DEVELOPMENT AND PRODUCTION PLAN: PLATFORM HIDALGO AND ASSOCIATED PIPELINES OCS LEASE P 0450 (SUPPLEMENT TO POINT ARGUELLO FIELD DPP)

OFFSHORE SANTA BARBARA COUNTY, CALIFORNIA

Chevron U.S.A. Inc.

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Address Inquiries to:

F. Robin
General Manager
Chevron U.S.A. Inc. - Western Region Offshore Projects
P. O. Box 8200
Concord, CA 94524
(415) 680-3115

or

C. Ghylin
General Manager
Chevron U.S.A. Inc. - Western Region Land Department
P. O. Box 8000
Concord, CA 94524
(415) 680-3333

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EXECUTIVE SUMMARY

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EXECUTIVE SUMMARY

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SECTION I

EXECUTIVE SUMMARY

1.1 Development and Production Overview

This Development and Production Plan (DPP) for Platform Hidalgo, on OCS Lease P 0450, is accompanied by an Environmental Report (ER) and has been prepared to comply with 30 CFR Section 250.34-2. It is a supplement to the Point Arguello Field Development and Production Plan, (Chevron U.S.A. Inc., December 1982).

Chevron U.S.A. Inc. (Chevron) is the operator and co-lessee of 14 Federal leases in the area between Point Arguello and Point Conception, California. Initial development of the leases will begin in 1985 with the installation of Platform Hermosa on OCS Lease P 0316. It is expected that Platform Hidalgo will be installed in 1986. OCS leases P 0316 and P 0450 are depicted in Figure 1.1. Hidalgo will be located approximately 6.5 statute miles southwest of Point Arguello and 13.6 statute miles northwest of Point Conception. The proposed consolidated Gaviota onshore processing facility and pipelines associated with these two platforms and others in the Point Arguello Area are expected to be operational during the first quarter of 1986.

Platform Hidalgo and its associated pipelines will be included in a joint Federal-State Environmental Impact Report/Environmental Impact Statement (EIR/EIS). This document will include information regarding the proposed Platform Hermosa, Platform Harvest (P-0315, Texaco) associated pipelines, and onshore processing at Gaviota. The document will also include an Area Study of OCS leases in the vicinity of the Arguello project area. The joint document is being prepared by A.D. Little Co. under the direction of the Minerals Management Service, lead agency for federal agencies and the County of Santa Barbara, lead agency for State of California agencies. The California Coastal Commission, State Lands Commission, and Governor's Office of Planning and Research are represented on a Joint Review Panel that was formed to oversee the EIR/EIS preparation along with lead agency representatives from the MMS and County of Santa Barbara. The current schedule indicates that a draft EIR/EIS will be available to the public and interested agencies in July, 1984. An analysis of cumulative impacts that may be associated with the activities presented in this DPP is included in the EIR/EIS described above.

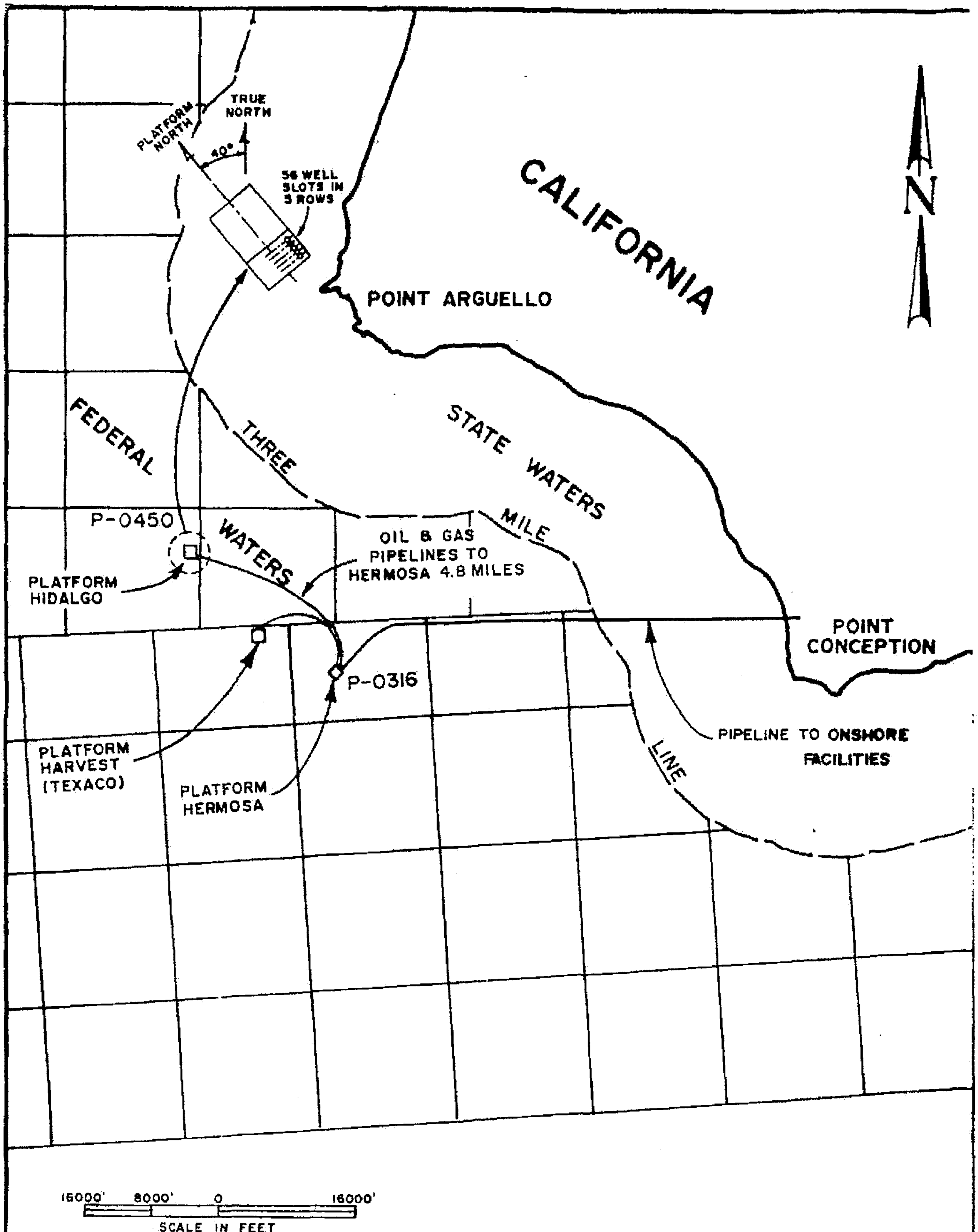
A complete schedule for the installation of Platform Hidalgo is shown in Figure 1.2. It is expected that initial oil will be produced in the first quarter of 1987. Oil production from the platform is expected to peak in 1992 at 20,000 barrels per day, and gas production will peak in 1996 at 10,000,000 standard cubic feet per day (10 MMSCF/D). The project is briefly summarized below.

1.1.1 Platform Hidalgo

Platform Hidalgo will be a three deck, eight leg drilling/production facility installed by conventional methods in approximately 430' (131 m) of water. Its coordinates will be X=710,970 meters and Y=3,819,245 meters (UTM Zone 10). The platform will contain fifty-six well slots, and initially 48 of these slots will be used for production wells. The additional eight slots will be utilized in later years to develop possible new hydrocarbon reservoirs discovered during the development drilling stages and as replacement wells for those development wells which are no longer economical or have to be abandoned for mechanical reasons. Two cantilever type drilling rigs will be used to drill the wells.

During production, free water will be separated from the oil. An oil emulsion will be delivered to the pipeline after metering. Water will also be removed from the gas before delivery to the pipeline to prevent pipeline deterioration or corrosion or other operational problems. Hydrocarbon condensate separated on the platform will be commingled with the oil and sent to shore.

A circulating heating media system will be used to provide heat for production processes. Cogeneration will be used on the platform to minimize air emissions. The heat source for the heating media will be waste heat recovered from the turbine drivers for the electrical generators. A submarine electrical power cable connecting Platform Hidalgo to Platform Hermosa will supply part of the power requirements for the platfrom and producing facilities. The power cable will be installed during the third or fourth quarter of 1986. It is anticipated that additional electrical power will be generated by four 2500 KW fuel gas-fired turbine generators. However, the maximum number of turbines used at any one time will be three, with one available on a standby basis. These gas-fired turbines will be equipped with water injection to reduce NO_x



PLATFORM LOCATION
LAMBERT GRID ZONE 6
X = 658,540 E. Y = 875,876 N.
WEST LONGITUDE 120° 42' 08.44"
NORTH LATITUDE 34° 29' 42.06"

UTM ZONE 10
X = 710,970 m E.
Y = 3,819,245 m N.

PLATFORM HIDALGO
POINT ARGUELLO FIELD
OCS P-0450
OFFSHORE SANTA BARBARA
COUNTY, CALIFORNIA
FIGURE 1.1

A-SB-4678-4

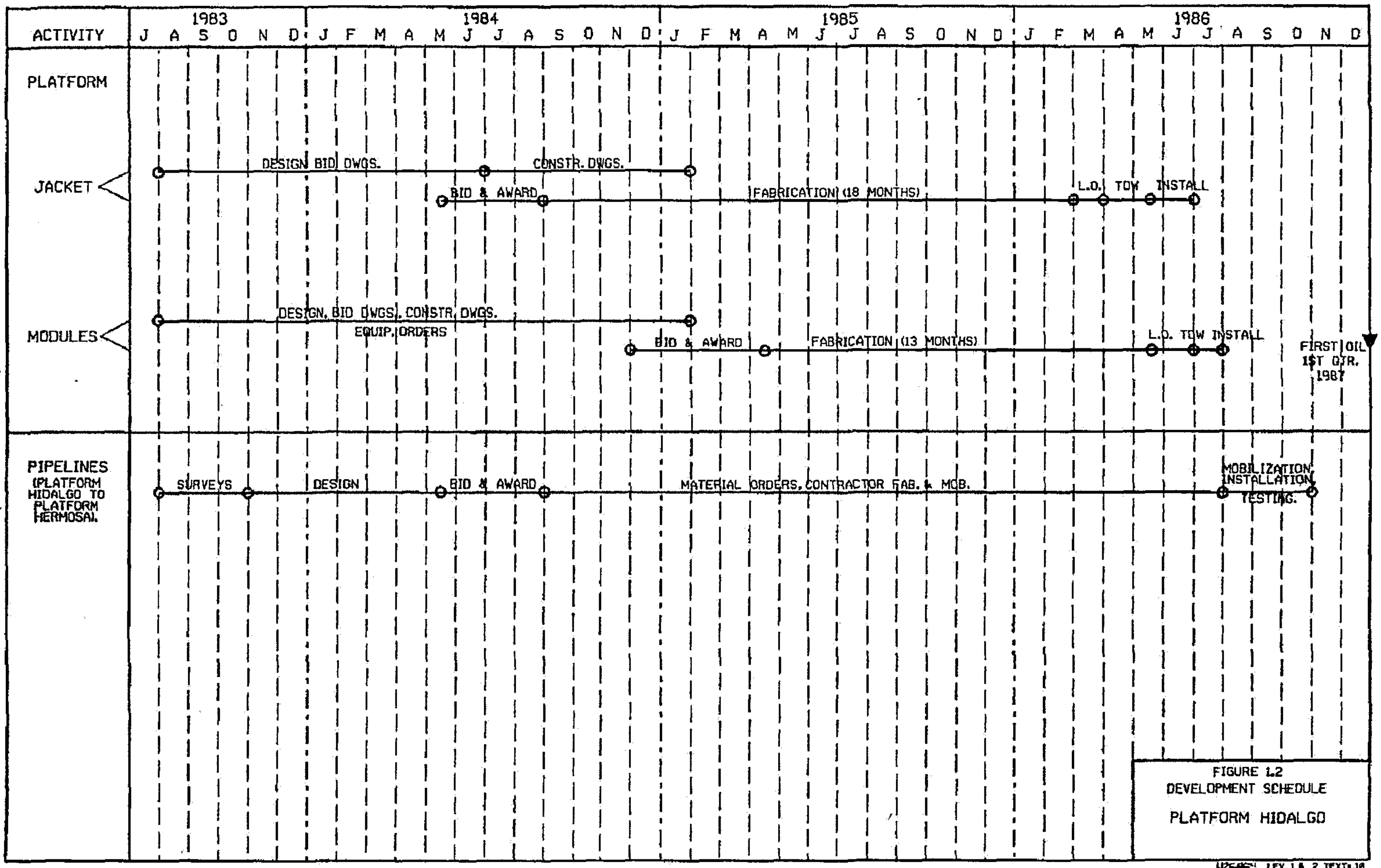


FIGURE 1.2
DEVELOPMENT SCHEDULE
PLATFORM HIDALGO

emissions. To further reduce emissions, a fugitive emission inspection and maintenance program will be instituted. The power cable will reduce the use of diesel fuel to start up the platform and the increased flexibility allowed by the cable will enable turbines to be run at higher loads, thus increasing their efficiency. The cable will be layed along the oil and gas pipeline corridor linking Hidalgo to Hermosa.

To minimize disturbance to the marine environment, any drilling mud or cuttings that have become contaminated with oil from a subsurface formation will not be discharged into the ocean but will be transported to shore and disposed of in a government approved disposal site. Non-oily cuttings will be disposed of at the drill site. All discharges will be in strict compliance with the National Pollution Discharge Elimination System (NPDES) Permit issued by the Environmental Protection Agency (EPA).

Extensive geophysical, biological, and archaeological surveys have been carried out to assure that the platform and associated pipelines (discussed below) will result in a minimum impact to the environment. Results of the surveys show that all significant ocean features will be avoided, including rocky outcrops and cultural resources.

1.1.2 Pipelines

Submarine pipelines will carry emulsified oil in a 14" to 18" (36 cm to 46 cm) line and gas in an 8" to 10" (20 cm to 25 cm) line from Platform Hidalgo to Platform Hermosa. The length of each of these lines from Platform Hidalgo to Platform Hermosa is approximately 4.8 statute miles (8 km). At Hermosa the oil and gas will enter consolidated pipelines that transport Pt. Arguello production to the consolidated onshore facilities at Gaviota. Please see the Point Arguello Field DPP and ER (Hermosa) for a full discussion regarding these facilities. The reader may also wish to refer to the Development Plan for Onshore Pipelines and Processing Facility on file with the County of Santa Barbara, Resource Management Department.

On deck tie-ins for three possible future platforms will be provided on Hidalgo. Production from possible future platforms would be commingled with Hidalgo's production and piped to Hermosa where it would enter the industry operated pipelines that go to shore.

The pipelines will be designed to ensure that they can be safely installed and operated in an environmentally acceptable manner and in compliance with MMS OCS Order No. 9. The lines will also be protected from corrosion and will be equipped with high and low pressure shutdowns to prevent any spillage of oil in the event of an emergency.

Environmental and geophysical surveys were carried out in the area of the pipeline route to establish that the pipeline would impact neither sensitive biological habitats nor significant cultural resources and would not be affected by any geological hazards or fault zones.

1.2 Oil and Gas Processing

Oil/water emulsion and natural gas produced at Platform Hidalgo will be transported via subsea and onshore pipelines to onshore treating facilities. Oil dehydration, gas sweetening, oil pumping, and gas compression will take place at new consolidated facilities located at Gaviota.

This new Gaviota plant is designed to heat and dehydrate 250,000 barrels per day (BPD) of total fluid. Up to 50,000 barrels per day of waste water will be cleaned according to NPDES permit conditions for disposal through an ocean outfall line at Gaviota. The reader may refer to the Point Arguello Field DPP and ER (Hermosa) and Development Plan for Onshore Pipelines and Facilities, on file with the MMS and Santa Barbara County, respectively, for a detailed discussion regarding the consolidated processing facilities at Gaviota.

1.3 Crude Oil Transportation

Although not a part of this Development and Production Plan, Chevron intends to transport its share of Platform Hidalgo's crude oil production from the Gaviota processing facility by means of a proposed industry pipeline from Santa Barbara County to the Los Angeles Basin. Construction could begin as early as the first quarter of 1986 and may be completed by late 1987. However, Hidalgo production will come onstream the first quarter of 1987. Therefore, Chevron proposes to use the existing Getty Marine Terminal at Gaviota for interim tankering until such pipeline is operational. Please note that the use of an industry pipeline will not eliminate the requirement for an expanded existing terminal or a proposed new marine terminal in Santa Barbara County. A marine terminal will be needed prior to the pipeline being operational. One will also be needed to move crude oil to destinations other than the Los Angeles Basin, and during periods when the pipeline is inoperative for technical reasons.

The Southern California coastal pipeline commitment may be subject to revisions in response to public and regulatory agency permitting concerns and continuing engineering, environmental, and economic analysis. There are presently five major crude transportation alternatives being pursued by other entities. These are discussed in Section 9 herein.

SECTION 2

GEOLOGY

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SECTION 2

GEOLOGY

2.1 Introduction

Chevron's area of planned development geographically lies on the California offshore continental border, approximately 14.4 miles west-northwest of Point Conception and 6.4 miles south-southwest of Point Arguello (Figure 2.1). The geologic discussions for this project have been subdivided into three major categories: Regional Geology (Section 2.2), Near-surface Geology (Section 2.3), and Subsurface Geology (Section 2.4). References are listed in Section 2.5.

Geological information presented in this report is based on publicly available scientific and technical reports, information and data supplied by Chevron, and special studies performed by retained consulting firms. The latter reports are referenced and referred to throughout the body of this report. Two Environmental Impact Statements for offshore lease sales No. 48 and No. 53 were used as basic source references for the surrounding region (References 2.5.1 and 2.5.2).

2.2 Regional Geology

2.2.1 Physiography

The Point Arguello area, which contains OCS Lease P 0450 (Figure 2.1), is located in a geologically complex transition zone between the Coast Ranges and Transverse Ranges geomorphic provinces (Figure 2.2). The Coast Ranges are characterized by predominantly northwest-trending structural features, while the Transverse Ranges display a predominantly east-west structural grain. At the junction between the provinces, a basin with northwest-trending structures has been formed.

The Point Arguello Field is located near the western terminus of the

Santa Barbara Basin, which is the principal offshore feature of the Transverse Ranges. The Santa Barbara Basin extends for approximately 70 miles (110 km) along an east-west axis, averages 22 miles (35 km) in width, and merges into the onshore Ventura Basin. It is bounded on the north by the Santa Ynez Mountains and on the south by the Channel Islands. Maximum water depths within this basin are about 2000' (600 m).

To the north of the Point Arguello Field is the Santa Maria Basin, which is the principal offshore feature within the southern part of the Coast Ranges province. This basin also extends onshore to the east. It is a shallow synclinorium bounded on the east by the Coast Ranges and on the west by the submerged Santa Lucia Bank (References 2.5.3 and 2.5.4). The major portion of the basin extends for approximately 124 miles, (200 km), from around Point Arguello northwest to Point Sur. Maximum water depths within this basin also approach 2000' (600 m).

In the proposed platform area, the primary physiographic features are the Arguello shelf, 5-7 miles (8-11 km) wide, and the Arguello slope (Figure 2.3). The shelf-break typically occurs at water depths of about 350'-400' (105 m-120 m). The Arguello slope extends southwesterly from the shelf-break into water depths greater than 2000' (600 m). The Arguello canyon system (described in Reference 2.5.3) dissects the outer continental shelf and slope to the west.

In the immediate vicinity of the platform, the seafloor exhibits an even surface, interrupted occasionally by exposures of underlying strata and tar seeps, the latter a common feature on the inner shelf near Point Conception. The largest seafloor features in the area are probably Miocene outcrops on the inner shelf, and exposures of Recent strata on the outer shelf.

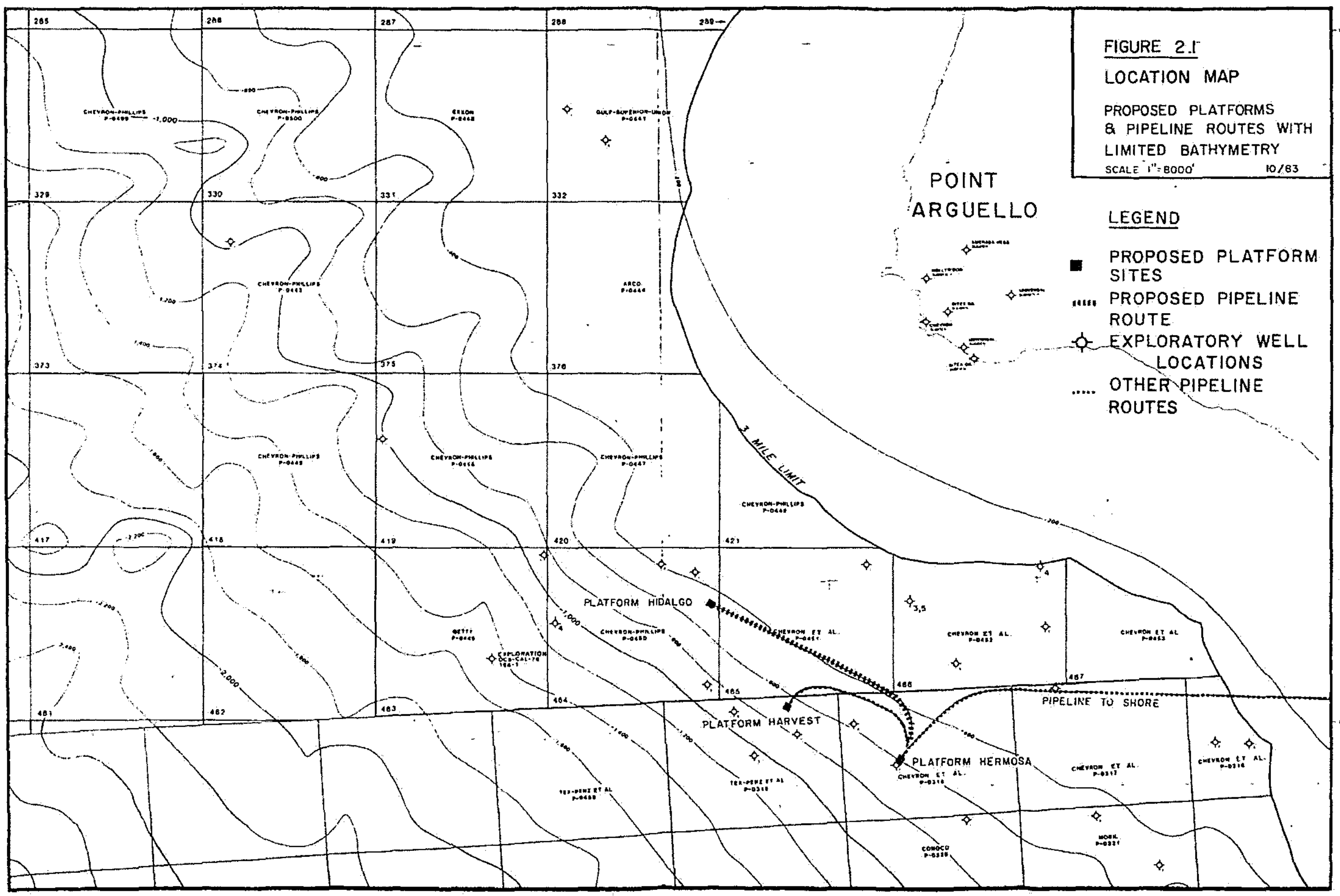
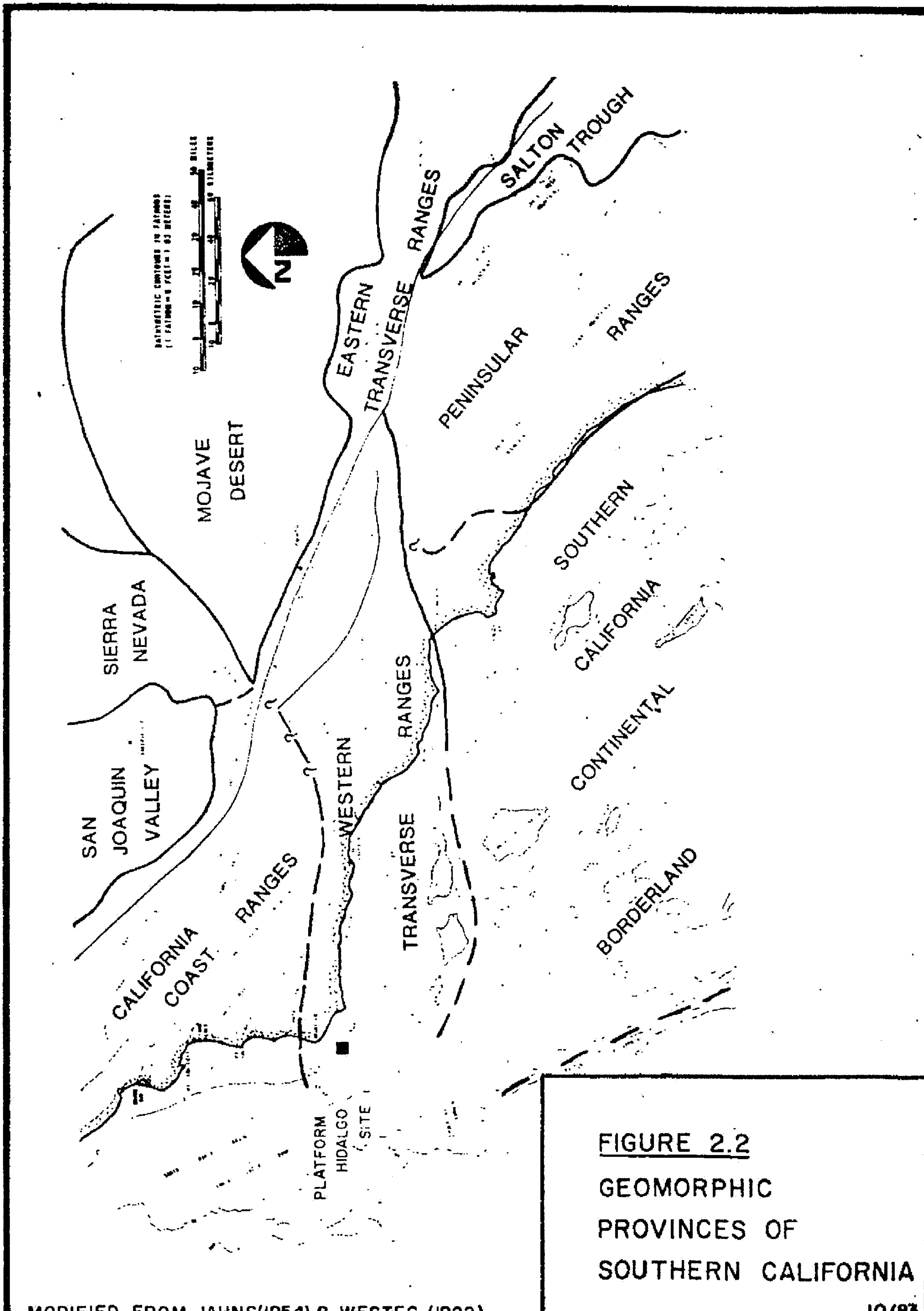


FIGURE 2.1
LOCATION MAP
PROPOSED PLATFORMS
& PIPELINE ROUTES WITH
LIMITED BATHYMETRY
SCALE 1"=8000'
10/83
POINT
ARGUELLO
LEGEND
PROPOSED PLATFORM SITES
PROPOSED PIPELINE ROUTE
EXPLORATORY WELL LOCATIONS
OTHER PIPELINE ROUTES
3 MILE LIMIT
PLATFORM HIDALGO
PLATFORM HARVEST
PLATFORM HERMOSA
PIPELINE TO SHORE



MODIFIED FROM JAHNS(1954) & WESTEC (1982)

FIGURE 2.2

GEOMORPHIC PROVINCES OF SOUTHERN CALIFORNIA

10/83

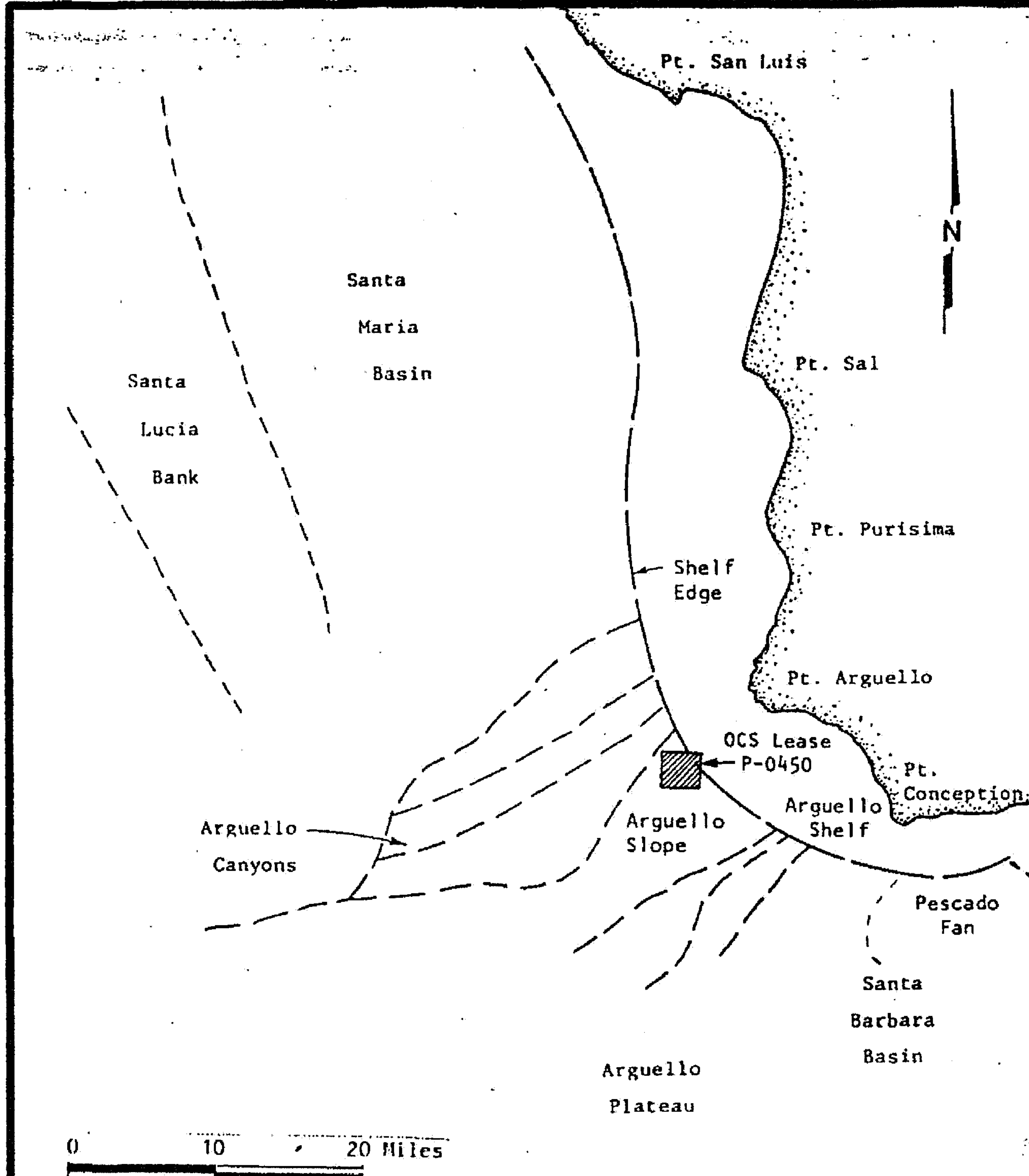


FIGURE 2.3

PHYSIOGRAPHIC SETTING PT. ARGUELLO

MODIFIED FROM McCLELLAND (1983)

2.2.2 Structure

The geologic structure in the Point Arguello area (Figure 2.4) appears to be controlled by a transition zone between the two previously mentioned physiographic and tectonic provinces. Within this zone, numerous folds and faults are present which have a northwest-southeast trend. These structures generally appear to have been initiated in Late Miocene time with tight folds near-shore, indicating that the area has been in compression since the end of Miocene time.

