SANTA YNEZ UNIT

DEVELOPMENT AND PRODUCTION PLAN UPDATE

JUNE 1985

SECTION I

DEVELOPMENT AND PRODUCTION OVERVIEW

- The offshore oil and gas gathering system for Development Options A and B has been modified as shown in revised Figures 1.2, 1.3, 1.4, and 1.5. The lines remain within the same pipeline corridor.

  - Rather than being decommissioned, the existing produced water line from the OS&T to Hondo A in revised Figures 1.2 and 1.3 for Development Option A will be converted to a NGL/gas pipeline to transport the net gas stream produced from the emulsion treating process on the OS&T back to the Hondo A platform.

  - The Option B pipeline configuration will have an emulsion pipeline from the Hondo B platform to the Las Flores Canyon oil treating facilities with the existing Hondo A pipeline being disconnected from the OS&T and tied in midline. The DPP shows an emulsion pipeline connecting Hondo B to Hondo A and a pipeline from Hondo A to the onshore oil treating facility.

  - The Option B gas pipeline configuration has also been altered to show a pipeline bringing gas onshore from the Sacate, Pescado, and Hondo B platform with branches originating at the Pescado and Hondo B platforms; and the second gas pipeline (existing) transporting gas solely from the Hondo A platform. The gas pipeline configuration in the DPP has one pipeline transporting gas onshore from the Sacate and Pescado fields and the second pipeline transporting gas onshore from the Hondo field.

  - The power cables from the onshore plant and between platforms are now dual cables, rather than one, in the Option B scenario. Instead of being connected to the Hondo A platform as shown in the DPP, the two cables from the onshore plant now connect to the Hondo B platform. There is an additional cable connecting the Hondo A and Hondo B platforms.

- Exxon has agreed to use pipeline transportation if it is available to our intended destination, Baytown, Texas, and if its cost is reasonable when balancing economic and environmental impacts of alternative transportation modes. However, since it is not certain at this point in time that a pipeline will be available or that its tariffs will be reasonable, Exxon is pursuing its marine alternative through the Las Flores Canyon Consolidated Marine Terminal (See Addendum to Section X).

- The nearshore Marine Terminal SALM has been relocated to 14,000 feet offshore. Table 1.1 and Figure 1.6 have been revised accordingly.

- The Development Options A and B schedules now reflect a one-year permitting delay, as shown in revised Figures 1.7 and 1.8. Drilling, production start-up, production profiles and construction activities are also all delayed one year for all proposed development.

TABLE 1.1

FACILITY LOCATIONS

Revised 6/85

	Lambert Coordinates, Zone 6		Polar Coordinates	
Facility	x	y	Longitude	Latitude
Hondo A	832,341	830,947	120° 07′ 14″ W	34° 23′ 27″ N
OS&T & SALM	838,727	835,892	120° 05′ 60″ W	34° 24′ 18″ N
Hondo B	817,960	826,503	120° 10′ 03″ W	34° 22′ 37″ N
Pescado A	780,320	816,840	120° 17′ 28″ W	34° 20′ 48″ N
Pescado B-1	773,330	818,290	120° 18′ 52″ W	34° 20′ 59″ N
Pescado B-2	787,400	817,800	120° 16′ 04″ W	34° 20′ 60″ N
Sacate	769,640	834,300	120° 19′ 43″ W	34° 23′ 36″ N
Marine Terminal	858,138	842,189	120° 02′ 11″ W	34° 25′ 27″ N

NOTE: Facility locations are approximate and may change slightly based on ongoing design studies.

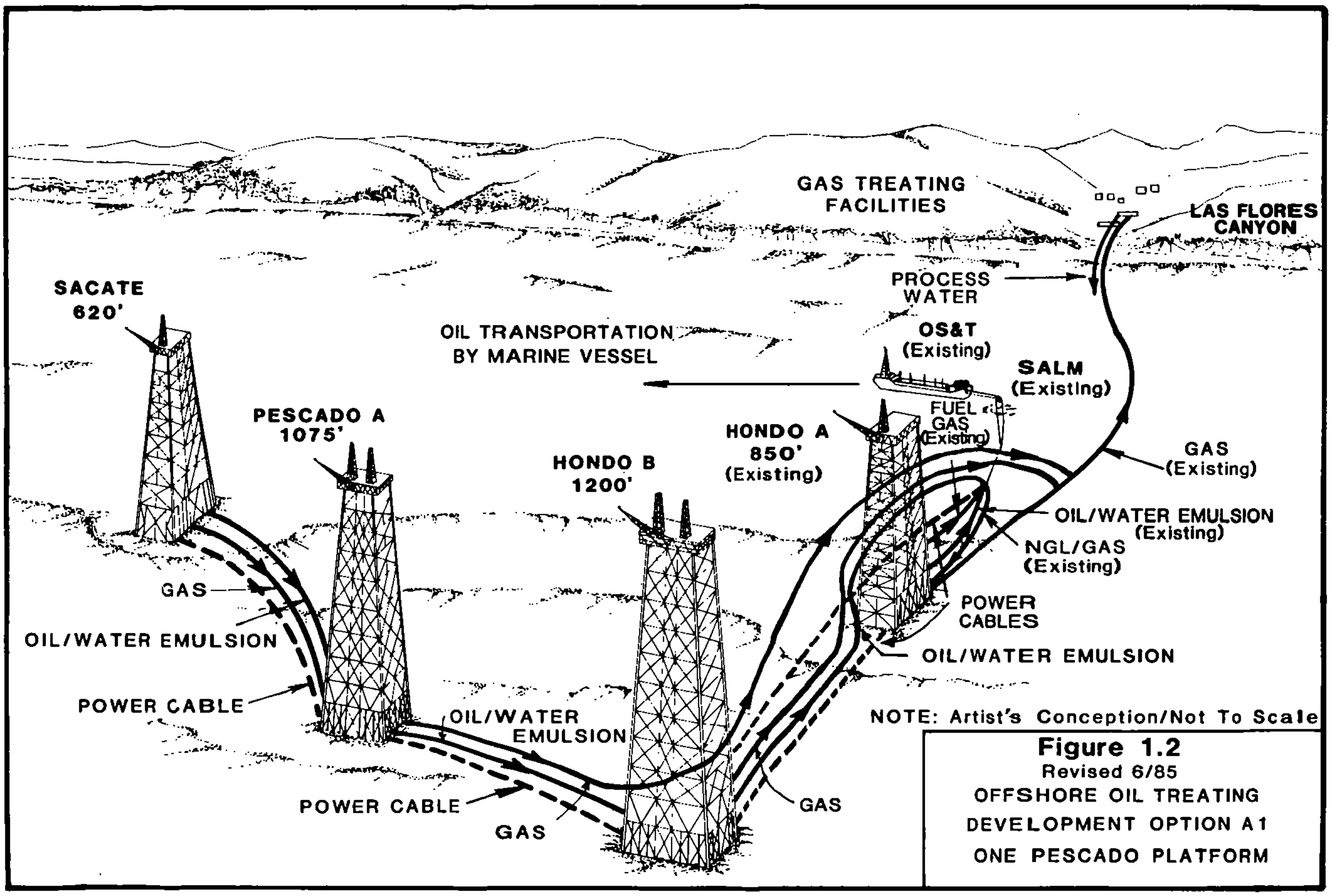
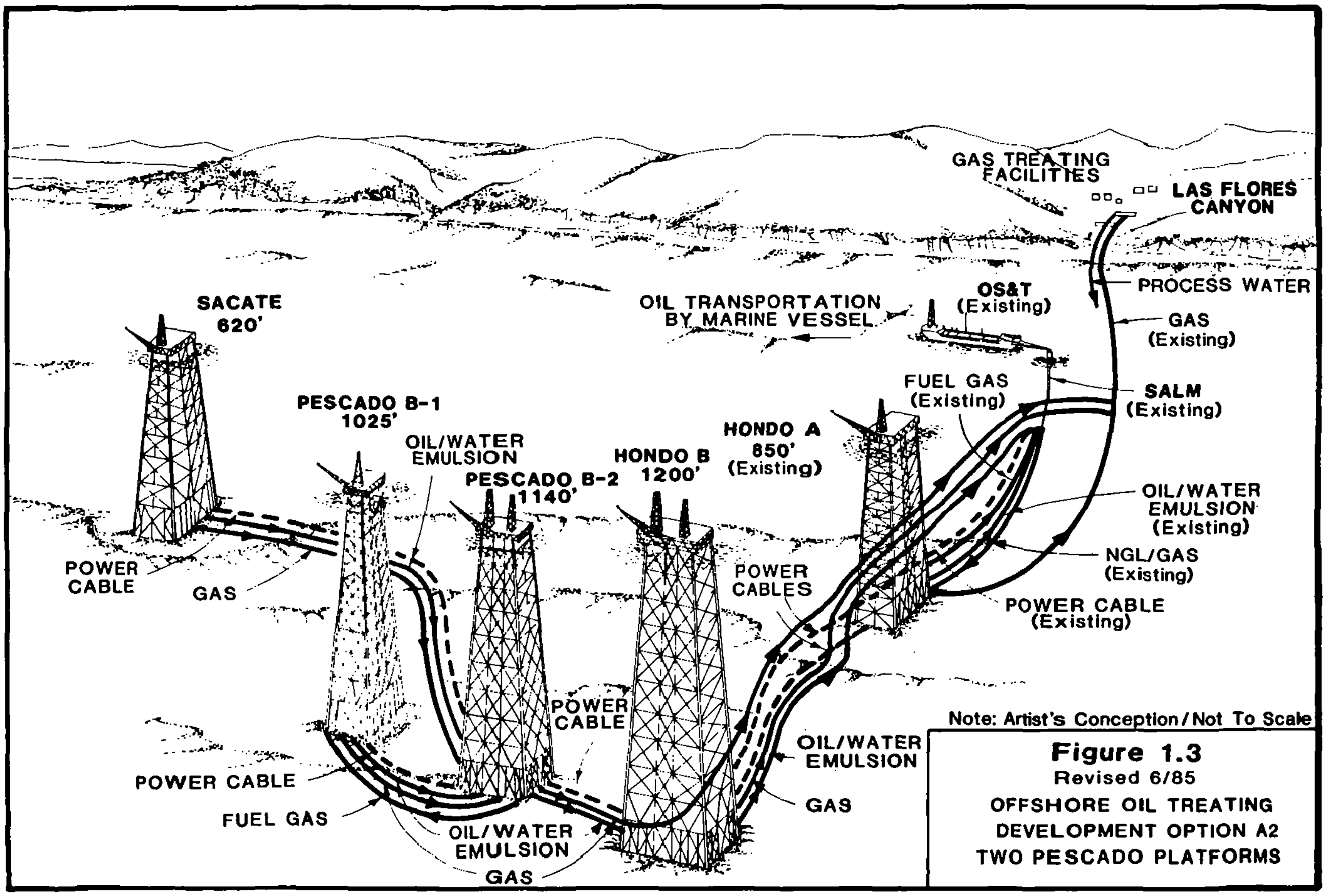


Figure 1.2
Revised 6/85
OFFSHORE OIL TREATING
DEVELOPMENT OPTION A1
ONE PESCADO PLATFORM



Note: Artist's Conception/Not To Scale

Figure 1.3
Revised 6/85
OFFSHORE OIL TREATING
DEVELOPMENT OPTION A2
TWO PESCADO PLATFORMS

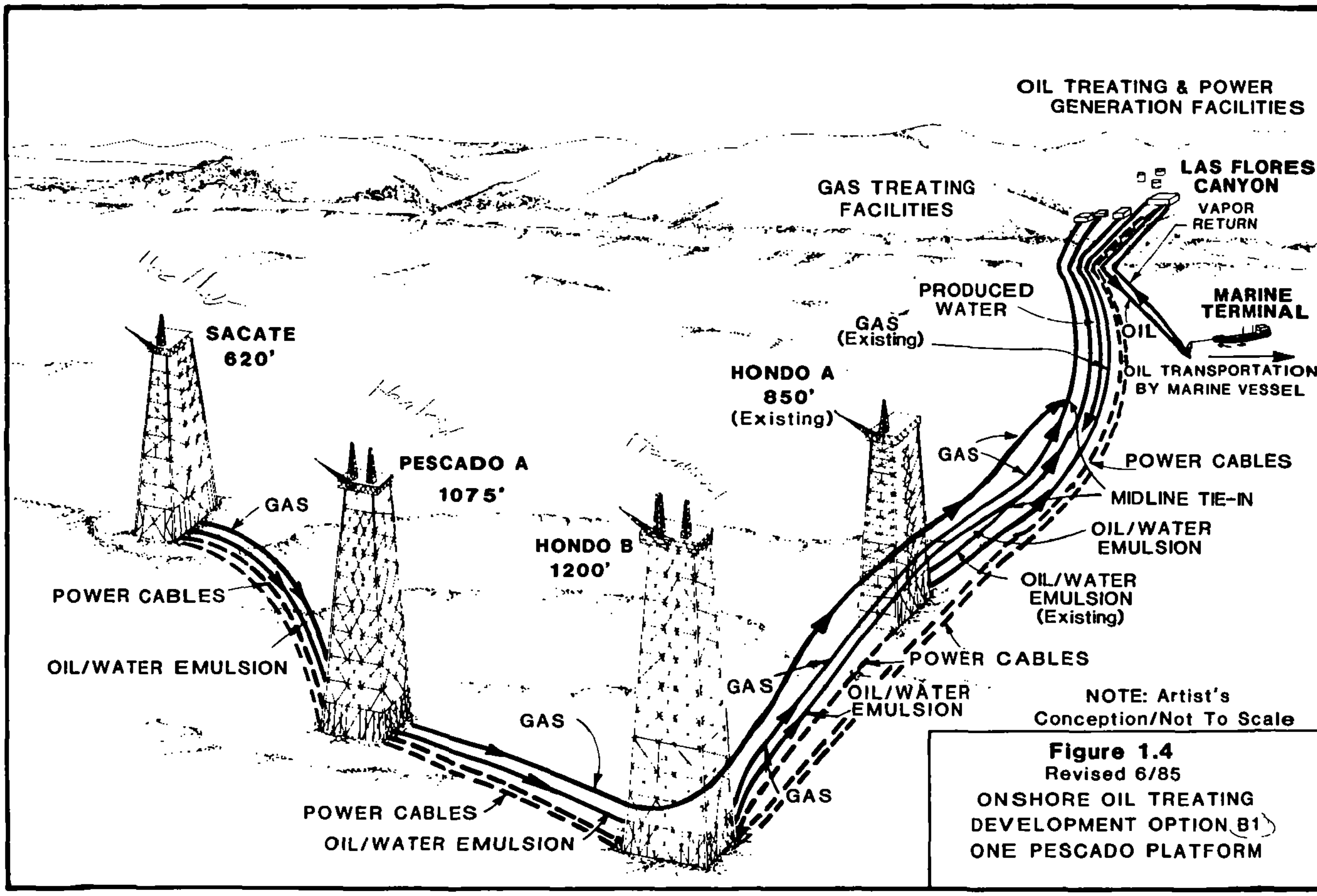
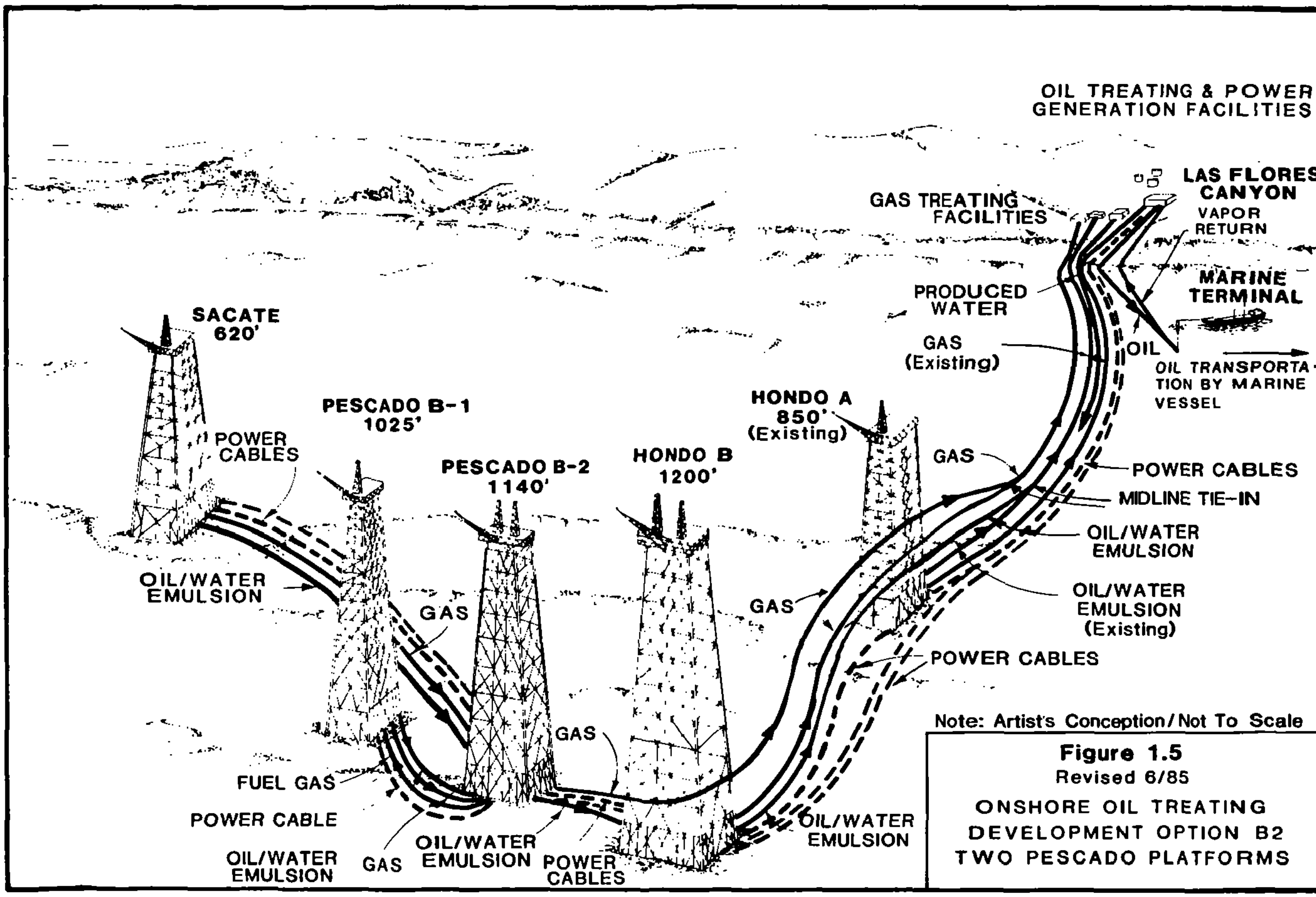


