OCS Study
MMS 99-0043

FINAL CALIFORNIA OFFSHORE OIL AND GAS ENERGY RESOURCES STUDY

**Development Scenarios
and Onshore Physical Infrastructure
in the Tri-County Area of
San Luis Obispo, Santa Barbara and Ventura**

Prepared by

DAMES & MOORE
A DAMES & MOORE GROUP COMPANY

under contract to

**MMS U.S. Department of the Interior
Minerals Management Service
Pacific OCS Region**

in cooperation with

California State Lands Commission
California Department of Conservation
California Coastal Commission
**County of San Luis Obispo
Department of Planning and Building**
**County of Santa Barbara
Department of Planning and Development**
**County of Ventura
Resource Management Agency**
Local Community Representatives
**Industry Offshore Leaseholders
Represented by the Operating Companies**

and the

**Western States Petroleum Association
Coastal Producers Committee**

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Prepared under MMS Contract
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JANUARY 26, 2000

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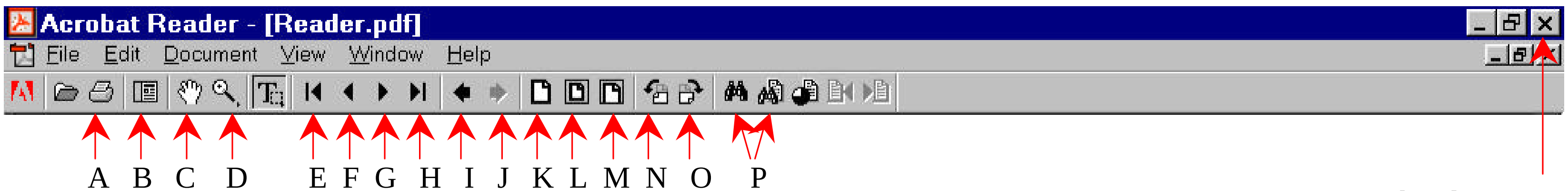
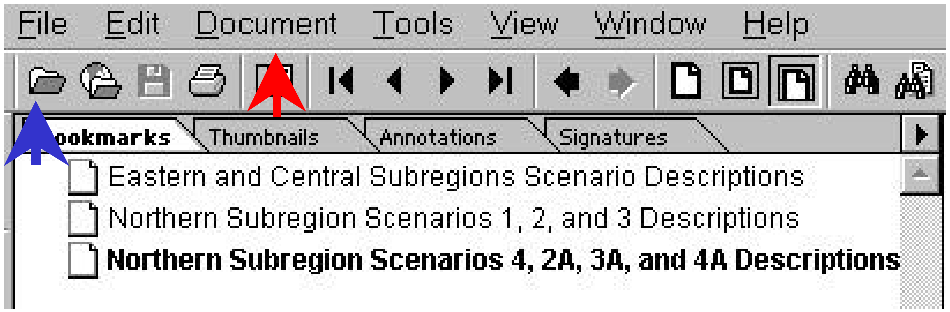
Disclaimer

This report has been reviewed by the Pacific Outer Continental Shelf Region, Minerals Management Service, U. S. Department of the Interior and approved for publication. The opinions, findings, conclusions or recommendations expressed in this report are those of the authors, and do not necessarily reflect the views of the Minerals Management Service. Mention of trade names or commercial products does not constitute endorsement or recommendation for use. This report has not been edited for conformity with Minerals Management Service editorial standards.

Navigation Instructions



A. Print
B. Show / Hide Bookmark Pane (see further instructions below)
C. Hand Tool. If you magnify a page to a size larger than the window, use the hand tool to move the page around so that you can view all the areas on it. Moving a PDF page with the hand tool is like moving a piece of paper on a desk with your hand. A hyperlink is indicated when the hand changes to a pointing finger (see hyperlink instructions on next page).
D. Magnification tool. You may also use the CTRL and + or CTRL and - keys on your keyboard.
E. Moves to the first page of the document. You may also use the Home key on your keyboard.
F. Moves to the previous page. You may also use the Page Up key on your keyboard.
G. Moves to the next page. You may also use the Page Down key on your keyboard.
H. Moves to the last page of the document. You may also use the End key on your keyboard.
I&J. I returns to previous view (also referred to as the “back button”). When J appears black, you may toggle between two views. (NOTE: If you scroll up or down on a page accessed by hyperlink, you may need to click the “back” button more than once to return to the prior page.)
K. View actual size
L. Fit page in window
M. View page zoomed to margin width
N&O. Rotate page 90 degrees
P. “Find” or “Search” in document



To view COOGER study scenario descriptions, click the bookmark icon (red arrow), click the “Bookmarks” tab (blue arrow), then click the desired description.

Navigation Instructions (Continued)

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This document contains hyperlinks to other pages within the document. To activate a hyperlink, place the mouse pointer over the text indicating a hyperlink (as described below). When the mouse pointer turns into a pointing finger, clicking the left mouse button will take you to the linked item. Clicking the back button on the toolbar (see item "I" on the previous page of these Navigation Instructions) will return you to the point you were in the document before clicking the hyperlink. (NOTE: If you scroll up or down on a page accessed by hyperlink, you may need to click the "back" button more than once to return to the prior page.)

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1.0 INTRODUCTION

1.1 INTRODUCTION

Development of oil and gas offshore California has a long history of controversy. Among the considerable list of issues contributing to the controversy is the extent to which development of the offshore Federal and State oil and gas resources places demands on the physical infrastructure in Ventura, Santa Barbara, and San Luis Obispo Counties (Tri-County area). Already, the infrastructure in this area supports production from offshore Federal and State leases. Undeveloped leases that might be developed could, depending on the schedule of development, add to or replace current production.

The California Offshore Oil and Gas Energy Resources (COOGER) study was designed by an intergovernmental work group to address the concern about the potential demands on onshore infrastructure from expanded offshore oil and gas development. The study examines different levels of demand for onshore physical infrastructure that might result from different rates of future oil and gas development on existing producing and undeveloped offshore leases. An analysis of potential physical onshore infrastructure capacity limitations is included under each scenario. The onshore infrastructure described and analyzed includes facilities to process, store, and transport crude oil, natural gas, liquified petroleum, and other by-products. It also includes: port and harbor facilities, airports, railways, and highway and roads used to transport products.

The geographic focus of the study is the coastal area of the Tri-County area, and the period analyzed is 1995 through 2015. Until very recently, there were 40 Federal and 23 State leases which are not yet developed or not producing. Recent lease expirations (four in Federal waters in August 1999 and four in State Tidelands in September 1999) have reduced the number of undeveloped leases, but do not affect the oil and gas resource base in the region and thus do not affect the development scenarios employed in the study. The federal lease expirations are currently being appealed. State leases which were recently quit-claimed include PRC 2206, PRC 2725, PRC 2726, and PRC 3499.

The COOGER study was initiated in 1995 at the request of the State of California and Ventura, Santa Barbara, and San Luis Obispo Counties. These jurisdictions requested that MMS provide critical information about the onshore infrastructure capacity limits to the potential development of existing offshore oil and gas leases in the Tri-County area. The study is a product of county government (Ventura, Santa Barbara, and San Luis Obispo), State of California (California Coastal Commission, State Lands Commission, California Division of Oil Gas and Geothermal Resources), the MMS, oil and gas industry, local non-energy businesses, and environmental groups who served on a Steering

Committee. Representatives from these organizations (except for environmental groups and the non-energy business community) jointly planned the scope of the study and participated in selecting the contractor for the study. The local environmental groups and non-energy business groups were added after the study was underway.

1.2 STUDY OBJECTIVES AND GOALS

The principal objective of the COOGER study is to provide information about the present and future level of offshore oil activity in the Tri-County area and to describe present and future physical onshore infrastructure that may act to constrain the level or rate of future development and production. The study is unique in that it addresses various levels of possible development and production from oil and gas fields beneath all the undeveloped offshore leases.

While the initial scope of factors to be considered in the COOGER study was very broad, the Steering Committee, by consensus, refined the scope of the report during the study. This included the deletion of report topics associated with environmental and socioeconomic issues from the body of this report. Appendix E outlines these decisions. The study does not attempt to address the gamut of issues raised concerning offshore development. It is designed to address the limited issues of onshore physical constraints to offshore development. Other issues are addressed in some of the most comprehensive environmental documents prepared in the United States (including development plan environmental impact analyses) and in studies recently completed and ongoing under the auspices of the MMS and/or the County of Santa Barbara. Appendix E includes references of several of these studies.

COOGER adds to the understanding of potential physical onshore constraints for a 20-year period (1995 - 2015, inclusive). The study includes the following information:

- The current regulatory framework that governs the development of offshore oil and gas, including supporting onshore infrastructure (Section 2.2).
- The rates of oil and gas production in 5-year increments - from leases under production in 1995 (Section 2.3).
- The onshore infrastructure that supports offshore development as of 1995, including the designed and permitted capacities (Section 2.4).
- The spare capacities available in the onshore and transportation infrastructure as of 1995 and as production from producing fields declines (Section 2.4).
- The possible decommissioning of infrastructure as some of the offshore fields reach the end of their economic lives (Section 2.4).

- Estimates of the economically recoverable oil and gas reserves from the 56 undeveloped Federal and State leases offshore the study region, and estimates of a range of scenarios (Section 3.0). Each of the scenarios addresses a different rate of development, ranging from no new development to maximum rates of development from the undeveloped leases.
- Assessment of the need for onshore infrastructure under each of the scenarios and the identification of potential onshore physical constraints (Section 4.0). Physical capacity limitations may include transportation or processing capacities associated with existing oil and gas related infrastructure. These constraints could act to limit offshore production under some scenarios.

The study is an **information document** and does not advocate or recommend any particular scenario. **It is not a decision-making document**. Decisions about future permitting activities associated with potential offshore oil and gas development will be made with the complete complement of information, of which this study will be part. Additional analyses undertaken under the National Environmental Policy Act (NEPA) and California Environmental Quality Act (CEQA) as well as other local, State, and Federal authorities will help complete the picture necessary to make decisions concerning permit applications pursuant to development. Other documents contributing to future decisions include recently completed studies funded by MMS and others on socioeconomic information; comprehensive safety audits on onshore facilities by local agencies; Santa Barbara County's North County Facilities Siting Study; Chevron Gaviota R-1 Review, and other studies that will be developed and completed over the next several years.

The COOGER study focuses only on **existing undeveloped leases**. Presidential Executive Order issued in June 1998 prohibits new leasing of Federal offshore oil and gas tracts until after 2012. New drilling in State of California tidelands and submerged waters is prohibited unless special circumstances are identified (such as where a field under an existing lease extends into an unleased area). There are presently no approved plans for new leasing in Federal or State waters.

1.3 PRINCIPAL STUDY REGION AND SUBREGIONS

The Principal Study Region is the near-coastal areas of Ventura, Santa Barbara, and San Luis Obispo Counties depicted in Figure 1-1. It encompasses all primary processing and storage facilities used to support offshore oil and gas development and production. For purposes of this study, the principal region is further divided into three subregions, also depicted in Figure 1-1. The subregions include:

- Eastern Subregion—Along the Pacific Coast, from south to north, the Eastern Subregion extends from the Ventura/Los Angeles county line to the northern (western) boundary of Carpinteria.

- Central Subregion—From south to north, the Central Subregion extends from the northern (western) boundary of Carpinteria to the Santa Ynez River.

- Northern Subregion—From south to north, the Northern Subregion extends from the Santa Ynez River to Point Estero.

1.4 STUDY SCOPE AND DEVELOPMENT SCENARIO GUIDELINES

The scope of the COOGER study is focused on the potential development of existing offshore oil and gas leases over a 20-year period from the end of 1995 through 2015. Projections of future industrial development and local conditions are presented in 5-year increments in the years 2000, 2005, 2010 and 2015 to provide a view of changes over time. The presentation of local conditions is focused upon industrial and public infrastructure which may affect, or be affected by, the rate and magnitude of offshore oil and gas development. The onshore infrastructure identified and evaluated in this report include:

- Oil and gas processing facility capacity as it relates to specific scenario guidelines,

- Oil and gas transport infrastructure related to offshore production, and

- Public infrastructure, such as roads, railroads, ports, harbors and airports.

To guide the definition of discrete development levels which describe a full range of potential offshore development, the Minerals Management Service and the COOGER study Steering Committee and Technical Management Team defined specific guidelines concerning offshore development scenarios to be evaluated. These guidelines include:

Eastern and Central Subregions

1) Scenario 1 - No further development of offshore leases.

2) Scenario 2 - Development of existing offshore leases using existing onshore facilities as currently permitted and constructed (whichever is less) without additional capacity. This scenario includes modifications to allow processing and transportation of different quality oil or natural gas.

3) Scenario 3 - Maximum development of existing offshore leases using existing onshore facilities by constructing added capacity at existing sites to handle expanded production, if needed.

4) Scenario 4 - Development of existing offshore leases considering the currently projected schedule for decommissioning and removal of existing onshore facilities. This may include new facilities and perhaps new sites to handle anticipated production.

Northern Subregion

1) Scenario 1 - No further development of offshore leases.

2) Scenario 2 - Development of existing Northern Subregion offshore leases using existing onshore facilities as currently permitted and constructed (whichever is less) without additional capacity. This scenario includes modifications to allow processing and transportation of different quality oil or natural gas. This scenario is not limited by market constraints as is Scenario 3 in this subregion (described below).

3) Scenario 3 - Development of existing Northern Subregion offshore leases using existing onshore facilities and/or new facilities, with expanded facility capacity if needed. Production rates are based on a realistic market demand estimate which considers crude oil characteristics and offshore operators' assessment of the most promising market for Santa Maria Basin heavy crude oil.

4) Scenario 4 - Development of existing Northern Subregion offshore leases using existing onshore facilities and/or new facilities, with expanded facility capacity if needed. Production rates are based on offshore operators' evaluation of the maximum potential commercial development without consideration of currently identified market capacity limitations.

5) Scenario 2A - Development of existing offshore leases using existing onshore facilities as currently permitted and constructed (whichever is less) without additional capacity. This scenario includes the potential processing of production from Central Subregion offshore leases which may be displaced by the decommissioning of Central Subregion onshore facilities, as well as production from Northern Subregion offshore leases. This scenario includes modifications to allow processing and transportation of different quality oil or natural gas. This scenario is not limited by market constraints.

6) Scenario 3A - Development of existing offshore leases using existing onshore facilities and/or new facilities, with expanded facility capacity if needed. This scenario includes the potential processing of production from Central Subregion offshore leases which may be displaced by the decommissioning of Central Subregion onshore facilities, in addition to production from Northern Subregion offshore leases. Production rates associated with Northern Subregion offshore leases are based on a realistic market demand estimate which considers crude oil characteristics and offshore operators' assessment of the most promising market for Santa Maria Basin heavy crude oil.

7) Scenario 4A - Development of existing offshore leases using existing onshore facilities and/or new facilities, with expanded facility capacity if needed. This scenario includes the potential processing of production from Central Subregion offshore leases which may be displaced by the decommissioning of Central Subregion onshore facilities, in addition to production from Northern Subregion offshore leases. Production rates associated with Northern Subregion offshore leases are based on offshore operators' evaluation of the maximum potential commercial development without consideration of currently identified market capacity limitations.

Each of the above-listed scenarios is addressed in terms of the onshore facility requirements, oil production rates, and demand on local infrastructure. This effort is intended to provide an improved understanding of the range of potential development options, and the general level of industrial activity associated with each option, and the range of demand on public and industrial infrastructure associated with these options. Although the original scope of the COOGER study included several environmental and socioeconomic topics, these study components were deleted by Steering Committee consensus to improve the report's focus on infrastructure capacities and demand, and to reduce confusion associated with the inclusion of topics which are routinely addressed in decisionmaking documents.

1.5 ASSUMPTIONS

This report draws upon existing information gathered, inventoried, and consolidated from publicly available technical documents, and industry and agency files and interviews. In addition, explicit assumptions were defined early in the study. The assumptions provided a foundation for the study, and have been expanded upon in the issue-specific analyses. The continued use of existing facilities is a necessary study assumption because this study is intended to provide information concerning the adequacy of existing onshore facility capacity in relation to potential future offshore development. This assumption is not intended to imply that such use is guaranteed. Even when facilities are operated within existing land use permit limitations, additional agency approvals may be required to address other permit requirements (such as air permit requirements, water discharge permits or other limitations) or issues associated with the extended life of the facility.

Santa Barbara County has recently expressed concerns regarding the safety of older facilities, and has suggested that safety audits should be completed before decisions are reached that could lead to the extended life of any onshore facility. Most of the existing facilities that could be considered for extended use under different scenarios are located in Santa Barbara County. County staff indicated that facility safety audits should evaluate facility design and operating procedures to identify possible upgrades to incorporate best available technology and allow the facility to operate safely throughout its projected extended life. As a part of this review, Santa Barbara County staff have recommended a detailed examination of the operating and maintenance history of the facility in question, including an evaluation of the record of accident incidents (including air and water releases) to help identify facility-specific concerns to be addressed by facility improvements. A comprehensive treatment of this topic has not yet been done, and is likely to be required in connection with development proposals which involve extended facility life or expanded capacity. The California State Lands Commission (SLC) is preparing a statewide engineering audit program to encompass both state offshore and onshore oil producing and separation facilities which will include the evaluation of safety system design, process controls, inspections, testing and maintenance of the facilities with the focus on best available protection of the marine environment and public safety.

Additional COOGER study assumptions include the following:

1) Economic viability of potential development was determined assuming that current operating costs and crude prices would prevail at all future dates. Potential market limitations were not considered except as specifically discussed in relation to individual Northern Subregion scenarios.

2) Discrete oil and gas fields will be the subjects of consideration for this study and reserve estimates will be done on a field basis. For the purpose of this study, a field is deemed to be an area within which hydrocarbons have been trapped and concentrated in one or more reservoirs in economically producible quantities. A field may refer to its geographically measurable surface area only, or may include its vertical subsurface dimensions.

3) Industry will endeavor to optimize production, processing and transportation facilities, both offshore and onshore. Such optimization may include efforts to use facilities in common, taking into consideration the following factors: existing regulations; distance between operations; timing and rate of oil and gas production; characteristics of oil; facility capacity; as well as the number and location of onshore entry points. Similarly, individual operators will propose future development activities on their leases at the rate and in the manner they desire subject to conditions of their lease agreement and subject to the management authority of the MMS and California State Lands Commission.

4) The Tri-County and state jurisdictions, including the California Coastal Commission, will endeavor to optimize onshore facilities as a means of minimizing adverse impacts. Such optimization may include requirements to consolidate processing facilities and sites, consolidate pipelines and pipeline corridors, and use of pipelines instead of other modes of transportation for crude oil and natural gas liquids.

5) Geological and engineering data will be drawn from publicly available and proprietary sources. The U.S. Minerals Management Service (MMS) and the California State Lands Commission (SLC) will ensure that each company's proprietary data are protected. Estimated recoverable reserves of hydrocarbons for each field will be developed using publicly available data and estimates provided by the oil companies. Projections based on field decline assume the operators will continue to work over wells, as they have in the past, to counteract the natural productivity decline. The MMS and SLC will verify, with independent analysis, whether those field estimates are reasonable. Ranges of values for reserve estimates and production rates will be used in the study.

6) Although policies and regulations that affect future oil and gas development may change in the future, this study focuses on potential development pursuant to policies and regulations in place currently and does not attempt to assume how future policies and regulations may change that potential development.

7) Estimates of future spare processing capacity at the onshore facilities assumes operators will maintain all equipment in working order at its 1995 design capacity.

8) Economic life of existing offshore production operations was determined using the posted price of crude oil at the beginning of the study base year (December 31, 1994), which ranged from \$9.50 to \$13.71 per barrel depending on oil gravity and other characteristics. Operating cost of offshore facilities were estimated using available cost data. Production forecasts were terminated when the economic life limits were reached and facility decommissioning is assumed to commence at this point.

9) Crude oil prices have varied substantially since the study base year, and changing prices could significantly change the expected economic life of offshore production operations in the COOGER study region. Crude oil prices are currently more than the prices used as the base for this study, and engineering modifications have been proposed for several facilities to reduce operating costs. As crude oil prices increase above study base year prices, the economic life of existing developed fields could be extended. Conversely, reductions in crude oil prices below study base year levels could shorten the economic life of existing developed fields. Because these changes cannot be accurately predicted,

this study does not attempt to factor future oil price changes or engineering advancements into the estimate of projected economic life of existing facilities.

10) Onshore facility economic life limits were assumed to extend to the entire life of any offshore production operation which currently depends upon that onshore facility. Onshore facility decommissioning is presumed to commence concurrent with the decommissioning of the last existing offshore production operation providing feedstock to the facility, except in scenarios which identify new development which could reasonably provide feedstock to the onshore facility within two years of this date.

11) Future oil and gas production from existing operations is assumed to include routine production enhancement techniques of existing wells.

12) Future production potential of known but undeveloped fields associated with existing leases was determined using available reservoir information and operator's inputs concerning their preferred development approach. This specifically assumes that each designated operator's development approach represents the maximum production potential which may be reasonably projected. Where operators' inputs were not available, production projections were based on decline curve techniques in conjunction with volumetric estimates.

13) Because the prediction of future crude oil prices is beyond the scope of this study, the determination of probable maximum economic development of existing undeveloped resources is based upon the posted price of crude oil at the beginning of the study base year (December 31, 1994). Crude oil prices have varied substantially since that date, and are currently lower than base year levels. Some of the offshore resources considered economically recoverable in this study may not actually be developable until oil prices return to base year levels, or until engineering advancements reduce operating costs enough to offset current low prices. It should be noted, however, that additional development of offshore oil and gas reserves on existing leases beyond the maximum levels predicted in this study would not occur even if substantially higher oil price assumptions were applied.

14) Baseline conditions and oil production estimates are projected over the study 20-year time frame based on data available during the COOGER study data collection period in 1996. Although some more recent information has been included as the study progressed, it is assumed that comprehensive updates of the information presented will be accomplished periodically to maintain the usefulness of this study.

15) Available data are assumed adequate to provide the information required in the COOGER study. No original field data collection or independent calculations using raw data are included in this study.

16) The COOGER study is intended to address specific issues which are related to infrastructure capacity affecting the development of existing undeveloped offshore leases, and does not represent a comprehensive analysis of environmental issues or potential impacts. Many topics of interest are not addressed, and their omission is not based on any assessment or opinion concerning their importance to project-specific decisions.

In addition to the specific assumptions listed above, additional information concerning report limitations and intended uses is presented in Appendix D. A glossary of terms and abbreviations used in this report which may be unfamiliar to some readers is presented in Appendix G.

2.0 CURRENT AND FUTURE BASELINE OIL AND GAS PRODUCTION AND RELATED ACTIVITY

2.1 OVERVIEW

The COOGER study addresses potential future levels of offshore oil and gas activities offshore the tri-counties of Ventura, Santa Barbara, and San Luis Obispo. The first step in this study involves the description of future conditions in the absence of new offshore development. This "future baseline" description provides a basis for comparison with other potential production scenarios. This projection of future conditions includes expected use of public infrastructure as well as demand for existing industrial capacity associated with changing offshore production. This study defines this future-case projection as a time-depending baseline. This baseline is used as the starting point for the evaluation of different development scenarios, some of which involve the development of known but currently undeveloped offshore oil and gas fields associated with existing offshore leases.

The current and future baseline projections presented in this report are organized according to three important topics to allow presentation of this information. These topics include:

- Offshore oil and gas production forecasts
- Onshore oil and gas facility characteristics and excess capacity forecasts
- Public and industrial transport infrastructure and refineries

In addition to these topics, a brief overview of environmental regulations applicable to oil and gas development is presented. These regulations are assumed to apply throughout the study timeframe, and represent regulatory constraints applicable to all future development scenarios. Future changes in regulations cannot be reasonably predicted, and such predictions are not attempted in this study.

2.2 SUMMARY OF REGULATIONS

There are numerous federal, state, and local regulations, administered by agencies at different government levels, that are applicable to the offshore and onshore facilities used to develop, produce, process and transport offshore-produced oil, gas and related products. The impact of certain regulations may apply to certain phases of a development project or apply throughout a project. Similarly, some agencies may be involved with certain phases or "location specific" parts of a development project; whereas, others may be involved throughout the life of the project.

To be successful, an existing or proposed development project must meet all of the requirements of the applicable regulations and agencies. This section provides an overview of key regulations, their intent and purview, the responsible government agencies, and the approval action required for oil and gas projects. These are summarized in Table 2.2-1. This section also provides a brief discussion on the federal, state and local process associated with "permitting" a "typical" oil and gas project in the Tri-County area. The discussion identifies the major steps for a "typical" project, but is not all-inclusive and is not a permitting plan for an individual project.

For the purpose of this discussion, the term "regulation" includes laws, acts, regulations, statutes, codes, and the like. The term "permit" includes permits, licenses, registrations, certifications, development plan approvals, conditional use permits, and other project- or facility-specific agency approvals. The term "facilities" means any facility and related equipment used to develop, produce, process or transport oil and gas and includes platforms, pipelines, onshore separation and processing facilities, and marine terminals.

2.2.1 Review of Development on the Federal Outer Continental Shelf

The federal Outer Continental Shelf (OCS) jurisdiction generally includes the area extending from 3 to 200 miles offshore. Oil and gas development in this area is regulated by the U.S. Department of the Interior, Minerals Management Service. Before the exploration and development process begins, the federal government issues leases for specific offshore areas. MMS leases OCS tracts for terms ranging from five to ten years, typically on a "bonus bid" basis (i.e., tracts go to the highest bidder). As part of the work to be done to prepare the lands to be included on the required five-year lease schedules, the 1978 Offshore Continental Shelf Lands Act mandates that the U.S. Department of the

Table 2.2-1
Regulatory Framework for Offshore Oil/Gas Development

Law/Regulation	Type of Project(s)	Government Agency	Permit/Approval
FEDERAL			
Outer Continental Shelf Lands Act Amendments (OCSLAA); 43 U.S.C. § 1331-1356	Federal OCS leasing, exploration, drilling and production facilities, oil and gas wells, offshore pipelines	Minerals Management Service (MMS)	Development/Production Plan Approval, Permit to Drill
National Environmental Policy Act; 42 U.S.C. § 4371 et seq.	Federal OCS development involving federal action with potential environmental effects (including approval of offshore oil and gas development).	All agencies participate, MMS typically acts as lead agency.	Environmental Impact Statement or Finding of No Significant Impact
Coastal Zone Management Act (CSMA); 16 U.S.C. § 1451-1464	Activities on the federal OCS	California Coastal Commission (CCC), National Oceanic and Atmospheric Administration (NOAA)	Consistency Certification
Clean Water Act; 33 U.S.C. § 1251-1376	All activities involving discharges to waters of the United States, including federal OCS, state tide lands and onshore	Environmental Protection Agency (EPA), Regional Water Quality Control Board (RWQCB)	NPDES Permit
Clean Air Act Amendments	Facilities involving air pollutant emissions (federal OCS, state tide lands and onshore)	Local Air Pollution Control District (APCD), Environmental Protection Agency (EPA)	Title V and Title III Permits
River and Harbor Act of 1899; 33 U.S.C. § 401 et seq.	Fill and placement of structures in waters of the United States (federal OCS, state tide lands, and onshore)	Army Corps of Engineers (COE), U.S. Coast Guard (commenting agency)	404 Permit (fill) Section 10 Permit (navigation)
Endangered Species Act; 16 U.S.C. § 1531-1543	All projects with potential effects on protected resources (federal OCS, state tide lands, and onshore)	Fish and Wildlife Service and National Marine Fisheries Service	Section 7 Consultation leading to a Biological Opinion, NEPA comments
Marine Mammal Protection Act of 1972	All projects with the potential to harass or harm marine mammals	National Marine Fisheries Service, U.S. Fish & Wildlife Service	Incidental Harassment Authorization
Migratory Bird Treaty Act 16 U.S.C. §703-711	All projects with potential effects on populations or habitats of migratory birds	U.S. Fish & Wildlife Service	None

Table 2.2-1 (Continued)

Law/Regulation	Type of Project(s)	Government Agency	Permit/Approval
STATE			
Submerged Lands Act; 43 U.S.C. § 139\01-1315	Mineral Extraction Projects & Support Facilities to Offshore Development in State Tidelands	California State Lands Commission	Right-of-Way/Land Use Lease and Development Approvals
Porter-Cologne Water Act; § 13000 et seq.	Water discharges in state tide lands and onshore	California Regional Water Quality Control Board	Waste Discharge Permit
California Endangered Species Act	All projects with the potential to affect State listed species	California Department of Fish & Game	Biological Opinion and Incidental Take Authorization
California Fish and Game Code; § 1600-1607	Onshore development involving the alteration of streambeds. Development on state tide lands or onshore which potentially affect state-listed species.	California Department of Fish and Game	Stream Alteration Permit Biological Opinion
Streets and Highway Code; § 660-734	Onshore development involving components within state highway rights-of-way.	Department of Transportation (CALTRANS)	Encroachment Permit
California Environmental Quality Act (CEQA); P.R.C. § 21000 et seq.	Projects on state tide lands or onshore requiring discretionary actions.	All agencies. California State Lands Commission typically acts as lead agency concerning offshore projects, local counties act as lead agency for onshore projects.	Environmental Impact Report (EIR) or Negative Declaration. Lead agency findings and Notice of Determination
California Coastal Act; P.R.C. § 30000 et seq.	Development on state tide lands and onshore development within the Coastal Zone.	California Coastal Commission (CCC), local planning agency where an approved Local Coastal Program exists	Coastal Development Permit
California Clean Air Act	Projects involving air pollutant emissions	Air Resources Board	(TBP)
California Code of Regulations, Title 14, Chapter 4	Onshore and state tide lands oil and gas well drilling proposals	California Department of Conservation, Division of Oil, Gas and Geothermal Resources	Permit for Oil and Gas Operations
California Code of Regulations, Title 14	Offshore oil and gas facilities	California Department of Fish & Game, Office of Spill Prevention and Response	Certificate of Financial Responsibility and Oil Spill Contingency Plan
LOCAL			
General Plan Zoning Ordinances Local Coastal Programs	All onshore development	County and City Governments	Land Use Permit, Conditional Use Permit, Coastal Development Permit
Federal Clean Air Act Local Rules & Regulations	All development (onshore, state tide lands, and federal OCS)	Air Pollution Control Districts	Authority to Construct, Permit to Operate, Clean Air Act Compliance, Title V and Title III

Interior (DOI) consider environmental, economic and social values of the OCS, as well as impacts of offshore drilling on marine, coastal and human environments (Section 1344 (a)(1)).

The permitting of an OCS project, including its state water and onshore components, typically requires the approval of federal, state, and local government authorities. A summary of the steps required in the OCS exploration and development approval process are provided on Table 2.2-2. Two of the key federal laws that govern the federal environmental review of OCS projects are 1) the National Environmental Policy Act (NEPA), which applies to the federal or OCS portion of development, and 2) the Outer Continental Shelf Lands Act (OCSLA).

The purpose of NEPA (P.L. 91-190, 42 U.S.C. 4321 et. seq.) is not only to maintain environmental quality, but to "fulfill the social, economic and other requirements" of United States citizens. If a proposed federal action (including issuance of a permit) has the potential to significantly affect the environment, agencies must prepare an Environmental Impact Statement (EIS) that considers the direct and indirect social, aesthetic, historic, economic, cultural, health and environmental impacts of the proposed action by making "integrated use" of both physical and social sciences. NEPA also requires that the public have an opportunity to comment on proposed developments.

The OCSLA (43 U.S.C. 1331 et. seq.), as modified by the Outer Continental Shelf Lands Act Amendments (P.L. 95-372, 43 U.S.C. 1801 et seq.) requires explicit attention to social and economic impacts in assessing OCS activities. OCSLA, as amended, establishes the Department of Interior (DOI) as the lead federal agency in assessing and managing "environmental impacts on the human, marine, and coastal environments of the OCS and the coastal areas which may be affected by oil and gas development" (43 U.S.C. 1346 (a)(1)). The MMS has issued regulations pursuant to the OCSLA to provide specific guidance concerning the technical and environmental requirements applicable to OCS development proposals.

The MMS typically acts as the NEPA lead agency for projects involving development on the federal OCS, in addition to its administration of the requirements of the OCSLA as amended. Several federal, state, and local agencies are also directly involved in the regulatory review of projects on the federal OCS. This includes state and local agencies which have been delegated authority to administer federal laws applicable to OCS development. The principal federal laws and review agencies involved in this effort are listed in Table 2.2-1.

Table 2.2-2

Summary of the Steps in OCS Exploration and Development Approval Process

	Local Government Participation
Exploration Phase:	T
1. Plan of Exploration	
2. Approval or Disapproval	T
3. Consistency Certification	T
4. Environmental Assessment (NEPA)	
5. MMS Application for Permit to Drill	T
6. Other Federal Permits	
7. Exploratory Drilling Begins	
Offshore and Onshore Development Phase:	
1. Development and Production Plan (DPP)	T
2. Onshore Development Planning	T
3. Consistency Certification by Coastal Commission	T
4. Consultation with Local governments[a]	T
5. Determination to Prepare an EIR/S (CEQA/NEPA)	
6. EIR/S Scoping Process	T
7. Draft EIR/S, Public Comment and Hearing on Draft EIR/S	T
8. Final EIR/S	
9. DPP Approval or Disapproval	
10. Final Development Plan/Local Agency Permits	T
11. MMS Application for Permit to Drill	
12. Building, grading, and construction Permits	T
13. Air Quality Permits	T
14. Other Federal Permits/Approvals[c]	T
15. State Permits[b]	T
16. Offshore Development Begins	

a. Indicates local government involvement through the Governor.

b. State permits could come before local permits, depending on which agency is the lead agency.

c. Includes U.S. Coast Guard review and approval of Oil Spill Contingency Plans.

Typical OCS development proposals often involve related facilities or operational modifications in state and local jurisdictional areas. The review of these project components involve the application of state and local regulations (described further in Sections 2.2.2 and 2.2.3). Joint National Environmental Policy Act (NEPA) and California Environmental Quality Act (CEQA) reviews are commonly conducted to coordinate this review effort. The administration of this effort usually involves the MMS as federal lead agency and the local government with jurisdictional authority at the location of onshore facilities acts as the state lead agency. If no onshore facilities are associated with the proposed project, but facilities are proposed in state tidelands, the California State Lands Commission typically acts as the state lead agency. To integrate the concerns of other agencies in the direction of the environmental study effort, a Joint Review Panel (JRP) is often formed to act as a management committee.

The process of obtaining the necessary approvals for an OCS project is initiated by submitting separate applications to the MMS and the local county (if onshore project components are involved). The application should provide detailed project descriptions for both the offshore and onshore project components. The initial application should also include a development and production plan (DPP), an environment report (ER) and other supporting documents (site-specific geohazards, cultural resources, and biological surveys, oil spill contingency plan, a hydrogen sulfide curtailment plan, and a critical operation contingency plan supplement), as appropriate. After the MMS reviews the application, the OCS portion may be submitted to other permitting agencies for review and approval. Table 2.2-3 lists several common approvals required by other agencies involved in the review of OCS development proposals. Platform design is approved under the MMS Platform Verification Program, and the MMS later oversees fabrication and installation of the platform.

After the MMS deems the application complete, as required by NEPA, the MMS can choose to prepare either an environmental assessment (EA) or an EIS. In addition, the MMS submits the OCS portion of the application to the California Coastal Commission (CCC). In accordance with the 1990 reauthorization of the Coastal Zone Management Act (16 U.S.C. Section 307(c)(1)), the application must contain a federal Consistency Certification that outlines the expected effects on the coastal zone of the proposed project and a finding that the project and its associated effects are consistent with California's Coastal Management Program. The CCC has consistency review authority for projects occurring on the federal OCS in accordance with the federal Coastal Zone Management Act, as amended.

Table 2.2-3
Other Approvals Needed for OCS Development

Responsible Agency	Type of Approval	Project Feature/Issue
U. S. Environmental Protection Agency	NPDES permit	Offshore waste discharges
U.S. Army Corps of Engineers	Permits	Structures in navigable waters
U.S. Coast Guard	Financial responsibility	Certification
U. S. Minerals Management Service	Right-of-way	Pipelines in OCS waters
California State Lands Commission	Right-of-way	Pipelines in state waters
County Air Pollution Control District	Permits	Construction and operation oil and gas production and processing facilities
California Regional Water Quality Control Board	Permit	Onshore and offshore waste discharge
U.S. Coast Guard	Documentation	Oil Spill Contingency Plans
Minerals Management Service	Documentation	Oil Spill Contingency Plans
California State Lands Commission	Documentation	Oil Spill Contingency Plans

If the CCC concurs with the consistency certification, the MMS will then approve the plan for development of the OCS portion of the project. If the CCC does not concur with the consistency certification, the MMS cannot issue its approval. Under such conditions, the CCC action may be appealed to the U.S. Secretary of Commerce. Local and state approval for a proposed project is also required for those projects that entail onshore facilities and/or invoke state jurisdiction.

2.2.2 Review of Development on State Tide and Submerged Lands

State tide and submerged lands include the area from mean high tide seaward to the three-mile boundary with the federal OCS. Development of oil and gas resources on existing leases in this area is subject to the regulatory authority of the California State Lands Commission (SLC). The SLC is responsible for minerals leasing activities, issuance of rights-of-way, and administration of CEQA requirements for projects involving new facilities on state tide and submerged lands. Development of resources on State Tide and Submerged lands involving facilities at onshore locations is subject to local agency authority, including local agency administration of CEQA requirements and other land use controls. The issuance of new oil and gas leases on State tide and submerged lands is currently restricted by the 1994 California Coastal Sanctuary Act (P.R.C. §6240 et seq.) which prohibits new leasing for oil and gas extraction in state waters except: (1) in the event of a severe national energy supply interruption; or (2) when the state determines that state-owned oil or gas deposits are being drained by producing wells located upon adjacent federal lands and the lease is in the best interests of the state. Development of oil and gas resources on existing leases is administered by the SLC. Key laws governing the SLC process and authority include the Submerged Lands Act (43 U.S.C. §1301-1315) and the California Environmental Quality Act (CEQA, P.R.C. §21000 et seq.). State Lands Commission regulations (Title 2, C.C.R. §2102-2175) and specific lease requirements specify technical and environmental standards and information requirements applicable to offshore development proposals. As the California lead agency for administration of the CEQA process, the SLC is responsible for coordination with other regulatory agencies and the public throughout the CEQA environmental review process. A summary of the SLC review process is presented in Table 2.2-4.

The California Coastal Commission (CCC) is another key agency involved in the review of development on state tide and submerged lands. This review is accomplished in accordance with

Table 2.2-4
Summary of California State Lands Commission (SLC) Review Process for Facilities Located on State Tide and Submerged Lands*

Sequence	Activity
1	Applicant submits a Development and Production Plan (DPP) to the SLC Minerals Resource Management Division.
2	Establish a reimbursement agreement between applicant and the SLC.
3	The SLC reviews the DPP for completeness and consistency with the SLC's Regulations for Drilling and Production (Title 2, California Code of Regulations, § 2102-2175) and basic CEQA requirements.
4	The SLC coordinates with other permitting agencies.
5	The SLC completes an Initial Study or determines the project will require an EIR (CEQA/NEPA).
6	The SLC (or a JRP) conducts EIR public scoping process.
7	The Draft EIR is prepared, circulated for public and agency comment, and hearings are conducted.
8	The EIR is finalized and distributed.
9	The SLC certifies the EIR, adopts findings, and mitigation monitoring program.
10	Other State and local agencies may begin processing permit applications (such as water discharge permits, air permits, etc.)
10	Other State and local permits are obtained. Following acquisition of other approvals, the SLC approves/disapproves the DPP.
12	Other State and local permits are obtained. Following acquisition of other approvals, the CCC approves/disapproves issuance of the Coastal Development Permit.
13	The Right-of-Way Lease is granted to the applicant (if required).
14	Offshore development commences.

*Development of resources on State Tide and Submerged Lands using drilling and production facilities located onshore are generally subject to land use controls and environmental review requirements of the affected local jurisdiction. In such cases, local agencies generally act as the lead agency during project review.

the requirements of the California Coastal Act (P.R.C. §30000 et seq.) which establishes stringent standards of environmental protection. Coordination between agencies is important during the Coastal Development Permit review process because some Coastal Act policies address issues which relate to the reviews conducted by other agencies. The California Coastal Act requires that all discretionary environmental permits necessary to commence project development must be issued prior to the issuance of the Coastal Development Permit.

Several other federal, state, and local agencies are directly involved in the regulatory review of projects on state tide and submerged lands. The principal laws and administering agencies involved in this effort are listed in Table 2.2-1.

2.2.3 Review of Onshore Development

2.2.3.1 Overview

While the state and federal governments both have direct management control over their respective offshore jurisdictions, local governments have direct control over the permitting of onshore production-related facilities such as oil and gas processing plants, pipelines, supply bases, and marine terminals. Development in unincorporated county areas is regulated by a county's comprehensive general plan, local coastal program, and zoning ordinances. The Local Coastal Program (LCP) includes the land use plan (or element), coastal zoning ordinance, coastal zoning district maps, and other implementing actions necessary to meet and implement the requirements of the California Coastal Act (section 30108.6 of the Coastal Act). The land use plan of the LCP is the relevant portion of a local government's general plan that is sufficiently detailed to indicate the kinds, location, and intensity of land uses, and the applicable resource protection and development policies. As a portion of the general plan, the land use plan has equal legal status with all other elements of the general plan. California law requires that a general plan must be integrated and internally consistent, both among the elements and within each element (Curtin, 1998). Local governments with a certified LCP have Coastal Development Permit authority in the onshore coastal zone area. Locally issued Coastal Development Permits for major energy facilities are appealable to the California Coastal Commission. Local resource management or planning agencies typically act as the CEQA lead agency for projects involving onshore facilities, even when these projects also involve components on state tide and submerged lands.

The onshore permitting process requires submission of county development planning applications. In addition to land-use permit applications, an environmental report and development plan are typically required. Emphasis is on land-use issues and the suitability of the proposed project site. Proposed projects that are found to be inconsistent with policies of the General Plan or Local Coastal Program may be denied, or the applicant may seek to amend the applicable planning documents.

In some cases, additional information or special processing requirements may apply. For example, San Luis Obispo County requires a "Specific Plan" and, in many cases, requires an EIR. If the county considers the application complete, it initiates the CEQA environmental review process. If the initial study of potential environmental effects identifies potentially significant impacts, or results in the conclusion that mandatory findings of significance apply, an Environmental Impact Report will be required.

After applications are considered complete, a Draft EIR/EIS is prepared (if required) and the public and governmental agencies comment on the document. The basic purposes of this process are: (1) to inform government decisionmakers and the public about the potential environmental effects of proposed actions; (2) to identify the ways environmental damage can be avoided or significantly reduced; (3) to prevent significant, avoidable environmental damage by requiring alternatives (including alternative sites) or imposition of mitigation measures; and (4) to disclose to the public why a project was approved if that project would have significant environmental effects (Curtin, 1998). In accordance with the federal and state environmental laws, public comments and other responsible party(s) comments are incorporated into the final document. An approved Final EIS/EIR allows the applicant to proceed with efforts to obtain most of the major permits associated with OCS development.

Agency reviews applicable to onshore development are listed on Table 2.2-1. Local government approvals required for onshore energy related development includes the following:

- Development Plan Approval
- Local Coastal Permit (based on requirements of the Local Coastal Program)
- Conditional Use Permit (CUP) [references consistency with LCP, General Plan (GP) and zoning ordinance]

- Consistency with General Plan Land Use Designation (and CUP)
- Consistency with Zoning Ordinance (and CUP)
- Building, Grading and Construction Permits
- Air Pollution Control Authority to Construct and Permit to Operate.

Local government typically is an active participant in the offshore components of oil and gas development. Although most local agencies only have jurisdiction for the onshore components of the project, revisions to the Outer Continental Shelf Lands Act and Clean Air Act delegate regulatory review responsibilities to local Air Pollution Control Districts for projects in state and federal waters. Under some circumstances, local residents are also directly incorporated into the final approval of some onshore facilities associated with offshore oil and gas development, as described below.

2.2.3.2 Ventura County - Save Open-Space and Agricultural Resources Ordinance

The voters of Ventura County approved the Save Open-Space and Agricultural Resources (SOAR) initiative to amend the County's General Plan. This amendment was implemented by ordinance in 1998, and is intended to limit the conversion of agricultural and open space lands to other uses, including oil and gas processing facilities. The ordinance which establishes this general plan amendment limits the County Board of Supervisors' authority to amend the General Plan provisions or to modify the land use designation of existing agricultural or open space lands. In general, the SOAR ordinance requires a public vote and simple majority approval of any proposed General Plan amendment that would modify general plan policies or alter specific parcel land use designations affecting agricultural, open space, and rural lands. The SOAR ordinance states:

> *"The purpose of this ordinance is to ensure that Agricultural, Open Space and Rural lands are not prematurely or unnecessarily converted to other more intensive development uses. Accordingly, this ordinance ensures that until December 31, 2020, the general plan provisions governing Agricultural, Open Space, and Rural land use designations, as amended herein, may not be changed except by vote of the people."*

The SOAR ordinance includes provisions which recognize specific areas with rural designations and an existing urban character, and allow limited flexibility to amend General Plan provisions without a popular vote as long as consistency with the findings and purpose of the SOAR ordinance is maintained. Although this ordinance does not specifically address industrial facilities, siting new facilities in Ventura County would very likely be affected. This ordinance would not affect the location of oil and gas facilities such as pipelines which are allowable on Agricultural, Open Space, and Rural Lands under existing General Plan policies.

2.2.3.3 Santa Barbara County - Measure A96

On March 26, 1996, the voters in Santa Barbara County approved Voter Approval Initiative, Measure A96, a voter referendum that amends the General Plan's Land Use Element and Coastal Land Use Plan, along with Articles II and III zoning ordinances which govern both coastal and inland portions of the County. The initiative states:

> *"any legislative approvals which would authorize or allow the development, construction, installation, or expansion of any onshore support facility for offshore oil and gas activity on the South Coast of the County of Santa Barbara (from Point Arguello to the Ventura County border) shall not be final unless such authorization is approved, in the affirmative, by a majority of the votes cast by the voters of the County of Santa Barbara in a regular election."*

Measure A96 voter referenda apply solely to legislative approvals of onshore support facilities, defined in the initiative as: "... any land use, installation, or activity proposed to effectuate or support the exploration, development, production, storage, processing, or other activities related to offshore energy resources.". Measure A96 does not apply to activities planned in the two South Coast "consolidation" sites located at Las Flores Canyon and at Gaviota. In addition, Measure A96 does not apply to the northern portion of the County of Santa Barbara.

2.2.3.4 San Luis Obispo County - Measure A

In addition to the other regulations, the voters of San Luis Obispo approved Measure A which also applies to onshore facilities, associated with offshore development, that received County authorization after January 1, 1986. Measure A was adopted as Policy 1A and the key provision reads:

> ***Section 1.*** *No permit, entitlement, lease, or other authorization of any kind within the County of San Luis Obispo which would authorize or allow the development, construction, installation, or expansion of any onshore support facility for offshore oil and gas activity shall be final unless such authorization is approved by a majority of the votes cast by a vote of the people of the County of San Luis Obispo in general or special election. For the purpose of this ordinance, the term "onshore support facility" means any land use, installation, or activity required to support the exploration, development, production, storage, processing, transportation, or related activities of offshore energy resources.*

2.2.3.5 City of San Luis Obispo Onshore Facility Code

The City of San Luis Obispo Municipal Code includes specific reference to onshore facilities associated with offshore oil and gas development. Chapter 17.92 of the Municipal Code specifies:

> *"No onshore support facility for offshore oil or gas development shall be allowed or permitted within the city until such time that the council proposes the inclusion of such uses in an appropriate zone district or districts, and such proposal has been approved by a vote of the people of the city."*

The public vote required by this ordinance would be in addition to any other approval requirements that may apply to a proposed facility.

2.3 OFFSHORE OIL AND GAS RESERVES AND PRODUCTION PROJECTIONS

This section provides an overview of the offshore fields from which the oil and gas currently are produced. The discussion of each field identifies the leases involved, identifies the formations being produced, the platforms in the field, and provides the basis for the future baseline projection. This discussion also summarizes the current production and the projected future production of oil and gas from the current and projected offshore development summed by subregion. The purpose is to illustrate the quantity and timing of projected future production from existing leases. The information is useful to better understand projected subregional trends. Information concerning employment associated with offshore operations and associated onshore facilities is included in Appendix A.3. Appendix A.4 presents information concerning property tax revenues associated with onshore facilities and facilities on State Tide and Submerged Lands.

Because of the confidential nature of the data, future production estimates for individual platforms and fields are not provided. The currently developed oil fields in the COOGER Study Region are as follows:

Eastern Subregion
Hueneme Field
Santa Clara Field
West Montalvo Field
Rincon Field
Dos Cuadras Field
Carpinteria Field
Sockeye Field
Pitas Point Field

Central Subregion
South Ellwood Field
Hondo Field (Santa Ynez Unit)
Pescado Field (Santa Ynez Unit)
Point Arguello Field

Northern Subregion
Point Pedernales Unit
Tranquillon Ridge Unit

2.3.1 Offshore Reserves in the Study Region

Overall, the Eastern, Central, and Northern Subregions are expected to experience the continued production of existing developed oil and gas reserves during the period 1995 to 2015. Under the future baseline projection, the expected total production from 1995 to 2015 for the entire COOGER Study Region is estimated at 568 million stock tank barrels (MMSTB) of oil, and 1111 billion standard cubic feet (BCF) of gas. Table 2.3-1 provides the future baseline projection of oil and gas production for the period 1995 to the end of 2015. Figure 2.3-1 illustrates the production trend associated with the data provided in the table. The projection for the fields currently under production shows yearly oil production dropping from 73.99 MMSTB in 1995 to 15.34 MMSTB by the year 2005 and to 4.38 MMSTB by the end of 2015. The projection for yearly gas production drops from 57.69 BCF in 1995 to 40.04 BCF by the year 2010 and to 35.00 BCF per year by the end of 2015.

The remainder of this section provides general information about each producing field and the platforms, drilling islands, and onshore wells from which the field is produced. Table 2.3-2 provides a summary of the wells on each platform, as of January 1, 1995. Sections 2.4.2, 2.4.3 and 2.4.4 discuss the onshore facilities in the Eastern, Central and Northern Subregions, respectively.

2.3.2 Eastern Subregion

The Eastern Subregion fields include the Hueneme, Santa Clara, West Montalvo, Rincon, Dos Cuadras, Carpinteria, Sockeye and Pitas Point fields. Under the future baseline projection, the expected total production from 1995 to 2015 from the Eastern Subregion is estimated at 52 million stock tank barrels (MMSTB) of oil and 102 billion standard cubic feet (BCF) of gas. Table 2.3-3 provides the future baseline projection of oil and gas production for the period 1995 to the end of 2015. Figure 2.3-2 illustrates the production trend associated with the data provided in the table. The projection indicates the existing fields under production are at a mature level of development and most are projected to reach their economic limits for the production of oil and gas between 2000 and 2005. Figure 2.3-3 shows the location of the offshore fields and facilities in the Eastern Subregion. A summary of the individual fields is provided below.

Table 2.3-1
Future Baseline—Oil, Gas, and Water Production Projections
COOGER Study Total

Year	COOGER Total		
	Oil (MMSTB)	**Gas (BCF)**	**Water (MMBBL)**
1995	73.99	57.69	67.45
2000	48.64	62.75	104.39
2005	15.34	63.38	40.79
2010	7.86	40.04	27.74
2015	4.38	35.00	19.93
TOTAL (1995 through 2015)	568	1111	1106

Unit abbreviations:
MMSTB = million stock tank barrel (oil)
BCF = billion standard cubic feet (gas)

Source: Scotia, 1995; Dames & Moore, 1999

Table 2.3-2
Offshore Well Count Data (as of 1/1/95)

Platform	Platform Located In Field / Unit	# Slots [1]	Oil Flow [2]	Oil Lift [3]	Oil/ Gas Shut [4]	Gas Comp. [5]	Water Inj. [6]	Gas Inj. [7]	P&A Suspend [8]	Water Disposal [9]	Total Wells
Eastern Subregion											
Gina	Hueneme Offshore Field	15		5	7/3	1		2			14
Gilda	Santa Clara Field	96		33	7		19		1		64
Onshore Wells	West Montalvo Field	N/A									11
Rincon Island [drilling island]	Rincon Field	68		16			7			1	24
Henry	Dos Cuadras Field	24	0	22	1						23
Hillhouse	Dos Cuadras Field	60	0	33	11		2		1	1	48
A	Dos Cuadras Field	57	0	25	12		7				54
B	Dos Cuadras Field	63	0	28	8		9				55
C	Dos Cuadras Field	60	0	25	2		11		1		39
Hogan	Carpinteria Field	66	0	15	17			4			36
Houchin	Carpinteria Field	60	0	14	18				1		33
Gail[10]	Sockeye Field	36	2	16	2/0	4				2	26
Grace	Santa Clara Field	48		7	12/4		1		3		27
Habitat	Pitas Point Field	24			0/7	13			2		22

Table 2.3-2 (Continued)

Platform	Platform Located In Field / Unit	# Slots [1]	Oil Flow [2]	Oil Lift [3]	Oil/ Gas Shut [4]	Gas Comp. [5]	Water Inj. [6]	Gas Inj. [7]	P&A Suspend [8]	Water Disposal [9]	Total Wells
Central Subregion											
Holly	South Ellwood Field	30		23					11	1	35
Hondo	Hondo Field / Santa Ynez Unit	28	7	15	3	1	1	1		1	29
Harmony	Hondo Field / Santa Ynez Unit	60		6	1						7
Heritage	Pescado Field / Santa Ynez Unit	60		9	1			1			11
Hermosa[10]	Point Arguello Field	48	5	6	1				2		14
Harvest[11]	Point Arguello Field	50		7	7				5		19
Hidalgo	Point Arguello Field	56		10							10
Northern Subregion											
Irene	Point Pedernales Unit	72	2	10	8				3		24

Source: Scotia 1995.

[1] # Slots - the total number of wells the platform was constructed to have (1 well per slot)
[2] Oil Flow - number of wells that will "flow" oil without the need for pumps
[3] Oil Lift - number of wells that produce oil using pumps
[4] Oil/Gas Shut - number of oil/gas wells that are shut in
[5] Gas Comp. - number of wells drilled in a gas-only zone (no oil)
[6] Water Inj. - number of wells used to inject water into the producing zone
[7] Gas Inj. - number of wells used to inject gas into the producing zone
[8] P&A Suspend - number of wells that have been plugged and abandoned
[9] Water Disposal - number of wells used to dispose of produced water
[10] Scotia well count data revised by Chevron
[11] Scotia well count data revised by Texaco

Table 2.3-3
Future Baseline Oil, Gas and Water Production Projections
Eastern Subregion

Year	Eastern Subregion Carpinteria, Dos Cuadras, Hueneme, Pitas Point, Rincon, Santa Clara, Sockeye, and West Montalvo		
	Oil (MMSTB)	**Gas (BCF)**	**Water (MMBBL)**
1995	9.02	19.07	28.02
2000	4.34	8.29	23.07
2005	0.82	0.98	2.60
2010	0.37	0.44	1.74
2015	0	0	0
TOTAL (1995 through 2015)	52	102	233

Unit abbreviations:
MMSTB = million stock tank barrel (oil)
BCF = billion standard cubic feet (gas)

Source: Scotia, 1995; Dames & Moore, 1999

2.3.2.1 Hueneme Field

The Hueneme Field is located in the eastern Santa Barbara Basin approximately four miles southwest of Port Hueneme and is a part of the Point Hueneme Unit which is comprised of federal leases OCS- P0202 and OCS-P0203. Oil gravity from the field averages 13.9 degrees API. Production is from the Sespe formation and is free of sulfur and hydrogen sulfide. Tests of the Monterey formation have proven the presence of gas.

The Hueneme Field is produced from Platform Gina which is located approximately six miles from shore in OCS Lease Number P-0202. Only one well from the platform is producing from lease OCS-P0203. The platform is located in 95 feet of water. Platform Gina was installed in 1980, and production began in 1982. There is no major oil-water-gas separation equipment on the platform; three-phase flow (i.e., a mixture of oil, water, and gas) is sent to the Mandalay Onshore Separation Facility. A separator on the platform is used to remove liquids from one well's gas production. There is also waterflood equipment on the platform. The hydrogen sulfide content of the gas is essentially zero parts per million.

The Hueneme Field is in a mature stage of development and most wells have established extrapolatable production declines. The future baseline projection is an extrapolation of the total field decline and should therefore include the net effect of well workovers (routine maintenance and production enhancement activities involving removal of sand and chemical treatments to improve oil flow into the well) to maintain well productivity. This assumes that the operator will continue to workover wells in the future and that the resulting attenuation of the rate decline will be similar to the recent past.

2.3.2.2 Santa Clara Field

The Santa Clara Field is located in the eastern Santa Barbara Basin, approximately 7 miles west of Oxnard and is one of two fields located in the Santa Clara Unit. Oil gravity is approximately 28 degrees API. The reservoirs produced include the Pico (sweet crude), Repetto (sweet crude) and the Monterey (sour crude). Production from the Monterey Formation in the Santa Clara Field can contain up to 2.5 percent sulfur and 100 parts per million hydrogen sulfide in the crude oil and up to 2,000 parts per million hydrogen sulfide in the gas. Production from reservoirs in the Repetto Formation is free of sulfur and hydrogen sulfide. In addition, non-associated gas has been found in all of the Pico reservoirs and in one of the Repetto reservoirs in lease OCS-P0217. The Santa Clara Field is produced from Platforms Gilda and Grace as described below.

Platform Gilda is located approximately 10 miles from shore in 205 feet of water on OCS Lease Number P-0216 and produces from leases OCS-P0215 and P0216. The platform was installed in 1981, and production began in 1981. Gas is separated from the wet oil and some water removal is conducted on the platform. The wet oil and gas are sent through two pipelines to the Mandalay Onshore Separation Facility. Some gas is sweetened (removal of hydrogen sulfide) on the platform for use on the platform. There is also waterflood equipment on the platform that is used to reinject produced water. The hydrogen sulfide content of the gas ranges from zero to 2,000 parts per million. Production data is provided in Appendix B.

Platform Grace is located in the eastern Santa Barbara Basin, approximately 10 miles north of Anacapa Island, in 318 feet of water on lease OCS P0217. The platform was installed in 1979, and production began in 1980. Historically, oil and gas were separated on the platform and oil and gas were sent to the Carpinteria Oil & Gas Processing Facility through two pipelines. As of August 1998, Chevron had shut in or plugged and abandoned all the production wells. The current operator (Venoco) has indicated that it may resume production from this platform in the future.

The Santa Clara Field is in a mature development stage. The future baseline projection was compiled by extrapolating platform total production decline data. Because both field operators have active well workover programs to attenuate the production decline, these extrapolations take into account the net impact of workovers in the recent past. The assumption implicit in the extrapolations is that the workover activities will continue into the future.

The forecasts of water production from each platform assume the total liquid production will remain constant at rates approximating the current conditions. No information was located to indicate the overall infrastructure would constrain future production with the exception of possible limitation due to the gas compressor on Platform Gilda.

The Repetto and Monterey formations are the source of the projected production. The Repetto formation produces sweet crude and gas with essentially no sulfur or H_2S in either the crude or gas. The Monterey formation produces sour crude which contains an estimated 2.5 percent sulfur and 100 ppm H_2S and gas containing an estimated 2,000 ppm H_2S.

During the remaining producing years, the average sulfur and H_2S in the total crude stream (Repetto and Monterey combined) is projected to range from 0.98 to 1.51 percent sulfur and from 40 to 69 ppm H_2S. The H_2S concentration is the gas is projected to range from 1,019 to 1,072 ppm.

2.3.2.3 West Montalvo Field

The West Montalvo Field is located at the eastern end of the Study Region. The majority of the West Montalvo Field is located onshore; however, the Field extends offshore into the California State tide and submerged lands (i.e., within 3 miles of shore). The majority of the production in the offshore portion comes from the Colonia zone of the Sespe formation.

The West Montalvo Field is produced from onshore wells, some of which are directionally drilled under the ocean ("offshore" wells). There are no platforms or drilling islands used to produce the offshore reserves. The "offshore" wells produce from State Lease No. PRC-375 and the onshore wells (i.e., those that produce from the onshore portion of the field) produce from State Lease 3314.

Field level decline-curve projections were used to generate the future baseline projection. Water production was forecasted by projection of the water cut increase with time. Information was not identified to indicate that the current infrastructure will constrain future production.

2.3.2.4 Rincon Field

The Rincon Field is located in state waters and is comprised of state leases PRC-145, PRC-410, PRC-427, PRC-429 and PRC-1466. Production is from the Pico formation and is sweet with essentially no sulfur or H_2S in the crude or gas.

As of August 1997, the Field was being produced from two locations: a man-made drilling island located approximately 0.6 miles from shore in 45 feet of water on lease PRC-1466 and eight onshore wells drilled into state waters in leases PRC-145 and PRC-410. Rincon Island is a man-made drilling island that was constructed in 1958 and began production in 1960. The island has its own oil/water/gas processing capability and is connected to the mainland by an elevated causeway. The onshore facility that processes the production from the onshore "offshore" wells is located approximately 1.2 miles south of the point where the causeway reaches shore.

When Scotia collected its data in early 1995, several pending approvals were on hold. Because the production was restricted in the twelve months prior to Scotia's data collection effort, the decline curves for individual wells were influenced. However, for consistency with other fields and limited alternative methods, the future baseline projection was constructed from field level decline curves. No constraints limiting production from the field were identified.

Since Scotia's data collection effort, the site has changed ownership and the current owner is evaluating methods for increasing production from the field including reworking and redrilling existing wells. The initiated, proposed, and planned improvements (as of August 1997), which were unknown at the time Scotia calculated the future baseline projection may result in production higher than originally projected. However, given the relatively small level of production from the facility, it is unlikely that the resulting production will significantly impact the operation of the facility or the subregion as a whole. Also, given the uncertainty over what actual production may be, Scotia's original projections are used in this study.

2.3.2.5 Dos Cuadras Field

The Dos Cuadras Field is located in the eastern Santa Barbara Basin, approximately six miles southwest of Carpinteria, California. The Field covers much of the northern portion of federal lease OCS-P0241 and extends into the northwestern corner of OCS-P0240. Oil sales gravity averages 24 degrees API. All production originates from reservoirs in the Repetto formation and is free of sulfur and H_2S. The Dos Cuadras Field is produced from four platforms including Platform Hillhouse in lease OCS-P0240 and Platforms A, B and C in OCS-P0241. Oil and gas produced at these platforms is transported to the Rincon Oil and Gas Processing Facility via pipelines from Platforms A and B with a landfall in Ventura County near Seacliff.

Platform Hillhouse is located approximately 6 miles from shore in 190 feet of water. Equipment located on the platform separates the total production into wet oil, gas and produced water which are then sent to Platform A through three separate pipelines. Production data is included in Appendix B. The platform was installed in 1969 and production began in 1970.

Platform A is located approximately 6 miles from shore in 188 feet of water. Equipment located on the platform separates the total production into wet oil, gas and produced water. The wet oil and gas are sent to the Rincon Oil & Gas Processing Facility in two pipelines and the produced water is disposed. Production data is included in Appendix B. The platform was installed in 1968 and production began in 1969.

Platform B is located approximately 6 miles from shore in 190 feet of water. The platform was installed in 1968, and production began in 1969. Equipment located on the platform separates the total production into wet oil, gas and produced water. The wet oil and gas are sent to the Rincon Oil & Gas Processing Facility in two pipelines and the produced water is disposed. Production data is included in Appendix B.

Platform C is located approximately 6 miles from shore in 192 feet of water. Equipment on the platform separates the total production into wet oil, gas and produced water which are sent through three pipelines to Platform B. Production data is included in Appendix B. The platform was installed in 1977 and production began in 1977.

The Dos Cuadras Field has reached a mature stage such that most wells exhibit fairly well-defined decline curves. Platform aggregated decline curves were extrapolated to provide the future baseline projection. Inherent in this approach is the assumption that the operator will continue to workover wells as has been done in the recent past, and that the degree of decline attenuation so achieved will continue into the future. The water production forecast assumes that the total liquid rate on each platform will remain constant and near to current rates. This assumption agrees with the historical records for the last two years (i.e. 1993 and 1994), prior to developing the projections. Given current and expected future production levels, relative to historic production levels, the existing platform, pipeline and onshore facilities are not expected to constrain future production of oil and gas from the Dos Cuadras Field.

2.3.2.6 Carpinteria Field

The Carpinteria Field is located in the eastern Santa Barbara Basin about four miles south of Carpinteria and extends across the three mile limit separating the state and federal jurisdictions. The Field covers portions of state leases PRC-3150 and PRC-4000, and federal leases OCS-P0166 and OCS-P0240. All production is from reservoirs in the Repetto Formation and is free of sulfur and hydrogen sulfide. Oil sales gravity is approximately 24 degrees API.

The state leases were produced by the removed Platforms Hope and Heidi which were both in lease PRC-3150. Platforms Heidi and Hope were removed in early 1996. The federal leases are being produced from Platforms Hogan and Houchin located in lease OCS-P0166 and by Platform Henry located in lease OCS-P0240. Oil and gas produced from these platforms are transported to the La Conchita Facility via pipelines from Platform Hogan with a landfall in Ventura County in the La Conchita area.

Platform Henry is located approximately 4.5 miles from shore in 174 feet of water. The platform was installed in 1979, and production began in 1980. Equipment on the platform separates the total production into wet oil, gas and produced water, which are sent through three pipelines to Platform Hillhouse. The produced wet oil from Platform Henry is treated to pipeline quality oil in an electrostatic treater on Platform Hillhouse. Production data is included in Appendix B.

Platform Hogan is located in 154 feet of water on federal OCS Lease Number P-0166. The platform was installed in 1967, and production began in 1968. Equipment on the platform separates the total production into wet oil and gas which, combined with the wet oil and gas from Platform Houchin, are sent to the La Conchita Oil and Gas Processing Facility. Production data is provided in Appendix B.

Platform Houchin is located in 163 feet of water on federal OCS Lease Number P-0166. The platform was installed in 1968, and production began in 1969. Equipment on the platform separates the total product into wet oil and gas which are sent to Platform Hogan. Production data is provided in Appendix B.

The Carpinteria Field is a mature, fully developed oil field in an advanced stage of depletion. The future baseline projection was prepared by extrapolation of platform aggregated decline curves. This approach assumes that operators will continue to workover wells, thus attenuating the future reservoir/platform decline to the same degree as has been observed in the recent past. The water production forecast assumes that the total liquid rate on each platform will remain constant and near current rates. This treatment agrees with the average total liquid rates during the last two to five years of historical record. The baseline projection is not constrained by platform, pipeline or onshore facility capacities. Thus the existing infrastructure has significant excess capacity.

2.3.2.7 Sockeye Field

The Sockeye Field is one of two fields located in the Santa Clara Unit and is comprised of federal leases OCS-P0204, OCS-P0205, OCS-P0208 and OCS-P0209. Most of the production is from the Upper Sespe (sweet), the Upper Topanga sandstones (sour), and the Monterey (sour) formations. Production from the Monterey Formation is projected to contain up to 5.4 percent sulfur and 300 parts per million of hydrogen sulfide (H_2S) in the crude oil and vapors and up to 9,300 parts per million of hydrogen sulfide in the produced gas. Production from reservoirs in the Sespe Formation is free of sulfur and hydrogen sulfide. Oil gravity averages 26 degrees API.

The Sockeye Field is produced from Platform Gail which is located in 739 feet of water on OCS Lease Number P-0205 approximately 11 miles west of Port Hueneme. The platform was installed in 1987, and production began in 1988. Historically, oil and gas were separated on the platform and the wet oil and gas were sent in two pipelines to Platform Grace, combined with the Platform Grace production, and sent to the Carpinteria Oil & Gas Processing Facility. As of August 1998, data from the MMS indicates that the produced water is removed and disposed at the platform and the gas is injected such that only pipeline quality oil is sent to the Carpinteria Oil & Gas Processing Facility. Hydrogen sulfide (H_2S) is removed from produced gas offshore, with a remaining concentration of less than 50 ppm in gas processed at the Carpinteria Facility.

The Sockeye Field has reached a mature development stage and many of the wells show extrapolatable decline curves. The future baseline projection was constructed by extrapolating the aggregated field decline curve. Implicit in this approach is the assumption that the operator will continue to workover wells to attenuate the production decline as has been done in the recent past. No information was identified to indicate that the current infrastructure would constrain future production. The current operator of the Sockeye Field (Venoco) has indicated that it plans to invest capital to enhance production from this field and has already increased gas production. Consequently, the economic life of this field may be longer than that estimated in this report, which is based on decline curves based on the prior operator's production maintenance program.

The crude produced from the Upper Topanga and Monterey are both sour. A forecast of sulfur and H_2S was made assuming that these reservoir fluids were similar. The split of the total production stream into sweet (Sespe) and sour (Upper Topanga and Monterey) was made by projecting the Sespe oil and gas projection declines. The crude and gas properties used to project the "mixture" included no sulfur or H_2S for the Sespe crude and gas and 5.4 percent sulfur and 300 ppm H_2S for the Upper Topanga and Monterey crude and 9,300 ppm H_2S for the Upper Topanga and Monterey gas.

During the remaining producing years, the average sulfur and H_2S in the total crude stream (combined) is projected to range from 2.19 to 3.56 percent sulfur and from 116 to 192 ppm H_2S. The H_2S concentration is the gas is projected to range from 2,234 to 7,149 ppm. As stated earlier, most of the H_2S in produced gas is removed offshore.

2.3.2.8 Pitas Point Field

The Pitas Point Field is located in the Pitas Point Unit and is comprised of federal leases OCS-P0234 and OCS-P0436. The Field is the only producing gas field in the Pacific OCS and produces sweet gas containing mostly methane. Produced condensate liquids average 38 degrees API gravity.

The Pitas Point Field is produced from Platform Habitat which is located in 290 feet of water, approximately 8 miles from shore. The platform was installed in 1981 and production began in 1983. The gas is dehydrated and compressed on the platform and is sent by pipeline to the Carpinteria Onshore Gas Terminal. A small amount of gas condensate liquid is recovered and is transported by boat to other facilities operated by the same operator. Production information through July 1997 is provided in Appendix B.

The Pitas Point Field is in decline and has a limited future productive life. The future baseline projection is based upon platform level decline-curve analysis and takes into account continuing addition of compressor capacity as the production declines. The water production forecast assumes that the produced liquid will continue to increase in water cut, but the annual water production never exceeds the volumes produced in 1994. It does not appear that future production will be constrained by the system's infrastructure.

2.3.3 Central Subregion

The Central Subregion fields include the South Ellwood, Hondo, Pescado, and Point Arguello fields. Under the future baseline projection, the expected total production from 1995 to 2015 from the Central Subregion is estimated at 489 MMSTB of oil, and 1003 BCF of gas. Table 2.3-4

Table 2.3-4

Future Baseline Oil, Gas and Water Production Projections

Central Subregion

Year	Central Subregion South Ellwood, Hondo, Pescado, and Point Arguello		
	Oil (MMSTB)	**Gas (BCF)**	**Water (MMBBL)**
1995	59.28	37.32	22.35
2000	42.09	53.95	61.53
2005	14.52	62.40	38.19
2010	7.49	39.60	26.00
2015	4.38	35.00	19.93
TOTAL (1995 through 2015)	489	1003	719

Unit abbreviations:
MMSTB = million stock tank barrel (oil)
BCF = billion standard cubic feet (gas)

Source: Scotia, 1995; Dames & Moore, 1999

Note: Table entries include estimates of total gross production processed at onshore facilities, including gas consumed as fuel gas at these facilities. This consumption may be substantial at some facilities, such as the Las Flores Canyon Oil and Gas Processing Facility which processes gas for use at the nearby cogeneration facility.

provides the future baseline projection production of oil and gas for the period 1995 to the end of 2015. Figure 2.3-4 illustrates the production trend associated with the data provided in the table. The projection for the fields currently under production shows oil production dropping from 59.28 MMSTB in 1995 to 14.52 MMSTB by the year 2005 and to 4.38 MMSTB by the end of 2015. The projection for gas production increases from 37.32 BCF in 1995 to 62.40 MMSTB by the year 2005 and then declining to 35.00 BCF per year by the end of 2015. Figure 2.3-5 shows the location of the offshore fields and facilities in the Central and Northern subregions. A summary of the individual fields is provided below.

2.3.3.1 South Ellwood Field

The South Ellwood Field is located in state waters near Goleta and includes leases PRC-208, PRC-3120, and PRC-3242. Projected production is from the Rincon and Monterey formation. The produced oil has a gravity of approximately 22 degrees API. The Rincon crude contains approximately 0.2 percent sulfur and no H_2S and the gas contains no H_2S. The Monterey crude contains approximately 4.0 percent sulfur and up to 10,000 parts per million (ppm) H_2S and the gas contains up to 15,000 ppm H_2S. Approximately 83 percent of the projected production is expected to come from the Monterey formation resulting in a crude mixture estimated to contain 3.9 percent sulfur and 9,700 ppm H_2S and a gas mixture estimated to contain 13,200 ppm H_2S. In addition, there are natural gas seeps that are collected using a "tent" system.

The South Ellwood Field is produced from Platform Holly which is located in 211 feet of water on lease PRC-3242 approximately 2 miles from shore in California State waters. Platform Holly was installed in 1965 and production began in 1966. Equipment on the platform separates the total production into wet oil and gas, which are sent to the Ellwood Oil & Gas Processing Facility in two pipelines. Production data is provided in Appendix B.

In addition to the platform, a seep containment tent was installed in 1983 to collect gas from natural seeps and the gas is sent to the Ellwood Oil & Gas Processing Facility by pipeline. Gas collected by the seep tents contains approximately 40 parts per million hydrogen sulfide.

The South Ellwood Field is apparently in a mature level of development. No new activity was evident as of December 31, 1994, and the future baseline projection was based on extrapolation of field level decline data and inputs from the facility operator at the time this analysis was conducted (Mobil). This approach assumes that operators will continue to workover wells, thus attenuating the future reservoir/platform decline to the same degree as has been observed in the recent past. The water production forecast assumes that the total liquid rate on the platform will remain constant and near to current rates. This treatment agrees with the average total liquid rates during the last seven years of historical data. No information was located to indicate future production will be constrained by platform, pipeline or onshore facility capacities.

The South Ellwood Field, Platform Holly and the associated infrastructure were sold to a new operator (Venoco) in August, 1997. The new operator indicates that efforts will be made to enhance production from the existing wells on Platform Holly, but currently does not have other plans to "expand". The new operator's production estimates are not expected to be constrained by the current infrastructure, and could extend the life of these facilities beyond that projected as future baseline conditions in this study.

2.3.3.2 Hondo Field

The Hondo Field is located in the Santa Ynez Unit which includes the Pescado Field (see below). The Hondo Field is comprised of leases OCS-P0180, OCS-P0181, OCS-P0187, OCS-P0188, OCS-P0190, OCS-P0191 and OCS-P0329. The majority of the production is from the Monterey formation and is heavy, sour (sulfur-containing) crude. A small quantity of sweet (low sulfur) crude is produced from sandstone reservoirs underlying the Monterey formation. Although no data was provided by the operator, the production from the Monterey Formation in the Hondo Field is projected to contain up to 4.5 percent sulfur and 8,000 parts per million hydrogen sulfide in the crude oil and up to 8,000 parts per million hydrogen sulfide in the gas. Oil gravity averages 16 degrees API. The Hondo Field is produced from Platforms Hondo and Harmony.

Platform Hondo is located in 842 feet of water on lease OCS-P0188 in the Santa Ynez Unit. The platform was installed in 1976. Production from the platform started in 1981. Equipment on the platform separates the total production into wet oil and gas. The wet oil is sent to Platform Harmony and the gas is sent to the Las Flores Canyon SYU Oil & Gas Processing Facility. Production data is provided in Appendix B.

Platform Harmony is located in 1,200 feet of water on lease OCS-P0190 in the Santa Ynez Unit. The platform was installed in 1989, and production began in 1993. Equipment on the platform separates the total production into wet oil and gas. The wet oil, combined with wet oil from platforms Hondo and Heritage, is sent to the Las Flores Canyon SYU Oil & Gas Processing Facility. The gas is sent to Platform Hondo. Production data is provided in Appendix B.

The future baseline projection of oil and net gas production (less gas reinjection) was constructed through review of limited confidential operator-generated profiles for both Hondo and Harmony platforms. The forecast of water production is based on the assumption that as water cuts increase artificial lift will be used to maintain productive capacity. The wells on Platforms Hondo, Harmony and Heritage (see discussion for the Pescado Field) may have the ability to produce at a higher rate than can be processed by existing equipment at the onshore Las Flores Canyon SYU Oil & Gas Processing Facility and so the processing capacity may constrain the rate of production from the field. The remaining production, as estimated in the future baseline projection, is predominantly from the Monterey formation resulting in a projected sulfur content in the crude of 4.5 percent and 8,000 ppm H_2S in the crude and gas.

2.3.3.3 Pescado Field

The Pescado Field is located in the Santa Ynez Unit which includes the Hondo Field (see above). The Pescado Field is comprised of leases OCS-P0182 and OCS-P0183. The principal oil reserves in the Pescado Field is the Monterey Formation which contains sulfur in the crude oil and hydrogen sulfide in the crude vapors and produced gas. As of August 1997, all oil production was from wells in the Monterey formation. Gas used on the platform is produced from the Gaviota formation.

The principal oil reserves are contained in the Monterey formation which is the assumed source of all of the forecasted production. The Vaqueros/Alegria and Gaviota sands have tested sweet crude, but are of limited extent. There are also non-associated gas reserves in the Matilija and Sacate massive zones. At present, the operator does not appear to have definite plans to produce from other than the Monterey and Gaviota formations.

The Pescado Field is produced from Platform Heritage which is located in 1,075 feet of water on lease OCS-P0182. The platform was installed in 1989, and production began in 1993. Equipment on the platform separates the total production into wet oil and gas. Subsea pipelines from Platform Heritage transport wet oil and natural gas to Platform Harmony. Wet oil is sent via pipeline from Platform Harmony to the Las Flores Canyon Oil & Gas Processing Facility. Natural gas is sent via pipeline to Platform Hondo, and from Platform Hondo on to the Las Flores Canyon Gas Facility. Production data is provided in Appendix B.

The future baseline projection was derived from confidential initial company projections including data from the initial round of development drilling for the Field. The wells on Platform Heritage, and on Platforms Hondo and Harmony (see discussion for the Hondo Field) may have the ability to produce at a higher rate than can be processed by existing equipment at the onshore Las Flores Canyon SYU Oil & Gas Processing Facility and so the processing capacity may constrain the rate of production from the field.

2.3.3.4 Point Arguello Field

The Point Arguello Field is located in the southern part of the offshore Santa Maria Basin, near the convergence of the Santa Maria and Santa Barbara basins. All production is from fractured reservoirs in the Miocene Monterey Formation, which contains sulfur and hydrogen sulfide. The produced oil can contain up to 3.6 percent sulfur and 1,500 parts per million hydrogen sulfide and the produced gas can contain up to 9,800 parts per million hydrogen sulfide. The average gravity of the crude is 19 degrees API. The Point Arguello Field is located in the Point Arguello Unit and is produced from three platforms.

Platform Hermosa is located in 603 feet of water on lease OCS-P0316. The platform was installed in 1985 and production began in 1991. Production data is provided in Appendix B.

Platform Harvest is located in 675 feet of water on lease OCS-P0315. The platform was installed in 1985 and production began in 1991. Production data is provided in Appendix B.

Platform Hidalgo is located in 430 feet of water on lease OCS-P0450. The platform was installed in 1986 and production began in 1991. Production data is provided in Appendix B.

As designed and historically operated, the Point Arguello operations involved only limited processing of the wet oil and gas on the platforms in order to keep the water content in the wet oil sent to shore at less than 20 percent. The wet oil and sour gas were sent to the Gaviota Facility for further treating. In 1998, the operator reconfigured operations that resulted in the produced water being removed at the platform and pipeline quality oil being sent to shore rather than being sent to the Gaviota Facility. Gas that is needed for platform fuel gas is treated in amine units to remove hydrogen sulfide and carbon dioxide. The removed hydrogen sulfide and carbon dioxide gas is mixed with the remaining gas stream that is injected offshore.

The future baseline production was constructed based upon decline-curve analysis and operator input and assumes that the reconfiguration efforts to lower operating costs and possibly extend the economic life of the facilities are successful. The principal constraint to increase production from the Field is limitations on the H_2S content of produced gas in the pipeline to the onshore facility and the lack of a gas cap in the formation which limits the ability to reinject the gas. Recent declines in gas production may suggest that future gas reinjection could be an option to extend the life of this Field. Offshore gas treating could also be considered. Separate projections of water cuts for each platform were used to forecast the water production, and substantial offshore water removal is accomplished prior to transporting produced oil to shore for processing.

The sulfur content and H_2S concentration of the crude is reported by the operator to be 3.6 percent and 1,500 ppm H_2S, respectively. The H_2S concentration of the gas varies with the crude type and ranges from 5,000 to 9,800 ppm. Not knowing what the production split is between the Monterey light and Monterey heavy, an average gas H_2S concentration of 7,300 ppm is proposed for planning purposes.

2.3.4 Northern Subregion

Point Pedernales is the only existing developed and active field in the Northern Subregion. Under the future baseline projection, the expected total production from 1995 to 2015 from the Northern Subregion is estimated at 27 million stock tank barrels (MMSTB) of oil, and 6 billion standard cubic feet (BCF) of gas. Table 2.3-5 provides the future baseline projection production of oil and gas for the period 1995 to the end of 2015. Figure 2.3-6 illustrates the production trend associated with the data provided in the table. The projection indicates the only field under production is at a mature level of development and is projected to reach its economic limit for the production of oil and gas between 2000 and 2005. Figure 2.3-5 shows the location of the offshore fields and facilities in the Central and Northern subregions.

Table 2.3-5

Future Baseline Oil, Gas and Water Production Projections

Northern Subregion

	Northern Subregion Point Pedernales		
Year	**Oil (MMSTB)**	**Gas (BCF)**	**Water (MMBBL)**
1995	5.69	1.31	17.08
2000	2.21	0.51	19.79
2005	0.00	0.00	0.00
2010	0.00	0.00	0.00
2015	0.00	0.00	0.00
TOTAL (1995 through 2015)	27	6	154

Unit abbreviations:
MMSTB = million stock tank barrel (oil)
BCF = billion standard cubic feet (gas)

Source: Scotia, 1995; Dames & Moore, 1999.

2.3.4.1 Point Pedernales

The Point Pedernales Field is located in the southern Santa Maria Basin, approximately six miles west of Point Pedernales and covers parts of federal leases OCS-P0440, OCS-P0441, OCS-P0437 and OCS-P0438. The entire productive area is within the boundaries of the Point Pedernales Unit. The oil is produced from the Monterey formation and is heavy, sour crude. The gravity of the oil produced averages 16 degrees API. The produced oil may contain up to 5 percent sulfur and up to 8,000 parts per million hydrogen sulfide in the crude oil vapors and produced gas.

The Field is produced from Platform Irene located in 242 feet of water on lease OCS-P0441. Oil and gas production from the field began in 1987. The platform was installed in 1985 and production began in 1987.

Equipment on the platform separates the total production into wet oil and gas which are then sent to the Lompoc Oil & Gas Processing Facility. Production data are presented in Appendix B. Since the initial data was collected, the operator of Platform Irene has changed. All but one of the wells producing (as of 12/31/94) exhibited extrapolatable production declines. The future baseline projection is based on an extrapolation of the total field production decline through December 31, 1994. Because the operator planned to drill approximately four new wells in 1995, the 1995 projected rate has been adjusted upward so as to more or less equal the average rate for 1994. The use of the field decline rate thereafter also takes into account the effects of prior workovers to reduce the impact of declining productivity, the implicit assumption being that the benefit to productivity will continue into the future as it has in the past.

Recent drilling activities from Platform Irene, conducted by the new operator, included a well that, while completed within the federal lease, may be producing from a structure that extends into state waters and that potential drainage associated with this well has been included in the future baseline data. The future baseline does not include reserves that could be produced from wells with downhole completions in state waters, drilled from Platform Irene or otherwise, because this area in state waters is not leased. No estimates of reserves in unleased areas are provided.

A projection of water cut was used to define the water production rate forecast. The forecast was facilitated by 1995 daily water production data provided by the operator.

The reported sulfur content of the Point Pedernales crude is 5 percent. The H_2S concentration of the crude oil vapors are assumed to be equal to the produced gas concentration which is reported to be 8,000 ppm.

2.4 ONSHORE OIL AND GAS FACILITY INFRASTRUCTURE

This section describes the oil and gas infrastructure in the Tri-County region. Unless noted, the information describes the conditions as they existed at the beginning of study year 1995.

2.4.1 Overview

Offshore oil and gas production in the Study Region is typically processed at local onshore facilities. Current onshore processing facilities prepare crude oil for shipment to major refining centers and produce natural gas for delivery to local consumer's via existing utilities. Natural gas liquids and liquefied petroleum gases are also produced, and are either blended with crude oil for transport or delivered to local markets via truck. Some of the processing facilities also produce sulfur which is transported to market by truck. In addition, the Santa Maria Refinery refines some offshore oil and produces asphalt, petroleum coke and sulfur which are transported to market by truck and rail. The volume of oil which may be processed at each onshore facility may be affected by the characteristics of the incoming crude oil feedstocks which alter the proportion of different products produced. Other characteristics, such as the amount of water in the incoming crude oil, presence of contaminants (sand, heavy metals, etc.), or chemical characteristics of the crude oil may affect the capacity of a specific facility with respect to a specific oil production source. This section of the COOGER study identifies the current and projected capacity of onshore facilities in the Study Region to provide a basis for the evaluation of potential future facilities needs in connection with different development scenarios.

Some of the onshore facilities process oil-containing fluids and/or gas received directly from wells or platforms producing from an offshore reserve. Examples include the Mandalay Onshore Facility, the Las Flores Canyon SYU Oil & Gas Processing Facility, and the Lompoc Oil & Gas Processing Facility. Table 2.4-1 identifies these facilities along with the corresponding platforms and offshore leases and provides an overview of the cumulative, peak and current throughput, of the facilities as of December 31, 1994. Table 2.4-2 identifies the nomenclature used to refer to these facilities in the COOGER Report along with other common names currently or historically used for the facilities. Table 2.4-3 provides a summary of the primary incoming and outgoing streams for each facility.

Other onshore facilities and pipelines receive materials after they have been processed by one of the facilities identified above. Examples include the Ellwood Marine Terminal, the All American

Pipeline, L.P., and the Santa Maria Refinery. Table 2.4-4 identifies these facilities and provides a summary of the primary incoming and outgoing streams for each facility.

More detailed information on the operation and characteristics of each facility is provided in the discussion below. The description of each facility is accompanied by a one or more figures which are designed to summarize facility-specific information and show how the facility "fits in" with the overall oil and gas industry in the Study Region. A summary of the methodology used to obtain and verify facility specific data is provided in Appendix A.2 and additional technical information is summarized in Appendix B. Information concerning employment associated with these facilities and related offshore operations is presented in Appendix A.3. Property tax information is presented in Appendix A.4. Information concerning air pollutant emissions associated with each facility is presented in Appendix A.5.

Table 2.4-1
Recent Processed Volumes
Study Region Oil and Gas Processing Facilities

Facility Name	Platform (first production, if provided)	Field / Unit (Lease Blocks)	Cumulative Production (through 12/31/94)			Current Production (as of . 1/1/95)			Peak Production[b] (as of 12/31/94)						
									Gas		Dry Oil		Wet Oil		
			Oil MMBO	Gas BCF	Water MMBW	Oil BOPD	Gas MCFD	Water BWPD	Yr	MCFD	Yr	BOPD	Yr	BOPD	BWPD
Eastern Subregion															
Mandalay Onshore Separation Facility	Gina (2/11/82)	Hueneme Offshore (202, 203)	8.8	2.8	25.2	1,044	394	7,152	'83	1,079	'83	4,312	'90	1,156	8,047
	Gilda (12/19/81)	Santa Clara (215, 216)	22.3	35.4	13.3	3,289	2,409	2,643	'84	17,323	'84	6,622	'88	5,096	4,334
West Montalvo Operations	Onshore Wells	West Montalvo (3314, 735)	1	0.5	0.9	447	570	525	'94	314	'93	602	'93	602	595
Rincon Island and State Lease 145/410 Oil & Gas Processing Facilities	Rincon Island [data for island only]	Rincon (145, 410, 427, 429, 1466)	4.4[1]	3.4[1]	10.8[1]	275	300	500	'81	701	'77[a]	1,011	'77[a]	1,011	2,784
Rincon Oil & Gas Processing Facility	Henry (5/16/80)	Carpinteria (166, 240)	15.1	12.5	8.5	1,588	537	2,202	'81	5,504	'84	4,704	'84	4,704	1,649
	Hillhouse (7/21/70)	Dos Cuadras (240, 241)	58.1	32.9	48.3	1,877	2,188	15,227	'71	15,422	'71	25,008	'71	25,008	1,381
	A (3/3/69)	Dos Cuadras (240, 241)	92.2	42.4	162.9	2,375	2,471	13,377	'71	15,252	'71	28,482	'71	28,482	3,449
	B (7/13/69)	Dos Cuadras (240, 241)	70.1	35.4	146.6	3,103	3,188	19,532	'71	11,748	'70	22,951	'71	22,545	4,340
	C (8/1/77)	Dos Cuadras (240, 241)	12.8	6.1	13	1,149	828	2,455	'78	1,433	'78	3,879	'80	2,816	2,099

Table 2.4-1 (Continued)

Facility Name	Platform (first production, if provided)	Field / Unit (Lease Blocks)	Cumulative Production (through 12/31/94)			Current Production (as of . 1/1/95)			Peak Production[b] (as of 12/31/94)						
			Oil MMBO	Gas BCF	Water MMBW	Oil BOPD	Gas MCFD	Water BWPD	Gas		Dry Oil		Wet Oil		
									Yr	MCFD	Yr	BOPD	Yr	BOPD	BWPD
La Conchita Oil & Gas Processing Facility	Hogan (6/10/68)	Carpinteria (State 3150, 400, Federal 166, 240)	17.9	17.9	32.8	545	1,184	2,852	'69	6,441	'69	9,526	'69	9,526	2,485
	Houchin (4/28/69)	Carpinteria (State 3150, 400, Federal 166, 240)	26.7	20	23.7	725	495	2,019	'70	7,186	'69	9,044	'70	8,258	2,153
Carpinteria Oil & Gas Processing Facility	Gail (9/19/88)	Sockeye (204, 205, 208, 209)	15.1	44.8	5.3	8,342	21,760	6,981	'92	23,682	'90	8,488	'94	7,647	4,449
	Grace (7/25/80)	Santa Clara (217)	8	21.6	7.9	1,186	984	611	'83	13,482	'83	2,959	'83	2,959	1,638
Carpinteria Onshore Gas Terminal	Habitat (12/15/83)	Pitas Point (234, 436)	0.2	184.3	2	14	20,636	946	'85	81,915	'85	93	'94	16	89
Eastern Subregion Subtotal			352.7	460	501.2	25,959	57,944	77,022							

Table 2.4-1 (Continued)

Facility Name	Platform (first production, if provided)	Field / Unit (Lease Blocks)	Cumulative Production (through 12/31/94)			Current Production (as of . 1/1/95)			Peak Production[b] (as of 12/31/94)						
			Oil MMBO	Gas BCF	Water MMBW	Oil BOPD	Gas MCFD	Water BWPD	Gas		Dry Oil		Wet Oil		
									Yr	MCFD	Yr	BOPD	Yr	BOPD	BWPD
Central Subregion															
Ellwood Oil & Gas Processing Facility	Holly	South Ellwood (208, 3120, 3242)	51.7	40.2	29.8	4,090	2,739	8,962	'68	8,389	'84	9,436	'87	7,132	7,721
	Field Total (seeps incl.)		53	48.7	31.3	4,090	3,498	8,962							
Las Flores Canyon SYU Oil & Gas Processing Facility & Las Flores Canyon Gas Processing Facility	Hondo (4/2/81)	Hondo/Santa Ynez Unit (180, 181, 187, 188, 190, 191, 329)	135.5	217.1	30.5	16,394	32,694	8,621	'86	59,216	'82	36,948	'83	36,340	3,696
	Harmony (12/30/93)	Hondo/Santa Ynez Unit (180, 181, 187, 188, 190, 191, 329)	3.1	1.7	0.8	19,014	11,481	5,767	'94	4,559	'94	8,397	'94	8,397	2,077
	Heritage (12/18/93)	Pescado/Santa Ynez Unit (182, 183)	5.5	1.5	0.1	34,875	9,935	518	'94	4,203	'94	13,932	'94	14,942	279
Gaviota Oil & Gas Processing Facility	Hermosa (6/9/91)	Point Arguello (315, 316)	33.5	14.5	2	29,371	15,590	5,501	'94	15,315	'94	31,537	'94	31,537	3,849
	Harvest (6/3/91)	Point Arguello (450)	32.4	15.2	2.5	34,600	16,820	7,799	'94	16,800	'94	35,256	'94	35,256	4,647
	Hidalgo (5/27/91)	Point Arguello (450)	10.4	4.4	2.3	7,508	3,064	4,502	'93	4,022	'93	9,901	'94	8,627	5,159
Central Subregion Subtotal			273.4	303.1	69.5	145,852	93,082	41,670							

Table 2.4-1 (Continued)

Facility Name	Platform (first production, if provided)	Field / Unit (Lease Blocks)	Cumulative Production (through 12/31/94)			Current Production (as of . 1/1/95)			Peak Production[b] (as of 12/31/94)						
			Oil MMBO	Gas BCF	Water MMBW	Oil BOPD	Gas MCFD	Water BWPD	Gas		Dry Oil		Wet Oil		
									Yr	MCFD	Yr	BOPD	Yr	BOPD	BWPD
Northern Subregion															
Lompoc Oil & Gas Processing Facility	Irene (4/13/87)	Point Pedernales Unit (437, 438, 440, 441)	41.8	9.1	25.7	14,182	4,097	31,399	'89	4,164	'89	19,816	'90	16,329	12,066
Northern Subregion Subtotal			41.8	9.1	25.7	14,182	4,097	31,399							
Grand Total for Study Area			667.9	772.2	596.4	185,993	155,123	150,091							

[a] Cumulative production for Rincon Island is for the period 1977-1994; data prior to 1977 was not included in the historical production database used for the study.

[b] Historic peak production rates reflect the daily average production during the calendar year prior to 1995 in which the maximum total production was recorded.

Note: Except for the Carpinteria Oil & Gas Processing Facility and the Las Flores Canyon SYU Oil & Gas Processing Facility, each onshore facility started operating when the first associated platform began producing oil and/or gas. The Carpinteria Facility started operating in approximately 1959 and the Las Flores Canyon SYU Oil & Gas Processing Facility started operating in 1993.

Table 2.4-2
Nomenclature and Common Names of Onshore Facilities
That Directly Receive Offshore Production

Formal Name of Facility	Other Common Current or Historic Names Used for the Facility
Eastern Subregion	
Mandalay Onshore Separation Facility	(Unocal or Torch) Mandalay Facility or Plant Mandalay Onshore Facility
West Montalvo Operations	(Berry) West Montalvo Facility or Plant (Berry) Oxnard Facility
Rincon Island and State Lease 145/410 Oil & Gas Processing Facilities	Rincon Island Richfield Island or Arco Island Rincon Island Facility & State Lease 145/410 Facility
Rincon Oil & Gas Processing Facility	(Mobil or Torch) Rincon Facility or Plant Rincon Plant, Rincon Onshore Facility Rincon Oil & Gas Treating Facility
La Conchita Oil & Gas Processing Facility	(Phillips) La Conchita Facility or Plant Pacific Offshore Operators Facility or POOI La Conchita
Carpinteria Oil & Gas Processing Facility	(Chevron) Carpinteria Facility or Plant, (Venoco) Carpinteria Facility or Plant, Carpinteria Plant or Carpinteria Gas Plant
Carpinteria Onshore Gas Terminal	(Texaco) Carpinteria Facility or Plant Carpinteria Gas Terminal
Central Subregion	
Ellwood Oil & Gas Processing Facility & Ellwood Marine Terminal	(Venoco) Ellwood Oil Facility or Plant (Mobil) Ellwood Oil Facility or Plant (Arco) Ellwood Oil Facility or Plant (Venoco, Arco, or Mobil) Marine Terminal
Las Flores Canyon SYU Oil & Gas Processing Facility	(Exxon) Las Flores Canyon Facility or Plant Las Flores Canyon Plant (Exxon) LFC Oil Facility
Las Flores Canyon Gas Processing Facility	POPCO Facility POPCO Gas Plant LFC Gas Facility
Gaviota Oil & Gas Processing Facility	(Chevron, Plains Resources, or Pt. Arguello Partners) Gaviota Facility Gaviota Plant Gaviota Oil & Gas Treating Facility
Gaviota Interim Marine Terminal	(Texaco) Gaviota Marine Terminal
Northern Subregion	
Lompoc Oil & Gas Processing Facility	Lompoc HS&P Facility Unocal HS&P Facility or Plant Torch HS&P Facility or Plant

Table 2.4-3
Operation Summary of Facilities That Directly Receive Offshore Production
(As of 1/1/95; updated to 12/98 where data provided)

Facility Name	Streams In From	Streams Out To
Eastern Subregion		
Mandalay Onshore Separation Facility	Wet Oil: Platforms Gina and Gilda Gas: Same	Oil: Ventura Pump Station Gas: Power Plant (formerly owned by Southern California Edison) P/W[(1)]: Platform Gilda for disposal
West Montalvo Operations	Wet Oil: Onshore wells that produce from offshore leases Gas: Same	Oil: Ventura Pump Station Gas: Power Plant (formerly owned by Southern California Edison) P/W: Injected Onsite
Rincon Island Oil & Gas Processing Facility	Wet Oil: Wells on the Island Gas: Same	Oil: 268,000 Barrel Venoco-Owned Tank at Rincon, then by pipeline to the Ventura Pump Station Gas: Compressor at Rincon Oil & Gas Processing Facility P/W: Injected onsite
(Rincon) State Lease 145/410 Oil & Gas Processing Facility	Wet Oil: From wells onshore Gas: Same	Oil: Trucked to Texaco Fillmore Pump Station Gas: Compressor at Rincon Oil & Gas Processing Facility P/W: Injected onsite
Rincon Oil & Gas Processing Facility	Wet Oil: Platforms Henry, Hillhouse, A, B, and C Gas: Same	Oil: 268,000 Barrel Venoco-Owned Storage Tank at the Rincon Facility, then by pipeline to the Ventura Pump Station Gas: Southern California Gas Company (SoCal Gas) P/W: Trucked Offsite
La Conchita Oil & Gas Processing Facility	Wet Oil: Platforms Hogan and Houchin Gas: Same	Oil: 268,000 Barrel Venoco-Owned Storage Tank by the Rincon Facility, then by pipeline to the Ventura Pump Station Gas: SoCal Gas and to platforms for gas lift wells P/W: Platforms for offshore disposal
Carpinteria Oil & Gas Processing Facility	Wet Oil: Platform Gail (wells on Platform Grace abandoned as of 12/98) Gas: Same	Oil: 268,000 Barrel Venoco-Owned Storage Tank by the Rincon Facility, then by pipeline to the Ventura Pump Station Gas: SoCal Gas P/W: Separated offshore and disposed or reinjected

Table 2.4-3 (Continued)

Facility Name	Streams In From	Streams Out To
Carpinteria Onshore Gas Terminal	Wet Oil: none Gas: Platform Habitat	Oil: none Gas: SoCal Gas P/W: none
Central Subregion		
Ellwood Oil & Gas Processing Facility	Wet Oil: Platform Holly Gas: Platform Holly and Seep Tents	Oil: Ellwood Marine Terminal for barge loading Gas: SoCal Gas P/W: Injected onsite Misc: LPG and sulfur trucked offsite
Las Flores Canyon SYU Oil & Gas Processing Facility & Las Flores Canyon Gas Processing Facility	Wet Oil: Platforms Hondo, Harmony and Heritage Gas: Same	Oil: AAPLP Coast Line to Gaviota Pump Station Gas: SoCal Gas P/W: Platform Harmony for disposal Misc: Propane and sulfur trucked offsite
Gaviota Oil & Gas Processing Facility	Wet Oil: Platforms Hermosa, Harvest and Hidalgo Gas: Being injected at Platforms as of 12/98	Oil: AAPLP Booster Station (tanks at Gaviota Oil Terminal)[(2)] Gas: none P/W: Ocean discharge/injection Misc: None (as of 12/98) Historically, propane and sulfur trucked offsite
Northern Subregion		
Lompoc Oil & Gas Processing Facility	Wet Oil: Platform Irene Gas: Same	Oil: Orcutt Pump Station Gas: SoCal Gas P/W: Injected onsite Misc.: Propane trucked offsite

(1) P/W = Produced water

(2) Since January 1995, the Gaviota Marine Terminal has been decommissioned; however, some of the tanks are still used in association with the AAPLP pipeline.

Table 2.4-4
Operation Summary of Secondary Facilities
(Processing Facilities, Pump Stations, and Marine Terminals)
(As of 1/1/95)

Facility Name & Type	Streams In From (Dry Oil Unless Noted)	Streams Out To (Dry Oil Unless Noted)
Eastern Subregion		
Ventura Marine Terminal (by Ventura Harbor)	Idle	Idle
"Texaco" Ventura Marine Terminal (by Fairgrounds)	Abandoned - Onshore Tanks Removed	None
Ventura Pump Station	Mandalay Onshore Separation Facility and West Montalvo Operations	Santa Paula Pump Station
Santa Paula Pump Station	Ventura Pump Station	Torrey Pump Station
Torrey Pump Station	Santa Paula Pump Station	Los Angeles area refineries
"Compressor" at Rincon Oil & Gas Processing Facility	Gas from the Rincon Island and State Lease 145/410 Oil & Gas Processing Facilities	Gas sales to SoCal Gas
268,000 Barrel Venoco-Owned Storage Tank by the Rincon Oil & Gas Processing Facility	Carpinteria, La Conchita, Rincon Island, and Rincon Oil and Gas Processing Facilities	Ventura Pump Station (see above) (then sent to Los Angeles area refineries)
Carpinteria Marine Terminal	Idle (historically used for gasoline and diesel)	Idle - not used in over 10 years, no plans for future use identified by operator
Central Subregion		
Ellwood Marine Terminal	Ellwood Oil & Gas Processing Facility	Typically sent by barge to refineries in the Los Angeles area, but can also be sent to San Francisco Bay area refineries
Gaviota Oil Terminal[(1)]	Gaviota Oil & Gas Processing Facility (stored in tanks prior to transport in AAPLP pipeline)	Marine terminal decommissioned - mooring system abandoned; some storage tanks used by AAPLP.
Cojo Marine Terminal	Idle	Santa Barbara County indicates the marine terminal is a legal non-conforming use, but has not operated in over 1 year and as such is considered abandoned and no longer permitted for use.
AAPLP Las Flores Pump Station	Storage Tanks at the Las Flores Canyon SYU Oil & Gas Processing Facility	AAPLP Coastal Line to AAPLP Gaviota Pump Station (outlet)

Table 2.4-4 (Continued)

Facility Name & Type	Streams In From (Dry Oil Unless Noted)	Streams Out To (Dry Oil Unless Noted)
AAPLP Booster Station (at the Gaviota Oil Terminal)	Tanks at the Gaviota Oil Terminal	AAPLP Gaviota Pump Station
AAPLP Gaviota Pump Station	AAPLP Booster Station	AAPLP "main line" to the AAPLP Sisquoc Pump Station
Northern Subregion		
AAPLP Sisquoc Pump Station	AAPLP Gaviota Pump Station and Las Flores Pump Station	AAPLP Emidio Pump Station (in Kern County) or to Santa Maria Pump Station
Santa Maria Pump Station	AAPLP Sisquoc Pump Station and onshore crude from the Santa Maria Valley	Summit Pump Station
Orcutt Pump Station	Oil from the Lompoc Oil & Gas Processing Facility	Summit Pump Station
Summit Pump Station	Oil from the Santa Maria Pump Station and Orcutt Pump Station	Avila Pump Station and/or to the Santa Maria Refinery
Avila Pump Station	Decommissioned as of 12/98	None
Santa Maria Refinery	Summit Pump Station	Semi-refined oil to junction north of the former Avila Beach Pump Station; sulfur and partly refined petroleum sent offsite by truck
Santa Maria Asphalt Refinery	Santa Maria Valley Crude (all received by truck)	Semi-refined products and asphalt to various markets by truck or rail

(1) Since January 1995, the Gaviota Marine Terminal has been decommissioned; however, some of the tanks are still used in association with the AAPLP pipeline.

2.4.2 Eastern Subregion

The onshore facilities located in the Eastern Subregion that process oil, gas, and/or produced water directly from offshore reserves include the:

- Mandalay Onshore Separation Facility
- West Montalvo Operations
- Rincon Island and State Lease 145/410 Oil & Gas Processing Facilities
- Rincon Oil & Gas Processing Facility
- La Conchita Oil & Gas Processing Facility
- Carpinteria Oil & Gas Processing Facility
- Carpinteria Onshore Gas Terminal

Figure 2.4-1 shows the relative location of each of these onshore facilities and shows the offshore fields and platforms from which they receive production.

As stated in Section 2.3, the projected future production from the offshore fields in the Eastern Subregion is in a state of decline. Consequently, the facilities listed above are currently processing less oil and/or gas than they were designed to process. The term "Spare Capacity" is used to define the difference between what a facility is designed or permitted to process and what the facility is actually processing at a point in time. The "Design Spare Capacity" is the maximum design throughput minus the actual throughput; whereas, the "Permitted Spare Capacity" is the permitted throughput minus the actual throughput. A decrease in the throughput of a facility results in an increased spare capacity. When a facility is decommissioned (removed), it has "0" spare capacity. If a facility operates any time during a 5-year period (i.e., 1995-2000, 2001-2005, 2006-2010, etc.), its spare capacity is assumed to be available at the end of that 5-year period. Table 2.4-5 lists the wet oil design capacity, permitted capacity, and projected spare capacity for each Facility at 5-year increments during the period 1995-2015. Table 2.4-6 lists the gas design capacity, permitted capacity, and projected spare capacity for each Facility at 5-year increments during the period 1995-2015. Spare capacity information related to gas or other streams is discussed in Appendix B. Figure 2.4-2 shows the projected wet oil design and permitted spare capacity for the Eastern Subregion, as a whole, at 5-year increments during the period 1995-2015. Figure 2.4-3 shows the projected gas design and permitted spare capacity for the Eastern Subregion, as a whole, at 5-year increments during the period 1995-2015.

More detailed information on the operation and characteristics of each facility in the Eastern Subregion is provided below.