Major offshore structural elements in the Coast Ranges province north of the proposed platform location are shown in Figure 2.4. These include the Hosgri, Purisima, and Lompoc faults and associated folds. The Santa Lucia Bank fault also lies within the Coast Ranges province, but is off the map to the west. The major onshore features include the Nacimiento fault, Santa Maria River-Foxen Canyon-Little Pine fault system, the Pezzoni-Casmalia-Los Alamos-Baseline fault system, and the Lions Head fault. These faults, both onshore and offshore, are generally characterized by right-lateral strike-slip separation, and are considered to be potential seismogenic sources in that they have been active since the late Pleistocene.

Major faults within the Transverse Ranges province are characterized by left-lateral and high-angle reverse components of displacement. Offshore in the Santa Barbara Channel these include the Pitas Point, Oak Ridge, Santa Cruz Island, and Santa Rosa Island faults. Other minor faults such as the F-1 (A, B, and C) have been reported by Yerkes et. al. (Reference 2.5.5). Onshore, the major faults within the Transverse Ranges are the Santa Ynez Main, Santa Ynez River, Honda, South Branch Santa Ynez (and offshore extension), Pacifico-North Branch Santa Ynez, and More Ranch - Arroyo Parida faults. Faults that are considered active are discussed in more detail in Section 4.5.

Principal tectonic stresses in the region can be inferred from:

(1) The orientation and geometry of geologic structures.
(2) Onshore in-situ stress measurements.
(3) Focal mechanism solutions for historic earthquakes.

Analysis of a conjugate fracture system to the east of the project area near Point Conception indicates a maximum principal stress direction of about N20°E (Reference 2.5.6). Onshore in-situ stress measurements at this same area indicate an average principal stress direction of 15 to 20 degrees east of north (Reference 2.5.6). Focal mechanism studies in the western Transverse Ranges (References 2.5.7 and 2.5.8) and southern Coast Ranges (Reference 2.5.9) show a strong right-lateral slip component on the northwest-trending faults, reverse-oblique slip on east-west-trending faults, and nearly pure reverse slip on the northwest-trending Santa Lucia Bank faults. These relationships are compatible with regional north-south to northeast-southwest directed principal compressive stresses in the Transverse Ranges and Coastal Ranges, respectively.

2.2.3 Stratigraphy and Hydrocarbon Potential

Sedimentary strata in the Point Arguello area range in age from Cretaceous (65-135 million years old) to Holocene (younger than about 11,000 years). Basement rocks are believed to be Franciscan metamorphics, based on their presence in the adjacent onshore areas of outcrop; basement was not penetrated in any of the deep exploratory wells drilled in the Point Arguello Field. These wells indicate that the sedimentary section is over 11,000' (3300 m) thick. A representative stratigraphic section for the Point Arguello region is shown on Figure 2.5. Regional onshore geology is shown on Figure 2.4.

Some of these formations vary considerably in thickness across the area because of depositional patterns or unconformities. There are two

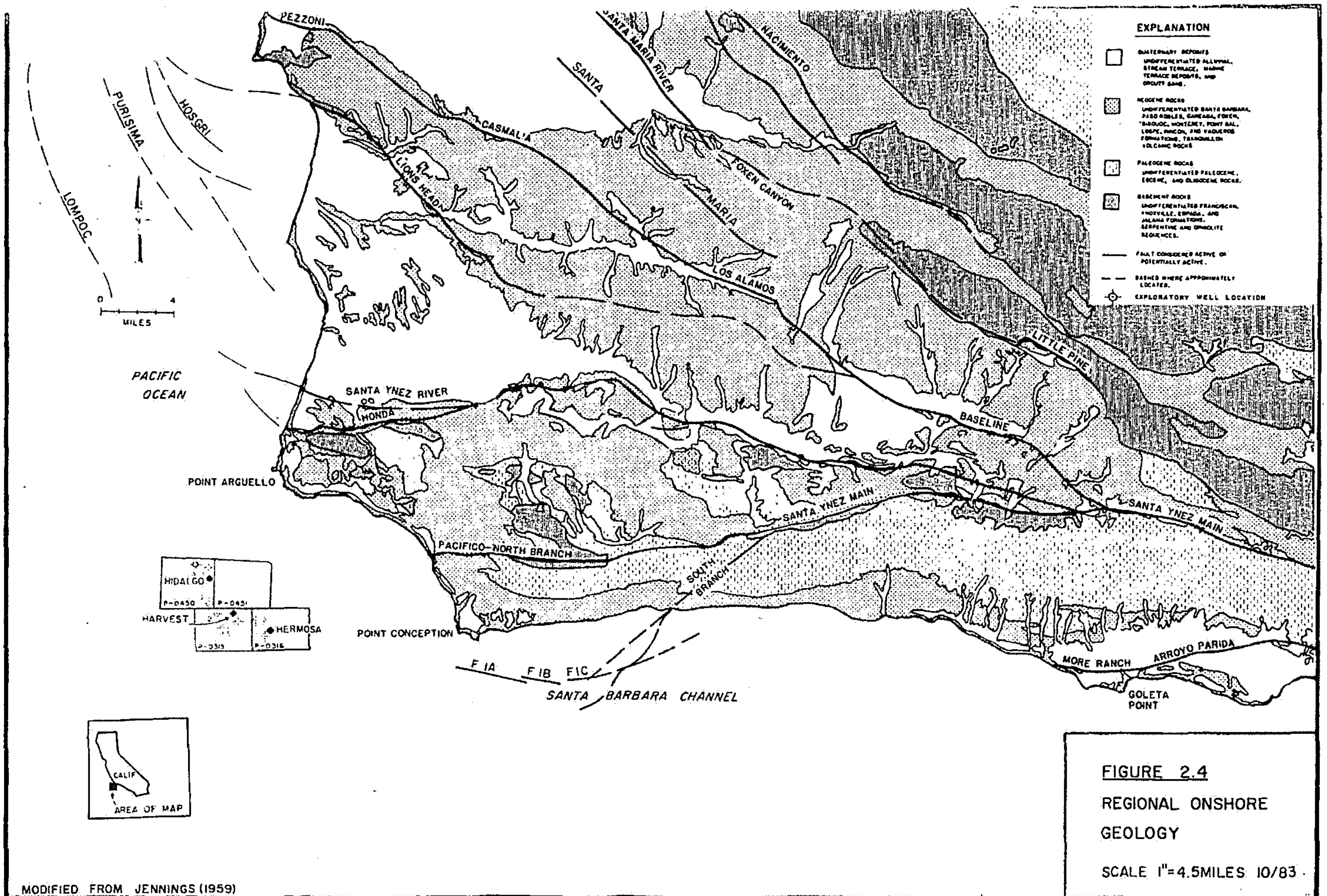


FIGURE 2.4

REGIONAL ONSHORE GEOLOGY

SCALE 1"=4.5MILES 10/83

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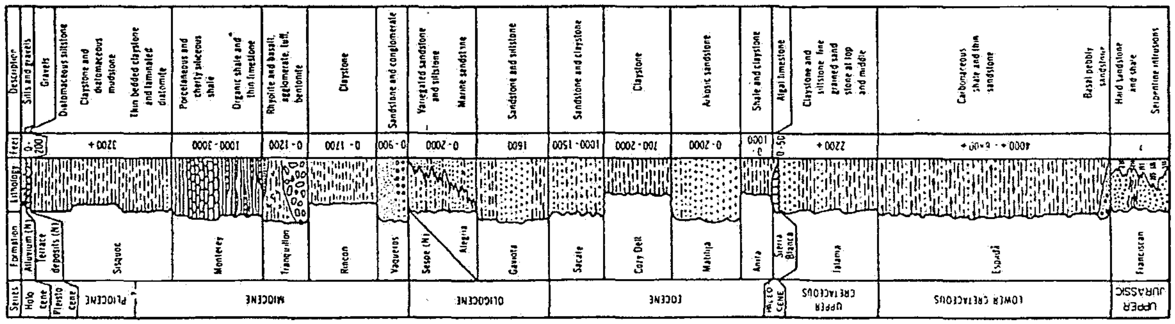

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FIGURE 2.5

STRATIGRAPHIC SECTION
WESTERN SANTA YNEZ
MOUNTAINS AND VICINITY

major unconformities: one at the base of the Miocene and another at the base of the Holocene. The Miocene unconformity has removed all of the Eocene sediments in the northwest direction. The Holocene unconformity has removed all of the Pliocene sediments in a northeastern direction.

2.2.3.1 Precretaceous Basement Rocks

Franciscan metamorphic and sedimentary rocks comprise the basement complex in Transverse Ranges Province. Two distinct basement rock assemblages can be identified from the relatively scarce outcrops (Reference 2.5.10). First, isolated occurrences of sheared graywacke, shale, chert, and associated serpentinite and ultramafic rocks of the Franciscan Formation are exposed in the northern Santa Ynez Mountains and have been penetrated in exploratory wells drilled on Santa Cruz Island north of the Santa Cruz Island fault. A second distinct basement complex of schistose metamorphic rocks (intruded by, and faulted against, igneous intrusive rocks) occurs on Santa Cruz Island south of the Santa Cruz Island fault.

2.2.3.2. Cretaceous Strata

Cretaceous sedimentary rocks consisting primarily of interbedded mudstones, siltstones, sandstones, and some conglomerates crop out around the margins of the Santa Barbara Basin. The closest exposure to the project area is along the Santa Ynez fault, roughly 12 miles east of the proposed development. In the offshore area, Cretaceous sediments were encountered in exploratory well OCS-CAL-78-164 #1 (Reference 2.5.11). This well was located approximately 4 miles west of the project area (Figure 2.1). In this well, Miocene strata were found to lie unconformably on the Cretaceous rocks, with the Paleogene section (i.e., Paleocene, Eocene, and Oligocene) missing. Cretaceous rocks were encountered at a depth of about 10,000' (3000 m).

2.2.3.3. Tertiary Strata

Paleocene rocks appear to be missing in the Point Arguello area; they were not encountered in the OCS-CAL-78-164 # 1 or in the Union and Exxon wells off Point Conception. Where exposed on San Miguel and Santa Cruz Islands, Paleocene units consist of about 1600' (480 m) of interlayered claystone, sandstone, and conglomerate (Reference 2.5.10).

Locally, Eocene rocks are marine sediments that crop out extensively in a continous belt along the crest and southern flank of the western Santa Ynez Mountains. In addition, Eocene rocks have been penetrated at depth beneath the central part of the Santa Barbara Channel and in several oil fields along the north and east Channel margins. Stratigraphic data from the Humble 1 and Union 14-6 wells, drilled several miles off Point Conception, show that they bottomed in Eocene age rocks (Reference 2.5.12). However, Eocene rocks were missing in the OCS-CAL-78-264 #1 well and the exploratory wells drilled in the Point Arguello area.

Similarly, Oligocene rocks were missing in all the Point Arguello area wells. Rocks of Oligocene age are exposed extensively on the south flank of the Santa Ynez Mountains and on Santa Rosa Island. These onshore rocks are unusual in the Santa Barbara Channel area in that they are primarily of non-marine origin. They consist of sandstones, conglomerates, mudstones, and siltstones. Westerly toward Point Conception, these non-marine sediments become marine and are named the Alegria and Gaviota formations. These westerly marine sediments consist mostly of sandstone and mudstone deposited in shallow water.

Sediments of Miocene age are exposed in broad areas along the Santa Barbara coastline and on the Channel Islands; they constitute the major portion of exposed sedimentary sequences in the Transverse Ranges. They are also present beneath much of the offshore region of the Santa Barbara and Santa Maria Basins.

Two wells in the project area penetrated the entire Miocene section, which rests unconformably on the Cretaceous. The Miocene sequence locally includes the Upper Miocene Sisquoc Formation, the Monterey Formation, the Point Sal Formation, and the underlying Tranquillon volcanics. The Lower Miocene Rincon and Vaqueros formations, present in the western Santa Barbara Channel, are absent in the Point Arguello area.

The primary Miocene strata present at Point Arguello are the siliceous shales, chert, sandstone, dolomite, and phosphatic shales of the Monterey Formation. These rocks are discussed further in Sections 2.4.1. and 3.2.

Above the Monterey lies the diatomaceous mudstones, sandstones, and siltstones of the Upper Miocene and Lower Pliocene Sisquoc Formation.

Other Pliocene rocks in the Santa Barbara Channel area consist of two lithologically similar units. The lower unit is informally named the "Repetto", and the upper unit is the "Pico". Both units consist of interbedded sandstone, siltstone and mudstone (Reference 2.5.10). In the Arguello area, the sand content increases toward the base of these Pliocene units. Pliocene rocks are exposed on the outer part of the offshore shelf from Point Arguello to Point Conception to Carpinteria. Onshore exposures of these formations within the Santa Barbara Channel region are very limited at the westerly end of the channel. The thickest onshore exposures occur in the Ventura Basin at the east end of the Santa Barbara Channel.

2.2.3.4. Quaternary Strata

Sediments of Pleistocene age are scattered throughout the Santa Barbara Channel region and Santa Maria Basin. These strata are generally separated into several units as follows (from oldest to youngest): Santa Barbara Formation (late Pliocene and early Pleistocene), San Pedro Formation (early Pleistocene), and an unnamed formation of late Pleistocene age. The Santa Barbara and San Pedro Formations consist of mudstones, siltstones, and conglomerates. Near Santa Barbara, these formations crop out only offshore along the outer edge of the mainland shelf. Onshore, they are either covered by younger strata or have been removed by erosion. The unnamed Upper Pleistocene deposits are widespread, generally discontinuous, and occur in varying thicknesses throughout the Channel region. Over most of the region, they are absent or appear only as a thin mantle on elevated marine terraces and the sea floor. Offshore, these Upper Pleistocene sediments consist of clays and silts which blanket the North Channel slope. They range in thickness from about 100' (30 m) at the top of the slope to about 1100' (330 m) at the base of the slope (Reference 2.5.10).

Holocene sediments cover the sea floor throughout much of the Santa Barbara and Santa Maria Basins. However, they are absent or very thin on large parts of the mainland shelf. West of Santa Barbara, the Holocene shelf deposits are locally as much as 125' (38 m) thick and vary in consistency from fine sands to silt to clay silts and clays (References 2.5.3. and 2.5.10).

2.2.3.5 Hydrocarbon-Bearing Strata

All of the sedimentary section above the basement metamorphics and sedimentary rocks of Franciscan age is considered to be potentially hydrocarbon-bearing. To date,

economically productive hydrocarbon reservoirs in Point Arguello Field have been found only within the Miocene Monterey Formation. This formation, where productive, is encountered at subsea depths ranging from 6600' (1980 m) to 8200' (2460 m). The hydrocarbon-bearing section also ranges up to 1000' (300 m) in thickness.

Only minor hydrocarbon production has been encountered in the Sisquoc Formation, which overlies the Monterey Formation, and in the Lower Miocene Point Sal Formation. Additional testing will be required to determine whether or not economically productive hydrocarbons exist within these formations.

2.3 Near Surface Geology

2.3.1 Introduction

Local and site-specific geological and geophysical surveys were conducted over and in the vicinity of OCS Lease P 0450 to assess geological conditions for the construction of Platform Hidalgo and a pipeline to Platform Hermosa (References 2.5.13 and 2.5.14). They consisted of two geophysical surveys and one soil boring cruise, which included the gathering of high resolution seismic data and shallow soil samples.

During July, 1981, Fairfield Industries (Reference 2.5.15) acquired high-resolution geophysical data in the Point Conception area. Sparker surveys, subbottom profiler, side-scan sonar, echo-sounder, and magnetometer records were obtained across OCS Lease P 0450.

During July-August, 1981, similar surveys were conducted by Fairfield Industries on OCS Leases P 0451, P 0452, and P 0453 (Reference 2.5.16).

During February, 1983, McClelland Engineers drilled two soil borings (M-20 and M-20A) on OCS Lease P-0450 to evaluate the proposed platform site (Reference 2.5.14).

During July and August, 1983, McClelland Engineers (Reference 2.5.13) sampled sixteen locations near the platform and along the pipeline route to Platform Hermosa with dart cores. In addition, they acquired high-resolution geophysical data during this time period, covering the platform site in great detail. The general areas around the platform and the pipeline route were covered with a less-detailed grid of high-resolution geophysical data.

Data collected since 1979 to evaluate the shallow geology and soil conditions were gathered in accordance with guidelines published by the Minerals Management Service in NTL (Notice to Leasee) 81-2, 82-2 and MMS OCS Order #8.

2.3.2 Geomorphology

The Arguello Field area consists of two morphologic provinces: 1) the Arguello shelf province, and 2) the Arguello smooth-slope province. The shelf province is part of the mainland shelf which extends along the California coastline. It is predominantly featureless, slopes southwesterly at between 1% (0.6°) and 2% (1.1°) to a water depth of about 400' (120 m) and varies in width from 3 miles (5 km) at Point Conception to about 7 miles (11 km) near Point Arguello. This province has a few small-scale irregularities scattered throughout its surface. These features vary from hard-bottom areas near the coastline to occasional small patches of firm sediments located near the shelf's outer edge. These latter features appear to be outcroppings of Pleistocene sediments which have not yet been buried by Holocene deposits.

The Arguello slope province, which commences at about the 400' water depth (120 m) slopes to the southwest from between 5% (3°) to 8% (5°). This slope continues southwesterly for over 12 miles (19 km) and into water depths greater than 2000' (600 m). In the immediate area of Chevron's proposed development the sea floor is generally smooth, except for:

- a northeast-southwest trending seafloor channel west of the proposed platform site,
- patchy areas of sedimentary rock outcrop to the north and east,
- scattered elevated seafloor features, and
- shallow seafloor depressions (Reference 2.5.13).

Seafloor Channel A seafloor channel is present within the survey area about 600' (180 m) west of the proposed platform site. This channel begins approximately at the shelf break and trends downslope (southwest) past the southwest margin of McClelland Engineers' platform survey area (Reference 2.5.14). Within the survey area, the depth of the seafloor channel ranges from a few feet at the shelf break to a maximum of 150' (45 m) at the southwest margin of the platform survey area. Sides of the channel typically have seafloor slopes ranging between 7% (4^{o}) at the head of the channel to about 17% (10^{o}) further downslope.

No evidence of seafloor slumping or other significant mass movement was observed on the geophysical records obtained within the survey area. On subbottom profiler records, the upper 12 ms (30' at an assumed velocity of sound in sediments of 5000' per second) of sediments appear to be the result of normal pelagic sedimentation. Strata below this depth are not as well resolved on geophysical records, due to the possible presence of shallow gas.

Sedimentary Rock Outcrops: Sedimentary rock crops out in some portions of the platform and pipeline survey areas. These areas of rock outcrop are characterized by a hard and irregular seafloor having local relief ranging from less than 3' (1 m) to a maximum of 15' (45 m). The areas of rock outcrop are discontinuous or "patchy", limited to the shelf portion of the survey areas, and aligned generally along the strike of bedding.

Elevated Seafloor Features: Numerous elevated seafloor features are present south of the proposed platform and in the northwest quadrant of OCS Lease P 0316. Except for one elevated feature about 3200' (960 m) east-northeast of the proposed Platform Hidalgo site, all these mapped features occur along the Arguello Slope. Many of the elevated features are rough and irregular, although occasionally some of them appear to be relatively smooth and rounded. Most of the elevated seafloor features occur within, or adjacent to, shallow seafloor depressions. Typical relief of the features ranges from 3' (1 m) to 15' (4.5 m); their maximum relief is about 30' (9 m). Individual features range from less than 100' (30 m) across to a maximum of about 600' (180 m) across.

Seafloor Depressions: Shallow seafloor depressions commonly surround areas of sedimentary rock outcrop and elevated seafloor features. Most depressions range in length from about 500' (150 m) to 3000' (900 m), and are generally smooth-sided with side slopes that range from 3% to 13% (1.7^o to 7.4^o). The depressions typically have a width of 200' (60 m) to 1000' (300 m). Depth of the depressions vary from 10' (3 m) or less to a maximum of about 30' (9 m). Shallow seafloor depressions occurring southwest of the shelf break generally trend downslope.

2.3.3 Geology

The surface geology between the proposed platform site and the shoreline at Point Conception is characterized by a variety of seafloor features having little relief. Most of the ocean floor is comprised of a thin layer of very young Holocene sands, silts and clays. These sediments are nearly horizontally bedded over the Arguello Shelf area. Off the shelf and on the slope, this young bedding dips southwesterly at the same rate as the slope (5^o to 8^o). Outcroppings of the underlying older sediments appear occasionally both on the shelf and on the slope. The largest outcrop areas occur near shore in state waters. Here, the Miocene Sisquoc Formation is exposed. The shoreline bluffs are also comprised of claystones and siltstones of the same age.

Seaward into the deeper waters, the outcrops become progressively smaller and contain younger sediments of Pleistocene-Pliocene age. There is an offshore thickening of the Holocene section, which tends to blanket the older underlying beds so that they do not crop out as frequently. Near the shelf edge, where the Holocene begins to thin, there is an increase in the number of outcrops of firm Pleistocene silts and clays. On the slope, Pleistocene sediments appear to be exposed in the bottoms of the channels and pockmarks that occur on the slope. Generally, the offshore surface geology exhibits very few structural forms. However, near the shelf edge, the outcrops of the Pleistocene sediments tend to be on trend and aligned with the regional northwest strike of the bedding.

2.4 Subsurface Geology

2.4.1 Point Arguello Oilfield

Location: The Point Arguello oil field is located approximately 13 miles due west of Point Conception and 6 miles due south of Point Arguello on the Federal OCS Leases P 0450, P 0451, P 0447, P 0316, and P 0315. The area which will be developed from Platform Hidalgo comprises the northwestern portion of the Arguello structure (Figure 2.6). Water depths on OCS Lease P 0450 range from 350' (105 m) to 1475' (443 m) over the production area. The platform will rest in 430' (131 m) of water.

Structure: The trapping structure is comprised of a doubly-plunging northwest-southeast trending anticline which appears to extend for about 6 miles across five Federal OCS Leases: P 0316, P 0315, P 0450, P 0451, and P 0447. OCS Lease P 0450 is near the northwestern culmination of this fold. Both the southwest and northeast flanks of the Point Arguello anticline are bounded by reverse faults which dip to the northeast. The current structural interpretation of the northwest end of the Point Arguello field is based on the interpretation of geophysical data and the results from the drilling of three exploratory wells on OCS Lease P 0450.

In general, the Point Arguello anticline is nearly symmetrical, with the flanks dipping about 35°. The dip on the northwesterly plunge of the fold is about 20°. Structural closure at the producing horizon is over 2000' (600 m).

Stratigraphy: Sedimentary strata in the area of the proposed development range in age from Cretaceous to Holocene. On OCS Lease P 0450, this section is over 11,000' (3300 m) in thickness. The sedimentary section varies from interbedded turbidite sands and shales to a thick section of siliceous shale. The shallowest and youngest sediments consist of silty clays of Holocene age. These sediments extend as a thin veneer over an unconformity that prior to their deposition exposed Pleistocene-Pliocene sediments. The Pleistocene-Pliocene sediments are predominantly siltstones and clay silts throughout, with occasional thin sands and limey streaks scattered from top to bottom. This section also becomes more sandy toward the base. All of these sediments unconformably overlie the Upper Miocene-Lower Pliocene Sisquoc Formation of shales and silts. Most of the Point Arguello structure is buried beneath the Pliocene-Miocene unconformity.

The Sisquoc overlies approximately 2300' (690 m) of Upper Miocene siliceous shale. The Monterey Formation is the principle reservoir rock for the Point Arguello field. The sediments in this formation are entirely in the quartz silica phase, with a high percentage of dolomite appearing in the lower portion. These brittle sediments are excellent for the generation of fracture permeability when tectonically stressed. The Lower Miocene Point Sal Formation, (i.e. basal Monterey) consists of silty shales with minor amounts of sand. The Tranquillon volcanics underly the Point Sal Formation. This Lower Miocene formation consists of tuffs and reworked volcanoclastics. The Miocene rests unconformably on the Upper and Lower Cretaceous in the field area.

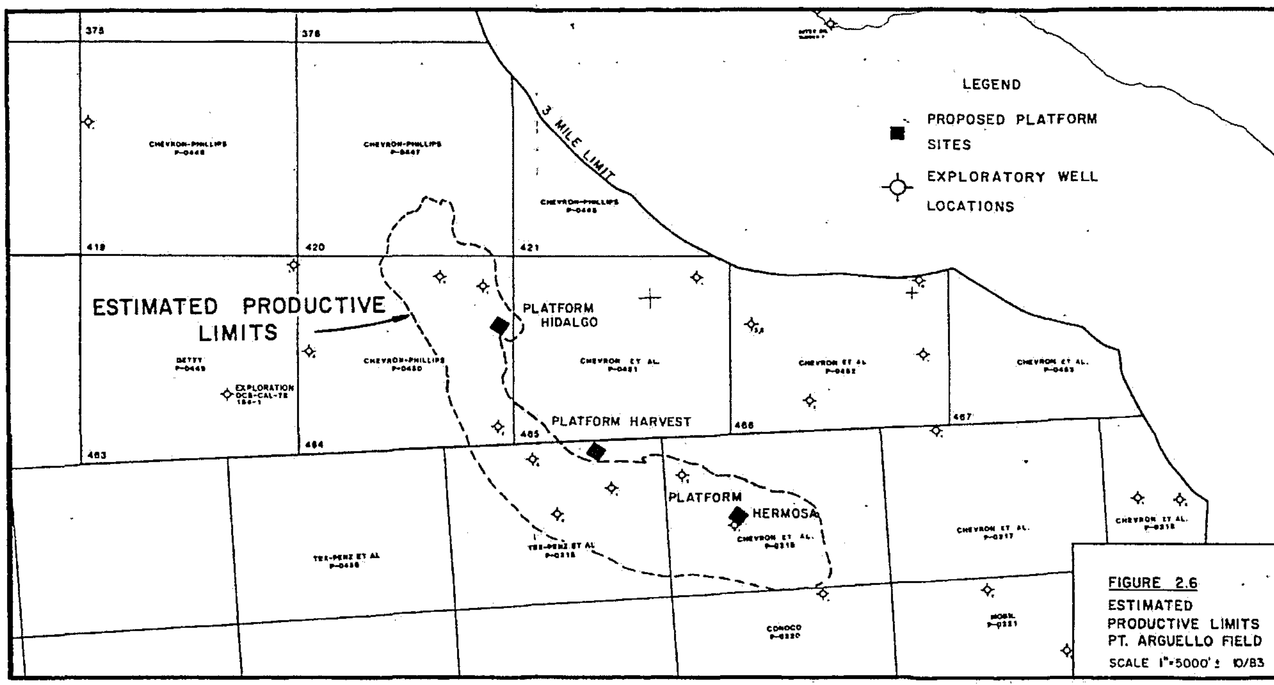

FIGURE 2.6
ESTIMATED PRODUCTIVE LIMITS
PT. ARGUELLO FIELD
SCALE 1"=5000' ± 10/83

These older sediments where penetrated to date consist of interbedded conglomerates, sands, and shales.

