Principles of Naval Architecture, a Society of

Naval Architects and Marine Engineers publication, 1967 Revised Edition.

Specifically, the design procedure prevents yielding of the shell by meeting the requirements of the von Sanden-Gunther formula found in Report No. 396 of U.S. Experimental Model Basin, _The Influence of Stiffening Rings on the Strength of Thin Cylindrical Shells Under External Pressure_, by Charles Trilling. Lobar buckling is checked by the Windenburg formula found in _Principles of Naval Architecture_. Elastic instability of ring stiffeners is prevented by using the von Sanden-Gunther formula found in Technical Memorandum No. 3, Bureau of Ships, U.S. Navy Department, _Preliminary Hull Design Data for Submarines_, by C. D. Anderson. General instability of the cylindrical shell and the ring stiffeners are checked by the procedure outlined in Report No. 1106, David Taylor Model Basin, U.S. Navy Department, _A Graphical Method for Determining the General Instability Strength of Stiffened Cylindrical Shells_, by Thomas E. Reynolds. Ring stiffener stress is checked by combining the bending stress calculated by the Kendrick formula with the hoop stress calculated by von Sanden-Gunther formula; both formulae are found in _Principles of Naval Architecture_.

4.2 Corrosion Control

The platform is protected from corrosion by coatings above mean water level and by cathodic protection below mean water level.

Protective Coating

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

(1) Galvanizing - applied to all hardware, fencing, handrails, and grating.

(2) Sheathing - synthetic rubber and monel sheathing is applied to all members in the wave zone between ELEV (-) 8'-0" and ELEV (+) 16'-0".

(3) Painting - a five-coat, 14-mil epoxy or vinyl system is applied to all surface areas above mean water level not protected by galvanizing or sheathing.

Cathodic Protection

The cathodic protection system used employs standard materials used in accordance with conventional engineering practices. The system is a galvanic anode system that will provide 10 ma/sq.ft.

of current density for surfaces in the water zone and 4 ma/sq.ft. current density for surfaces in the mud zone for approximately 20 years. Provision is made to switch to an impressed current system for the remainder of platform life after depletion of the galvanic system.

5. PLATFORM REMOVAL

Features that facilitate the removal of this platform were incorporated in its design. Following the depletion of all producing zones developed from the platform, wells will be plugged and abandoned. Well conductors will be cut below the mudline and removed; drilling and production equipment will be dismantled and removed; and the deck units will be removed. Auxiliary buoyancy tanks will be installed, all piling will be cut below the mudline, and the jacket legs and buoyancy tanks will be deballasted until the jacket floats. The jacket will then be removed and the site restored in accordance with permit requirements.

6. EARTHQUAKE RESPONSE INSTRUMENTATION

The platform will be equipped with appropriate instrumentation to measure response to earthquakes that might occur during its life. These response measurements will permit a final in-place test of response analyses.

The instrumentation will also permit vibration-response surveys that will provide data for an overall test of dynamic analyses used in design.

7. PLATFORM BEAUTIFICATION

The proposed Santa Ynez Unit platform will be located about five miles from the nearest land and its visibility will be limited. However, Humble and the architectural firm of Linesh and Reynolds, which planned the THUMS Islands Beautification Project, have conducted studies to develop platform beautification techniques. These range from techniques to camouflage the structure to those which accentuate the platform but in a modified form which may be more pleasing to the viewer.

A platform five miles at sea will be visible from shore less than one-half of the time; and when visible, it will appear to the viewer as a small black silhouette because of the back-lighting effect of the sun. Screening may be accomplished by use of panels to change the shape or clarity of the structure's silhouette. Another method of screening could be to utilize something that reaches out of the shadow area and reflects the natural light. A water spray from the upper deck of the platform has been considered. Partial tests of an offshore island at Seal Beach, shown in Figures 12 and 13, illustrate the possibility of this approach.

Work is continuing to develop and evaluate practical and effective beautification techniques for application on the initial platform.

TABLE I

DECK DESIGN LOADS

Live Load

	Drilling Deck	Production Decks
Equipment Area	750 psf	600 psf
Derrick Area	400 psf	400 psf

Derrick Corner Load: 400 kips/corner

Dead Load

Deck Weight in Air = 3120 kips

TABLE II

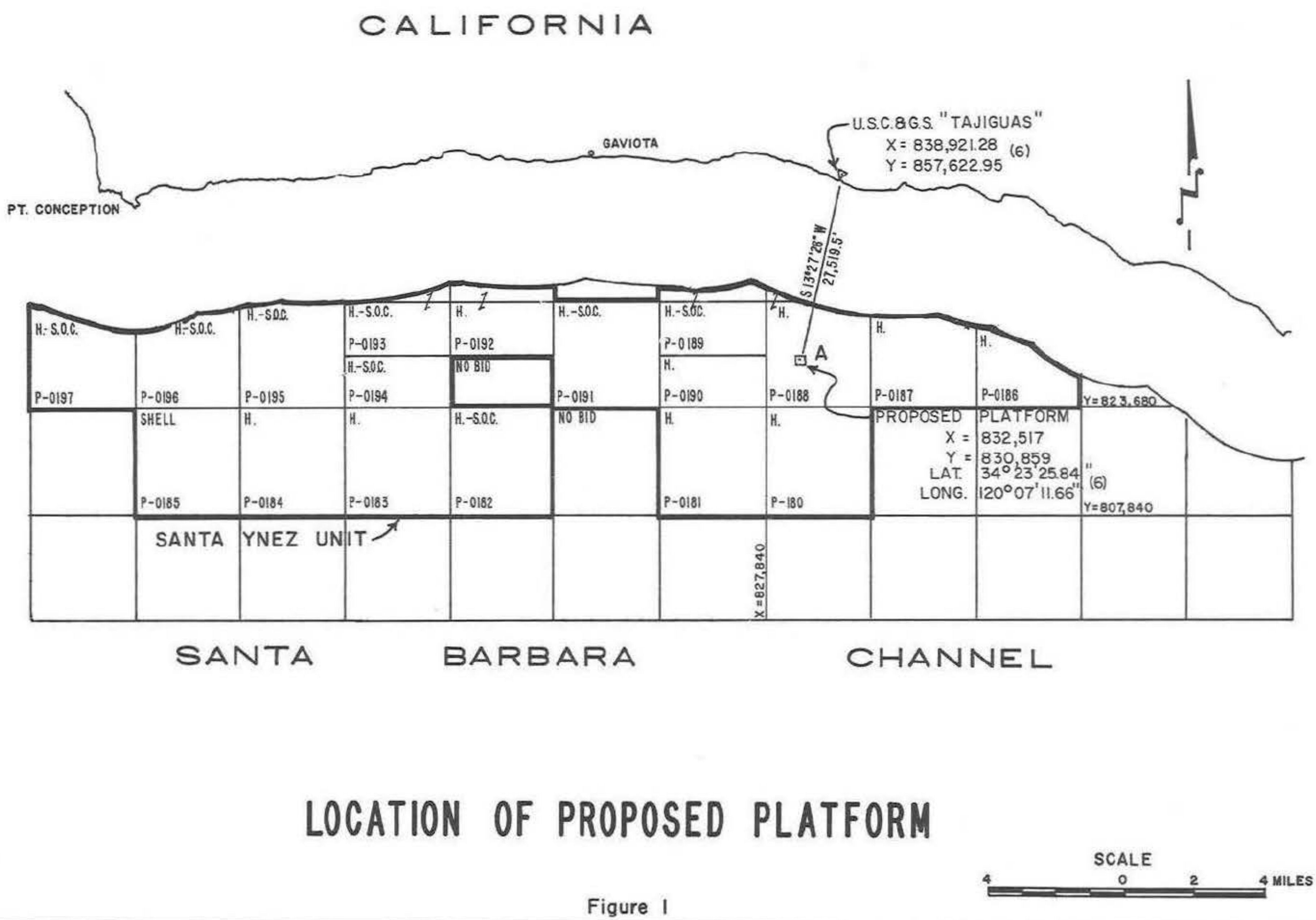
JACKET DESIGN LOADS

	Design Kips
Live Load	
1. Rig Drilling	950
2. Pipe Rack	1000
3. Mud Tanks	450
4. Drilling Equipment	1845
5. Production Equipment	2985
Total Live Load	7230

7,230,000

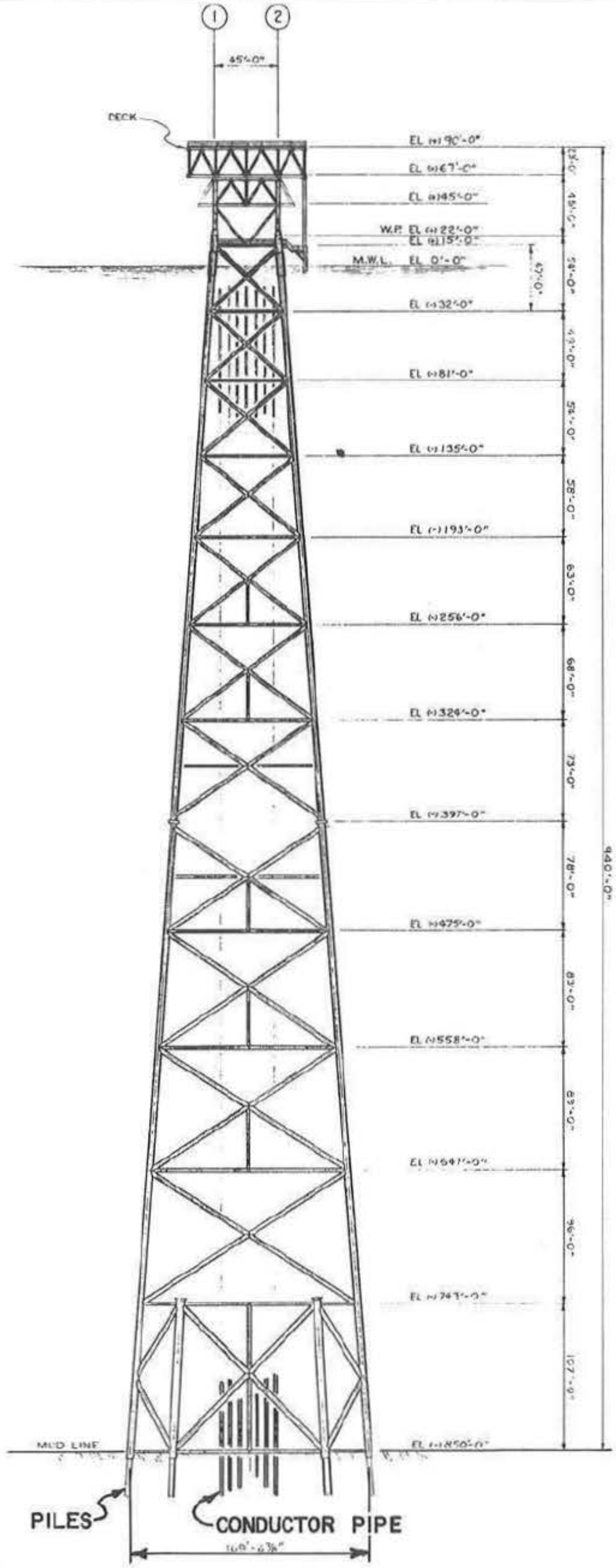
	Design Kips
Dead Load	
1. Deck Weight in Air	3120
2. Jacket Weight in Water	16200
Total Dead Load	19320

(Revised)



LOCATION OF PROPOSED PLATFORM

Figure 1



SOUTH ELEVATION

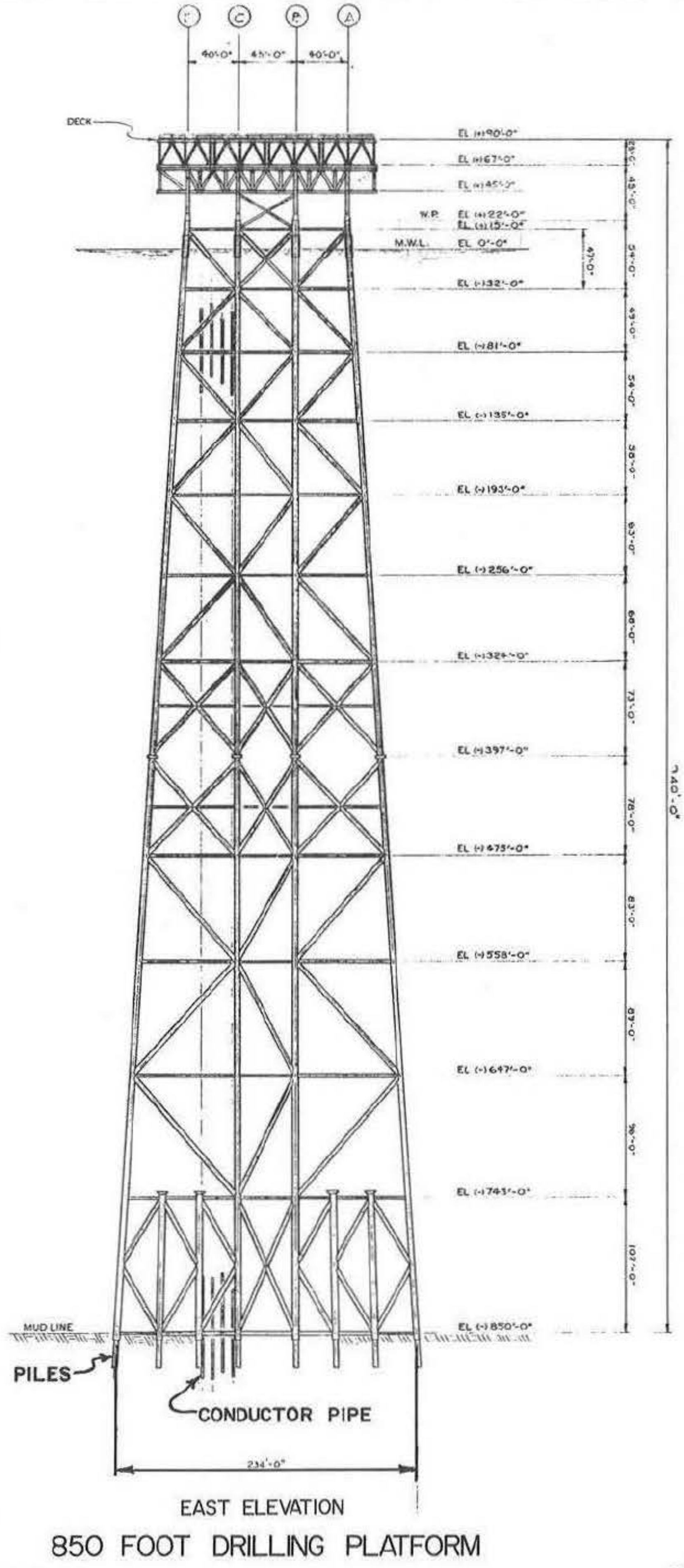
850 FOOT DRILLING PLATFORM

SANTA BARBARA CHANNEL

OCS-P0188

FIG. 2

Revision



EAST ELEVATION

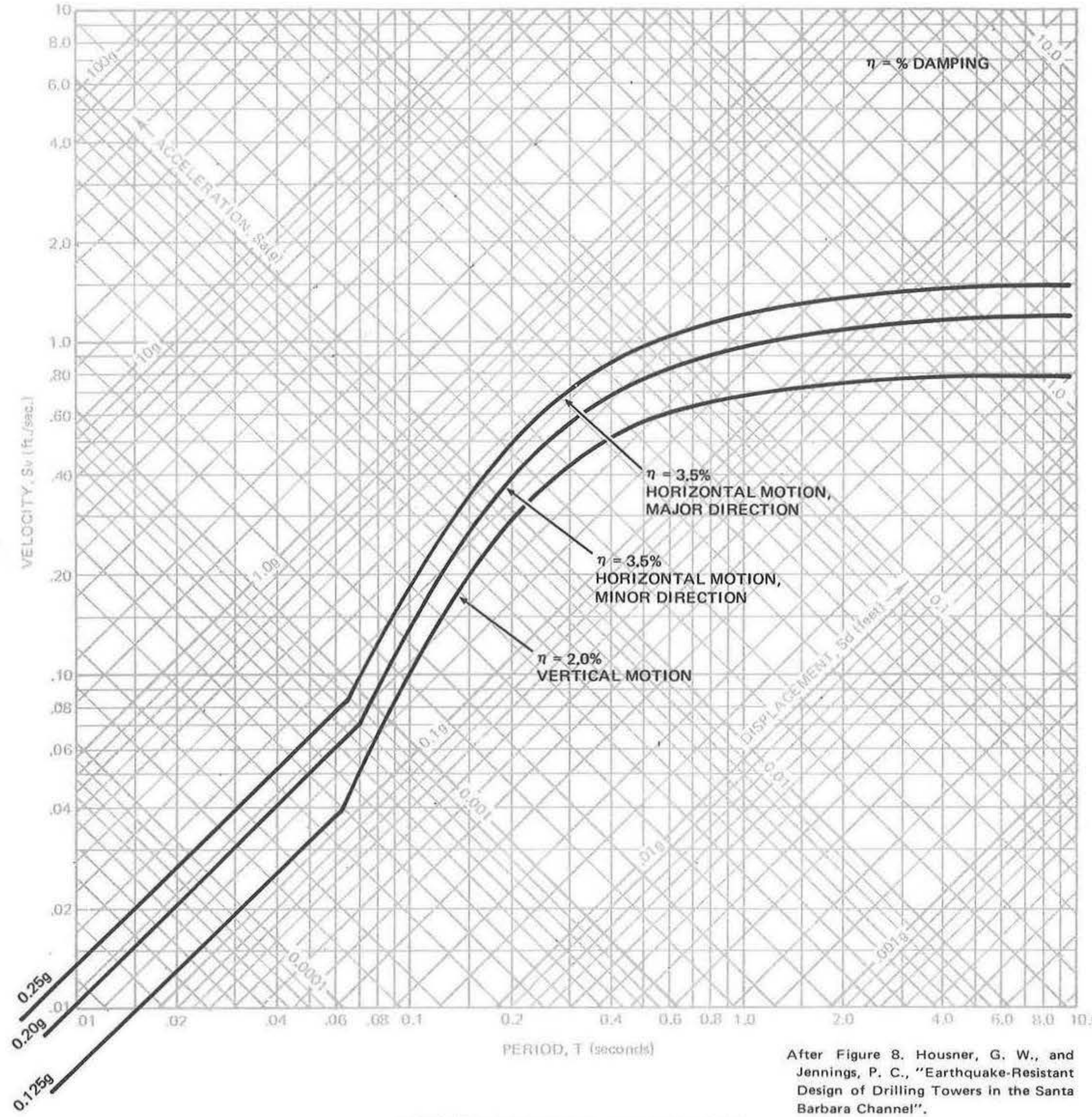
850 FOOT DRILLING PLATFORM

SANTA BARBARA CHANNEL

OCS-P0188

FIG. 3

Revision

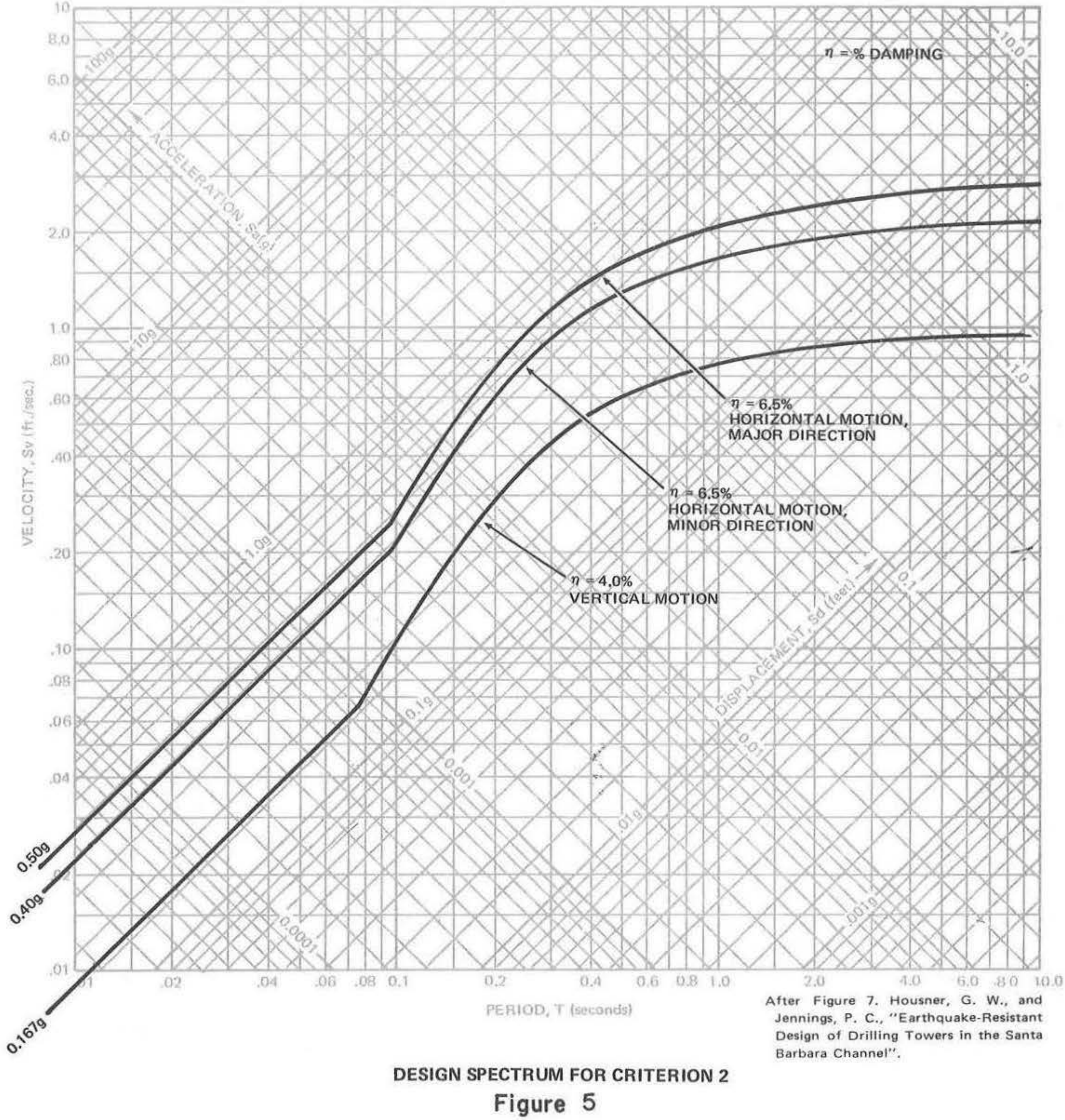


After Figure 8. Housner, G. W., and Jennings, P. C., "Earthquake-Resistant Design of Drilling Towers in the Santa Barbara Channel".

DESIGN SPECTRUM FOR CRITERION 1

Figure 4

Revision

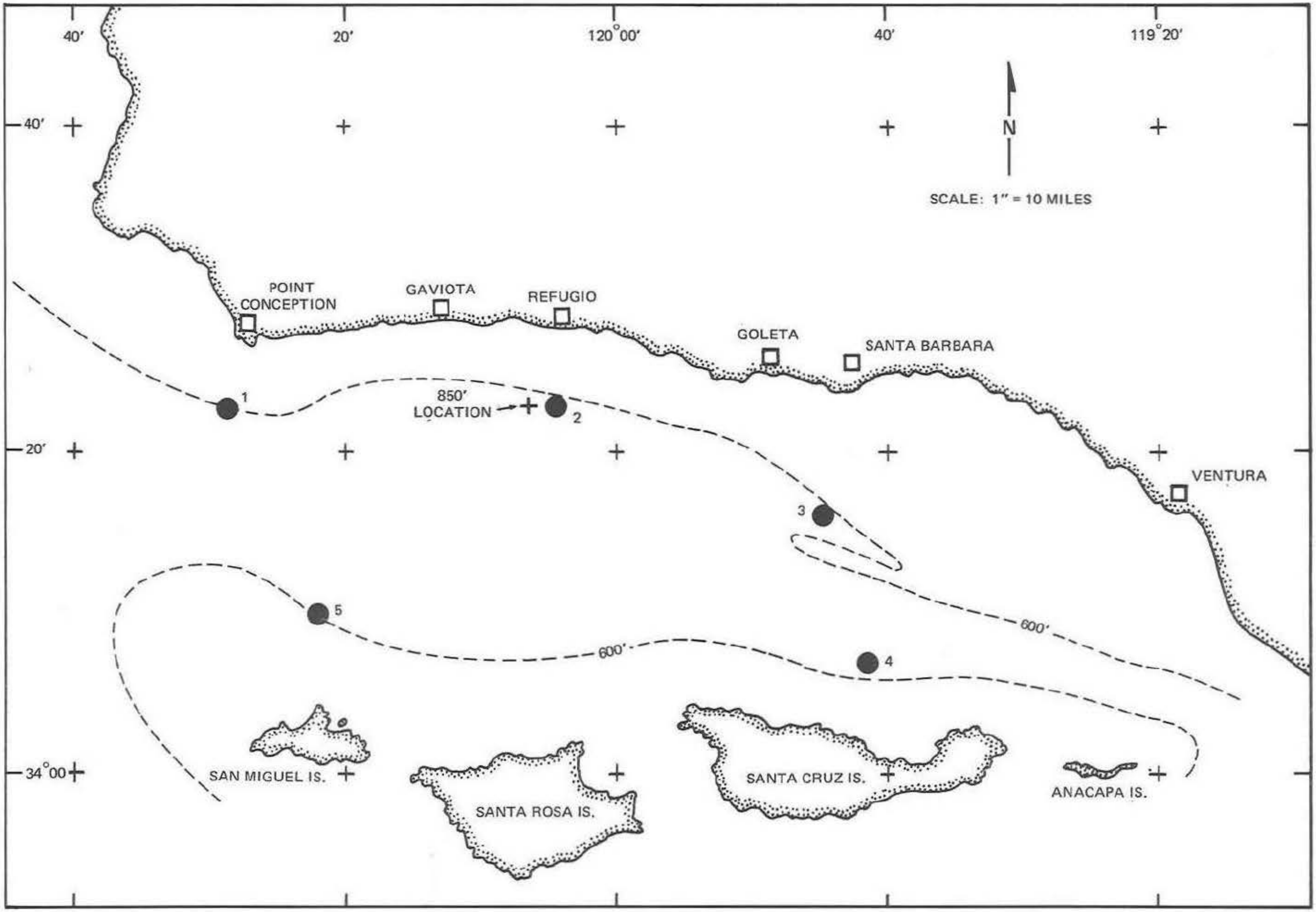


After Figure 7. Housner, G. W., and Jennings, P. C., "Earthquake-Resistant Design of Drilling Towers in the Santa Barbara Channel".

DESIGN SPECTRUM FOR CRITERION 2

Figure 5

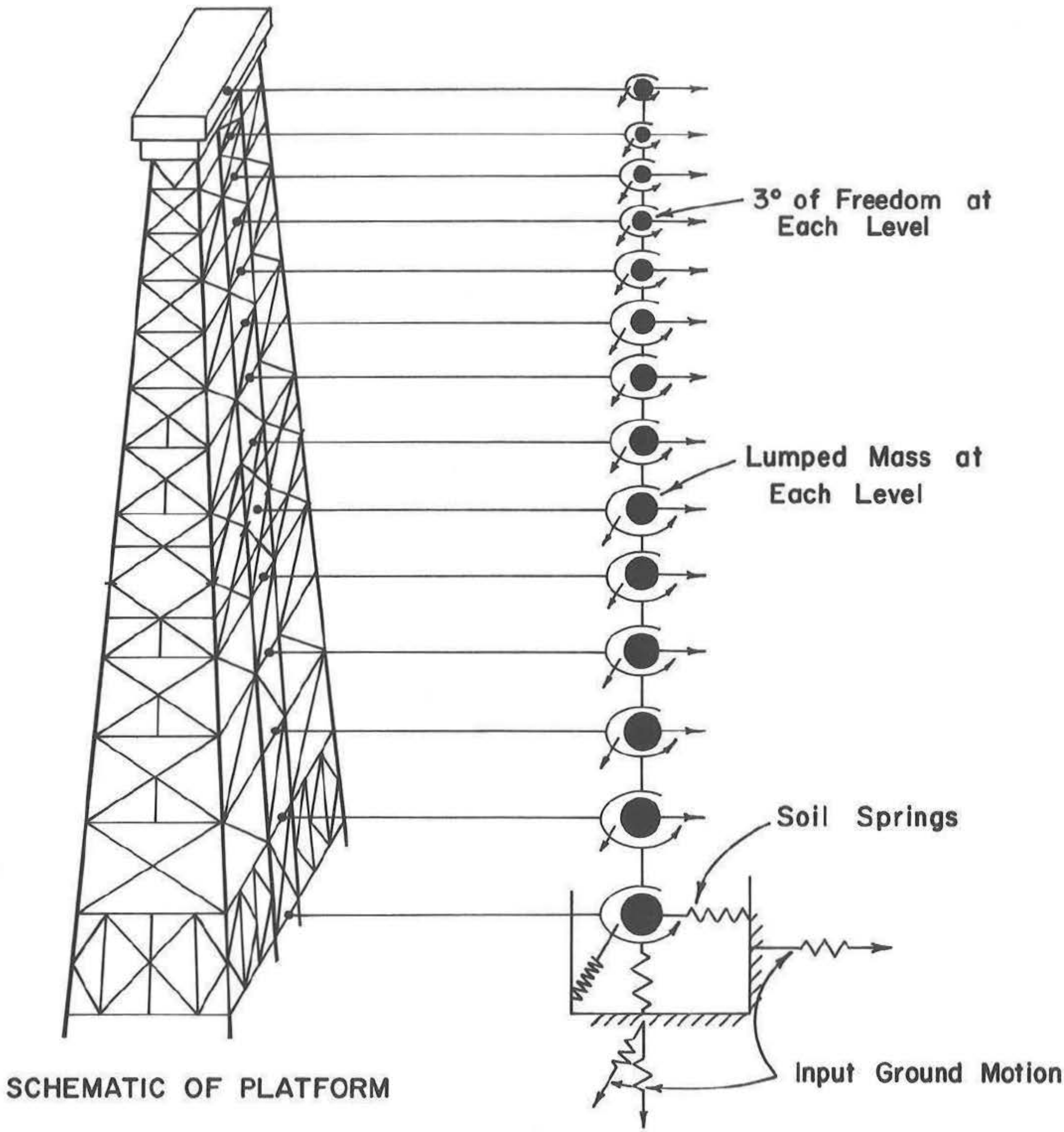
Revision



Revision

LOCATION OF SITES FOR HINDCASTS OF SEVERE STORMS

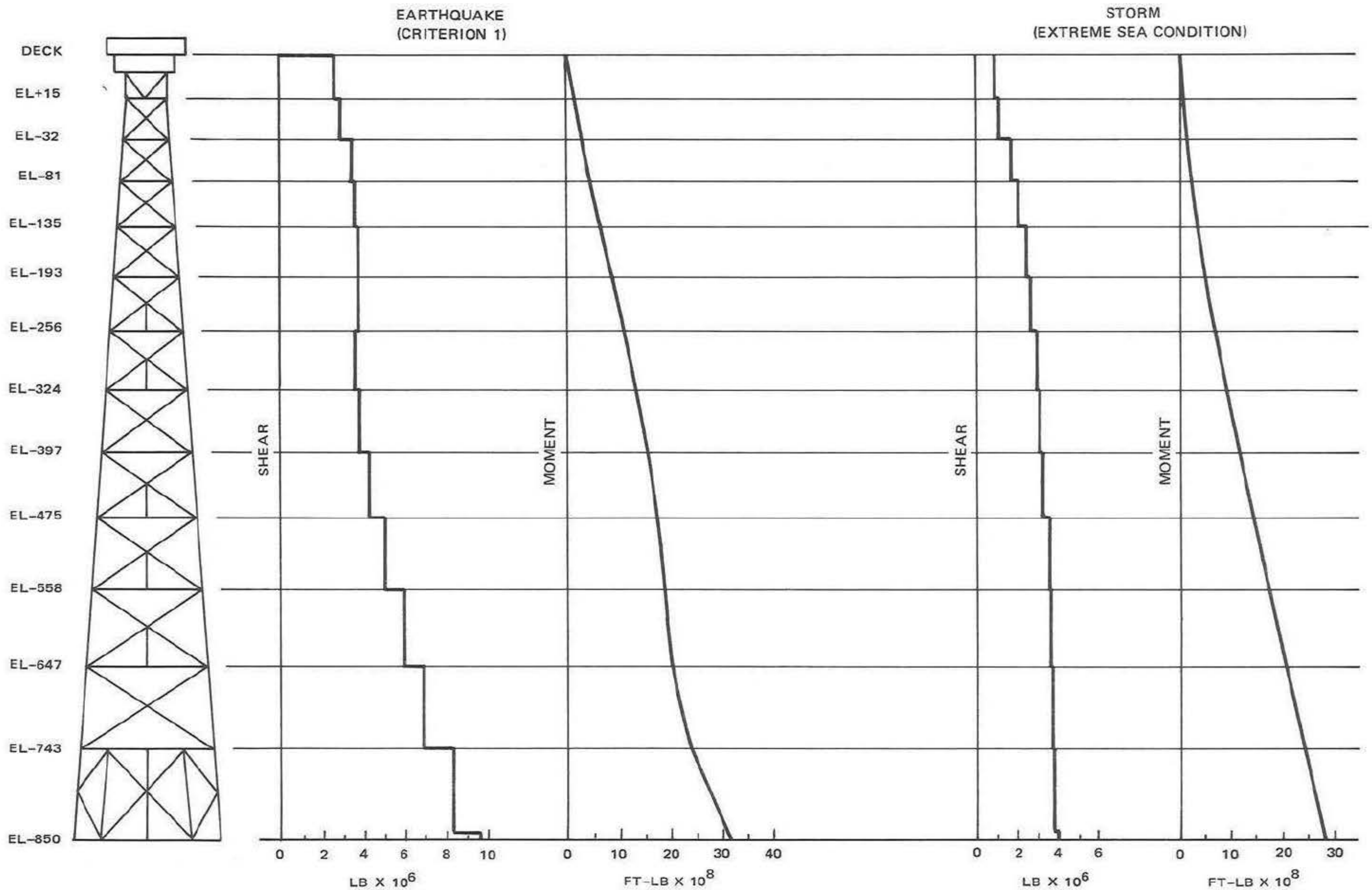
Figure 6



MODEL FOR DYNAMIC ANALYSES

Figure 7

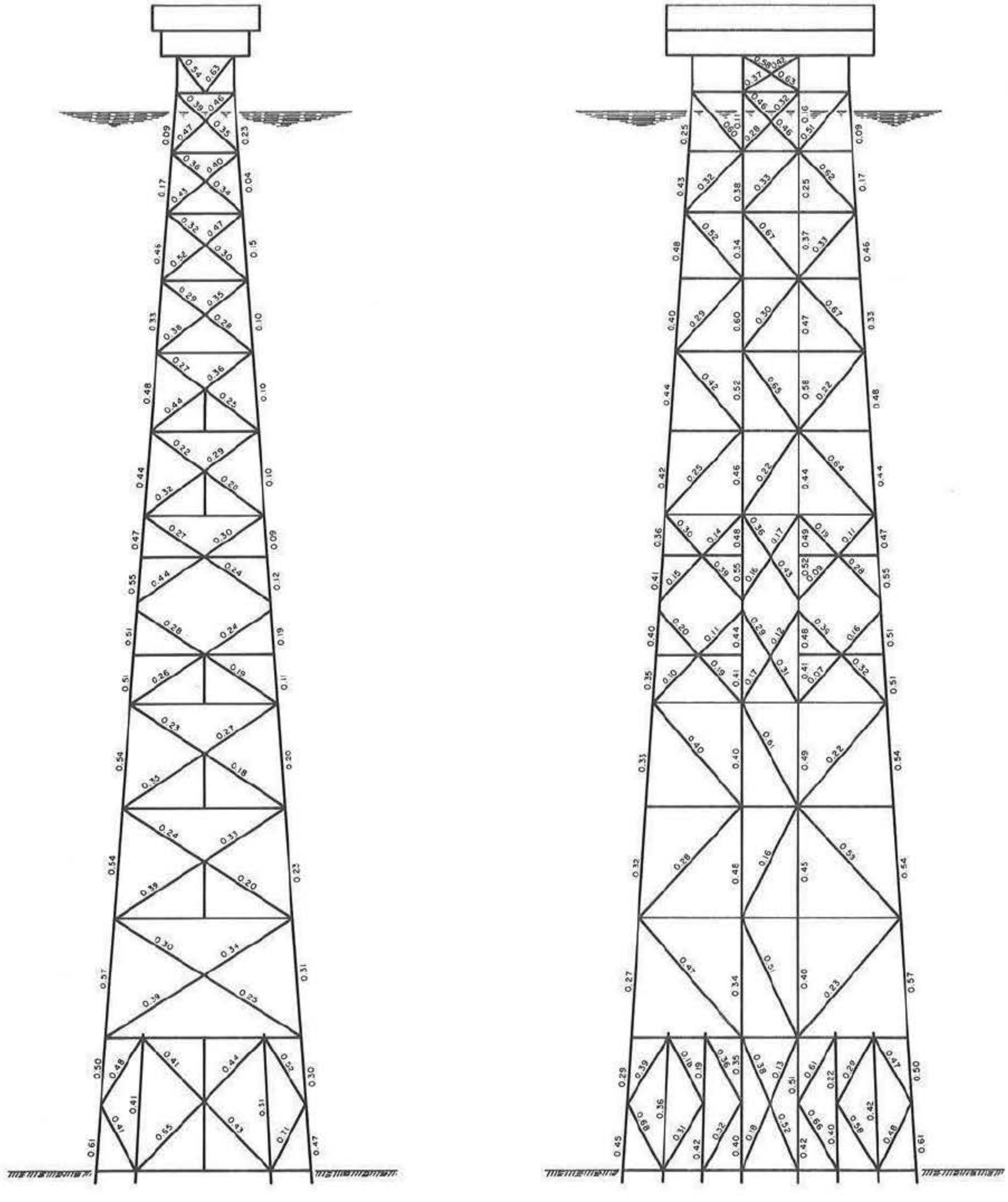
(Revision)



SHEAR AND MOMENT DIAGRAMS FOR EARTHQUAKE AND STORM LOADS (PRINCIPAL DIRECTION)

Figure 8

(Revision)



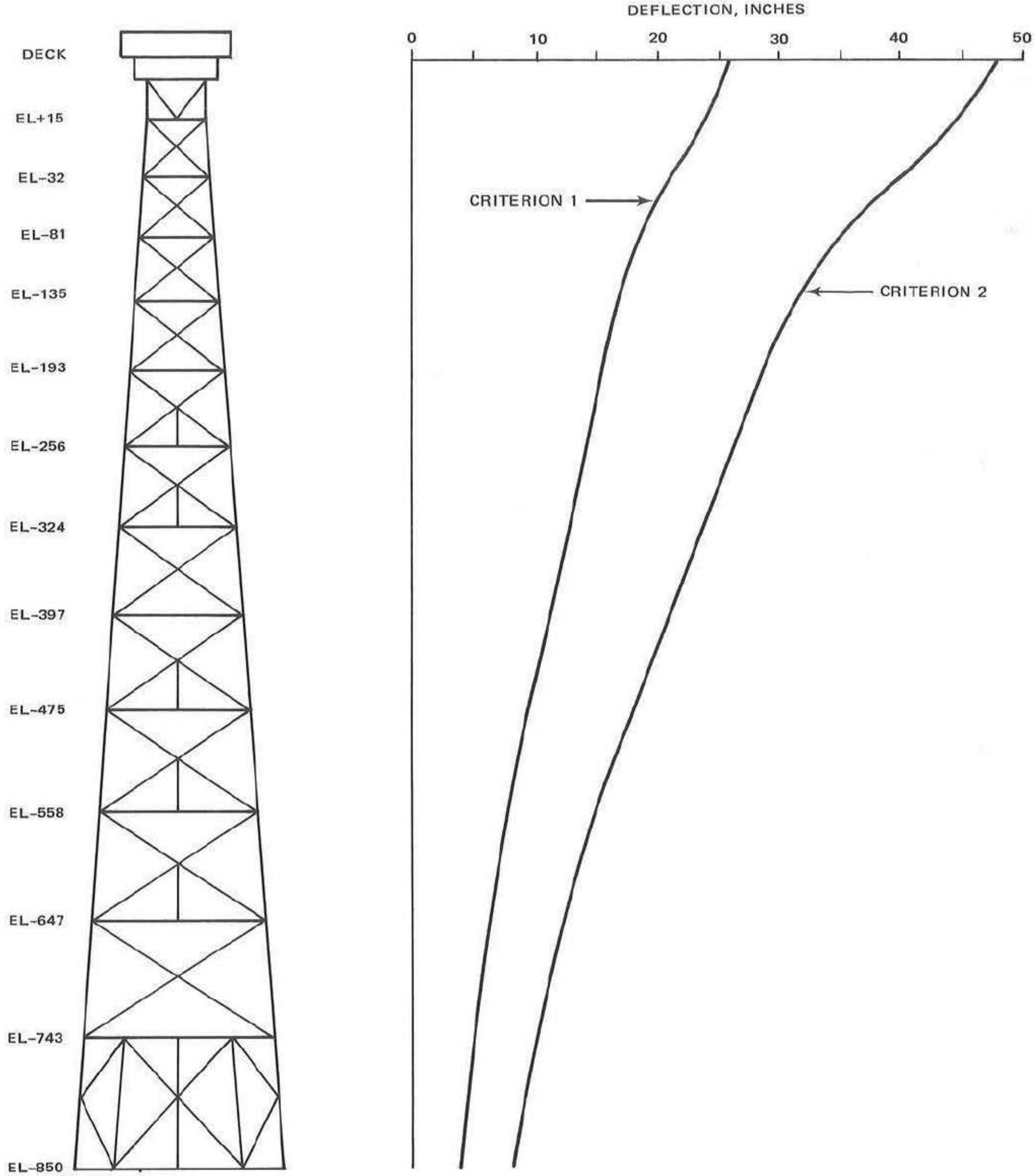
COMBINED STRESS PROPORTIONALITY FACTORS* FOR CRITERION 1 (DESIGN EARTHQUAKE)

*CALCULATED IN ACCORDANCE WITH SECT. 1.6 AISC "SPECIFICATION FOR THE DESIGN, FABRICATION & ERECTION OF STRUCTURAL STEEL FOR BUILDINGS," FEB. 12, 1969 WITH FACTOR OF SAFETY = 1.0 (YIELD CRITERIA)

NOTE: ELASTIC BEHAVIOR FOR VALUES OF 1.0 OR LESS.