Table 2.4-5
Wet Oil Processing Spare Capacity - Eastern Subregion

Facility	Design Capacity (BPD)	Permitted Capacity (BPD)	Spare Capacity (BPD)[3]					Comments
			1995	2000	2005	2010	2015	
Mandalay Onshore Separation Facility	25,000	25,000[1]	9,247	25,000	-	-	-	
West Montalvo Operations	1,197[2]	1,197[1][2]	249	885	1,197	-	-	
Rincon Island and State Lease 145/410 Oil & Gas Processing Facilities	3,795[2]	3,795[1][2]	2,749	0	0	0	3,795	
Rincon Oil & Gas Processing Facility	110,000	110,000[1]	97,942	102,913	110,000	-	-	
La Conchita Oil & Gas Processing Facility	27,000	27,000[1]	20,661	27,000	-	-	-	
Carpinteria Oil & Gas Processing Facility	40,000	40,000[1]	30,004	37,269	40,000	-	-	Operator of Carpinteria O&G Processing Facility reports (8/97) water plant abandoned - dewatering done offshore
Carpinteria Onshore Gas Terminal	110 MMCFD	110[1] MMCFD	N/A	N/A	N/A	N/A	-	This facility has no wet oil processing capability.
Eastern Subregion Totals	206,992	206,992	160,852	193,067	151,197	0	3,795	

Note: [1] Permitted Capacity assumed to equal Design Capacity unless specific permit conditions were identified.
[2] The operator of this facility did not have information on the maximum throughput. Consequently, the "maximum" throughput was assumed to be the same as the historic peak production as reported in the database used for the study.
[3] Table entries record the limiting capacity minus the actual oil processed during the year indicated. If no production is projected for an entire 5-year period, a dash is entered at the end of that period to reflect the potential shutdown or the potential decommissioning of the onshore facility during that period.

Table 2.4-6
Gas Processing Spare Capacity - Eastern Subregion

Facility	Design Capacity (MCFD)	Permitted Capacity (MCFD) (1)	Spare Capacity(MCFD)(4)					Comments
			1995	2000	2005	2010	2015	
Mandalay Onshore Separation Facility	18,000	6,000	3,004	6,000	-	-	-	"Permitted Spare Capacity" is 12000 MCFD less.
West Montalvo Operations	314(2)	314(1)(2)	0	207	314	-	-	
Rincon Island and State Lease 145/410 Oil & Gas Processing Facility	1,000(3)	1,000(1)(3)	792	0	0	0	1,000	
Rincon Oil & Gas Processing Facility	15,000	15,000(1)	6,551	10,868	15,000	-	-	
La Conchita Oil & Gas Processing Facility	22,000	22,000(1)	20,438	22,000	-	-	-	
Carpinteria Oil & Gas Processing Facility	28,000	28,000(1)	7,888	22,000	28,000	-	-	
Carpinteria Onshore Gas Terminal	110,000	110,000(1)	91,515	103,556	110,000	-	-	
Eastern Subregion Totals	194,314	182,314	130,188	164,631	153,314	0	1,000	

Note: (1) Permitted Capacity assumed to equal Design Capacity unless specific permit conditions were identified.
(2) The operator of this facility did not have information on the maximum throughput. Consequently, the "maximum" throughput was assumed to be the same as the historic peak production as reported in the database used for the study.
(3) No Design or Permitted Capacity limits identified - data from operator (exceeds historic peak production).
(4) Table entries record the limiting capacity minus the actual oil processed during the year indicated. If no production is projected for an entire 5-year period, a dash is entered at the end of that period to reflect the potential shutdown or the potential decommissioning of the onshore facility during that period.

2.4.2.1 Mandalay Onshore Separation Facility

General. The Mandalay Onshore Separation Facility (Mandalay Facility) is located near Oxnard and receives wet oil and gas from Platform Gina in the Hueneme Field and Platform Gilda in the Santa Clara Field. The Mandalay Facility is located on the coast next to the former Southern California Edison Mandalay Generating Station approximately two miles south of the mouth of the Santa Clara River. [Note: Houston Industries acquired this Southern California Edison facility after 1995; however, for familiarity it will be referred hereafter as the former Southern California Edison facility rather than Houston Industries facility.] A system schematic for the Mandalay Onshore Separation Facility is shown in Figure 2.4-4 and a plot plan of the Mandalay Facility is shown in Figure 2.4-5. A facility "profile" summary is provided in Appendix B.

Based on information provided by the operator, the Mandalay Facility's oil-water separation system has a wet oil processing design capacity of 25,000 barrels per day (BPD), a produced water treating design capacity of 15,000 barrels of water per day (BWPD), and a dry oil storage capacity of 8,000 barrels. The gas separation system uses glycol dehydration removal and has a design capacity of 18.0 million cubic feet per day (MMCFD) and is permitted for 6.0 MMCFD. The facility does not have a natural gas liquids (NGL) processing system; NGL is blended into the crude oil. The facility does not produce sulfur. Major equipment located at the facility includes:

- oil-water separation system that use heater-treaters and free-water knockouts;
- crude oil storage tanks;
- produced water storage tank;
- oil pipeline transfer pumps;
- water treatment system
- treated water discharge system;
- gas system using glycol dehydration;
- no NGL processing system; NGL blended into the crude oil;
- no sulfur recovery or disposition system;
- gas compressor plant

Offshore Flowlines/Pipelines. Production from Platform Gina is sent to the Mandalay Facility in a 10-inch diameter three-phase flow (i.e., a mixture of oil, water, and gas) pipeline and a 6-inch diameter sweet gas pipeline. The 6-inch gas pipeline transports gas from Well H-14 to shore. Prior to 1990, the gas pipeline was used to transport produced water from the onshore facility back to Platform Gina for discharge. Since that time, produced water is combined at the Mandalay Onshore Separation Facility with the produced water from Platform Gilda, treated and returned to Platform Gilda for injection or ocean disposal.

Production from Platform Gilda is sent to the Mandalay Facility in a 12-inch diameter wet oil pipeline and a 10-inch diameter gas pipeline. There is a 6-inch diameter treated produced water pipeline from the Mandalay Facility to Platform Gilda.

Product Distribution. Streams exiting the Mandalay Facility include oil, gas, and treated produced water. The oil is combined with the recovered natural gas liquids (NGL) and the combined stream is pumped (via a Tosco pipeline) to surge tanks at the Ventura Pump Station located near the Ventura Harbor. The gas is sold to the adjacent former Southern California Edison Mandalay Generating Station. The treated produced water is pumped to Platform Gilda for subsurface reinjection or deepwater discharge via an NPDES permitted outfall.

Information on the oil distribution pipeline is provided on a sub-regional level in the Eastern Pipeline System discussion in Section 2.4.2.8, the regional level in the product distribution system discussion in Section 2.5.1, and at the facility level in the corresponding Facility-specific table in Appendix B. In addition, Section 2.5.1 includes a diagram of the principal local and regional pipeline connections and information on which pipelines are proprietary and which are common carriers.

Spare Capacity / Permit & Operating Limitations. As of August, 1997, the Mandalay Facility had a baseline spare capacity of approximately 9,600 barrels per day of wet oil and 2.5 MMCFD of gas. Reportedly, the facility does not use fresh water and so water availability is not a limitation. Other than design limitations, the operator did not identify any operating constraints. No permit constraints were identified that would limit throughput to less than the design capacity.

Key System Dependencies

- Platform Gina depends on Platform Gilda for the disposal of treated produced water (via the Mandalay Facility).
- The Mandalay Onshore Separation Facility depends on the downstream oil and gas pipeline distribution system (see Eastern Pipeline System discussion).
- The Mandalay Onshore Separation Facility depends on the former Southern California Edison Mandalay Generating Station to take the produced gas.

Secondary Facilities. There are several facilities downstream from the Mandalay Onshore Separation Facility that are involved in the transport of crude oil from the Tri-County area. These include components of the "Eastern Pipeline System" (described below) including the Ventura Pump Station, the Santa Paula Pump Station, the Torrey Pump Station and the interconnected piping.

Future Facility Capacity. Production estimates predict that the quantity of wet oil and gas produced from Platforms Gina and Gilda and processed at the Mandalay Facility will decline annually over the remaining life of the facilities. As defined, a decrease in throughput corresponds to an increase in spare capacity.

Based on historic production and estimated economically recoverable reserve data for the two platforms, the economic life of the Mandalay Facility is projected to end by study year 2000. The loss of production from the Mandalay Facility will increase the available capacity in the pipeline from the Ventura Pump Station to the refineries in the Los Angeles area. In addition, there will be no gas from the facility to supply the generating station. When the platforms, Mandalay Facility and associated pipelines become idle, it is assumed that they will be removed, except for some pipelines which may be abandoned in place, unless a new use for the facility exists.

2.4.2.2 West Montalvo Operations

General. The West Montalvo Operations (West Montalvo Facility) is located near Oxnard in an undeveloped dunes area just north of the former Southern California Edison Mandalay Generating Station. Production is from the West Montalvo Field which is partly onshore and partly in California State waters. The offshore portion of the field is produced from wells that are onshore: there are no piers, platforms or drilling islands in or over the ocean. The oil and gas produced by these wells is sent to a dedicated tank battery (i.e., one that does not receive fluids from wells producing from onshore reserves). A facility "profile" summary is provided in Appendix B.

The oil from the 11 "offshore" wells is not commingled with the oil from the 13 "onshore" wells. The produced oil from the offshore reserves is processed in a different tank battery than the oil produced from onshore reserves. The two tank batteries include the following tankage: one 250 barrel tank, four 1,000 barrel tanks, and six 2,000 barrel tanks. These tanks include wash tanks, intermediate storage tanks, and shipping tanks. Some of the tanks are heated and insulated to help separate the oil from the water. Other processing equipment includes test traps, gas/liquid separators and gas fired heater treaters. The gas from the traps and the heater treater is routed to gas sales.

The total oil and gas production for the West Montalvo Operations was not identified because the entire system includes wells that produce from onshore portions of the field in addition to the wells that produce from the offshore portion of the field.

The information from the operator did not identify limitations due to the lack of commingling. Based on the data obtained, including the fact that oil is pumped into the sales line on a batch basis, no constraints or limiting capacities were identified related to the tankage or the lack of commingling. However if in the future the lack of commingling appears to be a constraint, it would not be difficult to connect the two tank battery systems.

The current operator uses nine employees to conduct the operations with duties being shared between the onshore and offshore aspects.

Offshore Flowlines/Pipelines. There are no offshore pipelines. Onshore flowlines (field gathering lines) from the individuals wells convey the wet oil and gas to one of two tank batteries for processing.

Product Distribution. The oil is pumped via two different pipelines (one 4-inch and one 6-inch) into separate connections, approximately 300 yards apart, on the Tosco pipeline that conveys oil from the Mandalay Onshore Separation Facility to the Ventura Pump Station which is part of the "Eastern Pipeline System" (described below). The gas is sold to the nearby former Southern California Edison Mandalay Generating Station. Produced water is treated and disposed of in onshore injection wells. As of August 1997, no oil, gas or produced water was leaving the facility by truck; however, this can be done, if necessary.

As a historical note, the oil used to be sent to the Ventura Pump Station via a separate pipeline that paralleled the pipeline from Mandalay. On December 24, 1993, the West Montalvo pipeline failed resulting in an oil spill that entered McGrath Lake and the ocean. Subsequent to the spill, the West Montalvo production was rerouted to the configuration described above.

Information on the oil distribution pipeline is provided on a sub-regional level in the Eastern Pipeline System discussion in Section 2.4.2.8, the regional level in the product distribution system discussion in Section 2.5.1, and at the facility level in the corresponding Facility-specific table in Appendix B. In addition, Section 2.5.1 includes a diagram of the principal local and regional pipeline connections and information on which pipelines are proprietary and which are common carriers.

Spare Capacity / Permit & Operating Limitations. The baseline spare capacity of the West Montalvo Facility was not identified and could be influenced by the quantity of oil, gas and water produced from the onshore wells if the operator commingled the onshore and offshore oil. The operator did not identify any processing constraints. No permit constraints were identified that would limit throughput to less than the design capacity.

Key System Dependencies

- The facility depends on the ability of the pipeline system (Eastern Pipeline System) to receive and further transport the oil.
- The facility depends on the Mandalay Generating Station to use the produced gas.

Secondary Facilities. The oil is pumped from the tank batteries by pipeline into the pipeline between the Mandalay Onshore Separation Facility and the storage tanks at the Ventura Pump Station located near the Ventura Harbor and is then pumped by pipeline to refineries in the Los Angeles area (see description of the "Eastern Pipeline System").

Future Baseline Operations. Production estimates predict that the quantity of wet oil and gas produced from the offshore portion of the field will decline annually until it is no longer profitable to operate these wells thereby resulting in an increased capacity at the tank battery that separates offshore production.

Based on historic production and estimated economically recoverable reserve data for the wells producing from the offshore portion of the field, the economic life of these "offshore" wells is projected to end by study year 2005. At that time, it is assumed that the wells and gathering pipelines will be abandoned or removed. The fate of the individual tank batteries will depend on whether the tank batteries will be used to process onshore production and whether the onshore production is still viable. The loss of the offshore production may decrease the quantity of oil sent to the Ventura Pump Station and subsequently pumped through the pipeline to the Los Angeles area refineries, unless production from the "onshore" wells increases accordingly.

2.4.2.3 Rincon Island (State Lease PRC 1466), and State Leases PRC 145/410 Oil & Gas Processing Facilities

This section discusses both the Rincon Island Oil & Gas Processing Facility and the State Lease 145/410 Oil & Gas Processing Facility. Although there are currently no oil, gas, or produced water pipelines interconnecting the two facilities, they are located in close proximity to each other. Both facilities are operated by the same company and both receive production from the Rincon Field.

General. The Rincon Island Oil & Gas Processing Facility (Rincon Island Facility) is located near La Conchita approximately 2.4 miles south of the Ventura-Santa Barbara County line. The island is located approximately 0.6 miles from shore and is connected to shore by a single-lane causeway. The shore-end of the causeway is approximately 1.3 miles northwest of the State Lease 145/410 Oil & Gas Processing Facility. A system schematic for the Rincon Island and State Lease 145/410 Oil & Gas Processing Facilities is shown in Figure 2.4-6. A facility "profile" summary is provided in Appendix B.

The Rincon Island Facility processes the wet oil and gas produced from the wells on the island. The wells produce from the Rincon Field. The processing activities are self-contained on the island and consist of production and test separators, a wash tank, stock tanks, heaters, gas processing compressors and dehydration equipment, shipping pumps, treated produced water injection and support systems.

The State Lease 145/410 Facility processes production from multiple onshore "offshore" wells that also produce from the Rincon Field. The facility is located approximately 3.5 miles south of the Ventura-Santa Barbara County line on the ocean side of the Rincon Oil & Gas Processing Facility (described below). The onshore State Lease 145/410 Oil & Gas Processing Facility uses production and test separators, wash tanks, stock tanks, gas compressors and dehydration equipment, treated produced water injection facilities, truck transfer equipment, and support systems and offices.

The total oil and gas production for the "Rincon Facilities" was not identified because the entire system includes wells that produce from onshore portions of the Rincon Field in addition to the wells that produce from the offshore portion of the field.

The combined island and onshore operations employ 10 full time personnel and a fluctuating number of contracted support.

Offshore Flowlines/Pipelines. Production from the wells on Rincon Island is processed on the island and consequently, there are no flowlines or pipelines transporting unprocessed wet oil or gas from the island.

The onshore State Lease 145/410 wells have gathering lines that transport the produced fluid and gas from the wells to the onshore processing area. All production and processing occur at the onshore facility.

Product Distribution. Streams exiting the Rincon Island Facility include oil and gas. Product pipelines suspended on the causeway include a 6-inch oil pipeline, and a 6-inch diameter gas pipeline in addition to a 2-inch diameter pipeline that transport fresh water from shore to the island. The oil is transferred to the 10-inch diameter pipeline flowing from the Carpinteria Oil & Gas Processing Facility (described below) and the 268,000 barrel Venoco-owned tank near the Rincon Oil & Gas Processing Facility. The gas is transferred to a compressor at the Rincon Oil & Gas Processing Facility and is sold to Southern California Gas Company. Information regarding the pipelines is provided in Appendix B and in the discussion of the "Eastern Pipeline System" section below. The treated produced water is reinjected in wells on the island.

The streams exiting the State Lease 145/410 Oil & Gas Processing Facility include oil and gas: the produced water is reinjected back into the Rincon Field formation via wells at the facility. Approximately every other day, oil from a shipping tank at the facility is loaded onto a truck and taken to a third party facility (Texaco's Fillmore Pump Station). The gas is sent via a 6-inch diameter gas pipeline to a compressor station at the Rincon Oil & Gas Processing Facility which compresses the gas and sells it by pipeline to the Southern California Gas Company.

Information on the oil distribution pipeline is provided on a sub-regional level in the Eastern Pipeline System discussion in Section 2.4.2.8, the regional level in the product distribution system discussion in Section 2.5.1, and at the facility level in the corresponding Facility-specific table in Appendix B. In addition, Section 2.5.1 includes a diagram of the principal local and regional pipeline connections and information on which pipelines are proprietary and which are common carriers.

Spare Capacity / Permit & Operating Limitations. The operator of the facilities did not identify any processing constraints at either facility. No permit constraints were identified that would limit throughput to less than the design capacity.

Key System Dependencies.

- Operation of the Rincon Island Facility depends on the causeway to provide access to the island and to support the pipelines to/from shore.
- Product distribution from the island depends on gas pipelines to the Rincon Oil & Gas Processing Facility and an oil pipeline to the 268,000 barrel Venoco-owned storage tank.
- Product distribution from the State Lease 145/410 Oil & Gas Processing Facility depends on a gas pipeline to the Rincon Oil and Gas Processing Facility and truck transport to Texaco's Fillmore Pump Station.
- Oil distribution from the State Lease 145/410 Facility relies on being able to truck the oil to the Texaco facility.

Secondary Facilities. The oil from Rincon Island is transferred to the 268,000 barrel Venoco-owned storage tank and is then pumped from this tank into the M-143 pipeline to the Ventura Pump Station. The gas is conveyed by pipeline to the Rincon Oil & Gas Processing Facility where the liquids are removed and the gas is sold to Southern California Gas Company.

Oil from the State Lease 145/410 Facility is trucked to the Texaco facility in Fillmore and from there the oil is pumped into a Texaco pipeline system that conveys the oil to the Los Angeles area. The gas is conveyed by pipeline to the Rincon Oil & Gas Processing Facility and is then sold to Southern California Gas Company.

Future Facility Capacity. Based on the data available as of 1/1/95, including the operator's production plans, production estimates predicted that the quantity of wet oil and gas processed at the two facilities would decline annually over the remaining life of the facilities. This would have resulted in annually increasing spare processing capacity. However, a new operator took over after January 1995. The new operator has started to implement a program that will increase annual oil production until approximately the year 2000 after which production is expected to decline annually over the remaining life of the facilities. Consequently, there will be a decrease in spare capacity until 2000 after which there should be an annual increase in the spare processing capacity at the facilities.

Based on historic production and estimated economically recoverable reserve data and considering the new operator's development plans, the economic life of the Rincon Island Facility is projected to continue into the year 2014. When the onsite wells, Rincon Island Facility and associated pipelines become idle, it is assumed that they will be removed except for some flowlines on the causeway which may be abandoned in place. It is unlikely the island will be removed; however, it is possible the causeway could be removed. Production from piers in the vicinity of Rincon Island has been discontinued, and the piers and related facilities have been removed.

The projected future increases in production from the Rincon Island Facility will reduce the available capacity in the Chevron pipeline and storage tank and the M-143 pipeline to the Ventura Pump Station. The future increases in gas production from Rincon Island and State Leases 145/410 will reduce the excess capacity of the gas handling system at the Rincon Oil & Gas Processing Facility. These increases will not exceed the existing capacity of the Rincon Oil & Gas Processing Facility.

Because the oil is trucked from the State Lease 145/410 Oil and Gas Processing Facility, there will not be any corresponding capacity changes in the "local area" oil pipeline system. Identified production increases are associated with development from Rincon Island, and increased production and related truck activity associated with the State Lease 145/410 Oil and Gas Processing Facility are not expected.

2.4.2.4 Rincon Oil & Gas Processing Facility

General. The Rincon Oil & Gas Processing Facility (Rincon Onshore Facility) is located in Ventura County approximately 3.5 miles south of the Ventura-Santa Barbara County line. This facility is located onshore, atop the coastal mountains inland of the coastal plain, and should not be confused with the Rincon Island Facility discussed previously. The Rincon Onshore Facility receives wet oil and gas from Platform Henry in the Carpinteria Field and Platforms Hillhouse, A, B, and C in the Dos Cuadras Field. A system schematic for the Rincon Oil & Gas Processing Facility is shown in Figure 2.4-7 and a plot plan of the Facility is shown in Figure 2.4-8. A facility "profile" summary is provided in Appendix B.

Major equipment located at the Facility includes six heater-treaters and free water knockouts; three produced-water storage tanks; four oil storage tanks; a compressor plant with seven compressors totaling 8,500 horsepower; a cogeneration plant; and an LTS gas dehydration unit. Based on information provided by the operator, the Rincon Onshore Facility's gas separation system uses glycol dehydration and carbon dioxide removal. The facility does not have a natural gas liquids (NGL) processing system; NGL is blended into the crude oil. The facility does not have a sulfur handling system and does not conduct gas sweetening activities. There are approximately 16 employees working at the Rincon Onshore Facility.

Offshore Flowlines/Pipelines. The flowline/pipeline system links the five platforms to each other and to the onshore Rincon Oil & Gas Processing Facility. Platforms Henry, Hillhouse and C are only linked by flowlines to Platforms A and B. Platforms A and B are connected by pipelines to the onshore facility. In addition, there is a treated produced water pipeline from the onshore facility back to Platforms A and B; however, this pipeline has been idle since 1990. Details on the pipelines and their contents is provided in Appendix B.

Product Distribution. Streams exiting the Rincon Onshore Facility include oil, gas, and produced water. Following treatment and storage, the oil is transferred to the 268,000 barrel Venoco-owned storage tank and is then pumped to the Ventura Pump Station for pipeline transportation to Los Angeles area refineries. The gas is sold to Southern California Gas Company. The treated produced water is transferred by truck offsite for disposal.

Information on the oil distribution pipeline is provided on a sub-regional level in the Eastern Pipeline System discussion in Section 2.4.2.8, the regional level in the product distribution system discussion in Section 2.5.1, and at the facility level in the corresponding Facility-specific table in Appendix B. In addition, Section 2.5.1 includes a diagram of the principal local and regional pipeline connections and information on which pipelines are proprietary and which are common carriers.

Spare Capacity / Permit & Operating Limitations. According to the operator, limitations to increasing the processing capacity of the Rincon Onshore Facility include limitations in the facility's air permits and bottlenecks in the equipment; however, there is room to expand. Reportedly, the facility does not use fresh water and so water availability is not a limitation. No permit constraints were identified that would limit throughput to less than the design capacity.

Key System Dependencies.

- Platform Henry depends on Platforms Hillhouse and A and the interconnecting flowlines.
- Platform Hillhouse depends on Platform A and the interconnecting flowlines.

- Platform C depends on Platform B and the interconnecting flowlines.
- The Rincon Oil & Gas Processing Facility depends on the downstream oil and gas pipeline distribution system ("Eastern Pipeline System").

Secondary Facilities. Adjacent to the Rincon Onshore Facility is a 268,000 barrel Venoco-owned storage tank. Crude oil is pumped from this tank through a 22-inch pipeline to the Ventura Pump Station (described in the "Eastern Pipeline System" section below).

Future Facility Capacity. Production estimates predict that the quantity of wet oil and gas produced from the platforms and processed at the Rincon Onshore Facility will decline annually over the remaining life of the facilities. This should result in annually increasing spare processing capacity at the Rincon Onshore Facility assuming it does not become limited (bottle-neck) in its ability to process a particular fraction (e.g., wet/dry oil, gas, produced water, etc.) of the incoming stream.

Based on historic production and estimated economically recoverable reserve data for the platforms, the economic life of the Rincon Onshore Facility is projected to end by study year 2005. When the platforms, Rincon Onshore Facility and associated pipelines become idle, it is assumed that they will be removed except for some flowlines which may be abandoned in place. The loss of production from the Rincon Onshore Facility will increase the available capacity in the pipelines from the Rincon Onshore Facility to Ventura area and from the Ventura area to the refineries in the Los Angeles area. In addition, there will be no gas from the facility entering the Southern California Gas Company's distribution system.

2.4.2.5 La Conchita Oil & Gas Processing Facility

General. The La Conchita Oil & Gas Processing Facility (La Conchita Facility) receives wet oil and gas from Platforms Hogan and Houchin in the Carpinteria Field. The facility is located in Ventura County approximately 1.5 miles south of the Ventura-Santa Barbara County line. A system schematic for the La Conchita Oil & Gas Processing Facility is shown in Figure 2.4-9. A facility "profile" summary is provided in Appendix B.

The facility storage capacity consists of 55,000 barrel tank for crude oil, a 5,000 barrel reject water tank, and a 10,000 barrel fire water storage tank. The gas from the platforms enters the facility at 30 psi and is compressed to 1000 psi using three stage compression prior to shipping. In order to handle the crude production, the site uses primary and secondary separators in conjunction with heater treaters. There are seven heaters located on site; however, only one of the heaters is currently in use. Additional equipment includes four retention tanks of which only two are in service, gas scrubbers, compressors and a gas flare. A by-product of the separation process is the daily generation of approximately 7-10 barrels of formation sand which is removed to another onshore facility for disposal.

As of August 1997, there were 10 company employees at the facility with the planned use of 15 employees if the facility was run at capacity.

Offshore Flowlines/Pipelines. There are four pipelines between Platform Hogan and the La Conchita Facility. Production from Platform Houchin is sent to shore via flowlines to Platform Hogan. Information on the flowlines and pipelines is provided in Appendix B.

Product Distribution. Historically, oil was transported through a 10-inch diameter Pacific Operators Inc. pipeline to the 268,000 barrel Venoco-owned storage tank near the Rincon Oil & Gas Processing Facility. However, this pipeline is currently, and probably permanently, shut down because of a landslide in the adjacent town of La Conchita. The La Conchita Facility is now connected into a Chevron pipeline between the Carpinteria Oil & Gas Processing Facility and the 268,000 barrel Venoco-owned storage tank adjacent to the Rincon Oil & Gas Processing Facility. The produced gas is either used or sold to Southern California Gas Company. Treated produced water is sent to the platforms for offshore disposal.

Information on the oil distribution pipeline is provided on a sub-regional level in the Eastern Pipeline System discussion in Section 2.4.2.8, the regional level in the product distribution system discussion in Section 2.5.1, and at the facility level in the corresponding Facility-specific table in Appendix B. In addition, Section 2.5.1 includes a diagram of the principal local and regional pipeline connections and information on which pipelines are proprietary and which are common carriers.

Spare Capacity / Permit & Operating Limitations. Appendix B identifies the spare capacities for the La Conchita Facility. The operator did not identify limitations. No permit constraints were identified that would limit throughput to less than the design capacity.

Key System Dependencies.

- Platform Houchin depends on Platform Hogan and the interconnecting flowlines.

- The La Conchita Oil & Gas Processing Facility depends on the downstream oil and gas pipeline distribution system (see "Eastern Pipeline System").

Secondary Facilities. Oil from the La Conchita Facility is pumped into a Venoco pipeline between the Carpinteria Oil & Gas Processing Facility and the 268,000 barrel Venoco-owned storage tank adjacent to the Rincon Oil & Gas Processing Facility. Ultimately, the oil is pumped by pipeline to the Ventura Pump Station (see discussion of "Eastern Pipeline System" below).

Future Facility Capacity. Production estimates predict that the quantity of wet oil and gas produced from the platforms and processed at the La Conchita Facility will decline annually over the remaining life of the facilities. This should result in annually increasing spare processing capacity at the La Conchita Facility assuming it does not become limited (bottle-neck) in its ability to process a particular fraction (e.g., wet/dry oil, gas, produced water, etc.) of the incoming stream.

Based on historic production and estimated economically recoverable reserve data for the platforms, the economic life of the La Conchita Facility is projected to end by study year 2000. When the platforms, La Conchita Facility and associated pipelines become idle, it is assumed that they will be removed except for some flowlines which may be abandoned in place. The loss of production from the La Conchita Facility will increase the available capacity at the Rincon Onshore Oil & Gas Processing Facility and the corresponding pipelines from the Rincon Onshore Oil & Gas Processing Facility to the Ventura area and to the refineries in the Los Angeles area. In addition, there will be no gas from the facility entering the Southern California Gas Company's distribution system.

2.4.2.6 Carpinteria Oil & Gas Processing Facility

General. The Carpinteria Oil & Gas Processing Facility (Carpinteria Facility) is located in Carpinteria in Santa Barbara County and was originally constructed in 1959 to receive wet oil and gas from Platforms Hilda, Hazel, Hope and Heidi all of which were decommissioned in 1996. The Carpinteria Facility also began receiving oil and gas production from Platform Grace in the Santa Clara Field in 1980 and from Platform Gail in the Sockeye Field in 1988. A system schematic for the Carpinteria Oil & Gas Processing Facility is shown in Figure 2.4-10 and a plot plan for the Facility is shown in Figure 2.4-11. A facility "profile" summary is provided in Appendix B. As of December 1998, the Facility was receiving produced gas and pipeline quality oil from Platform Gail. Platform Grace production had been suspended and all wells had been temporarily plugged.

The Carpinteria Facility has a design capacity of 40,000 BOPD wet oil and 28 MMCFD of gas. The Carpinteria Facility has some unused equipment and there is adequate space to install additional equipment. Based on information from the operator as of December 1998, the capacity of the gas plant is limited to approximately 28 MMCFD in the summer, but can process up to approximately 30 MMCFD in the winter. Depending on the season, the capacity is limited by either compressor capacity or glycol contactor capacity.

As of December 1998, the operator indicated that some of the equipment at the facility was not in operation because the wet oil was being dewatered on Platform Gail resulting in pipeline quality oil being received and temporarily stored in Tank 861 at the Carpinteria Facility prior to being sent by pipeline to the 268,000 barrel Venoco-owned storage tank adjacent to the Rincon Oil & Gas Processing Facility. Hydrogen sulfide is removed from the produced gas offshore, and this gas is then sent to the Carpinteria Oil & Gas Processing Facility for further processing including dehydration and separation of ethane and heavier hydrocarbons. These heavier hydrocarbons are blended into the crude for shipment by pipeline. Information from the operator indicates that the permitted equipment includes, but is not limited to, the following:

- oil-water separation system including heater-treaters and free-water knockouts;
- 8 gas compressors;
- oil treatment/storage vessels including one 217,000 barrel tank (Tank 861);
- gas system using glycol dehydration and low temperature separator;
- 3 Ferricat gas polishing towers; and
- heaters, stabilizers, natural gas liquids (NGL) storage, pig receivers, gasoline surge tank, and other equipment (not all of this equipment may be in operation at all times).

Offshore Flowlines/Pipelines. Historically, production from Platform Gail was sent by pipeline to connect into pipelines at Platform Grace located in the Santa Clara Field. Oil and gas production from Platform Grace, combined with the production from Platform Gail, was sent by pipeline to the Carpinteria Facility. As of December 1998, all production was from Platform Gail. Fluids produced on Platform Gail were being processed on the Platform and pipeline quality oil was being sent to the Carpinteria Facility by pipeline. Gas produced on Platform Gail was being sent to the Carpinteria Facility through a second pipeline.

Product Distribution. As of December 1998, the oil was being pumped to the 268,000 barrel Venoco-owned storage tank located near the Rincon Oil & Gas Processing Facility. The gas was being sold to Southern California Gas Company. Natural gas liquids (NGL) removed from the gas were being blended into the crude and were not being trucked offsite.

Information on the oil distribution pipeline is provided on a sub-regional level in the Eastern Pipeline System discussion in Section 2.4.2.8, the regional level in the product distribution system discussion in Section 2.5.1, and at the facility level in the corresponding Facility-specific table in Appendix B. In addition, Section 2.5.1 includes a diagram of the principal local and regional pipeline connections and information on which pipelines are proprietary and which are common carriers.

Spare Capacity / Permit & Operating Limitations. Spare capacity information for the Facility is shown in Appendix B and is based on the nominal design capacity of 28 MMCFD. Depending on the season, the capacity is limited by either compressor capacity (during summer) or glycol contactor capacity (during winter). The operator reported that the capacity of the facility is limited to 28 MMCFD in the summer, but can process up to 30 MMCFD in the winter. The degree to which capacity could be increased was not estimated. There is space available to expand. No permit constraints were identified that would limit throughput to less than the design capacity of 28 to 30 MMCFD.

Key System Dependencies.

- Platform Gail depends on interconnecting pipelines near Platform Grace.
- The Carpinteria Oil & Gas Processing Facility depends on the downstream oil and gas pipeline distribution system.

Secondary Facilities. The oil is pumped to the 268,000 barrel Venoco-owned storage tank near the Rincon Oil & Gas Processing Facility. From there, it is pumped by pipeline to the Ventura Pump Station, near Ventura Harbor, where it enters the pipeline system to the refineries located in the Los Angeles area (see "Eastern Pipeline System").

Future Facility Capacity. Production estimates predict that the quantity of wet oil and gas produced from the platforms and processed at the Carpinteria Facility will decline annually over the remaining life of the facilities in the absence of new development. This should result in annually increasing spare processing capacity at the Carpinteria Facility. Based on historic production and projected production profiles of wells in service in 1998, the economic life of the Carpinteria Facility would end by study year 2005 in the absence of new development. Although Chevron had indicated its intention to terminate production inputs to the Carpinteria Facility within this time frame, the current operator (Venoco) has stated its plans to invest in production enhancements to extend the economic life of Platforms Grace and Gail and the Carpinteria Facility.

When the platforms, Carpinteria Facility and associated pipelines are no longer economically viable, it is assumed that they will be removed except for some flowlines which may be abandoned in place or as otherwise required by applicable regulations. The loss of production from the Carpinteria Facility will increase the available capacity in the oil pipeline between the Carpinteria Facility and the 268,000 barrel tank located adjacent to the Rincon Oil & Gas Processing Facility and the corresponding pipelines from this tank to the Ventura area and to the refineries in the Los Angeles area. In addition, there will be no gas from the facility entering the Southern California Gas Company's distribution system.

2.4.2.7 Carpinteria Onshore Gas Terminal

General. The Carpinteria Onshore Gas Terminal (Carpinteria Gas Terminal) is located in Carpinteria and receives gas from Platform Habitat in the Pitas Point Field. The platform produces only gas (no oil). A system schematic for the Carpinteria Onshore Gas Terminal is shown in Figure 2.4-12. A facility "profile" summary is provided in Appendix B.

Based on information from the operator, major equipment located at the facility includes odor-inducing material storage and injection equipment. The Carpinteria Gas Terminal adds odorizing compounds to the gas, but does not process the gas in the same manner as gas is processed at the other facilities in the Study Region. There are no storage devices for the gas and after it leaves the facility it becomes part of the public utility's distribution system.

Offshore Flowlines/Pipelines. Production from Platform Habitat is sent to the Carpinteria Onshore Gas Terminal by pipeline. Neither the produced condensate or produced water is sent to shore by pipeline.

Product Distribution. Gas, the only stream leaving the Carpinteria Gas Terminal, is sold to Southern California Gas Company. The operator provided general information to indicate the condensate is periodically transported to another platform or onshore facility operated by the same operator and is mixed with the crude. The receiving location can vary; however the quantity is so small it is not expected to impact processing or spare capacity. The produced water is disposed of at the platform.

Spare Capacity / Permit & Operating Limitations. Spare capacity information is provided in Appendix B. Facility capacity is limited by compressor capability. Other than design limitations, the operator did not identify any processing constraints. No permit constraints were identified that would limit throughput to less than the design capacity.

Key System Dependencies.

- The Carpinteria Onshore Gas Terminal depends on the downstream gas pipeline distribution system.

Secondary Facilities. Gas from the Carpinteria Gas Terminal is sold to Southern California Gas Company. There are no secondary facilities.

Future Facility Capacity. Production estimates predict that the quantity of gas produced from the platform and processed at the Carpinteria Gas Terminal will decline annually over the remaining life of the facilities. This should result in annually increasing spare processing capacity at the Carpinteria Gas Terminal.

Based on historic production and estimated economically recoverable reserve data for the platform, the economic life of the Carpinteria Gas Terminal Facility is projected to end by study year 2005. When the platform, Carpinteria Gas Terminal and associated pipelines become idle, it is assumed that they will be removed except for some flowlines which may be abandoned in place. The loss of production from the Carpinteria Gas Terminal will reduce the quantity of gas entering the Southern California Gas Company's distribution system.

2.4.2.8 Eastern Pipeline System

General. The majority of the oil and gas products from the onshore processing facilities are transported to market using pipelines. Except for the small quantity of oil trucked from the State Lease 145/410 facility, all of the oil produced from the facilities in the Eastern Subregion ends up at the Ventura Pump Station where it is combined before being pumped by pipeline to refineries in the Los Angeles area. This section describes the pipeline system serving the facilities in the Eastern Subregion. The discussion is organized to describe how oil from facilities south of the

Ventura Pump Station cascade together and how oil from facilities north of the Ventura Pump Station cascade together. The overall pipeline system includes interfacility pipelines and pipelines that transport the products out of the COOGER Study Region. A system schematic of the Eastern Subregion Product Distribution System which shows the Eastern Pipeline System is shown in Figure 2.4-13. A summary of these pipelines and the associated pump stations is provided in Appendix B.

Onshore Pipelines. This discussion focuses on the onshore oil pipelines. In most cases, the produced gas is used by the industry or sold to a local utility company. Gas sold to a utility company is transferred to the utility company pipelines at each facility. An analysis of utility company pipelines is not included in this study.

Facilities South of the Ventura Pump Station (south to north)

The Mandalay Onshore Separation Facility sends oil via a 6- to 8-inch diameter, unheated pipeline to the Ventura Pump Station. For most of its length, the pipeline parallels Harbor Boulevard and is suspended, via "pipeline hangers", from the Harbor Boulevard bridge as it crosses the Santa Clara River. The shipping pumps at the facility have a capacity of approximately 830 barrels per hour. The historic (pre-1995) annual peak oil production from the Mandalay Onshore Separation Facility (i.e., Platforms Gina and Gilda) occurred in 1984.

The West Montalvo Operations send oil via two separate unheated pipelines that connect into the pipeline between the Mandalay Onshore Separation Facility and the Ventura Pump Station. The two pipelines are 6-inch and 8-inch diameter pipelines that originate from two separate tank batteries (one for offshore production and one for onshore production) and connect into the "Mandalay" pipeline approximately 300 yards apart. Both connections are on the south ("Mandalay") side of the Santa Clara River. Flow in these pipelines is intermittent (i.e., batch basis from the tank batteries). The historic (pre-1995) annual peak oil production from the West Montalvo Operations occurred in 1993.

Facilities North of the Ventura Pump Station (north to south)

The Carpinteria Oil & Gas Processing Facility sends oil via a Venoco-owned 10-inch diameter, unheated pipeline to a 268,000 barrel Venoco-owned storage tank located adjacent to the Rincon Oil & Gas Processing Facility. As of August 1997, the pipeline was operating at approximately

1,750 barrels per hour. For most of the distance between the facility and the storage tank, the pipeline is located in the railroad right-of-way that passes within 100 yards of the facility. This pipeline also passes within 100 yards of the La Conchita Oil & Gas Processing Facility and the Rincon Island and State 145/410 Oil & Gas Processing Facilities which are geographically located between the Carpinteria Facility and the storage tank. The historic (pre-1995) annual peak oil production from the Carpinteria Oil & Gas Processing Facility (i.e., Platforms Gail and Grace) occurred in 1990.

The La Conchita Oil & Gas Processing Facility sends oil via a POOI-operated 100 foot long, 4-inch diameter, unheated pipeline that connects into the 10-inch diameter pipeline that goes from the Carpinteria Oil & Gas Processing Facility to the 268,000 barrel Venoco-owned storage tank located adjacent to the Rincon Oil & Gas Processing Facility. The historic (pre-1995) annual peak oil production from the La Conchita Oil & Gas Processing Facility (i.e., Platforms Hogan and Houchin) occurred in 1969.

The Rincon Island Oil & Gas Processing Facility sends oil via a 6-inch diameter, unheated pipeline that connects into the 10-inch diameter pipeline that goes from the Carpinteria Oil & Gas Processing Facility to the 268,000 barrel Venoco-owned storage tank located adjacent to the Rincon Oil & Gas Processing Facility. The pipeline from the island is suspended on the causeway and then goes underground when it reaches shore, passes under Highway 101 and connects into the 10-inch diameter pipeline in the railroad right-of-way. The historic (between 1977-1995) annual peak oil production from Rincon Island occurred in 1977. Oil from the State Lease 145/410 Oil & Gas Processing Facility is transported by truck to a pump station operated by Equilon Pipeline Company located in Fillmore.

The Rincon Oil & Gas Processing Facility sends oil via a 6-inch diameter, unheated pipeline to the 268,000 barrel Venoco-owned storage tank located adjacent to the Rincon Oil & Gas Processing Facility. The 6-inch diameter pipeline is less than 100 yards long. The historic (pre-1995) annual peak oil production from the Rincon Oil & Gas Processing Facility (i.e., Platforms A, B, C, Henry and Hillhouse) occurred in 1971.

The 268,000 barrel Venoco-owned storage tank, located adjacent to the Rincon Oil and Gas Processing Facility sends oil via a short pipeline segment that connects into the Venoco-operated 22-inch diameter, unheated M-143 pipeline to the Ventura Pump Station. The flow in the M-143 pipeline is by gravity: there are no pumps.

The M-143 pipeline transports oil produced from the offshore facilities described above. As of August, 1997, approximately 810 barrels per hour of oil was transported from these facilities. In addition, the M-143 pipeline transports oil produced from onshore leases. As of August, 1997, approximately 105 barrels per hour was transported from onshore leases. The total flow was approximately 915 barrels per hour with at a pressure ranging from 150 to 300 psig.

Pipelines from the Ventura Pump Station

As described above, all offshore produced oil processed by facilities in the Eastern Subregion, except for oil processed at the State Lease 145/410 Oil & Gas Facility, is accumulated at Tosco's Ventura Pump Station. There is one pipeline from the Ventura Pump Station that transports oil to the Los Angeles area. As of August 1997, this pipeline was operated by Tosco. There are three pump stations on the pipeline. The pipeline will be discussed in segments between the pump stations.

The Ventura Pump Station sends oil to Tosco's Santa Paula Pump Station via an 8-inch diameter, unheated pipeline. From the Ventura Pump Station, the pipeline travels northeast into a railroad right-of-way and follows this right-of-way most of the way to the Tosco Santa Paula Pump Station. This pipeline typically operates at a pumping rate of approximately 1,000 barrels per hour.

The Santa Paula Pump Station sends oil to the Tosco Torrey Pump Station via an 8-inch diameter, unheated pipeline. From the Santa Paula Pump Station, the pipeline generally follows Telegraph Road east to the City of Fillmore and then turns south crossing under the Santa Clara River near Torrey Road and into Torrey Canyon to the Torrey Pump Station. This pipeline typically is operated at a pumping rate of approximately 1,000 barrels per hour. In the Fillmore area, other pipelines transporting onshore produced oil connect into the pipeline.

The Torrey Pump Station sends oil to the Los Angeles area via a 12-inch diameter, unheated pipeline. The pipeline heads south from the Torrey Pump Station and leaves the COOGER study Region on its way to the Los Angeles area. This pipeline is operated at a pumping rate of 1,300 barrels per hour.

Other Pipelines in the Eastern Subregion

In addition to the above pipelines, there are two other pipelines in the Eastern Subregion that transport oil to the Los Angeles area. Although no offshore oil is transported in these pipelines, except for a small quantity from the State Lease 145/410 Oil & Gas Processing Facility, they are in close proximity to the M-143 pipeline and could also be "reconnected" to the Ventura Pump Station by reconnecting the Texaco pipeline at the recently abandoned Texaco Ventura Marine Terminal (described below).

Equilon operates an 8.625-inch diameter unheated crude oil pipeline between Ventura and Newhall (in Los Angeles County - outside of the COOGER Study Region). The pipeline originates at the Equilon Willett Tank Farm located on Ventura Avenue several miles north of Ventura. Texaco formerly operated a pipeline between the Willett Tank Farm and the Ventura Pump Station (described above) that was connected to the long-time-idle Texaco Ventura Marine Terminal located between the Willett Tank Farm and the Ventura Pump Station. When the marine terminal was removed, the pipeline between the Willett Tank Farm and the Ventura Pump Station was "disconnected"; however, the majority of the pipeline remains intact. Texaco has discussed the potential abandonment of this pipeline, and its potential dedication to Ventura County as a possible fiber optic cable conduit, but no formal agreements have yet been reached.

The Equilon pipeline between Willet and Newhall is primarily used to transport onshore production; however, offshore production from the State Lease 145/410 Oil & Gas Processing Facility was commonly trucked to an Equilon pump station in Fillmore and is introduced into this pipeline. As of August 1997, the pipeline was idle between San Martinez Canyon and Newhall, and trucks are used to transport oil from San Martinez Canyon to the east. There are four 80,000-barrel storage tanks located at Willett Tank Farm; two are currently operable and two are idle. The oil is transferred from these tanks to a 35,000 barrel storage tank at Equilon's Ventura Pump Station (described below) located a few miles north of the Willett Tank Farm.

Equilon operates a tank farm on Ventura Avenue north of Ventura that processes oil produced onshore. Oil is sent from the tank farm via a 10-inch diameter oil pipeline to the Los Angeles area. Except for the small quantity of offshore oil from the State Lease 145/410 Oil & Gas Processing Facility, the pipeline transports onshore oil. As of August 1997, the Equilon pipeline was transporting approximately 45,000 barrels of oil per day. There are several pumping stations between Ventura and the Los Angeles area along this pipeline.

Facility Description. This section describes the three Tosco pump stations (Ventura, Santa Paula, and Torrey) that are on the main pipeline which carries offshore oil from the Eastern Subregion to the Los Angeles area.

The Ventura Pump Station is located approximately one-quarter mile south of the Ventura Harbor and consists of a 135,000 barrel tank, a 150,000 barrel tank and pumps. The Ventura Pump Station pumps oil to the Santa Paula Pump Station as described above.

The Santa Paula Pump Station is located in the east-central part of Santa Paula and consists of a 55,000 barrel storage tank and pumps. The Santa Paula Pump Station pumps oil to the Torrey Pump Station as described above.

The Torrey Pump Station is located south of Fillmore and the Santa Clara River in Torrey Canyon and consists of an 80,000 barrel storage tank and pumps. The Torrey Pump Station pumps oil to the Los Angeles area as described above.

Product Distribution. As described above, all of the offshore oil processed by facilities in the Eastern Subregion, except for the oil from the State Lease 145/410 Oil & Gas Processing Facility, is sent to the Los Angeles Area via pipelines connected directly to the facilities.

Also as described, the offshore-produced natural gas is used by the facilities (either by onshore facilities or offshore at the platforms) or is transferred by pipeline to the local utility company’s distribution pipeline system. An analysis of the utility company's pipeline system is not part of the COOGER study. No information was located to indicate that the utility company's pipeline system would constrain production.

Spare Capacity/Limits. The design and pumping capacity data provided by the pipeline operators was not of sufficient detail to make spare capacity assessments of the distribution system. However, the data provided combined with the historical peak production compiled indicates that most of the peak production periods showed oil quantities well in excess of the current production levels. The Eastern Subregion pipeline infrastructure was designed to handle the anticipated peak production. Therefore, the current pipeline infrastructure in the Eastern Subregion is not expected to constrain the production estimated in the future baseline projection. No permit constraints were identified that would limit throughput to less than the design capacity.

Key System Dependencies. As described above, each facility relies on the pipeline system, including the pump stations, to transport the oil to the Los Angeles area. Any significant loss of part of this system could constrain production from one or more of the facilities depending on where the problem occurred. In addition, in several of the pipelines, the offshore production must "share" space with oil produced onshore. If there were significant increases in onshore production, it could constrain offshore production. Additionally, it is assumed there will not be any significant reductions in the market for crude in the Los Angeles area.

Secondary Facilities. The description of the pipelines and pump stations shows the relationship between them and identifies those which are "secondary" to any individual pipeline or pump station.

Future Facility Capacity. Because most of the pipelines and pump stations described handle oil from multiple facilities and/or handle oil produced from onshore in addition to offshore production, it is unlikely that the pipelines will be abandoned during the period 1995-2015. If pipelines fail and cannot be replaced or are no longer needed, it is expected they would be flushed clean and then left in place or otherwise managed in accordance with applicable agency requirements, if any.

2.4.2.9 Support Facilities

Support facilities in the Eastern Subregion include Port Hueneme , Ventura Harbor , and the Carpinteria Pier . Port Hueneme is the only deep water port between Los Angeles and San Francisco. The Port has heavy lifting capabilities and is used by the offshore oil and gas industry to transfer equipment and supplies between marine vessels and land vehicles. This includes normal operating supplies as well as drilling equipment and materials. Port Hueneme is used by the work/supply boats serving all of the platforms; whereas, crew boats using the Port primarily service the Platforms in the southern end of the Santa Barbara Channel.

A portion of Ventura Harbor is used by the crew boats and work/supply boats that serve the offshore oil and gas industry. There are some loading/unloading facilities at the Ventura Harbor; however, heavy transfers are conducted at Port Hueneme.

The Carpinteria Pier is located south of the Carpinteria Oil & Gas Processing Facility and is owned and operated by the oil and gas industry: it is not used by the public. Equipment on the pier has light lifting capabilities. The pier is used to transfer personnel and light supplies onto crew boats and work/supply boats. Onshore, there is a supply storage area and parking lot for industry personnel. The crew boats using the Carpinteria Pier primarily serve the Platforms in close proximity to Carpinteria.

2.4.3 Central Subregion

The onshore facilities located in the Central Subregion that process oil, gas, and/or produced water directly from offshore reserves include the:

- Ellwood Oil & Gas Processing Facility and Ellwood Marine Terminal,
- Las Flores Canyon SYU Oil & Gas Processing Facility,
- Las Flores Canyon Gas Processing Facility, and
- Gaviota Oil & Gas Processing Facility.

Figure 2.4-14 shows the relative location of each of these onshore facilities as well as the offshore fields and platforms from which they receive production.

As stated in Section 2.3, the projected future production from the Ellwood Field is in a state of decline and, consequently, the Ellwood facilities listed above are currently processing less oil and/or gas than they were designed to process. The combined oil production from the Santa Ynez Unit, associated with the Las Flores Canyon facilities, and the Point Arguello Unit, associated with the Gaviota facility, appeared to have peaked in the mid-1990s and are projected to decline annually through the end of study year 2015. Consequently, these facilities are projected to have increasing spare capacity during this period in the absence of new production inputs to these facilities. Table 2.4-7 lists the wet oil design capacity, permitted capacity, and projected spare capacity (expressed as a total volume of oil/water mixture) for each Facility at 5-year increments during the period 1995-2015. Table 2.4-8 lists the gas design capacity, permitted capacity, and projected spare capacity for each Facility at 5-year increments during the period 1995-2015. Spare capacity information related to gas or other streams is discussed in Appendix B. Figure 2.4-15 shows the projected wet oil processing facility design and permitted spare capacity for the Central Subregion, as a whole, at 5-year increments during the period 1995-2015. Figure 2.4-16 shows the projected gas processing facility design and permitted spare capacity for the Central Subregion, as a whole, at 5-year increments during the period 1995-2015. As shown, spare capacity is projected to decline by study year 2010 due to the projected closure of facilities.

More detailed information on the operation and characteristics of each facility in the Central Subregion is provided below.

Table 2.4-7

Wet Oil Processing Spare Capacity - Central Subregion

Facility	Design Capacity (BPD)	Permitted Capacity (BPD)	Spare Capacity (BPD)[2] (wet oil)					Comments
			1995	2000	2005	2010	2015	
Ellwood Oil & Gas Processing Facility [1]	20,000	20,000	0	0	0	0	-	Permitted Spare Capacity is limited to Platform Holly production. The permitted capacity includes 13,000 BPD dry oil and 8,200 BWPD produced water. Design capacity is limited by the capacity of the oil/water separation system.
Las Flores Canyon SYU Oil & Gas Processing & Las Flores Canyon Gas Processing Facilities [3]	160,000	227,000	44,447	-10,454	65,597	68,243	93,397	The permit allows 227,000, but the equipment installed is designed for 160,000 (including 100,000 BPD dry oil and 60,000 BWPD produced water)
Gaviota Oil & Gas Processing Facility	125,000	250,000	45,428	70,335	85,000	125,000	-	The permit allows 250,000, but the equipment installed is designed for 125,000.
Central Subregion Totals	305,000	497,000	89,875	59,881	150,597	193,243	93,397	

Note: [1] Spare capacity is not available to production sources other than Platform Holly. At the direction of Santa Barbara County, Ellwood Oil & Gas Processing Facility spare capacity is treated as zero to reflect this limitation, although permitted and operational facility capacity includes: 13,000 BPD dry oil, 13 MMCFD dry gas, and 8,200 BWPD produced water. This capacity is presumed available to accommodate production from Platform Holly throughout the COOGER study time frame.

[2] Table entries record the limiting capacity minus the actual oil processed during the year indicated. If no production is projected for an entire 5-year period, a dash is entered at the end of that period to reflect the potential shutdown or the potential decommissioning of the onshore facility during that period.

[3] The projected capacity shortfalls are related to water production in excess of currently installed water treatment capacity. Existing facility permits allow additional water treatment capacity sufficient to accommodate this projected demand.

Table 2.4-8
Gas Processing Spare Capacity - Central Subregion

Facility	Design Capacity (MCFD)	Permitted Capacity (MCFD)[1]	Spare Capacity(MCFD)[3] 1995	2000	2005	2010	2015	Comments
Ellwood Oil & Gas Processing Facility[2]	20,000	13,000	10,118	11,458	12,175	13,000	-	Permitted Spare Capacity is limited to Platform Holly production.
Las Flores Canyon SYU Oil & Gas Processing & Las Flores Canyon Gas Processing Facilities	96,000	96,000	23,466	110	110	112	110	
Gaviota Oil & Gas Processing Facility	60,000 (built)	120,000	18,181	9,622	45,759	-	-	The permit allows 120000, but the equipment installed is designed for 60000.
Molino Gas Plant[4]	60,000	60,000	-	-	0	0	0	
Central Subregion Totals	236,000	289,000	51,765	21,190	58,044	13,112	110	

Note: (1) Permitted Capacity assumed to equal Design Capacity unless specific permit conditions were identified.
(2) Based on permit conditions, the Ellwood facilities can only receive production from Platform Holly and therefore access to identified permitted spare capacity would require production from Platform Holly.
(3) Table entries record the limiting capacity minus the actual gas processed during the year indicated. If no production is projected for an entire 5- year period, a dash is entered at the end of that period to reflect the potential shutdown or the potential decommissioning of the onshore facility during that period.
(4) The Molino facility is designed to process sweet gas by dehydration and removal of gas liquids. No sulfur removal equipment has been proposed for these facilities. Because these facilities have been proposed as single-purpose facilities, and are not intended to process gas from other production sources, excess capacity is assumed to be zero at this location at all times.

2.4.3.1 Ellwood Oil & Gas Processing Facility and Ellwood Marine Terminal

General. The Ellwood Oil & Gas Processing Facility receives wet oil and gas from Platform Holly in the South Ellwood Field. The Ellwood Oil & Gas Processing Facility is located approximately 1,600 feet southwest of the intersection of Highway 101 and Hollister Avenue at the west edge of Goleta in Santa Barbara County, approximately 900 feet inland from the ocean. The Ellwood Marine Terminal is located near the Ellwood Oil & Gas Processing Facility. A system schematic for the Ellwood Oil & Gas Processing Facility is shown in Figure 2.4-17 and a plot plan of the Facility is shown in Figure 2.4-18. Figure 2.4-19 provides a plot plan for the Ellwood Marine Terminal. A facility "profile" summary is provided in Appendix B.

Processes conducted at the Ellwood Oil & Gas Processing Facility include: 1) treating the oil emulsion to remove the produced water from the incoming wet oil stream, 2) treating the oil to reduce the hydrogen sulfide content in the treated crude, and 3) produced water treatment to prepare the produced water for disposal in an on-site disposal well. The sour gas is treated (sweetened) in a LOCAT sulfur removal unit prior to the gas being sold to the Southern California Gas Company.

The Ellwood Oil & Gas Processing Facility's wet oil processing equipment has a design capacity of 20,000 BPD. Facility permits currently limit processed oil output to a maximum of 13,000 BPD of dry oil. The oil storage capacity is 6,000 barrels at the Ellwood Oil & Gas Processing Facility plus 130,000 barrels at the Ellwood Marine Terminal. The Ellwood Oil & Gas Processing Facility has a water treatment design capacity of 8,200 BWPD and the treated produced water discharge system has a design capacity of 10,000 BWPD. The associated gas treatment system has a design capacity of 20 MMCFD, and a permit limit of 13 MMCFD. The facility has a natural gas liquids (NGL) processing system with a design capacity of 2,000 BPD. NGL is blended into the crude oil. LPGs are sold to local distributors and trucked offsite. The facility also produces sulfur.

In addition to receiving wet oil and sour gas from Platform Holly, the Ellwood Oil & Gas Processing Facility also receives gas collected from natural, underwater seeps. This gas is collected using "tents" on the ocean floor and the gas is sent to shore by pipeline. Approximately 550 MCFD of gas are collected by the seep “tents.”

Offshore Flowlines/Pipelines. Production from Platform Holly is sent to the Ellwood Oil & Gas Processing Facility in a 6-inch diameter wet oil pipeline and a 6-inch diameter sour gas pipeline. In addition, there is a 4-inch diameter utility pipeline from the Ellwood Oil & Gas Processing Facility to Platform Holly. An 8-inch diameter pipeline connects the seep tents to the Ellwood Oil & Gas Processing Facility.

Product Distribution. Streams exiting the Ellwood Oil & Gas Processing Facility include oil, gas, produced water, sulfur, and liquefied petroleum gas (LPG). NGLs are blended into the dry oil which is sent by pipeline to storage tanks located at the Ellwood Marine Terminal. The incoming gas is sweetened and sold to Southern California Gas Company. The treated produced water is disposed of in onsite injection wells. The Ellwood Oil & Gas Processing Facility produces approximately 2 tons of sulfur per day which is sent offsite by truck. The LPG is sent offsite by truck. Based on data obtained from the Santa Barbara County Department of Planning and Development, a total of 385 trucks of LPG were shipped during 1997 and 221 trucks during the period January - July, 1998.

Spare Capacity / Permit & Operating Limitations. Although the design capacity of the Ellwood Oil & Gas Processing Facility is 20,000 BPD of dry oil and 20 MMCFD of gas, there are air permit conditions that limit the facility to only 13,000 BPD dry oil and 13 MMCFD of gas. Santa Barbara County oil facility consolidation policies limit the Ellwood Oil & Gas Processing Facility and Ellwood Marine Terminal to handling only production that comes from Platform Holly, so there is effectively no permitted spare capacity available to accept production from other sources. In addition to this limitation, the Ellwood Oil and Gas Facility is classified as a legal non-conforming use which severely limits potential future modification or expansion of this facility or its operating permits. As presently designated, these facilities may not be modified except as required to comply with law or to reduce significant impacts, and any proposed modifications require Santa Barbara County review and approval. Modifications involving facility expansion would require approval of amendments to the Local Coastal Program by the Santa Barbara County Board of Supervisors and County voters, along with certification by the California Coastal Commission. Spare capacity information is provided in Appendix B.

Key System Dependencies. The Ellwood Oil & Gas Processing Facility depends on the Ellwood Marine Terminal and the related piping for shipment of the produced oil; the Ellwood Oil & Gas Processing Facility is not connected to a pipeline system (other than to the marine terminal).

Secondary Facilities. Oil from the Ellwood Oil & Gas Processing Facility is pumped to storage tanks that are part of the Ellwood Marine Terminal. Oil is pumped from the storage tanks to a barge loading terminal. The oil is typically transferred by barge to refineries in the Los Angeles area; however, the barges can also go to the San Francisco Bay area.

The Ellwood Marine Terminal (EMT) is located on 17-acres in Goleta, Santa Barbara County, and consists of an onshore storage and pumping facility and an offshore mooring terminal. The mooring system consists of a five point spread mooring pattern; the sixth mooring leg is not used. The EMT has been in existence since 1929 and has changed operatorship several times over the years. As of August 1997, a dedicated barge, the Jovalan, with a capacity of 56,000 barrels is used to transport the crude to refineries in the Los Angeles area; however, it is possible for the barge to go to the San Francisco Bay area. The barge has a draft of 19 feet when fully loaded. The barge is loaded approximately every 9 to 12 days and it takes 13 to 14 hours to fill the barge at a maximum pumping rate of 4,200 barrels per hour. The marine terminal can load vessels with drafts of not more than approximately 50 feet.

The EMT tank farm consists of two 80,000-barrel crude oil storage tanks, a 10,000-barrel fire water storage tank, two 300 barrel per hour electric motor-driven shipping pumps, an electric motor-driven transfer pump (unused) and a control building. The maximum operating capacity of the two 80,000-barrel storage tanks is limited to 65,000 barrels each. The onshore portion of the pipeline from the transfer pumps at the Ellwood Marine Terminal to the offshore loading connection has a 12-inch diameter; whereas, the offshore portion of the pipeline is comprised of 8-inch and 10-inch diameter sections. The marine terminal consists of a five point mooring area for tankers and barges located in approximately 57 feet of water.

Future Facility Capacity. Production estimates developed by Mobil (the operator until August 1997) predicted that the quantity of wet oil and gas produced from Platform Holly and processed at the Ellwood Oil & Gas Processing Facility would decline annually over the remaining life of the facilities in the absence of new development. This would result in annually increasing spare processing capacity at the Ellwood Oil & Gas Processing Facility, although this capacity is only available to oil and gas produced at Platform Holly under current Santa Barbara County policy limitations. Future modifications of Ellwood Oil & Gas Processing Facility permits to allow processing oil or gas from other sources are prohibited by the facility's current non-conforming use status, as discussed in the Spare Capacity/Permit & Operating Limitations section, above.

Based on historic production and projected production profiles developed by Mobil, the economic life of the Ellwood Oil & Gas Processing Facility would end by study year 2010 in the absence of new development. Venoco (the current operator of Platform Holly and the Ellwood Oil & Gas Processing Facility) has indicated that it is currently investing in the existing wells and facilities to extend the economic life of Platform Holly and the Ellwood Oil & Gas Processing Facility. No plans to expand current development to include the production of currently undeveloped resources have been announced as of August 1999, although economically viable development of substantial undeveloped resources could be accomplished from Platform Holly. Because the Ellwood Marine Terminal only serves the Ellwood Oil & Gas Processing Facility, it is assumed that when the Ellwood Oil & Gas Processing Facility is no longer economically viable, both these facilities will become idle. When the platform, Ellwood Oil & Gas Processing Facility, Ellwood Marine Terminal and associated pipelines become idle, it is assumed that they will be removed with the exception of some pipelines which may be abandoned in place. The loss of production from the Ellwood Oil & Gas Processing Facility will not affect the capacity of the subregional oil pipeline system because the oil is transported from the Tri-County area by barge. The Ellwood Oil & Gas Processing Facility's input of natural gas to the Southern California Gas Company's distribution system would also cease when these facilities are no longer in service.

2.4.3.2 Las Flores Canyon SYU Oil & Gas Processing Facility

General. The Las Flores Canyon SYU Oil & Gas Processing Facility (LFC Oil Facility) receives wet oil and gas from Platforms Hondo and Harmony in the Hondo Field and from Platform Heritage in the Pescado Field. Both the Hondo Field and the Pescado Field are in the Santa Ynez Unit (SYU). The LFC Oil Facility is located in a canyon north of Highway 101 approximately 15 miles west of Santa Barbara in Santa Barbara County. A system schematic from the Las Flores Canyon SYU Oil & Gas Processing Facility is shown in Figure 2.4-20 and a plot plan of the Las Flores Canyon facilities is shown in Figure 2.4-21. Figure 2.4-22 provides a block flow diagram for the Las Flores Canyon Facilities. A facility "profile" summary is provided in Appendix B.

Construction of onshore components commenced in April of 1988 and ended in May of 1993. Installation of offshore components commenced in October of 1989 and ended in November of 1992 (installation for the nearshore pipeline began in October of 1989 and ended in April of 1990, and installation of platforms and offshore pipeline began in December of 1991 and ended in November of 1992). Installation of the gas pipeline from Platform Heritage to Platform Harmony occurred in 1998.

The LFC Oil Facility operates in conjunction with, and is located adjacent to, the Las Flores Canyon Gas Processing Facility. All of the wet oil produced from the Santa Ynez Unit is processed at the LFC Oil Facility, but the gas is split between the two facilities for processing. Historically, the two facilities have been owned and operated by different companies. As of January 1999, the owner of the LFC Oil Facility acquired the LFC gas processing facility. However, the two facilities are discussed separately.

Processes at the LFC Oil Facility include: 1) an oil treating plant (OTP) where water is removed from the incoming wet oil stream; 2) a transportation terminal (TT) where the dry oil is stored prior to transfer to the All American Pipeline, L.P.; 3) a produced water treating plant (PWTP) where produced water is treated prior to offshore disposal; 4) a produced gas processing and sulfur removal facility (the stripping gas treatment plant - SGTP); and 5) a cogeneration power plant (CPP).

The oil treating plant (OTP) has two 50,000 BPD trains for a total nominal design capacity of 100,000 BPD of dry oil. The operator has discretionary permits to install one additional train to bring the total dry oil treatment capacity up to 140,000 BPD. The operator has discretionary permits to install equipment to treat up to 87,000 barrels of water per day (BWPD) and has installed two treatment trains with a total nominal design capacity of approximately 60,000 BWPD. The operator has a permit that allows the discharge of up to 92,000 barrels of produced water per day from Platform Harmony.

The stripping gas treatment plant (SGTP) is designed to process 21 MMCFD of gas to produce dry sweet gas for use onsite in the cogeneration power plant. The SGTP also is designed to produce up to 2,700 barrels per day of propane, 2,900 barrels per day of mixed butanes, and 20 short tons (2,000 pounds per ton) of sulfur from processing the hydrogen sulfide in the gas and crude.

The LFC Oil Facility is designed to retain the heavier fractions of the natural gas liquids (NGLs) in the oil stream and some of the NGLs recovered from the gas processing unit are also blended into the crude. The facility also accepts NGLs from the Las Flores Canyon Gas Processing Facility and blends them (except for propane) into the crude oil to the extent possible (and still meet the AAPLP specifications). In the future, if the vapor pressure exceeds the technical capacity of the AAPLP system, then butane may be shipped offsite by truck.

The Transportation Terminal consists of two 270,000 barrel storage tanks. As of August 1997, both tanks were being used to store dry oil. The Cogeneration Power Plant (CPP) has a design capacity of 49 megawatts (MW) and provides power for the onshore processing facility and provides power, via subsea cables, to the three offshore platforms. The CPP is designed to provide all of the power needed; however, it is connected to the Southern California Edison electric company grid system and can either add electricity to or take electricity from the grid.

The LFC Oil Facility covers approximately 113 acres of an approximately 2,500-acre site which is one of the Santa Barbara County approved "consolidation areas" (i.e., where other facilities can be co-located). The County's intent is that all new onshore treatment facilities planned for the southern part of the County be constructed at one of the consolidation areas. Currently, there is sufficient space for additional facilities in Las Flores Canyon.

Offshore Flowlines/Pipelines. The number, type and location of the flowlines/pipelines associated with Platform Hondo changed when Platforms Harmony and Heritage became operational in 1993 and the Offshore Storage and Treatment (OS&T) vessel was removed. A description of the flowlines/pipelines is provided in Appendix B.

An uncommon feature associated with the sour gas system is that the sour gas produced from Platforms Hondo, Harmony, and Heritage is sent to shore in one pipeline, but is then split for processing at the LFC Oil Facility and the Las Flores Canyon Gas Processing Facility (i.e., two different facilities receive sour gas from the same platforms).

Product Distribution. Streams exiting the LFC Oil Facility include oil, gas, produced water, NGL, and sulfur. Oil is stored at the onsite Transportation Terminal and then pumped, via the AAPLP Coastal Line (discussed in Section 2.4.3.8) to the outlet pipeline of the Gaviota Pump Station. Gas not used onsite is sold to Southern California Gas Company. Produced water is treated and is sent to Platform Harmony for deep water injection. Propane (LPG) is removed from the produced gas and is transported offsite by truck. Based on data obtained from the Santa Barbara County Department of Planning and Development, a total of 1,137 trucks of LPG were shipped during 1997 and 765 trucks were shipped during the period January-June, 1998. Sulfur is also transported offsite by truck.

Information on the oil distribution pipeline is provided on a sub-regional level in the AAPLP Pipeline System discussion in Section 2.4.3.8, the regional level in the product distribution system discussion in Section 2.5.1, and at the facility level in the corresponding Facility-specific table in Appendix B. In addition, Section 2.5.1 includes a diagram of the principal local and regional pipeline connections and information on which pipelines are proprietary and which are common carriers.

Spare Capacity / Permit & Operating Limitations. As of August 1997, the LFC Oil Facility was operating near the maximum design capacity of the oil treatment plant and had essentially no spare capacity. There is baseline spare capacity at the stripping gas treatment plant; however, the actual amount varies because the incoming gas is split with the Las Flores Canyon Gas Processing Facility and the split varies depending upon operating needs of the two facilities. The wells producing at the three platforms have the ability to produce more wet oil and gas than can be processed by the two onshore LFC facilities. Consequently, this limits the rate at which the offshore reserves can be produced. No permit constraints were identified that would limit throughput to less than the design capacity of the equipment installed.

Key System Dependencies.

- Platforms Hondo and Heritage depend on flowline connections near Platform Harmony for oil transport to the onshore facility.
- Platforms Harmony and Heritage depend on flowline connections near Platform Hondo for gas transport to the onshore facilities.
- Platforms Hondo and Heritage and the onshore facility depend on Platform Harmony for produced water disposal.
- The platforms depend on the CPP at the LFC Oil Facility for electricity.
- The platforms depend on the Las Flores Canyon Gas Processing Facility to process a significant portion of the produced gas.
- The LFC Oil Facility depends on the downstream oil and gas distribution system.

Secondary Facilities. There are several facilities in the downstream distribution system for oil produced at the Las Flores Canyon SYU Oil & Gas Processing Facility. Oil enters the AAPLP pipeline (discussed in Section 2.4.3.8) and can be routed to the Santa Maria Refinery, via the Sisquoc Pump Station, or other refineries outside the Study Region.

Future Facility Capacity. Production estimates predict that the quantity of wet oil produced from the platforms and processed at the LFC Oil Facility will peak in the late 1990s and then decline annually over the remaining study period 1995-2015. After the peak is reached, the decline in wet oil production should result in annually increasing spare processing capacity at the LFC Oil Facility. Production estimates predict that the quantity of gas produced from the platforms and processed at the LFC facilities will peak between the years 2000 and 2005 and will slightly decrease annually over the remaining study period 1995-2015.

Based on historic production and estimated economically recoverable reserve data for the platforms, the economic life of the LFC Oil Facility is projected to extend beyond study year 2015; the end of the project study period. Declining production from the LFC Oil Facility will increase the available capacity in the pipeline from the LFC Oil Facility to the AAPLP Gaviota Pump Station and in the AAPLP mainline out of the Tri-County area and subsequently in pipelines to the refineries in the Bakersfield, Los Angeles, San Francisco, mid-continent, and Texas Gulf Coast areas. The declining production will also reduce the quantity of gas entering the Southern California Gas Company's distribution system and the quantity of sulfur and propane trucked from Las Flores Canyon. The increasing production until the peak is reached will have the opposite impact on these systems.

2.4.3.3 Las Flores Canyon Gas Processing Facility

General. The Las Flores Canyon Gas Processing Facility (LFC Gas Facility) receives gas from Platforms Hondo and Harmony in the Hondo Field and from Platform Heritage in the Pescado Field. The Facility is located in a canyon north of Highway 101 approximately 15 miles west of Santa Barbara in Santa Barbara County. The LFC Gas Facility is located adjacent to and operated in conjunction with the Las Flores Canyon SYU Oil & Gas Processing Facility (described above). A facility "profile" summary is provided in Appendix B. Processes at the LFC Gas Facility include gas dehydration, sweetening, and compression and a sulfur recovery unit with a tail gas treatment unit.

Offshore Flowlines/Pipelines. The flowlines/pipelines from Platforms Hondo, Harmony, and Heritage are described in the section for the Las Flores Canyon SYU Oil & Gas Processing Facility (above).

Product Distribution. Streams exiting the LFC Gas Facility include the following. Sweetened gas is sold to Southern California Gas Company. As of late 1997, natural gas liquids (NGLs) started to be sent to the Las Flores Canyon SYU Oil & Gas Processing Facility by pipeline for blending into the crude. Prior to this time NGLs were trucked to the Las Flores Canyon SYU Oil & Gas

Processing Facility. Based on data obtained from the Santa Barbara County Department of Planning and Development, a total of 1,137 trucks of LPG were shipped during 1997 and 765 trucks were shipped during the first 6 months of 1998. Sulfur is also sent offsite by truck.

Spare Capacity / Permit & Operating Limitations. The LFC Gas Facility was originally designed for and operated at 30 MMCFD of gas, but was expanded to a capacity of 60-75 MMCFD, depending on the composition of the gas. No permit constraints were identified that would limit throughput to less than the design capacity unless so constrained by the following "Throughput Limitations" in the permit:

> *The POPCO gas processing facility* [(LFC Gas Facility)] *shall be limited to the following processing limitations:*
>
> *a. A maximum inlet rate of 75 MMCFD of sour gas containing a maximum of 7,000 ppm (0.7%) H_2S and 54,800 ppm (5.48%) CO_2 to be processed on any given day;*
>
> *b. A maximum inlet rate of 60 MMCFD of sour gas containing a maximum of 26,700 ppm (2.67%) H_2S and 73,700 ppm (7.37%) CO_2 to be processed on any given day;*
>
> *c. Maximum production of 60 long tons on any given day of molten sulfur;*
>
> *d. A maximum production of 75 MMCFD of treated (or sales) gas on an annual average basis (calendar day).*
>
> *The offshore-to-onshore sour gas pipeline shall be limited to a maximum throughput of 90 MMCFD; 75 MMCFD of sour gas to be processed at POPCO's facility (LFC Gas Facility) and 15 MMCFD of sour gas to be transported to Exxon's Stripping Gas Treating Plant (at the LFC Oil Facility) via the sour gas interconnect.*

Key System Dependencies

- The LFC Gas Facility depends on sour gas feedstock from Platforms Hondo, Harmony, and Heritage.

- The LFC Gas Facility depends on the downstream gas pipeline distribution system.
- The LFC Gas Facility depends on Southern California Edison for electricity.
- The LFC Gas Facility depends on the Las Flores Canyon SYU Oil & Gas Processing Facility for water.

Secondary Facilities. The Las Flores Canyon Gas Processing Facility is closely linked to the Las Flores Canyon SYU Oil & Gas Processing Facility and there are various interconnections, such as the NGL being sent for blending in the crude.

Future Facility Capacity. Production estimates predict that the quantity of gas produced from the platforms and processed at the LFC Gas Facility will peak between the years 2000 and 2005 and will slightly decrease annually over the remaining study period 1995-2015. After the peak is reached, the decline in production should result in annually increasing spare processing capacity at the LFC Gas Facility.

Based on historic production and estimated economically recoverable reserve data for the platforms, the economic life of the LFC Gas Facility is projected to extend beyond the year 2015; the end of the project study period. Declining production from the LFC Gas Facility will reduce the quantity of gas entering the Southern California Gas Company's distribution system and the quantity of sulfur, LPG, and propane trucked from Las Flores Canyon and the quantity of NGLs sent by pipeline to the Las Flores Canyon SYU Oil & Gas Processing Facility. The increasing production until the peak is reached will have the opposite impact on these systems.

2.4.3.4 Gaviota Oil & Gas Processing Facility

This section discusses the Gaviota Oil & Gas Processing Facility (Gaviota Facility) under both the "Design Configuration" and "Re-Configuration" operating strategies. The "Design Configuration", described in Section 2.4.3.4.1, reflects 1) the original operating strategy planned by the Point Arguello Partners (the owners) and the operator of the Point Arguello Project, 2) the facility originally approved and permitted by the regulatory agencies, and 3) the way the offshore and onshore facilities were designed, constructed and originally operated. The "Re-Configuration", described in Section 2.4.3.4.2, reflects the changes to the physical facilities and/or their method of operation implemented by the owners/operator of the Point Arguello Project and approved by the regulatory agencies in 1998.

Based on information from the owners/operator and the agencies, the Re-Configuration was implemented by the owners/operator as a means of streamlining operations to reduce costs within the operating environment at the time of implementation. Information from the owners/operator and the agencies indicates the Re-Configuration is not necessarily a permanent change and that with the proper agency approvals, the operations could revert to the Design Configuration strategy within the COOGER study time frame of 1995-2015.

The Molino Gas Project, located in the Gaviota Consolidation Area, began exploratory drilling in the summer of 1998. If the exploratory program is successful and commercial production commences, the Molino project is permitted to develop the Molino Gas Plant at this site. The Molino Project would transport sales gas directly into the Gas Company's transmission pipeline south of the production site. It is also permitted to transport natural gas liquids to the Gaviota Oil and Gas Processing Facility for processing, storage, and transportation. As of July 1999, the Molino Project was not sufficiently defined (in relation to the actual construction and gas volumes) to project how it will ultimately interface with the Gaviota Facility under either the "Design Configuration" or the "Re-Configuration".

In July 1999, Chevron announced its transfer of interest in the Gaviota Oil and Gas Processing Facility (and the offshore Pt. Arguello Unit) to Plains Resources. Torch has been proposed to act as operator of the Gaviota Facility and related offshore platforms, but this designation had not been approved by Santa Barbara County as of December 16, 1999. No change in the projected operation of these facilities had been proposed by Torch at the time this report was prepared.

2.4.3.4.1 Design Configuration

General. As designed and originally operated, the Gaviota Facility received wet oil and gas from Platforms Hermosa, Harvest, and Hidalgo in the Point Arguello Unit.

The Gaviota Facility is located near the coast along Highway 101 approximately 25 miles west of Santa Barbara in Santa Barbara County. The Gaviota Facility occupies approximately 60 acres and there is space for expansion (this is one of Santa Barbara County's consolidation areas). A system schematic for the Gaviota Oil & Gas Processing Facility is shown in Figure 2.4-23 and a plot plan of the Facility and consolidation area boundary is shown in Figure 2.4-24. Figure 2.4-25 provides a block flow diagram for the Facility. A facility "profile" summary is provided in Appendix B.

Construction of the Gaviota Facility and onshore pipelines commenced on November 5, 1985 and was completed December 27, 1987. Platform Hermosa was installed in October 1985, Platform Harvest was installed in June 1985 and Platform Hidalgo was installed in July 1986.

The physical equipment present at the Gaviota Facility is designed to process 125,000 barrels per day (BPD) of wet oil and 60 million cubic feet per day (MMCFD) of gas. The operator has a Development Plan Approval from Santa Barbara County to install additional equipment to increase the processing capacity to 250,000 BPD of wet oil and 120 MMCFD of gas. The original air permits allowed the onshore processing of 125,000 BPD of wet oil and 60 MMCFD of gas.

The oil storage capacity at the Gaviota Facility is 10,000 barrels, with additional storage available at the nearby Gaviota Oil Terminal (formerly the Gaviota Interim Marine Terminal) tank farm (see the "Gaviota Oil Terminal" and "AAPLP Pipeline System" descriptions in Sections 2.4.3.6 and 2.4.3.8 below) The Gaviota Facility has a produced water treatment plant and discharge system.

Information provided by the operator indicates the Gaviota Facility's gas separation system uses refrigeration and has a design capacity of 60 MMCFD. The gas liquid removal system is designed for 57 MMCFD. The Gaviota Facility has a natural gas liquids (NGL) processing system that is designed for 3,364 BPD. Most NGLs are blended into the crude oil while propane is transported by truck. The Gaviota Facility also has a gas sweetening system that uses diethanolamine (DEA) to sweeten the gas and a sulfur plant.

Major equipment at the Gaviota Oil & Gas Processing Facility includes:

- oil-water separation system using free-water knockouts with an electrostatic coalescer;
- oil surge and reject tanks;
- pipeline transfer pumps;
- produced water treatment system;
- treated produced water discharge system;
- gas refrigeration system;
- NGL system;
- gas liquid removal system;
- DEA gas sweetening system (design/actual same as above);
- sulfur recovery system;

- cogeneration plant;
- seawater desalinization unit.

Offshore Flowlines/Pipelines. As designed, the wet oil and gas produced from Platforms Hermosa, Harvest, and Hidalgo is sent to the Gaviota Facility through two separate pipelines. Approximately 10 miles of the oil and gas pipelines are offshore and approximately 16 miles are onshore paralleling the coast from their landfall near Point Conception to the Gaviota Facility. The platforms have equipment that removes some of the produced water from the oil such that the oil sent through the oil (PAPCO) pipeline to the Gaviota Facility contains less than 20 percent water. The produced gas (PANGL) pipeline transports sour gas to the Gaviota Facility.

Product Distribution. When operating as designed, streams exiting the Gaviota Facility include the following: 1) sulfur is sold and sent offsite by truck; 2) treated produced water is injected into an onshore oil field or discharged to the ocean; 3) sweetened gas is sold to Southern California Gas Company by pipeline; 4) LPG is sold and sent offsite by truck; and 5) oil, blended with butane and natural gas liquids (NGL), is pumped to storage tanks at the Gaviota Oil Terminal prior to being pumped to market in the AAPLP pipeline (described in Section 2.4.3.8). Based on data obtained from the Santa Barbara County Department of Planning and Development, a total of 405 trucks of LPG were shipped during 1997 when the Facility was processing produced gas.

Information on the oil distribution pipeline is provided on a sub-regional level in the AAPLP Pipeline System discussion in Section 2.4.3.8, the regional level in the product distribution system discussion in Section 2.5.1, and at the facility level in the corresponding Facility-specific table in Appendix B. In addition, Section 2.5.1 includes a diagram of the principal local and regional pipeline connections and information on which pipelines are proprietary and which are common carriers.

Spare Capacity / Permit & Operating Limitations. Spare capacity information is provided in Appendix B (based on "design capacity" as constructed without consideration of the owners'/ operator's operating strategy). As originally permitted, no permit constraints were identified that would limit throughput to less than the design capacity.

If the proposed Molino Gas Plant sends LPG and/or sales gas to the Gaviota Facility for storage, loading and/or shipment, this is not expected to impact the wet oil or gas processing capacity of the Gaviota Facility because these systems were not identified as limitations to the wet oil and gas processing capability.

Key System Dependencies.

- Platform Hidalgo depends on flowline connections near Platform Hermosa for transport of wet oil and sour gas.
- Platform Harvest depends on flowline connections near Platform Hermosa for transport of wet oil and sour gas.
- The Gaviota Facility depends on the Gaviota Oil Terminal storage tanks, the Gaviota Pump Station, the Gaviota Booster Station, and the All American Pipeline, L.P. to store and transport the produced oil.
- Although the proposed Molino Project may send LPGs and/or sales gas to the Gaviota Facility, the Gaviota Facility is not expected to depend on this input.

Secondary Facilities. There are several facilities in the downstream distribution system for oil produced at the Gaviota Oil & Gas Processing Facility. Oil enters the AAPLP "main line" pipeline (see the "AAPLP Pipeline System") and can be routed to the Santa Maria Refinery or other refineries outside the Study Region.

Future Facility Capacity. Production estimates predict that the quantity of wet oil and gas produced from the platforms and processed at the Gaviota Facility will decline annually over the remaining life of the facilities. This should result in annually increasing spare processing capacity at the Gaviota Facility.

The economic life of the Gaviota Facility, under the Future Baseline, is projected to end by study year 2005, based on historic production and estimated economically recoverable reserve data for the platforms. When the platforms, Gaviota Facility and associated pipelines become idle, it is assumed that they will be removed except for some flowlines which may be abandoned in place subject to any applicable regulatory agency requirements. The loss of production from the Gaviota Facility will increase the available capacity in the pipeline from the AAPLP Gaviota Booster Pump Station and in the AAPLP mainline out of the Tri-County area and subsequently in pipelines to the refineries in the Bakersfield, Los Angeles, San Francisco, mid-continent, and Texas Gulf Coast areas. The declining production will also reduce the quantity of gas entering the Southern California Gas Company's distribution system and the quantity of LPGs and sulfur trucked from Gaviota Facility.

2.4.3.4.2 Re-Configuration

In order to streamline operations and reduce costs under the current operating environment, the owners/operator of the Point Arguello Project requested and received approval from the Santa Barbara County Planning and Development (SBCP&D) Department to "re-configure" the oil and gas processing activities conducted on the platforms and at the Gaviota Facility. The Re-Configuration involves stabilizing (processing) all produced oil offshore on Platforms Harvest and Hermosa, and re-injecting all surplus gas at Platform Harvest. This results in only pipeline quality being sent to shore in the oil pipeline and no produced gas being sent to shore. A new production pipeline at the Gaviota Facility bypasses the onshore processing equipment except for the heating equipment which is used to heat the crude to meet the All American Pipe Line's temperature specification for the incoming oil. The SBCP&D approved this modification to the Point Arguello permit on August 27, 1998. As of approximately October 1, 1998, the facilities were operating under the Re-Configuration operating strategy.

The following describes the Gaviota Facility under the Re-Configuration operating strategy.

General. As implemented, the Re-Configuration project resulted in the addition of equipment at the platforms to allow the oil to be stabilized at Platforms Harvest and Hermosa and the gas to be reinjected at Platform Harvest. This resulted in only pipeline quality oil being sent to the Gaviota Facility. Other than re-routing the oil pipeline entering the Gaviota Facility from the platforms directly to the heating equipment, reportedly no equipment changes have been made at the Gaviota Facility that would decrease the facility capacity to below the design capacity of 125,000 barrels of wet oil per day and 60 MMCFD of gas.

According to information obtained from SBCP&D in January 1999, the Development Plan Approval for the Point Arguello Project still allow the Gaviota Facility to process up to 250,000 BPD of wet oil and 120 MMCFD of gas. Full development of the facility to this capacity would require additional ministerial land use clearances from Santa Barbara County.

As stated, the original air permits allowed the onshore processing of 125,000 BPD of wet oil and 60 MMCFD of gas. However, when the operator moved some of the processing activities offshore to the platforms and also entered into an Ozone Mitigation Agreement, the air permits for the Gaviota Facility were modified to reduce the throughput of the onshore facility to 62,500 barrels of wet oil per day and 30 MMCFD of gas. According to the Santa Barbara County Air Pollution

Control District (Menno, 1999), the permit limits for the Gaviota Facility could be increased up to their original levels (i.e., 125,000 BPD wet oil and 60 MMCFD of gas) if the operator files a permit modification, provides sufficient emission offsets, and meets other requirements of the SBCAPCD and SBCP&D. In other words, the throughput reduction due to the decrease in permitted air emissions is not a permanent change and could change again during the COOGER study period of 1995-2015.

Based on information from both the owners/operator and the agencies, the Re-Configuration project did not change the capabilities of or result in the removal of processing equipment from the Gaviota Facility.

Offshore Flowlines/Pipelines. Under the Re-Configuration, the oil pipeline from the platforms to the Gaviota Facility is being used to transport pipeline quality oil. Because all of the gas produced at the platforms is being re-injected, the gas pipeline from the platforms to the Gaviota Facility is idle.

Since reconfiguration, the PANGL gas pipeline has been used occasionally to transport gas purchased from the Southern California Gas Company to the platforms to fuel operations. As offshore gas production from the Point Arguello project dwindles, additional shipments of retail gas from the Southern California Gas Company could occur.

Product Distribution. Under the Re-Configuration, only pipeline quality oil is sent to shore where it is heated at the Gaviota Facility prior to being sent to the storage tanks at the adjacent Gaviota Oil Terminal pending shipment in the All American Pipe Line system. The produced gas is reinjected at the platforms and so there is no gas processing at the Gaviota Facility (i.e., no gas sales, no sulfur production, no LPG trucks, etc.)

Spare Capacity / Permit & Operating Limitations. As previously described, spare capacity is based on either a facilities design capacity or its land use permit limits; whichever, is less. The Re-Configuration does not change either the Gaviota Facility's design capacity or the SBCP&D's permit limits for the facility. Consequently, the "maximum available" spare capacity is the same as when the Gaviota Facility is operating under the "Design Configuration" described above both with and without consideration of the proposed Molino Project.

Under the Re-Configuration operating strategy, the Gaviota Facility is not processing any wet oil or gas (the pipeline quality oil bypasses the oil plant and no gas enters the gas plant). As defined, spare capacity is the difference between a facility's design or permitted capacity, whichever is limiting, and the actual quantity being processed. Because the limiting capacity has not changed and no oil or gas are processed at this facility under this operating strategy, the entire capacity of the Gaviota Facility would be spare capacity. In other words, the wet oil spare capacity is 125,000 BPD, subject to having the air permit limits reinstated to their original level. The wet oil would need to be transported to the Facility by some means other than the PAPCO pipeline which is used under the Re-Configuration operations to transport pipeline quality oil. The gas spare capacity is 60 MMCFD subject to having the air permit limits reinstated to their original level. Utilization of this spare capacity could require transport of gas by some means other than the PANGL pipeline, if that line is used to send utility gas to the Point Arguello platforms. Consequently, the spare capacity for the Gaviota Facility is less under the "Design Configuration" operating strategy (i.e., when wet oil and gas are being sent to shore) than under the "Re-Configuration" operating strategy. In keeping with the COOGER study evaluation of the most restrictive capacity in determining spare capacities, the spare capacity associated with the Gaviota Facility used in this report is based on the wet oil and gas production projections and the Design Configuration operating strategy.

Key System Dependencies. Under the Re-Configuration, the system dependencies are essentially the same as described in the "Design Configuration" discussion above. However, it could take several months or more to obtain the approvals needed and to complete other activities associated with re-starting the operation of the onshore facilities.

Secondary Facilities. Under the Re-Configuration, there are no changes in the secondary facilities from those discussed above to the extent the products being sent to them are still being produced.

Future Facility Capacity. The Re-Configuration project does not alter the total quantity of oil or gas that could be recovered from the Point Arguello Unit. The owners/operator reports the Re-Configuration has decreased operating costs which may result in an extended project life. The operator has not provided current economics data; however, and an independent assessment of potential extension of the project life cannot be accomplished using the methodology applied in the COOGER study. Consequently, the information present under the Design Configuration is used to estimate the project lifetime.

2.4.3.4.3 Condition R-1 Review and Potential Future Operational Changes

As of August 1999, the Santa Barbara County Department of Planning and Development was preparing a Programmatic Environmental Impact Report (PEIR) to analyze possible options for the Gaviota Facility. The need for this review was triggered by Condition R-1 of the Facility's Final Development Plan. The Draft PEIR will analyze a number of project options, including a return to full facility operations; a limited operations scenario assuming non-configured operations with pad space available for potential future users; and the full abandonment of the facility, eliminating its status as a consolidated oil and gas processing site. The Santa Barbara County Department of Planning and Development expects to submit a recommended option to the Santa Barbara County Planning Commission in January 2000. Because this recommendation is not yet known, its effect on the future baseline conditions and different scenarios addressed in this report cannot be accurately predicted.

If the Gaviota Facility remains and is returned to use as a wet oil processing facility, there are several operating options that could be used. As described above, in the Re-Configuration wet oil from the Point Arguello platforms is processed offshore at the platforms to remove the water and pipeline quality (dry) oil is sent to shore in the existing PAPCO pipeline. Future operating options could include:

- installing a new oil pipeline to transport wet oil from the newly developed leases to the Gaviota Facility for processing while continuing to transport dry oil from the Point Arguello platforms through the existing PAPCO pipeline;

- installing temporary storage equipment at the Point Arguello platforms and/or the platforms associated with newly developed leases to allow the existing PAPCO pipeline to operate in "batch flow" (e.g., send a batch of dry oil from the Point Arguello platforms and then send a batch of wet oil from the new platforms);

- changing the operation of the Point Arguello platforms so that they produce wet oil rather than dry oil (i.e., Design Configuration) and then combining the wet oil from the Point Arguello platforms with the wet oil from the platforms associated with the newly developed leases and transporting the total flow in the existing PAPCO pipeline to the Gaviota Facility for processing; or,

- continuing to operate the Point Arguello platforms to produce dry oil and then combining it with wet oil from the platforms associated with the newly developed leases and transporting the total flow in the existing PAPCO pipeline to the Gaviota Facility for processing.

If the Gaviota Facility is not returned to use as a wet oil processing facility, then the options include:

- installing water removal equipment on the platforms associated with the newly developed leases and/or additional water removal equipment on the Point Arguello platforms, if necessary, so that the wet oil from the newly developed leases is also processed to pipeline quality (dry) oil offshore with the combined flow being transported to the Gaviota Facility in the existing PAPCO pipeline (this is comparable to the current Re-Configuration operating strategy, but Santa Barbara County staff comments on the draft COOGER report suggested that this option could face permitting obstacles related to their opinion that this option could increase the risk of an offshore oil spill); or,

- continuing to operate the Point Arguello platforms under the Re-Configuration Strategy and directing oil from the newly developed leases to an onshore location other than the existing Gaviota Facility (e.g., a different onshore location such as the Lompoc Oil & Gas Facility or to another facility located at the Gaviota Consolidation Site).

Options for processing the produced gas from the Point Arguello platforms and/or from platforms associated with newly developed leases include essentially the same options as for the wet oil. Examples of these options include: send sour gas through the PANGL pipeline to the Gaviota Facility for processing; installing equipment on the platforms to process the sour gas offshore and send sweet gas through the PANGL pipeline to the Gaviota Consolidation Site for connection to the utility company pipelines (including use of offshore sweetened produced gas as a fuel source for existing Point Arguello platforms and new offshore facilities, with transport of excess gas to shore in the PANGL pipeline); inject all gas into the offshore reservoir; and/or, install a new pipeline to shore, if needed, to accommodate two different types of gas or gas flow directions.

The various options described above and others that may be identified as the Santa Barbara County Condition R-1 review proceeds would all be subject to environmental review prior to implementation.

2.4.3.5 Molino Gas Plant

The Molino Project was approved by the Santa Barbara County Planning Commission prior to the start of the COOGER study and, as such, is included in the Future Baseline discussion. The SBCP&D "Offshore Oil and Gas Status Report" for December 1998, provides the following update on the project:

> Benton (the owner/operator) announced that the drill stem test for the Molino Project's first test well in the Gaviota offshore reservoir proved to be non-commercial and has been temporarily abandoned while the economic benefits of alternative production modes are studied. All of the temporary production test equipment and drilling rig have been removed from the drilling and production site and the only activities at the site are the ongoing site restoration and revegetation activities required by the County permit conditions of approval. At this time, Benton has not indicated when drilling operations will resume.

The following sections briefly describe the approved Molino Project. The information is based on the Molino Gas Project Final EIR, dated June, 1996; project updates in several SBCP&D "Oil & Gas Offshore Oil and Gas Status Reports", and conversations with Benton personnel in January 1999.

General. As approved, the Molino Project will generally involve drilling one or more wells into one or more subsea sweet gas deposits from an onshore drilling location at the Gaviota Consolidation Area. The actual equipment and operations may change during the course of developing the project due to various factors including what the status of the Gaviota Facility is at the time the Molino Gas Plant begins operations, and based on the characteristics and volume of production.

The Gaviota Consolidation Area is located near the coast along Highway 101 approximately 25 miles west of Santa Barbara in Santa Barbara County. The western portion of the area is occupied by the Gaviota Oil & Gas Processing Facility (section 2.4.3.4). A map showing the approximate location of the project area within the consolidation area boundary is shown in Figure 2.4-24.

The Molino Project is planned to be completed in phases with the maximum production of all phases being permitted at 60 MMCFD of gas by the Santa Barbara County Department of Planning and Development. The project is not permitted to produce oil; however, some liquids will be removed from the gas.

Offshore Flowlines/Pipelines. There are no offshore flowlines. The onshore wells are drilled into the offshore reservoirs.

Product Distribution. As proposed, the gas will be sold to the Southern California Gas Company using an existing meter station at the Gaviota Facility or through a new connection depending on factors at the time the Molino Gas Plant is constructed. The LPG separated from the gas will either be sent by pipeline to the storage and loading facility at the Gaviota Facility or new storage and loading systems will be installed.

Spare Capacity / Permit & Operating Limitations. Spare capacity is based on the project's permitted limit of 60 MMCFD. The actual design capacity of the equipment to be installed will depend on the quantity of gas the operator expects to be able to produce based on data that is still being developed. Geologic data available for review during the COOGER study analysis were consistent with maximum production rates of 60 MMCFD or more.

Key System Dependencies.

- The project will depend on the Gas Plant to process the gas.
- The project may depend on the LPG storage and/or loading facilities at the Gaviota Facility and/or the sales gas system at the Gaviota Facility.
- The Molino Facility could be designed and operated as a self-sufficient facility if Gaviota Facility connections are not commercially or technically viable.

Secondary Facilities. As stated, the Gaviota Facility may be used to store and/or load LPG.

Future Facility Capacity. Production estimates predict that the quantity of gas will increase during the first few years of the project to the maximum permitted level where they will stay for a few years and then begin to decline annually over the remaining life of the facilities. This should result in annually increasing spare processing capacity at the Molino Gas Plant.

The economic life of the Molino Gas Plant is projected to end by study year 2012, based on the assumption the project will move forward by 2001. When this facility becomes idle, it is assumed it will be removed. The loss of production from the Molino Gas Plant will reduce the quantity of gas entering the Southern California Gas Company's distribution system and the quantity of LPGs trucked from the Molino Gas Plant or the Gaviota Facility.

2.4.3.6 Gaviota Oil Terminal

General. The Gaviota Oil Terminal was constructed in 1987 and began operation in 1991. The Gaviota Oil Terminal is located on the ocean side of Highway 101 opposite the Gaviota Oil & Gas Processing Facility (Gaviota Facility). Oil processed at the Gaviota Facility is pumped to storage tanks at the Gaviota Oil Terminal where it is temporarily stored in tanks prior to being gravity fed or pumped into the AAPLP pipeline. The Gaviota Oil Terminal does not receive production directly from offshore and does not process any produced oil, gas or water. A plot plan of the Gaviota Oil Terminal is shown in Figure 2.4-26. A facility "profile" summary is provided in Appendix B.

Facility Description. The tank farm at the Gaviota Oil Terminal covers approximately 36 acres. As of September 1999, there are six storage tanks at the Gaviota Oil Terminal of which three are active and three are idle. The idle tanks are not currently in working condition, but could be put back into service after being repaired. The combined maximum capacity of the six tanks is 670,500 barrels, and capacity in the three operating tanks is approximately 360,500 barrels.

The loading of marine tankers at the Gaviota Oil Terminal was suspended February 1, 1994 and the offshore terminal facilities have been abandoned to the shoreline. Oil from the tank farm is currently gravity fed or pumped to the AAPLP Gaviota Booster Station, then on to the Gaviota Pump Station.

Spare Capacity / Permit & Operating Limitations. The spare capacity (ability to hold more oil) in the storage tanks varies with the production from the Gaviota Facility and the pumping rate of the AAPLP pipeline. No limitations were identified. No permit constraints were identified that would limit throughput to less than the design capacity. The Terminal's permit limits its use to the export of a maximum of 100,000 barrels per day (over a 60-day average) of petroleum.

Key System Dependencies.

- The storage tanks depend on oil from the Gaviota Facility and the AAPLP Pipeline System.

Secondary Facilities. Oil stored in the tanks at the Gaviota Oil Terminal is gravity fed or pumped into the AAPLP pipeline system (described in section 2.4.3.8).

2.4.3.7 Cojo Bay Marine Terminal

General. The Cojo Bay Marine Terminal is located near Point Conception and has been idle for several years. Pursuant to Santa Barbara County ordinance, the marine terminal is a non-conforming use and considered to be abandoned, as established by Section 35-161.4 of the County's Coastal Zoning Ordinance. In accordance with this designation, intensification or expansion of the current use would not be allowed, which effectively prohibits the resumption of marine loading activity at this site. When it operated, the marine terminal received oil from near-shore offshore wells and from an onshore oil field.

In addition to the marine terminal, there is an onshore facility nearby that processed the wet oil from the offshore wells and from the wells in the onshore oil field. The processing facility and associated dry oil storage tank are currently idle. These facilities are also subject to the non-conforming use designation previously discussed, and resumption of use is currently not allowed.

As of December 1998, UNOCAL had filed an application to formally decommission and abandon the Cojo Marine Terminal facilities. This proposal includes the removal of the marine terminal equipment at this location and restoration of the facility site. UNOCAL has not yet applied to decommission the Cojo Bay processing facility.

2.4.3.8 AAPLP Pipeline System

General. The All American Pipeline, L.P. (AAPLP) System extends from the Las Flores Pump Station at the Las Flores Canyon SYU Oil & Gas Processing Facility to the Gaviota area, via the Coastal Line. It also includes the feeder line which transports Gaviota facility crude oil from the Gaviota Oil Terminal to the AAPLP Gaviota Pump Station. From the AAPLP Gaviota Pump Station crude oil then travels north, via the "main line" into northern Santa Barbara County before turning east into San Luis Obispo County and Kern County. At its Sisquoc Pump Station, AAPLP can deliver crude oil to the Santa Maria Refinery via the Tosco pipeline system or to AAPLP's Pentland Pump Station. At Pentland, crude oil can be delivered to other pipelines for delivery to Bakersfield, Los Angeles, San Francisco, or McCamey in west Texas where it connects to the Texas pipeline distribution system for final destination in the Gulf Coast or mid-continent. Within the COOGER Study Region, the AAPLP "main line" is designed to transport up to 300,000 BPD of dry oil with an average gravity of 19 to 21 degrees API; however, the operator reports that it could transport up to 425,000 BPD if additional pump capacity were installed.

Construction of the 30-inch Mainline began on May 10, 1986 at the Cuyama River and ended in the fall of 1986; however, additional installation of the Remote Terminal Units and High-Point Vent, along with replacement of the pipeline at the Cuyama Fault crossing occurred throughout 1989. Construction of the Sisquoc Pump Station and appurtenances began during the fall of 1987 and ended in late 1990. Construction of the Gaviota Pump Station began during summer of 1988 and ended during summer of 1990. Construction of the Booster Pump Station began during summer of 1989 and ended during summer of 1990. Construction of the Coastal Segment began in August of 1990 and ended by January of 1991. The Las Flores Canyon Pump Station was completed in 1994.

The AAPLP pipeline system currently transports all of the oil produced from the Santa Ynez Unit and Point Arguello facilities. The overall pipeline system includes interfacility pipelines and pipelines that transport the crude oil out of the COOGER Study Region. A summary of these pipelines and the associated pump stations is provided in Appendix B. The AAPLP route is shown on Figure 2.4-27 which also shows the Central Subregion Product Distribution System.

Onshore Pipelines. This discussion focuses on the onshore oil pipeline segments comprising the overall pipeline.

The Gaviota Oil & Gas Processing Facility sends oil by pipeline to the storage tanks located at the Gaviota Oil Terminal. The AAPLP Booster Station is adjacent to these storage tanks. Oil from the Gaviota Oil and Gas Processing Facility can also be delivered directly to AAPLP's Gaviota Booster Pump Station.

The AAPLP Booster Station receives oil from the storage tanks and pumps it through a 24-inch diameter insulated pipeline to the AAPLP Gaviota Pump Station. The design capacity of this pipeline is 150,000 BPD.

Oil from the Las Flores Canyon SYU Oil & Gas Processing Facility Transportation Terminal is pumped by the AAPLP Pump Station to the outlet of the AAPLP Gaviota Pump Station via the 24-inch diameter insulated "Coastal Line" pipeline. This pipeline has a design capacity of 150,000 BPD.

Crude oil received into the Gaviota Pump Station from the Las Flores and Gaviota Booster Pump stations are combined and transported to the Sisquoc Pump Station via a 30-inch diameter, insulated pipeline (the "main line"). This main line has a design capacity of 300,000 BPD.

The Sisquoc Pump Station can send the oil through two different pipelines. One option is to send the oil to the Santa Maria Pump Station via the Sisquoc Pipeline (described below in the "Northern Pipeline System" section). The second option is to send the oil via the 300,000 BPD capacity, 30-inch diameter AAPLP main line to the Pentland Pump Station (outside the COOGER Study Region). At Pentland, located approximately five miles east of Maricopa in Kern County, the AAPLP main line connects to other pipelines and the oil can be sent to the Bakersfield, Los Angeles or San Francisco refineries, to Mojave, California for rail car deliveries to Los Angeles, or to West Texas for further deliveries to the Gulf Coast or mid-continent regions.

Facility Description. This section describes the pump stations along the AAPLP that facilitate shipment of offshore oil from the Central Subregion. Information on the pipelines and pump stations is summarized below and in Appendix B.

Las Flores Pump Station

The AAPLP Las Flores Pump Station is located adjacent to two 270,000 barrel storage tanks located at the Las Flores Canyon SYU Oil & Gas Processing Facility. Oil from these tanks is transferred to the pump station via a 24-inch diameter, buried delivery pipeline. The oil is injected into the 30-inch diameter “mainline” immediately downstream of the pumps at the Gaviota Pump Station, via the 24-inch diameter Coastal Line. This pipeline pump station has a design capacity of 150,000 BPD.

Gaviota Booster Station

The Gaviota Booster Station is located in the northeastern corner of the Gaviota Oil Terminal. AAPLP's Gaviota Booster Pump Station inlet piping is connected to two delivery valves located within the Gaviota Oil Terminal which allow for oil to be received either from the Gaviota Oil Terminal tanks or the Gaviota Oil & Gas Plant Facility. During periods when AAPLP is not receiving oil from the Gaviota Oil Terminal, delivery valves described above are in the closed position. When AAPLP's pumps are operating, crude oil flows in underground pump suction piping, through a strainer system and into the vertical can booster pumps. The booster pumps provide sufficient pressure (e.g., 30 to 60 PSI) to move the crude oil out of the Booster Station and into the 24-inch feeder line pipeline which extends about 1,850 feet north into the meter/strainer system at the Gaviota Pump Station described below. This pipeline has a design capacity of 150,000 BPD and was operating at approximately 52,000 BPD as of May 1995. AAPLP transported about 30,000 BPD from the Gaviota Oil and Gas Processing Facility in June 1997, and averaged approximately 26,750 BPD in December 1998.

Gaviota Pump Station

The Gaviota Pump Station is located on the northeastern edge of the Gaviota Oil and Gas Processing Facility. The discharge piping of the Station receives crude oil originating from the Las Flores Pump Station via the 24-inch diameter Coastal Line and from the Gaviota Booster Pump Station via the 24-inch diameter "feeder" pipeline. Crude oil received from the Las Flores Pump Station enters the Gaviota Pump Station downstream of the pumps.

Crude oil received from the Gaviota Booster Station enters the Gaviota Pump Station at the meters/strainers. Once metered, the crude oil is routed to the suction header of the pumps and is discharged through the station control valve where it is commingled with the incoming crude oil stream from the Las Flores Pump Station and injected into the 30-inch diameter "main line" pipeline, via the scraper launcher system.

The Gaviota Pump Station has a design capacity of 150,000 BPD and AAPLP’s “mainline” pipeline has a design capacity of 300,000 BPD. Production from the Las Flores Canyon and Gaviota Facilities was approximately 160,000 BPD in May 1995, but had decreased to approximately 120,000 BPD in June 1997, slightly less than 100,000 BPD in June 1998, and 91,000 BPD in December 1998.