2.4.2 Pipeline Route

Discussions covering the geologic and geotechnical conditions along the proposed pipeline route between Platform Hidalgo and Platform Hermosa are covered in Section 7.3.

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SECTION 3
PROPRIETARY
RESERVOIR EVALUATION

Pursuant to the Freedom of Information Act (5 U.S.C. 552) and its implementing regulations (43 CFR Part 2) and as provided in 30 CFR 250.34-2, Section (a)(5), Section 3 is deleted from the public information copy of the Development and Production Plan. This section contains a detailed discussion of the reservoir in the Pt. Arguello Field. Section 3 is considered proprietary by Chevron. An outline of the information contained in this section is given in the Table of Contents for Section 3.

SECTION 4

PLATFORM SITE AND CONSTRUCTION

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PLATFORM SITE AND CONSTRUCTION

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SECTION 4

PLATFORM SITE AND CONSTRUCTION

4.1. Introduction

Platform Hidalgo will be designed to withstand site-specific environmental, installation and operational loads. The water depth and geology of the area has been evaluated extensively and will not present problems for setting, design or installation. This section describes the methodology that was used to develop the geological, geotechnical, oceanographic, and seismic design criteria. A description of the platform design and installation is also included. Detailed design data will be reviewed under the platform verification program in accordance with OCS Order 8. Design work is being performed by Bechtel Petroleum, Inc.

4.2 Onsite Geology

The Platform Hidalgo location was initially selected on the basis of geologic data that were obtained from geophysical records and the drilling of three exploratory wells. These data defined a commercial hydrocarbon accumulation which trends northwesterly across the eastern portion of the lease (Figure 2.6). In order to adequately develop this accumulation, by directional drilling from the shallowest possible water depth, with good foundation conditions, the site shown on Figure 2.5 was selected. Following this initial selection, regional and site-specific geologic studies were conducted by McClelland Engineers (References 2.5.13 and 2.5.14) at the proposed platform site and along the proposed pipeline route (Figure 2.1). These studies were conducted to assess geologic conditions and to develop geologic and geotechnical design criteria for the platform and pipeline. The conclusion of these studies is that the chosen platform location and pipeline route present no geologic problems to the design of these facilities. Site-specific findings by the consulting firm for the platform are summarized in the following paragraphs. The pipeline site-specific findings are covered in Section 7.3.

4.2.1 Bathymetry

Ocean floor water depths and sea floor topography at the proposed platform site are shown on Figure 4.1 of this report and Plate 5 of McClelland Engineers' report (Reference 2.5.13). A northeast-southwest trending rectangular area

8,000' by 8,000' (2400 m by 2400 m) centered on the platform site was surveyed, as well as a more detailed grid of 2000' by 2000' (600 m by 600 m), also centered on the platform site. This area and the platform site area are located on a slope with water depths that range from 350' (110 m) to 900' (270 m). At the proposed platform site, the water depth is 430' (131 m).

At the platform site, the ocean floor is generally smooth and slopes southwesterly at a grade of 4% (gradient of 1:25, dip of 2.3°). The sea floor in the surrounding area also slopes to the southwest with grades from 2% (1:50 or 1°) to 8.7% (1:11 or 5°). There are local depressions in this slope which disrupt the bottom and have been described by McClelland Engineers (Reference 2.5.13). These sea floor depressions range up to 10,500' (3150 m) in length, 4,000' (1200 m) in width, and penetrate from 3' to 150' (1 to 45 m) below the mudline. The side slopes of these depressions grade up to 17% (1:6 or 10°).

4.2.2 Ocean Bottom Conditions

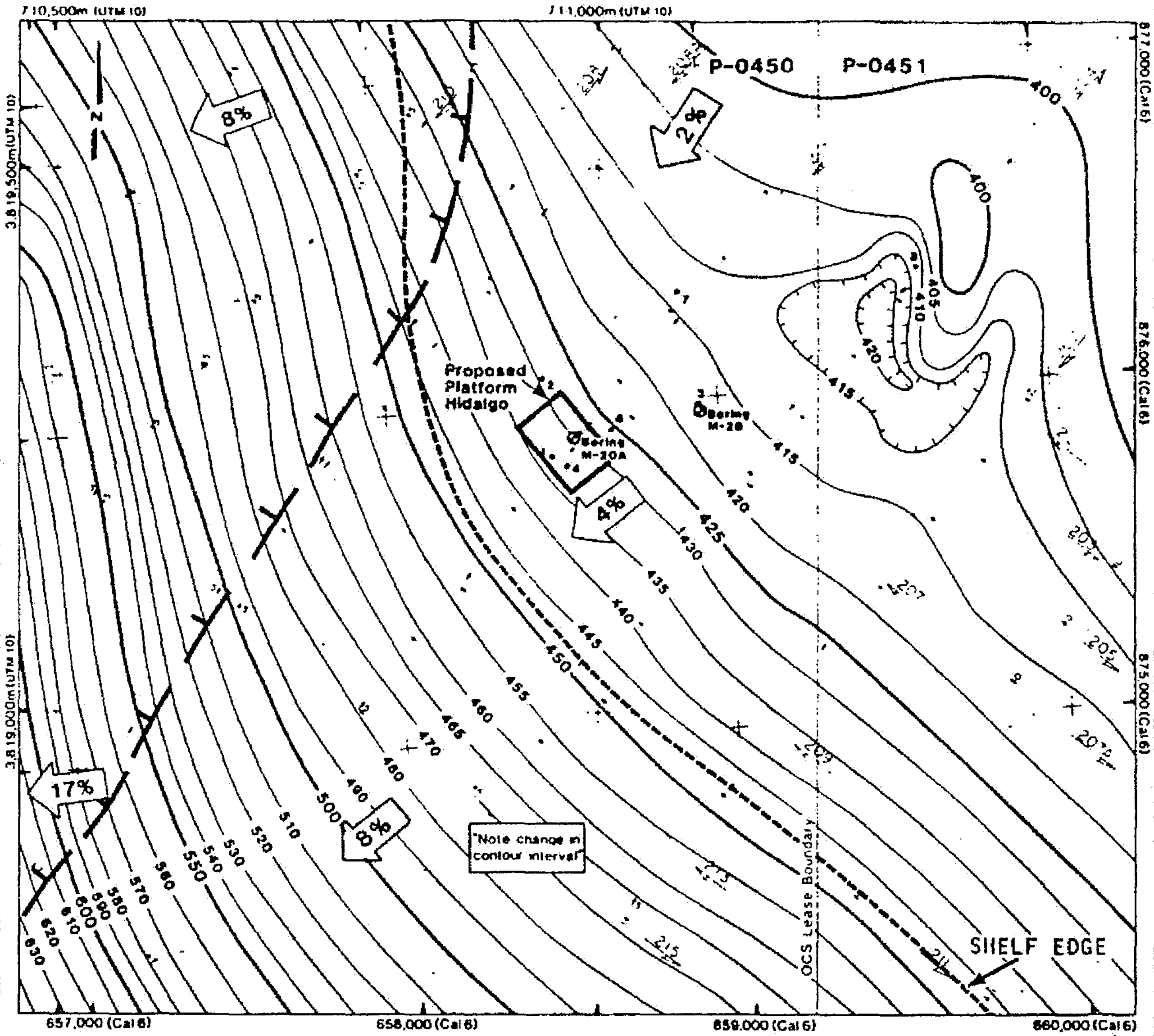
The McClelland Engineers' report (Reference 2.5.13) identifies sea floor features in the survey area that include small outcrops of stiffer sediments which form an irregular bottom topography, occasional natural gas seeps, anchor scars, previous drill sites, and some unidentified sonar targets. The area selected for the platform site is generally smooth and undisturbed by any of the above-mentioned features (Figure 4.2).

4.2.3 Shallow Gas and Hydrocarbon Seeps

There are occasional gas seepages in the area of OCS Lease P 0450 (shown as water column anomalies on Figure 4.2). These seeps have been noted in the records from the high resolution geophysical surveys. Generally, the gas seeps show up as plumes in the water column which start at the mudline. No seeps were noted in the platform area.

4.2.4 Shallow Overburden Sediments

An analysis of site-specific soil borings and high resolution geophysical surveys



400 Bathymetric contour in feet.

2% Direction and gradient of seafloor slope.

McClelland Engineers, Inc. soil boring.

Margin of seafloor channel. Sides of channel slope 7 to 17 percent.

Approximate location of Arguello Shelf Edge.

207 McClelland trackline number and vessel heading.

McClelland trackline fix mark.

McClelland dart core location and number.

Notes

1. Bathymetric contours are estimated to be accurate to within about 1.0 percent. Datum is Mean Lower Low Water.

2. Contour interval is 5 ft to 470 ft depth and 10 ft beyond 470 ft depth.

3. Fairfield tracklines are not shown.

MODIFIED FROM McCLELLAND (1983)

FIGURE 4.1

BATHYMETRIC MAP PLATFORM HIDALGO

SCALE 1"=500' 10/83

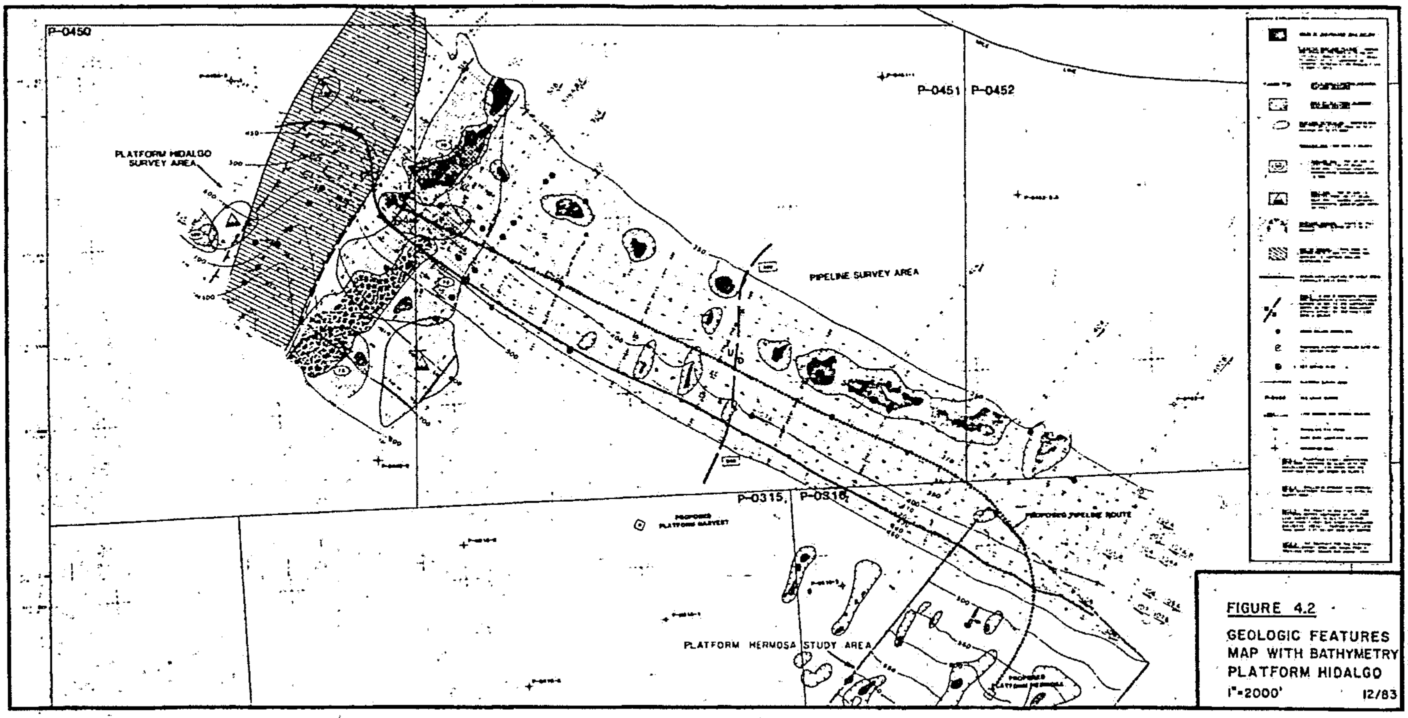


FIGURE 4.2

GEOLOGIC FEATURES MAP WITH BATHYMETRY PLATFORM HIDALGO

1"=2000' 12/83

indicates that the proposed construction site is underlain by Holocene and Pleistocene-Pliocene sediments to at least a depth of 450' (135 m) below the mud line (References 2.5.10 and 2.5.12). McClelland Engineers (Reference 2.5.14) have described three separate strata (Table 4.1). The upper stratum is a soft clayey silt of possible Holocene age. This stratum is 16' (5 m) thick and dips about 2° to the southwest at the platform site. The lower strata (B and C) vary from sandy silts to stiff clayey silts and probably are of Pleistocene-Pliocene age. These sediments dip about 4° to the southwest. All of the strata contain shells and shell fragments, indicating that they were probably deposited in a marine environment.

For the purpose of determining geotechnical characteristics, McClelland Engineers (Reference 2.5.14) made extensive laboratory tests on the soil samples recovered from two soil borings taken at and near the proposed platform site. Their report should be referred to for geotechnical details and laboratory results.

The Pleistocene-Pliocene sediments are slightly gasified in this area. Evidence of the presence of this finely dispersed gas is based on relative amplitude anomalies noted on high-resolution geophysical records. These anomalies are common in the vicinity of the proposed platform; however, the dispersed gas appears to be at very low (hydrostatic) pressure and is deep enough not to present a hazard to the platform. Several samples obtained in Boring M-20, drilled 375' (113 m) north-east of the platform site, contained small gas bubbles. The depth of this gassy zone corresponds to the top of a "bright" geophysical reflector that is interpreted to be gas. Indications are that this gas is at or near hydrostatic pressure and therefore presents no hazard to the platform. No seafloor depressions or water-column anomalies are associated with this gas, as is the case along the pipeline route to the east. In addition, during the drilling of wells OCS P 0450 #1, OCS P 0450 #2, and OCS P 0450 #3, no shallow gas was noted. Previous work for Platform Hermosa (Reference 4.7.1) indicated that the methane content in the shallow sediments was generally less than 10,000 ppm in the samples taken on OCS Lease P 0316, which is geologically similar to OCS

Lease P 0450. All of the methane present was dissolved in the pore water, and was not found in the bubble phase. This indicates that the gas is too finely dispersed within the Pleistocene sediments to cause any reduction in their shear strength. Conditions are very similar at OCS Lease P 0450.

4.2.5 Shallow Structural Geology

The McClelland Engineers report (Reference 2.5.13) should be referred to for a detailed description of the shallow geologic structure in the area of the proposed construction. The shallowest Holocene sediments have approximately the same dip as the mudline slope. Generally, the Pleistocene-Pliocene sediments dip 3° to 5° to the southwest. With depth, the dip within the Pleistocene-Pliocene sedimentary section increases to over 5°. In the area of the platform, the Pleistocene-Pliocene section is about 4000' (1200 m) thick, has relatively uniform bedding, contains a few minor unconformities and is not cut by any significant faults. At the platform site, no shallow faulting was found.

4.2.6 Deep Drilling Hazards

No abnormal drilling hazards are expected during drilling of the proposed wells. Chevron's drilling program will contain a casing program that will be in accordance with OCS Order #2 - Drilling Procedures. The deepest hole drilled in the area, Chevron's OCS P 0450 #1, was drilled to a measured vertical depth of 11,534' (3516 m). Similar to Chevron's other exploratory wells OCS P 0450 #2 and OCS P 0450 #3, no abnormal formation pressures were encountered. No loss of circulation occurred during the drilling of these wells. Because the reservoir fluids contain a low gas saturation, there is probably a very low potential for a blowout while drilling.

4.2.7 Earthquake Activity

The Santa Barbara coastal area from Ventura to Santa Maria is located within a seismically active portion of Southern California. Earthquake activity within

TABLE 4.1

PLATFORM SITE SOIL DESCRIPTION

		Penetration, Ft.			
		Boring M-20		Boring M-20A	
Stratum	Description	From	To	From	To
A	Very soft clayey silt	0	21	0	16
B	Sandy silt with silt layers	21	320	16	65+
C	Clayey silt with silt layers	320	399.5+	--	--

this area which might impact the platform was investigated by McClelland Engineers (Reference 2.5.14). Their study included a probabilistic seismic risk analysis which considered all the potential seismic sources shown on Figure 4.3. They then used an attenuation relationship to derive the site-specific accelerations at the Platform Hidalgo location. By this method, McClelland Engineers found that the highest peak horizontal ground accelerations within a 200-year return period at the site would be 0.18 g. From this peak acceleration, they derived a strength-level design response spectrum. Similarly, a response spectrum for ground motions from a "rare, intense" or "extreme" event in rock/stiff soil was developed. Their analysis concluded that the potential accelerations from such an event would be 0.33 g for rock/stiff soil within a 2000-year return period.

McClelland Engineers used a phased interdisciplinary approach to determine the potential earthquake ground motion at the proposed platform site. This procedure required: 1) the determination of geotechnical soil properties from site-specific soil borings; 2) seismotectonic modeling of the Santa Barbara Channel and Santa Maria Basin areas; 3) the determination of seismic risk and probable ground acceleration during both "extreme" and "strength"-level seismic events; and 4) the development of both an "extreme" and a "strength"-level response spectrum for Platform Hidalgo. Their procedure, described in McClelland Engineers' report to Chevron (Reference 2.5.14), follows:

1. Subsurface soil characteristics were determined (Reference 2.5.14).

2. Faults believed to be active or potentially active were mapped using compiled geologic and seismic information (Figure 4.3 and Table 4.2).

3. A source model for the generation of significant earthquakes was constructed. Table 4.3 lists these faults, along with their distances from the proposed platform site and their estimated limiting maximum earthquakes (i.e. "Extreme event").

4. A seismic risk analysis was conducted by combining the source model with acceleration levels at the site (Plate C-8, Reference 2.5.14) for attenuation relationships and with seismic activity (Plate C-7, Reference 2.5.14). In addition, background seismicity not associated with a specific source was also specified.

5. A 200-year mean recurrence interval was used to select a zero period acceleration of 0.18g for the design response spectrum (Plate C-11, Reference 2.5.14). An extreme response spectrum (Plate C-13, Reference 2.5.14) was also constructed, with a zero-period acceleration of 0.33g (2000 year return period). On Table 4.3, the limiting magnitude earthquakes are also the extreme level events.

As part of Federal requirement MMS OCS Order No. 8, Chevron will determine the proposed platform's structural response to earthquake loads. A Certified Verification Agent (CVA) will also verify the earthquake design for Platform Hidalgo.

The intent of the Federal requirements is to insure that structures subjected to earthquake loading have adequate energy absorption capacity to prevent collapse under a rare, intense earthquake. This ductility check must demonstrate that the structure-foundation system is capable of absorbing at least four times the amount of energy associated with the level of structural response determined in the strength analysis with the structure remaining stable.

The study by McClelland Engineers (Reference 2.5.14) concludes that the platform site will not be affected by sudden fault displacements, ground failure, or tsunamis. McClelland Engineers also present the following conclusions concerning the possible failure modes of the near surface sediments from earthquake activity:

1. Ground Rupture

A review of the published literature, an analysis of the test borings, and high-resolution geophysical surveys indicate that there are no fault traces

TABLE 4.2

EVENT NO.	DATE	EARTHQUAKE MAGNITUDE (RICHTER)[1]	APPROXIMATE DISTANCE OF EPICENTER FROM SITE KM(MI)
1[2]	21 Dec 1812	7.5	52 (32) to 95 (59)
2	1830	VII	61 (38)
3	17 Dec 1852	VIII	61 (38)
4	29 May 1854	VI	91 (57)
5	09 Jan 1857	VII	91 (57)
6	28 Jul 1902	VIII	29 (18)
7	31 Jul 1902	5.5	42 (26)
8	01 Aug 1902	VIII	29 (18)
9	11 Sep 1902	V	48 (30)
10	12 Dec 1902	VII	17 (11)
11	07 Dec 1906	VIII	88 (55)
12	29 Mar 1911	VI	60 (37)
13	20 Oct 1913	4.0	79 (49)
14	12 Jan 1915	5.5	42 (26)
15	01 Dec 1916	VII	61 (38)
16	13 Apr 1917	V	91 (57)
17	09 Jul 1917	VII	86 (53)
18	10 Jul 1917	VII	86 (53)
19	26 Jul 1917	V	57 (35)
20	26 Aug 1919	V	91 (57)
21	28 Jun 1920	V	82 (51)
22	05 Sep 1922	V	82 (51)
23	04 May 1923	V	82 (51)
24	29 Jun 1925	6.25	83 (52)
25	03 Jul 1925	VII	83 (52)
26	29 Jul 1925	V	91 (57)
27	24 Jun 1926	V	91 (57)
28	06 Jul 1926	V	91 (57)
29	09 Aug 1926	V	91 (57)
30	26 Aug 1927	V	91 (57)
31[2]	04 Nov 1927	7.5	21 (13) to 73 (45)
32	19 Nov 1927	VI	57 (35)
33	05 Dec 1927	V	11 (7)
34	31 Dec 1927	V	11 (7)
35	29 Mar 1928	VII	50 (31)
36	09 Sep 1929	VI	82 (51)
37	21 Jul 1931	4.0	82 (51)
38	26 Jun 1933	4.3	79 (49)
39	17 Dec 1934	4.5	34 (21)
40	18 Dec 1934	4.0	34 (21)
41	19 Mar 1935	4.0	9 (6)
42	09 Sep 1936	4.0	22 (14)
43	16 Oct 1936	4.0	37 (23)

HISTORIC SEISMICITY
Point Arguello Field Area

After McClelland Engineers, Inc. (1983)

Table 4.2
(Continued)

EVENT NO.	DATE	EARTHQUAKE MAGNITUDE (RICHTER) (1)	APPROXIMATE DISTANCE OF EPICENTER FROM SITE KM(MI)
44	01 Nov 1936	4.0	14 (9)
45	18 Nov 1936	4.5	16 (10)
46	16 Feb 1937	4.0	38 (24)
47	22 Nov 1937	4.5	14 (9)
48	03 Dec 1937	4.0	59 (37)
49	24 Dec 1937	4.0	8 (5)
50	29 Sep 1938	4.0	9 (6)
51	17 Oct 1939	4.0	9 (6)
52	21 May 1940	4.0	86 (53)
53	16 Jun 1940	4.0	9 (6)
54	10 Nov 1940	4.0	85 (53)
55	03 Apr 1944	4.0	63 (39)
56	13 Jun 1944	4.6	26 (16)
57	30 Nov 1944	4.1	35 (22)
58	01 Apr 1945	5.4	79 (49)
59	28 Jul 1945	4.2	58 (36)
60	27 Mar 1947	4.2	61 (38)
61	26 Aug 1949	4.2	17 (11)
62	27 Aug 1949	4.9	17 (11)
63	27 Aug 1949	4.0	79 (49)
64	21 Oct 1953	4.0	92 (57)
65	09 Aug 1956	4.0	87 (54)
66	16 Nov 1958	4.0	84 (52)
67	01 Oct 1959	4.5	16 (10)
68	01 Feb 1962	4.5	42 (26)
69	05 Mar 1962	4.5	80 (50)
70	10 Mar 1962	4.2	80 (50)
71	16 Sep 1962	4.0	91 (57)
72	06 Jun 1964	4.3	86 (53)
73	21 Jun 1966	4.1	44 (27)
74	28 Jun 1966	4.0	42 (26)
75 thru 79	26 Jun 1968 thru 07 Jul 1968	4.0 to 4.5	85 (53) to 110 (68)
80	12 Jun 1969	4.0	22 (14)
81 thru 92	22 Oct 1969 thru 03 Dec 1969	4.0 to 5.7	55 (34) to 85 (53)
93	13 Aug 1978	5.7	91 (57)
94	29 May 1980	4.7	46 (29)

(1) Earthquakes of Richter Magnitude 4.0 or greater are shown. Maximum Modified Mercalli Intensity is given for those events of Intensity V or greater to which no Richter Magnitude has been assigned.

(2) Several separate epicentral locations have been assigned to this event by different researchers.

Note: Data obtained from N.O.A.A. Earthquake File Printout, April 29, 1983.

HISTORIC SEISMICITY
Point Arguello Field Area

After McClelland Engineers, Inc. (1983)

Table 4.3

FAULT(S) OR FAULT ZONE	NEAREST DISTANCE TO SITE KM (MI)	APPROX. LENGTH KM (MI)	MAXIMUM[1] PROBABLE EARTHQUAKE	LIMITING[2] MAGNITUDE EARTHQUAKE	RELATIVE[3] ACTIVITY NUMBER
Honda	14 (9)	24 (15)	4 1/2	5 3/4	1
Santa Ynez River	18 (11)	80 (50)	6 1/4	7	5
F1C	22 (14)	20 (13)	5 1/4	6 1/4	3
Hosgri	24 (15)	145 (91)	6 1/4	7+[4]	4
Lompoc	25 (16)	25 (16)	6 1/4	7+[4]	4
Pacifico	27 (17)	18 (11)	4 1/4	5 1/2	1
Santa Cruz Island	28 (17)	120 (75)	5 1/2	6 3/4+[5]	4
Purisima	31 (19)	26 (16)	5	6	4
S. Branch Santa Ynez	33 (20)	23 (14)	5 1/2	6 1/2	2
Lions Head	35 (22)	60 (38)	5 1/2	6 3/4	1
Pezzoni-Casmalia-Alamos-Baseline	46 (29)	80 (50)	6	6 3/4	5
Main Santa Ynez	47 (29)	100 (63)	6	6 3/4	5
Santa Lucia Bank	50 (31)	100 (63)	6 1/4	7	5
Santa Maria	51 (32)	38 (24)	6	6 3/4	5
Santa Rosa Island	52 (32)	60 (38)	5 1/2	6 3/4	1
Little Pine	55 (34)	60 (38)	5 1/2	6 3/4	1
More Ranch-Arroyo Parida	62 (39)	75 (47)	5 3/4	6 3/4	3
Suey	63 (39)	25 (16)	5 1/4	6 1/2	1
Nacimiento	65 (40)	192 (120)	6	7 1/4	1
Big Pine	71 (44)	70 (44)	6	6 3/4	4
Red Mountain	89 (55)	55 (34)	6	7	3
Oak Ridge	94 (58)	100 (63)	6 1/4	7 1/4	2
Pitas Point	107 (66)	50 (31)	6	7	3
San Andreas	115 (71)	965(603)	7 1/2	8 1/4	5

(1) Estimated Maximum Earthquake for a 250-year return period.

(2) Estimated Maximum Earthquake for a 1,000-year return period (based on estimated maximum of 30 percent surface rupture of fault length during an event (computed from Slemmons, 1977).

(3) Estimated relative activity rating on a scale of 1 (low) to 5 (high):

	Minimum Age of Activity
5	Definite Historic Activity
4	Possible Historic Activity
3	Definite Holocene Activity
2	Possible Holocene Activity
1	Late Quaternary Activity

(4) Although an estimated maximum magnitude of 7 was computed for this fault, the 7.2 to 7.5 magnitude 1927 event has been postulated to have occurred along this fault.

(5) Although an estimated maximum magnitude of 6-3/4 was computed for this fault, the estimated 7 to 7.5 magnitude 1812 event has been postulated to have occurred along this fault.