Figure 9

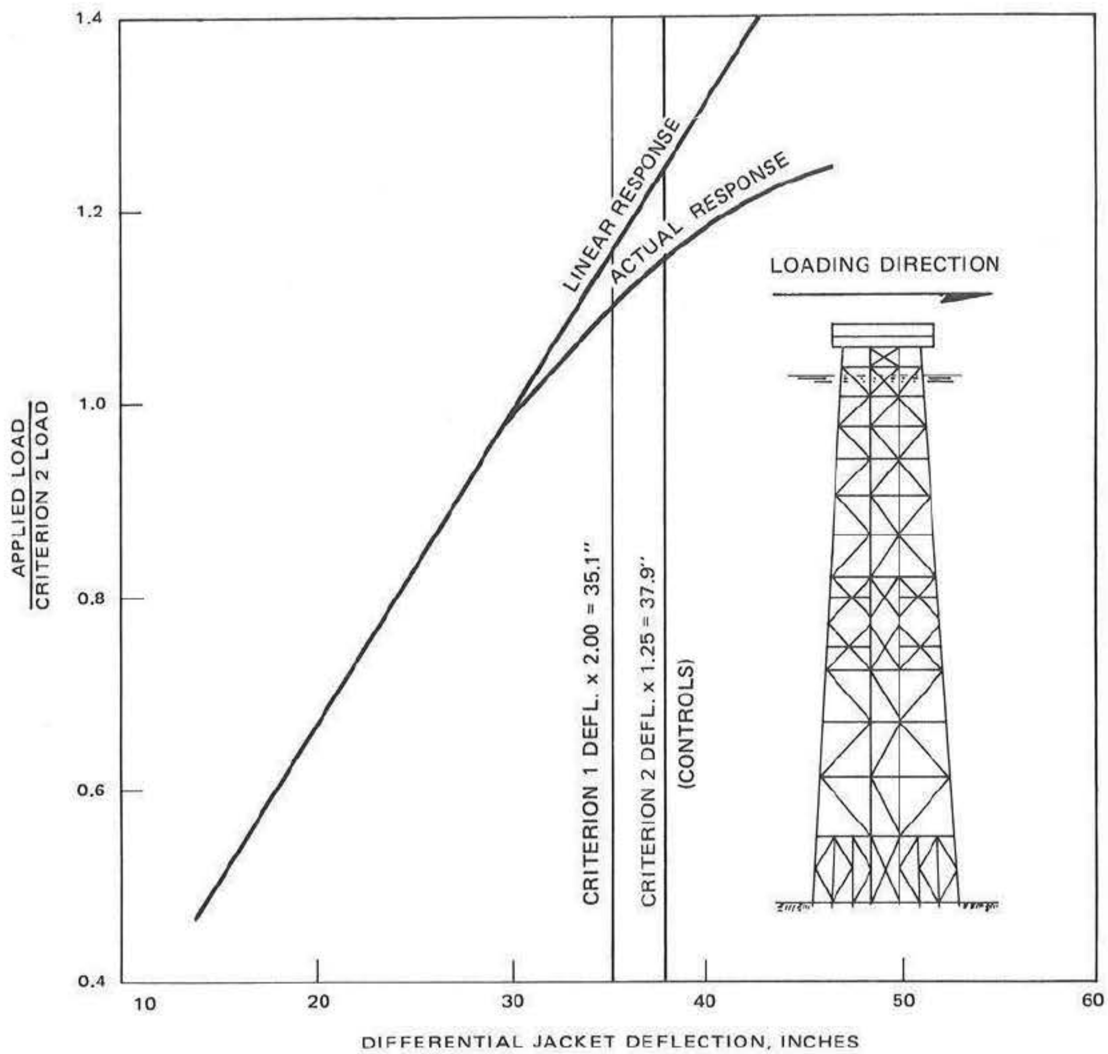
(Revision)



PLATFORM DEFLECTIONS FOR EARTHQUAKE LOADINGS

Figure 10

(Revision)



DIFFERENTIAL JACKET DEFLECTIONS

Figure 11

(Revision)

STRONGER EARTHQUAKES
CALIFORNIA AND WESTERN NEVADA

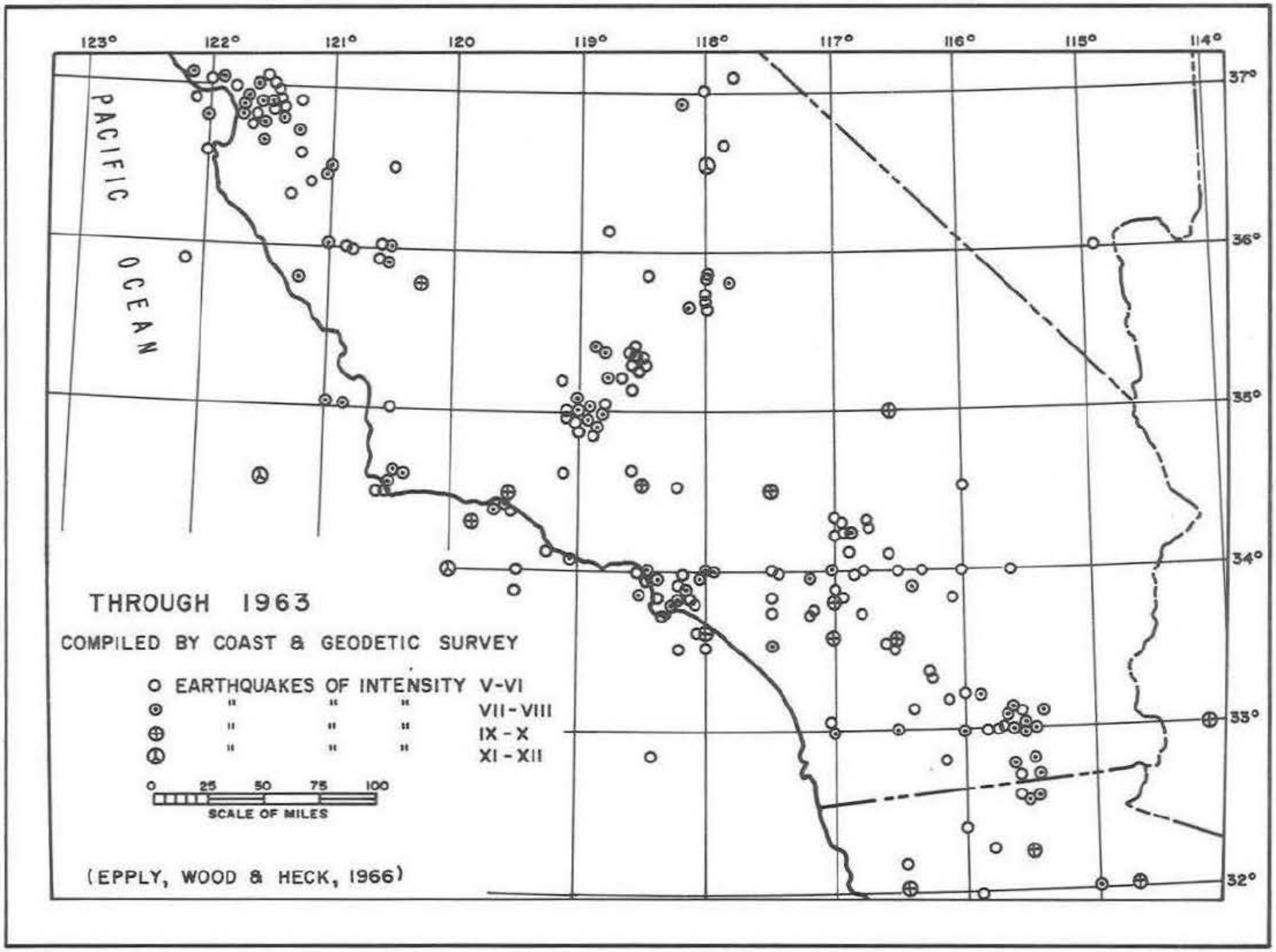
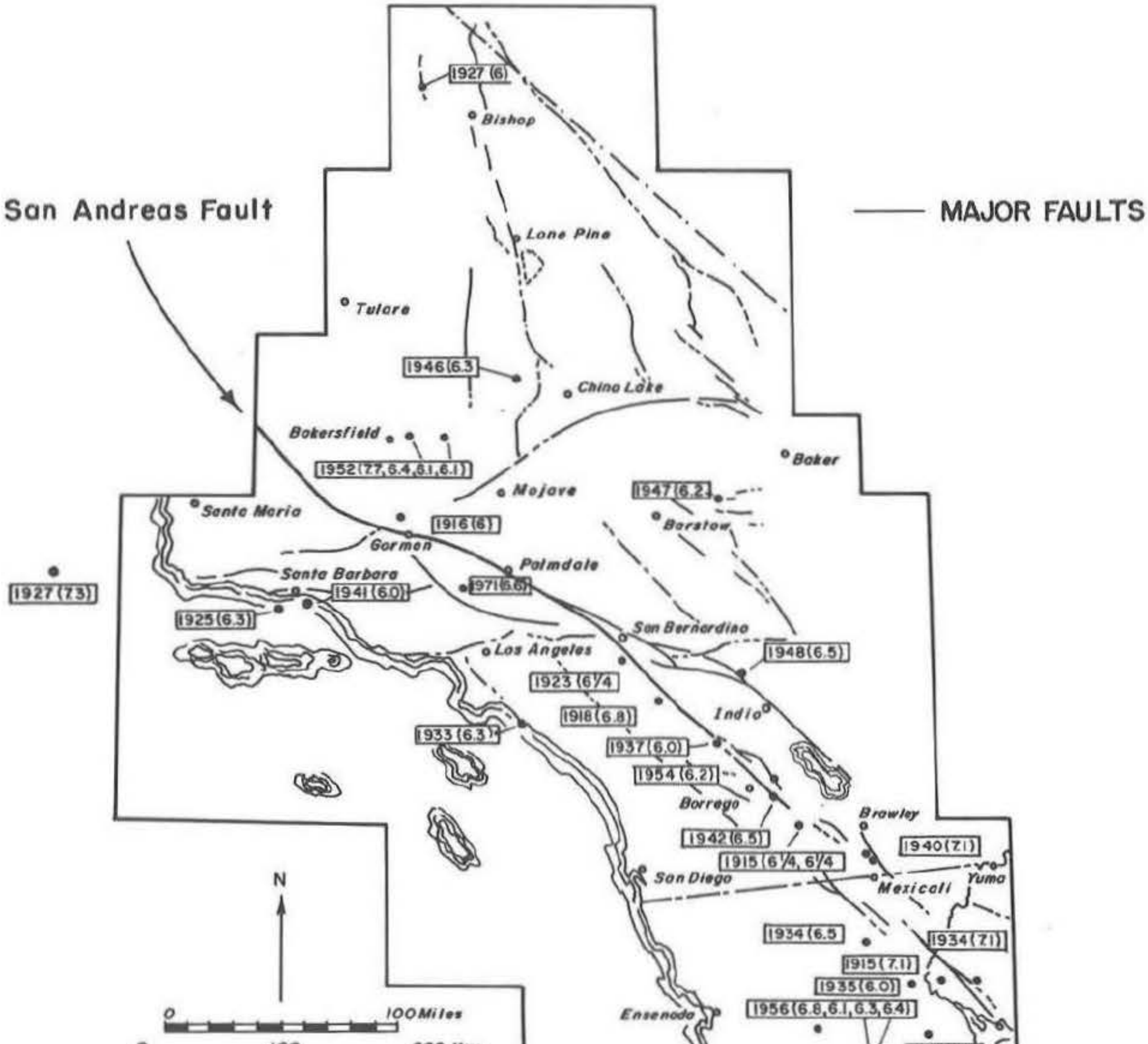
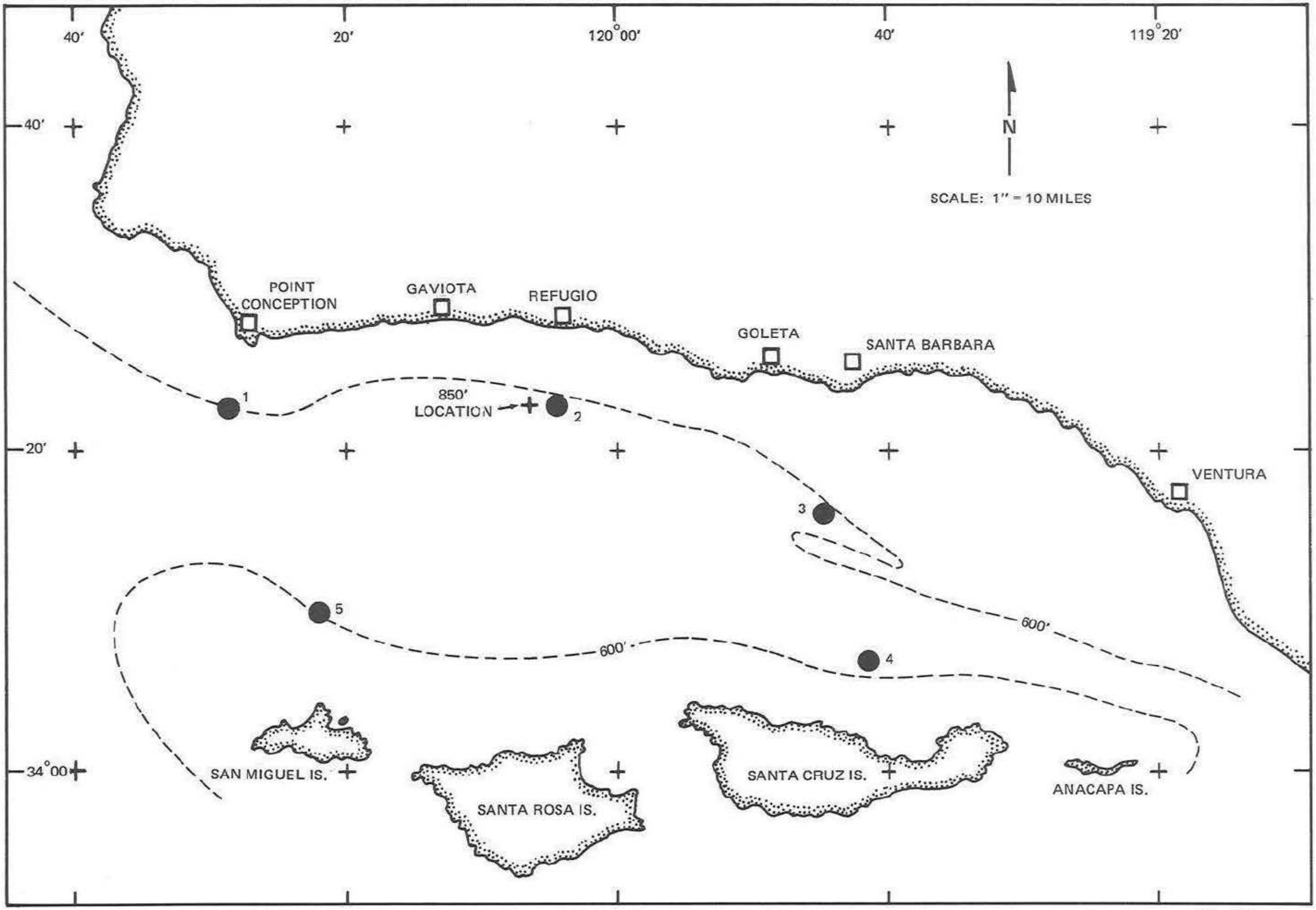


FIGURE 5



Earthquakes of Magnitude 6.0 and greater in
southern California region, 1912 – 1963.
(Allen, St. Amand, Richter and Nordquist, 1965).

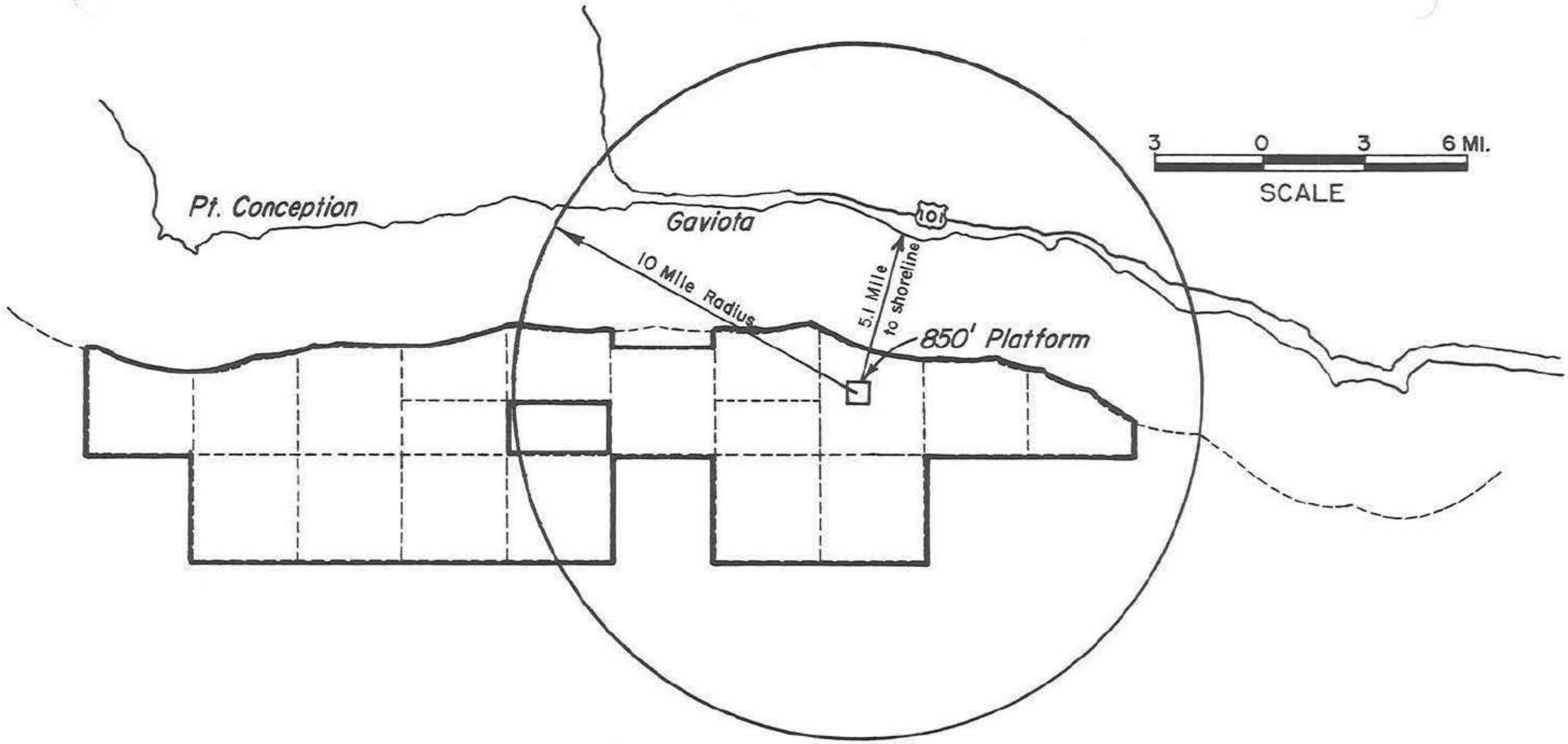
FIGURE 6



Revision

LOCATION OF SITES FOR HINDCASTS OF SEVERE STORMS

Figure 7



PLATFORM VISIBILITY FROM HIGHWAY 101
SANTA YNEZ UNIT

Figure 8

FIGURE 3, continued

Visibility Data by Months (1969, 1970, 1971)

	Visibility at 0800: number days visibility was 5 miles or less	Visibility 24 Hr. Period: number days visibility was 5 miles or less
1969		
Jan.	12	17
Feb.	7	9
Mar.	14	14
April	9	11
May	22	27
June	11	15
July	29	30
Aug.	29	30
Sept.	30	30
Oct.	14	15
Nov.	9	11
Dec.	12	14
Total:	198 days (54.25%)	223 days (61.1%)
1970		
Jan.	16	21
Feb.	13	16
Mar.	16	19
April	13	13
May	22	24
June	25	26
July	25	29
Aug.	28	31
Sept.	25	27
Oct.	20	22
Nov.	19	21
Dec.	4	6
Total:	226 days (61.9%)	225 days (69.86%)
1971		
Jan.	11	14
Feb.	12	14
Mar.	17	18
April	12	15
May	21	22
June	25	25
July	14	28
Aug.	16	22
Sept.	22	22
Oct.	12	13
Nov.	11	14
Dec.	3	7
Total:	176 days (48.22%)	214 days (58.63%)


PROPOSED FABRICATION SITE
WILMINGTON
LONG BEACH
SAN PEDRO
WEST BASIN
EAST BASIN
TURNING BASIN
CERRITOS CHANNEL
ISLAND
TERMINAL
LONG BEACH HARBOR
SOUTHEAST BASIN
LONG BEACH CHANNEL
MAIN CHANNEL
SAN PEDRO
BREAKWATER
0
1
2
MILES

Figure 4

Water Spray Test

Seal Beach, California

Figure 12

Water Spray Test Seal Beach, California

Figure 13

DRILLING

TABLE OF CONTENTS

DRILLING

DRILLING

ABSTRACT

This section discusses the drilling operations to be conducted from the initial 850-foot platform located on Parcel OCS P-0188. Bottomhole locations for the first 10 wells have been discussed in the GEOLOGIC AND RESERVOIR section. Subsequent wells will be drilled as discussed under "Long Range Plans." This section includes a discussion of the design criteria for the drilling procedures and equipment, a description of the major components of the drilling system and a typical drilling program.

Since the 1968 lease sale, Humble has successfully drilled 30 wells from floating drilling vessels in the Santa Barbara Channel. The 13 wells and 3 redrills in the vicinity of the Hondo Prospect have provided data on subsurface formations, fluid content and pressures which will aid in planning future drilling for maximum safety.

Design criteria and tentative equipment selections are detailed in this section. Selection of components for the drilling system will be finalized after the selection of a drilling contractor.

A typical drilling program for a Santa Ynez Unit development well is included. Each well will be drilled using this general procedure supplemented as necessary for the particular well program and anticipated drilling conditions.

1. DESIGN CRITERIA

1.1 Wind Forces

The rig will be designed to withstand 125 mph winds with 12,000 feet of 5" drill pipe racked in the derrick.

1.2 Deck Load

The design deck load is the maximum anticipated load exerted on the platform from simulataneous operation of the drilling rig, the associated support equipment and working supplies. Table 1 details the maximum anticipated loads.

1.3 Equipment Layout

The equipment layout will be selected to provide maximum efficiency and safety for the drilling operation. Facilities will be shared whenever possible to provide maximum utilization of the available area. Drawing No. 084-149A in Appendix 2.1 shows the anticipated drilling deck layout.

1.4 Drilling Equipment

The components of the drilling system will be selected to provide safe and efficient drilling capability to 16,000 feet. The derrick and hoisting equipment will be designed for a 1,000,000 pound capacity. The mud pumps will provide a minimum of 1700 total horsepower and be capable of sustained operations in excess of 2500 psi. The mud storage and treating system will have an 800 barrel capacity. The rotary derive system will provide 500 horsepower.

(Revised)

1.5 Wellheads

1.5.1 Pressure Rating - Each section of the wellhead will have a working pressure rating in excess of the maximum anticipated pressure imposed on that section.

1.5.2 Materials and Manufacturing Specifications - All components of the wellhead will be manufactured in accordance with API specifications.

1.5.3 Circulation Passages - The wellhead will provide fluid circulation passages between every set of casing and each succeeding smaller casing or tubing.

1.6 Casing

1.6.1 Safety Factors - All casing will be designed using a 1.312 safety factor on allowable internal burst pressure. A 1.8 safety factor on allowable joint strength or a 1.33 safety factor on pipe wall strength, whichever is the lesser, will also be used. A collapse safety factor of 1.125 will be used on all production or liner casing. All safety factors are based upon the API ratings for each type, grade and weight of casing. The joint strength design will assume no support from the borehole and will consider the stress generated in the casing by the deflection of the borehole.

1.6.2 Material Specifications - Controlled yield strength, quenched and tempered steel will be specified for all production casing and tubing subjected to sour oil and gas service. All material will conform to API specifications.

1.7 Well Control Equipment

1.7.1 Hydraulic Fluid Accumulators - The hydraulic fluid accumulators will have sufficient reserve capacity to operate all functions closed and open without the aid of the hydraulic pump and without reducing the chamber charge pressure below 1200 psi. This system will have two independent sources of power.

1.7.2 Blowout Preventer System - Four remotely controlled, hydraulically operated blowout preventers, consisting of two pipe rams, one blind ram and one bag type with working pressure in excess of the maximum anticipated surface pressure, will be installed on the surface casing and reinstalled on each succeeding casing string. Included in the system will be a drilling spool with side outlets, choke manifold, kill line and fill-up line. When drilling through the conductor casing a single remotely controlled bag type blowout preventer with blowdown line extending beyond the edge of the platform will be installed.

1.7.3 Safety Warning Devices - Safety warning devices, consisting of a pit volume totalizer system, an incremental flowrate indicator and a precision fill-up measurement system will be provided. Each of these warning systems will have visual displays at the drilling console. The pit totalizer system will also have an audio warning.

1.7.4 Fire Control System - Fire control equipment supplied on the platform will be supplemented by hand-held Class B-C extinguishers located on the rig floor and in the rig substructure area.

2. EQUIPMENT DESCRIPTION

2.1 Drilling Equipment

The drilling derrick will be of the 142 foot, 1,000,000 lb. class capable of withstanding 125 mph winds with 12,000 feet of 5" drill pipe racked in the derrick.

2.1.2 Substructure - The substructure will be capable of supporting the derrick loads, including a 500,000 lb. setback load. The substructure will provide 21.0 feet of unobstructed clearance for the blowout preventer equipment. Mechanical restraint equipment will be employed to restrain both longitudinal and transverse motion.

2.1.3 Pipe Rack - The pipe rack will be designed to support the full working load.

2.1.4 Drawworks - The drawworks will be of the 1500 input horsepower class capable of hoisting loads efficiently from 16,000 feet. This unit will be electric and will be equipped with a wireline core reel.

2.1.5 Hook, Traveling Block and Crown Block - The hook, traveling block and crown block will be of the 500-ton class and will be matched to provide efficient operation.

2.1.6 Mud Pumps - One 1000-horsepower pump and one pump of at least 700-horsepower will be utilized. Both pumps will be capable of sustained operation in excess of 2500 psi.

2.1.7 Liquid Mud Storage and Treating

(1) Mud Tankage - The liquid mud tankage will consist of three-220 barrel tanks manifolded to allow separate utilization as active mud tanks. A 100 barrel sandtrap settling tank will be located under the shale shakers. A 50 barrel mixing tank will be included in the tankage system. Agitation will be provided in the mixing tank and in all three active storage tanks.

(2) Mixing Pumps - Two 6" x 8" centrifugal pumps will be installed so that either unit can mix or circulate mud through either the desander, desilter or degasser.

(3) Mud Treating Equipment - The mud treating equipment will consist of dual screen shale shakers, a desander, a desilter and a degasser, each capable of processing 1000 gallons per minute.

2.1.8 Rotary Drive - The rotary drive will be of the 500 input horsepower class with a maximum opening of 37-1/2 inches and variable speed from zero to 220 rpm.

2.2 Pollution Control Equipment

2.2.1 Cuttings Washer - A cuttings washing device will be used to remove any oil which might be contained in the cuttings prior to their disposal in the ocean. All oil effluent from the cuttings washer will be contained and disposed of in an approved manner. No oil or drill cuttings, sand, or other solids containing oil will be discharged in the ocean.

2.2.2 Fluid Drip Pans - Fluid drip pans will be installed under all potential sources of leakage and piped to the platform drain system. Drip pans will be of sufficient size and capacity to prevent overflow and external spillage.

2.2.3 Trash Containers - 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.

2.3 Wellheads

2.3.1 Components - A normal wellhead will consist of a 20", 2000 psi casinghead; a 20", 2000 psi by 16", 3000 psi intermediate head; a 16", 3000 psi by 10", 5000 psi intermediate head; a 10", 5000 psi by 8", 5000 psi tubing head and an 8", 5000 psi by 4", 5000 psi Christmas tree. The Christmas tree will consist of two master valves, one crown valve, one wing valve and a choke assembly.

2.3.2 Drawings - Figures 1 and 2 detail the wellhead and Christmas tree assemblies. These drawings are typical of the assembly.

2.4 Casing

2.4.1 Sizes - Casing sizes will normally be 30" structural, 20" conductor, 16" surface, 10-3/4" intermediate, 7" or 7-5/8" production and 4" or 4-1/2" tubing. Each size of casing will be designed to meet the anticipated loads. The number and sizes of casing strings will be adjusted for specific well needs.

2.5 Well Control Equipment

2.5.1 Hydraulic Fluid Accumulators - The hydraulic fluid accumulators will be of the 160 gallon, 3000 psi class. Air and electricity will drive the dual power hydraulic pumps.

2.5.2 Blowout Preventer System

(1) Low Pressure System - The low pressure preventer system installed on the 20" conductor will be a 20-3/4", 2000 psi, bag type hydraulically actuated preventer. A large diameter blowdown line below this low pressure preventer will divert any formation away from the platform.

(2) High Pressure System - The high pressure blowout preventer system will consist of three ram-type preventers, consisting of two pipe rams and one blind ram, and one bag type preventer. This system will be of the 5000 psi class. Included in this system will be a side outlet drilling spool, a choke manifold, a kill line and a fill-up line. Figure 3 shows the arrangement of the components in this system.

2.5.3 Safety Warning Devices - See Design Criteria Section 1.7.3 above. Figure 4 shows the installation of these devices.

2.5.4 Fire Control System - See Design Criteria Section 1.7.4 above.

2.5.5 Drill Pipe Safety Devices - Drill pipe safety devices will be maintained on the rig floor and in the drill string as required by U.S.G.S orders.

3. OPERATING CONDITIONS AND PRACTICES

3.1 Operating Conditions

3.1.1 Weather - Based upon operating experience and historical data, weather will have little effect on drilling operations at the proposed platform location. Platform resupply operations can be conducted in seas of up to 6-8 feet. This limitation will not normally interfere with operations, since the consumable supplies stored on the platform are of sufficient quantity to permit operations to continue for approximately one week.

3.1.2 Reservoir Pressures - Reservoir pressures and fluid content are the important parameters that determine the required drilling fluid density needed for well control. Extensive measurements taken during drill stem tests on the exploratory and outpost wells have provided a basis for predicting these parameters on the Hondo Prospect.

3.2 Operating Practices

3.2.1 Well Control Training -

(1) General - Well control training is the key to successful well control practices. In accordance with the prevailing OCS orders, well control drills will be conducted until each crew is thoroughly

trained, and thereafter at least once each week for each crew.

(2) Additional Training - Key supervisory personnel, both operator and contractor, will receive extensive training in the proper techniques for handling well control situations. The Well Control Training Facility located in the Saticoy Field, Ventura County, California, provides realistic practice in controlling formation fluid influx and gas kicks. The training facility permits a well kick to be simulated by introducing a bubble of nitrogen gas into the wellbore, with the student practicing the proper procedures to bring the well safely under control. This facility is described more fully in Appendix 6.5.

3.2.2 Conductor Selection - The well conductor locations and reservoir targets will be selected to provide adequate distance between adjacent wells.

3.2.3 Directional Control

(1) Surveying - Directional surveys will be obtained at a sufficient number of locations to accurately determine the position of the wellbore.

(2) Well Course Surveillance - Well course surveillance will consist of calculating the location of all other wells, establishing the deviation trend and projecting it ahead of the actual wellbore to

identify the need for preventative action.

3.2.4 Other Practices - Other operating practices such as blowout preventer tests, casing pressure tests, waiting on cement time, and mud control practices will be in accordance with good drilling practices and applicable U.S.G.S. orders.

4. DRILLING IMPLEMENTATION

4.1 Well Summary

4.1.1 Bottom Hole Locations - Bottom hole locations for the initial 10 wells have been discussed in the GEOLOGIC AND RESERVOIR section. The average well will have a maximum angle of 39.0 degrees, a measured depth of 10,958 feet, and a true vertical depth of 8,885 feet. After drilling the first five wells, the geological information from this specific area will be thoroughly reviewed. Based on this data, field rules will be proposed to supplement the OCS orders.

The individual well data are itemized in the following table.

INDIVIDUAL WELL DATA

Reservoir Location	Target Location* North-South (+) (-)	Target Location* East-West (+) (-)	Total Depth TVD Feet	Measured Depth Feet	Maximum Angle Degrees
1	[redacted]	[redacted]	[redacted]	[redacted]	47
2	[redacted]	[redacted]	[redacted]	[redacted]	46
3	[redacted]	[redacted]	[redacted]	[redacted]	46
4	[redacted]	[redacted]	[redacted]	[redacted]	25
5	[redacted]	[redacted]	[redacted]	[redacted]	23
6	[redacted]	[redacted]	[redacted]	[redacted]	49
7	[redacted]	[redacted]	[redacted]	[redacted]	47
8	[redacted]	[redacted]	[redacted]	[redacted]	40
9	[redacted]	[redacted]	[redacted]	[redacted]	27
10	[redacted]	[redacted]	[redacted]	[redacted]	40
		Average	8885	10958	39.0

*Target location is referenced from the platform centerline Reservoir targets are located at the top of the Upper Siliceous Formation.

(Revised)

4.2 Typical Well Program

4.2.1 Mud Program - Sea water will be used as a drilling fluid through the setting of conductor casing. Mud will be used to drill the remainder of the well. The fluid density of the system will be maintained to overbalance formation pressures. The rheological properties will be maintained to effectively clean the hole of drilled cuttings and to minimize swabbing pressures.

4.2.2 Typical Drilling and Completion Program (Figure 5)

(1) Skid rig over conductor location and secure for drilling.

(2) Establish connections to ancillary equipment and power.

(3) Drill to 115 feet (± below mudline) and open simultaneously using a 26" bit and 36" hole opener.

(4) Circulate and condition the hole to run 30" casing.

(5) Run 30" casing with duplex guide shoe and landing hanger. Hang 30" casing on the platform well template and cement to the ocean floor. Release from the duplex shoe and remove the drill pipe from the hole.

(6) After waiting on cement a minimum of 8 hours, drill a 26" hole to 520 feet (± below the mudline). Circulate and condition the hole. Make a short trip up to the 30" casing and return to total depth. Circulate and condition the hole once again. Remove the drill pipe from the hole.

(7) Run 20" casing to total depth and cement back to the ocean floor.

(8) Install the API 20", 2000 psi casing head, and nipple up a single bag type preventer (20", 2000 psi) with diversion line and test.

(9) After waiting on cement for a minimum of 8 hours, pressure test the casing to 200 psi.

(10) Drill an 18-1/2" hole to 1250 feet (± below the mudline) implementing the planned directional program. Circulate and condition the mud and hole for casing.

(11) Run 16" casing and install and test the 20", 2000 psi by 16", 3000 psi intermediate casing head.

(12) Nipple up and pressure test the blowout preventer stack and choke manifold.

(13) After waiting on cement for a minimum of 12 hours, pressure test the 16" casing to 1000 psi.

(14) Drill a 14-3/4" hole to 2800 feet (± below the mudline) continuing along the planned directional program. Circulate and condition the mud and hole for casing.

(15) Run 10-3/4" casing and set at 2750 feet (± below the mudline). Cement using a sufficient volume to place the top of the cement at least 100 feet inside the 16" casing. Hang the 10-3/4" casing and install and test the 16", 3000 psi by 10", 5000 psi intermediate casing head. Reinstall and test the blowout preventer stack.

(Revised)

(16) After waiting on cement for at least 12 hours. pressure test the 10-3/4" casing to 1000 psi.

(17) Drill a 9-7/8" hole along the prescribed directional path to total depth. Circulate and condition mud and hole for logging.

(18) Run the desired formation evaluation tools.

(19) Condition the mud and hole for 7" or 7-5/8" casing.

(20) Run 7" or 7-5/8" casing to total depth. Cement using a sufficient volume to bring the top of the cement at least 500 feet above the uppermost hydrocarbon zone not previously cased.

(21) Test the 7" or 7-5/8" casing to 1500 psi or .2 psi per foot (true vertical depth) whichever is greater.

(22) Run cased hole correleation logs.

(23) Run the 4" or 4-1/2" tubing and associated production equipment. Remove the blowout preventer stack. Install Christmas tree and test. Rig down and prepare to skid to the next well.

(24) Displace the tubing with completion fluid and set the packer.

(25) Perforate the selected productive interval through a wireline pressure lubricator.

(26) Flow the well to establish the initial productivity.

(27) Stimulate the well as required through tubing without rig assistance.