Figure 1.4
Revised 6/85
ONSHORE OIL TREATING DEVELOPMENT OPTION B1
ONE PESCADO PLATFORM



Note: Artist's Conception/Not To Scale

Figure 1.5
Revised 6/85

ONSHORE OIL TREATING
DEVELOPMENT OPTION B2
TWO PESCADO PLATFORMS

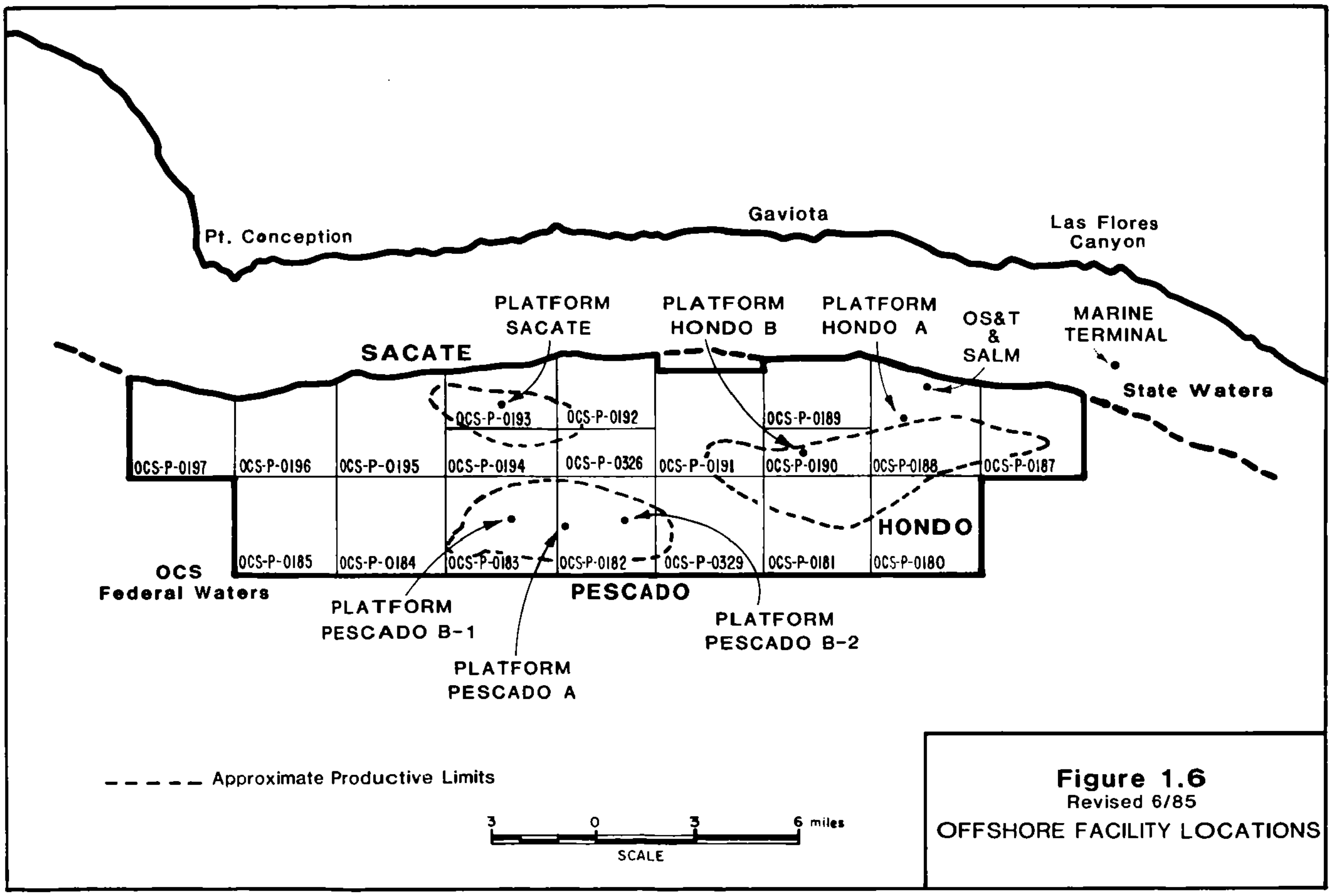
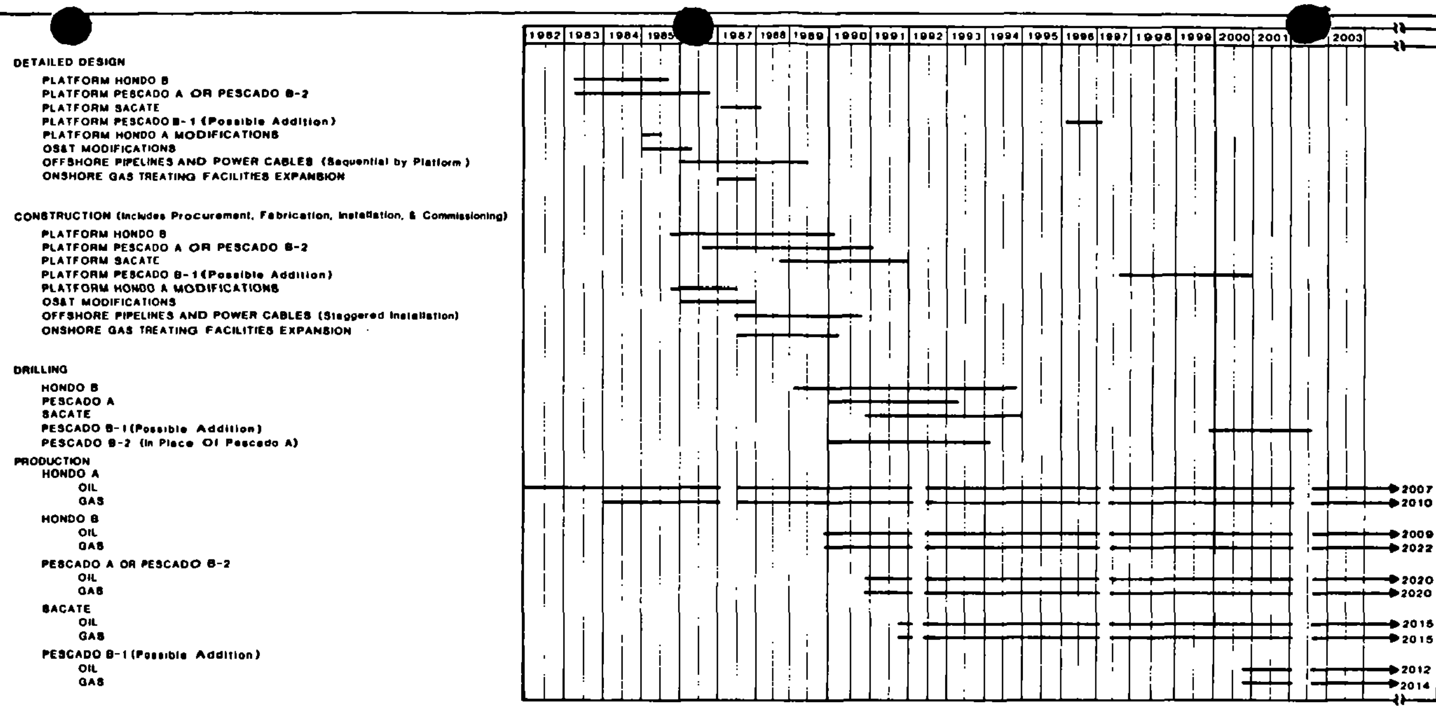


Figure 1.6
Revised 6/85
OFFSHORE FACILITY LOCATIONS



NOTES. 1. All Durations And Schedule Dates Are Approximate.

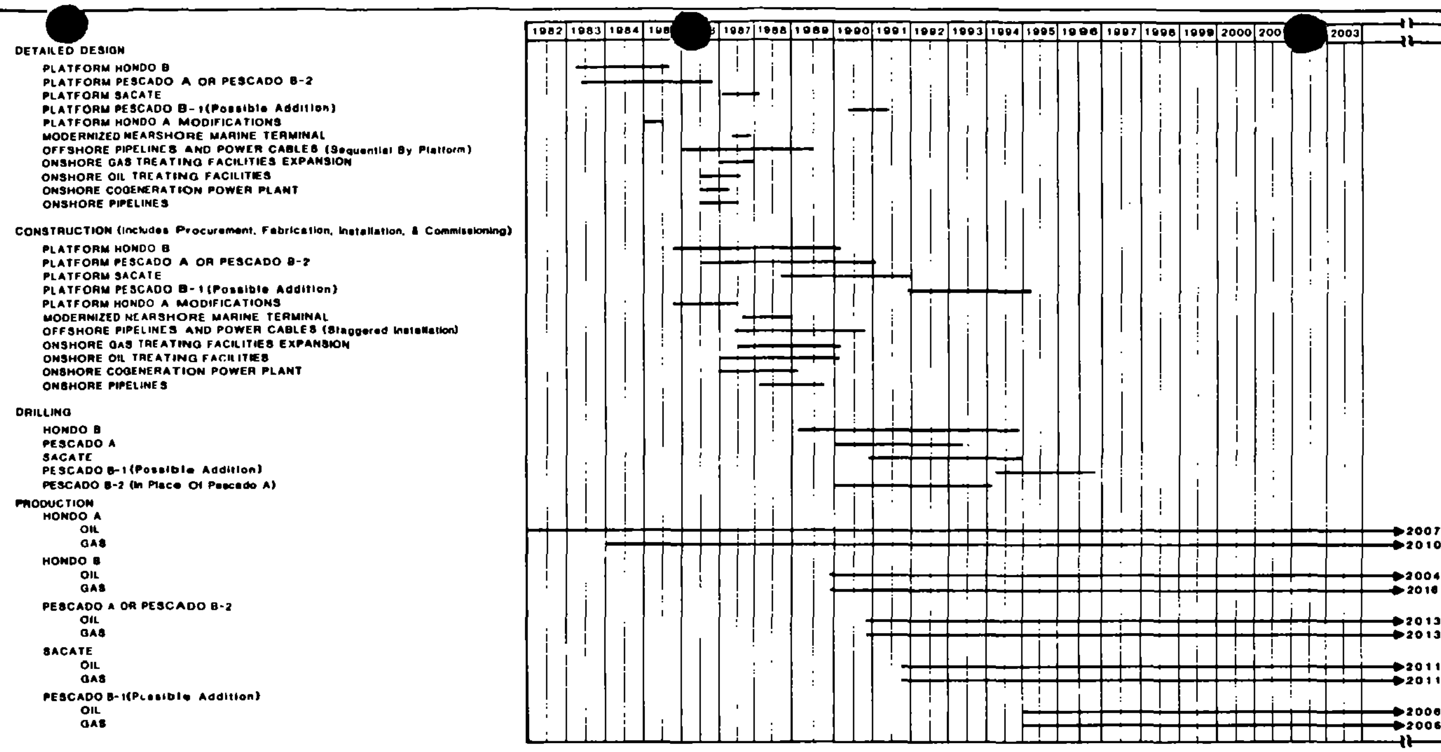
2. The Design And Construction Times For Pescado B-1 Indicated Above Include Allowances For Work Associated With The Additional Required Pipelines And Power Cables.