SIGNIFICANT FAULTS
Platform Hidalgo, Point Arguello Field

After McClelland Engineers, Inc. (1983)

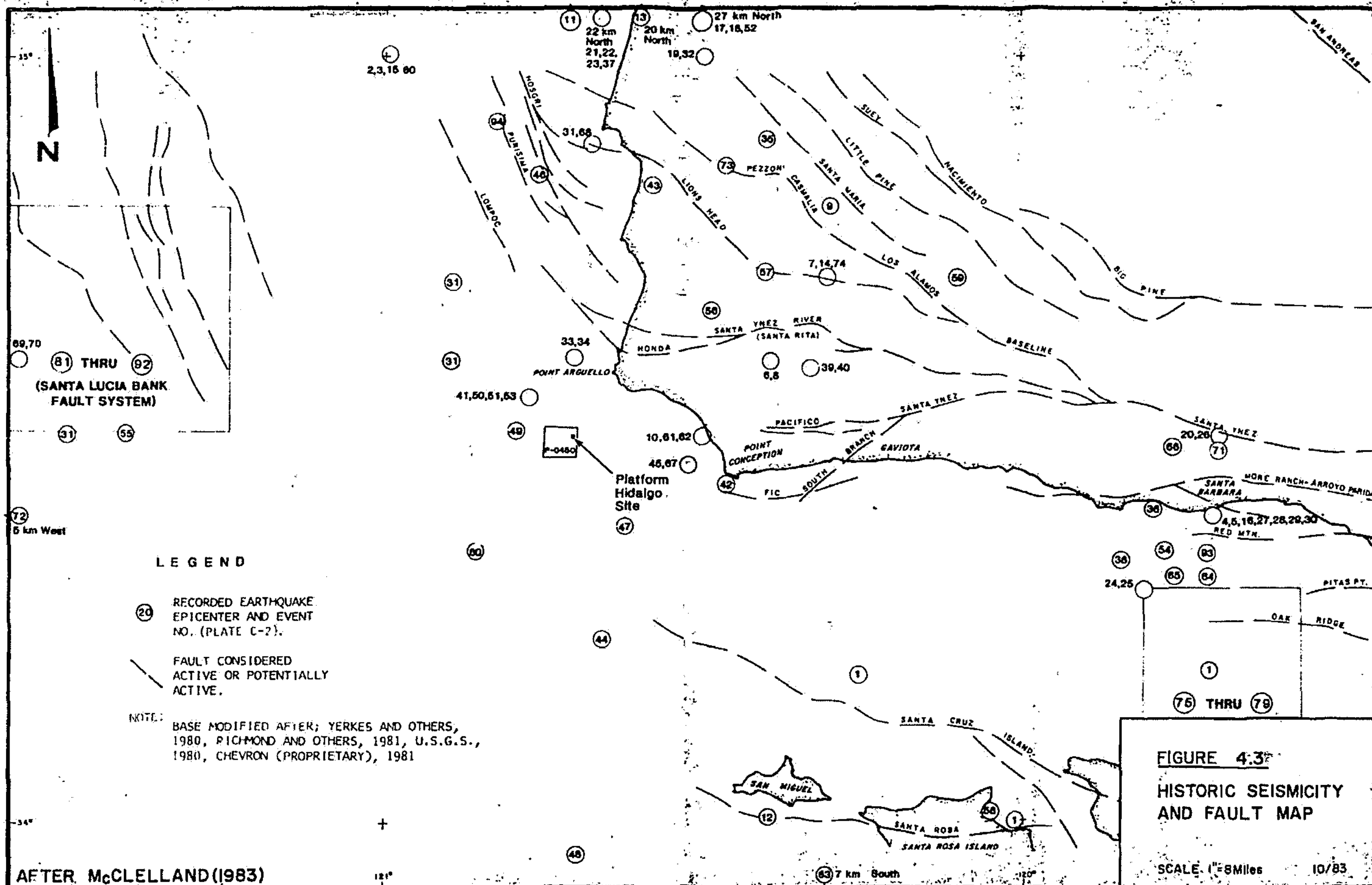


FIGURE 4.3
HISTORIC SEISMICITY AND FAULT MAP

SCALE: 1" = 8 Miles 10/83

beneath the proposed site. Therefore, ground rupturing from fault movement at the platform site is not anticipated during any nearby earthquakes.

2. Ground Failure

(a) Liquefaction

The subsurface soils at the proposed site can safely support the proposed drilling and production equipment. Studies to evaluate soil properties and liquefaction potential indicate that the potential for liquefaction at the proposed site is extremely low (Reference 2.5.14).

(b) Site Stability

Geophysical records show that there is no evidence of geologically recent instability in the platform site area. The slope of the ocean bottom in the immediate area varies from 2% to 8% (1^{o} to 5^{o}).

The observed cyclic properties and geologic conditions of the site suggest that the potential is low for significant loss of strength and stiffness or downslope movement of the surficial layer (16' to 21', 5 m to 6 m) of soft Recent sediments under strength-level earthquake loading.

During an extreme earthquake, significant loss of stiffness of the Recent soils is possible; however, downslope movement of these sediments is not anticipated. Below the Recent sediments, the predicted loss of stiffness is negligible and can be accomodated in the platform design.

4.2.8 Tsunami Hazards

Based on published records and the location of the platform site in open water, tsunami damage will not be a factor to be considered at the proposed platform location. Tsunamis or seismic waves are large oceanic waves that are generated by earthquakes, submarine volcanic eruptions or large submarine landslides. The waves are formed in groups having large wave-lengths and long periods. In deep water, wave heights (crest to trough) may be a few meters or less, wavelengths may be a hundred miles or more, and velocities may be greater than 400 knots (460 mph). However, as a tsunami enters shallower waters, its wave velocity diminishes, and its height increases. Waves can crest at heights of more than

100' (30 m) and strike with devastating force. Tsunami waves do not impact vessels or structures in open water because of their low amplitude and great breadth under these conditions.

The largest tsunami ever reported in California followed the 1812 earthquake in the Santa Barbara Channel. This wave may have reached land elevations of 50' (15 m) at Gaviota and 30'-35' (9-11 m) at Santa Barbara. The most recent tsunami to impact the California coastline occurred following the 1964 Alaskan earthquake. Only minor damage was sustained by small craft in some of the coastal harbors.

4.2.9 Subsidence

Surface subsidence due to reservoir fluid withdrawal is not expected to be a problem at the Pt. Arguello field for the following reasons:

1) The region has been in compression since the end of Miocene time.

2) The trapping structure, at the reservoir depth, has a good arch-supporting structure with associated thrust faulting.

3) The depth of burial of the oil-producing section is over 6000' (1800 m) below the ocean floor. This thick section of overburden will furnish additional support.

4) The hard, siliceous nature of the reservoir rock will lend additional support.

4.2.10 Hydrology

In the Pt. Arguello oil field area, no fresh water-bearing formations of any significance are encountered below 630' (190 m). Above this depth, there is no electric log record. However, soil borings showed the soils to consist mostly of impermeable silt-sized sediments. This upper tight section does contain interstitial fresh water. Chevron has not, however, encountered any fresh water-bearing sands in any of the wells drilled to date.

4.2.11 Other Mineral Deposits

Other than hydrocarbons, there are no other known mineral deposits of either commercial or noncommercial value on or adjacent to OCS Lease P 0450.

4.3 Cultural Resources

The area around proposed Platform Hidalgo and along the route of the proposed pipeline from Platform Hidalgo to Platform Hermosa was evaluated for cultural and archaeological resources. McClelland Engineers (Reference 2.5.13, Appendix E) retained the services of Ms. Heather Macfarlane to make this evaluation. Their report was performed in accordance with Minerals Management Service's order NTL 77-3 dated March 1, 1977. This order only requires that a cultural survey be made in waters of less than 394' (120 m) in depth. Since the 394' water depth was only a short distance from the platform site, their survey was continued out to water depth of 800' (240 m).

They concluded from this review that there are no identifiable prehistoric cultural resources in the area of the proposed project. However, the side scan sonar records showed one anomaly that could be interpreted as a shipwreck. This anomaly is over 3.5 miles from the platform site, and can easily be avoided during anchoring activities connected with platform construction. It will be discussed in Section 7.3.3.

4.4 Platform Structure

4.4.1. Geotechnical Design Criteria

Platform foundation design criteria for Platform Hidalgo will be based on geotechnical information obtained from extensive state-of-the-art investigations conducted in early 1983 by McClelland Engineers, Inc. (Reference 2.5.14). The information was obtained from pushed sample recovery, downhole cone penetrometer testing, in-situ remote vane testing, and gamma ray logging in deep boreholes. Results from the offshore boring program indicate that soil conditions at the platform site are favorable for the proposed construction and that potential liquefaction and slumping in subsurface soils will not be a hazard.

The static and dynamic laboratory program consisted of both conventional (classification, consolidation, permeability, miniature vane, triaxial, direct shear, and static and simple shear strength) and special (cyclic triaxial, cyclic simple shear, and resonant column) testing. The testing and analyses defined soil shear strength characteristics, lateral pile responses, axial pile responses, potential for scour, and the potential for soil liquefaction. All associated boring logs, laboratory test results, and engineering reports will be included in the detailed platform design submittal to the Minerals Management Services (MMS) in accordance with the Platform Verification Program (MMS OCS Order No. 8). Platform foundation design criteria will be site specific for the Hidalgo site and will be checked against API-RP2A guidelines for establishing minimum design criteria.

4.4.2 Design Standards

The platform structure will be designed in compliance with the MMS OCS Order NO. 8, API RP2A "Recommended Practices for Planning, Designing and

Constructing Offshore Platforms", and applicable American Institute of Steel Construction (AISC) guidelines. Additionally, the platform will meet or exceed all the elements of the MMS's "Requirements for Verifying the Structural Integrity of OCS Platforms".

4.4.3 Environmental Design Criteria

Design criteria for the platform are based on a 35 year platform life.

4.4.3.1 Earthquake Design Criteria

The earthquake design criteria are based on a detailed evaluation of earthquake potential in the western portion of the Santa Barbara Channel. They specifically account for the regional and local geologic structure, local active faulting, and local soil conditions. The design criteria are site specific. The platform design will meet both strength and ductility requirements for earthquake loading (see Section 4.2.7).

The strength requirement assures resistance to those ground motions most likely to occur during the platform's life without the platform's sustaining any significant structural damage. The strength level design site motion is expressed in terms of a smoothed response spectrum. The response spectrum method of analysis is used to evaluate the platform's dynamic elastic response to earthquake ground motion.

The ductility requirement provides a platform-foundation system that has sufficient energy absorption capacity such that the platform will not collapse in the event of rare intense ground shaking. Careful joint detailing and fabrication will ensure that the structure performs as designed under earthquake loading. The seismic environment does not present any problems that preclude the safe design, installation, and operation of the offshore structure.

4.4.3.2 Oceanographic Design Criteria

The oceanographic design criteria provide for waves, currents, tides, and winds which may occur during the expected life of the structure. A review of existing oceanographic data has been made to develop estimates of these values. Hindcasting models were made to provide required site specific information. An analysis of the oceanographic data and hindcast models indicate that oceanographic conditions offer no problems for the safe design, installation and operation of the offshore structure.

a. Waves

A sophisticated wave hindcast model which develops the directional wave spectrum was used to determine design waves at the platform site during selected west coast storm events. The model was developed by Ocean Weather, Inc. (Reference 4.7.2) and verified with site specific measurements. This state-of-the-art technology was used to determine design wave heights.

b. Currents

Extreme ocean current velocities were based on an analysis by Intersea Research Corporation (Reference 4.7.3) combining tidal wind driven and general background currents as a function of depth. The Intersea study was based on on-site measurements, historical data and theoretical considerations.

c. Wind

Ocean Weather Inc. compiled an extensive meteorological data set obtained offshore during past significant storms to provide the most accurate wind design criteria available (Reference 4.7.1). With this data Ocean Weather determined sustained wind velocities and gust velocities for which the platform will be designed to withstand.

d. Marine Growth

An extensive study of marine growth on other Santa Barbara Channel platforms will provide the basis for the marine growth design criteria.

4.4.4 Platform Design

The design work is being performed by Bechtel Petroleum Inc., and verified by a Certified Verification Agent according to MMS OCS Order No. 8. The design will consist primarily of stress analyses using established site specific design criteria to evaluate structural responses to extreme oceanographic, installation, operational, fatigue, and earthquake loading conditions. A comprehensive detailing of design criteria, site conditions, design analyses, and structural design will be provided as part of the Verification Documentation. A conceptual description of the proposed platform follows:

The platform will be a single piece, eight leg conventional jacket type platform installed in 430' (131 m) of water. The jacket will support a three-level deckincluding well conductors. Preliminary elevation views of the platform jacket are shown in Figure 4.4. The jacket configuration will be similar to that of conventional jacket platforms. The deck structure will provide space and load carrying capability for two drilling rigs and oil and gas production facilities. Layout arrangements of the drilling and production decks are shown in Figures 4.5, 4.6, 4.7, 4.8, and 4.9

4.5 Platform Installation

Fabrication and installation will follow conventional procedures for such structures. Complete details for the platform will be provided as part of the Verification Documentation pursuant to MMS OCS Order No. 8. Installation of the platform and commissioning of the facilities will require four to six months. Major marine equipment required for installation of the platform will include a derrick barge or ship, the jacket launch barge, cargo barges, tug boats, supply boats, and crewboats.

Generalized procedures applicable to the platform are as follows:

4.5.1 Fabrication

The principal components of the platform; the jacket, piling, and deck modules will be fabricated and assembled in onshore yards. Sites for construction and assembly will be determined when contracts are awarded.

4.5.2 Jacket Tow and Launch

Upon completion of fabrication, the jacket structure will be loaded onto a transportation/launch barge and secured for tow. The jacket will be towed from its fabrication site to the installation area, where it will be launched from its transport barge and floated horizontally in the water.

4.5.3 Jacket Upending

Following launch, the jacket will be towed to its installation site and upended by the flooding of selected leg compartments. Final positioning will be made with the derrick barge and further flooding will set the jacket on the sea floor.

4.5.4 Pile and Conductor Installation

The main piles will be installed through the jacket legs in approximately 100' (30 m) long welded sections. The skirt piles will be installed through pile sleeves

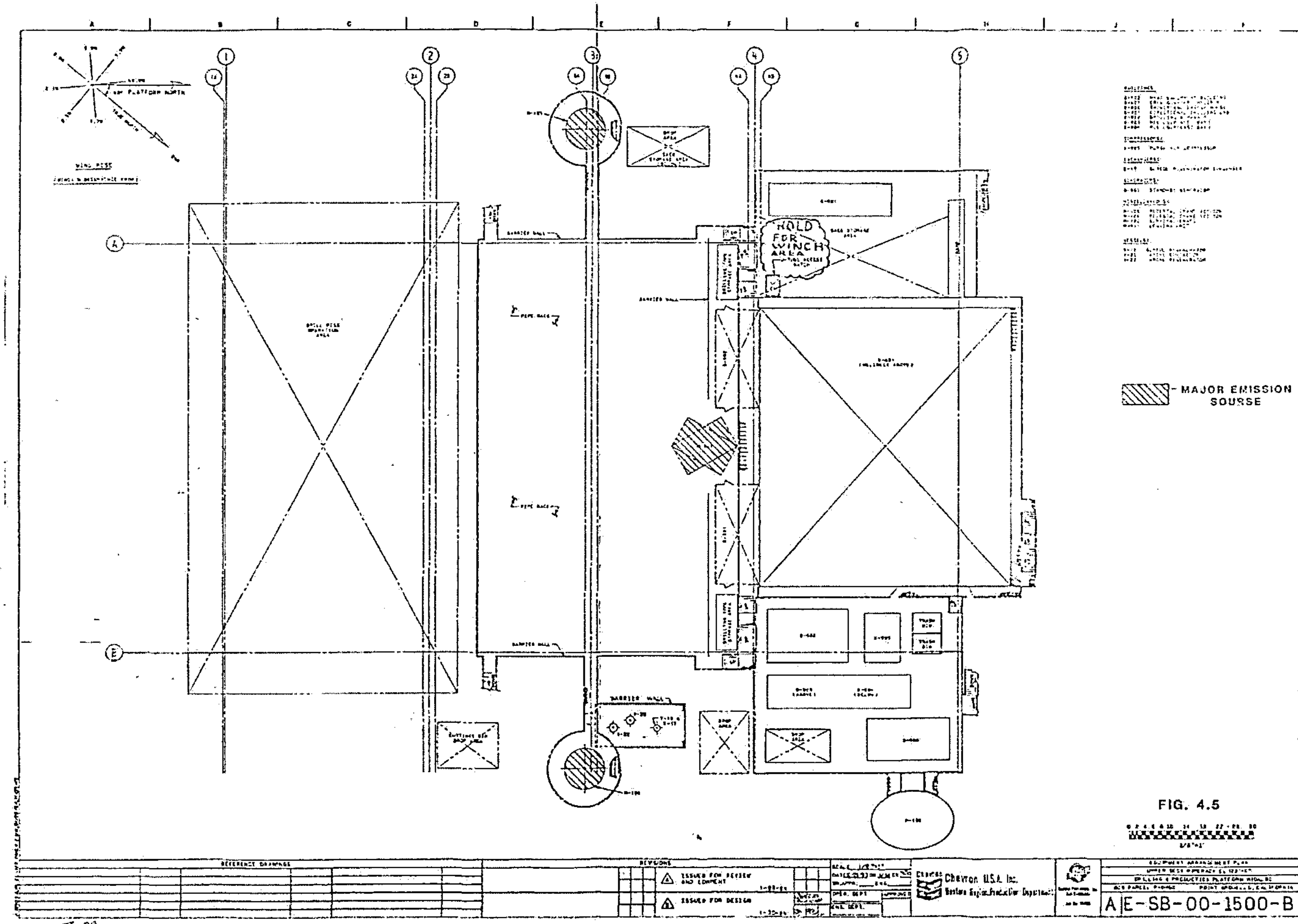
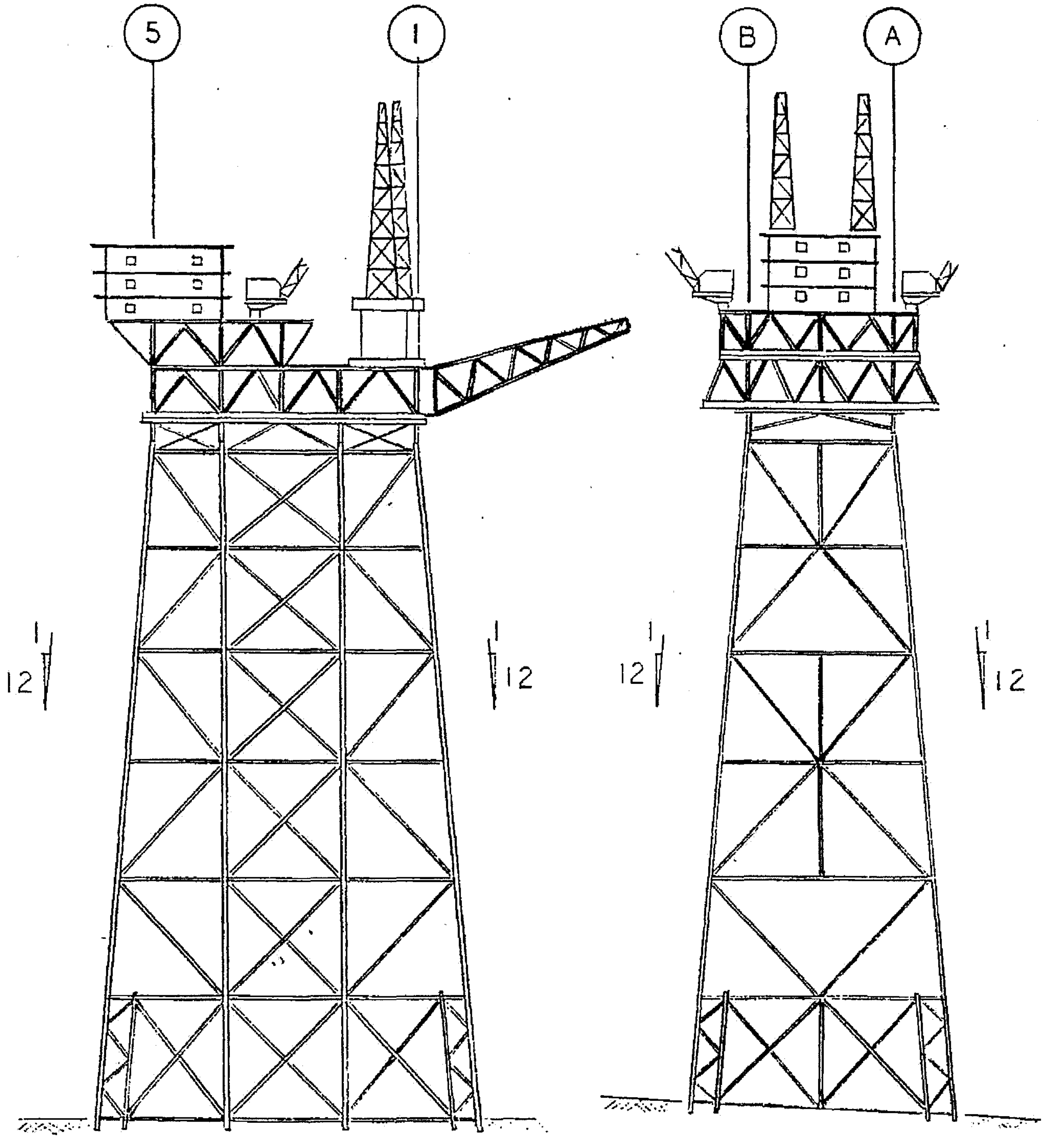

HOLD FOR WINCH AREA
BARRIER WALL
MAJOR EMISSION SOURSE
REFERENCE DRAWINGS
REVISIONS
ISSUED FOR REVIEW AND COMMENT
ISSUED FOR DESIGN
Chevron U.S.A. Inc.
A E-SB-00-1500-B

FIG. 4.5



WEST ELEVATION

NORTH ELEVATION

REVS.	1	2

Chevron U.S.A. Inc. Western Region, Production Department	Bechtel Petroleum, Inc. San Francisco Job No. 16023	SCALE 1:100 DATE 11-16-83 DR RAO CH___ DR. APP___ ENG___
		OPRG. DEPT. ___ APPROVED ENG. DEPT. ___
DRILLING & PRODUCTION PLATFORM HIDALGO OCS LEASE P-0450 POINT ARGUELLO, CALIFORNIA		FIGURE 4.4

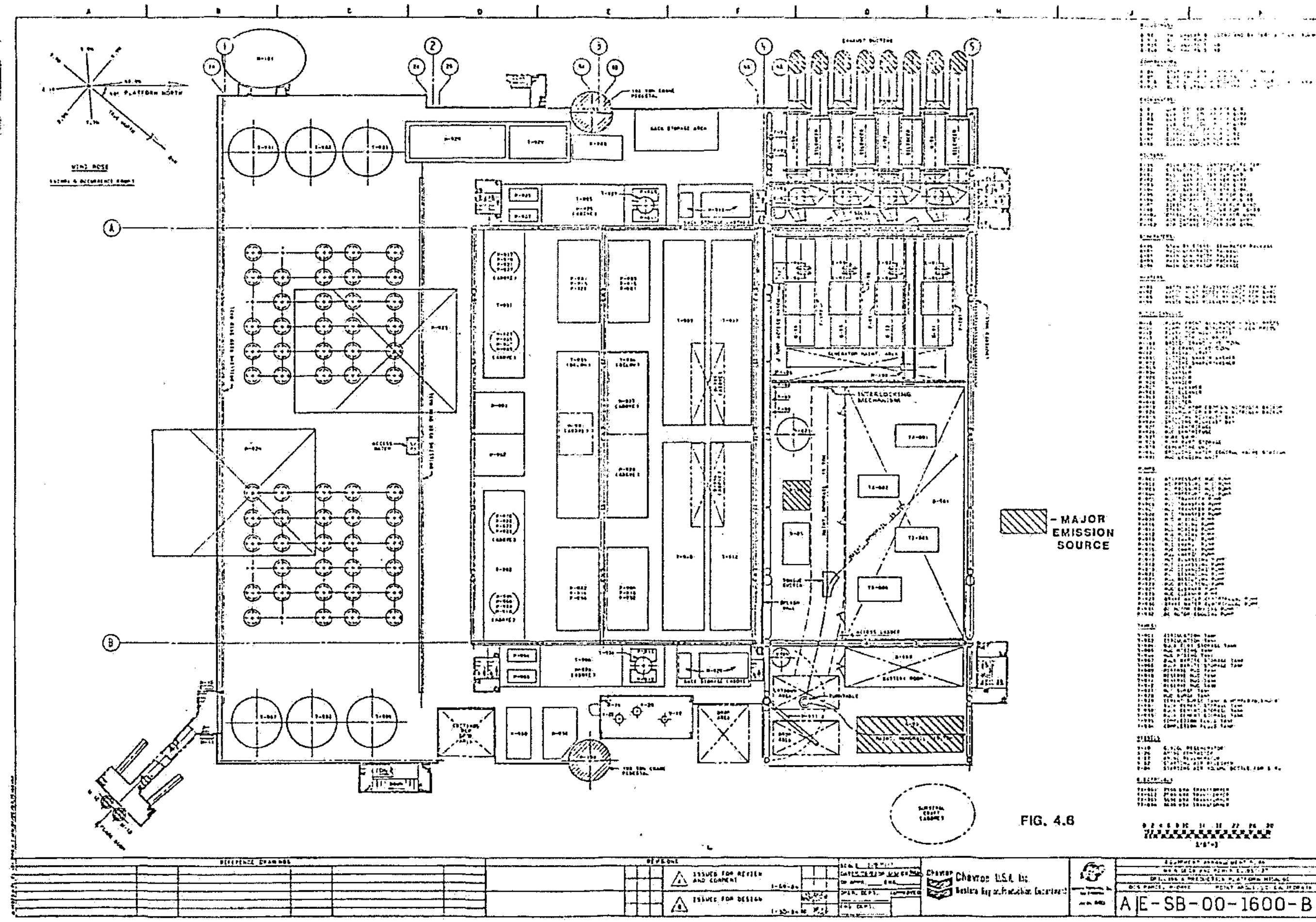

MAJOR EMISSION SOURCE
INTERLOCKING MECHANISM
Chevron U.S.A. Inc.
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FIG. 4.6

RECORD PRINT

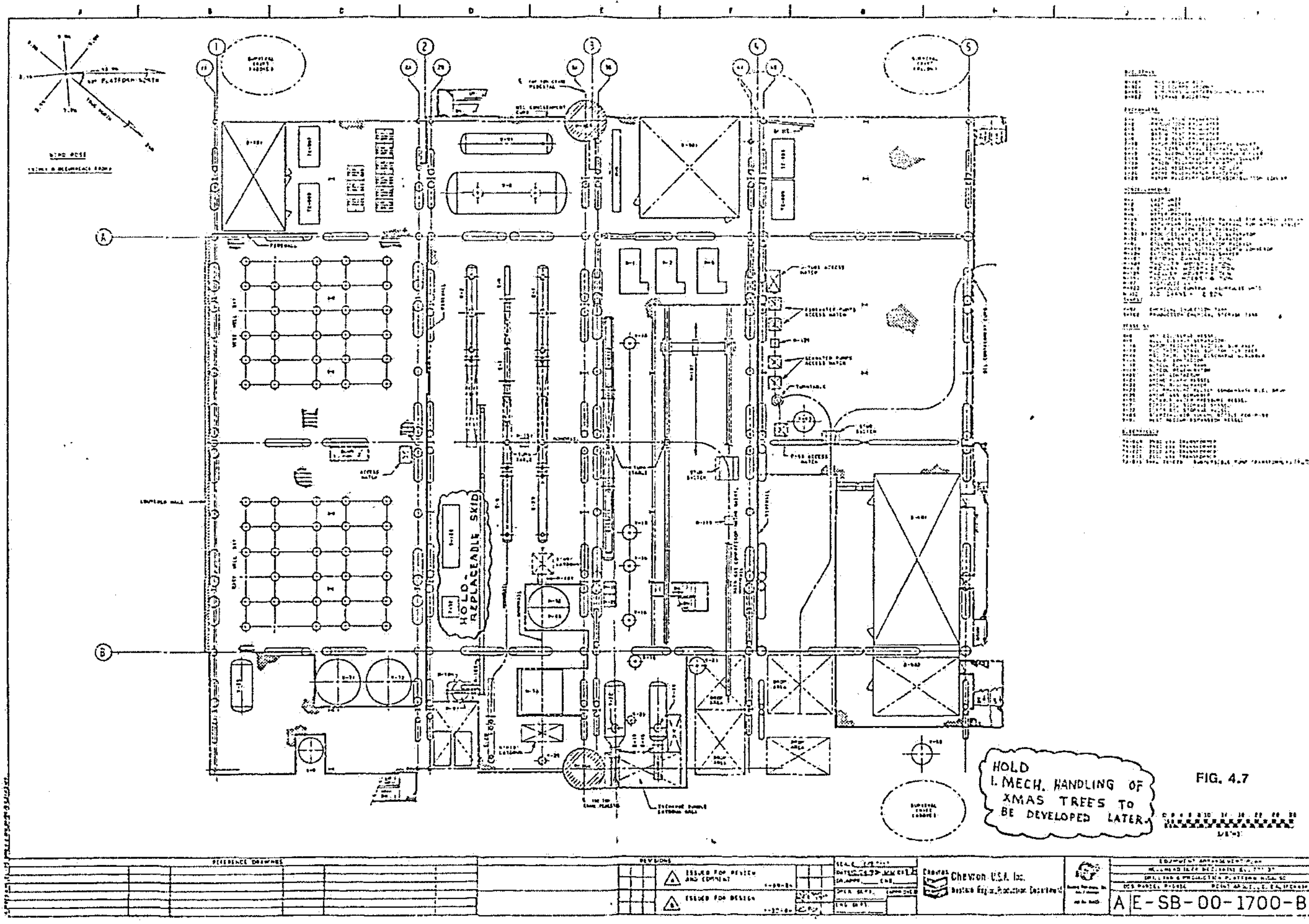
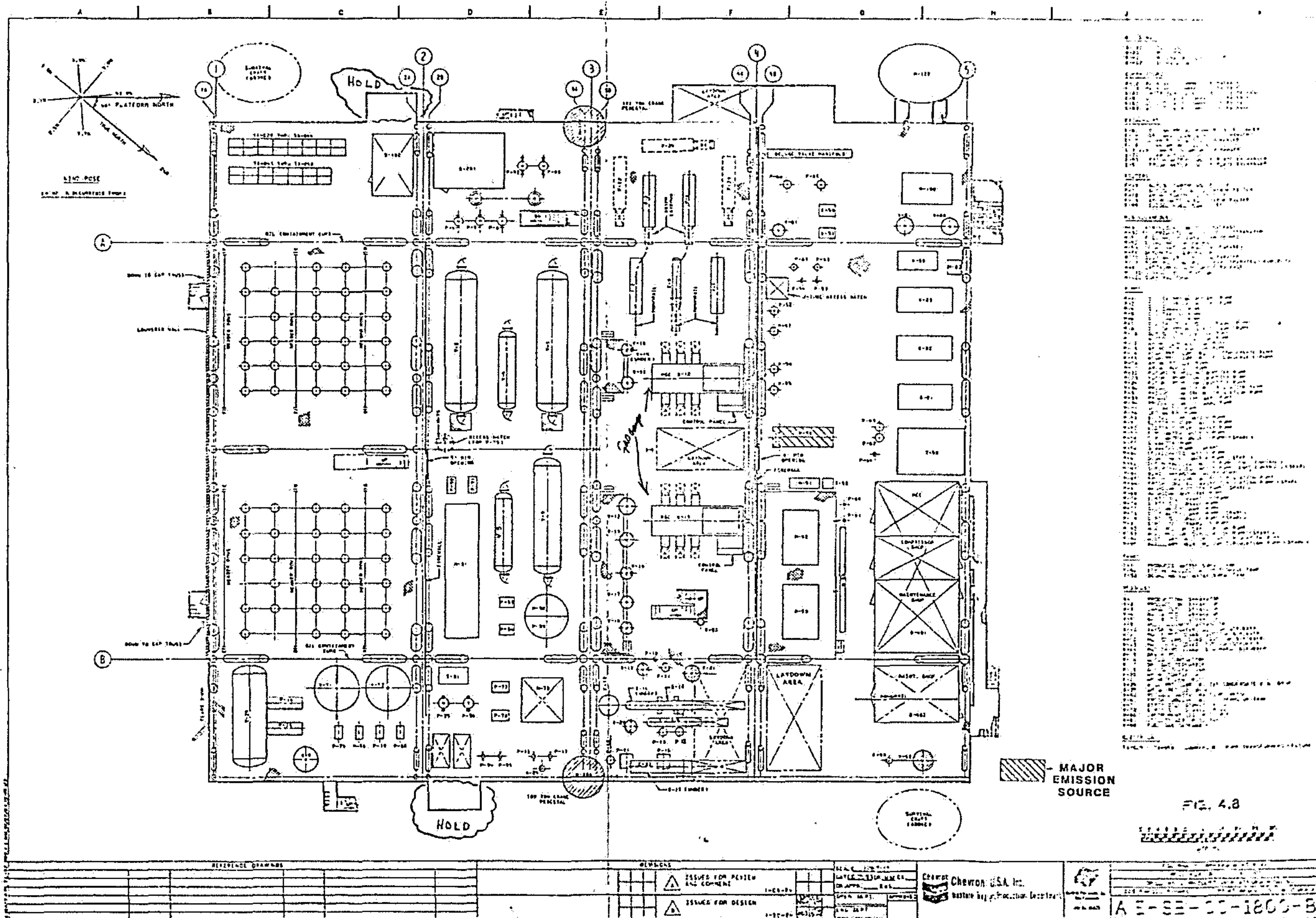