Sisquoc Pump Station

The Sisquoc Pump Station is located about 15 miles southeast of Santa Maria, California and approximately 5 miles northeast of Sisquoc, California. It is situated north of the Sisquoc River at the base of the Sierra Madre Mountain foothills and range. The Sisquoc Pump Station receives commingled crude oil from the Las Flores Canyon SYU and Gaviota Oil & Gas Processing Facilities via AAPLP's 30-inch diameter main line pipeline. Crude oil can be delivered to the Tosco Sisquoc pipeline connection for transport to the Santa Maria Pump Station, and/or into the 30-inch main line for continued shipment east toward the Pentland Pump Station in Kern County. The Sisquoc Pump Station has a design capacity of 300,000 barrels per day.

Product Distribution. As described above, all of the offshore oil processed by the Las Flores Canyon SYU and Gaviota Oil & Gas Processing Facilities is transported by the AAPLP Pipeline System. The oil can be routed to the Santa Maria Refinery in the northern subregion, to refineries in the Los Angeles or San Francisco areas, and to west Texas for further shipment to the Gulf Coast or mid-continent. In addition, the AAPLP main line connects to the Central California pipeline system which connects to the Bakersfield refinery area.

The AAPLP serves as the primary method for transporting NGLs from Santa Barbara County because the facilities that use the AAPLP pipeline are able to blend the heavier NGL fractions and butane into the crude oil, subject to the operating specifications of the pipeline system, rather than shipping these materials by truck. Propane (LPG) is the only NGL product routinely shipped by truck. The AAPLP, and the facilities that use the pipeline, are obligated by their Final Development Plan conditions to maximize the shipment of NGLs through the AAPLP pipeline.

Spare Capacity/Limits. As described above, the actual throughput of the AAPLP is substantially less than the design capacity. Consequently, the pipeline capacity is not expected to constrain the quantity or the type of oil that can be shipped assuming the characteristics of the crude oil mixture is similar to that currently being produced. There is potential that some of the heavy oil that could be produced from the undeveloped offshore Santa Maria Basin leases may not meet the pipeline operating specifications.

The concept of spare capacity for the AAPLP pipeline also needs to consider the ability of the system to handle oil blended with NGLs. Condition P-10 of the AAPLP permit requires that NGLs be blended into the crude to the extent feasible within technical and legal constraints. However, one of the technical limitations limits true vapor pressure to less than 11 psig when the oil is in floating roof tanks and as such, this limits the amount of butane that can be blended.

Key System Dependencies. As described above, each facility relies on the pipeline system, including the pump stations, to transport the oil to market. Any significant loss of part of this system could constrain production from one or more of the facilities depending on where the problem occurred and the duration of such an event.

Future Facility Capacity. Because most of the pipelines and pump stations described handle oil from multiple facilities, it is unlikely that the pipelines will be abandoned during the period 1995-2015. If pipelines fail and cannot be replaced or are no longer needed, it is expected that they would be flushed clean and left in place or otherwise managed in accordance with applicable agency requirements, if any.

2.4.3.9 Support Facilities

The only support facility in the Central Subregion is the Ellwood Pier which is located west of the Ellwood Oil & Gas Processing Facility. The Ellwood Pier is owned by Venoco and operated as an industrial support facility. It is not used by the public. Equipment on the pier has light lifting capabilities. The pier is used to transfer personnel and light supplies onto crew boats and work/supply boats. Onshore, there is a small supply storage area and parking lot for industry personnel. The crew boats using the Ellwood Pier primarily serve Platform Holly and other platforms west of Santa Barbara.

2.4.4 Northern Subregion

As of August 1997, the only onshore facility located in the Northern Subregion that processes oil, gas, and/or produced water directly from offshore reserves is the Lompoc Oil & Gas Processing Facility. Figure 2.4-28 shows the location of this onshore facility and shows the offshore field and platform from which it receives production. The Santa Maria Refinery is also located in the Northern Subregion, but it can only receive offshore oil after it has been treated by the Lompoc Oil & Gas Processing, Gaviota, or Las Flores Canyon facilities.

As stated in Section 2.3, the projected future production from the Point Pedernales Field is in a state of decline and consequently, the Lompoc Oil & Gas Processing Facility is currently processing less oil and/or gas than it was designed to process. The facility is projected to have increasing spare capacity during the period 1995 to 2015. Table 2.4-9 lists the wet oil design capacity, permitted capacity, and projected spare capacity for the Facility at 5-year increments during the period 1995-2015. Table 2.4-10 lists the gas design capacity, permitted capacity, and projected spare capacity for the Facility at 5-year increments during the period 1995 to 2015. Spare capacity information related to gas or other streams is discussed in Appendix B. Figure 2.4-29 shows the projected wet oil design and permitted spare capacity for the Northern Subregion, as a whole, at 5-year increments during the period 1995-2015. Figure 2.4-30 shows the projected wet oil design and permitted spare capacity for the Northern Subregion, as a whole, at 5-year increments during the period 1995-2015.

More detailed information on the operation and characteristics of each facility in the Northern Subregion is provided below.

Table 2.4-9
Wet Oil Processing Spare Capacity - Northern Subregion

Facility	Design Capacity (BPD)	Permitted Capacity (BPD)	Spare Capacity (BPD)[1]					Comments
			1995	2000	2005	2010	2015	
Lompoc Oil & Gas Processing Facility	80,000	36,000[2]	17,600	19,726	80,000	-	-	Design Spare Capacity is based on total fluid input and Permitted Spare Capacity is based on dry oil produced.
Northern Subregion Totals	80,000	36,000[2]	17,600	19,726	80,000	-	-	

Note: [1] Table entries record the limiting capacity minus the actual oil processed during the year indicated. If no production is projected for an entire 5-year period, a dash is entered at the end of that period to reflect the potential shutdown or the potential decommissioning of the onshore facility during that period.

[2] Permitted capacity is limited to 36,000 BOPD dry oil output.

Table 2.4-10
Gas Processing Spare Capacity - Northern Subregion

Facility	Design Capacity (MCFD)	Permitted Capacity (MCFD)	Spare Capacity(MCFD)[1]					Comments
			1995	2000	2005	2010	2015	
Lompoc Oil & Gas Processing Facility	15,000	15,000	11,411	13,608	15,000	-	-	
Northern Subregion Totals	15,000	15,000	11,411	13,608	15,000	-	-	

Note: [1] Table entries record the limiting capacity minus the actual oil processed during the year indicated. If no production is projected for an entire 5-year period, a dash is entered at the end of that period to reflect the potential shutdown or the potential decommissioning of the onshore facility during that period.

2.4.4.1 Lompoc Oil & Gas Processing Facility

General. The Lompoc Oil & Gas Processing Facility (also commonly referred to as the Lompoc HS&P Facility) receives wet oil and gas from Platform Irene in the Point Pedernales Unit. The Lompoc Oil & Gas Processing Facility is located approximately 400 feet east of Harris Grade Road approximately five miles north-northeast of Lompoc in Santa Barbara County. A system schematic for the Lompoc Oil & Gas Processing Facility is shown in Figure 2.4-31 and a plot plan is shown in Figure 2.4-32. A facility "profile" summary is provided in Appendix B.

Construction of onshore components, including the Lompoc Oil & Gas Processing Facility, Orcutt Pump Stations, and onshore pipelines (landfall to Lompoc Oil & Gas Processing Facility, and Lompoc Oil & Gas Processing Facility to Orcutt Pump Station) commenced July 15, 1986. Construction of the Orcutt Pump Station and Pipeline from Lompoc Oil & Gas Processing Facility to Orcutt Pump Station ended January 15, 1987. Construction of Lompoc Oil & Gas Processing Facility and pipeline from landfall to Lompoc Oil & Gas Processing Facility ended April 1, 1987.

Process operations at the Lompoc Oil & Gas Processing Facility include: oil treatment; gas treatment; produced water treatment; and oil reclamation, storage and shipment. The incoming wet oil is separated using heat exchangers, separators, free water knockouts, heater-treaters, and various storage tanks.

The Lompoc Oil & Gas Processing Facility was designed to process 80,000 barrels of wet oil per day and was processing approximately 68,000 barrels of wet oil per day (approximately 11,000 barrels of oil and 57,000 barrels of water) as of August 1997. The facility's permit limits it to 36,000 barrels per day of dry oil (product). The Lompoc Oil & Gas Processing Facility was designed to facilitate expansion and the site is a Santa Barbara County approved "consolidation area". It was constructed with pads, which would support expansion to 100,000 barrels of wet oil per day.

As of August 1997, the incoming gas was being dehydrated at the Lompoc Oil & Gas Processing Facility and disposed of into onsite injection wells. By mid-1998, the construction of a new 15 MMCFD gas plant was complete and the treated gas is being sold to the local gas utility. Produced water is treated in tanks and is then injected into nearby disposal wells in the Lompoc oil field.

Offshore Flowlines/Pipelines. Production from Platform Irene is sent to the Lompoc Oil & Gas Processing Facility in a 20-inch diameter wet oil pipeline and an 8-inch diameter sour gas pipeline. There is an 8-inch diameter pipeline between the platform and the processing facility that is not in use, which was originally installed to transport treated produced water to Platform Irene for discharge to the ocean. This pipeline could be converted to a spare wet oil or gas pipeline, provided adequate modifications are made. Because the Lompoc Oil & Gas Processing Facility is located inland, these pipelines have an onshore segment that is approximately 12 miles long.

Product Distribution. After treatment, the oil is stored in tanks and then pumped into a pipeline that goes to the Orcutt Pump Station, then to the Summit Pump Station and then to the Santa Maria Refinery (see the "Northern Pipeline System" discussion below). Since the new 15 MMCFD gas plant has become operational, the heavier NGLs are blended into the crude oil. Propane (LPG) and sulfur are shipped offsite by truck. Gas is sold to the local gas utility company via a 12-inch, 7.5-mile-long pipeline with a design capacity of 30 MMCFD and a permitted capacity of 15 MMCFD.

Information on the oil distribution pipeline is provided on a sub-regional level in the Northern Pipeline System discussion in Section 2.4.4.4, the regional level in the product distribution system discussion in Section 2.5.1, and at the facility level in the corresponding Facility-specific table in Appendix B. In addition, Section 2.5.1 includes a diagram of the principal local and regional pipeline connections and information on which pipelines are proprietary and which are common carriers.

Spare Capacity / Permit & Operating Limitations. Spare capacity information is summarized in Appendix B. Although the Lompoc Oil & Gas Processing Facility is designed to process up to 80,000 BPD of wet oil, it has a permit limit of 36,000 BOPD (dry oil) which, depending on the water fraction of the wet oil, could limit throughput. As of August 1997, the facility was permitted to process and reinject up to 9.205 MMCFD. With the recent gas plant expansion to 15 MMCFD, gas reinjection has been discontinued except during upset conditions. Under these conditions, injection is limited to 9.205 MMCFD. The current 15 MMCFD capacity has been used to determine gas plant spare capacity in this analysis.

The Lompoc Oil & Gas Processing Facility is permitted to receive oil from OCS leases P0441, P0437, P0438 and P0440. The facility is permitted to receive gas from these four OCS leases and from the Lompoc onshore fields.

Key System Dependencies.

- The Lompoc Oil & Gas Processing Facility depends on the downstream oil pipeline distribution system (see discussion of "Northern Pipeline System" below).

Secondary Facilities. There are numerous secondary facilities located north of the Lompoc Oil & Gas Processing Facility including the Santa Maria Refinery and the "Northern Pipeline System" described in the sections below.

Onshore Pipelines

The 20-inch diameter wet oil pipeline and 8-inch diameter sour gas pipeline from Platform Irene come onshore at Vandenberg Air Force Base (VAFB) north of the mouth of the Santa Ynez River and travel approximately 12 miles onshore to the Lompoc Oil & Gas Processing Facility. Treated natural gas is transported to the local gas utility via a 12-inch diameter, 7.5-mile-long onshore pipeline. Treated crude oil is sent to the Santa Maria Refinery via the Tosco pipeline system, as described in Section 2.4.4.4.

Future Facility Capacity. Production estimates predict that the quantity of wet oil and gas produced from the platform and processed at the Lompoc Oil & Gas Processing Facility will decline annually over the remaining life of the facilities. This should result in annually increasing spare processing capacity at the Lompoc Oil & Gas Processing Facility.

Based on historic production and estimated economically recoverable reserve data for the platform, the economic life of the Lompoc Oil & Gas Processing Facility is projected to end by study year 2005. When the platform, Lompoc Oil & Gas Processing Facility and associated pipelines become idle, it is assumed that they will be removed except for some flowlines which may be abandoned in place. The loss of production from the Lompoc Oil & Gas Processing Facility will increase the available capacity in the Tosco pipeline system north of the Lompoc Oil & Gas Processing Facility, the Santa Maria Refinery and possibly other facilities in northern Santa Barbara County and San Luis Obispo County as described in Section 2.4.4.4. Loss of the gas processed at the Lompoc Oil & Gas Processing Facility will result in less gas entering the Southern California Gas Company's distribution system.

2.4.4.2 Santa Maria Asphalt Refinery

General. The Santa Maria Asphalt Refinery (SMAR) was constructed in the 1930s and has been operated intermittently since that time. It most recently restarted operation on June 2, 1996 at a maximum throughput of 10,000 barrels of crude oil per day, including a truck transportation facility. A plot plan for the SMAR is provided as Figure 2.4-33. A facility "profile" summary is provided in Appendix B.

As of mid-1997, the SMAR currently had 21 company employees and 2 contract labor hires in addition to the approximate 25 truck drivers and 5 contract mechanics. If the facility were to operate at permitted capacity, facility employment could increase to 30 full time personnel and 40 drivers.

Onshore Pipelines. The SMAR does not receive feedstocks or send products by pipeline. Feedstocks are received by truck and products are transported by truck, but could also be transported by rail, if desired.

Facility Description. The SMAR receives approximately 5,000 BPD of heavy crude from several different nearby onshore fields and from the onshore San Ardo Field in Monterey County. This oil is delivered by truck only and offloaded at the facility for processing. Although currently not in use, the facility is connected to a rail spur giving it the capability to ship and/or receive materials by rail as well as by truck.

The refinery separates the heavy fractions of the crude from the distillates at a rate of about 125 barrels per hour in a multi-stage process using heat and vacuum fractionation. Approximately 35 percent of the input/output is in the form of distillates. The remaining products are asphalt and emulsion asphalt which is used for surface cover (paving).

The site includes storage capabilities consisting of a 35,000 barrel distillate tank, a 117,000 barrel crude storage tank, a 325,000 barrel asphalt tank used for winter storage, and approximately 80,000 barrels of heated storage for the asphalt products. All the products currently leave the facility via trucks: asphalt to customers batch plants; distillates to oil fields as diluent; and asphalt emulsion sold to customers.

Product Distribution. As of August 1997, all products were distributed by truck to local and non-local markets.

Spare Capacity / Permit & Operating Limitations. The SMAR has a baseline spare capacity of up to 5,000 barrels per day of heavy crude oil. The facility operator indicated that factors impacting the throughput of the facility include:

- If San Miguel crude were available, the SMAR could process up to 15,000 BPD with modification to the fractionation process and increasing the permitted allowable throughput;
- improve fractionation capabilities and permitted allowable throughput.

Specific permit limits could limit throughput depending on operating conditions.

Key System Dependencies. The SMAR is dependent on the availability of good feedstocks, a market for its products, and sufficient trucks to deliver these materials.

Secondary Facilities. The SMAR appears to be self-sufficient and does not rely on other offshore-oil related facilities for feedstocks or the distribution of products. Similarly, it does not compete for space in any pipelines.

Future Facility Capacity. Because the SMAR does not receive production from offshore activities and is not an integral part of the offshore-oil-related processing and distribution system, a future baseline analysis was not conducted.

2.4.4.3 Santa Maria Refinery

General. The Santa Maria Refinery is located on an approximately 100-acre site within a 1789-acre property owned by the refinery operator on the Nipomo Mesa about 8 miles north of the City of Guadalupe in southwestern San Luis Obispo County. Heavy crude oil from the Summit Pump Station can be pumped by pipeline to the Santa Maria Refinery for upgrading. The Santa Maria Refinery upgrades low gravity heavy crude oil by atmospheric and vacuum separation and produces semi-refined crude, petroleum coke and sulfur. A plot plan and a simplified flow diagram of the Santa Maria Refinery are shown in Figures 2.4-34 and 2.4-35, respectively. Adjacent to the refinery is the Tosco Carbon Plant which processes the coke and sulfur byproducts from the refinery. A facility "profile" summary is provided in Appendix B.

Onshore Pipelines. The Santa Maria Refinery does not receive any oil or gas directly from an offshore source but it can receive treated crude from the onshore facilities that process oil from Pt. Pedernales, Pt. Arguello, and the Santa Ynez Unit. The heavy crude is received by pipeline from the Summit Pump Station which is part of the "Northern Pipeline System" (described in Section 2.4.4.4). This crude is typically a mixture of offshore crude from the AAPLP Pipeline, via the Sisquoc Pipeline, and offshore crude from the Lompoc Oil & Gas Processing Facility (via Orcutt Station and Suey Junction). The Santa Maria Refinery can also receive oil produced from onshore fields. Pipelines leaving the Refinery go to the Summit Pump Station and to a pipeline north of the Avila Pump Station as summarized in the discussion for the Northern Pipeline System.

Facility Description. The crude oil is processed through vacuum distillation towers, a delayed coking unit and other refining process equipment in order to produce partially-refined oil products, sulfur, and petroleum coke. The straight run gas oil from the crude unit, the light and heavy gas oil from the vacuum unit and the light and heavy gas oil from the coker unit are blended and placed in storage tanks in preparation for transfer. Gas-fired equipment is used to provide heat to the various streams and equipment.

When operating at permitted capacity (44,440 barrels of oil per day on an annual average basis), the refinery produces approximately 16,000 barrels of naphtha, 23,100 barrels of gas oil, 91 long tons of sulfur, and 1,400 tons of petroleum coke. Approximately 10.2 MMCFD of fuel gas is produced and is consumed onsite.

Product Distribution. The partially-refined oils are sent offsite by pipeline as discussed in the Northern Pipeline System discussion (below). The sulfur is sent offsite by truck primarily for use in the agricultural industry. The petroleum coke is sent offsite by truck and by rail.

Spare Capacity / Permit & Operating Limitations. The facility typically operates at approximately 95 percent of its design capacity and, as such, has little spare capacity. The refinery is limited in its ability to expand given permit limitations and the need for voter approval under San Luis Obispo Policy 1A in the County's Local Coastal Program. As of August 1997, no plans to expand had been identified.

Key System Dependencies

- The supply of crude is dependent on the Summit Pump Station, AAPLP Pipeline System, and the Northern Pipeline System.

- The facility operation and throughput of specific product is also dependent on the specification requests from the receiving refineries in the San Francisco Bay area.

Secondary Facilities. Secondary facilities include components in the Northern Pipeline System, and refineries located in the San Francisco Bay area.

Future Facility Capacity. Because the SMR does not receive production directly from an offshore source, a baseline projection analysis was not conducted. The SMR receives offshore production from the Point Pedernales Field (processed by the Lompoc Oil & Gas Processing Facility), the Santa Ynez Unit (processed by the Las Flores Canyon SYU Oil & Gas Processing Facility) and the Point Arguello Unit (processed by the Gaviota Oil & Gas Processing Facility). In addition, the SMR receives crude from onshore oil fields.

The production from the Point Pedernales Field and Point Arguello Unit is expected to decline annually during the remaining economic life of these facilities which is expected to be by 2005. The production from the Santa Ynez Unit is projected to decline annually throughout the remainder of the 1995 to 2015 period. The projected declines in offshore production could result in a decrease in feedstock to the SMR from these sources, but total oil production from the Santa Ynez Unit would exceed the current Santa Maria Refinery average daily crude oil input throughout the COOGER study period. A decline in feedstock from offshore sources could be offset by an increase from onshore sources. Consequently, it is uncertain whether the spare capacity of the SMR would increase during the remainder of the period 1995 to 2015. Based on information available as of August 1997, the SMR is projected to continue operation during the remainder of the 1995 to 2015 period.

2.4.4.4 Northern Pipeline System

This section describes the primary pipeline system serving the Lompoc Oil & Gas Processing Facility and other facilities in the Northern Subregion. The text describes the "typical" configuration and operation of the system, but also identifies recent changes that have taken place as a result of the Avila Pump Station being taken out of service in February 1998 and the decommissioning of the Avila Pump Station, Marine Terminal and Tank Farm.

The removal of the Avila Pump Station resulted in the disconnection of the pipelines through the pump station and the need to re-route crude oil and/or partly refined oil that otherwise would have been sent through the Avila Pump Station. As of January 1999, the pipeline operator indicated there are currently no plans to construct a new pump station to replace the Avila Pump Station and no plans to reconnect the pipelines through the pump station; however, a pipeline right-of-way will be maintained in the event a business need warrants reconnection of the pipelines.

General. The oil from the one onshore processing facility (Lompoc Oil & Gas Processing Facility) located in the Northern Subregion is transported to market using pipelines. The discussion is organized to describe how oil moves northward from the Lompoc Oil & Gas Processing Facility. The overall pipeline system includes intra-facility pipelines and pipelines that transport the products out of the COOGER Study Region. Figure 2.4-36 shows the product distribution system for the Northern Subregion including the location of these pipelines. A summary of these pipelines and the associated pump stations is provided in Appendix B.

The primary pipeline system is operated by Tosco. The pipeline operator currently employs 12 company personnel for "Line 300," which includes the pipelines from Sisquoc to the Santa Maria Refinery, the pipeline from the Lompoc Oil & Gas Processing Facility to the Santa Maria Refinery, and the pipeline from the Summit Pump Station to the location of the former Avila Pump Station and on to the north. The pipeline operator employs 11 company personnel for "Line 400," which transports products from the Santa Maria Refinery on to the north.

Onshore Pipelines. This discussion focuses on the onshore oil pipelines. As of August 1998 the gas produced by the Lompoc Oil & Gas Processing Facility was being processed through a new gas plant and was being sold to the local gas utility company via a 12-inch diameter, 7.5-mile-long pipeline. The remainder of this section describes the oil and refined product pipelines in the Northern Subregion that transport offshore oil. Most of these pipelines are also used to transport oil from onshore sources.

The transport of oil from the Lompoc Oil & Gas Processing Facility to the Santa Maria Refinery is accomplished via a Tosco-owned pipeline system. This transport is limited by Santa Barbara County permit conditions to 36,000 barrels per day (BPD). The design capacity of different components of this system would allow higher flow rates without modification. Pump station capacities are generally the limiting features in the design capacity of this pipeline system, and include:

- Lompoc Facility Station (43,200 BPD)
- Orcutt Station (44,000 BPD); and,
- Summit Station (72,000 BPD).

The pipeline segments of this system and their design capacities are:

- Lompoc Facility to Orcutt Station, 12-inch diameter pipeline (96,000 BPD at 800 psig);
- Orcutt Station to Suey Junction, 8-inch diameter pipeline (50,400 BPD at 800 psig);
- Suey Junction to Summit Station, two pipelines including an 8-inch diameter pipeline (24,000 BPD at 800 psig) and a combination of 10-inch and 12-inch pipe (84,000 BPD at 800 psig but limited by permit conditions to 40,000 BPD); and,
- Summit Station to Santa Maria Refinery, 10-inch diameter pipeline (72,000 BPD at 800 psig).

Another element of the Northern Subregion pipeline system accommodates transport of oil from the AAPLP mainline at the Sisquoc Station to the Santa Maria Refinery via Suey Junction. This system is limited by permit conditions to a maximum throughput of 40,000 BPD at 800 psig. Flow is allowed from the AAPLP pipeline at Sisquoc to Summit Station (via Suey Junction), but not in the reverse direction. The design capacity of different components of this system is limited by pump station capacities, which include:

- Sisquoc Station (36,000 BPD);
- Santa Maria Station (38,400 BPD), this station is generally bypassed by some or all oil transported from Sisquoc resulting in an additive effect on total oil pumping input to pipelines downstream of the Santa Maria Station; and
- Summit Station (the same station as described above in connection with the Lompoc Oil and Gas Processing Facility, capacity 72,000 BPD).

The pipeline segments of this system and their design capacities are:

- Sisquoc Station to Santa Maria Station, 12-inch diameter pipeline (50,400 BPD at 1,000 psig);
- Santa Maria Station to Suey Junction, combination of 10-inch and 12-inch pipe (120,000 BPD at 800 psig); and

- Suey Junction to Santa Maria Refinery via Summit Station, same pipelines as discussed above in connection with the Lompoc Oil and Gas Processing Facility crude oil transport.

From the Santa Maria Refinery, "gas oil" or pressure distillate is moved through an 8- to 12-inch diameter, unheated pipeline to a connection with two 8-inch diameter pipelines near the City of San Luis Obispo. These pipelines transport this product northward to the Tosco Rodeo Refinery in the San Francisco Bay area. The design capacity of the 8- to 12-inch diameter pipeline is 36,000 BPD at a pressure of 1,000 psig. The design capacity of each of the two 8-inch diameter pipelines is 28,800 BPD.

Historically, the Santa Maria Refinery could send pressure distillate and "gas oil" through an 8-inch diameter, unheated pipeline to the Summit Pump Station from which it could be pumped to the Avila Pump Station. From the Avila Pump Station, two 8-inch diameter pipelines connect to the pipelines discussed above which transport product northward to the San Francisco Bay area. The pipeline from the Santa Maria Refinery to Summit Station has a design capacity of 41,000 BPD at a pressure of 1,000 psig. As of February 1998, the pipeline was idle and pipelines at the former Avila Pump Station had been disconnected from the northbound dual 8-inch pipeline which continues to the San Francisco Bay area. Reconnection of these pipelines would involve only minor construction effort.

Facility Description. This section describes the pump stations, identified above, that are on the main pipeline transporting offshore oil to facilities in the Northern Subregion and in the San Francisco Bay area. The Lompoc Oil & Gas Processing Facility, Santa Maria Refinery, and Santa Maria Asphalt Refinery are described in Section 2.4 above.

The Orcutt Pump Station has a design capacity of approximately 44,000 BPD. Facilities at the Orcutt Pump Station consist of heaters, a storage tank, and two 250-horsepower pumps. At the Orcutt Pump Station, the Point Pedernales crude is heated and mixed with lighter gravity crude produced onshore from the Lompoc and/or Orcutt area to be able to pump it to the Summit Pump Station.

The Summit Pump Station receives oil from the Orcutt and Santa Maria Pump Stations and could receive "gas oil" from the Santa Maria Refinery. The Summit Pump Station can send crude oil to the Santa Maria Refinery and previously could send "gas oil" to the former Avila Pump Station as described above. The Summit Pump Station has a design capacity of approximately 72,000 BPD.

Historically, oil from the Summit Pump Station could be routed to two locations. It could be pumped through a 10-inch diameter pipeline to the Santa Maria Refinery for upgrading or it could be pumped through a 12-inch diameter pipeline to the Avila Pump Station. Since February 1998, it can only be sent to the Santa Maria Refinery.

At the Santa Maria Pump Station, the oil received from the AAPLP Sisquoc Pump Station can enter an 80,000 barrel storage tank where it would be blended with onshore Santa Maria Valley crude or it can bypass the Santa Maria Pump Station. The Santa Maria Pump Station sends oil to the Suey Junction as described above. The Santa Maria Station has a design capacity of 38,400 BPD, and the Sisquoc Station has a design capacity of 36,000 BPD. Because the system is designed to operate with oil from Sisquoc by passing the Santa Maria Station pumps, pipelines downstream of the Santa Maria Station may receive inputs greater than the Santa Maria Station pumping capacity.

Product Distribution. As described above, oil from Point Pedernales (via the Lompoc Oil & Gas Processing Facility) and some oil from the Santa Ynez Unit and Point Arguello Unit, are transported by pipeline to the Santa Maria Refinery (historically the oil could also have been sent to facilities in the San Francisco Bay Area using pipelines through the former Avila Pump Station). In addition, some refined products from the Santa Maria Refinery are transported by pipeline as described above. As of August 1998, the natural gas handled at the Lompoc Oil & Gas Processing Facility was being processed and sold to the local gas utility company.

As of August 1997, the pipeline from the Santa Maria Refinery to the former Avila Marine Terminal had been disconnected.

Spare Capacity/Limits. The design and pumping capacity data provided by the pipeline operators was not of sufficient detail to make spare capacity assessments of the distribution system. However, the data provided combined with the historical peak production indicates that most of the peak production periods showed oil quantities well in excess of the current production levels. The current pipeline infrastructure in the Northern Subregion is not expected to constrain the production estimated in the future baseline projection.

Key System Dependencies. As described above, each facility relies on the pipeline system, including the pump stations, to transport the oil to other facilities in the Northern Subregion or to facilities in the San Francisco area. Any significant loss of part of this system could constrain production from one or more of the facilities depending on where the system constraint occurred. In addition, in several of the pipelines, the offshore production must "share" space with oil produced onshore. If there were significant increases in onshore production, it could constrain offshore production.

Secondary Facilities. The description of the pipelines and pump stations shows the relationship between them and identifies which ones are "secondary" to any individual pipeline or pump station.

Future Facility Capacity. Because most of the pipelines and pump stations described handle oil from multiple facilities and/or handle oil produced from onshore in addition to offshore production, it is unlikely that the pipelines will be abandoned during the period 1995-2015. If pipelines fail and cannot be replaced or are no longer needed, it is expected that they would be decommissioned and abandoned in accordance with requirements of the California State Fire Marshall's Office of Pipeline Safety and U.S. Department of Transportation.

2.4.4.5 Support Facilities

The only support facility in the Northern Subregion is the Avila Pier which is located at the Avila Beach Marine Terminal and is owned and operated by Unocal: it is not used by the public. As of August 1997, Unocal's pier was not being used to provide support services to offshore oil activities and no plans for such use were identified. If future use of the Unocal pier to support offshore oil activities is proposed, then it is likely a new Coastal Development Permit (CDP) review would be required along with voter approval pursuant to San Luis Obispo County Measure A.

2.5 PUBLIC AND INDUSTRIAL TRANSPORT INFRASTRUCTURE AND REFINERIES

The intrastate and interstate distribution of oil, gas and other products produced from the offshore leases may involve the use of pipelines, trucks, railroads, and marine vessels; however, not all of the onshore facilities have the ability to use all of these options. This section provides an overview of the intrastate and interstate distribution systems used to transport the offshore oil to refineries and the gas to sales. Figure 2.5-1 provides an overview of the entire Study Region showing the location of the onshore facilities and the primary product distribution system. Figures 2.5-2, 2.5-3, and 2.5-4 show the product distribution system for the Eastern, Central and Northern Subregions, respectively.

In addition to the transport of products, offshore oil activities place demands on public transportation infrastructure associated with the transportation of materials, supplies, and solid wastes associated with offshore exploration, development drilling, and routine operations of offshore and onshore facilities. Employment associated with these activities also generates commuter traffic on public roadways. A general description of the public and private infrastructure used by the offshore oil industry is presented below.

2.5.1 Industrial Transport Infrastructure

Pipelines are the primary means used to transport oil and gas within the COOGER Study Region, other parts of California, and interstate. In general, oil is the primary liquid product transported by pipeline; however, some facilities blend NGL into the oil and some partially refined products are sent by pipeline from the Santa Maria Refinery. Under normal operations, the produced natural gas is transported exclusively by pipeline. With the exception of the Mandalay Onshore Separation Facility and the West Montalvo Operations which sell gas to an adjacent power plant, the facilities transfer the gas to local utility company pipelines at the facilities. Consequently, there are essentially no onshore product gas pipelines operated by the offshore oil and gas industry. Information obtained from The Gas Company representatives did not identify specific limitations on the maximum quantity of gas that could be accepted from the facilities into The Gas Company's distribution system.

2.5.1.1 Local Area Pipelines

All three subregions have numerous local gathering and distribution pipelines operated by several different companies, but with the exception of some common connections to the All American Pipeline, L.P. (AAPLP) pipeline, described as the "All American Pipeline, L.P. (AAPLP) System" in Section 2.4.3.8 and the Tosco pipelines described as the "Northern Pipeline System" in Section 2.4.4.4, there are no inter-subregion connections and generally, few inter-company connections. Also, there are no pipeline connections in the Tri-County area that link offshore-related facilities northwest of Santa Barbara (in the Central and Northern Subregions) with offshore-related facilities southeast of Santa Barbara (in the Eastern Subregion). This general lack of interconnections limits the distribution options available to many of the processing facilities. The transportation of the offshore crude produced in the Study Region is also complicated by the fact that most of it is heavy and contains relatively high concentrations of sulfur. Sometimes this high-viscosity, high-sulfur (HVHS) type crude must be heated or blended with a lighter crude or diluent to make it easier to pump by pipeline.

During the past decade, several pipelines have been proposed to transport crude out of Santa Barbara County. One pipeline has actually been built. The AAPLP pipeline allows shipment of crude from the Las Flores Canyon and Gaviota areas in Santa Barbara County to refineries in the Bakersfield, Los Angeles and San Francisco areas, west Texas and Texas Gulf, Louisiana and the mid-continent. An intermediate tie-in at the Sisquoc Pump Station in northern Santa Barbara County makes it possible to divert crude to the Tosco Pipeline system ("Northern Pipeline System") and similar tie-ins at the AAPLP Pentland and Emidio Pump Stations makes it possible to divert crude to the Los Angeles area refineries. Tie-ins at Pentland in Kern County also make it possible for crude to be sent to the Bakersfield and San Francisco Bay area refineries. Pacific Pipeline completed the installation of a 20-inch diameter, 130,000 barrels per day capacity pipeline from Emidio to Los Angeles in March 1999. This pipeline adds pipeline capacity to transport oil from Kern County to the Los Angeles area and provides an alternative to the use of unit trains or marine tankships and barges.

2.5.1.1.1 Eastern Subregion Pipelines

The pipelines in the Eastern Subregion are described in Section 2.4.2.8 as the "Eastern Pipeline System". There are two pipeline systems from the Eastern Subregion to the refineries in the Los Angeles area operated by Tosco and Equilon. Texaco also has a pipeline from the Ventura Pump

Station to the Willet Tank Farm. This pipeline is currently idle, and we understand that discussions are underway concerning the possible dedication of this line to Ventura County for possible use as a fiber optic cable conduit. The Tosco pipelines are proprietary, and the Equilon pipeline is a common carrier. Both of these pipeline systems transport low sulfur oil and are unheated. The Tosco pipeline currently transports all of the offshore oil from the Eastern Subregion except for the small amount produced at the State Lease 145/410 Facility.

The pipelines from the Carpinteria and Ventura coastal areas transport offshore- and onshore-produced crude oil to refineries in the Los Angeles area. The pipeline from the Carpinteria Oil & Gas Processing Facility to the Rincon Oil & Gas Processing Facility is owned by Venoco. The pipeline from the Rincon Oil & Gas Processing Facility to Ventura is owned by Mobil, and connects to a pipeline owned by Tosco at the Ventura Pump Station.

In the Future Baseline scenario (Scenario 1), the total oil production from the facilities in the Eastern Subregion is projected to decline annually from study year 1995 until study year 2010 and all facilities are projected to be shut down by study year 2015. Consequently the quantity of oil sent through the existing pipelines is projected to decrease annually during the Study Period.

In Scenario 1, the Rincon Island Facility is projected to produce larger quantities of oil than available recent data indicate have been produced in the past. The data reviewed did not include the facility's initial operating period from 1960 to 1976, when the production levels were probably higher than during the period addressed by available data. Oil from the Rincon Island Facility is pumped to shore through a 6-inch diameter pipeline on the causeway and then enters the 10-diameter pipeline between Carpinteria and the 268,000 barrel storage tank adjacent to the Rincon Onshore Oil & Gas Processing Facility. Both pipelines are expected to be able to handle the projected flows.

2.5.1.1.2 Central Subregion Pipelines

The Central Subregion onshore crude oil pipeline system consists of local gathering lines and connections to the interstate All American Pipeline, L.P. (AAPLP) and intrastate Tosco Pipeline (Northern Pipeline System). Two of the four primary facilities in the Central Subregion (Las Flores Canyon SYU and Gaviota Oil & Gas Processing Facilities) can send crude oil out of the Subregion by pipeline. One facility, the Ellwood Oil & Gas Processing Facility, is only connected to a pipeline to the Ellwood Marine Terminal. The Central Subregion pipelines are discussed in Section 2.4.3.8 as the "AAPLP Pipeline System".

The Las Flores Canyon SYU Oil & Gas Processing Facility and the Gaviota Oil & Gas Processing Facility are connected to the AAPLP pipeline. Oil in the AAPLP pipeline can be sent to the Santa Maria Refinery via the Sisquoc-Santa Maria-Summit Pump Stations, refineries in Bakersfield, Los Angeles and San Francisco Bay areas via connections in Kern County, and to refineries in Texas, Louisiana and the mid-continent via the Texas intrastate and interstate pipeline systems.

In the Future Baseline scenario (Scenario 1), the oil production at the Las Flores Canyon and Gaviota facilities individually and in total is projected to decline annually from study year 1995 through study year 2015 and be well below the design capacities of the AAPLP Coastal, Feeder and Main Line pipeline sections. The pipeline system is expected to be able to handle the declining throughput. Although the Ellwood Facility is not connected to the AAPLP system, the AAPLP pipelines have available capacity in excess of the quantity of oil projected to be produced from the South Ellwood Field.

In Scenario 1, the oil production at the Ellwood Facility is projected to decline annually from study year 1995 through study year 2005. No production is projected in study years 2010 and 2015. The pipelines between the Ellwood Oil & Gas Processing Facility and the Ellwood Marine Terminal tank farm and the barge loading mooring area are expected to be able to handle the declining production projected for the Ellwood Facility.

2.5.1.1.3 Northern Subregion Pipelines

As of July 1999, offshore crude oil produced from the Northern Subregion is transported to the Santa Maria Refinery in San Luis Obispo County. From there, product distillates including gas oil (a refined fraction of crude oil somewhat heavier than kerosene) are shipped to refineries outside the study region (such as Tosco's Rodeo Refinery in the San Francisco Bay area) for further refining. These pipelines are discussed in Section 2.4.4.4 as the "Northern Pipeline System". In addition, the Sisquoc Pipeline connects the AAPLP Main Line to the Tosco pipelines comprising the Northern Pipeline System. Although the Tosco Sisquoc Pipeline is required by permit conditions to operate as a uni-directional pipeline (i.e, from the AAPLP Main Line to the Tosco pipeline connection at Suey Junction), it has the potential to operate as a bi-directional pipeline which could allow Northern Subregion offshore crude oil to be pumped into the AAPLP Mail Line to the San Joaquin Valley.

Offshore crude is brought onshore from the Point Pedernales field to the Lompoc Oil & Gas Processing Facility. Tosco Pipeline operates a pipeline from the Lompoc Oil & Gas Processing Facility that conveys crude oil north to the Summit Pump Station where it is routed to the Santa Maria Refinery. Prior to the recent removal of the Avila Pump Station, the Summit Pump Station was connected to an existing northbound pipeline system (two eight-inch diameter pipelines) by one twelve-inch diameter pipeline. This pipeline system was disconnected when the Avila pump station was removed, but could be reconnected in the future if needed. The Tosco pipeline from the Sisquoc Station on the AAPLP pipeline system connects to the pipelines used to transport crude oil from the Lompoc Facility to the Santa Maria Refinery at Tosco's Suey Junction, located south of the Summit Pump Station on the Tosco pipeline system.

In the Future Baseline scenario (Scenario 1) all of the oil projected to be processed at the Lompoc Oil & Gas Processing Facility is from Point Pedernales/Tranquillon Ridge and the volume is projected to decline from study year 1995 to study year 2000. Under this no new development scenario, the facility is not projected to be processing offshore oil in study years 2005, 2010 and 2015. The existing pipeline system is expected to be able to handle the declining production.

2.5.1.2 Intrastate and Interstate Pipelines

In addition to the pipelines within the Study Region, there are other intrastate and interstate pipelines used to transport Pacific OCS crude to the refining markets in the Bakersfield, Los Angeles and San Francisco areas and those in Texas, Louisiana and the mid-continent. Table 2.5-1 summarizes existing California crude pipelines, and Figure 2.5-5 shows a schematic of the crude oil pipelines in California that can transport offshore oil and their interstate ties.

Historically, the ability to transport large volumes of the Point Arguello and Santa Ynez Unit crude oil from the Santa Barbara Channel to the Los Angeles refinery center via pipeline was constrained by inadequate pipeline capacity for the HVHS crude. As of August 1998, only one common carrier pipeline, Arco Pipe Line Company's (APLC) Line 63, was available to transport western Santa Barbara Channel offshore crude oil to Los Angeles. Three smaller pipelines transport crude from eastern Santa Barbara County and Ventura County to the Los Angeles refineries (including two

Table 2.5-1
Existing California Crude Pipelines

No.	Operator Line Name (type[1])	Pipeline Diameter inches	Origin	Destination	Capacity (MBD[2])	Crude Source
1	APLC, Line 1 (c)	6 - 10	Bakersfield	Los Angeles	Idle	SJV[3] Blend
2	APLC, Line 63 (c)	16	Bakersfield	Los Angeles	115	SJV/OCS[4]
3	Mobil, M-70 (p)	16	Bakersfield	Los Angeles	95	SJV Heavy
4	Equilon (p)	20	Bakersfield	San Francisco	215	SJV Heavy
5	Chevron (p)	18	Bakersfield	San Francisco	95	SJV Blend
6	Tosco (p)	12 - 16	Bakersfield	San Francisco	72	SJV/OCS
7	Chevron (p)	12	Bakersfield	Estero Bay	60	SJV
8	Mobil (p)	12	San Ardo	Estero Bay	28	San Ardo
9	Tosco (p)	10 - 12	Santa Maria P/S	Suey Junction	120	OCS/Local/SJV
10	AAPLP (c)	30	Gaviota	Bakersfield	300	OCS/SJV
11	Equilon (p)	8	Fillmore	Ventura	NA	Local[5]
12	Tosco (p*)	12	Torrey P/S	Los Angeles	20/40	Local/OCS
13	Equilon (c)	10	Ventura Avenue P/S	Los Angeles	35	Local
14	APLC (c)	16	Los Angeles	McCamy (TX)	45/75	OCS/ANS[7]
15	Tosco (p)	12	Sisquoc P/S	Santa Maria P/S	50.4	OCS
16	Venoco (p*)	10	Carpinteria	Rincon 268,000 Tk.	42	OCS
17	POOI (p)	4	La Conchita	Rincon 268,000 Tk.	>0.6	OCS
18	RILP (p)	6	Rincon Island	Rincon 268,000 Tk.	>0.2	SW[8]
19	Tosco (p*)	6-8	Mandalay	Ventura P/S	20	OCS
20	Berry (p)	4 & 6	W. Montalvo	Ventura P/S	NA	SW/Local
21	Torch (p)	6	Rincon Fac.	Rincon 268,000 Tk.	8.5	OCS
22	Venoco, M-143 (p*)	22	Rincon 268,000 Tk..	Ventura P/S	72	OCS/Local
23	Pacific Pipeline (c)	20	Bakersfield	Los Angeles	130	SJV/OCS
24	Tosco (p*)	8 & 8	Avila P/S	San Francisco	57.6	OCS/Local
25	AAPLP (c)	24	Las Flores	AAPLP Main Line	150	OCS
26	Tosco (p*)	8	Ventura P/S	Fillmore P/S	24	OCS/Local

Table 2.5-1 (Continued)

No.	Operator Line Name (type[1])	Pipeline Diameter inches	Origin	Destination	Capacity (MBD[2])	Crude Source
27	Tosco (p*)	10 - 12 8	Suey Junction Suey Junction	Summit P/S Summit P/S	84 24	OCS/Local Local/SJV
28	Tosco (p*)	8	Orcutt P/S	Suey Junction	50.4	OCS/Local
29	Tosco (p*)	12	Lompoc O&G Proc. Facility	Orcutt P/S	96	OCS
30	Tosco (p*)	10 8	Summit P/S Santa Maria Refinery	Santa Maria Refinery Summit P/S	72 41	OCS/Local/SJV Idle
31	Tosco (p*)	8 & 8	Avila Terminal	Avila P/S	NA	Removed
32	Tosco (p*)	12	Summit P/S	Avila P/S	40	Idle
33	Tosco (p*)	8 - 12	Santa Maria Refinery	North of Avila P/S	36	OCS/Local & Product

Notes:

1. Type: (c) = common carrier; (p) = proprietary; (p*) = proprietary pipeline that transports oil from multiple companies under an operating agreement
2. MBD: thousand barrels per day
3. SJV: San Joaquin Valley
4. OCS: Outer Continental Shelf (offshore in federal waters)
5. Local: From onshore fields near the pipeline's origin (Ventura and Santa Barbara Counties)
6. P/S: Pump Station
7. ANS: Alaska North Slope
8. SW: Offshore Leases in State Waters

proprietary lines and one common carrier line); however, only one of these (Tosco) transports a significant quantity of offshore crude and there are no connecting pipelines between the Central and Eastern Subregion pipeline systems. Line 63 is a 16-inch unheated pipeline that runs 153 miles from near Pentland, where the AAPLP Main Line connects to Line 63 in Kern County, to the Hynes Terminal in Long Beach. The capacity of Line 63 varies from a maximum throughput of 115,000 barrels per day of San Joaquin Valley (SJV) light crude during the warm summer months, down to about 70,000 barrels per day for the high-viscosity, high-sulfur (HVHS) offshore crude oil. At full capacity, Line 63 typically transfers approximately 80,000 - 85,000 barrels per day of oil consisting of a blend of Kern County and offshore crude.

In the mid-1990s, the need for additional pipeline capacity to Los Angeles was intensified in part due to the shutdown of APLC's Line 1 due to damage by the January 1994 Northridge earthquake. The 30,000- to 35,000-barrel per day capacity of Line 1 was eliminated indefinitely. As necessary, APLC currently prorates space in its Line 63 if there is more oil nominated for shipment than can be transported.

The limited pipeline capacity available to transport offshore oil from Kern County to the Los Angeles area was addressed by construction of the new 132-mile long Pacific Pipeline between the Emidio Pump Station (Kern County) and Los Angeles. This system became operational in March 1999. The new pipeline is a 20-inch diameter, insulated pipeline with a design capacity of 130,000 barrels per day. The pipeline is a common carrier and is able to transport oil from the Santa Barbara Channel and Santa Maria Basin offshore areas (via a connection to the AAPLP) and/or from the San Joaquin valley or other onshore areas connected to the Emidio Pump Station.

AAPLP has blending facilities at Pentland located in the Bakersfield area. The AAPLP pipeline has connections to the other San Joaquin Valley pipeline systems allowing offshore crude to be sent to refineries in the Bakersfield, San Francisco Bay, and Los Angeles areas. In addition, the AAPLP main pipeline terminates at McCamey, Texas, where it connects to Texas intrastate and interstate pipeline systems giving access to refineries in Texas and Louisiana, as well as the mid-continent.

2.5.1.3 Marine Transportation

As of July 1999, the only active marine terminal used to transport offshore crude was the Ellwood Marine Terminal. Crude oil is loaded onto a barge and is typically transported to refineries in the Los Angeles area, but can be taken to refineries in the San Francisco area.

The barge that is typically used has a capacity of 56,000 barrels. The oil is pumped from the Ellwood Marine Terminal Tank Farm at a maximum rate of 4,200 barrels per hour and it takes approximately 13 to 14 hours to load the barge. Data provided by the Santa Barbara County Planning and Development Department for the 19-month period January 1997 through July 1998 indicates that a total of 43 barges were loaded with 2,272,209 barrels of oil. This results in an average of approximately 0.5 barges per week (2.26 barges per month) having an average load of 54,842 barrels of oil.

In the Future Baseline scenario (Scenario 1), the oil production from the Ellwood Facility is projected to decline annually through study year 2005 resulting in projected barge rates of 0.2 per week in study year 2000 and 0.1 in study year 2005. The facility is projected to cease operation prior to study year 2010.

2.5.2 Public Infrastructure

The public infrastructure provides facilities or services to all segments of the public and private sectors. Public infrastructure expected to experience the greatest direct demand associated with different levels of onshore development associated with offshore oil and gas activity includes public roads and highways, ports and harbors, airports, and railroads. The level of facilities and services provided is typically balanced between the needs of the users and available funds. Because the presence of onshore oil and gas facilities requires the use of these facilities and services by facility operations and by operation-related employees and service providers, a limited availability of facilities or services could constrain offshore oil and gas development. This section discusses key elements of the existing transportation public infrastructure used by the oil and gas industry. The primary public infrastructure features in the Tri-County Study Region are shown on Figure 2.5-6.

Industry use of the local transportation infrastructure is associated with product transportation, transportation of personnel and supplies, and related emergency services. The transportation of offshore produced crude oil, Liquefied Petroleum Gases (LPG), and Natural Gas Liquids (NGL) from and through the Tri-County area has been a subject of local concern for over a decade. Concerns related to public safety and potential environmental impacts related to transport accidents are key topics related to this subject. Marine supply operations are very controversial, with limited options for supply vessel bases (Port Hueneme) and concerns regarding local traffic and competition for dockside space with commercial fishing operations. Personnel transport generally raises few public infrastructure concerns, because private industry piers currently accommodate substantial crew vessel activity and local airports easily handle the oil-related helicopter activity. Issues associated with onshore personnel and supply transport by truck and automobile are generally focused on local traffic concerns, and are typically addressed in project-specific environmental studies. Local emergency services demand associated with the transport of hazardous materials by truck or rail is most appropriately evaluated from a cumulative regional perspective, however.

Crude oil produced offshore in the Tri-County area cannot be refined locally due to a lack of petroleum refining capacity. Some of the offshore oil produced in the COOGER study region is partially refined at the Santa Maria Refinery, and resulting product distillates (a blend of light and heavy gas oils) are transported by pipeline to the Rodeo Refinery in the San Francisco Bay area for further refining. All other offshore production within the study region is transported as crude oil to refining centers outside the Tri-County area. Refineries currently used to process oil produced in the Study Region are located in the Los Angeles, Bakersfield, and San Francisco Bay areas and in Texas and Louisiana. Crude transportation from the Tri-County area to these refining centers may be accomplished with a combination of pipelines, trucks, marine vessels, and railroad tank cars. Because of varying refinery demand for heavy and lighter crudes, and also for competitive reasons, the crude oil produced at a given facility may go to different places at different times. At the present time, most offshore produced crude oil is transported outside of the tri-counties area by pipeline, although oil from the Ellwood Facility is transported by marine barge. Oil is trucked from the State Lease 145/410 Facility to an onshore production related facility, within the Study Region, that is connected to a pipeline. Marine terminals and pipelines serve the oil and gas industry, not the public, and are not considered part of the public infrastructure. Major pipeline systems and marine terminal facilities are discussed in Section 2.5.1.

2.5.2.1 Roads & Highways

2.5.2.1.1 Overview

The Tri-County offshore oil and gas industry's primary use of roads and highways is for the distribution of products including LPG, NGL and sulfur and for the delivery of supplies and materials to onshore facilities and docks providing service to offshore operations. LPGs are removed from gas and oil streams and transported in high-pressure tanker trucks. NGL is typically blended into crude oil and transported by pipeline, but may be shipped by truck if necessary. Sulfur is produced from processing hydrogen sulfide and other sulfur compounds recovered during the sweetening (desulfurization) of oil and gas. Sulfur can be transported in molten form using tanker trucks and in solid form using dump-type trucks. Although not currently produced from offshore oil, asphalt produced at the Santa Maria Asphalt Refinery is also shipped by truck. In the future, there is potential that this facility could process some offshore oil. Roads and highways are also used by industry employees, suppliers, service providers, and commercial waste transporters.

Trucks used to transport the LPG and NGL include two types. Large tanker trucks, consisting of either a single large tank or two small tanks on trailers (doubles), can carry up to 8,500 gallons of product. These large trucks are typically used to transport products to markets outside the Tri-County area. Smaller trucks are used to deliver products to local markets. For example, smaller trucks are typically used to deliver LPG to residential customers who live in areas that are not served by a local gas utility.

All trucks must comply with requirements of the U.S. Department of Transportation, including design and operating specifications for pressurized tanks. The transportation routes used by the trucks will vary depending on the facilities involved and markets served. In most cases, trucks travel the shortest and fastest route possible to minimize fuel and labor costs (Santa Barbara County, 1990). However, some roads have restrictions on the weight or overall length of the truck, or the hazardous nature of the cargo. These restrictions may be imposed by state or local officials. The principal regional highways used by vehicles serving the onshore oil and gas facilities and the approximate level of traffic on these highways are shown in Table 2.5-2. The characteristics of these highways along with other highways and surface streets used to access the onshore facilities that support the offshore facilities are presented in Table 2.5-3.

Table 2.5-2
1997 Traffic Summary for Regional Highways

			All Traffic - Back			All Traffic - Ahead			Truck Traffic		
Highway	County	Description	Peak Hour	Peak Month	AADT	Peak Hour	Peak Month	AADT	All Trucks	5+ Axle	Year-V/E
1	VEN	Seacliff, Mobil Oil Pier Road	170	1200	1000	-	-	-	142	18	82-V
101	VEN	Camarillo Springs Road/Truck Scales	10500	121000	111000	11000	123000	110000	6438	2221	91-V
101	VEN	Jct. Route 126 East	7300	92000	84000	9800	124000	111000	4704	1529	91-V
101	SB	Carpinteria-Casitas Pass Road	7700	82000	69000	7300	79000	66000	5037	2297	96-E
101	SB	Las Positas (225)	13300	141000	133000	11700	131000	126000	9043	4712	97-E
101	SB	Jct. Route 217 South (UCSB)	10800	117000	111000	7500	82000	77000	8325	4337	96-E
101	SB	Storke Road	4050	54000	51000	3350	34000	32000	4641	2418	96-E
101	SB	Jct. Route 246 (Buellton)	1950	20700	18500	1900	20200	18000	2627	1576	97-E
101	SB	Jct. Route 135 (Los Alamos)	2900	31500	27000	2700	29000	25000	3510	1941	97-E
101	SB	Betteravia Road (Santa Maria)	3400	40500	38000	4400	58000	52000	3420	1864	97-E
101	SLO	Jct. Route 166 East	6000	68000	58000	4900	71000	53000	4350	2266	97-E
101	SLO	Jct. Route 227 N.-Grand (Arroyo Grande)	5700	55000	47000	5900	57000	48000	3901	2009	97-E
126	VEN	Victoria (Ventura)	3350	36000	32500	3550	37000	32500	2340	981	92-V
135	SB	Jct. Route 101 (Los Alamos)	270	3600	3000	180	2200	1900	165	67	97-E
166	SLO	Suey Road	230	2750	2350	260	2400	2000	480	236	97-V
246	SB	Jct. Route 101 (Buellton)	1400	17200	15500	1350	18500	16500	1318	381	97-E

Source: CalTrans, 1998 and CalTrans, 1999.
[Note - All traffic volume figures listed, including "peak hour", include traffic in both directions unless otherwise indicated]
"Year V/E" - The year that the truck traffic volume was "Verified" (i.e., counted) or "Estimated"

Table 2.5-3
Highways, Roads and Streets

Road/Highway/Street	From/To	General Description	Primary Use by the Offshore Oil & Gas Industry[(1)]
HIGHWAYS			
Highway 1	From Ventura to La Conchita in Ventura County	2 lane undivided	Service to Rincon area facilities by vacuum trucks, oil transport trucks, drilling/workover rigs, cranes and other heavy "maintenance" vehicles.
Highway 1	From Highway 101 to Lompoc in Santa Barbara County	2 lane undivided	Service to Lompoc Oil & Gas Processing Facility by vacuum trucks, cranes and other heavy "maintenance" vehicles.
Highway 1	From Highway 166 in Guadalupe in Santa Barbara County to Grover City in San Luis Obispo County	2 lane undivided	Service to the Santa Maria Refinery by vacuum trucks, product distribution trucks (e.g., sulfur, petroleum coke, oil and gas products), cranes, and other heavy "maintenance" vehicles.
Highway 101	From eastern boundary of Study Region northwest to Rincon Island area	Six lane divided freeway with on/off ramps	Service to Rincon area facilities by vacuum trucks, cranes and other heavy "maintenance" vehicles. This is also a primary route for NGL and other product transport trucks.
Highway 101	From Rincon Island area northwest to east edge of Santa Barbara	Four lane divided highway; non-freeway from Rincon Island area to Ventura-Santa Barbara County Line, freeway from county line to Santa Barbara	Service to La Conchita facility by vacuum trucks, cranes and other heavy "maintenance" vehicles. This is also a primary route for NGL and other product transport trucks.
Highway 101	From east edge of Santa Barbara northwest to Fairview offramp in Goleta	Six lane divided freeway with on/off ramps	Service to Ellwood area facilities by vacuum trucks, cranes and other heavy "maintenance" vehicles based in Ventura County. This is also a primary route for NGL and other product transport trucks.

Table 2.5-3 (Continued)

Road/Highway/Street	From/To	General Description	Primary Use by the Offshore Oil & Gas Industry(1)
Highway 101	From Fairview offramp in Goleta northwest and north to Atascadero in San Luis Obispo County	Four lane divided freeway with on/off ramps	Service to all facilities in western Santa Barbara and San Luis Obispo counties by vacuum trucks, cranes and other heavy "maintenance" vehicles. This is also a primary route for NGL and other product transport trucks.
Highway 126	From Highway 101 in Ventura to Santa Paula in Ventura County	4 lane divided freeway	Service to eastern Ventura County facilities (e.g., Santa Paula and Torrey Pump Stations) by vacuum trucks, cranes and other heavy "maintenance" vehicles and used by companies based in eastern Ventura County. This is also a possible route for NGL and other product transport trucks.
Highway 126	From Santa Paula to Fillmore	4 lane undivided with center turn lane	Service to eastern Ventura County facilities (e.g., Santa Paula and Torrey Pump Stations) by vacuum trucks, cranes and other heavy "maintenance" vehicles and used by companies based in eastern Ventura County. This is also a possible route for NGL and other product transport trucks.
Highway 135	Between Highway 101 and Highway 1	2 lane undivided	Service to Lompoc Oil & Gas Processing Facility by vacuum trucks, cranes and other heavy "maintenance" vehicles.
Highway 135	From junction with Highway 1 to Clark Avenue in Orcutt	4 lane divided	Service to Lompoc Oil & Gas Processing Facility by vacuum trucks, cranes and other heavy "maintenance" vehicles.

Table 2.5-3 (Continued)

Road/Highway/Street	From/To	General Description	Primary Use by the Offshore Oil & Gas Industry[(1)]
Highway 166	From Highway 1 in Guadalupe to Highway 101 in Santa Maria in Santa Barbara County	4 lane divided w/island 2 lane undivided	Service to the Santa Maria Refinery and Santa Maria Asphalt Refinery by vacuum trucks, product distribution trucks (e.g., sulfur, petroleum coke, asphalt, oil and gas products), cranes, and other heavy "maintenance" vehicles.
Highway 166	From Highway 101 in Santa Maria to Santa Barbara/Kern County Line	2 lane undivided	Service to northern Santa Barbara and San Luis Obispo counties by companies located in Kern County. This is also a primary route for transporting products from the Study Region to markets in Kern County and other areas.
Highway 246	From Highway 101 in Buellton to Highway 1 in Lompoc	4 lane undivided/divided 2 lane undivided	Service to Lompoc Oil & Gas Processing Facility by vacuum trucks, cranes and other heavy "maintenance" vehicles.

Table 2.5-3 (Continued)

Road/Highway/Street	From/To	General Description	Primary Use by the Offshore Oil & Gas Industry(1)
SURFACE STREETS			
Ventura County			
Victoria	From Highway 101 south to Channel Islands Blvd.	4 lane divided with median, center turn lane or turn islands (varies)	Primary service route for Port Hueneme to/from Highway 101 North (Santa Barbara). Typical use is by all types of vehicles used to transport supplies, equipment and other materials to/from the Port where they are transferred to/from vessels serving the offshore platforms.
Channel Islands Blvd.	From Victoria east to Ventura Road	4 lane divided (by drainage ditch) and with center turn islands	
Ventura Road	From Channel Islands south to Hueneme Road	4 lane divided with center turn islands	
Hueneme Road	From Ventura Road into the Port of Hueneme (main entrance)	4 lane undivided narrowing to 2 lane undivided	
Las Posas	From Highway 101 south to Hueneme Road a. from Highway 101 to Pleasant Valley Road b. from Pleasant Valley Road to Hueneme Road	 a. 4 lane undivided b. 2 lane undivided	Primary service route for Port Hueneme to/from Highway 101 South (Los Angeles). Typical use is by all types of vehicles used to transport supplies, equipment and other materials to/from the Port where they are transferred to/from vessels serving the offshore platforms.
Hueneme Road	From Las Posas west into the Port of Hueneme a. from Las Posas west to Saviers b. from Saviers west to Ventura Road c. from Ventura Road west into Port Hueneme	 a. 2 lane undivided b. 4 lane with turn islands c. narrows from 4 to 2 lanes undivided	
Harbor Boulevard	At Seward Exit from 101 south to Wooley Road	4 lane undivided w/center turn lane 4 lane with center island 2 lane undivided	Service to Mandalay, Ventura Pump Station, and West Montalvo facilities by vacuum trucks, oil transport trucks, drilling/workover rigs, cranes, and other heavy "maintenance" vehicles.

Table 2.5-3 (Continued)

Road/Highway/Street	From/To	General Description	Primary Use by the Offshore Oil & Gas Industry[(1)]
Santa Barbara County			
Bailard Road	From Highway 101 south to Carpinteria Avenue	2 lane undivided	Service to Carpinteria facilities by vacuum trucks, cranes and other heavy "maintenance" vehicles. Also used by the Clean Seas Cooperative vehicles to access their main storage yard adjacent to the Carpinteria facilities.
Carpinteria Avenue	From Bailard Road west to Dump Road (private)	2 lane undivided	
Storke Road	From Highway 101 south to El Colegio Road (UCSB) in Goleta	4 lane undivided	Service to Ellwood Oil & Gas Processing Facility and Ellwood Marine Terminal by vacuum trucks, cranes, and other heavy "maintenance" vehicles.
Hollister Avenue	From Highway 101 east to Storke Road in Goleta	2 lane undivided 4 lane with center turn lane 4 lane divided by islands	
Purisima Road	From Highway 246 to Highway 1 near Lompoc	2 lane undivided	Service to Lompoc Oil & Gas Processing facility by vacuum trucks, cranes and other heavy "maintenance" vehicles.
Harris Grade Road	From Highway 1 to Highway 135 north of Lompoc	2 lane undivided	
Clark Avenue	From Highway 135 to Highway 101 in Orcutt	4 lane with center turn lane	
Betteravia Road	From Highway 101 in Santa Maria west to Santa Maria Asphalt Refinery	4 lane divided with island 2 lane undivided	Service to Santa Maria Asphalt Refinery by vacuum trucks, oil transport trucks, cranes and other heavy "maintenance" vehicles.

Table 2.5-3 (Continued)

Road/Highway/Street	From/To	General Description	Primary Use by the Offshore Oil & Gas Industry[1]
San Luis Obispo County			
Tefft Street	From Highway 101 in Nipomo west to Pomeroy Road	2 lane undivided	Service to the Santa Maria Refinery by vacuum trucks, product distribution trucks (e.g., sulfur, petroleum coke, oil and gas products), cranes, and other heavy "maintenance" vehicles.
Pomeroy Road	From Tefft Street northwest to Willow Road	2 lane undivided	
Willow Road	From Pomeroy Road west to Highway 1	2 lane undivided	

(1) All highway and road sections are used by industry employees, contractors, vendors and similar light vehicles.
(2) The term “maintenance is used as a collective term to refer to maintenance, repair, or other service-type vehicles.

Truck transport of petroleum products (LPG and sulfur) is generally used to deliver products for local use within the Study Region, or export from the study region via U.S. 101 south, Highway 126 east, or Highway 166 east. Based on the information reviewed during the COOGER study, it appears that no crude oil, LPG, sulfur or other products are currently being transported north of San Luis Obispo county by truck or rail from any of the onshore facilities in the Study Region that receive oil or gas directly from an offshore facility. The Santa Maria Refinery processes offshore oil after it has been processed at the Lompoc Oil & Gas Processing Facility and may transport products to various markets by truck or rail. As part of a Santa Barbara County sponsored study, A. D. Little (1990) studied several truck and rail routes from facilities in Santa Barbara County to markets in the Los Angeles, Bakersfield, and San Francisco Bay areas. For transport of LPGs to the Los Angeles and San Francisco Bay areas, A.D. Little concluded that the risk difference between truck and rail transport was insufficient to make a decision as to the mode of transport based on levels of risk alone. However, A.D. Little found that truck transport to the Bakersfield area has a significantly lower risk than rail transport because the preferred truck route is substantially shorter and avoids many more population centers.

Truck Activity

Because many of the facilities in three subregions use the same highways to transport the products they produce, the overall assessment of highway use should consider that trucks generated by a facility in one subregion may travel on highways in a different subregion. The following highway distribution routes were identified as being used by the onshore facilities used to process offshore oil:

- Trucks travel on Highway 101 north (or on local roads) to northern Santa Barbara County or San Luis Obispo County and deliver the products (e.g., commercial LPG to customers and sulfur to agriculture-related products companies). Under normal operations, no trucks were identified as traveling on Highway 101 north out of San Luis Obispo county (i.e., into Monterey County).

- Trucks travel on Highway 101 north and then travel on Highway 166 east to Kern County (out of the Study Region).

- Trucks travel on Highway 101 south to Highway 126 east into Los Angeles County (out of the Study Region except for trucks carrying crude oil from State Lease 145/410 that unload at a pump station in Fillmore)

- Trucks travel on Highway 101 south into Los Angeles County

The procedures used to project the number of trucks and cars associated with the offshore oil industry activities are described in Appendix A.6. The number of product trucks is based on the estimated average daily production of oil, gas, sulfur, LPG or other products for the specified study year (i.e., 2000, 2005, 2010 and 2010). In other words, these averages reflect a single year's production rate. The number of supply and crew vessels serving the platforms and the employee vehicle traffic associated with these vessels is more dependant on the general level of activity than on the volume of oil and gas produced. For this reason, the methods used to calculate the number of trucks carrying supplies to or from Port Hueneme and the number of cars associated with the vessel traffic at Port Hueneme and the Carpinteria and Ellwood piers is based on an average level of activity (employment, well drilling schedules, and offshore construction activity) over each 5-year study interval (e.g., the interval January 1, 2001 through December 31, 2005 is represented by study year 2005). As a result, these projections are weekly averages over the 5-year time intervals.

2.5.2.1.2 Eastern Subregion

Roads and Highways Used

The primary highways in the Eastern Subregion are U.S. Highway 101 and State Highway 126. Highway 101 traverses the width of the Eastern Subregion and runs adjacent to or near onshore facilities in the Subregion; however, use of surface streets is required to reach several of the facilities. Highway 101 South is the primary route from the Eastern Subregion to markets in the Los Angeles area. Highway 126, which intersects Highway 101 in Ventura, provides a direct route to Interstate 5 in northern Los Angeles County and markets in the Bakersfield area. Highway 101 North is the primary route from the Eastern Subregion to the Central and Northern Subregions and to markets to the north, including those in the San Francisco Bay Area. The principal highway segments used to access facilities in the Eastern Subregion are listed on Table 2.5-2 and shown on Figure 2.5-7, and include the following:

- Hwy 1 between Ventura and La Conchita
- Hwy 101 within the Eastern Subregion
- Hwy 126 between Ventura and the Eastern Subregion boundary (Ventura-Los Angeles County Line)

The most common surface street routes used to access the facilities from the main highways are as follows:

- <u>Mandalay Onshore Separation Facility, West Montalvo Operations</u>
  - Exit Hwy 101 at Victoria and go south, to either:
    - Gonzales Road west to Harbor Boulevard, then south to facilities
    - Fifth Street west to Harbor Boulevard, then north to facilities

- <u>Carpinteria Oil & Gas Processing Facility / Carpinteria Onshore Gas Terminal</u>
  - Exit Hwy 101 at Bailard Road and go south to Carpinteria Avenue
  - Carpinteria Avenue west to Dump Road (private); turn toward ocean

The Rincon Island and State Lease 145/410 Oil & Gas Processing Facility, Rincon Oil & Gas Processing Facility and La Conchita Oil & Gas Processing Facility are within one-eighth mile of Highway 101 and do not involve the significant use of surface streets.

Although it does not process oil or gas, Port Hueneme is an important feature in the Eastern Subregion related to the offshore oil industry. All supply vessels serving the platforms in all three subregions operate out of Port Hueneme. In addition, some of the platforms in the Eastern Subregion are served by crew vessels operating out of Port Hueneme. As a result, there are various surface streets used to transport personnel, supplies and equipment to and from Port Hueneme. The most common routes used to access the Port from Highway 101 are the following.

- <u>Port Hueneme</u>
  On Highway 101 coming from the south (Los Angeles):
  - Exit Hwy 101 at Las Posas and go south to Hueneme Road
  - Hueneme Road west into the Port

On Highway 101 coming from the north (Santa Barbara):

- Exit Hwy 101 at Victoria
- Victoria south to Channel Islands Boulevard
- Channel Islands Boulevard east to Ventura Road
- Ventura Road south to Hueneme Road
- Hueneme Road west into the Port

Table 2.5-4 shows a summary of the traffic data provided for key intersections on the surface streets used to access Port Hueneme from Highway 101. In addition to these routes, it is expected that some of the personnel and materials from local suppliers travel to the Port on other surface streets..

The above access routes from Highway 101 to Port Hueneme may change in the future. In mid-1999, the Ventura County Transportation Commission agreed to be the lead agency on a project that will involve highway and street modifications to create a designated route from Highway 101 (both northbound and southbound) to Port Hueneme. The new route is projected to be completed by 2003 and so by study year 2005 the preferred truck route to Port Hueneme is expected to be as follows:

- Exit Hwy 101 at Rice Ave. and go south to Hueneme Road
- Hueneme Road west into the Port

Truck Activity

With one exception, the processing facilities in the Eastern Subregion currently do not transport crude oil, LPG, sulfur or other products by truck. As of September 1998, the State Lease 145/410 Facility was shipping approximately 8-10 150-barrel trucks of oil per week to a Texaco operated pipeline pump station in Fillmore. These trucks travel Highway 101 South to Highway 126 East into Fillmore. The trucked oil is produced from portions of the oil field that are "onshore" and portions that are "offshore" and the operator did not specify the ratio or provide other information

Table 2.5-4
Traffic Summary for Surface Street Access to Port Hueneme

Intersection	Traffic Count Date / Time	V / C	LOS
Victoria at Hwy 101 SB Ramp	1997 - AM 1997 - PM	0.60 0.68	A B
Victoria at Olivas Park	1997 - AM 1997 - PM	0.55 0.91	A E
Victoria at Wooley Road	04/07/98 - PM	0.68	B
Channel Islands at Victoria	04/21/98 - PM	0.74	C
Channel Islands at Ventura Rd.	02/05/98 - PM	0.74	C
Hueneme Road at Saviers	02/11/98 - PM	0.41	A
Rice Ave. at Highway 101	05/13/97 - PM	0.79	C
Rice Ave. at Route 34	04/23/98 - PM	0.64	B
Rice Ave. at Pleasant Valley/Rte. 1	02/09/98 - PM	0.64	B

Notes: V/C - volume divided by capacity (for overall intersection)
LOS - level of service (for overall intersection)
Data provided did not include future traffic / level of service projections.

Backup Data Shows the Following for Traffic Flow Approaching Intersections:

1. Southbound Victoria approaching the Channel Islands Intersection
2 lanes with a capacity of 3,200 vehicles per hour (1,600 per lane)
PM peak hour southbound traffic (from 101) = 1,077 vehicles
V/C = 1,077/3,200 = 0.34 (LOS = A)

2. Westbound Channel Islands approaching the Victoria Intersection
2 lanes with a capacity of 3,200 vehicles per hour (1,600 per lane)
PM peak hour westbound traffic = 1,330 vehicles
V/C = 1,330/3,200 = 0.42 (LOS = A)

3. Eastbound Hueneme approaching the Saviers Road Intersection
2 lanes with a capacity of 3,200 vehicles per hour (1,600 per lane)
Peak hour eastbound traffic = 479 vehicles
V/C = 479/3,200 = 0.15 (LOS = A)

4. Westbound Hueneme approaching the Saviers Road Intersection
1 lanes with a capacity of 1,600 vehicles per hour (1,600 per lane) [widens to 2 lanes before intersection]
Peak hour westbound traffic = 818 vehicles
V/C = 818/1,600 = 0.51 (LOS = A)

Source: City of Oxnard, 1998

to allow identification of how many of the trucks are transporting offshore oil. Similarly, the operator did not specify how long the facility might operate, but it is associated with the Rincon Island Facility which is expected to continue producing through 2014. No increases in the production from the State Lease 145/410 Facility are projected and so the number of trucks is projected to remain constant until study year 2010 and then decline to zero by study year 2015.

Population projections for Ventura County prepared by the Ventura Council of Governments and by the California State Department of Finance show total growth from the year 2000 to 2010 of 12% and 16%. If it is assumed that traffic volumes will grow as population grows, the constant and then declining number of trucks from the State Lease 145/410 Facility, as well as the products from Central Subregion operations which are projected to come into Ventura County from Santa Barbara County, are expected to represent a decreasing percentage of the total traffic on Highways 101 and 126.

Except for the State Lease 145/410 Facility, none of the existing facilities in the Eastern Subregion were identified as transporting crude oil or products (e.g., sulfur, LPG, etc.) by truck and none are projected to begin transporting products by truck during the study period. In Scenario 1 (Future Baseline), none of the facilities in the Eastern Subregion are expected to expand and no new facilities are projected to be constructed. Therefore, the use of the roads by employees, waste haulers and other service providers is projected to remain unchanged or decrease overall, except for possible temporary increases during decommissioning, as the facilities are removed during the study period.

As stated, supply vessels originating from Port Hueneme serve the platforms in all three subregions. As such, offshore activities in all three subregions have the potential to generate traffic on the highways and surface streets serving the Port. Because the Future Baseline scenario (Scenario 1) projects there will be platforms operating in the Central Subregion throughout the 1995-2015 Study Period, there will be traffic on the roads accessing the Port throughout the entire Study Period. This includes traffic associated with normal operations (e.g., the delivery of supplies to the Port for transfer to the platforms and the pick up of waste received at the Port from the platforms) and traffic associated with other activities such as well drilling, workovers and platform decommissioning). In addition, automobile traffic associated with vessel crews and offshore employees add to local traffic near Port Hueneme.

In the Future Baseline scenario (Scenario 1, all subregions) the total number of trucks accessing Port Hueneme is projected to average 209 per week for study year 2000, increase to an average of 321 per week in study year 2005 and then decline annually to an average of 63 per week in study year 2010 and 20 per week in study year 2015. However, the total number of vehicles (trucks and cars) is projected to decline slightly from an average of 878 in 1997 to 729 in study year 2000 and 688 in study year 2005 and then decline sharply to 101 in study year 2010 and to 32 in study year 2015. If it is assumed that total traffic volumes will grow as population grows, the overall declining number of vehicles accessing the Port will represent a decreasing percentage of the total traffic in the vicinity of Port Hueneme due to offshore oil related activities.

Traffic associated with the offshore oil industry is only a portion of the total traffic to Port Hueneme. The Port is used as an import location for vehicles which must be distributed to dealerships; an import/export location for fruits and vegetables that must be delivered or distributed to market; and a local base of operations for the local commercial fishing industry which requires vehicles to distribute seafood to market. For example, Port representatives reported that in operating year July 1997 through June 1998, 135,262 automobiles were imported through Port Hueneme. Assuming an average of 9 cars per transport vehicle, this corresponds to 15,029 trucks per year or 41 trucks per day. According to representatives of the Port, they do not prepare summaries of how many trucks or other vehicles access the Port. Similarly, the Port representatives were not able to provide data summaries of the average number of vehicles using the Port associated with the supply and crew vessels serving the offshore oil industry.

Crew vessel activity at the Carpinteria Pier also generates local vehicular traffic in that area. In the Future Baseline scenario the total number of trucks and cars accessing the Carpinteria Pier (or designated parking areas) in association with the crew vessel trips remains constant at an average of 462 per week through study year 2005 and then declines to zero per week in study years 2010 and 2015. If it is assumed that traffic volumes will grow as population grows, the overall constant and then declining number of offshore-industry-related vehicles accessing the Carpinteria Pier should represent a decreasing percentage of the total traffic in the vicinity of the Carpinteria Facilities due to offshore oil related activities.

2.5.2.1.3 Central Subregion

Roads and Highways Used

The primary highway in the Central Subregion is U.S. Highway 101. Highway 101 traverses the width of the Central Subregion and runs adjacent to or near the onshore facilities in the Subregion; however, use of surface streets is required to reach several of the facilities. Highway 101 South is the primary route from the Central Subregion to the Eastern Subregion and to markets in the Los Angeles area. Highway 101 North is the primary route from the Central Subregion to the Northern Subregion and markets to the north, including those in the San Francisco Bay Area. The principal highway segments used in the Central Subregion are shown on Figure 2.5-8, and include the following:

- Hwy 101 Within the Central Subregion

The most common surface street routes used to access the facilities from the main highways are as follows:

- Ellwood Oil & Gas Processing Facility
    - Exit Highway 101 at Hollister Avenue (Winchester Canyon) and go east on Hollister to the Sandpiper Golf Course entrance; turn into the golf course and take the access road to the facility. The Hollister/Winchester interchange with Highway 101 is the one used by the sulfur and LPG trucks from the Ellwood Oil & Gas Processing Facility.

- Ellwood Marine Terminal
    - Exit Hwy 101 at Storke Road and go south toward UCSB; turn right onto a private road by the Ocean Meadows Golf Course and proceed to the tank farm. The tank farm temporarily stores oil for the marine terminal and crude oil trucks are not loaded or unloaded at the tank farm (i.e., no product trucks).

The Las Flores Canyon SYU Oil & Gas Processing Facility, Las Flores Canyon Gas Processing Facility, Molino Facility project site, and Gaviota Oil & Gas Processing Facility are adjacent to Highway 101. Entry to these facilities is by short (less than one mile) access roads having on/off ramps from Highway 101. The majority of the traffic on these access roads is to/from the facilities.

All of the facilities in the Central Subregion rely on Highway 101 to transport product sulfur and/or LPG. As of September 1998, no sulfur or LPG was being transported between facilities in the Central Subregion and no sulfur or LPG was being distributed to customers "between" these facilities. As such, there is essentially a corridor on Highway 101 between the Hollister/Winchester exit (Ellwood Facility) at the south/east end and the Mariposa Reina exit (Gaviota Facility) at the north/west end. All sulfur and LPG trucks from the Central Subregion enter onto Highway 101 within this corridor and then exit either traveling north toward Santa Maria or south toward Ventura. As of September 1998, the Hollister/Winchester exit was essentially at the western edge of Goleta/Santa Barbara and the section of Highway 101 described by the Ellwood-Gaviota corridor is sparsely populated. The concept of the Ellwood-Gaviota corridor is useful because it allows the various scenarios and study years for the Central Subregion as a whole to be discussed based on the total number of trucks from all facilities that exit the corridor regardless of which facility they came from. Other than the short section of Hollister avenue between the Ellwood Facility and Highway 101, there are essentially no surface streets used.

Table 2.5-2 provides a summary of the traffic volumes on sections of Highway 101 in the Central Subregion. In addition, Tables 3.1 and 3.3 of the Santa Barbara County Association of Governments (SBCAG) "1995 Regional Transportation Plan, Adopted September 21, 1995" provide traffic volume data for selected sections of Highway 101, based on 1993 CalTrans data and provide traffic projections for the year 2015. The projected average weekday traffic volume on Highway 101 in the Storke-Hollister section in the year 2015 is 26,000 which is a decrease from the 1993 traffic volume of 31,500. All other sections of Highway 101 between Storke and the Santa Barbara-Ventura County line are projected to have annual growth in the number of vehicles between 1993 and 2015 and the annual increases range from 0.1% to 2.7%. All of the sections of Highway 101 listed in the Santa Maria area (Clark Avenue to Donovan Road) are projected to have annual growth in the number of vehicles between 1993 and 2015, and the annual increases range from 1.4% to 3.0%.

Truck Activity

Crude oil is not transported by truck from facilities in the Central Subregion. Various products from the oil and gas processing activities are transported by truck from facilities in the Central Subregion. Sulfur and LPG are trucked from the Ellwood Oil & Gas Processing Facility. Sulfur and LPG are trucked from the Las Flores Canyon Facilities (i.e., the Las Flores Canyon SYU Oil & Gas Processing Facility and Las Flores Canyon Gas Processing Facility). Until the recent process reconfiguration at the Point Arguello platforms that resulted in the shutdown of the onshore wet oil and gas processing systems, sulfur and LPG were produced at and trucked from the Gaviota Oil & Gas Processing Facility. In the Future Baseline scenario study years 2005 and 2010, the Molino Facility is projected to generate LPG trucks.

Information obtained from the Santa Barbara County Department of Planning and Development indicates that LPG and/or sulfur are trucked from four facilities in the Central Subregion portion of Santa Barbara County. These are:

- A total of 385 trucks were sent from the Ellwood Oil & Gas Processing Facility during 1997 and 221 trucks during January through July 1998. Typically, all of the LPG trucks travel Highway 101 north and then Highway 166 east into Kern County. Typically, the sulfur trucks travel Highway 101 north to agricultural facilities in northern Santa Barbara or San Luis Obispo counties. None of the trucks were identified as north out of San Luis Obispo County.

- A total of 1,137 trucks were sent from the Las Flores Canyon SYU Oil & Gas Processing Facility during 1997 and 765 trucks through June 1998. A total of 329 trucks were sent from the Las Flores Canyon Gas Processing Facility during 1997. Typically, approximately 80 percent of the LPG trucks travel Highway 101 South into Los Angeles County; approximately 10 percent travel Highway 101 south and then Highway 126 east in northern Los Angeles County; and approximately 10 percent travel Highway 101 north to communities within the Study Region. Typically all of the sulfur trucks travel Highway 101 south to Wilmington in Los Angeles County.

- A total of 405 trucks were sent from the Gaviota Oil & Gas Processing Facility during 1997. The destinations of these trucks are expected to be similar to those for the Las Flores Canyon facilities.

Santa Barbara County's Resolution 93-480 requires operators of the Las Flores Canyon Facilities, Gaviota Oil & Gas Processing Facility, and Lompoc Oil & Gas Processing Facility (in the Northern Subregion) to blend NGL into the crude oil transported by pipeline or marine vessel to the extent feasible. When the Las Flores Canyon Gas Processing Facility was recently expanded, a pipeline was installed to transport the heavier NGLs to the Las Flores Canyon SYU Oil & Gas

Processing Facility to blend these NGLs into the crude stream prior to transfer into the AAPLP pipeline.

Under Resolution 93-480, facilities that continued to send products by highway were required to prepare a Transportation Risk Management and Prevention Program. In addition, federal and California regulations, including the California Vehicle Code, impose many safety and operating requirements on trucks used to transport NGL, LPG, and other flammable and/or pressurized cargos.

Typically, the NGL and LPG are transported by truck from processing facilities to destinations in Kern and Los Angeles counties. The NGL (pentane and heavier) and LPG (propane and butane) are transported by single or double tank tanker trucks having capacities up to 8,500 gallons. These products are flammable and transported in pressurized tanks. Consequently, accidents involving these trucks have the potential to cause fires or explosions.

Resolution 93-480 specifies that NGL that cannot be blended with crude and that is being sent to Kern County be transported by truck rather than by rail. In addition, Resolution 93-480 specifies preferred transportation routes for trucks transporting NGL/LPG from these facilities. These routes were identified in a Santa Barbara County sponsored study (A.D. Little, 1990), which also identified potential routes which were not preferred for such transport. The identified preferred routes include:

- B2 - Truck route B2 from Santa Barbara County to the Bakersfield area requires the trucks to proceed on Highway 101 to Highway 166 near Santa Maria and then proceed east on Highway 166 out of Santa Barbara County. From Highway 166, it is recommended the trucks use Highway 99 north into the Bakersfield area.

- LA1 - Truck route LA1 from Santa Barbara County to refineries in the Los Angeles area requires trucks to proceed south on Highway 101 into Ventura County and recommends that they proceed on Highway 101 to Interstate 405 and then proceed south on Interstate 405 to the Wilmington area.

- LA2 - Truck route LA2 from Santa Barbara County to refineries in the Los Angeles area requires trucks to proceed on Highway 101 to Highway 166 and then proceed east on Highway 166 out of Santa Barbara County. The route recommends the trucks proceed east on Highway 166 to Interstate 5 and then proceed south on Interstate 5 to Interstate 405 and then proceed south on Interstate 405 to the Wilmington area.

The truck routes that were evaluated and concluded to not be the preferred routes include:

- B1 - Truck route B1 from Santa Barbara County to Bakersfield follows US Highway 101 north to State Route 46 east to State Route 99 south into Bakersfield.

- B3 - Truck route B3 from Santa Barbara County to Bakersfield follows US Highway 101 south to State Route 126 east to Interstate 5 north to State Route 99 north into Bakersfield.

- LA3 - Truck route LA3 from Santa Barbara County to Los Angeles follows US Highway 101 south to State Route 126 east to Interstate 5 south to State Route 60 to Interstate 710 south to Interstate 405 to the Wilmington Area.

Product transport associated with Central Subregion production generally follows the specified preferred routes.

A summary of projected future baseline product truck traffic associated with Central Subregion facilities is presented in Table 2.5-5. Under the future baseline conditions, gas processing at the Ellwood Facility is expected to decline annually through study year 2005. The gas processing rate at the LFC Facilities is expected to remain essentially constant through study year 2015. The Gaviota Facility is not expected to process gas onshore. The Molino Facility is projected to be processing gas in study years 2005 and 2010 with the rate being less in 2010. For the Central Subregion as a whole, the quantity of gas processed is projected to increase from study year 1995 to 2005 and then decrease through study year 2015. The number of trucks projected to travel south

Table 2.5-5
Summary of Product Trucks - Central Subregion
Scenario 1 - Future Baseline

Study Year (CS1)	Dir On 101	Ellwood		LFC		Gaviota		Molino		Total		*Total Trucks Per Week
		Sulfur (wk.)	LPG (wk.)	Sulfur (wk.)	LPG (wk.)	Sulfur (wk.)	LPG (wk.)	Sulfur (wk.)	LPG (wk.)	Sulfur (wk.)	LPG (wk.)	
1998	N	2	7	0	3	0	0	-	-	2	10	12
	S	0	0	4	29	0	0	-	-	4	29	33
2000	N	0.8	2.9	0	3	0	0	-	-	1	6	7
	S	0	0	4	29	0	0	-	-	4	29	33
2005	N	0.4	1.6	0	3	-	-	0	18	1	23	24
	S	0	0	4	29	-	-	0	0	4	29	33
2010	N	-	-	0	3	-	-	0	5	0	8	8
	S	-	-	4	29	-	-	0	0	4	29	33
2015	N	-	-	0	3	-	-	-	-	0	3	3
	S	-	-	4	29	-	-	-	-	4	29	33

* Total trucks per week - number that travel 101 North or South from the "Ellwood-Gaviota Corridor".
Note: "Partial" trucks are rounded up to next whole number.

on Highway 101 through Santa Barbara toward Ventura remains constant at 33 per week in study years 2000, 2005, 2010 and 2015. As discussed, it is projected that the traffic volume on Highway 101 in the Santa Barbara area will increase by 1.4 to 3.0% per year during the period 1993 to 2015. The constant number of project trucks should represent a decreasing percentage of the total traffic on Highway 101 in the Santa Barbara area.

Some traffic increases are projected for northbound product transport under future baseline conditions. The total number of trucks per week of sulfur and LPG projected to exit the Ellwood-Gaviota corridor on Highway 101 north toward Santa Maria increases from 7 in study year 2000 to 24 in study year 2005, decreases to 8 in study year 2010, and further decreases to 3 in study year 2015. The increase in study year 2005 is primarily due to the LPG trucks from the Molino Facility. For the facilities currently present (i.e., excluding the Molino Facility), the total number of trucks per week of sulfur and LPG projected to exit the Gaviota-Ellwood corridor on Highway 101 north toward Santa Maria decreases annually from 7 in study year 2000 to 3 in study year 2010 and then to zero in study year 2015. Of the 24 trucks per week traveling north in 2005, approximately 20 are projected to use Highway 166 into Kern County.

In addition to the trucks used to transport products, there is traffic at the Ellwood Pier associated with crew vessel activity. In the Future Baseline scenario the total number of trucks and cars accessing the Ellwood Pier (or designated parking areas) in association with the crew vessel trips is projected to increase from 517 in study year 2000 to 814 in study year 2005 and then decline annually to 385 in study year 2010 and to 154 in study year 2015. The relative increases in the study year 2000 to 2005 interval exceeds the projected traffic growth rate for Highway 101 near the Ellwood Pier.

2.5.2.1.4 Northern Subregion

Roads and Highways Used

The primary highways in the Northern Subregion used in conjunction with the offshore oil industry are U.S. Highway 101 and State Highways 246, 135, 166, and 1. Highway 101 traverses the length of the Northern Subregion, but does not run adjacent to the onshore facilities in the subregion. Highway 101 South is the primary route from the Northern Subregion to the Central and Eastern Subregions and to markets in the Los Angeles area. Highway 101 North is the primary route from the Northern Subregion to the markets to the north including those in the San Francisco Bay area. Major highways used by the industry include:

- Highway 246 between Highway 101 at Buellton and Lompoc can be used to connect with Purisima and Harris Grade roads to access the Lompoc Oil & Gas Processing Facility.

- Highway 135 west from Highway 101 at Los Alamos to Harris Grade Road can be used to access the Lompoc Oil & Gas Processing Facility.

- Highway 166 traverses the Northern Subregion in an east-west orientation and intersects Highway 101 in Santa Maria. Highway 166 is the primary route from the Santa Maria area to the markets in Kern County including those in the Bakersfield area. Highway 166 also connects with Interstate 5 in Kern County.

- Highway 1 provides access to the western part of the Northern Subregion including access to the Lompoc Oil & Gas Processing Facility via Harris Grade Road and the Santa Maria Refinery. Highway 1 intersects the north-south oriented Highway 101 and the east-west oriented Highways 246 and 166.

The specific highway segments used in the Northern Subregion are shown on Figure 2.5-9, and include the following:

- Hwy 1 Between Hwy 101 and Lompoc in Santa Barbara County

- Hwy 1 Between Hwy 166 (Guadalupe) and Grover City

- Hwy 101 Between the Northern Subregion's southern boundary and its northern boundary

- Hwy 135 Between Hwy 101 (Los Alamos) and Clark Avenue (Orcutt)

- Hwy 166 Between Hwy 1 (Guadalupe) and Hwy 101 (Santa Maria)
  Between Hwy 101 (Santa Maria) and Santa Barbara\Kern Co.

- Hwy 246 Between Hwy 101 (Buellton) and Hwy 1 (Lompoc)

The most common surface street routes used to access oil and gas facilities from the main highways are as follows:

- Lompoc Oil & Gas Processing Facility
  - Exit Hwy 246 at Purisima Road and go west to Hwy 1 north (near Lompoc) Exit Hwy 1 at Harris Grade Road and go north to facility

  - Exit Hwy 101 at Clark Avenue (Orcutt) and go west to Hwy 135 south Exit Hwy 135 at Harris Grade Road and go south to facility

- Santa Maria Asphalt Refinery
  - Exit Hwy 101 at Betteravia Road and go west to Sinton Road North on Sinton Road to facility

- Santa Maria Refinery
  - Exit Hwy 101 at Tefft Street and go west to Pomeroy Road
  - Pomeroy Road northwest to Willow Road
  - Willow Road west to Highway 1 to facility

Table 2.5-6 provides a summary of traffic volumes for selected sections of the highways and surface streets described above.

Table 2.5-6
Traffic Summary for Northern Subregion Surface Streets

Intersection	Survey Year	Peak Hour Approach Volume	V / C	LOS
Route 1 at Purisima Road (intersection of Rte. 1 / Purisima / Harris Grade)	1996	1,350	0.47	A
Route 135 NB at Clarke Avenue (Orcutt)	1996	1,782	0.35	A
Clark Avenue at Bradley Road (Orcutt - between Rte. 135 and Hwy. 101)	1997	2,386	0.61	B

Notes: Peak hour approach volume is approach to intersection from all directions
V/C - volume divided by capacity (for overall intersection)
LOS - level of service (for overall intersection)
Data provided did not include future traffic / level of service projections.

Source: Santa Barbara County Association of Governments, 1998.

Intersection	Survey Date	Avg. Daily Traffic	Peak Hours	Peak Hr Vol	Peak Day & Volume
Tefft Street west of Mary (between Pomeroy & Highway 101)	05/20/94	12,031	11:00 A 5:00 P	731 1,070	Fri. 13,778
Pomeroy west of Olympic (between Tefft & Willow)	09/25/93	5,052	8:00 A 4:00 P	327 537	Fri. 5,713
*Willow Road east of Route 1 (between Pomeroy & Rte. 1)	7/95	3,439	-	-	-

Notes: * Data provided did not include future traffic / level of service projections.

Source: San Luis Obispo Council of Governments, 1998.

The Santa Barbara County Association of Governments (SBCAG) "1995 Regional Transportation Plan, Adopted September 21, 1995" provides traffic volume data for selected sections of Highway 101. That report provides traffic volume information for various sections of Highway 101 in the Santa Maria area. Although it does not provide LOS levels, this can be correlated with information presented based on traffic volume and number of lanes. In 1993 (the year addressed in the SBCAG study), the highest northbound PM peak hour volume for any section in the Santa Maria area was 1,707 and the highest southbound PM peak hour volume for any section was 1,576. The annual traffic increase during the period 1993-2015 ranges from 1.4% to 3.0% for various roadway segments. In the year 2015, the highest northbound PM peak hour volume for any section is projected to be 2,683 and the highest southbound PM peak hour volume for any section is projected to be 2,476.

Information obtained from the Santa Barbara County Department of Planning and Development indicates that LPG and sulfur are trucked from one facility in the Northern Subregion portion of Santa Barbara County. This is:

- A total of 62 trucks were sent from the Lompoc Oil & Gas Processing Facility during the period October through December 1997 and 57 trucks during the four months of data reported in 1998. Typically the LPG trucks travel Highway 101 north and then Highway 166 east into Kern County. Typically, the sulfur trucks travel on local roads or Highway 101 north to agricultural facilities in northern Santa Barbara or San Luis Obispo counties. These trucks are required to comply with Resolution 93-480, described above.

No crude oil is transported by truck from the Lompoc Oil & Gas Processing Facility. Trucks may be used to transport sulfur, petroleum coke, asphalt, or other products from the Santa Maria Refinery, Santa Maria Asphalt Refinery, or other pump stations in the Northern Subregion.

In the Future Baseline scenario (Scenario 1), it is projected that the industry's use of roads and highways will be for the same purposes as described above. It is unlikely that other modes of transportation (pipeline, rail, or marine tanker) for the LPG and sulfur will be developed during the study period 1995-2015 given the declining production projections. In the Future Baseline scenario, the number of trucks of sulfur and LPG generated by the Lompoc Oil & Gas Processing Facility is projected to decrease from a total of 5 per week in 1997 to 2 in study year 2000. The facility is projected to cease operations prior to study year 2005.

As previously described, the Lompoc Oil & Gas Processing Facility is expected to reach the end of its economic life before the year 2015 under the future baseline scenario. If this occurs, it is assumed that the facilities will be removed or abandoned soon after they become idle. Activities associated with the decommissioning of the Lompoc Oil & Gas Processing Facility may cause a temporary increase in the use of the roads and highways near the facility as equipment is transferred and manpower levels are increased. In the long term, use of vehicles to supply materials to the facility or transport products from it will decrease. In addition, the use of the roads and highways by other vehicles (e.g., employees, contractors, and service providers) will decrease.

2.5.2.2 Ports & Harbors

2.5.2.2.1 Overview

There are twenty offshore platforms in the COOGER Study Region. Personnel, equipment, supplies, and other materials are transported to and from the platforms primarily by vessel and some of these vessels use public ports and harbors. In addition, there are two piers (Carpinteria and Ellwood) and a marine terminal owned and used exclusively by the oil and gas industry. These two piers are not used by the public, and therefore are not considered part of the public infrastructure. These private facilities are discussed in Section 2.4. Information concerning vessel traffic at these private piers is included with this discussion for completeness.

There are two main types of vessels used. Crew vessels are used primarily to transport oil company and contractor personnel who work on the platforms and may also be used to transport a small amount of equipment or supplies. Crew vessels typically operate from Port Hueneme and the Carpinteria and Ellwood Piers. Supply or work vessels are larger vessels that are used to transport the majority of supplies, including well drilling and workover supplies, and heavy equipment to and from the platforms. Supply/work vessels operate from Port Hueneme, but may berth at Ventura Harbor when not in service.

2.5.2.2.2 Eastern Subregion

There are three ports/harbors in the Eastern Subregion:

- Port Hueneme in the City of Port Hueneme - Port Hueneme is the only deep water port between Los Angeles and San Francisco and is used by commercial ships to load and unload goods. Port Hueneme is also used by supply (work) vessels and crew vessels that service offshore platforms.

- Channel Islands Harbor in the City of Oxnard - Channel Islands Harbor is used primarily by recreational vessels and commercial fishing vessels. Vessels associated with the offshore oil and gas industry typically do not use the Channel Islands Harbor.

- Ventura Harbor in the City of Ventura - Ventura Harbor is used primarily by recreational vessels and commercial fishing vessels, but does provide berths for some of the supply/work vessels that service offshore platforms.

Table 2.5-7 presents a summary of the offshore oil related vessel trips from Port Hueneme and the Carpinteria (Casitas) and Ellwood Piers in the Future Baseline scenario. The table shows the number of vessels originating from each location going to facilities in each Subregion by study year. The numbers represent weekly averages over each 5-year study interval. Information on truck and vehicle traffic associated with these vessel trips is provided in Section 2.5.2.1.2.

In the Future Baseline scenario (Scenario 1), it is projected that the average number of offshore oil related vessels from Port Hueneme will decrease from 94 per week in 1997 to 75 per week in study year 2000, increase slightly to 78 in study year 2005 and decline sharply to 13 per week in study year 2010 and 4 per week in study year 2015.

2.5.2.2.3 Central Subregion

The only public port/harbor in the Central Subregion is Santa Barbara Harbor which is used primarily by fishing, commercial and recreational vessels. Vessels providing routine services to

Table 2.5-7
Summary of Offshore Oil-related Vessel Trips[1]
All Vessels for Scenario 1 - Future Baseline
Total COOGER Study Region

	1997	2000	2005	2010	2015
All Vessels from Port Hueneme and the Carpinteria and Ellwood Piers					
Eastern Subregion	91	91	99	0	0
Central Subregion	98	73	59	59	18
Northern Subregion	1	1	4	0	0
All Vessels from Port Hueneme					
Eastern Subregion	49	49	57	0	0
Central Subregion	44	25	17	13	4
Northern Subregion	1	1	4	0	0
All Supply (Work) Boats from Port Hueneme					
Eastern Subregion	7	7	39	0	0
Central Subregion	44	25	17	13	4
Northern Subregion	1	1	4	0	0
All Crew Boats from Port Hueneme and the Carpinteria and Ellwood Piers					
Eastern Subregion	84	84	60	0	0
Central Subregion	55	47	42	46	14
Northern Subregion	0	0	0	0	0
All Crew Boats from Port Hueneme					
Eastern Subregion (only)	42	42	18	0	0
All Crew Boats from the Carpinteria Pier (Casitas Pier)					
Eastern Subregion (only)	42	42	42	0	0
All Crew Boats from the Ellwood Pier					
Central Subregion (only)	55	47	42	46	14

[1]This table presents the number of offshore oil related vessel trips per week originating from Port Hueneme and the Carpinteria and Ellwood Piers, as designated, for various study years in Scenario 1 (Future Baseline) "No Further Development".

the offshore oil and gas industry typically do not use Santa Barbara Harbor to load/unload personnel, supplies or equipment (but may refuel at this harbor). Vessels belonging to the Clean Seas Oil Spill Response Cooperative are anchored east of Stearns Wharf at the Santa Barbara Harbor.

In the future baseline case, Santa Barbara Harbor is expected to continue as the base of operations for the Clean Seas Oil Spill Response Cooperative vessels. Because this activity is not directly related to the rate of offshore oil and gas production or number of operating platforms, the future baseline level of activity at Santa Barbara Harbor is expected to be comparable to current activities throughout the 1995 to 2015 COOGER study period. No new activities associated with offshore oil and gas development are expected at the Santa Barbara Harbor during this period (i.e., the Santa Barbara Harbor is not projected to be used as a base for personnel or material transport).

2.5.2.2.4 Northern Subregion

There are three public ports\harbors in the Northern Subregion:

- Avila Bay - The Avila Bay area is used primarily by recreational vessels and fishing vessels. There is a pier owned by Unocal that historically was used as a marine terminal to load oil tankers. As of July 1999, this marine terminal has been decommissioned. No future use of Avila Bay is expected to be associated with offshore oil and gas development.

- Morro Bay - Morro Bay is used primarily by commercial and recreational vessels. Vessels associated with the offshore oil industry do not typically use Morro Bay.

- Estero Bay - The Estero Bay area is used primarily by recreational vessels and fishing vessels. There is a private mooring area with two loading spots that were historically used to load oil tankers which is currently in the process of being decommissioned.

Currently, offshore activities in the Northern Subregion are served by vessels from Port Hueneme or from ports outside the Tri-County area. No activity associated with offshore oil and gas operations currently occurs at any of the Northern subregion ports, and no new demand for port-related services has been identified in connection with the future baseline development scenario (Scenario 1) from 1995 to 2015.

2.5.2.3 Railroads

2.5.2.3.1 Overview

Although the Coastal Line of the Union Pacific Railroad traverses almost the entire "length" of the Principal Study Region and passes within close proximity to many of the onshore facilities, only the Santa Maria Refinery and Santa Maria Asphalt Refinery are configured to load/unload rail cars. As of July 1999, the Santa Maria Refinery was using rail cars for petroleum coke and sulfur: the Santa Maria Asphalt Refinery was not using rail cars.

During 1997, some of the OCS oil reaching the central California pipeline system was being transported by pipeline by Tosco to the Mojave area where it was being loaded on to rail tank cars (unit trains) for transport to the Los Angeles area. Although other destinations were not being served by unit trains, these trains could be used to transport the oil to other refineries in California or elsewhere in North America. The completion of the Pacific Pipeline system added pipeline capacity to transport crude oil from Kern County to the Los Angeles area and should provide a viable alternative to the use of unit trains. As of July 1999, unit trains outside the study region were still used to transport some California OCS crude oil, however.

With the installation of rail spurs and loading facilities, rail transportation could be an alternative means of transporting NGL, LPG, and sulfur from some onshore processing facilities. Rail cars used to transport these materials must comply with the requirements of the U.S. Department of Transportation, including design and operating specifications for pressurized tanks.

Because most of the onshore processing facilities do not have rail spurs or loading facilities and because rail transportation is not the preferred method for transporting the oil, gas, NGL or LPG, it is unlikely that the use of railroads by the onshore processing facilities will change significantly during the study period 1995-2015 in Scenario 1 (Future Baseline - no additional development scenario).

As previously described, it is projected that some of the processing facilities will reach the end of their economic life before the year 2015 and it is assumed that the facilities will be removed or abandoned soon after they become idle. Activities associated with the decommissioning of an individual facility are not expected to require the use of railroad services.

2.5.2.3.2 Industry Use

The Coastal Line of the Union Pacific Railroad traverses the length of the Tri-County area. In past assessments, the feasibility of transporting crude oil from the Tri-County area to refineries outside the Tri-County area by rail has been considered. Currently, no offshore crude oil is being transported by rail within the COOGER Study Region.

Rail transport of products associated with offshore oil production currently occurs only in the Northern Subregion. The Santa Maria Refinery currently ships sulfur and petroleum coke by rail. In the absence of new development, Northern Subregion offshore crude oil input to this facility is projected to decline to zero by 2005 (although inputs from onshore sources or other offshore sources connected to the AAPLP and Sisquoc Pipeline system could maintain inputs to this facility). Rail transport associated with Northern Subregion offshore oil production would not occur beyond 2005 in the future baseline case, but could include products associated with Central Subregion offshore production.

2.5.2.4 Airports

2.5.2.4.1 Overview

Although most of the transportation to and from the offshore facilities is by vessel, each of the platforms has a helicopter landing pad. Helicopters are used to transport employees to and from the platforms, most commonly for platforms located furthest from shore. Some of the onshore facilities, such as the Las Flores Canyon SYU Oil & Gas Processing Facility, also have helicopter landing pads. Helicopters are also used to provide emergency medical transportation services and assist in personnel rescue efforts. These helicopters are typically based at airports within the Tri-County area. In addition, local airports are used by personnel conducting business with the petroleum industry. Table 2.5-8 provides a summary of the projected number of offshore oil related helicopter trips from each of the airports in the Study Region for the Future Baseline scenario.

Table 2.5-8
Summary of Offshore Oil-Related Helicopter Trips
from All Airports in the COOGER Study Region
Scenario 1 - Future Baseline

	1997	**2000**	**2005**	**2010**	**2015**
From the Santa Barbara Airport to					
Central Subregion Facilities	39	33	27	14	11
Northern Subregion Facilities	0	0	0	0	0
From the Lompoc Airport to					
Northern Subregion (only)	4	4	3	0	0
From the Santa Maria Airport to					
Northern Subregion (only)	0	0	0	0	0
Total from All Airports	43	37	30	14	11

Note: No "regularly scheduled" oil-industry related flights are projected from airports in the Eastern Subregion and no flights are projected to go to facilities in the Eastern Subregion from airports outside the Eastern Subregion under any of the scenarios.

2.5.2.4.2 Eastern Subregion

As of July 1999, no offshore oil industry flights were being made from any of the airports in the Eastern Subregion.

The Camarillo Airport is used primarily by private aircraft; no commercial passenger aircraft is currently used at this airport. As of July 1999, the Minerals Management Service (MMS) inspectors were using helicopters from the Camarillo Airport to fly to platforms in the Southeastern Santa Barbara Channel (as far northwest as Platform Heritage). The MMS flights average five per week.

The Santa Paula Airport is used primarily by private aircraft; no commercial passenger aircraft are currently used at this airport.

The Oxnard Airport is the closest public airport to platforms in the southeastern part of the Santa Barbara Channel. The Oxnard Airport is served by commercial passenger aircraft.

Because offshore activity levels are expected to decline within the Eastern Subregion over the 1995 to 2015 study period in the future baseline case, the industry's use of airports in the Eastern Subregion is not expected to change. The flights conducted by the MMS are projected to continue at a constant level throughout the study period.

2.5.2.4.3 Central Subregion

The Santa Barbara Airport is the closest public airport to platforms in the central portion of the Santa Barbara Channel and, as of July 1999, was the only Central Subregion airport providing scheduled service to the platforms. Although several offshore operations are projected to decline in the future baseline case, continued production from existing operations will continue to require helicopter support from the Santa Barbara Airport. As shown in Table 2.5-8, the number of flights per week is projected to decline annually an average of 33 flights per week in study year 2000 to 11 flights per week in study year 2015. As shown, there is a relatively sharp decline between study year 2005 and 2010.

2.5.2.4.4 Northern Subregion

The Lompoc and Santa Maria Airports are the closest public airports to Platform Irene in the Northern Subregion. Helicopter services transport personnel and provide emergency services to these platforms. Although there are other airports in the Northern Subregion (e.g., San Luis Obispo), these were not identified as being used by the offshore oil and gas industry.