3. OS&T Drydocking Will Also Interrupt Production For 17 Weeks In 2011 And 14 Weeks In 2006, 2016. Durations And Years Are Approximate

4. The Current Production Plan Is Based Only On Primary Recovery. Successful Application Of Improved Recovery Techniques Would Extend The Field Lives Beyond The Dates Given Above

Figure 1.7
Revised 8/84

OFFSHORE OIL TREATING DEVELOPMENT OPTION A SCHEDULE



NOTES: 1. All Durations And Schedule Dates Are Approximate.

2. The Design And Construction Times For Pescado B-1 Indicated Above Include Allowances For Work Associated With The Additional Required Pipelines And Power Cables.

3. The Current Production Plan Is Based Only On Primary Recovery. Successful Application Of Improved Recovery Techniques Would Extend The Field Lives Beyond The Dates Given Above.

Figure 1.8
Revised 8/84

ONSHORE OIL TREATING
DEVELOPMENT OPTION B
SCHEDULE

SECTION II

GEOLOGY

- No changes.

SECTION III

RESERVOIR EVALUATION

- Current reservoir description for Hondo B and Pescado is substantially the same as previously reported. Refinements to interpretations have not affected physical development plans and are therefore not addressed in this addendum.

- One additional exploration well (OCS P-0183 No. 2) was drilled at Pescado during late 1982. An addendum to Table 3.1 lists the location and depth of this well. A revised Figure 3.1 shows bottom-hole locations of all exploratory wells including the addition. The well tested oil in the Monterey formation. Results of drill stem tests are presented in an addendum to Table 3.5 of Appendix A.

- The project development schedule for all alternatives (Option A, Option B, and single vs. two platform development at Pescado) has been delayed by one year from previously reported schedules. Drilling, production initiation, and production profiles are all delayed one year for all proposed platforms (Hondo B, Pescado, and Sacate).

- Single platform development at Pescado is currently the preferred alternative and development planning is proceeding in that direction.

Bottomhole Locations

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

Proprietary

Not for Public Release

SECTION IV

PLATFORMS

- The DPP discusses the design and fabrication of a two-piece platform structure. Currently, both one-piece and two-piece jacket designs are being evaluated.

- Pescado and Hondo B platform design bases now include three level deck systems designs. The DPP discusses the two-level deck system design.

SECTION V

DRILLING

- The drilling rigs for Development Option A will be powered by the platform turbines, instead of the diesel engines discussed in the DPP.

SECTION VI

SUBSEA PRODUCTION SYSTEMS

o No changes.

SECTION VII

OFFSHORE PLATFORM FACILITIES

- The Hondo A gas compression capacity has been expanded from the 20 MSCFD given in Section 7.3.1 to 35 MSCFD for sales and an additional 35 MSCFD from the High Pressure Separator for injection.
- The addition of a fired heater on Hondo A to reheat emulsion from the other platforms (Sections 7.3.2 and 7.13.11) will not be required.
- Process changes from the Hondo B, Pescado and Sacate offshore platform facilities include the following:
  - Natural gas conditioning has been added; and the natural gas liquids (NGL) will be pumped into the emulsion pipeline and metered with the emulsion stream, as shown in revised Figure 7.41. The process described in the DPP used gas dehydration with no liquid hydrocarbon removal.
  - Aerial cooling for process heat removal will be replaced by a once-through seawater cooling system.
- Gas sales to POPCO of 30 MSCFD were initiated December, 1983 as anticipated in Section 7.3.1 of the DPP.
- Pipeline sizing and tie-in configurations have been updated. See revised Figures 7.2 and 7.3 and also the Addendum to Section VIII.
- The platform free water shipping and metering system described in Section 7.10.4 has been eliminated.
- Supplementally fired heaters for the waste heat exchanger will not be required for the new platforms, as originally discussed in DPP Section 7.9.3.
- The deck drainage system description given in Section 7.11.5 has been revised to properly describe our current plans. An updated description follows:
  - Process Deck drainage (mostly water) is routed to the Open Drain Sump where skimmed oil is pumped to the Closed Drain Sump and water flows to the Skim Pile. The Skim Pile is the final stage of treatment prior to ocean disposal. Any oil that might collect on top of the Skim Pile is also pumped to the Closed Drain.
  - Closed drains, which handle drainage from the process, will flow to the Closed Drain Sump. Liquids from this sump will be pumped to the Emulsion Surge Tanks.

- Wellbay and Drilling Deck drainage will be routed to the Wellbay Drain Sump. During drilling operations, liquids from the Wellbay Drain Sump will be pumped to the Drilling Deck for treatment.

- The Pipeline Booster Heaters have been eliminated from the Hondo B and Pescado Platform designs.

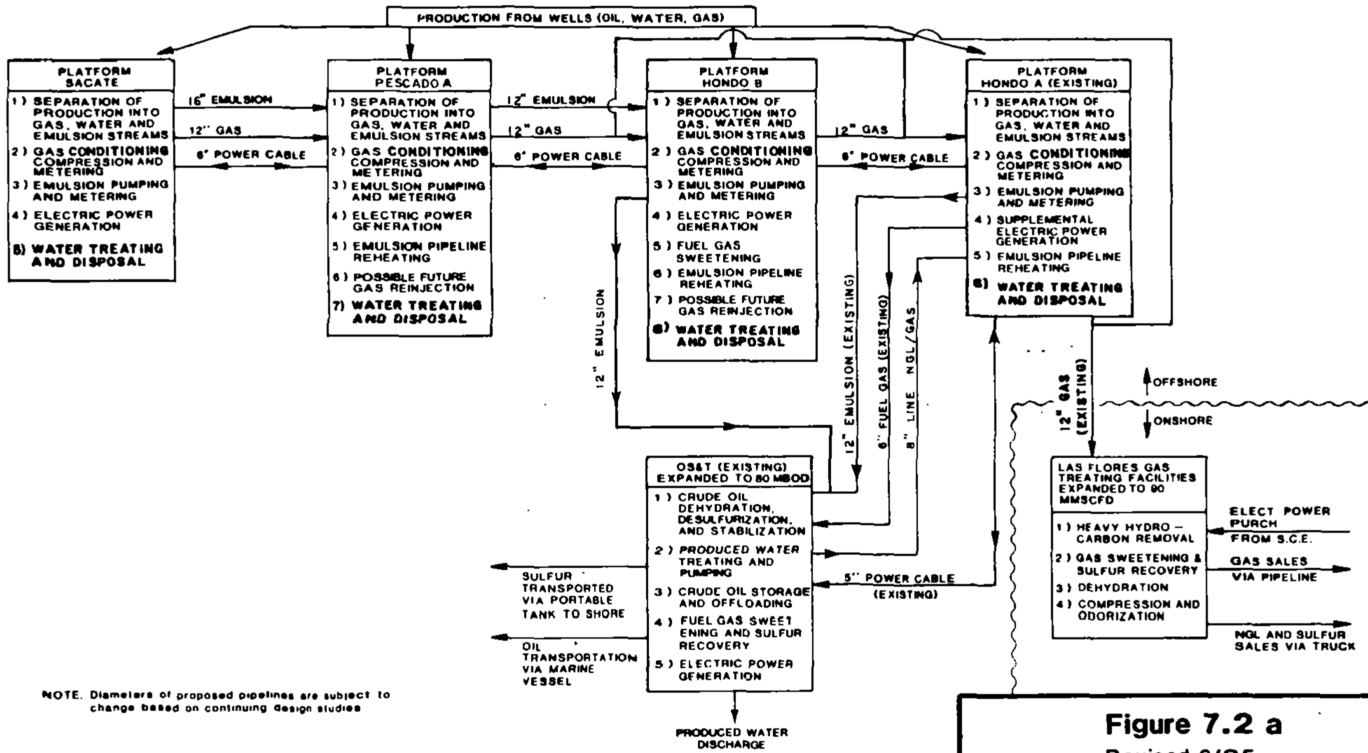


Figure 7.2 a
Revised 6/85
DEVELOPMENT OPTION A1
OFFSHORE OIL TREATING
FUNCTIONAL BLOCK DIAGRAM

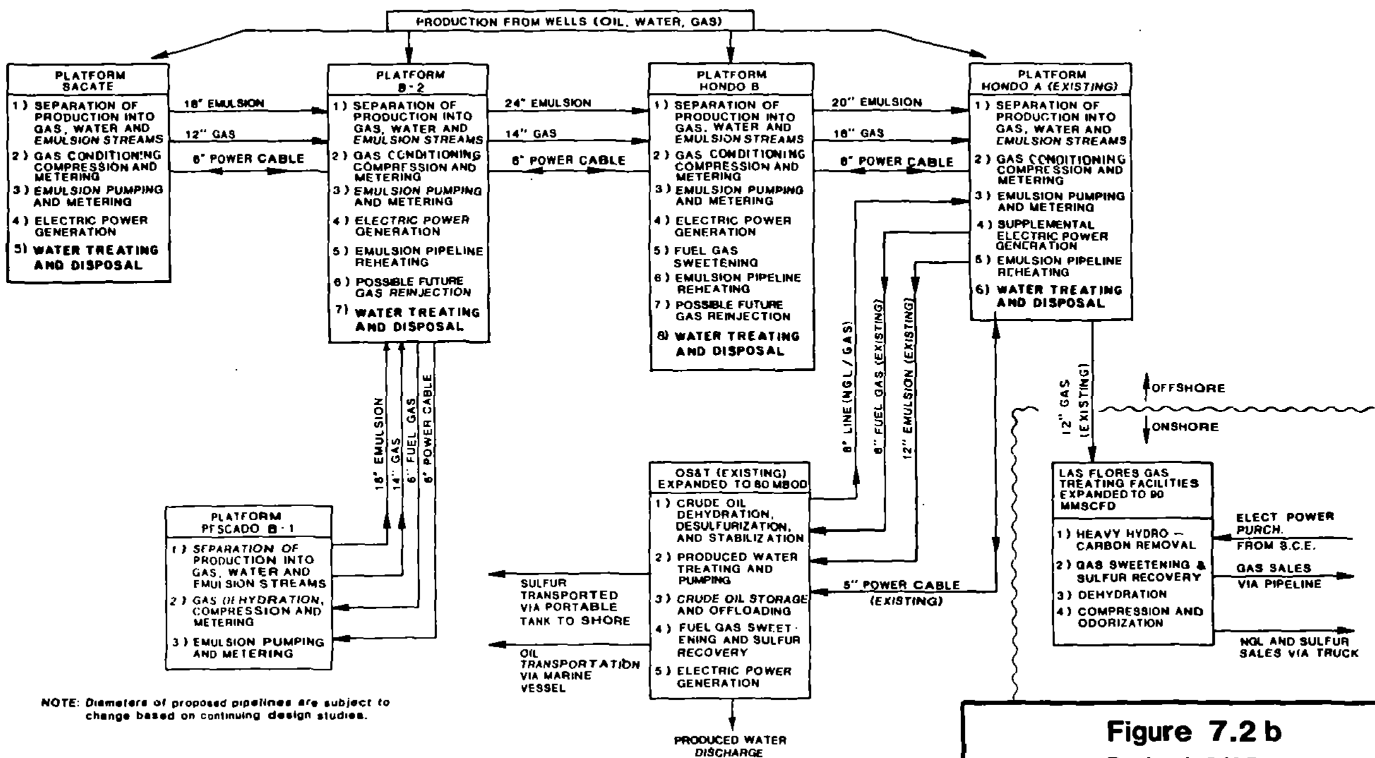
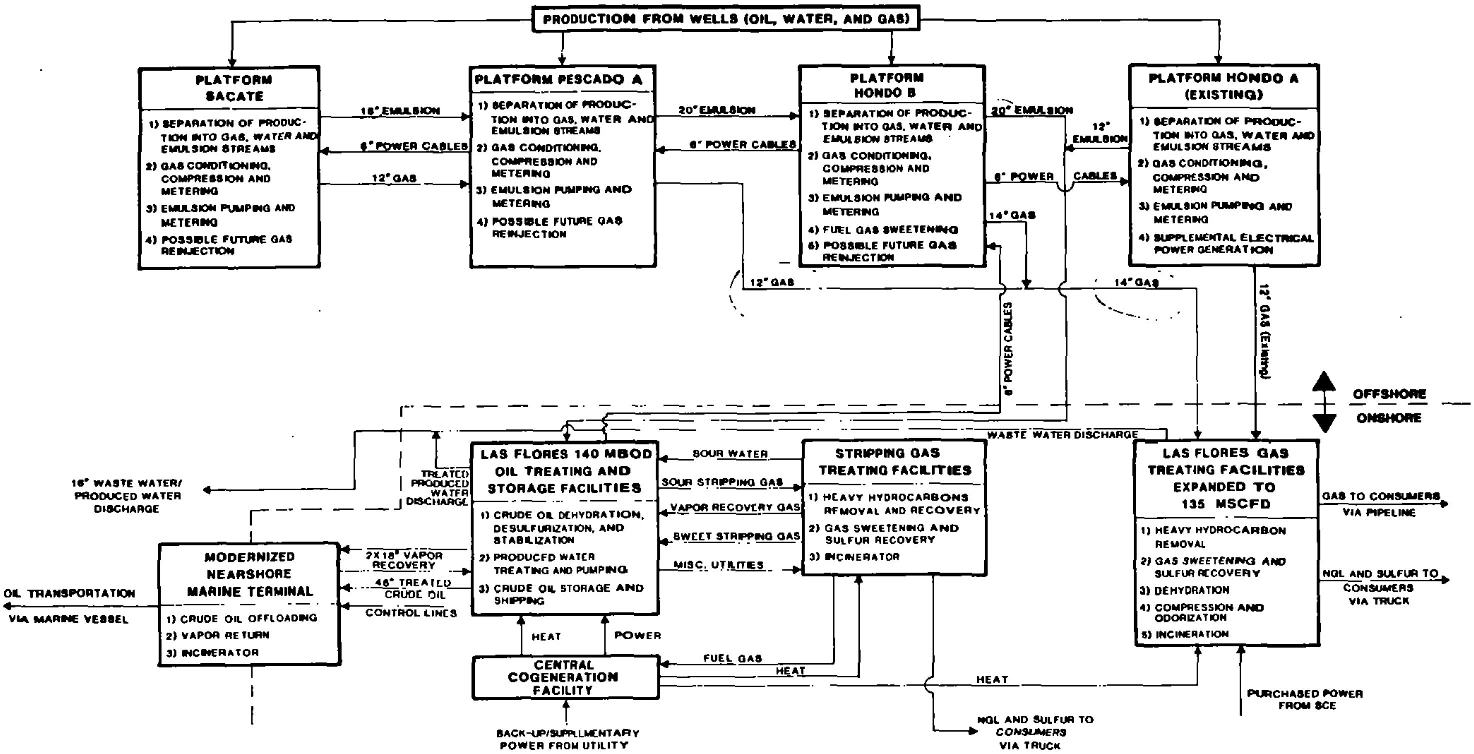