FIG. 4.7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HOLD
PLATFORM NORTH
LAYDOWN AREA
MAJOR EMISSION SOURCE
Chevron U.S.A. Inc.
ISSUED FOR REVIEW AND COMMENT
ISSUED FOR DESIGN
A-3-SE-00-1800-B

FIG. 4.8

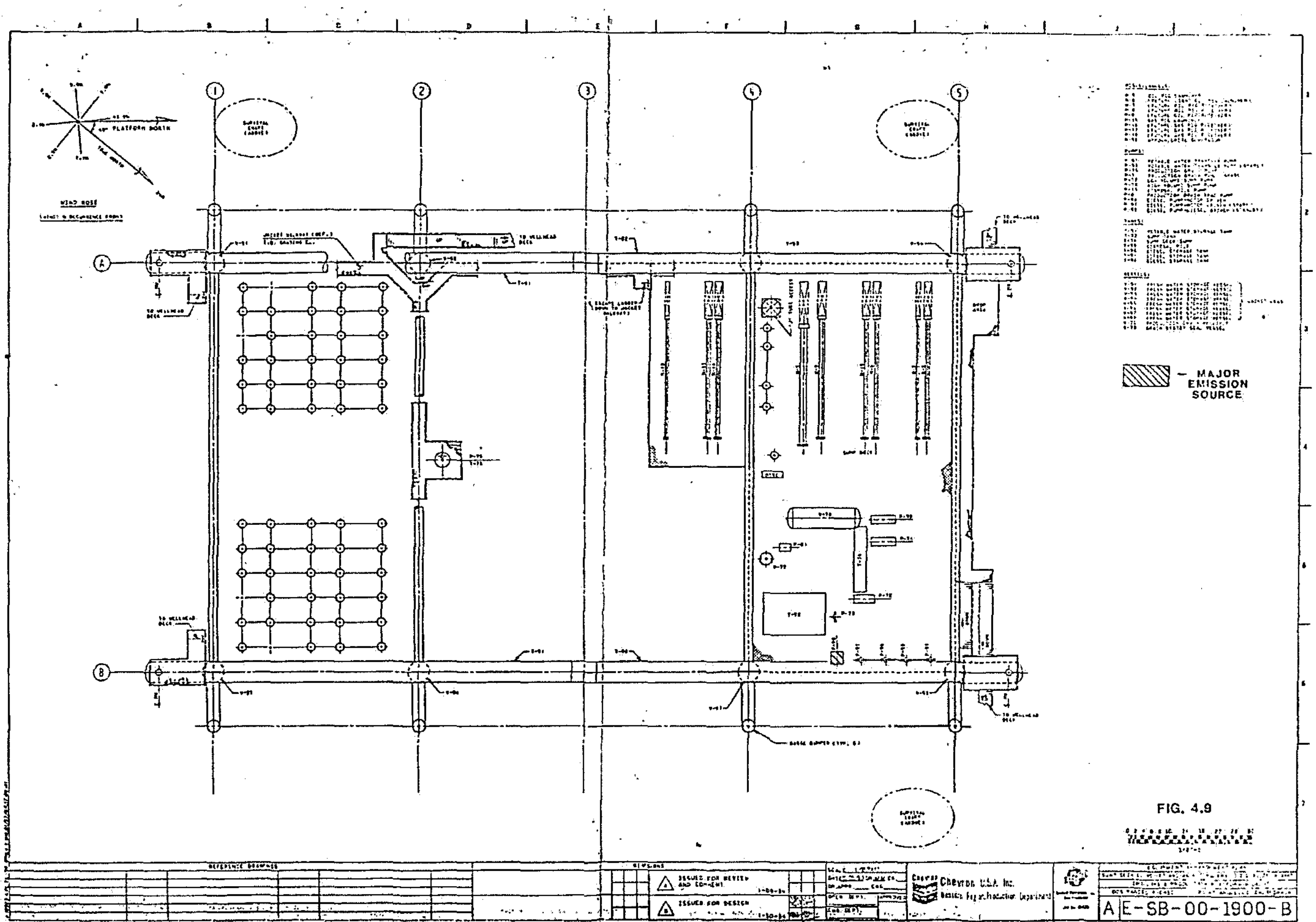
PLATFORM NORTH
WIND ROSE
MAJOR EMISSION SOURCE
REFERENCE DRAWINGS
REVISIONS
ISSUED FOR REVIEW AND COMMENT
ISSUED FOR DESIGN
Chevron U.S.A. Inc.
A E-SB-00-1900-B

FIG. 4.9

and driven to their design penetration with the aid of a retrievable follower. Design penetration is estimated to be 300' (90 m) below the mudline. Both main and skirt piles will be grouted to the jacket structure. The well conductors will be installed with the drilling rig at the time each well is spudded.

4.5.5 Deck Setting

Jacket captruss units will be set and welded to the jacket for support of the deck structure. The decks, composed of four to six modules with production equipment preinstalled, will be transported by barge from the assembly site to the offshore installation site. The modules will be lifted by the derrick barge, set on the jacket captruss and welded into place. The flare boom and other miscellaneous components will then be attached to the deck structure.

4.5.6 Hookup and Commissioning

Following setting of deck modules, offshore crews will make structural, piping, electrical and instrumentation interconnections between modules, and will test and commission all systems.

4.6 Platform Removal

When the reservoir from which Platform Hidalgo produces is depleted, the platform will be removed in accordance with the applicable MMS regulations. The structure will be disposed of or used as an artificial reef as dictated by the applicable environmental engineering and economic restraints at the time. Ultimate disposition of the platform (i.e. salvage for scrap, salvage for placement as an artificial reef, etc.) will depend on various factors which must be addressed at that time.

4.7 References

4.7.1 Woodward-Clyde Consultants (1982). Geochemical Investigation of 6 Foundation Borings, Offshore California Interpretative Report. Report prepared for McClelland, Inc. 12 p.

4.7.2 Cardone, V. J. (1982). Final Report Wave Hindcast of Point Conception Area NW Type Storms, Ocean Weather Inc.

4.7.3 Intersea Research Corp. (1981). Wave, Current, And Wind Measurement Program During Exploratory Drilling Operation In The Western Santa Barbara Channel, Station A. Report prepared for Chevorn USA Inc. (Rept 13381-1). 71p.

SECTION 5

DRILLING FACILITIES

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DRILLING FACILITIES

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SECTION 5

DRILLING FACILITIES

5.1 Introduction

Platform Hidalgo will have slots for a maximum of 56 wells. Two electric drilling rigs and associated crews and services will be contracted to drill the 48 wells presently planned. Development drilling is planned to span approximately five years, and require 2.5 months per well. Approximately 9 wells will be drilled each year. The additional eight slots will be utilized in later years to develop possible new hydrocarbon reservoirs discovered during the development drilling stages and as replacement wells for those development wells which are no longer economical or have to be abandoned for mechanical reasons. Two cantilever type drilling rigs will be used to drill the wells.

All operations will be conducted with safety to personnel and the environment as the primary consideration. Drilling operations, pollution prevention systems, and safety systems will be in accordance with MMS OCS Orders No. 2 and No. 5, EPA NPDES permit conditions, and API Recommended Practices.

5.2 Drilling Equipment

All drilling equipment and services will be handled on a contract basis. Preliminary drilling equipment layouts are shown on Figure 4.4. Major drilling equipment will include:

5.2.1 Rig Components

Two land-type cantilever masts, 152' (46 m) high with 20,000' (6000 m) drilling and 1,000,000 lb. hook-load capacities, will be required. The masts will be designed in accordance with API Standard 4D for freestanding masts.

The drawworks will be electrically powered (rated at 2000 HP) and be complete with rotary table drive. The hook, traveling block, and crown block will be of 500 ton load rated capacity to match the mast. The drill string will be 5" (12.7 cm) drill pipe.

5.2.2 Substructures

The substructure of each rig will be capable of supporting the derrick and setback loads. It will be designed to provide unobstructed clearance for the blowout prevention equipment.

Each substructure will be supported on a skidbase, resting on elevated skidbeams. The skidbase will be equipped with a hydraulic jacking system to allow transition along the direction of the well rows. The substructure will also be equipped with hydraulic jacks to allow lateral skidding over the desired well. Mechanical restraint equipment will be provided to prevent substructure movement once positioned over the desired location.

5.2.3 Drilling Mud System

A separate mud system will be provided for each drilling rig. Each mud system will be equipped with two mud pumps (approximately 1600 HP each), and approximately 2300 bbls. of active and reserve mud tank capacity. The system will include a mud mixing tank, trip tank and a sand trap tank below the shale shaker.

Return mud will be treated with separate high speed shale shakers, mud cleaner, desilters, and degassers for each rig. The shale shaker units will be equipped with a cuttings washing system to clean oily cuttings before ocean disposal through the disposal caisson approximately 150' (46) m below the ocean surface. Muds and cuttings discharged into the ocean, therefore, will be oil-free. Cuttings that cannot be cleaned by washing will be diverted to a waste cuttings holding tank, to be hauled ashore for disposal in a government approved disposal site.

Mud volumes will be closely monitored using a pit volume totalizer system, an incremental flowrate indicator, and a precision fill-up measurement system. These warning systems will have visual and audible alarm signals at the driller's console. A common bulk material handling system will be provided with 3000 cu. ft. (85 cu. m.) storage capacity for clay and 4000 cu. ft. (113 cu. m.) for barite materials. Sacks of mud additives (chemicals, lost circulation material, etc.), needed on the platform will be stored on pallets.

5.2.4 Cementing Unit

One electric powered dual cementing unit and three 2000 cu. ft. (56 cu. m.) bulk storage tanks will be provided for well cementing operations.

5.2.5 Power Generation

Rig power will be provided by a submarine power cable that will connect Platform Hidalgo to Platform Hermosa. This cable will supply part of the power requirements for the platform and producing facilities. It is anticipated that additional electrical power will be generated by four 2500 KW fuel-gas-fired turbine generators for total platform requirements. These turbines will be equipped with water injection to reduce NO_x emissions. However, the maximum number of turbines used at one time will be three, with one available on standby.

Each rig will utilize a silicon controlled rectifier (SCR) system to convert alternating current to the direct current required by the drawworks, rotary table, mud pumps, and cementing unit motors. Transformers will convert the generated AC power to lower voltages, as necessary, for the AC equipment on the rig.

A separate 1250 KW emergency diesel generator will also be used to supply standby power for the drilling rigs. The BOP accumulator and lighting will be tied into a 850 KW emergency diesel generator, as part of the platform standby system.

5.2.6 General Layout

The drilling mud system equipment, cementing unit and completion tank will be located on the upper deck. Above the mud package will be the pipe rack. Outboard of the pipe rack, on each side of the platform, will be the platform cranes. The masts, subbases, drawworks, and associated equipment will be installed on the skidbase at the upper deck level. Contractors living quarters and offices will be located in a central quarters building.

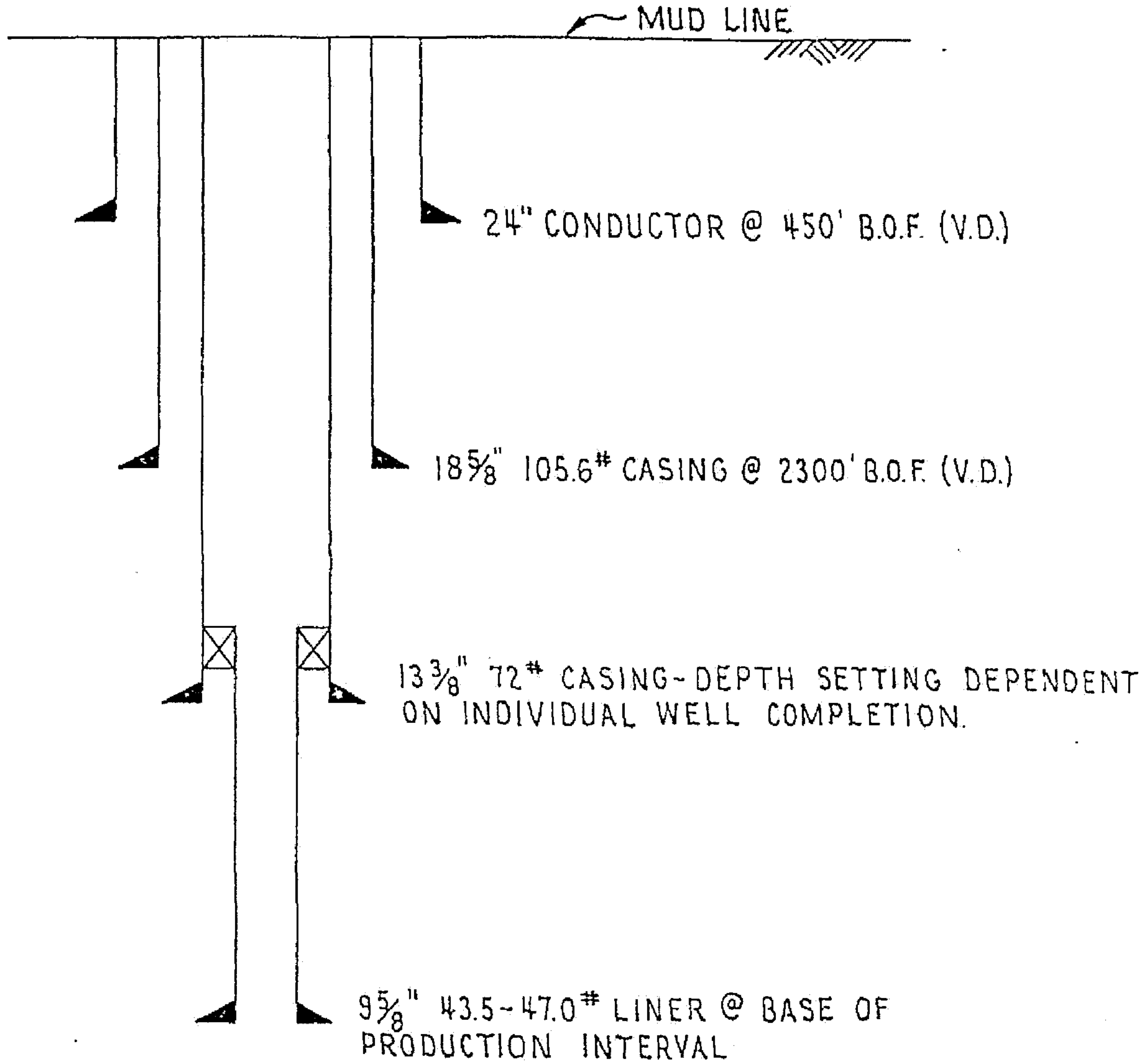
5.3. Drilling Operations

5.3.1 Casing Program

Depending on individual well completions, two different casing programs are anticipated. When wells are completed with 4" production tubing, the planned casing program consists of 24" conductor, 18-5/8" intermediate casing, and 13-3/8" production casing. A 9-5/8" liner will be hung below the 13-3/8" casing at the top of the production interval, as shown in Figure 5.1. For wells completed with 2-7/8" production tubing, the planned casing program consists of 24" conductor, 13-3/8" intermediate casing and 9-5/8" production casing. A 7" liner will be hung below the 9-5/8" casing at the top of the production interval, as shown in Figure 5.2.

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

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



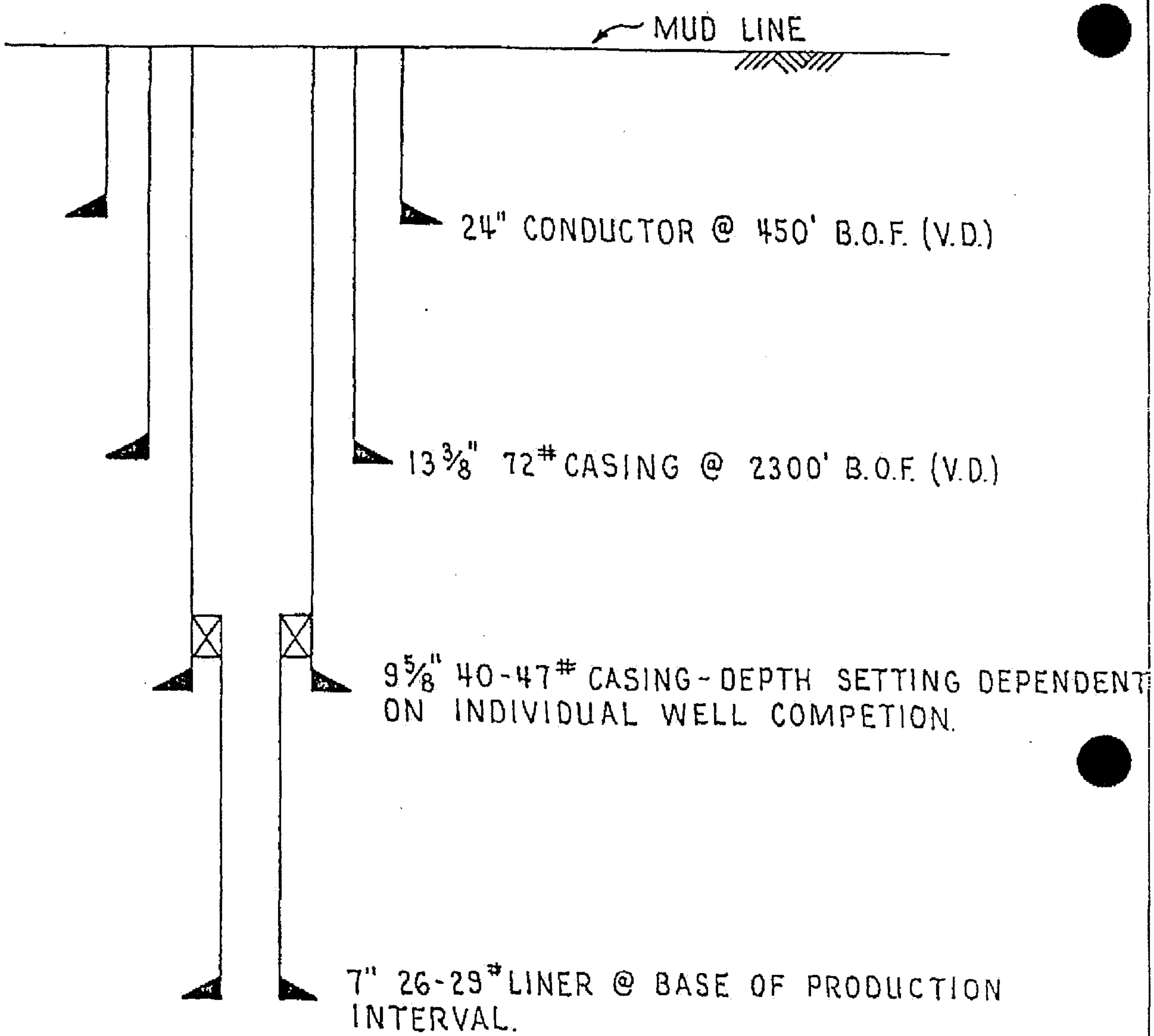
NOTE: B.O.F. (V.D.) BELOW OCEAN FLOOR (VERTICAL DEPTH)

PLATFORM HIDALGO
PROPOSED CASING PROGRAM
TYPICAL WELL SKETCH
4" PRODUCTION TUBING COMPLETION

NO SCALE

FIGURE 5.1

A-SB-46?



NOTE: B.O.F. (V.D.) BELOW OCEAN FLOOR (VERTICAL DEPTH)

PLATFORM HIDALGO
PROPOSED CASING PROGRAM
TYPICAL WELL SKETCH
2 7/8" PRODUCTION TUBING COMPLETION

NO SCALE

FIGURE 5.2

A-SB-4630

5.3.2. Well Completions

Cemented and perforated liners will be used where it is necessary to produce selectively in locations subject to gas or water intrusion. When gas or water intrusion is not anticipated, slotted casing may be used. The completion tubing string will be designed for natural flow but will allow for conversion to electric downhole submersible pumps.

5.3.3 Wellhead Equipment

All wellhead components will meet API specifications. The working pressure of each wellhead section will exceed the maximum anticipated pressure imposed on that section. The wellhead will provide fluid circulation passage between each set of casing and each succeeding smaller casing or tubing.

5.3.4 Blowout Prevention Equipment (BOPE)

Each rig will have separate blowout prevention equipment (BOPE) systems.

Blowout prevention systems will be operated and tested in accordance with MMS OCS Order No. 2 and/or field rules. These systems will be hydraulically operated with control stations at the driller's console on the rig floor, at the accumulator unit, and at a remote platform location. Each rig will have its own accumulator unit.

Since two different completions are anticipated, two different BOP stacks are proposed (see Figure 5.3 for BOP Stack and Hydraulic Controls Schematic).

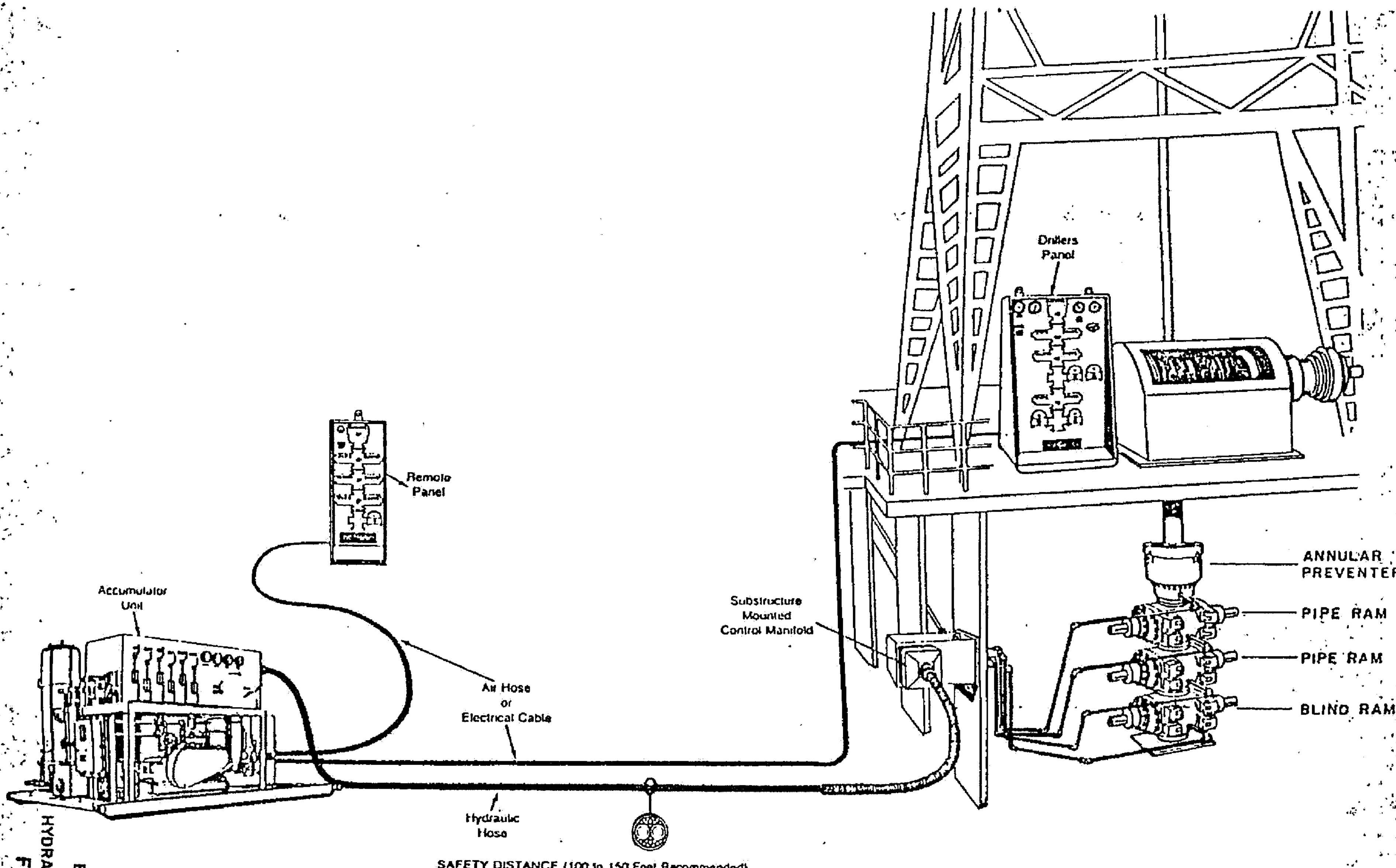
For the casing program as shown on Figure 5.1, the low pressure system will consist of a 29-1/2" 500 psi annular-type blowout preventer with diverter system (see Figure 5.4 for Diverter System Schematic) installed for drilling below the 24" conductor pipe. After 18-5/8" surface casing is landed and cemented, the low pressure BOPE stack will be removed. A 3000 psi 20" Class III BOPE stack will then be nippled up to the surface casing head with a riser. The BOP equipment will include an annular preventer, one pipe ram, and a blind ram. After the above BOPE and the 13-3/8" casing is landed and cemented, the Class III BOPE stack will be removed. A 5000 psi 13-5/8" Class IV BOPE stack will then be nippled up to the 13-3/8" casing head with a riser. The BOPE will include an annular preventer, two pipe rams and a blind ram. For the casing program shown on Figure 5.2, the low pressure system will be the same as previously described. After the 13-3/8" casing is landed and cemented, the low pressure BOPE stack will be removed. A 5000 psi 13-5/8" Class IV BOPE stack will then be nippled up on the surface casing head with a riser. The BOPE will include an annular preventer, two pipe rams and a blind ram. All the above BOPE will be actuated by pressure provided by a hydraulic accumulator unit located at a remote platform location.