As of July 1999, oil industry flights to Platform Irene, the only platform in the Northern Subregion, were from the Lompoc Airport. As shown in Table 2.5-8 for the Future Baseline scenario, the number of flights per week is projected to decline from 4 per week in study year 2000 to 3 in study year 2005. The platform is projected to be shut down prior to study year 2010. No offshore oil industry related flights are projected for study years 2010 and 2015.

The Santa Maria Airport is served by commercial passenger aircraft and is also used by private aircraft. As of July 1999, no offshore oil industry flights were originating from the Santa Maria Airport. However, the Minerals Management Service (MMS) inspectors were using helicopters from the Santa Maria Airport to fly to platforms in the Santa Maria Basin and Northwestern Santa Barbara Channel (as far southeast as Platform Hermosa). The MMS flights average five per week.

2.5.3 Refineries

This section provides a brief overview of refinery systems in California (excluding the Santa Maria Refinery which is discussed elsewhere in this report in detail), Texas, and Louisiana, as of early 1995, and their ability to refine crude oil produced offshore in the Tri-County area.

There are three refinery centers in California that can receive and process offshore crude from the Study Region. However, not all of the refineries within each refining center can process the generally heavy, high-sulfur crude produced from the Monterey Formation in the COOGER Study Region. These refinery centers are currently supplied by pipeline, rail and marine transportation and are located in the Los Angeles, San Francisco Bay and Kern County areas. Additional refineries with the capability to process California OCS crude are located near the Texas Gulf Coast and in the Texas Panhandle and these are served by pipelines connected to the COOGER Study Region. Each of the refineries in these centers may need to displace heavy crude from existing sources to accommodate additional offshore production. Table 2.5-9 shows the estimated total capacity of the larger high conversion refineries to process crude with the range of characteristics found in California offshore crude. There are other smaller refineries in each of these three areas.

2.5.3.1 Southern California Refineries

Six large high conversion refineries are located in southern California and include Chevron at El Segundo, Mobil at Torrance, Arco at Carson, and Tosco, Texaco, and Ultramar at Wilmington. These refineries process San Joaquin Valley, Alaska North Slope, Los Angeles area, and foreign imported crudes in addition to some crude produced offshore in the Tri-County area. The Arco refinery has historically processed almost exclusively Alaska North Slope crude. There are other smaller refineries in the Los Angeles area, some of which purchase crude to produce asphalt.

2.5.3.2 Central California Refineries

There are six relatively small refineries in the Bakersfield area that primarily process local, San Joaquin Crude, but are connected to the central California pipeline system and can receive OCS crude. Because the OCS crude is blended with local crude in the various tank farms, pump stations and pipelines, the actual quantity of OCS crude processed at these refineries was not identified.

2.5.3.3 Northern California Refineries

Five of California's eleven largest refineries are located in the northern part of the state and include the Tosco refinery in Rodeo, Chevron at Richmond, Exxon at Benicia, and Tosco and Shell at Martinez. In Kern County, the AAPLP Main Line connects to the central California pipeline system which can transport OCS crude to the Bay Area. Because the OCS crude is blended with onshore-produced crude in the various tank farms, pump stations and pipelines, the actual quantity of OCS crude processed at the Bay Area refineries was not identified. There are other small refineries in the Bay Area, some of which purchase crude to produce asphalt (e.g. Huntway). As discussed in Section 2.5.1.1.3, an existing Tosco pipeline system connects the Santa Maria Refinery (within the Northern Subregion) to the Tosco Rodeo Refinery in the San Francisco Bay area. This pipeline system is used to transport partially refined products from the Santa Maria Refinery to the Rodeo Refinery.

Table 2.5-9
Estimated Crude Refining Capability

Company	Location	Distillation Capacity (MBSD)	Onshore Processing Capability of Tri-County Crude Best Estimate (MBSD)
CALIFORNIA			
Chevron	El Segundo	362	40
Texaco	Wilmington	78	10
Mobil	Torrance	130	30
Shell	Wilmington	149	10
Union	Los Angeles	111	0
Ultramar	Wilmington	72	35
Subtotal	Southern California	902	125
Texaco "Tosco"	Bakersfield	65	NA
Texaco "Mohawk"	Bakersfield	65	NA
Texaco "IVEC"	Bakersfield	65	NA
Former "Witco"	Kern Co.	10	NA
Kern Oil Refining	Kern Co.	20	NA
San Joaquin Refining	Kern Co.	10	NA
Chevron	Richmond	195	25
Tosco	Martinez	133	30
Shell	Martinez	143	30
Exxon	Benicia	132	10
Unocal	Santa Maria/Rodeo	120	10
Subtotal	Northern California	723	105
TOTAL	California	1,860	230
TEXAS & LOUISIANA			
Exxon	Baytown, TX	448	40
Conoco	Westlake, LA	164	40
Champlin	Corpus Christi, TX	160	0
Chevron	Port Arthur, TX	258	10
Lyondell	Houston, TX	286	30
Amoco	Texas City, TX	440	50
Phillips	Borger, TX	110	5
Star (Texaco)	Port Arthur, TX	278	10
Citgo	Lake Charles, LA	305	20
Coastal	Corpus Christi, TX	95	15
TOTAL	Gulf Coast	2,544	220

*NA = No information available

2.5.4 Alaska North Slope Crude Export Ban

In 1973, Congress imposed the Alaska North Slope (ANS) Ban which prohibited the export of crude oil produced in Alaska. As a result, the closest major refining centers for the ANS crude were the refineries in the Los Angeles and San Francisco Bay areas. The large quantity of ANS crude, combined with the quantity of onshore and offshore California production, and the fact that the ANS and many California crude oils were heavy, resulted in an oversupply (i.e. the volumes and types of crude oil available for refining in California was more than the refining capacity available for the oil). Because of economic and/or other factors, the refineries were "accepting" such large quantities of ANS crude oil that the onshore and offshore California producers had to look for other refining markets, most of which were in Texas and Louisiana. The refineries ability to get the lower cost ANS crude impacted the price for California crude and the increased costs associated with shipping California crude to Texas and Louisiana impacted the economic viability of some California operations. In 1994, the Department of Energy (DOE) conducted a study that projected the unrestricted export of ANS crude would result in a wellhead price increase for both ANS and California crude. The U.S. government lifted the ANS Ban in May 1996.

Since the ANS Ban was lifted, some ANS crude has been exported to other countries, and the quantity of Alaska production has decreased significantly. This decline in Alaska North Slope crude oil production could be partially offset by currently proposed developments that have not yet received agency approval, and the Minerals Management Service has suggested that new federal and state lease sales could lead to substantial new discoveries on the North Slope. Several major oil companies (notably Arco and BP Alaska) have expressed their intention to maintain production levels beyond 1999 through the implementation of new projects, but total production of ANS crude oil is still expected to decline. Peak crude oil production from North Slope reservoirs occurred in 1988 at production rates of 2 million barrels per day. By 1995 ANS production had declined to 1.45 million barrels per day. Current projections of ANS production which include the development of recent discoveries predict continued declines to 0.94 million barrels per day in 2005, and 0.38 million barrels per day by 2015 (Alaska Department of Natural Resources, 1997). Production declines and exports of ANS crude oil have resulted in more "local" refining capacity available to California producers. Information from the California Independent Petroleum Association (CIPA), indicates many California operators have seen some price increases since the ANS Ban was lifted. However, these data are insufficient to credit this increase to the lifting of the Ban, given there are other factors such as the reduction in ANS crude being produced. No studies assessing the impact of lifting the Ban could be located; however, CIPA indicated it was expected that the DOE would be conducting such a study.

3.0 DETERMINATION OF FUTURE BASELINE AND POTENTIAL DEVELOPMENT SCENARIOS

3.1 OVERVIEW

The evaluation of different development scenarios requires an understanding of three principal factors:

1) the current and recent historical level of oil and gas activity;

2) the future level of oil and gas activity expected over the next twenty years if no further development of existing offshore leases occurs; and,

3) the potential level of new offshore development associated with known, but undeveloped, resources on existing leases.

The first two factors are discussed in Section 2.0 of this report, and provide a future baseline of generally declining oil and gas production throughout the study region in the absence of new development. The first scenario addressed in each study subregion specifically addresses the declining production and associated facility closures associated with this baseline. The third factor varies according to the development controls and assumptions applied.

During public workshops associated with the COOGER study, suggestions were received concerning scenarios to be evaluated in this study. These suggestions recommended scenarios addressing no further offshore development, the expeditious decommissioning of all operations recognized as nearing the end of their useful life, and lease buyback and termination of existing offshore operations. The no further development scenario is included in this study as Scenario 1. The expeditious decommissioning scenario is included in the Eastern and Central Subregion analyses, and its effect on potential future development of known undeveloped resources is addressed. This scenario is not included in the Northern Subregion because it results in the same future production estimates as Scenario 1. The lease buyback and termination of existing operations is not evaluated because a practical method for estimating the probable cost and identifying a suitable finance mechanism for such a scenario was not apparent. The COOGER study has applied an economic viability test to define upper limits of potential future development within the study region, and this scenario does not appear to meet a similar test of financial viability. It should be noted, however, that some of the development evaluated in the report could require extensions of original lease terms. Requests for extensions are subject to the review of MMS or California State Lands Commission. Each of these agencies has specific standards applicable to lease extension review, and may deny extension requests. If all currently undeveloped leases were canceled prior to development, the result would be equivalent to the Scenario 1 conditions addressed in this report. This section of the COOGER study presents the estimates of future oil and gas production rates and related facilities associated with each development scenario outlined by the scenario guidelines presented in Section 1.2.

The production rates and associated development activity presented in this report were determined using a multi-step process. First, the baseline scenario was described assuming that no new development would occur (Scenario 1). Secondly, geologic data and operator analyses were reviewed to define the maximum level of development and likely production profiles that could occur without considering potential constraints. Third, the maximum rate of development was determined based on an evaluation of resource delineation, engineering, and regulatory approvals required. The Fourth, and final, step involved the application of the COOGER Study Steering Committee-specified development controls and assumptions to eliminate or modify specific resources. These controls and assumptions are discussed in Section 1.2 of this report, including the specific guidelines applicable to each development scenario described in this section. One important assumption applied to this exercise is that oil and gas development is assumed to maximize total production by the use of existing facilities wherever it is economically feasible to do so, as long as it complies with current regulations. The permit and design capacities of all facilities and the legal non-conforming status of some facilities affects the source and amount of oil and gas that may be processed at specific locations, and this was considered in the development of specific scenarios.

The estimates of development potential and projected production from existing leases are based on 1995 data. These data are subject to considerable revision based on actual field performance, technological advancement, and operator decisions. Periodic updates of the data presented should be performed to incorporate significant changes and maintain the usefulness of this information.

3.2 DETERMINING MAXIMUM POTENTIAL DEVELOPMENT OF EXISTING LEASES

To provide a factual basis for future development scenarios, a detailed review of proprietary reservoir data provided by the MMS, California State Lands Commission, and offshore operators was accomplished by The Scotia Group, Inc., an independent oil and gas advisory firm. The focus of this effort was the determination of oil-in-place, estimated oil recovery factors, and related details concerning oil and gas reserves associated with each identified oil field. Operator development concepts and proprietary Development and Production Plans were reviewed as one input to development planning and production profile forecasts. In addition, most operators provided company-proprietary data concerning reserves characteristics and development planning. Once the basic reservoir characteristics and reserves were defined, generic development options were evaluated to develop project cost inputs to the reservoir economic evaluation.

The Scotia Group calculated potential reserves using a Monte Carlo probablistic simulation based on the data collected. For conventional sandstone reservoirs (non-Monterey), the input to the simulator included distributions for: net reservoir rock volume determined from provided volumetric maps, porosity, water saturation, formation volume factor, and recovery factor (recoverable fraction of original oil in place). Generally, these were triangular distributions defined by a maximum value, a minimum value and most likely value. Monterey formation reserves are commonly computed as the product of the gross rock volume also determined from available maps and the recoverable oil volume per unit rock volume appropriate to the development plan. This latter method was applied in the Monte Carlo simulator by specifying gross rock volume (acre-feet) and recovery fractions (barrels of oil/acre-foot) distributions. The major advantage of the Monte Carlo technique is that it associates reserves with a level of probability. The analysis conducted for this study reports the estimated production from each field for three different probability levels. This includes the P(10) (production estimate that only has a 10% chance of being exceeded), and P(90) (production estimate that has a 90% chance of being exceeded by actual production). In the following discussions of reserves for each development prospect, the P(90) and P(10) values define the range of possible values from minimum to maximum and the P(50) value is taken as the most likely reserves estimate. The project economics and development scenarios presented in this report are based on P(50) production estimates.

Worley International, Inc. and Belmar Engineering provided engineering support for the COOGER study, and performed evaluations of a range of potential development options for each identified prospect. These options included new conventional steel jacket drilling and production platforms, extended drilling from existing platforms, minimum-facility fixed platforms, tension leg platforms, floating production systems, hybrid platform and subsea well complexes, and onshore drill sites. A range of development drilling techniques were also addressed, including conventional directional drilling, extended-reach drilling with or without long horizontal sections, and multi-lateral wells. Consistent with the basis COOGER study assumption that maximum use of existing industrial facilities will occur, availability of existing offshore pipelines to connect new developments to onshore processing facilities or onshore pipeline systems was an important factor included in the consideration of development options. Once a range of development options were identified, estimated costs of each option were determined and the option which maximized production with the best return on investment was identified for further analysis.

The capital cost estimates for offshore platforms, facilities, and pipelines were generated using Belmar Engineering's development cost program. Drilling and completion costs for wells were generated using Belmar's well cost program. Operating costs were developed using fixed and variable unit costs reflecting the specific type of development planned, and results were compared to actual records of offshore facility operating costs where these were available. Monthly operating costs averaged over the life of the field were used in this analysis. Operational costs of existing onshore facilities, development costs of new facilities, inter-company charges for shared use of onshore facilities, and pipeline tariffs associated with the use of existing offshore pipelines to connect to onshore facilities were not included in the Belmar Engineering cost analysis. Because the Belmar cost estimates represent an intermediate step in the project economic feasibility analysis, and this analysis is focused on a simple yes or no determination of economic viability, this simplification of the Belmar cost estimate is not expected to adversely affect study results so long as this simplification is considered when the economic viability of each offshore prospect is evaluated. The economic viability of each prospect was evaluated based on P(50) reserves estimates, oil and gas production rates projected by actual operator production plans or developed from the Belmar optimum development option, capital and operating costs estimated by Belmar Engineering, and crude oil prices based on the gravity of the dominant reservoir crude. Figure 3.2-1 indicates the crude oil price inputs used in this study. Adjustments to the crude oil prices were accomplished to reflect several factors, including pipeline tariff of $0.68 per barrel of oil; and federal royalty reimbursements of $1.00 per barrel of royalty oil were applied as an adjustment to non-royalty product prices (the range of crude oil prices used in this study is from $9.50 to $13.71 per barrel). Produced gas price was assumed at $1.68 per thousand cubic feet (MCF), and a processing and handling cost of $1.00 per MCF was assumed. This resulted in a net gas value of $0.68 per MCF. The following assumptions were applied to the evaluation of economic viability of each prospect:

1. Platform design, construction, and installation in project year one and two (total cost equally split).

2. Pipelines and production facilities completed in year two.

3. Development drilling begins in year two.

4. Production begins in year three.

5. Crude oil pricing was based on gravity of oil from the dominant reservoir unit (Monterey, Vaqueros, etc.). No price escalation factors were applied; prices were held constant.

6. All economics were run pre-federal tax.

The viability of each project was judged on the basis of the following routine oil industry economic yardsticks:

- Payout Period: must be less than eight years.
- Return On Investment (ROI): must be greater that 1.5:1.
- Discounted Rate of Return (ROR): should be greater than 10%

If the economics show the project will not payout or fails to provide an ROI greater than 1.5, the project would be an economic failure. If the project meets the payout and ROI criteria but has an ROR less than 10%, then the project would be considered uneconomic. Economic failures and uneconomic projects were not included in our projections of potential future production. The only exception to this involved cases where the operator expressed definite plans to pursue development in spite of marginal current economics or where the confirmed reserves estimated are only a portion of a larger suspected resource which is expected to alter the project economics. This effort resulted in the identification of several currently undeveloped resources on existing leases which are considered economically viable. These areas of potential future development are shown on Figures 3.2-2 and 3.2-3.

The optimum production profile of each prospect determined to be economically viable was then used to define the maximum rate of production (assuming P(50) reserves) from individual prospects. To transform this information into development scenarios, it was necessary to define the year of initial production from each currently undeveloped oil and gas prospect on existing leases (refer to Section 3.3).

3.3 DETERMINING THE DEVELOPMENT SCHEDULE OF IDENTIFIED RESOURCES

Proposed exploration and development schedules from operators of undeveloped leases in federal waters and an analysis of the projected year of initial production from each identified undeveloped oil field were used as a starting point for the determination of development schedules associated with each scenario. Operator schedules were compared to a list of pre-production activities and associated time-frames which were independently determined to verify operator schedules. This effort confirmed that all operator schedules are reasonable (that is, no project development is projected to occur in less time than the independently determined minimum time frame), and most are very close to the schedule that was independently determined. As a result, the development schedules addressed in this report reflect the individual field development schedules provided by the offshore operators to the extent they are consistent with other scenario guidelines. It should be noted that Northern Subregion scenario guidelines specified by the COOGER study Steering Committee established production rate limits for the expanded development scenarios (Scenarios 3 and 4). These limitations are well below the production potential of Northern Subregion offshore fields, and are based on current industry assessments of potential markets for Northern Subregion crude oil considering expected crude oil characteristics. Although all fields in the Northern Subregion are expected to encounter continuing activity associated with exploration and evaluation from 2000 through 2015, the production limitations specified by the COOGER study scenario guidelines suggest that production from the Point Sal, Purisima Point, and Santa Maria fields is not likely to begin until after 2015. This analysis is consistent with the offshore operator's current assessment of likely development schedules. An explanation of the specific schedule of development of each field and resulting subregional oil and gas production associated with each scenario is presented in Section 3.5.

An independent assessment of the projected year of initial development of each identified offshore oil field was originally developed because operator inputs were not available. The approach used provides a reasonable basis for the evaluation of operator-supplied schedules and allows the determination of development schedules for offshore development for which operator schedules are not available. This analysis was accomplished using a list of specific pre-production activities and incremental time frames which were defined in consultation with the MMS and COOGER study Steering Committee technical subcommittee. As explained in the description of each activity presented below, many of these activities are routinely accomplished concurrent with other pre-production activities. The time periods assigned to each activity represent incremental additional time required to accomplish that activity assuming that the concurrent pursuit of multiple activities would occur. For example, a potential development which requires the regulatory review and fabrication of new offshore structures along with the modification of an existing onshore facility is estimated to require a total of four years to complete these activities when both components of the project are pursued concurrently. This is the sum of the three-year time increment estimated for regulatory review and fabrication of the offshore structure and the one-year additional increment associated with the review and fabrication of a modified onshore facility. This approach allows the identification of the most rapid pace of development of each offshore field in the absence of specific operator proposals to provide a starting point in the determination of a range of possible future offshore development scenarios.

A summary of the individual activities required prior to production from each development identified as feasible under this study is presented on Table 3.3-1. This table also presents the projected year of initial production from each field. The individual activities and minimum incremental time frames for the activities reflected on this table include:

- Administrative Discussions - This activity includes operator/agency negotiations concerning unit determinations, royalty renegotiation, or other administrative issues that may be required in connection with a specific development. This activity would be accomplished concurrent with field delineation and preliminary engineering, and has been assumed to result in no additional time to initial production.

- Exploration/Delineation - Applicable to fields which have not been confirmed by an exploratory well, or which were identified as requiring further delineation drilling during our evaluation of developable resources. This activity is assigned a one-year time period in this analysis.

- Engineering/Development of New Technology - This task is applicable to prospects which involve production characteristics, water depth, or crude oil transport or processing issues that have not previously been addressed in the Pacific OCS or represent significant advances in oil and gas technology. This activity is assigned a one-year time period in addition to routine engineering.

- Engineering/Existing Offshore and Onshore Facilities - Fields which may be developed from existing offshore or onshore facilities and using existing onshore processing facilities are considered in this category. This activity is assigned a one-year time period.

- Engineering/New Offshore Structure - This task is applicable to fields which are expected to be produced from new offshore facilities, or from a new onshore drillsite. If engineering of new or modified onshore facilities is required, it is assumed to be accomplished concurrently, and no additional time is required. This activity is assigned a two-year time period.

- Approvals/Existing Offshore and Onshore Facilities - This task represents the minimum regulatory review and approval process for projects involving existing facilities. A one-year time period is assigned to this activity.

- Approvals and Fabrication/New Offshore Structures - This task involves regulatory reviews and approvals, and facility fabrication efforts. The minimum time period assumed for this activity is three years.

- Approvals and Fabrication/Modification of Existing Onshore Facility - This task involves regulatory review and approvals, and facility fabrication efforts. Although these efforts are expected to proceed concurrently with offshore facility approvals, the additional complexity of the review process is expected to add a minimum of six months to the review, approval, and fabrication process.

- Approvals and Fabrication/New Onshore Facility - This task involves regulatory review and approvals including siting and alternatives analyses, and facility fabrication efforts. Although these efforts are expected to proceed concurrently with offshore facility approvals, the additional complexity of the siting and review process is expected to add a minimum of one year to the review, approval, and fabrication process.

- Facility Installation, Commissioning and Pre-production Start-up - This task involves site construction, facilities testing, and initial drilling activities preceding production. This activity is assigned a one-year time period.

- Start-up Delay/Multiple Field Developments - This task represents a special category assigned to multiple developments implemented by a single operator. It assumes that operators would implement a phased development to allow an evaluation of results from prior development. This start-up delay is intended to apply to multiple field developments that are pursued with concurrent or overlapping engineering and review processes to avoid an unrealistic projection of concurrent start-up of multiple fields in the Northern Subregion. The assumed start-up delay is two years (minimum).

The start of production years indicated in Table 3.3-1 were used to define the initial production from each offshore prospect without consideration of other factors, such as operator cash flow management, marketability of production, and environmental review process delays. The production startup estimates were combined with unrestricted potential oil and gas production profiles to develop a high-case estimate of the composite total production rate from currently undeveloped prospects for each study subregion without regard to prescribed scenario guidelines, onshore constraints, or operator limitations. This composite total was used as a starting point for the iterative process of defining the specific development and associated production rates reflected by each scenario to be addressed in the COOGER study. This process included the evaluation of production limitations associated with policy-related input limitations and expansion constraints as well as limitations specified by individual scenario guidelines (including production limits and possible development schedule delays). This approach allows the determination of the maximum annual oil and gas production associated with each development scenario (based on P(50) reserves estimates), and identification of the level of concurrent activity during each 5-year time increment addressed by this study. Delays caused by factors not addressed by this study would generally reduce total production over the entire COOGER study 20-year time period, but could cause short-term activity peaks associated with overlapping activities. The results of this effort are described in Section 3.5.

TABLE 3.3-1
DETERMINATION OF INITIAL PRODUCTION FROM NEW FIELDS - COOGER STUDY REGION

	Administrative (0 yrs. - concurrent) (Unit Redetermination, Royalty Renegotiation)	Exploration/Delineation Well Required	Engineering/ New Technology	Engineering/Existing Offshore and Onshore Facility	Engineering/New Offshore Structure	Approvals - Existing Offshore & Onshore Facilities	Approvals - New Offshore Structure	Approvals - Modify Existing Onshore Facility	Approvals - New Onshore Facility	Start-up - Commission & Drill	Start-up Delay - Multiple Developments	Complete Development Application	Start Production
EASTERN													
Carpinteria				U		U				U		1999	2001
Cavern Point		U		U		U				U		2002	2002
Rincon										U		1998	1999
CENTRAL													
Molino				U		U				U		1996	2001
South Ellwood				U		U		U		U		1999	2002
Gato Canyon		U			U		U			U		2004	2007
Sacate				U		U				U		1998	2002
Sword		U	U		U		U			U		2005	2009
Rocky Point-Jalama				U		U				U		2000	2002
Cojo					U		U			U		2000	2004
Piñon Electra				U		U				U		2000	2002
NORTHERN													
Bonito-Sugar Maple		U			U		U			U		2004	2009
Lion Rock	U	U	U		U		U		U	U		2003	2008
Point Sal	U	U	U		U		U		U	U	U	*	*
Purisima Point	U	U	U		U		U		U	U	U	*	*
Santa Maria	U	U	U		U		U		U	U	U	*	*

*Based on operator inputs available, characteristics data, and expected market limitations, these fields are not expected to be developed during the COOGER study time frame under any of the scenarios considered. Activities associated with exploration and resource evaluation would occur during the COOGER study time frame, however.

3.4 DEFINING SCENARIO-SPECIFIC OIL AND GAS PRODUCTION RATES

The determination of scenario-specific oil and gas production rates was accomplished by combining the projected future baseline oil and gas production inputs at each existing onshore processing facility with additional production from currently undeveloped prospects on existing leases. To accomplish this, each undeveloped prospect was assigned to a specific onshore facility by considering projected facility excess capacity and existing offshore pipeline systems that could be used to transport production to the onshore facility. The specific guidelines applicable to each scenario were applied to limit new production inputs in cases where adequate facility capacity was not available and facility expansions were specifically prohibited by the scenario definition. These limitations were used to modify the production rates associated with undeveloped fields on existing leases. Development schedule modifications were also considered, but none were necessary to accommodate the scenarios as presented in this report. Some scenarios resulted in the determination that certain prospects would not be developed during the COOGER twenty-year time frame, however. Where facility capacity constraints did not limit production, this scenario development process specifically assumed that all offshore prospects would be developed according to the schedule indicated on Table 3.3-1. It was also assumed that the optimum development rate defined by the optimal P(50) production profiles would be achieved unless limited by a facility capacity constraint. This approach resulted in the determination of the maximum annual production of oil and gas associated with each scenario. It should be noted that these scenarios are intended to reflect a range of potential development based on specific development limitations. Refinement of the limitations applied, modification of development schedules, and project-specific limitations and performance could all contribute to a continuous range of potential development scenarios between those presented in this report.

The effect of accelerated facility decommissioning and removal of specific developments was addressed as a separate scenario to clearly illustrate the consequence of this activity in terms of future oil and gas production. Where facility decommissioning affected a specific prospect, alternate processing facilities were identified and the economics of prospect development were reevaluated. If no economically viable alternate development could be identified, the affected prospect was deleted from the future production estimates. In the Central Subregion, the projected decommissioning of Point Arguello Field facilities resulted in the determination that several offshore prospects in the Central Subregion could be developed as economically viable projects with pipeline connections to the Platform Irene pipeline system which is currently connected to Northern Subregion onshore facilities. This determination resulted in the identification of three additional Northern Subregion scenarios to reflect the effect of the Central subregion decommissioning scenario under different Northern Subregion scenario guidelines. Details concerning individual scenarios and the scenario-specific production rates and facilities associated with each scenario are presented in Section 3.5.

3.5 SCENARIO-SPECIFIC DEVELOPMENT AND PRODUCTION

3.5.1 Overview

The region addressed by this study is currently developed to produce oil and gas from existing leases on the federal OCS and California State Tide and Submerged Lands. Twenty-one offshore facilities (twenty platforms and one man-made island) and three onshore drillsites (Mandalay, Rincon, and Molino) are currently developed. Production from these operations is currently processed at twelve onshore processing facility sites. Without further offshore development (Scenario 1 in this study), the number of offshore platforms and onshore processing facilities would decline rapidly. Under this scenario, four offshore facilities (three platforms and one man-made island) and three onshore processing facilities would remain in the study region by 2010 and beyond. Development scenarios which address the possibility of continued offshore development still indicate reductions in the numbers of offshore and onshore facilities. Scenarios involving the highest levels of potential development project a total of eleven offshore facilities (ten platforms and one man-made island) and eight onshore processing facilities would remain in the study region by 2010 and beyond. A summary of the projected number of facilities associated with each scenario addressed by this study is presented in Table 3.5-1. Detailed information concerning facilities associated with each scenario is presented in Sections 3.5.2 through 3.5.4.

As discussed in Section 2.3, future oil and gas production within the study region is expected to decline substantially in the absence of new offshore development. Figure 3.5-1 illustrates the projected oil production rate associated with each study subregion if no further offshore development occurs. For comparative purposes, Figure 3.5-2 illustrates oil production levels associated with Scenario 3 in each subregion. This scenario reflects the maximum potential development of oil and gas resources on existing leases without limitations imposed by processing facility capacity in the Eastern and Central Subregions; and addresses the full development of Northern Subregion resources reflecting a realistic estimate of the potential markets for this production developed in consultation with the operator of Northern Subregion leases. Detailed information concerning the potential oil and gas production associated with each scenario addressed in this study is presented in Sections 3.5.2 through 3.5.4.

TABLE 3.5-1
EXISTING AND POTENTIAL FUTURE OIL AND GAS FACILITIES

Scenario	Number of Offshore Facilities		Number of Onshore Facilities	
	Today	2010	Today	2010
Scenario 1 - No further offshore development	21	4	12	3
Scenario 2 - further offshore development within existing onshore facility capacity	21	11	12	7
Scenario 3 - further offshore development with expanded onshore capacity (with market-limited Northern Subregion Production)	21	11	12	8
Scenario 4 - further offshore development with accelerated facility decommissioning in Eastern and Central Subregions, and development of Northern Subregion facilities to accommodate displaced production and maximum (not market-limited) Northern Subregion Production	21	8-10	12	7

3.5.2 Eastern Subregion

The Eastern Subregion offshore resources are currently produced from 13 offshore structures and two onshore drill sites. As indicated in Tables 3.5-2 and 3.5-3, production from this subregion is expected to decline to 1005 barrels of oil per day and 1.2 million standard cubic feet of gas per day by the year 2010 under Scenario 1 (no new development on existing leases). Table 3.5-4 lists the current production facilities and associated onshore processing facilities in the Eastern Subregion. The locations of existing onshore processing facilities are shown on Figure 3.5-3. As indicated in that table, Rincon Island and the onshore production and processing facilities operated by the Rincon Island Limited Partnership are the only facilities currently projected to continue operations beyond the year 2005 if no new development of existing leases occurs. This projection does not reflect Venoco's intention to enhance production from Platform Gail, and possibility of resumed production from Platform Grace. These platforms and the associated Carpinteria Oil & Gas Processing Facility were acquired by Venoco in February 1999, and plans for production enhancements were not available for incorporation into this study. Although the current operator (Venoco) has indicated its intent to continue operating these facilities beyond 2005, this operation is not included in the current projection due to the lack of specific data available to project production enhancements. The currently projected future baseline condition in the absence of new offshore development is illustrated on Figure 3.5-4. Production from the Eastern Subregion would cease by the year 2015 under this scenario.

Scenario 2 assumes that new development of existing leases will occur, but that this development would be constrained by the capacity of existing onshore processing facilities. Scenario 3 assumes that the maximum potential development of existing leases would occur, and that onshore facilities could be expanded to accommodate production increases. As indicated by Tables 3.5-2 and 3.5-3, the production levels associated with both these scenarios is identical. In other words, the existing capacity of onshore processing facilities in the Eastern Subregion is adequate to accommodate the maximum future production from existing leases, and expansion of onshore facilities would not be required. Under both Scenarios 2 and 3, production would still decline from present levels, and would cease by the year 2015. The locations of expected active onshore facilities with continued offshore development under these scenarios are shown on Figure 3.5-5. As indicated by Table 3.5-4, two offshore facilities would have extended service lives under these scenarios (Platforms Gail and Hogan).

Scenario 4 assumes that new development of existing leases could occur, but that existing facilities would be decommissioned and removed shortly following the economic limit of production. This includes the abandonment of Platform Hogan by the year 2000 and Platforms Grace and Gail by 2001. Onshore facilities associated with these platforms (La Conchita, Carpinteria, and pipelines from Carpinteria to Rincon) would also be decommissioned and removed under this scenario. Because these facilities would not be available to develop currently undeveloped resources under this scenario, and these resources are not adequate to justify the installation of new platforms, total production under this scenario is substantially less than Scenarios 2 and 3. As indicated by Table 3.5-4, all offshore facilities other than Rincon Island would be removed by 2005, and production from offshore leases in the Eastern Subregion would cease by 2015 under Scenario 4.

TABLE 3.5-2
EASTERN SUBREGION
SUMMARY OF OIL PRODUCTION BY SCENARIO

	Oil Production (Barrels Per Day, Average)				TOTAL 1995-2015 (MMSTB)
	2000	2005	2010	2015	
Scenario 1 No new development on existing leases	2649	0	0	0	0
Scenario 2 Development of existing leases within the capacity of existing onshore facilities	16484	17952	9106	1011	0
Scenario 3 Maximum development of existing leases including the expansion of capacity at existing onshore facilities	2649	12058	5687	0	0
Scenario 4 Development of existing leases considering the abandonment of existing facilities	2649	2640	1386	620	0

TABLE 3.5-3
EASTERN SUBREGION
SUMMARY OF NATURAL GAS PRODUCTION BY SCENARIO

	Natural Gas Production (Thousand Standard Cubic Feet Per Day, Average)				TOTAL 1995-2015 (MMCF)
	2000	2005	2010	2015	
Scenario 1 No new development on existing leases	6000	0	0	0	0
Scenario 2 Development of existing leases within the capacity of existing onshore facilities	36686	17235	34950	12852	0
Scenario 3 Maximum development of existing leases including the expansion of capacity at existing onshore facilities	6000	45014	24514	0	0
Scenario 4 Development of existing leases considering the abandonment of existing facilities	6000	3168	1664	744	231

Table 3.5-4
COOGER Study Scenarios
Active Oil and Gas Facilities - Eastern Subregion
by Scenario and Year

Scenario Year	Onshore Processing Facility	Production Facilities	Oil Field
Scenario 1			
1995	Mandalay	Gina Gilda	Hueneme Santa Clara
	West Montalvo	West Montalvo (Onshore)	West Montalvo
	Rincon Island	Rincon Island	Rincon
	Rincon	Henry Hillhouse Platform A Platform B Platform C	Carpinteria Dos Cuadras Dos Cuadras Dos Cuadras Dos Cuadras
	Rincon Tank (Via Carpinteria)	Gail Grace	Sockeye Santa Clara
	La Conchita	Houchin Hogan	Carpinteria Carpinteria
	Carpinteria Gas Terminal	Habitat	Pitas Point
2000	West Montalvo	West Montalvo (Offshore)	West Montalvo
	Rincon Island	Rincon Island	Rincon
	Rincon	Henry Platform A Platform B	Carpinteria Dos Cuadras Dos Cuadras
	Rincon Tank (Via Carpinteria)	Gail Grace	Sockeye Santa Clara
	Carpinteria Gas Terminal	Habitat	Pitas Point
2005	Rincon Island	Rincon Island	Rincon
2010	Rincon Island	Rincon Island	Rincon
2015	None	None	None

Table 3.5-4 (Continued)

SCENARIO YEAR	ONSHORE PROCESSING FACILITY	PRODUCTION FACILITIES	OIL FIELD
Scenario 2			
1995	Mandalay	Gina Gilda	Hueneme Santa Clara
	West Montalvo	West Montalvo (Onshore)	West Montalvo
	Rincon Island	Rincon Island	Rincon
	Rincon	Henry Hillhouse Platform A Platform B Platform C	Carpinteria Dos Cuadras Dos Cuadras Dos Cuadras Dos Cuadras
	Rincon Tank (Via Carpinteria)	Gail Grace	Sockeye Santa Clara
	La Conchita	Houchin Hogan	Carpinteria Carpinteria
	Carpinteria Gas Terminal	Habitat	Pitas Point
2000	West Montalvo	West Montalvo (Onshore)	West Montalvo
	Rincon Island	Rincon Island	Rincon
	Rincon	Henry Platform A Platform B	Carpinteria Dos Cuadras Dos Cuadras
	Rincon Tank (Via Carpinteria)	Gail Grace	Sockeye Santa Clara
	La Conchita (Idle)	Hogan (Idle)	Idle
	Carpinteria Gas Terminal	Habitat	Pitas Point
2005	Rincon Island	Rincon Island	Rincon
	Rincon Tank (Via Carpinteria)	Gail	Cavern Point
	La Conchita	Hogan	Carpinteria
2010	Rincon Island	Rincon Island	Rincon
	Rincon Tank (Via Carpinteria)	Gail	Cavern Point
2015	None	None	None

Table 3.5-4 (Continued)

SCENARIO YEAR	ONSHORE PROCESSING FACILITY	PRODUCTION FACILITIES	OIL FIELD
Scenario 3[(1)]			
1995	Mandalay	Gina Gilda	Hueneme Santa Clara
	West Montalvo	West Montalvo (Onshore)	West Montalvo
	Rincon Island	Rincon Island	Rincon
	Rincon	Henry Hillhouse Platform A Platform B Platform C	Carpinteria Dos Cuadras Dos Cuadras Dos Cuadras Dos Cuadras
	Rincon Tank (Via Carpinteria)	Gail Grace	Sockeye Santa Clara
	La Conchita	Houchin Hogan	Carpinteria Carpinteria
	Carpinteria Gas Terminal	Habitat	Pitas Point
2000	West Montalvo	West Montalvo (Onshore)	West Montalvo
	Rincon Island	Rincon Island	Rincon
	Rincon	Henry Platform A Platform B	Carpinteria Dos Cuadras Dos Cuadras
	Rincon Tank (Via Carpinteria)	Gail Grace	Sockeye Santa Clara
	La Conchita (Idle)	Hogan (Idle)	Idle
	Carpinteria Gas Terminal	Habitat	Pitas Point
2005	Rincon Island	Rincon Island	Rincon
	Rincon Tank (Via Carpinteria)	Gail	Cavern Point
	La Conchita	Hogan	Carpinteria
2010	Rincon Island	Rincon Island	Rincon
	Rincon Tank (Via Carpinteria)	Gail	Cavern Point
2015	None	None	None

(1) All projected development of existing leases can be accommodated within the existing capacity of existing onshore processing facilities. As a result, this scenario is identical to Scenario 2.

Table 3.5-4 (Continued)

SCENARIO YEAR	ONSHORE PROCESSING FACILITY	PRODUCTION FACILITIES	OIL FIELD
Scenario 4[(2)]			
1995	Mandalay	Gina Gilda	Hueneme Santa Clara
	West Montalvo	West Montalvo (Onshore)	West Montalvo
	Rincon Island	Rincon Island	Rincon
	Rincon	Henry Hillhouse Platform A Platform B Platform C	Carpinteria Dos Cuadras Dos Cuadras Dos Cuadras Dos Cuadras
	Rincon Tank (Via Carpinteria)	Gail Grace	Sockeye Santa Clara
	La Conchita	Houchin Hogan	Carpinteria Carpinteria
	Carpinteria Gas Terminal	Habitat	Pitas Point
2000	West Montalvo	West Montalvo	West Montalvo
	Rincon Island	Rincon Island	Rincon
	Rincon	Henry Platform A Platform B	Carpinteria Dos Cuadras Dos Cuadras
	Rincon Tank (Via Carpinteria)	Gail Grace	Sockeye Santa Clara
	Carpinteria Gas Terminal	Habitat	Pitas Point
2005	Rincon Island	Rincon Island	Rincon
2010	Rincon Island	Rincon Island	Rincon
2015	None	None	None

(2) Facilities assumed removed under this scenario that would affect future development of existing leases include Platform Hogan by the year 2000 and Platform Grace by the year 2001. Under this scenario, all production from Platforms Grace and Gail would be terminated in the year 2000, and platform removal would occur in 2001.

3.5.3 Central Subregion

The Central Subregion offshore resources are currently produced from seven offshore structures and one onshore drillsite. As indicated in Tables 3.5-5 and 3.5-6, production from this subregion is expected to steadily decline to 12,000 barrels of oil per day and 95.9 million standard cubic feet of gas per day by the year 2015 under Scenario 1 (no new development on existing leases). Table 3.5-7 lists the current production facilities and associated onshore processing facilities in the Central Subregion. The locations of existing onshore processing facilities are shown on Figure 3.5-6. As indicated in Table 3.5-7 and Figure 3.5-7, current Santa Ynez Unit offshore platforms (Hondo, Harmony, and Heritage) and the associated onshore processing facilities in Las Flores Canyon are the only facilities expected to remain in operation by the year 2010 if no new development on existing leases occurs. With the possible exception of Platform Hondo, these facilities are expected to remain in operation beyond the 20-year time frame of the COOGER study. Although development of the Sacate Field has already been approved, limitations on new development associated with this scenario are presumed to preclude development of this field.

Scenario 2 involves the development of existing leases limited by the capacity of existing onshore processing facilities. This scenario specifically assumes that all currently operational onshore processing facilities will be available to accommodate production from new development in accordance with existing land use permit and design limitations. This scenario could result in several new developments, including expansion of production from the South Ellwood Field (from existing Platform Holly and/or a new production facility), with resulting production processed at Las Flores Canyon and Ellwood. Several new fields could also be developed under this scenario, including: Piñon-Electra, Cojo, Rocky Point, Jalama, Sword, and Gato Canyon. These new field developments could be developed from two new offshore platforms, additional wells from two existing platforms (Hidalgo and Hermosa), and one new onshore drillsite. South Ellwood Field development would proceed under the restrictions placed on the Ellwood Oil and Gas Processing Facility by the Santa Barbara County consolidation policies and the facility's legal non-conforming use status, both of which restrict the potential expansion of that onshore facility. As a result, South Ellwood Field production expansion beyond the Ellwood Oil and Gas Processing Facility capacity would be processed at Las Flores Canyon. Production from Piñon-Electra, Rocky Point, Jalama, and Sword would be processed at the Gaviota Oil and Gas Facility (in addition to Point Arguello Field production), which has adequate capacity to accommodate this additional production without expansion. Although Sword is expected to produce very low gravity crude (10.6E API), information available from offshore operators suggests that this resource is expected to be suitable for blending with lighter production streams for pipeline transport. Existing capacity at the Las Flores Canyon onshore facility would be adequate to accommodate projected oil production inputs from South Ellwood and Gato Canyon in addition to Santa Ynez Unit without limitation, but existing gas plant capacity limits would not accommodate potential gas production from outside the Santa Ynez Unit. This limitation could also reduce or delay Sacate Field gas production under this scenario. This scenario would involve substantial oil and gas production increases as compared to Scenario 1, as indicated on Tables 3.5-5 and 3.5-6. The locations of expected active onshore facilities with continued offshore development under this scenario are shown on Figure 3.5-8.

Scenario 3 addresses the maximum potential development of existing leases, and allows the potential expansion of capacity at existing onshore facilities (limited to designated facility consolidation areas on the Santa Barbara County south coast). As with Scenario 2, this scenario assumes that all currently operational onshore facilities will be available to accommodate production from existing development. This scenario would result in several new developments. As discussed under Scenario 2, Scenario 3 would allow additional development of the South Ellwood Field from existing Platform Holly (or a new production facility), with production in excess of 13,000 BPD (dry oil) and 13,000 MCFD (dry gas) handled at Las Flores Canyon. This scenario would also include the development of the Gato Canyon Field from one new offshore platform and substantially expanded development of the Sacate Field before 2005 from an existing platform, both of which would also be processed at Las Flores Canyon. Las Flores Canyon facilities could accommodate the projected increase in oil production without expansion, but an increase in gas plant capacity would be required to process natural gas volumes projected under this scenario. Piñon-Electra, Sword, Jalama, Rocky Point, and Cojo fields would also be developed under this scenario. Production from these fields would be processed at Gaviota. This development scenario would involve one to three new offshore platforms and one new onshore drill site as indicated on Table 3.5-7. The locations of expected active onshore facilities with continued offshore development under this scenario are shown on Figure 3.5-8. This scenario involves substantial production increases when compared to Scenario 1, as indicated on Tables 3.5-5 and 3.5-6.

Scenario 4 addresses the development of existing leases with the assumption that existing facilities would be decommissioned and removed shortly after reaching the economic limit of production. In this case Chevron's previously stated intention to remove Point Arguello Field platforms (Hermosa, Harvest, and Hidalgo) and the Gaviota onshore processing facility in the year 2001 was specifically assumed (though it is acknowledged that this currently appears unlikely to occur). This abandonment activity would reduce the total production from known, undeveloped fields in the Central Subregion. Some of the currently undeveloped resources in the Central Subregion that would otherwise be accommodated at the Gaviota onshore facility could generate development pressure at other facilities under this scenario. Specifically, this scenario could result in additional expansion at the Las Flores Canyon facility to accommodate gas production from the Cojo Field (no expansion of Las Flores Canyon oil processing capacity would be required). Expansion of the Lompoc Oil and Gas Processing Facility (in the Northern Subregion) would also be required to receive production from Rocky Point, Jalama, and Sword Fields. Because the Piñon-Electra Field can only be economically produced by development from existing Platform Hidalgo, this resource would be totally eliminated under this scenario. Tables 3.5-5 and 3.5-6 indicate the production processed at Central Subregion facilities under this scenario, and the effect of displaced production on different Northern Subregion development scenarios is specifically addressed as Scenarios 2A, 3A, and 4A in Section 3.5.4 of this report.

TABLE 3.5-5
CENTRAL SUBREGION
SUMMARY OF OIL PRODUCTION BY SCENARIO

	Oil Production (Barrels Per Day, Average)				TOTAL 1995-2015 (MMSTB)
	2000	2005	2010	2015	
Scenario 1 No new development on existing leases	133093	62466	24938	12000	4
Scenario 2 Development of existing leases within the capacity of existing onshore facilities	115317	127649	133602	105415	964
Scenario 3 Maximum development of existing leases including the expansion of capacity at existing onshore facilities	133093	135658	112713	124036	41
Scenario 4 Development of existing leases considering the abandonment of existing facilities	133093	93375	97910	66553	22

TABLE 3.5-6
CENTRAL SUBREGION
SUMMARY OF NATURAL GAS PRODUCTION BY SCENARIO

	Natural Gas Production (Thousand Standard Cubic Feet Per Day, Average)				TOTAL 1995-2015 (MMCF)
	2000	2005	2010	2015	
Scenario 1 No new development on existing leases	107375	204038	117427	95890	35000
Scenario 2 Development of existing leases within the capacity of existing onshore facilities	147811	199044	145794	137100	1167445
Scenario 3 Maximum development of existing leases including the expansion of capacity at existing onshore facilities	107375	251042	183427	163390	56864
Scenario 4 Development of existing leases considering the abandonment of existing facilities	107375	194151	176027	134590	47264

Table 3.5-7
COOGER Study Scenarios
Active Oil and Gas Facilities - Central Subregion
by Scenario and Year

SCENARIO YEAR	ONSHORE PROCESSING FACILITY	PRODUCTION FACILITIES	OIL FIELD
Scenario 1			
1995	Ellwood	Holly	South Ellwood
	Las Flores Canyon	Hondo Harmony Heritage	Hondo Hondo Pescado
	Gaviota	Hermosa Hidalgo Harvest	Point Arguello Point Arguello Point Arguello
2000	Ellwood	Holly	South Ellwood
	Las Flores Canyon	Hondo Harmony Heritage	Hondo Hondo Pescado
	Gaviota	Hermosa Hidalgo Harvest	Point Arguello Point Arguello Point Arguello
2005	Ellwood	Holly	South Ellwood
	Las Flores Canyon	Hondo Harmony Heritage	Hondo Hondo Pescado
	Gaviota	Harvest	Point Arguello
	Molino Gas Plant	Molino Drillsite (Onshore)	Molino
2010	Las Flores Canyon	Hondo Harmony Heritage	Hondo Hondo Pescado
	Molino Gas Plant	Molino Drillsite (Onshore)	Molino
2015	Las Flores Canyon	Hondo Harmony Heritage	Hondo Hondo Pescado

Table 3.5-7 (Continued)

SCENARIO YEAR	ONSHORE PROCESSING FACILITY	PRODUCTION FACILITIES	OIL FIELD
Scenario 2			
1995	Ellwood	Holly	South Ellwood
	Las Flores Canyon	Hondo Harmony Heritage	Hondo Hondo Pescado
	Gaviota	Hermosa Hidalgo Harvest	Point Arguello Point Arguello Point Arguello
2000	Ellwood	Holly	South Ellwood
	Las Flores Canyon	Hondo Harmony Heritage	Hondo Hondo Pescado
	Gaviota	Hermosa Hidalgo Harvest	Point Arguello Point Arguello Point Arguello
2005	Ellwood	Holly	South Ellwood
	Las Flores Canyon	Holly or New Production Facility Hondo Harmony Heritage	South Ellwood Hondo Hondo Pescado, Sacate
	Gaviota	Hidalgo Harvest Cojo Drillsite (Onshore) Hermosa	Piñon Electra Point Arguello Cojo Rocky Point, Jalama
	Molino Gas Plant	Molino Drillsite (Onshore)	Molino
2010	Ellwood	Holly	South Ellwood
	Las Flores Canyon	Holly or New Production Facility Hondo Harmony Heritage Gato Platform	South Ellwood Hondo Hondo Pescado, Sacate Gato Canyon
	Gaviota	Cojo Drillsite (Onshore) Hermosa Sword Platform (or existing platform)	Cojo Rocky Point, Jalama Sword
	Molino Gas Plant	Molino Drillsite (Onshore)	Molino

Table 3.5-7 (Continued)

SCENARIO YEAR	ONSHORE PROCESSING FACILITY	PRODUCTION FACILITIES	OIL FIELD
Scenario 2 (Cont.)			
2015	Ellwood	Holly	South Ellwood
	Las Flores Canyon	Holly or New Production Facility Hondo Harmony Heritage Gato Platform	South Ellwood Hondo Hondo Pescado, Sacate Gato Canyon
	Gaviota	Cojo Drillsite (Onshore) Sword Platform (or existing platform)	Cojo Sword
Scenario 3			
1995	Ellwood	Holly	South Ellwood
	Las Flores Canyon	Hondo Harmony Heritage	Hondo Hondo Pescado
	Gaviota	Hermosa Hidalgo Harvest	Point Arguello Point Arguello Point Arguello
2000	Ellwood	Holly	South Ellwood
	Las Flores Canyon	Hondo Harmony Heritage	Hondo Hondo Pescado
	Gaviota	Hermosa Hidalgo Harvest	Point Arguello Point Arguello Point Arguello
2005	Ellwood	Holly	South Ellwood
	Las Flores Canyon	Holly or New Production Facility Hondo Harmony Heritage	South Ellwood Hondo Hondo Pescado, Sacate
	Gaviota	Hidalgo Harvest Cojo Drillsite (Onshore) Hermosa	Piñon Electra Point Arguello Cojo Rocky Point, Jalama
	Molino Gas Plant	Molino Drillsite (Onshore)	Molino

Table 3.5-7 (Continued)

SCENARIO YEAR	ONSHORE PROCESSING FACILITY	PRODUCTION FACILITIES	OIL FIELD
Scenario 3 (Cont.)			
2010	Ellwood	Holly	South Ellwood
	Las Flores Canyon	Holly or New Production Facility Hondo Harmony Heritage Gato Platform	South Ellwood Hondo Hondo Pescado, Sacate Gato Canyon
	Gaviota	Cojo Drillsite (Onshore) Hermosa Sword Platform (or existing platform)	Cojo Rocky Point, Jalama Sword
	Molino Gas Plant	Molino Drillsite (Onshore)	Molino
2015	Ellwood	Holly	South Ellwood
	Las Flores Canyon	Holly or New Production Facility Hondo Harmony Heritage Gato Platform	South Ellwood Hondo Hondo Pescado, Sacate Gato Canyon
	Gaviota	Cojo Drillsite (Onshore) Sword Platform (or existing platform)	Cojo Sword
Scenario 4(3)			
1995	Ellwood	Holly	South Ellwood
	Las Flores Canyon	Hondo Harmony Heritage	Hondo Hondo Pescado
	Gaviota	Hermosa Hidalgo Harvest	Point Arguello Point Arguello Point Arguello

(3) Facilities assumed removed under this scenario which would affect the future development of identified resources include Platform Hermosa, Platform Hidalgo, Platform Harvest, the Gaviota Oil and Gas Processing Facility, and pipelines connecting these facilities. This scenario assumes that production from all three Point Arguello Field platforms would cease by the end of the year 2000, and removal of offshore platforms and the onshore processing facility would be completed by the end of 2001. The offshore and onshore pipeline system would be decommissioned and abandoned during the same period.

Table 3.5-7 (Continued)

SCENARIO YEAR	ONSHORE PROCESSING FACILITY	PRODUCTION FACILITIES	OIL FIELD
Scenario 4[3] (Cont.)			
2000	Ellwood	Holly	South Ellwood
	Las Flores Canyon	Hondo Harmony Heritage	Hondo Hondo Pescado
	Gaviota	Hermosa Hidalgo Harvest	Point Arguello Point Arguello Point Arguello
2005	Ellwood	Holly	South Ellwood
	Las Flores Canyon	Holly or New Production Facility Hondo Harmony Heritage Cojo Drillsite (Onshore)	South Ellwood Hondo Hondo Pescado, Sacate Cojo
	Molino Gas Plant	Molino Drillsite (Onshore)	Molino
2010	Ellwood	Holly	South Ellwood
	Las Flores Canyon	Holly or New Production Facility Hondo Harmony Heritage Gato Platform Cojo Drillsite (Onshore)	South Ellwood Hondo Hondo Pescado, Sacate Gato Canyon Cojo
	Molino Gas Plant	Molino Drillsite (Onshore)	Molino
2015	Ellwood	Holly	South Ellwood
	Las Flores Canyon	Holly or New Production Facility Hondo Harmony Heritage Gato Platform Cojo Drillsite (Onshore)	South Ellwood Hondo Hondo Pescado, Sacate Gato Canyon Cojo

(3) Facilities assumed removed under this scenario which would affect the future development of identified resources include Platform Hermosa, Platform Hidalgo, Platform Harvest, the Gaviota Oil and Gas Processing Facility, and pipelines connecting these facilities. This scenario assumes that production from all three Point Arguello Field platforms would cease by the end of the year 2000, and removal of offshore platforms and the onshore processing facility would be completed by the end of 2001. The offshore and onshore pipeline system would be decommissioned and abandoned during the same period.

3.5.4 Northern Subregion

The Northern Subregion offshore resources are currently produced from one offshore structure. The locations of existing onshore processing facilities are shown on Figure 3.5-9. As indicated in Tables 3.5-8 and 3.5-9, production from this subregion will cease to occur by the year 2005 under Scenario 1 (no new development on existing leases). This future baseline condition in the absence of new offshore development is illustrated on Figure 3.5-10. As indicated on Table 3.5-10, all current offshore production in the Northern Subregion is produced at Platform Irene, and processed at the Lompoc Oil & Gas Processing Facility. Without further development, Platform Irene is projected to be removed in 2003 or 2004. The Santa Maria Asphalt Plant is listed in the COOGER study documentation because it has been suggested as a potential future recipient of Northern Subregion production, but it does not currently receive any feedstock from offshore production.

Scenario 2 involves the development of existing leases limited by the capacity of the existing onshore processing facility, and allowing the modification of facilities to accommodate different crude oil characteristics. The locations of expected active onshore facilities with continued offshore development under this scenario are shown on Figure 3.5-11. Under this scenario, the dry oil processing capacity of the Lompoc Oil & Gas Processing Facility would limit total production to no more than 36,000 barrels of oil per day, which could be produced from one platform and a collection of subsea satellite wells. The platform would be associated with the Bonito and Sugar Maple Fields (located in the Central Subregion, but expected to be connected to existing Point Pedernales Unit facilities). Because production limits associated with this scenario would constrain Lion Rock Field production, it is most likely that this production would be accomplished by a satellite well installation. Based on the determination of the initial year of potential production from those fields, it is expected that Platform Irene would be removed shortly before the Bonito platform is installed unless new production enhancement or additional development from Platform Irene is implemented which was not addresed in this study. The analysis in this study projects the removal of Platform Irene in 2003 or 2004. The current operator of Platform Irene recently filed an application to drill into currently unleased areas in State waters. If approved, this activity could extend the economic life of Platform Irene. Because the resources associated with this proposal are not associated with existing leases, they are not included in the COOGER study. Although the Bonito and Sugar Maple Fields are expected to produce oil compatible with existing Lompoc Oil & Gas Processing Facility (20E API as compared to existing Point Pedernales Field gravity of 16.5E API), this scenario could require substantial modifications to the Lompoc Oil & Gas Processing Facility to accommodate the processing and transport requirements of the low gravity (approximately 11E API), asphaltic crude expected to be produced from the Lion Rock Field. Specific facilities modifications that may be required are not presently known, and will be determined by the responsible operator when more detailed production characteristics data are available and a complete marketing plan for this production is developed. Some portion of this production may be processed to produce asphalt pitch, and other crude oil fractions may be separated locally. Alternatively, the entire production stream could be transported to processing facilities outside the Tri-Counties area. In addition to the asphaltic nature of the Lion Rock Field production, a high metals content is also expected. The specific characteristics of the Lion Rock hydrocarbon resource presents substantial technical challenges concerning production techniques and pipeline transport to onshore facilities. In addition, metals content may limit the availability of refineries willing to receive this oil. These technical issues apply to other Santa Maria Basin fields as well, and are applicable to all Northern Subregion scenarios. None of the other known undeveloped resources in the Northern Subregion would be produced during the COOGER study twenty-year time frame under this scenario.

Scenario 3 reflects a realistic Lion Rock Field production estimate based on an evaluation of the potential market for high-grade asphalt conducted by Aera Energy, the operator of the existing leases with known undeveloped resources in the Northern Subregion. This Lion Rock production would be added to the full development of the Bonito and Sugar Maple Fields, located in the Central Subregion but expected to be connected to the Point Pedernales facilities. The locations of expected active onshore facilities with continued offshore development under this scenario are shown on Figure 3.5-11. Under this scenario, production from the Lion Rock Field would be market-limited to 25,000 barrels of oil per day, and would most likely be produced from a single offshore platform in the Lion Rock Field. Because this scenario does not limit onshore processing to existing sites, it is possible that a new onshore processing facility would be developed at a location with convenient access to rail transportation facilities. This scenario presumes the local separation of Lion Rock production into an asphalt pitch component (about 40 percent of total production) and a blended pipeline transportable crude component (about 60 percent of total production). It should be noted that marketing plans for this production have not yet been developed, and other crude processing and transport options may be identified in the future. The existing Lompoc Oil & Gas Processing would continue operations in connection with Bonito and Sugar Maple Fields production. The existing Platform Irene would be removed shortly before the Bonito Platform is installed (in 2003 or 2004, as discussed under Scenarios 1 and 2, unless the operator's current proposal to drill into currently unleased areas in State waters is approved), but the existing Point Pedernales pipeline system is expected to remain to transport production to onshore facilities. None of the other known undeveloped resources in the Northern Subregion would be produced during the COOGER study twenty-year time frame under this scenario.

Scenario 4 reflects the maximum commercial development of existing Northern Subregion leases based on an evaluation of potential markets for high-grade asphalt conducted by Aera Energy, including an optimistic consideration of potential export markets beyond the PAD V market area (California, Nevada, Arizona, Oregon, and Washington), and the potential marketing of a greater portion of Lion Rock crude outside the asphalt market. This production would be added to the full development of the Bonito and Sugar Maple Fields (located in the Central Subregion but expected to be connected to the Point Pedernales Unit facilities). The locations of expected active onshore facilities with continued offshore development under this scenario are shown on Figure 3.5-11. Under this scenario, production from the Lion Rock Field would be market-limited to 75,000 barrels of oil per day. This production rate would be accomplished by one offshore platform in the Lion Rock Field, possibly with extended reach drilling or satellite subsea development facilities. As with Scenario 3, this scenario would most likely include the development of a new onshore facility at a location with convenient access to rail transportation facilities. For the purpose of calculating transport demand, 40 percent of the total crude oil production is assumed to be processed to asphalt pitch or other heavy products which require rail or truck transport, and the remaining 60 percent is assumed to be a pipeline transportable blended crude. The existing Lompoc Oil & Gas Processing would continue operations in connection with the Bonito and Sugar Maple Fields. The existing Platform Irene would be removed at about the same time the Bonito Platform is installed (in 2003 or 2004, as discussed under Scenarios 1 and 2, unless the operator's current proposal to drill into currently unleased areas in State waters is approved). None of the other known undeveloped resources in the Northern Subregion would be produced during the COOGER study twenty-year time-frame under this scenario.

Scenario 2A reflects the effect of facility abandonments in the Central Subregion on the future onshore processing in the Northern Subregion, and includes the Scenario 2 limitation that all development is limited to the processing capacity of existing onshore facilities without expansion. The locations of expected active onshore facilities with continued offshore development under this scenario are shown on Figure 3.5-11. Under this scenario several Central Subregion offshore resources that were eliminated from the Central Subregion Scenario 4 are expected to connect to the Lompoc Oil & Gas Processing Facility via the Platform Irene pipelines. The offshore fields that could be developed in this manner include Rocky Point, Jalama, and Sword. In addition to platforms described in connection with Northern Subregion scenarios, this development would involve up to two offshore platforms (in addition to the Bonito Platform in the Central Subregion offshore area) and a series of connecting offshore pipelines. These developments would consume the available capacity at the Lompoc Oil & Gas Processing Facility, represent crude oil feedstocks comparable to that which the Lompoc Facility is designed to process, and would be developed soon following Platform Irene's productive life. For these reasons, these developments would be expected to displace potential production from the Lion Rock Field that might otherwise be processed at the Lompoc Oil & Gas Processing Facility during the COOGER study twenty-year time frame. It is unlikely that the 10,000 barrels per day limitation of the Santa Maria Asphalt refinery that would apply to this scenario would be adequate to justify the investment in onshore facilities modifications and pipeline facilities that would be required to support the Lion Rock development, and so no development of the Lion Rock Field or other Northern Subregion offshore leases would occur under this scenario.

Scenarios 3A and 4A reflect the combination of the processing of displaced Central Subregion production at the Lompoc Oil & Gas Processing Facility (as described in Scenario 2A) with the development of the Bonito, Sugar Maple, and Lion Rock Field offshore resources as described in Scenarios 3 and 4. These scenarios are not constrained by capacity limits at existing facilities, and could involve the expansion of the Lompoc Oil & Gas Processing Facility and the development of a new onshore facility with convenient rail access that is specifically designed to process production from the Lion Rock Field. The locations of expected active onshore facilities with continued offshore development under this scenario are shown on Figure 3.5-11. As indicated in Table 3.5-8, oil production processed at Northern Subregion onshore facilities could reach a peak that is approximately equivalent to current Central Subregion production levels under Scenario 4A.

TABLE 3.5-8
NORTHERN SUBREGION
SUMMARY OF OIL PRODUCTION BY SCENARIO

	Oil Production (Barrels Per Day, Average)				TOTAL 1995-2015 (MMSTB)
	2000	2005	2010	2015	
Scenario 1 No new development on existing leases	7474	0	0	0	0
Scenario 2 Development of existing Northern Subregion leases up to the capacity of existing onshore facilities, without market limitation	6055	0	36000	32529	113
Scenario 3 Market-based realistic production from existing Northern Subregion leases based on crude oil characteristics (Aera low-case production estimates). May include new onshore facilities	6055	0	0	0	0
Scenario 4 Maximum commercial development of existing Northern Subregion leases based on crude oil characteristics (Aera high-case production estimates). May include new onshore facilities.	6055	0	0	0	37
Scenario 2A Maximum development of existing leases within the capacity of existing onshore facilities, including production from offshore leases in the Central Subregion which could be displaced by the abandonment of the Gaviota processing facility.	6055	19500	35762	36000	155
Scenario 3A Market-based realistic production from existing Northern Subregion leases (Aera low-case production estimates), combined with production from offshore leases in the Central Subregion which could be displaced by the abandonment of the Gaviota processing facility.	0	0	28500	25029	37
Scenario 4A Maximum commercial development of existing Northern Subregion leases based on crude oil characteristics (Aera high-case production estimates), combined with production from offshore leases in the Central Subregion which could be displaced by the abandonment of the Gaviota processing facility.	0	0	35000	52500	56

TABLE 3.5-9
NORTHERN SUBREGION
SUMMARY OF NATURAL GAS PRODUCTION BY SCENARIO

	Natural Gas Production (Thousand Standard Cubic Feet Per Day, Average)				TOTAL 1995-2015 (MMCF)
	2000	**2005**	**2010**	**2015**	
Scenario 1 No new development on existing leases	1718	0	0	0	0
Scenario 2 Development of existing Northern Subregion leases up to the capacity of existing onshore facilities, without market limitation	1392	0	15000	15000	42263
Scenario 3 Market-based realistic production from existing Northern Subregion leases based on crude oil characteristics (Aera low-case production estimates). May include new onshore facilities	1392	0	0	0	0
Scenario 4 Maximum commercial development of existing Northern Subregion leases based on crude oil characteristics (Aera high-case production estimates). May include new onshore facilities.	1392	0	0	0	30118
Scenario 2A Maximum development of existing leases within the capacity of existing onshore facilities, including production from offshore leases in the Central Subregion which could be displaced by the abandonment of the Gaviota processing facility.	1392	9800	15000	15000	65088
Scenario 3A Market-based realistic production from existing Northern Subregion leases (Aera low-case production estimates), combined with production from offshore leases in the Central Subregion which could be displaced by the abandonment of the Gaviota processing facility.	0	0	14250	12515	22684
Scenario 4A Maximum commercial development of existing Northern Subregion leases based on crude oil characteristics (Aera high-case production estimates), combined with production from offshore leases in the Central Subregion which could be displaced by the abandonment of the Gaviota processing facility.	0	0	17500	26300	39717

Table 3.5-10
COOGER Study Scenarios
Active Oil and Gas Facilities - Northern Subregion
by Scenario and Year

SCENARIO YEAR	ONSHORE PROCESSING FACILITY	PRODUCTION FACILITIES	OIL FIELD
Scenario 1			
1995	Lompoc	Irene	Point Pedernales
	Santa Maria Asphalt	None	None
2000	Lompoc	Irene	Point Pedernales/ Tranquillon Ridge
	Santa Maria Asphalt	None	None
2005	Santa Maria Asphalt	None	None
2010	Santa Maria Asphalt	None	None
2015	Santa Maria Asphalt	None	None
Scenario 2			
1995	Lompoc	Irene	Point Pedernales
	Santa Maria Asphalt	None	None
2000	Lompoc	Irene	Point Pedernales/ Tranquillon Ridge
	Santa Maria Asphalt	None	None
2005	Lompoc (Idle)	None	None
	Santa Maria Asphalt	None	None
2010	Lompoc	Bonito Platform Lion Rock Platform	Bonito, Sugar Maple Lion Rock
	Santa Maria Asphalt	None	None
2015	Lompoc	Bonito Platform Lion Rock Satellite Wells	Bonito, Sugar Maple Lion Rock
	Santa Maria Asphalt	None	None

Table 3.5-10 (Continued)

SCENARIO YEAR	ONSHORE PROCESSING FACILITY	PRODUCTION FACILITIES	OIL FIELD
Scenario 3			
1995	Lompoc	Irene	Point Pedernales
	Santa Maria Asphalt	None	None
2000	Lompoc	Irene	Point Pedernales/ Tranquillon Ridge
	Santa Maria Asphalt	None	None
2005	Lompoc (Idle)	None	None
	Santa Maria Asphalt	None	None
2010	Lompoc	Bonito Platform	Bonito, Sugar Maple
	Expanded Santa Maria Asphalt/ Modified Lompoc/ or New Facility	Lion Rock Platform	Lion Rock
2015	Lompoc	None	None
	Expanded Santa Maria Asphalt/ Modified Lompoc/ or New Facility	Lion Rock Platform	Lion Rock
Scenario 4			
1995	Lompoc	Irene	Point Pedernales
	Santa Maria Asphalt	None	None
2000	Lompoc	Irene	Point Pedernales/ Tranquillon Ridge
	Santa Maria Asphalt	None	None
2005	Lompoc (Idle)	None	None
	Santa Maria Asphalt	None	None
2010	Lompoc	Bonito Platform	Bonito, Sugar Maple
	Expanded Santa Maria Asphalt/ Expanded Lompoc/ or New Facility	Lion Rock Platform	Lion Rock

Table 3.5-10 (Continued)

SCENARIO YEAR	ONSHORE PROCESSING FACILITY	PRODUCTION FACILITIES	OIL FIELD
Scenario 4 (Cont.)			
2015	Lompoc	Bonito Platform	Bonito, Sugar Maple
	Expanded Santa Maria Asphalt/ Expanded Lompoc/ or New Facility	Lion Rock Platform and Satellite Wells	Lion Rock
Scenario 2A			
1995	Lompoc	Irene	Point Pedernales
	Santa Maria Asphalt	None	None
2000	Lompoc	Irene	Point Pedernales/ Tranquillon Ridge
	Santa Maria Asphalt	None	None
2005	Lompoc	Rocky Point Platform	Rocky Point, Jalama
	Santa Maria Asphalt	None	None
2010	Lompoc	Bonito Platform Rocky Point Platform	Bonito, Sugar Maple Rocky Point, Jalama
	Santa Maria Asphalt	None	None
2015	Lompoc	Bonito Platform Sword Platform	Bonito, Sugar Maple Sword
	Santa Maria Asphalt	None	None
Scenario 3A			
1995	Lompoc	Irene	Point Pedernales
	Santa Maria Asphalt	None	None
2000	Lompoc	Irene	Point Pedernales/ Tranquillon Ridge
	Santa Maria Asphalt	None	None

Table 3.5-10 (Continued)

SCENARIO YEAR	ONSHORE PROCESSING FACILITY	PRODUCTION FACILITIES	OIL FIELD
Scenario 3A (Cont.)			
2005	Lompoc	Rocky Point Platform	Rocky Point, Jalama
	Santa Maria Asphalt	None	None
2010	Lompoc	Bonito Platform Rocky Point Platform Sword Platform	Bonito, Sugar Maple Rocky Point, Jalama Sword
	Expanded Santa Maria Asphalt/ or New Facility	Lion Rock Platform	Lion Rock
2015	Lompoc	Bonito Platform Sword Platform	Bonito, Sugar Maple Sword
	Expanded Santa Maria Asphalt/ or New Facility	Lion Rock Platform	Lion Rock
Scenario 4A			
1995	Lompoc	Irene	Point Pedernales
	Santa Maria Asphalt	None	None
2000	Lompoc	Irene	Point Pedernales/ Tranquillon Ridge
	Santa Maria Asphalt	None	None
2005	Lompoc	Rocky Point Platform	Rocky Point, Jalama
	Santa Maria Asphalt	None	None
2010	Lompoc	Bonito Platform Rocky Point Platform Sword Platform	Bonito, Sugar Maple Rocky Point, Jalama Sword
	Expanded Santa Maria Asphalt/ or New Facility	Lion Rock Platform	Lion Rock

SCENARIO YEAR	ONSHORE PROCESSING FACILITY	PRODUCTION FACILITIES	OIL FIELD
Scenario 4A (Cont.)			
2015	Lompoc	Bonito Platform Sword Platform	Bonito, Sugar Maple Sword
	Expanded Santa Maria Asphalt/or New Facility	Lion Rock Platform and Satellite Wells	Lion Rock

Northern Subregion Scenario Definitions:

Scenario 1: No new development of existing offshore leases, and no production input to northern facilities from offshore leases outside the northern subregion.

Scenario 2: Development of existing offshore leases in the northern subregion within the existing capacity of onshore facilities, and no production input to northern facilities from offshore leases outside the northern subregion.

Scenario 3: Market-based realistic production case considering northern subregion crude oil characteristics (low-case production). May include new facilities. No production input from offshore leases outside the northern subregion.

Scenario 4: Maximum commercial development of northern subregion resources based on operator's high case estimate. Includes new facilities or expansion of existing facilities. No production input from offshore leases outside the northern subregion.

Scenario 2A: Maximum development of existing leases within the capacity of existing onshore facilities, including production from offshore leases in the Central Subregion which could be displaced by the abandonment of the Gaviota processing facility.

Scenario 3A: Market-based realistic production from existing Northern Subregion leases (Aera low-case production estimates), combined with production from offshore leases in the Central Subregion which could be displaced by the abandonment of the Gaviota processing facility.

Scenario 4A: Maximum commercial development of existing Northern Subregion leases based on crude oil characteristics (Aera high-case production estimates), combined with production from offshore leases in the Central Subregion which could be displaced by the abandonment of the Gaviota processing facility.

4.0 PHYSICAL INFRASTRUCTURE DEMAND

As explained in prior sections of this report, offshore oil and gas operations and related onshore activity generate demands on industrial and public infrastructure in the Tri-County region of Ventura, Santa Barbara, and San Luis Obispo Counties. These demands are projected to decline substantially over the next several years in the absence of further development of existing offshore leases, as described in Sections 2.4 and 2.5 of this report. Section 3.0 of this report describes several possible scenarios addressing further development to define a range of industrial activity from the least intensive (no further development of existing offshore leases) to the most intensive (maximum commercially viable development with the potential for additional onshore processing capacity). This section describes the physical infrastructure demand associated with each potential development scenario.

4.1 INDUSTRIAL PROCESSING FACILITY DEMAND

4.1.1 Eastern Subregion

As explained in Section 3.5.2, production of oil and gas is projected to decline substantially in the Eastern Subregion in the absence of further offshore development. Under this scenario (Scenario 1), Rincon Island and associated Lease 145/410 onshore facilities are the only Eastern Subregion facilities that would remain active beyond 2005. Scenario 2 (further development within the capacity of existing onshore facilities) would extend the operation of some offshore fields and related onshore facilities, and by definition would not require any expansion of onshore facility capacity. Because substantial excess onshore facility capacity is expected as a result of declining production from currently producing offshore fields, the maximum commercially viable development of existing offshore leases (Scenario 3) could also be accommodated without any expansion of existing onshore facilities. As with Scenario 2, Scenario 3 would extend the commercial life of some existing onshore facilities. The accelerated decommissioning scenario (Scenario 4) would be nearly identical to the no further development scenario (Scenario 1). Two currently undeveloped offshore prospects that could be developed from existing platforms under Scenarios 2 and 3 would not be developed under this scenario, as resources associated with these prospects are not projected to be sufficient to support the expense of installing a new platform.

4.1.2 Central Subregion

In the absence of further offshore development (Scenario 1), oil and gas production in the Central Subregion would steadily decline through the COOGER study time period, as discussed in Section 3.5.3. Under this scenario, the existing onshore processing facilities at Gaviota and Ellwood would be removed prior to 2010. The Las Flores Canyon facility would be the only active oil and gas processing facility in the Central Subregion by the year 2015.

Further offshore development on existing leases within the capacity of existing onshore processing facilities (Scenario 2) would result in sustained production rates of 74 to 94 percent of 1997 levels through 2015. Under this scenario, existing facilities at Ellwood, Gaviota, and Las Flores Canyon would all remain operational through 2015. Capacity limitations at the Ellwood Oil and Gas Processing Facility (and restrictions associated with that facility's legal, non-conforming use status) would require that oil production associated with the further development of the South Ellwood Field would most likely be processed at Las Flores Canyon. A new oil pipeline connection would be required to accommodate the transport of South Ellwood Field production to the Las Flores Canyon site. Gato Canyon is likely to be connected via pipeline to the Hondo Platform site, and no new onshore pipeline is expected. The Las Flores Canyon Oil and Gas Processing Facility has ample capacity to accommodate additional oil production from the South Ellwood Field, as well as production from the Gato Canyon Field. Natural gas production from these fields would be limited by Las Flores Canyon Facility capacity under this scenario, however, and excess gas from the South Ellwood and Gato Canyon Fields is presumed to be reinjected under Scenario 2. Development of the Rocky Point, Jalama, Cojo, and Sword Fields could be accommodated at the Gaviota Oil and Gas Processing Facility without expansion, but this could be affected by the capacity and operational status of existing Point Arguello Field pipelines as described in Sections 2.4.3.4.2 and 2.4.3.4.3. All identified commercially viable offshore fields could still be developed during the COOGER study time frame under Scenario 2, however.

Development associated with Scenario 3 would be identical to that described for Scenario 2, with the exception of the expansion of natural gas processing facilities at Las Flores Canyon to accommodate natural gas production from the South Ellwood and Gato Canyon Fields in excess of the existing Las Flores Canyon Facility's capacity. This would also require a new gas pipeline (in addition to the oil pipeline referred to under Scenario 2) to transport natural gas from the South Ellwood Field to Las Flores Canyon.

Central Subregion Scenario 4 involves the accelerated decommissioning of the Gaviota Oil and Gas Processing Facility and associated offshore platforms Hermosa, Harvest, and Hidalgo. Under this scenario, the Piñon-Electra offshore field would not be economically viable. Some of the other currently undeveloped fields on existing Central Subregion leases (Rocky Point, Jalama, and Sword) could still be developed, but their production would most likely be processed in the Northern Subregion. The effect of this demand for Northern Subregion processing capacity is discussed in Section 4.1.3 (below) under Scenarios 2A, 3A, and 4A.

4.1.3 Northern Subregion

Only one offshore platform currently produces oil and gas handled at a Northern Subregion onshore processing facility, and that platform is expected to cease production before 2005 (see Section 3.5.4). No oil would be produced from Northern Subregion offshore leases beyond 2005 in the absence of new development (Scenario 1).

Further offshore development within the capacity of existing onshore processing facilities (Scenario 2) would accommodate the development of the Bonito Field, and would severely limit the potential development of the Lion Rock Field. This scenario would result in over four times more total production than Scenario 1 over the COOGER twenty-year time frame. Maximum daily production rates would be approximately one-fourth of recent (1997) production rates in the Central Subregion. Maximum fluid production rates under this scenario would be approximately 70 percent of current (1997) Northern Subregion production rates, but would include a much higher proportion of oil. Although projections developed for this study include some production from the Lion Rock Field, this production could be so severely limited that it may not be economically viable. Under those circumstances, total production associated with Scenario 2 could be less than projected in this report.

Scenario 3 in the Northern Subregion describes the offshore development that could occur if onshore facility capacity expansions were allowed. This scenario is limited by the Lion Rock Field offshore operator's assessment of asphalt market limits. Even with this limitation, this scenario would result in substantially greater oil production than that associated with either Scenarios 1 or 2. These oil production rates would be slightly more than one-third of recent (1997) production rates in the Central Subregion. Total fluids processed at onshore facilities in the Northern Subregion would be approximately 25 percent greater than current (1997) Northern Subregion oil production rates. This scenario would require the addition of a new processing facility in addition to the continued operation of the existing Northern Subregion facility. Although this new facility could be co-located at the Lompoc Oil & Gas Processing Facility site, proposal of a new facility to accommodate Lion Rock Field production is more likely to focus on locations which allow railroad access for heavy product transport. Review of the truck transport information presented in this report (Section 4.4) provides information concerning trucking activity requirements associated with this scenario if rail access is not available.

Scenario 4 reflects the development of existing Northern Subregion offshore leases with allowance of onshore facility expansions and a liberal view of potential asphalt markets (including export outside the western United States PAD V marketing area) or markets for other heavy products. This scenario would result in substantially greater production than Northern Subregion Scenarios 1, 2, or 3, and total oil production of about 70 percent of recent (1997) production rates in the Central Subregion. This scenario would involve one new onshore processing facility in addition to the continued operation of the existing Lompoc Oil & Gas Processing Facility, and this new facility would be comparable in size to the existing Las Flores Canyon Facility.

Scenarios 2A, 3A, and 4A involve comparable assumptions concerning potential expansion of onshore facility capacity as explained for Scenarios 2, 3, and 4. These scenarios reflect the increased demand for Northern Subregion onshore processing capacity that would result from Central Subregion Scenario 4. Under Scenario 2A, increased demand for processing capacity from Central Subregion facilities would eliminate capacity available for Lion Rock Field production, and that offshore field would not be produced during the COOGER study period under this scenario. Scenarios 3A and 4A would both result in new onshore facilities associated with Lion Rock Field production (as described in relation to Scenarios 3 and 4, above), and would also result in a nearly 40 percent expansion of the Lompoc Oil & Gas Processing Facility oil processing capacity permit limits.

4.2 PIPELINES

The purpose of this section is to describe pipeline capacity issues associated with the various scenarios and study years and to identify potential pipeline capacity constraints. The analysis presented in this section assumes that each pipeline is capable of transporting oil at its design or historic peak rate, whichever is higher.

As discussed in section 2.5.1.1 and 2.5.1.2, pipelines are the primary method used to transport oil within the COOGER Study Region and to other parts of California and the interstate markets. All of the onshore facilities that directly process offshore oil are connected to an oil distribution pipeline except the State Lease 145/410 facility which trucks oil to an onshore-related pump station within the Study Region (which is connected to a pipeline) and the Ellwood Facility which ships oil from the Ellwood Marine Terminal by barge.

4.2.1 Eastern Subregion Pipeline System

As described in the "Eastern Pipeline System" discussion, all of the offshore oil from the Eastern Subregion (except the oil from the State Lease 145/410 Facility) is transported by pipeline to Tosco's Ventura Pump Station and is pumped to the Los Angeles area.

As described by individual scenarios below, the Eastern Pipeline System is projected to have sufficient capacity in all scenarios and all study years to accommodate the combined product oil flow from the Eastern Subregion facilities.

4.2.1.1 Scenario 1

In Scenario 1, the total oil production from the facilities in the Eastern Subregion is projected to decline annually from study year 1995 until study year 2010 and all facilities are projected to be shutdown prior to study year 2015. Consequently the quantity of oil sent through the existing pipelines is projected to decrease annually during the Study Period.

In Scenario 1, the quantity of oil produced by each individual facility, except for the Rincon Island Facility, is projected to decline annually until each facility ceases operation. The Rincon Island

Facility is projected to produce a higher volume of oil in study years 2000 and 2005 than the historic data reviewed indicate have been produced in the past; however, the data reviewed did not include the facility's initial operating period from 1960 to 1976 when the production levels are expected to have been higher than during the period data was available. Oil from the Rincon Island Facility is pumped to shore through a 6-inch diameter pipeline on the causeway and then enters the 10-inch diameter pipeline between Carpinteria and the 268,000 barrel storage tank adjacent to the Rincon Onshore Oil & Gas Processing Facility. Both pipelines are expected to be able to handle the projected flows.

4.2.1.2 Scenario 2

In Scenario 2, the total oil production from the facilities in the Eastern Subregion is projected to be less in study years 2000, 2005, 2010 and 2015 than the total production in study year 1995. Consequently, the subregional pipeline system is expected to be able to handle the generally declining throughput.

In Scenario 2, three of the facilities in the Eastern Subregion are projected to have production increases above the 1995 rate. These are described as follows.

- In Scenario 2, the Rincon Island Facility has the same production projections as described in Scenario 1.

- In Scenario 2, the La Conchita Facility is projected to produce oil at a higher rate in study year 2005 than in 1995, but well below the historic peak production in 1969. This increase is due to additional projected production from the Carpinteria Field from wells on Platform Hogan.

- In Scenario 3, oil would be routed through the Carpinteria Oil & Gas Facility location at a higher rate in study year 2005 than in 1995, and at a higher rate than the historical production data indicates (based only on data for Platforms Gail and Grace and not including data for when Platforms Hope, Heidi, Hazel and Hilda were operating). This increase is due to the projected production from the Cavern Point field which is projected to be reached from wells on Platform Gail. However, the projected production in 2005 is less than one-half of the Carpinteria Facility's design capacity of 40,000 barrels of oil per day and it is assumed the pipelines and related equipment were sized to handle the design capacity.

Because the increases described are below historic production levels and/or below the design capacity of the facilities, the pipeline capacity is not expected to constrain the projected level of offshore production.

4.2.1.3 Scenario 3

In the Eastern Subregion, the production projections for Scenario 3 are the same for each facility and in total as the production estimates for Scenario 2. As in Scenario 2, the pipeline capacity is not expected to constrain the projected level of offshore production.

4.2.1.4 Scenario 4

The production projections for Scenario 4 are nearly the same for each facility and in total as the production estimates for Scenario 1. As in Scenario 1, the pipeline capacity is not expected to constrain the projected level of offshore production.

4.2.2 Central Subregion Pipeline System

The Central Subregion onshore product oil pipeline system primarily consists of the All American Pipeline, L.P. (AAPLP) pipeline system described in Section 2.4.3.8. Oil from the Las Flores Canyon SYU Oil & Gas Processing Facility flows from Las Flores Canyon to Gaviota through a 150,000 barrel per day capacity pipeline (AAPLP Coastal Pipeline) where it connects to the 300,000 barrel per day capacity AAPLP "Main Line" originating near the Gaviota Facility. The Gaviota Facility is connected to the "Main Line" by a 150,000 barrel per day capacity "Feeder Line". Flow in the Main Line can be routed to the Northern Pipeline System at the Sisquoc Pump Station or be pumped to Kern County.

As described in Section 2.4.3.4, as of September 1998, the three Point Arguello Unit platforms (Hermosa, Harvest and Hidalgo) sending oil to the Gaviota Facility were being operated under a

"Reconfiguration" operating strategy in which the wet oil was being processed to remove produced water offshore at the platforms rather than at the onshore Gaviota Facility. This change in processing location is not expected to change the quantity of oil produced. As such, the analysis of the pipeline system's ability to handle the oil is not dependant on whether the wet oil is processed onshore or offshore.

The Ellwood Oil & Gas Processing Facility is not connected to a regional pipeline system. This facility is restricted as a legal non-conforming use by Santa Barbara County's south coast consolidation policies. Future development of the South Ellwood Field not covered by the current land use permit beyond the capacity of this facility is expected to be processed at Las Flores Canyon and transported by the AAPLP pipeline system. The Ellwood Oil & Gas Processing Facility is connected by pipeline to the Ellwood Marine Terminal. Issues related to this pipeline and the marine terminal are discussed in Section 4.3.

The Las Flores Canyon Gas Processing Facility does not produce oil and the Molino Facility is not projected to produce oil. Consequently, these two facilities are not connected to an oil distribution pipeline.

As described by individual scenarios below, the AAPLP pipeline system is projected to have sufficient capacity in all scenarios and all study years to accommodate the combined product oil flow from the Las Flores Canyon and Gaviota facilities. In addition, this pipeline system could accommodate the entire crude oil production associated with the Ellwood Facility under any of the scenarios addressed. This would require a new pipeline to connect the Ellwood Facility to the AAPLP pipeline system.

4.2.2.1 Scenario 1

In Scenario 1, the oil production at the Las Flores Canyon and Gaviota facilities individually and in total is projected to decline annually from study year 1995 through study year 2015 and be well below the design capacities of the AAPLP Coastal, Feeder and Main Line pipeline sections. The pipeline system is expected to be able to handle the declining throughput. Although the Ellwood Facility is not connected to the AAPLP system, the AAPLP pipelines have available capacity in excess of the quantity of oil projected to be produced by the Ellwood Facility in Scenario 1.

4.2.2.2 Scenario 2

In Scenario 2, the production projections for the Las Flores Canyon Facility decline annually through study year 2005, increase slightly in study year 2010, and decline in study year 2015, and are below the design capacity of the AAPLP Coastal pipeline. The production projections for the Gaviota Facility decrease from 1995 to study year 2000 and then increase annually through study year 2015, but remain below the 1995 production rate and below the design capacity of the facility. In each study year, the projected Gaviota Facility production is less than one-half of the design capacity of the AAPLP Feeder pipeline. In each study year, the projected oil production from the two facilities combined is less than the design capacity of the AAPLP Main Line. Consequently, the pipeline capacity is not expected to be a constraint on the production at these two facilities.

Although the Ellwood Facility is not connected by pipeline to the Las Flores Canyon Facility or the AAPLP Coastal pipeline, the combined production projected for the Ellwood Facility and the Las Flores Canyon Facility in each study year is less than the design capacity of the AAPLP Coastal pipeline and when combined with the production from the Gaviota Facility is less than the capacity of the Main Line.

4.2.2.3 Scenario 3

In Scenario 3, the oil production projections for the Las Flores Canyon Facility are the same as in Scenario 2. In each study year the projected production is less than the design capacity of the AAPLP Coastal pipeline. In Scenario 3, the production projections for the Gaviota Facility are the same as in Scenario 2. In each study year, the Gaviota Facility production is less than one-half of the design capacity of the AAPLP Feeder pipeline. In each study year, the projected oil production from the two facilities combined is less than the design capacity of the AAPLP Main Line. Consequently, the pipeline capacity is not expected to be a constraint on the production at these two facilities.

Although the Ellwood Facility is not connected by pipeline to the Las Flores Canyon Facility or the AAPLP Coastal pipeline, the combined production projected for the Ellwood Facility and the Las Flores Canyon Facility in each study year is less than the design capacity of the AAPLP

Coastal pipeline, and when combined with the production from the Gaviota Facility total crude oil input to the AAPLP is less than the capacity of the Main Line.

4.2.2.4 Scenario 4

In Scenario 4, the production projections for the Las Flores Canyon Facility decrease annually through study year 2015. In each study year the projected production is less than the design capacity of the facility and the AAPLP Coastal pipeline. In Scenario 4, the production projections for the Gaviota Facility are the same as in Scenario 1 for study year 2000 and the facility is projected to be removed before study year 2005. The projected production rate in study year 2000 is less than the design capacity of the AAPLP Feeder pipeline. In each study year, the projected oil production from the two facilities combined is less than the design capacity of the AAPLP Main Line. Consequently, the pipeline capacity is not expected to be a constraint on the production at these two facilities.

Although the Ellwood Facility is not connected by pipeline to the Las Flores Canyon Facility or the AAPLP Coastal pipeline, the combined production projected for the Ellwood Facility and the Las Flores Canyon Facility in each study year is less than the design capacity of the AAPLP Coastal pipeline. When combined with the production from the Gaviota Facility, total input to the AAPLP is less than the capacity of the Main Line.

4.2.3 Northern Subregion Pipeline Systems

Offshore crude is brought onshore from Point Pedernales/Tranquillon Ridge to the Lompoc Oil & Gas Processing Facility from which the product oil enters the Tosco pipeline described in Section 2.4.4.4 as the "Northern Pipeline System". As of early 1999, the oil from the Lompoc Oil & Gas Processing Facility was being pumped to the Santa Maria Refinery from the Summit Pump Station on this pipeline system.

In some of the potential development scenarios, it is projected that oil will be produced from the Lion Rock Unit in the Offshore Santa Maria Basin (OSMB). Based on preliminary test data, the OSMB oil appears to be heavy (i.e., lower gravity), viscous and asphaltic and has different pumping characteristics than oil being produced from Point Pedernales/Tranquillon Ridge and offshore fields in the Eastern and Central Subregions. It is projected that the OSMB crude will be partially processed to produce asphalt or other heavy products (estimated at 40% of each barrel of oil produced) and pipeline quality oil (estimated at 60% of each barrel of oil produced). The pipeline quality oil produced as a result of this processing would be similar in gravity and viscosity to the oil currently transported in the AAPLP system, and it is expected this pipeline oil could be sent to the Northern Pipeline System and/or the AAPLP Main Line.

As described by individual scenarios below, the Northern Pipeline System is projected to have sufficient capacity in all study years of Scenarios 1, 2 and 2A to accommodate the projected oil flow in the Northern Subregion. In Scenarios 3, 4, 3A and 4A, the projected combined oil flows for the Subregion may exceed the capacity of the Northern Pipeline System, but not the capacity of the AAPLP Main Line which originates in the Central Subregion and traverses the Northern Subregion.

4.2.3.1 Scenario 1

In Scenario 1, all of the oil projected to be processed at the Lompoc Oil & Gas Processing Facility is from Point Pedernales/Tranquillon Ridge and the volume is projected to decline from 1995 to study year 2000. Under this no further offshore development scenario, the facility is not projected to be processing offshore oil in study years 2005, 2010 and 2015. During the remaining projected operation, the existing pipeline system is expected to be able to handle the declining production.

4.2.3.2 Scenario 2

In Scenario 2, the projected oil production rate for study year 2000 is the same as for study year 2000 in Scenario 1. The Lompoc Oil & Gas Processing Facility is projected to be idle in study year 2005 and then is projected to process oil and gas from the Bonito, Sugar Maple, and Lion Rock Fields in study years 2010 and 2015. In study year 2010, the total product oil rate is limited by the dry oil permit limit for the facility (36,000 barrels per day) and then declines in study year 2015. Scenario 2 assumes the oil production from Lion Rock is limited as a result of the onshore facility capacity limit.

The existing Tosco pipeline is expected to handle the Lompoc Facility's permitted level of oil production. The only portion of this pipeline system which could require expansion to accommodate this production is the Orcutt Pump Station, which currently has a design capacity of 24,000 barrels per day. In addition, it is unclear whether the product from the Lion Rock Field could be pumped using the current pumping system, or whether modifications would need to be made to accommodate the transport of Lion Rock oil in this system.

4.2.3.3 Scenario 3

In Scenario 3, the projected oil production rate for study year 2000 is the same as for study year 2000 in Scenario 1. The Lompoc Oil & Gas Processing Facility is projected to be idle in study year 2005 and then is projected to process oil and gas from the Bonito and Sugar Maple Fields in study years 2010 and 2015. The production from the Bonito and Sugar Maple Fields is projected to be less than the wet oil and dry oil permit limits for the Lompoc Oil & Gas Processing Facility in study year 2010 and 2015. Because the total quantity of oil produced is within the current permit/design limits of the Lompoc Oil & Gas Processing Facility, it is expected that the Tosco pipeline (Northern Pipeline System) has sufficient capacity for this oil.

In addition, Scenario 3 projects that there will be production from the Lion Rock Unit in study years 2010 and 2015, and that this production will be sent onshore to a new facility. The Lion Rock Field is projected to produce 25,000 barrels of oil per day under this scenario based on the expected potential market for asphalt. This case results in a projected pipeline oil rate of 15,000 barrels per day and an asphalt or other heavy product rate of 10,000 barrels per day.

In study years 2010 and 2015, the total pipeline transported oil production from the two Northern Subregion facilities is projected to exceed the current 36,000 barrels per day dry oil permit limit for the Lompoc Oil & Gas Processing Facility by approximately 20 percent. The existing pipeline pump design capacity at the Lompoc Facility is adequate to accommodate this increase, and has a capacity of 43,200 barrels per day. The pipeline design capacity between the Lompoc Facility and the Santa Maria Refinery is limited by the pipe segment from Orcutt Station to Suey Junction, which has a design capacity of 50,400 barrels per day. The Orcutt Pump Station currently has a pump capacity of 24,000 barrels per day, which would require expansion under this scenario if this system was used to transport all of the Northern Subregion crude oil. The AAPLP Main Line is projected to have sufficient capacity to handle the total flow in addition to that coming from the Central Subregion (including the Ellwood Facility, if connected) assuming the oil has characteristics within the AAPLP's acceptance criteria. A pipeline connection to the AAPLP would need to be installed in the Northern Subregion to accommodate this transport.

4.2.3.4 Scenario 4

In Scenario 4, the projected operation and product oil rate for the Lompoc Oil & Gas Processing Facility is the same as in Scenario 3 for all study years (i.e., receipt of production from Point Pedernales/Tranquillon Ridge through study year 2000 and from the Bonito and Sugar Maple Fields in study years 2010 and 2015).

In addition, Scenario 4 projects that there will be production from the Lion Rock Field, and that the production will be sent onshore to a new facility. The Lion Rock Platform is projected to produce 58,000 barrels of oil per day in study year 2010 and 75,000 barrels of oil per day in study year 2015 which represents the operator's "maximum case" based on the potential to capture much of the western USA (PAD V) market for asphalt and to export asphalt outside the PAD V region. This case results in a Lion Rock contribution to the pipeline oil rate of 45,000 barrels per day and a heavy product rate of 30,000 barrels per day in study year 2015.

In study years 2010 and 2015, the total pipeline transported oil production from the two facilities is projected to be between 1.75 and 1.95 times the 36,000 barrels per day dry oil permit limit for the Lompoc Oil & Gas Processing Facility. This scenario would require the expansion of the Tosco system or installation of a new pipeline to connect the Lion Rock pipeline transportable product to the AAPLP pipeline system. Use of the Tosco system would require expansion of the pipe segment from Orcutt Station to Suey Junction, and could include a new pipeline (or system modifications to accommodate flow reversal) from Suey Junction to the Sisquoc Pump Station connection with the AAPLP system. Transport of other Northern Subregion production is well within the capacity of the existing Tosco pipeline system. The AAPLP Main Line is projected to have sufficient capacity to handle the total flow in addition to that coming from the Central Subregion (including the Ellwood Facility, if connected) assuming the oil has characteristics within the AAPLP's acceptance criteria. A pipeline connection to the AAPLP would be required in the Northern Subregion to accommodate this transport.

4.2.3.5 Scenario 2A

For study year 2000, Scenario 2A is the same as Scenarios 1 and 2. That is, the Lompoc Oil & Gas Processing Facility is the only facility operating in the Northern Subregion that receives production directly from Platform Irene (Point Pedernales and Tranquillon Ridge) and the volume of oil produced is less than the capacity of the Northern Pipeline System.

In Scenario 2A, it is projected that the Gaviota Facility in the Central Subregion is removed by study year 2001 and that the production from some Central Subregion leases that would have been processed at the Gaviota Facility is routed to the Lompoc Oil & Gas Processing Facility. It is projected that production from these leases will increase from study year 2005 to reach the Lompoc Oil & Gas Processing Facility's 36,000 barrels per day of dry oil permit limit by study year 2015. The 36,000 barrel per day oil limit is below the design capacity of the Northern Pipeline System. In Scenario 2A, there is no production projected for the Lion Rock Unit because it is projected that the Lompoc Oil & Gas Processing Facility's capacity is taken as described above and no new facilities are constructed.

4.2.3.6 Scenario 3A

For study year 2000, Scenario 3A is the same as Scenarios 1 and 3. That is, the Lompoc Oil & Gas Processing Facility is the only facility operating in the Northern Subregion that receives production directly from Platform Irene (Point Pedernales and Tranquillon Ridge) and the volume of oil produced is less than the capacity of the Northern Pipeline System.

In Scenario 3A, it is projected that the Gaviota Facility in the Central Subregion is removed by study year 2005 and that the production from some leases that would have been processed at the Gaviota Facility is routed to the Lompoc Oil & Gas Processing Facility. It is projected that production from these leases will increase from study year 2005 to 2015, and will exceed the Lompoc Oil & Gas Processing Facility's 36,000 barrels per day of dry oil permit limit in study years 2010 and 2015. Total production handled at this facility would be within the capacity of Tosco's Northern Pipeline system in 2005, and would exceed the permit and design capacities of this pipeline system in 2010 and 2015. The AAPLP Main Line is projected to have sufficient capacity to handle the total flow from the Lompoc Oil and Gas Processing Facility in addition to that coming from the Central Subregion (including the Ellwood Facility, if connected), assuming the oil has characteristics within the AAPLP's acceptance criteria. A pipeline connection to the AAPLP would need to be installed in the Northern Subregion to accommodate this transport, or expansion of the existing Tosco system to Suey Junction and permit authorization for reverse flow deliveries to the AAPLP using existing pipelines would be required.

In addition to the production handled at the Lompoc Facility described above, Scenario 3A projects that there will be production from the Lion Rock Field in study years 2010 and 2015. This production will be sent onshore to a new facility (at the Lompoc site or a new location). The Lion Rock Field is projected to produce 25,000 barrels of oil per day under this scenario based on the expected potential market for asphalt. This case results in a projected pipeline oil rate of 15,000 barrels per day and a heavy product rate of 10,000 barrels per day. Pipeline transport of this 15,000 barrels per day could not be accommodated in the Tosco pipeline system, and would require a new pipeline connection to the AAPLP Main Line. The AAPLP Main Line has sufficient capacity to handle this additional throughput in addition to the projected throughput associated with Central Subregion production and potential throughput associated with Lompoc Oil & Gas Processing Facility output under this scenario. AAPLP acceptance of Northern Subregion production would depend on the conformance with AAPLP's oil characteristics acceptance criteria, however.

4.2.3.7 Scenario 4A

For study year 2000, Scenario 4A is the same as Scenarios 1 and 4. That is, the Lompoc Oil & Gas Processing Facility is the only facility operating in the Northern Subregion that receives production directly from a platform; all production is from Point Pedernales and the volume of oil produced is less than the capacity of the Northern Pipeline System. Also in Scenario 4A, it is projected that the Lompoc Oil & Gas Processing Facility will receive the same quantities of oil from the same sources as described in Scenario 3A. Total production handled at this facility would be within the capacity of Tosco's Northern Pipeline System in 2005, and would exceed the permit and design capacity of this system in 2010 and 2015. The AAPLP Main Line is projected to have sufficient capacity to handle the total flow from the Lompoc Oil and Gas Processing Facility in addition to that coming from the Central Subregion (including the Ellwood Facility, if connected), assuming the oil has characteristics within the AAPLP's acceptance criteria. A pipeline connection to the AAPLP system would be required to accommodate this transport, or expansion of the existing Tosco system from Lompoc to Suey Junction and permit authorization for reverse flow from Suey Junction to the AAPLP at Sisquoc would be required.

In addition to the production handled at the Lompoc Facility described above, Scenario 4A projects that there will be production from the Lion Rock Field which would be sent onshore to a new facility. The Lion Rock Field is projected to produce 58,000 barrels of oil per day in study year 2010 and 75,000 barrels of oil per day by study year 2015 which represents the operator's "maximum case" based on the potential to capture much of the western USA (PAD V) market for asphalt and to export asphalt or other heavy product outside the PAD V region. This case results in a Lion Rock contribution to the pipeline oil rate of 45,000 barrels per day and a heavy product rate of 30,000 barrels per day in study year 2015. Pipeline transport of these volumes could not be accommodated by the Tosco pipeline system, and would require a new pipeline connection to the AAPLP Main Line. The AAPLP Main Line has sufficient capacity to handle this additional throughput in addition to the throughput associated with Central Subregion production and potential throughput associated with Lompoc Oil and Gas Processing Facility output under this scenario. AAPLP acceptance of Northern Subregion production would depend on the conformance with AAPLP's oil characteristics acceptance criteria, however.

4.3 MARINE TRANSPORT

As of July 1999, the Ellwood Marine Terminal is the only active marine terminal in the Study Region. The Ellwood Marine Terminal serves only the Ellwood Oil & Gas Processing Facility. The Ellwood Marine Terminal consists of a tank farm and offshore mooring. There are pipelines connecting the Ellwood Oil & Gas Processing Facility to the tank farm and the tank farm to the mooring.

Both the Ellwood Oil & Gas Processing Facility and the Ellwood Marine Terminal are legal, non-conforming uses pursuant to Santa Barbara County policies for consolidation of oil and gas facilities and transportation of oil. Study assumption number 6 assumes no change in this status;

therefore, future development of the South Ellwood Field not in compliance with these restrictions would be likely processed at Las Flores Canyon, which has direct access to the All American Pipeline for transporting crude oil and NGLs to refineries. The offshore development projected in Scenarios 3 and 4 assumes that no expansion of the Ellwood Oil & Gas Processing Facility would occur, and any increased offshore production beyond that facility's current legally permitted use would be processed at Las Flores Canyon.

As of August 1997, one barge was being loaded every 9 to 12 days at the Ellwood Marine Terminal. At the maximum pumping rate of 4,200 barrels per hour, it takes approximately 13 to 14 hours to load the barge and the entire barge loading activity (mooring, loading, and departure) can be conducted in 24 hours. Physically, the Ellwood Marine Terminal could load up to 7 barges per week, but it is not clear if this required use is consistent with the legal non-conforming use status. The physical ability to load 7 barges per week does not indicate that such use is allowed by right. None of the scenarios project oil production rates high enough to require this level of barge activity. As a result, the physical loading capacity of the existing Ellwood Marine Terminal does not represent a constraint to any of the potential development scenarios.

4.4 ROADS AND HIGHWAYS

This section discusses key elements of the existing highway and road system used by the oil and gas industry and how the use of these elements could change by Subregion, scenario, and study year. This section will focus on regional traffic issues and on subregional or facility-specific traffic issues.

As described in Section 2.5.2, the major highways serving the onshore facilities are Highway 101, Highway 126 and Highway 166. Essentially all truck-transported products (sulfur and LPG) produced at the various onshore facilities are transported over portions of these highways. Because these distribution routes cross Subregional boundaries, products produced in one Subregion may result in additional traffic in another Subregion. Consequently, it is appropriate to discuss traffic associated with the transport of products on a Study Region-wide basis. This discussion is provided in Section 4.4.1.

In addition to the major highways used for product distribution, there are local road systems used to access Port Hueneme and the Ellwood and Carpinteria Piers. This traffic is specific to personnel and supply transfer locations rather than to specific facilities and is expected to be more of a local or Subregional concern. These traffic issues are discussed for the Eastern, Central and Northern Subregions in Section 4.4.2, 4.4.3 and 4.4.4, respectively. These discussions do not focus on employee or service provider traffic at the operating facilities, as this traffic is expected to remain relatively constant at each facility as long as the facility is operating.

4.4.1 Contribution to Projected Traffic on Regional Roads & Highways

The distribution of products produced at the various offshore oil related onshore facilities is discussed in Section 2.5.2. Figure 4.4-1 shows the major highways used in the Study Region for the distribution of LPG, sulfur and other products.

Other than the majority of the oil and natural gas which are sent by pipeline, other products are typically transported by truck. The facilities sending product by truck include the State Lease 145/410 Facility, the Ellwood Oil & Gas Processing Facility, the Las Flores Canyon SYU Oil & Gas Processing and Las Flores Canyon Gas Processing Facility, and the Lompoc Oil & Gas Processing Facility. Some of the scenarios also project the shipment of products from Gaviota Oil & Gas Processing Facility (including LPGs it receives from the Molino Facility to the extent they cannot be blended with crude oil for pipeline shipment), and the facility that would process the Lion Rock Field crude.

As described in Section 2.5.2, all of the products that are not distributed within the Study Region leave the Study Region by traveling on Highway 101 South into Los Angeles County, Highway 126 East into Los Angeles County, or Highway 166 East into Kern County. None of the trucks were identified as traveling on Highway 101 North out of San Luis Obispo County.

Using the oil and gas processing rates projected for each facility along with the baseline operating data provided by the facility operators, estimates were made of the number of trucks of each type of product (e.g., LPG, sulfur, crude oil or heavy product/asphalt) that would be produced in each scenario by study year. The procedure used and the results are shown by facility, scenario and study year in Appendix A.6.

Figure 4.4-2 provides a schematic of the Highway 101, 126 and 166 system and shows the relative locations of the facilities to several of the cities along Highway 101. The figure represents the combined product traffic from the facilities under the scenario combination of Eastern Subregion Scenario 1, Central Subregion Scenario 1 and Northern Subregion Scenario 1. This combination of scenarios results in the lowest number of total product trucks of all possible combinations of scenarios addressed in this study. The boxes shown on the figure identify the total number of product trucks projected for various highway sections. For simplicity, the Ellwood, Las Flores Canyon, and Gaviota Facilities are shown as a single entry point to Highway 101, and all product traffic from these facilities continue on Highway 101 to the south or north. As shown, the number of trucks traveling south through the city of Santa Barbara is projected to remain constant in all future study years in Scenario 1 and all of these trucks originate from the Las Flores Canyon Facilities. The number of trucks traveling north on Highway 101 in the Central and Northern Subregions and east on Highway 166 is projected to be highest in 2005 with a total northbound product traffic of 31 trucks per week. This traffic is primarily associated with production at the Molino Facility, which is shipped to the Gaviota Facility via pipeline and, from there, is projected to generate 24 trucks per week in 2005.