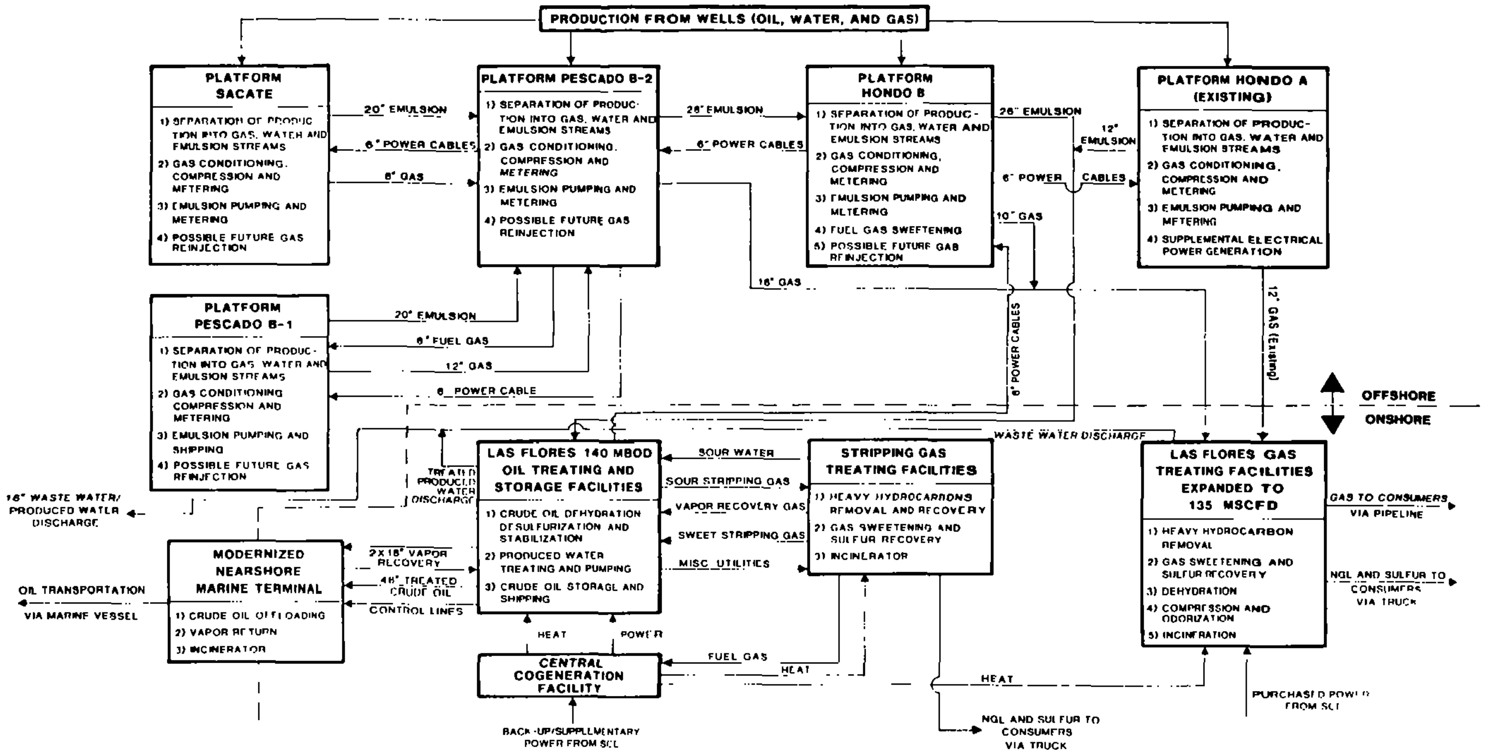
Figure 7.2 b
Revised 6/85
DEVELOPMENT OPTION A2
OFFSHORE OIL TREATING
FUNCTIONAL BLOCK DIAGRAM



NOTE: Diameters of proposed pipelines are subject to change based on continuing design studies.

Figure 7.3a
Revised 6/85

DEVELOPMENT OPTION B1 ONSHORE OIL TREATING FUNCTIONAL BLOCK DIAGRAM



NOTE: Diameters of proposed pipelines are subject to change based on continuing design studies

Figure 7.3b
Revised 6/85
DEVELOPMENT OPTION B2 ONSHORE OIL TREATING FUNCTIONAL BLOCK DIAGRAM

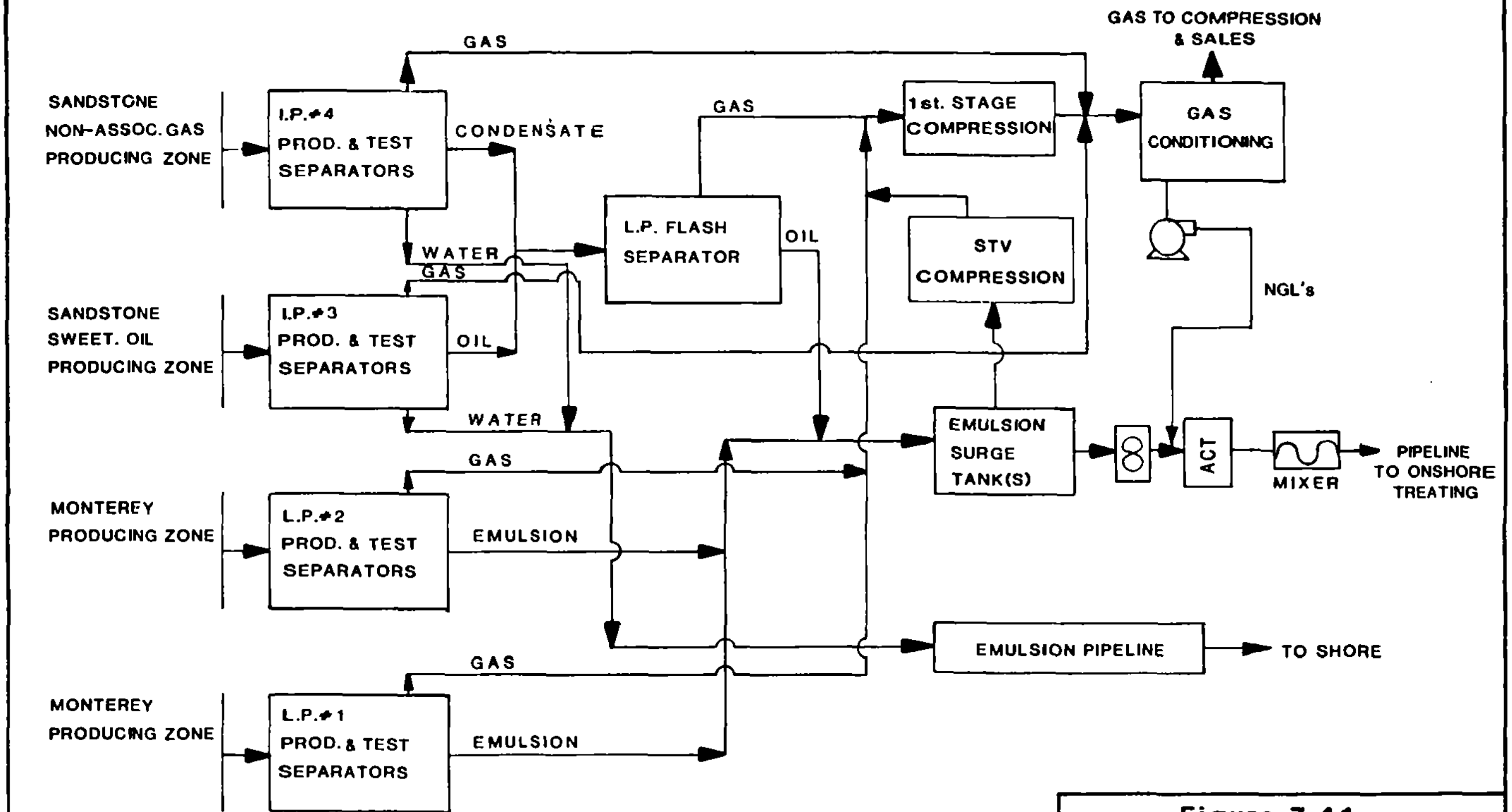


Figure 7.41
Revised 6/85
TYPICAL FLUID FLOW TO A PLATFORM A.C.T. METER

SECTION VIII

PIPELINES

- The offshore oil and gas gathering system for Development Options A and B has been modified as previously shown in revised Figures 1.2, 1.3, 1.4, and 1.5. The lines remain within the same pipeline corridor. Tables 8.1, 8.2, and 8.3 have also been revised to indicate the most current design information.

  - Rather than being decommissioned, the existing produced water line from the OS&T to Hondo A in revised Figures 1.2 and 1.3 for Development Option A will be converted to a NGL/gas pipeline to transport the net gas stream produced from the emulsion treating process on the OS&T back to the Hondo A platform.

  - The Option B pipeline configuration will have an emulsion pipeline from the Hondo B platform to the Las Flores Canyon oil treating facilities with the existing Hondo A pipeline being disconnected from the OS&T and tied in midline. The DPP shows an emulsion pipeline connecting Hondo B to Hondo A and a pipeline from Hondo A to the onshore oil treating facility.

  - The Option B gas pipeline configuration has also been altered to show a pipeline bringing gas onshore from the Sacate, Pescado, and Hondo B platform with branches originating at the Pescado and Hondo B platforms; and the second gas pipeline (existing) transporting gas solely from the Hondo A platform. The gas pipeline configuration in the DPP has one pipeline transporting gas onshore from the Sacate and Pescado fields and the second pipeline transporting gas onshore from the Hondo field.

  - The power cables from the onshore plant and between platforms are now dual cables, in the Option B scenario rather than a single cable. Instead of being connected to the Hondo A platform as shown in the DPP, the two cables from the onshore plant now connect to the Hondo B platform. There is an additional cable connecting the Hondo A and Hondo B platforms.

  - Various pipeline diameters have been revised. Revised Tables 8.1, 8.2 and 8.3 include those changes though they may change again as the final design and configuration are optimized.

TABLE 8.1

OFFSHORE PIPELINE SYSTEM CHARACTERISTICS

OFFSHORE OIL TREATING - DEVELOPMENT OPTION A

Pipeline Segment	Development Option	Segment Length (miles)	Gas Pipeline: Design Flow Rate (MSCFD)	Gas Pipeline: Diameter[a] (inches)	Emulsion Pipeline: Design Flow Rate (KBD)[b]	Emulsion Pipeline: Diameter[a] (inches)
Sacate to Pescado A	A1	4	40	12	20	16
Pescado A to Hondo B	A1	7	-	-	65	12[f]
Pescado A to Midline tie-in	A1	12	70	12	-	-
Hondo B to OS&T	A1	5	-	-	110	12[f]
Hondo B to midline tie-in	A1	5	70	12	-	-
Hondo A to OS&T[d]	A1/A2	2	-	-	120	12[e]
Hondo A to Shore	A1/A2	7	90	12[e]	-	-
Sacate to Pescado B-2	A2	5	40	12	20	18
Pescado B-1 to Pescado B-2[c]	A2	3	50	14	40	18
Pescado B-2 to Hondo B	A2	6	60	14	60	24
Hondo B to Hondo A	A2	3	90	18	120	20

[a] Pipeline diameters optimized to minimize construction and operating costs. Diameters listed are subject to change based on continuing design studies.
[b] Volume of emulsion throughput (oil plus water).
[c] Plus 6-inch diameter fuel gas line.
[d] Plus 6-inch diameter fuel gas line and 8-inch diameter return water line (both existing; water line NGL return).
[e] Existing line.
[f] Insulated lines

NOTE: 1. Development Option A1 - One Pescado Platform Configuration.
2. Development Option A2 - Two Pescado Platform Configuration.

Revised June, 1985

TABLE 8.2

ONSHORE PIPELINE SYSTEM CHARACTERISTICS

Fluid	Development Option	Pipeline Origin	Pipeline Destination	Onshore Length (miles)	Pipeline Diameter (inches)[b]	Design Flow Rate
Produced gas[a]	A,B	Platform Hondo A	Gas Treating facilities	1.6	12	90 MSCI
Produced gas	B	Platforms Pescado A and Hondo B	Gas treating facilities	1.6	14	140
Sales gas[a]	A,B	Gas treating facilities	Gas distribiution systems tie-in	1.6	12	110 MSCI
Crude oil/water emulsion	B	Platform Hondo A/Hondo B	Oil treating facilities	1.6	20	210 KBD
Treated produced water	B	Oil treating facilities	Offshore outfall	1.6	16	70 KBD
Product crude oil	B	Oil treating facilities	Nearshore SALM	1.6	46	45 KBH
Inert gases and hydrocarbon vapors (vapor-balance line)	B	Nearshore SALM	Oil treating facilities	1.6	2 x 18"	8
Hydraulic fluid (hydraulic control line bundle)	B	Oil treating facilities	Nearshore SALM	1.6	8 x 3/8"	-

[a] Existing pipeline.
[b] Diameters of proposed pipelines are subject to change based on continuing design studies.

NOTE: 1. Development Option A - Offshore Oil Treating.
2. Development Option B - Onshore Oil Treating.

Revised June, 1985

TABLE 8.3

OFFSHORE PIPELINE SYSTEM CHARACTERISTICS

OFFSHORE OIL TREATING - DEVELOPMENT OPTION B

Pipeline Segment	Development Option	Segment Length (miles)	Gas Pipeline Design Flow Rate (MSCFD)	Gas Pipeline Diameter[a] (inches)	Emulsion Pipeline Design Flow Rate (KBD)[b]	Emulsion Pipeline Diameter[a] (inches)
Sacate to Pescado A	B1	4	30	12	30	16
Pescado A to Hondo B	B1	7	-	-	100	20
Pescado A to Midline tie-in	B1	12	70	12	-	-
Hondo B to Shore	B1	10	70	14	210	20
Hondo A to Shore[d]	B1/B2	7	90[d]	12[d]	-	-
Hondo A to Midline Tie-in	B1	3	-	-	35	12[f]
Shore to Nearshore SALM[e]	B1/B2	3	8	2x18"	45KBH	46
Shore to Water Outfall	B1/B2	1.5	-	-	70[g]	16
Sacate to Pescado B-2	B2	5	30	8	30	20
Pescado B-1 to Pescado B-2[c]	B2	3	30	12	50	20
Pescado B-2 to Hondo B	B2	6	-	-	120	26
Pescado B-2 to Shore	B2	16	170	16	-	-
Hondo B to Midline Tie-in	B2	5	70	10	-	-
Hondo B to Shore	B2	10	-	-	220	26
Hondo A to Midline Tie-in	B2	3	-	-	35	12[f]

a Pipeline diameters optimized to minimize construction and operating costs. Diameters listed are subject to change based on continuing design studies.
b Volume of emulsion throughput (oil plus water).
c Plus 6-inch diameter fuel gas line.
d Existing line.
e Product Oil plus hydraulic control line bundle.
f Existing line to be disconnected from OS&T and tied-in midline to the Hondo B to Shore 20" line.
g Treated produced water.

NOTE: 1. Development Option B1 - One Pescado Platform Configuration.
2. Development Option B2 - Two Pescado Platform Configuration.

Revised June, 1985

SECTION IX

OIL AND GAS TREATING FACILITIES

- The Las Flores Canyon site development plan has changed substantially from that originally submitted with the DPP. The changes are illustrated in revised Figure 9.2. Figure 9.3 has been modified to reflect the as built 30 MMSCFD gas treating facility. This facility started up in December of 1983.