Below the BOPE a drilling spool will be provided with side outlets for separate choke and kill lines. The kill line will have two valves located adjacent to the BOPE, a master and a control valve. The choke line will be in accordance with "API Recommended Practice for Blowout-Prevention Equipment Systems".

Chevron is currently working with various manufacturers of BOP equipment to determine the feasibility of fabricating an 18-3/4" bore 5000 psi Class IV BOP stack. Successful fabrication of such a stack would eliminate the need for the two stack system as now proposed.

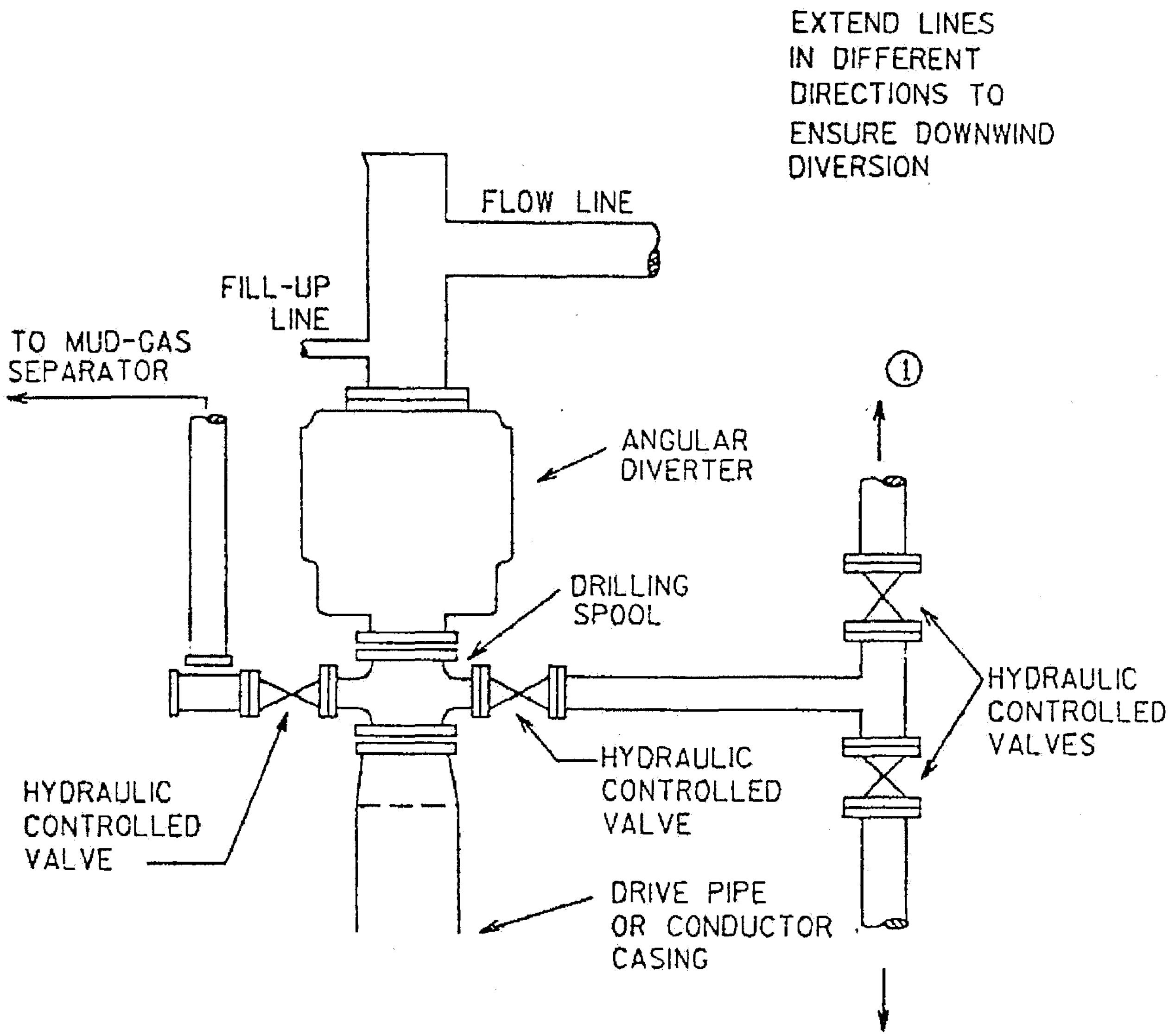
5.3.5 Typical Drilling Procedure

Typical drilling programs for the different development wells are given here. Each well will be drilled using these general procedures



BOP STACK
AND
HYDRAULIC CONTROLS
FIGURE 5.3

DIVERTER-PREVENTER HOOKUP



DIVERTER-PREVENTER HOOKUP
FIGURE 5.4
A-SB-4681

DATE: 3-7-83

supplemented as necessary for the particular well program and anticipated drilling conditions.

A typical Monterey well with 4" tubing completions will follow this general procedure:

1. Move and rig-up. Lower 24" conductor pipe to ocean floor.

2. Drill 22" hole to 450' B.O.F. (V.D.). Under-ream hole to 30" and cement 24" conductor pipe.

3. Install diverter and low pressure BOPE stack on 24" conductor and test.

4. Directionally drill 17" hole to 2300' B.O.F. (V.D.). Under-ream hole to 22".

5. Run and cement 18-5/8" casing at 2300' B.O.F. (V.D.).

6. Install Class III BOPE stack and test.

7. Directionally drill 17" hole to the proper depth for setting 13-3/8" casing. Run logs.

8. Run and cement 13-3/8" casing. Install Class IV BOPE stack and test.

9. Drill 12¼" hole to proper depth below 13-3/8" casing. Run logs.

10. Run and cement 9-5/8" liner.

11. Run logs.

12. Perforate the production interval.

13. Install completion tubing.

14. Remove BOPE stack and install Christmas tree.

A typical Monterey well with 2-7/8" tubing completions will follow this general procedure:

1. Move and rig-up. Lower 24" conductor pipe to ocean floor.

2. Drill 22" hole to 450' B.O.F. (V.D.). Under-ream hole to 30" and cement 24" conductor pipe.

3. Install diverter and low pressure BOPE stack on 24" conductor and test.

4. Directionally drill 17" hole to 2300' B.O.F. (V.D.).

5. Run and cement 13-3/8" casing at 2300' B.O.F. (V.D.).

6. Install Class IV BOPE stack and test.

7. Directionally drill 12¼" hole to the proper depth. Run logs.

8. Run and cement 9-5/8" casing.

9. Directionally drill 8½" or 8-3/4" hole to proper depth. Run logs.

10. Run and cement 7" liner.

11. Run logs.

12. Perforate the production interval.

13. Run completion tubing.

14. Remove BOPE stack and install Christmas tree.

5.3.6 Pollution Prevention

All runoff from drilling equipment will go to the deck drainage system. Oil will be removed to levels specified in NPDES permit conditions before the runoff is discharged to the ocean through the disposal caisson. Collection of any runoff will be facilitated by the inclusion of 6" (15 cm) high containment curbs extending around the perimeter of the platform on all decks.

A cleaning and handling system will be installed for each drilling rig below the shale shakers. Cuttings produced by drilling operations will be washed free of oil by this equipment prior to their disposal into the ocean through the disposal caisson. Oily cuttings that cannot be washed free of oil will be conveyed to metal bins for storage until they can be taken to shore for disposal in a government approved disposal site. Drilling muds discharged into the ocean through the disposal caisson will be oil-free. If the drilling mud has become contaminated with oil from a subsurface formation it will not be discharged into the ocean, but will be transported ashore and disposed of at an approved disposal site.

In the unlikely event that an overboard spill occurs, the offshore facilities will be serviced by an oil spill containment/cleanup vessel dedicated to the Pt. Arguello Field platforms. Oil spill containment/cleanup equipment will be similar to that carried by the vessel Mr. Clean II of the Clean Seas Cooperative. For a detailed discussion of the proposed actions and oil spill equipment in case of an oil spill occurrence, please refer to the Oil Spill and Emergency Contingency Plan for Platform Hidalgo (Reference 5.4.1).

5.3.7 Safety Features

The safety system includes the following. See Section 6.4.4 for additional information.

5.3.7.1 Fire Suppression

a. A saltwater pumping system.

b. 1-1/4" (3.2 cm) hard rubber hose reels to provide water and foam coverage at any point on the platform with two hoses.

c. Zone-controlled dry-pipe deluge sprinkler systems capable of wetting critical surfaces with a water density of not less than 0.25 gpm gallons per minute (gpm) per square foot.

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

e. Dry chemical, CO_2, and Halon fire extinguishers.

f. Halon flooding protection system.

g. Standpipe connections at the boat landings for fireboat use.

h. Fire hydrant riser and connections at stair landings.

5.3.7.2 Fire Detection and Alarm

a. Ultraviolet flame detectors.

b. Smoke detectors

c. Combustible gas detectors.

d. Thermal rate-of-rise detectors located in buildings.

e. Fusible plugs in the process and drilling areas that alert operators to a fire (via an alarm), initiate shutdown of affected equipment, and activate deluge sprinkler systems and firewater pumps.

f. A Modicon programmable controller will be used for automatic control of the platform safety systems, annunciation of alarms, and shutdowns.

5.3.7.3 H_2S Detection and Alarm

Toxic gas detection will be provided in all areas where sour gas (H_2S) is anticipated. There will be H_2S sensors with alarms on the wellhead deck, main deck, upper deck, and in the ventilation system which supplies air to enclosed areas.

5.3.7.4 H_2S Contingency Plan

Appendix 7 of the Oil Spill and Emergency Contingency Plan for Platform Hidalgo (Reference 5.4.1) contains a detailed emergency plan to be followed when encountering formations that contain hydrogen sulfide while drilling wells.

5.3.7.5 Critical Operations and Curtailment Plan

In compliance with MMS OCS Order No. 2, a Critical Operations and Curtailment Plan has been submitted as Appendix 6 of the Oil Spill and Emergency Contingency Plan for Platform Hidalgo. This plan describes the critical operations that are likely to be conducted and in what circumstances or conditions the critical operations are to be curtailed.

5.3.7.6 Escape and Lifesaving Equipment

The escape system provided on Platform Hidalgo will include life jackets and three survival capsules accommodating 50 persons each. From time of arrival of a helicopter at Platform Hidalgo , injured personnel can be delivered to Goleta Valley Hospital in approximately 25 minutes.

5.3.7.7 Safety Control Systems

Safety, anti-pollution, and control systems will be installed on all piping headers, machinery, and vessels pursuant to OCS Order No. 5. The system will be a combination of electric and pneumatic controls. All automatic control valves will be designed to be fail-safe. Control devices will include the following:

1. High-low pressure alarm and shutdown sensors.

2. High-low liquid level alarm and shutdown sensors.

3. Flow safety valves.

4. Pressure safety valves.

5. Vibration sensors.

6. High-low temperature alarm and shutdown sensors.

All of the above items will be designed and installed to facilitate periodic testing. These devices will be tested for accurate operation on a schedule to be approved by the MMS.

In addition, all of these safety devices will be interconnected through a central control panel. When a malfunction occurs, an alarm will be sounded; and if the condition is not immediately corrected, the platform will shut down. Shut-downs will be accomplished by automatically closing the surface controlled subsurface safety valves and the surface controlled surface safety valves. Produced fluid will continue to move off the platform through the pipeline until the equipment is automatically shut-down by either low levels or low pressure. If the malfunction is pipeline related, liquids would not be pumped off the platform.

5.3.8 Crew and Supply Transport

Drilling crews will work regular 12-hour shifts, and will be quartered on the platform. Helicopters (10 to 30 passenger) will be used to transport drilling and production crew members to the platform from the Santa Barbara airport. Day drilling shifts are expected to contain 18 persons and night shifts 17 persons. Supply boats will transport supplies as required. Weather should have little effect on helicopter and supply boat operations, but emergency facilities and supplies will be provided at the platform to allow at least one week of normal operations if supply delivery is interrupted. A standby crew boat will be retained to transport crews in the event that the weather is unacceptable for helicopter transport. Personnel will be able to enter and leave the platform at a small boat landing on the platform. Approximately seven days out of the year, weather conditions prevent helicopter travel to the Pt. Conception area (Reference 5.4.2).

5.4 References

5.4.1 Chevron U.S.A. Inc. (1983). Oil Spill and Emergency Contingency Plan for Platform Hidalgo OCS Lease P 0450.

5.4.2 Petroleum Helicopters, 1984. Goleta, California. Personal Communication, April 18, 1984.

SECTION 6

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SECTION 6

PLATFORM FACILITIES

6.1 Introduction

This section describes all production equipment and related facilities to be installed on the platform and is divided into the following four parts: (1) Production Process Facilities, (2) Utility Systems, (3) Support Facilities, and (4) Environmental Impact Mitigation Measures.

The platform will contain production facilities for the initial separation of the produced oil, gas, and water. An oil emulsion will be sent to onshore facilities for crude stabilization and water removal. Gas will be dehydrated and will also be sent to shore. Gas and oil will be transported in separate pipelines to Platform Hermosa for trans-shipment to shore through an industry pipeline system. Equipment, controls, monitors, safety devices, etc., will be installed in accordance with applicable OCS Orders and industry standards.

All initial production will be from the Monterey Formation. Drill stem production tests made in this area indicate that the reservoir consists of zones with varying hydrocarbon properties (GOR and gravity). All tests indicated the presence of sulfur with average level of 2 percent by weight in the oil. The average gravity is 26° API.

Primary gas and emulsion separation occurs on the platform with the bulk of the gas going to an onshore gas treating plant for liquids removal and sweetening. A small portion of the gas will be utilized on the platform as fuel for the power generation equipment. H_2S will be removed from fuel gas before use with an amine unit. Anticipated average H_2S concentration in associated gas is approximately 5000 ppm. Separated produced water, and deck drainage, and other water discharges will be treated and cleaned in compliance with EPA NPDES permit conditions before discharge into the ocean.

Utility systems and support facilities will be provided to allow the platform to be as self-reliant as possible. Provisions for power supply, potable water production, standby power, safety systems, etc., have been made to allow operations to continue safely even though platform resupply may be interrupted for several days.

6.2 Production Facilities

6.2.1 Design Criteria

Reservoir data utilized in the design of platform facilities have been obtained from wells drilled on OCS Lease P 0450.

6.2.2 General Layout

As shown on Figures 4.4 to 4.8, process equipment has been located to minimize the length of interconnecting piping and to segregate this equipment from personnel-occupied areas. Fire walls and doors on the well deck effectively segregate the well bay from production equipment and the production equipment from the utility and safety equipment.

6.2.3 Wellheads and Flow Manifolds

Fifty-six well slots will be provided; forty-eight producing wells are presently planned, with eight spare slots provided for future reservoir evaluation drilling. The wells will be arranged in five rows, with short flowlines connecting each well to a manifold system.

The manifold system will allow production to be switched between pool and test separators. Lines for casing gas recovery, hydraulic and pneumatic controls, etc., will also be provided. All wells will be equipped with surface and subsurface safety valves in accordance with MMS OCS Order No. 5.

6.2.4 Artificial Lift

It is anticipated that artificial lift will eventually be required for all wells. It may be necessary for producing some weaker wells immediately upon completion. Therefore, provisions for submersible electric pumps will be provided initially.

6.2.5 Production Separation

The crude oil to be produced will be of relatively low API gravity and relatively high viscosity. It is planned to produce into three-phase separators for primary oil/gas/water separation. Wells are to be manifolded in such a manner as to be able to isolate wells for individual testing and gauging and to place the remaining wells into the "pool" three phase separators. The production stream to the separators is to be heated to 150°F to assist in water and gas removal. An oil emulsion will then flow to the production surge vessel. The production surge vessel will operate at about 3.0 psig to further assist in degassing the emulsion.

Three test separators and heaters will be provided. One of the three separators will be sized to handle high volume wells. These separators will be equipped for three phase separation and metering. Each well will be tested at least once a month in order to facilitate reservoir evaluation.

A well cleanup separator will be provided for the initial unloading of wells to remove mud and water until the well is flowing sufficiently to be turned into the normal production separators. See Figure 6.1 for a plan of the crude oil separation facilities.

6.2.6 Oil Cleaning

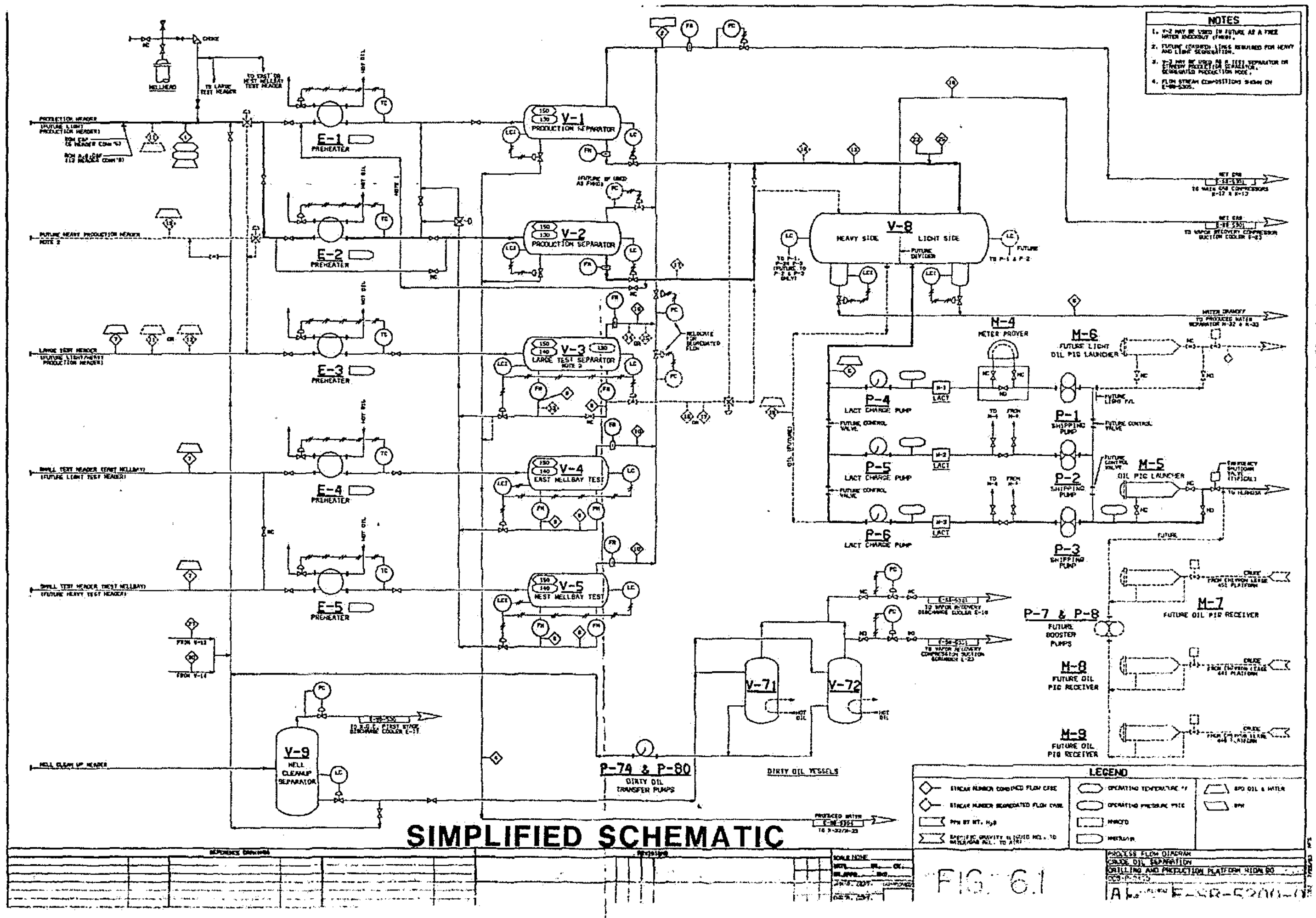
All crude stabilization and final dewatering will be provided for at the onshore treating facility, described in Section VIII.

6.2.7 Oil Shipping

Emulsion collected in the production surge vessel will be boosted to a pressure of 100 psig to 200 psig to maintain bubble point depression. Metering of the emulsion and gas is discussed in Section 6.2.9. Since the oil pipeline to Hermosa has capacity for additional platforms, the shipping pump's discharge pressure will vary depending on the amount of oil tendered to the line and the temperature. The design discharge pressure for the pumps is not expected to exceed ANSI 600 design pressure (1480 psig at 100°F).

6.2.8 Gas Processing/Compression

Produced gas from the three-phase production and test separators will be compressed to pipeline shipping pressure by electric motor-driven reciprocating compressors. Provisions will be made to recover low pressure gas such as that available from the casing annulus, production surge vessel and blanketing gas from utility tanks and vessels. Since the gas pipeline to Platform Hermosa has capacity for additional platforms, the compressor discharge pressure will vary with throughput. However, the maximum compressor discharge is not expected to exceed



SIMPLIFIED SCHEMATIC

FIG. 6.1

ANSI 600 design pressure (1480 psig at 100°F).

Each stage of compression will be equipped with suction scrubbers, discharge coolers, and various unloaders and clearance pockets to allow for handling of varying gas production rates. Dehydration facilities will be provided on the platform to avoid hydrate formation and corrosion in the pipeline. Conservative design capacity will be provided to minimize the need for flaring. See Figure 6.2 for a plan of the gas compression facilities.

6.2.9 Oil and Gas Metering

All oil and gas leaving the platform will be metered. Oil, with water that has not been removed in a three phase separator, will leave the platform as an emulsion. This will require measurement of volume and quality with the required accuracy and repeatability to allocate the total dry oil from the treating plant (onshore) back to each platform. Custody transfer will be at the platform or at the onshore treating plant. The net oil will be measured by the oil sales meter located at the downstream end of the onshore treating plant. Oil sales will be allocated based on procedures detailed in the transportation system tariff.

The platform emulsion will be metered by double case positive displacement type meters equipped with a mechanical prover. In order to achieve the best measurement accuracy, there will be no water existing as a separate phase. This is accomplished by the installation of one or more inline static mixers. This mixer assures uniform distribution of water and oil in an emulsion.

To assist in the allocation of commingled platform oil production, each emulsion meter system will have a proportional-to-flow composite sampling device, with the sampling point immediately upstream of the meters. The sample accumulated in the storage container will be representative of all the crude oil delivered to the gathering system from the platform and will be the basis of the gravity and basic sediment and water (BS&W) measurements necessary to allocate treated oil back to the appropriate platform. For details of the proposed metering plans, please refer to the Point Arguello Field, Development and Production Plan, Appendix A-1, Chevron USA Inc., December 1982 (Reference 6.6.1).

Gas volumes consumed as fuel and those delivered to the offshore gas gathering pipeline system will be metered with orifice type metering instruments operated in accordance with the specifications contained in the American Gas Association publication "Orifice Metering of Natural Gas, Gas Measurement Report Number 3."

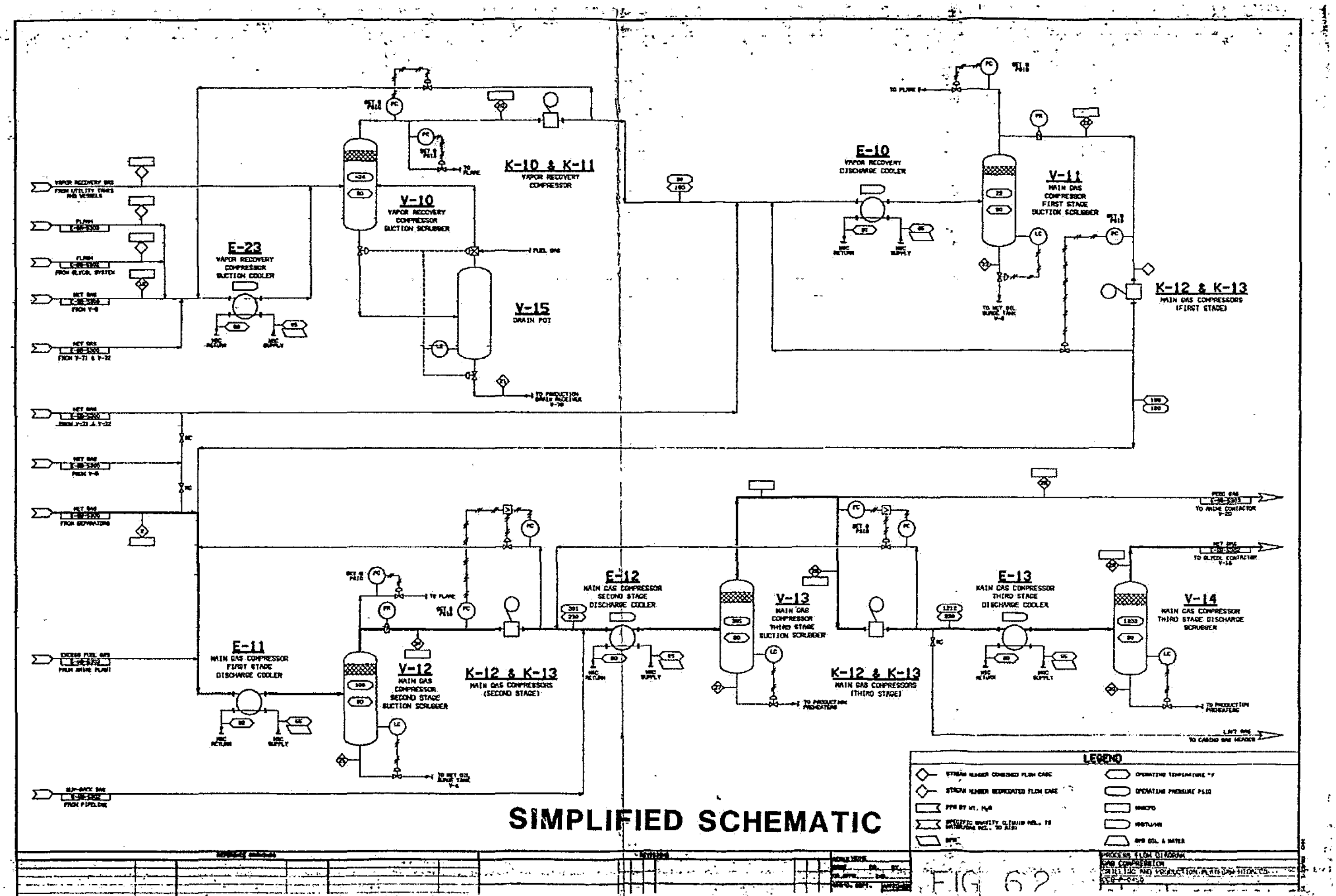
For well-test purposes, the platform test separators will be outfitted with orifice type gas metering instruments, and digital readout oil and water meters with capacitance type water cut sensors.

6.2.10 Condensate Handling

Condensate collected from the gas scrubbers will flow, depending on scrubber operating pressures, to the production surge vessel or to the production preheater upstream of the three phase separators. Ultimate destination of all condensate collected on the platform will be to the production surge vessel for commingling with the emulsion for shipment to shore via Platform Hermosa.

6.2.11 Relief and Vent Systems

All high pressure balanced relief valves on vessels and gas compressors, as well as stack regulators on the gas collection systems, will be



K-10 & K-11
VAPOR RECOVERY COMPRESSOR
V-10
VAPOR RECOVERY COMPRESSOR SUCTION SCRUBBER
E-23
VAPOR RECOVERY COMPRESSOR SUCTION COOLER
V-15
DRAIN POT
E-10
VAPOR RECOVERY DISCHARGE COOLER
V-11
MAIN GAS COMPRESSOR FIRST STAGE SUCTION SCRUBBER
K-12 & K-13
MAIN GAS COMPRESSORS (FIRST STAGE)
E-11
MAIN GAS COMPRESSOR FIRST STAGE DISCHARGE COOLER
V-12
MAIN GAS COMPRESSOR SECOND STAGE SUCTION SCRUBBER
K-12 & K-13
MAIN GAS COMPRESSORS (SECOND STAGE)
E-12
MAIN GAS COMPRESSOR SECOND STAGE DISCHARGE COOLER
V-13
MAIN GAS COMPRESSOR THIRD STAGE SUCTION SCRUBBER
K-12 & K-13
MAIN GAS COMPRESSORS (THIRD STAGE)
E-13
MAIN GAS COMPRESSOR THIRD STAGE DISCHARGE COOLER
V-14
MAIN GAS COMPRESSOR THIRD STAGE DISCHARGE SCRUBBER
LEGEND
SIMPLIFIED SCHEMATIC
PROCESS FLOW DIAGRAM
GAS COMPRESSION

FIG. 62

manifolded together to a high pressure stack scrubber and flare. Low pressure relief valves from the vapor recovery system, tanks, compressor spacer block vents, etc., will be manifolded together to a vapor stack scrubber and flare.

Both the high pressure and vapor stack flares will be incorporated into a single flare boom. Liquids collected in the stack scrubbers will be recycled to the production treating system for reprocessing.