TABLE 1

DESIGN DECK LOADS
DRILLING DECK

Live Load

Rig Drilling	Kips	Oper. Load-Kips
Derrick	86	
Crown Block	10	
Travel Block	16	
Rotary	14	
Swivel	15	
Drawworks	110	
Floor	25	
Line	14	
Tools	20	
Hydril Accumulator	12	
Kelly	3	
Cooling Water	15	
Substructure	150	
Pipe Set-back	395	
Subtotal	885	885
Pipe Rack		
13,000' of 5" Drill Pipe	250	
2,000' of 5" Heavy-Wall Drill Pipe	100	
240' of 10" x 3" Drill Collar	60	60
450" of 7-1/2" x 3" Drill Collar	60	60
1,000' of 24" Casing	80	
1,500' of 20" Casing	150	
2,400' of 16" Casing	200	
4,500' of 10-3/4" Casing	230	
13,000' of 7-5/8" Casing	440	440
13,000" of 4-1/2" Tubing	150	150
Dead Weight	100	100
Subtotal	1820	810

(Revised)

TABLE I (Continued)

Mud Tanks	Kips	Oper. Load-Kips
800 bbl (12#/gal)	400	
Dead Weight	150	
Subtotal	550	550

Drilling Equipment	Kips	Oper. Load-Kips
2 Mud Pumps	60	
1 Mud Logging Unit	15	
2 Mixing Pumps	20	
1 Surge Tank	10	
1 Cement Pump Unit	55	
1 Well Logging Unit	25	
2 Mud P-Tanks	240	
2 Cement P-Tanks	160	
2 Air Compressors	30	
2 Cranes	120	
1 Diesel Fuel Pods	70	
1 Starting Engine Unit	10	
Electrical Equipment	80	
1 Quarters with Heliport	400	
2 Pumps	20	
Bulk Storage (mud)	100	
Acid Storage	150	
Tool Storage	30	
Water Tank	500	
Subtotal	2095	2095
Total Load	5350	4340

WELLHEAD ASSEMBLY

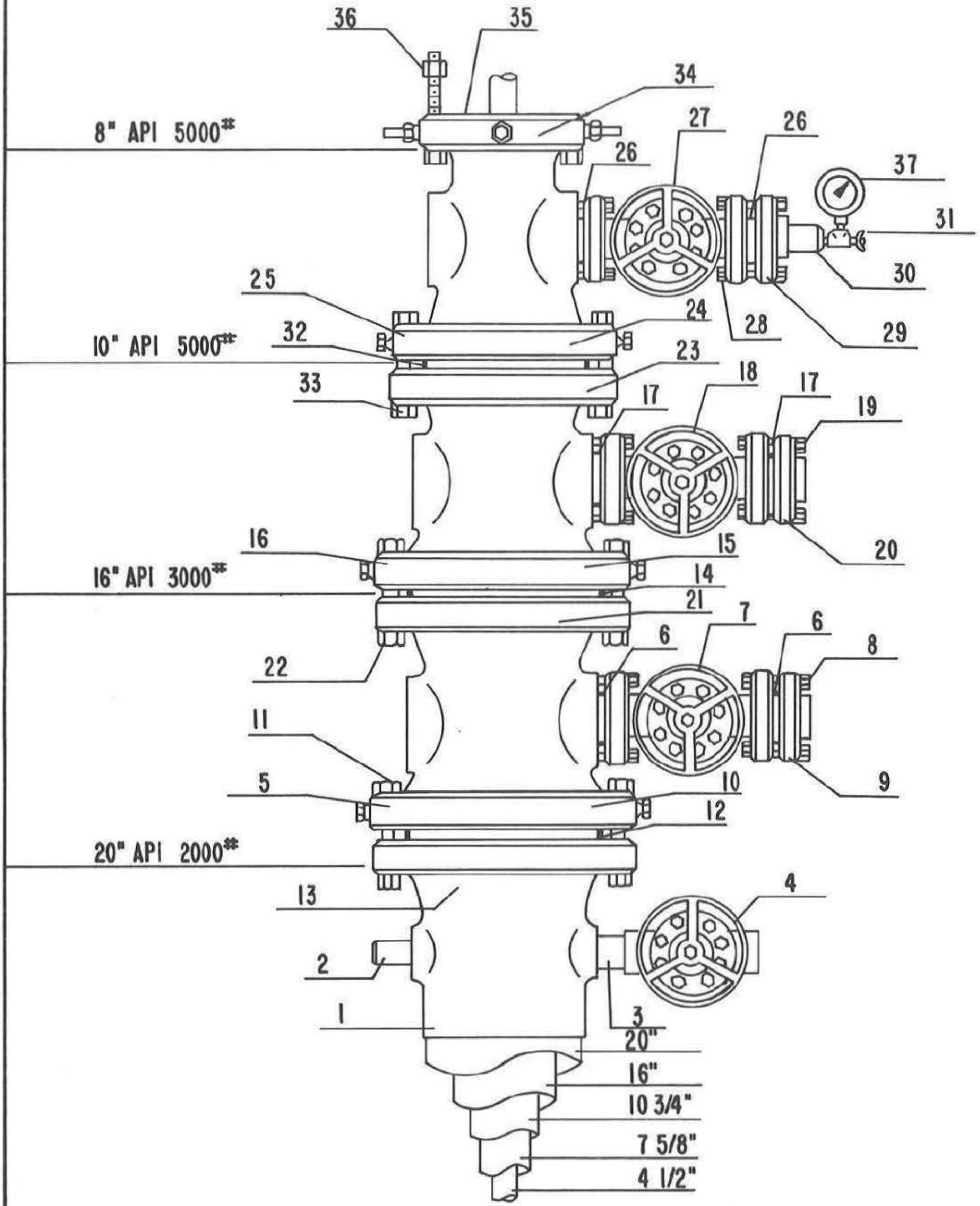


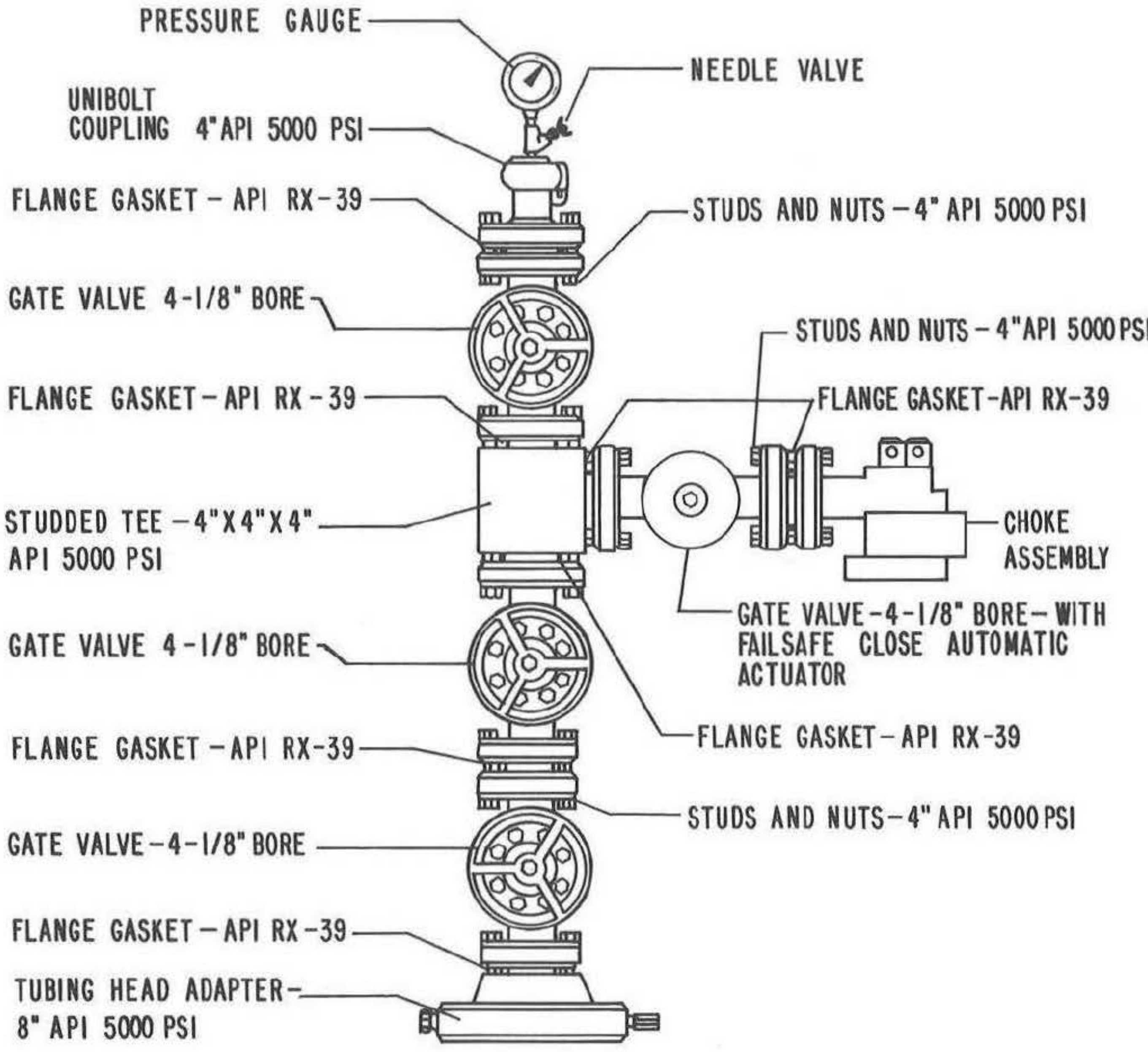
Figure I

PART DESCRIPTIONS

1. Casing Head-20" API 2000 psi
2. Bull Plug-2" API 2000 psi
3. Nipple-2" Double Extra Strong
4. Gate Valve-2" API 2000 psi
5. Casing Head-20" API 2000 psi x 16" API 3000 psi
6. Ring Gasket-API #2-24
7. Gate Valve-2" API 3000 psi
8. Studs And Nuts-2" API 3000 psi
9. Companion Flange-2" API 3000 psi
10. Casing Packoff-Size 16"
11. Studs And Nuts-20" API 2000 psi
12. Ring Gasket-20" API 2000 psi
13. Casing Hanger-Size 16"
14. Ring Gasket-16" API 3000 psi
15. Casing Packoff-Size 10-3/4"
16. Casing Head-16" API 3000 psi x 10" API 5000 psi
17. Ring Gasket-API #R-24
18. Gate Valve-2" API 5000 psi
19. Studs And Nuts-2" API 5000 psi
20. Companion Flange-2" API 5000 psi
21. Casing Hanger-Size 10-3/4"
22. Studs And Nuts-16" API 3000 psi
23. Casing Hanger-Size 7-5/8"
24. Casing Packoff-Size 7-5/8"
25. Tubing Head-10" API 5000 psi x 8" API 5000 psi
26. Ring Gasket-2" API 5000 psi
27. Gate Valve-2" API 5000 psi
28. Studs And Nuts-2" API 5000 psi
29. Companion Flange-2" API 5000 psi
30. Nipple-2" XX Heavy
31. Needle Valve 5000 psi WOG.
32. Ring Gasket-10" API 5000 psi
33. Studs And Nuts-10" API 5000 psi
34. Tubing Hanger-Size 4-1/2"
35. Ring Gasket-8" API 5000 psi
36. Studs And Nuts-8" API 5000 psi
37. Pressure Gauge-0-5000 psi

FIGURE 1 (Cont.)

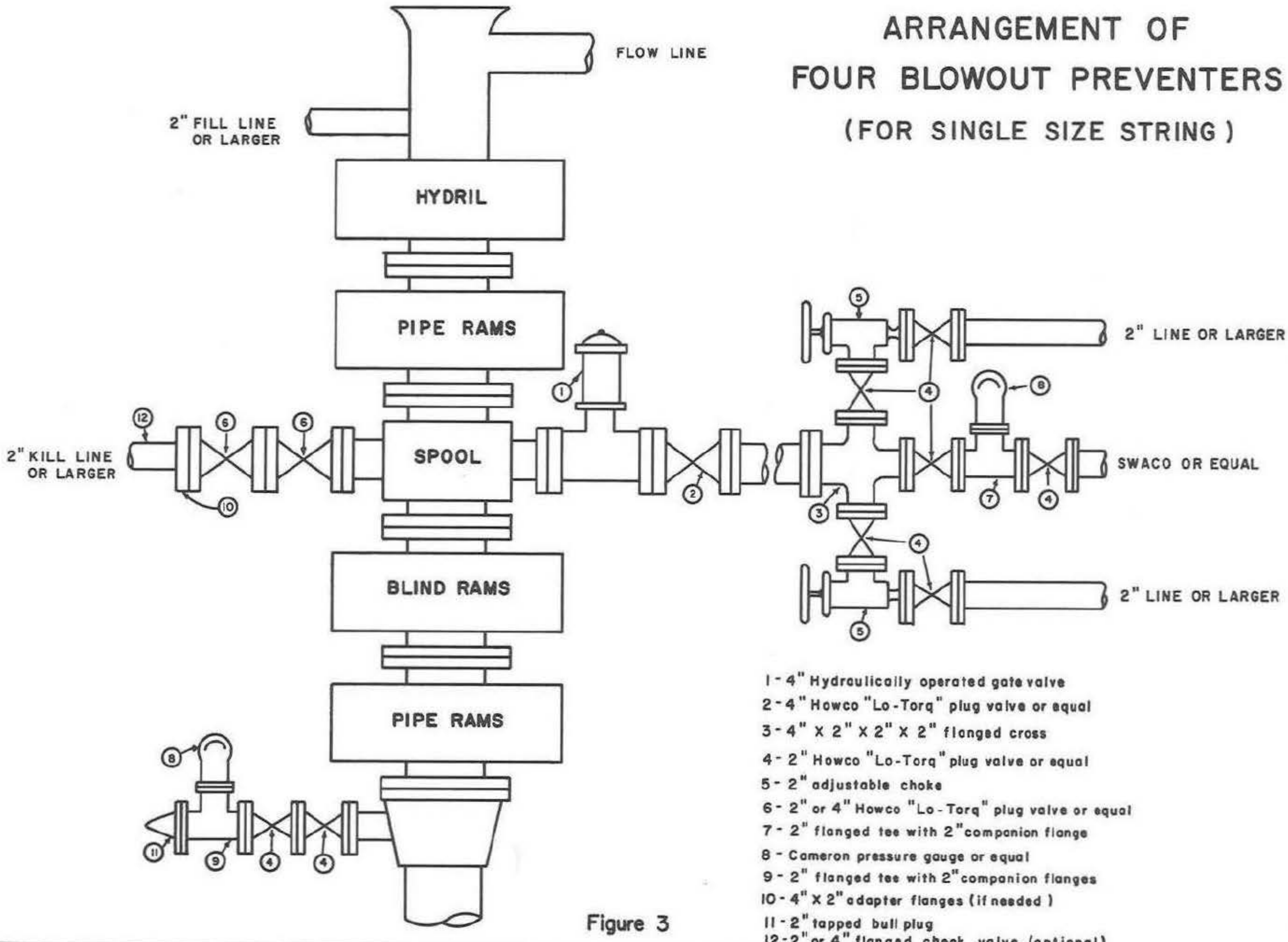
CHRISTMAS TREE



4" API 5000 PSI

Figure 2

ARRANGEMENT OF FOUR BLOWOUT PREVENTERS (FOR SINGLE SIZE STRING)



1 - 4" Hydraulically operated gate valve
2 - 4" Howco "Lo-Torq" plug valve or equal
3 - 4" X 2" X 2" X 2" flanged cross
4 - 2" Howco "Lo-Torq" plug valve or equal
5 - 2" adjustable choke
6 - 2" or 4" Howco "Lo-Torq" plug valve or equal
7 - 2" flanged tee with 2" companion flange
8 - Cameron pressure gauge or equal
9 - 2" flanged tee with 2" companion flanges
10 - 4" X 2" adapter flanges (if needed)
11 - 2" tapped bull plug
12 - 2" or 4" flanged check valve (optional)

Figure 3

WELL CONTROL SAFETY DEVICES

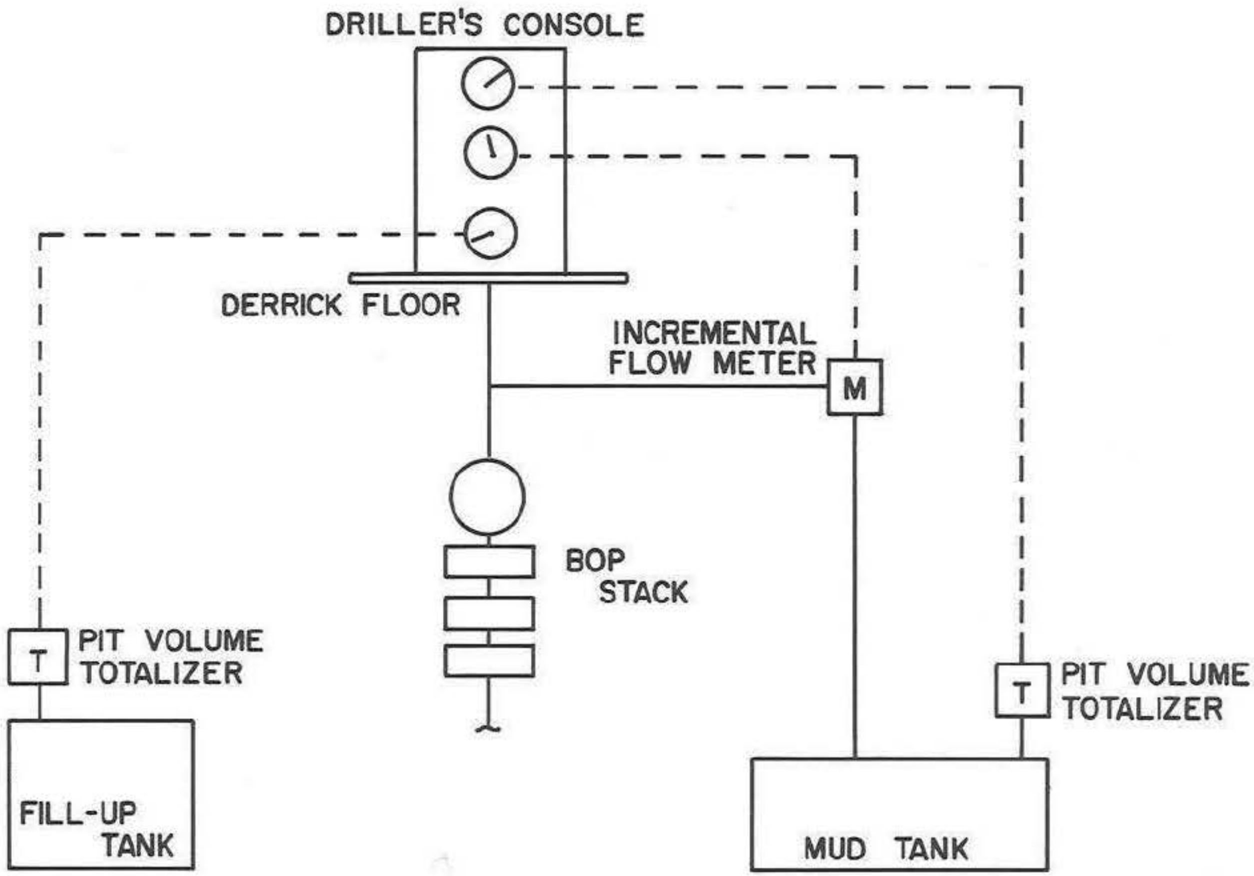


Figure 4

WELLBORE SKETCH
(NOT TO SCALE)

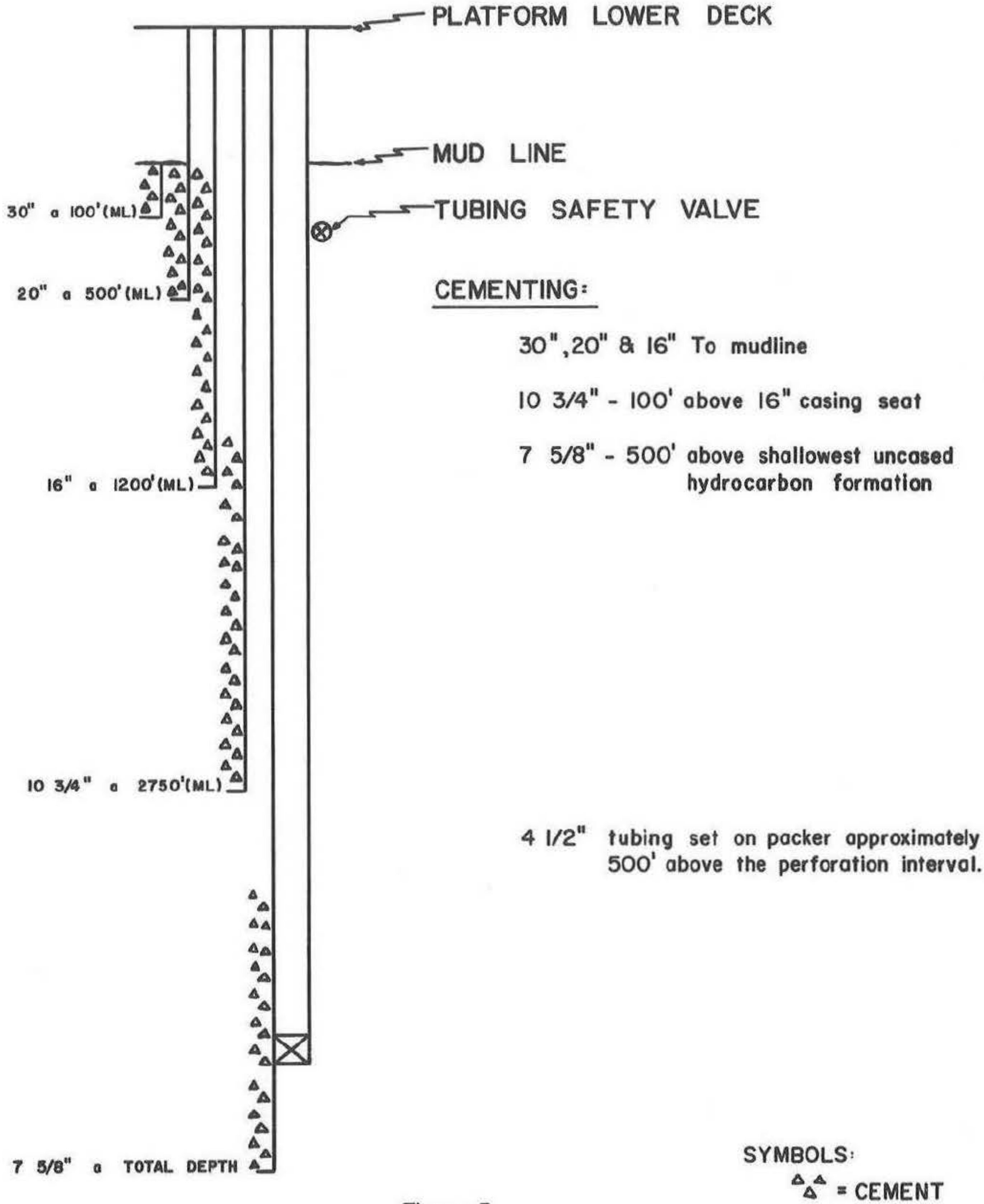


Figure 5

OFFSHORE PRODUCTION FACILITIES

TABLE OF CONTENTS

OFFSHORE PRODUCTION FACILITIES

OFFSHORE PRODUCTION FACILITIES

ABSTRACT

The initial Santa Ynez Unit platform will contain production facilities to process the produced oil, gas, and water. The oil will be separated from the gas and transported to shore through a pipeline, the gas will be compressed for pipeline transportation to shore, and the free water will be treated and cleaned to remove oil prior to disposal in the ocean. This section summarizes design objectives and criteria, descriptions of the major equipment, and construction and installation of the offshore production facilities. Appendices 2.1 and 3.1 present in complete detail all the design specifications for these facilities.

INTRODUCTION

Production and support facilities on the offshore platform are designed to provide for the separation of produced fluids from the Monterey chert and sandstone reservoirs prior to transporting the oil and gas to processing facilities and disposing of the water. Major platform equipment includes well manifolds, production and test separators, gas compressors, produced-water cleanup equipment and crude oil shipping pumps. The nominal design capacity of the production facilities is shown in section 1.2.1. Detailed design criteria are outlined in the next section.

The overall handling and disposition of produced fluids is illustrated by the simplified flow diagram in Figure 1. Free water and gas are separated from the crude oil in two stages, with the second stage occurring in the crude oil surge tank operated at atmospheric pressure. All produced gas is compressed to sales pressure, dehydrated, and transported to onshore gas facilities. To provide an alternative for disposition, the gas compressors are capable of compressing the gas for injection into the Monterey reservoir through a gas injection well. Produced water is treated and cleaned to permit ocean disposal. The oil-water emulsion from the surge tank is pumped to shore for additional treating and storage. The crude oil heater shown in Figure 1 maintains the temperature of the crude oil surge tank above 105°F, to remove vapors from the crude before movement to shore.

The detailed facility descriptions which follow are based on a Humble-directed design study performed by Hobbs-Bannerman Corporation and titled "Engineering Study for Initial Platform Production Facilities-Santa Barbara Channel". A two-volume copy of the study is labeled as Appendix 2.1. The Hobbs-Bannerman Engineering Study defines and specifies all the production and support equipment required on the initial platform.

1. DESIGN CRITERIA AND OBJECTIVES

1.1 Objectives

(1) Provide facilities necessary for separation, handling, and disposition of the produced fluids, and to design these facilities to comply with

applicable codes, regulations, and OCS Orders.

(2) Provide centralized control monitoring, and safety shut in systems which will moniter major platform facilities and shut in production and/or platform during abnormal operating conditions and emergencies.

(3) Minimize vapor emissions to the atmosphere and minimize duration and frequency of emergency gas flaring.

1.2 Criteria

1.2.1 Individual Reservoir Production Facility Design Rates, Pressures, Fluid Characteristics

	Monterey Chert	Sandstone
Number of Completions	25	3
Oil Rate, b/d	60,000	5,000
Water Rate, b/d	24,000	2,000
Gas Rate, Mscf/d	28,000	5,000
Well Manifold Design Pressure, psi	1,440	2,160
Production Separator Design Pressure, psi	275	500
Oil Gravity, °API	16-23	30-37
Gas Gravity (Air = 1.0)	0.85	0.70
Gas H_2S Content, mol%	0.4-1.5	0

1.2.2 Produced Water Disposal

Effluent water will contain less than 50 ppm oil.

1.2.3 Gas Dehydration

Gas to sales or injection will contain less than 7 lb. of water per MMscf.

1.2.4 Oil Shipping

Pumps will be capable of 60,000 b/d of oil-water emulsion at a discharge pressure of 1000 psig.

1.2.5 Crude Oil Heating

Crude oil surge tank temperature will be maintained above 105°F by waste heat recovery from gas turbine generators. A Therminol system will be utilized for heat transfer.

1.2.6 Gas Compression Design

Volume, Initial Development	14 MMscf/d
" , Total Platform	28 MMscf/d
Discharge Pressure	1000 psig-sales
" "	3500 psig-injection

1.2.7 Safety Provisions

1.2.7.1 All wellheads will have pneumatic, fail-close, automatic shut-in valves, actuated by flowline high-low pressure pilots. Where required, each well will contain a surface actuated fail-close subsurface valve set a minimum of 100 feet below the mudline.

1.2.7.2 Each production separator will be equipped with high and low pressure and level controls to shut in producing wells under abnormal conditions.

1.2.7.3 Crude surge tank high and low level and high pressure alarms will shut in all wells.

1.2.7.4 Shipping pump high and low pressure alarms will shut down the pumps and close the pipeline block valves.

1.2.7.5 The main gas scrubber high and low level and pressure alarms will shut in all wells. The sweet gas scrubber high and low level and pressure alarms will shut in all sandstone wells.

1.2.7.6 The fire fighting system will be designed to close all subsurface safety valves and all wellhead valves and pipeline shut-in valves. It will automatically energize the fire extinguishing system upon detection of flame in wellhead or production equipment areas.

1.2.7.7 The gas detection system will be designed to close all subsurface safety valves, all wellhead valves, and pipeline shut-in valves upon detection of combustible gas exceeding 50% of the lower explosive limit (LEL) in wellhead areas or production equipment spaces. Loss of instrument air will initiate a similar shut-in procedure.

1.2.7.8 All abnormal functions will actuate an annunciator and visually indicate to the operator the equipment upset condition. Test switches will be provided to allow complete testing of all alarms and to shut down electrical circuits without disruption of platform operations.

1.2.7.9 Fusible plugs will be used to make the platform shut-in systems sensitive to fires and cause shut-in of wells exposed to excessive heat.

All electrical and pneumatic circuits will be of fail-safe design with the exception of the fire and gas detectors, which are self-monitoring with alarms to indicate circuit failure.

1.2.8 Living Quarters

Living quarters for 50 men or less will be provided. Structural design will be in full accordance with the AISC Code of Standard Practice and the structure will be able to withstand 30 pound per square foot horizontal wind loading.

1.2.9 Heliport

The second story roof of the living quarters will serve as a heliport. The heliport will conform to all Federal Aviation Agency regulations and be designed in accordance with FAA advisory circular "Heliport Design Guide" AC/150/5390, latest edition.

1.2.10 Electrical System

Electric power may be provided through a 34.5 KV power cable from shore designed for a continuous load rating of 340 amperes. The power cable will be constructed in accordance with all applicable IPCEA and NEMA standards, and the electrical work will comply with Title 24 of the California Administrative Code and the National Electric Code, latest edition.

Transformers, switchgear, motor starters and other electrical equipment on the platform will be installed in a pressurized room, and all switchgear will be designed in accordance with applicable USA and NEMA standards. Motor starters will be designed in accordance with applicable NEMA and IEEE standards.

If power is provided from shore, auxiliary power of up to 2,250 KW will be provided by gas turbine generators on the platform. A 24-volt D.C. power system including batteries and a solid-state charger will be provided for certain electrical circuits where power dips or an outage may upset the operation.

All areas of the platform production facilities will be classified as Class 1, Group D, Division 1 or 2 for electrical equipment and electrical work except for non-hazardous areas such as (a) the switchgear room and welding room (pressurized), and (b) the crew quarters. (Class 1, Division 1 locations are those in which hazardous concentrations of flammable gases or vapors exist continuously, intermittently, or periodically under normal operating conditions. Class 1, Division 2 locations are those in which volatile flammable liquids, vapors or gases will normally be confined within closed containers or closed systems. Group D, in this case, refers to atmospheres containing natural gas.)

1.2.11 Vent and Flare Systems

All relief valves and vents from pressurized equipment will be piped to a vent scrubber and a flare stack which extends at least 100 feet from one corner of the platform.

1.2.12 Drainage and Leakage

Curbs, gutters and drains will be provided on both the drilling and production decks to divert fluids to a drain sump.

1.2.13 Sewage Treatment

Sewage effluent will meet the following requirements:

Biochemical Oxygen Demand, max.	50	ppm
Suspended Solids, max.	150	ppm
Chlorine Residual, min.	1.0	mg/liter

1.2.14 Navigation Warning Equipment

The platform facilities will be equipped with the necessary navigation warning equipment prescribed by the U.S. Coast Guard and the Federal Aviation Administration.

1.2.15 Codes and Rules

Section 1.6 of the Hobbs-Bannerman study describes compliance with OCS Orders; equipment, materials, and construction codes are referenced throughout the study.

2. DESCRIPTION OF MAJOR EQUIPMENT AND SUBSYSTEMS

2.1 Deck and Equipment Layouts

The drilling and production equipment will be installed on two platform decks prior to the beginning of operations. Drilling equipment will be installed on the upper deck. Production equipment will be installed on the lower deck except for the gas compressor units, which will be on the upper deck.

2.1.1 Upper Deck

The equipment locations for the upper deck are shown on Drawing 084-149A of the Hobbs-Bannerman study. This layout includes the drilling equipment, the gas compression units, the living quarters and two cranes.

2.1.2 Lower Deck

The equipment locations for the lower deck are shown on Drawing 084-149 of the Hobbs-Bannerman study. The layout includes the oil handling equipment, the water handling equipment, the well areas, the electrical facilities, the gas turbine driven generators, and other miscellaneous equipment.

2.2 Equipment List

Major equipment for the production platform is listed and briefly described in the Index Section of the referenced engineering study.

2.3 Process Descriptions and Flow Diagrams

The referenced Hobbs-Bannerman Engineering Study in Appendices 2.1 (two volumes) contains complete descriptions, specifications, and drawings for the facilities. All process piping and fabrication for oil, gas, and produced water are to be in accordance with ANSI Code B 31.3.

All process piping and vessels will also be internally coated to protect against corrosion. A summary of specific systems follows.

2.3.1 Wellheads and Flow Manifolds

Each completion is equipped with a master valve and wing valve on the tree. Downstream of the wing valve is a surface safety valve with a valve actuator and an adjustable flow bean. A short flowline connects the tree to the switching manifold header. The flowline is equipped with high-low pressure pilots to shut in the safety valve because of out-of-limit pressures and a check valve to prevent back flow from the header.

At the header, each well can be switched among production separators, a test separator, and a well cleaning separator. Remote control valve actuators are installed on the lines going to production and test separators. Large common lines take the commingled production to the production separators. The specifications for the wellhead and flow manifolds are available in Section 2.0 of the engineering study. Drawings 084-169 and 084-170 show these facilities.

2.3.2 Oil Handling

Three-phase separation of the Monterey production will be accomplished at 85 psig in two separators, each designed for up to 30,000 bopd. First stage separation of fluids produced from the sandstone reservoirs will be accomplished at 350 psig in a single separator designed for 5000 bopd. Sandstone crude will be commingled with Monterey production in the surge tanks. Two separators, designed for 5000 bopd each, will be installed for individual well tests. Separated oil will be routed into three closed production surge tanks where the crude will be degassed down to atmospheric pressure. The surge tanks will provide 8 minutes retention time at the peak rate.

Between the first stage separator and the surge tanks, the oil will be heated to at least 105°F through heat exchangers using waste heat from 3 gas turbine-driven generators. The heating operation is designed to remove as much gas as possible from the crude. The degassed crude emulsion will be metered and transferred to shore by three positive-displacement pumps, each designed to pump 20,000 bopd at 1000 psig discharge pressure. The specifications for the oil handling equipment are available in Sections 2 through 5 of the engineering study.

The following drawings are the most informative:

Vessel	Vessel Number	Drawing Number
Test Separators	V-2A & V-2B	084-101
Production Separators and Gas Scrubber	V-1A & V-3	084-107
Production Separator and Sandstone Separator	V-1B & V-1C	084-108
Production Surge Tanks	V-4A, V-4B & V-4C	084-123
Well Cleaning Separator and Tank	V-1D & V-10	084-126
Crude Oil Shipping Pumps	-	084-127

Other drawings generally show the piping or construction details of the equipment.

2.3.3 Gas Handling

Gas separated in the production and test separators will be routed through gas scrubbers to gas compression units. Initially, only two units will be installed with two more units added as needed. Each unit is designed to compress seven million cubic feet per day from a suction pressure of 85 psig to a discharge pressure of 1000 psig for sale or 3500 psig for injection. Compressed gas will be dehydrated in a glycol contactor prior to sales or injection. Gas vapors from the surge tanks and other atmospheric process units will be gathered and compressed to 85 psig by a vapor compression system. No gas will be vented or flared under normal operations except to degas units for repairs. A complete description of the gas handling system is available in Section 7 of the attached engineering report. Drawings 084-190 through 084-196 reference the gas facilities.

2.3.4 Water Handling

Water separated in the production and test separators, together with water from the drilling operations and the deck drains, will be routed through a dirty water surge tank, into a flotation unit for oil removal and then to a clean water surge tank. Oil will be skimmed off in the dirty water surge tank and in the flotation unit and transferred to the oil sump. From the oil sump, the oil will be returned to the production surge tanks. A turbidity monitor will check water quality at the flotation cell to insure that only clean water is placed in the final clean water surge tank. From this tank, the water will flow via a disposal tube into the ocean at -200 feet subsea. The water cleaning system specifications are included in Section 9.0 of the Hobbs-Bannerman study and Drawing 084-120 shows the piping and instrumentation diagram of this system.

2.4 Vapor Control System

The presence of hydrogen sulfide in the Monterey chert production requires a facility design which prevents venting of produced gases in the working areas or to the atmosphere. The platform facilities are designed to minimize vapor emissions as follows:

(1) All vessels which may emit vapors, including water handling facilities, are vented under pressure control into the vapor recovery system, which is continuously evacuated by the crude oil surge tank vapor compressors.

(2) Compressor cylinders will be equipped with a vented packing and double compartment distance piece to divert seal leaks into the vapor recovery system.

(3) A blowdown header will connect each compressor manual blowdown valve to the stock tank vapor suction. If at least one compressor train is running, depressuring and purging for maintenance can be performed without venting or flaring.

(4) Each compressor stage will be equipped with automatic block and equalizing valves to facilitate starting without depressuring.

The gas detector system is installed in the wellhead areas, in the main production equipment areas, and in the compressor room. The gas detectors alarm at 20% of the lower explosive limit (LEL) and the platform wells are shut in at 50% LEL. The gas detectors are described in Section 1.5 with specifications in Section 12.3 of the Hobbs-Bannerman study. Drawing 084-147 shows the gas detector locations.

Under abnormal conditions and shutdown of vessels for repairs, vapors and gas can be vented or flared through the 100-foot vent stack. All relief valves and burst heads are connected to this system. All gas and vapors must first pass through the vent scrubber to prevent liquids from going to the vent stack. This vent and flare system is described in Section 11.0 of the Hobbs-Bannerman study. Drawing 085-138 shows the vent system.

2.5 Fire Protection System

The fire protection system consists of three basic parts: 1) fire prevention, 2) fire detection and source control, and 3) fire fighting equipment. The fire protection and gas detection systems specifications are included in Section 12.0 of the Hobbs-Bannerman study.

2.5.1 Fire Prevention

The first step in fire protection is fire prevention. No sources of ignition are allowed on the platform where gas or flammable products could reach them. No open fires are permitted and ignition sources are kept in pressurized, sealed rooms (Example - welding room and electrical switchgear room). Electrical equipment in potentially hazardous areas is specified to meet Class 1, Group D, Division 1 requirements wherever practical.

2.5.2 Fire Detection and Source Control

Fire detectors are located on the platform as shown on Drawing 084-147. These units are of the ultra violet light sensitive type. The fire detectors can be delayed up to 8 seconds to prevent false alarms, but after 8 seconds the system will shut in the surface and subsurface valves on all wells and start the fire water pumps. In addition to the active detection, fusible plugs are installed in the emergency shut-in system. These have a low melting point, and cause the platform to shut in because of fire.

In general, the fire detection and gas detection system not only detects the fire and fuel source, but also initiates actions to stop the fire and the supply of fuel.

2.5.3 Fire Fighting Equipment

The fire fighting system is supplied by firewater and washdown loops which take suction from the ocean. The firewater loop is fed by two 800 gpm electric-driven pumps which discharge at 150 psi.

A standby 800 gpm diesel-driven pump is also available. The washdown loop is supplied by a 300 gpm electric-driven pump. This provides a total of 2700 gpm with all pumps working. Provisions have been made at the boat landings to permit connection of additional boat-mounted pumps to supplement the platform firewater system.

The fire fighting equipment consists of four fixed spray systems, six hose reel stations on each of the firewater and washdown loops, and three fire monitors. The fire protection water system is described in Section 1.4 and the overall system is shown on Drawing 084-124.

Supplemental fire fighting equipment such as CO_2 extinguishers and dry chemical units will be located at the emergency shut-in stations for use on small fires. These are shown on Drawing 084-147.

2.6 Pollution Control

Control will be exercised over oil, gas, water, solid wastes, and sewage to insure that untreated or hazardous substances are not discharged to the atmosphere or to the ocean. The oil and gas systems are designed to prevent any discharge. The water treating system is designed to clean the water to USGS standards prior to disposal.

2.6.1 Drainage System

Pressure and gravity drains discharge into sumps.

An oil sump collects oil from all pressure drains and pumps it to the production surge tanks. The water drains collect at another sump, where the water is pumped into the dirty water surge tank for processing. This system is shown on Drawing 084-120.

2.6.2 Vapor Control

Previously discussed in Part 2.4 of this Section.

2.6.3 Sewage Treatment

An accelerated aeration type sewage plant, completely automatic in operation, will treat platform raw sewage. Treated effluent will be discharged below the ocean surface. The plant will be designed so that the effluent will contain less than 50 ppm of biochemical oxygen demand, less than 150 ppm suspended solids, and a chlorine residual of at least 1.0 mg/liter. This unit is completely described in Section 16.1 of the Hobbs-Bannerman study.

2.6.4 Trash and Garbage

These materials will be accumulated in metal containers and transported to shore for disposal.

2.7 Electrical System

The electrical power system for the production platform is supplied with electric power from shore by submarine cable. Up to 20,000 KW of power is available for the drilling rigs, the gas compressors, miscellaneous production facilities, and submersible artificial lift pumps. Three gas turbine driven generators will generate up to 2,250 KW, but this will be used for emergency power and for some production facilities in order to obtain waste heat for oil heating. The electrical system is described and specified in Section 10.0 of Appendix 2.1. The electrical single-line diagrams for the platform are shown on Drawings 084-301 and 084-302. The generators are specified in Section 8.0 of Appendix 2.1.

2.8 Safety Shut-in System

The safety shut-in system for the production platform is made up of a platform shut-in system and a production shut-in system.

The platform shut-in system is actuated under the following conditions:

(1) Emergency shut-in from a master control panel

(2) Emergency shut-in from manual stations at the boat landings, heliport deck and exit stairways

(3) Fire detection ?

(4) Gas detection - upper limits

(5) Pressure loss in hydraulic and instrument air control loops caused by fire melting the fusible plugs

(6) Loss of instrument air

The platform shut-in system will close the pipeline outlet valves and the subsurface and surface safety valves on all wells.

The production shut-in system functions as follows:

(1) High and low pressures and levels in the Monterey production separators will shut-in the surface safety valves on the Monterey wells.

(2) High and low pressures and levels in the sandstone production separator and sweet gas scrubber will close a valve on the inlet piping to the scrubber and shut in the surface safety valves on all sandstone wells.

(3) High and low pressures and levels in the main gas scrubber will close a valve on the inlet piping to the scrubber and shut in the surface safety valves on all wells.

(4) High pressure and high level in the crude oil surge tanks will shut in the surface safety valves on all wells.

(5) High and low pressure or a discrepancy in the volumetric metering of the oil pipeline closes the pipeline valve and shuts in the surface safety valves on all wells.

(6) High or low flowline pressure for a well will shut in the individual surface safety valve.

The safety systems are described in more detail in Section 1.2 of Appendix 2.1. Drawing 084-148 shows the pneumatic shut-in system, and Drawing 084-303 shows the electrical shut-in system.

2.9 Central Control

A central control room provides an operator with the capability of monitoring the platform operations and performing many control functions. The data displayed within the control room will include the following:

Status and Alarms

(1) Status of wellhead valves - open or closed

(2) Well on test

(3) High and low pressure alarms

(4) High and low level alarms

(5) High and low temperature alarms

(6) Fire detector activation

(7) Gas detector activation

(8) Aid-to-navigation malfunctions

(9) Gas venting

(10) Gas compressor status

(11) Generator shutdown

(12) High oil content in water alarm

(13) Loss of instrument air

Data

(1) Oil production

(2) Gas production

(3) Water production

(4) Well test volumes

The platform shut-in system can be manually activated at any time by the control room operator.