- Site 1 on Figure 9.2 is the original 13.6 acres approved for construction. The initial 30 MMSCFD gas treating facility, currently in operation, was constructed on 6.3 acres within this approved area. Under Development Option A, the gas treating facility expansion to 90 MMSCFD will require approximately 3.3 acres more than the initial gas treating facility. Under Development Option B, the gas treating facility expansion to 135 MMSCFD, a standalone stripping gas treating facility, and the NGL storage for both facilities will require approximately 3.6 acres more than the initial gas treating facility. Neither development option will require more plot space than the original 13.6 acre site. Figure 9.3 and 9.4 as well as Tables 9.3 and 9.4 have been updated to reflect these modifications.

- Exxon has continued to expand on its original commitment to accommodate future oil and gas facilities expansion. Development plans have been refined to the extent possible, consistent with the SYU FEIS/R and Santa Barbara County permit conditions. In doing so, several major SYU facilities have been relocated. Crude oil storage is now sited entirely in Corral Canyon east of Corral Creek. Oil treating and cogeneration facilities lie on an expanded 13+ acre pad which can accommodate future oil treating expansion. Marine Terminal pumping facilities have also been relocated to Corral Canyon leaving over 4 acres available in the northern portion of the existing Las Flores Canyon site for future gas treating. Preparation of these sites requires earthwork of approximately 1,300,000 cubic yards compared to 510,000 cubic yards mentioned in the DPP. Figure 9.6 has been revised through the addition of two new figures 9.6a and 9.6b. These figures depict current plot plans of the oil treating/power generation and terminal facilities.

- Under Option B, the stripping gas to the oil treating facility will be supplied by a standalone stripping gas facility rather than the expanded gas treating facility. It was necessary to design a standalone stripping gas treating facility to ensure that the stripping gas facility would be available at startup of the oil treating facility. This eliminates potential oil production delays if gas contracting terms could not be agreed upon which would force a delay in gas plant expansion. Additionally, a standalone stripping gas facility provides operational flexibility by separating facilities required for oil production from those required for gas production. The processes involved in the standalone stripping gas facility are described in Attachment A. Exact quantities of sweet and sour stripping gas have not fully been defined.

- Fuel gas to the steam boilers will contain a maximum of 240 ppm of sulfur compounds. Flares will be provided with forced air blowers, steam injection, or high velocity mixing burners to reduce smoke.

- Process wastewater from the POPCO gas treating facility is currently being trucked to an appropriate disposal site. This method of disposal will probably continue until an ocean outfall line becomes available under either development option. For both Development Options A and B, process wastewater from the gas treating facilities will first be treated to remove hydrogen sulfide and other undesirable components and then blended with treated produced water from the oil treating facilities. Processed water from both the gas treating facility and the oil treating facility will be treated to the required quality and then pipelined to an offshore outfall discharge in accordance with a NPDES permit (see Figures 1.2 and 1.3). This wastewater outfall line may be located as much as 1.5 miles offshore as conditioned by Santa Barbara County.

- The current design for the expanded gas treating facilities under both development options differs from that originally proposed in the 1982 DPP by the addition of Thermal DeNOx equipment and potential NGL treating units for the total NGL production as described in Attachment B. Additionally, under Option B the existing fired boilers will be shut down when the gas plant is expanded to 135 MMSCFD. Hot oil steam generators will be used to capture waste heat from the cogeneration plant hot oil system and supply part of the gas treating facility's steam needs. An incinerator waste heat boiler will supply the remaining steam needs. The storage tanks for methanol, refrigerant, waste liquid and firewater will not require expansion under either development option.

- For Development Option A, the steam boilers will use low NOx burners as well as the Thermal DeNOx process (ammonia injection into the firebox) to reduce nitrogen oxide emissions. For Development Option B, the waste heat incinerator will use low NOx burners as well as the Thermal DeNOx process to reduce nitrogen oxide emissions.

- Emissions of hydrogen sulfide and sulfur dioxide from the gas treating facilities will be minimized by processing the acid gas in sulfur recovery units where 99.9 percent of the hydrogen sulfide will be converted to elemental sulfur. The remaining tail gas will then be incinerated by combustion in either the steam boiler burners (Option A) or the waste heat incinerator (Option B).

- Compressor seal leakage will be routed to either the steam boiler burners (Option A) or waste heat incinerator (Option B) for combustion to reduce fugitive emissions.

- The Oil Treating Facility Rerun Tanks will be 40,000 barrel dome-roof tanks rather than 20,000 barrel cone-roof tanks, mentioned in the DPP, Section 9.5.3.4.

- The cogeneration power plant has been downsized to 25 MW consistent with the SYU permit conditions. Additionally, Selective Catalytic Reduction (SCR) technology is being applied with water injection to reduce NOx emissions by over 90 percent. The cogeneration plant will receive fuel from the stand-alone stripping gas treating facility rather than from the expanded gas treating facilities as described in the original DPP. This cogen plant will supply the electrical and waste heat requirements of the stripping gas treating facility and the oil treating facility, and will supply waste heat to the expanded gas treating facility hot oil steam generators.

ATTACHMENT A

Stripping Gas Treating Facilities

The oil plant will require a stripping gas treating facility to handle sour gas produced by the oil treating processes. The stripping gas treating facility will be capable of upgrading the stripping gas for use as fuel gas or for return to the oil plant for use as sweet stripping gas in the oil plant stabilizer. The stripping gas facility will require heavy hydrocarbon removal, gas sweetening, sulfur recovery, and potential NGL treating see Figure 9.16).

The sour stripping gases from the oil plant will first be air cooled to condense out free water for handling by the sour water system. The air cooler will also condense out hydrocarbon liquids for subsequent processing in the deethanizer. Pipeline gas from the platforms will be used as make-up gas to the stripping gas facility as needed for process equipment loading, fuel gas demand, and for recycling gas back to the oil plant as a sweet, dry stripping gas supply stream.

The sour pipeline gas from the platforms must first be hydrate inhibited using ethylene glycol injection into the gas stream. Hydrates are ice-like solids that form in gas streams which are chilled below ambient temperatures. The pipeline gas can then be refrigerated to condense out its heavy hydrocarbons which are processed in the deethanizer, while the remaining gas is routed to the high pressure contactor for gas sweetening.

The heavy hydrocarbon liquids condensed out of the oil plant's sour stripping gas and the pipeline gas are then stabilized in the deethanizer to produce an NGL liquid product. The deethanizer overhead is a refrigerated gas stream and it will also require hydrate inhibition with ethylene glycol injection. The deethanizer overhead gas will be sweetened in the low pressure contactor.

The ethylene glycol is separated from the gas and hydrocarbon liquids downstream of its hydrate inhibition injection point so that it may be regenerated for reuse. The injected glycol will absorb water and therefore require regeneration similar to the TEG units in the existing POPCO gas plant. The water and other minor amounts of vapors generated by ethylene glycol regeneration will be captured by the vapor recovery system.

To enhance marketing flexibility, Exxon may choose to process NGL's further for the removal of small quantities of undesirable components. If these NGL treating facilities are installed, the NGL from the deethanizer bottoms will be processed through COS catalyst beds, MEA amine treating, Merox caustic treating, and calcium chloride drier beds for removal of COS, H_2S, CO_2, mercaptans, and H_2O. Following these processes, the sweetened NGL will be stored in pressurized tanks prior to transportation to market.

The high and low pressure contactors use the same Flexsorb gas sweetening solvent and solvent regeneration system. Acid gas is removed from the Flexsorb gas sweetening solvent by its steam reboiled regenerator.

The sulfur recovery unit (SRU) is fed with acid gas from the Flexsorb Tail Gas Treating unit and the MEA unit. The sulfur compounds in the acid gas are converted into elemental sulfur by the Claus unit in the SRU. A Flexsorb Tail Gas Treating unit is also included in the SRU for increased removal of residual sulfur in the tail gas. When operating in series, the Claus unit and the Tail Gas Treating unit will remove over 99.9 percent of the sulfur contained in the acid gas. The sulfur will be temporarily stored at the site and then trucked away for sale.

The remaining tail gas will then be incinerated to convert all residual sulfur compounds and hydrocarbons into SO_2, CO_2, and H_2O. The incinerator will provide some steam generation via waste heat recovery while utilizing Thermal DeNOx for emission control. The remaining heat requirements of the stripping gas treating facility will be provided by the waste heat recovery system of the cogeneration plant.

ATTACHMENT B

NGL Treating For Gas Treating Facility Expansion

To enhance marketing flexibility, Exxon may choose to process NGL's for the removal of small quantities of undesirable components. If installed, these NGL treating facilities will be designed as follows.

NGL treating requires two separate processes in series with the first being a DGA Treating Unit designed to remove COS, H_2S, and CO_2 from the NGL stream. The process is based on a reaction-absorption-regeneration cycle using a circulating solution of Diglycolamine (DGA). Untreated NGL is contacted in a liquid/liquid contactor with an aqueous DGA solution. Treated NGL then proceeds through a water wash step to recapture entrained DGA and then onward to the second NGL treating unit. Regeneration of Diglycolamine solution is similar to the regeneration step previously discussed for sulfinol in the gas sweetening section 9.3.2.1.

In the second NGL Treating Unit, the DGA treated NGL contacts caustic for mercaptan removal. The mercaptan sulfur is extracted from the NGL in a Mercaptan Sulfur Extraction Contactor as the NGL and caustic flow concurrently downward through the contactor to an Extraction Stage Caustic/NGL Separator. The separated NGL then exits and flows to the mercaptan oxidation stage for further caustic treatment. Caustic in the bottom of the separator vessel is transferred to the Caustic Regeneration System.

As the NGL enters the mercaptan oxidation stage, minute amounts of process air are injected into the NGL through an air sparger. The air/NGL mixture flows to the top of a Mercaptan Sulfur Oxidation Contactor and the NGL and caustic flow concurrently through the contactor while the mercaptans are converted to disulfides. Upon entering the Oxidation Stage Separator, the caustic and NGL phases disengage and the treated NGL flows out of the top of the separator and exits the system.

The mercaptide-bearing caustic from the mercaptan sulfur extraction system enters the Oxidizer Tower after first being steam-heated. Air is metered into the Oxidizer Tower through a distributor nozzle and as the caustic/air mixture rises through the Oxidizer Tower, oxygen reacts with sodium mercaptide and converts it to disulfide oil (DSO). The two-phase mixture flows by gravity from the top of the Oxidizer Tower to the inlet of the DSO/caustic Separator. The DSO rises to a dome atop the DSO/caustic separator for separation to the DSO tank. Residual offgas disengages in the vapor space in the dome and is flowed to the incinerator. Regenerated caustic is returned to the initial mercaptan sulfur extraction stage by pumps.

TABLE 9.3

Major Equipment Additions to the Gas Treating Facilities
Expansion from 30 MMSCFD to 90 MMSCFD

Description	No.
Instrument Air Dryer	1
Lean Solvent Filter	2
Deareator	1
Process Water Carbon Filter/Softener Unit	1
Steam Boilers	2
Gas/Gas Exchangers	4
Gas/Stabilizer Feed Exchanger	2
Gas Chiller	2
Stabilizer Feed/Btms Exchanger	2
Stabilizer Overhead Condenser	2
Stabilizer Reboiler	2
Amine Reclaimer	1
Amine Still Reboiler	1
Amine Exchangers	4
Amine Still Reflux Condenser	1
Amine Cooler	1
Refrigerant Condensers	2
Flash Gas Refrigeration Exchanger	1
Lean Solvent Coolers	8
Lean/Rich Solvent Exchangers	7
Stripper Overhead Condensers	3
Stripper Reboilers	3
TEG/Gas Exchanger	1
Reflux Vaporizer	1
Reflux Superheater	1
Recompressor Gas Cooler	1
Recompressor Intercooler	2
Sales Gas Cooler	2
SWS Overhead Condenser	1
Waste Water Cooler	1
Condensate Cooler	1
Ammonia Vaporizer	1
Thermal DeNOx Air Compressor	2
Refrigerant Compressors	3
Recompressors	3
Sales Gas Compressors	3
Instrument Air Compressors	3
Stabilizer Reflux Pumps	3
Lean Solvent Pumps	3
Lean Solvent Booster Pumps	3
Stripper Reflux Pumps	2
NGL Product Pumps	2

TABLE 9.3

Page Two

Description	No.
Wash Column Pumps	2
SWS Feed Pumps	2
SWS Reflux Pumps	2
SWS Bottoms Pumps	2
Deareator Feed Pumps	2
Boiler Feedwater Pumps	2
Condensate Pumps	2
SRU BFW Booster Pumps	2
Blowdown Pumps	2
Wash Col. Water Pumps	2
Condensate Cooler Feed Pumps	2
BFW Storage Tank	1
Ammonia Storage Tank	1
Feed Gas Water Separator	2
Inlet Gas TEG Contactor	1
Main Separator	2
Water Separator	2
ByPass Separator	1
Stabilizer	1
Stabilizer Accumulator	1
60MM SCFD NGL Amine Contactor	1
60MM SCFD NGL Water Wash Tank	1
30MM SCFD NGL Amine Contactor	1
30MM SCFD NGL Water Wash Tank	1
Amine Flash Tank	1
Amine Still	1
Amine Still Reflux Accumulator	1
Refrigerant Surge Tank	1
1st Stage Refrigerant Scrubber	1
2nd Stage Refrigerant Scrubber	1
Refrigerant Flash Tank	1
H.P. Contactor	1
L.P. Contactor	1
Fuel Gas Contactor	1
Stripper	1
Reclaimer	1
Treated Gas Wash Column	1
L.P. Scrubber	1
Stripper Reflux Accumulator	1
L.P. Flash Tank	1
Sales Gas TEG Contactor	1
Solvent Drain Vessel	1
Sour Water Stripper	1

Description	No.
SWS Overhead Accumulator	1
SWS Feed Surge Drum	1
Condensate Flash Separator	1
Instrument Air Receiver	1
Blowdown Flash Drum	1
Pressure Drain Vessel	1
Atm. Blowdown Flash Drum	1
TEG Drain Vessel	1
Housekeeping Drain Vessel	1
Oily Water Separator	1
ZTOF/LRGO Flare	1
Flare K.O. Drum Hydrocarbon	1
Flare K.O. Drum Acid Gas	1
NGL Storage Spheres	4
NGL Storage Tanks	5
Sour NGL Storage Vessel	1
Sales Gas Metering & Odorizing Skid	1
NGL Treating Skid	4
TEG Regeneration Skid - GPU	2
TEG Regeneration Skid - Sour Gas Treating	2
Disulfide Oil Tank	2
Fresh Caustic Tank	2
Spent Caustic Tank	2
SRU Air Blowers	4
SRU Acid Gas K.O. Drum	2
SRU Acid Gas Preheater	2
SRU Converters	2
SRU Sulfur Pit	2
SRU Reaction Furnace	2
SRU Sulfur Condensers	8
TGU Oxidizer Air Blowers	4
TGU Reducing Gas Generator	2
TGU Steam Generator	2
TGU Sulfur Melter Pit	2
TGU Fresh Rinse Water Tank	2
TGU Chemical Make-up Pit	2
TGU Sulfur Slurry Filter Pkge	2
TGU Sulfur Slurry Basin	2
TGU Balance Basis	2
TGU Oxidizer Basin	2
TGU Absorber/Reaction Tank	2
TGU Desuperheater/Contact Condenser	2
TGU Stretford Sol'n Circulation Pumps	4