6.2.12 Produced Water Treatment and Disposal

Produced free water resulting from the separation process on the platform will be discharged to the ocean at the MLLW-150' (46 m) depth through a disposal caisson. This water is discharged primarily from the two production separators with a smaller volume discharged from the test separators. To meet the requirements of 40 CFR 435, Effluent Limitations for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, the water will be treated by passing it through a corrugated plate interceptor followed by an air flotation cell to remove suspended oil from the water. The oil content of the discharge water will be less than 72 ppm (instantaneous average). Oily solids resulting from this treating process will be pumped to a waste tank for disposal onshore. All discharges will be in accordance with the general NPDES permit. See Figure 6.3 for a plan of the produced water treatment and disposal facilities.

6.3 Utility Systems

The platform design will include the following utilities:

6.3.1 Power

A submarine electrical power cable connecting Platform Hidalgo to Platform Hermosa will supply part of the power requirements for the platform and producing facilities. The power cable will be installed during the third or fourth quarter of 1986. It is anticipated that additional electrical power will be generated at 4160 volts by four 2500 KW fuel-gas-fired turbine generators. However, the maximum number of turbines used at any one time will be three, with one available on standby. All electrical wiring and equipment on the platform will conform to National Electrical Code requirements. Water will be injected into the turbines to reduce NO_x emissions. It is expected that a 70% or better reduction in NO_x emissions can be achieved. Electric motors for oil shipping pumps and the main gas compressors will operate at 600V. Stepdown transformers and motor control centers will operate general process and utility loads at 480V.

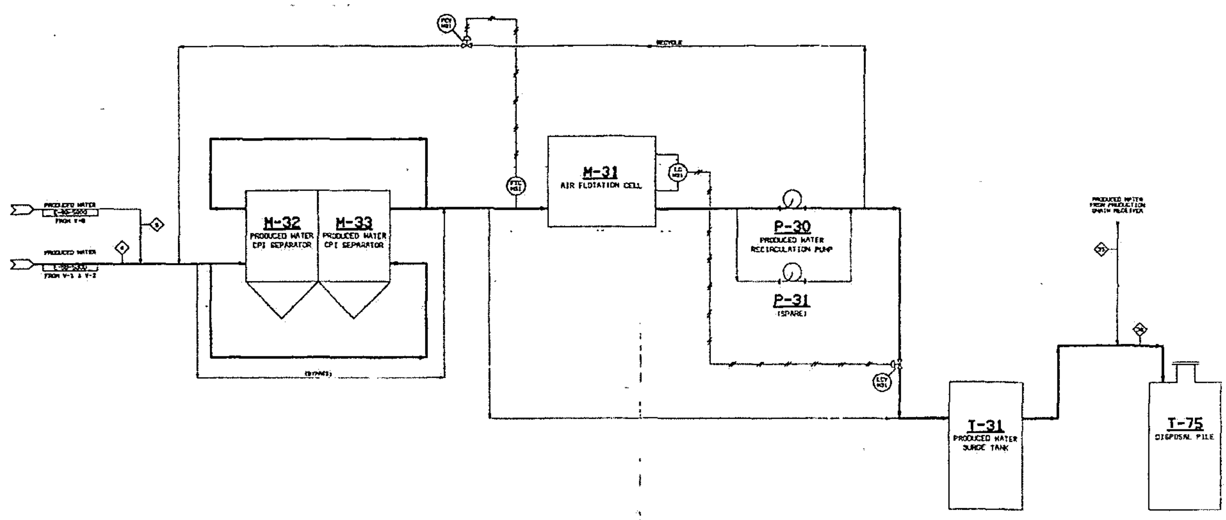
6.3.2 Emergency Power Generation

Emergency power generation will be supplied by two diesel powered generators. One unit (850 KW) will provide electric power under standby conditions for critical services such as blowout prevention accumulators, lights, air pressuring systems, sump pumps, etc. A separate 1250 KW emergency generator will be used to supply standby power for the drilling rigs. The diesel generators will have air starters and separate air reservoir tanks.

6.3.3 Diesel Fuel

Diesel fuel usage will include the intermittent use of the cranes, emergency generators, standby starting air compressor, and diesel fire pump.

Permanent diesel storage (900 bbls.) will be provided in three cap truss storage tanks. Transfer pumps, filters, distribution piping, and day



LEGEND

OPERATING TEMPERATURE °F

OPERATING PRESSURE PSIG

SIMPLIFIED SCHEMATIC

FIG. 63

PROCESS FLOW DIAGRAM
PRODUCED WATER

tanks at each engine will be included. Connections will be provided for the transfer of the diesel fuel from supply boats to the cap truss storage tanks.

6.3.4 Fuel Gas

The primary use of fuel gas on the platform is for the turbine generators. With the power cable installed, once the initial wells have gone on production, turbines will be switched from diesel to produced fuel gas. Other potential uses for fuel gas on the platform include the vapor recovery makeup system and blanket gas.

Because the produced gas contains H_2S, an Amine Unit will be provided to produce sweetened gas to fuel gas specification (less than 50 ppm H_2S). See Figure 6.4 for a plan of the Amine Unit.

6.3.5 Desalination System

Two 100% vapor compression desalination units (one stand-by) will be utilized to produce fresh water from sea water for the potable water, demineralized water, and drilling water systems. The desalination system will keep the potable water system and mixed bed demineralizer supplied with 4 ppm TDS water, while any surplus will go to potable water storage.

Demineralized water requirements will be based on the fuel-rate of the turbines, an estimated 1 pound of water per pound of fuel injected into the combustion chamber. Water from the vapor compression unit will enter a mixed bed cartridge type demineralizer where the total dissolved solids will be reduced from 4 ppm to less than 0.5 ppm. A demineralized water holding tank will be provided between the demineralizer and the turbine generators.

6.3.6 Potable Water

Fresh water produced from the desalination unit will continually resupply the 300 bbl. potable water storage tank. This water will be utilized in the quarters building. Potable water fountains are also to be installed in operating areas.

6.3.7 Freshwater -Drilling

Fresh drilling water storage capacity will be provided in the jacket legs. The water will be removed from the legs by means of compressed utility air. This water will be used primarily for mixing drilling muds and cement. Makeup into the system will be from the desalinator with the balance transported by work boats from shore.

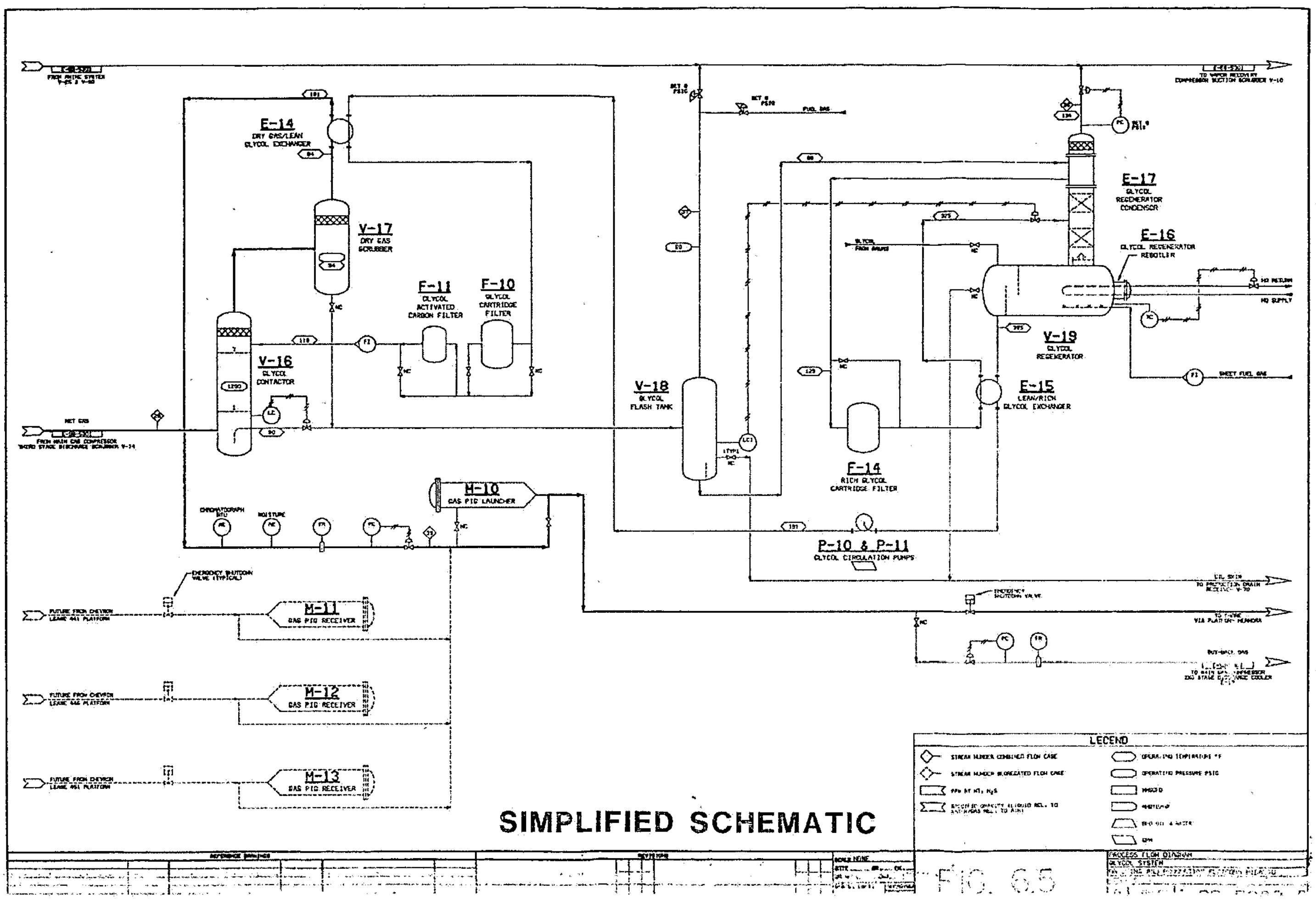
6.3.8 Process Heating

A circulating heating media system will be used to provide heat for production and test separator heat exchangers, the production surge tank, glycol regeneration (Figure 6.5), and amine regeneration. Cogeneration will be used on the platform, that is, the heat source for the heating media will be waste heat recovered from the turbine drivers for the electrical generators.

The system consists of a heating fluid surge tank, circulating pumps, supply and return headers, and a heat source (i.e. turbine drivers for generators).

6.3.9 Utility Air

Three rotary screw air compressors will be provided to distribute a supply of 125 psi air throughout the platform for such uses as air tools


E-14
DRY GAS/LEAN GLYCOL EXCHANGER
V-17
DRY GAS SCRUBBER
V-16
GLYCOL CONTACTOR
F-11
GLYCOL ACTIVATED CARBON FILTER
F-10
GLYCOL CARTRIDGE FILTER
M-10
GAS PIG LAUNCHER
M-11
GAS PIG RECEIVER
M-12
GAS PIG RECEIVER
M-13
GAS PIG RECEIVER
V-18
GLYCOL FLASH TANK
F-14
RICH GLYCOL CARTRIDGE FILTER
P-10 & P-11
GLYCOL CIRCULATION PUMPS
E-17
GLYCOL REGENERATOR CONDENSER
E-16
GLYCOL REGENERATOR REBOILER
V-19
GLYCOL REGENERATOR
E-15
LEAN/RICH GLYCOL EXCHANGER
FUEL GAS
HM RETURN
HM SUPPLY
SWEET FUEL GAS
WET GAS
FROM MAIN GAS COMPRESSOR
CHROMATOGRAPH
MOISTURE
EMERGENCY SHUTDOWN VALVE (TYPICAL)
FUTURE FROM CHEVRON
TO SHORE
LEGEND
SIMPLIFIED SCHEMATIC
PROCESS FLOW DIAGRAM
GLYCOL SYSTEM
FIG. 6.5

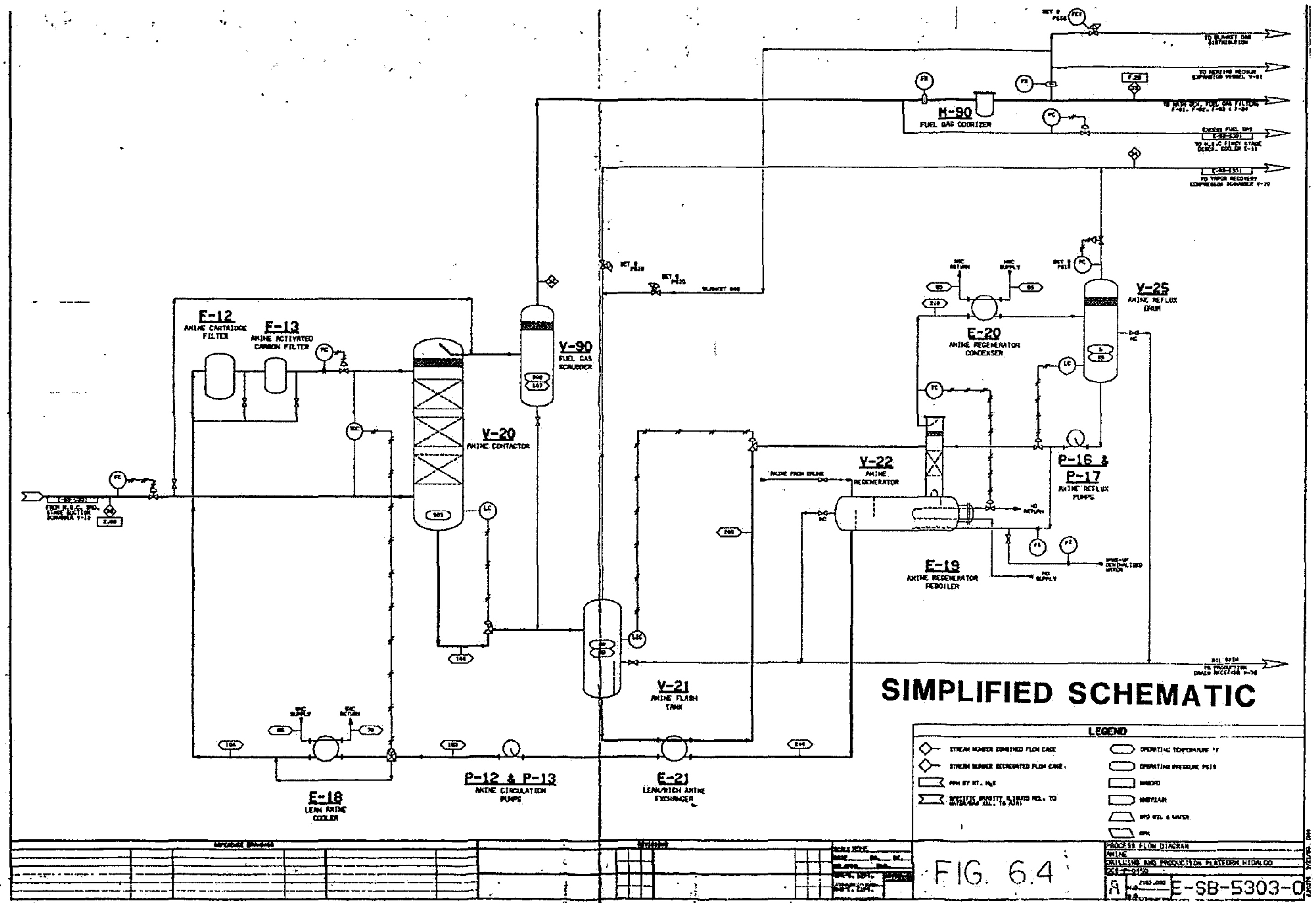

F-12
AMINE CARTRIDGE FILTER
F-13
AMINE ACTIVATED CARBON FILTER
V-20
AMINE CONTACTOR
V-90
FUEL GAS SCRUBBER
M-90
FUEL GAS ODORIZER
E-20
AMINE REGENERATOR CONDENSER
V-25
AMINE REFLUX DRUM
V-22
AMINE REGENERATOR
P-16 &
P-17
AMINE REFLUX PUMPS
E-19
AMINE REGENERATOR REBOILER
V-21
AMINE FLASH TANK
E-21
LEAN/RICH AMINE EXCHANGER
P-12 & P-13
AMINE CIRCULATION PUMPS
E-18
LEAN AMINE COOLER
SIMPLIFIED SCHEMATIC
LEGEND
PROCESS FLOW DIAGRAM
E-SB-5303-0

FIG. 6.4

and hoists, moving drill water, air-powered hydraulic pumps, sewage treatment air scour, DC motor purge, etc.

6.3.10 Instrument Air

An instrument air system will be provided to compress, dry, store and distribute an adequate supply of 100 psi instrument air throughout the platform process area.

6.3.11 Starting Air

Two high pressure reciprocating compressors (one diesel, one electric) will be used to provided starting air for the turbines, the emergency generators, and the diesel firewater pump. Enough storage capacity will be provided to start this equipment when the platform is not generating power (shutdown mode).

6.3.12 Seawater

Saltwater will be provided for fire suppression, washdown, flushing water for cleaning cuttings, process cooling, and the desalinator. The fire suppression system will be designed for approximately 2000 gallons per minute. A second system will provide 3000 gallons per minute capacity for the process cooling systems, the desalinator, and other miscellaneous systems.

6.3.13 Sewage Treatment

A packaged sewage treatment unit will be incorporated to process the sewage from the quarters building. The effluent from this unit will comply with U.S. Coast Guard requirements found in 33 CFR 159.53(b) and will be discharged to the ocean through the disposal caisson.

6.3.14 Chemical Injection

Numerous small storage tanks and metering pumps will be provided for injection of corrosion inhibitors, antifoam agents, etc.

The platform will include a hypochlorite generator for supplying chlorine to the saltwater intake system and sewage treatment unit as required.

6.3.15 Lighting

Platform lighting will meet or exceed the API RP14F recommended levels of illumination. Indoor lighting will consist of fluorescent fixtures and outdoor lighting will consist of high pressure sodium vapor fixtures. Critical lighting circuits will be connected to a battery backup system to provide emergency lighting in the event of a power failure.

6.3.16 Deck Drainage

Drainage from the upper and main decks will go into a corrugated plate interceptor (CPI) where oil will be separated. This oil will then flow into the sealed production drain system for eventual processing in the main production separators. Clean water from the CPI is discharged to the ocean through the disposal caisson.

Drainage from the wellhead deck and wellhead mezzanine deck goes into a sump tank for initial oil/water separation. Water is then pumped to the CPI for additional separation and processing as outlined above for the upper and main deck drainage system. The oil is then drained into the sealed production drain system for processing as outlined above.

Drainage from the sump deck will go to the sump deck sump. Fluid from the sump will be pumped to the CPI in a similar manner described above for the wellhead deck drainage.

All decks will be solid steel plate and have a 6" (15cm) high curb around the perimeter to prevent any runoff from overflowing into the ocean. Spray shields will be included where necessary to prevent liquid hydrocarbon spray from reaching the ocean.

6.4 Support Facilities

6.4.1 Hydraulic Control

A hydraulic pressure system will be provided for downhole subsurface safety control valves. The system will include pneumatically-controlled pumps, reservoir tanks, filters, and a distribution system. This is a closed loop, hydraulically powered system with spent fluid returning to a pump suction reservoir.

6.4.2 Process Control and Monitoring

The general process and associated equipment will be monitored and controlled from the central control room. All monitoring and control functions such as process temperatures, pressures, flow rates, and liquid levels will be by a programmable controller system.

In the event that normal process controls are unable to maintain the process within prescribed operating limits, alarms will be triggered in the control room to warn the operators of impending upset conditions. These alarms will cause a horn to sound and a light to flash to indicate the precise nature of the trouble.

Should the operator not be able to correct an alarm condition before it reaches the next prescribed operational limit, the following types of safety equipment are provided to protect the process and associated equipment:

- o High/Low Pressure Sensors (Shutdowns)
- o High Temperature Sensors (Shutdowns)
- o High/Low Liquid Level Sensors (Shutdowns)
- o Pressure Safety Valves (Relief)
- o High/Low Flow Sensors (Shutdown)
- o Automatic Emergency Shutdown (ESD) System
- o Manual Emergency Shutdown (ESD) System
- o Surface and Subsurface Well Safety Valves
- o Equipment Isolation Shutdown Valves (SDV's)

This safety shutdown equipment is applied in accordance with MMS OCS Order No. 5, OCS Order No. 9, and API Recommended Practice RP-14C.

6.4.3 Personnel Quarters

Personnel quarters are to be sized for normal drilling and production activities. Facilities include sleeping accommodations for about 90 persons with restroom facilities, locker room, wash room, galley, dispensary, and a recreation/training room. The quarters building will be designed to minimize transmission of vibration and noise. A heliport will be situated on top of the quarters building.

6.4.4 Fire Suppression, Detection, and Alarm

Primary fire protection will be by sight and manual (push buttons at each hose reel) initiation by platform personnel. Secondary protection will be by automatic detection using U.V. fire detectors, fusible plug loops, and low firewater header pressure switches. Both manual and automatic initiation signals are sent to a controller which in turn initiates an alarm and starts at least one electric fire pump. Should the controller not maintain continuous communications with either the electric or the diesel control system, the respective pump(s) will start automatically.

The deluge system piping will be routed to maximize reliability and minimize friction loss. Automatic valves for the deluge systems will be placed in safe areas where a fire zone header branches off the main system.

Firewater pumps will be specified to meet pump curves which ensure constant flow at constant line pressure as required for fire fighting. Pumps will furnish not less than 150 percent of the rated capacity at 65 percent of the total rated head.

The following is a brief description of the fire suppression system components:

(a) Two electric submersible fire pumps to provide firewater (1000 gpm/pump minimum) at 100 psi residual pressure to the platforms deluge system, hose reels, and fire monitors. Each pump will start automatically by a signal from its low pressure switch on the firewater header.

(b) One standby diesel-powered right angle drive vertical turbine fire pump to provide firewater (2000 gpm minimum) at 100 psi residual pressure to the platform's deluge system, fire monitors, and hose reels. The pump will start (air start) automatically by a signal from its low pressure switch on the firewater header. The pressure setting will be lower than that of the two electric fire pump start settings.

(c) Two 50 gpm (maximum) centrifugal jockey water pumps (one operating, one standby) to maintain the firewater header at 150 psi. The pumps will get their suction from the cooling water header and will prevent automatic starting of the main fire pumps due to system leaks or small firewater demands.

(d) Adequate 1" to 1-1/4" hard rubber hose reels to provide water/foam coverage at any point on the platform with two 100 ft. hoses.

(e) Deluge system with automatic area controls capable of wetting critical deck areas not occupied by major equipment with water density of not less than 0.25 gpm/ft^2. The system will also protect the wellhead area and process equipment with the following design densities:

1)	pipe racks and manifold area	0.25 gpm/ft^2
2)	hydrocarbon pumps	0.50 gpm/ft^2
3)	flare knock-out drum	0.25 gpm/ft^2
4)	immediate wellhead area	0.50 gpm/ft^2
5)	surrounding wellhead area	0.30 gpm/ft^2
6)	top half of separator vessels	0.30 gpm/ft^2
7)	inlet coolers	0.30 gpm/ft^2
8)	process deck area	0.25 gpm/ft^2

(f) Two 250 gpm fire monitors on the main deck to cover the BOP stacks and the upper well bay area.

(g) Portable fire extinguishers of the appropriate size and class for the anticipated hazard will be provided and located to permit coverage of the entire platform deck areas and buildings. Different types used are dry chemical, CO_2, and Halon.

(h) Automatic Halon 1301 flooding protection system will be provided in each turbine generator enclosure.

(i) Manual fire alarm pull stations will be provided in the Generator Room and Quarters Buildings.

(j) Firehose connections at the boat landing (for fire boat use) will be piped to the platform distribution system.

(k) Fire hydrant riser and connections at all stair landings.

(l) Automatic dry chemical spray over stove and grill in the quarters building.

The following is a brief description of the fire detection and alarm system components:

(a) Ultraviolet sensors. These will signal a local controller which will signal the platform Modicon programmable controller. An audible alarm is then initiated which will start the firewater suppression system and shutdown sequence.

(b) Fusible plugs will initiate the same events as the ultraviolet sensors.

(c) Visual sighting. Personnel can initiate shutdown and suppression activities from the main control room or fusible plug panels.

(d) Thermal rate-of-rise detectors. These will signal the Modicon programmable controller, initiate an audible alarm, and shutdown building ventilation.

(e) Turbine encosure ultraviolet and rate-of-rise detectors. These will signal a local controller which will signal the Modicon programmable controller. An audible alarm is then initiated which will start the Halon flooding system, will start the diesel generator, and will shut off the turbine fuel supply.

6.4.5 Escape and Lifesaving Equipment

The platform will be equipped with three U.S. Coast Guard approved escape/survival capsules, accomodating 50 persons each, plus an adequate number of life preservers, life floats, ring life buoys, first aid kits, litters, and other lifesaving appliances as required by 33 CFR 144.

6.4.6 Corrosion Control

Corrosion is to be controlled by using corrosion-resistant coatings on the top-side structures and equipment, an underwater sacrificial anode system, and internal coating for selected piping, vessels and tanks. Corrosion inhibitors will also be added during operations. In addition, piping will be designed with adequate corrosion allowance and valves will be specified with appropriate trims for the expected corrosive surfaces.

6.4.7 Aids to Navigation

Aids to navigation will consist of four quick-flashing, Coast Guard approved white lights visible for 5 miles (one light at each corner of the platform), and a Coast Guard approved fog horn with a 2-mile audible range. All aids to navigation will meet Coast Guard Regulations for Class A Structures (33 CFR 67.20). The platform will be painted white to assure high visibility to passing vessels.

The flare boom and each drilling rig derrick will be illuminated for aviation safety with a combination of steady and flashing red lights. The heliport perimeter is outlined with lights plus one flashing amber beacon. The heliport lights are illuminated only during flight operations.

Chevron has met with Texaco and discussed the joint use of a United States Coast Guard approved Automatic Radar Plotting Aid (ARPA) unit to be installed on a platform or a standby boat in the Point Arguello area. The platform will be alerted of an approaching vessel's location by an authorized observer manning the ARPA unit.

6.4.8 Communication Facilities

Intra-platform communication will utilize hardwired speakers and handsets. Additionally, there will be hand-held portable radios for operational communication.

For external communication with crew boats, supply boats, helicopters, shore bases, other platforms, etc., there will be a radio system. A Company-owned microwave system will provide telephone service and circuits for the pipeline leak detection system and pipeline emergency shutdown system.

6.5 Environmental Impact Mitigation Measures

6.5.1 Turbine Water Injection

Although not required by regulation, turbines on the platform will be equipped with water injection to reduce emissions of NOx. The system will inject demineralized water (approximately 0.5 ppm or less solids content) into the turbine. Injection of water will lower combustion temperatures and low combustion temperatures result in lower rates of NOx production. Injection rates of 0.5 to 1.0 pounds of water per pound of fuel are expected. At these injection rates reductions of 70% or greater have been demonstrated.

Solar, Ruston, and Allison turbines are currently being considered for use on the platform. Significant operating experience with these and other turbines has demonstrated the feasibility of water injection. Water injection has been proven to be feasible by emissions compliance tests on the San Diego Union-Tribune Centaur generator which utilizes water injection to reduce NO_X emissions (Reference 6.6.2). Information regarding water injection is available in "Standards for Support and Environmental Impact Statement, Volume 1, Proposed Standards of Performance for Stationary Gas Turbines", EPA, September, 1977. Chevron is continuing to follow the progress of water injection technology.

6.5.2 Gas Blanketing and Vapor Recovery

All pressure vessels, surge tanks and other process equipment operating at or near atmospheric pressure, are connected to a gas blanketing and vapor recovery header system which maintains a slight positive pressure on the system. As gas is released from process fluids or forced out of vessels and tanks as they are filled, it is compressed by vapor recovery compressors and flows into the sales gas system. As fluids are withdrawn from vessels or tanks, blanket gas is made up from the platform fuel gas system. This type of gas blanketing and vapor recovery reduces explosion hazards by eliminating oxygen, eliminates VOC (volatile organic compounds) emissions normally associated with atmospheric tanks and vessels, and recovers energy that would otherwise be lost.

6.5.3 Waste Heat Recovery

A significant amount of heat is required on the platform for process heating and to assist in degassing the emulsion before shipment. Heat is also required to regenerate glycol and amine used in the gas dehydration and sweetening systems, respectively. Since gas turbines are used for power generation, waste heat will be recovered from the turbine exhaust to satisfy platform heat requirements. This measure conserves fuel and reduces emissions by reducing or eliminating the need for fired heaters. It also lowers the temperature of the turbine exhaust entering the atmosphere.

6.5.4 Spill Prevention and Containment

All platform facilities are designed to prevent the occurrence of an oil spill. The platform decks are enclosed with a containment curb to prevent accidental spillage on the decks from going overboard. Deck drains gather up fluids and route them to sumps where the solids and liquids are separated. The liquids are pumped back into the main emulsion separation system; solids are stored for intermittent transportation to shore for disposal. All process bleed valves and drains are also routed to a sump from which fluids are pumped back into the main emulsion separation system. All liquid relief valves are piped into closed systems with liquids flowing to a surge tank from which they are pumped back into the main emulsion separation system.