The operator can also open and close each wellhead safety valve and place wells on or off test. The control system is described in Section 13.0 of the Hobbs-Bannerman study and references Drawings 084-303 through 084-309. The central control panel is described in Section 13.2, and Drawing 084-310 shows the panel.

2.10 Other Facilities

Other platform facilities include crew quarters, platform cranes, storage for diesel fuel, potable water, and acid. These are specified in Sections 14.0 through 17.0 of the Hobbs-Bannerman study. Diesel fuel is stored in the crane pedestals and pumped to its use points. Potable water is transported to the platform by supply boats and stored in a 500-barrel tank. The potable water system is shown in Drawing 084-139. Crew quarters for 50 men or less will be installed on the upper deck. Two 75-ton cranes will be installed on opposite sides of the platform to handle supplies and materials for the drilling and producing operations. The acid storage tank or tanks will provide the capacity to hold adequate acid for well acidizing.

3. CONSTRUCTION AND INSTALLATION

Construction of the production facilities is discussed in Section 19.0 of the Hobbs-Bannerman study. Major skid-mounted facilities will be fabricated by individual suppliers and shipped by truck, rail, or barge to the prime contractor. The prime contractor will assemble these facilities on the deck sections at his fabrication yard. Most of the major pieces of equipment will be installed and connected in the construction yard. Since the deck will be built in four sections,it will be necessary to field-connect piping which crosses into other sections.

Offshore construction work will consist of setting the deck sections, connecting piping between sections with pipe spools, and installing electrical wiring which crosses deck sections. Peripheral equipment, such as the generator units, the flare boom, the compressor units, and the living quarters will be installed offshore. These are generally self-contained, prefabricated pieces of equipment and will require only minor offshore hookups.

Moving personnel and materials to the construction work location will require extra transportation facilities. Initially, personnel can be housed on the derrick barge. After the living quarters are installed, personnel will remain on the job site, and will go to shore only for days off. Materials will come from Los Angeles or Port Hueneme. Fire protection will be provided by the derrick barge until the platform fire pumps are installed. The construction of production facilities should have little impact on the local area except for weekly personnel movements.

4. FACILITY OPERATIONS

The facility operations are discussed in Section 20.0 of the Hobbs-Bannerman report. Under normal conditions, the platform will be attended 24 hours a day. All significant production data and alarms will be monitored in a central control room where operating personnel can evaluate the data and control or shut in the facilities as required. Personnel will be required to adjust equipment on a periodic basis.

The platform facilities are designed to release no odors under normal conditions. All sewage and produced water are contained on the platform and treated in accordance with USGS regulations before disposal. Noise levels will meet the requirements of the Occupational Safety and Health Act of 1970.

SIMPLIFIED FLOW DIAGRAM

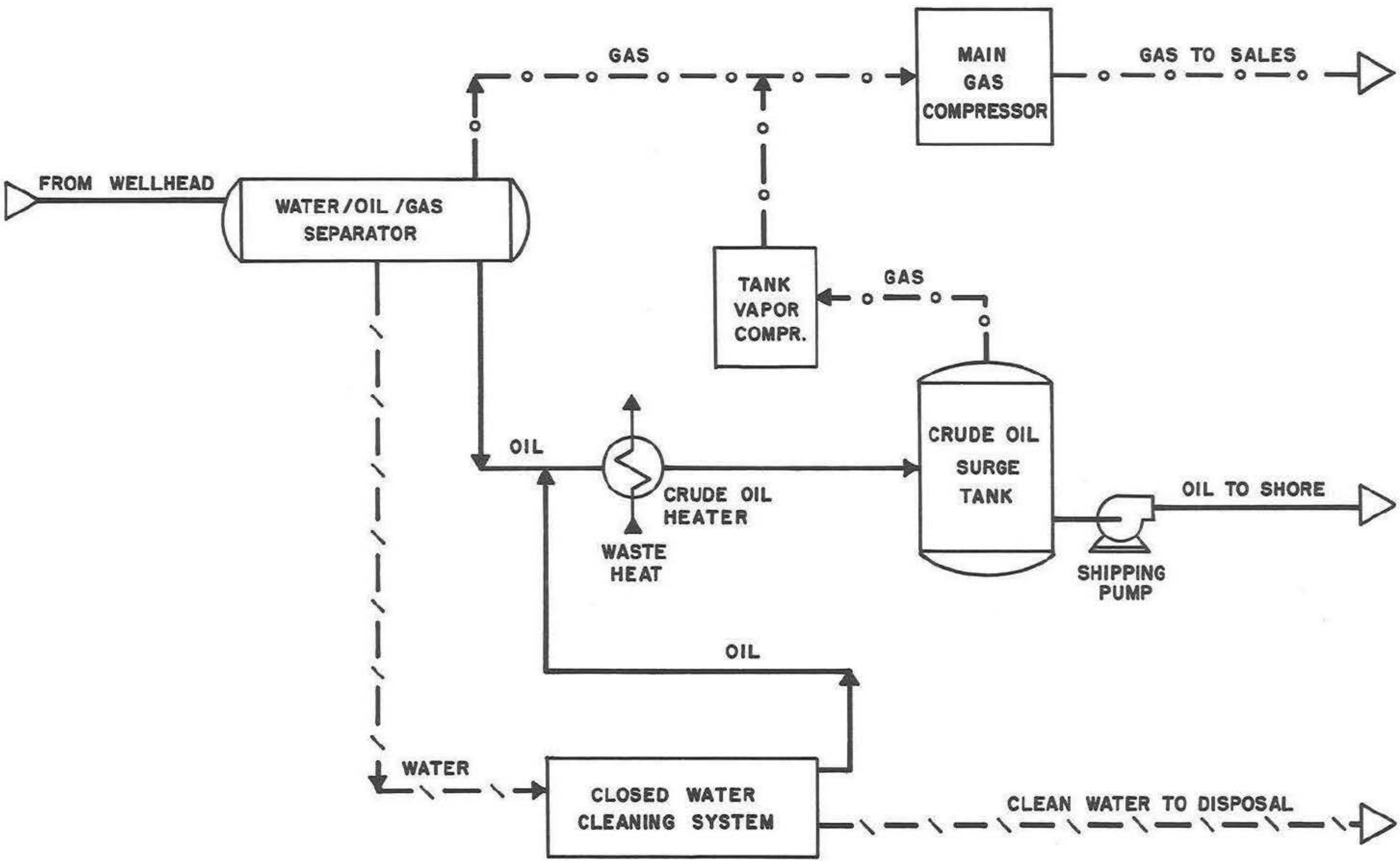


FIGURE I

PIPELINES

TABLE OF CONTENTS

PIPELINES

PIPELINES

ABSTRACT

This section is a plan for the design, construction and operation of one 16-inch oil pipeline and one 12-inch gas pipeline for the transport of oil and gas production from Humble's proposed platform in OCS P-0188 in the Santa Ynez Unit to an onshore facility in Corral Canyon. The plan consists of (1) a statement of design criteria, (2) a summary of design procedures and specification of major components, (3) a discussion of construction methods, and (4) a description of pipeline operation and safety shut-in equipment.

INTRODUCTION

From the platform, situated in approximately 850 feet of water, the oil and gas pipelines will be routed in a northeasterly direction to the shoreline, and then in a northerly direction following Corral Canyon to a treating and storage facility. Both lines will pass under U.S. Highway 101 and the Southern Pacific Railroad in a bored, cased crossing. The offshore length of each line is approximately 6.7 miles; the on- 35,500' shore length of each is about one mile. A plan and profile of the offshore route are shown in Figures 1 and 2, respectively; Figure 3 shows the onshore route and topography; and Figure 4 shows a schematic plan of the pipeline system.

1. DESIGN CRITERIA AND OBJECTIVES

1.1 Products to be Transported

The 16-inch oil line will be designed for a maximum throughput of 80,000 to 90,000 barrels per day of approximately 20.0°API gravity crude. The design maximum throughput for the 12-inch gas line will be approximately 90 MMCF/day.

1.2 Applicable Regulations and Codes

The oil line will be designed in compliance with USGS, Conservation Division, Branch of Oil & Gas Operations, Pacific Region, OCS Order No. 9, dated June 1, 1971, ANSI B31.4-1971, "Liquid Petroleum Transportation Piping Systems," and Department of Transportation Regulation 49, Part 195, "Transportation of Liquids by Pipeline." Gas and oil piping on the offshore platform, including the platform riser, will be designed in compliance with B31.3-1966, "Petroleum Refinery Piping." The gas line will be designed in compliance with USGS, Conservation Division, Branch of Oil & Gas Operations, Pacific Region, OCS Order No. 9, dated June 1, 1971, ANSI B31.8-1968, "Gas Transmission and Distribution Piping Systems," and Department of Transportation Regulation 49, Part 192, "Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards."

1.3 Stability

The offshore portions of both pipelines will be designed to resist movement under the action of on-bottom currents predicted to occur during the design 100-year storm. The basis of these predicted currents is a study by Oceanographic Services, Incorporated, of Santa Barbara, California. Appendix 6.4 contains a copy of their report. Stability will be achieved by proper design for submerged pipeline weight and by burial of both lines through the surf zone out to a water depth of approximately 200 feet.

The offshore route of both pipelines will be selected to avoid any hazardous bottom conditions. The bases for such a route selection will be the following surveys and reports:

(1) A coring and bottom sampling program that was conducted by Humble between 1949 and 1971. Results of this program pertinent to this pipeline plan are shown in Figure 1.

(2) A side scan sonar survey and study which covers most of the pipeline route. The field work was performed by the GAI-GMX Division of E.G.&G. International in 1970. Interpretation and reporting were done by Esso Production Research Company for Humble. Appendix 1.2 contains a copy of the report.

(3) A detailed description of the near-surface geology of the Santa Ynez Unit (Appendix 1.3).

(4) A shore approach survey performed by General Oceanographics, Inc. in 1971. This survey was for the purpose of determining sediment thickness

over the portion of the route where the pipelines are to be buried. (Appendix 5.6.)

1.4 Maximum Operating Pressure

The maximum operating pressure of the 16-inch oil line will be 1440 psi. The maximum operating pressure of the 12-inch gas line will also be 1440 psi. Each line will be designed to withstand this maximum operating pressure under applicable codes and regulations.

1.5 External Pressure

Both the oil pipeline and the gas pipeline will be designed to withstand external loads, including hydrostatic pressures with the pipelines void and with their absolute internal pressure equal to one atmosphere.

1.6 Other Stresses

Both pipelines will be designed under applicable codes and regulations to withstand stresses which result from the following loads and conditions:

(1) Thermal expansion (or contraction) of the pipeline combined with internal pressure
(2) Fluid expansion effects
(3) Earthquakes
(4) Dynamic effects
(5) Dead Loads
(6) Surges

1.7 Corrosion Protection

1.7.1 External Corrosion

The pipelines will be protected against external corrosion by means of external coatings and cathodic protection. Components of the cathodic protection system for which periodic replacement is not economical (e.g., sacrificial anodes on the offshore sections) will be designed for a minimum 30-year life.

1.7.2 Internal Corrosion

Steps which will be taken to mitigate internal corrosion include the use of inhibitors and/or internal pipe coatings. Corrosivity tests and monitoring of internal corrosion will dictate the extent of corrosion control programs.

2. DETAILED PIPELINE DESIGN

2.1 Pipeline Stability

A pipeline must have sufficient weight to resist the current forces which tend to cause it to slide. Resistance to lateral sliding is developed through the pipe-soil interaction and is similar to frictional resistance. The design weights for the two pipelines were based on currents associated with the average of the highest one percent of all waves expected in the 100-year design storm. As an added precaution, all portions of the pipelines were designed to withstand a $\pm 10°$ variation in storm direction and a minus 5 percent wall thickness variation in the steel pipe.

The design weights for stability of the buried portions of the pipelines were based on the Report of the Pipeline Flotation Research Council, Journal of Pipeline Division, Proceedings of ASCE, Vol. 92, Proc. Paper 4737, March 1966, pp. 27-71.

Details of the pipeline stability design procedure are presented in Appendix 5.3.

2.2 Internal Design Pressures

2.2.1 Oil Pipeline

2.2.1.1 Offshore Portion

Design of oil pipelines under DOT Regulation 49, Part 195 is in compliance with ANSI B31.4, "Liquid Petroleum Transportation Piping Systems," which is incorporated into the DOT Regulation by reference. Figure 2 shows a minimum wall thickness (nominal) for the offshore portion of the 16-inch oil line of 0.625". This thickness selection is primarily based on the stability design (above). The pipe will be Grade B, seamless or ERW (specified minimum yield: 35,000 psi). The design working pressure for 16" Grade B pipe with 0.625" wall thickness computed in compliance with ANSI 31.4 is 1969 psi. Since this design working pressure of 1969 psi exceeds the maximum design operating pressure of 1440 psi, the proposed 16" pipe meets code requirements for internal pressure.

2.2.1.2 Onshore Portion

The pipe proposed for use in the onshore portion of the 16" oil line is 0.312" nominal wall thickness, ERW, Grade X-52 (specified minimum yield: 52,000 psi). Higher grade pipe is used onshore than offshore since increased wall thickness for stability is not required. The design working pressure of this pipe computed in compliance with ANSI B31.4 is 1460 psi, which exceeds the maximum design operating pressure of 1440 psi. The pipe is therefore adequate for the internal pressure design requirements of ANSI B31.4.

2.2.1.3 Platform Piping

Platform piping will be designed in compliance with ANSI B31.3, "Petroleum Refinery Piping." Based on B31.3, the wall thickness of the 16" oil piping, including fittings, will be 0.750". The design working pressure of 16" x 0.750" Grade B, seamless line pipe is 1572 psi with a corrosion allowance of 0.05". The pipe is therefore adequate for internal pressure requirements of ANSI B31.3.

2.2.1.4 Valves and Flanges

All valves and flanges used in the 16" oil pipeline (offshore, onshore and at the platform) will be ANSI 600 (working pressure: 1440 psi).

2.2.2 Gas Pipeline

2.2.2.1 Offshore Portion

Design of the gas pipeline is in compliance with Department of Transportation (DOT) Regulation

49, Part 192 and ANSI B31.8, "Gas Transmission & Distribution Piping Systems." Figure 2 shows a minimum nominal wall thickness of 0.500" for the offshore portion of the 12" gas pipeline. The pipe will be Grade B, seamless or ERW. The design working pressure for the 12" x 0.500" pipe for Class I location and with a corrosion allowance of 0.075" is 1675 psi. The pipe is therefore adequate for the maximum design working pressure of 1440 psi. Some internal corrosion may be anticipated, therefore the internal corrosion allowance of 0.075" is included in the above design calculation as prescribed in B31.8 - 841.171 (b).

2.2.2.2 Onshore Portion

The pipe proposed for use on the onshore portion of the 12" gas pipeline is 0.375" nominal wall thickness, X-52, ERW. The design working pressure of this pipe computed in compliance with DOT 192.105 (and also ANSI B31.8) is 1762 psi with an internal corrosion allowance of 0.075" for a Class I location. For a Class II location this pipe would have a design working pressure of 1468 psi and would therefore still meet design requirements for 1440 psi service should the location class change at some future date because of an increase in population density in the vicinity of the pipeline.

2.2.2.3 Platform Piping

Platform piping will be designed in compliance with ANSI B31.3, "Petroleum Refinery Piping." The selected pipe is 12" x 0.625" Grade B, seamless. The design working pressure of this pipe computed in compliance with ANSI B31.3 is 1525 psi with an internal corrosion allowance of 0.075" for temperatures of -20° to +100°F. For temperatures between 100°F. and 200°F. the design working pressure is 1457 psi which still exceeds the maximum design operating pressure of 1440 psi.

2.2.2.4 Valves and Flanges

All valves and flanges used in the 12" gas pipeline (offshore, onshore and on the platform) will be ANSI 600.

2.3 External Pressures

The more nearly a pipe's cross section approaches a perfect circle, and the lower its diameter-to-thickness ratio, the higher its resistance to collapse from external pressure. Formulae for calculation of resistance of tubes to collapse are given in Appendix 5.4.

The critical portions of both pipelines from the standpoint of collapse are in the 850-foot water depth at the platform. Computations using the formulae in Appendix 5.4 show that for either of the pipelines to be in danger of collapse when void, it would have to be more than 7% out-of-round. Pipe manufactured in accordance with standard mill practice is less than 2% out-of-round. Therefore the pipelines will be safe from collapse. The onshore portion of the pipelines will be ditched and backfilled, and external loads on the pipelines will be negligible.

2.4 Other Stresses

2.4.1 Thermal Expansion and Contraction

Thermal expansion is introduced into a pipeline when the fluid temperature in the line is greater than the temperature at which the pipeline was installed. Conversely, contraction is introduced into a pipeline when the fluid temperature is lower than the temperature at which the pipeline was installed. The 16-inch oil line will be installed at an anticipated temperature of approximately 60°F. Since the crude temperature will range between 45° and 95°F, both expansion and contraction will be introduced.

Because the oil line will be buried onshore and for a distance of approximately 13,000 feet offshore, it is considered a restrained line. It must therefore conform to the requirements of B31. 4-419.6.4. If there is a net longitudinal compressive stress, compliance with the code requires that the net longitudinal compressive stress, plus the hoop stress, plus the bending stress must not exceed 90% of the specified minimum yield strength of the pipe. It is also essential that total combined tensile stresses be well below the minimum yield of the pipe material.

Both pipelines are adequately designed to withstand anticipated thermal stresses under the above criteria. Thermal stress design is discussed in more detail in Appendix 5.5.

2.4.2 Fluid Expansion Effects

The oil pipeline will be provided with relief valves to prevent over-pressuring of any component in the system from ambient heating of the static liquid contents.

2.4.3 Earthquake

In the event of an earthquake in the vicinity of the pipelines, neither line should sustain damage to the point of rupture. This conclusion is based on the following factors.

(1) The sea bottom, seismic and side scan sonar surveys and near-surface geologic studies indicate that the pipelines cross no faults. (Appendices 1.2, 1.3, 5.6.)

(2) The route of the pipelines has been selected to avoid potential landslide areas. The onshore portions of the pipelines will also be buried and thus protected from falling rocks.

(3) The predicted longitudinal stresses which may be produced in the pipelines by vibratory ground motions generated by an earthquake will be less than 4500 psi for the buried portions. (The unburied portions will be virtually unaffected.) These stresses, when combined with the longitudinal stresses resulting from maximum internal pressure, give a combined longitudinal stress of 30% of minimum yield (worst case) for the 16" oil line (ANSI B31.4 allows 80% of specified minimum yield), and a combined longitudinal stress of 25% of minimum yield (worst case) for the 12" gas line.

A report, "Earthquake Resistant Design of Oil Transmission Lines" by Dr. P. C. Jennings of the California Institute of Technology, is attached as Appendix 5.1.

2.4.4 Dynamic Effects

2.4.4.1 Impact

There are no known internal or external impact forces to account for in the design of the oil or gas pipelines.

2.4.4.2 Wind

There are no wind effects to consider.

2.4.4.3 Vibration

Piping at pumps and compressors will be designed, anchored and supported so that vibration in the pipelines will be negligible.

2.4.4.4 Subsidence

The offshore sea bottom coring, seismic, and side scan sonar surveys indicate that the pipeline route crosses no areas of subsidence or soil instability. The pipeline route onshore has been selected to avoid potential landslide areas.

2.4.5 Dead Loads

Dead loads on the pipeline components will be negligible. At highway and railroad crossings a casing will be installed which will comply with the requirements of API RP 1102, "Liquid Petroleum Pipelines Crossing Railroad and Highways."

2.4.6 Surge

High pressure shutdown devices and relief valves will be provided in the oil pipeline to prevent overpressuring from any cause, including surge.

3. CONSTRUCTION AND INSTALLATION

3.1 Fabrication

Fabrication of the oil pipeline will comply with DOT Regulation 49, Part 195, Sections 195.214 through 195.234. Fabrication of the gas pipeline will comply with DOT Regulation 49, Part 192, Subpart E. Specific points related to welding of both pipelines are as follows:

(1) Welding procedures and welders must be tested and qualified under Sections 2 & 3, API Standard 1104, January, 1968 edition.

(2) Acceptability of welds is to be determined according to the standards in Section 6, API Std. 1104, January, 1968.

(3) On both the oil pipeline and gas pipeline, 100% of the girth welds will be radiographically inspected.

3.2 Installation

3.2.1 Construction Methods

The onshore portions of both pipelines will be installed using conventional land-type pipeline construction methods and equipment. Right-of-way clearing, grading, ditching and backfilling will be performed in such a manner to cause a minimum disturbance to existing topography and environment. The pipeline will be buried to a minimum cover depth of 3 feet.

Clean-up will begin immediately behind ditch backfilling operations. The construction area will be restored as nearly as practicable to its original (or better) condition. Line markers will be installed as required by DOT 195.410 (oil line) and DOT 192.707 (gas line).

The portions of both pipelines from the shoreline to the 300-foot water depth contour (a distance of approximately 26,000 feet) will be installed by one of two methods: (1) by pulling them from shore with buoys attached to reduce the pipe's submerged weight on bottom, or (2) by the stinger-laybarge method. The construction technique will be influenced by relative economics and availability of equipment at the time of installation.

If the pull method is used, a fabrication barge would be positioned in shallow (e.g., 25 feet) water and the pipe would be pulled along the bottom in the direction of the platform to a water depth of 300 feet.

Both pipelines will be buried through the beach and surf zone and out to a water depth of 200 feet. If possible, a cover depth of 3 feet will be used. However, as reported by General Oceanographics (Appendix 5.6) the sediment layer is thin between the 25-foot contour and surf zone. Where the pipelines cannot be buried in this area, sacks of sand-cement mixture will be placed over the pipelines to insure stability. In the beach proper and in the surf zone immediately adjacent to the beach the pipeline will be buried by excavation of the bedrock if necessary.

The portion of both pipelines between the platform and the 300-foot contour will be installed by the reverse J-tube method illustrated in Figure 5. The pipe is pulled downward through a J-tube preinstalled during platform fabrication.

Approximately 10,500 feet of each pipeline will be installed by this procedure. The 16" oil pipeline will be pulled through a 20" x 0.500" J-tube having a radius of curvature of 125 feet. The 12" gas pipeline will be pulled through a 16" x 0.500" J-tube having a radius of curvative of 115 feet. Details of J-tube configuration are shown on Drawing HQE - 215-13 (Appendix 1.4). This method of pipeline riser installation was developed and field tested by Esso Production Research Company. The method is described in detail in an article in the April, 1971 issue of Pipe Line Industry magazine.

The portion of both pipelines installed with J-tubes will be coated with a 60-mil thickness of polypropylene applied over a 10-mil thickness of thermosetting coating (NAP-GARD or SCOTCHKOTE 202) with a 10-mil adhesive thickness between. Field Joints will be covered with polyethylene heat-shrinkable sleeves. The portion of each pipeline which will remain permanently inside of its respective J-tube will be of heavier wall than the adjacent on-bottom section (for the 12" 0.625" vs 0.500", for the 16", 0.750" vs. 0.625"). These heavier sections will be coated with a 1/4" thickness of high density neoprene rubber, the same material used to protect platform structural members in the splash zone. This rubber coating

(Revised)

will insure against corrosion and electrical communication between the pipeline riser and the platform structure, thus permitting use of separate cathodic protection systems for the platform and the pipelines.

Verified calculation procedures show that the weights of the 12" pipe and the 16" pipe will provide sufficient pushing force to move each pipe through its J-tube. In fact, support will be required to control rate of movement. Thus the pulling force will be only that required to overcome friction between pipeline and sea bottom. Assuming a conservatively high coefficient of friction between soil and pipe of 0.75, the following pulling force requirements may be estimated:

Line	Maximum Pulling Force	Tensile Stress	% SMY
12"	105,000 lbs	5,000 psi	15%
16"	130,000 lbs.	4,500 psi	13%

These pulling forces are within the capability of available equipment, and the tension stresses these forces will produce are within safe limits.

3.2.2 Connection

The two pipeline sections will be joined at the 300-foot contour by a mechanical joint or by welding in a hyperbaric underwater chamber. If, however, a laybarge is used to install the portions of the offshore lines that are shoreward of the 300-foot contour, the necessity for onbottom connections can be eliminated.

Where sections of pipe of different wall thickness are joined, transition sections with tapered inside diameter will be used to facilitate pigging and to eliminate points of stress concentration.

3.2.3 Inspection

All materials will be inspected for defects and for compliance to codes and specifications before installation in pipelines. All girth welds will be 100% inspected by radiography as specified above. Application of pipe coatings will be inspected in coating yards to insure conformance with specifications. During construction and after completion, the offshore portions of the pipelines will be inspected by divers to insure that the buried portions have specified depth of ditch, that the pipeline is resting on and firmly supported by a competent bottom, and that the pipeline has not been damaged during installation. Diver visual inspection will be augmented by side scan sonar surveys, photography and television. In addition to the types of inspection outlined above, all pipeline construction operations will be inspected to insure compliance with applicable regulations, codes, specifications and sound engineering practices.

3.2.4 Testing

Hydrostatic testing of the 16" oil pipeline will be conducted in compliance with DOT Regulation 49, Part 195, Subpart E. The hydrostatic test pressure of 1800 psi (1.25 times the maximum design operating pressure of 1440 psi) will be held for a minimum period of 24 hours.

Hydrostatic testing of the 12" gas pipeline will be conducted in compliance with DOT Regulation 49, Part 192, Subpart J. The hydrostatic test pressure of 1800 psi (1.25 times the maximum design operating pressure of 1440 psi) will be held for a minimum of 8 hours.

4. CORROSION PROTECTION

4.1 External Corrosion

Both pipelines will be protected against external corrosion by dielectric pipe coatings and cathodic protection systems. The onshore portions of both lines and the offshore portions between the 300-foot contour and the shoreline will be coated with semi-plasticized coal tar enamel, reinforced with fiberglass and protected with a 30 lb. felt covering. The field joints will be coated with compatible materials. The portions of the pipelines between the 300-foot contour and the platform will be coated with polypropylene over thin film as described in Section 3.2.1.

The cathodic protection system design for both lines consists of sacrificial anodes (zinc offshore and magnesium onshore) with a small rectifier on the platform. System details are summarized in Table 1. The system was designed by Cathodic Protection Service of Houston, Texas. A copy of their report and specifications is attached as Appendix 5.2.

4.2 Internal Corrosion

Internal pipe coatings and/or inhibitors will be used to mitigate internal corrosion. In addition, design of the gas pipeline wall thickness includes an allowance for corrosion of 0.075". Both pipelines will be designed so that inspection equipment can be run through them at any time in the future to detect any internal corrosion. These inspections, as well as corrosivity tests of the oil and gas, will dictate the corrosion control program.

5. PIPELINE OPERATION

5.1 Normal Operation

Flow diagrams of the 16" oil pipeline system and the 12" gas pipeline system are shown in Figures 6 and 7. The terminal operator at the Corral Canyon treating facility will have control of the pipelines and will be able to open or close any of the motor-operated valves in the scraper trap assemblies. The terminal operator will know the position (open or closed) of these valves on both lines at all times via a visual display in the control building.

5.2 Variations from Normal Operations

All components of both pipelines will be protected by pressure relief valves. Leak detection and automatic pipeline shutdown are discussed in the Surveillance Plan (Appendix 5.7). Automatic shut-in valves for both lines are located in the shoreline area.

5.3 Operation, Inspection, Reporting

The 16" oil line and subsystems will be operated and regularly inspected in compliance with USGS, OCS Order No. 9 and DOT Regulation 49, Part 195, and required reports and records will be submitted. The 12" gas line and subsystems will be operated and regularly inspected in compliance with USGS, OCS Order No. 9 and DOT Regulation 49, Part 192, and required reports and records will be submitted. The cathodic protection system for the 12" gas line is designed and will be operated in compliance with DOT Regulation 49, Part 192, Subpart I. The cathodic protection system for the 16" oil line is designed and will be operated in compliance with DOT Regulation 49, Part 195, Subpart F.

Annual surveys of the pipelines will be made with electronic instruments, such as the Linalog. Special launching and receiving traps will be provided for such instruments.

TABLE 1

PROPOSED CATHODIC PROTECTION SYSTEM

DUAL OIL AND GAS PIPELINES FROM INITIAL PLATFORM TO SHORE SITE

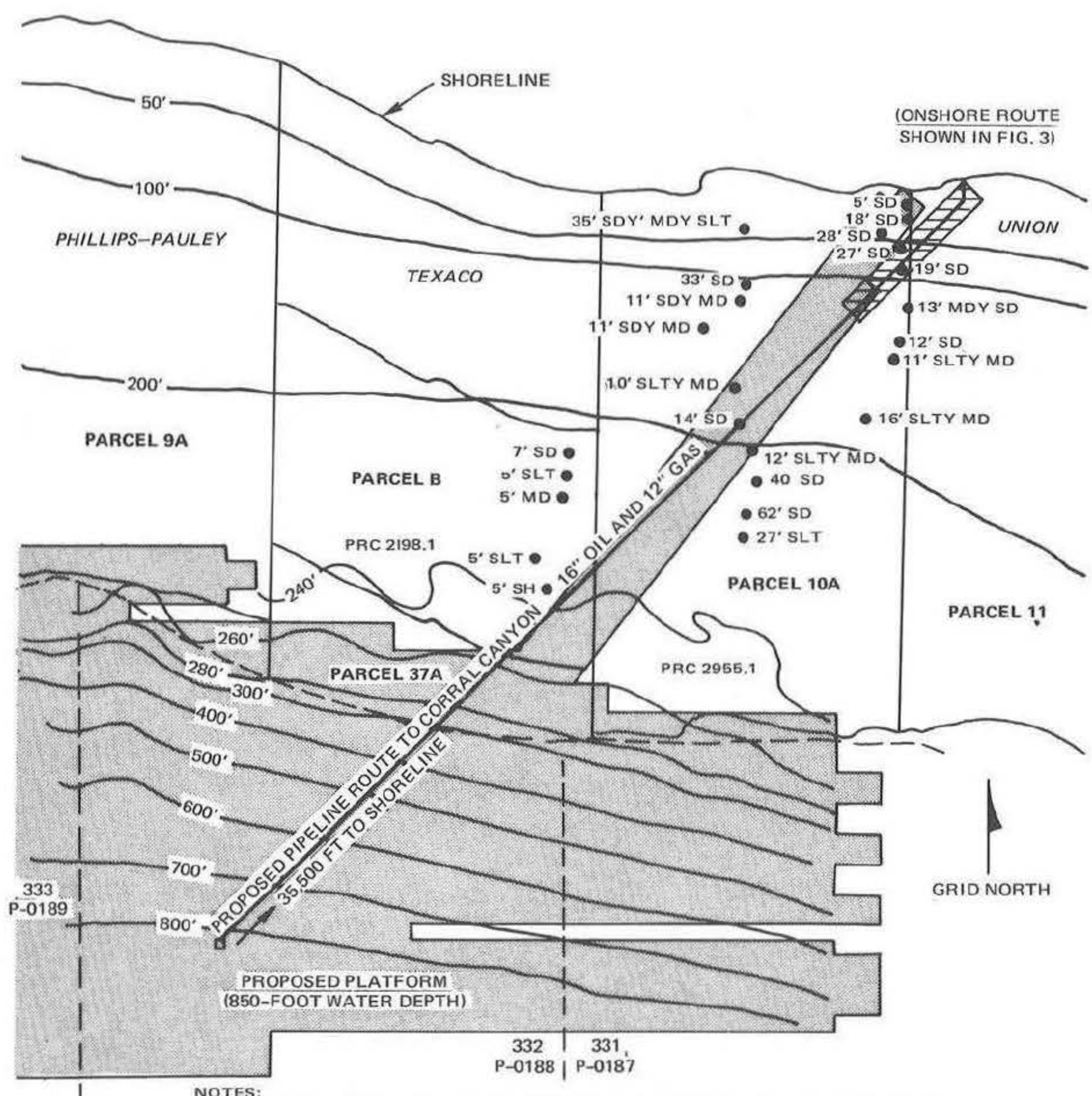
LINE SEGMENT	TYPE OF PIPE COATING	APPROX. LENGTH (FEET)	PROPOSED PROTECTIVE SYSTEM	NO. AND SIZE OF PROTECTIVE UNITS	DESIGN LIFE (YEARS)
Onshore	Doped & Wrapped	5800	Magnesium Anodes	2 groups of 10 DOW (1) Type - 20D2 (20 lb)	15*
Beach to 200' WD	Doped & Wrapped 1-1/2" concrete 16" - - 1-3/4" concrete on 12"	13,000	Zinc Bracelets	18 semi-cylindrical type per CPS Dwg. S-216, on 750' spacing, 240 and 290 lb. weights on 12" and 16" respectively	30+
200' - 300' WD	Doped & Wrapped 1-1/2" concrete	13,000	Zinc Bracelets	Same as above(2)	30+
300' WD to Platform	60 mil polypropylene thin film epoxy	10,500	Rectifier-Pb,Ag anode system located on platform	One 15 volt, 50 Ampere D.D. Rectifier operating in conjunction with platform anode system	20*

(1) Install one test lead on each pipeline at midpoint between anode groups

(2) Install a zinc bracelet on last joint of concrete coated pipe (each line)

* Replaceable Systems

ROUTE MAP FOR 16-INCH OIL AND 12-INCH GAS PIPELINES FROM 850-FOOT PLATFORM TO SHORE.



NOTES:

- EACH SOLID CIRCLE SHOWN REPRESENTS A LOCATION WHERE A BOTTOM SAMPLE WAS TAKEN AND BOTTOM SEDIMENT REMOVED BY JETTING IN ORDER TO EXPOSE FIRM UNDERLYING MATERIAL (TYPICALLY CLAY SHALE). THICKNESS AND TYPE OF SEDIMENT IS SHOWN. SURVEY MADE 1949–51. SHADED AREA WAS SURVEYED WITH SIDE-SCAN SONAR BY EG&G IN 1970. AREA SHOWN HATCHED SURVEYED BY GENERAL OCEANOGRAPHICS, JUNE 1971.

FIG. 1.

PROFILE OF PROPOSED 12-INCH AND 16-INCH PIPELINES,
SANTA YNEZ UNIT-SBC.

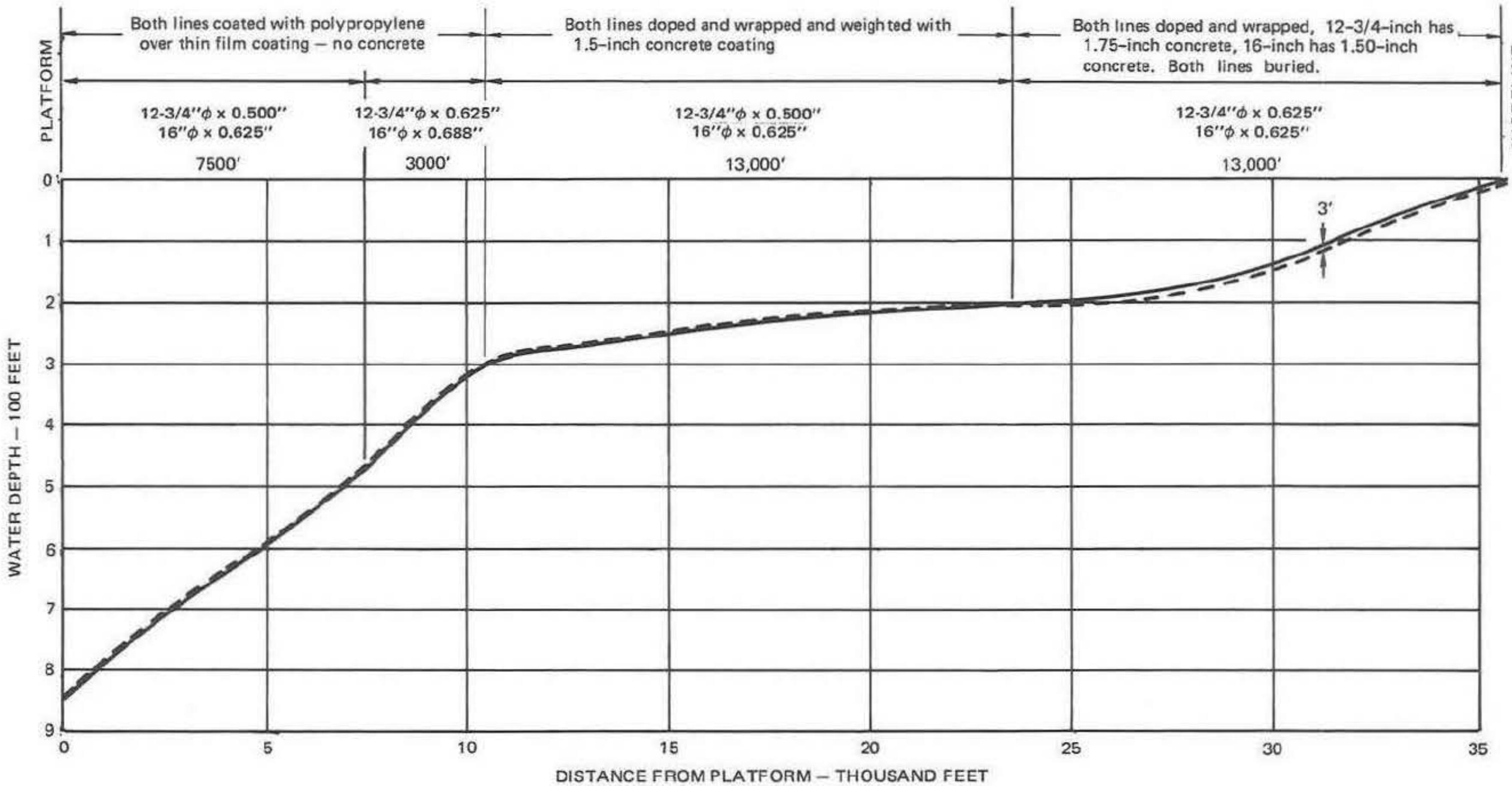


FIG. 2.