TABLE 9.4

Major Equipment Additions to the Gas Treating Facilities
Expansion from 30 MMSCFD to 135 MMSCFD

Description	No.
Instrument Air Dryer	1
Pig Receiver	1
Lean Solvent Filter	2
Deareator	1
Process Water Carbon Filter/Softener Unit	1
Incinerator Waste Heat Boilers	2
Hot Oil Steam Generators	3
Combustion Chambers	2
Gas/Gas Exchangers	4
Gas/Stabilizer Feed Exchanger	2
Gas Chiller	2
Stabilizer Feed/Btms Exchanger	1
Stabilizer Overhead Condenser	2
Stabilizer Reboiler	2
Amine Reclaimer	1
Amine Still Reboiler	1
Amine Exchangers	4
Amine Still Reflux Condenser	1
Amine Cooler	1
Refrigerant Condensers	5
Lean Solvent Coolers	14
Lean/Rich Solvent Exchangers	12
Stripper Overhead Condensers	4
Stripper Reboilers	5
TEG/Gas Exchanger	1
Reflux Vaporizer	1
Reflux Superheater	1
Recompressor Gas Cooler	1
Recompressor Intercooler	2
Sales Gas Cooler	1
SWS Overhead Condenser	1
Waste Water Cooler	1
Condensate Cooler	1
Amine Vaporizer	1
Refrigerant Compressors	3
Recompressors	3
Sales Gas Compressors	3
Instrument Air Compressors	3
Incinerator Air Blowers	3
Thermal DeNOx Air Compressors	2
Stabilizer Reflux Pumps	3
Lean Solvent Pumps	3

TABLE 9.4

Page Two

Description	No.
Lean Solvent Booster Pumps	3
Stripper Reflux Pumps	2
NGL Product Pumps	2
Wash Column Pumps	2
SWS Feed Pumps	2
SWS Reflux Pumps	2
SWS Bottoms Pumps	2
Deareator Feed Pumps	2
Low Pressure BFW Pumps	2
Condensate Pumps	2
SRU BFW Booster Pumps	2
Blowdown Pumps	2
Wash Col. Water Pumps	2
Condensate Cooler Feed Pumps	2
Incinerator Stacks	2
Incinerator Burners	2
BFW Storage Tank	1
Slug Separator Vessels	6
Feed Gas Water Separator	2
Inlet Gas TEG Contactor	1
Main Separator	2
Water Separator	2
ByPass Separator	1
Stabilizer	1
Stabilizer Accumulator	1
60MM SCFD NGL Amine Contactor	1
60MM SCFD NGL Water Wash Tank	1
75MM SCFD NGL Amine Contactor	1
75MM SCFD NGL Water Wash Tank	1
Amine Flash Tank	1
Amine Still	1
Amine Still Reflux Accumulator	1
Refrigerant Surge Tank	1
1st Stage Refrigerant Scrubber	1
2nd Stage Refrigerant Scrubber	1
Refrigerant Flash Tank	1
H.P. Contactor	1
L.P. Contactor	1
Fuel Gas Contactor	1
Stripper	1
Reclaimer	1
Treated Gas Wash Column	1
L.P. Scrubber	1
Stripper Reflux Accumulator	1

Description	No.
L.P. Flash Tank	1
Sales Gas TEG Contactor	1
Solvent Drain Vessel	1
Sour Water Stripper	1
SWS Overhead Accumulator	1
SWS Feed Surge Drum	1
Condensate Flash Separator	1
Instrument Air Receiver	1
Blowdown Flash Drum	1
Pressure Drain Vessel	1
Atm. Blowdown Flash Drum	1
TEG Drain Vessel	1
Housekeeping Drain Vessel	1
Oily Water Separator	1
Ammonia Storage Tank	1
ZTOF/LRGO Flare	1
Flare K.O. Drum Hydrocarbon	1
Flare K.O. Drum Acid Gas	1
NGL Storage Spheres	5
NGL Storage Tanks	5
Sour NGL Storage Vessel	1
Sales Gas Metering & Odorizing Skid	1
NGL Treating Skid	4
TEG Regeneration Skid - GPU	2
TEG Regeneration Skid - Sour Gas Treating	2
Disulfide Oil Tank	1
Fresh Caustic Tank	1
Spent Caustic Tank	1
SRU Air Blowers	4
SRU Acid Gas K.O. Drum	2
SRU Acid Gas Preheater	2
SRU Converters	2
SRU Sulfur Pit	2
SRU Reaction Furnace	2
SRU Sulfur Condensers	8
TGU Oxidizer Air Blowers	4
TGU Reducing Gas Generator	2
TGU Steam Generator	2
TGU Sulfur Melter Pit	2
TGU Fresh Rinse Water Tank	2
TGU Chemical Make-up Pit	2
TGU Sulfur Slurry Filter Pkge	2
TGU Sulfur Slurry Basin	2
TGU Balalnce Basis	2
TGU Oxidizer Basin	2
TGU Absorber/Reaction Tank	2
TGU Desuperheater/Contact Condenser	2
TGU Stretford Sol'n Circulation Pumps	4

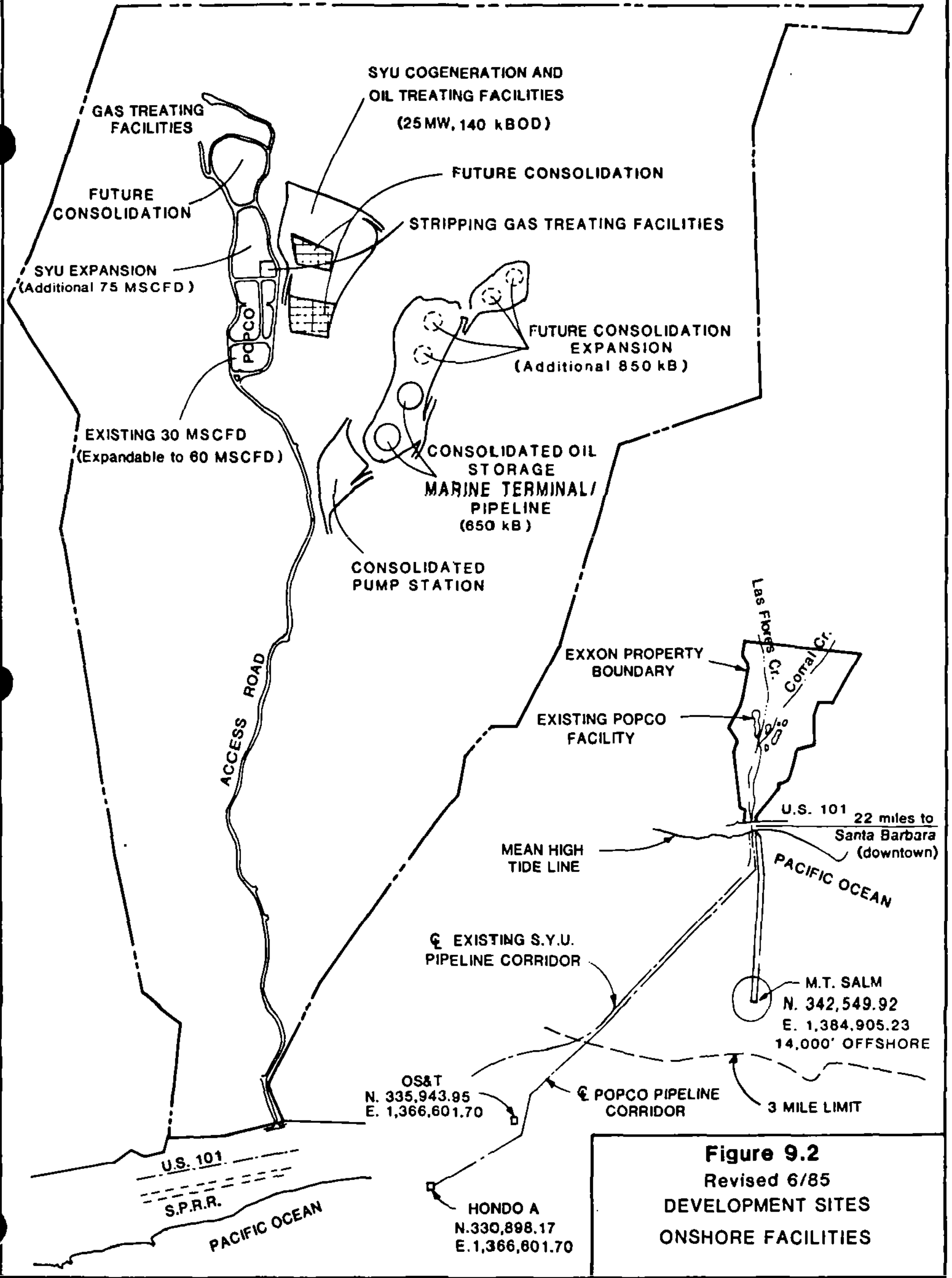


Figure 9.2
Revised 6/85
DEVELOPMENT SITES
ONSHORE FACILITIES

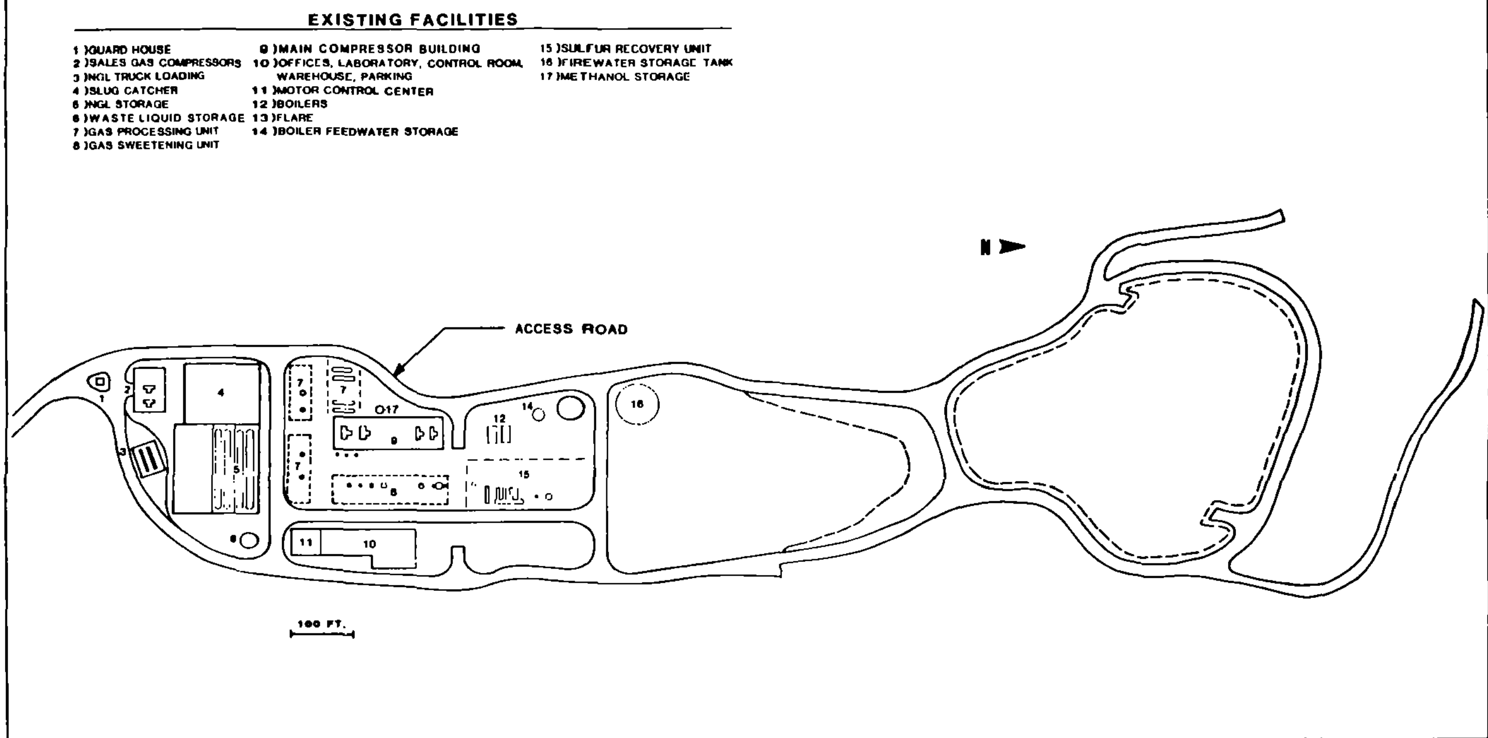


FIGURE 9.3
Revised 12/83
EXISTING 30 MCFD GAS TREATING FACILITIES GENERAL PLOT PLAN

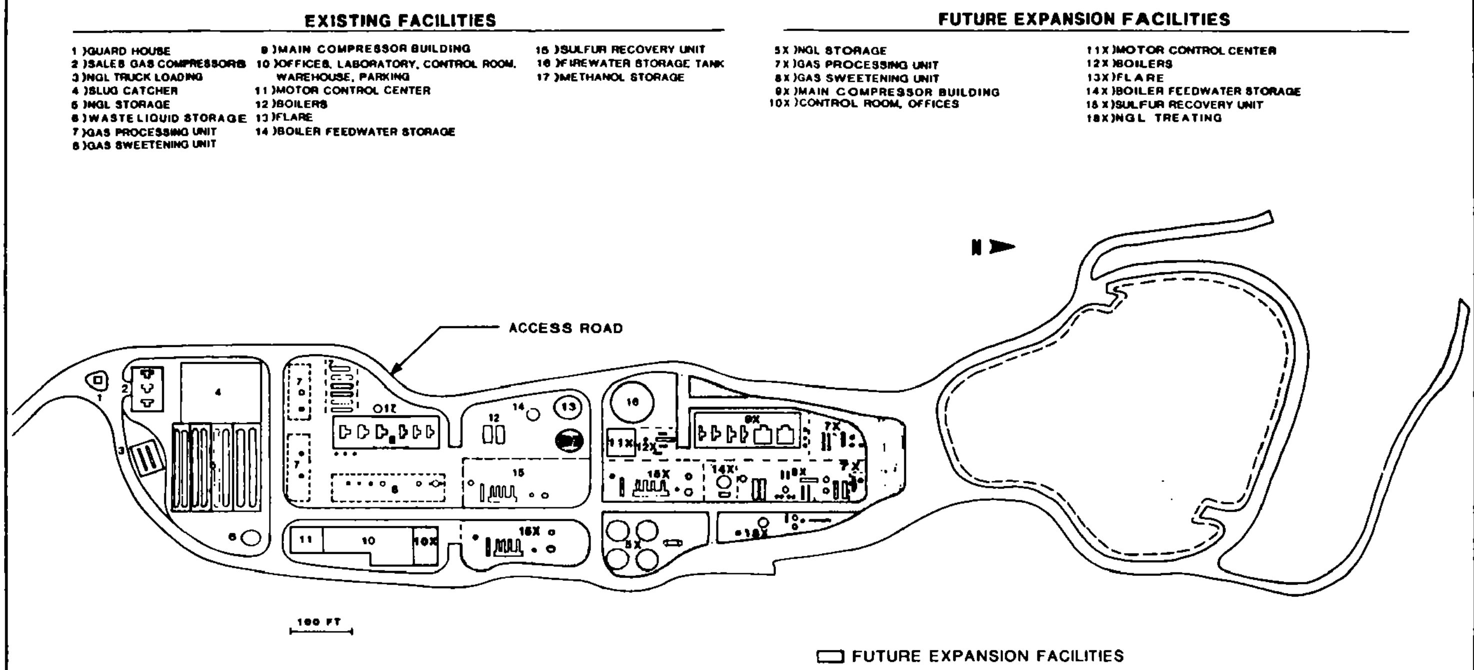


FIGURE 9.4
Revised 8/84
DEVELOPMENT OPTION A
90 MCFD
GAS TREATING FACILITIES
GENERAL PLOT PLAN

EXISTING FACILITIES

1)GUARD HOUSE
2)SALES GAS COMPRESSORS
3)NGL TRUCK LOADING
4)SLUG CATCHER
5)NGL STORAGE
6)WASTE LIQUID STORAGE
7)GAS PROCESSING UNIT
8)GAS SWEETENING UNIT
9)MAIN COMPRESSOR BUILDING
10)OFFICES, LABORATORY, CONTROL ROOM, WAREHOUSE, PARKING
11)MOTOR CONTROL CENTER
12)BOILERS
13)FLARE
14)BOILER FEEDWATER STORAGE
15)SULFUR RECOVERY UNIT
16)FIREWATER STORAGE TANK
17)METHANOL STORAGE