Because the total number of trucks of LPG, sulfur and heavy product (such as asphalt) projected to travel on the highways is directly related to the total quantity of oil and gas processed at the facilities, the scenarios and study years having the potential to generate the greatest number of trucks are those involving further offshore development and expanded onshore facilities. The combined number of trucks of LPG, sulfur and crude oil projected for four different development scenario combinations are provided on Figures 4.4-3 through 4.4-6. Because heavy product (such as asphalt) transport is a feature of interest with regard to specific Northern Subregion scenarios, this traffic is addressed separately on Figures 4.4-7 and 4.4-8. The potential transport of heavy product by rail could replace some or all of the heavy product truck traffic, and this is specifically addressed in Figure 4.4-9. Note that the only Eastern Subregion facility currently or projected to generate product trucks is the State Lease 145/410 Facility (which transports crude oil by truck). Because the number of trucks from this facility is the same under all scenarios, different product transport traffic levels are determined by the combination of Central and Northern Subregion scenarios.

Figure 4.4-3 represents the combined LPG, sulfur and crude oil product traffic from the facilities under the scenario combination of any Eastern Subregion scenario, Central Subregion Scenario 3, and Northern Subregion Scenario 3. The maximum product truck traffic associated with this combination of scenarios would occur in 2010, and would result in up to 62 truck trips per week northbound on Highway 101 and/or Highway 166, and up to 73 truck trips per week southbound on Highway 101. In study year 2000, all of the trucks traveling south through the city of Santa Barbara are projected to originate from the Las Flores Canyon Facilities. Eighty percent or more of the trucks traveling south through the City of Santa Barbara in study years 2005, 2010 and 2015 are projected to originate from the Las Flores Canyon Facilities. All other product trucks projected to travel south through the city of Santa Barbara in study years 2005, 2010 and 2015 originate from the Gaviota Facility. In study year 2000, up to ten trucks per week are projected to travel north on Highway 101 in the Central and Northern Subregions. In study year 2005, approximately 50 percent of the trucks traveling on Highway 101 north of the city of Santa Barbara originate from the Ellwood Facility and this number decreases to about 48 percent in 2010 and to 31 percent in 2015. In study year 2005, production associated with the Molino Facility is shipped to the Gaviota Facility via pipeline and, from there, contributes approximately 40 percent of the northbound traffic. In study year 2010, the Lompoc/Lion Rock facilities contribute approximately 32 percent of the northbound traffic which increases to approximately 57 percent by study year 2015. As shown, the majority of the northbound trucks travel on Highway 166 east.

Figure 4.4-4 represents the combined LPG, sulfur and crude oil product traffic from the facilities under the scenario combination of any Eastern Subregion scenario, Central Subregion Scenario 3 and Northern Subregion Scenario 4. The maximum northbound product truck traffic associated with this combination of scenarios would occur in 2015, and would result in up to 95 truck trips per week northbound on Highway 101 and/or eastbound on Highway 166. The maximum southbound product truck traffic would occur in 2010, and would result in up to 73 truck trips per week southbound on Highway 101. In study year 2000, all of the trucks traveling south through the city of Santa Barbara are projected to originate from the Las Flores Canyon Facilities. Eighty percent or more of the trucks traveling south through the City of Santa Barbara in study years 2005, 2010 and 2015 are projected to originate from the Las Flores Canyon Facilities. All other product trucks projected to travel south through the city of Santa Barbara in study years 2005, 2010 and 2015 originate from the Gaviota Facility. In study year 2000, up to ten trucks per week are projected to travel north on Highway 101 in the Central and Northern Subregions. In study year

2005, approximately 50 percent of the trucks traveling on Highway 101 north of the city of Santa Barbara originate from the Ellwood Facility and this number decreases to about 43 percent in 2010 and to 18 percent in 2015. In study year 2005, production associated with the Molino Facility is shipped via pipeline to the Gaviota Facility and, from there, contributes approximately 40 percent of the northbound traffic. In study year 2010, the Lompoc/Lion Rock facilities contribute approximately 39 percent of the northbound traffic which increases to approximately 76 percent by study year 2015. As shown, the majority of the northbound trucks travel on Highway 166 east. As shown for study years 2010 and 2015, there would be an even larger increase in the projected number of trucks (than shown on Figure 4.4-3) on Highway 101 in the Northern Subregion and on Highway 166 through the Northern Subregion due to an increased quantity of LPG and sulfur.

Figure 4.4-5 represents the combined LPG, sulfur and crude oil product traffic from the facilities under the scenario combination of any Eastern Subregion scenario, Central Subregion Scenario 4 and Northern Subregion Scenario 3A. The maximum northbound product truck traffic associated with this combination of scenarios would occur in 2010, and would result in up to 81 truck trips per week northbound on Highway 101 and/or eastbound on Highway 166. The maximum southbound product truck traffic would occur in 2005, and would result in up to 65 truck trips per week southbound on Highway 101. In study years 2000, 2005, 2010 and 2015, all of the trucks traveling south through the City of Santa Barbara are projected to originate from the Las Flores Canyon Facilities. In study year 2000, up to ten trucks per week are projected to travel north on Highway 101 in the Central and Northern Subregions. In study year 2005, approximately 43 percent of the trucks traveling on Highway 101 north of the city of Santa Barbara originate from the Ellwood Facility and this number decreases to about 37 percent in 2010 and to 21 percent in 2015. In study year 2005, production associated with the Molino Facility contributes approximately 35 percent of the northbound traffic. In study year 2010, the Lompoc/Lion Rock facilities contribute approximately 49 percent of the northbound traffic which increases to approximately 72 percent by study year 2015. As shown, the majority of the northbound trucks travel on Highway 166 east.

Figure 4.4-6 represents the combined product traffic from the facilities under the scenario combination of any Eastern Subregion scenario, Central Subregion Scenario 4 and Northern Subregion Scenario 4A. The maximum northbound product truck traffic associated with this combination of scenarios would occur in 2015, and would result in up to 120 truck trips per week northbound on Highway 101 and/or eastbound on Highway 166. The maximum southbound product truck traffic would occur in 2005, and would result in up to 65 truck trips per week southbound on Highway 101. In study years 2000, 2005, 2010 and 2015, all of the trucks traveling south through the City of Santa Barbara are projected to originate from the Las Flores Canyon Facilities. In study year 2000, up to ten trucks per week are projected to travel north on Highway 101 in the Central and Northern Subregions. In study year 2005, approximately 43 percent of the trucks traveling on Highway 101 north of the city of Santa Barbara originate from the Ellwood Facility and this number decreases to about 34 percent in 2010 and to 14 percent in 2015. In study year 2005, production associated with the Molino Facility contributes approximately 35 percent of the northbound traffic. In study year 2010, the Lompoc/Lion Rock facilities contribute approximately 53 percent of the northbound traffic which increases to approximately 82 percent by study year 2015. As shown, the majority of the northbound trucks travel on Highway 166 east. As shown for study years 2010 and 2015, there would be an even larger increase in the projected number of trucks (than shown on Figure 4.4-5) on Highway 101 in the Northern Subregion and on Highway 166 through the Northern Subregion due to an increased quantity of LPG and sulfur.

The scenario combinations described above illustrate that both the market-limited and maximum-case Lion Rock production scenarios (Northern Subregion Scenarios 3 and 4 or 3A and 4A) have the potential to increase the number of trucks traveling on Highway 101 and Highway 166 east in the Northern Subregion due to the production of LPG and sulfur. In addition to LPG and sulfur, the facility that would be used to process crude from the Lion Rock Unit is also expected to produce heavy products, such as asphalt, that may not be suitable for transport by pipeline and would likely be transported by truck and/or rail. The location of a processing facility for the Lion Rock crude is not yet known, and production rates vary by scenario. Consequently, the quantity of heavy products produced and the local roads used can only be roughly estimated at this time. After initial processing, it is projected that the quantity of heavy products produced will be approximately 40 percent of the total barrels of oil produced and the remaining 60 percent will be transported by pipeline. For the purpose of this analysis, heavy product traffic associated with Lion Rock production is assumed to enter the regional roadway system on Highway 101 at approximately the same location as current Lompoc Oil and Gas Processing Facility LPG trucks.

For the heavy products transported to market by truck, it is projected that two-thirds will be transported on Highway 166 east into Kern County and one-third will be transported on Highway

101 south into Los Angeles County. Figure 4.4-7 shows the projected number of 140-barrel capacity trucks of product transported on each of these routes for Northern Subregion Scenarios 3 and 3A. Figure 4.4-8 shows the projected number of trucks of heavy product transported on each of these routes for Northern Subregion Scenarios 4 and 4A. Both of these Figures show the maximum number of trucks assuming that all of the heavy products produced are transported by truck.

The number of truck trips to transport the heavy products can be reduced if the products are transported by rail in tank cars. The rail service could be at the Facility where the Lion Rock crude is processed or could be at a relatively close loading location where shuttle trucks could be used to transport the products from the processing facility to the loading facility.

Table 4.4-1 and Figure 4.4-9 show examples of potential combinations of tank trucks and unit trains that could be used to transport heavy product under different Northern Subregion scenarios. As shown for Scenarios 3 and 3A, the projected 500 trucks per week of heavy product could be replaced by about two unit trains per week. For Scenarios 4 and 4A, the projected 1,500 trucks per week could be replaced by about six unit trains per week. Details of this analysis are provided in Appendix A.6.

Using the oil and gas processing rates projected for each facility along with the baseline operating data provided by the facility operators, estimates were made of the number of trucks of each type of product (e.g., LPG, sulfur, crude oil or heavy product/asphalt) that would be produced in each scenario by study year. The procedure used and the results are shown by facility, scenario and study year in Appendix A.6.

Table 4.4-1
Examples of Potential Combinations
of Truck and Rail Transport of Heavy Product[1]

Scenario / Study Year Combinations	Heavy Product/Asphalt Distribution Combination Examples				
	Amount Sent by Truck (%)	Tank Trucks per Week	Amount Sent by Rail (%)	Tank Cars per Week	Unit Trains per Week
Northern Subregion Scenario 2 2010 & 2015	100	150	0	0	0
	75	113	25	11.0	0.16
	50	75	50	22.1	0.32
	25	38	75	33.1	0.47
	0	0	100	44.1	0.63
Northern Subregion Scenarios 3 and 3A 2010 & 2015	100	500	0	0	0
	75	375	25	36.8	0.53
	50	250	50	73.5	1.05
	25	125	75	110.3	1.58
	0	0	100	147.1	2.10
Northern Subregion Scenarios 4 and 4A 2010	100	1,160	0	0	0
	75	870	25	85.3	1.22
	50	580	50	170.6	2.44
	25	290	75	255.9	3.66
	0	0	100	341.2	4.87
Northern Subregion Scenarios 4 and 4A 2015	100	1,500	0	0	0
	75	1,125	25	110.3	1.58
	50	750	50	220.6	3.15
	25	375	75	330.9	4.73
	0	0	100	441.2	6.30

[1]Refer to Appendix A.6 for information concerning the calculation of information in this table.

Figure 4.4-2 provides a schematic of the Highway 101, 126 and 166 system and shows the relative locations of the facilities to several of the cities along Highway 101. The figure represents the combined product traffic from the facilities under the scenario combination of Eastern Subregion Scenario 1, Central Subregion Scenario 1 and Northern Subregion Scenario 1. This combination of scenarios results in the lowest number of total product trucks of all possible combinations of scenarios addressed in this study. The boxes shown on the figure identify the total number of product trucks projected for various highway sections. For simplicity, the Ellwood, Las Flores Canyon, Molino and Gaviota Facilities are shown as a single entry point to Highway 101 because there are no major highway intersections on this section of Highway 101, and all product traffic from these facilities continue on Highway 101 to the south or north. As shown, the number of trucks traveling south through the city of Santa Barbara is projected to remain constant in all future study years in Scenario 1.

Because the total number of trucks of LPG, sulfur and heavy product (such as asphalt) projected to travel on the highways is directly related to the total quantity of oil and gas processed at the facilities, the scenarios and study years having the potential to generate the greatest number of trucks are those involving further offshore development and expanded onshore facilities. The combined number of trucks of LPG, sulfur and crude oil projected for four different development scenario combinations are provided on Figures 4.4-3 through 4.4-6 to illustrate LPG, sulfur, and crude oil transport traffic volumes associated within different scenario combinations. Because heavy product (such as asphalt) transport is a feature of interest with regard to specific Northern Subregion scenarios, this traffic is addressed separately on Figures 4.4-7 and 4.4-8. The potential transport of heavy product by rail could replace some or all of this truck traffic, and this is specifically addressed in Figure 4.4-9. Note that the only Eastern Subregion facility currently or projected to generate product trucks is the State Lease 145/410 Facility (which transports crude oil by truck). Because the number of trucks from this

facility is the same under all scenarios, different product transport traffic levels are determined by the combination of Central and Northern Subregion scenarios.

Figure 4.4-3 represents the combined product traffic from the facilities under the scenario combination of any Eastern Subregion scenario, Central Subregion Scenario 3, and Northern Subregion Scenario 3. The key features of this combination are that the Gaviota Facility is projected to be operating and producing sulfur and LPG and that Lion Rock is projected to be producing asphalt at a market-limited production rate. As shown for study years 2005, 2010, and 2015, an increase in trucks on Highway 101 in the Northern Subregion and on Highway 166 through the Northern Subregion would be projected.

Figure 4.4-4 represents the combined product traffic from the facilities under the scenario combination of any Eastern Subregion scenario, Central Subregion Scenario 3 and Northern Subregion Scenario 4. The key features of this combination are that the Gaviota Facility is projected to be operating and producing sulfur and LPG and that Lion Rock is projected to be producing LPG and sulfur at the maximum production rate (i.e., from 58,000 BOPD in study year 2010 and from 75,000 BOPD in study year 2015). As shown for study years 2005, 2010, and 2015, there would be an even larger increase in the projected number of trucks (than shown on Figure 4.4-3) on Highway 101 in the Northern Subregion and on Highway 166 through the Northern Subregion due to an increased quantity of LPG and sulfur.

Figure 4.4-5 represents the combined product traffic from the facilities under the scenario combination of any Eastern Subregion scenario, Central Subregion Scenario 4 and Northern Subregion Scenario 3A. On of the key features of this combination is that the Gaviota Facility is not projected to be operating and some of production that would have been processed at that facility is redirected to the Lompoc Oil & Gas Processing Facility in the Northern Subregion. Whereas most of the trucks from the Gaviota Facility were projected to travel Highway 101 south, trucks from the Lompoc Facility are projected to travel on Highway 101 north and Highway 166 east. This combination also includes LPG and sulfur trucks associated with the market-limited production of Lion Rock crude.

Figure 4.4-6 represents the combined product traffic from the facilities under the scenario combination of any Eastern Subregion scenario, Central Subregion Scenario 4 and Northern Subregion Scenario 4A. The key features of this combination are that it combines the shutdown of the Gaviota Facility and the subsequent change in the operation of the Lompoc Oil & Gas Processing Facility with the LPG and sulfur production associated with the maximum production from Lion Rock. As shown for study years 2005, 2010, and 2015, there is an even larger increase in the projected number of trucks (than shown on Figure 4.4-5) on Highway 101 in the Northern Subregion, and on Highway 166 through the Northern Subregion.

The scenario combinations described above illustrate that both the market-limited and maximum Lion Rock production scenarios have the potential to increase the number of trucks traveling on Highway 101 in the Northern Subregion due to the production of LPG and sulfur, and Highway 166 east.

In addition to the trucks associated with the transport of sulfur, LPG and crude oil from the facilities described above, it is projected that the facility used to process crude from the Lion Rock Unit will also produce heavy products, including asphalt, that may not be suitable for transport by pipeline and will likely be transported by truck and/or rail. The quantity and projected processing location for the Lion Rock crude varies by scenario and consequently the quantity of heavy products produced and the local roads used may vary. After initial processing, it is projected that the quantity of heavy products produced will be approximately 40 percent of the total barrels of oil produced and the remaining 60 percent will be transported by pipeline.

For the heavy products transported to market by truck, it is projected that two-thirds will be transported on Highway 166 east into Kern County and one-third will be transported on Highway 101 south into Los Angeles County. Figure 4.4-7 shows the projected number of 140-barrel capacity trucks of product transported on each of these routes for Northern Subregion Scenarios 3 and 3A where the quantity of oil produced is based on market-limit conditions. Figure 4.4-8 shows the projected number of trucks of heavy product transported on each of these routes for Northern Subregion Scenarios 4 and 4A where the quantity of oil produced is based on the maximum commercial production estimate, including potential export markets. Both of these Figures show the maximum number of trucks assuming that all of the heavy products produced are transported by truck.

The number of truck trips to transport the heavy products can be reduced if the products are transported by rail in tank cars. The rail service could be at the Facility where the Lion Rock crude is processed or could be at a relatively close loading location where shuttle trucks could be used to transport the material from the processing facility to the loading facility.

Table 4.4-1 and Figure 4.4-9 show examples of potential combinations of tank trucks and unit trains that could be used to transport heavy product under different Northern Subregion scenarios. As shown for Scenarios 3 and 3A, the projected 500 trucks per week of heavy product could be replaced by about two unit trains per week. For Scenarios 4 and 4A, the projected 1,500 trucks per week could be replaced by about six unit trains per week. Details of this analysis are provided in Appendix A.6.

4.4.2 Eastern Subregion Traffic Constraints

There are several traffic issues in the Eastern Subregion including the use of highways by trucks transporting product, the use of highways and roads associated with the transport of personnel and materials to Port Hueneme, and the use of highways and roads to access the Carpinteria Pier which is used by vessels transporting personnel and supplies to the offshore facilities. These types of traffic are discussed in the sections below.

4.4.2.1 Facility Traffic Constraints

The State Lease 145/410 Facility transports some crude by truck on the regional highways. This activity is included in the regional discussion in Section 4.4.1.

4.4.2.2 Port Hueneme Traffic Constraints

Port Hueneme is used by supply (work) vessels serving the offshore platforms in all three Subregions and also is used by crew vessels that serve some of the platforms in the Eastern Subregion. As such, current or future activities that occur offshore in the Central and Northern Subregions have the potential to influence traffic at the Port and on Eastern Subregion roads.

Some of the vehicles (e.g., trucks, cars) accessing Port Hueneme are expected to use portions of Highways 101 and 126, and all need to use surface streets. As described in Section 2.5.2, traffic accessing the Port related to the supply and crew vessels is more closely linked to the level of offshore activity than to the volume oil or gas being produced and sent to shore.

Because the traffic at the Port is dependent on the activities conducted in all three Subregions, it is appropriate to review the projected traffic levels based on possible combinations of scenarios that could occur. Projections of the volume of cars and trucks accessing the Port in the various scenarios and study years, as well as for the various scenario combinations, were made and the procedures used and detailed results are provided in Appendix A.6. A summary of the projected total traffic (i.e., cars and trucks combined) and the projected truck traffic for key scenario combinations are discussed in the sections below.

4.4.2.2.1 Cumulative Traffic at Port Hueneme

Table 4.4-2 provides a summary of the scenario combinations resulting in the maximum total vehicle traffic at the Port by study year. As shown, all scenario combinations start out with the same baseline traffic for 1997 and the projections for study year 2000 are essentially the same for all scenario combinations.

By study year 2005, the various scenario combinations begin to show their differences. In study year 2005, there are 12 scenario combinations that give the maximum traffic volume of an average of 1,207 vehicles per week. The level of 1,207 is an increase of 38 percent from the level in 1997. The key features of these scenario combinations is that they all include the maximum future development scenario (Scenario 3) in the Central Subregion. They also include some level of additional development in the Eastern and Northern Subregions, but not necessarily the maximum. This is important in that it shows decisions made regarding facilities in the Central Subregion could result in a traffic increase in the Eastern Subregion that is above the level of traffic increase that would be expected due to a general increase in population.

Table 4.4-2
Summary of Scenario Combinations Resulting in Maximum
Total Vehicle Traffic Volumes at Port Hueneme

Scenario Combinations			**Average Number of Vehicle Trips Per Week**				
Eastern	**Central**	**Northern**	**1997**	**2000**	**2005**	**2010**	**2015**
Scenario Combinations Resulting in Maximum Vehicles in 1997[2]							
*[1]	*	*	876	--	--	--	--
Scenario Combinations Resulting in Maximum Vehicles in Study Year 2000[2]							
1	*	*	876	729	--	--	--
2	*	*					
3	*	*					
Scenario Combinations Resulting in Maximum Vehicles in Study Year 2005[2]							
2 2	2 3	2 2	876	729	1207	767	277
2 2	2 3	3 3				852	284
2 2	2 3	4 4				1,045	289
3 3	2 3	2 2				767	265
3 3	2 3	3 3				852	273
3 3	2 3	4 4				1,045	278
Scenario Combinations Resulting in Maximum Vehicles in Study Year 2010[2]							
2 2	3 2	4 4[3]	876	729	1,207	1,045	289
3 3	3 2	4 4[3]					278
2 2	3 2	3 3	876	729	1,207	852	284
3 3	3 2	3 3					273
Scenario Combinations Resulting in Maximum Vehicles in Study Year 2015							
2	4	2A	876	729	1,165	474	382

Notes
(1) A "*" means all scenarios in this Subregion give same results for the listed combination.
(2) Where only one value is provided for multiple scenario combinations, the value is the same for each combination.
(3) Northern Scenario 4 is a maximum case and should be reviewed in the context of the same Eastern and Central Subregion scenarios in combination with the Northern Subregion market-based Scenario 3.

In study year 2010, the four scenario combinations projected to have the greatest level of traffic at Port Hueneme all include Scenario 4 in the Northern Subregion. In these combinations, the projected traffic averages 1,045 vehicles per week which represents a 19 percent increase over the 1997 level. Because Northern Subregion Scenario 4 represents the maximum production from Lion Rock without considering market limitations, it is also appropriate to look at conditions under the market-limited scenario. This combination (substituting Scenario 3 for Scenario 4 in the Northern Subregion) projects an average traffic level of 852 trips per week, which is a 2 percent decrease below the 1997 level. Again, decisions made about offshore facilities outside the Eastern Subregion could result in traffic increases in excess of the increase that would be expected due to projected population increase.

In study year 2015, the scenario combination projected to generate the greatest level of Port Hueneme area traffic is Eastern Subregion Scenario 2, Central Subregion Scenario 4 and Northern Subregion Scenario 2A. The projected traffic volume averages 382 vehicles per week which represents a 56 percent decrease from the 1997 level.

In contrast to Table 4.4-2, Table 4.4-3 provides a summary of the scenario combinations resulting in the minimum total vehicle traffic at Port Hueneme by study year. As shown, all scenario combinations begin with the same baseline traffic for 1997, and the projections for study year 2000 are essentially the same for all scenario combinations.

In study year 2005, the scenario combination with the lowest level of traffic is Eastern Subregion Scenario 4, Central Subregion Scenario 1, and Northern Subregion Scenario 1. The key features of this combination are that in the Eastern Subregion, some facilities have been abandoned early (prior to study year 2005) and the facilities in the Central and Northern Subregions are operating under the no further development scenarios. The projected traffic level of 589 vehicles per week represents a 33 percent decrease from the 1997 level.

In study year 2010, the two scenario combinations that project the lowest level of traffic are Eastern Subregion Scenario 1 or 4, Central Subregion Scenario 1, and Northern Subregion Scenario 1. The projected traffic level of 101 vehicles per week is a sharp decrease from the level in study year 2005 and represents an 88 percent decrease from the level in 1997.

Table 4.4-3
Summary of Scenario Combinations Resulting in Minimum
Total Vehicle Traffic Volumes at Port Hueneme

Scenario Combinations			Average Number of Vehicle Trips Per Week				
Eastern	**Central**	**Northern**	**1997**	**2000**	**2005**	**2010**	**2015**
Scenario Combinations Resulting in Minimum Vehicles in 1997[2]							
*[1]	*	*	876	--	--	--	--
Scenario Combinations Resulting in Minimum Vehicles in Study Year 2000[2]							
4	*	*	876	723	--	--	--
Scenario Combinations Resulting in Minimum Vehicles in Study Year 2005[2]							
4	1	1	876	723	589	101	32
Scenario Combinations Resulting in Minimum Vehicles in Study Year 2010[2]							
1	1	1	876	729	688	101	32
4	1	1		723	589		
Scenario Combinations Resulting in Minimum Vehicles in Study Year 2015[2]							
1	1	1	876	729	688	101	32
4	1	1		723	589		

Notes
(1) A "*" means all scenarios in this Subregion give same results for the listed combination.
(2) Where only one value is provided for multiple scenario combinations, the value is the same for each combination.

In study year 2015, the two scenario combinations that project the lowest level of traffic are Eastern Subregion Scenario 1 or 4, Central Subregion Scenario 1 and Northern Subregion Scenario 1. The projected traffic level of 32 vehicles per week represents a 96 percent decrease from the level in 1997.

The above analysis shows that additional offshore development, especially in scenario combinations including Central Subregion Scenario 3, have the potential to result in traffic increases in the Eastern Subregion; whereas, scenario combinations which involve substantial reductions of offshore activity have the potential to decrease offshore oil related traffic in the Port Hueneme area.

4.4.2.2.2 Truck and Auto Contribution to Port Hueneme Traffic

The information presented in Appendix A.6 provides projections separately for cars and trucks in addition to total traffic. In general, the average supply vessel trip results in more material pickup/delivery truck trips than personal vehicle trips. The average crew vessel trip results in more personal vehicle trips than material pickup/delivery trucks. As the ratio of supply vessels to crew vessels increases, the proportion of traffic due to trucks is expected to increase relative to the proportion due to cars. As the ratio of supply vessels to crew vessel decreases, the proportion of traffic due to trucks is expected to decrease.

As described in Section 2.5, crew vessels from Port Hueneme only serve some of the Platforms in the Eastern Subregion. As these platforms are removed (which is projected under all scenarios), there will be fewer crew vessels using the Port and the ratio of trucks to cars reflected in Port Hueneme area traffic is projected to increase. Crew vessels from Port Hueneme do not travel to platforms in the Central and Northern Subregions, but supply vessels from Port Hueneme do. In scenario combinations where there is an increased demand for supply vessels in the Central and Northern Subregions, the ratio of trucks to cars accessing the Port is expected to increase more substantially.

4.4.2.3 Carpinteria Pier Traffic Constraints

The Carpinteria Pier is used by crew vessels to transport personnel and light supplies to some of the platforms located in the Eastern Subregion. Crew vessels from the Carpinteria Pier typically do not travel to platforms in the Central or Northern Subregions. Appendix A.6 provides the procedure and results for projecting the number of vehicle trips associated with the crew boat activity.

Table 4.4-4 provides a summary of the projected traffic at the Carpinteria Pier. The average number of vehicles in study year 2000 is projected to be 462 per week for all scenarios, as was the case in 1997. In study year 2005, the average number is projected to range from 374 (a decrease of 20 percent from 1997) to 528 (an increase of 20 percent from 1997). In study year 2010 and 2015, the projected number of vehicles is projected to decline sharply to less than 15 percent of the number in 1997. In Scenarios 1 and 4, the number drops to zero.

4.4.3 Central Subregion Traffic Constraints

4.4.3.1 Facility Traffic Constraints

The primary highway in the Central Subregion is U.S. Highway 101. Highway 101 traverses the width of the Central Subregion and runs adjacent to or near each of the onshore facilities in the subregion; however, use of surface streets is required to reach several of the facilities. Facility-specific product traffic presented in Appendix A.6 would occur on these local roadways. Each of the facilities in the Central Subregion produces sulfur and/or LPG, and these products are transported by truck on the regional highway system described in Section 4.4.1. As indicated in Appendix A.6, individual facility product transport traffic is relatively low, and is not expected to be a limiting constraint for Central Subregion facilities.

4.4.3.2 Ellwood Pier Traffic Constraints

Although not a public facility, the Ellwood Pier is used by crew vessels to transport personnel and light supplies to some of the platforms located in the Central Subregion. Table 4.4-5 provides a summary of the projected vehicle traffic associated with the crew vessels originating from the Ellwood Pier.

Table 4.4-4
Summary of Traffic Associated with Offshore Oil-Related Crew Vessel Trips
Originating from the Carpinteria Pier by Scenario

	1997	2000	2005	2010	2015
Eastern Subregion					
Scenario 1	462	462	462	0	0
Scenario 2	462	462	528	66	44
Scenario 3	462	462	528	66	44
Scenario 4	462	495	374	0	0

Note: This table presents the projected average number of vehicles associated with the offshore oil related crew vessel trips per week originating from the Carpinteria Pier (Casitas Pier). The numbers shown are weekly averages for each 5-year Study interval (e.g., study year 2005 covers 01/01/2001 - 12/31/2005).

Table 4.4-5
Summary of Vehicle Traffic Associated with Offshore Oil-Related Crew Vessel Trips Originating from the Ellwood Pier by Scenario

	1997	**2000**	**2005**	**2010**	**2015**
Central Subregion					
Scenario 1	605	517	462	506	154
Scenario 2	605	517	847	550	506
Scenario 3	605	517	847	550	506
Scenario 4	605	517	847	550	506

Note: This table presents the projected average number vehicles associated with the offshore oil related crew vessel trips per week originating from the Ellwood Pier. The numbers shown are weekly averages for each 5-year Study interval (e.g., study year 2005 covers 01/01/2001 - 12/31/2005).

As shown, the average number of vehicles per week in 1997 was 605 per week and this is projected to decline in study year 2000 to 517 which is an approximately 15 percent decrease from the 1997 level. In study year 2005, the average number is projected to range from a low of 462 (a decrease of 24 percent from 1997) to a high of 847 (an increase of 40 percent from 1997). In study year 2010, the average number is projected to range from a low of 506 (a decrease of 16 percent from 1997) to a high of 550 (a decrease of nine percent from 1997). In study year 2015, the average number is projected to range from a low of 154 (a decrease of 75 percent from 1997) to a high of 506 (a decrease of 16 percent from 1997). The greatest increases reflected by these traffic levels represent only a 40% change from 1997 conditions, but this traffic could become an increasing concern as urban and recreational development continues in the vicinity of the Ellwood Pier.

4.4.4 Northern Subregion Traffic Constraints

The primary highways in the Northern Subregion used to transport products from the onshore facilities are Highway 101 and Highway 166. The product trucks associated with the Northern Subregion products are discussed in Section 4.4.1. As indicated in that discussion, transport of heavy products (asphalt, etc.) associated with Scenarios 3 and 4 (or 3A and 4A) in the Northern Subregion dominates all product traffic estimates. Under these scenarios, these trucks could represent a substantial traffic burden on local roadways in the vicinity of any site selected for installation of Lion Rock onshore processing facilities. As discussed in Section 4.4.1, this truck traffic could be eliminated by relatively few trains if rail access is available to transport this product.

4.5 PORTS AND HARBORS

As of September 1998, there were twenty offshore platforms in the COOGER Study Region. Personnel, equipment, supplies, and other materials are transported to and from the platforms primarily by boat, and some of these boats use public ports and harbors. In addition, there are two piers (Carpinteria and Ellwood) owned and used exclusively by the oil and gas industry.

4.5.1 Eastern Subregion Port Activity & Constraints

There are three ports/harbors in the Eastern Subregion: Channel Islands Harbor, Ventura Harbor and Port Hueneme. Port Hueneme is the only one typically used to support the offshore oil industry. In addition, crew boats use the Carpinteria (Casitas) Pier.

4.5.1.1 Port Hueneme Activity & Constraints

Port Hueneme is used by supply (work) vessels serving the offshore platforms in all three Subregions and also is used by crew vessels that serve some of the platforms in the Eastern Subregion. Table 4.5-1 provides a summary of all offshore-oil related vessels (supply and crew vessels) projected to use Port Hueneme in each scenario for all three Subregions. Table 4.5-2 provides similar data for supply vessels, and Table 4.5-3 provides similar data for crew vessels. The methodology for projecting the number of vessels along with details of the scenario combination results is provided in Appendix A.6.

Because Port Hueneme's supply vessel activities are an integral part of the activities in all three Subregions, the vessel activity at Port Hueneme needs to be evaluated giving consideration to the various scenario combinations that could occur. Vehicle traffic associated with these vessel activities is provided in Section 4.4.

Representatives of the Oxnard Harbor District, which operates Port Hueneme, did not specify a maximum number of vessel trips that could be accommodated. As of October 1998, these representatives stated that there was sufficient wharf space and time available to accommodate a significant increase in the number of vessels.

In 1997, there were a total average of 94 vessel trips (supply and crew vessels combined) per week from Port Hueneme. By study year 2000, the total number is projected to decrease to 75 or 76 vessels per week for all scenario combinations. The analysis for study years 2005, 2010 and 2015 is presented below.

Table 4.5-1
Summary of Offshore Oil-Related Round Trips for
All Vessels from Port Hueneme by Scenario
Total COOGER Study Region

	1997	2000	2005	2010	2015
Eastern Subregion					
Scenario 1	49	49	57	0	0
Scenario 2	49	49	71	17	16
Scenario 3	49	49	71	17	16
Scenario 4	49	49	46	0	0
Central Subregion					
Scenario 1	44	25	17	13	4
Scenario 2	44	25	62	48	13
Scenario 3	44	25	62	48	13
Scenario 4	44	25	42	17	6
Northern Subregion					
Scenario 1	1	1	4	0	0
Scenario 2	1	1	7	26	2
Scenario 3	1	1	7	37	3
Scenario 4	1	1	7	61	4
Scenario 2A	1	1	22	21	22
Scenario 3A	1	1	22	57	5
Scenario 4A	1	1	22	82	6

This table presents the projected average number of offshore oil related vessel trips per week originating from Port Hueneme. The numbers include supply/work boats and crew boats. The numbers shown are weekly averages for each 5-year Study interval (e.g., study year 2005 covers 01/01/2001 - 12/31/2005).

Table 4.5-2
Summary of Offshore Oil-Related Supply Vessel Trips
Originating from Port Hueneme
Total COOGER Study Region

	1997	2000	2005	2010	2015
Eastern Subregion					
Scenario 1	7	7	39	0	0
Scenario 2	7	7	44	5	7
Scenario 3	7	7	44	5	7
Scenario 4	7	10	30	0	0
Central Subregion					
Scenario 1	44	25	17	13	4
Scenario 2	44	25	62	48	13
Scenario 3	44	25	62	48	13
Scenario 4	44	25	42	17	6
Northern Subregion					
Scenario 1	1	1	4	0	0
Scenario 2	1	1	7	26	2
Scenario 3	1	1	7	37	3
Scenario 4	1	1	7	61	4
Scenario 2A	1	1	22	21	22
Scenario 3A	1	1	22	57	5
Scenario 4A	1	1	22	82	6

This table presents the projected average number of offshore oil related supply (work) boat trips per week. The numbers shown are weekly averages for each 5-year Study interval (e.g., study year 2005 covers 01/01/2001 - 12/31/2005)

Table 4.5-3
Summary of Offshore Oil-Related Crew Vessel Trips
Originating from Port Hueneme by Scenario

	1997	**2000**	**2005**	**2010**	**2015**
Eastern Subregion					
Scenario 1	42	42	18	0	0
Scenario 2	42	42	28	12	9
Scenario 3	42	42	28	12	9
Scenario 4	42	39	16	0	0

Note: This table presents the projected average number of offshore oil related crew vessel trips per week originating from Port Hueneme. The numbers shown are weekly averages for each 5-year Study interval (e.g., study year 2005 covers 01/01/2001 - 12/31/2005).

Crew vessels from Port Hueneme are not projected to travel to platforms in the Central or Northern Subregions.

4.5.1.1.1 Study Year 2005

In study year 2005, the maximum number of vessel trips is projected to be 140, which corresponds to those twelve combinations which include the Eastern Subregion Scenario 2 or 3; Central Subregion Scenario 2 or 3; and Northern Subregion Scenario 2, 3, or 4. A level of 140 vessel trips per week is an increase of 49 percent from the 1997 level. In study year 2005, the minimum number of vessels is 68, which corresponds to the combination of the Eastern Subregion Scenario 4; Central Subregion Scenario 1; and Northern Subregion Scenario 1. A level of 68 vessel trips per week is a decrease of 28 percent from the 1997 level.

4.5.1.1.2 Study Year 2010

In study year 2010, the maximum number of vessel trips is projected to be 126, which corresponds to the four combinations which include the Eastern Subregion Scenario 2 or 3; Central Subregion Scenario 2 or 3; and Northern Subregion Scenario 4. A level of 126 vessel trips per week is an increase of 34 percent from the 1997 level.

As described, Northern Subregion Scenario 4 represents the Lion Rock operator's maximum production case. Using the more likely Northern Subregion Scenario 3 rates (i.e., Eastern Subregion Scenario 2 or 3; Central Subregion Scenario 2 or 3; and Northern Subregion Scenario 3) results in a projected average of 102 vessel trips per week which is an increase of nine percent from the 1997 level.

In study year 2010, the minimum number of vessels is 13, which corresponds to the Eastern Subregion Scenarios 1 or 4; Central Subregion Scenario 1; and Northern Subregion Scenario 1. A level of 13 vessel trips per week is a decrease of 86 percent from the 1997 level.

4.5.1.1.3 Study Year 2015

In study year 2015, the maximum number of vessel trips is projected to be 44, which corresponds to the two combinations which include the Eastern Subregion Scenario 2 or 3; Central Subregion Scenario 4; and Northern Subregion Scenario 2A. A level of 44 vessel trips per week is a decrease of 53 percent from the 1997 level.

In study year 2015, the minimum number of vessels is 4, which corresponds to the Eastern Subregion Scenarios 1 or 4; Central Subregion Scenario 1; and Northern Subregion Scenario 1. A level of 4 vessel trips per week is a decrease of 96 percent from the 1997 level.

4.5.1.2 Carpinteria Pier

The Carpinteria Pier is used by crew vessels to transport personnel and light supplies to some of the platforms located in the Eastern Subregion. Crew vessels from the Carpinteria Pier typically do not travel to platforms in the Central or Northern Subregions. Table 4.5-4 provides a summary of the projected number of crew vessels by scenario and study year.

As shown, the average number of crew vessels in study year 2000 is projected to be 42 per week for all scenarios as was the case in 1997. In study year 2005, the average number is projected to range from 34 (a decrease of 20 percent from 1997) to 48 (an increase of 20 percent from 1997). In study year 2010 and 2015, the projected number of crew vessels is projected to decline sharply to less than 15 percent of the number in 1997. In Scenarios 1 and 4, the number drops to zero. Carpinteria Pier capacity is not expected to represent a constraint with respect to any of the identified offshore development scenarios.

Traffic associated with the crew vessels using the Carpinteria Pier is discussed in Section 4.4.

4.5.2 Central Subregion Port Activity & Constraints

The only public port/harbor in the Central Subregion is Santa Barbara Harbor which is used primarily by fishing, commercial and recreational vessels. Vessels providing routine services to the offshore oil and gas industry typically do not use Santa Barbara Harbor for the transfer of personnel or supplies, but may refuel at the harbor. In addition, vessels belonging to the Clean Seas Oil Spill Response Cooperative are anchored east of Stearns Wharf at the Santa Barbara Harbor. As discussed above, there is a private pier (Ellwood) that is used by the offshore oil industry.

Table 4.5-4
Summary of Offshore Oil-Related Crew Vessel Trips
Originating from the Carpinteria Pier by Scenario

	1997	2000	2005	2010	2015
Eastern Subregion					
Scenario 1	42	42	42	0	0
Scenario 2	42	42	48	6	4
Scenario 3	42	42	48	6	4
Scenario 4	42	45	34	0	0

Note This table presents the projected average number of offshore oil related crew vessel trips per week originating from the Carpinteria Pier (Casitas Pier). The numbers shown are weekly averages for each 5-year Study interval (e.g., study year 2005 covers 01/01/2001 - 12/31/2005).

Crew vessels from the Carpinteria Pier are not projected to travel to platforms in the Central or Northern Subregions.

Although not a public facility, the Ellwood Pier is used by crew vessels to transport personnel and light supplies to some of the platforms located in the Central Subregion. Crew vessels from the Ellwood Pier typically do not travel to platforms in the Eastern or Northern Subregions. Table 4.5-5 provides a summary of the projected number of crew vessels by scenario and study year. As shown, the average number of crew vessels in 1997 was 55 per week. Crew vessel activity is projected to decline in study year 2000 to 47, an approximately 15 percent decrease from the 1997 level. In study year 2005, the average number is projected to range from a low of 42 (a decrease of 24 percent from 1997) to a high of 77 (an increase of 40 percent from 1997). In study year 2010, the average number is projected to range from a low of 46 (a decrease of 16 percent from 1997) to a high of 50 (a decrease of nine percent from 1997). In study year 2015, the average number is projected to range from a low of 14 (a decrease of 75 percent from 1997) to a high of 46 (a decrease of 16 percent from 1997). Ellwood Pier capacity is not expected to represent a constraint with respect to any of the identified offshore development scenarios.

Traffic associated with the crew vessels using the Ellwood Pier is discussed in Section 4.4.

4.5.3 Northern Subregion Port Activity & Constraints

There are three public ports/harbors in the Northern Subregion: Avila Bay, Morro Bay and Estero Bay. None of these public facilities are currently used on a typical basis by vessels providing support to the offshore oil industry.

Currently, offshore oil activities in the Northern Subregion are served by vessels from Port Hueneme or from ports outside the Tri-County area. A private pier formerly associated with the Avila Marine Terminal is located at Avila Bay. This pier is not currently used to provide support services to offshore oil and gas activities and no plans for such use have been identified. If such use was to be proposed, a Coastal Development Permit is likely to be required, as well as voter approval pursuant to San Luis Obispo County Measure A. No activity associated with offshore oil and gas operations currently occurs at any of the Northern Subregion ports, and no new use of Northern Subregion ports has been identified in connection with any of the development scenarios identified in this report.

Table 4.5-5
Summary of Offshore Oil-Related Crew Vessel Trips
Originating from the Ellwood Pier by Scenario

	1997	**2000**	**2005**	**2010**	**2015**
Central Subregion					
Scenario 1	55	47	42	46	14
Scenario 2	55	47	77	50	46
Scenario 3	55	47	77	50	46
Scenario 4	55	47	77	50	46

Note This table presents the projected average number of offshore oil related crew vessel trips per week originating from the Ellwood Pier. The numbers shown are weekly averages for each 5-year Study interval (e.g., study year 2005 covers 01/01/2001 - 12/31/2005).

Crew vessels from Ellwood Pier are not projected to travel to platforms in the Eastern or Northern Subregions.

4.6 RAIL

4.6.1 Industrial Use of Railroads

As described in Section 2.5.2.3, the Coastal Line of the Union Pacific Railroad traverses the length of the COOGER Study Region and runs adjacent to or near many of the onshore processing facilities. However, none of the facilities receiving oil or gas directly from an offshore platform transport oil or product by rail. The only facilities with a dedicated rail spur are the Santa Maria Refinery and the Santa Maria Asphalt Refinery. As of September 1998, offshore crude oil was not being shipped by rail within the Tri-County area.

4.6.1.1 Eastern Subregion Rail Transport

None of the facilities in the Eastern Subregion are constructed to use rail services. As stated in the pipeline section above, the existing pipelines are expected to handle the projected production for all scenarios and study years. Consequently, there does not appear to be sufficient demand to begin rail service, and none of the facility operators identified plans to use rail service in the future.

4.6.1.2 Central Subregion Rail Transport

None of the facilities in the Central Subregion are constructed to use rail services. As stated in the pipeline section above, the existing AAPLP pipeline system is expected to handle the projected oil production for all scenarios and study years. This includes capacity to accept oil production from the Ellwood Facility which is not currently connected to an intrastate/interstate distribution pipeline. Consequently, there does not appear to be sufficient demand to begin rail service, and none of the facility operators identified plans to use rail service in the future.

4.6.1.3 Northern Subregion Rail Transport

Rail transport of products associated with offshore oil refining currently occurs only at the Santa Maria Refinery in the Northern Subregion. This refinery receives the oil after it has been processed at the Lompoc Oil & Gas Processing Facility. The Lompoc Oil & Gas Processing Facility, the only facility in the Northern Subregion that directly receives offshore oil and gas, is not in close proximity to a rail line. The Santa Maria Asphalt Refinery (SMAR) can currently ship asphalt and other products by rail; however, this facility is not processing offshore oil.

As discussed in the Road and Highways section (Section 4.4), the processing of Lion Rock Field production in Scenarios 3, 4, 3A and 4A is projected to result in the production of relatively large quantities of heavy product (asphalt or other products) which could be transported by truck or rail. If the facility used to process the Lion Rock Field oil is served by rail and is constructed with rail car loading capability, there is potential that some of the heavy product could be transported by rail. If the heavy product is transported in 20,000 gallon (476 barrel) rail cars instead of 140 barrel trucks, each rail car used replaces 3.4 trucks. Section 4.4.1 describes the use of truck and rail cars and gives examples of truck/rail distribution.

As stated in the pipeline section above, the Northern Pipeline System alone, or in combination with the AAPLP Main Line is expected to be able to accommodate the quantity of oil projected for each of the scenarios and study years assuming the oil from the Lion Rock Field can meet the pipeline operator's specifications. Although Scenario 2 projects up to 7,500 barrels per day of Lion Rock Field oil will be processed at the Lompoc Oil & Gas Processing Facility in study years 2010 and 2015, which results in 3,000 barrels per day of heavy product requiring approximately 21 trucks for transport. It is not expected that an operator would install a rail line to the Lompoc Oil & Gas Processing Facility for this level of heavy product production. Consequently, the only likely use of rail services is expected to occur in study years 2010 and 2015 for Scenarios 3, 4, 3A and 4A which are described in section 4.4.1 and summarized below.

4.6.1.3.1 Scenarios 3 and 3A

In Scenario 3, it is projected that a new facility will be processing 25,000 barrels of Lion Rock crude per day in study years 2010 and 2015, which will result in the production of approximately 15,000 barrels per day of pipeline quality oil and 10,000 barrels per day of heavy product. If it is assumed that the facility has a rail spur and all of the asphalt is loaded on 20,000 gallon (476 barrel) rail tank cars, then approximately 21 tank cars would be loaded per day (compared to 71 trucks per day). Assuming a unit train size of 70 cars, two unit trains of asphalt would be sent per week. It is expected the Union Pacific Coast Line could handle this additional level of activity.

4.6.1.3.2 Scenarios 4 and 4A

In Scenario 4, it is projected that a new facility will be processing 58,000 barrels of Lion Rock crude per day in study year 2010, which will result in approximately 34,800 barrels per day of pipeline quality oil and 23,200 barrels of heavy product. This same facility is projected to process 75,000 barrels per day of Lion Rock crude in study year 2015, resulting in approximately 45,000 barrels per day of pipeline quality oil and 30,000 barrels per day of heavy product. If it is assumed that the facility has a rail spur and all of the asphalt is loaded on 20,000 gallon (476 barrel) rail tank cars, then approximately 49 tank cars would be loaded per day (compared to 166 trucks per day) in study year 2010. This would result in approximately five 70-car unit trains per week. In study year 2015, approximately 63 tank cars would be loaded per day (compared to 214 trucks per day), which would result in approximately six to seven 70-car unit trains per week. It is expected the Union Pacific Coast Line could handle this additional level of activity.

4.7 AIRPORTS

4.7.1 Industrial Use of Airports

Although personnel and supply transportation to and from most of the offshore platforms is by boat, each platform has a helicopter landing pad. Helicopters are used to transport employees, and sometimes light supplies. The location of the platform is the primary factor regarding whether helicopters are used. For those platforms where helicopters are used, the number of helicopter trips is not directly dependant on the volume of oil and gas being produced. The number of trips is more closely linked with the number of personnel working at the platforms (e.g., operations personnel, well drilling/abandonment personnel, decommissioning personnel, etc.). Note for the purpose of this discussion, a "flight" or "trip" refers to a round trip in which the helicopter takes off from and lands back at the airport. The use of helicopters is discussed in Section 2.5.2.4.

In addition to projecting the number of flights by scenario within each Subregion, an analysis was conducted of the projected number of helicopter flights for the total Study Region (i.e., total flights from all airports) under all possible scenario combinations. Because none of the helicopter operators identified "routine scheduled" flights to platforms in the Eastern Subregion other than agency inspection flights which are relatively constant, the analysis assumes an average of zero flights per week to Eastern Subregion platforms. Consequently, the analysis in this report is based on the combinations of Central and Northern Subregion scenarios which reflect routine helicopter operations related to platform activity. A summary table of "Projected Combined Helicopter Activity Associated with Each Combination of Scenarios" is provided in Appendix A.6. In all scenario combinations, the average number of flights in 1997 was 43 per week and is projected to decline to 37 per week by study year 2000. The largest decrease in flights is projected for those combinations with Scenario 1 for both the Central and Northern Subregions. In these combinations, the projected total number of flights decreases annually to 11 flights per week in study year 2015 (a 71% decrease from 1997). The largest increase in flights is projected in study year 2010, and is associated with the combination of Central Subregion Scenario 2 or 3 and Northern Subregion Scenario 4. In these combinations, the total number of flights is projected to average 75 flights per week from all airports (a 92% increase from 1997). As projected, 43 of these flights will originate from the Santa Barbara Airport (a 10% increase over 1997) and the other 32 will originate from the Lompoc and/or Santa Maria Airports. The total of 32 flights per week for the Northern Subregion airports is eight times greater than the current offshore industry helicopter activity from these airports, but is less than the 39 flights per week average from the Santa Barbara Airport in 1997.

4.7.1.1 Eastern Subregion Airport Activity

Airports within the Eastern Subregion include the Camarillo Airport, Oxnard Airport and the Santa Paula Airport. None of the offshore operators in the Eastern Subregion identified plans to begin routine use of helicopters for travel to the platforms. The average number of helicopter flights per week to platforms in the Eastern Subregion is projected to be zero for all scenarios and study years.

4.7.1.2 Central Subregion Airport Activity

The only airport in the Central Subregion used by the oil industry is the Santa Barbara Airport. Table 4.7-1 provides a summary of the projected average number of offshore-oil related helicopter flights to facilities in the Central and Northern Subregions from the Santa Barbara Airport for each scenario and study year. There are no flights to Eastern Subregion facilities. An analysis of these data indicates that there was an average of 39 flights per week in 1997 and there are projected to be an average of 33 flights per week in study year 2000 for all scenario combinations (a 15 percent decrease from 1997).

The maximum number of flights in study year 2005 is projected to be 36 per week under Central Subregion Scenarios 2 or 3 in combination with Northern Subregion Scenario 1, 2, 3 or 4. This represents an approximately eight percent decrease from the 1997 level. The minimum number of flights in study year 2005 is projected to be 27 per week under Central Subregion Scenario 1 in combination with Northern Subregion Scenario 1, 2, 3, or 4 or under Central Subregion Scenario 4 combined with Northern Subregion Scenarios 2A, 3A or 4A. This represents an approximately 38 percent decrease from the 1997 level.

The maximum number of flights in study year 2010 is projected to be 43 per week under Central Subregion Scenarios 2 or 3 in combination with Northern Subregion Scenario 1, 2, 3 or 4. This represents an approximately 10 percent increase from the 1997 level. The minimum number of flights in study year 2010 is projected to be 14 per week under Central Subregion Scenario 1 in combination with Northern Subregion Scenario 1, 2, 3 or 4. This represents an approximately 64 percent decrease from the 1997 level.

The maximum number of flights in study year 2015 is projected to be 30 per week under Central Subregion Scenario 4 combined with Northern Subregion Scenario 2A. This represents an approximately 23 percent decrease from the 1997 level. The minimum number of flights in study year 2015 is projected to be 11 per week under Central Subregion Scenario 1 in combination with Northern Subregion Scenario 1, 2, 3, or 4. This represents an approximately 72 percent decrease from the 1997 level.

Table 4.7-1
Summary of Offshore Oil Related Helicopter Round Trips
From Central Subregion Airports

	1997	2000	2005	2010	2015
Central Subregion					
Scenario 1	39	33	27	14	11
Scenario 2	39	33	36	43	25
Scenario 3	39	33	36	43	25
Scenario 4	39	33	14	17	14
Northern Subregion					
Scenario 1	0	0	0	0	0
Scenario 2	0	0	0	0	0
Scenario 3	0	0	0	0	0
Scenario 4	0	0	0	0	0
Scenario 2A	0	0	13	5	16
Scenario 3A	0	0	13	17	8
Scenario 4A	0	0	13	17	8

Note:
1. All flights originate from the Santa Barbara Airport
2. No oil industry-related flights are projected to go to Eastern Subregion facilities.
3. Per the scenario definitions, Scenario Central 4 combines with North 2A, 3A or 4A.

In summary, the number of helicopters trips from the Santa Barbara Airport under the various scenario combinations and study years is projected to range from a high of 43 per week (10 percent over the 1997 level) to a low of 11 (72 percent less than the 1997 level). Airport capacity in the Central Subregion does not appear to represent a constraint with respect to any of the identified scenarios.

4.7.1.3 Northern Subregion Airport Activity

There are several airports located in the Northern Subregion including the Lompoc Airport and the Santa Maria Airport. As of September, 1998, the one offshore operator in the Northern Subregion was using a helicopter service operating from the Lompoc Airport to transport personnel and light supplies to Platform Irene. There were no offshore oil company helicopter flights from the Santa Maria Airport, though routine MMS inspection flights did originate from that location.

In some of the scenarios, it is projected there will be a platform installed in the Lion Rock Field. It is projected that this platform will be served by helicopters from the Santa Maria Airport, which is the closer of the two airports to the probable location of the platform; however, some or all of these flights could occur from the Lompoc Airport instead.

Although there are other airports in the Northern Subregion (e.g., San Luis Obispo Airport), these were not identified as being used by the offshore oil and gas industry or by the MMS or as being planned for use in the future.

Table 4.7-2 provides a summary of the projected average number of offshore-oil related helicopter flights from the Lompoc and Santa Maria Airports. Because it is possible that all of these flights could come from one airport, the following analysis is based on total Northern Subregion helicopter activity. An analysis of the combined data indicates that there was an average of four flights per week in 1997. An average of four flights per week in each scenario in study year 2000 are projected, and an average of four flights per week in each scenario, except Scenario 1, are projected in study year 2005. The number of flights projected for study year 2005 in Scenario 1 is three per week which represents a 25 percent decrease from 1997.

Table 4.7-2
Summary of Offshore Oil Related Helicopter Round Trips
From Northern Subregion Airports

From the Lompoc Airport:	1997	2000	2005	2010	2015
Northern Subregion (only)					
Scenario 1	4	4	3	0	0
Scenario 2	4	4	4	11	4
Scenario 3	4	4	4	11	4
Scenario 4	4	4	4	11	4
Scenario 2A	4	4	4	11	4
Scenario 3A	4	4	4	11	4
Scenario 4A	4	4	4	11	4

From the Santa Maria Airport:	1997	2000	2005	2010	2015
Northern Subregion (only)					
Scenario 1	0	0	0	0	0
Scenario 2	0	0	0	3	2
Scenario 3	0	0	0	9	4
Scenario 4	0	0	0	20	6
Scenario 2A	0	0	0	0	0
Scenario 3A	0	0	0	9	4
Scenario 4A	0	0	0	20	6

Note:
1. All flights originate from the Lompoc or Santa Maria Airports
2. No oil industry-related flights are projected to go to Eastern Subregion facilities.
3. Per the scenario definitions, Scenario Central 4 combines with North 2A, 3A or 4A.

The maximum number of flights in study year 2010 is projected to be 31 per week under Scenarios 4 and 4A, which is nearly eight times the 1997 level. The 31 flights per week could be split between two airports and, as a comparison, the total number is approximately 80 percent of the average number of flights per week from the Santa Barbara Airport in 1997. The second highest number of flights (other than Scenario 4 or 4A - Lion Rock maximum case) is projected to be 20 flights per week under Scenario 3 which represents five times the 1997 activity level. The minimum number of flights in study year 2010 is projected to be zero per week under Scenario 1.

The maximum number of flights in study year 2015 is projected to be 10 per week under Scenarios 4 and 4A, which represents a 150 percent increase above the 1997 level. The ten flights per week could be split between two airports and, as a comparison, the total number is approximately 26 percent of the average number of flights per week from the Santa Barbara Airport in 1997. The second highest number of flights (other than Scenario 4 or 4A - Lion Rock maximum case) is projected to be eight flights per week under Scenarios 3 and 3A, which represents a 100 percent increase over 1997. The minimum number of flights in study year 2010 is projected to be zero per week under Scenarios 1 and 2A.

In summary, the number of helicopters trips combined from the Lompoc and Santa Maria Airports under the various scenario combinations and study years is projected to range from a high of 31 per week to a low of zero. Although the high end of this range represents a substantial increase above current helicopter flight activity, the projected activity level is expected to be well within the operating capacity of the affected airports.

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APPENDIX A

METHODOLOGY
AND ADDITIONAL DATA

APPENDIX A METHODOLOGY AND ADDITIONAL DATA

A.1 RESERVES AND PRODUCTION PROJECTIONS

A.1.1 Background and Definitions

To evaluate the potential future development of existing offshore leases, the COOGER study addresses the known oil and gas resources associated with existing offshore leases in the Santa Barbara Channel and Santa Maria Basin area. This effort was accomplished by The Scotia Group, Inc. (Scotia) under contract to Dames & Moore. The accomplishment of this effort involved Scotia's review of agency geology and reservoir data and oil industry proprietary exploration results and production concepts to develop an independent estimate of resources, reserves, and likely future production.

The accomplishment of this effort involves the analysis of several parameters which influence the ultimate determination of potential future oil and gas production from an oil field. A few definitions and assumptions associated with the COOGER study methodology include:

- **Production Scenarios**: Production profiles generated and reserves developed when considering differing production scenarios within the study area will fall under this category. Such reserves will run the full spectrum of both MMS and SPE reserves definitions categories since such scenarios will include reserves developed by various schemes within known fields that are developed and undeveloped, as well as fields that may be hypothetically developed on poorly understood or even undrilled structures.

- **Economic Life/Limit**: As part of the study, the **economic life/limit** of the fields was projected based on production rate decline curves extrapolated through the end of the first year in which the field productions was considered to be uneconomical. In these cases, the economic limit was calculated using the base case (12/31/94) posted price and platform operating costs. Unfortunately, Unocal was the only offshore operator that provided operating costs data to the MMS: all other operators responsible for currently producing operations declined direct requests to provide cost data or did not have these data available. Thus, the operating costs for non-Unocal platforms was estimated by analogy to the Unocal-operated platforms. Although the production forecasts have been terminated at the estimated economic life/limit, it is common practice for platforms to continue beyond this time. This is so partly because for some period of time, the revenues may still exceed the direct expenses of operation. Other incentives such as hope for oil price increases, the possibility of negotiating royalty relief, the large cost of platform abandonment, or the possibility of using the platform as infrastructure for the development of nearby prospects, also come into consideration.

With regard to an onshore facility, the economic life/limit is the point in the future where it is projected the facility will cease operations due to a lack of sufficient feedstocks, economic conditions, and/or other reasons. These projections may not be reliable given the uncertainties involved in their estimation.

- **MMS Reserves Definition**: The MMS uses a standardized set of definitions of resources that recognize the following categories. Resources are graduated from one category to the next based upon the specified criteria being satisfied.

a. Undiscovered Resources - These are resources estimated from broad geologic knowledge or theory and existing outside of known fields or known accumulations. They may exist in untested prospects, on unleased acreage or on undrilled lease acreage, or in known fields in undiscovered pools.

b. Discovered Resources - Once leased acreage is drilled and it is determined to contain oil or gas, the lease is considered to have discovered resources. Such resources are at a location and of a quantity that is known or estimated from specific geologic or engineering evidence and includes economic, marginally economic, and sub-economic components. Discovered resources are further subdivided into unproved and proved reserves depending upon the evidence of economic and geologic viability and their development status.

c. Unproved Reserves - Unproved reserves contain two basic categories which are dependent upon the degree of certainty associated with the estimate and the distinction of whether or not a Development and Production Plan (DPP) has been submitted to the MMS. At such a time as a DPP has been submitted, possible reserves are classified as probable.

d. Proved Reserves - Reserves are upgraded to the proved category when there is reasonable expectation that producing facilities to exploit the reserves will be installed. Such reserves are termed proved undeveloped. After the facilities have been installed and sustained production has begun, the reserves are further upgraded to proved developed reserves.

- **SPE Reserves Definitions**: The Society of Petroleum Engineers (SPE) reserves definitions also recognize proved, probable and possible reserves; however, the distinction between such categories is more associated with the certainty level of the estimate as opposed to the development status of the field in question.

  a. Proved Reserves - Proved reserves can be estimated with reasonable certainty to be recoverable under current economic conditions. Current economic conditions include prices and cost prevailing at the time of the estimate. Proved reserves may be developed or undeveloped.

  b. Proved Developed Reserves - Proved developed reserves are assigned to areas drained by existing wells and undeveloped reserves are only assigned when they are within one direct offset of existing proved locations. The reserves must have facilities to process and transport those reserves to market that are operational at the time of the estimate or there is a reasonable expectation that such facilities will be installed in the future.

  c. Unproved Reserves - Unproved reserves are based on geologic and/or engineering data similar to that used in estimates of proved reserves, but technical, contractual, economic, or regulatory uncertainties preclude such reserves as being classified as proved. Estimates of unproved reserves are not routinely compiled under the SPE definitions and are not additive to proved reserves because of different levels of uncertainty associated with the estimate. Unproved reserves are subdivided into probable and possible categories. Probable reserves are defined as those that are more likely to be recovered than not. Possible reserves are less certain than probable, and can be estimated with a low degree of certainty insufficient to indicate whether they are more likely to be recovered than not.

It should be noted that in both the MMS and SPE reserves definitions systems, economics is a key factor. This is stated explicitly in the SPE definitions and is implicit in the MMS definitions in that the process of generating a DPP and going through the approval process will obviously not be attempted in the case of fields which have uneconomic quantities of potential reserves. Through the process of developing cost estimates and coming up with the type development scenarios for undeveloped fields in the Study Area. Scotia applied an initial economic screening test to ensure that this aspect of both reserves definitions system is preserved in the estimates of future production.

A.1.2 Data Collection and Evaluation

Scotia's data collection and evaluation effort involved the collection of data from the Minerals Management Service, California State Land Commission and offshore operators responsible for leases in the COOGER study area. Onsite inspection of available technical data was accomplished at agency and oil industry offices, and data copies were collected for review of assumptions and interpretations. Scotia personnel also discussed their data review effort with agency and industry engineers and geologists to identify additional information to allow Scotia's compilation of future production estimates. The principal steps involved in this effort are as follows:

- **MMS/SLC Files** - Scotia made a data collection trip to the Minerals Management Services (MMS) offices in Camarillo and the State Lands Commission (SLC) offices in Long Beach. The following types of information were collected.

  a. Development and Production Plans (DPP) including operator designated proprietary data - These documents contained the original development plans including details of the proposed infrastructure and the proposed development methodology. In most cases, anticipated reserves were expressed as ranges and little was available in the way of anticipated production profiles.

  b. Annual review meeting notes and Maximum Efficient Rate (MER) and Maximum Production Rate (MPR) submissions - This information provided a valuable source of ongoing activities within each field area and an outline for near future plans. The MER and MPR reports were the primary sources for the reservoir parameter data. The most recent several years of annual review meeting documents were obtained for each field.

  c. Sundry reports and correspondence - A review of files was made to extract and obtain relevant reports and correspondence relating particularly to the anticipated reserves and production profiles from each field and also any information that was pertinent to the identification of practical, physical or reservoir constraints that may be relevant.

  d. MMS/SLC in-house estimates and worksheets - This information was collected as backup to reserves estimates made by these agencies and included basic volumetric parameters, summaries of crude oil and gas properties and analyses, and workups performed on basic reservoir data, including pressure analysis, work with core data, and any special core analysis interpretation or PVT data workup. This information provided the backup for auditing of volumetric or material balance reserves estimates.

e. Wireline logs - A representative suite of logs for one or more wells in each reservoir was copied for each field. This information was collected in analog form.

f. Maps - A variety of maps were available from company and MMS/SLC that involved sand and pay maps. In addition, some reservoir mapping was available and such maps were obtained as backup to the reserves estimates.

g. Digital Data - Certain digital data forms were available including production information and zone data. Some of this information was obtained.

h. Production Data - Monthly production data and injection histories were provided by the MMS for all wells in federal waters and by the SLC for all wells in state waters.

- **Company Proprietary Data** - A listing of all companies having offshore operating interests within the Study Area was compiled and a letter was sent to each company describing the Study itself and requesting cooperation in terms of data release and assistance in sharing information that was unavailable from other data sources. This list included certain companies who, while not having interest in producing units, were in involved with non-producing units which would be the subject of subsequent states of the Study. The following is a list of the principal companies who were contacted by Scotia.

Berry Petroleum	Pacific Operators Offshore, Inc. (POOI)
CalResources (Aera Energy)	Phillips Petroleum
Chevron USA, Inc.	Texaco Exploration & Production, Inc.
Exxon Company USA	Torch Operating Company
Mobil Exploration & Producing	Samedan Oil Corporation
Molino Energy Company	Unocal Corporation

- **Public Domain Data** - The principal public domain data source used in this Study was Petroleum Information (PI) Corporation's National Production System (NPS) database. This database contains historical monthly oil, gas and water production on a well-by-well basis for both the federal offshore and state waters areas. This data was purchased in its entirety from PI and loaded to Scotia's reserves and economics database software. This software allowed a well-by-well projection of production and pressure history performance, allowing the reserves scenarios to be developed. In addition, the software was used to perform an economic analysis allowing the calculation of economic limits based on input of relevant controlling parameters. Other public domain data sources included PI's Well History Control System (WHCS) which was in obtained in hard copy form.

- **Publications** - Literature searches were performed on major sources of publications including the AAPG, SPE and other technical literature to assemble a bibliography of published information on the study area. This bibliography was then reviewed and relevant parameters added to the databases on each field or unit.

A.1.3 Data Analysis

The quantity of technical data available in the study area is immense. All available information has relevance to the construction of realistic profiles of future oil and gas production and the review of such information represents an extremely complicated and time-consuming task. To analyze the data within the time and manpower constraints of the project, an audit procedure, having the following characteristics, was used:

- Assembly of basic technical information and previous estimates. This exercise consisted of reviewing available documents and previous estimates made by others and summarizing all key technical parameters that effect the estimate and its backup.

- Review of estimates with current operators. Since a reservoir and production forecast is commonly revised as additional data is collected during production, the most recent available forecasts and estimates were reviewed with each individual operator and the operator's current opinions were recorded. In addition, aspects of current constraints to increases in future production were discussed and documented with each operator. Where access to operator data was not available, the projections were performed using decline curve techniques in conjunction with volumetric estimates.

- Based on the completed interview, existing profiles were adjusted and the basis behind each estimate documented. In certain cases, this necessitated an adjustment to the profile to honor the available data.

- Documentation of economic limits. The controlling parameters with respect to overall platform economics were researched and documented and the minimum economic rate established on a platform-by-platform basis.

- Interaction of platform production with processing capability. Individual platform projections were combined so that platforms producing into a common facility were handled as a combined unit to ensure that a proper interaction of all capacity considerations was achieved.

A.1.4 Reserves Estimates and Production Profile Construction

The two principal methods for estimation of reserves were volumetrics and decline curve analysis. The volumetric method consists of mapping each hydrocarbon-bearing reservoir and performing estimates of net rock volume, porosity and water saturation, and then combining these data with the appropriate formation volume factor to obtain an in-place oil or gas volume. Such volumes are calculated down to known fluid contacts or, in the absence of information on fluid contacts, down to the lowest known level of hydrocarbon occurrence in the reservoir. Hydrocarbons below the lowest known occurrence may be classified under the SPE scheme as probable or possible. The recovery of in-place oil and gas reserves is dependent upon an assessment of drive mechanism in the reservoir, well spacing and the location of wellbores in the reservoir, as well as other factors. The ability of wells to produce at their maximum rate is dependent upon the existence of adequate processing and sales facilities.

The scheduling of volumetrically estimated recoverable reserves to generate a production profile is estimated via a variety of techniques ranging from the application of analogs, evaluation of well test results, and development of reservoir simulations.

The decline curve analysis method for estimating reserves consists of projecting established trends in oil, gas or water production and extrapolating these trends to an economic limit. This provides a profile for future production and, via integration of the profile, recoverable reserves. The decline curve method as a stand-alone methodology does not provide information on original in-place volumes or the recovery efficiency of such in-place reserves. Such recovery will be dependent upon existing well spacing and production practices.

Two differing methods were used in performing the projections using the decline curve technique. The first was to perform the analysis at the well level and then to add the individual well projections together by platform to derive a composite platform-level projection. This method is essentially a PDP-style (Proved Developed Producing reserves defined by the Society of Petroleum Engineers) projection that represents the status quo situation with no account for future enhancement activities. Such activities could include resizing of pumps or adjustments to gas lift or compression changes that would act to arrest the decline at critical points in the life of a well. The second method was to add together all historical production profiles by platform and to thus construct a composite decline curve and use this curve as the basis for projection. This projection will incorporate the enhancement activities described above and is the preferred projection type for the baseline projection. Where this projection and the PDP-styled projection are the same, it can be concluded that little in the way of production enhancement is taking place.

Due to the audit type approach that was utilized in this Study, existing profiles generated by the operator, MMS, or other parties were utilized as a starting point and the basis for generation of such profiles examined. This included the effects of constraints and consideration of the types of data and methodology utilized in constructing the profiles originally. In many cases, the operators had constructed complex reservoir simulation models and utilized such models to optimize rates and well spacings. In other situations, the resulting profiles were more theoretically based and in such situations a reasonableness test was applied based upon analog relationships.

In order to incorporate the constraints that exist, all platforms that were connected to a given processing facility were combined in the construction of their production profiles so that the facilities constraints, if any, could be directly linked to platform level production. This ensures that projections made at the platform level did not result in a combined stream which exceeded any facilities constraints.

Projections based on production rate decline were extrapolated though the end of the first year in which the field production became uneconomic. In these cases, the economic limit was determined using current posted prices and platform operating costs (as of 12/31/94). Unfortunately, only Unocal had provided operating cost data to the MMS, and all other operators declined direct requests to provide cost data (Scotia, 1995). Thus, operating costs for other platforms were estimated by analogy to the Unocal-operated platforms.

A.2 EXISTING FACILITY INVENTORY AND CAPACITY DETERMINATION

A.2.1 FACILITY IDENTIFICATION AND INITIAL CONTACTS

At the beginning of the COOGER study, the COOGER Technical Management Team (TMT) identified those onshore facilities, associated with offshore oil and gas development, that were to be included in the study. To initiate the data collection activities in 1995, Worley contacted each of the subject facilities to identify a facility representative and to introduce the purpose of the study.

Worley then prepared data collection questionnaires specific to various types of onshore facilities (e.g., onshore processing facilities, marine terminals, etc.) and for the platforms that were connected to the onshore facilities. These questionnaires were sent to the facility contacts who were asked to complete them.

After the questionnaires were submitted, Worley scheduled a site visit for each facility, subject to approval from the facilities' operators. During the site visits, a Worley representative met with facility personnel to review the information on the questionnaire, to ask questions about facility equipment and operations, and to make visual observations of the facility. As appropriate, Worley obtained maps, plot plans, or other helpful documents and took photographs where allowed.

In addition to obtaining information from the facility operators, Worley reviewed selected publicly available reports (e.g., EIRs, Development Plans, etc.), agency reports and newsletters, and other related documents to obtain additional facility information.

Worley then prepared a draft report summarizing the facilities and their operations and submitted the appropriate section of the report to each operator to review and verify the data collected. Worley incorporated the operators' comments, as appropriate, and provided the final report to Dames & Moore. Dames & Moore used the information from Worley, as appropriate, to prepare the TMT-internal draft Task II/III report issued in January 1997. Although much of this information has been updated since the January 1997 draft, plot plans, facility schematics, and facility operational descriptions based on information collected during Worley’s efforts are presented in the general facility descriptions in this study.

A.2.2 SUPPLEMENTAL DATA COLLECTION AND VERIFICATION

Subsequent to receiving comments on the January 1997 draft report, Dames & Moore conducted activities to verify, update, and supplement the facility-specific information provided in the draft report. To accomplish this objective, Dames & Moore completed the following activities.

Because some of the facilities had changed ownership since the initial data collection activities conducted by Worley, Dames & Moore contacted each facility to identify the current owner/operator and to identify the current facility contacts.

Dames & Moore then discussed the project goals and the data needs for the study with each operator and requested additional information to update and supplement the existing information so that the report could better achieve the desired goals. The quantity of information requested varied depending on the amount of information previously obtained. In most cases, Dames & Moore provided the facility operators with a copy of the information pertaining to his/her facility and asked the operator to either verify that the information was still accurate or provide updated information. In addition, a list of supplemental information needs was provided to each operator. With the exception of Tosco (operator of the Santa Maria Refinery and associated pipeline system), all Tri-Counties operators provided input at this phase of the investigation.

Dames & Moore then conducted site visits at several facilities to collect additional information required for this study which was not obtained from the operator responses described above. During the site visits, a Dames & Moore representative met with facility personnel to review the information in the report and the new information requested, to ask questions about facility equipment and operations, and to make visual observations of the facility. When possible, Dames & Moore obtained additional information in the form of maps and operating data. Dames & Moore also made followup phone calls to clarify the information obtained.

In addition, to obtain updated and expanded information that was not provided by the operators, Dames & Moore visited selected Ventura and Santa Barbara County agencies to review selected publicly available reports (e.g., EIRs, Development Plans, etc.), agency reports and newsletters, and other related documents and interviewed agency personnel familiar with key facilities in order to obtain additional facility information. Agency reviews of early drafts of the public COOGER report resulted in the identification of additional facility information and permit data that were not previously provided. This report incorporates all information provided by Tri-Counties agencies as of September 7, 1999.

A.3 EMPLOYMENT

This appendix discusses employment trends by industry sectors for each county to establish the context of oil and gas development. Future employment, including details related to each future scenario condition is then discussed to identify general issues and the potential constraints to development. Direct offshore oil and gas related employment under each future condition was estimated based on current local employment levels and anticipated facility changes. In general, each estimated future scenario condition attempts to predict changes in businesses within or directly linked to the oil and gas sector which are defined as direct employment. No attempt at defining employment level effects to indirect or induced business activity is attempted, since this topic is related to a more complex issue of local business diversification and geographic expansion. The phenomenon of local business transformation in response to reduced activity in a basic industry (such as the oil and gas industry) has been suggested as an important element of the local economic system which is inadequately addressed by commonly applied input-output socioeconomic models (Molotch and Woolley, 1994).

The employment data presented in the charts that follow are grouped by industry for ease of comparison between industry sectors, and current and future conditions. Percentage employment by sector for each county is presented for 1998 and 2004. The mining sector, which includes oil and gas related jobs, is less than one percent in all cases. In addition, the construction sector typically includes oil and gas related employment opportunities. For the Tri-County area, construction represents less than five percent of the jobs in each county, with a portion of those jobs attributable to oil and gas related facilities. In addition to the presentation of employment by sector, the number of local jobs directly associated with offshore oil and gas development has been identified by discussion with industry personnel and review of local socioeconomic monitoring data.

The determination of existing and future local employment was accomplished for each facility addressed in the COOGER study (including both offshore and onshore facilities) by telephone and site interviews with cooperating local operators and evaluation of agency-collected data (such as SEMP files). The specific sources of employment data used to compile this information are listed in Table A.3-1. Where no data were provided by the operator or facility-specific agency data files, estimates were developed based on project Environmental Impact Report estimates and evaluation of employment at similar facilities for which employment data were available. The analysis of future employment associated with each development scenario was accomplished by

TABLE A.3-1

DIRECT EMPLOYMENT INFORMATION SOURCES

	Information Sources Used to Compile COOGER Employment Estimates
Eastern Subregion	
Onshore Facilities	
Mandalay	Operator Inputs, Torch, December 1996
West Montalvo	Operator Inputs, Berry Petroleum, November 1996
Rincon Island & Onshore	Operator Inputs, Berry Petroleum, November 1996
Rincon Oil & Gas Processing	Operator Inputs, Torch, December 1996
La Conchita	Operator Inputs, Pacific Operators Offshore Inc., August 1997
Carpinteria Oil & Gas	Operator Inputs, Chevron, August 1997
Carpinteria Gas Terminal	Estimated based on D&M knowledge of operations
Exxon Thousand Oaks Office	Operator Inputs, Exxon, August 1997
Chevron Ventura Office	Operator Inputs, Chevron, August 1997
Offshore Production Facilities	
Platform A	Operator Inputs, Torch, December 1996
Platform B	Operator Inputs, Torch, December 1996
Platform C	Operator Inputs, Torch, December 1996
Platform Hillhouse	Operator Inputs, Torch, December 1996
Platform Henry	Operator Inputs, Torch, December 1996
Platform Hogan	Operator Inputs, Pacific Operators Offshore Inc., August 1997
Platform Houchin	Operator Inputs, Pacific Operators Offshore Inc., August 1997
Platform Gina	Operator Inputs, Torch, December 1996
Platform Gilda	Operator Inputs, Torch, December 1996
Platform Grace	Operator Inputs, Chevron, July 1997
Platform Gail	Operator Inputs, Chevron, July 1997
Platform Habitat	Operator Inputs, Torch, July 1997
New Activity	
Platform Installation	Socioeconomic Monitoring Program data, 1993; Pt. Arguello Field EIR/EIS, November 1984; Operator Inputs, Exxon, December 1996
Onshore Facility Construction	Socioeconomic Monitoring Program data, 1993; Pt. Arguello Field EIR/EIS, November 1984; Pt. Pedernales ER(P), August 1984; Operator Inputs, Exxon, December 1996
Platform Decommission & Removal	Operator Inputs, Chevron, September 1998; Santa Barbara County Energy Division Well Abandonment Records, September 1998
Onshore Facility Decommission & Removal	Estimated based on onshore facility construction & crew estimates (referenced above), and operator inputs from Chevron, July 1997.
Well Drilling	Socioeconomic Monitoring Program data, 1992 & 1993; Pt. Arguello Field EIR/EIS, November 1984

TABLE A.3-1 (Continued)

	Information Sources Used to Compile COOGER Employment Estimates
Central Subregion	
Onshore Facilities	
Ellwood Facility & Marine Terminal	Operator Inputs, Mobil, December 1996; Venoco update, August 1997
Texaco Gaviota Terminal	Operator Inputs, Texaco, November 1996
Gaviota Facility	Operator Inputs, Chevron, August 1997
Exxon Las Flores Canyon Oil & Gas Facility	Operator Inputs, Exxon December 1996; update August 1997
POPCO Las Flores Canyon Gas Facility	Operator Inputs, POPCO, December 1996; Exxon update, June 1999
All American Pipeline	Operator Inputs, AAPLP, July 1997
Cojo Bay Marine Terminal & Drillsite	Estimated based on idle status of facilities
Venoco Offices	Operator Inputs, Venoco, August 1997
Molino Gas Facility & Drillsite	Operator Inputs, Benton Oil, November 1998
Offshore Production Facilities	
Platform Holly	Operator Inputs, Mobil, December 1996
Platform Hondo	Operator Inputs, Exxon, December 1996
Platform Heritage	Operator Inputs, Exxon, December 1996
Platform Harmony	Operator Inputs, Exxon, December 1996
Platform Hermosa	Operator Inputs, Chevron, July 1997
Platform Hidalgo	Operator Inputs, Chevron, July 1997
Platform Harvest	Operator Inputs, Chevron, July 1997
New Activity	
Platform Installation	Socioeconomic Monitoring Program data, 1993; Pt. Arguello Field EIR/EIS, November 1984; Operator Inputs, Exxon, December 1996
Onshore Facility Construction	Socioeconomic Monitoring Program data, 1993; Pt. Arguello Field EIR/EIS, November 1984; Pt. Pedernales ER(P), August 1984; Operator Inputs, Exxon, December 1996
Platform Decommissioning & Removal	Operator Inputs, Chevron, September 1998; Santa Barbara County Energy Division Well Abandonment Records, September 1998
Onshore Facility Decommissioning & Removal	Estimated based on onshore facility construction & crew estimates (referenced above), and operator inputs from Chevron, July 1997.
Well Drilling	Socioeconomic Monitoring Program data, 1992 & 1993; Pt. Arguello Field EIR/EIS, November 1984

TABLE A.3-1 (Continued)

	Information Sources Used to Compile COOGER Employment Estimates
Northern Subregion	
Onshore Facilities	
Lompoc HS&P	Operator Inputs, Torch, December 1996
Santa Maria Asphalt	Operator Inputs, Santa Maria Asphalt Refinery, October 1998
Santa Maria Refinery	UCSB Economic Forecast Project data files, 1998 data
Torch Office	Operator Inputs, Torch, December 1996
Offshore Production Facilities	
Platform Irene	Operator Inputs, Torch, December 1996
New Activity	
Platform Installation	Socioeconomic Monitoring Program data, 1993; Pt. Arguello Field EIR/EIS, November 1984; Operator Inputs, Exxon, December 1996
Onshore Facility Construction	Socioeconomic Monitoring Program data, 1993; Pt. Arguello Field EIR/EIS, November 1984; Pt. Pedernales ER(P), August 1984; Operator Inputs, Exxon, December 1996
Platform Decommissioning & Removal	Operator Inputs, Chevron, September 1998; Santa Barbara County Energy Division Well Abandonment Records, September 1998
Onshore Facility Decommissioning & Removal	Estimated based on onshore facility construction & crew estimates (referenced above), and operator inputs from Chevron, July 1997.
Development Well Drilling	Socioeconomic Monitoring Program data, 1992 & 1993; Pt. Arguello Field EIR/EIS, November 1984

assuming that current employment will be maintained without change as long as each facility remains in operation. In addition to facility-specific employment, employment at local oil company offices which is directly related to study region offshore operations is also included. Direct services to the offshore industry, such as development drilling, offshore and onshore industrial facility construction, and construction-related services associated with the decommissioning and removal of offshore and onshore facilities were separately determined based on SEMP records and operator inputs. Operator-supplied information and SEMP data files were used to determine the county of residence of facility employees. Because several operators provided information on the condition that it be presented only in aggregate with other data, detailed facility-specific data are not presented in this report. As explained above, most of the employment estimates are based on direct operator inputs, and are believed to accurately reflect current employment. Although specific information required to calculate confidence intervals associated with the employment projections in this study is not available, the general stability of the oil and gas sector employment in the Tri-Counties (as discussed in Sections A.3.1.1, A.3.2.1, and A.3.3.1) suggests that use of current employment to estimate future employment levels at the same facilities is a reasonable approach. Complete records of facility-specific employment estimates associated with each development scenario are filed with the Minerals Management Service as the technical basis of information in the report. These detailed files will facilitate the MMS future update of information in this report if such updates are desired. SEMP records were used to develop estimated distributions of employees associated with drilling services and offshore facility construction and decommissioning, and these distributions were applied to these employment sectors in all scenarios involving these activities.

Direct employment associated with the offshore oil and gas industry within the Tri-Counties COOGER study region is summarized for each COOGER study development scenario in Table A.3-2. Because future activities may represent a variety of possible combinations of scenarios within different study subregions, a separate tabulation of all possible combinations is presented on Table A.3-3. These employment estimates were also developed on a County-specific basis, and are presented in the context of other County-specific employment data in the remaining subsections of this Appendix.

TABLE A.3-2

DIRECT EMPLOYMENT BY SCENARIO
TOTAL COOGER STUDY REGION

	1997	2000	2005	2010	2015
Eastern Subregion					
Scenario 1	376	369	300	91	97
Scenario 2	376	361	367	152	160
Scenario 3	376	361	367	152	160
Scenario 4	376	369	296	91	97
Central Subregion					
Scenario 1	523	489	419	339	208
Scenario 2	523	489	530	515	415
Scenario 3	523	489	554	515	415
Scenario 4	523	489	462	375	338
Northern Subregion					
Scenario 1	169	169	177	99	99
Scenario 2	169	169	171	264	196
Scenario 3	169	169	171	350	246
Scenario 4	169	169	171	475	306
Scenario 2A	169	169	234	237	261
Scenario 3A	169	169	234	516	365
Scenario 4A	169	169	234	640	425

TABLE A.3-3
PROJECTED COMBINED DIRECT EMPLOYMENT
ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]

TOTAL - ALL COUNTIES

Scenario[2] (E,C,N)	1997	2000	2005	2010	2015
1, 1, 1	1068	1027	896	529	404
1, 1, 2	1068	1027	891	694	501
1, 1, 3	1068	1027	891	780	551
1, 1, 4	1068	1027	891	905	611
1, 2,1	1068	1027	1007	705	611
1, 2,2	1068	1027	1001	869	708
1, 2,3	1068	1027	1001	956	758
1, 2,4	1068	1027	1001	***1081***	818
1,3,1	1068	1027	1031	705	611
1,3,2	1068	1027	1025	869	708
1,3,3	1068	1027	1025	956	758
1,3,4	1068	1027	1025	***1081***	818
1,4,1	1068	1027	939	565	534
1,4,2	1068	1027	933	730	631
1,4,3	1068	1027	933	816	681
1,4,4	1068	1027	933	941	741
1,4,2A	1068	1027	997	703	695
1,4,3A	1068	1027	997	983	800
1,4,4A	1068	1027	997	***1106***	860
2, 1, 1	1068	1019	963	590	467
2, 1, 2	1068	1019	957	755	564
2, 1, 3	1068	1019	957	842	614
2, 1, 4	1068	1019	957	967	674
2, 2,1	1068	1019	***1073***	766	674
2, 2,2	1068	1019	1067	931	771
2, 2,3	1068	1019	1067	1017	821
2, 2,4	1068	1019	1067	***1142***	881
2,3,1	1068	1019	***1097***	766	674
2,3,2	1068	1019	***1091***	931	771
2,3,3	1068	1019	***1091***	1017	821
2,3,4	1068	1019	***1091***	***1142***	881
2,4,1	1068	1019	1006	627	597
2,4,2	1068	1019	1000	791	694
2,4,3	1068	1019	1000	878	744
2,4,4	1068	1019	1000	1003	804
2,4,2A	1068	1019	1063	764	759
2,4,3A	1068	1019	1063	1044	864
2,4,4A	1068	1019	1063	***1167***	924

[1]Bold italicized numbers indicate increase compared to the base year (1997)

[2]Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion scenario.

TABLE A.3-3 (Continued)
PROJECTED COMBINED DIRECT EMPLOYMENT
ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]

TOTAL - ALL COUNTIES

Scenario[2] (E,C,N)	1997	2000	2005	2010	2015
3, 1, 1	1068	1019	963	590	467
3, 1, 2	1068	1019	957	755	564
3, 1, 3	1068	1019	957	842	614
3, 1, 4	1068	1019	957	967	674
3, 2,1	1068	1019	***1073***	766	674
3, 2,2	1068	1019	1067	931	771
3, 2,3	1068	1019	1067	1017	821
3, 2,4	1068	1019	1067	***1142***	881
3, 3, 1	1068	1019	***1097***	766	674
3, 3, 2	1068	1019	***1091***	931	771
3, 3, 3	1068	1019	***1091***	1017	821
3, 3, 4	1068	1019	***1091***	***1142***	881
3, 4, 1	1068	1019	1006	627	597
3, 4, 2	1068	1019	1000	791	694
3, 4, 3	1068	1019	1000	878	744
3, 4, 4	1068	1019	1000	1003	804
3, 4, 2A	1068	1019	1063	764	759
3, 4, 3A	1068	1019	1063	1044	864
3, 4, 4A	1068	1019	1063	***1167***	924
4, 1, 1	1068	1027	892	529	404
4, 1, 2	1068	1027	886	694	501
4, 1, 3	1068	1027	886	780	551
4, 1, 4	1068	1027	886	905	611
4, 2, 1	1068	1027	1002	705	611
4, 2, 2	1068	1027	996	869	708
4, 2, 3	1068	1027	996	956	758
4, 2, 4	1068	1027	996	***1081***	818
4, 3, 1	1068	1027	1026	705	611
4, 3, 2	1068	1027	1020	869	708
4, 3, 3	1068	1027	1020	956	758
4, 3, 4	1068	1027	1020	***1081***	818
4, 4, 1	1068	1027	934	565	534
4, 4, 2	1068	1027	929	730	631
4, 4, 3	1068	1027	929	816	681
4, 4, 4	1068	1027	929	941	741
4, 4, 2A	1068	1027	992	703	695
4, 4, 3A	1068	1027	992	983	800
4, 4, 4A	1068	1027	992	***1106***	860

[1]Bold italicized numbers indicate increase compared to the base year (1997)

[2]Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion scenario.

A.3.1 Ventura County

A.3.1.1 Overall Employment

Total employment in Ventura County was 271,200 jobs in October 1998 (California Employment Development Department, 1998A). This represents a total civilian unemployment rate of 5.8%, which is substantially higher than the national average unemployment rate of 4.2%. The share of employment associated with each sector for a single year, 1998, is presented in Figure A.3-1 based on data from the California Employment Development Department (1998A). Services comprise the single largest sector with 28.4 percent of total employment. Retail and wholesale trade combined accounted for 22.5 percent of employment while the government sector, including federal, state and local direct employees and military, represents 16.3 percent of the total. With over 67 percent of the employment from services, trade or government, the remaining sectors ranked by their share of employment are (with the share in parentheses): manufacturing (12.6%); agriculture (6.2%); finance, insurance and real estate (5.3%); construction (4.5%); transportation, communications and utilities (3.7%); and oil and gas and mining (0.5%). The oil and gas sector refers to the exploration and production of the resources which represent the majority of basic oil and gas employment. Refining and pipeline transportation are sometimes included as part of the petroleum industry although the population and employment multipliers that affect socioeconomic change are focused on the exploration and production sectors.

In addition to employees in offshore oil exploration and production, there are employees in other sectors whose jobs depend on the oil and gas industry in their role as suppliers or contractors. For instance, material in a report to the California Coastal Operators Group (General Research Corporation, 1985) surveyed 45 companies engaged in offshore oil service industry in the three counties. The Ventura County location of substantial oil-related construction and service industries, as well as the principal industrial port in the region (Port Hueneme) results in the creation of Ventura County employment associated with construction, development drilling, and the decommissioning and removal of offshore oil and gas facilities. Employment associated with service contractors directly involved in offshore activities or related onshore facilities is included in the COOGER study employment estimates. Direct oil company employment and construction services associated with facility installation and removal is also included. Indirect employment resulting from the household expenditures of local workers, government agency employment associated with the regulation of offshore activities, and industry services not specifically related to the operation, construction, or decommissioning of individual offshore facilities or related onshore facilities is not included.

The actual employment data constantly change by a small amount. The unpredictable changes in employment in various sectors are part of the natural variability in the employment situation. Figure A.3-2 shows the recent changes in employment for some major economic sectors. Employment in the oil and gas sector changed little in comparison to the changes occurring in other sectors during the fifteen years reported on this figure. One reason for this may be that total employment in the oil and gas industry is small relative to other sectors. Worthy of note is that changes in construction employment are not closely linked to the oil and gas sector. It is also notable that sectors such as manufacturing, government, services, and trade exhibit large year-to-year changes.

A.3.1.2 Future Offshore Oil Related Employment

The UCSB Forecasting Project (1996) has developed predictions of employment by sector. In contrast with 1998, Figure A.3-1 indicates that the service sector is projected to increase employment to 32 percent from 28.4 percent, while government and manufacturing are projected to decline. The role of oil and gas employment, a part of the mining sector, remains small in both time periods.

Because Ventura County employment associated with offshore oil and gas activities is affected by offshore operations throughout the COOGER study region, a complete understanding of the potential future employment effect of different development scenarios requires a consideration of combinations of scenarios in different subregions. Information concerning estimated Ventura County direct employment associated with each scenario addressed in this report is listed in Table A.3-4. Table A.3-5 presents the combined direct employment totals for each possible combination of development scenarios. As indicated by this table, the Eastern Subregion accelerated decommissioning scenario (Scenario 4) combined with the Central Subregion future baseline scenario (Scenario 1) result in the steepest and most immediate employment declines between 2001 and 2005, with continuing steep declines from 2006 to 2010. These scenario combinations result in the loss of approximately 115 direct jobs in Ventura by 2005, and an additional 214 jobs by 2010. Combinations of scenarios involving maximum development of Central Subregion leases (Scenario 3) result in relatively stable Ventura County employment through 2005, followed by substantial declines from 2006 through 2015. No combination of scenarios results in a net increase of Ventura County direct employment above 1997 levels.

As indicated by Table A.3-5, overall Ventura County direct employment associated with offshore oil and gas activities is relatively low. Long-term employment projections suggest employment

TABLE A.3-4

DIRECT EMPLOYMENT BY SCENARIO
VENTURA COUNTY

	1997	2000	2005	2010	2015
Eastern Subregion					
Scenario 1	349	342	259	91	97
Scenario 2	349	334	316	136	132
Scenario 3	349	334	316	136	132
Scenario 4	349	341	252	91	97
Central Subregion					
Scenario 1	228	194	159	115	91
Scenario 2	228	194	231	216	159
Scenario 3	228	194	238	216	159
Scenario 4	228	194	172	125	111
Northern Subregion					
Scenario 1	0	0	8	0	0
Scenario 2	0	0	12	41	0
Scenario 3	0	0	12	58	0
Scenario 4	0	0	12	97	0
Scenario 2A	0	0	58	54	66
Scenario 3A	0	0	37	99	29
Scenario 4A	0	0	37	138	29

TABLE A.3-5
PROJECTED COMBINED DIRECT EMPLOYMENT
ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]

VENTURA COUNTY

Scenario[2] (E,C,N)	1997	2000	2005	2010	2015
1, 1, 1	577	536	427	206	187
1, 1, 2	577	536	431	247	187
1, 1, 3	577	536	431	263	187
1, 1, 4	577	536	431	303	187
1, 2,1	577	536	498	307	256
1, 2,2	577	536	502	349	256
1, 2,3	577	536	502	365	256
1, 2,4	577	536	502	405	256
1,3,1	577	536	505	307	256
1,3,2	577	536	509	349	256
1,3,3	577	536	509	365	256
1,3,4	577	536	509	405	256
1,4,1	577	536	440	216	208
1,4,2	577	536	443	258	208
1,4,3	577	536	443	274	208
1,4,4	577	536	443	314	208
1,4,2A	577	536	489	271	274
1,4,3A	577	536	468	315	237
1,4,4A	577	536	468	354	237
2, 1, 1	577	527	484	251	222
2, 1, 2	577	527	488	292	222
2, 1, 3	577	527	488	309	222
2, 1, 4	577	527	488	348	222
2, 2,1	577	527	556	353	291
2, 2,2	577	527	559	394	291
2, 2,3	577	527	559	411	291
2, 2,4	577	527	559	450	291
2,3,1	577	527	563	353	291
2,3,2	577	527	566	394	291
2,3,3	577	527	566	411	291
2,3,4	577	527	566	450	291
2,4,1	577	527	497	262	243
2,4,2	577	527	501	303	243
2,4,3	577	527	501	319	243
2,4,4	577	527	501	359	243
2,4,2A	577	527	546	316	309
2,4,3A	577	527	526	360	273
2,4,4A	577	527	526	400	273

[1]Bold italicized numbers indicate increase compared to the base year (1997)

[2]Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion scenario.

TABLE A.3-5 (Continued)
PROJECTED COMBINED DIRECT EMPLOYMENT
ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]

VENTURA COUNTY

Scenario[2] (E,C,N)	1997	2000	2005	2010	2015
3, 1, 1	577	527	484	251	222
3, 1, 2	577	527	488	292	222
3, 1, 3	577	527	488	309	222
3, 1, 4	577	527	488	348	222
3, 2,1	577	527	556	353	291
3, 2,2	577	527	559	394	291
3, 2,3	577	527	559	411	291
3, 2,4	577	527	559	450	291
3, 3, 1	577	527	563	353	291
3, 3, 2	577	527	566	394	291
3, 3, 3	577	527	566	411	291
3, 3, 4	577	527	566	450	291
3, 4, 1	577	527	497	262	243
3, 4, 2	577	527	501	303	243
3, 4, 3	577	527	501	319	243
3, 4, 4	577	527	501	359	243
3, 4, 2A	577	527	546	316	309
3, 4, 3A	577	527	526	360	273
3, 4, 4A	577	527	526	400	273
4, 1, 1	577	535	420	206	187
4, 1, 2	577	535	424	247	187
4, 1, 3	577	535	424	263	187
4, 1, 4	577	535	424	303	187
4, 2, 1	577	535	491	307	256
4, 2, 2	577	535	495	349	256
4, 2, 3	577	535	495	365	256
4, 2, 4	577	535	495	405	256
4, 3, 1	577	535	498	307	256
4, 3, 2	577	535	502	349	256
4, 3, 3	577	535	502	365	256
4, 3, 4	577	535	502	405	256
4, 4, 1	577	535	433	216	208
4, 4, 2	577	535	437	258	208
4, 4, 3	577	535	437	274	208
4, 4, 4	577	535	437	314	208
4, 4, 2A	577	535	482	271	274
4, 4, 3A	577	535	461	315	237
4, 4, 4A	577	535	461	354	237

[1]Bold italicized numbers indicate increase compared to the base year (1997)

[2]Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion scenario.

levels between one-third to one-half 1997 levels for all combinations of scenarios during the 2011 to 2015 time period. These employment reductions represent a major portion of the total oil and gas sector employment, and are likely to be highly visible to those directly involved in the offshore industry. Nonetheless, both the short-term and long-term employment changes indicated by Table A.3-5 are well within the employment variability indicated on Figure A.3-2. These job losses also represent a small component of the local employment, and are unlikely to result in a noticeable effect on the overall County employment, regardless of the specific offshore development scenarios which actually occur.

A.3.2 Santa Barbara County

A.3.2.1 Overall Employment

Total employment in Santa Barbara County was 169,800 jobs in October 1998 (California Employment Development Department, 1998B). This represents a total civilian unemployment rate of 3.9%, which is slightly lower than the national average unemployment rate of 4.2%. The share of employment by industry sector for 1998 is presented in Figure A.3-3 based on data from the California Employment Development Department (1998B). The share of employment by sectors are very similar between Ventura and Santa Barbara. Services comprise the single largest sector with 28.8 percent of total employment. Retail and wholesale trade combined accounted for 21.9 percent of employment while the government sector, including federal, state and local direct employees and military represents 18.8 percent of the total. With 69.5 percent of the employment from services, trade or government, the remaining sectors ranked by their share of employment are (with the share in parentheses): manufacturing (10%); agriculture (8%); finance, insurance and real estate (4.4%); construction (4.1%); transportation, communications and utilities (3.5%); and oil and gas and mining (0.5%).

Although Santa Barbara County has a long history of both onshore and offshore oil and gas production operations, employment related to oil field service companies is less than that in Ventura County. Several offices of independent oil and gas producers are located in Santa Barbara County, however. These include companies such as Torch, Venoco, Ogle Petroleum, and Benton Oil. Employment associated with company offices involved in local offshore oil and gas production, construction employment associated with facility installation and removal, and service contractors directly involved in these activities are included in the COOGER study employment estimates. Indirect employment resulting from the household expenditures of local workers, agency employment related to the regulation of offshore activities, and industry services which are not directly associated with the operation, construction, or decommissioning of individual offshore facilities or related onshore facilities is not included.

As in Ventura County, irregular changes in sector employment are a part of the normal variability in the economic system. Figure A.3-4 shows the recent changes in employment for some major economic sectors. Employment in the oil and gas sector changed little in comparison to the changes occurring in other sectors. Changes in construction employment are again not closely linked to the oil and gas sector and sectors such as manufacturing, government, services and trade exhibit large year-to-year changes.

A.3.2.2 Future Offshore Oil Related Employment

The Santa Barbara County Association of Governments (SBCAG, 1994) and the UCSB Forecasting Project (1996) have developed predictions of employment by sector, excluding the self-employed. In contrast with 1998, Figure A.3-3 for the year 2004 indicates that the service sector is projected to increase employment to 31 percent from 28.8 percent while government and manufacturing are projected to decline according to the UCSB Forecasting Project. It is important to note that differences of several percentages exist between the SBCAG and UCSB data sets, where each percentage point is approximately 2,000 jobs. For instance, by 2005, the Regional Growth Forecast assumes that the service sector will employ 28 percent. The role of oil and gas (and mining) employment in either report remains small and roughly constant in each time period.

All three subregions addressed by the COOGER study include onshore facilities in Santa Barbara County, and activities in each subregion affect Santa Barbara County employment. For this reason, consideration of the potential future employment effect of different development scenarios requires the consideration of combinations of scenarios in different subregions. Estimates of Santa Barbara County direct employment associated with each scenario are presented in Table A.3-6. Table A.3-7 presents the combined direct employment totals for each possible combination of development scenarios. As indicated by Table A.3-7, relatively minor employment changes are expected between 2001 through 2005 regardless of the combination of development scenarios. These projected changes range from a maximum employment reduction of 28 jobs (associated with Eastern Subregion accelerated decommissioning Scenario 4 and Central Subregion future baseline Scenario 1) to maximum employment increases of 32 jobs (associated with Eastern Subregion further development Scenario 2 or 3, Central Subregion accelerated decommissioning Scenario 4, and Northern Subregion expanded development Scenario 3A or 4A). Differences between scenarios are most pronounced from 2006 through 2015, when future baseline Scenario 1 in all subregions results in a steadily declining employment to less than one-third of 1997 levels by 2015.

TABLE A.3-6

DIRECT EMPLOYMENT BY SCENARIO
SANTA BARBARA COUNTY

	1997	2000	2005	2010	2015
Eastern Subregion					
Scenario 1	27	27	34	0	0
Scenario 2	27	27	38	15	27
Scenario 3	27	27	38	15	27
Scenario 4	27	27	34	0	0
Central Subregion					
Scenario 1	267	273	245	215	109
Scenario 2	267	273	268	272	241
Scenario 3	267	273	282	272	241
Scenario 4	267	273	268	236	216
Northern Subregion					
Scenario 1	70	70	68	0	0
Scenario 2	70	70	58	115	97
Scenario 3	70	70	58	181	147
Scenario 4	70	70	58	258	207
Scenario 2A	70	70	68	74	85
Scenario 3A	70	70	91	299	234
Scenario 4A	70	70	91	374	294

TABLE A.3-7
PROJECTED COMBINED DIRECT EMPLOYMENT
ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]

SANTA BARBARA COUNTY

Scenario[2] (E,C,N)	**1997**	**2000**	**2005**	**2010**	**2015**
1, 1, 1	364	***370***	347	215	109
1, 1, 2	364	***370***	337	329	206
1, 1, 3	364	***370***	337	***396***	256
1, 1, 4	364	***370***	337	***473***	316
1, 2,1	364	***370***	***370***	272	241
1, 2,2	364	***370***	360	***387***	338
1, 2,3	364	***370***	360	***453***	***388***
1, 2,4	364	***370***	360	***530***	***448***
1,3,1	364	***370***	***385***	272	241
1,3,2	364	***370***	***374***	***387***	338
1,3,3	364	***370***	***374***	***453***	***388***
1,3,4	364	***370***	***374***	***530***	***448***
1,4,1	364	***370***	***370***	236	216
1,4,2	364	***370***	360	351	313
1,4,3	364	***370***	360	***417***	363
1,4,4	364	***370***	360	***494***	***423***
1,4,2A	364	***370***	***369***	310	301
1,4,3A	364	***370***	***393***	***535***	***450***
1,4,4A	364	***370***	***393***	***610***	***510***
2, 1, 1	364	***370***	351	230	137
2, 1, 2	364	***370***	340	345	234
2, 1, 3	364	***370***	340	***411***	284
2, 1, 4	364	***370***	340	***488***	344
2, 2,1	364	***370***	***374***	287	268
2, 2,2	364	***370***	363	***402***	***365***
2, 2,3	364	***370***	363	***468***	***415***
2, 2,4	364	***370***	363	***545***	***475***
2,3,1	364	***370***	***389***	287	268
2,3,2	364	***370***	***378***	***402***	***365***
2,3,3	364	***370***	***378***	***468***	***415***
2,3,4	364	***370***	***378***	***545***	***475***
2,4,1	364	***370***	***374***	251	243
2,4,2	364	***370***	363	***366***	340
2,4,3	364	***370***	363	***433***	***390***
2,4,4	364	***370***	363	***510***	***450***
2,4,2A	364	***370***	***373***	325	328
2,4,3A	364	***370***	***396***	***550***	***477***
2,4,4A	364	***370***	***396***	***626***	***537***

[1]Bold italicized numbers indicate increase compared to the base year (1997)

[2]Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion scenario.

TABLE A.3-7 (Continued)
PROJECTED COMBINED DIRECT EMPLOYMENT
ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]

SANTA BARBARA COUNTY

Scenario[2] (E,C,N)	1997	2000	2005	2010	2015
3, 1, 1	364	***370***	351	230	137
3, 1, 2	364	***370***	340	345	234
3, 1, 3	364	***370***	340	***411***	284
3, 1, 4	364	***370***	340	***488***	344
3, 2,1	364	***370***	***374***	287	268
3, 2,2	364	***370***	363	***402***	***365***
3, 2,3	364	***370***	363	***468***	***415***
3, 2,4	364	***370***	363	***545***	***475***
3, 3, 1	364	***370***	***389***	287	268
3, 3, 2	364	***370***	***378***	***402***	***365***
3, 3, 3	364	***370***	***378***	***468***	***415***
3, 3, 4	364	***370***	***378***	***545***	***475***
3, 4, 1	364	***370***	***374***	251	243
3, 4, 2	364	***370***	363	***366***	340
3, 4, 3	364	***370***	363	***433***	***390***
3, 4, 4	364	***370***	363	***510***	***450***
3, 4, 2A	364	***370***	***373***	325	328
3, 4, 3A	364	***370***	***396***	***550***	***477***
3, 4, 4A	364	***370***	***396***	***626***	***537***
4, 1, 1	364	***370***	347	215	109
4, 1, 2	364	***370***	336	329	206
4, 1, 3	364	***370***	336	***396***	256
4, 1, 4	364	***370***	336	***473***	316
4, 2, 1	364	***370***	***370***	272	241
4, 2, 2	364	***370***	359	***387***	338
4, 2, 3	364	***370***	359	***453***	***388***
4, 2, 4	364	***370***	359	***530***	***448***
4, 3, 1	364	***370***	***384***	272	241
4, 3, 2	364	***370***	***374***	***387***	338
4, 3, 3	364	***370***	***374***	***453***	***388***
4, 3, 4	364	***370***	***374***	***530***	***448***
4, 4, 1	364	***370***	***370***	236	216
4, 4, 2	364	***370***	359	351	313
4, 4, 3	364	***370***	359	***417***	363
4, 4, 4	364	***370***	359	***494***	***423***
4, 4, 2A	364	***370***	***369***	310	301
4, 4, 3A	364	***370***	***392***	***535***	***450***
4, 4, 4A	364	***370***	***392***	***610***	***510***

[1]Bold italicized numbers indicate increase compared to the base year (1997)

[2]Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion scenario.

Combinations of scenarios which involve accelerated decommissioning (Scenario 4) in the Central Subregion and Northern Subregion facility expansion (Scenarios 3A and 4A) result in the most substantial increases in Santa Barbara County employment, maintaining about 100 to 150 new jobs through this period (a 25 to 40 percent increase above 1997 levels).

As indicated by Table A.3-7, overall Santa Barbara County direct employment associated with offshore oil and gas activities is relatively low. The employment changes projected represent a substantial percentage of the total oil and gas sector employment, and are likely to be highly visible to those involved in the offshore industry. Scenario combinations which result in increased employment in Santa Barbara County could offset projected Ventura County employment declines and would be less noticeable from a regional perspective. Regardless of the scenario combination, projected employment increases and decreases are all within the recent employment variability indicated on Figure A.3-4, and represent a relatively small component of total Santa Barbara County employment.