In the unlikely event that an overboard spill occurs, the offshore facilities will be serviced by an oil spill containment/cleanup vessel dedicated to the Pt. Arguello Field platforms. Oil spill containment/cleanup equipment will be similar to that carried by the vessel Mr. Clean II of the Clean Seas Cooperative. For a detailed discussion of the proposed actions and oil spill equipment in case of an oil spill occurrence, please refer to the Oil Spill and Emergency Contingency Plan for Platform Hidalgo (Reference 5.4.1).

6.5.5 Emergency Flare

All vapor safety relief valves exhaust into a closed flare header system which gathers the emergency releases and routes them through a scrubber to one of two flare burners. The high and low pressure burners are designed to be smokeless.

6.5.6 Common Grid Electrical Power Generation and Distribution

In order to minimize the amount of installed electric generating capacity, future platforms will be interconnected to a submarine power cable between Platforms Hidalgo and Hermosa. Each platform will then draw upon the spare capacity of the overall system during generator maintenance rather than having to install spare generating capacity on each individual platform.

By reducing the overall amount of generating horsepower installed, the per unit percent load is increased. This results in an increased thermal efficiency of each unit and thus reduced overall fuel consumption and emissions.

6.5.7 Fugitive Emission Inspection Program

Fugitive emissions are those which result from leaks around pump seals, valve stems, hatches, connections and other process components. To minimize these hydrocarbon emissions, Chevron will institute a fugitive emission inspection and maintenance plan on Platform Hidalgo.

6.6 References

6.6.1 WESTEC Services, Inc. (1982). Point Arguello Field, Development and Production Plan. Report prepared for Chevron U.S.A. Inc.

6.6.2 Solar Turbines Incorporated (1982). Emissions Performance Tests of the Centaur Generator Set w , Water Injection for Union-Tribune - PD37201. Report prepared for the San Diego Union - Tribune.

SECTION 7

PIPELINE SYSTEM

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SECTION 7

PIPELINE SYSTEM

7.1 Introduction

Current analysis indicates that a 14" to 18" oil line and a 8" to 10" gas line will be needed to transport produced oil and gas from Platform Hidalgo to Platform Hermosa. At Hermosa the oil and gas will enter industry pipelines that will transport Point Arguello production to onshore facilities. Please refer to Point Arguello Field DPP and ER (Hermosa) for a detailed discussion regarding the consolidated industry pipelines from Hermosa to the onshore processing facility at Gaviota. The Hidalgo lines will be sized to accommodate anticipated production from any other (future) platforms in the Pt. Arguello Field. Total design capacities for the lines are approximately 100,000 BPD of emulsion and 75 MMSCFD of gas.

The following sections will present the pipeline route selection, corridor details, design codes, design basis, expected operations, and other considerations.

7.2 Pipeline Route

The proposed pipeline route is shown in Figure 1.2. The length of the oil and gas lines from Hidalgo to Platform Hermosa is approximately 4.8 miles (8 km). The line profile is a gradual slope from a 430' (131 m) water depth at Hidalgo to a 602' (183 m) depth at Hermosa.

7.3 Pipeline Corridor: Platform Hidalgo to Platform Hermosa

Surveys and detailed geological evaluations recently completed along the proposed pipeline route by McClelland Engineers Inc. (References 2.5.13 and 2.5.14) indicate the following features:

7.3.1 Geology/Hazards

A detailed geophysical investigation was performed along the pipeline route from Platform Hidalgo to Platform Hermosa by McClelland

Engineers in 1983 (Reference 2.5.13). The corridor surveyed by McClelland Engineers was 4500' (1200 m) wide and 24,000' (7200 m) long. Based on this survey work, the final route for the pipeline was selected to avoid seafloor anomalies (Plates 6 and 15, Reference 2.5.13).

The geological conditions along the proposed pipeline route are favorable for the laying and maintaining of the line. The route does not cross any active faults. Further, the seafloor sediments along the route will adequately support the pipeline under normal static (non-earthquake) conditions. The seafloor slopes are shallow, ranging from 2% to 4% (1.1^{o} to 2.3^{o}). The shallow subsurface geology consists of homoclinal gently-dipping Pleistocene-Pliocene sediments, overlain unconformably by a nearly flat-lying layer of young sediments that are considered to be Holocene in age. Additional details on these geologic conditions along the pipeline route are given in Sections 2.3.2 and 2.3.3 of this report and in the McClelland Engineers report on the shallow geology along the pipeline route (Reference 2.5.13).

7.3.2 Geotechnical

McClelland Engineers (Reference 2.5.14) concluded in their geotechnical report that the construction and maintenance of a pipeline along the proposed route from Platform Hidalgo to Platform Hermosa is feasible. This report should be referred to for a detailed discussion of geotechnical conditions. In summary, they concluded that, along the pipeline route, the upper 10'-30' (3-10 m) of these sediments are clayey silts. McClelland Engineers Inc. concluded from their studies of this soil that, despite possible loss of stiffness, no downslope movement is expected during extreme earthquake loading.

7.3.3 Cultural

McClelland Engineers (References 2.5.13, Appendix E) utilized the services of Ms. Heather Macfarlane to review the route of the proposed pipeline for cultural and archaeological resources. Based on her findings and the geological hazards assessment, the final route for the pipeline was selected so that it avoids all of the anomalies noted. One anomaly which could be a shipwreck (located in 390' (120 m) of water, about 600' (180 m) from the proposed pipeline route) was identified in her report. This area will be avoided during anchoring activities associated with the platform and pipeline construction.

7.4 Design Codes

Oil and gas pipelines will be designed, constructed, tested, operated, and inspected in accordance with the latest edition of the following design standards:

- o Liquid Petroleum Transportation Piping Systems, American National Standards Institute (ANSI) B31.4.
- o Gas Transmission and Distribution Piping Systems, American National Standards Institute (ANSI) B31.8.
- o Transportation of Liquids by Pipeline: Minimum Federal Safety Standards, Department of Transportation Regulation 49, Part 195.
- o Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, Department of Transportation Regulation 49, Part 192.
- o Recommended Practice for Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines, American Petroleum Institute Publication API-RP 1111.
- o OCS Order No. 9.

7.5 Pipeline Design Basis

A schematic of the pipeline system from Platform Hidalgo to Platform Hermosa is included as Figure 7.1. On deck tie-ins for three possible future platforms will be provided. Production from possible future platforms would be commingled with Hidalgo's production and piped to Hermosa, where it would enter industry pipelines to shore.

The oil characteristics used in sizing studies to date are:

Gravity: 20° API

Oil Viscosity: 4050 cp at 45°F
620 cp at 77°F
220 cp at 104°F
59.8 cp at 158°F

Based on laboratory tests, there is a 20% variation of viscosity with pressure, and this has been included in the flow calculations. Temperatures at Hidalgo have been predicted using a network analysis. Using a maximum 20% water cut, inlet pressure of 725 psig to the industry oil pipeline at Hermosa, and predicted temperatures, the maximum pressure required at Hidalgo for the design flow of 100,000 BPD is about 1,050 psig.

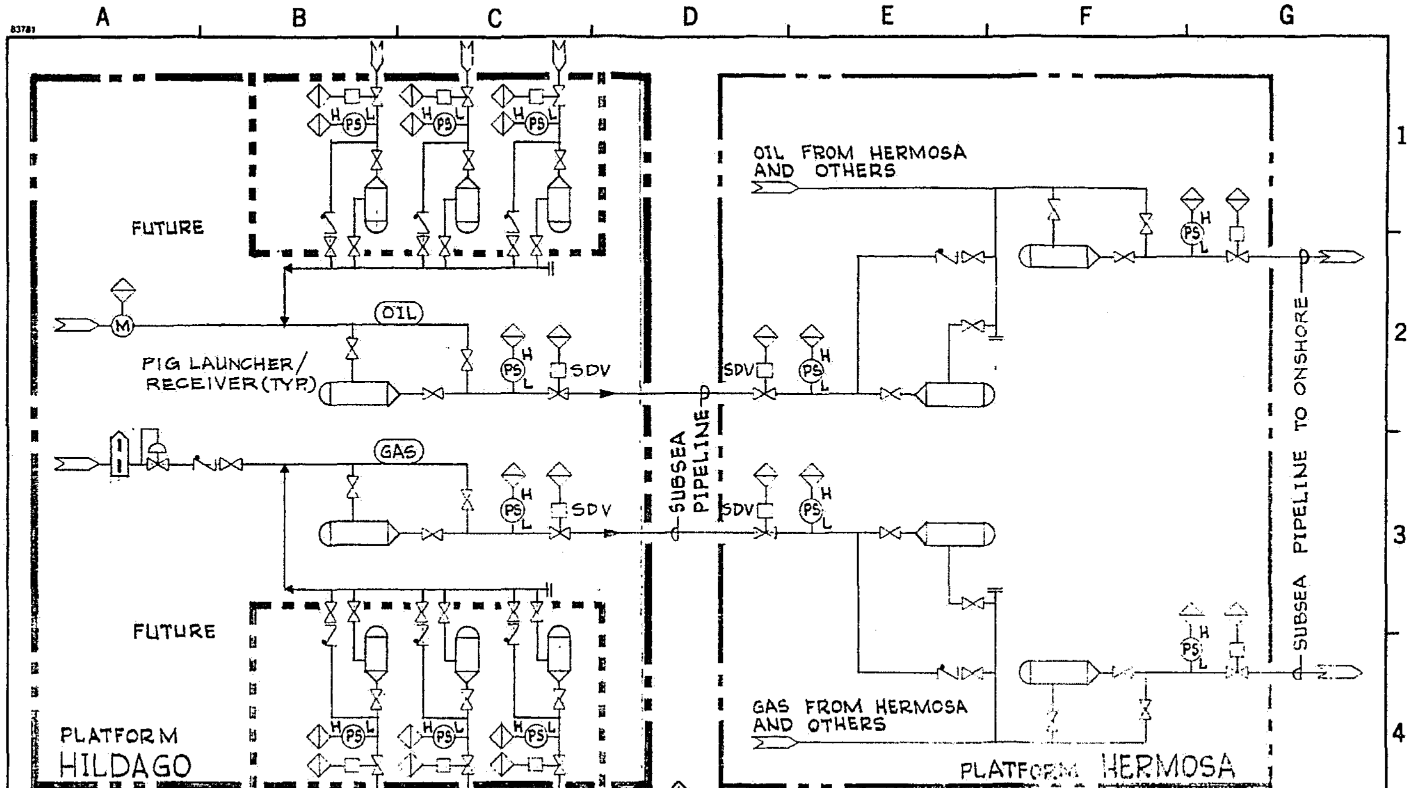
The gas will be dehydrated to its hydrocarbon dewpoint when leaving Platform Hidalgo. As the temperature drops, liquids will condense. Assuming a 1150 psig discharge at Hidalgo and a required 900 psig pressure at Hermosa, and using pigging spheres to control the effects of liquids, the 10" line will handle 75 MMSCFD.

The pipelines will also be capable of operating successfully at offpeak capacity. For the oil line, calculations show that a restart can be accomplished with the line contents at 50°F if there is an extended shutdown. For the gas line, low flows will cause excessive pressure drops if condensed liquids were allowed to accumulate. Therefore, pigging will be scheduled to avoid this situation.

The proposed pipelines will be designed to ensure that they can be safely installed and operated in an environmentally acceptable manner. Specific design data will be supplied in compliance with MMS OCS Order No. 9.

7.5.1 Design/Operating Conditions

Maximum design pressure of both the oil and gas pipelines to Platform Hermosa will require less wall thickness than that required to withstand installation stresses. However, an ANSI 600 (1480 psig) system will be the



FLOW RECORDER. (M) LEASE AUTOMATIC CUSTODY TRANSFER.
(PS) PRESSURE SWITCH (HIGH & LOW). SDV SHUTDOWN VALVE.

REVISIONS

DR. LASH CH.

DR. APP.

ENGR.

OPR'G. DEPT. APPROVED

ENG'R. DEPT.

Chevron U.S.A. Inc.
Western Region, Production Department

Bechtel Petroleum, Inc.
San Francisco
Job No. 15023

SCALE NONE

DATE 11-16-83

PIPELINE SYSTEM SCHEMATIC

DRILLING & PRODUCTION PLATFORM HIDALGO

OCS PARCEL P-0450 POINT ARGUELLO, CALIFORNIA

FIGURE 7.1

minimum design pressure. Maximum operating pressures are expected to be less than 1200 psig in the crude line and less than 1200 psig in the gas line.

By adjusting the discharge pressures, the pipelines will be capable of handling the range of expected flows at maximum efficiency. The oil line size will be sufficient to transport up to 100 MBPD of crude oil emulsion. The gas pipeline will be sized to have a capacity of 75 MMSCFD.

Temperature of crude in the oil pipeline is expected to range from 50°F to 125°F. Temperature of the gas line is expected to range from 50°F to 75°F. The pipelines will be designed to accommodate thermal effects without damage.

7.5.2 Mechanical Design

Pipeline materials specifications will be developed to satisfy requirements of both operating and installation modes. Pipe buckle arrestors will be installed where diameter to wall thickness ratios are insufficient to protect the pipe from propagating buckles.

Pipelines will be designed to resist predicted recurring environmental loads resulting from steady-state and wave induced currents, seabed soil liquefaction, slumping and mud slides, and seismic activity. A report is being prepared on ocean currents, based on site specific current surveys previously carried out in the area (Reference 4.7.3).

7.5.3 Corrosion Protection

Pipelines will be protected from external corrosion by coatings and cathodic protection (sacrificial anodes). Internal corrosion will be controlled through the use of corrosion inhibitors, through proper selection of pipeline materials, and additional pipewall thickness to provide corrossion allowance.

7.5.4 Construction and Installation

Construction equipment, methods and procedures will be selected to insure that the pipelines are not overstressed during installation. Pipeline installation will most likely be by the conventional pipe lay barge/stinger method, reel barge, bottom tow, or bottom pull methods. Each of these methods will be evaluated on a technical and economic basis. An anomaly noted 600' (180 m) from the proposed pipeline route will be avoided during anchoring activities associated with the pipeline construction.

Risers will be connected to pipelines using methods selected on the basis of technical and economic analysis. Risers will be pre-installed on the jackets. Connection to the pipeline will most likely be made using flanges or mechanical connectors. J-tubes will be provided for the smaller diameter gathering lines tying into Hidalgo.

Prior to construction, all pipe and coatings will be inspected for defects. Pipeline welding procedures and welders will be qualified. During construction, all girth welds will be 100 percent radiographically inspected. Full time, qualified inspectors will monitor all phases of construction. Pipelines will be gauged and will be pressure tested with corrosion inhibited water to 1.25 times the maximum design pressure. The test water will remain in the pipelines until production begins and will be treated in accordance with applicable regulations prior to disposal.

Conventional Lay Barge/Stinger Method

Pipe joints, 40' to 60' (12 m to 18 m) feet in length, are welded together offshore on a floating deck and then lowered to the seabed in a controlled configuration to prevent overstressing. The pipe joints are welded into a continuous string or a large, gently curved production ramp. The anchored lay barge is pulled forward by anchors or pipe lengths as each new joint is added. During pull up, the pipe string passes down the ramp onto a stringer, and to the ocean floor in an S-curve configuration. Tensioners positioned along the production ramp provide a hold back force which limits the curvature of the pipe string and hence the maximum stress to which the pipe is subjected.

Reel Method

The reel method uses a continuous pipe string assembled on shore and coiled onto a reel. The pipe and reel are placed on the lay vessel and transported to the installation location. At the site, the pipe is uncoiled from the reel, straightened and placed on the ocean floor. This process continues until the reel is empty, where upon the lay vessel returns to shore to refill the reel.

The reel diameter is such that plastic pipe deformaties occur during coiling and uncoiling. In order to prevent pipe flattening during the process a heavy wall thickness (0.625") has been selected.

Bottom Tow Method

The bottom tow method utilizes the concept of towing long strings of pipe, made up onshore, along the seabed to the installation site. Pipe sections are transported to a shore facility close to the site, welded and pulled into the water as its length increases. The pipe string is towed by a vessel connected by cable to a pipe pulling head or sled.

The pipe will be coated with 1" of concrete to protect the pipe and its corrosion coating against seabed abrasion. In addition the route over which the pipe string is to be towed, will be carefully selected and surveyed to avoid bottom contours and obstructions which could damage the pipe or lead to overstressing.

Connection of the pipelines to the platforms will be completed by pulling neoprene coated joints into J-tubes at Hidalgo, and by flanged spool connections to preinstalled pipes in the Hermose J-tubes.

Bottom Pull Method

A fabrication barge, a pull barge, and a support tugboat are the vessels needed during these operations. Pipline sections welded onshore would be loaded onto the fabrication barge. The fabrication barge would be towed out, positioned near Platform Hidalgo, and secured by four anchors (accomplished by the support tugboat). Six anchors, set by the tugboat, would be used to lock the pull barge into position seaward of the fabrication barge.

After the subsea pipeline has been pulled seaward to a position near the stern of the pull barge, progress then halts. The supply tugboat then returns, tows the pull barge closer to Platform hidalgo, and the six anchors are reset. The barge is again locked in position. It is anticipated that the pull barge would be repositioned five times, at approximately 5,000' (1524 m) intervals, during the construction of the proposed subsea pipelines between platforms Hidalgo and Hermosa.

7.6 Pipeline Operations

The communications between facilities will be designed to meet all code and operating requirements.

The oil/water emulsion entering offshore pipelines will be metered on each platform using positive displacement meters. Meter provers will also be installed on each platform. Metered offshore volumes will be continuously compared to metered volumes delivered at the onshore process facility. High and low pressure shut-down devices will automatically shut-in offshore production and shut-down pipelines if changes in pressure (high or low) exceed preset limits. Pipelines coming onto and leaving platforms will have automatic shut-down valves operated in accordance with MMS OCS Order No. 9. System alarms will be activated if significant differences between input and output volumes are measured, as required by MMS OCS Order No. 9. Appropriate measures will be taken to assess the validity of alarms when they occur and to shut-in the affected pipeline. The leak detection system will be designed in accordance with MMS OCS Order No. 9.

The oil pipeline is monitored in two ways to detect leaks and limit the amount of oil spilled in the event of a leak. Very large leaks (i.e., pipeline rupture) will be detected by a low pressure sensor on the pipeline exit from the platform. In the event that this sensor detects an abnormally low pressure caused by a pipeline break, all oil shipping pumps will be automatically stopped. A volumetric detection system is planned to detect smaller leaks. Present proven leak detection technologies can sense leaks of between 1 to 5% of the flow volume. Data necessary for such detection will be transmitted via a combined microwave/cable transmission system to a central computer control center at Gaviota where a dispatcher will monitor operations on a 24-hour/day basis.

Gas entering offshore pipelines will also be metered, as will deliveries to the onshore facilities. A continuous comparison is not feasible due to the 2-phase nature of the flow.

Alternate technologies for leak detection will be investigated. These alternates may be proposed in addition to the above if considered suitable.

Corrosion inhibitors, pipeline pigs, and instrumented pigs will be used as needed to assure that pipelines remain free of potentially harmful deposits, corrosion products and defects. For the gas line, pigging will be used to displace condensate in the line and to control pressure drop.

All Hidalgo pipelines will be operated in accordance with MMS OCS Order No. 9. This will include external inspections of the lines, testing of safety devices, and actuation of isolating valves on the prescribed schedule.

7.7 Other Considerations

7.7.1 Capacity Increases

The Platform Hidalgo lines are currently sized to handle the peak Chevron production and estimated volumes from three other possible platforms that may produce in the Pt. Arguello Field.

Provision will be made on Platform Hidalgo for the addition of booster pumps in the event that they are required for increasing pressure on incoming oil pipelines. No recompression of incoming gas is proposed. Gas will go directly into the Hidalgo gas pipeline.

7.7.2 Fishing/Marine Pipeline Compatibility

The pipelines are expected to lie on the seabed. There are no current plans for installation of any appurtenances for subsea tie-ins on the Hidalgo pipelines. If provision is made for future subsea tie-ins, a smooth cover for the pipeline that rests on the seabed will be installed to ensure compatibility with fishing equipment and to preclude damage to the pipeline systems. Any other small protrusions on the pipeline will be smoothed with an attachment to the pipeline itself. The large diameter, concrete coated pipelines will withstand trawl board impacts and damage.

7.7.3 Seabed Topographic Alterations

The use of anchored vessels for pipeline installation could result in marking the seabed. At this time, we are uncertain whether these disturbances would be permanent and what would constitute a compromise to fishing interests or other involved parties. We plan to develop additional information by studying the seabed soils, currents, etc. and meeting with these parties. With the background data in hand, various alternatives to mitigate the situation will be explored. These could include the use of installation techniques which minimize seabed topography changes or treatment of the problem after installation. The overall economics and technical feasibility of the options will be determined, and an acceptable solution to all parties will be pursued.

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SECTION 8

ONSHORE PROCESSING FACILITIES

8.1 Introduction

To consolidate facilities, the production from Platform Hidalgo will be treated in an industry processing facility at Gaviota. While not part of this plan, a description of the consolidated facilities is included in this document for informational purposes only.

Briefly, oil dehydration, gas treatment, oil pumping, and gas compression facilities will be installed at the existing gas plant located at Gaviota in Santa Barbara County. Of the total 52-acre site, the oil and gas processing facilities will require approximately 27 acres. The site will be designed to permit expansion with minimum disruption to existing equipment when plant additions are required (i.e., modular trains).

Oil dehydration equipment and gas compressors will be installed in stages as Point Arguello Field production increases. Such expansions are expected to occur over a period of six years. The facilities shown will be designed to heat and dehydrate approximately 250,000 barrels of total fluid per day, and to sweeten and treat 120 million standard cubic feet per day (120 MMSCFD) of sour gas. The design is based on a Price Waterhouse (third-party) study (Reference 8.5.1) of properties, rates, components. While the pipeline is designed to handle future discoveries, the process plant can expand more easily if necessary. Up to 50,000 barrels per day (BPD) of produced water will be cleaned and disposed of through an ocean outfall and diffuser line. The reader may also wish to refer to the Development Plan for Onshore Pipelines and the Gaviota Processing Facility, Santa Barbara County, Chevron U.S.A., Inc., June 1983 (Reference 8.5.2) for additional information. This document is on file with the County of Santa Barbara, Resource Management Department.

8.2 Production Handling Facilities

8.2.1 Oil Dehydration and Shipping

The primary function of the oil processing facility is to remove water and solids from the crude oil stream, and to stabilize the oil to an acceptable vapor pressure, thus rendering it acceptable for transportation to a refinery. The facility will also have the capability to reduce the hydrogen sulfide content in the treated crude oil to 10 ppm or less, to treat the separated brine (produced water) so as to be suitable for ocean disposal, and to provide short-term crude oil storage facilities.

8.2.1.1 Inlet

Crude oil emulsion and free water will enter the Gaviota facility from the onshore pipeline. It will pass through an inlet metering station when first reaching Gaviota. The volume of crude reaching Gaviota will be continuously compared to the offshore shipping meters. Differences exceeding preset limits will result in alarms and/or automatic shut in of offshore facilities as warranted.

A valve located downstream of the inlet metering system can direct a portion of the incoming emulsion to the rerun tank if necessary. Crude from the rerun tank will then be pumped into the system downstream from the control valve when operating conditions permit. The rerun tankage will perform the dual function of either providing surge capacity in the event of an onshore facilities shutdown or acting as a transfer point to reintroduce production into the treating facilities.

Emulsion then enters a free water knock out (FWKO) vessel where free water that has settled out in the pipeline will be routed to the produced water treatment plant.

8.2.1.2 Oil Dehydration

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

The emulsion will first enter the FWKO vessel and then enters heat exchangers that utilize waste heat from the cogeneration power plant supplying electrical power to the onshore facility (see Section 8.3.3 regarding the cogeneration facilities). In addition, excess heat from oil and water streams leaving the coalescers will be transferred to the incoming emulsion stream. The oil and water mixture then flows to the dehydration vessels.

Electrostatic grids located in the processing section of each treating (coalescer) vessel cause droplets of water suspended in the oil stream to be attracted to each other (coalesce). These larger drops of water then settle to the bottom of the treater more rapidly than they would without this coalescing section. The use of electrostatic treaters coupled with an emulsion heater will result in a net fuel savings and corresponding heater emissions reduction. Dehydrated oil will also pass through a dry oil/wet oil exchanger to preheat the incoming crude. Produced water extracted during dehydration will flow through heat exchangers and will be commingled with free water from the FWKO before entering the produced water treating facility.

8.2.1.3 Oil Shipping

Dehydrated oil will leave the dehydration unit with a water content of less than three percent. Actual water cut will vary depending upon the difficulty in breaking the emulsion and the percent water in the emulsion when it reaches the Gaviota facility. Before entering the shipping tank, the crude stream will pass through a monitor to ensure that it meets pipeline specifications; crude that does not will be sent to the rerun (reject) tank. Off-specification crude (i.e., water cut greater than three percent) will be pumped through the treating vessels again. A 10,000 barrel insulated shipping tank will provide about 2 to 4 hours surge capacity at peak flow rates. The rerun (reject) tank will have a 40,000 barrel crude capacity. The crude oil will be transported from the Gaviota processing facility to Chevron's El Segundo Refinery by means of a proposed industry pipeline from Santa Barbara County to the Los Angeles Basin.

8.2.2 Waste Water Handling

Water treatment equipment and processes are designed to remove the oil and solids from the water to such a degree that the water is suitable for ocean discharge through the outfall pipeline. Produced water removed during oil and gas dehydration will be stored in a 5000 bbl oily water tank. From this tank, waste water will be processed through a corrugated plate interceptor (CPI), and two 77,000 bbl/day flotation units. Gas flotation units induce gas into the produced water in an air flotation chamber. The gas bubbles expand and carry the oil and solids to the surface, where they are skimmed off. "Clean" water is then drawn off and discharged through the proposed ocean outfall line.

The produced water will be monitored for water quality (pH and TSS), and routed through the treated water tank (3000 bbl). Then if flows directly to the outfall line. If for any reason the required water quality, as determined by the Regional Water Quality Control Board, is not achieved, the produced water will be routed back to the re-run tank for further treatment.

Liquids and suspended solids removed during water treating will be collected in the sump tank. Oil will be pumped to the dirty oil tank, and water will be pumped to the oily water tank. Solids will be hauled away by vacuum truck and disposed of at a government approved disposal site.

8.2.3 Ocean Outfall

Chevron proposes to construct an ocean outfall at Gaviota to handle up to 50,000 bbls. per day of produced water. The proposed ocean outfall line will extend southward from the water treatment facility, through the Getty marine terminal site and parallel an existing submerged pipeline alignment directly offshore. The submarine line will be sized at 12" (30 cm) in diameter, 3500' (1066 m) in length. The outfall dispersion segment at the terminus of the line will be 12" (30 cm) in diameter and 150' (45 m) long. The outfall release point will start at the 70' (21 m) water depth or 300' (91 m) beyond the historical kelp bed, whichever is greater. The offshore portion of the line will be assembled onshore and installed with the use of a lay barge or towing technique. The alignment of the outfall line will avoid rocky outcrop areas.

Effluent concentrations will be in compliance with the discharge requirements of the Water Quality Control Plan for Ocean Waters (i.e., California Ocean Plan) as determined by the California State Water Resources Control Board (SWRCB). The outfall effluent will also meet the criteria of the SWRCB Ocean Thermal Plan. The Thermal Plan requires that discharge will not exceed 4°F above ambient after initial dilution, at a point 1000' (305 m) from the discharge..

Sampling, monitoring and reporting of this effluent discharge will also be in accordance with permit requirements. Chevron, as operator, will conduct self-monitoring programs and submit reports necessary to determine compliance with the waste discharge requirements. Such monitoring programs shall comply with Guidelines for Monitoring the Effects of Waste Discharge on the Ocean issued by the Executive Director of the State Board. Adherence to these guidelines will ensure that any impact from potential thermal pollution will be mitigated to acceptable levels.

8.2.4 Boiler Feedwater Treatment System

The boiler feedwater system is a recyclable (closed) water supply system, utilizing fresh water for start-up and makeup requirements. Fresh water makeup is introduced into the system from nearby groundwater wells at a rate of 2000 barrels per day (bpd).

Fresh water is filtered, stored in a 180 bbl tank, and pumped to the oil and gas plant for utility water. For potable water needs, the filtered fresh water undergoes chemical treatment and will be stored in the potable storage tank (100 bbl.). A continuous supply of 25-30 barrels of water per day will be available for drinking water, showers, and eyewash stations.

Blowdown from the waste heat recovery boiler is transferred to the blowdown and recycle tank, filtered, and then recycled, entering a two-stage deionizer process. The deionized water may be stored, with a portion of the water used as dilution for the caustic deionizer units. The remaining deionized water will enter the steam condenser and deaerating feedwater heater, and commingle with steam from the waste heat recovery boiler and condensate return in the condensate surge vessel. The feedwater is then run through a "polishing" filter and deionizer and enters the waste heat recovery boiler at a rate of 1860 BWPD and operating conditions of 90 psig and 140°F.

8.2.5 Blanket Gas System

Sweet gas provided from the gas treating facility will be used as makeup or blanket gas for all tanks and vessels such as the flotation units, coalescer, crude stabilizer and storage tanks. Gas from the vapor blanketing system will be compressed by the blanket gas compressor. The majority of the gas from the blanket gas compressor will be sent to the gas treating facilities.