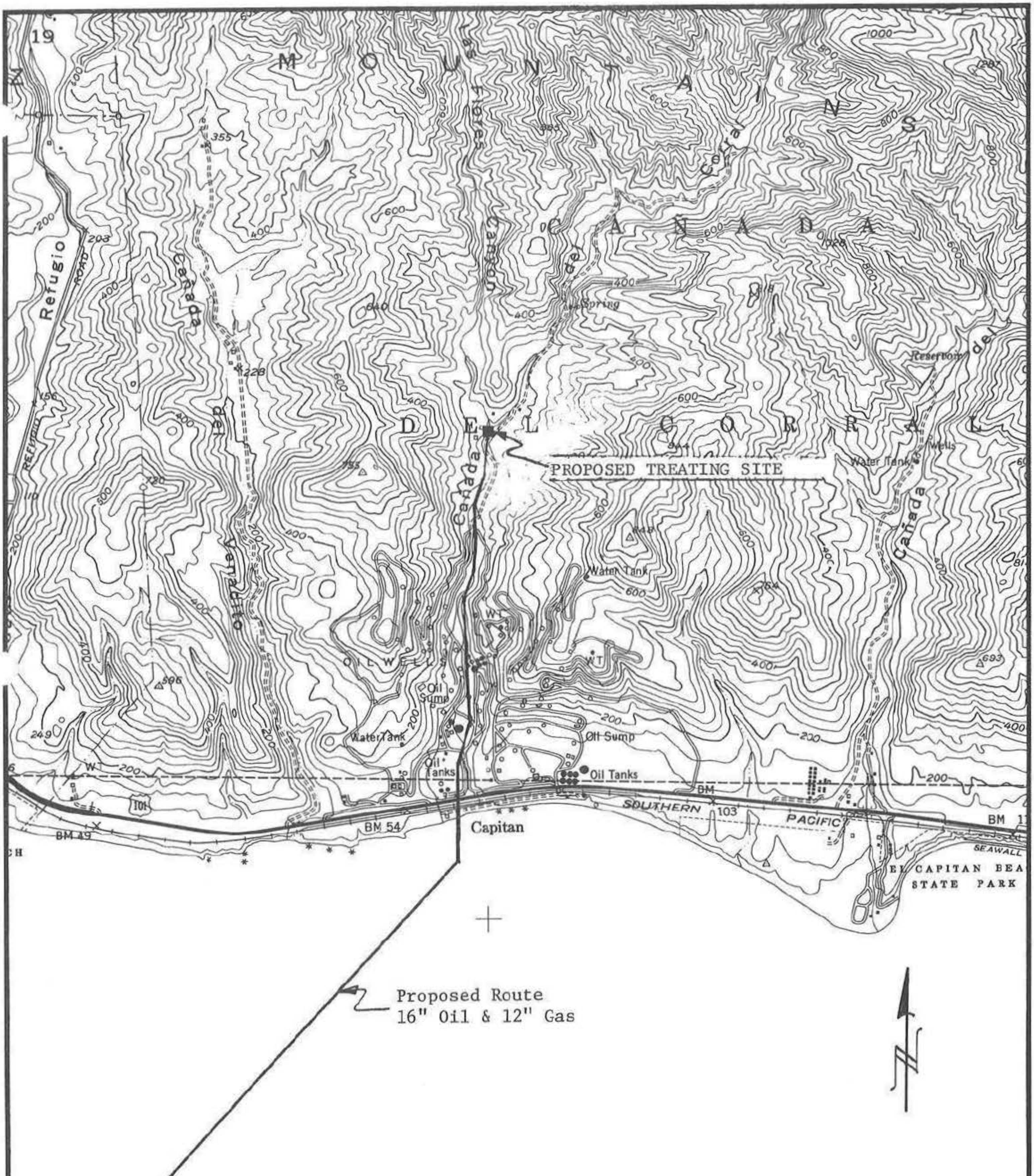


Figure 3

ONSHORE ROUTE OF PROPOSED 12" & 16" PIPELINES

PIPELINE SYSTEMS

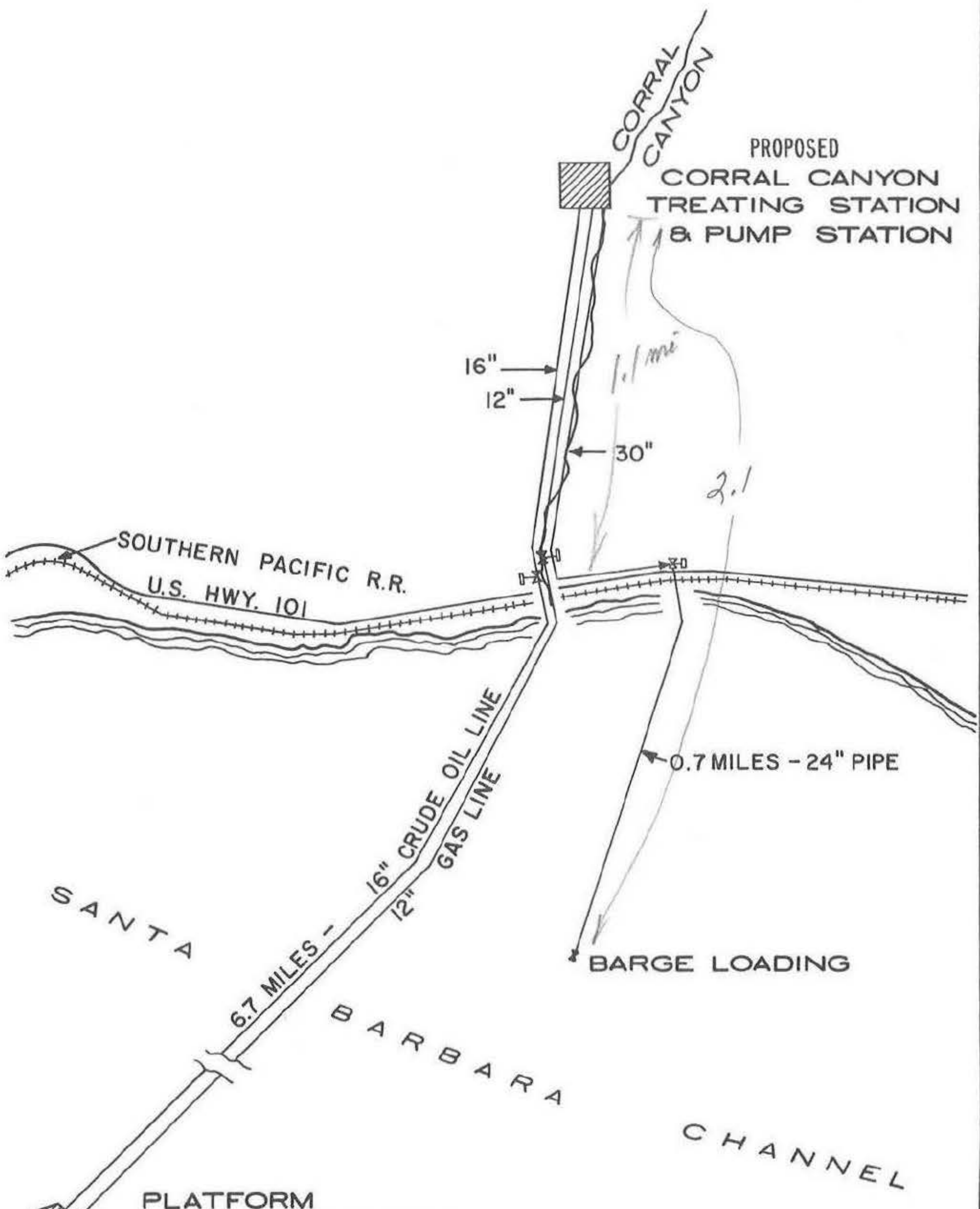


Figure 4

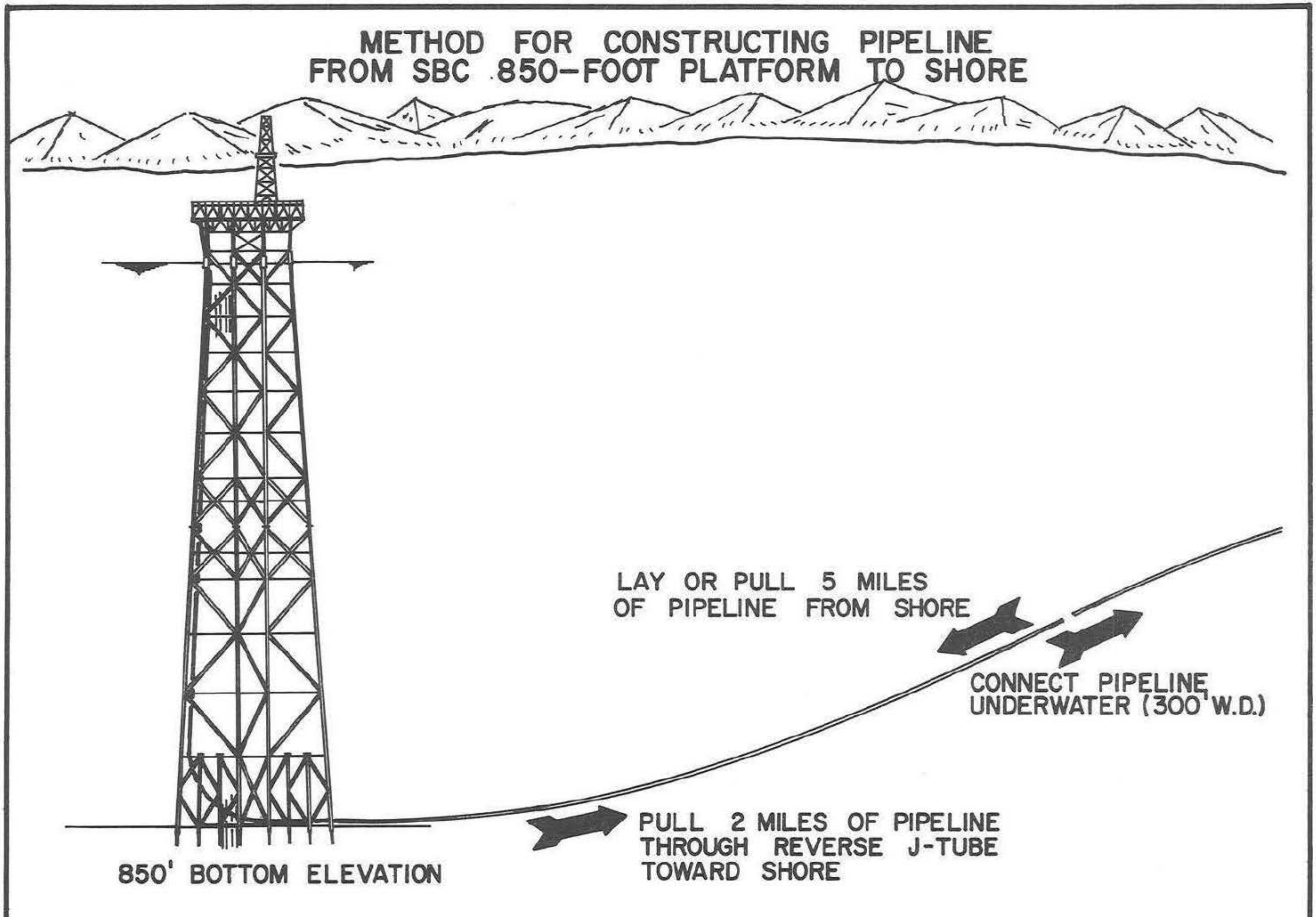
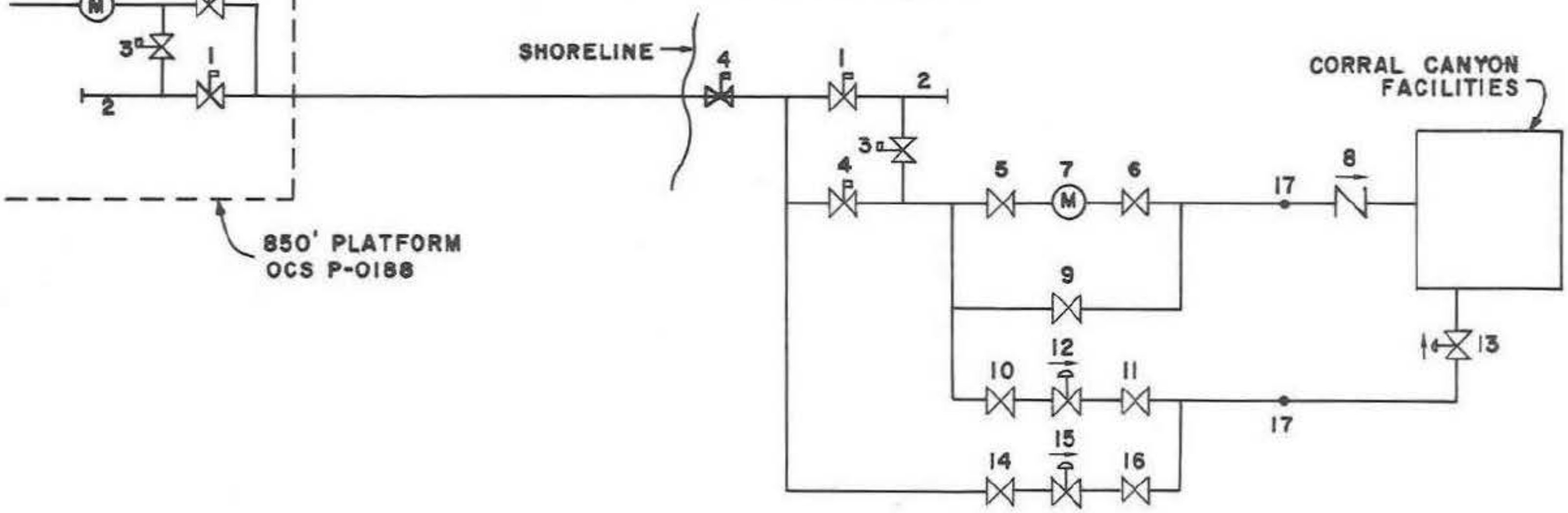


Figure 5

(Revised)

16" OIL PIPELINE FROM 850-FOOT PLATFORM TO CORRAL CANYON FACILITIES
SANTA YNEZ UNIT, SBC.



1. 16" ANSI 600 gate valve, through conduit, scraper entry, motor operated—normally closed. (These also serve as automatic and remote shut-in valves when running scrapers.)
2. 18" scraper entry barrel—entry will be equipped with drain line, pressure gauge and closure.
3. 12" ANSI 600 gate valve, motor operated, scraper bypass—normally closed.
4. 16" ANSI 600 gate valve, motor operated—normally open. (These also serve as the automatic and remote shut-in valves.)

5&6. 12" ANSI 150 gate valve, manually operated—normally open.

7. 8" ANSI 600 turbine meter (for continuous surveillance—normally in operation).
8. 16" ANSI 150 check valve.
9. 12" ANSI 150 gate valve, manually operated—normally closed.

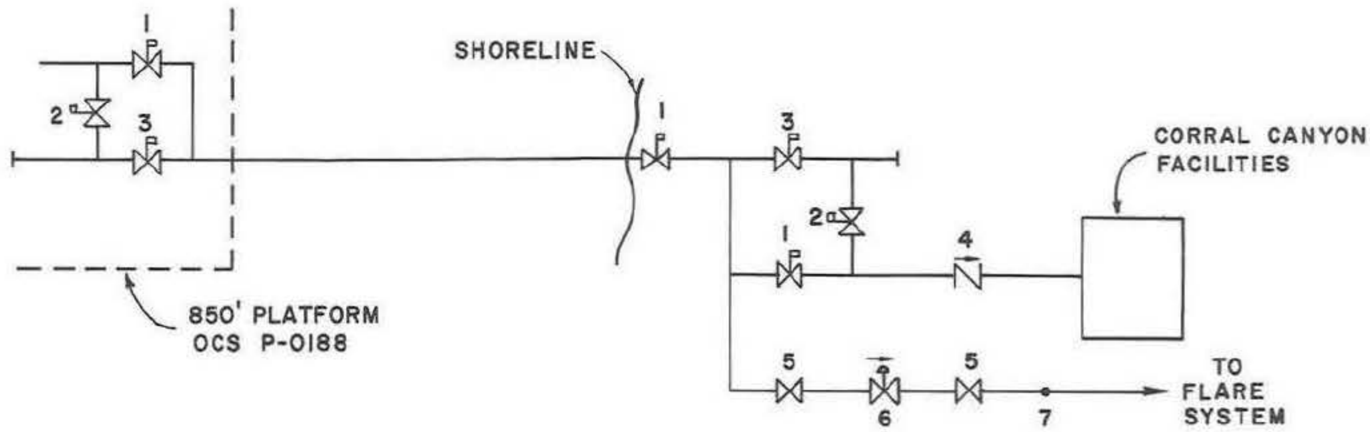
10&11. 12" ANSI 150 gate valve, manually operated—normally sealed or locked open.

12. 8" ANSI 600 relief valve (set to permit flow to start at 100 psi).
13. 12" ANSI 150 check valve.
14. 4" ANSI 600 gate valve, manually operated—normally sealed or locked open.
15. 4" ANSI 600 relief valve (set to permit flow to start at 1440 psi).
16. 4" ANSI 150 gate valve, manually operated normally sealed or locked open.
17. Flow Detector

FIG. 6.

12" GAS PIPELINE FROM 850 – FOOT PLATFORM TO CORRAL CANYON FACILITIES

SANTA YNEZ UNIT, SBC.



1. Three - 12" ANSI 600 gate valves, motor operated, normally open. (These three valves also serve as automatic and remote shut-in valve.)
2. Two - 8" ANSI 600 valves, scraper by-pass, motor operated, normally closed.
3. Two - 12" ANSI 600 gate valves, through conduct scraper entry, motor operated, normally closed. (These two valves also serve as automatic and remote shut-in valves when running scrapers.)
4. One - 12" ANSI 600 check valve.
5. Two - 4" ANSI 600 valves, normally locked - or sealed open.
6. One - 4" ANSI 600 relief valve (set to relieve, if pressure rises approximately 100 psi above normal.)
7. Flow detector.

FIG. 7.

ONSHORE TREATING FACILITIES

MARINE TERMINAL

TABLE OF CONTENTS

MARINE TERMINAL

MARINE TERMINAL

ABSTRACT

This section describes the marine loading terminal and related facilities located at Corral Canyon. The purpose of the facility is to transfer and meter treated crude from storage tanks to marine barges or tankers moored offshore. The facility consists of a pumping station onshore, a connecting pipeline, and a single buoy mooring and loading system located about three-quarters of a mile offshore. Also included are communications and control facilities.

INTRODUCTION

An existing operational marine terminal at Corral Canyon (Figure 1) will be used as the nucleus for the Santa Ynez Unit marine loading facility. A number of modifications will be made to handle the larger anticipated volumes. The facility will consist of: (Figure 2)

(1) A pump station, including three electric drive centrifugal pumps, five positive displacement flow meters, a control center and associated equipment.

(2) 7500 feet of buried onshore pipeline and 3800 feet of submarine pipeline.

(3) A Single Anchor Leg Mooring System (SALM) located about three-quarters of a mile offshore (Figures 3 and 4).

(4) An integrated system of flow control, monitoring, and automatic shutdown equipment.

The design loading rate is 25,000 barrels per hour of degassed 20°API crude. A detailed engineering study of the upgraded terminal is attached as Appendix 5.8.

1. DESIGN CRITERIA AND OBJECTIVES

1.1 Objectives

1.1.1 Mooring

Provide a Single Anchor Leg Mooring capable of restraining a 25,000 dwt barge in seas with up to 10-foot significant wave heights, capable of withstanding a 100-year storm without damage, and located to provide adequate water depth and sufficient room for maneuvering during berthing operations.

1.1.2 Piping System and Pump Station

Provide a pump station and piping system which comply with all applicable codes, laws, and regulations, and which incorporate centralized operational control and automatic shutdown procedures.

1.2 Design Criteria

The design criteria summarized below were used for the layout and design of the Single Anchor Leg Mooring (SALM). These criteria are not necessarily for normal operating conditions, but represent the extremes for which the berth has been designed.

Amplified discussion of the basis and application of these criteria is included in referenced Appendix 5.8.

1.2.1 Vessel Characteristics

The SALM has been designed to restrain the following barge-tug unit:

25,000 dwt Barge	6000 hp Tug
500 ft. length	150 ft. length
90 ft. beam	40 ft. beam
31 ft. loaded draft	21 ft. draft

1.2.2 Weather

	Operational (w/Vessel at Moor)	Severe* (w/o Vessel)
Significant Wave Ht.	10 feet	22 feet
Current	1.0 knots	2.0 knots
Wind Velocity	40 mph	75 mph

* 100-year storm

1.2.3 Piping System and Pump Station

The design criteria summarized below were used for the design of the piping system and pump station. These criteria are not for normal operating conditions, but represent the extremes for which the system was designed. As previously stated, amplified discussion of the basis and application of these criteria is included in referenced Appendix 5.8.

(1) External Forces - design is based upon the external forces from wind, currents,

and waves in accordance with the criteria listed above for the sea berth.

(2) System Design Pressures

Pump Station	- 275 psig at 100°F
Pipeline	- 275 psig at 100°F
Loading Hose	- 250 psig working pressure
	1600 psig burst pressure
Surge Pressures	- 10% allowable over design pressures
Surge Pressure Control	- limited by closing rates of manual and motor operated valves

(3) External (Collapse) Pressures - all piping is designed to resist collapse when operating at a vacuum under full overburden loads.

(4) The offshore pipeline will be buried or suitably stabilized with weighting material. The line will be coated and wrapped and cathodically protected with a sacrificial anode system both onshore and offshore. Sea bottom conditions are described in Appendix 5.9.

1.2.4 Safety Provisions

(1) Safe startup of the loading operation to prevent overpressuring any portion of the system will be guaranteed by the use of permissive start circuits in the pump motor starting circuits.

(2) An automatic safety shutdown will stop all pumps and close the shoreline block valve in the event of excessive flow rates or a ten percent overpressure at the shoreline block valve. Relief valves will be provided on the pump discharge header for the discharge of full pump capacity back to the tank farm in case of overpressure.

2. DESIGN AND DESCRIPTION OF MAJOR COMPONENTS AND SUBSYSTEMS

General design descriptions, materials and characteristics of the sea berth components, piping system and pump station are described below. The general layout of the facilities is shown in Figure 2. Detailed equipment design is presented and discussed in Section 3 of Appendix 5.8. Specific code references and areas of application are listed in Section 3.1 of the referenced appendix.

2.1 Single Anchor Leg Mooring (SALM)

A single buoy mooring allows a ship to swing freely into the prevailing wind and current, thereby reducing to a minimum the resultant forces exerted on the ship. The Single Anchor Leg Mooring (SALM), an advanced concept of the single buoy mooring system, consists of a buoy secured to the sea bed by an anchor chain and base. (Figure 4)

In addition to the advantages of a single buoy mooring, the SALM eliminates the need for numerous anchoring points and long anchor chains. Berthing and deberthing operations are simplified. It presents less of an obstruction to the maneuvering of the vessel and is not generally subject to damage by the ship. Furthermore, the principal rotating mechanical elements require a minimum of maintenance and are positioned beneath the harsh splash zone environment.

The SALM shown on Figure 4, and described more fully in referenced Appendix 5.8, consists of an oil transfer system and a mooring system combined in one unit. Mooring loads from the vessel are transmitted through the mooring line assembly to the buoy, from the buoy center shaft to the riser chain, and through the chain to the swivel housing center pipe connected to the base. Crude flows from the submarine line into the base piping system, from there into the swivel housing, and finally into the loading hose system leading to the barge. Protection against corrosion is provided by the use of special materials, by extra thicknesses on certain subsystems, and by cathodic protection.

2.2 Piping System and Pump Station

The piping system and pump station described below are depicted in the general plans (Figures 3 and 4 of Appendix 5.8) and on the flow diagram for the system (Figure 5). Detailed discussion of equipment design is included in Section 3.3 of Appendix 5.8.

2.2.1 Piping System

	Onshore	Offshore
Line Length	7500 ft.(approx)	3800 ft.
Diameter	30 in.	24 in.
Wall Thickness	0.25 in.	0.50 in.
Specification	API-5LX-42	API-5L-Grade B seamless
Design Pressure	275 psig @100°F	275 psig @ 100°F
Coating	Coated and wrapped	Coated and wrapped plus 3" concrete weight coat
Cathodic Protection	Sacrificial magnesium	Zinc bracelets (30-year life)

The 30-in. onshore buried pipeline reduces to 24 in. at the 24-in. shoreline block valve. The valve is equipped with an electric motor actuator operated from the control center at the Corral Canyon facilities. The 24-in. submarine line is equipped with a 24-in. ball valve at the SALM. The ball valve has a hydraulic actuator served by two 1-in. diameter hydraulic oil lines from a shore-based oil pump, accumulator and reservoir. The hydraulic pump and ball valve are operated from the control center. To avoid surges due to rapid closure, the ball valve controls are electrically interlocked so they cannot be operated when the shoreline valve is open.

2.2.2 Pump Station

The pump station is located near the crude oil storage tanks at the Corral Canyon facilities. The station includes three motor-driven centrifugal pumps in parallel, each rated at 8,333 bbl/hr at 115 psi differential head. The suction pressure delivered by the booster pumps will be 40 psig and discharge pressure of the station pumps will be 155 psig. Discharge pressure is controlled by two double seated control valves in parallel. Relief valves capable of relieving the full rated flow back to tankage are installed downstream of the control valves. Flow is metered by five 16-in. positive displacement meters in parallel rated at 5,000 bbl/hr. each. Each meter is equipped with a pulse generator, a transmitter, an electronic totalizer and ticket printers. A bi-directional meter prover is provided.

2.2.3 Control Center

A manned control, surveillance and communication center is provided. Data displayed within the control center will include the following:

(1) Open-closed position of all operation valves and on-off condition of each pump

(2) Flow rate and total flow for each meter.

(3) Pump suction and discharge pressure. Discharge pressure will be recorded and remotely controlled.

(4) Temperature of the flowing stream. Temperature will also be recorded.

(5) Radio communications equipment will be installed to permit continuous communication with the barge during mooring, loading, and deberthing.

A manually and/or automatically activated safety shutdown system is provided. Automatic safety shutdown is triggered by:

(1) Excessive total flow rate as registered by the flow meter electronic totalizer

(2) Pressure 10 percent over normal, as detected by the high pressure shutdown switch at the shoreline valve.

The safety shutdown system can be manually activated at any time by the control room operator and will be activated if communication with the barge is lost at any time during loading operations.

A schematic diagram of the surveillance and safety shutdown system is presented in Figure 6.

3. CONSTRUCTION AND INSTALLATION

Components of the SALM will be fabricated in the contractor's shops and transported to the site for assembly, installation and testing. The coated and wrapped onshore pipeline will be buried with a 3-foot minimum cover on a pad of rock-free fill. The offshore pipeline will be laid from an anchored barge and will be pulled toward a deadman anchor onshore. Prefabricated weight-coated joints will be welded and coated on the barge. In the surf zone the line will have a 4-foot minimum cover except where rock excavation is required. In those areas, a minimum cover of eighteen inches will be maintained. Beyond the surf zone the pipe will be stabilized on bottom by burial or by suitable anchorage.

The piping system and pump station will be thoroughly tested during construction and before start-up. All girth welds on the pipeline will be subjected to radiographic inspection. All pipe coatings and wrappings will be tested for holidays before installation. All valve seats will be tested to their full-rated hydrotest pressure before installation. All pipelines will be tested to a minimum of 1.25 times the design pressure, and pump station piping will be hydrotested to a minimum of 1.5 times design pressure.

Additional details of construction, installation and testing are included in Appendix 5.8.

SITE PLAN
EXISTING FACILITIES

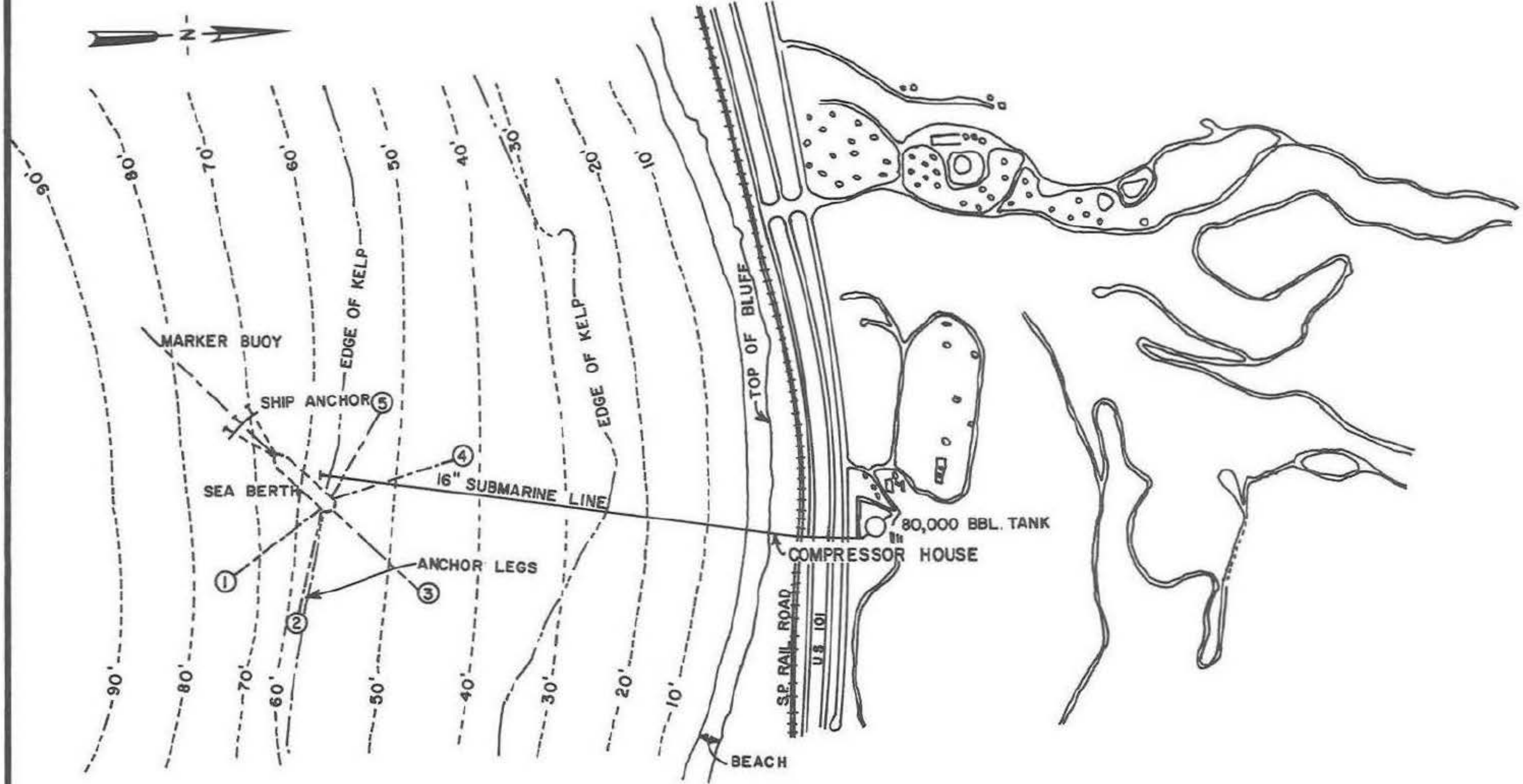


Figure 1

DATUM: M.L.L.W. O.O FT.

PIPELINE SYSTEMS

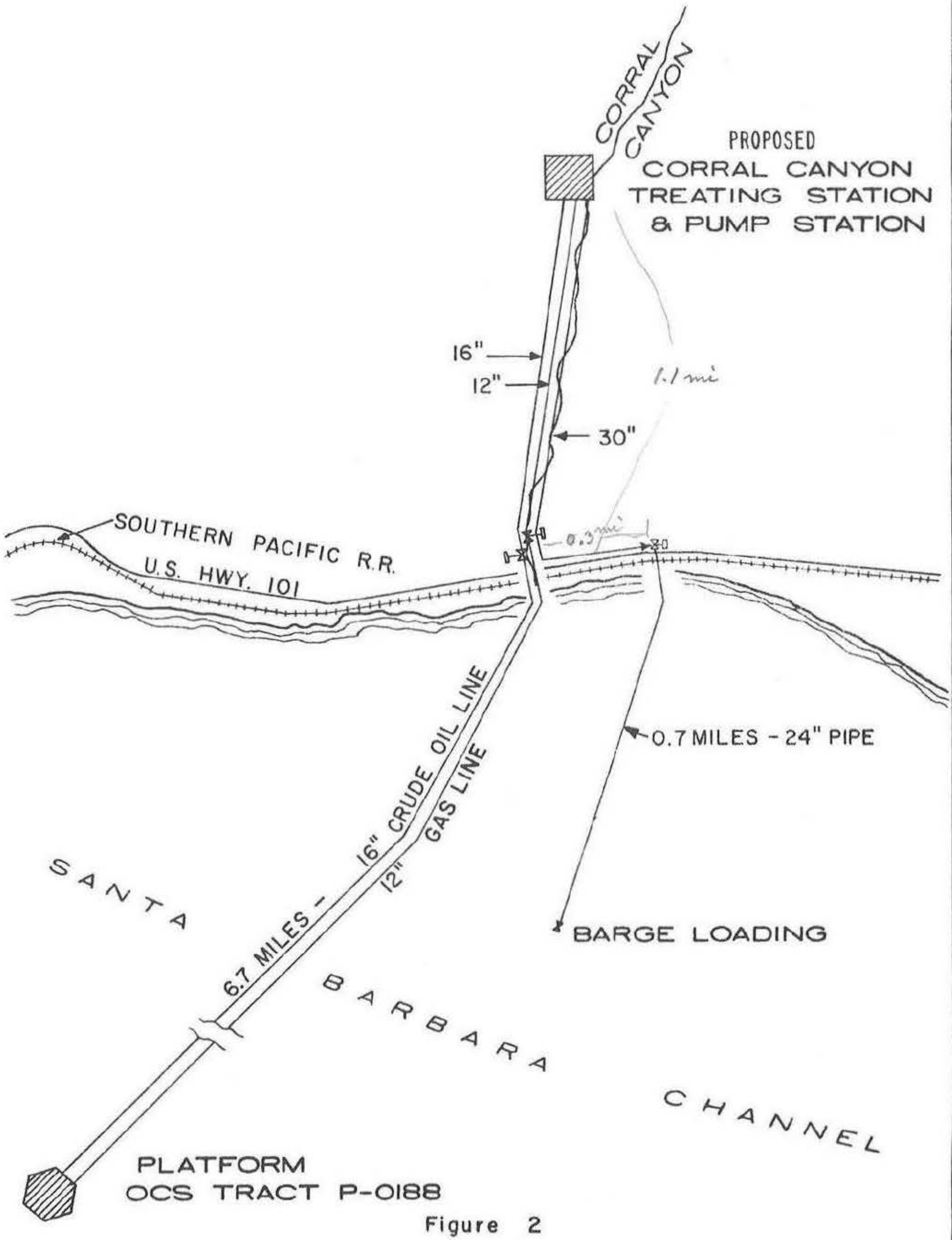
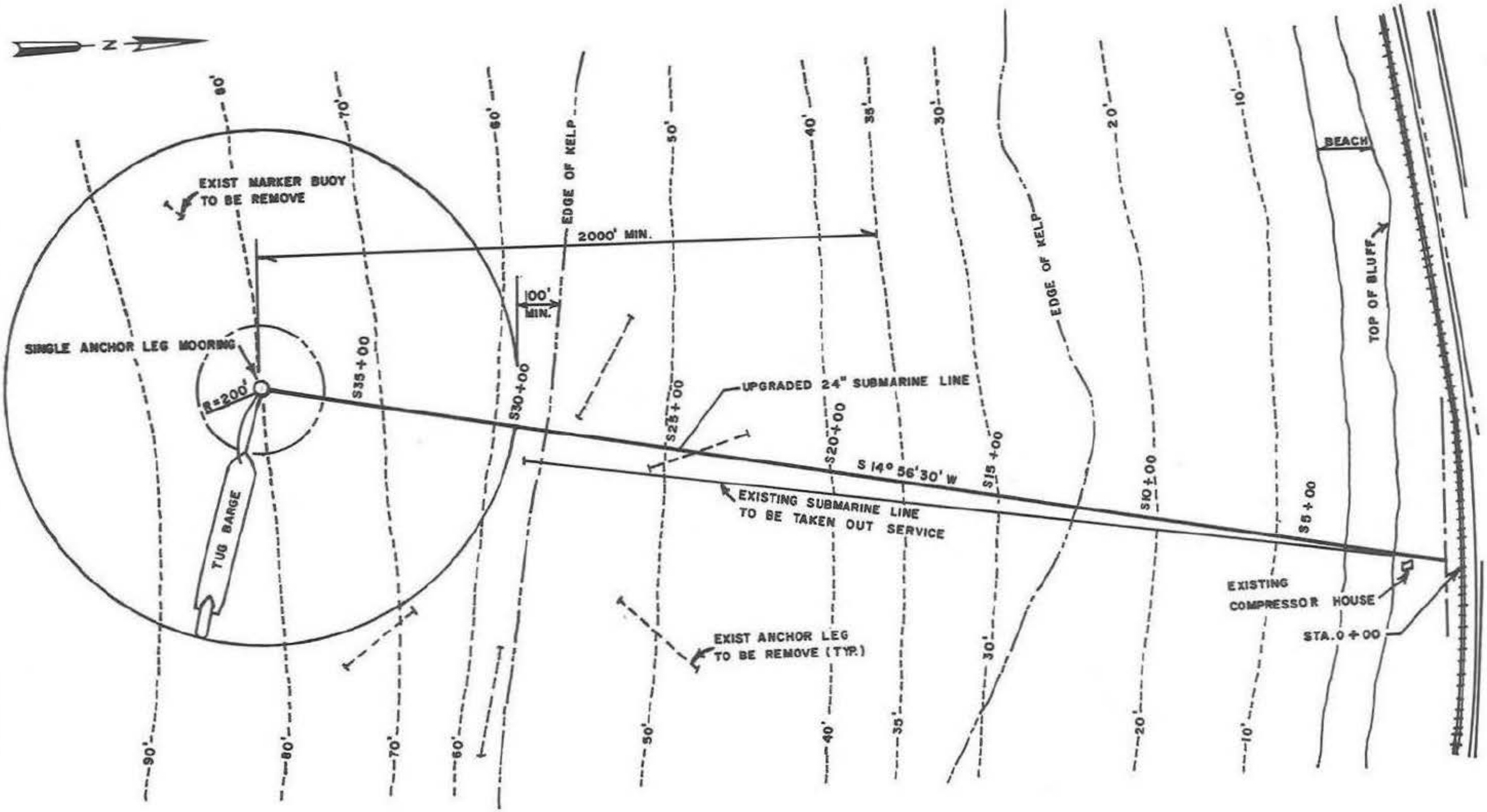


Figure 2

GENERAL PLAN
SEA BERTH & SUBMARINE LINE



DATUM: M.L.L.W. 0.0 FT.

Figure 3

SINGLE ANCHOR LEG MOORING

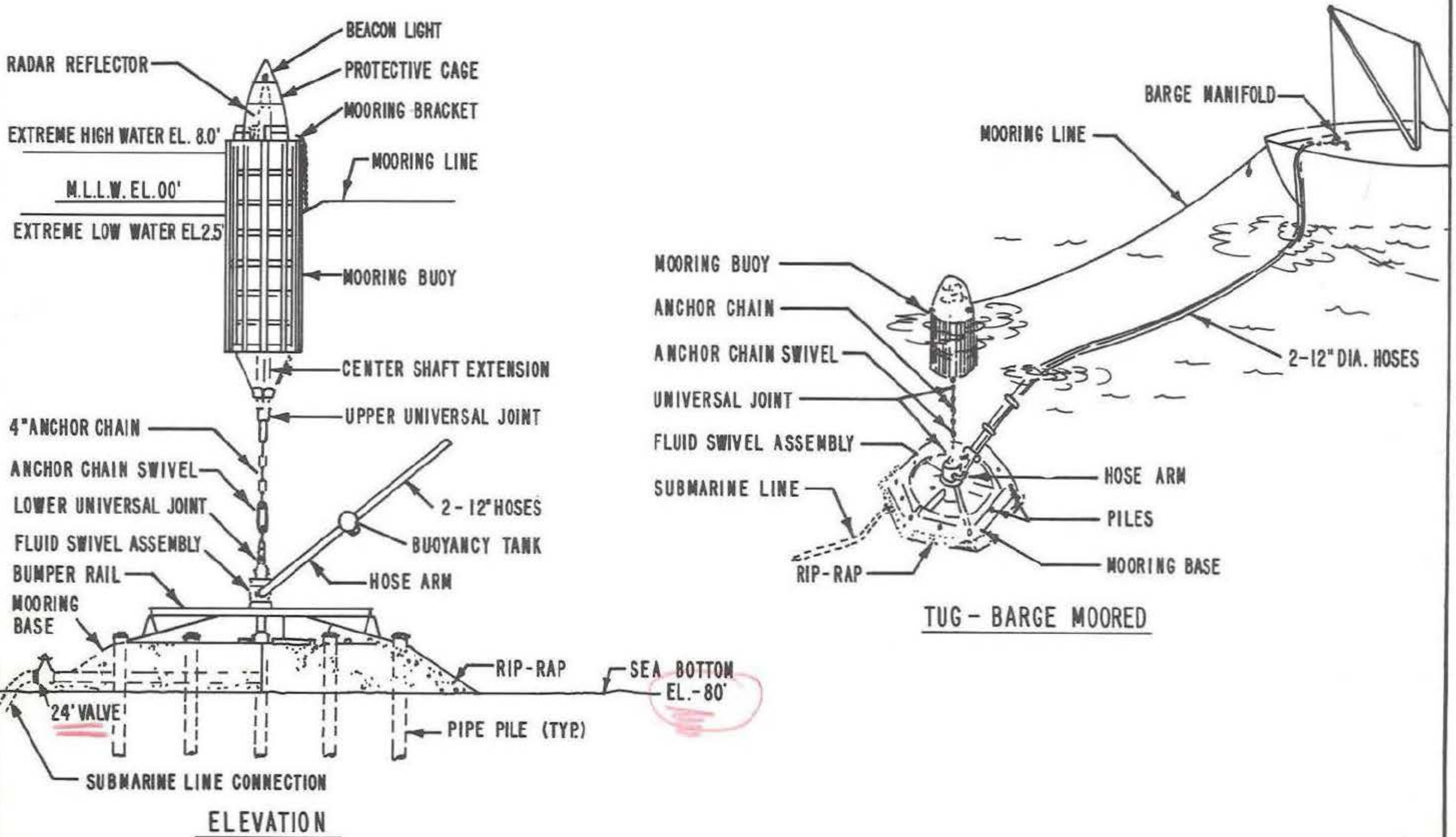
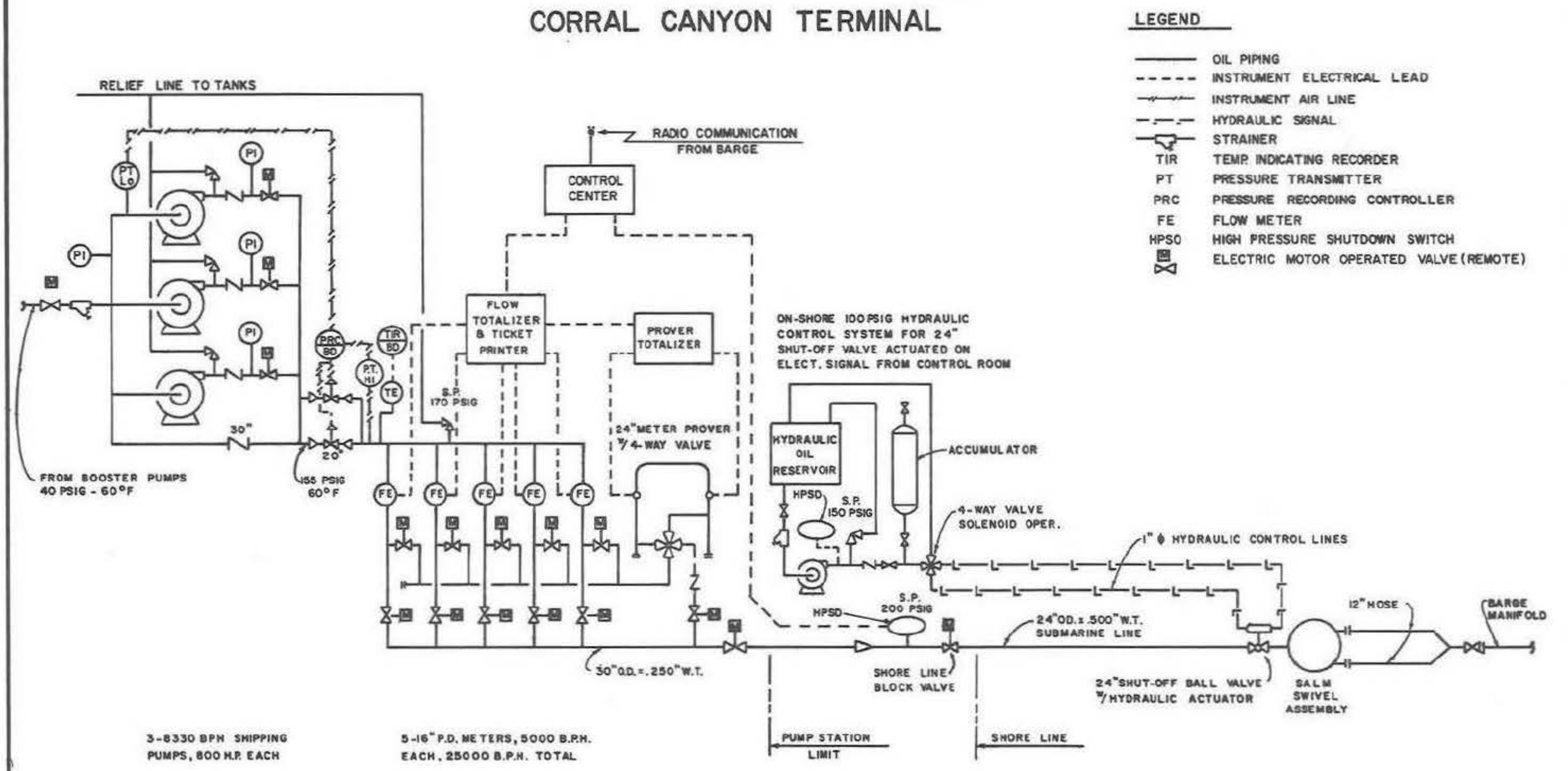


Figure 4

FLOW DIAGRAM
CRUDE OIL PIPING SYSTEM
CORRAL CANYON TERMINAL



NOTES:

1. BEFORE PUMP MOTORS CAN START, A PERMISSIVE START CIRCUIT REQUIRES ESTABLISHMENT OF FOLLOWING CONDITIONS:
   a) RADIO COMMUNICATION FROM BARGE.
   b) AN ELECTRICAL SIGNAL GENERATED BY GRAVITY FLOW THROUGH FLOW METERS.