A.3.3 San Luis Obispo County

A.3.3.1 Overall Employment

The sector share of employment for 1998, is presented in Figure A.3-5 based on data from the California Employment Development Department (1998C). In San Luis Obispo, trade, services (retail and wholesale combined), and government are nearly equally important with 20.3, 19.5, and 19.2 percent shares (respectively) of employment. With 59 percent of the employment from services, trade or government, the remaining sectors ranked by their share of employment are (with the share in parentheses): agriculture (6.5%); manufacturing (6.4%); construction (4.4%); transportation, communications and utilities (4%); finance, insurance and real estate (3.9%); and oil and gas and mining (0.1%).

Although there is no offshore development adjacent to San Luis Obispo County, onshore oil and gas production operations, a small refinery, and past marine terminal facilities have established local employment associated with the oil and gas industry. Existing San Luis Obispo County employment associated with offshore oil and gas development includes personnel involved in onshore facility operations, offshore facility operations, drilling related activity, and facility construction services. Direct employment is reflected by the COOGER study estimates. Indirect employment associated with household expenditures of oil and gas industry employees, agency employment related to the regulation of industry activity, and industry services which are not directly related to the operation, construction, or decommissioning of individual offshore facilities or related onshore facilities is not included.

As in the other counties, irregular changes in sector employment are a part of the normal variability of the economic system. Figure A.3-6 shows the recent changes in employment for some major economic sectors. Employment in the oil and gas sector changed little in comparison to the changes occurring in other sectors indicating that the oil and gas sector has historically added little variation to the normal variability in the system. Changes in construction employment are again not closely linked to the oil and gas sector and sectors such as manufacturing, government, services, and trade exhibit large year-to-year changes.

A.3.3.2 Future Offshore Oil Related Employment

The UCSB Forecasting Project (1996) has developed predictions of employment by sector. In contrast with 1998, Figure A.3-5 indicates that the service sector is projected to increase employment to 30 percent from 19.5 percent. The share of oil and gas employment, a part of the mining sector, is essentially zero in either time period.

Other than employment at the Santa Maria Refinery, only limited San Luis Obispo County employment is associated with the offshore oil and gas industry. As indicated by Table A.3-8, very little San Luis Obispo County employment is associated with offshore development scenarios in the Eastern and Central subregions. Table A.3-9 indicates that San Luis Obispo County employment associated with offshore oil and gas development is projected to be relatively stable under all combinations of scenarios. The projected employment changes are a very small component of local employment, and are not likely to result in a measurable effect on overall county employment regardless of the specific combination of offshore development scenarios which actually occur.

TABLE A.3-8

DIRECT EMPLOYMENT BY SCENARIO
SAN LUIS OBISPO COUNTY

	1997	2000	2005	2010	2015
Eastern Subregion					
Scenario 1	0	0	8	0	0
Scenario 2	0	0	13	1	1
Scenario 3	0	0	13	1	1
Scenario 4	0	1	10	0	0
Central Subregion					
Scenario 1	28	23	15	10	8
Scenario 2	28	23	31	26	15
Scenario 3	28	23	33	26	15
Scenario 4	28	23	22	14	11
Northern Subregion					
Scenario 1	99	99	100	99	99
Scenario 2	99	99	101	108	99
Scenario 3	99	99	101	111	99
Scenario 4	99	99	101	120	99
Scenario 2A	99	99	108	108	110
Scenario 3A	99	99	106	119	102
Scenario 4A	99	99	106	128	102

TABLE A.3-9
PROJECTED COMBINED DIRECT EMPLOYMENT
ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]

SAN LUIS OBISPO COUNTY

Scenario[2] (E,C,N)	**1997**	**2000**	**2005**	**2010**	***2015***
1, 1, 1	127	122	123	109	107
1, 1, 2	127	122	123	117	107
1, 1, 3	127	122	123	121	107
1, 1, 4	127	122	123	***130***	107
1, 2,1	127	122	***138***	125	114
1, 2,2	127	122	***139***	***134***	114
1, 2,3	127	122	***139***	***138***	114
1, 2,4	127	122	***139***	***146***	114
1,3,1	127	122	***141***	125	114
1,3,2	127	122	***141***	***134***	114
1,3,3	127	122	***141***	***138***	114
1,3,4	127	122	***141***	***146***	114
1,4,1	127	122	***130***	113	110
1,4,2	127	122	***130***	121	110
1,4,3	127	122	***130***	125	110
1,4,4	127	122	***130***	***134***	110
1,4,2A	127	122	***138***	122	120
1,4,3A	127	122	***136***	***133***	113
1,4,4A	127	122	***136***	***141***	113
2, 1, 1	127	122	***128***	109	108
2, 1, 2	127	122	***129***	118	108
2, 1, 3	127	122	***129***	121	108
2, 1, 4	127	122	***129***	***130***	108
2, 2,1	127	122	***144***	126	115
2, 2,2	127	122	***145***	***135***	115
2, 2,3	127	122	***145***	***138***	115
2, 2,4	127	122	***145***	***147***	115
2,3,1	127	122	***146***	126	115
2,3,2	127	122	***147***	***135***	115
2,3,3	127	122	***147***	***138***	115
2,3,4	127	122	***147***	***147***	115
2,4,1	127	122	***135***	113	111
2,4,2	127	122	***136***	122	111
2,4,3	127	122	***136***	125	111
2,4,4	127	122	***136***	***134***	111
2,4,2A	127	122	***143***	123	121
2,4,3A	127	122	***141***	***133***	114
2,4,4A	127	122	***141***	***142***	114

[1]Bold italicized numbers indicate increase compared to the base year (1997)

[2]Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion scenario.

TABLE A.3-9 (Continued)
PROJECTED COMBINED DIRECT EMPLOYMENT
ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]

SAN LUIS OBISPO COUNTY

Scenario[2] (E,C,N)	1997	2000	2005	2010	2015
3, 1, 1	127	122	***128***	109	108
3, 1, 2	127	122	***129***	118	108
3, 1, 3	127	122	***129***	121	108
3, 1, 4	127	122	***129***	***130***	108
3, 2,1	127	122	***144***	126	115
3, 2,2	127	122	***145***	***135***	115
3, 2,3	127	122	***145***	***138***	115
3, 2,4	127	122	***145***	***147***	115
3, 3, 1	127	122	***146***	126	115
3, 3, 2	127	122	***147***	***135***	115
3, 3, 3	127	122	***147***	***138***	115
3, 3, 4	127	122	***147***	***147***	115
3, 4, 1	127	122	***135***	113	111
3, 4, 2	127	122	***136***	122	111
3, 4, 3	127	122	***136***	125	111
3, 4, 4	127	122	***136***	***134***	111
3, 4, 2A	127	122	***143***	123	121
3, 4, 3A	127	122	***141***	***133***	114
3, 4, 4A	127	122	***141***	***142***	114
4, 1, 1	127	122	125	109	107
4, 1, 2	127	122	126	117	107
4, 1, 3	127	122	126	121	107
4, 1, 4	127	122	126	***130***	107
4, 2, 1	127	122	***141***	125	114
4, 2, 2	127	122	***142***	***134***	114
4, 2, 3	127	122	***142***	***138***	114
4, 2, 4	127	122	***142***	***146***	114
4, 3, 1	127	122	***143***	125	114
4, 3, 2	127	122	***144***	***134***	114
4, 3, 3	127	122	***144***	***138***	114
4, 3, 4	127	122	***144***	***146***	114
4, 4, 1	127	122	***132***	113	110
4, 4, 2	127	122	***133***	121	110
4, 4, 3	127	122	***133***	125	110
4, 4, 4	127	122	***133***	***134***	110
4, 4, 2A	127	122	***140***	122	120
4, 4, 3A	127	122	***138***	***133***	113
4, 4, 4A	127	122	***138***	***141***	113

[1]Bold italicized numbers indicate increase compared to the base year (1997)

[2]Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion scenario.

A.4 PROPERTY TAXES

In addition to taxes paid by employees and induced businesses, offshore oil and gas production and related onshore activities generate local government revenues through direct payments to local agencies, state taxes, and federal contributions of a portion of royalty revenues to State and local programs. Three categories of local government revenue streams are particularly relevant to an understanding of the effect of the offshore oil and gas industry in the COOGER study area. These revenue streams include: property tax, intergovernmental transfers, and direct payments (mitigation fees). Of these revenues, only property taxes are predictably linked to specific development scenarios. The revenues associated with intergovernmental transfers are influenced by several factors beyond the level of local offshore development, and cannot be clearly correlated to individual scenarios. For this reason, the information presented in this report is focused on local property tax collections.

In general, the oil and gas industry augments the revenue streams of federal, state, and local governments through contributions to specific programs designed to manage and/or mitigate the potential ramifications of offshore and onshore oil and gas related activities. Depending on the jurisdiction's fee structure, local governments sometimes incur unrecoverable costs associated with permitting, enforcement, and public service response related to major new projects. In addition, it has been suggested that the permitting and existence of oil and gas facilities may have reduced the attraction and retention of other businesses; however, this suggestion was not investigated in this report. These issues are all likely to generate substantial interest in connection with project-specific reviews of individual projects. Lack of currently available information and uncertain nature of development conditions applicable to specific projects that would be developed in connection with individual scenarios prevent the detailed consideration of these topics in this report. The current depiction of property tax receipts are provided herein to show the contribution of offshore oil and gas development to local revenues.

A.4.1 Ventura County

Cities and counties earn revenue from different mixtures of property taxes, state and federal transfers, sales taxes, and user charges. Figure A.4-1 shows the major revenue sources for Ventura County. The largest revenue sources are intergovernmental transfers (based in part on income taxes), property taxes, sales taxes and other taxes, and charges for services. In addition to property tax revenue distributed to the County, property taxes collected by the County are apportioned to numerous public units such as cities and special purpose districts in the tax area where property is located.

Facilities related to the offshore oil and gas industry provide a significant base for property taxes. In Ventura County, property taxes distributed to the County accounted for 18 percent of County revenues in 1993-1994. Property taxes associated with offshore oil and gas related facilities are not among the largest tax collections County-wide, and the aggregate total of property tax collections associated with offshore oil and gas facilities account for approximately 0.1 percent of total County property tax collections. Table A.4-1 presents 1998 property tax receipts associated with offshore oil and gas facilities. Because of full or partial exemptions in property tax payments for government and non-profit organizations, none of the top three employers in Ventura County appear as significant payers of property taxes.

In the absence of new offshore development in the future, Ventura County could lose over 70 percent of current oil and gas facility tax revenues by the year 2005. With the removal of onshore facilities, it is expected that the property tax would revert, at least in the short term, to a significantly lower rate.

Table A.4-1

Offshore Oil and Gas Facility Property Taxes[1]
Ventura County
1997/1998 Tax Year

	Property Tax Collections ($1000s)	**Percent of Total Property Tax Collections**
Rincon Island L.P.	205.4	0.05
Berry Petroleum	23.8	0.01
Nuevo Energy	122.5	0.03
Mobil Oil Company	79.3	0.02
Signal Hill Services (La Conchita Facility)	11.6	0.00
SUBTOTAL[2]	442.5	0.10
TOTAL COUNTY	426,876.8	100.00

1 Source: Kada, 1999; Ventura County Auditor-Controller, 1999.

2 Subtotal presents the sum of estimated property taxes associated with principal facilities only. Data concerning property taxes associated with pipeline systems and ancillary facilities were not available.

A.4.2 Santa Barbara County

Figure A.4-2 provides the recent record of revenues for Santa Barbara County. The individual sources are property taxes, intergovernmental transfers (based in part on income taxes), sales taxes and other taxes, and charges for services. Like Ventura, the relative importance of local taxes remained stable while that of intergovernmental transfers increased between 1980 and 1995. In addition to property tax revenue retained by the County, property taxes collected by the County are apportioned to cities and special public service districts in the tax area where the property is located.

In fiscal year 1998-99, net property tax receipts in Santa Barbara County amounted to approximately $280.6 million (Anthony, 1998). Total property tax receipts attributable to all facilities and properties related to offshore oil and gas projects or offshore mineral rights amounted to $12,945,353 for the same period, or 4.6% of the total receipts in fiscal year 1998-99 (Table A.4-2). Eighty-eight percent (88%) of the offshore-related property taxes are attributable to the two consolidated processing facilities on the south coast. Exxon's Las Flores Canyon facility, including the recently purchased POPCO gas processing facility, represents $9,344,500 of property tax receipts in fiscal year 1998-99 while the Gaviota Oil & Gas Facility and related pipelines represent $2,053,500.

Property taxes are distributed to the County as both obligated and discretionary funds. School districts and colleges receive 60% of the property tax revenue. Dependent districts in the County receive 7%, or $20,588,682 and the County's General Fund receives 20% or $49,190.769. Total discretionary revenues in fiscal year 1998-99 were $105.6 million. Of this total, $59.1 million are spent on State maintenance of effort requirements or other County match for State-mandated programs. The remaining $46.5 million are truly discretionary to the Board of Supervisors. Property taxes contributed 56% of the County's discretionary funds. These discretionary funds are primarily used to finance County administration and legal counsel, Board of Supervisors, County staff personnel, community services (such as park operations, land-use planning), and public facilities (such as surveyor and roads).

Under future baseline conditions, the potential decommissioning of oil and gas facilities would reduce property tax receipts. Exxon's Las Flores Canyon facilities, representing the largest individual property tax receipt in the County at $9 million annually, would remain operative. Losses can be expected, however. While the exact figure is not known, the projected closure of

Table A.4-2
Offshore Oil and Gas Facility Property Taxes[3]
Santa Barbara County
1998/99 Tax Year

	Property Tax Collections ($1,000s)	Percent of Total Property Tax Collections
Chevron Carpinteria/Summerland Leases	27.4	0.01
Nuevo Summerland	0.4	0.00
Atlantic Richfield Ellwood Leases	40.1	0.01
Pt. Arguello Natural Gas (PANGLCO)	167.8	0.06
Pt. Arguello Pipeline Co. (PAPCO)	319.4	0.11
Gaviota Oil & Gas Facility	1,566.3	0.56
Texaco Gaviota Oil Terminal	208.5	0.07
UNOCAL Pipelines	10.3	0.00
UNOCAL Pt. Conception Leases	0.5	0.00
Torch Lompoc	291.7	0.10
Torch, misc.	2.3	0.00
Exxon, misc.	17.7	0.01
Pacific Interstate Pitas Point	43.2	0.02
Nuevo Carpinteria Leases	4.0	0.00
Molino Energy	2.1	0.00
Shell Molino	11.6	0.00
Las Flores Canyon Facilities (Exxon SYU Oil and Gas Facility, POPCO Gas Processing Facility)	9,344.5	3.33
All American Pipeline, L.P.	11.5	0.00
Venoco Carpinteria and Related Facilities (Carpinteria Facility, Carpinteria Pier, and Platform Grace & Pipelines)	150.3	0.05
Venoco Ellwood and Related Facilities (Ellwood Facility, Ellwood Pier, Ellwood Offshore Leases, and Ellwood Marine Terminal)	712.6	0.25
SUBTOTAL[4]	12,945.4	4.70
TOTAL COUNTY	280,580.1	100.00

[3] Source: Anthony, 1998

[4] Table Entries indicate principal facilities only. County-wide total includes oil and gas related property taxes not addressed by specific entry.

the Gaviota Marine Terminal, Point Pedernales processing facilities near Lompoc and the Carpinteria oil and gas facilities between 2000 and 2005 could reduce receipts by $678,000. The loss of property tax receipts from the Carpinteria facility would be partially offset if the city zones this site for commercial development. Alternatively if the site is dedicated to public recreation, no offset would result.

During the period of 2005 to 2010, closure of the Ellwood and Gaviota facilities could reduce receipts by another $2,600,000. No new development is expected to occur at Gaviota, so subsequent property tax receipts from those parcels will remain relatively low. Ellwood, however, is zoned for private recreational use. If the Ellwood site is developed, its property tax obligation would increase accordingly. There are no projected additional losses during the final 5-year period of the COOGER projection - 2010 through 2015.

If considered in isolation, the reduction in property tax receipts could represent an annual loss of $1,966,800 in revenues to schools, $163,900 to cities within the County, $131,120 to independent special districts $131,120 to redevelopment agencies, and $229,460 to dependent special districts of the County. It would also result in an annual loss of discretionary funds to the County of $455,600. These losses are not expected to affect currently funded governmental services, except for natural decreases in services required for oil and gas activity. The County's discretionary funds are projected to increase over the next few years in the County, as new residential and commercial development occurs and as property values increase (although property tax revenue from increased property values is limited by California law). The County Administrator's Office projects discretionary funds to increase from $105.6 million in fiscal year 1998-99 to $126 million in fiscal year 2002-2003. The reduction in property taxes received from the oil and gas sector could reduce this projection slightly, and could partially offset additional revenue growth to the year 2010. These tax revenue losses would not result in the projection of a net decrease in total revenues in any future year, however.

A.4.3 San Luis Obispo County

Figure A.4-3 provides the recent record of revenues for San Luis Obispo County. The individual sources are intergovernmental transfers (based in part on income taxes), property taxes, sales taxes, and other taxes, and charges for services. Local taxes as a revenue source has remained stable while that of intergovernmental transfers has steadily increased over the past fifteen years. In addition to property tax revenue retained by the County, property taxes collected by the County are apportioned to cities and special public service districts in the area where the property is located.

Facilities related to the oil and gas industry contribute toward property tax revenues. In San Luis Obispo County, property taxes in total account for 25 percent of County revenues in 1994 (California State Office of the Controller, 1993-94). Property taxes on the Santa Maria Refinery, Chemicals Facility, and pipeline system total approximately $2.4 million. These facilities are expected to remain in operation throughout the COOGER study period. The County's three largest employers qualify for full or partial property tax exemptions under provisions for government and non-profit organizations. Thus, none of the top three employers in San Luis Obispo appear as significant contributors toward property tax revenues.

A.5 AIR QUALITY METHODOLOGY AND FACILITY EMISSIONS DATA

The analysis of air quality constraints associated with onshore facilities required to support offshore oil and gas operations was accomplished by review of available documents addressing local air quality, agency regulations, and facility operations. The data collection effort involved a review of current Clean Air Plans prepared by the counties of Ventura, Santa Barbara, and San Luis Obispo, as well as agency-compiled documentation of regional emissions inventories, local air quality and meteorological data, agency emissions control regulations, and industry permit files. Design and operating data concerning specific facilities addressed in this study were compiled from a combination of industry facility records and agency files. Professional contacts with agency and industry personnel were used to supplement our review of applicable air quality control regulations, future air quality planning emissions assumptions, and facility operations.

The estimation of future baseline emissions from oil and gas facilities associated with offshore oil and gas production is an important component of the analysis of air quality-related constraints. To develop these estimates, the current actual and agency-permitted emissions of each facility were first determined. Because oil production rates in the year 2000 and beyond are projected to decline from current levels from all facilities in the future baseline, the lesser of the two emissions estimates (actual or agency-permitted emissions) was used to estimate the emissions from each facility for each year that facility is expected to operate. In the future baseline case, it is assumed that no new development of currently undeveloped oil and gas reserves will occur. This scenario also assumes that onshore facilities will cease operations during the same year that the last offshore production facility which provides input to that facility reaches its economic limit. Because declining emissions associated with reduced throughput at each facility cannot be accurately determined with the information available, no attempt has been made to reduce individual facility emissions rates to reflect reduced throughput prior to facility shut-down. In addition, several operators of offshore facilities noted that individual operations sometimes continue beyond their calculated economic limit. To address this, each individual facility's emissions were included in the total annual emissions in each five-year incremental projection if that facility is expected to operate at any time during that period. In other words, any facility which is expected to be operational between January 1, 2001 and December 31, 2005 would be included in the year 2005 predicted emissions. If that same facility is expected to cease operations on or before December 31, 2005, it would not be included in the predicted emissions for the year 2010.

In the process of completing the COOGER study, the Steering Committee determined that evaluation of air pollutant emissions associated with each scenario would not be conducted as part of the COOGER study. Detailed modeling of future development will be accomplished through project-specific permitting processes in a manner far more comprehensive than can be accomplished in the COOGER study. This appendix presents background information concerning air pollutant emissions and emission reduction credits that may be useful to provide a context for the evaluation of individual projects. Table A.5-1 presents the current attainment status of each county in the COOGER study region. Existing County-wide emissions inventories are presented in Tables A.5-2, A.5-3, and A.5-4. Emissions associated with specific offshore oil and gas facilities and projected future emissions associated with the future baseline (no new development) scenario are presented in Tables A.5-5 through A.5-10. Listings of active emission reduction credits filed by the Air Pollution Control Districts in each county are presented in Tables A.5-11, A.5-12, and A.5-13.

Table A.5-1

Attainment Status
(As Of January, 1999)

County	CO		NO_x		Ozone		PM_{10}		SO_x	
	California	**Federal**	**California**	**Federal**	**California**	**Federal**	**California**	**Federal**	**California**	**Federal**
Ventura	Attainment	Attainment	Attainment	Attainment	Non-Attainment	Non-Attainment	Non-Attainment	Attainment	Attainment	Attainment
Santa Barbara	Attainment	Attainment	Attainment	Attainment	Non-Attainment	Non-Attainment	Non-Attainment	Attainment	Attainment	Attainment
San Luis Obispo	Attainment	Attainment	Attainment	Attainment	Non-Attainment	Attainment	Non-Attainment	Attainment	Attainment	Attainment

California - Relative to California Clean Air Act Standards

Federal - Relative to Federal Clean Air Act Standards - attainment/nonattainment status has not been determined for the new 8-hour O_3 standard or the 24-hour and annual $PM_{2.5}$ standard.

Table A.5-2
1995 County-Wide Emissions Inventory
Ventura County[1]

Source Category	Emissions (Tons per Year)				
	ROC	CO	NO_x	SO_x	PM_{10}
Stationary Sources					
Oil and Gas Related Fuel Combustion	73	1,533	548	--	--
Petroleum Production and Marketing	2,701	--	--	--	--
Other Stationary Source Fuel Combustion	73	2,847	2,263	146	183
Waste Disposal	73	37	--	--	--
Cleaning and Surface Coatings	2,117	--	--	--	37
Industrial Processes (non-petroleum)	110	37	--	37	256
TOTAL STATIONARY SOURCES	5,147	4,454	2,811	183	476
Area Sources					
Solvent Evaporation	4,745	--	--	--	--
Miscellaneous	1,350	10,950	730	--	7,665
TOTAL AREA SOURCES	6,095	10,950	730	--	7,665
Mobile Sources					
On-road Motor Vehicles	12,410	116,800	14,600	365	475
Other Mobile Sources	1,643	14,965	3,650	475	219
TOTAL MOBILE SOURCES	14,053	131,765	18,250	840	694
Natural (Non-Anthropogenic) Sources					
TOTAL NATURAL SOURCES	1,424	110	--	--	--
TOTAL COUNTY EMISSIONS	26,719	147,279	21,791	1,023	8,835

[1] Source: California Air Resources Board, 1998

Total emissions per year were determined by multiplying average daily emissions by a factor of 365.

Table A.5-3
1995 County-Wide Emissions Inventory
Santa Barbara County[1]

Source Category	Emissions (Tons per Year)				
	ROC	CO	NO_x	SO_x	PM_{10}
ONSHORE SOURCES					
Stationary Sources					
Oil and Gas Related Fuel Combustion	350.28	1,111.62	1,142.95	43.06	47.42
Petroleum Production and Marketing	1,886.77	103.55	49.38	5.62	12.04
Other Stationary Source Fuel Combustion	39.84	189.75	463.56	63.01	26.37
Waste Disposal	367.21	0.33	0.57	--	--
Cleaning and Surface Coatings	1,532.04	--	--	--	--
Industrial Processes (non-petroleum)	49.34	30.91	0.01	467.07	185.75
TOTAL STATIONARY SOURCES	4,225.48	1,436.16	1,656.47	578.76	271.58
Area Sources					
Solvent Evaporation	3,624.79	--	--	--	0.10
Miscellaneous	512.36	5,863.01	380.62	8.19	19,066.68
TOTAL AREA SOURCES	4,137.15	5,863.01	380.62	8.19	19,066.78
Mobile Sources					
On-road Motor Vehicles	6,752.97	65,484.65	8,668.75	208.05	261.58
Other Mobile Sources	951.31	10,121.74	3,455.44	178.95	173.72
TOTAL MOBILE SOURCES	7,704.28	75,606.39	12,124.19	387.00	435.30
Natural (Non-Anthropogenic) Sources					
TOTAL NATURAL SOURCES	32,279.09	1,359.10	904.20	--	193.25
TOTAL ONSHORE EMISSIONS	48,346.00	84,264.66	15,065.48	973.95	19,966.90
OFFSHORE SOURCES					
Stationary Sources					
Oil and Gas Related Fuel Combustion	27.51	166.04	305.68	14.51	13.47
Petroleum Production and Marketing	408.81	58.70	10.75	91.58	3.14
Cleaning and Surface Coatings	34.17	--	--	--	--
Industrial Processes (non-petroleum)	--	--	--	--	0.75
TOTAL STATIONARY SOURCES	470.49	224.74	316.43	106.09	17.36
Mobile Sources					
TOTAL MOBILE SOURCES	476.14	1,267.23	7,614.32	5,259.42	617.18
Natural (Non-Anthropogenic) Sources					
TOTAL NATURAL SOURCES	648.44	--	--	--	--
TOTAL OFFSHORE EMISSIONS	1,595.07	1,491.97	7,930.75	5,365.51	634.54
TOTAL COUNTY EMISSIONS	**49,941.07**	**85,756.63**	**22,996.23**	**6,339.46**	**20,601.44**

[1] Source: Santa Barbara County Air Pollution Control District, 1997.

Table A.5-4
1995 County-Wide Emissions Inventory
San Luis Obispo County[1]

Source Category	Emissions (Tons per Year)				
	ROC	**CO**	**NO_x**	**SO_x**	**PM_{10}**
Stationary Sources					
Oil and Gas Related Fuel Combustion	37	73	256	37	--
Petroleum Production and Marketing	986	--	73	4,015	146
Other Stationary Source Fuel Combustion	37	329	1,059	767	73
Waste Disposal	--	--	--	--	--
Cleaning and Surface Coatings	1,314	--	--	--	--
Industrial Processes (non-petroleum)	73	--	--	--	146
TOTAL STATIONARY SOURCES	1,461	402	1,388	4,819	365
Area Sources					
Solvent Evaporation	1,643	--	--	--	--
Miscellaneous	1,168	14,235	256	--	9,490
TOTAL AREA SOURCES	2,811	14,235	256	--	9,490
Mobile Sources					
On-road Motor Vehicles	4,380	47,450	6,935	183	219
Other Mobile Sources	1,205	9,855	3,650	146	219
TOTAL MOBILE SOURCES	5,505	57,305	10,585	329	438
Natural (Non-Anthropogenic) Sources					
TOTAL NATURAL SOURCES	438	8,030	110	--	1,132
TOTAL COUNTY EMISSIONS	10,215	79,972	12,339	5,148	11,425

[1] Source: California Air Resources Board, 1998

Total emissions per year were determined by multiplying average daily emissions by a factor of 365.

Table A.5-5

1995 Oil and Gas Facility Emission Inventory—Eastern Subregion

FACILITY NAME	1995 Actual Emissions (TPY)				1997 Permitted Emissions (TPY)			
	ROC	NOx	SOx	PM_{10}	ROC	NOx	SOx	PM_{10}
Primary Facilities								
Ventura County								
Mandalay Onshore Separation Facility	0.10	2.10	neg[(1)]	0.10	8.35	7.00	0.09	0.43
West Montlavo Operations	6.30	2.10	neg	neg	20.08	1.44	0.02	0.12
Rincon Island Oil & Gas Processing Facility	6.60	neg	neg	neg	34.47	0.15	0.00	0.02
State Lease 145/410 Oil & Gas Processing Facility								
Rincon Oil & Gas Processing Facility	10.60	17.20	0.10	2.40	13.08	21.61	0.15	3.19
La Conchita Oil & Gas Processing Facility	10.50	8.20	neg	0.50	8.96	6.33	0.07	0.81
Santa Barbara County								
Carpinteria Oil & Gas Processing Facility	82.39	12.82	0.94	0.59	148.72	80.92	3.48	3.94
Carpinteria Onshore Gas Terminal	0.76	0.00	0.00	0.00	4.27	0.00	0.00	0.00
Secondary Facilities								
Ventura County								
Ventura Marine Terminal[(2)]	-	-	-	-	-	-	-	-
Ventura Pump Station	1.80	0.10	neg	0.10	4.80	24.60	1.57	1.81
Santa Paula Pump Station	0.60	neg	neg	neg	3.11	0.00	0.00	0.00
Torrey Pump Station	1.50	0.10	neg	neg	3.73	4.02	0.03	0.43
Vintage Petroleum Onshore Compressor Facility	133.80	42.20	0.10	2.30	230.55	82.60	1.00	4.32
Venoco Rincon Storage Tank	neg	neg	neg	neg	1.69	0.00	0.00	0.00
Platforms								
Ventura County								
Gina	78.00	1.90	0.20	0.10	9.53	24.34	0.32	1.46
Gilda	87.20	5.50	0.20	0.30	41.85	83.87	1.11	4.98
Gail	126.60	78.80	2.00	6.50	34.02	86.22	2.32	10.04
Grace	147.40	31.90	0.20	1.60	24.85	129.02	2.77	6.39

Table A.5-5 (Continued)

FACILITY NAME	1995 Actual Emissions (TPY)				1997 Permitted Emissions (TPY)			
	ROC	NOx	SOx	PM_{10}	ROC	NOx	SOx	PM_{10}
Santa Barbara County								
Henry	18.59	17.36	1.66	1.64	39.37	113.56	9.00	10.13
Hillhouse	34.51	11.42	1.14	1.03	58.65	112.06	9.22	10.07
A	33.62	8.68	0.83	0.85	56.06	112.80	9.62	10.29
B	32.81	8.17	0.74	0.80	64.72	112.91	9.68	10.33
C	23.25	4.30	0.45	0.42	43.71	111.86	9.11	10.01
Hogan	5.65	4.17	0.81	0.47	11.05	48.25	7.30	4.20
Houchin	8.47	4.18	0.83	0.45	12.12	48.25	7.30	4.20
Habitat	19.92	33.80	1.92	2.67	31.90	99.35	19.51	15.08
Total	870.97	295.00	12.12	22.82	909.64	1311.16	93.67	112.25

Sources: Ventura County Air Pollution Control District (1997), and Santa Barbara County Air Pollution Control District (1997a)

[1] neg = negligible

[2] This facility has been dismantled.

Table A.5-6

Future Baseline Oil and Gas Facility Emission Inventory[1]

Eastern Subregion

Facility Name	2000 Predicted Emissions (TPY)				2005 Predicted Emissions (TPY)				2010 Predicted Emissions (TPY)				2015 Predicted Emissions (TPY)			
	ROC	NOx	SOx	PM_{10}	ROC	NOx	SOx	PM_{10}	ROC	NOx	SOx	PM_{10}	ROC	NOx	SOx	PM_{10}
Primary Facilities																
Ventura County																
Mandalay Onshore Separation Facility	0.10	2.10	neg	0.10	0	0	0	0	0	0	0	0	0	0	0	0
West Montalvo Operations	6.30	2.10	neg	neg	6.30	2.10	neg	neg	0	0	0	0	0	0	0	0
Rincon Island Oil & Gas Processing Facility and State Lease 145/410 Oil & Gas Processing Facility	6.60	neg	neg	neg	6.60	neg	neg	neg	0	0	0	0	0	0	0	0
Rincon Oil & Gas Processing Facility	10.60	17.20	0.10	2.40	10.60	17.20	0.10	2.40	0	0	0	0	0	0	0	0
La Conchita Oil & Gas Processing Facility	8.96	6.33	0.07	0.81	0	0	0	0	0	0	0	0	0	0	0	0
Santa Barbara County																
Carpinteria Oil & Gas Processing Facility	82.39	12.82	0.94	0.59	82.39	12.82	0.94	0.59	0	0	0	0	0	0	0	0
Carpinteria Onshore Gas Terminal	0.76	0.00	0.00	0.00	0	0	0	0	0	0	0	0	0	0	0	0
Secondary Facilities																
Ventura County																
Ventura Marine Terminal[2]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ventura Pump Station	1.80	0.10	neg	0.10	1.80	0.10	neg	0.10	1.80	0.10	neg	0.10	1.80	0.10	neg	0.10
Santa Paula Pump Station	0.60	neg	neg	neg	0.60	neg	neg	neg	0.60	neg	neg	neg	0.60	neg	neg	neg
Torrey Pump Station	1.50	0.10	neg	neg	1.50	0.10	neg	neg	1.50	0.10	neg	neg	1.50	0.10	neg	neg
Vintage Petroleum Onshore Compressor Facility	133.80	42.20	0.10	2.30	133.80	42.20	0.10	2.30	0	0	0	0	0	0	0	0
Venoco Rincon Storage Tank	neg	neg	neg	neg	neg	neg	neg	neg	0	0	0	0	0	0	0	0

Table A.5-6 (Continued)

Facility Name	2000 Predicted Emissions (TPY)				2005 Predicted Emissions (TPY)				2010 Predicted Emissions (TPY)				2015 Predicted Emissions (TPY)			
	ROC	NOx	SOx	PM_{10}	ROC	NOx	SOx	PM_{10}	ROC	NOx	SOx	PM_{10}	ROC	NOx	SOx	PM_{10}
Platforms																
Ventura County																
Gina	78.00	1.90	0.20	0.10	0	0	0	0	0	0	0	0	0	0	0	0
Gilda	87.20	5.50	0.20	0.30	0	0	0	0	0	0	0	0	0	0	0	0
Gail	34.02	86.22	2.32	10.04	34.02	86.22	2.32	10.04	0	0	0	0	0	0	0	0
Grace	24.85	129.02	2.77	6.39	24.85	129.02	2.77	6.39	0	0	0	0	0	0	0	0
Santa Barbara County																
Henry	18.59	17.36	1.66	1.64	0	0	0	0	0	0	0	0	0	0	0	0
Hillhouse	34.51	11.42	1.14	1.03	0	0	0	0	0	0	0	0	0	0	0	0
A	33.62	8.68	0.83	0.85	33.62	8.68	0.83	0.85	0	0	0	0	0	0	0	0
B	32.81	8.17	0.74	0.80	0	0	0	0	0	0	0	0	0	0	0	0
C	23.25	4.30	0.45	0.42	0	0	0	0	0	0	0	0	0	0	0	0
Hogan	5.56	4.17	0.81	0.47	0	0	0	0	0	0	0	0	0	0	0	0
Houchin	8.47	4.18	0.83	0.45	0	0	0	0	0	0	0	0	0	0	0	0
Habitat	19.92	33.80	1.92	2.67	0	0	0	0	0	0	0	0	0	0	0	0
Total	654.30	397.67	15.08	31.46	336.46	298.44	7.06	22.67	3.90	0.20	0	0.10	3.90	0.20	0	0.10

[1]Predicted emissions were estimated based on 1995 actual emissions except La Conchita facility, Platform Gail and Platform Grace, which are based on 1995 permitted emissions. Platform Grace is not producing at present, but is still permitted at the indicated emission levels. Appendix A.5 describes the determination of table entries.

[2]This facility has been dismantled.

neg = negligible

Sources for actual and permitted 1995 emissions are Santa Barbara County Air Pollution Control District (1997a) and Ventura County Air Pollution Control District (1997).

Table A.5-7
1995 Oil and Gas Facility Emission Inventory
Central Subregion

Facility Name	Actual Emissions (TPY)*				Permitted Emissions (TPY)*			
	ROC	NOx	SOx	PM_{10}	ROC	NOx	SOx	PM_{10}
Primary Facilities								
Ellwood Oil & Gas Processing Facility	106.25	11.61	0.44	1.36	79.98	16.96	8.63	3.44
Las Flores Canyon SYU Gas Processing Facility	118.41	17.67	7.04	1.47	80.39	40.15	25.30	5.03
Las Flores Canyon SYU Oil & Gas Processing Facility	42.64	43.65	3.27	31.30	45.32	101.86	37.71	38.97
Gaviota Oil & Gas Processing Facility	148.28	22.16	0.21	9.06	154.91	83.74	22.51	25.49
Secondary Facilities								
Ellwood Marine Terminal	2.73	1.18	0.08	0.05	2.91	-	-	-
Gaviota Interim Marine Terminal	18.85	2.04	0.41	0.09	23.12	6.34	0.66	0.23
Cojo Marine Terminal	idle	idle	idle	idle				
AAPLP Gaviota Interim Marine Terminal Pump Station	0.26	neg	neg	neg	1.01	-	-	-
AAPLP Gaviota Pump Station	0.63	neg	neg	neg	0.56	-	-	-
Platforms								
Holly	25.20	9.02	0.63	0.38	44.09	138.32	13.84	7.94
Hondo	73.47	65.12	21.14	6.29	156.25	332.71	113.06	29.77
Harmony	40.73	51.14	19.71	5.45	118.48	339.28	124.83	30.95
Heritage	40.77	52.51	15.32	6.31	117.28	339.28	123.97	30.95
Hermosa	47.22	63.10	11.73	3.54	84.77	230.20	72.75	18.68
Harvest	59.67	130.66	31.09	3.54	72.57	295.58	44.57	9.75
Hidalgo	29.74	63.51	10.31	3.15	73.19	202.60	36.39	16.77
Total	754.85	533.37	121.38	71.99	1,054.83	2,127.02	624.22	218.03

Source: Santa Barbara Air Pollution Control District (1997a)

neg = negligible
* Changes made in 1997 to the operating permits for some facilities reduced their allowable emissions below 1995 actual emission levels.

Table A.5-8
Future Baseline Oil & Gas Facility Emission Inventory[1]
Central Subregion

Facility Name	2000 Predicted Emissions (TPY)				2005 Predicted Emissions (TPY)				2010 Predicted Emissions (TPY)				2015 Predicted Emissions (TPY)			
	ROC	NOx	SOx	PM_{10}	ROC	NOx	SOx	PM_{10}	ROC	NOx	SOx	PM_{10}	ROC	NOx	SOx	PM_{10}
Primary Facilities																
Ellwood Oil & Gas Processing Facility	79.98	16.96	8.63	3.44	79.98	16.96	8.63	3.44	79.98	16.96	8.63	3.44	0	0	0	0
Las Flores Canyon SYU Gas Processing Facility	80.39	40.15	25.30	5.09	80.39	40.15	25.30	5.09	80.39	40.15	25.30	5.09	80.39	40.15	25.30	5.09
Las Flores Canyon SYU Oil & Gas Processing Facility	42.64	43.65	3.27	31.30	42.64	43.65	3.27	31.30	42.64	43.65	3.27	31.30	42.64	43.65	3.27	31.30
Gaviota Oil & Gas Processing Facility	148.28	22.16	0.21	9.06	148.28	22.16	0.21	9.06	0	0	0	0	0	0	0	0
Secondary Facilities																
Ellwood Marine Terminal	2.73	1.18	0.08	0.05	2.73	1.18	0.08	0.05	2.73	1.18	0.08	0.05	0	0	0	0
Gaviota Oil Terminal	18.85	2.04	0.41	0.09	18.85	2.04	0.41	0.09	0	0	0	0	0	0	0	0
Cojo Marine Terminal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AAPLP Gaviota Interim Marine Terminal Pump Station	neg	neg	neg	neg	0	0	0	0	0	0	0	0	0	0	0	0
AAPLP Gaviota Pump Station	neg	neg	neg	neg	neg	neg	neg	neg	0	0	0	0	0	0	0	0
Platforms																
Holly	25.20	9.02	0.63	0.38	25.20	9.02	0.63	0.38	25.20	9.02	0.63	0.38	0	0	0	0
Hondo	73.47	65.12	21.14	6.29	73.47	65.12	21.14	6.29	73.47	65.12	21.14	6.29	73.47	65.12	21.14	6.29
Harmony	40.73	51.14	19.71	5.45	40.73	51.14	19.71	5.45	40.73	51.14	19.71	5.45	40.73	51.14	19.71	5.45
Heritage	40.77	52.51	15.32	6.31	40.77	52.51	15.32	6.31	40.77	52.51	15.32	6.31	40.77	52.51	15.32	6.31
Hermosa	47.22	63.10	11.73	3.54	47.22	63.10	11.37	3.54	0	0	0	0	0	0	0	0
Harvest	59.57	130.66	31.09	3.54	59.67	130.66	31.09	3.54	0	0	0	0	0	0	0	0
Hidalgo	29.74	63.51	10.31	3.15	29.74	63.51	10.31	3.15	0	0	0	0	0	0	0	0
Total	689.57	561.20	147.83	77.69	670.82	559.16	147.06	77.60	385.91	279.73	94.08	58.31	278.00	252.57	84.74	54.44

[1] Predicted emissions were estimated based on 1995 actual emissions and the future facility operation projections, with the exception of the Ellwood facility and Las Flores Canyon Facilities which were reported based on permitted emissions. Appendix A.5 describes the determination of table entries.
neg. = negligible
Source for actual and permitted 1995 emissions is Santa Barbara County Air Pollution Control District (1997a)

Table A.5-9
1995 Oil and Gas Facility Emission Inventory[1]
Northern Subregion

Facility Name	Actual Emissions (TPY)				Permitted Emissions (TPY)			
	ROC	NOx	SOx	PM_{10}	ROC	NOx	SOx	PM_{10}
Primary Facility								
Santa Barbara County								
Lompoc HS&P Facility	93.94	2.93	1.34	0.29	63.97	71.96	13.32	7.21
Secondary Facility								
Santa Barbara County								
Sisquoc Pump Station	0.40	neg	neg	neg	0.51	-	-	-
Santa Maria Pump Station	3.32	0.00	0.00	0.00	4.44	2.26	1.24	1.28
Orcutt Pump Station	2.91	0.03	0.00	0.03	4.31	1.67	0.60	0.64
Santa Maria Asphalt Refinery	20.35	13.06	12.69	1.30	57.78	23.57	64.59	7.00
San Luis Obispo County								
Summit Pump Station[2]	neg	neg	neg	neg	-	-	-	-
Santa Maria Refinery	146.73	94.85	74.14	11.60	146.73	94.85	74.14	11.60
Platform								
Santa Barbara County								
Irene	29.09	22.23	2.25	2.01	31.91	62.83	10.74	5.85
Total	276.74	133.1	90.42	15.23	309.65	257.14	164.63	33.58

[1] Sources: Santa Barbara County Air Pollution Control District (1997a) and San Luis Obispo County air Pollution Control District (1997)
neg = negligible
a. 1995 Actual Emissions Estimates for Selected Facilities (SLOCAPCD 1997)
b. 1995 Point Source Emission Summary Report (SBCAPCD 1997)
c. Oil Gas Facility Permitted Emissions (SBCAPCD 1997)

[2] San Luis Obispo County does not have emission limits on the facilities but regulates maximum emissions on the basis of process throughput limits.

Table A.5-10
Future Baseline Oil and Gas Facility Emission Inventory[1]
Northern Subregion

Facility Name	2000 Predicted Emissions (TPY)				2005 Predicted Emissions (TPY)				2010 Predicted Emissions (TPY)				2015 Predicted Emissions (TPY)			
	ROC	NOx	SOx	PM_{10}	ROC	NOx	SOx	PM_{10}	ROC	NOx	SOx	PM_{10}	ROC	NOx	SOx	PM_{10}
Primary Facility																
Santa Barbara County																
Lompoc HS&P Facility	63.97	71.96	13.32	70.21	63.97	71.96	13.32	7.21	0	0	0	0	0	0	0	0
Secondary Facilities																
Santa Barbara County																
AAPLP Sisquoc Pump Station	neg	neg	neg	neg	neg	neg	neg	neg	neg	neg	neg	neg	neg	neg	neg	neg
Santa Maria Pump Station	3.32	0	0	0	3.32	0	0	0	3.32	0	0	0	3.32	0	0	0
Orcutt Pump Station	2.91	0.03	0	0	2.91	0.03	0	0	0	0	0	0	0	0	0	0
Santa Maria Asphalt Refinery	20.35	13.06	12.69	1.30	20.35	13.06	12.69	1.30	20.35	13.06	12.69	1.30	20.35	13.06	12.69	1.30
San Luis Obispo County																
Summit Pump Station	neg	neg	neg	neg	neg	neg	neg	neg	neg	neg	neg	neg	neg	neg	neg	neg
Santa Maria Refinery	146.73	94.85	74.14	11.60	146.73	94.85	74.14	11.60	146.73	94.85	74.14	11.60	146.73	94.85	74.14	11.60
Platform																
Santa Barbara County																
Irene	29.09	22.23	2.25	2.01	29.09	22.23	2.25	2.01	0	0	0	0	0	0	0	0
Total	266.37	202.13	102.4	17.93	271.77	202.13	102.40	22.12	170.40	107.91	86.83	12.90	107.40	107.91	86.83	12.90

[1]Predicted emissions were estimated based on 1995 actual emissions (except at Lompoc HS&P facility) and the future facility operation projections. Lompoc HS&P Facility projections are based on permitted emissions. Appendix A.5 describes the determination of table entries.
neg = negligible
Sources for actual and permitted 1995 emissions are Santa Barbara County Air Pollution Control District (1997a) and San Luis Obispo County Air Pollution Control District (1997)

Table A.5-11
Customer List - ERCs by Company

Company Name	Area of County	ERC	ROC	NOx	PM_{10}	SOx	Limit*	Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
Aera Energy LLC	Ventura (Ojai)	1063	4.11	0.00	0.12	0.01	U	25%	25%	25%	25%
Aera Energy LLC	Ventura (Ojai)	1053	0.02	0.00	0.01	0.00		25%	25%	25%	25%
Aera Energy LLC	Ventura (Ojai)	1050	2.05	0.00	0.00	0.00	U	25%	25%	25%	25%
Aera Energy LLC	Ventura (Ojai)	1129	0.85	0.00	0.17	0.03	U	25%	25%	25%	25%
Aera Energy LLC	Ventura (Ojai)	1058	0.10	0.00	0.02	0.00	U	25%	25%	25%	25%
Aera Energy LLC	Ventura (Ojai)	1128	0.00	0.00	0.00	0.01	U	25%	25%	25%	25%
Aera Energy LLC	Ventura (Ojai)	1059	0.31	0.00	0.16	0.01	U	25%	25%	25%	25%
Aera Energy LLC	Ventura (Ojai)	1062	0.87	0.00	0.32	0.03	U	25%	25%	25%	25%
Aera Energy LLC	Ventura (Ojai)	1087	0.03	0.00	0.00	0.00	U	25%	25%	25%	25%
Aera Energy LLC	Ventura (Ojai)	1127	355.00	0.00	0.00	0.00	U	25%	25%	25%	25%
Aera Energy LLC	Ventura (Ojai)	1130	0.00	0.00	0.00	0.30	U	25%	25%	25%	25%
Aera Energy LLC	Ventura (Ojai)	1036	0.00	0.00	0.44	0.04		25%	25%	25%	25%
Aera Energy LLC	Santa Paula	1038	1.33	3.34	0.45	0.01	U	25%	25%	25%	25%
Amgen Inc.	Camarillo	1101	0.00	8.70	0.00	0.00		25%	25%	25%	25%
Amgen Inc.	Thousand Oaks	1141	0.11	0.13	0.07	0.01	U	23%	23%	25%	29%
Berry Petroleum Co.	Oxnard	1037	6.85	0.00	0.00	0.00	U	25%	25%	25%	25%
Boeing N.American - Rocket	Santa Paula	1119	0.54	0.76	0.00	0.00		25%	25%	25%	25%
Boeing N.American - Rocket	Simi Valley	1035	0.00	0.00	0.12	0.47	U	25%	25%	25%	25%
Boeing N.American - Rocket	Simi Valley	1148	0.24	2.44	0.49	0.10	U	0%	25%	64%	11%
Chevron USA Production Co.	Oxnard	1027	1.01	1.75	0.18	0.01	U	25%	25%	25%	25%
Chevron USA Production Co.	Oxnard	1025	0.16	1.61	0.05	0.01	U	25%	25%	25%	25%
Chevron USA Production Co.	Oxnard	1026	26.13	2.40	0.30	0.03	U	25%	25%	25%	25%
Chevron USA Production Co.	Oxnard	1029	0.03	0.00	0.00	0.00	U	25%	25%	25%	25%
Chevron USA Production Co.	Oxnard	1002	0.47	0.08	0.04	0.00		25%	25%	25%	25%
Chevron USA Production Co.	Oxnard	1001	0.11	0.00	0.01	0.00		25%	25%	25%	25%
Chevron USA Production Co.	Oxnard	1028	0.38	0.00	0.00	0.00	U	25%	25%	25%	25%
Chevron USA Production Co.	OCS Area	1139	0.39	0.00	0.13	0.01	U	25%	25%	25%	25%
Compositair	Camarillo	1072	0.00	0.06	0.00	0.00		25%	25%	25%	25%
Cook Composites & Polymer	Oxnard	1126	0.68	0.00	0.00	0.00	U	25%	25%	25%	25%

Table A.5-11 (Continued)

Company Name	Area of County	ERC	ROC	NOx	PM_{10}	SOx	Limit*	Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
Everest & Jennings Inc.	Camarillo	1096	0.54	0.51	0.03	0.01	U	25%	25%	25%	25%
Freight Container Corporation	Oxnard	1116	5.44	0.06	0.00	0.00	U	25%	25%	25%	25%
Gilroy Foods Inc.	Oxnard	1020	0.00	0.09	0.01	0.00	U	25%	25%	25%	25%
Granite Construction Co.	Santa Paula	1100	0.03	0.47	0.76	0.01	U	27%	30%	18%	25%
Halaco Engineering Co.	Oxnard	1124	0.64	0.00	3.44	0.02	U	25%	25%	25%	25%
Hunter Resources Development	Fillmore	1125	0.09	0.01	0.01	0.00		25%	25%	25%	25%
Hunter Resources Development	Fillmore	1013	0.61	6.39	0.00	0.00		25%	25%	25%	25%
Kaiser Aluminum & Chemical	Camarillo	1150	0.00	0.24	0.00	0.00		25%	25%	25%	25%
KTI Engineers & Constructors	Port Hueneme	1034	0.00	0.00	1.50	0.00	U	25%	25%	25%	25%
Mobil Exp & Producing US I	Ventura (Ojai)	1064	0.34	0.00	0.00	0.00	U	25%	25%	25%	25%
Naval Air Weapons Station	Oxnard	1112	2.39	0.00	0.00	0.00		25%	25%	25%	25%
Naval Air Weapons Station	Oxnard	1113	0.00	0.07	0.00	0.04		25%	25%	25%	25%
Naval Air Weapons Station	Oxnard	1114	0.00	0.00	0.12	0.00	U	25%	25%	25%	25%
Naval Air Weapons Station	Oxnard	1108	0.01	0.06	0.00	0.00	U	25%	25%	25%	25%
Naval Air Weapons Station	OCS Area	1110	0.44	0.00	0.00	0.00		25%	25%	25%	25%
Nestle Food Company	Oxnard	1137	0.11	1.54	0.12	0.02	U	11%	12%	57%	20%
Northrop Grumman Corp.	Thousand Oaks	1046	0.00	0.00	0.01	0.01	U	25%	25%	25%	25%
Northrop Grumman Corp.	Thousand Oaks	1024	5.98	0.00	0.00	0.00	U	25%	25%	25%	25%
Northrop Grumman Corp.	Thousand Oaks	1146	3.50	0.01	0.00	0.00	U	25%	25%	25%	25%
Nuevo Energy Company	Ojai	1018	0.03	2.22	0.18	0.02	U	25%	25%	25%	25%
Nuevo Energy Company	Ojai	1019	0.28	0.00	0.00	0.00	U	25%	25%	25%	25%
Nuevo Energy Company	Fillmore	1017	0.35	22.37	0.09	0.01	U	25%	25%	25%	25%
Nuevo Energy Company	Fillmore	1149	1.67	0.00	0.00	0.00		25%	25%	25%	25%
Nuevo Energy Company	Piru	1031	0.01	16.50	0.05	0.00	U	25%	25%	25%	25%
Nuevo Energy Company	Camarillo	1007	0.25	0.00	0.00	0.00	U	25%	25%	25%	25%
Nuevo Energy Company	Simi Valley	1088	0.01	0.06	0.00	0.00	U	25%	25%	25%	25%
Nuevo Energy Company	Simi Valley	1070	0.16	0.00	0.00	0.00	U	25%	25%	25%	25%
Occidental Chemical Corp.	Oxnard	1131	0.07	3.79	1.33	0.02	U	25%	25%	25%	25%
Orxy Energy Company	Oxnard	1030	2.48	0.00	0.00	0.00		25%	25%	25%	25%
Oxnard Lemon Company	Oxnard	1152	0.00	0.10	0.00	0.00	U	25%	25%	25%	25%

Table A.5-11 (Continued)

Company Name	Area of County	ERC	ROC	NOx	PM_{10}	SOx	Limit*	Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
Pacific Custom Materials Inc.	North Zone	1151	0.00	0.00	0.60	0.00		25%	25%	25%	25%
Pacific Operators Offshore Inc.	Ventura (Ojai)	1075	0.00	14.88	0.00	0.00		25%	25%	25%	25%
Pacific Operators Offshore Inc.	Ventura (Ojai)	1093	0.30	0.89	0.09	0.02		25%	25%	25%	25%
Proctor & Gamble Paper Prod.	Oxnard	1134	0.00	0.00	2.81	0.00		25%	25%	25%	25%
Proctor & Gamble Paper Prod.	Camarillo	1081	45.84	0.00	0.00	0.00		25%	25%	25%	25%
Reichhold Chemicals Inc.	Santa Paula	1136	0.00	0.10	0.00	0.00		25%	25%	25%	25%
Santa Fe Energy Operating Pr	Fillmore	1076	0.01	0.00	0.00	0.00	U	25%	25%	25%	25%
Santa Fe Minerals Inc.	Fillmore	1009	0.55	0.00	0.00	0.00	U	25%	25%	25%	25%
Seneca Resources Corp.	Ojai	1142	2.65	0.64	0.00	0.00		25%	25%	25%	25%
Seneca Resources Corp.	Ventura (Ojai)	1138	0.00	0.31	0.00	0.00		25%	25%	25%	25%
Seneca Resources Corp.	North Zone	1132	0.06	0.02	0.00	0.00		25%	25%	25%	25%
Seneca Resources Corp.	North Zone	1135	0.03	0.00	0.00	0.00	U	25%	25%	25%	25%
Shell Pipe Line Corporation	Camarillo	1006	7.15	0.00	0.00	0.00		25%	25%	25%	25%
Siemens Solar Industries	Ventura (Ojai)	1153	3.00	0.00	0.00	0.00	U	25%	25%	25%	25%
Southern California Edison	Ojai	1094	5.47	5.57	0.00	0.02		25%	25%	25%	25%
Southern California Edison	Ventura (Ojai)	1091	20.67	0.00	0.00	0.03		25%	25%	25%	25%
Southern California Edison	Ventura (Ojai)	1097	14.37	0.38	0.00	0.03		25%	25%	25%	25%
Southern California Edison	Santa Paula	1078	0.00	3.66	0.00	0.02		25%	25%	25%	25%
Southern California Edison	Santa Paula	1083	0.00	0.22	0.00	0.01		25%	25%	25%	25%
Southern California Edison	Fillmore	1109	0.13	1.93	0.00	0.00		25%	25%	25%	25%
Southern California Edison	Fillmore	1085	0.00	0.42	0.00	0.00		25%	25%	25%	25%
Southern California Edison	Fillmore	1084	0.00	0.09	0.00	0.00		25%	25%	25%	25%
Southern California Edison	Fillmore	1080	0.71	0.17	0.00	0.00		25%	25%	25%	25%
Southern California Edison	Fillmore	1079	0.00	0.72	0.00	0.01		25%	25%	25%	25%
Southern California Edison	Camarillo	1092	0.00	78.24	0.22	0.03		25%	25%	25%	25%
Southern California Edison	North Zone	1107	3.96	3.20	0.00			25%	25%	25%	25%
Southern California Edison	North Zone	1104	3.90	2.66	0.00	0.01		25%	25%	25%	25%
Southern Pacific Milling Co.	Ventura (Ojai)	1090	0.00	0.00	0.89	0.00	U	25%	25%	25%	25%
St. John's/Pleasant Valley Ho	Oxnard	1089	0.00	0.18	0.00	0.00		25%	25%	25%	25%
Tenby Inc.	Oxnard	1022	10.82	0.00	0.00	0.00		25%	25%	25%	25%

Table A.5-11 (Continued)

Company Name	Area of County	ERC	ROC	NOx	PM_{10}	SOx	Limit*	Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
Tenby Inc.	Oxnard	1021	19.35	0.00	0.00	0.00		25%	25%	25%	25%
Texaco E and P Inc.	Ventura (Ojai)	1048	0.00	0.20	0.08	0.00	U	25%	25%	25%	25%
Texaco E and P Inc.	Ventura (Ojai)	1047	117.00	0.00	0.00	0.00	U	25%	25%	25%	25%
Texaco E and P Inc.	Ventura (Ojai)	1051	0.00	0.08	0.01	0.34	U	25%	25%	25%	25%
Texaco E and P Inc.	Ventura (Ojai)	1049	0.00	0.00	0.08	0.00	U	25%	25%	25%	25%
Texaco E and P Inc.	Fillmore	1082	0.44	1.67	0.09	0.03		25%	25%	25%	25%
Texaco E and P Inc.	Piru	1033	0.55	0.00	0.00	0.00	U	25%	25%	25%	25%
Texaco Refining and Marketing	Fillmore	1008	1.13	0.00	0.00	0.00	U	25%	25%	25%	25%
The Termo Company	Santa Paula	1102	0.02	0.00	0.00	0.00	U	25%	25%	25%	25%
U.S. Navy - NCBC	Port Hueneme	1121	0.00	0.00	3.90	0.00		25%	25%	25%	25%
U.S. Navy - NCBC	Port Hueneme	1154	0.14	1.24	0.10	0.06	U	40%	20%	14%	26%
U.S. Navy - NCBC	Port Hueneme	1144	0.40	3.29	0.06	0.02	U	45%	24%	15%	16%
U.S. Navy - NCBC	Camarillo	1140	0.00	0.15	0.00	0.00		25%	25%	25%	25%
Unocal	Santa Paula	1044	0.13	0.00	0.00	0.00	U	25%	25%	25%	25%
Unocal	Simi Valley	1145	4.32	0.00	0.00	0.00	U	25%	25%	25%	25%
Venoco, Inc.	Oxnard	1147	0.08	0.00	0.00	0.00		25%	25%	25%	25%
Vintage Petroleum Inc.	Ventura (Ojai)	1123	2.35	3.49	0.14	0.02	U	25%	25%	25%	25%
Vintage Petroleum Inc.	Ventura (Ojai)	1057	0.38	1.33	0.04	0.00	U	25%	25%	25%	25%
Vintage Petroleum Inc.	Ventura (Ojai)	1056	0.31	3.17	0.09	0.01		25%	25%	25%	25%
Vintage Petroleum Inc.	Ventura (Ojai)	1054	0.00	5.93	0.18	0.02	U	25%	25%	25%	25%
Vintage Petroleum Inc.	Santa Paula	1041	12.57	47.37	0.15	0.02	U	25%	25%	25%	25%
Vintage Petroleum Inc.	Santa Paula	1040	0.27	0.00	0.00	0.00	U	25%	25%	25%	25%
Vintage Petroleum Inc.	Santa Paula	1042	0.18	0.00	0.00	0.00		25%	25%	25%	25%
Vintage Petroleum Inc.	Santa Paula	1095	0.02	0.00	0.00	0.00		25%	25%	25%	25%
Vintage Petroleum Inc.	Fillmore	1115	0.54	0.85	0.05	0.00		25%	25%	25%	25%
Vintage Petroleum Inc.	Fillmore	1011	0.35	0.00	0.00	0.00	U	25%	25%	25%	25%
Vintage Petroleum Inc.	Fillmore	1010	0.24	0.00	0.00	0.00	U	25%	25%	25%	25%
Vintage Petroleum Inc.	Fillmore	1003	0.28	0.00	0.00	0.00	U	25%	25%	25%	25%

* The column labeled "Limit*" indicates whether a limitation has been placed on the use of the ERC (a check within the box lindicates that a limitation applies). The limitation only applies to ROC and NOx. (Rule 26.4.D.3)

Table A.5-12
List of All Active ERC Certificates
Santa Barbara County

Company Name	Contact	Phone #	Cert. No.	Zone	NOx	ROC	CO	SOx	PM	PM_{10}
US Air Force - VAFB	Lt. Col. S. Westfall	(805) 734-8232	0003-0902	North	32.80	0.43	8.78	3.50	8.23	4.21
Saba Petroleum	Mr. Mike Neuhauser	(805) 348-1244	0011-1103	North	2.27	7.83	2.62			
Grefco Minerals	Mr. Glenn P. Jones	(310) 517-0706	0010-1103	North	5.80	6.89	22.61	4.20	10.95	5.47
The Pt. Arguello Companies	Mr. S.G. Martindale	(805) 658-4339	0012-1103	South	0.09	0.01				
Nuevo Energy Company	Mr. Kevin Wright	(805) 739-9111	0008-1003	North	0.04	0.01	0.08			

Table A.5-13
Available Emission Reduction Credits
San Luis Obispo County

Company	Tons Per Year			
	ROC	**SOx (as SO_2)**	**PM_{10}**	**NOx**
Unocal Corporation	11.124	2.968	0.088	11.097
Unocal Corporation	0.074			2.399
Unocal Corporation				21.591
Union Asphalt Corporation		2.60		
Union Asphalt Corporation			1.47	
Total	**11.198**	**5.568**	**1.558**	**35.087**

A.6 TRANSPORT ACTIVITY CALCULATIONS AND DATA

A.6.1 Product Transport by Truck

At present, only one offshore development transports crude oil by truck within the COOGER study region. Other than that facility, the only products currently transported by truck are LPG and sulfur. Some potential future development scenarios in the Northern Subregion could also involve the truck transport of heavy products, including asphalt. The calculation of truck activity associated with each facility is described below, and results of these calculations are presented on Tables A.6-1 through A.6-12.

The calculation of sulfur truck traffic generated by each facility was determined based on the projected natural gas production rate and the expected H_2S concentration in the gas stream. The operators of the Ellwood, Las Flores Canyon and Lompoc Facilities were contacted to identify the quantity of sulfur produced at a given gas processing rate and H_2S concentration. The operators also identified the corresponding size and number of trucks needed to transport the sulfur and identified the typical locations where the sulfur was sent. At the time the data was collected, the Gaviota Facility was not processing gas; however, historic sulfur production information for the Gaviota Facility was obtained from Santa Barbara County Planning and Development and was used along with information that the sulfur producing equipment at the Gaviota Facility is similar in operation to the equipment at the Las Flores Canyon Facilities. This information was used to define a factor for each facility that allowed conversion of gas production and H_2S concentration projections to an estimated number of sulfur trucks per week for each facility. Estimates of sulfur production for the processing of Lion Rock gas are based on the factor developed for the Lompoc HS&P Facility giving consideration to the expected difference in H_2S concentration.

As with the sulfur truck activity described above, LPG truck activity was calculated based on known gas production and LPG truck activity at individual study region facilities. Existing LPG truck activity was used to define a factor based on known natural gas production rates that was then applied to future natural gas rates for each scenario. Estimates of LPG truck activity for potential future developments were based on factors derived from production at nearby fields for which data were available.

Crude oil truck traffic was calculated based on a standard tank truck volume (150 barrels) and actual data concerning current production rates and number of trucks. Because this transport represented a portion of a larger Eastern Subregion production operation, study projections assume that this truck activity will remain constant as long as the production operation continues, and changes in production levels will be reflected in changes in pipeline transport volume associated with that development.

Asphalt is not currently produced as an OCS crude oil product in the study region, but the production of heavy products, including asphalt, could be an important part of some scenarios in the Northern Subregion. Based on operator information, the crude oil from the northern Offshore Santa Maria Basin (such as the Lion Rock Unit), as produced, may not meet the acceptance criteria imposed by the operators of the Northern Pipeline System and/or All American Pipeline System and some processing of the crude may be necessary before transport by pipeline can be used. Based on preliminary information, the operator projects that after limited processing, approximately 60 percent of the total barrels produced could be acceptable for pipeline transport and 40 percent would be in the form of heavy products, including asphalt, that could be transported by truck or rail. This 60/40 split was used to project the volume of heavy product that would be produced The volume of heavy product produced can be transported in 140-barrel tank trucks or could be transported by rail as described below.

The distribution of product-related truck traffic on regional highways was estimated based on information from operators of existing facilities. Tables A.6-1 through A.6-12 indicate the principal highways used and the number of truck trips estimated to transport products, including all heavy products, out of the study region associated with each processing facility. This information was determined as follows:

- Eastern Subregion: The only product transport in the Eastern Subregion is associated with crude oil transport from the State Leases PRC 145/410 facilities. Product from these facilities is transported southbound on Highway 101 and continues eastbound on Highway 126 to Fillmore. This information was based on data provided by the facility operator.

- Central Subregion: Central Subregion facilities which generate product transport activity occur along Highway 101 from Gaviota to Ellwood. Product transport listed on Tables A.6-2 through A.6-5 indicates total traffic continuing northbound on Highway 101 past Gaviota, and traffic continuing southbound on Highway 101 past Ellwood. This information was based on data provided by facility operators and trucking companies involved in product transport.

- Northern Subregion: Projected Northern Subregion product transport leaves the COOGER study region by two principal routes: eastbound on Highway 166; and, southbound on Highway 101. Traffic destined for the eastbound Highway 166 route is expected to use Highway 101 locally, with the direction of travel depending on the location of the facility originating the traffic. The transport distribution for the existing Lompoc Oil & Gas Processing Facility indicated on Tables A.6-7 through A.6-12 was based on information provided by the current facility operator. The same distribution was assumed for potential future product transport of LPG and sulfur associated with Lion Rock Field production. No operator projections of heavy product transport distribution associated with Lion Rock Field production were available, and this distribution was assumed as two-thirds eastbound on Highway 166 and one-third southbound on Highway 101. Because the location of the facility associated with this production is not yet known, the direction of local heavy product truck traffic on Highway 101 to access Highway 166 cannot be accurately predicted at this time.

The truck traffic estimates in the tables described above assume that all of the heavy products produced from processing the Offshore Santa Maria Basin crude are transported by truck. The operator of the Santa Maria Asphalt Refinery indicated that heavy products, including asphalt, are typically transported in either 140-barrel tank trucks or in 20,000 gallon (476 barrel) rail tank cars. This information was used to estimate the number of trucks and an equivalent number of unit trains (based on 70 rail tank cars per unit train) that would be associated with the transport of heavy product produced from the processing of Offshore Santa Maria Basin crude. Using these capacities, one 70-car unit train transports the same volume as approximately 238 tank trucks. The heavy products produced could be transported all by truck, all by unit trains, or by a combination of trucks and unit trains. Depending on whether the processing facility has rail access, the rail tank cars could be loaded at the processing facility or trucks could be used to shuttle the heavy product to an offsite rail tank car loading facility. Table A.6-13 shows examples of the average number of weekly tank truck trips and/or unit train trips needed to transport the total quantity of heavy product produced. The distribution of trucks leaving the study area eastbound on Highway 166 and southbound on Highway 101 in relation to different levels of rail transport is shown on Table A.6-14. As shown in Table A.6-13, scenarios involving the market-limited development of the Offshore Santa Maria Basin resources (Scenarios 3 and 3A) could eliminate heavy product truck transport traffic entirely with two unit trains per week. Maximum development scenarios (Scenarios 4 and 4A) would require nearly one unit train per day to completely eliminate truck transport of the heavy product. As this indicates, the use of trains to transport some or all of the heavy products can substantially reduce the associated truck traffic on regional highways. Because the location of the facility, the type of products to be produced, and their associated markets are not known, it is not possible to project the rail routes that may be used or the relative traffic reductions on specific regional highways.

TABLE A.6-1
EASTERN SUBREGION PRODUCT TRANSPORT TRUCK ACTIVITY
(TRUCKS PER WEEK)
ALL SCENARIOS

	Study Year				
	"1998"	**2000**	**2005**	**2010**	**2015**
Mandalay					
Sulfur	0	0	0	0	0
LPG	0	0	0	0	0
West Montalvo					
Sulfur	0	0	0	0	0
LPG	0	0	0	0	0
Rincon Island/State Lease 145/410*					
Sulfur	0	0	0	0	0
LPG	0	0	0	0	0
Crude	8-10	8-10	8-10	8-10	0
Rincon Onshore					
Sulfur	0	0	0	0	0
LPG	0	0	0	0	0
La Conchita					
Sulfur	0	0	0	0	0
LPG	0	0	0	0	0
Carpinteria Oil & Gas					
Sulfur	0	0	0	0	0
LPG	0	0	0	0	0
Carpinteria Gas Terminal					
Sulfur	0	0	0	0	0
LPG	0	0	0	0	0
SUBREGION TOTAL					
Sulfur	0	0	0	0	0
LPG	0	0	0	0	0
Crude	8-10	8-10	8-10	8-10	0

*All traffic is projected to travel southbound on Highway 101

TABLE A.6-2
CENTRAL SUBREGION PRODUCT TRANSPORT TRUCK ACTIVITY
(TRUCKS PER WEEK)
SCENARIO 1

	Direction on 101	Study Year				
		"1998"	2000	2005	2010	2015
Ellwood						
Sulfur	N S	2 0	1 0	0.4 0	- -	- -
LPG	N S	7 0	3 0	1.6 0	- -	- -
Las Flores Canyon						
Sulfur	N S	0 4	0 5	0 5	0 5	0 5
LPG	N S	3 29	4 34	4 34	4 34	4 34
Gaviota[1]						
Sulfur	N S	0 0	0 0	- -	- -	- -
LPG	N S	0 0	0 0	- -	- -	- -
Molino[2]						
Sulfur	N S	- -	- -	0 0	0 0	- -
LPG	N S	- -	- -	24 0	6 0	- -
Total						
Sulfur	N S	2 4	1 5	1 5	0 5	0 5
LPG	N S	10 29	7 34	30 34	10 34	4 34
Total Trucks Per Week[3]	**N** **S**	**12** **33**	**8** **39**	**31** **39**	**10** **39**	**4** **39**

1 Assumes the Gaviota facility is NOT processing any gas in study year 2000 (i.e., reconfiguration).
2 Projected traffic reflects LPG transport associated with Molino production, though this traffic is likely to originate at the Gaviota Facility. Projected traffic levels reflect permit requirements which specify that NGLs are to be blended with crude oil and transported by pipeline to the maximum extent technically feasible. Propane transport by truck is allowed, and is reflected in this table.
3 Total trucks per week - number that travel 101 North or South from the "Ellwood-Gaviota Corridor".

TABLE A.6-3
CENTRAL SUBREGION PRODUCT TRANSPORT TRUCK ACTIVITY
(TRUCKS PER WEEK)
SCENARIO 2

	Direction on 101	Study Year				
		"1998"	2000	2005	2010	2015
Ellwood						
Sulfur	N S	2 0	1 0	5 0	5 0	5 0
LPG	N S	7 0	3 0	25 0	25 0	25 0
Las Flores Canyon						
Sulfur	N S	0 4	0 5	0 4	0 4	0 4
LPG	N S	3 29	4 34	4 34	4 34	4 34
Gaviota[1]						
Sulfur	N S	0 0	0 0	0 1	0 1	0 1
LPG	N S	0 0	0 0	1 5	1 9	1 10
Molino[2]						
Sulfur	N S	- -	- -	0 0	0 0	- -
LPG	N S	- -	- -	24 0	6 0	- -
Total						
Sulfur	N S	2 4	1 5	5 5	5 5	5 5
LPG	N S	10 29	7 34	54 39	36 43	30 44
Total Trucks Per Week[3]	**N** **S**	**12** **33**	**8** **39**	**59** **44**	**41** **48**	**35** **49**

1 Assumes the Gaviota facility is not processing gas from Pt. Arguello (Hermosa, Hidalgo and Harvest), but does process gas from other fields projected to send produced gas to the Gaviota Facility (included fields reached by wells drilled from these platforms as well as new platforms).

2 Projected traffic reflects LPG transport associated with Molino production, though this traffic is likely to originate at the Gaviota Facility. Projected traffic levels reflect permit requirements which specify that NGLs are to be blended with crude oil and transported by pipeline to the maximum extent technically feasible. Propane transport by truck is allowed, and is reflected in this table.

3 Total trucks per week - number that travel 101 North or South from the "Ellwood-Gaviota Corridor".

TABLE A.6-4
CENTRAL SUBREGION PRODUCT TRANSPORT TRUCK ACTIVITY
(TRUCKS PER WEEK)
SCENARIO 3

	Direction on 101	**Study Year**				
		"1998"	**2000**	**2005**	**2010**	**2015**
Ellwood						
Sulfur	N S	2 0	1 0	5 0	5 0	3 0
LPG	N S	7 0	3 0	25 0	25 0	14 0
Las Flores Canyon						
Sulfur	N S	0 4	0 5	0 5	0 6	0 6
LPG	N S	3 29	4 34	5 47	5 48	5 41
Gaviota[1]						
Sulfur	N S	0 0	0 0	0 1	0 1	0 1
LPG	N S	0 0	0 0	1 5	1 9	1 10
Molino[2]						
Sulfur	N S	- -	- -	0 0	0 0	- -
LPG	N S	- -	- -	24 0	6 0	- -
Total						
Sulfur	N S	2 4	1 5	5 6	5 7	3 7
LPG	N S	10 29	7 34	55 52	37 57	20 51
Total Trucks Per Week[3]	**N** **S**	**12** **33**	**8** **39**	**60** **58**	**42** **64**	**23** **58**

1 Assumes the Gaviota facility is not processing gas from the Pt. Arguello Unit, but does process gas from other fields projected to send produced gas to the Gaviota Facility (including fields reached by wells drilled from Hermosa, Hidalgo and Harvest as well as new platforms).

2 Projected traffic reflects LPG transport associated with Molino production, though this traffic is likely to originate at the Gaviota Facility. Projected traffic levels reflect permit requirements which specify that NGLs are to be blended with crude oil and transported by pipeline to the maximum extent technically feasible. Propane transport by truck is allowed, and is reflected in this table.

3 Total trucks per week - number that travel 101 North or South from the "Ellwood-Gaviota Corridor".

TABLE A.6-5
CENTRAL SUBREGION PRODUCT TRANSPORT TRUCK ACTIVITY
(TRUCKS PER WEEK)
SCENARIO 4

	Direction on 101	Study Year				
		"1998"	2000	2005	2010	2015
Ellwood						
Sulfur	N S	2 0	1 0	5 0	5 0	3 0
LPG	N S	7 0	3 0	25 0	25 0	14 0
Las Flores Canyon						
Sulfur	N S	0 4	0 5	0 6	0 6	0 6
LPG	N S	3 29	4 34	5 50	5 49	5 42
Gaviota[1]						
Sulfur	N S	0 0	0 0	- -	- -	- -
LPG	N S	0 0	0 0	- -	- -	- -
Molino[2]						
Sulfur	N S	- -	- -	0 0	0 0	- -
LPG	N S	- -	- -	24 0	6 0	- -
Total						
Sulfur	N S	2 4	1 5	5 6	5 6	3 6
LPG	N S	10 29	7 34	54 50	36 49	19 42
Total Trucks Per Week[3]	**N** **S**	**12** **33**	**8** **39**	**59** **56**	**41** **55**	**22** **48**

1 Assumes the Gaviota facility is not processing gas in study year 2000 (i.e., reconfiguration) and is removed by study year 2005.
2 Projected traffic reflects LPG transport associated with Molino production, though this traffic is likely to originate at the Gaviota Facility. Projected traffic levels reflect permit requirements which specify that NGLs are to be blended with crude oil and transported by pipeline to the maximum extent technically feasible. Propane transport by truck is allowed, and is reflected in this table.
3 Total trucks per week - number that travel 101 North or South from the "Ellwood-Gaviota Corridor".

TABLE A.6-6
NORTHERN SUBREGION PRODUCT TRANSPORT TRUCK ACTIVITY
(TRUCKS PER WEEK) - SCENARIO 1

	Highway and Direction[1]	Study Year				
		"1998"	2000	2005	2010	2015
Lompoc HS&P (as built)						
Sulfur	101N 166E 101S	0.3 0 0	0.1 0 0	- - -	- - -	- - -
LPG	101N 166E 101S	0 4 0	0 1 0	- - -	- - -	- - -
Heavy Product Fraction (Asphalt or Other)[2]	101N 166E 101S	- - -	- - -	- - -	- - -	- - -
Modified HS&P, Expanded Santa Maria Asphalt Refinery or New Facility						
Sulfur	101N 166E 101S					
LPG	101N 166E 101S					
Heavy Product Fraction (Asphalt or Other)[2]	101N 166E 101S					
Total						
Sulfur	101N 166E 101S	1 0 0	1 0 0	- - -	- - -	- - -
LPG	101N 166E 101S	0 4 0	0 1 0	- - -	- - -	- - -
Heavy Product Fraction (Asphalt or Other)[2]	101N 166E 101S	- - -	- - -	- - -	- - -	- - -
Total Trucks Per Week	**101N 166E 101S**	**1 4 0**	**1 1 0**	**- - -**	**- - -**	**- - -**

[1] Principal highway used and direction of travel:
101N = Highway 101 northbound for consumption in Northern Subregion
166E = Highway 166 eastbound out of the study region
101S = Highway 101 southbound out of the study region

[2] Table entries assume 100 percent of heavy product transported by truck. Use of alternative transport (such as rail) could substantially reduce or eliminate truck traffic associated with heavy product transport.

TABLE A.6-7
NORTHERN SUBREGION PRODUCT TRANSPORT TRUCK ACTIVITY
(TRUCKS PER WEEK) - SCENARIO 2

	Highway and Direction[1]	Study Year				
		"1998"	2000	2005	2010	2015
Lompoc HS&P (as built)						
Sulfur	101N 166E 101S	0.3 0 0	0.1 0 0	0 0 0	0.9 0 0	0.8 0 0
LPG	101N 166E 101S	0 4 0	0 1 0	0 0 0	0 13 0	0 13 0
Heavy Product Fraction (Asphalt or Other)[2]	101N 166E 101S	- - -	- - -	- - -	0 100 50	0 100 50
Modified HS&P, Expanded Santa Maria Asphalt Refinery or New Facility						
Sulfur	101N 166E 101S					
LPG	101N 166E 101S					
Heavy Product Fraction (Asphalt or Other)[2]	101N 166E 101S					
Total						
Sulfur	101N 166E 101S	1 0 0	1 0 0	0 0 0	1 0 0	1 0 0
LPG	101N 166E 101S	0 4 0	0 1 0	0 0 0	0 13 0	0 13 0
Heavy Product Fraction (Asphalt or Other)[2]	101N 166E 101S	- - -	- - -	- - -	0 100 50	0 100 50
Total Trucks Per Week	**101N 166E 101S**	**1 4 0**	**1 1 0**	**0 0 0**	**1 113 50**	**1 113 50**

[1] Principal highway used and direction of travel:
101N = Highway 101 northbound for consumption in Northern Subregion
166E = Highway 166 eastbound out of the study region
101S = Highway 101 southbound out of the study region

[2] Table entries assume 100 percent of heavy product transported by truck. Use of alternative transport (such as rail) could substantially reduce or eliminate truck traffic associated with heavy product transport.

TABLE A.6-8
NORTHERN SUBREGION PRODUCT TRANSPORT TRUCK ACTIVITY
(TRUCKS PER WEEK) - SCENARIO 3

	Highway and Direction[1]	Study Year				
		"1998"	2000	2005	2010	2015
Lompoc HS&P (as built)						
Sulfur	101N 166E 101S	0.3 0 0	0.1 0 0	0 0 0	0.8 0 0	0.7 0 0
LPG	101N 166E 101S	0 4 0	0 1 0	0 0 0	0 12 0	0 10 0
Heavy Product Fraction (Asphalt or Other)[2]	101N 166E 101S	- - -	- - -	- - -	- - -	- - -
Modified HS&P, Expanded Santa Maria Asphalt Refinery or New Facility						
Sulfur	101N 166E 101S	- - -	- - -	- - -	0.3 0 0	0.9 0 0
LPG	101N 166E 101S	- - -	- - -	- - -	0 6 0	0 19 0
Heavy Product Fraction (Asphalt or Other)[2]	101N 166E 101S	- - -	- - -	- - -	0 333 167	0 333 167
Total						
Sulfur	101N 166E 101S	1 0 0	1 0 0	0 0 0	2 0 0	2 0 0
LPG	101N 166E 101S	0 4 0	0 1 0	0 0 0	0 18 0	0 29 0
Heavy Product Fraction (Asphalt or Other)[2]	101N 166E 101S	- - -	- - -	- - -	0 333 167	0 333 167
Total Trucks Per Week	**101N 166E 101S**	**1 4 0**	**1 1 0**	**0 0 0**	**2 351 167**	**2 362 167**

[1] Principal highway used and direction of travel:
101N = Highway 101 northbound for consumption in Northern Subregion
166E = Highway 166 eastbound out of the study region
101S = Highway 101 southbound out of the study region

[2] Table entries assume 100 percent of heavy product transported by truck. Use of alternative transport (such as rail) could substantially reduce or eliminate truck traffic associated with heavy product transport.

TABLE A.6-9
NORTHERN SUBREGION PRODUCT TRANSPORT TRUCK ACTIVITY
(TRUCKS PER WEEK) - SCENARIO 4

	Highway and Direction[1]	**Study Year**				
		"1998"	**2000**	**2005**	**2010**	**2015**
Lompoc HS&P (as built)						
Sulfur	101N 166E 101S	0.3 0 0	0.1 0 0	0 0 0	0.8 0 0	0.7 0 0
LPG	101N 166E 101S	0 4 0	0 1 0	0 0 0	0 12 0	0 10 0
Heavy Product Fraction (Asphalt or Other)[2]	101N 166E 101S	- - -	- - -	- - -	- - -	- - -
Modified HS&P, Expanded Santa Maria Asphalt Refinery or New Facility						
Sulfur	101N 166E 101S	- - -	- - -	- - -	0.6 0 0	2.8 0 0
LPG	101N 166E 101S	- - -	- - -	- - -	0 13 0	0 58 0
Heavy Product Fraction (Asphalt or Other)[2]	101N 166E 101S	- - -	- - -	- - -	0 773 387	0 1000 500
Total						
Sulfur	101N 166E 101S	1 0 0	1 0 0	0 0 0	2 0 0	4 0 0
LPG	101N 166E 101S	0 4 0	0 1 0	0 0 0	0 25 0	0 68 0
Heavy Product Fraction (Asphalt or Other)[2]	101N 166E 101S	- - -	- - -	- - -	0 773 387	0 773 387
Total Trucks Per Week	**101N 166E 101S**	**1 4 0**	**1 1 0**	**0 0 0**	**2 798 387**	**4 1068 500**

[1] Principal highway used and direction of travel:
101N = Highway 101 northbound for consumption in Northern Subregion
166E = Highway 166 eastbound out of the study region
101S = Highway 101 southbound out of the study region

[2] Table entries assume 100 percent of heavy product transported by truck. Use of alternative transport (such as rail) could substantially reduce or eliminate truck traffic associated with heavy product transport.

TABLE A.6-10
NORTHERN SUBREGION PRODUCT TRANSPORT TRUCK ACTIVITY
(TRUCKS PER WEEK) - SCENARIO 2A

	Highway and Direction[1]	**Study Year**				
		"1998"	**2000**	**2005**	**2010**	**2015**
Lompoc HS&P (as built)						
Sulfur	101N 166E 101S	0.3 0 0	0.1 0 0	2.3 0 0	1 0 0	1 0 0
LPG	101N 166E 101S	0 4 0	0 1 0	0 8 0	0 13 0	0 13 0
Heavy Product Fraction (Asphalt or Other)[2]	101N 166E 101S	- - -	- - -	- - -	- - -	- - -
Modified HS&P, Expanded Santa Maria Asphalt Refinery or New Facility						
Sulfur	101N 166E 101S					
LPG	101N 166E 101S					
Heavy Product Fraction (Asphalt or Other)[2]	101N 166E 101S					
Total						
Sulfur	101N 166E 101S	1 0 0	1 0 0	2 0 0	1 0 0	1 0 0
LPG	101N 166E 101S	0 4 0	0 1 0	0 8 0	0 13 0	0 13 0
Heavy Product Fraction (Asphalt or Other)[2]	101N 166E 101S	- - -	- - -	- - -	- - -	- - -
Total Trucks Per Week	**101N 166E 101S**	**1 4 0**	**1 1 0**	**2 8 0**	**1 13 0**	**1 13 0**

[1] Principal highway used and direction of travel:
101N = Highway 101 northbound for consumption in Northern Subregion
166E = Highway 166 eastbound out of the study region
101S = Highway 101 southbound out of the study region

[2] Table entries assume 100 percent of heavy product transported by truck. Use of alternative transport (such as rail) could substantially reduce or eliminate truck traffic associated with heavy product transport.

TABLE A.6-11
NORTHERN SUBREGION PRODUCT TRANSPORT TRUCK ACTIVITY
(TRUCKS PER WEEK) - SCENARIO 3A

	Highway and Direction[1]	Study Year				
		"1998"	2000	2005	2010	2015
Lompoc HS&P (as built)						
Sulfur	101N 166E 101S	0.3 0 0	0.1 0 0	2.3 0 0	3.4 0 0	4.5 0 0
LPG	101N 166E 101S	0 4 0	0 1 0	0 8 0	0 30 0	0 32 0
Heavy Product Fraction (Asphalt or Other)[2]	101N 166E 101S	- - -	- - -	- - -	- - -	- - -
Modified HS&P, Expanded Santa Maria Asphalt Refinery or New Facility						
Sulfur	101N 166E 101S	- - -	- - -	- - -	0.3 0 0	0.9 0 0
LPG	101N 166E 101S	- - -	- - -	- - -	0 5.6 0	0 19 0
Heavy Product Fraction (Asphalt or Other)[2]	101N 166E 101S	- - -	- - -	- - -	0 333 167	0 333 167
Total						
Sulfur	101N 166E 101S	1 0 0	1 0 0	2 0 0	4 0 0	6 0 0
LPG	101N 166E 101S	0 4 0	0 1 0	0 8 0	0 36 0	0 51 0
Heavy Product Fraction (Asphalt or Other)[2]	101N 166E 101S	- - -	- - -	- - -	0 333 167	0 333 167
Total Trucks Per Week	**101N 166E 101S**	**1 4 0**	**1 1 0**	**2 8 0**	**4 369 167**	**6 384 167**

[1] Principal highway used and direction of travel:
101N = Highway 101 northbound for consumption in Northern Subregion
166E = Highway 166 eastbound out of the study region
101S = Highway 101 southbound out of the study region

[2] Table entries assume 100 percent of heavy product transported by truck. Use of alternative transport (such as rail) could substantially reduce or eliminate truck traffic associated with heavy product transport.

TABLE A.6-12
NORTHERN SUBREGION PRODUCT TRANSPORT TRUCK ACTIVITY
(TRUCKS PER WEEK) - SCENARIO 4A

	Highway and Direction[1]	Study Year				
		"1998"	2000	2005	2010	2015
Lompoc HS&P (as built)						
Sulfur	101N 166E 101S	0.3 0 0	0.1 0 0	2.3 0 0	3.4 0 0	4.5 0 0
LPG	101N 166E 101S	0 4 0	0 1 0	0 8 0	0 30 0	0 32 0
Heavy Product Fraction (Asphalt or Other)[2]	101N 166E 101S	- - -	- - -	- - -	- - -	- - -
Modified HS&P, Expanded Santa Maria Asphalt Refinery or New Facility						
Sulfur	101N 166E 101S	- - -	- - -	- - -	0.6 0 0	2.8 0 0
LPG	101N 166E 101S	- - -	- - -	- - -	0 13 0	0 58 0
Heavy Product Fraction (Asphalt or Other)[2]	101N 166E 101S	- - -	- - -	- - -	0 773 387	0 1000 500
Total						
Sulfur	101N 166E 101S	1 0 0	1 0 0	2 0 0	4 0 0	8 0 0
LPG	101N 166E 101S	0 4 0	0 1 0	0 8 0	0 43 0	0 90 0
Heavy Product Fraction (Asphalt or Other)[2]	101N 166E 101S	- - -	- - -	- - -	0 773 387	0 1000 500
Total Trucks Per Week	**101N 166E 101S**	**1 4 0**	**1 1 0**	**2 8 0**	**4 816 387**	**8 1090 500**

[1] Principal highway used and direction of travel:
101N = Highway 101 northbound for consumption in Northern Subregion
166E = Highway 166 eastbound out of the study region
101S = Highway 101 southbound out of the study region

[2] Table entries assume 100 percent of heavy product transported by truck. Use of alternative transport (such as rail) could substantially reduce or eliminate truck traffic associated with heavy product transport.

TABLE A.6-13
EXAMPLES OF POTENTIAL COMBINATIONS OF TRUCK AND RAIL TRANSPORT OF HEAVY PRODUCT[1]

Scenario / Study Year Combinations	Projected Offshore Santa Maria Basin Production (BOPD)	Heavy Product / Asphalt Prod. (BPD)[(1)]	Heavy Product/Asphalt Distribution Combination Examples				
			Amount Sent by Truck (%)	Tank Trucks per Week[(2)]	Amount Sent by Rail (%)	Tank Cars per Week[(2)]	Unit Trains per Week[(2)]
Northern Subregion Scenario 2 2010 & 2015	7,500	3,000	100	150	0	0	0
			75	113	25	11.0	0.16
			50	75	50	22.1	0.32
			25	38	75	33.1	0.47
			0	0	100	44.1	0.63
Northern Subregion Scenarios 3 and 3A 2010 & 2015	25,000	10,000	100	500	0	0	0
			75	375	25	36.8	0.53
			50	250	50	73.5	1.05
			25	125	75	110.3	1.58
			0	0	100	147.1	2.10
Northern Subregion Scenarios 4 and 4A 2010	58,000	23,200	100	1,160	0	0	0
			75	870	25	85.3	1.22
			50	580	50	170.6	2.44
			25	290	75	255.9	3.66
			0	0	100	341.2	4.87
Northern Subregion Scenarios 4 and 4A 2015	75,000	30,000	100	1,500	0	0	0
			75	1,125	25	110.3	1.58
			50	750	50	220.6	3.15
			25	375	75	330.9	4.73
			0	0	100	441.2	6.30

Notes: (1) Heavy Product/Asphalt production is estimated as 40% of total Offshore Santa Maria Basin Production
(2) Tank Trucks at 140 barrels each; Tank Cars at 476 barrels (20,000 gallons each); Unit Trains at 70 Tank Cars each (33,320 barrels).

TABLE A.6-14
Weekly Product Truck Trips for Offshore Santa Maria Basin Heavy Product/Asphalt Scenario Combinations: Any Eastern / Any Central / Northern as Listed

Highway 166 East Into Kern County						
Northern Subregion Scenario Number	Amount Sent by Truck (%)	1995	2000	2005	2010	2015
Scenario 2	100	0	0	0	100	100
	75	0	0	0	75	75
	50	0	0	0	50	50
	25	0	0	0	25	25
Scenarios 3 & 3A	100	0	0	0	333	333
	75	0	0	0	250	250
	50	0	0	0	167	167
	25	0	0	0	83	83
Scenarios 4 & 4A	100	0	0	0	773	1,000
	75	0	0	0	580	750
	50	0	0	0	387	500
	25	0	0	0	193	250

Highway 101 South Into Los Angeles County						
Scenario	Amount Sent by Truck (%)	1995	2000	2005	2010	2015
Scenario 2	100	0	0	0	50	50
	75	0	0	0	38	38
	50	0	0	0	25	25
	25	0	0	0	13	13
Scenarios 3 & 3A	100	0	0	0	167	167
	75	0	0	0	125	125
	50	0	0	0	83	83
	25	0	0	0	42	42
Scenarios 4 & 4A	100	0	0	0	387	500
	75	0	0	0	290	375
	50	0	0	0	193	250
	25	0	0	0	97	125

A.6.2 Traffic Generated by Supply and Crew Vessel Activity

In addition to product transport traffic, roadway traffic associated with supply vessel and crew vessel activity is an important feature of different offshore development scenarios. This traffic includes truck deliveries of supplies and equipment to Port Hueneme, trucks associated with light supplies at crew transfer locations (Carpinteria/Casitas Pier and Ellwood Pier), and automobile traffic associated with vessel operators and offshore crew access to vessel transport locations. Supply vessel and crew vessel activity was calculated as described in Sections A.6.3 and A.6.4. This information was used to calculate the onshore vehicular traffic associated with this activity using information presented in available environmental documents concerning traffic levels associated with vessel activity. The Santa Barbara County, MMS EIR/EIS addressing the Point Arguello Field development (A.D. Little, 1984), provided particularly useful information in this analysis. Traffic associated with vessel activity was determined as follows:

1 supply vessel trip	=	5 truck trips 3 automobile trips
1 crew vessel trip	=	1 truck trip 10 automobile trips

These factors were used to determine the scenario-specific traffic data presented in Tables A.6-15 through A.6-19.

Because Port Hueneme is the only port providing supply vessel service to study region offshore facilities, offshore development in all three subregions contributes to onshore traffic in the Port Hueneme area. For this reason, the combined traffic at Port Hueneme was calculated for each possible combination of offshore development scenarios (Table A.6-20). The truck traffic and automobile traffic which were combined to produce the totals in Table A.6-20 are presented individually in Tables A.6-21 and A.6-22.

TABLE A.6-15
TRUCK AND AUTOMOBILE TRAFFIC ASSOCIATED WITH SUPPLY BOAT TRIPS
TOTAL COOGER STUDY REGION[1]
(ALL SUPPLY BOATS ORIGINATE AT PORT HUENEME)

	1997			2000			2005			2010			2015		
	Boats (per week)	**Trucks (per week)**	**Cars (per week)**	**Boats (per week)**	**Trucks (per week)**	**Cars (per week)**	**Boats (per week)**	**Trucks (per week)**	**Cars (per week)**	**Boats (per week)**	**Trucks (per week)**	**Cars (per week)**	**Boats (per week)**	**Trucks (per week)**	**Cars (per week)**
Eastern Subregion															
Scenario 1	7	35	21	7	35	21	39	195	117	0	0	0	0	0	0
Scenario 2	7	35	21	7	35	21	44	220	132	5	25	15	7	35	21
Scenario 3	7	35	21	7	35	21	44	220	132	5	25	15	7	35	21
Scenario 4	7	35	21	10	50	30	30	150	90	0	0	0	0	0	0
Central Subregion															
Scenario 1	44	220	132	25	125	75	17	85	51	13	65	39	4	20	12
Scenario 2	44	220	132	25	125	75	62	310	186	48	240	144	13	65	39
Scenario 3	44	220	132	25	125	75	62	310	186	48	240	144	13	65	39
Scenario 4	44	220	132	25	125	75	42	210	126	17	85	51	6	30	18
Northern Subregion															
Scenario 1	1	5	3	1	5	3	4	20	12	0	0	0	0	0	0
Scenario 2	1	5	3	1	5	3	7	35	21	26	130	78	2	10	6
Scenario 3	1	5	3	1	5	3	7	35	21	37	185	111	3	15	9
Scenario 4	1	5	3	1	5	3	7	35	21	61	305	183	4	20	12
Scenario 2A	1	5	3	1	5	3	22	110	66	21	105	63	22	110	66
Scenario 3A	1	5	3	1	5	3	22	110	66	57	285	171	5	25	15
Scenario 4A	1	5	3	1	5	3	22	110	66	82	410	246	6	30	18

[1]This table presents the projected average number of offshore oil related supply (work) boat trips per week. The numbers shown are weekly averages for each 5-year Study interval (e.g., study year 2005 covers 01/01/2001 - 12/31/2005). All supply boats are projected to originate from Port Hueneme.

TABLE A.6-16
TRUCK AND AUTOMOBILE TRAFFIC ASSOCIATED WITH CREW BOAT TRIPS
TOTAL COOGER STUDY REGION[1]

	1997			2000			2005			2010			2015		
	Boats (per week)	Trucks (per week)	Cars (per week)	Boats (per week)	Trucks (per week)	Cars (per week)	Boats (per week)	Trucks (per week)	Cars (per week)	Boats (per week)	Trucks (per week)	Cars (per week)	Boats (per week)	Trucks (per week)	Cars (per week)
Eastern Subregion															
Scenario 1	84	84	840	84	84	840	60	60	600	0	0	0	0	0	0
Scenario 2	84	84	840	84	84	840	76	76	760	18	18	180	13	13	130
Scenario 3	84	84	840	84	84	840	76	76	760	18	18	180	13	13	130
Scenario 4	84	84	840	84	84	840	50	50	500	0	0	0	0	0	0
Central Subregion															
Scenario 1	55	55	550	47	47	470	42	42	420	46	46	460	14	14	140
Scenario 2	55	55	550	47	47	470	77	77	770	50	50	500	46	46	460
Scenario 3	55	55	550	47	47	470	77	77	770	50	50	500	46	46	460
Scenario 4	55	55	550	47	47	470	77	77	770	50	50	500	46	46	460
Northern Subregion															
All Scenarios	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

[1]This table presents the projected average number of offshore oil related crew boat trips per week originating from Port Hueneme and the Carpinteria and Ellwood Piers. The numbers shown are weekly averages for each 5-year Study interval (e.g., study year 2005 covers 01/01/2001 - 12/31/2005).

TABLE A.6-17
TRUCK AND AUTOMOBILE TRAFFIC ASSOCIATED WITH CREW BOAT TRIPS ORIGINATING FROM PORT HUENEME[1]

	1997			2000			2005			2010			2015		
	Boats (per week)	Trucks (per week)	Cars (per week)	Boats (per week)	Trucks (per week)	Cars (per week)	Boats (per week)	Trucks (per week)	Cars (per week)	Boats (per week)	Trucks (per week)	Cars (per week)	Boats (per week)	Trucks (per week)	Cars (per week)
Eastern Subregion															
Scenario 1	42	42	420	42	42	420	18	18	180	0	0	0	0	0	0
Scenario 2	42	42	420	42	42	420	28	28	280	12	12	120	9	9	90
Scenario 3	42	42	420	42	42	420	28	28	280	12	12	120	9	9	90
Scenario 4	42	42	420	39	39	390	16	16	160	0	0	0	0	0	0
Central Subregion															
All Scenarios	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Northern Subregion															
All Scenarios	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

[1]This table presents the projected average number of offshore oil related crew boat trips per week originating from Port Hueneme. The numbers shown are weekly averages for each 5-year Study interval (e.g., study year 2005 covers 01/01/2001 - 12/31/2005).

TABLE A.6-18
TRUCK AND AUTOMOBILE TRAFFIC ASSOCIATED WITH CREW BOAT TRIPS ORIGINATING FROM THE CARPINTERIA PIER[1]

	1997			2000			2005			2010			2015		
	Boats (per week)	**Trucks (per week)**	**Cars (per week)**	**Boats (per week)**	**Trucks (per week)**	**Cars (per week)**	**Boats (per week)**	**Trucks (per week)**	**Cars (per week)**	**Boats (per week)**	**Trucks (per week)**	**Cars (per week)**	**Boats (per week)**	**Trucks (per week)**	**Cars (per week)**
Eastern Subregion															
Scenario 1	42	42	420	42	42	420	42	42	420	0	0	0	0	0	0
Scenario 2	42	42	420	42	42	420	48	48	480	6	6	60	4	4	40
Scenario 3	42	42	420	42	42	420	48	48	480	6	6	60	4	4	40
Scenario 4	42	42	420	45	45	450	34	34	340	0	0	0	0	0	0
Central Subregion															
All Scenarios	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Northern Subregion															
All Scenarios	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

[1]This table presents the projected average number of offshore oil related crew boat trips per week originating from the Carpinteria Pier (Casitas Pier). The numbers shown are weekly averages for each 5-year Study interval (e.g., study year 2005 covers 01/01/2001 - 12/31/2005).

TABLE A.6-19
TRUCK AND AUTOMOBILE TRAFFIC ASSOCIATED WITH CREW BOAT TRIPS ORIGINATING FROM ELLWOOD PIER[1]

	1997			2000			2005			2010			2015		
	Boats (per week)	**Trucks (per week)**	**Cars (per week)**	**Boats (per week)**	**Trucks (per week)**	**Cars (per week)**	**Boats (per week)**	**Trucks (per week)**	**Cars (per week)**	**Boats (per week)**	**Trucks (per week)**	**Cars (per week)**	**Boats (per week)**	**Trucks (per week)**	**Cars (per week)**
Eastern Subregion															
All Scenarios	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Central Subregion															
Scenario 1	55	55	550	47	47	470	42	42	420	46	46	460	14	14	140
Scenario 2	55	55	550	47	47	470	77	77	770	50	50	500	46	46	460
Scenario 3	55	55	550	47	47	470	77	77	770	50	50	500	46	46	460
Scenario 4	55	55	550	47	47	470	77	77	770	50	50	500	46	46	460
Northern Subregion															
All Scenarios	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

[1]This table presents the projected average number of offshore oil related crew boat trips per week originating from the Ellwood Pier. The numbers shown are weekly averages for each 5-year Study interval (e.g., study year 2005 covers 01/01/2001 - 12/31/2005).