FUTURE EXPANSION FACILITIES

4X)SLUG CATCHER
5X)NGL STORAGE
7X)GAS PROCESSING UNIT
8X)GAS SWEETENING UNIT
9X)MAIN COMPRESSOR BUILDING
10X)CONTROL ROOM, OFFICES
11X)MOTOR CONTROL CENTER
12X)BOILERS
13X)FLARE
14X)BOILER FEEDWATER STORAGE
15X)SULFUR RECOVERY UNIT
18X)NGL TREATING

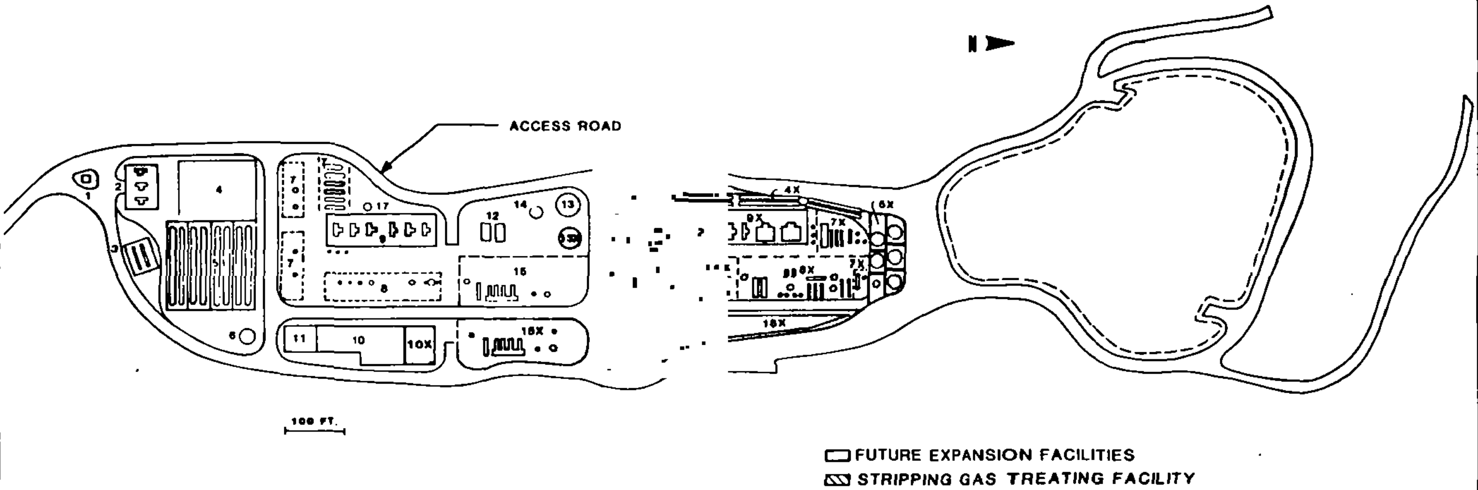
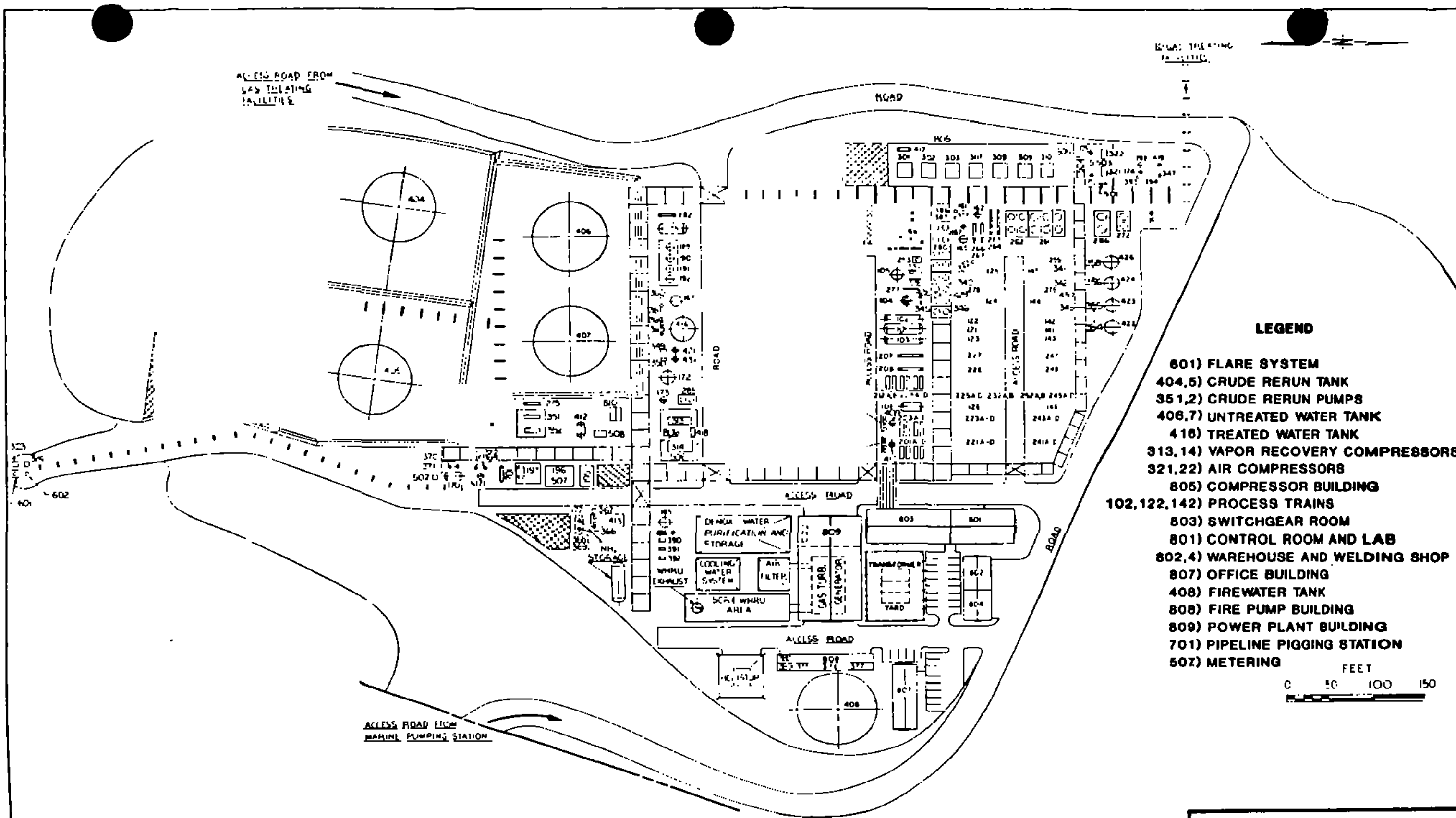


FIGURE 9.5
Revised 6/85
DEVELOPMENT OPTION B
135 MCFD GAS TREATING FACILITIES AND STRIPPING GAS TREATING FACILITIES GENERAL PLOT PLAN



DENOTES AREAS PROVIDED FOR FUTURE FACILITIES

Figure 9.6a
Revised 6/85
DEVELOPMENT OPTION B
ONSHORE OIL TREATING/STORAGE/ POWER GENERATION FACILITIES

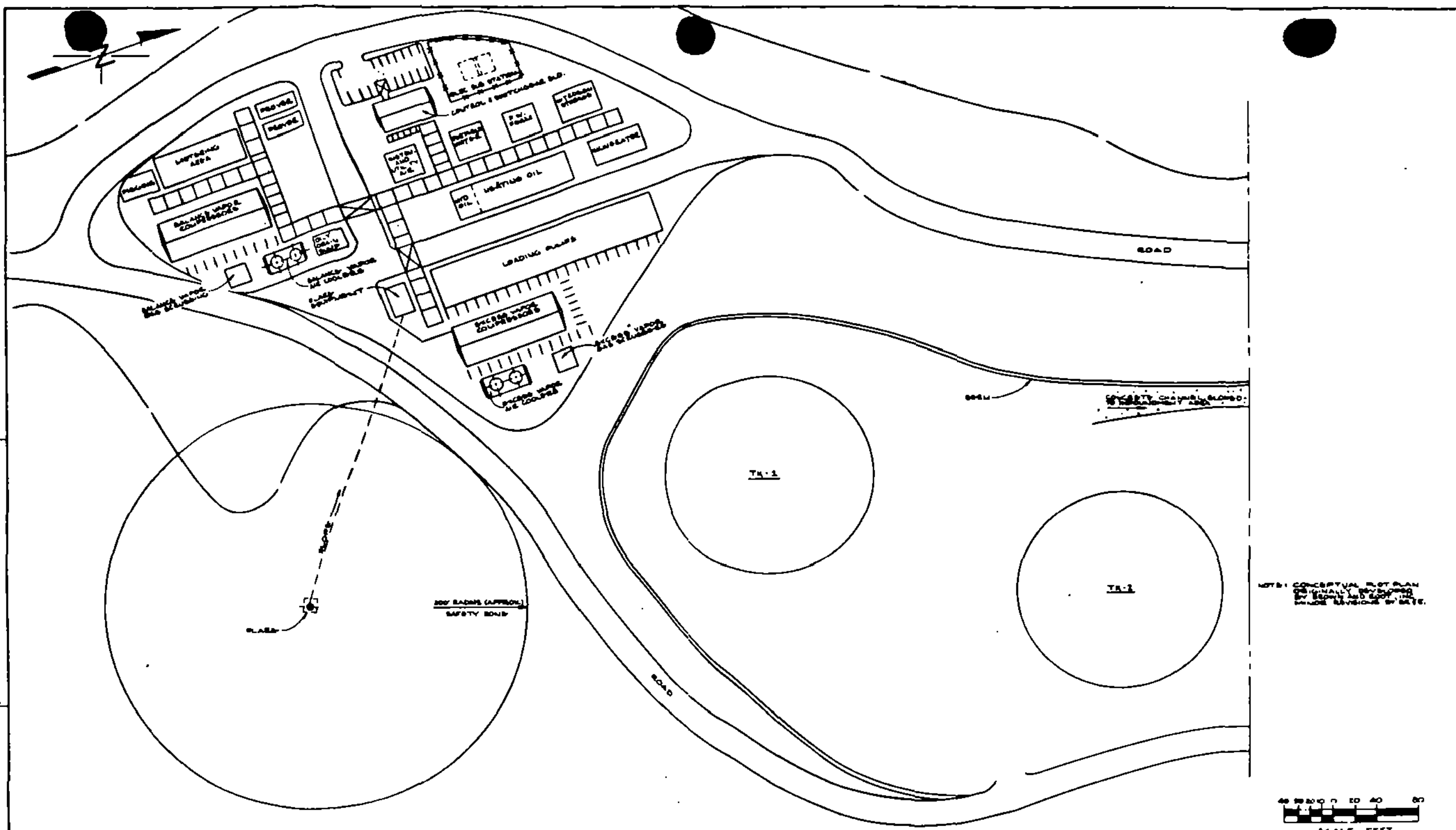


Figure 9.6b
Revised 6/85

DEVELOPMENT OPTION B ONSHORE OIL STORAGE AND PUMPING STATION

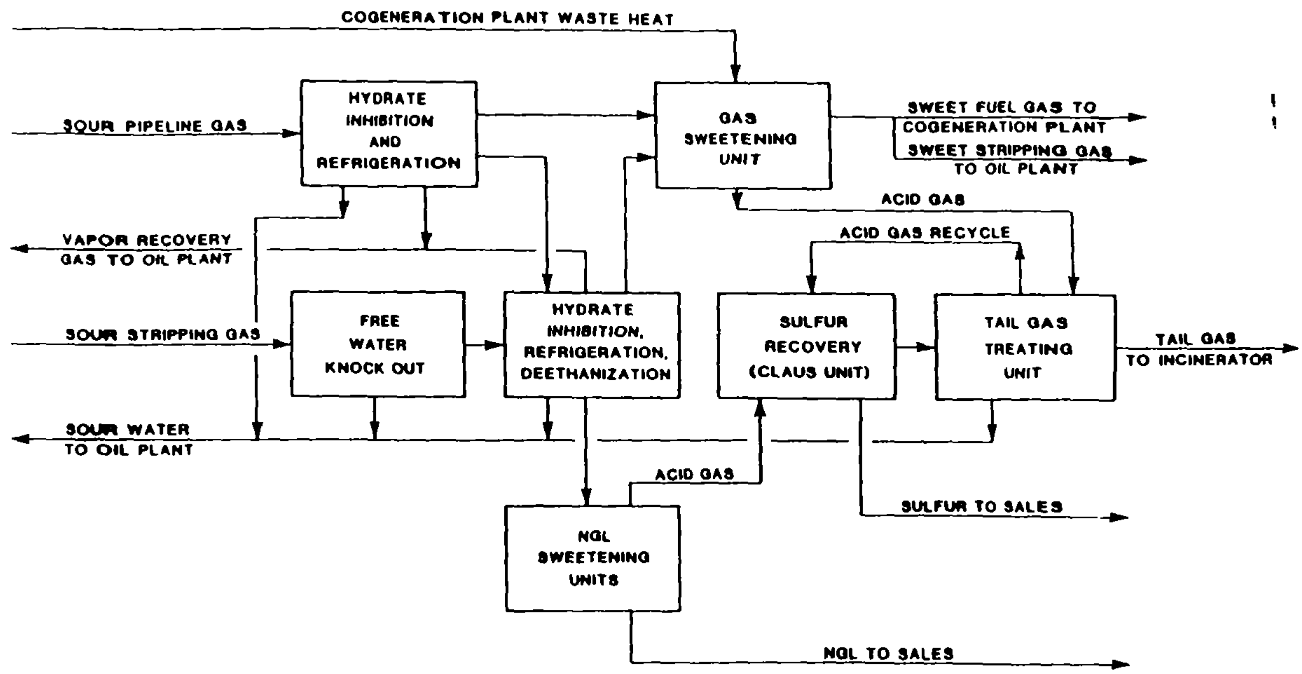


Figure 9.16
Revised 6/85
STRIPPING GAS TREATING FACILITIES PROCESS FLOW SYU DEVELOPMENT OPTION B

SECTION X

CRUDE TRANSPORTATION

o The Intent of Section X of the Development and Production Plan (DPP) for the Santa Ynez Unit (SYU) is to describe those alternatives to be available for transportation of treated crude oil produced in association with SYU Development Option B (Onshore Oil Treating). As noted in the original submittal, transportation associated with Development Option A (Offshore Oil Treating) is described elsewhere in the document.

o The following is intended to update Section X of the original December, 1982 document to reflect developments which have occurred since its submission.