Figure 5

SAFETY SHUTDOWN & SURVEILLANCE DIAGRAM

SURVEILLANCE AND SAFETY CONTROLS

A. RECORDED AND DISPLAYED ON CONTROL PANEL
   1. FLOW
   2. TEMPERATURE
   3. DISCHARGE PRESSURE

B. DISPLAYED ON CONTROL PANEL
   1. VALVE OPEN-CLOSED POSITION
   2. PUMP MOTORS - ON-OFF
   3. SUCTION PRESSURE

C. PERMISSIVE START CIRCUIT ON SHIPPING PUMP MOTOR CONTROLS REQUIRES:
   1. ACTUATE MANUAL PERMISSIVE START PUSH BUTTON ON COMMAND FROM BARGE.
   2. FLOW THROUGH METER TO GENERATE ELECTRIC SIGNAL.

D. MANUAL SAFETY SHUTDOWN
   1. ACTUATE ONE PUSH BUTTON

E. AUTOMATIC SHUTDOWN ACTUATED BY:
   1. 10% OVER PRESSURE AT SHORELINE
   2. EXCESS FLOW

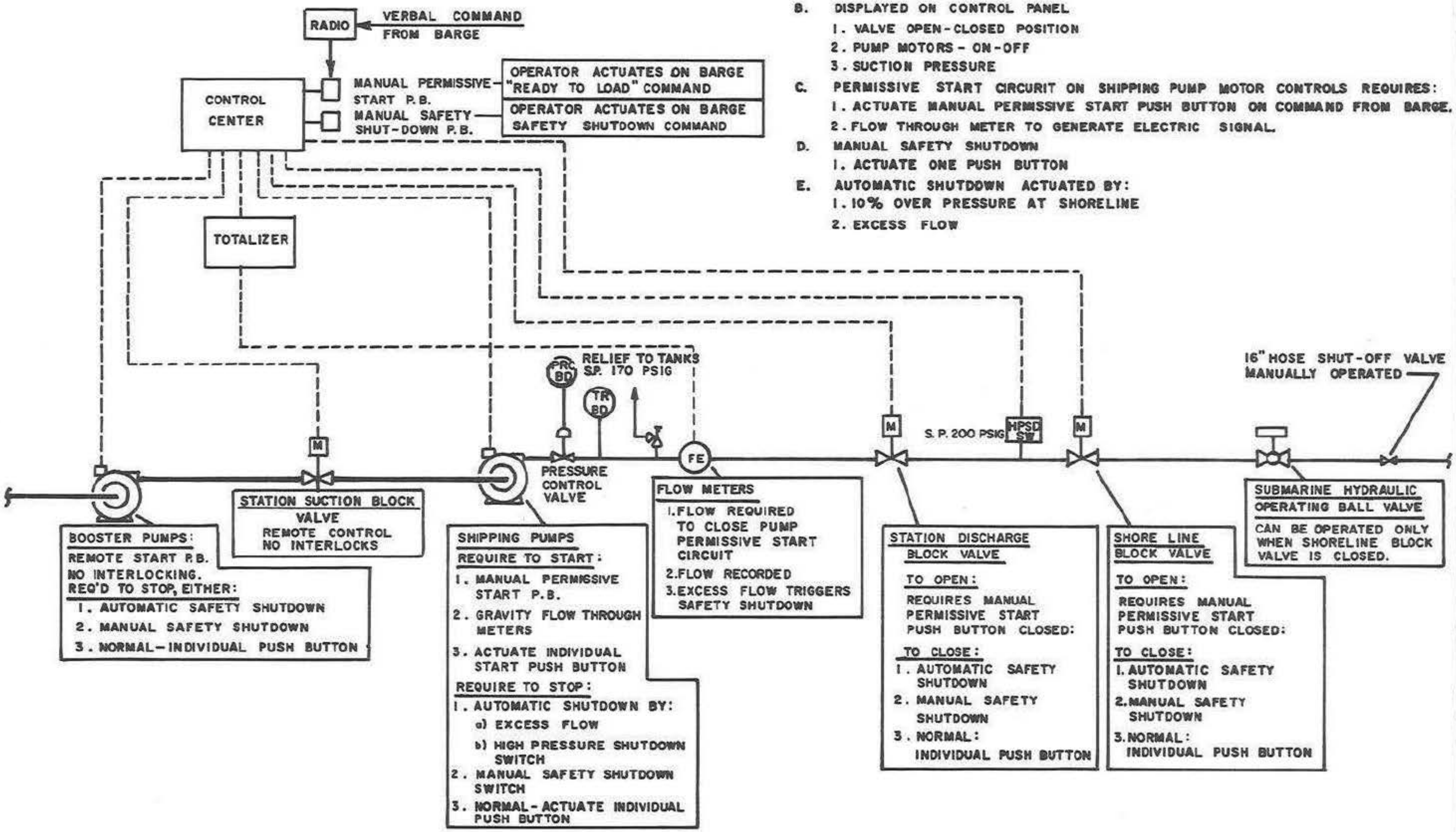


Figure 6

OFFSHORE STORAGE AND TERMINAL

TABLE OF CONTENTS

OFFSHORE STORAGE AND TERMINAL

OFFSHORE STORAGE AND TERMINAL

ABSTRACT

This section discusses a plan for treatment and storage of crude produced from the proposed initial platform to a floating storage and terminal facility. A 28,000 dwt tanker or seagoing barge of similar tonnage would be moored to a Single Anchor Leg Mooring System. Crude oil would be delivered to the floating storage vessel through an ocean floor pipeline from the initial platform. The vessel would be modified or constructed to receive, treat and store crude oil for transfer to shuttle vessels, and to treat and dispose of salt water separated from the crude.

INTRODUCTION

Included as part of this Supplemental Plan is an offshore floating storage and terminal system which Humble will install and use if required to expedite the commencement of production or to test producing wells prior to construction of onshore facilities. This system would provide for final treatment of the crude, storage, and offloading to marine barges or tankers of the same type used in connection with the shore site.

The floating vessel and mooring system discussed in this section are designed to be installed in the northeast corner of OCS Lease P-0188 in 300 to 400 feet of water adjacent to the proposed pipeline route to shore (Figure 1). Production facilities installed on the vessel would separate water from the crude, direct the crude oil to the vessel storage tanks, and clean the water to USGS standards for disposal in the ocean. Treated crude would be offloaded to shuttle vessels for transport to market. (Figure 2.)

The following sections present design criteria, descriptions of major equipment and subsystems, and a summary of fabrication and installation techniques for major components of the offshore storage facility. These components consist of:

(1) Approximately 9,000 feet of 12-inch subsea oil pipeline.

(2) A Single Anchor Leg Mooring (SALM) or equivalent system designed for 300- to 400-foot water depths and which includes a safety shut-in system.

(3) Modifications to the floating storage vessel (specialized mooring systems and conversion for storage and installation of treating facilities).

(4) Production equipment designed to separate water from the crude, direct the oil to storage, and clean the water to USGS standards for disposal.

1. DESIGN CRITERIA AND OBJECTIVES

Plans for the offshore storage facility have been developed in accordance with the following general objectives and criteria:

(1) Provide a facility capable of treating 40,000 barrels of oil per day, providing up to 200,000 barrels of storage and cleaning water to 50 ppm oil or less for disposal in the ocean.

(2) Provide a mooring system to safely moor the treating and storage vessel during conditions of 20-foot

significant wave heights and 75 mph winds, which includes a system for safely releasing the vessel from the mooring.

(3) Provide an offloading system capable of functioning in 8-10-foot significant wave heights.

(4) Provide a facility which meets all applicable codes and regulations, including maximum safeguards for safety and pollution control.

2. WEATHER CONDITIONS

Two types of weather data were gathered for the preparation of detailed offshore storage plans: 1) severe storm data were used to determine the maximum design forces in the floating storage mooring; 2) operational weather data were used to determine design criteria for the shuttle vessel alongside berthing equipment and to estimate the efficiency of the offloading operation.

2.1 Severe Storm Data

The ten most severe storms hindcast over a 70-year period in the vicinity of OCS Lease P-0188 are consistent in their behavior and indicate that the proposed location is in the least severe weather area in the Santa Barbara Channel (Appendix 6.2). The maximum wind is expected to be 75 mph from E-SE, with wind waves building to a significant wave height of 16-18 feet in the worst storms with an average period of 8-9 seconds. Swells during the severe storms tend to build about 24 hours after the maximum waves and may reach significant heights of 15-20 feet maximum with an average period of 12-15 seconds from the W-SW direction.

The ten most severe storms at this location persisted for an average of a little under three days. The maximum waves, swells, or combined waves and swells did not persist for this entire period, however. The average of these storms is characterized by combined significant wave heights due to wind waves and swells of 18.5 feet sustained for a duration of 70 hours. Generally low values of observed current indicate that current would have a small effect on mooring forces.

The hindcast indicates that significant wave heights due to combined waves and swells occurring simultaneously exceeded 20 feet only 36 hours total in all 10 severe storms. The mooring is designed to moor the floating terminal in up to 20-foot significant wave heights.

2.2 Operational Weather Data

Operational seas for offloading (which will be limited to the 8-10-foot range) can be anticipated 90 to 96% of the time on an annual basis at the proposed location. (See Appendix 6.1.) The frequency of operational weather would be less in the winter and greater in the summer. Operational weather is defined as being sea conditions which permit the delivery vessel to maneuver, berth alongside, and safely take on oil from the floating storage vessel.

Based on observations from the drilling vessel under contract to Humble, the persistence of non-operational weather will not be a serious problem. On an annual basis, there is a 20% probability that 8-foot seas will persist for more than one day and a 10% probability that they will persist for more than two days. There are no data to indicate that non-operational weather would persist for longer than four days, even in the winter.

3. PIPELINE FROM PLATFORM

3.1 General

The 12-inch pipeline, which will serve the offshore storage terminal, will be designed and installed using criteria and procedures similar to those specified for the 12-inch gas line in the PIPELINES section of the Plan, except that initially the line will be constructed only from the platform to the 300- to 400-foot contour (Figure 1). The design of this pipeline under USGS OCS Order No. 9, DOT Regulation 49, Part 192 and ANSI B31.8-1968 for gas service is also adequate for design requirements applicable to crude service (DOT Regulation 49, Part 195 and ANSI B31.4-1971).

Operation of the pipeline will include a sphere launcher and receiver and a subsea safety shut-in valve.

3.2 Design Criteria and Objectives

3.2.1 Product to be Transported

The 12-inch oil line will have an approximate maximum throughput of 40,000 barrels per day of 20.0° API Gravity crude.

3.2.2 Applicable Regulations and Codes

The design of the pipeline conforms to applicable regulations and codes for use in liquid petroleum transportation.

3.2.3 Maximum Operating Pressure

The maximum operating pressure of the 12-inch pipeline will be 400 psi while in crude service.

3.2.4 Other Criteria

Design criteria for stability, external pres-ure, "other stresses," and corrosion protection are the same as stated in the PIPELINES section.

3.3 Discussion of Pipeline Design

3.3.1 Pipeline Stability

The pipeline is designed for on-bottom stability while in gas service. In oil service its submerged weight will be greater and resistance to sliding will be further increased.

3.3.2 Internal Design Pressure

The minimum wall thickness (nominal) for the 12-inch pipeline in oil service will be 0.500".

The design working pressure for 12" x 0.500" Grade B seamless or ERW line pipe under DOT Regulation 49, Part 195 (and ANSI B31.4) is 1976 psi. Since this design working pressure of 1976 psi exceeds the maximum design operating pressure of 400 psi, the pipe meets code requirements for internal pressure. Platform piping (including riser) will be designed in accordance with ANSI B31.3, under which the selected wall thickness of 0.625" is satisfactory.

3.3.3 External Pressure

The design of the pipeline to resist external pressure while in gas service will be satisfactory with the line in oil service.

3.3.4 Other Stresses

(1) Initially, the pipeline will not be buried or confined. Therefore, there is no provision required for accommodation of thermal stresses.

(2) Relief valves and safety shut-in valves will be provided to prevent overpressuring of the line from any cause.

(3) Since the line will not be buried and bottom survey data have indicated no faults or unstable areas along the route, vibratory stresses exerted on the pipeline by earthquakes would not affect the pipeline's integrity.

3.3.5 Corrosion Protection

Protection against external and internal corrosion will be as specified in the design of the 12-inch gas line in the PIPELINES section. Appendix 5.2 contains a cathodic protection system design for the 12-inch line while in oil service.

3.3.6 Safety and Valving System

A flow diagram for the 12-inch line from the platform to the offshore storage terminal is shown in Figure 3. All components of the pipeline are protected by pressure relief valves and safety shut-in valves and are designed for maximum operating pressure, including surge.

3.4 Fabrication, Installation, Inspection and Testing

Fabrication, installation, and inspection of the pipeline will be as specified in the PIPELINES section for that portion of the 12-inch gas line from the platform to the 300-400-foot depth contour, except that construction will terminate at the 300-400-foot contour. The pipeline will be connected by divers to the base of the Single Anchor Leg Mooring (SALM) by means of a flexible hose.

Hydrostatic testing of the 12-inch pipeline will be conducted in accordance with DOT Regulation 49, Part 195, Subpart E. A hydrostatic test pressure of

1800 psi will be held for a minimum of 24 hours. Although the maximum design operating pressure of the pipeline will be only 400 psi, this higher test pressure will be applied to verify the pipe's adequacy for future use as a gas line with a maximum design operating pressure of 1440 psi.

4. SINGLE ANCHOR LEG MOORING SYSTEM (SALM)

4.1 Principles of Operation

Like conventional Single Point Mooring (SPM) buoys, the moored vessel is free to rotate 360 degrees about the SALM mooring buoy as the weather changes direction. Thus, the vessel always tends to ride bow to the wind, waves and current, minimizing mooring forces. In addition, the SALM resists the mooring forces by means of a single shaft fixed to a foundation on the ocean floor. In the neutral position, the SALM shaft is supported by the upward force of the nearly submerged buoy. In the design condition, the environmental forces on the storage vessel are resisted by the restoring moment of the angularly displaced shaft and buoy, which act like an inverted pendulum. (Figure 4.) The bow hawser will stretch under these conditions, adding springiness to the system. A detailed description of this mooring system is attached (Appendix 5.11).

4.2 Experience

A SALM was installed in 140 feet of water at the marine terminal facilities of a Humble affiliate at Marsa El Brega, Libya, in October 1969. It is designed for up to 300,000 dwt tankers moored in up to 15-foot significant wave heights. Through July, 1970, 45 tankers, ranging in size up to the 171,000 dwt ESSO MERCIA, had successfully moored to the SALM and loaded 28 million barrels of crude oil. Since then, it has been in continual use. There has been one incident of a tanker accidentally running over the SALM buoy. There was only superficial damage to the buoy and no damage to the fluid swivel or underwater hose. Another SALM of similar design is currently being installed in 80 feet of water at the refinery terminal of a Humble affiliate in Okinawa.

4.3 Design Criteria and Objectives

The design criteria summarized below were used for the layout and design of the Single Anchor Leg Mooring (SALM). These criteria are not necessarily the normal operating conditions but represent the extremes for which the berth is designed. Amplified discussion of the basis and application of these criteria is included in referenced Appendix 5.11.

4.3.1 Vessel Characteristics

	Converted Tanker	Barge
Dead Weight Tonnage	28,000 long tons	30,500 long tons
Displacement	36,600 long tons	35,000 long tons

	Converted Tanker	Barge
Length, overall	628 ft	--
Beam	82 ft, 9 in	95 ft, 0 in
Draft, loaded	33 ft, 1 in	31 ft, 6 in
Total Capacity (20° API)	191,000 barrels	210,000 barrels

(Actual oil storage capacity will be reduced by the volume of produced salt water retained in the vessel.)

4.3.2 Environmental Conditions

Design significant wave heights - 20 ft

Design wind velocity - 75 mph

Maximum tide variation - 8.6 ft

4.3.3 Soil Conditions

The bottom soil conditions on OCS Lease P-0188 have been determined by numerous soil borings. The information gathered demonstrates that pilings can be designed to resist the horizontal component of mooring forces on the mooring base. Final piling design will be based upon a confirmation boring at the installation site.

4.3.4 Design Volumes

Throughput	40,000 barrels per day (maximum capacity 80,000 barrels per day 20° API)
Temperature	50 - 130°F

4.3.5 System Design Pressures

Normal working pressure	150 psig (at surface)
Hose working pressure	225 psig (at surface)
Allowable surge pressure	400 psig
Hose burst pressure	1600 psig (1000 psig test)

The system will be designed to resist collapse forces induced by hydrostatic loads when operating with zero internal pressure.

4.3.6 Seismic

The system will be designed to resist ground accelerations as recommended for the production platform (Appendix 1.1).

4.4 Description of SALM Design

4.4.1 General

The SALM is described in detail in Appendix 5.11. The design specifications as shown are for a water depth of 300 feet, but are also applicable for 400 feet by lengthening the single anchor leg shaft. No other significant changes in strength or dimensions will be required. Mechanical details of the on-bottom portion of the mooring would be re-examined before finalizing design for 400-foot water depths. System design is summarized briefly below and is described in detail in Appendix 5.11.

4.4.2 Mechanical Design

The general arrangement of the SALM is illustrated in Figure 5. A mooring base rests on the sea floor and is anchored by piles. A tubular riser is attached to the center of this base by a base universal joint. A load-bearing shaft surrounded by a fluid swivel housing is mounted on the top of this riser. An anchor leg consisting of universal joints, a six-inch diameter anchor chain and an anchor swivel, connects a mooring buoy to the top of the shaft. The vessel is moored to the mooring buoy by three 5-inch diameter nylon hawsers.

The 12-inch diameter underwater pipeline from the production platform terminates in a manifold near the mooring base. A flexible hose connects this manifold to 12-inch diameter piping within the riser, which in turn connects with the fluid swivel housing. An underwater hose connects the fluid swivel housing to a floating hose on the surface which is connected to the manifold on the side of the vessel. A series of safety valves, which shut off the flow when pressure deviates from the normal range, is provided.

The system as designed permits passage of a spherical 12-inch diameter pipeline pig.

4.4.3 Safety Shutdown System

A safety shutdown system is incorporated into storage vessel loading lines and is designed to be independent of the platform safety system. It consists of four 12-inch full-opening ball valves equipped with valve operators and hydraulic accumulators to provide closing pressure in the event the control system fails. The valves are strategically located to permit automatic isolation of the SALM from the inlet pipeline and isolation of crude oil contained in the riser and cargo hose in the event of fluid swivel or cargo hose leakage. Figure 6 and Appendix 5.11.) The control system will automatically close the ball valves in the event of abnormal pressure conditions.

4.5 Fabrication, Installation, Inspection and Testing

The mooring base, base universal joint, riser, fluid swivel housing and shaft, fluid swivel, and shaft universal joint will be fabricated and assembled onshore (Drawing SK-5119-2 of Appendix 5.11). The mooring base will be compartmented so that it will float. The riser will have buoyancy material affixed to it so that it will float and remain approximately vertical when completely submerged. The above assembly will be towed to location and lowered to the ocean floor by controlled flooding. The base then will be anchored by drilling steel piling through the base from a floating drilling vessel. The piling will be securely grouted to the base and weight material added.

The mooring buoy, buoy universal joint, anchor chain, and anchor chain swivel will be separately fabricated and assembled onshore. The mooring buoy will be towed to location and lowered in the water by adding ballast to permit connection of the anchor chain swivel to the shaft universal joint by divers. Then the ballast water will be pumped out of the mooring buoy until the specified net positive buoyancy is achieved.

The base hose, underwater hose, floating hose, and hydraulic control line connections will be made by divers. The mooring lines will be attached to the mooring eye of the buoy. The system will then be ready for permanent mooring to the floating storage vessel.

The mooring, piping, and safety systems will be thoroughly tested before and during construction and before start-up. All hoses will be subjected to extensive acceptance tests, including a 1000 psi pressure test (Attachment 2 in Appendix 5.11). All valve seats will be tested to their full rated hydrotest pressure before installation. All coatings and wrappings will be tested for holidays before installation. The completed system will be tested to full rated surge pressure (400 psig) before start-up.

5. VESSEL AND MODIFICATIONS

5.1 General

Two vessel types will be considered for service as a floating storage and treating vessel. An existing ship, of the 28,000 dwt tanker ESSO NEWARK class, could be used after modification, or a seagoing barge of the 30,500 dwt ENCO PORT EVERGLADES class could be constructed specifically for this service.

Detailed plans for the modification of a 28,000 dwt tanker to serve as a floating storage vessel have been developed which describe the intended modifications in sufficient detail for shipyard bidding purposes. The storage vessel would be modified by adding facilities for receiving emulsified crude oil and water from the initial platform, treating and storing the oil for transfer to a shuttle vessel, and treating and disposal of salt water separated from the crude. The major features of the modifications plans and related technology are described below as they relate to permanent bow mooring, alongside mooring and offloading, storage and ballast, and community facilities. (Crude oil and water treatment facilities are discussed in subsequent sections.) The technical details for the most part would be equally applicable to the construction of a new seagoing barge of similar tonnage designed specifically for service as a floating storage vessel.

Humble recognizes that when major alterations or conversions of existing vessels are proposed for changes in service, the feasibility of certain improvements in construction standards which contribute materially to safety shall be considered (cf. U. S. Coast Guard Navigation and Vessel Inspection Circular No. 12-65). These considerations have been made and, where applicable, have been included in the modification plans.

Any vessel selected for modification would be a classed and certified U. S. flag vessel. The modifications would not in any way alter the class or certification of the vessel. New barge construction would be in compliance with applicable codes and regulations.

5.2 Permanent Bow Mooring

The single-point mooring attachment to the SALM will be accomplished by a three-hawser mooring line ending with a 3-1/2 inch Die-Lok chain. The tension in the chain will be measured and recorded.

In the event actual or forecasted weather conditions begin to approach or exceed the design storm and load conditions for the mooring, prudent operations might dictate disconnecting the vessel from the mooring. Provisions have therefore been made for disconnecting the bow hawsers. This will be accomplished by means of a remotely controlled quick-disconnecting chain stopper augmented by a manually operated releasing device. The stopper will be adequately shielded to protect personnel from the released chain. Provision will be made to pass a retrieving line through the stopper for reconnecting the chain. If it is necessary to disconnect from the mooring, the storage vessel will move into a sheltered harbor.

Because of changing vessel freeboard and submergency of the SALM buoy, the chain will have a working angle varying from horizontal to 23° below horizontal. Fairleading will be provided as required. Maximum measurable chain tension will be 700,000 pounds. The design stress for the stopper will be based on the breaking strength of the chain and the yield of the material used in the construction of the stopper.

To facilitate lifting and handling the 12-inch diameter floating hose connecting the vessel to the SALM, a davit or boom of suitable design will be provided on the port rail of the foredeck. A suitable structure will be provided at the deck edge to adequately support the floating hose over the side. The support will not interfere with the operation of or access to the hose connections or safety valve system.

5.3 Alongside Mooring and Offloading

Estimates of the relative motion between two vessels moored alongside, the design forces in the ship fendering system, and the design forces in the spring and breast lines between the two ships are based on model studies of similar vessels in 9-foot significant wave height bow seas. The fendering system selected consists of four pneumatic fenders and nylon spring and breast lines which will withstand the forces expected during the limiting operational sea conditions of 8- to 10-foot significant wave height.

The arrangement of the pneumatic fenders, the spring and breast lines and winches proposed for the storage vessel, is shown in Figure 7. Four pneumatic, rubber fenders about eleven feet in diameter will be provided to protect the hull when moored to the shuttle barge. Each fender will be handled by a hydraulically actuated boom type davit and winch as shown. Twelve hawsers, 4-inch nominal diameter, will be furnished. Each hawser will have a minimum breaking strength of 360,000 pounds. Six hawsers will be installed on the mooring winches. The remaining six hawsers will be installed upon suitable storage reels located in the vessel's stores. Walkways in the vicinity of mooring lines will be adequately shielded with wire mesh to prevent injury to personnel in case of line breakage. Hydraulically actuated brakes on each winch hold the maximum static load in each nylon rope. The brakes will automatically set in the event of hydraulic failure. Remote controls for all six winches will be provided at a central location. The four breast line winches will be rated for 70,000 pound loads, and the two spring line winches for 120,000 pound loads.

Cargo transfer from the floating storage vessel to the shuttle vessel moored alongside is specified to be conducted either by two hoses or two nominal 10-inch diameter loading arms. The vessel used for delivery of crude oil from the floating storage vessel will be equipped with a safe loading arm or hose connection system. Two loading lines are specified so that the total main cargo pump capacity of the storage vessel could be utilized by connecting them in parallel.

5.4 Storage and Ballast

A typical 28,000 dwt tanker has 30 individual cargo tanks; 10 are located internally on the center line of the vessel (center tanks) and 20 are located along the sides (wing tanks). Bow and stern sections are not used for cargo storage. Capacity of individual wing tanks varies from 3200 to 6200 barrels. The center tanks are larger (8200 to 12,000 barrels) and provide about 50% of total storage capacity. A newly constructed barge would also be of compartmented design.

Treated crude oil will be stored in the vessel's cargo tanks. Each tank used for oil storage will be equipped with a high level alarm. The cargo tanks will also be used to hold substandard crude for recycling through the treating facilities, and to clarify produced salt water for disposal (Section 6.3.5). No storage tanks will be installed on the deck of the vessel. Cargo tanks to be used for clarification of produced water will be thoroughly cleaned and suitably coated before the unit enters service. Ballast systems will not be required since the produced water clarification tanks and oil storage tanks can be adjusted to trim the vessel. The only fluid discharged from the vessel will be produced salt water treated to USGS standards.

The nominal storage capacity of a converted 28,000 dwt tanker is approximately 191,000 barrels of 20° API crude. Useful oil storage capacity will be reduced by the weight of produced salt water retained in the vessel's tanks for cleaning.

5.5 Community Facilities

Many additional modifications to the storage vessel have also been specified to enhance its utility and safety as a manned, permanently moored offshore storage vessel. Some of the most important are summarized below:

(1) Modification to the vessel's power and steam distribution system to provide heat and power to the oil treating facilities.

(2) A lighted helicopter platform.

(3) A wood-grid protected supply boat mooring station will be constructed on the port side of the storage vessel. An 11,000 lb capacity stores crane will be pedestal mounted for use in handling cargo from supply boats.

(4) The sanitary system will be specified to meet applicable regulations. Sewage will be treated by a U. S. Public Health Service approved "aerobic digestion process" treatment plant.

The storage vessel will be equipped with radio communication equipment, interconnected with the unified communication network proposed for Humble's petroleum operations in the Santa Ynez Unit. Primary communication between the storage vessel and offshore platform will be by mobile radio. Portable transmitters will be used for coordination of along-side mooring and offloading. The storage vessel will also be equipped with standard marine radio equipment and channels. Additional details of the communication system may be found in the OPERATING AND CONTINGENCY PLANS section of this report.

6. CRUDE OIL TREATING FACILITIES

6.1 General

Crude heating, treating, and water cleaning equipment on the vessel will provide the capability to 1) remove produced water from the crude oil by heating, 2) clean the produced water to a quality that will allow ocean disposal under USGS regulations, and 3) prevent gas vapor emissions. The facilities are designed to process a daily volume of 40,000 barrels of oil with 10,000 barrels of water.

A simplified flow diagram of the treating facilities is shown in Figure 8. The degassed emulsion from the platform is heated slightly with steam from the vessel's system before entering a flow splitter. This unit allows delivery of equal volumes of emulsion to each heater treater. Additional heating of the emulsion using steam is done in the flow splitter and heater treaters. The water-free crude from the heater treater is cooled through heat exchangers using sea water and cold emulsion from the pipeline. Water removed from the crude is cleaned for ocean disposal through a closed system.

The following facility descriptions are based on a Humble-directed design study by Hobbs-Bannerman Corporation. A copy of the study is attached as Appendix 5.12. This Hobbs-Bannerman study defines and specifies the equipment required to treat the oil on a vessel offshore. The treating facilities are designed to comply with existing OCS Orders for platform facilities.

6.2 Design Objectives and Criteria

The oil treating facilities will accomplish the following:

(1) Produce a minimum amount of vapor by using closed systems with vapor recovery, cooling the oil after heating, and providing for disposal of all vapors.

(2) Provide a daily fluid capacity of 40,000 barrels of oil with up to 10,000 barrels of water, and the capability to treat the oil to 2% water or less.

(3) Provide central control and alarm monitoring for all oil treating systems, monitor the pipeline for leaks by metering flow from the platform, and provide adequate firefighting equipment including a sprinkler system.

(4) Clean the produced water to a quality of less than 50 ppm of oil.

The design criteria for the crude oil treating facilities are summarized below. These criteria are not necessarily the normal conditions but represent the maximum design conditions.

(1) System Design Pressures:

Piping - 1440 psi

Oil treating vessels - 150 psi

Heat Exchanger - 275 psi

(2) System Design Temperatures:

The oil is to be treated at 160°F

(3) External Forces:

Design is based on vessel motion in rough seas of:

Heave - 5 to 10 feet

Pitch - 5 degrees

Roll - 8 degrees

(4) Corrosion Allowance:

1/16" to 1/8" on selected components. All piping and vessels are internally coated.

(5) Electrical Classification:

Class I, Group D, Division 1 in process areas.

(6) Applicable Codes:

Design is in accordance with the applicable codes listed in Section 1.4 of Appendix 5.12.

(7) Safety Provisions:

A central control room allows central monitoring and control of important operating conditions. A relief valve is provided on the inlet line to protect the system against overpressure. All process vessels and heat exchangers are protected against overpressure by relief valves.

6.3 Description of Major Equipment and Subsystems

6.3.1 General

The referenced design study (Appendix 5.12) contains a complete design for the crude oil treating system, including specifications and drawings. The study contains a General Description in Section 1.0, Equipment Specifications in Sections 2.0 to 6.0, Standard Specifications in Section 7.0, Facility Construction in Section 8.0, and a Drawing List in Section 9.0. A brief summary of the treating system follows.

6.3.2 Equipment Layouts

The treating facilities will be installed on the deck of the vessel. The layout of these facilities is shown on Drawing 154-201. (Appendix 5.12.)

6.3.3 Equipment List

The major equipment for the crude oil treating system is listed in the index of the design study. A brief description of size and working pressure is shown on Sheets 1-3. (Appendix 5.12.)

6.3.4 Oil Treating

Degassed crude oil and water from the production platform will be piped to the vessel. The crude oil mixture is heated in a heat exchanger from approximately 80°F to 95°F using hot clean oil from the heater treaters. The mixture is sent to a flow splitter which provides additional heating and equal distribution of flow to four heater treaters. The crude oil mixture is heated to 160°F in the treaters, which reduce the water content of the oil to less than 2%. The oil leaving the treaters is first cooled with the incoming mixture and then cooled to 95°F with sea water in heat exchangers. From the seawater heat exchangers, the clean oil is sent to the vessel's storage tanks. The cooling of the oil is specified to minimize vapor losses and emissions in the storage tanks. The specifications for the oil treatment and storage equipment are described in Section 2.0 of the design study. Piping and instrumentation diagram 154-202 shows the crude oil system.

6.3.5 Water Treating

Water separated from the oil is processed to remove oil prior to ocean disposal. Oil is skimmed off in the water surge tanks and the four-stage flotation unit and transferred to the oil sump. A turbidity monitor will check the water quality from the flotation unit to insure that only clean water is placed in the clean water surge tank. The clean water is passed through several stages of gravity separation and skimming in the vessel's tanks before being discharged in the ocean through the vessel's discharge system. The water cleaning system's specifications are included in Section 3.0 of the design study. Drawing 154-203 shows the piping and instrumentation diagram of the system.

6.3.6 Vapor Control

Vapor emissions from the oil in the storage tanks are collected in a vent system and piped to the vessel's incinerator system. Excess vapors from the water tanks and flotation unit are collected through a blower and piped to the incinerator. The gas system equipment specifications are included in Section 4.0, and Drawing 154-205 shows the piping and instrumentation diagram for this system.

6.3.7 Safety Shut-in System

The marine riser system delivering production to the vessel is equipped with a system of four spring-loaded, hydraulically actuated fail-safe valves (Figure 6). This system activates automatically in the event of high or low pressure in the riser-loading hose systems, or upon loss of hydraulic pressure. High level in the flow splitter or high or low levels in the vessel cargo tanks will activate this safety system. Activation of the fire or gas detectors will also activate the safety system, as will manual shut-in from the central control panel or from shut-in stations located about the vessel.

The feed lines to each heater treater are equipped with spring-loaded fail-safe block valves. High or low pressure, low level, or high temperature in a heater treater will close the individual block valve to that treater.

6.3.8 Electrical System

Electrical power for the oil treating system is supplied by the vessel's generating facilities. Up to 500 KW of power may be required if all equipment draws full load. The electrical system is described in Section 5.0 of the design study.

6.3.9 Control System

The control system provides the operator with the capability of monitoring the treating system from the central control room. The annunciator panel has status indicators for 20 alarm points including:

(1) High and low pressures in the pipeline, treaters and flow splitter.

(2) High and low levels in the flow splitter, treaters, and water surge tank.

The fire detector and gas detector systems' control panels are mounted on the central panel and indicate the status of each point.

The oil and water production and water turbidity are also displayed.

The control system is described in Section 6.0 of the design study and on Drawing 154-212. The central control panel is shown on Drawing 154-213.

6.3.10 Fire Protection System

The fire protection facilities are furnished by the marine vessel's system. Fire detectors are located at the treating facilities. They will activate the fixed sprinkler system over the process vessels. Two fire monitors on the ship's system can also supply water to control a fire.

6.4 Construction and Installation

Construction of the treating system is discussed in Section 8.0 of the design study. Generally, major skid-mounted facilities will be fabricated by individual suppliers and delivered to the shipyard for completion by the prime contractor. The prime contractor will assemble these facilities as shown in the layout drawing. All work will be completed in the shipyard, with no offshore work anticipated.