TABLE A.6-20
PROJECTED COMBINED TOTAL TRAFFIC (AUTOS AND TRUCKS)
AT PORT HUENEME
ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]
(Round Trips Per Week)

Scenario[2] (E,C,N)	1997	2000	2005	2010	2015
1, 1, 1	876	729	688	101	32
1, 1, 2	876	729	707	312	49
1, 1, 3	876	729	707	396	57
1, 1, 4	876	729	707	590	62
1, 2, 1	876	729	***1048***	388	104
1, 2, 2	876	729	***1067***	598	122
1, 2, 3	876	729	***1067***	683	129
1, 2, 4	876	729	***1067***	***876***	134
1, 3, 1	876	729	***1048***	388	104
1, 3, 2	876	729	***1067***	598	122
1, 3, 3	876	729	***1067***	683	129
1, 3, 4	876	729	***1067***	***876***	134
1, 4, 1	876	729	***886***	136	49
1, 4, 2	876	729	***904***	346	67
1, 4, 3	876	729	***904***	431	74
1, 4, 4	876	729	***904***	624	79
1, 4, 2A	876	729	***1025***	305	227
1, 4, 3A	876	729	***1025***	591	87
1, 4, 4A	876	729	***1025***	793	96
2, 1, 1	876	729	828	270	187
2, 1, 2	876	729	847	481	205
2, 1, 3	876	729	847	565	212
2, 1, 4	876	729	847	759	217
2, 2, 1	876	729	***1188***	557	260
2, 2, 2	876	729	***1207***	767	277
2, 2, 3	876	729	***1207***	852	284
2, 2, 4	876	729	***1207***	***1045***	289
2, 3, 1	876	729	***1188***	557	260
2, 3, 2	876	729	***1207***	767	277
2, 3, 3	876	729	***1207***	852	284
2, 3, 4	876	729	***1207***	***1045***	289
2, 4, 1	876	729	***1026***	305	205
2, 4, 2	876	729	***1044***	515	222
2, 4, 3	876	729	***1044***	600	230
2, 4, 4	876	729	***1044***	793	235
2, 4, 2A	876	729	***1165***	474	382
2, 4, 3A	876	729	***1165***	760	242
2, 4, 4A	876	729	***1165***	***962***	252

[1]Bold italicized numbers indicate increase compared to the base year (1997)
[2]Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion

TABLE A.6-20 (Continued)
PROJECTED COMBINED TOTAL TRAFFIC (AUTOS AND TRUCKS)
AT PORT HUENEME
ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]
(Round Trips Per Week)

Scenario[2] (E,C,N)	1997	2000	2005	2010	2015
3, 1, 1	876	729	828	270	176
3, 1, 2	876	729	847	481	193
3, 1, 3	876	729	847	565	200
3, 1, 4	876	729	847	759	205
3, 2, 1	876	729	***1188***	557	248
3, 2, 2	876	729	***1207***	767	265
3, 2, 3	876	729	***1207***	852	273
3, 2, 4	876	729	***1207***	***1045***	278
3, 3, 1	876	729	***1188***	557	248
3, 3, 2	876	729	***1207***	767	265
3, 3, 3	876	729	***1207***	852	273
3, 3, 4	876	729	***1207***	***1045***	278
3, 4, 1	876	729	***1026***	305	193
3, 4, 2	876	729	***1044***	515	210
3, 4, 3	876	729	***1044***	600	218
3, 4, 4	876	729	***1044***	793	223
3, 4, 2A	876	729	***1165***	474	370
3, 4, 3A	876	729	***1165***	760	230
3, 4, 4A	876	729	***1165***	***962***	240
4, 1, 1	876	723	589	101	32
4, 1, 2	876	723	608	312	49
4, 1, 3	876	723	608	396	57
4, 1, 4	876	723	608	590	62
4, 2, 1	876	723	***949***	388	104
4, 2, 2	876	723	***968***	598	122
4, 2, 3	876	723	***968***	683	129
4, 2, 4	876	723	***968***	***876***	134
4, 3, 1	876	723	***949***	388	104
4, 3, 2	876	723	***968***	598	122
4, 3, 3	876	723	***968***	683	129
4, 3, 4	876	723	***968***	***876***	134
4, 4, 1	876	723	787	136	49
4, 4, 2	876	723	806	346	67
4, 4, 3	876	723	806	431	74
4, 4, 4	876	723	806	624	79
4, 4, 2A	876	723	***926***	305	227
4, 4, 3A	876	723	***926***	591	87
4, 4, 4A	876	723	***926***	793	96

[1]Bold italicized numbers indicate increase compared to the base year (1997)
[2]Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion

TABLE A.6-21
PROJECTED COMBINED TRUCK TRAFFIC AT PORT HUENEME ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]
(Round Trips Per Week)

Scenario[2] (E,C,N)	**1997**	**2000**	**2005**	**2010**	**2015**
1, 1, 1	301	209	***321***	63	20
1, 1, 2	301	209	***333***	195	31
1, 1, 3	301	209	***333***	248	35
1, 1, 4	301	209	***333***	***369***	39
1, 2,1	301	209	***546***	242	65
1, 2,2	301	209	***558***	***374***	76
1, 2,3	301	209	***558***	***427***	81
1, 2,4	301	209	***558***	***548***	84
1,3,1	301	209	***546***	242	65
1,3,2	301	209	***558***	***374***	76
1,3,3	301	209	***558***	***427***	81
1,3,4	301	209	***558***	***548***	84
1,4,1	301	209	***445***	85	31
1,4,2	301	209	***457***	217	42
1,4,3	301	209	***457***	269	46
1,4,4	301	209	***457***	***390***	49
1,4,2A	301	209	***532***	191	142
1,4,3A	301	209	***532***	***369***	54
1,4,4A	301	209	***532***	***496***	60
2, 1, 1	301	209	***354***	101	63
2, 1, 2	301	209	***366***	232	73
2, 1, 3	301	209	***366***	285	78
2, 1, 4	301	209	***366***	***406***	81
2, 2,1	301	209	***579***	280	108
2, 2,2	301	209	***591***	***411***	119
2, 2,3	301	209	***591***	***464***	123
2, 2,4	301	209	***591***	***585***	126
2,3,1	301	209	***579***	280	108
2,3,2	301	209	***591***	***411***	119
2,3,3	301	209	***591***	***464***	123
2,3,4	301	209	***591***	***585***	126
2,4,1	301	209	***478***	122	73
2,4,2	301	209	***490***	254	84
2,4,3	301	209	***490***	***307***	89
2,4,4	301	209	***490***	***428***	92
2,4,2A	301	209	***565***	228	184
2,4,3A	301	209	***565***	***407***	97
2,4,4A	301	209	***565***	***533***	103

[1] Bold italicized numbers indicate increase compared to the base year (1997)
[2] Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion

TABLE A.6-21 (Continued)
PROJECTED COMBINED TRUCK TRAFFIC AT PORT HUENEME
ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]
(Round Trips Per Week)

Scenario[2] (E,C,N)	1997	2000	2005	2010	2015
3, 1, 1	301	209	***354***	101	55
3, 1, 2	301	209	***366***	232	66
3, 1, 3	301	209	***366***	285	71
3, 1, 4	301	209	***366***	***406***	74
3, 2,1	301	209	***579***	280	100
3, 2,2	301	209	***591***	***411***	111
3, 2,3	301	209	***591***	***464***	116
3, 2,4	301	209	***591***	***585***	119
3, 3, 1	301	209	***579***	280	100
3, 3, 2	301	209	***591***	***411***	111
3, 3, 3	301	209	***591***	***464***	116
3, 3, 4	301	209	***591***	***585***	119
3, 4, 1	301	209	***478***	122	66
3, 4, 2	301	209	***490***	254	77
3, 4, 3	301	209	***490***	***307***	81
3, 4, 4	301	209	***490***	***428***	85
3, 4, 2A	301	209	***565***	228	177
3, 4, 3A	301	209	***565***	***407***	89
3, 4, 4A	301	209	***565***	***533***	95
4, 1, 1	301	222	276	63	20
4, 1, 2	301	222	288	195	31
4, 1, 3	301	222	288	248	35
4, 1, 4	301	222	288	***369***	39
4, 2, 1	301	222	***501***	242	65
4, 2, 2	301	222	***513***	***374***	76
4, 2, 3	301	222	***513***	***427***	81
4, 2, 4	301	222	***513***	***548***	84
4, 3, 1	301	222	***501***	242	65
4, 3, 2	301	222	***513***	***374***	76
4, 3, 3	301	222	***513***	***427***	81
4, 3, 4	301	222	***513***	***548***	84
4, 4, 1	301	222	***400***	85	31
4, 4, 2	301	222	***411***	217	42
4, 4, 3	301	222	***411***	269	46
4, 4, 4	301	222	***411***	***390***	49
4, 4, 2A	301	222	***487***	191	142
4, 4, 3A	301	222	***487***	***369***	54
4, 4, 4A	301	222	***487***	***496***	60

[1]Bold italicized numbers indicate increase compared to the base year (1997)
[2]Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion

TABLE A.6-22
PROJECTED COMBINED AUTOMOBILE TRAFFIC AT PORT HUENEME ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]
(Round Trips Per Week)

Scenario[2] (E,C,N)	1997	2000	2005	2010	2015
1, 1, 1	575	520	367	38	12
1, 1, 2	575	520	374	117	19
1, 1, 3	575	520	374	149	21
1, 1, 4	575	520	374	221	23
1, 2,1	575	520	502	145	39
1, 2,2	575	520	509	224	46
1, 2,3	575	520	509	256	48
1, 2,4	575	520	509	329	50
1,3,1	575	520	502	145	39
1,3,2	575	520	509	224	46
1,3,3	575	520	509	256	48
1,3,4	575	520	509	329	50
1,4,1	575	520	441	51	19
1,4,2	575	520	448	130	25
1,4,3	575	520	448	162	28
1,4,4	575	520	448	234	30
1,4,2A	575	520	493	114	85
1,4,3A	575	520	493	221	32
1,4,4A	575	520	493	297	36
2, 1, 1	575	520	474	170	125
2, 1, 2	575	520	481	249	131
2, 1, 3	575	520	481	280	134
2, 1, 4	575	520	481	353	136
2, 2,1	575	520	***609***	277	152
2, 2,2	575	520	***616***	356	158
2, 2,3	575	520	***616***	388	161
2, 2,4	575	520	***616***	460	163
2,3,1	575	520	***609***	277	152
2,3,2	575	520	***616***	356	158
2,3,3	575	520	***616***	388	161
2,3,4	575	520	***616***	460	163
2,4,1	575	520	548	183	131
2,4,2	575	520	555	262	138
2,4,3	575	520	555	293	141
2,4,4	575	520	555	366	143
2,4,2A	575	520	***600***	246	198
2,4,3A	575	520	***600***	353	145
2,4,4A	575	520	***600***	429	149

[1]Bold italicized numbers indicate increase compared to the base year (1997)
[2]Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion

TABLE A.6-22 (Continued)
PROJECTED COMBINED AUTOMOBILE TRAFFIC
AT PORT HUENEME
ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]
(Round Trips Per Week)

Scenario[2] (E,C,N)	1997	2000	2005	2010	2015
3, 1, 1	575	520	474	170	120
3, 1, 2	575	520	481	249	127
3, 1, 3	575	520	481	280	130
3, 1, 4	575	520	481	353	132
3, 2,1	575	520	***609***	277	147
3, 2,2	575	520	***616***	356	154
3, 2,3	575	520	***616***	388	157
3, 2,4	575	520	***616***	460	159
3, 3, 1	575	520	***609***	277	147
3, 3, 2	575	520	***616***	356	154
3, 3, 3	575	520	***616***	388	157
3, 3, 4	575	520	***616***	460	159
3, 4, 1	575	520	548	183	127
3, 4, 2	575	520	555	262	133
3, 4, 3	575	520	555	293	136
3, 4, 4	575	520	555	366	138
3, 4, 2A	575	520	***600***	246	193
3, 4, 3A	575	520	***600***	353	141
3, 4, 4A	575	520	***600***	429	145
4, 1, 1	575	501	313	38	12
4, 1, 2	575	501	320	117	19
4, 1, 3	575	501	320	149	21
4, 1, 4	575	501	320	221	23
4, 2, 1	575	501	448	145	39
4, 2, 2	575	501	455	224	46
4, 2, 3	575	501	455	256	48
4, 2, 4	575	501	455	329	50
4, 3, 1	575	501	448	145	39
4, 3, 2	575	501	455	224	46
4, 3, 3	575	501	455	256	48
4, 3, 4	575	501	455	329	50
4, 4, 1	575	501	387	51	19
4, 4, 2	575	501	394	130	25
4, 4, 3	575	501	394	162	28
4, 4, 4	575	501	394	234	30
4, 4, 2A	575	501	439	114	85
4, 4, 3A	575	501	439	221	32
4, 4, 4A	575	501	439	297	36

[1]Bold italicized numbers indicate increase compared to the base year (1997)
[2]Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion

A.6.3 Supply Vessel Activity at Port Hueneme

Projections of supply vessel activity associated with different offshore development scenarios were developed by analysis of recent supply vessel activity in relation to the offshore activities supported by these operations. Actual vessel activity data were collected from Tidewater Marine and C&C Boats, two companies providing most of the offshore supply vessel service to the offshore industry. In addition, the Oxnard Harbor District "Year to Year Cargo Summary" for fiscal year ending June 20, 1998 and their "Vessel Call Report for FY 1997/1998" were used to identify annual cargo tonnage for different years, and monthly vessel calls during fiscal year 1998. These data were used to define supply vessel activities associated with normal platform operations. A summary of the supply vessel activity data collected is presented in Table A.6-23.

In addition to data addressing routine operations, industry estimates of supply vessel activity associated with past proposals for development well drilling, platform installation, and platform decommissioning and removal were used. Principal references used in this effort included the Santa Barbara County/MMS Point Arguello Field EIR/EIS (A.D. Little, 1984) and the MMS OCS Leases P-0523 and P-0524 exploration and drilling plan (Dames & Moore, 1989). These data indicated supply vessel activity of one supply vessel per day over a 6.5 month platform installation and hookup period, and one supply vessel per day associated with development well drilling (over an average of 75 days per well). Platform decommissioning activities were separated into well plugging and abandonment and equipment and structure removal activities. These activities were assumed to require comparable short-term supply vessel support as corresponding platform installation and development drilling, but were estimated to require approximately one-half the total time to complete.

Existing vessel activity records were evaluated in relation to available offshore employment data to develop supply boat activity projections associated with different offshore development scenarios. This approach is intended to simplify the process of report updates to reflect future scenario revisions. Employment data are considered a reasonable measure of the level of activity at a specific facility, and have been substantially documented by operator inputs to this study and by data collected under the Tri-Counties Socioeconomic Monitoring Program (SEMP). Employment data for each existing offshore platform and for platform installation and well drilling activity were used to define a series of factors that may be used to estimate weekly supply vessel activity based on total Full-Time-Equivalent employment for that facility or activity. Where individual facility data were not available (as in the case of potential future platforms associated with some scenarios), a composite factor was developed based on data available for comparable nearby facilities. An example of this calculation is as follows:

Total FTE, Platforms Holly, Hondo, Harmony, Heritage, Hermosa, Hidalgo, Harvest, and Irene:	210
Total weekly work vessel traffic, same facilities:	13
Average work vessel traffic per FTE (13/210):	0.0619

Table A.6-24 lists the facility-specific and composite factors used to develop supply vessel activity projections in this study. These factors were combined with scenario-specific employment estimates (Appendix A.3) to determine average weekly supply vessel activity associated with each five-year time period addressed in the COOGER study. Results are shown for each scenario addressed by the COOGER study in Table A.6-25. Table A.6-26 presents composite results for each possible combination of subregional scenarios.

TABLE A.6-23

SUPPLY VESSEL ACTIVITY DATA
ROUTINE PLATFORM OPERATIONS
(AVERAGE VESSEL TRIPS PER WEEK)

Platform Operations	Supply Vessels (Per Week)
Gina Gilda	3
Gail Grace Hermosa Harvest Hidalgo	7
Hogan Houchin	0
A, B, C Henry Hillhouse Habitat	1
Holly	1
Hondo Harmony Heritage	4
Irene	1

TABLE A.6-24
SUPPLY VESSEL ACTIVITY FACTORS
BASED ON FULL-TIME-EQUIVALENT EMPLOYMENT

	Supply Vessels per FTE, per week
Eastern Subregion	
Offshore Production Facilities	
Platform A	0.0115
Platform B	0.0115
Platform C	0.0115
Platform Hillhouse	0.0115
Platform Henry	0.0115
Platform Hogan	0.0000
Platform Houchin	0.0000
Platform Gina	0.1000
Platform Gilda	0.1000
Platform Grace	0.0732
Platform Gail	0.0732
Platform Habitat	0.0115
New Activity	
Platform Installation	0.3526
Platform Decommissioning & Removal	0.3824
Well Drilling	0.4121

TABLE A.6-24 (Continued)
SUPPLY VESSEL ACTIVITY FACTORS
BASED ON FULL-TIME-EQUIVALENT EMPLOYMENT

Central Subregion	
Offshore Production Facilities	
Platform Holly	0.0667
Platform Hondo	0.0471
Platform Heritage	0.0471
Platform Harmony	0.0471
Platform Hermosa	0.0805
Platform Hidalgo	0.0805
Platform Harvest	0.0805
Sword Platform	0.0619
Gato Canyon Platform	0.0471
New Activity	
Platform Installation	0.3526
Platform Decommissioning & Removal	0.3824
Well Drilling	0.4121
Northern Subregion	
Offshore Production Facilities	
Platform Irene	0.0435
Bonito Platform	0.0619
Lion Rock Platform	0.0619
Rocky Point Platform	0.0619
New Activity	
Platform Installation	0.3526
Platform Decommissioning & Removal	0.3824
Development Well Drilling	0.4121

TABLE A.6-25

SUPPLY VESSELS BY SCENARIO
TOTAL COOGER STUDY REGION
(AVERAGE VESSEL ROUND TRIPS PER WEEK)

	1997	2000	2005	2010	2015
Eastern Subregion					
Scenario 1	7	7	39	0	0
Scenario 2	7	7	44	5	7
Scenario 3	7	7	44	5	7
Scenario 4	7	10	30	0	0
Central Subregion					
Scenario 1	44	25	17	13	4
Scenario 2	44	25	62	48	13
Scenario 3	44	25	62	48	13
Scenario 4	44	25	42	17	6
Northern Subregion					
Scenario 1	1	1	4	0	0
Scenario 2	1	1	7	26	2
Scenario 3	1	1	7	37	3
Scenario 4	1	1	7	61	4
Scenario 2A	1	1	22	21	22
Scenario 3A	1	1	22	57	5
Scenario 4A	1	1	22	82	6

TABLE A.6-26
PROJECTED COMBINED SUPPLY VESSEL ACTIVITY
ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]
(AVERAGE VESSEL ROUND TRIPS PER WEEK)

Scenario[2] (E,C,N)	**1997**	**2000**	**2005**	**2010**	**2015**
1, 1, 1	52	33	***61***	13	4
1, 1, 2	52	33	***63***	39	6
1, 1, 3	52	33	***63***	50	7
1, 1, 4	52	33	***63***	***74***	8
1, 2,1	52	33	***106***	48	13
1, 2,2	52	33	***108***	***75***	15
1, 2,3	52	33	***108***	***85***	16
1, 2,4	52	33	***108***	***110***	17
1,3,1	52	33	***106***	48	13
1,3,2	52	33	***108***	***75***	15
1,3,3	52	33	***108***	***85***	16
1,3,4	52	33	***108***	***110***	17
1,4,1	52	33	***85***	17	6
1,4,2	52	33	***88***	43	8
1,4,3	52	33	***88***	***54***	9
1,4,4	52	33	***88***	***78***	10
1,4,2A	52	33	***103***	38	28
1,4,3A	52	33	***103***	***74***	11
1,4,4A	52	33	***103***	***99***	12
2, 1, 1	52	33	***65***	18	11
2, 1, 2	52	33	***68***	44	13
2, 1, 3	52	33	***68***	***55***	14
2, 1, 4	52	33	***68***	***79***	14
2, 2,1	52	33	***110***	***54***	20
2, 2,2	52	33	***113***	***80***	22
2, 2,3	52	33	***113***	***90***	23
2, 2,4	52	33	***113***	***115***	23
2,3,1	52	33	***110***	***54***	20
2,3,2	52	33	***113***	***80***	22
2,3,3	52	33	***113***	***90***	23
2,3,4	52	33	***113***	***115***	23
2,4,1	52	33	***90***	22	13
2,4,2	52	33	***92***	48	15
2,4,3	52	33	***92***	***59***	16
2,4,4	52	33	***92***	***83***	17
2,4,2A	52	33	***107***	43	35
2,4,3A	52	33	***107***	***79***	17
2,4,4A	52	33	***107***	***104***	19

[1]Bold italicized numbers indicate increase compared to the base year (1997)
[2]Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion

TABLE A.6-26 (Continued)
PROJECTED COMBINED SUPPLY VESSEL ACTIVITY ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]
(AVERAGE VESSEL ROUND TRIPS PER WEEK)

Scenario[2] (E,C,N)	1997	2000	2005	2010	2015
3, 1, 1	52	33	***65***	18	9
3, 1, 2	52	33	***68***	44	11
3, 1, 3	52	33	***68***	***55***	12
3, 1, 4	52	33	***68***	***79***	13
3, 2,1	52	33	***110***	***54***	18
3, 2,2	52	33	***113***	***80***	20
3, 2,3	52	33	***113***	***90***	21
3, 2,4	52	33	***113***	***115***	22
3, 3, 1	52	33	***110***	***54***	18
3, 3, 2	52	33	***113***	***80***	20
3, 3, 3	52	33	***113***	***90***	21
3, 3, 4	52	33	***113***	***115***	22
3, 4, 1	52	33	***90***	22	11
3, 4, 2	52	33	***92***	48	14
3, 4, 3	52	33	***92***	***59***	14
3, 4, 4	52	33	***92***	***83***	15
3, 4, 2A	52	33	***107***	43	33
3, 4, 3A	52	33	***107***	***79***	16
3, 4, 4A	52	33	***107***	***104***	17
4, 1, 1	52	36	***52***	13	4
4, 1, 2	52	36	***54***	39	6
4, 1, 3	52	36	***54***	50	7
4, 1, 4	52	36	***54***	***74***	8
4, 2, 1	52	36	***97***	48	13
4, 2, 2	52	36	***99***	***75***	15
4, 2, 3	52	36	***99***	***85***	16
4, 2, 4	52	36	***99***	***110***	17
4, 3, 1	52	36	***97***	48	13
4, 3, 2	52	36	***99***	***75***	15
4, 3, 3	52	36	***99***	***85***	16
4, 3, 4	52	36	***99***	***110***	17
4, 4, 1	52	36	***77***	17	6
4, 4, 2	52	36	***79***	43	8
4, 4, 3	52	36	***79***	***54***	9
4, 4, 4	52	36	***79***	***78***	10
4, 4, 2A	52	36	***94***	38	28
4, 4, 3A	52	36	***94***	***74***	11
4, 4, 4A	52	36	***94***	***99***	12

[1]Bold italicized numbers indicate increase compared to the base year (1997)
[2]Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion

A.6.4 Crew Vessel Activity

Projections of crew vessel activity associated with different offshore development scenarios were developed by analysis of recent crew vessel activities in relation to the offshore activities supported by these operations. Actual vessel activity data were collected from Tidewater Marine and C&C Boats, and additional data were provided by offshore operators. These data were used to define crew vessel activity associated with routine platform operations. A summary of the crew vessel activity data is presented in Table A.6-27.

In addition to the information discussed above, industry estimates of crew vessel activity associated with development well drilling, platform installation, and platform decommissioning and removal were used. Where specific data were not available, crew vessel activity estimates were developed based on available information from comparable operations. Additional references used in this effort included the Santa Barbara County/MMS Point Arguello Field EIR/EIS (A.D. Little, 1984) and the MMS OCS Leases P-0523 and P-0524 exploration and drilling plan (Dames & Moore, 1989).

Existing vessel activity records were evaluated in relation to available offshore employment data to develop crew vessel activity projections associated with different offshore development scenarios that could be readily updated to reflect future scenario revisions. Employment data are expected to provide a reasonable indicator of the demand for crew vessel activity, since the two are directly related. Employment data addressing each existing offshore platform were combined with crew vessel data for that platform to develop platform-specific crew vessel activity factors based on total Full-Time-Equivalent employment for that platform. These factors were used to develop crew vessel activity estimates associated with routine operations, well drilling, and platform decommissioning at each platform based on the estimated FTE employment for each activity. Crew vessel activity estimates associated with new platforms (including installation) were developed by application of factors determined for nearby facilities. For example, Sword Platform estimates were based on the crew vessel activity factor for Platforms Hermosa, Hidalgo, and Harvest, and Gato Canyon Platform estimates were based on the factor developed from Platforms Hondo, Harmony, and Heritage. An example of the crew vessel activity calculation is as follows:

Total FTE, Platforms A, B, C, Henry, Hillhouse, and Habitat:	87
Total weekly crew vessel traffic, same facilities:	28
Average crew vessel traffic per FTE (28/87):	0.3218

Table A.6-28 lists the facility-specific and composite factors used to develop crew vessel activity projections in this study. These factors were combined with scenario-specific employment estimates (Appendix A.3) to determine average weekly crew vessel activity associated with each five-year time period addressed in the COOGER study. The origin of crew vessels (Port Hueneme, Carpinteria/Casitas Pier, and Ellwood Pier) serving each offshore facility is also tabulated on Table A.6-28. Total crew vessel traffic associated with each scenario addressed in the COOGER study is indicated in Table A.6-29, and this information is summarized by the originating location of vessel trips in Table A.6-30. Table A.6-31 presents composite results for each possible combination of subregional scenarios.

TABLE A.6-27

CREW VESSEL ACTIVITY DATA
ROUTINE PLATFORM OPERATIONS
(AVERAGE VESSEL TRIPS PER WEEK)

Platform Operations	Crew Vessels (Per Week)
Gina Gilda	28
Gail Grace	14
Hermosa Harvest Hidalgo	0
Hogan Houchin	14
A, B, C Henry Hillhouse Habitat	28
Holly	28
Hondo Harmony Heritage	14
Irene	0

TABLE A.6-28
CREW VESSEL ACTIVITY FACTORS
BASED ON FULL-TIME-EQUIVALENT EMPLOYMENT

	Crew Vessels per FTE (per week)	Crew Vessel Origin[1]
Eastern Subregion		
Offshore Production Facilities		
Platform A	0.3218	C
Platform B	0.3218	C
Platform C	0.3218	C
Platform Hillhouse	0.3218	C
Platform Henry	0.3218	C
Platform Hogan	0.8750	C
Platform Houchin	0.8750	C
Platform Gina	0.9333	H
Platform Gilda	0.9333	H
Platform Grace	0.3415	H
Platform Gail	0.3415	H
Platform Habitat	0.3218	C
New Activity		
Platform Installation	0.4828	
Platform Decommissioning & Removal		
Platform A	0.3218	C
Platform B	0.3218	C
Platform C	0.3218	C
Platform Hillhouse	0.3218	C
Platform Henry	0.3218	C
Platform Hogan	0.8750	C
Platform Houchin	0.8750	C

[1]Crew Vessel locations of origin, as follows:
H = Port Hueneme
C = Carpinteria/Casitas Pier
E = Ellwood Pier

TABLE A.6-28 (Continued)
CREW VESSEL ACTIVITY FACTORS
BASED ON FULL-TIME-EQUIVALENT EMPLOYMENT

	Crew Vessels per FTE (per week)	**Crew Vessel Origin[1]**
Platform Gina	0.9333	H
Eastern Subregion (Continued)		
New Activity (Continued)		
Platform Decommissioning & Removal (Continued)		
Platform Gilda	0.9333	H
Platform Grace	0.3415	C
Platform Gail	0.3415	C
Platform Habitat	0.3218	C
Well Drilling		
Platform Hogan	0.8750	C
Platform Gail	0.3415	C
Rincon Island	0.0000	
Central Subregion		
Offshore Production Facilities		
Platform Holly	1.8667	E
Platform Hondo	0.1647	E
Platform Heritage	0.1647	E
Platform Harmony	0.1647	E
Platform Hermosa	0.0000	
Platform Hidalgo	0.0000	
Platform Harvest	0.0000	
Sword Platform	0.0000	
Pinon-Electra	0.0000	E
Gato Canyon Platform	0.1647	E

[1]Crew Vessel locations of origin, as follows:
H = Port Hueneme
C = Carpinteria/Casitas Pier
E = Ellwood Pier

TABLE A.6-28 (Continued)
CREW VESSEL ACTIVITY FACTORS
BASED ON FULL-TIME-EQUIVALENT EMPLOYMENT

	Crew Vessels per FTE (per week)	Crew Vessel Origin[1]
Central Subregion (Continued)		
New Activity		
Platform Installation		
Gato Canyon Platform	0.1647	E
Sword Platform	0.0000	
Platform Decommissioning & Removal		
Platform Holly	1.8667	E
Platform Hermosa	0.0000	
Platform Hidalgo	0.0000	
Platform Harvest	0.0000	
Well Drilling		
Gato Canyon Platform	0.1647	E
Rocky Point (Hermosa)	0.0000	
Pinon Electra (Hidalgo)	0.0000	
Sword Platform	0.0000	
Holly/South Ellwood	1.8667	E
Base Year Wells	0.1647	E
Sacate (Heritage)	0.1647	E
Northern Subregion		
Offshore Production Facilities		
Platform Irene	0.0000	
Bonito Platform	0.0000	
Rocky Point Platform	0.0000	
Lion Rock Platform	0.0000	

[1]Crew Vessel locations of origin, as follows:
H = Port Hueneme
C = Carpinteria/Casitas Pier
E = Ellwood Pier

TABLE A.6-28 (Continued)
CREW VESSEL ACTIVITY FACTORS
BASED ON FULL-TIME-EQUIVALENT EMPLOYMENT

	Crew Vessels per FTE (per week)	**Crew Vessel Origin[1]**
Northern Subregion (Continued)		
New Activity		
Platform Installation	0.0000	
Platform Decommissioning & Removal	0.0000	
Development Well Drilling	0.0000	

[1]Crew Vessel locations of origin, as follows:
H = Port Hueneme
C = Carpinteria/Casitas Pier
E = Ellwood Pier

TABLE A.6-29
CREW BOATS BY SCENARIO
TOTAL COOGER STUDY REGION
(AVERAGE VESSEL ROUND TRIPS PER WEEK)

	1997	2000	2005	2010	2015
Eastern Subregion					
Scenario 1	84	84	60	0	0
Scenario 2	84	84	76	18	13
Scenario 3	84	84	76	18	13
Scenario 4	84	84	50	0	0
Central Subregion					
Scenario 1	55	47	42	46	14
Scenario 2	55	47	77	50	46
Scenario 3	55	47	77	50	46
Scenario 4	55	47	77	50	46
Northern Subregion					
Scenario 1	0	0	0	0	0
Scenario 2	0	0	0	0	0
Scenario 3	0	0	0	0	0
Scenario 4	0	0	0	0	0
Scenario 2A	0	0	0	0	0
Scenario 3A	0	0	0	0	0
Scenario 4A	0	0	0	0	0

TABLE A.6-30
CREW BOATS BY SCENARIO
FROM POINT OF ORIGIN
(AVERAGE VESSEL ROUND TRIPS PER WEEK)

From Carpinteria/Casitas Pier:

	1997	2000	2005	2010	2015
Eastern Subregion					
Scenario 1	42	42	42	0	0
Scenario 2	42	42	48	6	4
Scenario 3	42	42	48	6	4
Scenario 4	42	45	34	0	0
Central Subregion					
All Scenarios	0	0	0	0	0
Northern Subregion					
All Scenarios	0	0	0	0	0

From Port Hueneme:

	1997	2000	2005	2010	2015
Eastern Subregion					
Scenario 1	42	42	18	0	0
Scenario 2	42	42	28	12	9
Scenario 3	42	42	28	12	9
Scenario 4	42	39	16	0	0
Central Subregion					
All Scenarios	0	0	0	0	0
Northern Subregion					
All Scenarios	0	0	0	0	0

From Ellwood Pier:

	1997	2000	2005	2010	2015
Eastern Subregion					
All Scenarios	0	0	0	0	0
Central Subregion					
Scenario 1	55	47	42	46	14
Scenario 2	55	47	77	50	46
Scenario 3	55	47	77	50	46
Scenario 4	55	47	77	50	46
Northern Subregion					
All Scenarios	0	0	0	0	0

TABLE A.6-31
PROJECTED COMBINED CREW BOAT ACTIVITY
ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]
(AVERAGE VESSEL ROUND TRIPS PER WEEK)

Scenario[2] (E,C,N)	1997	2000	2005	2010	2015
1, 1, 1	139	131	102	46	14
1, 1, 2	139	131	102	46	14
1, 1, 3	139	131	102	46	14
1, 1, 4	139	131	102	46	14
1, 2,1	139	131	137	50	46
1, 2,2	139	131	137	50	46
1, 2,3	139	131	137	50	46
1, 2,4	139	131	137	50	46
1,3,1	139	131	137	50	46
1,3,2	139	131	137	50	46
1,3,3	139	131	137	50	46
1,3,4	139	131	137	50	46
1,4,1	139	131	137	50	46
1,4,2	139	131	137	50	46
1,4,3	139	131	137	50	46
1,4,4	139	131	137	50	46
1,4,2A	139	131	137	50	46
1,4,3A	139	131	137	50	46
1,4,4A	139	131	137	50	46
2, 1, 1	139	131	118	64	27
2, 1, 2	139	131	118	64	27
2, 1, 3	139	131	118	64	27
2, 1, 4	139	131	118	64	27
2, 2,1	139	131	***153***	68	60
2, 2,2	139	131	***153***	68	60
2, 2,3	139	131	***153***	68	60
2, 2,4	139	131	***153***	68	60
2,3,1	139	131	***153***	68	60
2,3,2	139	131	***153***	68	60
2,3,3	139	131	***153***	68	60
2,3,4	139	131	***153***	68	60
2,4,1	139	131	***153***	68	60
2,4,2	139	131	***153***	68	60
2,4,3	139	131	***153***	68	60
2,4,4	139	131	***153***	68	60
2,4,2A	139	131	***153***	68	60
2,4,3A	139	131	***153***	68	60
2,4,4A	139	131	***153***	68	60

[1]Bold italicized numbers indicate increase compared to the base year (1997)
[2]Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion

TABLE A.6-31 (Continued)
PROJECTED COMBINED CREW BOAT ACTIVITY
ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]
(AVERAGE VESSEL ROUND TRIPS PER WEEK)

Scenario[2] (E,C,N)	1997	2000	2005	2010	2015
3, 1, 1	139	131	118	64	32
3, 1, 2	139	131	118	64	32
3, 1, 3	139	131	118	64	32
3, 1, 4	139	131	118	64	32
3, 2,1	139	131	***153***	68	64
3, 2,2	139	131	***153***	68	64
3, 2,3	139	131	***153***	68	64
3, 2,4	139	131	***153***	68	64
3, 3, 1	139	131	***153***	68	64
3, 3, 2	139	131	***153***	68	64
3, 3, 3	139	131	***153***	68	64
3, 3, 4	139	131	***153***	68	64
3, 4, 1	139	131	***153***	68	64
3, 4, 2	139	131	***153***	68	64
3, 4, 3	139	131	***153***	68	64
3, 4, 4	139	131	***153***	68	64
3, 4, 2A	139	131	***153***	68	64
3, 4, 3A	139	131	***153***	68	64
3, 4, 4A	139	131	***153***	68	64
4, 1, 1	139	131	92	46	14
4, 1, 2	139	131	92	46	14
4, 1, 3	139	131	92	46	14
4, 1, 4	139	131	92	46	14
4, 2, 1	139	131	127	50	46
4, 2, 2	139	131	127	50	46
4, 2, 3	139	131	127	50	46
4, 2, 4	139	131	127	50	46
4, 3, 1	139	131	127	50	46
4, 3, 2	139	131	127	50	46
4, 3, 3	139	131	127	50	46
4, 3, 4	139	131	127	50	46
4, 4, 1	139	131	127	50	46
4, 4, 2	139	131	127	50	46
4, 4, 3	139	131	127	50	46
4, 4, 4	139	131	127	50	46
4, 4, 2A	139	131	127	50	46
4, 4, 3A	139	131	127	50	46
4, 4, 4A	139	131	127	50	46

[1]Bold italicized numbers indicate increase compared to the base year (1997)
[2]Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion

A.6.5 Helicopter Activity

Projections of helicopter activity associated with different offshore development scenarios were developed by analysis of recent helicopter activity in relation to the offshore activities supported. Actual helicopter activity data were collected from offshore operators and published reports (A.D. Little, 1984 and Dames & Moore, 1989). These data were used to define helicopter activity associated with routine platform operations, and with specific activities (well drilling, platform installation, and platform decommissioning and removal).

Existing helicopter activity records were evaluated in relation to available offshore employment data to develop helicopter activity projections that could be readily updated to reflect future scenario revisions. Employment data are expected to provide a reasonable indicator of the demand for helicopter activity, since the two are directly related. Employment data for offshore platforms using helicopter service were combined with helicopter activity factors based on total Full-Time-Equivalent employment for each platform. These factors were used to estimate routine operational helicopter activity and helicopter flights associated with well drilling, platform installation, and platform decommissioning. The estimates developed in this study do not include agency inspection flights, since these are not directly related to individual facilities or the level of development. The Minerals Management Service currently operates five flights per week from the Camarillo Airport and five flights per week from the Santa Maria Airport. These flights would continue under all scenarios as long as offshore production facilities remain on the federal OCS. The calculation of helicopter activity factors was accomplished as indicated by the following example:

Total FTE, Platform Irene:	23
Total weekly helicopter traffic, Platform Irene:	4
Average weekly helicopter traffic per FTE (4/23):	0.1739

Table A.6-32 lists the facility-specific and composite factors used to develop helicopter activity projections in this study. These factors were combined with scenario-specific employment estimates (Appendix A.3) to determine average weekly helicopter activity associated with each five year time period addressed in the COOGER study. The origin of helicopter flights (Santa Barbara Airport, Lompoc Airport, and Santa Maria Airport) serving each offshore facility is also tabulated on Table A.6-32. Total helicopter traffic associated with each scenario addressed in the COOGER study is indicated in Table A.6-33, and this information is summarized by the originating location of helicopter flights in Table A.6-34. Table A.6-35 presents composite results for each possible combination of subregional scenarios. Because the Santa Barbara airport could support helicopter flights to offshore facilities associated with more than one study subregion, composite results of total helicopter flights originating from the Santa Barbara Airport for each possible combination of subregional scenarios is presented in Table A.6-36.

TABLE A.6-32
HELICOPTER ACTIVITY FACTORS
BASED ON FULL-TIME-EQUIVALENT EMPLOYMENT

OFFSHORE ACTIVITY	**Helicopter Flights Per FTE (Per Week)**	**Originating Airport[1]**
Eastern Subregion Offshore		
Production Facilities[2]	0.0000	--
New Activity		
Platform Installation	0.0000	--
Platform Decommissioning & Removal	0.0000	--
Well Drilling	0.0000	--
Central Subregion Offshore		
Production Facilities		
Platform Holly	0.0000	
Platform Hondo	0.1294	SBA
Platform Heritage	0.1294	SBA
Platform Harmony	0.1294	SBA
Platform Hermosa	0.2069	SBA
Platform Hidalgo	0.2069	SBA
Platform Harvest	0.2069	SBA
Sword Platform	0.2069	SBA
Gato Canyon Platform	0.1294	SBA
New Activity		
Platform Installation		
Gato Canyon Platform	0.1294	SBA
Sword Platform	0.2069	SBA
Platform Decommissioning & Removal		
Platform Holly	0.0000	SBA
Platform Hermosa	0.2069	SBA
Platform Hidalgo	0.2069	SBA
Platform Harvest	0.2069	SBA

[1]Helicopter originating airports include:
SBA = Santa Barbara
LOM = Lompoc
SMA = Santa Maria
[2]No Eastern Subregion platforms are routinely served by helicopter flights

TABLE A.6-32 (Continued)
HELICOPTER ACTIVITY FACTORS
BASED ON FULL-TIME-EQUIVALENT EMPLOYMENT

OFFSHORE ACTIVITY	**Helicopter Flights Per FTE (Per Week)**	**Originating Airport[1]**
Central Subregion Offshore (Continued)		
New Activity (Continued)		
Well Drilling		
Gato Canyon Platform	0.1294	SBA
Rocky Point (Hermosa)	0.2069	SBA
Pinon Electra (Hidalgo)	0.2069	SBA
Sword Platform	0.2069	SBA
Holly/South Ellwood	0.0000	SBA
Sacate (Heritage)	0.1294	SBA
Base Year Wells	0.1294	SBA
Northern Subregion Offshore		
Production Facilities		
Platform Irene	0.1739	LOM
Bonito Platform	0.1739	LOM
Lion Rock Platform	0.1739	SMA
Rocky Point Platform	0.2069	SBA
New Activity		
Platform Installation		
Bonito Platform	0.1739	LOM
Lion Rock Platform	0.1739	SMA
Sword Platform	0.2069	SBA
Rocky Point Platform	0.2069	SBA
Platform Decommissioning & Removal		
Irene	0.1739	LOM
Well Drilling		
Bonito	0.1739	LOM
Lion Rock/Santa Maria Basin	0.1739	SMA
Sword Platform	0.2069	SBA
Rocky Point Platform	0.2069	SBA

[1]Helicopter originating airports include:
SBA = Santa Barbara
LOM = Lompoc
SMA = Santa Maria

[2]No Eastern Subregion platforms are routinely served by helicopter flights

TABLE A.6-33
HELICOPTERS BY SCENARIO
TOTAL COOGER STUDY REGION
(AVERAGE HELICOPTER ROUND-TRIP FLIGHTS PER WEEK)

	1997	2000	2005	2010	2015
Eastern Subregion					
Scenario 1	0	0	0	0	0
Scenario 2	0	0	0	0	0
Scenario 3	0	0	0	0	0
Scenario 4	0	0	0	0	0
Central Subregion					
Scenario 1	39	33	27	14	11
Scenario 2	39	33	36	43	25
Scenario 3	39	33	36	43	25
Scenario 4	39	33	14	17	14
Northern Subregion					
Scenario 1	4	4	3	0	0
Scenario 2	4	4	4	15	6
Scenario 3	4	4	4	21	9
Scenario 4	4	4	4	32	10
Scenario 2A	4	4	17	17	21
Scenario 3A	4	4	17	37	17
Scenario 4A	4	4	17	48	19

TABLE A.6-34
HELICOPTERS BY SCENARIO
FROM POINT OF ORIGIN
(AVERAGE HELICOPTER ROUND-TRIP FLIGHTS PER WEEK)

From Santa Barbara Airport:

	1997	2000	2005	2010	2015
Eastern Subregion					
All Scenarios	0	0	0	0	0
Central Subregion					
Scenario 1	39	33	27	14	11
Scenario 2	39	33	36	43	25
Scenario 3	39	33	36	43	25
Scenario 4	39	33	14	17	14
Northern Subregion					
Scenario 1	0	0	0	0	0
Scenario 2	0	0	0	0	0
Scenario 3	0	0	0	0	0
Scenario 4	0	0	0	0	0
Scenario 2A	0	0	13	5	16
Scenario 3A	0	0	13	17	8
Scenario 4A	0	0	13	17	8

***From Oxnard Airport*:**

	1997	2000	2005	2010	2015
Eastern Subregion					
All Scenarios	0	0	0	0	0
Central Subregion					
All Scenarios	0	0	0	0	0
Northern Subregion					
All Scenarios	0	0	0	0	0

TABLE A.6-34 (Continued)
HELICOPTERS BY SCENARIO
FROM POINT OF ORIGIN
(AVERAGE HELICOPTER ROUND-TRIP FLIGHTS PER WEEK)

From Lompoc Airport:

	1997	2000	2005	2010	2015
Eastern Subregion					
All Scenarios	0	0	0	0	0
Central Subregion					
All Scenarios	0	0	0	0	0
Northern Subregion					
Scenario 1	4	4	3	0	0
Scenario 2	4	4	4	11	4
Scenario 3	4	4	4	11	4
Scenario 4	4	4	4	11	4
Scenario 2A	4	4	4	11	4
Scenario 3A	4	4	4	11	4
Scenario 4A	4	4	4	11	4

***From Santa Maria Airport*:**

	1997	2000	2005	2010	2015
Eastern Subregion					
All Scenarios	0	0	0	0	0
Central Subregion					
All Scenarios	0	0	0	0	0
Northern Subregion					
Scenario 1	0	0	0	0	0
Scenario 2	0	0	0	3	2
Scenario 3	0	0	0	9	4
Scenario 4	0	0	0	20	6
Scenario 2A	0	0	0	0	0
Scenario 3A	0	0	0	9	4
Scenario 4A	0	0	0	20	6

TABLE A.6-35
PROJECTED COMBINED HELICOPTER ACTIVITY
ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]
(AVERAGE HELICOPTER ROUND-TRIP FLIGHTS PER WEEK)

Scenario[2] (E,C,N)	**1997**	**2000**	**2005**	**2010**	**2015**
1, 1, 1	43	37	30	14	11
1, 1, 2	43	37	31	28	17
1, 1, 3	43	37	31	34	20
1, 1, 4	43	37	31	***45***	21
1, 2,1	43	37	39	***43***	25
1, 2,2	43	37	40	***58***	31
1, 2,3	43	37	40	***64***	34
1, 2,4	43	37	40	***75***	35
1,3,1	43	37	39	***43***	25
1,3,2	43	37	40	***58***	31
1,3,3	43	37	40	***64***	34
1,3,4	43	37	40	***75***	35
1,4,1	43	37	17	17	14
1,4,2	43	37	18	32	20
1,4,3	43	37	18	38	23
1,4,4	43	37	18	***49***	25
1,4,2A	43	37	31	34	35
1,4,3A	43	37	31	***54***	31
1,4,4A	43	37	31	***66***	33
2, 1, 1	43	37	30	14	11
2, 1, 2	43	37	31	28	17
2, 1, 3	43	37	31	34	20
2, 1, 4	43	37	31	***45***	21
2, 2,1	43	37	39	***43***	25
2, 2,2	43	37	40	***58***	31
2, 2,3	43	37	40	***64***	34
2, 2,4	43	37	40	***75***	35
2,3,1	43	37	39	***43***	25
2,3,2	43	37	40	***58***	31
2,3,3	43	37	40	***64***	34
2,3,4	43	37	40	***75***	35
2,4,1	43	37	17	17	14
2,4,2	43	37	18	32	20
2,4,3	43	37	18	38	23
2,4,4	43	37	18	***49***	25
2,4,2A	43	37	31	34	35
2,4,3A	43	37	31	***54***	31
2,4,4A	43	37	31	***66***	33

[1]Bold italicized numbers indicate increase compared to the base year (1997)
[2]Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion

TABLE A.6-35 (Continued)
PROJECTED COMBINED HELICOPTER ACTIVITY
ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]
(AVERAGE HELICOPTER ROUND-TRIP FLIGHTS PER WEEK)

Scenario[2] (E,C,N)	**1997**	**2000**	**2005**	**2010**	**2015**
3, 1, 1	43	37	30	14	11
3, 1, 2	43	37	31	28	17
3, 1, 3	43	37	31	34	20
3, 1, 4	43	37	31	***45***	21
3, 2,1	43	37	39	***43***	25
3, 2,2	43	37	40	***58***	31
3, 2,3	43	37	40	***64***	34
3, 2,4	43	37	40	***75***	35
3, 3, 1	43	37	39	***43***	25
3, 3, 2	43	37	40	***58***	31
3, 3, 3	43	37	40	***64***	34
3, 3, 4	43	37	40	***75***	35
3, 4, 1	43	37	17	17	14
3, 4, 2	43	37	18	32	20
3, 4, 3	43	37	18	38	23
3, 4, 4	43	37	18	***49***	25
3, 4, 2A	43	37	31	34	35
3, 4, 3A	43	37	31	***54***	31
3, 4, 4A	43	37	31	***66***	33
4, 1, 1	43	37	30	14	11
4, 1, 2	43	37	31	28	17
4, 1, 3	43	37	31	34	20
4, 1, 4	43	37	31	***45***	21
4, 2, 1	43	37	39	***43***	25
4, 2, 2	43	37	40	***58***	31
4, 2, 3	43	37	40	***64***	34
4, 2, 4	43	37	40	***75***	35
4, 3, 1	43	37	39	***43***	25
4, 3, 2	43	37	40	***58***	31
4, 3, 3	43	37	40	***64***	34
4, 3, 4	43	37	40	***75***	35
4, 4, 1	43	37	17	17	14
4, 4, 2	43	37	18	32	20
4, 4, 3	43	37	18	38	23
4, 4, 4	43	37	18	***49***	25
4, 4, 2A	43	37	31	34	35
4, 4, 3A	43	37	31	***54***	31
4, 4, 4A	43	37	31	***66***	33

[1]Bold italicized numbers indicate increase compared to the base year (1997)
[2]Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion

TABLE A.6-36
PROJECTED COMBINED HELICOPTER ACTIVITY FROM SANTA BARBARA AIRPORT ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]
(AVERAGE HELICOPTER ROUND-TRIP FLIGHTS PER WEEK)

Scenario[2] (E,C,N)	1997	2000	2005	2010	2015
1, 1, 1	39	33	27	14	11
1, 1, 2	39	33	27	14	11
1, 1, 3	39	33	27	14	11
1, 1, 4	39	33	27	14	11
1, 2,1	39	33	36	***43***	25
1, 2,2	39	33	36	***43***	25
1, 2,3	39	33	36	***43***	25
1, 2,4	39	33	36	***43***	25
1,3,1	39	33	36	***43***	25
1,3,2	39	33	36	***43***	25
1,3,3	39	33	36	***43***	25
1,3,4	39	33	36	***43***	25
1,4,1	39	33	14	17	14
1,4,2	39	33	14	17	14
1,4,3	39	33	14	17	14
1,4,4	39	33	14	17	14
1,4,2A	39	33	27	22	31
1,4,3A	39	33	27	35	23
1,4,4A	39	33	27	35	23
2, 1, 1	39	33	27	14	11
2, 1, 2	39	33	27	14	11
2, 1, 3	39	33	27	14	11
2, 1, 4	39	33	27	14	11
2, 2,1	39	33	36	***43***	25
2, 2,2	39	33	36	***43***	25
2, 2,3	39	33	36	***43***	25
2, 2,4	39	33	36	***43***	25
2,3,1	39	33	36	***43***	25
2,3,2	39	33	36	***43***	25
2,3,3	39	33	36	***43***	25
2,3,4	39	33	36	***43***	25
2,4,1	39	33	14	17	14
2,4,2	39	33	14	17	14
2,4,3	39	33	14	17	14
2,4,4	39	33	14	17	14
2,4,2A	39	33	27	22	31
2,4,3A	39	33	27	35	23
2,4,4A	39	33	27	35	23

[1]Bold italicized numbers indicate increase compared to the base year (1997)
[2]Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion

TABLE A.6-36 (Continued)
PROJECTED COMBINED HELICOPTER ACTIVITY FROM SANTA BARBARA AIRPORT ASSOCIATED WITH EACH COMBINATION OF SCENARIOS[1]
(AVERAGE HELICOPTER ROUND-TRIP FLIGHTS PER WEEK)

3, 1, 1	39	33	27	14	11
3, 1, 2	39	33	27	14	11
3, 1, 3	39	33	27	14	11
3, 1, 4	39	33	27	14	11
3, 2,1	39	33	36	***43***	25
3, 2,2	39	33	36	***43***	25
3, 2,3	39	33	36	***43***	25
3, 2,4	39	33	36	***43***	25
3, 3, 1	39	33	36	***43***	25
3, 3, 2	39	33	36	***43***	25
3, 3, 3	39	33	36	***43***	25
3, 3, 4	39	33	36	***43***	25
3, 4, 1	39	33	14	17	14
3, 4, 2	39	33	14	17	14
3, 4, 3	39	33	14	17	14
3, 4, 4	39	33	14	17	14
3, 4, 2A	39	33	27	22	31
3, 4, 3A	39	33	27	35	23
3, 4, 4A	39	33	27	35	23
4, 1, 1	39	33	27	14	11
4, 1, 2	39	33	27	14	11
4, 1, 3	39	33	27	14	11
4, 1, 4	39	33	27	14	11
4, 2, 1	39	33	36	***43***	25
4, 2, 2	39	33	36	***43***	25
4, 2, 3	39	33	36	***43***	25
4, 2, 4	39	33	36	***43***	25
4, 3, 1	39	33	36	***43***	25
4, 3, 2	39	33	36	***43***	25
4, 3, 3	39	33	36	***43***	25
4, 3, 4	39	33	36	***43***	25
4, 4, 1	39	33	14	17	14
4, 4, 2	39	33	14	17	14
4, 4, 3	39	33	14	17	14
4, 4, 4	39	33	14	17	14
4, 4, 2A	39	33	27	22	31
4, 4, 3A	39	33	27	35	23
4, 4, 4A	39	33	27	35	23

[1]Bold italicized numbers indicate increase compared to the base year (1997)
[2]Numbers indicate the scenarios combined to determine entries in each row. The first number refers to the Eastern Subregion scenario, the second number refers to the Central Subregion scenario, and the third number refers to the Northern Subregion

APPENDIX B

OIL & GAS FACILITY TECHNICAL DETAILS

APPENDIX B
OIL & GAS FACILITY TECHNICAL DETAILS

This Appendix provides additional technical information for the facility "systems" described in Sections 2.3 and 2.4. Figure B-1 identifies the facilities in the Eastern Subregion including identification of the offshore fields, the platforms that produce them, the onshore facilities associated with the platforms, and the pipelines that connect the facilities and that transport the products to market. Figure B-2 provides this information for the facilities in the Central and Northern Subregions.

This Appendix also includes a "System Profile" table for each onshore facility and pipeline system. The facility System Profile tables include information on the fields, platforms, pipelines, and distribution system connected to the facility and provide information about the facility. The pipeline System Profile tables include information about the pipelines, pump stations, and marine terminals, as applicable. A list of System Profile tables is presented on the following page.

LIST OF "SYSTEM PROFILE" TABLES

Table No. **Facility or Pipeline System**

TABLE B-1
SYSTEM PROFILE: MANDALAY ONSHORE SEPARATION FACILITY

BLOCK 1: FIELD PROFILE											
						Cumulative Production (12/31/94)			Current Production (1/1/95 unless noted)		
Field/ Unit	Lease Blocks in Field/Unit (OCS unless noted as a State Lease (PRC or SACS)	Name of Platforms in Field / Unit	Production From (formation)	Sulfur & H_2S in Oil (%/ppm)	H_2S in Gas (ppm)	Oil MMBO	Gas BCF	Water MMBW	Oil BOPD	Gas MCFD	Water BWPD
Hueneme	202, 203	Gina	Sespe	0/0	0	8.8	2.8	25.2	760 [(1)]	560 [(1)]	5,800 [(1)]
Santa Clara	215, 216, 217	Gilda	Monterey Repetto	2.5/100 0/0	2000 0	22.3	35.4	13.3	3,300 [(1)]	1,900 [(1)]	5,500 [(1)]

BLOCK 2: PLATFORM PROFILE														
					Well Information (as of 12/31/94 unless noted)									
Platform Name	Operator (as of 8/97)	Platform in Lease No.	Water Depth (ft.)	Year Installed	No. of Slots	Oil Flow	Oil Lift	Oil/Gas Shut In	Gas Complt.	Water Inject.	Gas Inject.	P&A Suspend	Water Disposal	Total Wells
Gina	Torch	202	95	1981	15	0	5	7	0	0	2	0	0	14
Gilda	Torch	216	205	1981	96	0	33	7/3	1	19	0	1	0	64

Notes: [(1)] Data from operator or agency representative (8/97); N/A - Not Applicable

TABLE B-1
SYSTEM PROFILE: MANDALAY ONSHORE SEPARATION FACILITY

BLOCK 3: FLOWLINE/PIPELINE PROFILE			
From / To	Material	Diameter	Comments
Gina to Mandalay Facility	3 phase (oil, water, gas) emulsion	10"	Design Flowrate: 15,000 BPD
Gina to Mandalay Facility	Gas	6"	Design Flowrate: 2,500 MCFD
Gilda to Mandalay Facility	Wet Oil	12"	Design Flowrate 20,000 BPD
Gilda to Mandalay Facility	Gas	10"	Design Flowrate: 10,000 MCFD
Mandalay Facility to Gilda	Treated Produced Water	6"	Design Flowrate: 15,000 BPD

TABLE B-1
SYSTEM PROFILE: MANDALAY ONSHORE SEPARATION FACILITY

BLOCK 4: FACILITY PROFILE (Note: "Current" and "Spare" are as of 1/1/95 unless noted)											
Process: Wet Oil (Input) (BPD Total Fluid) (Oil/Water Separation)				Process: Gas Processing / Treatment (MCFD)				Process: Water Treatment Plant (BWPD) (Produced Water Treatment Prior to Discharge)			
Design	Permit	Current	Spare	Design	Permit	Current	Spare	Design	Permit	Current	Spare
25,000	25,000 [2]	15,360 [1]	9,640	18,000 [1]	6,000 [2]	2,460 [1]	15,540 [1] (vs. design)	15,000	15,000 [1]	11,300 [1]	3,700

BLOCK 5: PRODUCT STORAGE & DISTRIBUTION PROFILE (Note: "Current" is as of 1/1/95 unless noted)							
Material	Onsite Storage	Quantity Distributed		Sent To	Sent By	Frequency	Comments
		Design	Current				
Oil (BOPD)	8,000 BBL	20,000	See Block 1	Ventura Pump Station	Pipeline	Continuous	See "Eastern Pipeline System" discussion
Gas (MCFD)	N/A	N/A	See Block 1	SCE - Mandalay Power Plant	Pipeline	Continuous	
Prod. Water (BWPD)	N/A	15,000	See Block 1	Platform Gilda	Pipeline	Continuous	
LPG	N/A						
Sulfur	N/A						
NGL	N/A			Blend into crude	N/A	N/A	

Notes: [1] Data from operator or agency representative (8/97); [2] Assume same as design; N/A - Not Applicable

TABLE B-2
SYSTEM PROFILE: WEST MONTALVO OPERATIONS

BLOCK 1: FIELD PROFILE											
Field/ Unit	Lease Blocks in Field/Unit (OCS unless noted as a State Lease (PRC or SACS)	Name of Platforms in Field / Unit	Production From (formation)	Sulfur & H_2S in Oil (%/ppm)	H_2S in Gas (ppm)	Cumulative Production (12/31/94)			Current Production (1/1/95 unless noted)		
						Oil MMBO	Gas BCF	Water MMBW	Oil BOPD	Gas MCFD	Water BWPD
West Montalvo	PRC-3314 & 735 (State Waters)	N/A	Colonia zone of Sespe formation	0/0	0	1.0	0.5	0.9	380 (1)	240(1)	580(1)

BLOCK 2: PLATFORM PROFILE															
Platform Name	Operator (as of 8/97)	Platform in Lease No.	Water Depth (ft.)	Year Installed	Well Information (as of 12/31/94 unless noted)										
					No. of Slots	Oil Flow	Oil Lift	Oil/Gas Shut In	Gas Complt.	Water Inject.	Gas Inject.	P&A Suspend	Water Disposal	Total Wells
N/A	Berry	N/A	N/A	N/A	N/A									11

BLOCK 3: FLOWLINE/PIPELINE PROFILE			
From / To	Material	Diameter	Comments
3314 Tank Battery to Ventura Tosco Pipeline	Oil	4"	Intermittent, Dry Oil to Sales
735 Tank Battery to Ventura Tosco Pipeline	Oil	6"	Intermittent, Dry Oil to Sales

Notes: (1) Data from operator or agency representative (8/97); N/A - Not Applicable

TABLE B-2
SYSTEM PROFILE: WEST MONTALVO OPERATIONS

BLOCK 4: FACILITY PROFILE (Note: "Current" and "Spare" are as of 1/1/95 unless noted)											
Process: Wet Oil (Input) (BPD Total Fluid) (Oil/Water Separation)				Process: Gas Processing / Treatment (MCFD)				Process: Water Treatment Plant (BWPD) (Produced Water Treatment Prior to Discharge)			
Design	Permit	Current	Spare	Design	Permit	Current	Spare	Design	Permit	Current	Spare
1197 (1)	1197 (2)	960 (1)	237	314(1)	314 (2)	240 (1)	74	595(1)	595 (2)	580 (1)	15

BLOCK 5: PRODUCT STORAGE & DISTRIBUTION PROFILE (Note: "Current" is as of 1/1/95 unless noted)							
Material	Onsite Storage	Quantity Distributed		Sent To	Sent By	Frequency	Comments
		Design	Current				
Oil (BOPD)	8,000 BBL	Rating Unknown (1)	See Block 1	Ventura Pump Station	Pipeline	Intermittent	
Gas (MCFD)	N/A	Rating Unknown (1)	See Block 1	SCE - Mandalay Power Plant	Pipeline	Continuous	
Prod. Water (BWPD)	8,250 BBL	Rating Unknown (1)	See Block 1	Onsite Injection Wells	Pipeline	Continuous	

Notes: (1) Data from operator or agency representative (8/97); (2) Assume same as design; N/A - Not Applicable

TABLE B-3
SYSTEM PROFILE: RINCON ISLAND AND STATE LEASE 145/410 OIL & GAS PROCESSING FACILITIES

BLOCK 1: FIELD PROFILE											
Field/ Unit	Lease Blocks in Field/Unit (OCS unless noted as a State Lease (PRC or SACS)	Name of Platforms in Field / Unit	Production From (formation)	Sulfur & H_2S in Oil (%/ppm)	H_2S in Gas (ppm)	Cumulative Production (12/31/94)			Current Production (1/1/95 unless noted)		
						Oil MMBO	Gas BCF	Water MMBW	Oil BOPD	Gas MCFD	Water BWPD
Rincon	PRC 427, 429, 1466	N/A (Rincon Island)	Pico	0/0	0	4.4	3.4	10.8	240 (1)	1,000(1)	500(1)
Rincon	PRC 145, 410	Onshore "offshore" wells	Pico	0/0	0	N/A	N/A	N/A	60(1)	500(1)	750(1)

BLOCK 2: PLATFORM PROFILE														
Platform Name	Operator (as of 8/97)	Platform in Lease No.	Water Depth (ft.)	Year Installed	Well Information (as of 12/31/94 unless noted)									
					No. of Slots	Oil Flow	Oil Lift	Oil/Gas Shut In	Gas Complt.	Water Inject.	Gas Inject.	P&A Suspend	Water Disposal	Total Wells
Rincon Island	Rincon Island Ltd. Partners	PRC 1466	45	1958	68	0	22 (1)	0	0	7	0	0	1	30
Onshore Wells for 145/410	Rincon Island Ltd. Partners	PRC 145, 410	N/A (onshore)	1958	N/A	0	8 (1)	0	0	1	0	0	0	9

Notes: (1) Data from operator or agency representative (8/97); N/A - Not Applicable

TABLE B-3
SYSTEM PROFILE: RINCON ISLAND AND STATE LEASE 145/410 OIL & GAS PROCESSING FACILITIES

BLOCK 3: FLOWLINE/PIPELINE PROFILE			
From / To	Material	Diameter	Comments
Rincon Island to 268,000 BBL Venoco Storage Tank	Oil	6" to 10" Chevron	
Rincon Island to Rincon Oil and Gas Processing Facility	Gas	6"	
State Lease 145/410 Facility to Rincon Oil and Gas Processing Facility	Gas	6"	
State Lease 145/410 Facility trucked to Texaco-Fillmore Pump Station	Oil	N/A	
From shore to Rincon Island	Fresh Water	2"	

TABLE B-3
SYSTEM PROFILE: RINCON ISLAND AND STATE LEASE 145/410 OIL & GAS PROCESSING FACILITIES

BLOCK 4: FACILITY PROFILE (Note: "Current" and "Spare" are as of 1/1/95 unless noted)											
Process: Wet Oil (Input) (BPD Total Fluid) (Oil/Water Separation)				Process: Gas Processing / Treatment (MCFD)				Process: Water Treatment Plant (BWPD) (Produced Water Treatment Prior to Discharge)			
Design	Permit	Current	Spare	Design	Permit	Current	Spare	Design	Permit	Current	Spare
3,795 [(1)]	3,795 [(1)]	1550 [(2)]	2245	1,000 [(3)]	1,000 [(3)]	1,000	0	2,784 [(1)]	2,784 [(1)]	1,250	1,534

Notes: [(1)] Historic peak operation for data available (1977-1994); [(2)] Data from operator or agency representative (8/97); [(3)] Data from operator that exceeds historic peak production (1977-1994)

TABLE B-3
SYSTEM PROFILE: RINCON ISLAND AND STATE LEASE 145/410 OIL & GAS PROCESSING FACILITIES

BLOCK 5A: PRODUCT STORAGE & DISTRIBUTION PROFILE

Rincon Island

Material	Onsite Storage	Quantity Distributed		Sent To	Sent By	Frequency	Comments
		Design	Current				
Oil (BOPD)	2,000 BBL	2,500	See Block 1	268,000 Barrel Venoco Tank	Pipeline	Continuous	
Gas (MCFD)	None	N/A	See Block 1	Rincon Oil and Gas Processing Facility	Pipeline	Continuous	
Prod. Water (BWPD)	3,000 BBL	N/A	See Block 1	Injection	Pipeline	Continuous	
LPG	N/A						
Sulfur	N/A						

BLOCK 5B: PRODUCT STORAGE & DISTRIBUTION PROFILE

State Lease 145/410 Facility

(Note: "Current" is as of 1/1/95 unless noted)

Material	Onsite Storage	Quantity Distributed		Sent To	Sent By	Frequency	Comments
		Design	Current				
Oil (BOPD)	2,750	2,000	See Block 1	Equilon Fillmore Pump Station	Truck	1 every other day	
Gas (MCFD)	None	N/A	See Block 1	Rincon Oil and Gas Processing Facility	Pipeline	Continuous	
Prod. Water (BWPD)	2,750	N/A	See Block 1	Injection	Pipeline	Continuous	
LPG	N/A						
Sulfur	N/A						

TABLE B-4
SYSTEM PROFILE: RINCON OIL & GAS PROCESSING FACILITY

BLOCK 1: FIELD PROFILE

Field/ Unit	Lease Blocks in Field/Unit (OCS unless noted as a State Lease (PRC or SACS)	Name of Platforms in Field / Unit	Production From (formation)	Sulfur & H_2S in Oil (%/ppm)	H_2S in Gas (ppm)	Cumulative Production (12/31/94)			Current Production (1/1/95 unless noted)		
						Oil MMBO	Gas BCF	Water MMBW	Oil BOPD	Gas MCFD	(2) Water BWPD
Carpinteria	240	Henry	Repetto	0.00	0.00	15.1	12.5	8.5	1,100 (1)	464 (1)	2,700 (1)
Dos Cuadras	240 241	Hillhouse	Repetto	0.00	0.00	58.1	32.9	48.3	1,900 (1)	1,800 (1)	7,000 (1)
		A	Repetto	0.00	0.00	92.2	42.4	162.9	2,900 (1)	2,300 (1)	27,000 (1)
		B	Repetto	0.00	0.00	70.1	35.4	146.6	2,000 (1)	2,600 (1)	25,000 (1)
		C	Repetto	0/0	0	12.8	6.1	13.0	1,220 (1)	825 (1)	2,900 (1)

BLOCK 2: PLATFORM PROFILE

Platform Name	Operator (as of 8/97)	Platform in Lease No.	Water Depth (ft.)	Year Installed	Well Information (as of 12/31/94 unless noted)									
					No. of Slots	Oil Flow	Oil Lift	Oil/Gas Shut In	Gas Complt.	Water Inject.	Gas Inject.	P&A Suspend	Water Disposal	Total Wells
Henry	Torch	240	174	1979	24	0	22	1	0	0	0	0	0	23
Hillhouse	Torch	240	190	1969	60	0	33	11	0	2	0	1	1	48
A	Torch	241	188	1968	57	0	35	12	0	7	0	0	0	54
B	Torch	241	190	1968	63	0	38	8	0	9	0	0	0	55
C	Torch	241	192	1977	60	0	25	2	0	11	0	1	0	39

Notes: (1) Data from operator or agency representative (8/97); (2) Most water separated on platform and reinjected rather than sent to shore; N/A - Not Applicable

TABLE B-4

SYSTEM PROFILE: RINCON OIL & GAS PROCESSING FACILITY

BLOCK 3: FLOWLINE/PIPELINE PROFILE			
From / To	Material	Diameter	Comments
Henry to Hillhouse	Wet Oil	8"	
Henry to Hillhouse	Wet Gas	8"	
Henry to Hillhouse	Produced Water	6"	
Hillhouse to “A”	Oil	8"	
Hillhouse to “A”	Wet Gas	8"	
Hillhouse to “A”	Fire Water	6"	
“C” to “B”	Wet Oil	6"	
“C” to “B”	Wet Gas	6"	
“B” to “C”	Injection Water	6"	
“A” and “B” to Rincon Oil and Gas Processing Facility	Wet Oil	12"	
“A” and “B” to Rincon Oil and Gas Processing Facility	Wet Gas	12"	
“A” and “B” to Rincon Oil and Gas Processing Facility	Water	6"	
Rincon Oil and Gas Processing Facility to 268,000 BBL Venoco Tank	Oil	6"	Design flowrate: 40,000 BPD

TABLE B-4
SYSTEM PROFILE: RINCON OIL & GAS PROCESSING FACILITY

BLOCK 4: FACILITY PROFILE (Note: "Current" and "Spare" are as of 1/1/95 unless noted)											
Process: Wet Oil (Input) (BPD Total Fluid) (Oil/Water Separation)				Process: Gas Processing / Treatment (MCFD)				Process: Water Treatment Plant (BWPD) (Produced Water Treatment Prior to Discharge)			
Design	Permit	Current	Spare	Design	Permit	Current	Spare	Design	Permit	Current	Spare
110,000	110,000	12,058	97,942	15,000	15,000 [(1)]	8,449	6,551	50,000	50,000 [(1)]	2,442	47,558.00

BLOCK 5: PRODUCT STORAGE & DISTRIBUTION PROFILE (Note: "Current" is as of 1/1/95 unless noted)							
Material	Onsite Storage	Quantity Distributed		Sent To	Sent By	Frequency	Comments
		Design	Current				
Oil (BOPD)	50,000	40,000	See Block 1	Venoco Tank	Pipeline	Continuous	
Gas (MCFD)	N/A	15,000	See Block 1	SoCal Gas	Pipeline	Continuous	
Prod. Water (BWPD)	N/A	50,000	See Block 1	Santa Clara Wastewater	Truck[(1)]	Varies	Most dewatering is performed at the platforms and limited water is separated onshore
LPG, NGLs	N/A			Blend in Crude (if any)			
Sulfur	N/A						

Notes: [(1)] Assume same as design; N/A - Not Applicable

TABLE B-5
SYSTEM PROFILE: LA CONCHITA OIL & GAS PROCESSING FACILITY

BLOCK 1: FIELD PROFILE

Field/ Unit	Lease Blocks in Field/Unit (OCS unless noted as a State Lease (PRC or SACS)	Name of Platforms in Field / Unit	Production From (formation)	Sulfur & H_2S in Oil (%/ppm)	H_2S in Gas (ppm)	Cumulative Production (12/31/94) Oil MMBO	Gas BCF	Water MMBW	Current Production (1/1/95 unless noted) Oil BOPD	Gas MCFD	Water BWPD
Carpinteria	State 3133, 3150 Fed 166, 240	Hogan	Repetto	0/0	0	17.9	17.9	32.8	545	1,184	2,852
		Houchin	Repetto	0/0	0	26.7	20.0	23.7	725	495	2,019

BLOCK 2: PLATFORM PROFILE

Platform Name	Operator (as of 8/97)	Platform in Lease No.	Water Depth (ft.)	Year Installed	Well Information (as of 12/31/94 unless noted) No. of Slots	Oil Flow	Oil Lift	Oil/Gas Shut In	Gas Compl.	Water Inject.	Gas Inject.	P&A Suspend	Water Disposal	Total Wells
Hogan	POOI	166	154	1967	66	0	15	17	0	0	4	0	0	36
Houchin	POOI	166	163	1967	60	0	14	18	0	0	0	1	0	33

TABLE B-5
SYSTEM PROFILE: LA CONCHITA OIL & GAS PROCESSING FACILITY

BLOCK 3: FLOWLINE/PIPELINE PROFILE			
From / To	Material	Diameter	Comments
Houchin to Hogan	Wet Oil	10"	
Houchin to Hogan	Gas	12"	Design pressure: 30 psi Current pressure (8/97)
Hogan to La Conchita	Wet Oil	10"	
Hogan to La Conchita	Gas	12"	Design Pressure: 30 psi Current pressure (8/97)
Hogan to Houchin	Water	4"	
Hogan to Houchin	Gas lift	10"	
La Conchita to 268,000 BBL Venoco Storage Tank	Oil	4"	
La Conchita to SoCal Gas Company	Gas	N/A	
La Conchita to Hogan	Water	4"	
La Conchita to Hogan	Gas Lift	10"	

Notes: N/A - Not Applicable

TABLE B-5
SYSTEM PROFILE: LA CONCHITA OIL & GAS PROCESSING FACILITY

BLOCK 4: FACILITY PROFILE (Note: "Current" and "Spare" are as of 1/1/95 unless noted)											
Process: Wet Oil (Input) (BPD Total Fluid) (Oil/Water Separation)				Process: Gas Processing / Treatment (MCFD)				Process: Water Treatment Plant (BWPD) (Produced Water Treatment Prior to Discharge)			
Design	Permit	Current	Spare	Design	Permit	Current	Spare	Design	Permit	Current	Spare
27,000	27,000 (2)	6,141 (1)	2,859	22,000	22,000 (2)	1,679 (1)	20,321	N/A	N/A	4,871 (1)	N/A

BLOCK 5: PRODUCT STORAGE & DISTRIBUTION PROFILE (Note: "Current" is as of 1/1/95 unless noted)							
Material	Onsite Storage	Quantity Distributed		Sent To	Sent By	Frequency	Comments
		Design	Current				
Oil (BOPD)	55,000 BBL	27,000	See Block 1	Venoco 268,000 BBL Storage Tank	Pipeline	Continuous	
Gas (MCFD)	N/A	22,000	See Block 1	Platform	Pipeline	Continuous	For gas lift wells
				SoCal Gas	Pipeline	Continuous	
Prod. Water (BWPD)	5,000 BBL	N/A	See Block 1	Platforms	Pipeline	Continuous	
LPG	N/A						
Sulfur	N/A						
Fire Water	10,000 BBL			Platforms	Pipeline	Continuous	

Notes: (1) Data from operator or agency representative (8/97); (2) Assume same as design; N/A - Not Applicable

TABLE B-6
SYSTEM PROFILE: CARPINTERIA OIL & GAS PROCESSING FACILITY

BLOCK 1: FIELD PROFILE

Field/ Unit	Lease Blocks in Field/Unit (OCS unless noted as a State Lease (PRC or SACS)	Name of Platforms in Field / Unit	Production From (formation)	Sulfur & H_2S in Oil (%/ppm)	H_2S in Gas (ppm)	Cumulative Production (12/31/94)			Current Production (1/1/95 unless noted)		
						Oil MMBO	Gas BCF	Water MMBW	Oil BOPD	Gas MCFD	Water BWPD
Sockeye	204, 205, 208, 209	Gail	Monterey & Sespe	5.4/0	9,300	15.1	44.8	5.3	8,342	21,760	6,981
Santa Clara	215, 216, 217	Grace	Monterey & Sespe	2.5/0	2,000	8.0	21.6	7.9	1,186	984	611

BLOCK 2: PLATFORM PROFILE

Platform Name	Operator (as of 2/99)	Platform in Lease No.	Water Depth (ft.)	Year Installed	Well Information (as of 12/31/94 unless noted)									
					No. of Slots	Oil Flow	Oil Lift	Oil/Gas Shut In	Gas Complt.	Water Inject.	Gas Inject.	P&A Suspend	Water Disposal	Total Wells
Gail	Venoco	205	739	1987	36	2	16	2/0	4	0.00	0.00	0.00	2	26
Grace	Venoco	217	318	1979	48	0.00	7	12/4	0.00	1	0.00	3	0.00	27

TABLE B-6
SYSTEM PROFILE: CARPINTERIA OIL & GAS PROCESSING FACILITY

BLOCK 3: FLOWLINE/PIPELINE PROFILE			
From / To	Material	Diameter	Comments
Gail to Grace	Oil	8"	Design flowrate: 15,000 BPD Design Pressure: 1,480 psi
Gail to Grace	Sour Gas	8"	Design flowrate: 20,000 MCFD Design Pressure: 1480 psi
Gail to Grace	Spare	8"	Design flowrate: 20,000 MCFD Design Pressure: 740 psi
Grace to Carpinteria	Oil	10"	Design flowrate: 25,000 BPD Design Pressure: 740 psi
Grace to Carpinteria (H_2S removed to less than 50 ppm)	Gas	10" to 12"	Design flowrate: 30,000 MCFD Design Pressure: 740 psi
Carpinteria to 268,000 BBL Venoco Storage Tank adjacent to the Rincon Oil and Gas Facility	Oil	10"	Design flowrate: 25,000 BPD Design Pressure: 740 psi
Carpinteria Oil & Gas to SoCal Gas	Gas	10"	Design flowrate: 30,000 MCFD Design Pressure: 1,480 psi

TABLE B-6
SYSTEM PROFILE: CARPINTERIA OIL & GAS PROCESSING FACILITY

BLOCK 4: FACILITY PROFILE (Note: "Current" and "Spare" are as of 1/1/95 unless noted)											
Process: Wet Oil (Input) (BPD Total Fluid) (Oil/Water Separation)				Process: Gas Processing / Treatment (MCFD)				Process: Water Treatment Plant (BWPD) (Produced Water Treatment Prior to Discharge)			
Design	Permit	Current	Spare	Design	Permit	Current	Spare	Design	Permit	Current	Spare
40,000	40,000 (1)	9,996	30,004	28,000	28,000 (1)	20,112	7,888	As of August 1997, plant abandoned and oil is dewatered offshore			

BLOCK 5: PRODUCT STORAGE & DISTRIBUTION PROFILE (Note: "Current" is as of 1/1/95 unless noted)							
Material	Onsite Storage	Quantity Distributed		Sent To	Sent By	Frequency	Comments
		Design	Current				
Oil (BOPD)	217,000	N/A	See Block 1	268,000 BBL Venoco Storage Tank	Pipeline	Continuous	
Gas (MCFD)	N/A	N/A	See Block 1	SoCal Gas	Pipeline	Continuous	H_2S removed offshore. Onshore gas processing includes final removal of remaining 50 ppm.
Prod. Water (BWPD)	N/A	N/A	See Block 1				Separated on platform and reinjected
LPG	N/A						Blended with oil
Sulfur	N/A						

Notes: (1) Assume same as design; N/A - Not Applicable

TABLE B-7
SYSTEM PROFILE: CARPINTERIA ONSHORE GAS TERMINAL

BLOCK 1: FIELD PROFILE											
Field/ Unit	Lease Blocks in Field/Unit (OCS unless noted as a State Lease (PRC or SACS)	Name of Platforms in Field / Unit	Production From (formation)	Sulfur & H_2S in Oil (%/ppm)	H_2S in Gas (ppm)	Cumulative Production (12/31/94)			Current Production (1/1/95 unless noted)		
						Oil MMBO	Gas BCF	Water MMBW	Oil BOPD	Gas MCFD	Water BWPD
Pitas Point	234, 436	Habitat	Lower Repetto, Pico	N/A / N/A	0	0.2	184.3	2.0	10 (1)	10,600 (1)	1,000 (1)

BLOCK 2: PLATFORM PROFILE														
Platform Name	Operator (as of 8/97)	Platform in Lease No.	Water Depth (ft.)	Year Installed	Well Information (as of 12/31/94 unless noted)									
					No. of Slots	Oil Flow	Oil Lift	Oil/Gas Shut In	Gas Compl.	Water Inject.	Gas Inject.	P&A Suspend	Water Disposal	Total Wells
Habitat	Torch	234	290	1981	24	0	0	0/7	13	0	0	2	0	22

BLOCK 3: FLOWLINE/PIPELINE PROFILE			
From / To	Material	Diameter	Comments
Habitat to Carpinteria Onshore Gas Terminal	Gas	12.75	Design flowrate: 110 MMCFD

Notes: (1) Data from operator or agency representative (8/97); N/A - Not Applicable

TABLE B-7
SYSTEM PROFILE: CARPINTERIA ONSHORE GAS TERMINAL

BLOCK 4: FACILITY PROFILE (Note: "Current" and "Spare" are as of 1/1/95 unless noted)											
Process: Wet Oil (Input) (BPD Total Fluid) (Oil/Water Separation)				Process: Gas Processing / Treatment (MCFD)				Process: Water Treatment Plant (BWPD) (Produced Water Treatment Prior to Discharge)			
Design	Permit	Current	Spare	Design	Permit	Current	Spare	Design	Permit	Current	Spare
N/A	N/A	N/A	N/A	110,000	110,000 (2)	10,600 (1)	99,400	N/A	N/A	N/A	N/A

BLOCK 5: PRODUCT STORAGE & DISTRIBUTION PROFILE (Note: "Current" is as of 1/1/95 unless noted)							
Material	Onsite Storage	Quantity Distributed		Sent To	Sent By	Frequency	Comments
		Design	Current				
Oil (BOPD)	N/A						Condensate taken to another platform or shore by boat
Gas (MCFD)	None	110,000	See Block 1	SoCal Gas	Pipeline	Continuous	
Prod. Water (BOPD)	N/A						Handled offshore
LPG	N/A						
Sulfur	N/A						

Notes: (1) Data from operator or agency representative (8/97); (2) Assume same as design; N/A - Not Applicable

TABLE B-8
SYSTEM PROFILE: EASTERN PIPELINE SYSTEM

BLOCK 1: PIPELINE SYSTEM PROFILE							
Pipeline From / To	Material	Line Diameter	Heated (Yes or No)	Type P-Private C-Common	Throughput Design (BBLs/Hr)	Throughput Typical (BBLs/Hr)	Comments
Carpinteria Oil & Gas Processing Facility to 268,000 BBL Venoco tank at the Rincon Oil & Gas Processing Facility	Oil	10"	No	P	1,750	400	Pump capacity for design rate
La Conchita Oil & Gas Processing Facility to the pipeline from the Carpinteria Oil & Gas Processing Facility to the 268,000 BBL Venoco tank	Oil	4"	No	P	N/A	50	
Rincon Island Oil and Gas Processing Facility to the pipeline from the Carpinteria Oil & Gas Processing Facility to the 268,000 BBL Venoco tank	Oil	6"	No	P	N/A	10	
Rincon Oil & Gas Processing Facility to 268,000 BBL Venoco tank at the Rincon Oil & Gas Processing Facility	Oil	6"	No	P	N/A	350	
268,000 BBL Venoco tank at the Rincon Oil & Gas Processing Facility to M-143 Pipeline Block Valve	Oil	22"	No	P	3,000	810	Design pressure: 880 psig Typical pressure: 150-300 psig County information
M-143 Pipeline Block Valve by the 268,000 BBL Venoco tank to Ventura Pump Station	Oil	22"	No	P	3,000	915	Design pressure: 880 psig Typical pressure: 150-300 psig County information. Two connections from onshore oil fields connect into the M-143 pipeline en route.
Mandalay Onshore Separation Facility to Ventura Pump Station	Oil	6/8"	No	P	833	550	Pump capacity for design rate
Ventura Pump Station to Santa Paula Pump Station	Oil	8"	No	P		1,000	

TABLE B-8
SYSTEM PROFILE: EASTERN PIPELINE SYSTEM

BLOCK 1: PIPELINE SYSTEM PROFILE							
					Throughput		
Pipeline From / To	Material	Line Diameter	Heated (Yes or No)	Type P-Private C-Common	Design (BBLs/Hr)	Typical (BBLs/Hr)	Comments
Santa Paula Pump Station to Torrey Pump Station	Oil	8"	No	P		1,000	
Torrey Pump Station to Los Angeles	Oil	12"	No	P		1,300	

Notes: N/A - Not Applicable

TABLE B-8
SYSTEM PROFILE: EASTERN PIPELINE SYSTEM

BLOCK 2: PUMP STATION / MARINE TERMINAL PROFILE					
	Storage Tank Capacity (BBL)		Pumping Rate (Output) (Barrels per Hour - BPH)		
Pump Station / Marine Terminal	Design	Permit	Design	Typical	Comments
1. Ventura Pump Station	285,000	285,000	N/A	1,000	
2. Santa Paula Pump Station	55,000	55,000	N/A	1,000	
3. Torrey Pump Station	160,000	160,000	1,666[(1)]	1,300	
4. 268,000 BBL Venoco tank at the Rincon Oil & Gas Processing Facility	268,000	268,000	3,000	900	

Notes: N/A - Not Applicable; [(1)] Data from operator or agency representative

TABLE B-9

SYSTEM PROFILE: ELLWOOD OIL & GAS PROCESSING FACILITY / ELLWOOD MARINE TERMINAL

BLOCK 1: FIELD PROFILE

Field/ Unit	Lease Blocks in Field/Unit (OCS unless noted as a State Lease (PRC or SACS)	Name of Platforms in Field / Unit	Production From (formation)	Sulfur & H_2S in Oil (%/ppm)	H_2S in Gas (ppm)	Cumulative Production (12/31/94)			Current Production (1/1/95 unless noted)		
						Oil MMBO	Gas BCF	Water MMBW	Oil BOPD	Gas MCFD	Water BWPD
Ellwood and South Ellwood	PRC 208, 3120, 3242	Holly (data for Holly only)	Monterey, Rincon, Sisquoc	4.0/ 10,000 (Monterey)	15,000 (Monterey)	51.7	40.2	29.8	4,090	2,739	8,962
		Total for Holly, Subsea, & Seep Tents	Monterey, Rincon, Sisquoc, Vaquero/Sespe	Average 3.9/9,700	Average 13,200	53.0	48.7	31.3	4,090	3,498	8,962

BLOCK 2: PLATFORM PROFILE

Platform Name	Operator (as of 8/97)	Platform in Lease No.	Water Depth (ft.)	Year Installed	Well Information (as of 12/31/94 unless noted)									
					No. of Slots	Oil Flow	Oil Lift	Oil/Gas Shut In	Gas Complt.	Water Inject.	Gas Inject.	P&A Suspend	Water Disposal	Total Wells
Holly	Venoco	3242	211	1969	30	0.00	23	0.00	0.00	0.00	0.00	11	1	35

TABLE B-9
SYSTEM PROFILE: ELLWOOD OIL & GAS PROCESSING FACILITY / ELLWOOD MARINE TERMINAL

BLOCK 3: FLOWLINE/PIPELINE PROFILE			
From / To	Material	Diameter	Comments
Holly to Ellwood Oil & Gas Processing Facility	Wet oil	6"	
Holly to Ellwood Oil & Gas Processing Facility	Gas	6"	
Seep Tents to Ellwood Oil & Gas Processing Facility	Gas	8"	

TABLE B-9
SYSTEM PROFILE: ELLWOOD OIL & GAS PROCESSING FACILITY / ELLWOOD MARINE TERMINAL

BLOCK 4: FACILITY PROFILE (Note: "Current" and "Spare" are as of 1/1/95 unless noted)											
Process: Dry Oil (Output) BPD (Oil/Water Separation)				Process: Gas Processing / Treatment (MCFD)				Process: Water Treatment Plant (BWPD) (Produced Water Treatment Prior to Discharge)			
Design	Permit	Current	Spare (1)	Design	Permit	Current	Spare (1)	Design	Permit	Current	Spare (1)
20,000	13,000	3,334	0	20,000	13,000	2,882	0	8,200	8,200 (2)	6,668	0

BLOCK 5: PRODUCT STORAGE & DISTRIBUTION PROFILE (Note: "Current" is as of 1/1/95 unless noted)							
Material	Onsite Storage	Quantity Distributed		Sent To	Sent By	Frequency	Comments
		Design	Current				
Oil (BOPD)	6,000 BBL	10,000	See Block 1	Marine Terminal	Pipeline	Continuous	Barge loading every 9-12 days (Additional storage at Marine Terminal)
Gas (MCFD)	N/A	N/A	See Block 1	SoCal Gas	Pipeline	Continuous	
Prod. Water (BWPD)	10,000 BBL	N/A	See Block 1	Onsite Injection Wells	Onsite Pipeline	Continuous	
Sulfur	N/A	N/A	4,000 lbs/day	Sales	Truck		
NGL/LPG (3)	N/A	N/A	See Comment	LPG to Sales	Truck		Number of truck trips in 6/97. Total 198 trucks during Jan-June 1997.

N/A - Not Applicable

Notes: (1) Spare capacity is not available to production sources other than Platform Holly. At the direction of Santa Barbara County, Ellwood Oil Facility spare capacity is treated as zero to reflect this limitation, although Facility capacity to accommodate up to 13,000 BPD dry oil, 13 MMCFD gas, and 8,200 BWPD produced water is presumed available for production from Platform Holly throughout the COOGER study time frame.
(2) Assume same as design
(3) NGL blended into crude

TABLE B-10
SYSTEM PROFILE: LAS FLORES CANYON SYU OIL & GAS PROCESSING FACILITY

BLOCK 1: FIELD PROFILE											
Field/ Unit	Lease Blocks in Field/Unit (OCS unless noted as a State Lease (PRC or SACS)	Name of Platforms in Field / Unit	Production From (formation)	Sulfur & H_2S in Oil (%/ppm)	H_2S in Gas (ppm)	Cumulative Production (12/31/94)			Current Production (1/1/95 unless noted)		
						Oil MMBO	Gas BCF	Water MMBW	Oil BOPD	Gas MCFD	Water BWPD
Hondo/SYU	180, 181, 187, 188, 190, 191, 329, 461	Hondo	Monterey	#4.5/8,000	#8,000	135.5	217.1	30.5	16,394	32,694	8,621
		Harmony	Monterey	#4.5/8,000	#8,000	3.1	1.7	0.8	19,014	11,481	5,767
Pescado /SYU	182,183	Heritage	Monterey	#4.5/8,000	#8,000	5.5	1.5	0.1	34,875	9,935	518

BLOCK 2: PLATFORM PROFILE														
Platform Name	Operator (as of 8/97)	Platform in Lease No.	Water Depth (ft.)	Year Installed	Well Information (as of 12/31/94 unless noted)									
					No. of Slots	Oil Flow	Oil Lift	Oil/Gas Shut In	Gas Compl.	Water Inject.	Gas Inject.	P&A Suspend	Water Disposal	Total Wells
Hondo	Exxon	188	842	1976	28	7	15	3	1	1	1	0	1	29
Harmony	Exxon	190	1,200	1992	60	0	6	1	0	0	0	0	0	7
Heritage	Exxon	182	1,075	1992	60	0	9	1	0	0	1	0	0	11

TABLE B-10
SYSTEM PROFILE: LAS FLORES CANYON SYU OIL & GAS PROCESSING FACILITY

BLOCK 3: FLOWLINE/PIPELINE PROFILE			
From / To	Material	Diameter	Comments
Heritage to Harmony	Wet Oil	20"	
Heritage to Harmony (proposed as of 8/97)	Gas	12"	
Harmony to Las Flores Canyon Oil & Gas Processing Facility	Wet Oil	20"	Design flowrate: 125,000 BPD
Las Flores Canyon Oil & Gas Processing Facility to Harmony	Water	12"	
Harmony to Hondo	Gas	12"	
Hondo to Harmony	Wet Oil	14"	
Hondo to Las Flores Canyon Oil & Gas Processing Facility & Las Flores Canyon Gas Processing Facility	Gas	12"	Design flowrate: 90 MMCFD
Las Flores Canyon Oil & Gas Processing Facility to AAPLP Sisquoc Pump Station	Oil	24"	Design flowrate: 150,000 BPD Design pressure: 1028 psi

TABLE B-10
SYSTEM PROFILE: LAS FLORES CANYON SYU OIL & GAS PROCESSING FACILITY

BLOCK 4: FACILITY PROFILE (Note: "Current" and "Spare" are as of 1/1/95 unless noted)											
Process: Dry Oil (Output) BPD (Oil/Water Separation)				Process: Gas Processing / Treatment (MCFD)				Process: Water Treatment Plant (BWPD) (Produced Water Treatment Prior to Discharge)			
Design	Permit	Current	Spare	Design	Permit	Current	Spare	Design	Permit	Current	Spare
100,000 [1]	140,000	90,397	9,603	21,000 (as built)	21,000	21,000	0	60,000	87,000	25,156	34,844
Process:				Process: Stripping Gas Treatment Plant (Sulfur)				Process: Cogen Unit			
Design	Permit	Current	Spare	Design	Permit	Current	Spare	Design	Permit	Current	Spare
				20 TPD	20 TPD [2]	Varies	Varies	49 MW	49 MW	Varies	Varies

BLOCK 5: PRODUCT STORAGE & DISTRIBUTION PROFILE (Note: "Current" is as of 1/1/95 unless noted)							
Material	Onsite Storage	Quantity Distributed		Sent To	Sent By	Frequency	Comments
		Design	Current				
Oil (BOPD)	540,000 BBL	N/A	See Block 1	AAPLP System	Pipeline	Continuous	See "AAPLP Pipeline System"
Gas (MCFD)	N/A	N/A	See Block 1	SoCal Gas	Pipeline	Continuous	Processed gas also consumed onsite in cogeneration plant and other uses.
Prod. Water (BWPD)	N/A	N/A	See Block 1	Platform Harmony	Pipeline	Continuous	
Sulfur	N/A	N/A	N/A	Sales	Truck	Periodic	
NGL/LPG [3]	N/A	N/A	N/A	NGL Blended into crude LPG to sales	LPG by Truck	Periodic	62 truck trips in June 1997 Total 305 truck during the period Jan-May 1997

Notes: [1] Data from operator or agency representative (8/99); [2] Assume same as design; [3] Operation as of 8/98; N/A - Not Applicable

TABLE B-11
SYSTEM PROFILE: LAS FLORES CANYON GAS PROCESSING FACILITY

BLOCK 1: FIELD PROFILE

Field/ Unit	Lease Blocks in Field/Unit (OCS unless noted as a State Lease (PRC or SACS)	Name of Platforms in Field / Unit	Production From (formation)	Sulfur & H_2S in Oil (%/ppm)	H_2S in Gas (ppm)	Cumulative Production (12/31/94)			Current Production (1/1/95 unless noted)		
						Oil MMBO	Gas BCF	Water MMBW	Oil BOPD	Gas MCFD	Water BWPD
Hondo	180, 181, 187, 188, 190, 191, 329	Hondo	Monterey	<4.5/800 0	#8,000	135.5	217.1	30.5	16,394	32,694	8,621
		Harmony	Monterey	<4.5/8000	#8,000	3.1	1.7	0.8	19,014	11,481	5,767

BLOCK 2: PLATFORM PROFILE

Platform Name	Operator (as of 8/97)	Platform in Lease No.	Water Depth (ft.)	Year Installed	Well Information (as of 12/31/94 unless noted)									
					No. of Slots	Oil Flow	Oil Lift	Oil/Gas Shut In	Gas Compl t.	Water Inject.	Gas Inject.	P&A Suspend	Water Disposal	Total Wells
Hondo	Exxon	188	842	1976	28	7	15	3	1	1	1	0	1	29
Harmony	Exxon	190	1,200	1992	60	0	6	1	0	0	0	0	0	7

TABLE B-11
SYSTEM PROFILE: LAS FLORES CANYON GAS PROCESSING FACILITY

BLOCK 3: FLOWLINE/PIPELINE PROFILE			
From / To	Material	Diameter	Comments
Harmony to Hondo	Gas	12"	
Hondo to Las Flores Canyon Oil & Gas Processing Facility & Las Flores Canyon Gas Processing Facility	Gas	12"	Design flowrate: 90 MMCFD
Las Flores Canyon Gas Processing Facility to Las Flores Canyon Oil & Gas Processing Facility	NGL	3"	Planning installation 4/97 Design flowrate: 400,000 BPY

TABLE B-11
SYSTEM PROFILE: LAS FLORES CANYON GAS PROCESSING FACILITY

BLOCK 4: FACILITY PROFILE (Note: "Current" and "Spare" are as of 1/1/95 unless noted)											
Process: Wet Oil (Input) (BPD Total Fluid) (Oil/Water Separation)				Process: Gas Processing / Treatment (MCFD)[1]				Process: Water Treatment Plant (BWPD) (Produced Water Treatment Prior to Discharge)			
Design	Permit	Current	Spare	Design	Permit	Current	Spare	Design	Permit	Current	Spare
N/A				75,000	75,000	36,544	23,466	N/A			

BLOCK 5: PRODUCT STORAGE & DISTRIBUTION PROFILE (Note: "Current" is as of 1/1/95 unless noted)							
Material	Onsite Storage	Quantity Distributed		Sent To	Sent By	Frequency	Comments
		Design	Current				
Oil (BOPD)	N/A						Facility processes gas only from 2 Exxon platforms and is expanding capacity to 60 MMCFD
Gas (MCFD)	N/A	N/A	See Block 1	SoCal Gas	Pipeline	Continuous	
Prod. Water (BWPD)	N/A						
Sulfur	N/A	N/A	N/A	Sales	Truck		Distribution permit limitation: 60 LTPD
NGL/LPG [2]	N/A	N/A	115 trucks	Sales	Truck		115 trucks during June 1997 [3]

Notes: [1] Spare Capacity reflects prior permit limit of 60,000 MCFD, Design and Permit Capacities reflect current (9/99) levels; [2] NGL sent by pipeline to Las Flores Canyon SYU Oil & Gas Processing Facility and blended into crude as of 8/98; [1] Data from operator or agency representative (8/97); N/A - Not Applicable

TABLE B-12
SYSTEM PROFILE: GAVIOTA OIL & GAS PROCESSING FACILITY

BLOCK 1: FIELD PROFILE

Field/ Unit	Lease Blocks in Field/Unit (OCS unless noted as a State Lease (PRC or SACS)	Name of Platforms in Field / Unit	Production From (formation)	Sulfur & H_2S in Oil (%/ppm)	H_2S in Gas (ppm)	Cumulative Production (12/31/94)			Current Production (1/1/95 unless noted)		
						Oil MMBO	Gas BCF	Water MMBW	Oil BOPD	Gas MCFD	Water BWPD
Point Arguello Unit	315, 316, 320, 447, 450, 451	Hermosa	Monterey	#3.6/ #1,500	#9,800	33.5	14.5	2.0	29,371	15,590	5,501
		Harvest	Monterey	#4.0/ #1,500	#10,000	32.4	15.2	2.5	34,600	16,820	7,799
		Hidalgo	Monterey	#3.6/ #1,500	#9,800	10.4	4.4	2.3	7,508	3,064	4,502

BLOCK 2: PLATFORM PROFILE

Platform Name	Operator (as of 8/97)	Platform in Lease No.	Water Depth (ft.)	Year Installed	Well Information (as of 12/31/94 unless noted)									
					No. of Slots	Oil Flow	Oil Lift	Oil/Gas Shut In	Gas Complt.	Water Inject.	Gas Inject.	P&A Suspend	Water Disposal	Total Wells
Hermosa	Chevron	316	602	1985	48	5	6	1	0	0	0	2	0	14
Harvest	Chevron	315	670	1985	50	0	7	7	0	0	0	5	0	19
Hidalgo	Chevron	450	430	1986	56	0	10	0	0	0	0	0	0	10

TABLE B-12
SYSTEM PROFILE: GAVIOTA OIL & GAS PROCESSING FACILITY

BLOCK 3: FLOWLINE/PIPELINE PROFILE			
From / To	Material	Diameter	Comments
Harvest to Hermosa	Wet Oil	12"	Design flowrate: 80,000 BPD [1] Design pressure: 1,480 psig [1]
Harvest to Hermosa	Sour Gas	8"	Design flowrate: 60 MMCFD [1] Design pressure: 1,480 psig [1]
Hidalgo to Hermosa	Wet Oil	16"	Design flowrate: 100,000 BPD [1] Design pressure: 1,480 psig
Hidalgo to Hermosa	Sour Gas	10"	Design flowrate: 75 MMCFD [1] Design pressure: 1,480 psig
Hermosa to Gaviota Oil & Gas Processing Facility	Wet Oil	24"	Design flowrate: 200,000 BPD [1] Design pressure: 700 psig [1]
Hermosa to Gaviota Oil & Gas Processing Facility	Sour Gas	20"	Design flowrate: 250 MMCFD Design pressure: 1,400 psi
Gaviota Oil & Gas Processing Facility to AAPLP Booster Station via Gaviota Oil Terminal Tanks	Oil	24"	Design flowrate: 150,000 BPD Design pressure: 275 psi

Notes: [1] Data from operator or agency representative (8/97); N/A - Not Applicable

TABLE B-12
SYSTEM PROFILE: GAVIOTA OIL & GAS PROCESSING FACILITY

BLOCK 4: FACILITY PROFILE (Note: "Current" and "Spare" are as of 1/1/95 unless noted)											
Process: Wet Oil (Input) (BPD Total Fluid) (Oil/Water Separation)				Process: Gas Processing / Treatment (MCFD)				Process: Water Treatment Plant (BWPD) (Produced Water Treatment Prior to Discharge)			
Design	Permit	Current	Spare	Design	Permit	Current	Spare	Design	Permit	Current	Spare
125,000 (as built)	250,000	79,572	45,428	60,000 (1) (as built)	120,000	24,501	35,499	25,000	25,000 (2)	10,890	14,110
Process: NGL System (BPD)				Process: Gas/Liquid Removal (MMCFD)				Process: Sulfur Recover Unit (LTPD)			
Design	Permit	Current	Spare	Design	Permit	Current	Spare	Design	Permit	Current	Spare
3,364	3,364 (2)	1,800	1,564	75	75 (2)	29	28	20	20 (2)	8	12

BLOCK 5: PRODUCT STORAGE & DISTRIBUTION PROFILE (Note: "Current" is as of 1/1/95 unless noted)							
Material	Onsite Storage	Quantity Distributed		Sent To	Sent By	Frequency	Comments
		Design	Current				
Oil (BOPD)	10,000 BBL	250,000	See Block 1	AAPLP System	Pipeline	Continuous	Additional storage at the Gaviota Oil Terminal
Gas (MCFD)	N/A	N/A	See Block 1	SoCal Gas	Pipeline	Continuous	
Prod. Water (BWPD)	N/A	N/A	See Block 1	Ocean	Pipeline	Continuous	
Sulfur (LTPD)	N/A	20	8	Sales	Truck	Varies	
NGL/LPG (BPD)	N/A	3,364	See Comment	LPG (NGL blended into crude)/sales	Truck	Varies	45 truck trips for June 1997 (1) Total 215 trucks during the period Jan-June 1997

Notes: (1) Data from operator or agency representative (8/97); (2) Assume same as design; N/A - Not Applicable

TABLE B-13
SYSTEM PROFILE: GAVIOTA OIL TERMINAL

BLOCK 1: PIPELINE SYSTEM PROFILE							
Pipeline From / To	Material	Line Diameter	Heated (Yes or No)	Type P-Private C-Common	Throughput		Comments
					Design (BBLs/Day)	Storage (BBLs/Day)	
Gaviota Oil & Gas Processing Facility to storage tanks at the Gaviota Oil Terminal	Oil	20"	No	C	200,000		Facility is only used for storage of oil from the Gaviota Oil & Gas Processing Facility prior to gravity feed or pumping it into the AAPLP feederline pipeline
AAPLP Booster Station (by storage tanks) to AAPLP Gaviota Pump Station	Oil	24"	No	C	150,000		From the Gaviota Oil Terminal storage tanks crude oil is gravity fed or pumped to AAPLP's booster station where it is pumped via the 24-inch feederline to metering systems at the Gaviota Pump Station

TABLE B-13
SYSTEM PROFILE: GAVIOTA OIL TERMINAL

BLOCK 2: PUMP STATION / MARINE TERMINAL PROFILE							
	Storage Tank Capacity (BBL)		Pumping Rate (Output) (Barrels per Day - BPD)				
Pump Station / Marine Terminal	Design	Permit	Design	Permit	Typical	Spare	Comments
AAPLP Booster Station	N/A	N/A	150,000	150,000	28,000	122,000	The AAPLP Booster Station has no storage tanks; it relies on the storage tanks at the Gaviota Oil Terminal
Gaviota Oil Terminal	350,000 (in service)		N/A				The terminal is not used to load barges or tankers. It is in the process of being dismantled.

Notes: N/A - Not Applicable

TABLE B-14
SYSTEM PROFILE: COJO BAY MARINE TERMINAL

BLOCK 1: PIPELINE SYSTEM PROFILE							
Pipeline From / To	Material	Line Diameter	Heated (Yes or No)	Type P-Private C-Common	Throughput		Comments
					Design (BBLs/Hr)	Typical (BBLs/Hr)	
Cojo storage tank to marine loading	Oil	N/A	N/A	N/A	N/A	N/A	Terminal is idle and likely will not operate again per Santa Barbara County

BLOCK 2: PUMP STATION / MARINE TERMINAL PROFILE						
Pump Station / Marine Terminal	Storage Tank Capacity (BBL)		Pumping Rate (Output) (Barrels per Hour - BPH)			Comments
	Design	Permit	Design	Typical	Spare	
Cojo Bay Marine Terminal	N/A	N/A	N/A	N/A	N/A	See Block 1

Notes: N/A - Not Applicable

TABLE B-15
SYSTEM PROFILE: AAPLP PIPELINE SYSTEM

BLOCK 1: PIPELINE SYSTEM PROFILE							
Pipeline From / To	Material	Line Diameter	Heated (Yes or No)	Type P-Private C-Common	Throughput Design (BBLs/Hr)	Throughput Typical (BBLs/Hr)	Comments
Las Flores Canyon Pump Station to Gaviota Pump Station	Oil	24"	N[(1)]	C	6,250	2,645	4-1250 hp electrical centrifugal pumps Insulated line Design pressure: 1028 psig
Gaviota Booster Station to Gaviota Pump Station	Oil	24"	N[(1)]	C	6,250	1,230	Insulated line 3 vertical can booster pumps Design pressure: 275 psig
Gaviota Pump Station to Sisquoc Pump Station	Oil	30"	N[(1)]	C	12,500	3,875	Pump—3,750 hp Insulated line Design pressure: 1,341 psig
Sisquoc Pump Station to Pentland Pump Station	Oil	30"	N[(1)]	C	12,500	2,536	Insulated line 3-2,500 hp and 1-1,250 hp electrical, centrifugal pumps Design pressure: 1,341 psig

Notes: [(1)] Not currently operated as a heated pipeline although capability exists from the Pentland Pump Station eastward along the pipeline system to Texas; N/A - Not Applicable

TABLE B-15
SYSTEM PROFILE: AAPLP PIPELINE SYSTEM

BLOCK 2: PUMP STATION / MARINE TERMINAL PROFILE						
	Storage Tank Capacity (BBL)		Pumping Rate (Output) (Barrels per Hour - BPH)			
Pump Station / Marine Terminal	Design	Permit	Design	Typical	Spare	Comments
Las Flores Pump Station	0	0	6,250	2,645	3,605	No storage, draw from storage tanks at Las Flores Canyon SYU Oil & Gas Processing Facilities
Gaviota Booster Station	0	0	6,250	1,230	5,020	No storage at booster station, use tanks at Gaviota Oil Terminal
Gaviota Pump Station	0	0	6,250	3,875	2,375	No storage, draw from storage at Gaviota Oil & Gas Processing Facility
Sisquoc Pump Station	0	0	12,500	3,800	8,700	No storage, combined crude oil from Las Flores and Gaviota pumped to Tosco or to Pentland

Notes: N/A - Not Applicable

TABLE B-16
SYSTEM PROFILE: LOMPOC HS&P FACILITY

BLOCK 1: FIELD PROFILE											
						Cumulative Production (12/31/94)			Current Production (1/1/95 unless noted)		
Field/ Unit	Lease Blocks in Field/Unit (OCS unless noted as a State Lease (PRC or SACS)	Name of Platforms in Field / Unit	Production From (formation)	Sulfur & H_2S in Oil (%/ppm)	H_2S in Gas (ppm)	Oil MMBO	Gas BCF	Water MMBW	Oil BOPD	Gas MCFD	Water BWPD
Point Pedernales Unit	437, 438, 440, 441	Irene	Monterey	5/2,000	2,000	41.8	9.1	25.7	11,000 (1)	4,500 (1)	57,000 (1)

BLOCK 2: PLATFORM PROFILE														
					Well Information (as of 12/31/94 unless noted)									
Platform Name	Operator (as of 8/97)	Platform in Lease No.	Water Depth (ft.)	Year Installed	No. of Slots	Oil Flow	Oil Lift	Oil/Gas Shut In	Gas Complt.	Water Inject.	Gas Inject.	P&A Suspend	Water Disposal	Total Wells
Irene	Torch	441	242	1985	72	2	10	8	0	0	0	3	0	24

BLOCK 3: FLOWLINE/PIPELINE PROFILE			
From / To	Material	Diameter	Comments
Irene to Lompoc HS&P Facility	Wet Oil	20"	Design pressure: 2,160 psig
Irene to Lompoc HS&P Facility	Sour Gas	8"	Design pressure: 2,160 psig
Lompoc HS&P Facility to Irene	Water	8"	

Notes: (1) Data from operator or agency representative (8/97)

TABLE B-16
SYSTEM PROFILE: LOMPOC HS&P FACILITY

BLOCK 4: FACILITY PROFILE (Note: "Current" and "Spare" are as of 1/1/95 unless noted)											
Process: Wet Oil (Input) (BPD Total Fluid) (Oil/Water Separation)				Process: Gas Processing / Treatment (MCFD)				Process: Water Treatment Plant (BWPD) (Produced Water Treatment Prior to Discharge)			
Design	Permit	Current	Spare	Design	Permit	Current	Spare	Design	Permit	Current	Spare
80,000 (Wet In)	36,000 (Dry Out)	66,000 wet (1) 11,000 dry (1)	14,000 wet 25,000 dry	15,000	15,000	4,500 (1)	10,500	57,000	57,000 (2)	46,800	10,200

BLOCK 5: PRODUCT STORAGE & DISTRIBUTION PROFILE (Note: "Current" is as of 1/1/95 unless noted)							
Material	Onsite Storage	Quantity Distributed		Sent To	Sent By	Frequency	Comments
		Design	Current				
Oil (BOPD)	100,000 BBL cap. permit max. 25,000	N/A	See Block 1	Orcutt Pump Station	Pipeline	Continuous	See "Northern Pipeline System" Quantity distribution permit limit: 36,000 dry oil
Gas (MCFD)	N/A	9,000 (15,000 new)	See Block 1	Currently injected (1) SoCal Gas (new plant)	Pipeline	Continuous	Expanding gas plant from 9 to 15 MMCFD, in progress 8/97 Quantity distribution permit limit: 15,000
Prod. Water (BWPD)	N/A	N/A	See Block 1	Onshore Lompoc Oil Field	Pipeline for injection	Continuous	Injected in oil field
NGL/LPG	N/A			NGL blend into crude LPG to sales	Truck	Periodic	Approximately 14 trucks per month
Sulfur	N/A						

Notes: (1) Data from operator or agency representative (8/97); (2) Assume same as design; N/A - Not Applicable/Provided

TABLE B-17
SYSTEM PROFILE: SANTA MARIA ASPHALT REFINERY

BLOCK 1: FIELD PROFILE												
Field/ Unit	Lease Blocks in Field/Unit (OCS unless noted as a State Lease (PRC or SACS)	Name of Platforms in Field / Unit	Production From (formation)	Sulfur & H_2S in Oil (%/ppm)	H_2S in Gas (ppm)	Cumulative Production (12/31/94)			Current Production (1/1/95 unless noted)		
						Oil MMBO	Gas BCF	Water MMBW	Oil BOPD	Gas MCFD	Water BWPD
N/A											

BLOCK 2: PLATFORM PROFILE														
Platform Name	Operator (as of 8/97)	Platform in Lease No.	Water Depth (ft.)	Year Installed	Well Information (as of 12/31/94 unless noted)									
					No. of Slots	Oil Flow	Oil Lift	Oil/Gas Shut In	Gas Complt.	Water Inject.	Gas Inject.	P&A Suspend	Water Disposal	Total Wells
N/A														

BLOCK 3: FLOWLINE/PIPELINE PROFILE			
From / To	Material	Diameter	Comments
N/A			

Notes: N/A - Not Applicable

TABLE B-17
SYSTEM PROFILE: SANTA MARIA ASPHALT REFINERY

BLOCK 4: FACILITY PROFILE (Note: "Current" and "Spare" are as of 1/1/95 unless noted)											
Process: Dry Oil (BPD)				Process: Distillate Processing (BPD)				Process: Water Treatment Plant (BWPD) (Produced Water Treatment Prior to Discharge)			
Design	Permit	Current	Spare	Design	Permit	Current	Spare	Design	Permit	Current	Spare
10,000	10,000	5,000 (1)	5,000	3,000 (1)	3,000 (2)	1,750 (1)	1,250	N/A			

BLOCK 5: PRODUCT STORAGE & DISTRIBUTION PROFILE (Note: "Current" is as of 1/1/95 unless noted)							
Material	Onsite Storage (BBLS)	Quantity Distributed		Sent To	Sent By	Frequency	Comments
		Design	Current				
Oil	117,000	N/A	See comments	Sales	Truck	Daily or as needed	Product type and quantity varies depending on feedstock. Asphalt quantity distribution permit limit: 10,000
Distillate	35,000	3,000	See comments	Sales	Truck	Daily or as needed	
Asphalt	325,000	10,000	See comments	Sales	Truck	Daily or as needed	

Notes: (1) Data from operator or agency representative (8/97); (2) Assume same as design; N/A - Not Applicable

TABLE B-18
SYSTEM PROFILE: SANTA MARIA REFINERY

BLOCK 1: FIELD PROFILE												
Field/ Unit	Lease Blocks in Field/Unit (OCS unless noted as a State Lease (PRC or SACS)	Name of Platforms in Field / Unit	Production From (formation)	Sulfur & H_2S in Oil (%/ppm)	H_2S in Gas (ppm)	Cumulative Production (12/31/94)			Current Production (1/1/95 unless noted)		
						Oil MMBO	Gas BCF	Water MMBW	Oil BOPD	Gas MCFD	Water BWPD
N/A											

BLOCK 2: PLATFORM PROFILE														
Platform Name	Operator (as of 8/97)	Platform in Lease No.	Water Depth (ft.)	Year Installed	Well Information (as of 12/31/94 unless noted)									
					No. of Slots	Oil Flow	Oil Lift	Oil/Gas Shut In	Gas Complt.	Water Inject.	Gas Inject.	P&A Suspend	Water Disposal	Total Wells
N/A														

Notes: N/A - Not Applicable

TABLE B-18
SYSTEM PROFILE: SANTA MARIA REFINERY

BLOCK 3: FLOWLINE/PIPELINE PROFILE			
From / To	Material	Diameter	Comments
Summit Pump Station to Santa Maria Refinery	Dry Oil	10"	Design flowrate: 72,000 BPD Design pressure: 800 psig
Santa Maria Refinery to Summit Pump Station	Naphtha/Gas Oil	8"	Design flowrate: 41,000 BPD Design pressure: 1,000 psig
Santa Maria Refinery to North of Avila Pump Station	Crude/Gas Oil Distillate	8"	Design flowrate: 36,000 BPD Design pressure: 1,000 psig

TABLE B-18
SYSTEM PROFILE: SANTA MARIA REFINERY

BLOCK 4: FACILITY PROFILE
(Note: "Current" and "Spare" are as of 1/1/95 unless noted)

Process: Dry Oil (Input) (BPD Total Fluid)				Process: Gas (MCFD)				Process:			
Design	Permit	Current	Spare	Design	Permit	Current	Spare	Design	Permit	Current	Spare
44,440	44,440	42,220	220	10,736	10,736 (1)	10,200	536				

BLOCK 5: PRODUCT STORAGE & DISTRIBUTION PROFILE
(Note: "Current" is as of 1/1/95 unless noted)

Material	Onsite Storage	Quantity Distributed		Sent To	Sent By	Frequency	Comments
		Design	Current				
Oil (BOPD)	N/A (2)	1,685	1,600	San Francisco Bay Area	Pipeline	Batch	Plant is running at 95% capacity
Gas (MCFD)	N/A	10,736	10,200	Used onsite	Onsite pipelines	Continuous	
Naphtha (BPD)	N/A(2)	1,682	1,600	San Francisco Bay Area	Pipeline	Batch	
Distillate Oil	N/A(2)	N/A	N/A	San Francisco Bay Area			
Coke (TPD)	N/A(3)	N/A	1,400	Sales	Truck or rail	Periodic	
Sulfur (TPD)	N/A(3)	96	91	Sales	Truck	Periodic	

Notes: (1) Assume same as design; (2) Tank service can change as needed; (3) Stored in piles; N/A - Not Applicable

TABLE B-19
SYSTEM PROFILE: NORTHERN PIPELINE SYSTEM

BLOCK 1: PIPELINE SYSTEM PROFILE							
					Throughput		
Pipeline From / To	Material	Line Diameter	Heated (Yes or No)	Type P-Private C-Common	Design (BBLs/Day)	Typical (BBLs/Day)	Operating Pressure (psig)
Lompoc HS&P Facility to Orcutt Pump Station	Crude Oil	12"	No	P	96,000	34,000	Design pressure: 800 Typical pressure: 250
Orcutt Pump Station to Suey Junction	Crude Oil	8"	Yes	P	50,400	34,000	Design pressure: 800 Typical pressure: 450-750
Sisquoc Pump Station to Santa Maria Pump Station	Crude Oil	12"	No	P	50,400	20,000	Design pressure: 1000 Typical pressure: 250-400
Santa Maria Pump Station to Suey Junction	Crude Oil	10" and 12"	No	P	120,000	30,000	Design pressure: 800 Typical pressure: 700-750
Suey Junction to Summit Pump Station	Crude Oil	10" and 12" and 8"	No	P	108,000	42,000	Design Pressure: 800
Summit Pump Station to Santa Maria Refinery	Crude Oil	10"	Yes	P	72,000	42,000	Design pressure: 800 Typical pressure: 250-350
Summit Pump Station to Avila Pump Station	Crude Oil	12"	Yes	P	40,000	Idle	Design pressure: 800
Santa Maria Refinery to Summit Pump Station	Naphtha Gas Oil	8"	No	P	41,000	Idle	Design pressure: 1000
Santa Maria Refinery to North of Avila	Naptha/Gas Oil /Distillate	8" - 12"	No	P	36,000	37,500	Design pressure: 1000
Avila to out of Study Region	Naptha/Gas Oil / Distillate	Two 8"	Yes	P	57,600	37,500	

TABLE B-19
SYSTEM PROFILE: NORTHERN PIPELINE SYSTEM

BLOCK 2: PUMP STATION PROFILE						
	Storage Tank Capacity (BBL)		Pumping Rate (Output) (Barrels per day BPD)			
Pump Station / Marine Terminal	Design	Permit	Design	Typical	Spare	Comments
Orcutt Pump Station	N/A	N/A	44,000	Varies	Varies	Permit Capacity 36,000 BPD
Summit Pump Station	N/A	N/A	72,000	Varies	Varies	
Sisquoc Pump Station	N/A	N/A	36,000	Varies	Varies	
Santa Maria Pump Station	80,000	N/A	30,400	Varies	Varies	

Notes: N/A - Not Applicable

APPENDIX C

UPDATE MONITORING

APPENDIX C
UPDATE MONITORING

C.1 BACKGROUND

The COOGER study presents a twenty year projection of offshore oil and gas development potential and onshore infrastructure demands associated with a range of hypothetical development scenarios. The study projections are based on offshore geologic, exploratory well and production performance data which were available in 1995 and supplemental detail provided by participating offshore operators from 1995 through 1998. Information concerning onshore processing facility capacities and pipeline system capacities are current as of July 1999, as are the projected development schedules of existing undeveloped offshore leases. As (or if) the process of offshore oil exploration, delineation, and development proceeds, new information will become available that may justify updates to this report to maintain its usefulness. The need for such updates is directly related to the degree of variance between actual and expected conditions, and the effect of this variance on topics related to infrastructure demand. This appendix outlines a straightforward procedure to help evaluate the need for report updates.