- Currently, three methods are proposed for transporting SYU crude oil from an onshore treating plant to locations at which it may be refined. Exxon has proposed a consolidated industry marine terminal at Las Flores Canyon (LFC). All American Pipeline Company (AAPL) has proposed a 30-inch pipeline from LFC to Freeport, Texas. The Southern California Pipeline System group (SCPS) has proposed a 30-inch pipeline over an inland route from LFC to Los Angeles.

- In the December, 1982 DPP, Exxon proposed the construction of a Modernized Nearshore Marine Terminal to facilitate tanker transportation of its SYU crude processed through an onshore treating plant. Section 10.2 of the DPP described in some detail the major components, construction, and operation of such a facility. Exxon also anticipated the possibility of an industry marine terminal in LFC. In Section 10.5, Exxon "...offered the proposed SYU terminal... as the nucleus for a permanent industry marine terminal." Santa Barbara County (SBC) denied Exxon's SYU marine terminal permit in August, 1984. Exxon subsequently, in March, 1985, filed application for its LFC Consolidated Marine Terminal (CMT). This terminal is intended to be for industry use.

- Major component descriptions and construction and operation details for the LFC CMT are included with the SBC applications (85-DP-15cz and 85 CP-16cz made March 8, 1985) and a subsequent submission (Responses to SBC Questions, made May 3, 1985) requested by SBC for application completeness. These documents are incorporated by reference in this addendum to the DPP as descriptive of Exxon's current marine alternative. Additionally DPP Figures 10.1, 10.3 and 10.4 have been revised to reflect the current design which includes the SALM located 14,000 feet offshore.

o As previously mentioned, other transportation systems may also be available for transportation of SYU crude oil.

- The All American Pipeline was not included in the December, 1982 DPP since it had not yet been proposed. However, it has progressed to the point where major permits have been received. Detailed information

1985 DPP revisions

relative to the AAPL proposal can be found in several documents, the most recent of which is the Final Environmental Impact Report/Environmental Impact Statement for the Celeron/All American and Getty Pipeline Project proposed for the California State Lands Commission and the Bureau of Land Management, Department of the Interior, certified in January, 1985.

- The SCPS is a development of and replaces the Southern California Coastal Pipeline described in Section 10.3 of the December, 1982 DPP. SCPS plans to construct along an inland route from LFC through Emidio to the Los Angeles area. SCPS has obtained all rights to a permit granted to Getty Trading and Transportation Company for a pipeline from Gaviota to Emidio. Detailed information relative to this segment can be found in the Final Environmental Impact Report/Environmental Impact Statement for the Celeron/All American, and Getty Pipeline projects referenced above. Application for the pipeline segment from Emidio to Los Angeles has yet to be filed.

o Exxon has agreed to use pipeline transportation if it is available to our intended destination, Baytown, Texas, and if its cost is reasonable when balancing economic and environmental impacts of alternative transportation modes. However, since it is not certain at this point in time that a pipeline will be available or that its tariffs will be reasonable, Exxon is pursuing its marine alternative through the LFC CMT.

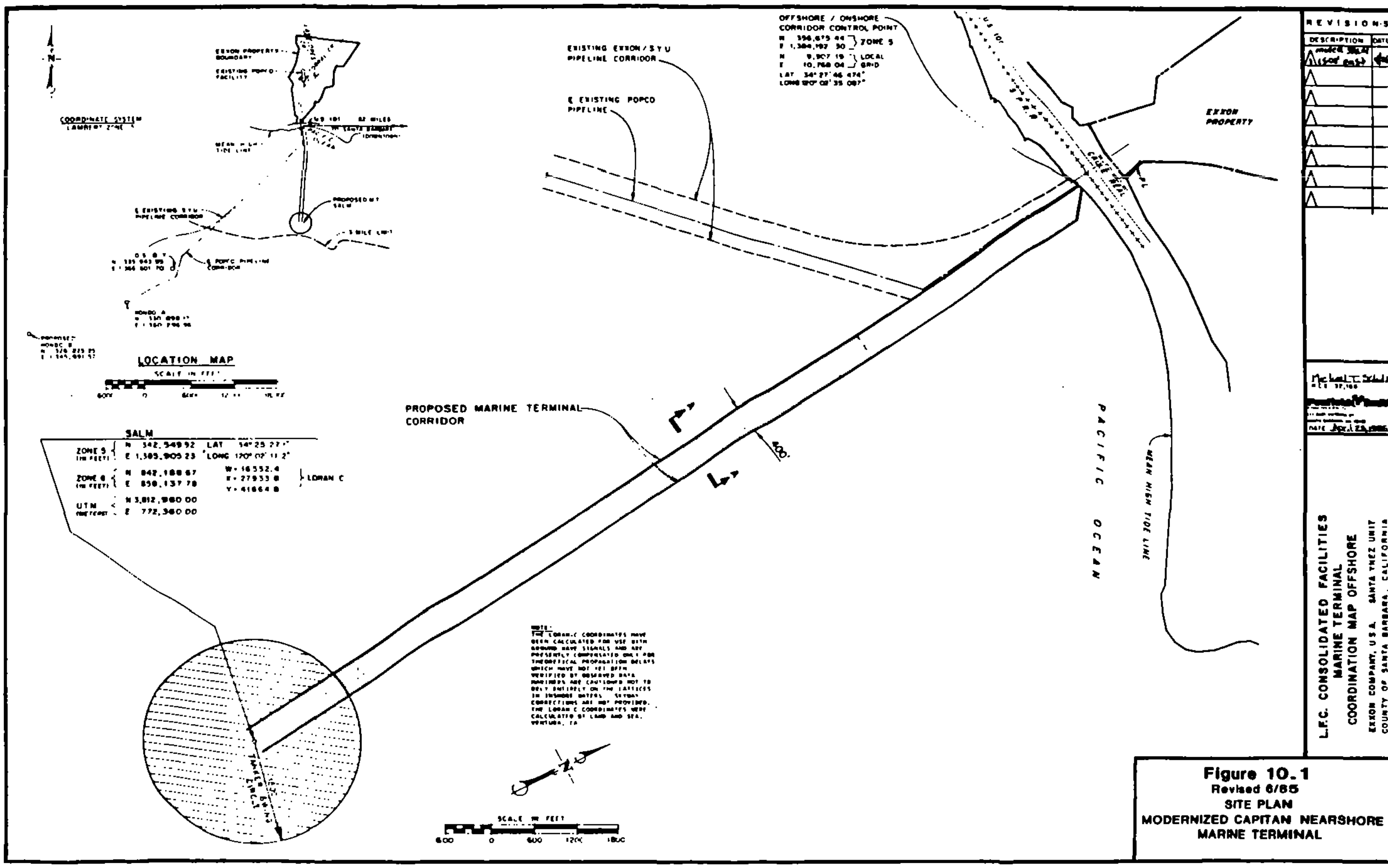
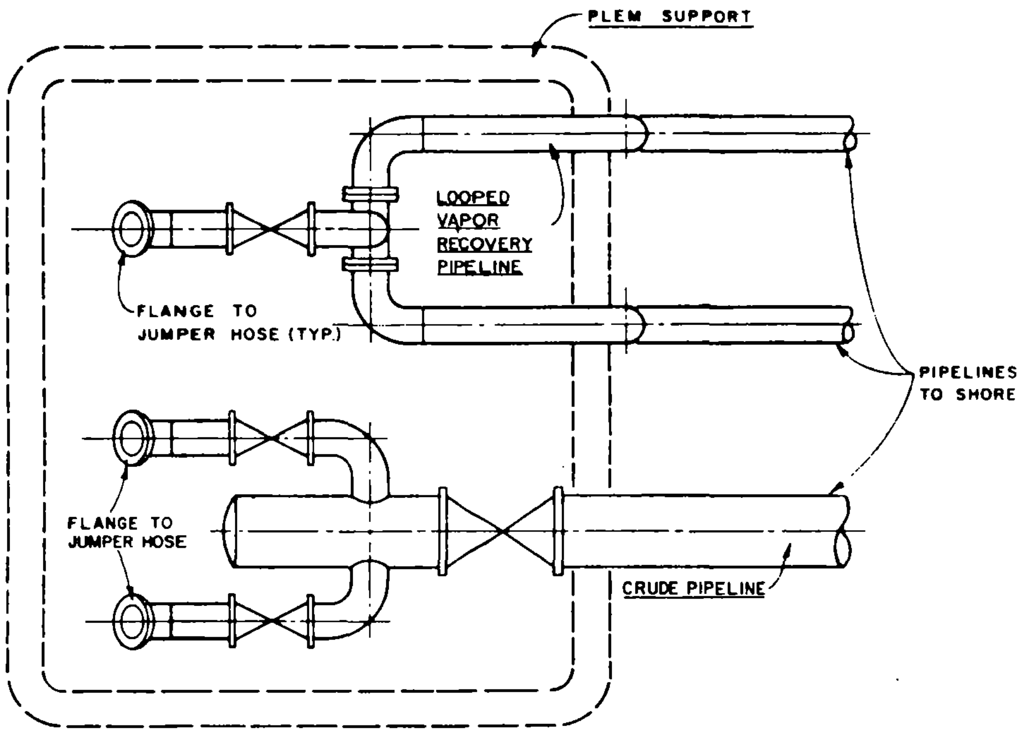


Figure 10.1
Revised 6/85
SITE PLAN
MODERNIZED CAPITAN NEARSHORE MARINE TERMINAL

WO 7379 (17-001)



PLAN OF PIPELINE END MANIFOLD (PLEM)

CONCEPTUAL DRAWING
Not To Scale

Figure 10.3
Revised 6/85

VAPOR BALANCE PIPELINE
END MANIFOLD
NEARSHORE MARINE TERMINAL

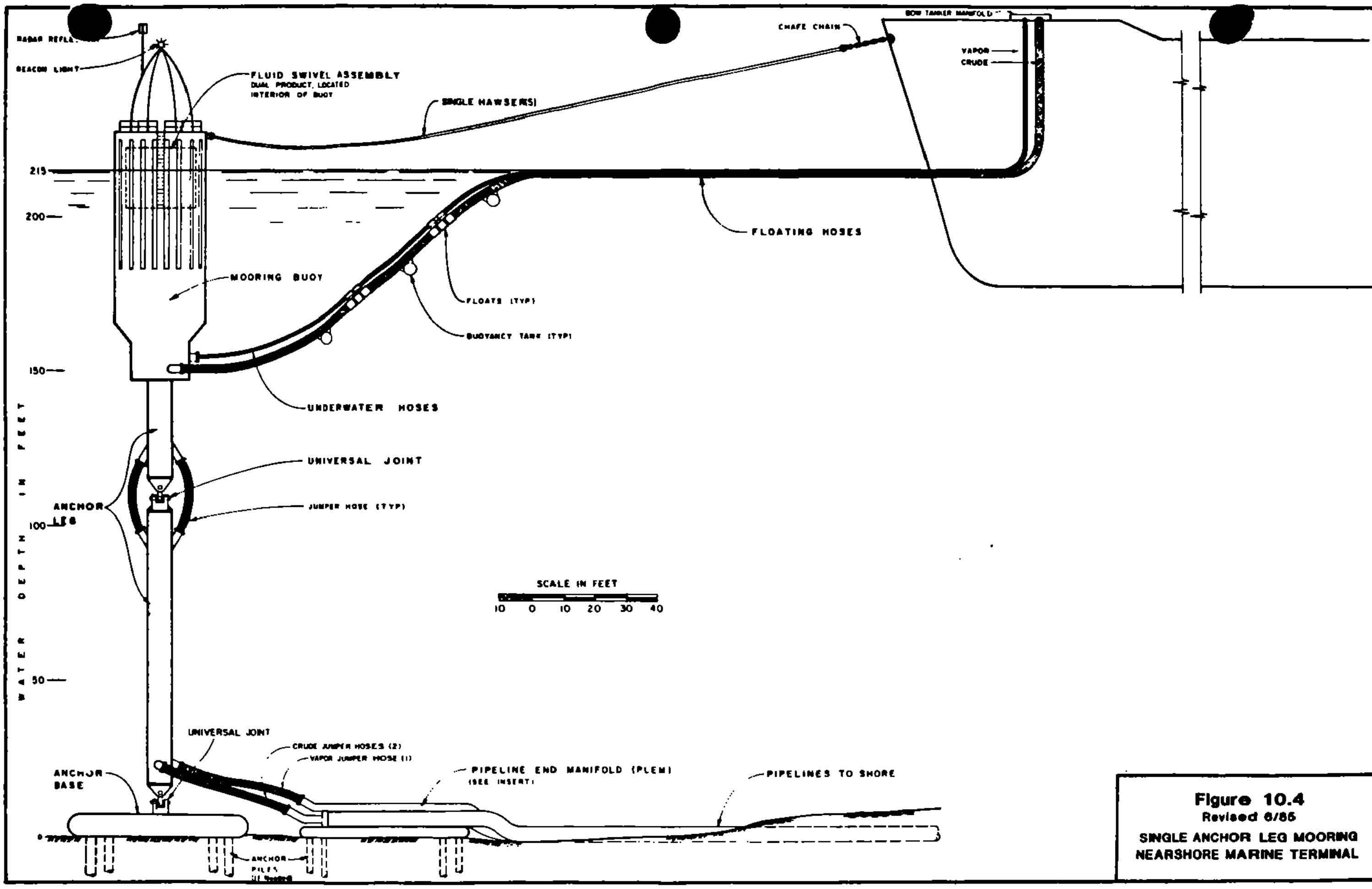


Figure 10.4
Revised 6/85
SINGLE ANCHOR LEG MOORING
NEARSHORE MARINE TERMINAL

SECTION XI

OPERATIONS

- Dedicated Marine Terminal operators will be required since the facilities control room is now located on the east side of Corral Creek. All other OPP discussion is appropriate for the new terminal.

- The Stripping Gas Treating Facility introduced in the Addendum to Section IX will be operated from the Oil Plant control room. An auxiliary building will also be constructed at the Facility and manned by two field operators who will maintain direct communication with the main control room.

June, 1985