PROPOSED 12-INCH OIL LINE FROM 850' PLATFORM TO OFFSHORE STORAGE TERMINAL

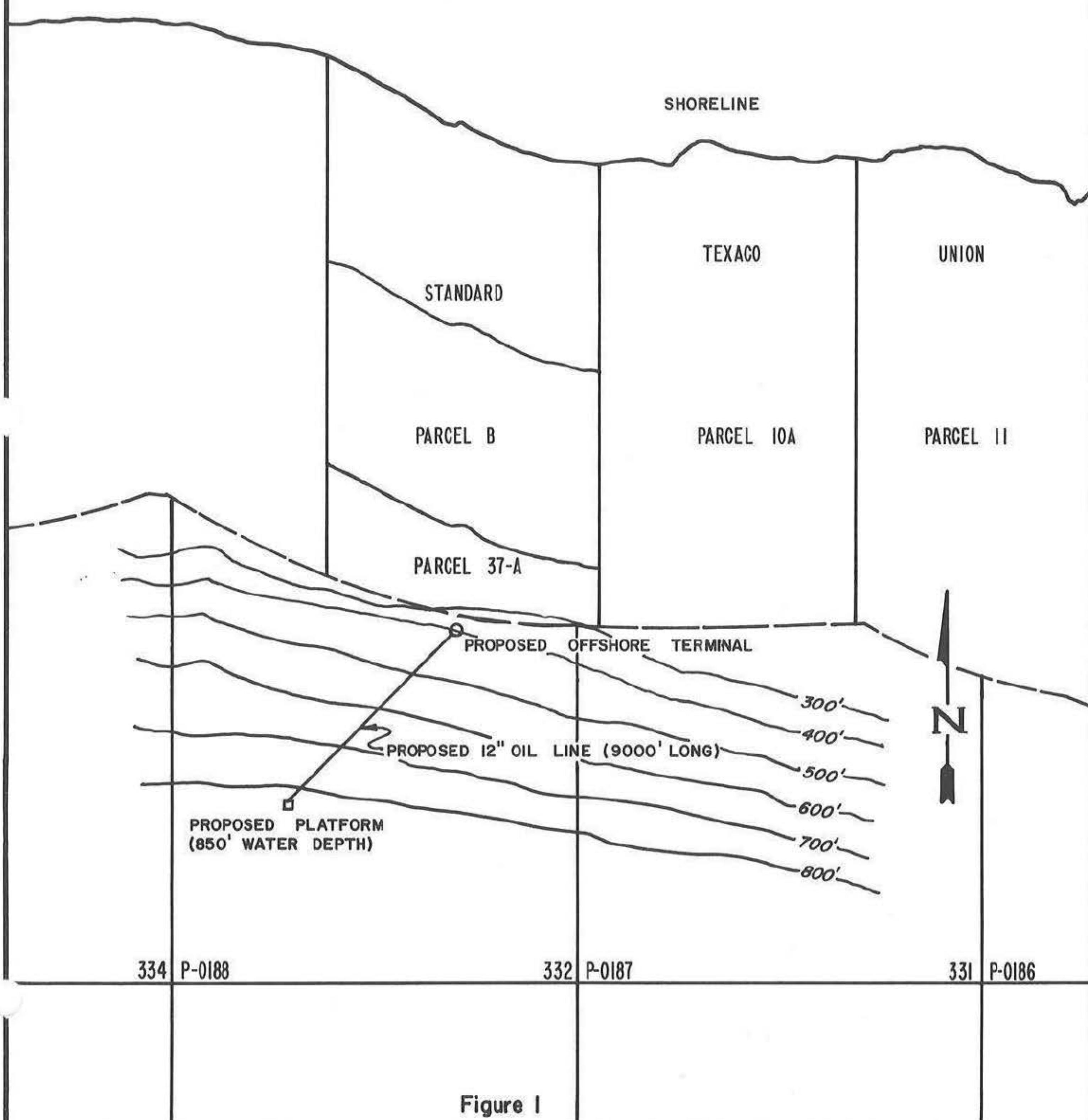


Figure 1

PROPOSED OFFSHORE STORAGE AND TERMINALLING SYSTEM

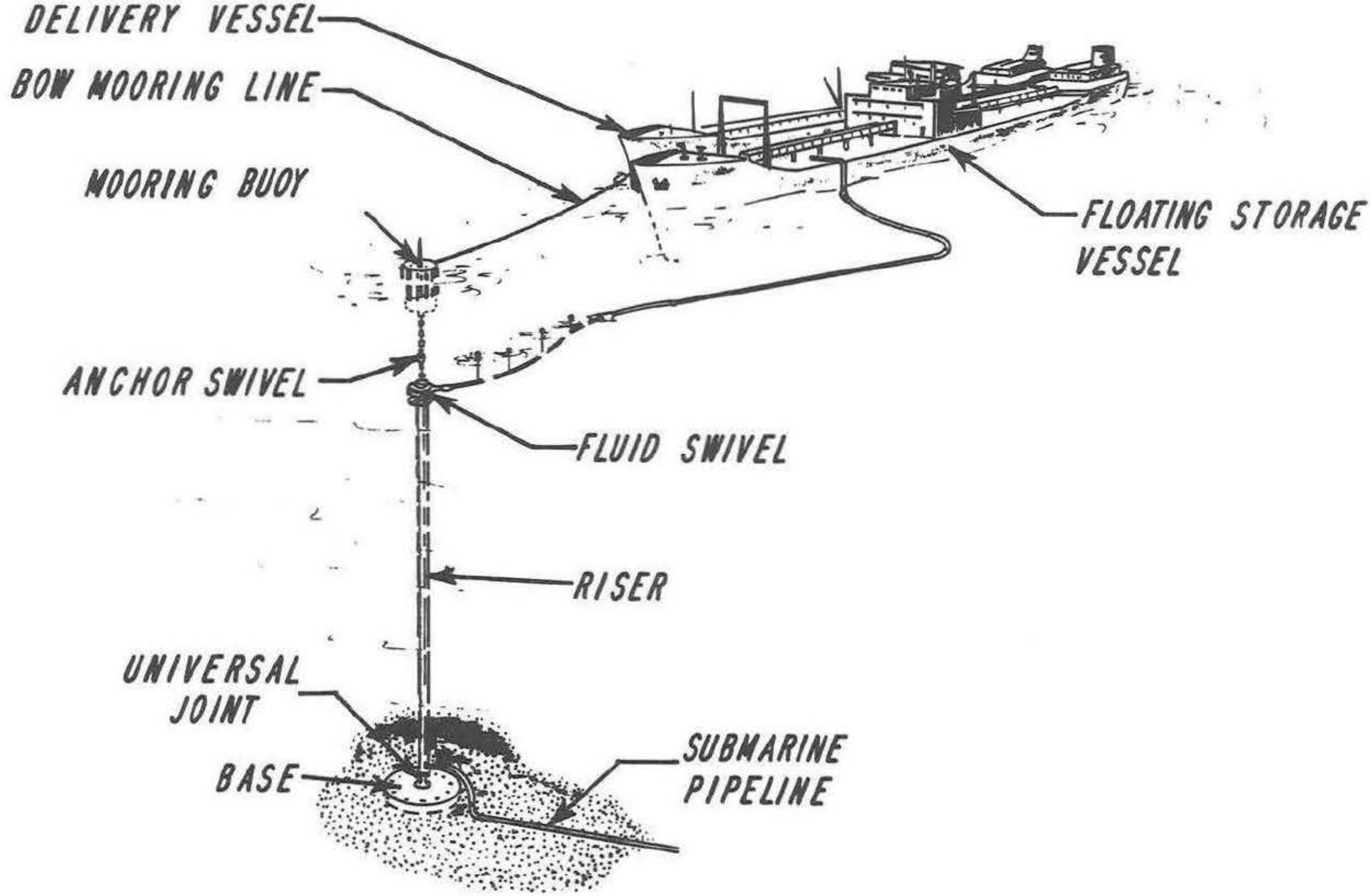
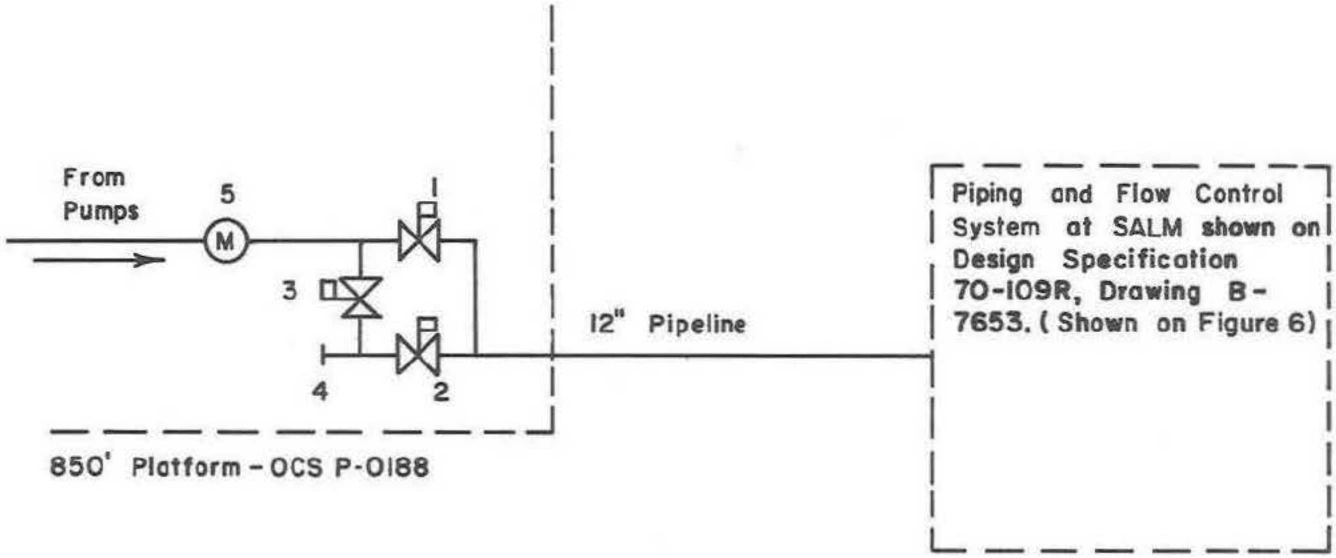


Figure 2

12" OIL PIPELINE FROM 850-FOOT PLATFORM TO OFFSHORE STORAGE TERMINAL



1. 12" ANSI 600 gate valve, motor-operated, normally open. (This valve also serves as automatic and remote shut-in valve.)
2. 12" ANSI 600 gate valve, motor operated, normally closed. (This valve also serves as automatic and remote shut-in valve when running spheres.)
3. 8" ANSI 600 gate valve, motor operated normally closed.
4. 14" sphere launching barrel. Will be equipped with drain line, pressure gauge & closure.
5. 8" ANSI 600 turbine meter (for continuous surveillance - normally in operation.)

Figure 3

PRINCIPLE OF SALM OPERATION

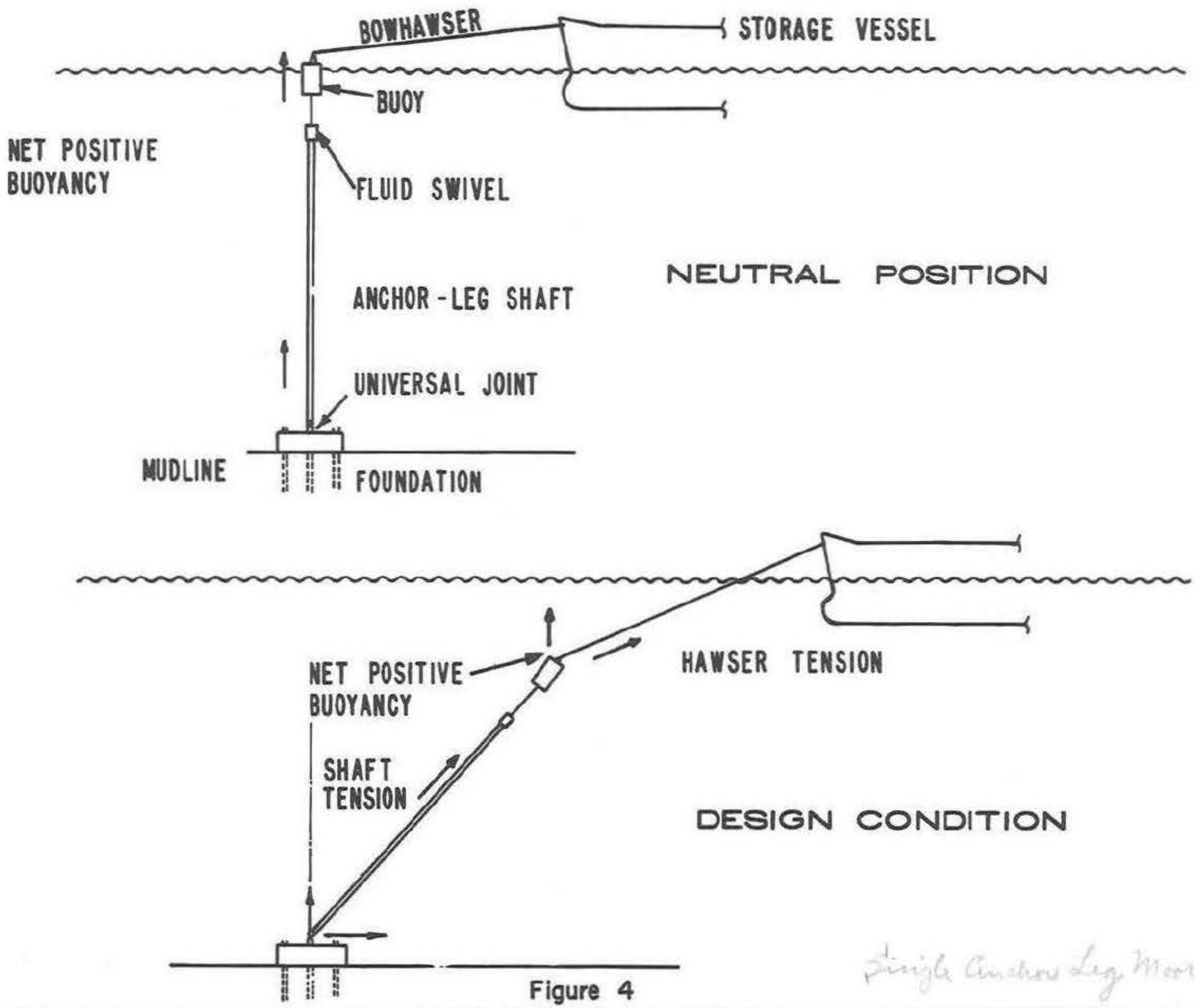


Figure 4

Single Anchor Leg Mooring

SINGLE ANCHOR LEG MOORING

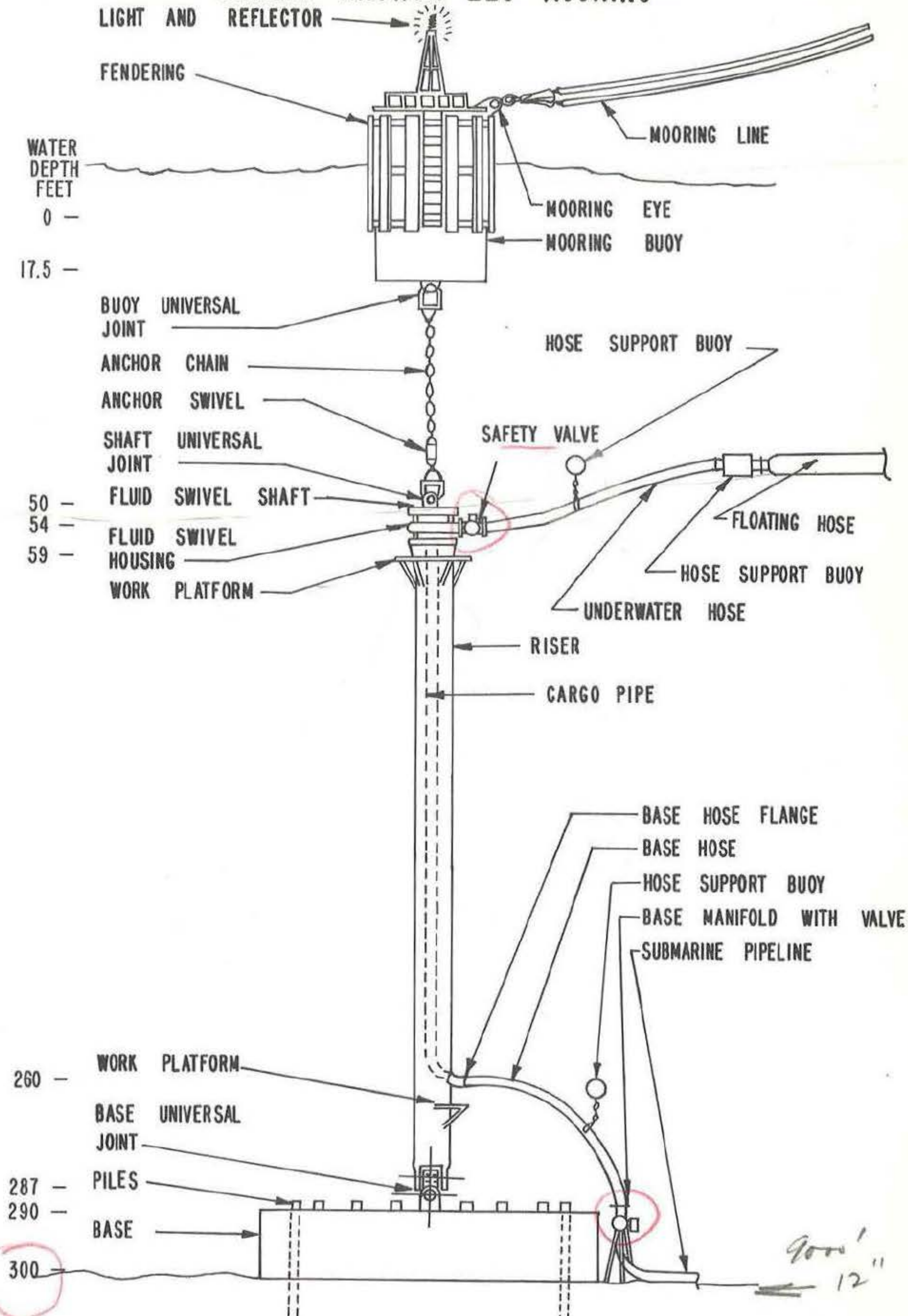
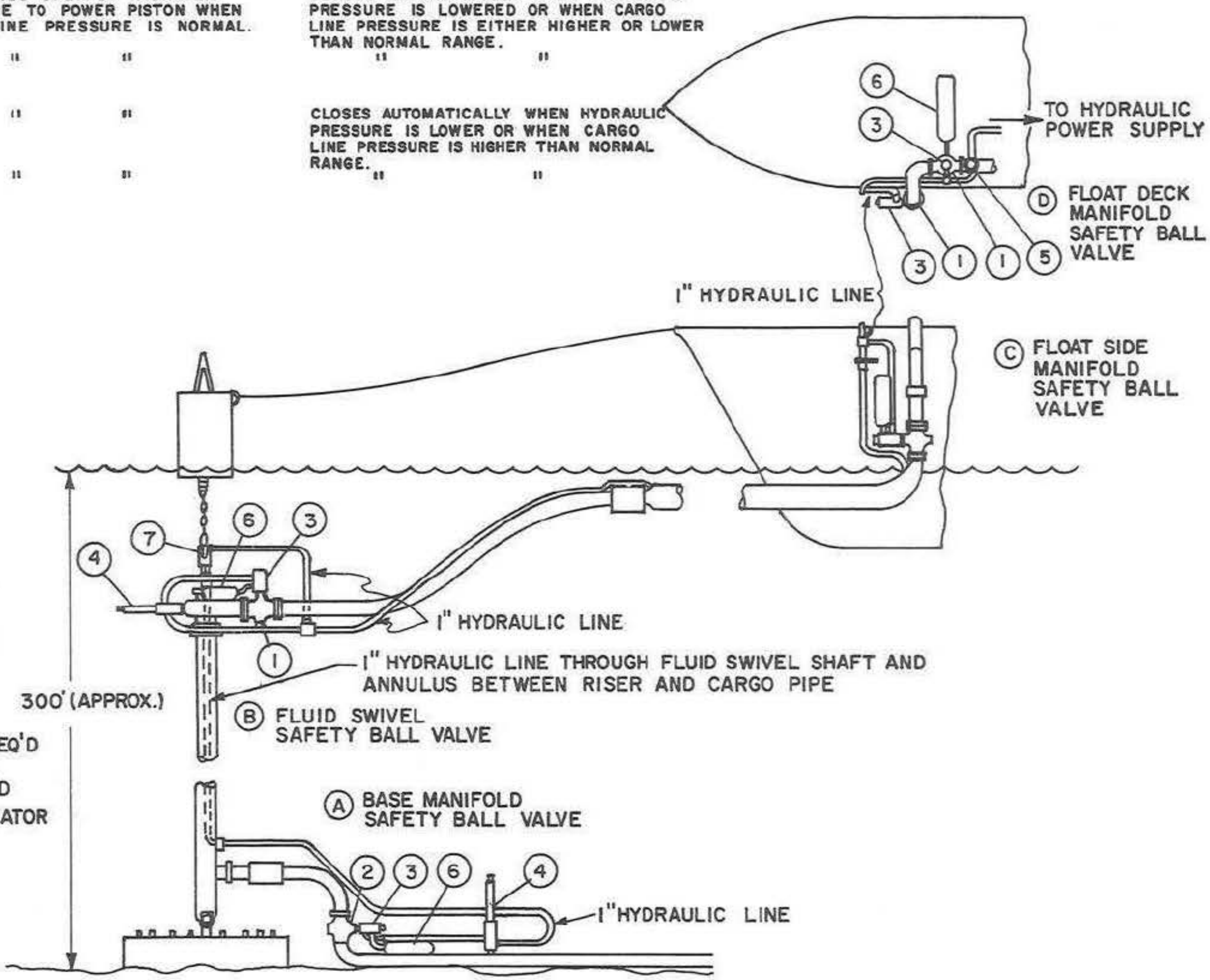


Figure 5

SINGLE ANCHOR LEG MOORING SAFETY VALVE SYSTEM

OPERATION SCHEDULE

OPERATION SCHEDULE	OPEN POSITION	CLOSED POSITION
(A) BASE MANIFOLD SAFETY BALL VALVE	MAINTAINED OPEN BY HYDRAULIC PRESSURE TO POWER PISTON WHEN CARGO LINE PRESSURE IS NORMAL.	CLOSES AUTOMATICALLY WHEN HYDRAULIC PRESSURE IS LOWERED OR WHEN CARGO LINE PRESSURE IS EITHER HIGHER OR LOWER THAN NORMAL RANGE.
(B) FLUID SWIVEL SAFETY BALL VALVE	" "	" "
(C) FLOAT SIDE MANIFOLD SAFETY BALL VALVE	" "	CLOSES AUTOMATICALLY WHEN HYDRAULIC PRESSURE IS LOWER OR WHEN CARGO LINE PRESSURE IS HIGHER THAN NORMAL RANGE.
(D) FLOAT DECK MANIFOLD SAFETY BALL VALVE	" "	" "



COMPONENTS

1. CAMERON BALL VALVE 800301-6-20 (17"-300 PSI ANS) 3 REQ'D
2. CAMERON BALL VALVE 800303-6-20 (12" -300 PSI ANS) 1 REQ'D
3. CAMERON POWER PISTON OPERATOR 501100-7-1 4 REQ'D
4. CAMERON BLOCK AND BLEED FIG. 17 CLOSE ON HIGH OR LOW PRESSURE 2 REQ'D
5. CAMERON BLOCK AND BLEED FIG. 17 CLOSE ON HIGH PRESSURE ONLY 1 REQ'D
6. PARKER HANNIFIN HYDRAULIC ACCUMULATOR A 6R0347B1 4 REQ'D
7. AEROQUIP SERIES 5500 SWIVEL JOINT (1" - 3000 PSI)

FIGURE 6

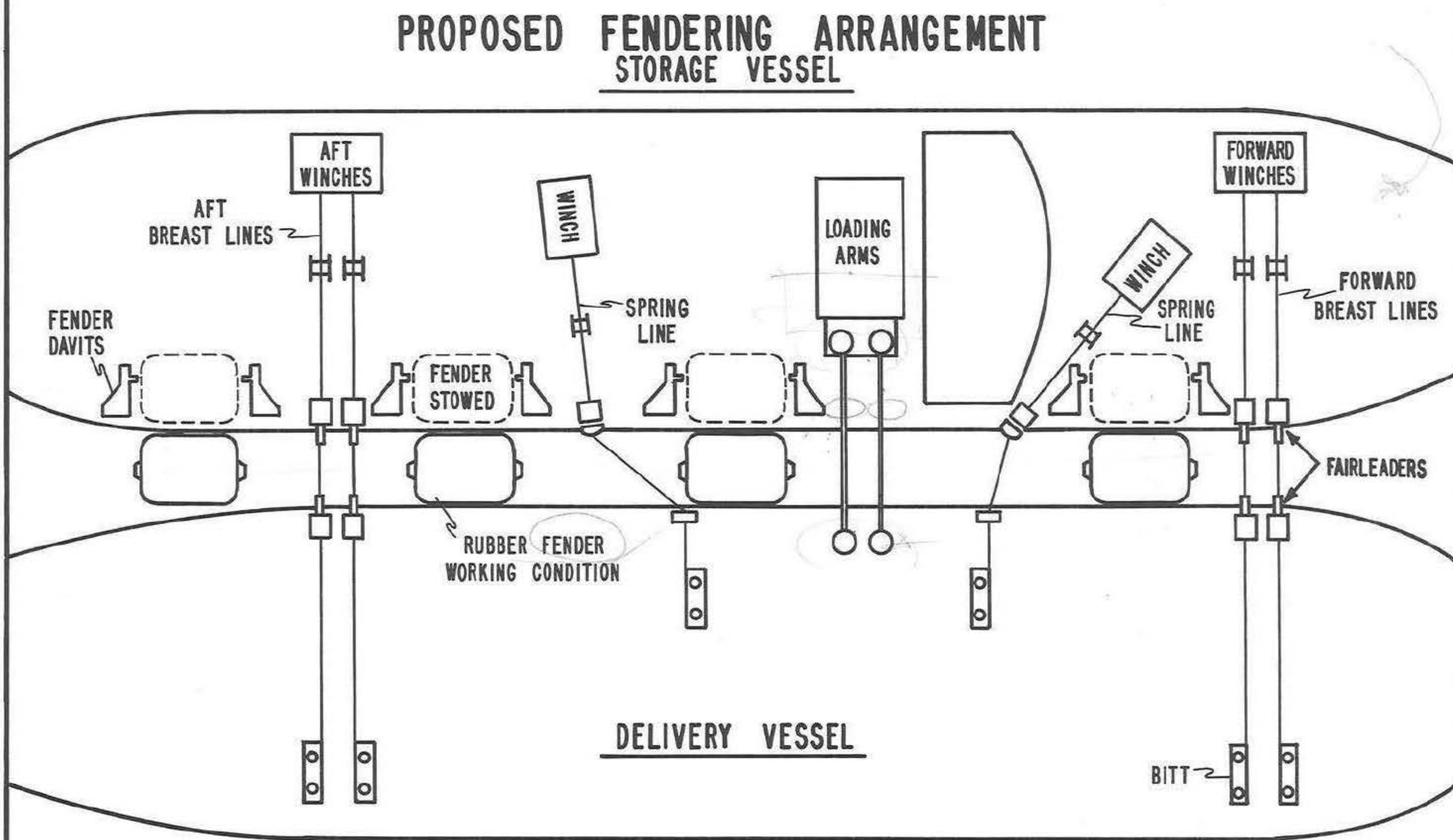

PROPOSED FENDERING ARRANGEMENT
STORAGE VESSEL
AFT WINCHES
AFT BREAST LINES
WINCH
SPRING LINE
LOADING ARMS
WINCH
SPRING LINE
FORWARD WINCHES
FORWARD BREAST LINES
FENDER DAVITS
FENDER STOWED
FAIRLEADERS
RUBBER FENDER WORKING CONDITION
DELIVERY VESSEL
BITT

Figure 7

OFFSHORE VESSEL TREATING FACILITIES

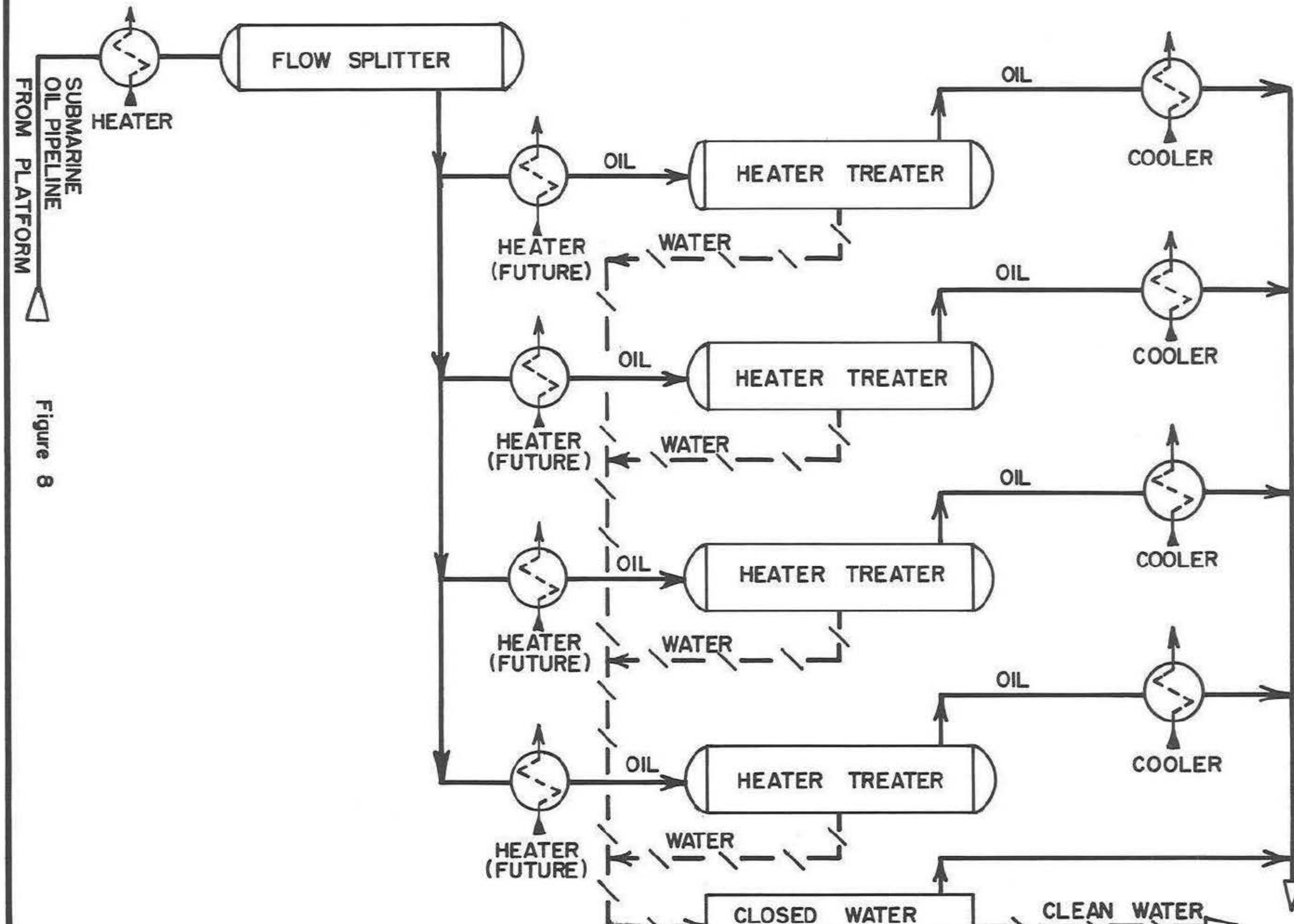


Figure 8

PRODUCT TRANSPORTATION

TABLE OF CONTENTS

PRODUCT TRANSPORTATION

PRODUCT TRANSPORTATION

ABSTRACT

Santa Ynez Unit crude will be moved to markets in the Los Angeles/Long Beach area by tankers or tug/barge units. Sulfur and gas plant liquids will be trucked to markets primarily in the Los Angeles area. Natural gas will be sold to a pipeline customer at the Corral Canyon treating facility. This section summarizes design product volumes for the three year period covered by this Plan, discusses available transportation methods, reviews transporation techniques utilized in current oil production operations, and presents details of the proposed barging and trucking operations.

INTRODUCTION

The Corral Canyon Treating Facility is designed for approximate initial product volumes as follows:

Crude oil	40,000	Barrels per Day
Residue Gas	23,000	Mcf per Day
Sulfur	8.4	Long Tons per Day
Butane-Plus	960	Barrels per Day

Refineries in the Los Angeles/Long Beach area will be the major market outlet for the crude oil. A marine terminal now serving the Capitan Oil Field is available for loading crude into vessels. This terminal will be modified to load Santa Ynez Unit crude into tankers or specially constructed tug/barge units.

Residue natural gas will be sold to a pipeline customer at the Corral Canyon site. An existing pipeline crossing the mouth of Corral Canyon would probably be used to transport this gas to California consumers. There are no existing transportation systems for marketing the sulfur and butane-plus products. Although there is some local demand for these products, major markets are expected to be in the Los Angeles/Long Beach area. These products will initially be trucked to market along the existing freeway system.

These transportation methods are essentially identical to those currently in use in the area. All crude produced along the coastline west of Carpenteria is moved to market by marine vessels loading from terminals near shore. Natural gas production is piped through existing systems and gas plant liquids are moved by truck.

1. CRUDE OIL BARGING

1.1 General

The items discussed in this section are terminal locations and traffic patterns, loading operations, discharge operations, and transit.

1.2 Location

The marine transportation unit will primarily operate between a terminal in the Santa Ynez Unit and terminals at Los Angeles/Long Beach. Some crude may be moved to local markets or to refineries in other areas, such as San Francisco. The loading facility will include a

Single Anchor Leg Mooring (SALM) loading terminal located at an existing loading berth at Corral Canyon and/or an offshore floating terminal located on OCS Lease P-0188. The charts (Figures 1 & 2) show these loading points and the approximate route to Los Angeles/Long Beach.

1.3 Transportation Unit

1.3.1 Vessel Description

The primary vessel used to transport Santa Ynez Unit crude will be a 25-30,000 dwt tanker or a linked tug/barge unit of approximately 25,000 dwt. A linked tug/barge unit is comprised of a barge notched in the stern and a tug which fits into this notch. The two units are securely linked together and operate as a single unit (Figure 3). Equipment of this design in use today by Humble and other companies has operating statistics similar to tankers of like size. The basic reasons for selection of the tug/barge unit are construction and operating economics; however, inherent design features of a tug/barge offer other advantages. These are: 1) high maneuverability, and 2) slow service speeds. High maneuverability results from twinscrew propulsion and sophisticated rudder systems. Slow service speeds are the result of hydrodynamic effects. The combination of maneuverability, slow service speeds, and advanced radar systems is desirable.

The largest unit contemplated for Santa Ynez Unit service is 25,000 dwt. Approximate dimensions are:

Barge	Tug
500 ft. length	150 ft. length
90 ft. beam	40 ft. beam
31 ft. loaded draft	21 ft. draft
	6000-7000 horsepower

If greater capacity is required, two smaller units of similar design will probably be used in place of the single large unit. Basic vessel design will be the same for operation from either the shore terminal or offshore terminal.

1.3.2 Design Criteria

The equipment regulations of the United States Coast Guard and the classification rules of the American Bureau of Shipping will be used in designing the vessels. The applicable Coast Guard regulations are subchapters C and D of the Code of Federal Regulations, Title 46, Chapter I. Pertinent American Bureau of Shipping (ABS) Classification Rules are "Rules for Building and Classing Steel Barges for Offshore Service" and "Rules for Building and Classing Steel Vessels."

In addition, Humble design criteria, some of which exceed present regulatory agencies' criteria, are:

Navigation Equipment - loran, high resolution radar, bridge to bridge radio, gyro compass.

Cargo Equipment - Remote reading tank gauges, remote shutdown of cargo pumps, high level alarms.

Ballast System - Totally segregated ballast system. The only openings to the sea will be into the ballast tanks, with no internal cross connection of cargo and ballast compartments.

Mooring - The two loading facilities under consideration are an offshore floating unit and a single point mooring. The mooring equipment will be designed and selected to match the terminal equipment.

1.3.3 General Vessel Operations

The vessel will operate on a 24 hour basis between the loading point and the various discharge terminals. All crew changes, provisioning etc. will be conducted at the discharge terminals.

The normal operational mode will be as a linked unit; however, certain weather conditions dictate that the barge must be pulled on a hawser. This is the method now used by all seagoing barges on the Pacific Coast. The expected limits for linked operation are seas of 8-10 ft. significant wave height. On the basis of historical wave data presented in Table 1, linked tug/barge operations are expected to undergo restrictions about 6% of the time.

Changing from linked operation to a hawser mode in waves of 8-10 ft. is a proven procedure and is accomplished with control over the barge throughout the maneuver. Re-entry into the stern notch and resumption of linked operation is also a proven procedure, however, it requires more favorable conditions than the maximum operating limits. If wave heights are above the maximum limits, the operators will move to a protected location and conduct the link-up.

In order to operate at the proposed loading terminals the unit will normally be in a linked mode.

The crews of Humble operated vessels will be full-time employees of Humble Oil & Refining Company, and will hold all licenses required by the Coast Guard. They will be trained in the operation of the unit, its on-deck equipment and its navigational equipment prior to entry in service. The unit's deck officers will be trained in mooring operations and will have pilotage for the Los Angeles/Long Beach harbors.

1.4 Operations - Loading

1.4.1 Shore Site Terminal

The shore site terminal will be located in Corral Canyon on the site of a facility presently used by another oil company for loading crude. The present facility will be modified and converted to a Single Anchor Leg Mooring (SALM) from the existing multiple point mooring. The new mooring will be located 3800 ft. from shore and 2000 ft. from the 35 ft. depth contour. This will provide four ship lengths of maneuvering room for the proposed tug/barge unit and 3 ship lengths for the largest tankers that could use the mooring. This maneuvering area will permit the shuttle unit to approach the mooring on a heading into the wind. The shuttle unit and SALM will be designed for a self-mooring operation. This technique requires no assistance from shore, and relies upon the ship's equipment to make fast to the mooring. A shore based launch will be used as necessary.

The SALM has been designed for an operational limit of 10 ft. significant wave heights. This will restrict operations approximately 1% of the time (Table 1). The tug/barge unit will be able to depart from the SALM in a hawser mode during high seas.

The loading will be conducted according to procedures consistent with USCG regulations, Part 35, subchapter D, and established Humble practice. The procedures will include but not be limited to such practices as:

(1) Using standardized check lists for the loading operation.

(2) Lashing all cargo discharge valves during loading and while loaded during transit.

(3) Plugging all deck scuppers and drains which open to the sea.

(4) Visual inspection of loading hose prior to loading.

(5) Testing all primary and back-up communication circuits between shuttle unit and shore station.

(6) Continuously monitoring tank levels.

Barge loading supervisors and pumphouse personnel will be in direct radio contact using hand held UHF radios. Flow delivered to the shore terminal will be monitored and communicated to the shore terminal on a regular basis. If volume pumped and volume received differ, the shore terminal will shut down all valves and pumps. Tank levels will be continuously monitored during the loading operation. During the tank topping phase of loading, the shore station will secure all main pumps and the crude will flow into the tanks at a reduced rate. During this phase, control of oil flow will be on the barge at the hose termination valve and at individual cargo compartment valves. This will reduce dependency on communication links in case of emergency. Loading will take approximately seven hours. After the loading has been completed, the submarine hose will be disconnected and blanked at the hose termination, and checked for leakage before being returned to the water.

1.4.2 Offshore Floating Terminal

The offshore floating terminal will be a 28-30,000 dwt vessel modified for use as a storage unit. The terminal will be moored to a Single Anchor Leg Mooring (SALM) in 300-400 ft. of water.

This mooring arrangement will permit the storage vessel to react to the prevailing forces of wind and surface currents by aligning headon to the resultant vector of the forces. As the transport unit approaches the floating terminal it will operate against the same forces and will be able to approach the side of the storage vessel on the same heading. After closing to the side of the storage vessel, the two units will be linked together at the bow and stern by a resilient mooring system which permits relative motion of the vessels.

Loading will be performed through hoses or metal loading arms mounted on the floating terminal vessel and designed to compensate for the relative motions of the two vessels. The loading precautions listed in the Shore Site Terminal description (Section 1.4.1) will be observed. Loading rates will be reduced during final loading stages to avoid spills from overfilling the tanks. Communications during the loading process will be by direct voice link between barge and terminal loading personnel by the use of hand held UHF radios. This will keep deck personnel in constant communication during all phases of the loading process, especially the critical phase of topping off tanks. Barge loading personnel will have physical control over valves which stop the flow of oil, reducing dependence on the communications link.

Loading at the offshore terminal will be subject to operational weather limits. Experience gained by affiliated companies has substantiated the design criteria used for the offshore terminal. Predicted weather limits for loading operations are 8-10 ft. significant wave heights. This is the same limit used for linked tug/barge operation. (Table 1). If weather beyond operational limits is experienced, and the tug and barge are in a hawser mode, mooring will not be attempted and loading will not be conducted. If weather conditions become severe during the loading operations, the tug will move the barge away from the terminal.

1.4.3 Chartered Vessels

Chartered vessels loading crude at either terminal will be required to have deck and cargo equipment compatible with the terminal facility.

In addition, they will be checked prior to loading for adequate communication and back-up equipment.

These vessels will not be permitted to load unless they follow deballasting procedures consistent with the operation of Humble-owned equipment. They will be restricted to the discharge of totally clean ballast water. All cargo valves with discharge to the sea will be required to be lashed and sealed before loading commences. In order to assure that all procedures are followed, a Humble employed mooring master or terminal supervisor will go aboard chartered vessels calling on a one time or infrequent basis. He will advise the ship's officers of proper procedures. Vessels which are chartered for long periods will be selected for compatible design and reputable operation. In addition, long term charter contracts will provide for alterations to equipment to insure proper ballast handling.

1.5 Operations - Transit

The primary discharge points will be in the Los Angeles/Long Beach Harbor area to the south. The unit will transit between the loading and discharge points using the recommended traffic lanes while entering and leaving the loading areas.

The route of transit is shown in Figure 2.

The topographical characteristics of the land near the shore loading site provide a high quality radar reflection for safe navigation during periods of low visibility. A fathometer will supplement the radar information. The mooring buoy will be equipped with a radar reflector. The offshore terminal is an inherently good radar reflector and can be located in fog. Historical visibility data are given in Table 1.

The high traffic density portion of the transit is the Los Angeles/Long Beach Harbor complex. The Los Angeles Harbor area is now basically under the control of the Los Angeles Pilot Association, a Civil Service group. All vessels under registry, and enrolled vessels which do not carry a qualified officer with Los Angeles pilotage, are required to have a Los Angeles pilot on board to enter the harbor. The Los Angeles Harbor Pilot Station is equipped with radar. All pilots carry VHF radio units, and normally maintain contact with each other and the shore based pilot advisory station. In addition, the vast majority of enrolled vessels with pilotage capabilities converse with the pilot association regarding vessel movements.

The Long Beach area pilot group, Jacobson Pilots, Inc., is a private concern, but in other respects, it is similar to the Los Angeles group. Jacobson is equipped with radar and maintains contact with all of its pilots as well as with the naval base concerning Navy ship movements.

The Los Angeles and Long Beach Pilot Associations (both of which control vessel movement) are ideally situated for their assumed monitoring responsibilities. Both are within visual contact of the harbor entrance and normal navigation hazards. When fog or other abnormal restrictions occur, both groups impose whatever restrictions on entrance or exit passages that they feel are required to insure safety.

No traffic controls or other similar regulations have been required in the Harbor area. Means of VHF communication with all ships, particularly Navy vessels, is highly recommended by the pilot groups and is endorsed by Humble, along with mandatory use of the harbor pilot radar services.

Humble will provide the capability for bridge-to-bridge communication. Although Humble intends to employ deck officers with Los Angeles/Long Beach pilotage, the vessels' operators will comply with advisory information from the pilot groups.

1.6 Operations - Discharge

The major portion of all produced crude will be shipped to Los Angeles/Long Beach refineries. The harbor complex is a major world port with adequate facilities for the operation of the proposed tug/barge units.

The deep draft tanker channel to the Union Oil Dock in Los Angeles has a depth of 51 feet. Ships in the 70-80,000 dwt category presently navigate this channel. The remainder of the docks in the Los Angeles Harbor area have about 35 feet of water, thus limiting tanker size to about 30,000 dwt. The Long Beach Channel has approvals at 65 feet. This depth will permit tankers of 200,000 dwt to enter port. The ARCO dock on Terminal Island is presently handling 120,000 dwt vessels. The proposed Humble dock on Pier "J" will have 60 feet of water and will be capable of handling 190,000 dwt vessels. Other tanker docks in the Long Beach area have depths ranging from 35 to 50 feet.

Discharge operations will be conducted at numerous refineries and terminals in the Los Angeles/Long Beach Harbors. Prior to discharge at a terminal, shoreside personnel from Humble will contact the terminal to establish mooring and loading procedures. Discharge will be supervised by the licensed personnel normally assigned to the vessel. They will follow regulations established by Coast Guard and State authorities.

1.7 Safety and Pollution Control

1.7.1 Controls

The operational goal will be the prevention of accidents and resultant pollution. Inherent pollution sources such as noise, exhaust emissions, biological wastes, and oil wastes will be addressed in the design stages of the tug/barge unit. The technology to eliminate these problems is presently available and will be utilized.

Biological wastes will be retained in a shipboard holding tank for discharge into treatment facilities at the discharge ports.

Noise abatement devices will be installed on the power units of the tug and on barge deck equipment.

Diesel engines will be utilized as the prime movers for tug/barges. These engines are efficient power sources and emit low levels of unburned hydrocarbons. The engines will be selected to comply with California state standards in force at the time the vessels enter service.

The primary sources of oil pollution from ships are the cumulative result of tank cleaning and ballasting operations and minor operational accidents. The dumping of oily ballast and overfilling of tanks are two major causes of minor spills ("Causes of Oil Spills from Ships in Port" Proceedings of Joint Conference on Prevention and Control of Oil Spills, June 1971, American Petroleum Institute, Washington, D. C.) Pumping oily ballast overboard will be eliminated by design criteria which specify segregated ballast compartments and piping. The segregated ballast tank approach also eliminates the additional problems associated with handling and properly treating oily ballast water.

The probability of accidental spills occurring at the loading point from overfilling tanks will be minimized by direct reading tank gauges, high level tank alarms, and constant monitoring of tank levels. Slight expected spillage occurring at the ship's flange where loading and discharge connections are made will be caught in a drip pan and returned to the cargo tanks.

The probability of ship grounding or collision will be reduced by shipboard information aids and proper crew competence. Informational aids such as radar and fathometers will be installed on the tug/barge. Crew competence will be assured by selection of qualified personnel, training in equipment utilization, and establishment of operating policies. In addition to training and instruction in good operational practices, shipboard personnel will also be trained for proper reaction to accidental spills in order to minimize any damage.

1.7.2 Contingency Plans

Although the goal of the equipment design and operational procedures is to prevent pollution, prudent planning dictates that contingency actions be developed to minimize the effects of any spill. Humble, with the assistance of Clean Seas, Inc., will provide response capability to oil spill accidents involving Humble-operated facilities or vessels. (See OPERATING AND CONTINGENCY PLANS section).

Long Beach and Los Angeles have an oil spill cooperative organized by local industries and operators to provide spill cleanup assistance. Humble is a member of the Petroleum Industry Coastal Emergency Cooperative, as are the owners of the terminals to which the Santa Ynez Unit crude will be shipped. A similar organization called Clean Bays, Inc. provides assistance in the San Francisco area, another potential discharge location for Santa Ynez Unit crude.

1.8 Equipment Failure

If the designated tug/barge transportation units should suffer breakdown or undergo scheduled repair or maintenance, replacement equipment will be utilized. The replacement equipment may be chartered equipment or a vessel owned by Humble Oil & Refining Company.

The offshore floating terminal will require no modification for handling different vessels. At the shore site terminal a mooring vessel will be required at all moorings. The vessel will assist in mooring replacement vessels not designed for self-mooring.

All chartered equipment will be required to use clean tanks for ballast and will not be permitted to discharge oily ballast overboard. A Humble employed loading supervisor will be aboard the vessels to assure that proper communications are maintained and to observe proper loading practice.

2. SULFUR AND NATURAL GAS LIQUIDS DISPOSITION

2.1 General

A maximum of approximately 1,000 barrels of gas liquids and up to 10 long tons of sulfur can be recovered daily from the processed natural gas during initial development operations. These products will be transported to markets via truck - the gas liquids as a butane-plus raw mix and the sulfur in molten form. Although there will be some local demand for these products, the major markets are expected to be the refining and chemical industries in the Los Angeles/Long Beach area. This area has nearly 60 percent of the refinery processing capacity in California and accounts for over 30 percent of the sulfur consumed in the manufacture of sulfuric acid.

2.2 Initial Phase Disposition

Based on a 5 days/week product shipment schedule to minimize weekend traffic, eight trucks, each making one round trip per 8-hour day, will be required to move the natural gas liquids to Los Angeles/Long Beach. Basing four trucks at each end of the haul will minimize congestion. Two-spot loading will be utilized for natural gas liquids. The sulfur production can be transported in four truck loads per 5-day week with single-spot loading.

2.3 Future Disposition

If further development results in significantly higher recovery of natural gas liquids, rail tank cars or marine barges may also be used to transport the product to markets.

TABLE 1

WAVE HEIGHT, WIND AND VISIBILITY DATA FOR THE SANTA BARBARA CHANNEL IN THE VICINITY OF THE SHORE LOADING SITE AND OFFSHORE FLOATING TERMINAL

SUMMARY-DEEP WATER WAVE HEIGHTS (1969-1970)*

	PERCENT OF WAVES AT TABULATED HEIGHT						
HEIGHT / MONTH	0-1.9'	2-3.9'	4-5.9'	6-7.9'	8-9.9'	10-11.9'	12-13.9'
JAN	8.5	57.9	17.0	12.5	5.0	-	-
FEB	10.5	50.8	20.8	10.5	6.0	1.4	-
MARCH	-	27.0	28.5	24.9	14.9	3.9	1.2
APRIL	-	5.0	45.1	19.3	24.3	5.5	0.8
MAY	1.2	23.4	50.3	18.7	5.6	0.8	-
JUNE	12.0	45.3	36.0	6.7	-	-	-
JULY	10.9	58.2	29.9	1.0	-	-	-
AUG	12.9	75.8	11.3	-	-	-	-
SEPT	34.0	61.0	4.0	1.0	-	-	-
OCT	29.5	50.0	16.4	4.1	-	-	-
NOV	25.8	58.0	14.8	1.4	-	-	-
DEC	16.7	54.2	20.1	7.8	1.2	-	-
MEAN (%)	13.5	47.1	24.5	9.0	4.8	0.9	0.2

* Compiled from data in Oceanographic Services Inc. Report OSI #239-2.

TABLE 1 (CONT.)

WIND DATA

A summary of weather information for the Five Mile Trend Area of the Channel (should be representative of most of the Channel with the exception of Point Conception and the Islands) is as follows:

1. For all months except August, September, October, and November; the average conditions are as shown.

DIRECTION (% Occurrence)				MAGNITUDE (% Occurrence)		
CALM	NW	SE	NE & SW	5-10 knots	10-20 knots	20+ knots
24%	48%	20%	8%	34%	27%	39%

August, September, October, and November

DIRECTION * (% Occurrence)				MAGNITUDE (% Occurrence)		
CALM	NW	SE	NE & SW	5-10 knots	10-20 knots	20+ knots
5%	51%	26%	13%	54%	26%	20%

*The 5% occurrences not shown were of small consequence and variable in nature.

SOURCE: Clean Seas, Inc.

TABLE 1 (CONCLUDED)

VISIBILITY (GAVIOTA AREA)

SEASON	FOG OCCURRENCE (%)	% LESS THAN 1 MILE	% LESS THAN 2 MILES	% LESS THAN 5 MILES
WINTER	5-10	2	4-8	10-15
SPRING	10-15	2	4-8	20
SUMMER	15-20	2-4	8-12	20
FALL	15-20	6-8	12-16	15-20

SOURCE: U.S. Fleet Weather Central, San Diego, California

OPERATING AND CONTINGENCY PLANS

TABLE OF CONTENTS

OPERATING AND CONTINGENCY PLANS

(4) Adequate and reliable communication systems

1. PLATFORM PRODUCTION OPERATIONS

1.1 General

This section outlines operating practices and procedures for the initial 850-foot platform, with emphasis on operations after initial drilling has been completed. Paramount considerations in establishing these guidelines are to provide maximum safety for operating personnel and maximum protection for the environment. A detailed description of surveillance systems and equipment is included in Appendix 2.1.

1.2 Manning and Supervision

A field superintendent will have operational responsibility for the platform and associated production equipment. Continuous voice communication with shore will be available at all times via telephone, microwave and radio systems. Platform personnel will operate the wells and production equipment located on the initial platform. Crew quarters will be located on the platform during the initial drilling operations. These quarters may be removed following completion of the initial drilling program. The platform will be serviced by both helicopter and boat transportation. All aspects of helicopter operations will be in accordance with FAA regulations and Humble's Aviation Department policies.

Personnel will normally be transported to and from the platform by crew boats operating from nearby ports. Helicopter transportation will be available for emergency conditions.

Operating supplies will normally be transported on the crew boats or special supply boats. Seagoing barges will be used to transport bulky equipment items too large or too heavy for transport on crew and supply boats. Helicopter transport will be available to transport light loads of equipment and supplies during rough weather or at other times when rapid delivery is desired.

1.3 Personnel and Equipment Safety

Emergency shutdown of operations and evacuation of the platform is expected to be highly infrequent. However, formal detailed contingency plans and procedures, similar to those now in effect for our floating rigs, will be developed. The contingency plans will be posted in strategic locations on the platform and discussed in detail with all personnel.

Emergency life support equipment, including gas masks, respiratory equipment, protective fire suits, life preservers and life rafts, will be stocked and maintained on the platform to meet or exceed USCG regulations.

The platform fire and gas detection systems, emergency shutdown system and fire fighting system will provide protection to personnel as well as to the platform structure and facilities. Manual or automatic activation of the fire or emergency shutdown system will activate audio and visual alarms, shut down the entire platform (including shut-off of each well), secure all pipelines leaving the platform, and activate audio and visual alarms in the central control room at the Corral Canyon treatment facility. Automatic detection of out-of-bound gas concentrations will activate audio and visual alarms and shut down all or part of the production facilities depending upon the location and concentration of gas detected. Emergency manually operated platform shutdown controls will be located at several strategic locations on the platform. Fire extinguishers will be provided to meet USGS regulations and may be used to augment the deluge fire water system. Design details of the fire system, emergency shutdown system, and gas detection system are included in the OFFSHORE PRODUCTION FACILITIES section, and in Appendix 2.1. Well servicing work and workovers will be conducted with adequate blowout prevention equipment and with safety precautions similar to those maintained in our drilling operations.

Platform maintenance work will be planned with the specific goal of minimizing on-site welding.

A pressurized welding room will be installed on the platform. Any open welding on the platform which cannot be avoided will be conducted under strict standards of safety, cleanliness and fire prevention.

Electrical power will normally be supplied by submarine cable from shore. Auxiliary gas turbine generators will be installed to provide emergency power if the primary power supply fails. These generators are capable of operating all electrical equipment required to maintain safety of operations. An auxiliary diesel-driven fire pump is also provided to insure complete fire protection in the unlikely event of failure of both the primary and secondary power systems.

1.4 Monitoring and Surveillance

As described in the OFFSHORE PRODUCTION FACILITIES section, a comprehensive program of monitoring and surveillance of production equipment and systems has been developed. The main feature of this program is the central control room proposed for installation on the initial platform. Data from most of the sensing devices detailed in the OFFSHORE PRODUCTION FACILITIES section and Appendix 2.1 will be displayed in the central control room. The control room operator will have the ability to start and stop the shipping pumps and gas compressors directly from his panel as well as the ability to open and close pipeline valves and to shut down all or part of the platform wells and production equipment.

The control room display of platform systems and equipment will include the following:

Wellheads - status of surface safety valve.

Hydraulic System for Safety Valves - status, low-pressure alarm.

Instrument Air System - low-pressure alarm.

Production Manifolds - status of each valve (test or production).

Primary Separators - status, high and low pressure alarms, high and low-level alarms.

Test Separators - status, high and low pressure alarms, high and low-level alarms, oil, water and gas output rates.

Crude Oil Surge Tanks - high and low pressure alarms, high and low-level alarms.

Shipping Pumps - status, high and low pressure alarms, fail-to-start alarms.

Pipelines - high and low pressure alarms, flow rate (volumetric input-output comparison on oil line will be displayed at the Corral Canyon control room).

Surge Tank Vapor Compressor - status.

Gas Compressors - status, suction pressure and alarm.

Water Disposal - rate.

Fire Fighting System - status, fail-to-start alarm.

Communication System - circuit failure alarm.

The control room will be provided with continuous voice communication with the Corral Canyon shore site and nearby surface vessels.

1.5 Shutdown Criteria

Detection of certain alarms results in an automatic platform shutdown. Activation of an automatic shut-in alarm stops crude oil pumps and gas compressors, closes the block valves on the pipelines leaving the platform, and shuts in wells at both the wellhead safety valves and at the subsurface valve below the ocean floor. The following alarms result in an automatic shut-in:

(1) Activation of fire system

(2) Identification of upper limit gas concentrations

(3) Loss of fire systems

(4) Loss of electrical system

(5) Low pressure in instrument air system

Platform shutdown can also be manually initiated by activation of the emergency shutdown or fire systems. These systems could be activated by platform personnel in the event of an emergency situation.

Many subsystems are also protected by local shutdown systems. These include high-low pressures or levels in treating vessels, high level in surge tanks, etc. (See Appendix 2.1.)

1.6 Pollution Control

Prevention is the most effective method of pollution control and will be a primary objective of Santa Ynez Unit operations. A general prevention policy has been developed and will be followed during all phases of platform operations. This policy includes:

(1) Personnel education

(2) Periodic pollution inspections and follow-up on corrective action

(3) Frequent "spill drills" which include deployment of containment and recovery devices

(4) Periodic review of well control procedures

(5) Regular inspections of equipment and safety shutdown systems

2. PIPELINE OPERATIONS

2.1 General

This section summarizes operating and surveillance plans for the 16-inch oil and 12-inch gas pipelines extending from the 850-foot platform to the onshore treating and storage facilities in Corral Canyon. A detailed description of surveillance systems and equipment is included in Appendix 5.7.

The pipelines and subsystems will be operated and inspected regularly in compliance with OCS Order No. 9 and DOT Regulation 49, Part 195 (oil line) and Part 192 (gas line) and required reports and records will be submitted.

2.2 Manning and Supervision

Primary control of the offshore pipelines will be at the Corral Canyon control room. Continuous voice communication with the offshore platform will be available at all times via telephone, microwave and radio systems. Regularly assigned personnel will be responsible for operation, surveillance, inspection, and maintenance.

2.3 Personnel and Equipment Safety

As described in the PIPELINES section, all components of both pipelines are protected by pressure relief valves or are designed for maximum operating pressure. Automatic and manual shutdown systems are provided.

2.4 Monitoring and Surveillance

Surveillance of the oil and gas pipelines will include:

(1) Pressure sensing devices - high and low pressure

(2) Flow sensing device - low flow

(3) Visual inspection

(4) Continuous volumetric comparison (oil line) - measure in and out

A central control room will be provided at Corral Canyon. Important operating parameters will be displayed to controllers, including telemetered pressure at each end of each line, compressor and shipping pump operations on the offshore platform, and valve line-up information. Controllers can shut down either line and stop the offshore compressors and pumps in the event of any out-of-bounds condition. The sea surface above the pipelines will be visually inspected on a weekly basis. Submerged portions of the lines will be inspected annually by side scan sonar or other means.

2.5 Shutdown Criteria

The following conditions will result in automatic shutdown of the affected pipelines.

(1) High or low pressure on the platform end of the line

(2) Low flow rate

(3) Discrepancy in input-output comparison, oil line

3. ONSHORE FACILITY OPERATIONS

3.1 General

This section presents operating and surveillance plans for the Corral Canyon treating and storage facilities. A detailed description of surveillance systems and equipment is included in Appendices 4.5 and 4.6.

3.2 Manning and Supervision

A superintendent will have operational responsibility for the facility site and associated production and storage equipment. Continuous voice communication with the offshore platform will be available at all times via telephone, microwave, and radio systems. Regularly assigned personnel will be responsible for operation, surveillance, inspection and maintenance.

3.3 Personnel and Equipment Safety

As described in the ONSHORE TREATING FACILITIES section, all treating vessels will have high and low liquid level controllers and alarms and pressure relief valves. The crude oil storage area will be provided with a fire foam system. Shutdown of operations and evacuation of the facility is highly improbable. However, formal detailed contingency plans and procedures will be developed for emergency situations. The contingency plans will be posted in strategic locations about the site and discussed in detail with all personnel. These plans will be developed after consultation with local fire department authorities. Emergency life support equipment, including gas masks, respiratory equipment and protective fire suits, will be stocked and maintained as required.

The facility emergency shutdown system and fire fighting system will provide protection to personnel as well as to the facilities. Manual or automatic activation of the shutdown system will shut down the entire facility including the inlet oil and gas pipelines and the outlet sales gas line. Emergency shutdown control stations will be located at several points within the site as illustrated in Appendices 4.5 and 4.6. Design details of the fire system and emergency shutdown system are included in the ONSHORE TREATING FACILITIES section and in Appendices 4.5 and 4.6. Electric power will normally be supplied by the public utility distribution system. Auxiliary diesel-electric generators will be installed to provide emergency power if the primary power supply fails. These generators are capable of operating all electrical equipment required to maintain safety of operation.

3.4 Monitoring and Surveillance

As described in the ONSHORE TREATING FACILITIES section, a comprehensive program for monitoring and surveillance of production equipment and systems has been developed. The main feature of this program is the central control room proposed for installation at the Corral Canyon site. Operating variables such as pressures, temperatures, flow rates and liquid levels from the various units will be transmitted to the control room where they will be displayed. Alarm points and automatic shutdown alarms will also be displayed in the control room.

Shutdown of the entire facility can be initiated by the control room operator. In addition to total shutdown, certain units and individual pieces of equipment have their own safety shutdown systems. These include flame failure shutdown systems on fired equipment, vibration shutdown on fans for aerial coolers, and pump shutdown in the event of low level in suction vessels. The various shutdown systems are described more fully in Appendices 4.5 and 4.6.

Surveillance, control and shutdown equipment will be tested and inspected at regular intervals.

3.5 Shutdown Criteria

The following conditions will result in automatic shutdown of the facility. Partial shutdown of the facility is explained in referenced Appendices 4.5 and 4.6.

Oil Treating and Storage

Oil

(1) Electrical Power Failure
(2) Fire
(3) Manual Activation of Emergency Shutdown Switch
(4) High Level in Crude Oil Storage Tanks
(5) High or Low Pressure on Inlet Oil Pipeline
(6) High Level in Effluent Water Storage Tanks

Gas Plant

Gas

(1) Electrical Power Failure
(2) Fire
(3) Manual Activation of Emergency Shutdown Switch

(4) High or Low Pressure on Inlet Gas Pipeline

(5) High H_2S Concentration at Contactor Outlet

In addition to the shutdown criteria enumerated above, shutdown of the pipelines entering the facility would have the net effect of shutting down the entire facility due to low pressure in the inlet pipelines. The emergency shutdown system noted above could be activated by facility personnel in the event of any hazardous or emergency polluting situation. Emergency shutdown stations will be located at several locations within the facility (see Appendices 4.5 and 4.6).

4. MARINE TERMINAL OPERATIONS

4.1 General

This section summarizes operating and surveillance plans for the onshore pump station, piping system and sea berth located 3/4 of a mile offshore from Corral Canyon. A detailed description of surveillance systems and equipment is included in Appendices 5.7 and 5.8. Appendix 5.10 lists operating procedures to be followed while loading tug/barges or tankers at the sea berth. Marine vessel operations are discussed in the PRODUCT TRANSPORTATION section.

4.2 Manning and Supervision

Principal operational control of the pump station, piping system, and sea berth will be located at the

Corral Canyon control room. During berthing, deberthing and cargo transfer operations personnel from the marine vessel will execute all necessary functions in coordination with the terminal operator using hand-held UHF radios. A standby vessel will be available to assist the vessel if necessary (see <u>PRODUCT TRANSPORTATION</u> section).

4.3 <u>Personnel and Equipment Safety</u>

As described in the <u>MARINE TERMINAL</u> section and in Appendix 5.8, all components of the pumping, piping and loading systems are protected by pressure relief valves or are designed for maximum operating pressure. Automatic or manual shutdown systems are provided.

4.4 <u>Monitoring and Surveillance</u>

Surveillance of the loading system will include:

(1) High and low pressure sensing devices

(2) Flow rate measuring devices

(3) Visual inspection

A central control room will be provided at Corral Canyon. Important operating parameters will be displayed to terminal operators, including status of all operations valves and shipping pumps, flow rate and total flow, and temperature and pressure of pipeline flow. Operators can shut down the system and close isolation valves in the event of any out-of-bounds condition. The loading line route will be inspected on a weekly basis, and the submarine line will be inspected annually by Linalog or other means. The Marine Terminal Operating Plan (Appendix 5.10) will be used as a general guide for planning routine inspections of the marine terminal loading facility.

4.5 Shutdown Criteria

The following conditions will result in automatic shutdown of the loading system:

(1) High flow rate as registered by the flow meter totalizer

(2) Pressure 10% over normal

Shutdown will be manually initiated in the event of loss of radio communication with the marine vessel.

5. OFFSHORE STORAGE AND TERMINAL OPERATIONS

5.1 General

This section outlines operating practices and procedures for the offshore storage and terminal vessel. A description of surveillance systems and equipment is included in Appendices 5.11 and 5.12. Operation of the marine vessels used for transport of treated crude to market is discussed in the PRODUCT TRANSPORTATION section.

5.2 Manning and Supervision

A supervisor will have overall responsibility for all aspects of vessel operation. Regularly assigned personnel will be responsible for operation, surveillance and maintenance of the production equipment and storage tanks. Vessel personnel would also be responsible for coordination of crude oil offloading (see Section 5.6).

The storage vessel will be serviced by both helicopter and boat transportation. Personnel and material transportation and operations will be similar to those for the platform (Section 1.2 preceeding).

The primary method of communications to the adjacent production platform will be by mobile radio. A permanent base station for this radio system will be installed on the production platform. The use of high gain antennas will provide telephone quality communications over the local area. The platform base station will be interfaced with Humble's communications network in the Santa Ynez Unit. The storage vessel will also be equipped with marine radio, including Channel 06 Bridge-to-Bridge frequency for local traffic control.

5.3 Personnel and Equipment Safety

As described in the OFFSHORE STORAGE AND TERMINAL section, processing equipment will have high and low liquid level controllers and alarms, high and low pressure shutdown and alarms, and pressure relief valves. The inlet pipeline and riser system is equipped with a system of two surface and two sea floor fail-safe safety and shut-in valves connected to high and low pressure shutdown and alarm systems. The mooring hawser load will be monitored and alarmed for high tension. Manual and automatic release systems are provided. Oil storage tank levels on both the treating vessel and shuttle vessel will be monitored and alarmed for high level.

Evacuation of the vessel is not anticipated. However, formal detailed contingency plans and procedures, similar to those now in effect for our floating rigs, will be developed. The contingency plans will be posted in strategic locations on the vessel and discussed in detail with all personnel.

The vessel fire and gas detection systems, emergency shutdown system and fire fighting system will provide protection to personnel as well as to the vessel and facilities. Manual or automatic activation of the fire or emergency shutdown system will shut down the entire facility (including oil transfer pumps if offloading) and secure the inlet pipeline and loading hose. Automatic detection of out-of-bounds gas concentrations will shut down all or part of the production facilities depending upon the location and concentration of gas detected. Emergency manually operated shutdown controls will be located at several strategic locations on the vessel. Design details of the fire and gas detection systems and emergency shutdown systems are included in the <u>OFFSHORE STORAGE AND TERMINAL</u> section and in Appendices 5.11 and 5.12.

Maintenance work will be planned with the specific goal of minimizing on-site welding with modular or plug-in type equipment used wherever practical. Any open welding which cannot be avoided will be conducted under strict standards of safety, cleanliness, and fire protection.

Electrical power will normally be supplied by permanent generating equipment. Multiple units will be employed to insure against power failure.

5.4 Monitoring and Surveillance

The central control room concept described previously has also been incorporated in the offshore storage terminal design. Data from most of the sensing devices listed in the OFFSHORE STORAGE AND TERMINAL section and Appendix 5.12 will be displayed in the central control room. In the event of out-of-bounds conditions, the control room operator will have the ability to stop the oil transfer pumps directly from his panel as well as the ability to close the inlet pipeline valves, and to shut down all or part of the production equipment.

The control room display of vessel systems and production equipment will include the following:

Bow Hawser - Tension and alarm

Inlet Pipeline - High-low pressure alarms, status of safety valves

Hydraulic System for Safety Valves - Status, low pressure alarm

Flotation Unit - High turbidity alarm

Oil Storage Tanks - Level indicators, high level alarms

Gas Detection System - Status and alarms

Fire Fighting System - Status, pressure, activation alarms

Status and alarms for high and low pressures and levels are also provided for the production facilities, including vessels, treaters, tanks, vapor compressors, etc., as described in Appendix 5.12.

5.5 Shutdown Criteria

The following criteria will result in automatic shutdown of the production facilities. Activation of an automatic alarm shuts down all production systems, closes the block valves on the inlet pipeline and loading hose, and stops the cargo pumps if offloading or transferring oil. These include:

(1) Activation of fire detection system

(2) Upper limit gas detection

(3) Mooring hawser failure

(4) Power failure

(5) Low pressure in instrument air system

Emergency shutdown can also be initiated by manual activation of the emergency shutdown or fire system. These systems could be activated by operating personnel in the event of an emergency situation.

The production facilities and other equipment are also protected by local shutdown systems. These include high and low pressures or levels in treating vessels, surge tanks, etc.

5.6 Offloading

Offloading procedures are detailed in the PRODUCT TRANSPORTATION section. Offloading will be conducted according to procedures which are consistent with U.S.C.G. rules and regulations for tank vessels, Part 35, Subchapter D, and established Humble practice. The procedures will include but not be limited to such practices as:

(1) Use of standardized check lists for the loading operation

(2) Visual inspection of loading connections prior to landing

(3) Test of all communication circuits between shuttle unit and storage vessel prior to loading

(4) Loading will not begin until the shuttle vessel master has signaled readiness

(5) Continuous monitoring of tank levels

(6) Reduced loading rate and close visual attention while topping off

During cargo transfer operations, personnel on the tug/barge shuttle vessel will execute all necessary functions in close coordination with terminal personnel. Upon completion of offloading, all cargo discharge valves on the floating terminal will be lashed and visually inspected.

5.7 Release from Mooring

Routine maintenance schedules or infrequently severe weather may require that the floating terminal release from the mooring and proceed to a sheltered port. Releasing would follow a step-wise procedure developed to promote safety and prevent pollution:

(1) Close in all production on the development platform, close the pipeline block valves at the platform.

(2) Bleed the connecting pipeline to atmospheric pressure.

(3) Close the pipeline block valves at the SALM, at the end of the loading hose, and at the vessel manifold.

(4) Disconnect the floating hose and hydraulic line at the vessel manifold. Flange off the hose and hydraulic line.

(5) Secure the loading hose and release the vessel from the mooring.

The vessel would then transit to a pre-selected harbor.

The mooring and loading systems as designed could also be adapted to permit remote emergency release in a matter of seconds:

(1) Remotely close the SALM, hose and deck manifold safety valves.

(2) Remotely disconnect the loading hose between the deck manifold and hose safety valves.

(3) Remotely release the mooring hawser.

An electronic lockout would prevent disconnecting the mooring hawser or loading hose before closing the safety valves. The decision to execute an emergency release would be based on the judgment of the supervisor considering existing and anticipated weather conditions and monitored haswer tension.

6. CRUDE OIL TRANSPORT

The operating plan for transport of treated crude oil from the marine terminal at Corral Canyon or from the offshore storage and terminal facility is detailed in the PRODUCT TRANSPORTATION section of the Plan.

7. CONTINGENCY PLANS

7.1 General

The operating and surveillance plans provide an integrated procedure for monitoring and surveillance of all components of the production system from the wellbore to point of delivery to the refiner. The plans are intended to clearly define responsibilities and to provide for implementation of contingency plans in the event of abnormal conditions.

This section outlines contingency plans developed by Humble and affiliates for offshore and onshore oil spills involving Humble-operated facilities or vessels. It should be noted that techniques for clean-up of oil spills are advancing rapidly. The response plans and equipment lists referenced herein are based upon current technology, and upon existing clean-up capabilities.

It can be anticipated that future advancements in the technology of oil spill clean-up will result in revision of the plans presented herein.

7.2 Offshore Oil Spill Contingency Plan

7.2.1 General

Appendix 6.6 contains Humble's Western Division "Safety and Emergency Operations Manual" for the Santa Barbara Channel. The primary intent of this manual is to provide the following:

(1) An emergency organization and communications network for immediate action

(2) Guidelines for safe practices and personnel training

(3) General procedures for emergency operations

(4) Guidelines for pollution prevention and control.

Section III of the manual contains procedures for oil spill containment and clean-up, and lists the location and type of equipment maintained by Humble for this purpose. The containment and clean-up procedures are outlined in Section 7.2.2 below.

Appendix 6.7 contains the Clean Seas Inc., "Oil Spill Clean-up Manual," dated September 1, 1971. Clean Seas Inc. (CSI) is a non-profit corporation formed in 1970 by 14 member oil companies operating in the Santa Barbara Channel. The purpose of the corporation is to provide oil spill clean-up equipment for immediate response to requests by member companies.

7.2.2 Plan of Action

After a leak has been detected and action initiated to eliminate the cause of the spill, certain persons and agencies must be notified. Notification will be the responsibility of the Humble supervisor at the affected facility.

Humble's Western Division Emergency Operations Team will immediately be notified of any oil spill so that clean-up units can be mobilized. The U.S. Coast Guard, the U.S. Geological Survey, and other appropriate agencies will be notified of any oil spill or gas leak in coastal waters as soon as it is detected.

Humble's Oil Spill Contingency Plan (Appendix 6.6) will be activated by members of the Emergency Operations Team upon notification of an oil spill situation. The contingency plan consists of four sequential phases. Phase I includes initial actions and notifications as described above, including notification of Clean Seas, Inc. Phase II includes mobilization and deployment of locally available equipment sufficient to handle essentially all small to moderate oil spills. Listings of equipment owned by Humble and others in the Santa Barbara area have been developed to expedite Phase II mobilization. These listings are continuously updated to insure reliability and rapid mobilization in the event of need.

Larger spills would be handled by the Phase III plan. This plan includes 1) mobilization of equipment from the entire Pacific Coast, 2) mobilization of equipment from the Gulf Coast, and 3) construction and/or purchase of additional new equipment as needed.

The Phase IV plan includes final clean-up and documentation, and is common to both Phase II and Phase III efforts. Oil spill clean-up operations will be performed by Humble with assistance from Clean Seas as needed. Humble will maintain overall responsibility for the clean-up operation and will provide coordination of all activities. Clean Seas will provide equipment, materials, and manpower as necessary to augment those provided by Humble.

7.3 Onshore Oil Spill Contingency Plan

7.3.1 General

This section outlines an Oil Spill Contingency Plan pertaining to the operation of 1) the on-land portion of two proposed pipelines extending from the proposed initial platform on OCS Lease P-0188 to a treating station - marine terminal in Corral Canyon, 2) the treating station, storage tanks and marine terminal pump station, and 3) the on-land portion of a proposed pipeline extending from the pump station to an offshore loading mooring.

7.3.2 Plan of Action

The following actions will be initiated after a leak has been detected and the contributing line or lines have been blocked off:

(1) Necessary company personnel will be notified

(2) Proper authorities will be notified

(3) Necessary action to contain the spill with the major objective of preventing any oil from reaching the beach

(4) Pipeline repairs

(5) Environmental restoration.

In the event of a line leak resulting in an oil spill, the line will automatically shut down and block valves will close. If a leak is in a location that could be hazardous to the public, local authorities will be contacted immediately and adequate guards will be posted. Repairs will be initiated and spilled oil will be confined in pits or otherwise limited by dikes or dams to permit recovery and disposal and prevent oil from reaching the beach.

To minimize seepage of oil into the subsoil, free oil will be removed into temporary storage pits as it collects. This stored oil will be transported to the terminal site and discharged into a permanent storage tank.

Repair procedures will depend upon the extent and type of damage experienced. Pipeline repairs will include the application of protective coating where required and inspection of all repair welds.

Oil-soaked soil will be picked up and hauled off to a suitable disposal site or restored in situ. There are several proven reclamation methods available. A decision as to which method is most appropriate will be made on the basis of soil type, extent, and other on-site elements.

7.4 Discharge Terminal Oil Spill Contingency Plan

Humble will provide response capabilities for oil spills involving Humble-operated vessels or facilities at the discharge terminals for Santa Ynez Unit crude. Humble's efforts will be augmented as needed by the Petroleum Industry Coastal Emergency Cooperative in the Los Angeles-Long Beach area and Clean Bays, Inc. in the San Francisco area. These organizations are similar to Clean Seas, Inc. Humble is a member of each of the groups.

8. COMMUNICATIONS PLAN

8.1 General

A unified communications network will connect all phases of Humble's petroleum operations in the Santa Ynez Unit area. Offshore and related onshore facilities will be operated to provide instantaneous and reliable communications.

Several modes of communication will be used to provide a complete system serving all locations. This system will include microwave, cable, VHF/UHF mobile radio, MF/VHF marine radio, and leased telephone company facilities.

Basic communications will be provided by a microwave radio and cable system. Channels will be derived for telephones, data telemetry and control operations.

A mobile radio system will provide portable and "back up" voice communication to all locations. Vessels will be equipped with all radio-telephone marine channels required by the Federal Communications Commission.

8.2 Microwave Radio and Cable Systems

Primary communications for data and voice between the offshore platform and the Corral Canyon control room will be provided by microwave radio. Communications are essentially line of sight, and at these distances will be immune to interruptions caused by atmospheric conditions and other propagation factors. Equipment reliability will be enhanced by the use of standby transmitters, receivers, and batteries.

The basic microwave radio frequency will be multiplexed with channels used for voice communication, such as intercom "hot lines" and telephone company interconnection. Others will be used for data transmission. All multiplex equipment will be of the individual channel oscillator type, so that failures, if they occur, will not affect more than one channel.

An existing microwave system of this type provides voice and data communication to Humble's floating drilling rigs.

Interconnection between the microwave tower and the onshore control room will be provided by multi-pair buried cable. This cable will also interconnect the UHF base station with the control room console.

Another cable, buried in the ditch with the marine terminal loading line, will connect the terminal to the valve near the shoreline. Control operations will be direct-wired to the terminal building for maximum reliability and simplicity.

8.3 Mobile Radio

Mobile radio communications will be provided between the shore site, platform, and all vessels and aircraft. The onshore station will have the advantage of the elevation near the terminal, and will provide telephone-quality communication over the local area and up to 50 miles offshore. All vessels and platforms will be equipped with mobile radio, using base station high-gain antennas. Barge loading coordination will utilize hand-carried portable transceivers on the vessels. These will be a special type recently developed by Humble and the radio manufacturer which are safe for operation in areas containing petroleum vapors and gases.

8.4 Marine Radio

Vessels will be equipped with standard marine radio-telephone operating in the VHF (156-162 MHz) band. Channel 16 National Distress, Safety and Calling Frequency will be monitored. This radio will also be equipped with the Channel 06 Bridge-to-Bridge frequency for local traffic conditions and Public Correspondence channels as necessary for interconnection with coast stations.

8.5 Clean Seas, Inc. Radio

Humble will participate in the Clean Seas, Inc. radio system. This system contemplates installation of a UHF repeater station on Santa Ynez Peak and approximately 10 mobile units to be used when necessary in Clean Seas, Inc. operations. There will also be a mobile van equipped as a command post base station for use as required.

8.6 Undersea Cable

The submarine power cable between the onshore substation and the offshore platform will be equipped with six voice frequency pairs. These will be arranged for emergency use in the unlikely event of microwave system failure.

SUBMERGED PRODUCTION SYSTEM

SUMMARY OUTLINE
SUPPLEMENTAL PLAN OF OPERATIONS
SANTA YNEZ UNIT

LONG RANGE PLANS

INDEX TO APPENDICES

LONG RANGE PLANS

LONG RANGE PLANS

Location and timing of future Unit development will be influenced by the results of the initial development program. Studies based on wells drilled in the Hondo Area indicate there are three to five billion barrels of oil in place in the Monterey with an API gravity of 10° and above. The percentage volume which can be recovered will become more definitive as additional data are gathered and production history is obtained. In addition to the 10° API crude, there are substantial volumes of oil in the Monterey with gravities of less than 10° API and significant volumes of both oil and gas in the Miocene, Oligocene, and Eocene sandstone reservoirs.

Future operations will consist of drilling 18 additional wells from the 850-foot platform for further development of the Monterey Zone and the sandstone reservoirs. Following completion of the drilling program from the first platform, which serves approximately 1800 acres, two additional facilities will be required on OCS P-190 to complete development of the remaining 3300 acre western end of the Hondo reservoir. These facilities will be a fixed platform located in 900-1000 feet of water to develop the northern flank of the structure plus a Submerged Production System located in up to 1500 feet of water to develop the southern structural flank. A Submerged Production System may be used in place of the 900 to 1000 foot platform, making the total Hondo Field development the 850 foot platform and two Submerged production Systems. Production from Submerged Production Systems would be pipelined to the initial 850 foot platform.

Other exploration within the Santa Ynez Unit but outside the Hondo Field area indicate other significant accumulations of oil and gas. The Pescado Area discovery, located about eight miles south-southwest of the Hondo Field, was announced after drilling OCS P-0182-1 well which tested gas with a high liquid content from 250 feet of Eocene sandstone. The well produced 800 barrels per day from Miocene and Ogliocene sandstone reservoirs plus over 1000 barrels per day combined rate from 1400 feet of Monterey siliceous zone. Flank well OCS P-0183-1 also tested oil from the Monterey siliceous zone. Although additional drilling will be necessary prior to finalizing development plans, a fixed platform in 1000-1200 feet of water or a Submerged Production System in conjunction with a surface support structure will be given consideration.

Another high potential for production is the Sacate Area, nine miles west of Hondo Field. Well OCS P-0193-1 tested oil from Oligocene sandstone reservoirs that totaled over 2200 barrels per day. Also, well OCS P-0195-2 directly to the west and on the same trend tested over 1000 barrels per day from Eocene and Monterey reservoirs. These potential hydrocarbon

(Revised)

reserves are in water depths of 700-900 feet. This water depth indicates probable platform development; however, the Submerged Production System will also be considered.

INDEX TO APPENDICES

INDEX TO APPENDICES
SUPPLEMENTAL PLAN OF OPERATIONS - SANTA YNEZ UNIT

(Revised)

Volume No.	Appendix No.	Title of Appendix
IV	4.1	Preliminary Environmental Base Line Survey of Corral Canyon Site, Santa Barbara County, California Metronics Associates, Inc. February, 1971
	4.2	Airflow Tests at Santa Barbara, California Metronics Associates, Inc. June, 1971
	4.3	Geotechnical Feasibility Investigation, Proposed Petroleum Treating and Storage Facility, Corral Canyon Site D, County of Santa Barbara, California Geotechnical Consultants, Inc. September, 1971
	4.4	Site Improvement Report, Humble Oil & Refining Company Onshore Facilities - Corral Canyon, Site "D" Penfield & Smith Engineers Inc. September, 1971
	4.5	Engineering Study for Crude Oil Treating and Storage Facility, Santa Barbara Channel Stearns-Roger Corporation August, 1971
	4.6	Engineering Study for Gas Processing Facility, Santa Barbara Channel Stearns-Roger Corporation August, 1971
V	5.1	Earthquake Resistant Design of Oil Transmission Pipelines Doctor P. C. Jennings August, 1971

Volume No.	Appendix No.	Title of Appendix
V (Continued)	5.11	Design Specification No. 70-109R, Covering Single Anchor Leg Mooring, Santa Barbara Channel, California Esso Production Research Company July, 1971
	5.12	General Description of Production Facilities, Offshore Crude Oil Treating & Storage, Santa Barbara Channel Hobbs-Bannerman Corporation September, 1971
VI	6.1	Wave Statistics for Seven Deep Water Stations Along the California Coast National Marine Consultants December, 1960
	6.2	Storm Wave Study, Santa Barbara Channel Oceanographic Services, Inc. Report #166-2 March, 1969
	6.3	A Study of Wave Conditions Along a Tow Route From Long Beach to a Proposed Location Off Gaviota Oceanographic Services, Inc. Report #240-2 July, 1971
	6.4	Study of Ocean Currents Affecting Proposed Pipeline in Santa Barbara Channel, Easterly Route Oceanographic Services, Inc. Report #222-2A June, 1971
	6.5	Well Control Training Humble Oil & Refining Company October, 1971