The COOGER study defines a range of development and related infrastructure demand in relation to different general policy controls, which are expressed as scenario guidelines. The most restrictive of these guidelines is described in Scenario 1 (in all subregions), which describes future offshore oil activity and related infrastructure demand without any further offshore development. This scenario defines the low end of the range of oil and gas production and related activity. The least restrictive of the COOGER study scenarios is Scenario 3 in the Eastern and Central Subregions and Scenario 4 in the Northern Subregion. These scenarios define the upper end of the range of commercially viable offshore oil and gas production and related activity in the absence of onshore facility capacity limitations or other limits associated with industrial or public infrastructure capacity. The COOGER study also provides intermediate scenarios to help illustrate the effect of more moderate scenario guidelines. The information in this report is expected to provide a useful overview of oil industry infrastructure demand as long as actual development activity is within the range defined by the extremes addressed in this report.

Because this report is based on a twenty-year projection of a highly uncertain business, future conditions could vary substantially from current projections. Individual variations that yield subregion-wide results within the range described in this study are not expected to justify a detailed study update, but may require ongoing recordkeeping to accumulate all such variations in possible future updates. Once actual conditions (or revised industry projections, if available) yield results outside the COOGER study range described by aggregate subregional results, a study update may be warranted. The information that should be routinely monitored to evaluate the need for such updates, and a suggested procedure for applying the information in the COOGER report and its confidential data appendices (and accompanying database) to accomplish this evaluation is described below. In addition to the maintenance of study accuracy, periodic study updates may be appropriate to extend the study time frame addressed by this report.

C.2 MONITORING OF INDUSTRY ACTIVITY

The information presented in the COOGER study represents a summary of detailed facility-specific and field-specific data that was developed using proprietary data provided by the MMS, CSLC, and participating companies. A confidential technical appendix accompanies the COOGER report which presents detailed annual data concerning projected production and related activity for individual offshore and onshore facilities associated with each scenario described in the COOGER report. This confidential technical appendix provides the primary data source for the update evaluation process. The aggregate total of projections for all facilities within a subregion provide the basis for the COOGER study analysis. The principal factors which influence study results and can be easily monitored to identify appropriate updates include:

- Projected development schedules of undeveloped fields on existing leases
- Actual production from active offshore facilities and onshore processing facilities used
- Industrial infrastructure changes associated with the decommissioning or addition of facilities (onshore and offshore)
- Level of well drilling activity

Although the confidential technical appendix should be used for detailed analysis during the update evaluation process, a summary of the COOGER study projections for each scenario is presented in Tables C.2-1 through C.2-5 as a reference for monitoring purposes. The collection of data and evaluation of update requirements is discussed below.

C.2.1 Projected Development Schedules

Operator proposals related to field exploration, delineation, and development should be monitored by accumulating proposals and applications filed with regulatory agencies. Lease suspension proposals, exploration plans, and development/production plans filed with the MMS and CSLC will be particularly useful input to this aspect of the update analysis. To evaluate this information in the context of COOGER study projections, the following information should be tabulated:

- List of oil fields to be developed (compare to COOGER list to identify new fields or deletions of previously identified fields)
- Activities required prior to field development and production for each field (compare to COOGER study Table 3.3-1)
- Projected first production from each field (compare to COOGER study Table 3.3-1, scenario-specific facility activity schedules in Tables 3.5-4, 3.5-7, and 3.5-10, and annual production tables for each field in the COOGER confidential appendix)
- Projected schedule of exploratory and development well drilling in numbers of wells per year (compare to field-specific well drilling schedules in the COOGER confidential technical appendix)

The data tabulated above should then be reviewed to identify substantial differences from the expectations in the COOGER study. This information should be used to modify the development timetables reflected in the field-specific annual production estimates in the COOGER confidential technical appendix and accompanying database.

C.2.2 Actual Production Data

Actual production data associated with all existing facilities should be collected and compared to the facility-specific annual production projections which are presented for five-year increments in the COOGER report (and are presented by year in the COOGER confidential technical appendix). If consistent differences are noted in multiple years, the original reserve estimate and decline curve for the field in question should be reevaluated. Isolated differences should be addressed by revision of the COOGER production database. Aggregate total production for each subregion should be compared to COOGER projections for the same years as a convenient cross-check. Substantial differences between actual production and COOGER projections for the same five-year period (approximately 10% greater than Scenario 3 [Central and Eastern] or Scenario 4 [Northern], or 10% less than Scenario 1) indicate that a study update may be appropriate. Further analysis is required to fully evaluate the need for an update. This additional analysis involves the analysis of additional data concerning industrial infrastructure described below along with the development schedule and production data already discussed.

C.2.3 Industrial Infrastructure Capacity

Agency records of onshore facility modifications, decommissioning, and new facilities should be collected to update the transport and processing facility design and permitted capacity in each subregion. This information should be readily available from development plan applications or permits from county planning agencies. Useful data may also be available from county air pollution control districts, regional water quality control boards, and the California Coastal Commission. Facility capacity data presented in Section 2.4 of the COOGER report should be compared to this information. If differences are noted, corrections should be entered into the COOGER facility technical database. Any new processing facility site in the Eastern or Central Subregion would likely require a COOGER study update, since no new sites were anticipated in these subregions. Only one new site was identified for any scenario in the Northern Subregion, and a report update would be appropriate if two or more new facilities are identified in this area. Early facility decommissioning or modified facility capacities may contribute to the need to update this report, and should be evaluated along with other information to confirm the need of a report update.

C.3 EVALUATION OF UPDATE NEEDS

If the monitoring activity described in Section C.2 fails to identify any clear discrepancies with the COOGER study five-year summary tabulations or the detailed annual tabulations in the confidential technical appendix, a study update is not needed. If one or more of the topics listed above reveal substantial differences, a reevaluation of development extremes should be accomplished to determine the need for a comprehensive study update. This reevaluation should be accomplished as follows:

- Projected development schedule data discussed in Section C.2.1 should be used to revise the development timetables reflected in the COOGER confidential database Scenario 3 (Eastern and Central Subregions) and Scenario 4 (Northern Subregion). Revisions reflecting the termination and decommissioning of existing operations should also be incorporated into these scenarios, as well as into Scenario 1 for all subregions.

- The COOGER confidential database should also be revised by entering actual production records and updated decline curve analysis results where they were identified as necessary (discussed in Section C.2.2).

- Industrial transport and processing capacities should be updated on the COOGER confidential database.

- The Scenario 1, Scenario 3 (Eastern and Central Subregions), and Scenario 4 (Northern Subregion) production analysis should be rerun by application of the COOGER confidential database. Results should be tabulated for each 5-year period presented in the COOGER report for comparison.

The interpretation of the results of this effort may involve subjective judgement concerning identified differences. In general, if projected production in each subregion is within the low and high production estimates reflected by COOGER study results for Scenarios 1 and 3 (or Scenario 4 in the Northern Subregion) during each 5-year period, a report update is not necessary. If the projected production is within low and high estimates in some cases and never falls outside this range by more than 10 percent, the decision to pursue a study update should incorporate qualitative factors, such as the nature of specific facility changes or potential for concentrated activity which was not reflected in the original analysis. Even if a study update is not pursued, redefinition of scenario components and documentation of development schedule revisions would be appropriate to communicate identified changes and provide clear input to future updates. Projected production greater than 10% beyond the range defined by the low and high COOGER scenario estimates should be addressed by updating the COOGER study analysis.

The analysis of updated production data should be presented as subregional totals for each COOGER study five-year period in direct comparison to the original COOGER projections. This aggregate presentation could be released to interested parties, such as County agencies, to discuss decisions concerning document updates. These updates may be focused on individual components of the COOGER study, such as a single subregion or specific facility changes. If updates are accomplished in this manner, results should be issued as report amendments to minimize effort and cost. A master list of all report amendments should be updated and released with each new amendment.

TABLE C.2-1
COOGER STUDY ACTIVITY PROJECTIONS[1]
SCENARIO 1

	2000	2005	2010	2015
Eastern Subregion				
Oil Production Daily Average (BOPD)	11,895	2,247	1,005	0
Gas Production Daily Average (MMCFD)	22.7	2.7	1.2	0.0
No. Platforms Installed	0	0	0	0
No. Platforms Removed	0	12	0	0
No. Wells Drilled	0	0	0	0
Central Subregion				
Oil Production Daily Average (BOPD)	115,317	39,678	20,521	12,000
Gas Production Daily Average (MMCFD)	147.8	171.0	108.5	95.9
No. Platforms Installed	0	0	0	0
No. Platforms Removed	0	2	2	0
No. Wells Drilled	46	0	0	0
Northern Subregion				
Oil Production Daily Average (BOPD)	6,055	0	0	0
Gas Production Daily Average (MMCFD)	1.4	0.0	0.0	0.0
No. Platforms Installed	0	0	0	0
No. Platforms Removed	0	1	0	0
No. Wells Drilled	0	0	0	0

[1] Table entries for well drilling and platform installation and removal indicate the totals for the preceding 5-year period (e.g.: entries for the year 2005 include the total number of referenced activities over the period January 1, 2001 through December 31, 2005). Daily average production rates of oil and gas reflect the single year referenced (i.e.: table entries for the year 2005 present the average daily production rate over the period January 1, 2005 through December 31, 2005).

TABLE C.2-2
COOGER STUDY ACTIVITY PROJECTIONS[1]
SCENARIO 2

	2000	2005	2010	2015
Eastern Subregion				
Oil Production Daily Average (BOPD)	11,895	16,749	6,692	0
Gas Production Daily Average (MMCFD)	22.7	49.7	25.7	0.0
No. Platforms Installed	0	0	0	0
No. Platforms Removed	0	10	1	1
No. Wells Drilled	0	65	0	0
Central Subregion				
Oil Production Daily Average (BOPD)	115,317	127,649	133,602	105,415
Gas Production Daily Average (MMCFD)	147.8	199.0	145.8	137.1
No. Platforms Installed	0	0	2	0
No. Platforms Removed	0	0	2	1
No. Wells Drilled	46	98	110	0
Northern Subregion				
Oil Production Daily Average (BOPD)	6,055	0	36,000	32,529
Gas Production Daily Average (MMCFD)	1.4	0.0	15.0	15.0
No. Platforms Installed[2]	0	0	1	0
No. Platforms Removed	0	1	0	0
No. Wells Drilled	0	4	67	0

[1] Table entries for well drilling and platform installation and removal indicate the totals for the preceding 5-year period (e.g.: entries for the year 2005 include the total number of referenced activities over the period January 1, 2001 through December 31, 2005). Daily average production rates of oil and gas reflect the single year referenced (i.e.: table entries for the year 2005 present the average daily production rate over the period January 1, 2005 through December 31, 2005).

[2] Table entry reflects a singe platform associated with Bonito Field development. This scenario also includes subsea well development in the Lion Rock Field.

TABLE C.2-3
COOGER STUDY ACTIVITY PROJECTIONS[1]
SCENARIO 3

	2000	2005	2010	2015
Eastern Subregion				
Oil Production Daily Average (BOPD)	11,895	16,749	6,692	0
Gas Production Daily Average (MMCFD)	22.7	49.7	25.7	0.0
No. Platforms Installed	0	0	0	0
No. Platforms Removed	0	10	1	1
No. Wells Drilled	0	65	0	0
Central Subregion				
Oil Production Daily Average (BOPD)	115,317	127,649	133,602	105,415
Gas Production Daily Average (MMCFD)	147.8	233.9	182.0	151.4
No. Platforms Installed	0	0	2	0
No. Platforms Removed	0	0	2	1
No. Wells Drilled	46	128	80	0
Northern Subregion				
Oil Production Daily Average (BOPD)	6,055	0	53,500	50,029
Gas Production Daily Average (MMCFD)	1.4	0.0	21.0	35.8
No. Platforms Installed	0	0	2	0
No. Platforms Removed	0	1	0	0
No. Wells Drilled	0	4	95	0

[1] Table entries for well drilling and platform installation and removal indicate the totals for the preceding 5-year period (e.g.: entries for the year 2005 include the total number of referenced activities over the period January 1, 2001 through December 31, 2005). Daily average production rates of oil and gas reflect the single year referenced (i.e.: table entries for the year 2005 present the average daily production rate over the period January 1, 2005 through December 31, 2005).

TABLE C.2-4
COOGER STUDY ACTIVITY PROJECTIONS[1]
SCENARIO 4

	2000	2005	2010	2015
Eastern Subregion				
Oil Production Daily Average (BOPD)	11,895	2,247	1,005	0
Gas Production Daily Average (MMCFD)	22.7	2.7	1.2	0.0
No. Platforms Installed	0	0	0	0
No. Platforms Removed	0	12	0	0
No. Wells Drilled	0	30	0	0
Central Subregion				
Oil Production Daily Average (BOPD)	115,317	96,865	91,340	52,915
Gas Production Daily Average (MMCFD)	147.8	209.8	160.9	125.1
No. Platforms Installed	0	0	1	0
No. Platforms Removed	0	3	0	0
No. Wells Drilled	46	80	25	0
Northern Subregion				
Oil Production Daily Average (BOPD)	6,005	0	86,500	100,029
Gas Production Daily Average (MMCFD)	1.4	0.0	30.0	82.5
No. Platforms Installed[2]	0	0	2	0
No. Platforms Removed	0	1	0	0
No. Wells Drilled	0	4	171	0

1 Table entries for well drilling and platform installation and removal indicate the totals for the preceding 5-year period (e.g.: entries for the year 2005 include the total number of referenced activities over the period January 1, 2001 through December 31, 2005). Daily average production rates of oil and gas reflect the single year referenced (i.e.: table entries for the year 2005 present the average daily production rate over the period January 1, 2005 through December 31, 2005).

2 Table entry reflects one Bonito Field Platform and one Lion Rock Field Platform. Full development of this scenario also includes a Lion Rock Field Subsea Satellite well installation.

TABLE C.2-5
COOGER STUDY ACTIVITY PROJECTIONS[1]
NORTHERN SUBREGION SCENARIOS 2A, 3A, AND 4A

	2000	2005	2010	2015
Scenario 2A				
Oil Production Daily Average (BOPD)	6,055	19,500	35,762	36,000
Gas Production Daily Average (MMCFD)	1.4	9.8	15.0	15.0
No. Platforms Installed	0	1	1	1
No. Platforms Removed	0	1	0	1
No. Wells Drilled	0	43	57	35
Scenario 3A				
Oil Production Daily Average (BOPD)	6,055	19,500	95,762	102,529
Gas Production Daily Average (MMCFD)	1.4	9.8	42.1	62.1
No. Platforms Installed	0	1	3	0
No. Platforms Removed	0	1	0	1
No. Wells Drilled	0	43	150	0
Scenario 4A				
Oil Production Daily Average (BOPD)	6,055	19,500	128,762	152,529
Gas Production Daily Average (MMCFD)	1.4	9.8	51.1	108.8
No. Platforms Installed[2]	0	1	3	0
No. Platforms Removed	0	1	0	1
No. Wells Drilled	0	43	226	0

[1] Table entries for well drilling and platform installation and removal indicate the totals for the preceding 5-year period (e.g.: entries for the year 2005 include the total number of referenced activities over the period January 1, 2001 through December 31, 2005). Daily average production rates of oil and gas reflect the single year referenced (i.e.: table entries for the year 2005 present the average daily production rate over the period January 1, 2005 through December 31, 2005).

[2] This table entry reflects one platform on each of the following fields: Bonito, Lion Rock, Sword, and Rocky Point. Full development of this scenario also includes a Lion Rock Field Subsea Satellite well installation.

APPENDIX D

REPORT LIMITATIONS,
DATA INPUTS,
AND INTENDED USE

APPENDIX D
REPORT LIMITATIONS, DATA INPUTS, AND INTENDED USE

D.1 INDEPENDENCE AND CONFLICT OF INTEREST

This report has been prepared by Dames & Moore with substantial technical input from The Scotia Group. All evaluations performed by Dames & Moore and Scotia presented in this report were conducted on a labor-effort fee basis for the MMS, and Dames & Moore and Scotia have not and will not receive any benefit which may be regarded as affecting their ability to render an unbiased opinion on the petroleum interest evaluated as part of this study.

D.2 PURPOSE, SCOPE, AND USE OF THIS REPORT

This report was commissioned by the MMS under a contract to Dames & Moore. The brief for this study is explicitly defined in the original proposal and in answers to questions posed as part of contract negotiation. The scope of the project was restricted to this brief and specifically excluded the performance of original work, the direction being to perform audits of provided data. Substantial portions of the analysis were conducted using proprietary information which has been reviewed by the MMS, but cannot be publicly released in connection with this report. The provided data are covered by a confidentiality agreement.

D.3 AVAILABLE DATA

This study was based on data supplied by the MMS, California State Lands Commission, and cooperating oil companies, on public domain information and on non-proprietary data from in-house files. The supplied data was reviewed for reasonableness from a technical perspective. As is common in oil field situations, basic physical measurements taken over time cannot be verified independently in retrospect. As such, beyond the application of normal professional judgment, such data must be accepted as representative. While we are not aware of any falsification of records or data pertinent to the results of this study, Dames & Moore and Scotia do not warrant the accuracy of the data and accept no liability for any losses from actions based upon reliance on data which is subsequently shown to be falsified or erroneous.

D.4 FUTURE NET REVENUE ESTIMATES

Future net revenue estimates are based upon the estimated future production profile and stated prices for oil and gas adjusted for capital expenditure, operating costs, and interest reversions, without consideration of severance taxes, ad valorem taxes, and federal income tax liability, or any other types of encumbrance that might exist against the evaluated prospects. The estimates do not include the salvage value for the leases or the cost of abandonment and site restoration. The present worth of future net revenues reflects the application of certain discount factors and does not represent an estimate of fair market value for the properties.

Future net revenue and present worth of future net revenue estimates are representative of the pricing and development/recompletion scenarios that have been modeled. Such estimates should not be construed as exact quantities. Future production rates, product prices, development costs and revenues from the sale of petroleum products could differ from the estimates presented. Modification of drilling schedules, availability of capital, and many other factors outside the realm of an engineering estimate could result in significant variances from the estimates presented herein.

D.5 EXCLUSIONS

Dames & Moore and Scotia cannot attest that any of the prospects presented in this report will ever be developable or economically producible and such an opinion does not form part of this report. Cost and pricing parameters were assumed or in some cases supplied by third parties, and a thorough independent evaluation of these details were beyond the scope of this study effort. Operating cost data were derived from examination of summarized available information provided by the MMS and cooperating offshore operators, and should not be considered as a comprehensive analysis. This report is restricted to an independent technical audit of supplied raw and interpretive data assuming successful development of the subject properties. Dames & Moore and Scotia are not in a position to comment on the financial ability of individual operators to perform the development program or their willingness to make such investments in the future. It is not the intention or purpose of this report to comment on title, ownership or legal encumbrances, any commercial or business relationships or sunk costs involved in acquiring the properties.

D.6 FIELD VISIT AND INSPECTION

No field visit to the properties which are the subject of this report has been made. As is customary in this type of evaluation, a field visit was not considered necessary. As such, Dames & Moore and Scotia are not in a position to comment on the state of operations of any existing facility, or that such operations are in compliance with any state or federal regulations that may apply to them.

D.7 LIMITATIONS OF THE USE OF INFORMATION PRESENTED

This report has been prepared on a best efforts basis to address the requirement of the brief specified by the MMS. The results and conclusions represent informed professional judgments based on the data available and the budget and time frame allowed to perform this work. No warranty is implied or expressed that actual results will conform with these estimates. This study is not intended to provide the basis for any financial investments, and should be used only as an information document to explore the potential onshore facility requirements and related community issues associated with different levels of offshore development in the COOGER study area.

APPENDIX E

COOGER STEERING COMMITTEE

STUDY SCOPE DECISIONS

APPENDIX E
COOGER STEERING COMMITTEE STUDY SCOPE DECISIONS

During the COOGER study process, information concerning a broad range of topics was collected and evaluated. The COOGER Steering Committee reviewed several drafts of study results, and progressively refined the study content as the most useful products of this study became apparent. This process led to the current study, which addresses the capacity of the onshore infrastructure (public and industrial) and its relationship to demand associated with different scenarios which define a range of potential future offshore development. Although all the topics originally addressed by the COOGER study investigations are important, many could not be presented in sufficient detail to satisfy all members of the Steering Committee. In other cases, topics which were originally included did not present meaningful differences where broad scenarios were considered, and were determined to be better addressed with regard to specific project proposals. Additional topics were deleted because more detailed work on comparable topics had already been completed, such as:

- *Paulsen, Krista,* et al. Petroleum Extraction in Ventura County, California: An Industrial History. *Camarillo: Minerals Management Service (OCS Study MMS 98-0047). 1998.*
- *Nevarez, Leonard,* et al. Petroleum Extraction in Santa Barbara County, California: An Industrial History. *Camarillo, Minerals Management Service (OCS Study MMS 98-0048), 1998.*
- *Beamish, Thomas D.,* et al. Petroleum Extraction in San Luis Obispo County, California: An Industrial History. *Camarillo, Minerals Management Service (OCS Study MMS 98-0049), 1998.*
- *Molotch, Harvey and John Woolley.* Evaluation of Current Programs to Identify and Mitigate Socioeconomic Impacts in the Santa Barbara Channel: An Analysis of SEMP. *Camarillo: Minerals Management Service, 1994.*
- *Powers, Michael.* Monitoring and Mitigating Socioeconomic Impacts of Offshore Related Oil and Gas Development, 1985-1995: A Case Study.
- *Board of Supervisors, County of Santa Barbara.* Coastal Resource Enhancement Fund: Guidelines, *1998.*

- *Board of Supervisors, County of Santa Barbara.* Fisheries Enhancement Fund: Guidelines. *1987.*
- *Board of Supervisors, County of Santa Barbara.* Local Fishermen's Contingency Fund: Guidelines, *1997.*

A summary of the topics originally considered for evaluation in the COOGER study that were removed by Steering Committee consensus is presented below.

Environmental Topics

- **Onshore environmental constraints** including land use, water supplies, biological, cultural, and air quality were reviewed in the preliminary draft report but are no longer addressed in the COOGER report. Based on reviews of early drafts of COOGER report sections, the Steering Committee concluded that these topics would best be addressed by other studies. One such study is the Santa Barbara County North County siting study which will address air quality, biology, geology, hydrology, cultural resources, noise, visual aesthetics, land use, public safety, and transportation. Any proposed development of new or expanded infrastructure onshore will be subject to comprehensive environmental review pursuant to the California Environmental Quality Act as well as local government land use permitting processes. Based on the COOGER study analysis, new onshore oil and gas processing facilities are only projected to be needed in the Northern Subregion. Site-specific analyses of environmental factors done for any future onshore development projects, including air quality analyses based upon future air quality standards and regulations, may reveal potential constraints which were not evident in the preliminary draft COOGER report.

Socioeconomic Topics

- Many **socioeconomic factors** addressed in early drafts of the report have been eliminated. However, socioeconomic topics are important to consider when new oil and gas projects are developed. Environmental Impact Statements already completed discuss the potential effect of oil and gas activities to important recreation and tourism sectors of the local economy. Socioeconomic topics are addressed during the environmental review of individual projects. They are also addressed in specialized studies such as the research recently completed by Dr. Harvey Molotch for the MMS (see references). This study may be consulted in addition to this report. The COOGER study does not consider any safety constraints that may be associated with existing onshore oil and gas facilities. Local regulatory agencies may require comprehensive safety audits of onshore facilities in the future and the results of these audits may affect the scenarios included in this report.

The public workshops revealed a substantial amount of controversy focused on the environmental and socioeconomic sections. Comments received at the workshops requested a variety of environmental factors such as oil spills be addressed in the study. Other comments requested in-depth analyses of tourism be included in the study. The Steering Committee decided to delete the environmental and socioeconomic sections for the following reasons:

- In some cases, the information is unnecessary to accomplish the purpose of COOGER. For instance, high-case projections of future offshore development in the Eastern Subregion of the study area will not result in any new demand for physical infrastructure (although see comment about possible future safety audits above). In the Central Subregion, demand for new processing capacity can be accommodated at existing consolidated processing sites. In the Northern Subregion, Santa Barbara County is examining in detail environmental constraints associated with development of offshore leases.

- Some of the controversy over the quality of information in the environmental and socioeconomic sections of previous COOGER drafts appears largely unnecessary. For example, there is no need to examine environmental and socioeconomic constraints in subregions where new offshore development is not expected to result in new demand for physical infrastructure onshore.

- COOGER provides a broad regional perspective of possible future offshore development which is not intended to replace more detailed site-specific analyses. Much of the previous environmental information, however, focused on a site-specific scale rather than the broad regional scale.

- The previous scope of the COOGER report, which entailed analyses of onshore physical, environmental, and socioeconomic constraints to future offshore oil and gas development, no longer appeared to be manageable within a single report. Some sections, such as physical infrastructure, were substantially more detailed than other sections, leading to an apparent inconsistency in presentation of analyses.

- The task of revising the environmental and socioeconomic sections to the extent requested by some members of the Steering Committee and some members of the public could not be accomplished without substantial delay and expansion of the scope of the study. Most members of the Steering Committee desired to complete the study rather than delay.

- The Steering Committee was concerned that the criticism with regard to the environmental and socioeconomic sections could potentially affect the future credibility of the other sections.

Revenues, Taxes and Employment Topics

- **Revenue from Offshore Oil and Gas Development**. Offshore oil and gas development generates revenues for Federal and State governments by way of lease sale bonuses, rents, and royalties. This same development also generates property tax and sales tax revenue for local government and serves as a source of employment. Because the scope of the COOGER study was refined to focus on the potential physical constraints to future development, and because these revenues do not change the potential constraints examined in the various scenarios, they have been eliminated from the report.

APPENDIX F

COMMENTS AND RESPONSES

APPENDIX F
COMMENTS AND RESPONSES

This appendix presents comments received on the Draft California Offshore Oil and Gas Energy Resources Study (COOGER study, September 25, 1999) and responses to those comments. The COOGER study involved a lengthy development process with substantial input from the public and from a Steering Committee of agency, industry, and community representatives. This input included several rounds of written comments on early releases of different report components which resulted in the evolution of the original study concept to this Final report. Those comments are not reproduced in this appendix, but are available for review by contacting the MMS Pacific OCS Region office.

COMMENT #1

Santa Barbara COOGER Workshop
10/28/99

Carla Frisk representing State Senator Jack O'Connell – written comments submitted. 1-1

Linda Krop – ditto of what is in O'Connell letter – Need for report to be current – updated annually. (See 8/26/99 letter) 1-2

Leases will be developed inconsistent with scenarios in report and lease expiration reality report needs to refer to expiration process. 1-3

And that California Coastal Commission will assert its influence on lease expiration. Safety issue – appreciate deletions (plus environment/socioeconomic deletion). Would like to see safety included as capacity issue – because of age of facilities (including facility safety records). 1-4

Future development scenarios no explanation of why Santa Maria leases will not be developed by 2015. 1-5

Socioeconomic information – keep in appendices – still concern about some of the facts – i.e. Property taxes – does not refer to future used that would separate property tax revenue- report should reflect accurate information. 1-6

Revenue – royalty revenue to State and Federal is not related to the development of these leases. 1-7

Ariana Katovich – Isla Vista resident sees effects of oil on water and ecological systems – intolerable – here Venoco leaking now. Reality about petroleum use and amount we use; growing population is pressuring sensitive habitats; oil is not acceptable anywhere at any price; scared about impacts – system is working too slow not worth hazards – explore renewable resources – wind, solar, no new development. 1-8

Santa Barbara benefits economically for being a beautiful community – let's not endanger that; alternatives. Sword fisherman: oil worker ethyl bromide – needs to be stopped – oil industry provides revenue to workers – lots of emotional issues and facts – oil is a relatively safe industry – lots of polarity here – look at more holistically - where will oil go if we drive it from the United States – to Third World. 1-9

G.O.O. President

Study – completely misses the boat ignores two constraints – health and safety of the community and the environment – Avila problems and others (Guadalupe) need to be mentioned. See environment protected. 1-10

Eric Cardenas – Elwood resident lives with reality and threat every day – This is an emotional isssue and not an easy issue. Safety of oil industry – might be safer than other industries – but is not safe; need to pursue alternative energy sources – oil industry controls exploration of 1-11

Comment #	Comment
1-1	Refer to responses to written comments included as comment number two.
1-2	A procedure for identifying the need for COOGER report updates is presented in Appendix C of the COOGER report. The MMS has not yet determined a specific schedule for report updates.
1-3	The schedule of lease development reflected in the COOGER report scenarios is consistent with current offshore operators' development projections.
1-4	Facility safety records were requested of Santa Barbara County, but were not made available for review during the course of the COOGER study. This topic was not identified as a potential study topic until late in the development of the COOGER study, and the Steering Committee did not reach a consensus directing its inclusion in the study.
1-5	Additional explanation of the timing of Santa Maria Basin developments has been incorporated into Section 3.3.
1-6	Analysis of potential future property tax revenues associated with individual scenarios (and related facility site use conversions) was specifically deleted from the COOGER study by Steering Committee direction.
1-7	It is not clear what portion of the COOGER report this comment refers to. The federal government contributes a portion of royalty revenues from federal OCS production to State and local programs. Production from federal leases in the COOGER study area contributes royalty revenues which help support these programs.
1-8	This comment does not suggest a revision to the COOGER report.
1-9	This comment does not suggest a revision to the COOGER report.
1-10	The COOGER study is focused on the specific topics directed by the Steering Committee, and is not intended to be a comprehensive review of all topics related to oil and gas development.
1-11	This comment does not suggest a revision to the COOGER report.

alternative industries. Third World country impact – if oil moves there – alternatives will address this – impact on indigenous populations. 1-11 cont.

Jobs – we all need them – pursue jobs in alternative energy businesses/enterprises need oil company to work with us here. 1-12

Continued opposition to offshore oil development off of Santa Barbara. 1-13

Peter Maly (worker-oil) all in this together – safety and environment issues are critical – we all use/vote for oil and gas by our habits – there is demand for oil – need to develop alternatives – research was impacted by lower oil prices – shares concern about Third World development and lack of safety assurances. Alternative energy development may be 50-100 years out – make commitment to quit using oil and gas – direct politicians to spend money to develop alternative energy resources – industry is safer than in 1969 (royalty reductions; tax credits – offer?) more fatalities in tourism – U. S. oil industry – work together to seek new energy resources. 1-14

Hannah Eckberg – G. O. O. Noticed industry and environmentalist sitting her divided – we have solutions now: solar; hydrogen fuel cells; playing field is not level – we subsidized oil industry via taxes vs developing alternative energy sources – alternative energy creates more jobs. There are other industries to support – organic cotton; hemp. Scared of future – of a degraded environment in the future; government keeps us addicted to fossil fuels set message out about November 16 – get oil out –clean alternatives now incorporate sustainable/renewable energies and industries – shift to other modes of transit (mass, bicycles, carpooling) spend time visioning what we want . This is 4th and 5th hearing – need better way to take notes – missed heart of input and participants comments. 1-15

Eric Nelson UCSB student. Oil industry effects us very much here; don't single anyone out – have something in common we all live here – tourism killing people – dying from car fumes/emissions –if not now, later. Making a commitment – can't stop immediately – want gradual change – we are making a difference (carpooling) – single drivers, carpool make changes that continue to provide jobs; let leases expire – it's the wrong road. Came here because loves beaches, weather, people. Hates the traffic Uses car rarely – walking; biking – wants fresh air. 1-16

3rd workshop – Peggy – announcement should be on postcards vs. full sheet – Both sides good comments – honors positions of current oil workers – in this together –we all are – We are looking at a problem - safety of oil industry given known spills – chooses to ride a bike to do her best - $2 million to look at problem vs. solutions. 1-17

Comment #	Comment
1-12	This comment does not suggest a revision to the COOGER report.
1-13	This comment does not suggest a revision to the COOGER report.
1-14	This comment does not suggest a revision to the COOGER report.
1-15	This comment does not suggest a revision to the COOGER report.
1-16	This comment does not suggest a revision to the COOGER report.
1-17	This comment does not suggest a revision to the COOGER report.

SB-1

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STATE CAPITOL, ROOM 5035
SACRAMENTO, CA 95814
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SAN LUIS OBISPO OFFICE
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VENTURA, CA 93001
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California State Senate

SENATOR
JACK O'CONNELL
EIGHTEENTH SENATORIAL DISTRICT

CHAIR:
BUDGET & FISCAL REVIEW
SUBCOMMITTEE ON EDUCATION
COASTAL CAUCUS
MAJORITY CAUCUS
MEMBER:
BUDGET AND FISCAL REVIEW
BUSINESS AND PROFESSIONS
CONSTITUTIONAL AMENDMENTS
EDUCATION
ENVIRONMENTAL QUALITY
GOVERNMENTAL ORGANIZATION
JUDICIARY

COMMENT #2

October 28, 1999

Frederick L. White
Minerals Management Service
Pacific OCS Region
770 Paseo Camarillo, MS 7300
Camarillo, CA 93010

Dear Mr. White:

I want to begin by stating that while I still have some concerns about the California Offshore Oil and Gas Energy Resources (COOGER) Report, I believe that the changes made to it since the last workshop have significantly improved the report. I am particularly pleased to see that the Environmental Setting and Socioeconomic Conditions sections of the report have been removed.

The most valuable portion of the report, as I stated in my March 8, 1999 letter to you, the Offshore Oil and Gas Reserves and Production Projects (now Current and Future Baseline Oil and Gas Production and Related Activity) and the Onshore Oil and Gas Facility Infrastructure Sections, is now the report's main focus, along with a section on Public and Industrial Transport Infrastructure Refineries. As an inventory of existing offshore oil fields and facilities, the report can be a valuable reference document, but only if it is kept up to date. It is, therefore, imperative that the MMS make a commitment to updating the COOGER report annually. Otherwise the usefulness of the information in the report will be short-lived and it will very quickly become obsolete. 2-1

For example, the current document is already missing several pieces of information which could affect the future capacity of onshore facilities. The sections related to the Eastern Subregion contain no information about the status of the POOI leases, which exist in State waters. It has recently come to my attention that the State Lands Commission has received an application from POOI to develop these leases from Platform Hogan. While the application has not yet been deemed complete, the COOGER report should, at minimum, discuss how the development of these leases could affect the future capacity of oil and gas facilities in that subregion. 2-2

Secondly, while page 2-138 in the Central Subregion section states that Benton has not indicated when drilling operations will resume on the Molino project, it continues to assume that the project will begin production in 2001. It further fails to note that both the County of Santa Barbara and the State Lands Commission have granted drilling deferments for this project only until November of 2000. 2-3

Comment #	Comment
2-1	Appendix C of the COOGER report presents a procedure for identifying the need for report updates. The MMS has not yet determined a specific schedule for report updates.
2-2	The development of untapped resources under state leases from Platform Hogan is identified in the COOGER study and included in the Eastern Subregion Scenarios 2 and 3.
2-3	The expiration of drilling deferments in November 2000 is consistent with the COOGER study estimate of earliest production in 2001.

Frederick White
October 28, 1999
Page Two

The sections on the Northern Region also fail to mention that the State Lands Commission has received and filed an application from Nuevo Energy to drill from Platform Irene into State waters. While I realize that COOGER specifically does not address oil development on unleased tracts, I believe that it is important to note that such an application has been filed and, if approved, could have an impact on future oil and gas facility capacity in that subregion. 2-4

The statement under Assumptions on page 1-8 regarding the County's concern that, as facilities age, safety issues could affect their spare capacity, is a critical piece of information. Unfortunately, the balance of the report discusses spare capacity only as a function of permitted capacity minus existing use. The possibility that a facility's total capacity could be reduced for safety reasons is not mentioned in any of the other sections of the report. At minimum, a footnote should be included in the charts which portray spare capacity indicating that the estimates could be reduced, based on safety audits. 2-5

Finally, I must repeat my concerns that, given the multitude of factors involved, the scenarios for future development, with the exception of the no new development scenario, are ultimately as good as anyone's guess. The Department of the Interior has already allowed 4 of the 36 tracts to expire and is currently considering whether additional tracts should be allowed to expire. This decision alone could significantly change the scenarios for future development. In fact, the COOGER report indicates in a number of places, although no reason is given, that the Point Sal, Purisima Point and Santa Maria units will not be developed until after 2015. Based on this information, it seems to me that these leases cannot meet their due diligence requirements and should, therefore, be expired. 2-6

In any case, I want to conclude by, again, expressing my strong support for the "no additional development" scenario. Only this scenario can guarantee that our spectacular coast will not suffer from the impacts of additional oil land gas development which, based on past experience, are all but certain, or be fouled by an oil spill that we cannot predict or prevent. The citizens for the Central Coast deserve no less.

Sincerely,

Jack O'Connell

JACK O'CONNELL

JO:cdf
E8b
cc: Congresswoman Lois Capps
US Senator Barbara Boxer
US Senator Dianne Feinstein
Thomas Kitsos, Acting Director, MMS
Carolita Kallaur, Associate Director, MMS

Comment #	Comment
2-4	Section 3.5.4 has been revised to include a reference to this recent application.
2-5	Engineering designs and permit limitations both consider safety issues, and we have not identified any data which suggests that any facility addressed in the COOGER study is unsafe as presently operated.
2-6	The discussion of development timing of the Point Sal, Purisima Point, and Santa Maria Fields has been expanded (refer to Section 3.3). It is acknowledged that projections of future development scenarios involve substantial uncertainties. The COOGER study estimates are based on a careful analysis of substantial volumes of data, and are not a simple guess as suggested by this comment.

COMMENT #3

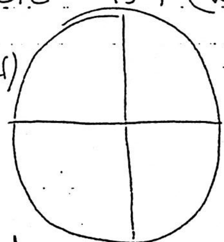
5B-2

Oct.28.99

310/573-6233
E.T. Cocca
513 Palisades Dr.
Pacific Palisades, Ca.
90272

I'm taking a "spiritual Bungy cord jump" here to speak up ~~here~~ on this Cooger Public WK Shop

Thank you - all of you who showed up to support the important ecological factor at stake here... let us keep our ocean clean and free of oil. the one "cross hair" I see here is; (where the vertical crosses the horizontal)



FREEDOM

freedom to enjoy a clean ocean

We, the people, and I am speaking for all the birds, fish, animals concerned,

namely, all of us...

deserve this freedom: it is essential to life!

Love from Elizabeth Cocca

/ frequent visitor to the Malibu area

3-1

Comment #	Comment
3-1	This comment does not suggest a revision to the COOGER report.

Oki
Design

graphic design
illustration
fine art

**DATE:
5 Nov. '99**

FROM:

Peggy Oki

5966 Via Real #3
Carpinteria, CA 93013
ph./fx. 805 684 3573

okicalagic@earthlink.net

TO:

Minerals Management Service

770 Paseo Camarillo
Camarillo, CA 93010

COMMENT #4

Dear Sirs and Madammes,

I attended the C.O.O.G.E.R. workshop which you hosted in Santa Barbara, on 28 October '99. This was my third attendance of your workshops. I made a verbal statement. But the method with which public comments were being recorded, I must say were insuffient. And due to this, I am finding it necessary to write to you to reiterate my viewpoint regarding the workshop and decisions that you will make in the very near future.

I do not support further Coastal or Offshore Oil &/Or Gas development along the California coast. I do not support further development of this resource. The threats to the environment, in obtaining, processing, and transporting this resource are potentially devastating. And historically, there have been some major oil spillages to which the oil companies have failed to take full responsibility for. The inherent pollution problems caused by the usage of fossil fuel energy are known. 4-1

There are sustainable alternatives without the inherent problems of fossil fuels. I support development and complete transformation to these sustainable resources. I urge you to seriously consider the impacts of future oil & gas development, and realize the responsibility of your decision which will determine the environmental quality of our precious coastline.

Sincerely,

Peggy Oki

Peggy Oki

Comment #	Comment
4-1	These comments do not suggest a revision to the COOGER report.

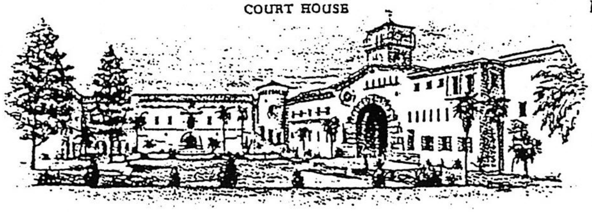
JSAN ROSE
:cond District
Vice-Chair

L MARSHALL
'hird District

ONI GRAY
ourth District

I URBANSKE
Fifth District

COURT HOUSE



COUNTY OF SANTA BARBARA

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BOARD OF SUPERVISORS
105 East Anapamu Street
Santa Barbara, California 93101
Telephone (805) 568-2190
information line

November 2, 1999

Dr. Lisle Reed, Director
Pacific OCS Region
Minerals Management Service
770 Paseo Camarillo
Camarillo, CA 93010

COMMENT #5

RE: 9/25/99 Draft of COOGER and recent requests for suspensions.

Dear Dr. Reed:

On behalf of the Santa Barbara County Board of Supervisor, I thank you, your staff, and the COOGER Steering Committee for the concerted effort to respond to concerns raised by this Board and many members of the public forthrightly. This draft of COOGER, dated September 25, 1999, represents a notable improvement over the previous draft. Although reduced in scope, the current draft provides useful information about the status of offshore development, and leaseholders' plans to develop leases that have remained idle for many years. This information will be quite useful to us as we consider the onshore implications of future offshore oil and gas development and the abandonment of existing facilities and leases.

The Board applauds recent revisions to the COOGER study that explicitly acknowledge the importance of this County's policies with regard to offshore oil and gas development. In
particular, our consolidation policies and the legal, non-conforming status of the Ellwood Oil and 5-1
Gas Processing Facility and the Ellwood Marine Terminal are of paramount importance to this County and will affect where new production is processed.

The Board also supports recent MMS actions to terminate the COOGER-related suspensions, allow four of the leases to expire, and require leaseholders to submit plans for the remaining 36 leases with due diligence, as required by the OCS Lands Act. However, we support the request by the California Coastal Commission to review any plans of exploration or further lease suspensions under the CZMA prior to action by the MMS.

The Board also remains concerned about COOGER's projections for the Point Sal, Santa Maria, and Purisima Point units, located in the northern Santa Maria Basin. The 13 leases contained in these units, which were leased over 18 years ago, are not projected to begin production until

Comment #	Comment
5-1	These comments do not suggest a revision to the COOGER report. It should be noted, however, that Section 3.3 of the COOGER report has been modified to include additional information concerning the Point Sal, Purisima Point, and Santa Maria Fields which are specifically addressed by this comment.

some unidentified date beyond the year 2015. Accordingly, they will have remained idle for more than 33 years since their original lease date. There can be no dispute that these leases have not met the lease obligations of due diligence. The Board urges the MMS to deny any further suspensions pursue expiration of these leases unless a clear demonstration of due diligence is made.

5-1
cont.

Again, the Board thanks you for the opportunity to comment on COOGER. The Energy Division will submit technical comments on this draft by November 15. We request that you direct your staff to revise the final publication, based on these comments to correct any latent errors. We look forward to the final version of COOGER and look forward to working with the MMS on other pending issues.

Respectfully,

Naomi Schwartz
Chair, Board of Supervisors
County of Santa Barbara

cc: California Coastal Commission
State Lands Commission
Board of Supervisors, San Luis Obispo County
Board of Supervisors, Ventura County
COOGER Steering Committee

County of Santa Barbara
Planning and Development
John Patton, Director

November 8, 1999

RECEIVED
NOV 10 [illegible]
OFFICE OF THE REGIONAL DIRECTOR
PACIFIC OCS REGION

Dr. Lisle Reed, Regional Director
Pacific OCS Region
Minerals Management Service
770 Paseo Camarillo
Camarillo, CA 93010

RE: COOGER draft of September 25, 1999

COMMENT #6

Dear Lisle:

I am forwarding our final comments on the COOGER study. The recent draft reflects a much improved version and has already proven to be useful in our work here at the Energy Division. Our comments are relatively minor compared to previous reviews of COOGER drafts, and should not require much more work to incorporate. If your staff or Dames & Moore require more clarification of our comments, or believe they cannot incorporate a comment, please direct them to call me or Doug Anthony so we can fix any problems.

Again, I wish to thank you for your efforts during the previous Steering Committee meeting to focus on resolving outstanding issues with the study. Your efforts have resulted in a much more informative and accurate document.

The only remaining, outstanding issue with the COOGER report remains to be the commitment you will make to updating it as needed. I believe we can address this issue once the study is finalized.

Sincerely,

Dianne L. Meester

Dianne Meester
Manager, Energy Division

Attachment: Specific Comments

ATTACHMENT A: SPECIFIC COMMENTS

1.0 INTRODUCTION

The introduction reads much better. We note three inaccuracies that require correction and one statement that requires clarification for the final document.

Page 1-1, third paragraph, third sentence. Since the author has amended the number of federal leases examined under this study, the reduction in state leases should also be noted for consistency. Two state tideland leases have been quitclaimed (PRC 2725 and PRC 2726) and a third lease has been released (PRC 3499). This action was approved by the SLC at its meeting of September 3, 1999. Please modify the sentence in question to read as follows: 6-1

Recent lease expirations (four in Federal waters in August 1999 and three in State Tidelands in September 1999) have reduced ... .

Pages 1-2 and 1-3, bullets. Grammatical structure. Some of the bullets contain more than one sentence and, therefore, the list should probably be restructured as complete sentences. Also, please delete space between sixth and seventh bullet for consistency with others. 6-2

Page 1-3, first full bullet. For clarification, please reword the first sentence of this bullet as follows: *Assesses the need for onshore infrastructure under each of the scenarios and then ~~analyzes~~ identifies potential onshore physical constraints.* This change reflects the content of chapter 4 more accurately. 6-3

Page 1-3, last paragraph in section 1.2, third sentence. This sentence is incorrect. First, we believe the subject of the sentence was intended to be *leasing* rather than *drilling.* Second, we note that, in certain circumstances, new leasing can be considered by the SLC; that is, where a field under an existing lease extends into an unleased area. Such circumstances are known to exist for the Tranquillon Ridge field, for example. Also note section 6872.5 of the Public Resources Code. Perhaps Paul Mount could provide some more accurate language to correct this sentence. 6-4

Page 1-5, first sentence of Section 1.4. The reference to the years 1995 to 2015 as a 20-year period remains confusing since the years referenced actually equals a 21-year period. 6-5

1.0 CURRENT AND FUTURE BASELINE OIL AND GAS PRODUCTION AND RELATED ACTIVITY

Page 2-11, first paragraph of subsection 2.2.3.1, third sentence. This sentence incorrectly characterizes the status of the LCP with respect to other elements of the General Plan. Please re-write to read as follows: ~~*Although all elements of the General Plan apply to development within the coastal zone, the Local Coastal Program (LCP) (which includes the coastal plan, coastal zoning ordinance, coastal zoning district maps, and other implementing actions) addresses specific policies which supersede other General Plan policies. The LCP identifies acceptable development in the Coastal Zone and clarifies local policies and requirements which implement the requirements of the California Coastal Act.*~~ *The Local Coastal Program (LCP) includes the land use plan (or element), coastal zoning ordinance, coastal zoning district maps, and other* 6-6

Comment #	Comment
6-1	The suggested revision has been incorporated.
6-2	The suggested revision has been incorporated.
6-3	The text has been revised to refer to the identification of constraints, rather than analysis, as suggested. The report text differs slightly from the suggestion to maintain proper grammatical structure.
6-4	The text has been revised in response to this comment.
6-5	The text has been clarified in response to this comment.
6-6	The suggested revision has been incorporated.

implementing actions necessary to meet and implement the requirements of the California Coastal Act (section 30108.6 of the Coastal Act). The land use plan of the LCP is the relevant portion of a local government's general plan that is sufficiently detailed to indicate the kinds, location, and intensity of land uses, the applicable resource protection and development policies. As a portion of the general plan, the land use plan has equal legal status with all other elements of the general plan. California law requires that a general plan must be integrated and internally consistent, both among the elements and within each element (Curtin, 1999, p. 21). 6-6 cont.

Page 2-17. Shouldn't the OCS Tranquillon Ridge Unit be included in the list of units for the Northern Subregion? We understand from Table 3.5-10 that this unit is currently producing and considered as part of the baseline (i.e., Scenario1). 6-7

Page 2-34, Table 2.3-4. As you know, we have begun to use COOGER to assist in several projects. In doing so, we discovered that the figures for oil and gas production in 1995 appear to be somewhat inconsistent with production reported by the DOGGR for the same year (i.e., 56.72 barrels of oil/condensate and 29.43 Bcf of net gas, noting that gross gas is significantly higher for the Hondo and Pescado fields). Can these differences be reconciled? If not, which source, COOGER or DOGGR represents the more accurate information? 6-8

Page 2-55, Northern Subregion, third column. Please add: *Misc: Propane trucked offsite.* This will make the table more complete and also consistent with information provided on page 2-158. 6-9

Page 2-105, footnote 3. Replace the word *oil* with the word *gas*. 6-10

Page 2-107, Figure 2.4-16. The spare capacity figures used here appear to be wrong. Shouldn't these figures be consistent with those provided in the last row of Table 2.4-8? 6-11

Page 2-117, paragraph on spare capacity, typo in first sentence. Delete the word *has* following the word *essentially.* 6-12

Page 2-125, last paragraph, second sentence. Please rewrite to read: *The new operator for the Gaviota facility is not known at this time.* Alternatively, you can wait for the County's Planning Commission hearing on December 15, 1999, in which it will consider approval or change in operator for the facility. 6-13

Page 2-127, list of major equipment at the Gaviota facility. Please replace *oil storage tanks* with *oil surge and reject tanks*. Also please add the desal unit to the list. 6-14

Page 2-131, second paragraph. Please revise this paragraph to read as follows: *Since reconfiguration, the PANGL gas pipeline has been used occasionally to transport gas purchased from the Southern California Gas Company to the platforms to fuel operations. As offshore gas production from the Point Arguello project dwindles, additional shipments of retail gas from the Southern California Gas Company will likely occur.* 6-15

Page 2-133, last bullet that discusses offshore processing. Please revise to state: *installing water removal equipment on the platforms associated with newly developed leases and/or additional* 6-16

Comment #	Comment
6-7	The Tranquillon Ridge Unit has been added to the list on page 2-17.
6-8	The COOGER projections include all gas processed at onshore facilities, including gas that is used as fuel at those facilities. In the case of the Las Flores Canyon facilities (which process gas from the Hondo and Pescado Fields), substantial onsite gas consumption occurs in connection with the facility operations and the operation of the onsite cogeneration facility. We understand that DOGGR records reflect sales gas, and those volumes are consistent with the COOGER 1995 amounts. The discrepancies between the original COOGER 1995 oil production estimates and actual DOGGR records for the same year are very minor (only 2.56 MMSTB for the entire year) and confirm the approach originally used to estimate the 1995 production. A footnote has been added to Table 2.3-4 in response to this comment.
6-9	The text has been revised as suggested.
6-10	The text has been revised as suggested.
6-11	Table 2.4-8 correctly reflects the Steering Committee direction that spare capacity should reflect design or permitted capacity, whichever is most limiting. Because Figure 2.4-16 presents design and permitted spare capacities separately, these values differ from the last row of Table 2.4-8.
6-12	The suggested revision has been incorporated.
6-13	Updated information has been inserted based on the Planning Commission action on December 15, 1999.
6-14	The suggested revisions have been incorporated.
6-15	The suggested revision has been incorporated.
6-16	The suggested revision presents the same option as described in the original text, with the addition of an opinion concerning permitting issues. Revised text has been inserted to reflect this Santa Barbara County staff opinion, but the wording of this revision differs from the comment suggestion to more clearly reflect the source of this opinion.

water removal equipment on the Point Arguello platforms, if necessary so that wet oil from newly developed leases can be processed offshore (however, this option would likely face permitting obstacles due to the increased risk of an offshore oil spill); or, 6-16 cont.

Page 2-134, bulleted item. Isn't the issue availability of the gathering pipelines and not availability of the processing facility? Please revise accordingly to give the reader clearer understanding of the constraints due to the reconfigured operations of Point Arguello. 6-17

Page 2-158, Product Distribution. What happens to sulfur? 6-18

Page 2-165, first paragraph of Facility Description. Thank you for clarifying the composition of the partially refined oil stream that leaves the upgrader facility. Please ensure that this clarification is repeated consistently throughout the document where reference is made to this stream (e.g., page 2-184, last paragraph, second sentence, and page 2-192 last paragraph, second sentence). 6-19

Page 2-171, first partial paragraph, last sentence. Please reword as follows: These pipelines ***are*** ~~may~~ also ~~be~~ used to transport oil from onshore sources. 6-20

2.0 DETERMINATION OF FUTURE BASELINE AND POTENTIAL DEVELOPMENT SCENARIOS

Page 3-13, first paragraph. The explanation provided in this paragraph appears to give the reader a good introduction to projecting earliest reasonable schedules that lead to start of production for all State Tidelands leases and all but three of the OCS units. However, this paragraph does not address the schedules for development of Point Sal, Purisima Point, and Santa Maria Units adequately. These latter schedules are vague and, from what section 3.5 appears to suggest, are driven by market constraints and downstream (refinery) technical constraints. Consequently, we request the addition of one to two sentences to explain that these three units are considered differently than the rest of the fields analyzed in the report. 6-21

Page 3-47, first paragraph, typo in last sentence. Insert the word *the* in front of COOGER. 6-22

Page 3-48, last paragraph, typo in first sentence. *PAD V* should read *PADD V*. The acronym means Petroleum Administration for Defense Districts. This typo appears in other sections of the draft report as well. Please use global search to correct. 6-23

4.0 PHYSICAL INFRASTRUCTURE DEMAND

Page 4-4, second paragraph, typos in first and second sentences. (1) Change *PAD* to *PADD*. (2) Change *greater production that* to *greater production than*. 6-24

Page 4-6, last bullet. The discussion of the Carpinteria oil and gas processing facility is somewhat confusing because Chapter 3.0 suggests that oil would bypass (or pass through) the facility and be processed at Rincon. Please add a sentence to clarify that Venoco is looking at different options for processing future production from the eastern subregion. 6-25

Comment #	Comment
6-17	The text section addressed by this comment specifically refers to the processing options in the event the Gaviota facility is not available for use as a wet oil processing facility. The option described correctly reflects one possibility under these conditions. The options focused on pipeline constraints (which assume that wet oil could be processed at the Gaviota Facility) are described in the prior section of the referenced paragraph. When reviewed in its entirety, this paragraph provides the reader with a view of a full range of options related to the potential future uses of the Gaviota Facility and related pipeline systems.
6-18	The text has been revised to reflect the shipment of by-product sulfur by truck.
6-19	The text on page 2-184 already refers to the composition of the partially refined oil stream from the Santa Maria Refinery. The text on page 2-192 has been revised to specifically explain that the partially refined product stream is a blend of light and heavy gas oils.
6-20	Not all of the pipelines referred to currently transport onshore produced oil. The text has been revised to reflect that most of the pipelines referred to also transport onshore oil.
6-21	Revised text has been inserted as suggested.
6-22	The suggested revision has been incorporated.
6-23	The acronym PAD V used in the COOGER study refers to the western USA Petroleum Administration District used for statistical reporting purposes by the American Petroleum Institute and addressed by the Oil & Gas Journal Energy Database. The acronym PAD V is correct.
6-24	Refer to response 6-23 for comment (1). The suggested revision (2) has been incorporated.
6-25	The referenced report section addresses pipeline system capacities, and is not intended to address processing facility capacity and future processing options. The report text has been revised to clarify that references to the Carpinteria Oil and Gas Processing Facility are intended to describe the route of the oil transport and explain the basis of expectations concerning pipeline system capacities.

Page 4-8, second paragraph, second sentence. Capacity is not the only limitation placed on the Ellwood oil and gas processing facility by the county's south coast consolidation policies and the legal non-conforming use status of the facility. It also cannot process "new production" unless the operator can satisfactorily demonstrate that it has a vested right to do so. Please reword this sentence as follows: *This facility is restricted as a legal non-conforming use and by the county's south coast consolidation policies. Future development of the South Ellwood Field not covered by the current land-use permit is expected to be processed at Las Flores Canyon and transported by the AAPLP pipeline system.* 6-26

Page 4-17, first paragraph, last sentence. For the same reason as stated above, please replace the word *capacity* with the word *use*. 6-27

The following four comments seek clarification about shipment of LPGs that are produced at the Molino facility. Benton is permitted to ship all NGL production, including LPG, to the Gaviota processing facility only. This shipment may occur by truck during exploration. Once production starts, the shipment of NGL from the Molino production site to Gaviota must occur via dedicated pipeline. From Gaviota, heavier NGLs are blended, as the current draft notes and lighter ends, namely propane, may be shipped via truck. Under all circumstances, long-distant shipment of NGLs, including LPGs, produced at Molino leaves from Gaviota.

Page 4-18, second paragraph of subsection 4.4.1, last sentence. Please revise to read: *Some of the scenarios also project the shipment of products from Gaviota Oil & Gas Processing Facility (including LPGs it receives from the Molino Facility to the extent they cannot be blended with crude oil for pipeline shipment), and the facility that would process the Lion Rock Field crude.* 6-28

Page 4-19, second paragraph, fifth and last sentences. Please revise to read:

For simplicity, the Ellwood, Las Flores Canyon, and Gaviota Facilities are shown as a single entry point to Highway 101, and all product traffic from these facilities continue on Highway 101 to the south or north. 6-29

This traffic is primarily associated with production at the Molino Facility, which is shipped to the Gaviota Facility via pipeline and, from there, is projected to generate 24 trucks per week in 2005. 6-30

Page 4-21, last paragraph, second to last sentence. Please revise to read: *In study year 2005, production associated with the Molino Facility is shipped via pipeline to the Gaviota Facility and, from there, contributes approximately 35 percent of the northbound traffic.* 6-31

Pages 4-41 through 4-30. Remove all references to the Molino Facility because, as strictly controlled by permit, long-distant shipments of LPG via highway do not depart from this facility. 6-32

Page 4-41, typo in third column. Please widen this column so the entire word *Northern* fits on one line. 6-33

Comment #	Comment
6-26	The suggested revision has been incorporated.
6-27	The suggested revision has been incorporated.
6-28	The suggested revision has been incorporated.
6-29	The suggested revision has been incorporated.
6-30	The suggested revision has been incorporated.
6-31	The suggested revision does not recognize that the text addresses Central Subregion Scenario 4, which specifically assumes that the Gaviota Facility would be removed before Study Year 2005. This scenario assumption was directed by the COOGER study Steering Committee. No revision to the report text of the referenced paragraph was implemented in response to this comment. The prior two paragraphs were modified in accordance with this comment, however.
6-32	Reference to the Molino Facility does not appear in the text on the pages specified by this comment. If this comment is intended to address Figures 4.4-2 through 4.4-8, the suggested revision is not considered appropriate because it would delete information concerning the source of truck traffic which may be useful to some readers.
6-33	The suggested revision has been incorporated.

APPENDIX A METHODOLOGY AND ADDITIONAL DATA

Section A.3. All tables that contain projections of future employment. First, thank you for expanding the introduction to explain the source of information and methodology used to project future trends in employment based on different scenarios. Second, the tables nonetheless remain confusing because we cannot determine what is influencing increases in several instances (e.g., why does scenarios 3 and 4 for the northern region vary by so much?). Consequently, please provide additional explanation in subsections A.3.1.2, A.3.2.2, and A.3.3.2 so we can better understand the numerous variations in employment trends affected via different scenarios. 6-34

APPENDIX E COOGER STEERING COMMITTEE STUDY SCOPE DECISIONS

Page E-2, paragraph about Environmental Topics. Please expand to mention the following two points: (1) Santa Barbara County has embarked on a comprehensive siting study to address potential future demand for new processing capacity in the Northern Subregion. That study is addressing potential constraints of air quality, biology, geology, hydrology, cultural resources, noise, visual aesthetics, land use, public safety, and transportation. (2) Note that new facilities are only projected to be needed in the northern area. 6-35

Page E-2, paragraph about Socioeconomic Topics, third sentence. Please delete reference to the siting study. As noted above, it is examining environmental topics. 6-36

Page E-2, paragraph about Environmental Topics, typo in fifth sentence. Replace the word *restraints* with the word *constraints*. 6-37

Page E-3, first bullet, third sentence. Please revise as follows to improve accuracy: *In the central subregion, demand for new processing capacity can be accommodated at existing consolidated processing sites.* 6-38

Comment #	Comment
6-34	The variations in employment associated with different scenarios and scenario combinations are caused by the different levels of offshore development, related onshore facility construction, and schedules of offshore and onshore facility decommissioning associated with individual scenarios. Employment estimates associated with individual facilities were based on specific inputs from facility operators, as documented in Table A.3-1, many of whom requested that this facility-specific information remain confidential. Because the analysis referred to by this comment addresses 76 different combinations of scenarios (documented in Tables A.3-3, A.3-5, A.3-7, and A.3-9) it is difficult to provide a concise explanation of all variations identified without releasing detailed facility-specific data. Specific questions, such as the one in this comment addressing Northern Subregion Scenarios 3 and 4 are easily addressed, however. In that case employment differences are primarily associated with Scenario Four's substantial increases in offshore development and drilling activity, and the construction and operation workforce associated with a substantially larger onshore processing facility. The MMS has received a confidential facility-specific employment database as a product of the COOGER study, and may be able to provide responses to other specific questions as they arise. Because the employment analysis was deleted from the body of the COOGER study by Steering Committee direction, expansion of the employment appendix to explain the source of variability associated with the large number of scenario combinations is not considered appropriate.
6-35	The suggested revisions have been incorporated.
6-36	The suggested revision has been incorporated.
6-37	The suggested revision has been incorporated.
6-38	The suggested revision has been incorporated.

COUNTY OF SANTA BARBARA
PLANNING AND DEVELOPMENT

MEMORANDUM

TO: Dean Hargis, Dames & Moore
Fred White, Minerals Management Service

FROM: Doug Anthony

DATE: December 15, 1999

RE: COOGER, one more small correction

If the final has not yet gone to copy, please correct the first line of page 2-138 in the 9-25-99 draft. Replace Santa Barbara County Planning and Development Department with Santa Barbara County Planning Commission. Thank you. 6-39

Comment #	Comment
6-39	The suggested revision has been incorporated.

State of California - The Resources Agency GRAY DAVIS, Governor
DEPARTMENT OF FISH AND GAME
http://www.dfg.ca.gov
1416 Ninth Street
Sacramento, CA 95814

November 10, 1999

Mr. Frederick L. White
Contracting Officers Technical Representative
Minerals Management Service
770 Paseo Camarillo
Camarillo, California 93010-6064

RE: Draft COOGER Study Dated September 25, 1999

Dear Mr. White: COMMENT #7

California Department of Fish and Game (Department) staff have reviewed the September 25, 1999 Draft California Offshore Oil and Gas Energy Resources (COOGER) Study, Development Scenarios and Onshore Physical Infrastructure in the Tri-County Area of San Luis Obispo, Santa Barbara, and Ventura. The COOGER Study examines the demands on onshore physical infrastructure from expanded offshore oil and gas development of the undeveloped leases that could be developed to add to or replace current production, for the time period of 1995 through 2015.

The purpose of this letter is to provide Department comments on the COOGER Study. While the Study does an adequate job of evaluating onshore physical constraints to offshore oil development, the Department believes the Study is deficient in a number of areas. In general, these areas are: 1) evaluating potential impacts to the environment (impacts to marine and terrestrial ecosystems, as well as impacts to specific species); 2) evaluating potential increased risks from oil spills; and 3) recognizing Department's Office of Spill Prevention and Response (OSPR) regulatory requirements. Following are our specific comments. 7-1

1) *COOGER Study*: Page 1-2 and Appendix E provide the broad initial scope of factors included in the study. The report explains that a Steering Committee refined the scope of the study to address only limited issues of onshore physical constraints to offshore development. Appendix E states that the onshore environmental constraints section was included in the preliminary draft report, but is no longer addressed in the COOGER Study because, "The task of revising the environmental and socioeconomic sections to the extent requested by some members of the Steering Committee and some members of the public could not be accomplished without substantial delay and expansion of the scope of the study."

Department comment: Many issues, including environmental issues of concern to the Department, such as the protection of sensitive terrestrial and marine habitats and associated species, and the potential risks from oil spills due to increased oil production, are topics that deserve attention when discussing scenarios for future 7-2

Conserving California's Wildlife Since 1870

Comment #	Comment
7-1	The COOGER study is not intended to address environmental impacts, oil spill risk, or oil spill regulatory requirements.
7-2	We do not question the importance of the topics listed by this comment. The COOGER study was never intended to present an environmental impact analysis, and the COOGER study Steering Committee specifically excluded environmental topics to improve the study's focus on onshore physical infrastructure.

offshore oil activity. It is unfortunate that many of the original topics, such as the onshore environmental constraints topic, addressed by the COOGER Study, were deleted simply because they "could not be presented in sufficient detail to satisfy all members of the Steering Committee" as stated on page E-1. This omission seriously calls into question the usefulness of the study results. Thus, the Department requests that the onshore and other pertinent environmental constraints sections be re-evaluated and included into the final Study report. There is a plethora of existing information on these environmental topics that could have been summarized and incorporated into this study without causing a substantial delay (especially since this Study began in 1995) and could have fit into the original scope of the onshore environmental constraints section. 7-2 cont.

2) *COOGER Study*: Page 1-3 states, "The study is an information document and does not advocate or recommend any particular scenario. It is not a decision-making document."

Department comment: The Department agrees that this document should not be used for decision-making purposes since, in its current state, it is to limited in its scope (e.g., the onshore environmental constraints section was deleted). 7-3

3) *COOGER Study*: As stated on pages 1-3 and E-2, the Department understands that any proposed development of new or expanded infrastructure onshore will be subject to California Environmental Quality Act review and that site-specific analyses of environmental issues will be evaluated in each individual Environmental Impact Report (EIR).

Department comment: The Department believes potential cumulative environmental impacts need to be addressed in the "overall" Study, since the Study addresses constraints for a 20-year period for future offshore oil development. The Department does not believe that individual EIR's will be able to adequately and thoroughly evaluate all potential, cumulative environmental impacts associated from potential future projects. For example, the Department doubts that an EIR prepared in the year 2000 for a specific proposed oil platform, will be able to thoroughly evaluate all the potential, cumulative environmental impacts that could be associated with past and future (2015) drilling of offshore oil platforms. 7-4

4) *COOGER Study*: The principal objective of the COOGER Study is to provide information about present and future levels of offshore oil activity and to describe the present and future onshore infrastructure; the facilities which process, store, and transport crude oil, natural gas, liquified petroleum, and the port and harbor facilities, airports, railways, roads and highways that transport the products.

Department comment: While the Department understands that the principal objective of the COOGER Study is to address the limited issues of onshore physical 7-5

Comment #	Comment
7-3	No revision to the COOGER study is recommended by this comment.
7-4	The evaluation of cumulative impacts is a required component of Environmental Impact Reports prepared pursuant to the California Environmental Quality Act. The COOGER study may provide information that will be useful to the development of these cumulative impact analyses.
7-5	The COOGER study Steering Committee specifically excluded oil spill risk from the study content.

constraints to offshore development, we believe there are "onshore physical constraints" associated with oil spill response. As such, the Department recommends there be some discussion as to the potential increase in risk from oil spills. We found only one reference to oil spills in this Study (one sentence in Appendix E) noting a comment received at a public workshop requesting oil spills be addressed. The Department agrees with this public comment. The potential constraints of oil spill cleanup, the potential need (constraint) for additional oil spill response equipment ("infrastructure" needed) from increased offshore production, the potential economic impacts (constraints) from oil spills, and the potential increased risk (constraint) from oil spills to onshore and offshore habitats and associated biota should all be considered. 7-5 cont.

5) *COOGER Study*: Table 2.2-1 lists the regulatory framework for offshore oil and gas development and Table 2.2-3 lists approvals needed for outer continental shelf development.

Department comment: There was no mention of the OSPR's, oil spill response and prevention requirements. Subdivision 4, Section 791, Title 14, California Code of Regulations (CCR), requires certificates of financial responsibility for marine facilities, where a spill could impact the marine waters of the state. Additionally, Section 817, Title 14, CCR requires marine facilities to submit an oil spill contingency plan. The COOGER Study needs to address these regulations in the context of current and future offshore and onshore physical infrastructure. 7-6

As I am sure you are aware, many of the oil spills in recent years have been from pipelines. More specifically, numerous oil spills have been from pipelines used to transfer oil from offshore platforms to onshore facilities. The recent Aera Energy oil spill in southern California that was first reported on October 31, 1999 where the pipeline between offshore platform Eureka and Elly began leaking oil, is just one example of numerous oil spills the Department's OSPR has responded to involving a leaking pipeline associated with an offshore platform and/or onshore facility. Being a state trustee agency responsible for oil spill response, the Department has special interest in any current and future development of offshore oil leases. As such, the Department appreciates the opportunity to review the COOGER Study. As always, Department personnel are available to discuss our comments, concerns, and recommendations in greater detail. To arrange for a discussion of this and other local oil spill prevention and response issues, please contact Ms. Melissa Boggs at (805) 772-1756 or Mr. Ken Wilson at (805) 568-1229.

Sincerely,

DeWayne Johnston

Mr. DeWayne Johnston,
Regional Manager, Marine Region

Mr. Gary Gregory, Administrator
Office of Spill Prevention and Response

Comment #	Comment
7-6	The referenced information has been incorporated into Table 2.2-1.

cc: Ms. Marilyn Fluharty
Department of Fish and Game
San Diego, California

Ms. Melissa Boggs
Department of Fish and Game
Morro Bay, California

Mr. Ken Wilson
Department of Fish and Game
Santa Barbara, California

11-10-99

Mr. Fred White
Minerals Management Service
770 Paseo Camarillo
Camarillo, CA 93010

COMMENT #8

Mr. White:

I would like to submit the following written comments in regard to the COOGER study.

Regarding the scenario of a lease buyback, it states on page 3-1 of the study that the buyback and termination of existing leases was not evaluated "because a practical method for estimating the probable cost and identifying a suitable finance mechanism for such a scenario was not apparent."

Although a suitable finance mechanism to repay the oil companies the billion dollars they have spent on the existing leases, both developed and undeveloped, might not have been readily "apparent" to the study team, a sharp group of accountants should fairly easily be able to estimate the probable cost (read liability) of a lease buyback. 8-1

The finance mechanism is irrelevant at this stage. An informational report must contain how much money the government (read taxpayers) would owe the oil companies if it buys the existing leases back so that informed decisions can be made.

Regarding the safety of the existing facilities, Ms. Linda Krop, General Counsel for the Environmental Defense Center, stated at the public comment session on 10-28-99 that the safety of the existing facilities should be addressed as a capacity/permit factor in the report.

Addressing facility safety as a capacity/permit factor in the study is completely inappropriate for one main reason - it already is addressed in the current facility permit process and operational capacity performance! A multitude of agencies such as the MMS, CAL-OSHA, the US Coast Guard, County Environmental Health Departments and local fire departments regulate the oil industry facilities. These agencies have the legal authority to cite, fine and even stop operations of these facilities when they find violations. 8-2

Although Ms. Krop is correct when she says that some of the facilities are old, one has to remember that no facility is operated beyond its safe capacity at any time. In fact, as the COOGER study shows, most all of the facilities operate below their designed capacity.

Finally, although the study is fairly comprehensive, it would be very helpful for most readers if the final report included an Executive Summary that captured the main ideas of the report. Even though the study does not make any recommendations regarding future development, there are conclusions made throughout the study. For instance, on page A. 4-2 the study concludes that Ventura County could lose over 70% of current oil and gas facility tax revenues within the next 8-3

<u>Comment #</u>	<u>Comment</u>
8-1	The COOGER study is not intended to be a decision document. The analysis of potential development scenarios was focused on economically viable development. The lease buy-back option was not recognized as potentially viable, and it was not considered necessary to evaluate it in detail.
8-2	Safety is not addressed as a capacity-limiting factor in the COOGER study except as it may already be incorporated into the design capacity or permit limitations applicable to individual facilities.
8-3	An executive summary is presented in the Final COOGER report.

five years unless there is new offshore development. The study also concludes that Santa Barbara County would be facing an annual loss of over $3 million dollars in property tax revenue, 2/3 of which is dedicated to the schools. Where do Ventura and Santa Barbara Counties expect to make up this revenue shortfall? Decision-makers must consider these questions. 8-3 cont.

In conclusion, it is absolutely critical that the final COOGER study include the following items for the reasons stated above: 1) the amount of financial liability the government has to the oil companies for a lease buyback program, 2) a statement indicating that the safety of the current facilities is carefully monitored and regulated by a multitude of agencies and therefore is not considered as a separate capacity/permit issue, and 3) an Executive Summary that highlights the main conclusions of the report. 8-4

Thank you for considering my comments and including them in the process.

Dan Gremaud

Dan Gremaud
12 Estates Avenue
Ventura, CA 93003
805-289-1663

Comment #	Comment
8-4	These comments are addressed in Responses 8-1, 8-2, and 8-3.

White, Frederick

From: Don & Ellen Dollar <ddollar@ccaccess.net> at -smtp
Sent: Saturday, November 13, 1999 8:24 PM
To: White, Frederick
Subject: Cooger

COMMENT #9

I understand that Secretary Babbitt is requiring that EIRs be written for the proposed oil leases.

I wish to be on all mailing and notification lists for those EIRs.

Please add the following public comment on Cooger:
One main problem I have with the current Cooger oil leases, is that the leases occur first, then the various reviews. I feel that this is very wrong - it gives the oil and exploration companies somewhat of a proprietary interest, before the public can have any input, let along address social, economic or environmental issues or concerns. I think this is a major procedural issue, in other words, by leasing first, then reviewing, you are getting the horse before the cart. Also, the oil and exploration companies obtain proprietary information from public resources and that information is withheld from the public. This is not a fair due process for the public or public resources. 9-1

Don Dollar
2357 Banderola
San Luis Obispo CA 93401

Comment #	Comment
9-1	This comment does not suggest any revision to the COOGER report. The commentor should be aware that there is substantial opportunity for public input prior to the issuance of offshore leases, including opportunities to comment on the proposed overall 5-year leasing program and additional opportunities to comment on each proposed lease sale. Environmental Impact Statements are circulated for public review and input in connection with each of these actions.

White, Frederick

From: bberwager@venocoinc.com at ~smtp
Sent: Monday, November 15, 1999 7:01 PM
To: White, Frederick
Cc: bberwager@venocoinc.com at ~smtp
Subject: COMMENTS TO FINAL DRAFT OF COOGER

COMMENT #10

Dear Fred-

Looks like this monster project is about to end. I'll be able to attend the Dec. 2 Steering Committee meeting. I trust that my comments of August 24, 1999 will be included along with others for review and discussion. It seems like we always get the comments from SB County, and I want to ensure that they get a chance to see an alternative view.

With regards to the latest draft, I have a few suggested revisions:

1. Page 1-10, Paragraph 9, change the 2nd sentence from "Although crude oil prices are currently less..." to "Although crude oil prices are currently more...". 10-1

2. Section 1.5, Add a paragraph in the introduction to address why socioeconomic information has been removed from the document. I know this is touched upon way back in Appendix E, but it is important to note upfront. 10-2

3. Page 2-32, please note that gas from Platform Gail is sweetened offshore and then transported to shore for compression and sale. The gas is not injected offshore. The gas that arrives at Carpinteria has no H2S contained in it. Furthermore, it should be noted that the current operator of the Sockeye Field (Venoco) has plans to invest capital to do additional development drilling, recompletions, and waterflooding to enhance the field's production, and has already tripled the field's gas production from the level of the previous operator. Therefore, the economic life of the field under all scenarios will be longer than estimates in the COOGER report. 10-3

Bruce Berwager
Santa Barbara Channel Asset Manager
Venoco, Inc.
520 East Montecito St., Box 9
Santa Barbara, CA 93103
805-884-7461
email: bberwager@venocoinc.com

Comment #	Comment
10-1	The suggested revision has been incorporated into the report text.
10-2	The suggested revision has been incorporated into the report text.
10-3	The suggested revision has been incorporated into the report text.

NOV-19-1999 15:15

COMMENT #11

1849•1999 from the Desk of Frederick L. White

(702) 837-1600

November 19, 1999

Dean, this fax is Ventura County comments. As in the past they are primarily marked up pages. It should have should have 22 pages with cover. 11-1

Minerals Management Service
OEE, ESS
770 Paseo Camarillo
Camarillo, CA 93010

Voice Phone # (805) 389-7830
FAX Phone # (805) 389-7874
e-mail frederick.white@mms.gov

Comment #	Comment
11-1	The following pages present specific document revisions requested by Ventura County. Except as noted below, these revisions were implemented as suggested, or in a manner comparable to that suggested. The only suggested revision that was not implemented was the identification of the name and/or number of each pipeline in the Eastern Subregion. This could not be implemented because we could not locate specific names for these pipelines. The COOGER text is sufficiently detailed to allow the identification of specific facilities, however.

Each of the above-listed scenarios is addressed in terms of the onshore facility requirements, oil production rates, and demand on local infrastructure. This effort is intended to provide an improved understanding of the range of potential development options, and the general level of industrial activity associated with each option, and the range of demand on public and industrial infrastructure associated with these options.

1.5 ASSUMPTIONS

This report draws upon existing information gathered, inventoried, and consolidated from publicly available technical documents, and industry and agency files and interviews. In addition, explicit assumptions were defined early in the Study. The assumptions provided a foundation for the Study, and have been expanded upon in the issue-specific analyses. Because this study is intended to provide information concerning the adequacy of existing onshore facility capacity in relation to potential future offshore development, the continued use of existing facilities is a necessary study assumption. ~~Although~~ the continued use of existing onshore facilities provides a starting point for scenarios addressed in this study, although this assumption is not intended to imply that such use is guaranteed, facilities, Even when operated within existing land use permit limitations, may require additional agency approvals ~~may be required~~ to address other permit requirements (such as air permit requirements, water discharge permits or other limitations) or issues associated with the extended life of the facility. In some cases, the extended life of an existing facility may not be preferable to other options. Santa Barbara County has recently expressed concerns regarding the safety of older facilities, and has suggested that safety audits should be completed before decisions are reached that could lead to the extended life of any onshore facility. ~~Since~~ Most of the existing facilities that could be considered for extended use under different scenarios are located in Santa Barbara County. Therefore, this County's concerns regarding this topic could affect future development. County staff indicated that facility safety audits should evaluate facility design and operating procedures to identify possible upgrades to incorporate best available technology and allow the facility to operate safely throughout its projected extended life. As a part of this review, Santa Barbara County staff have recommended a detailed examination of the operating and maintenance history of the facility in question, including an evaluation of the record of accident incidents (including air and water releases) to help identify facility-specific concerns to be addressed by facility improvements. A comprehensive treatment of this topic has not yet been done, and is likely to be required in connection with development proposals which involve extended facility life or

expanded capacity. The California State Lands Commission (SLC) is preparing a statewide engineering audit program to encompass both state offshore and onshore oil producing and separation facilities which will include the evaluation of safety system design, process controls, inspections, testing and maintenance of the facilities with the focus on best available protection of the marine environment and public safety. Additional study assumptions include the following:

1) Economic viability of potential development was determined assuming that current operating costs and crude prices would prevail at all future dates. Potential market limitations were not considered except as specifically discussed in relation to specific Northern Subregion scenarios. directly ?

2) Discrete oil and gas fields will be the subjects of consideration for this study and reserve estimates will be done on a field basis. For the purpose of this study, a field is deemed to be an area within which hydrocarbons have been trapped and concentrated in one or more reservoirs in economically producible quantities. A field may refer to its geographically measurable surface area only, or may include its vertical subsurface dimensions.

3) Industry will endeavor to optimize production, processing and transportation facilities, both offshore and onshore. Such optimization may include efforts to use facilities in common, taking into consideration the following factors: existing regulations; distance between operations; timing and rate of oil and gas production; characteristics of oil; facility capacity; as well as the number and location of onshore entry points. Similarly, individual operators will propose future development activities on their leases at the rate and in the manner they desire subject to conditions of their lease agreement and subject to the management authority of the MMS and California State Lands Commission.

4) The Tri-County and state jurisdictions, including the California Coastal Commission, will endeavor to optimize onshore facilities as a means of minimizing adverse impacts. Such optimization may include requirements to consolidate processing facilities and sites, consolidate pipelines and pipeline corridors, and use of pipelines instead of other modes of transportation for crude oil and natural gas liquids.

2.4.2.1 Mandalay Onshore Separation Facility

General. The Mandalay Onshore Separation Facility (Mandalay Facility) is located near Oxnard and receives wet oil and gas from Platform Gina in the Hueneme Field and Platform Gilda in the Santa Clara Field. The Mandalay Facility is located on the coast next to the former Southern California Edison Mandalay Generating Station approximately two miles south of the mouth of the Santa Clara River. [Note: Houston Industries acquired this Southern California Edison facility after 1995; however, for familiarity it will be referred hereafter as the former Southern California Edison facility rather than Houston Industries facility.] A system schematic for the Mandalay Onshore Separation Facility is shown in Figure 2.4-4 and a plot plan of the Mandalay Facility is shown in Figure 2.4-5. A facility "profile" summary is provided in Appendix B.

Based on information provided by the operator, the Mandalay Facility's oil-water separation system has a wet oil processing design capacity of 25,000 barrels per day (BPD), a produced water treating design capacity of 15,000 barrels of water per day (BWPD), and a dry oil storage capacity is 8,000 barrels. The gas separation system uses glycol dehydration removal and has a design capacity of 18.0 million cubic feet per day (MMCFD) and is permitted for 6.0 MMCFD. The facility does not have a natural gas liquids (NGL) processing system; NGL is blended into the crude oil. The facility does not produce sulfur. Major equipment located at the facility includes:

- oil-water separation system that use heater-treaters and free-water knockouts;
- crude oil storage tanks;
- produced water storage tank;
- oil pipeline transfer pumps;
- water treatment system
- treated water discharge system;
- gas system using glycol dehydration;
- no NGL processing system; NGL blended into the crude oil;
- no sulfur recovery or disposition system;
- gas compressor plant

Offshore Flowlines/Pipelines. Production from Platform Gina is sent to the Mandalay Facility in a 10-inch diameter three-phase flow (i.e., a mixture of oil, water, and gas) pipeline and a 6-inch diameter sweet gas pipeline. The 6-inch gas pipeline transports gas from Well H-14 to shore. Prior

to 1990, the gas pipeline was used to transport produced water from the onshore facility back to Platform Gina for discharge. Since that time, produced water is combined at the Mandalay Onshore Separation Facility with the produced water from Platform Gilda, treated and returned to Platform Gilda for injection or ocean disposal.

Production from Platform Gilda is sent to the Mandalay Facility in a 12-inch diameter wet oil pipeline and a 10-inch diameter gas pipeline. There is a 6-inch diameter treated produced water pipeline from the Mandalay Facility to Platform Gilda.

Product Distribution. Streams exiting the Mandalay Facility include oil, gas, and treated produced water. The oil is combined with the recovered natural gas liquids (NGL) and the combined stream is pumped (via a Tosco pipeline) to surge tanks ~~located~~ at the Ventura Pump Station located near the Ventura Harbor. The gas is sold to the adjacent former Southern California Edison Mandalay Generating Station. The treated produced water is pumped to Platform Gilda for subsurface reinjection or deepwater discharge via an NPDES permitted outfall.

Information on the oil distribution pipeline is provided on a sub-regional level in the Eastern Pipeline System discussion in Section 2.4.2.8, the regional level in the product distribution system discussion in Section 2.4.5, and at the facility level in the corresponding Facility-specific table in Appendix B. In addition, Section 2.4.5 includes a diagram of the principal local and regional pipeline connections and information on which pipelines are proprietary and which are common carriers.

Spare Capacity / Permit & Operating Limitations. As of August, 1997, the Mandalay Facility had a baseline spare capacity of approximately 9,600 barrels per day of wet oil and 2.5 MMCFD of gas. Reportedly, the facility does not use fresh water and so water availability is not a limitation. Other than design limitations, the operator did not identify any operating constraints. No permit constraints were identified that would limit throughput to less than the design capacity.

Key System Dependencies

- Platform Gina depends on Platform Gilda for the disposal of treated produced water (via the Mandalay Facility).
- The Mandalay Onshore Separation Facility depends on the downstream oil and gas pipeline distribution system (see Eastern Pipeline System discussion).

Information on the oil distribution pipeline is provided on a sub-regional level in the Eastern Pipeline System discussion in Section 2.4.2.8, the regional level in the product distribution system discussion in Section 2.4.5, and at the facility level in the corresponding Facility-specific table in Appendix B. In addition, Section 2.4.5 includes a diagram of the principal local and regional pipeline connections and information on which pipelines are proprietary and which are common carriers.

Spare Capacity / Permit & Operating Limitations. Appendix B identifies the spare capacities for the La Conchita Facility. The operator did not identify limitations. No permit constraints were identified that would limit throughput to less than the design capacity.

Key System Dependencies.

- Platform Houchin depends on Platform Hogan and the interconnecting flowlines.
- The La Conchita Oil & Gas Processing Facility depends on the downstream oil and gas pipeline distribution system (see "Eastern Pipeline System").

Venoco

Secondary Facilities. Oil from the La Conchita Facility is pumped into a Chevron pipeline between the Carpinteria Oil & Gas Processing Facility and the 268,000 barrel ~~Venoco-owned~~ storage tank adjacent to the Rincon Oil & Gas Processing Facility. Ultimately, the oil is pumped by pipeline to the Ventura Pump Station (see discussion of "Eastern Pipeline System" below).

Future Facility Capacity. Production estimates predict that the quantity of wet oil and gas produced from the platforms and processed at the La Conchita Facility will decline annually over the remaining life of the facilities. This should result in annually increasing spare processing capacity at the La Conchita Facility assuming it does not become limited (bottle-neck) in its ability to process a particular fraction (e.g., wet/dry oil, gas, produced water, etc.) of the incoming stream.

Based on historic production and estimated economically recoverable reserve data for the platforms, the economic life of the La Conchita Facility is projected to end by study year 2000. When the platforms, La Conchita Facility and associated pipelines become idle, it is assumed that they will be removed except for some flowlines which may be abandoned in place. The loss of production from the La Conchita Facility will increase the available capacity at the Rincon Onshore Oil & Gas Processing Facility and the corresponding pipelines from the Rincon Onshore Oil & Gas Processing Facility to the Ventura area and to the refineries in the Los Angeles area. In addition, there will be the no gas from the facility entering the Southern California Gas Company's distribution system.

Clara River. Flow in these pipelines is intermittent (i.e., batch basis from the tank batteries). The historic (pre-1995) annual peak oil production from the West Montalvo Operations occurred in 1993.

Facilities North of the Ventura Pump Station (north to south)

pipeline #+ owner?

The Carpinteria Oil & Gas Processing Facility sends oil via a 10-inch diameter, unheated pipeline to a 268,000 barrel Venoco-owned storage tank located adjacent to the Rincon Oil & Gas Processing Facility. As of August 1997, the pipeline was operating at approximately 1,750 barrels per hour. For most of the distance between the facility and the storage tank, the pipeline is located in the railroad right-of-way that passes within 100 yards of the facility. This pipeline also passes within 100 yards of the La Conchita Oil & Gas Processing Facility and the Rincon Island and State 145/410 Oil & Gas Processing Facilities which are geographically located between the Carpinteria Facility and the storage tank. The historic (pre-1995) annual peak oil production from the Carpinteria Oil & Gas Processing Facility (i.e., Platforms Gail and Grace) occurred in 1990.

pipeline #+ owner?

The La Conchita Oil & Gas Processing Facility sends oil via an approximately 100 foot long, 4-inch diameter, unheated pipeline that connects into the 10-inch diameter pipeline that goes from the Carpinteria Oil & Gas Processing Facility to the 268,000 barrel Venoco-owned storage tank located adjacent to the Rincon Oil & Gas Processing Facility. The historic (pre-1995) annual peak oil production from the La Conchita Oil & Gas Processing Facility (i.e., Platforms Hogan and Houchin) occurred in 1969.

The Rincon Island Oil & Gas Processing Facility sends oil via a 6-inch diameter, unheated pipeline that connects into the 10-inch diameter pipeline that goes from the Carpinteria Oil & Gas Processing Facility to the 268,000 barrel Venoco-owned storage tank located adjacent to the Rincon Oil & Gas Processing Facility. The pipeline from the island is suspended on the causeway and then goes underground when it reaches shore, passes under Highway 101 and connects into the 10-inch diameter pipeline in the railroad right-of-way. The historic (between 1977-1995) annual peak oil production from Rincon Island occurred in 1977. As described above, oil from the State Lease 145/410 Oil & Gas Processing Facility is transported by truck to a pump station operated by Texaco located in Fillmore.

The Rincon Oil & Gas Processing Facility sends oil via a 6-inch diameter, unheated pipeline to the 268,000 barrel Venoco-owned storage tank located adjacent to the Rincon Oil & Gas Processing

The Torrey Pump Station sends oil to the Los Angeles area via a 12-inch diameter, unheated pipeline. The pipeline heads south from the Torrey Pump Station and leaves the COOGER Study Region on its way to the Los Angeles area. This pipeline is operated at a pumping rate of 1,300 barrels per hour.

Other Pipelines in the Eastern Subregion

In addition to the above pipelines, there are two other pipelines in the Eastern Subregion that transport oil to the Los Angeles area. Although no offshore oil is transported in these pipelines, except for a small quantity from the State Lease 145/410 Oil & Gas Processing Facility, they are in close proximity to the M-143 pipeline and could also be "reconnected" to the Ventura Pump Station by reconnecting the Texaco pipeline at the recently abandoned Texaco Ventura Marine Terminal (described below).

EQuiLon Pipeline Co. PO BOX 24340 Vta. 93002 Oren Hoover 653-2014 [illegible] pipeline

Texaco operates an 8.625-inch diameter unheated crude oil pipeline between Ventura and Newhall (in Los Angeles County - outside of the COOGER Study Region). The pipeline originates at the Texaco Willett Tank Farm located on Ventura Avenue several miles north of Ventura. Texaco formerly operated a pipeline between the Willett Tank Farm and the Ventura Pump Station (described above) that was connected to the long-time-idle Texaco Ventura Marine Terminal located between the Willett Tank Farm and the Ventura Pump Station. When the marine terminal was removed, the pipeline between the Willett Tank Farm and the Ventura Pump Station was "disconnected"; however, the majority of the pipeline remains intact.

now owned + operated by EQUILON Pipeline Co.

The Texaco pipeline between Ventura and Newhall is primarily used to transport onshore production; however, offshore production from the State Lease 145/410 Oil & Gas Processing Facility is trucked to a Texaco pump station in Fillmore and is introduced into this pipeline. As of August 1997, the pipeline was idle between Fillmore and Newhall because it is "under" Highway 126 east of Fillmore and Highway 126 is currently undergoing a major widening project. Because of this, the flow direction from the Fillmore Pump Station has temporarily been reversed (i.e., toward the Willett Tank Farm) to transport onshore produced crude to Ventura. There are four 80,000-barrel storage tanks located at Willett Tank Farm; two are currently operable and two are idle. The oil is transferred from these tanks to a 35,000 barrel storage tank at Shell's Ventura Pump Station (described below) located a few miles north of the Willett Tank Farm.

?

Aera operates a tank farm on Ventura Avenue north of Ventura that processes oil produced onshore. Oil is sent from the tank farm via a 10-inch diameter oil pipeline to the Los Angeles area. Except for the small quantity of offshore oil from the State Lease 145/410 Oil & Gas Processing Facility, that enters via the Texaco pipeline, the pipeline transports onshore oil. As of August 1997, the Shell pipeline was transporting approximately 45,000 barrels of oil per day. There are several pumping stations between Ventura and the Los Angeles area along this pipeline. EQ ?

Facility Description. This section describes the three pump stations (Ventura, Santa Paula, and Torrey) that are on the main pipeline which carries offshore oil from the Eastern Subregion to the Los Angeles area.

The Ventura Pump Station is located approximately one-quarter mile south of the Ventura Harbor and consists of a 135,000 barrel tank, a 150,000 barrel tank and pumps. The Ventura Pump Station pumps oil to the Santa Paula Pump Station as described above.

The Santa Paula Pump Station is located in the east-central part of Santa Paula and consists of a 55,000 barrel storage tank and pumps. The Santa Paula Pump Station pumps oil to the Torrey Pump Station as described above.

The Torrey Pump Station is located south of Fillmore and the Santa Clara River in Torrey Canyon and consists of an 80,000 barrel storage tank and pumps. The Torrey Pump Station pumps oil to the Los Angeles area as described above.

Product Distribution. As described above, all of the offshore oil processed by facilities in the Eastern Subregion, except for the oil from the State Lease 145/410 Oil & Gas Processing Facility, is sent to the Los Angeles Area via pipelines connected directly to the facilities.

Also as described, the offshore-produced natural gas is used by the facilities (either by onshore facilities or offshore at the platforms) or is transferred by pipeline to the local utility company's distribution pipeline system. An analysis of the utility company's pipeline system is not part of the COOGER Study. No information was located to indicate that the utility company's pipeline system would constrain production.

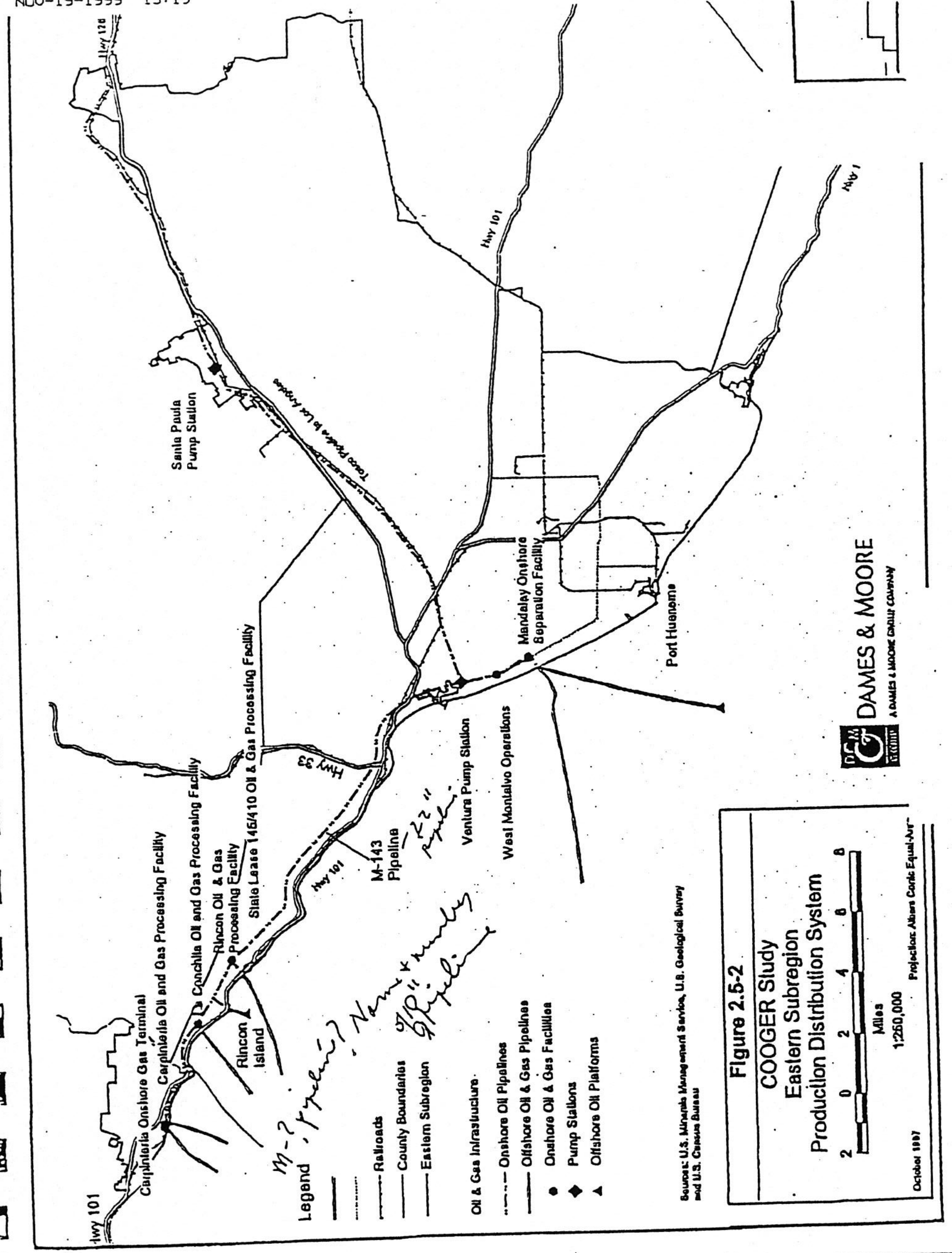


Figure 2.5-2
COOGER Study
Eastern Subregion
Production Distribution System

2.5.1.1 Local Area Pipelines

All three subregions have numerous local gathering and distribution pipelines operated by several different companies, but with the exception of some common connections to the All American Pipeline, L.P. (AAPLP) pipeline, described as the "All American Pipeline, L.P. (AAPLP) System" in Section 2.4.3.7 and the Tosco pipelines described as the "Northern Pipeline System" in Section 2.4.4.6, there are no inter-subregion connections and generally, few inter-company connections. Also, there are no pipeline connections in the Tri-County area that link offshore-related facilities northwest of Santa Barbara (in the Central and Northern Subregions) with offshore-related facilities southeast of Santa Barbara (in the Eastern Subregion). This general lack of interconnections limits the distribution options available to many of the processing facilities. The transportation of the offshore crude produced in the Study Region is also complicated by the fact that most of it is heavy and contains relatively high concentrations of sulfur. Sometimes this high-viscosity, high-sulfur (HVHS) type crude must be heated or blended with a lighter crude or diluent to make it easier to pump by pipeline.

During the past decade, several pipelines have been proposed to transport crude out of Santa Barbara County. One pipeline has actually been built. The AAPLP pipeline allows shipment of crude from the Las Flores Canyon and Gaviota areas in Santa Barbara County to refineries in the Bakersfield, Los Angeles and San Francisco areas, west Texas and Texas Gulf, Louisiana and the mid-continent. An intermediate tie-in at the Sisquoc Pump Station in northern Santa Barbara County makes it possible to divert crude to the Tosco Pipeline system ("Northern Pipeline System") and similar tie-ins at the AAPLP Pentland and Emidio Pump Stations makes it possible to divert crude to the Los Angeles area refineries. Tie-ins at Pentland in Kern County also make it possible for crude to be sent to the Bakersfield and San Francisco Bay area refineries. Pacific Pipeline completed the installation of a 20-inch diameter, 130,000 barrels per day capacity pipeline from Emidio to Los Angeles in March 1999. This pipeline adds pipeline capacity to transport oil from Kern County to the Los Angeles area and provides an alternative to the use of unit trains or marine tankships and barges.

2.5.1.1.1 Eastern Subregion Pipelines

The pipelines in the Eastern Subregion are described in Section 2.4.2.8 as the "Eastern Pipeline System". There are three pipelines from the Eastern Subregion to the refineries in the Los Angeles area. Tosco and Shell have pipelines from Ventura to Los Angeles and Texaco has a pipeline from

EQUILON? check: Oren Hoover. 653-2014

Ventura to Newhall that connects to the Arco Pipe Line Company's (APLC) pipeline. Texaco and Tosco's pipelines are proprietary; however, the Shell pipeline is a common carrier. All of these pipelines transport low sulfur oil and are unheated. The Tosco pipeline transports all of the offshore oil from the Eastern Subregion except for the small amount produced at the State Lease 145/410 Facility.

The pipelines from the Carpinteria and Ventura coastal areas transport offshore- and onshore-produced crude oil to refineries in the Los Angeles area. The pipeline from ~~the Carpinteria~~ Oil & Gas Processing Facility to the Rincon Oil & Gas Processing Facility is owned by Venoco. The pipeline from the Rincon Oil & Gas Processing Facility to Ventura is owned by ~~Mobil and Chevron~~ and connects to a pipeline owned by Tosco at the Ventura Pump Station.

In the Future Baseline scenario (Scenario 1), the total oil production from the facilities in the Eastern Subregion is projected to decline annually from Study Year 1995 until Study Year 2010 and all facilities are projected to be shut down by Study Year 2015. Consequently the quantity of oil sent through the existing pipelines is projected to decrease annually during the Study Period.

In Scenario 1, the Rincon Island Facility is projected to produce larger quantities of oil than available historic data indicate have been produced in the past. The data reviewed did not include the facility's initial operating period from 1960 to 1976 ~~when the~~ production levels were probably higher than during the period addressed by available data, ~~however~~. Oil from the Rincon Island Facility is pumped to shore through a 6-inch diameter pipeline on the causeway and then enters the 10-diameter pipeline between Carpinteria and the 268,000 barrel storage tank adjacent to the Rincon Onshore Oil & Gas Processing Facility. Both pipelines are expected to be able to handle the projected flows.

2.5.1.1.2 Central Subregion Pipelines

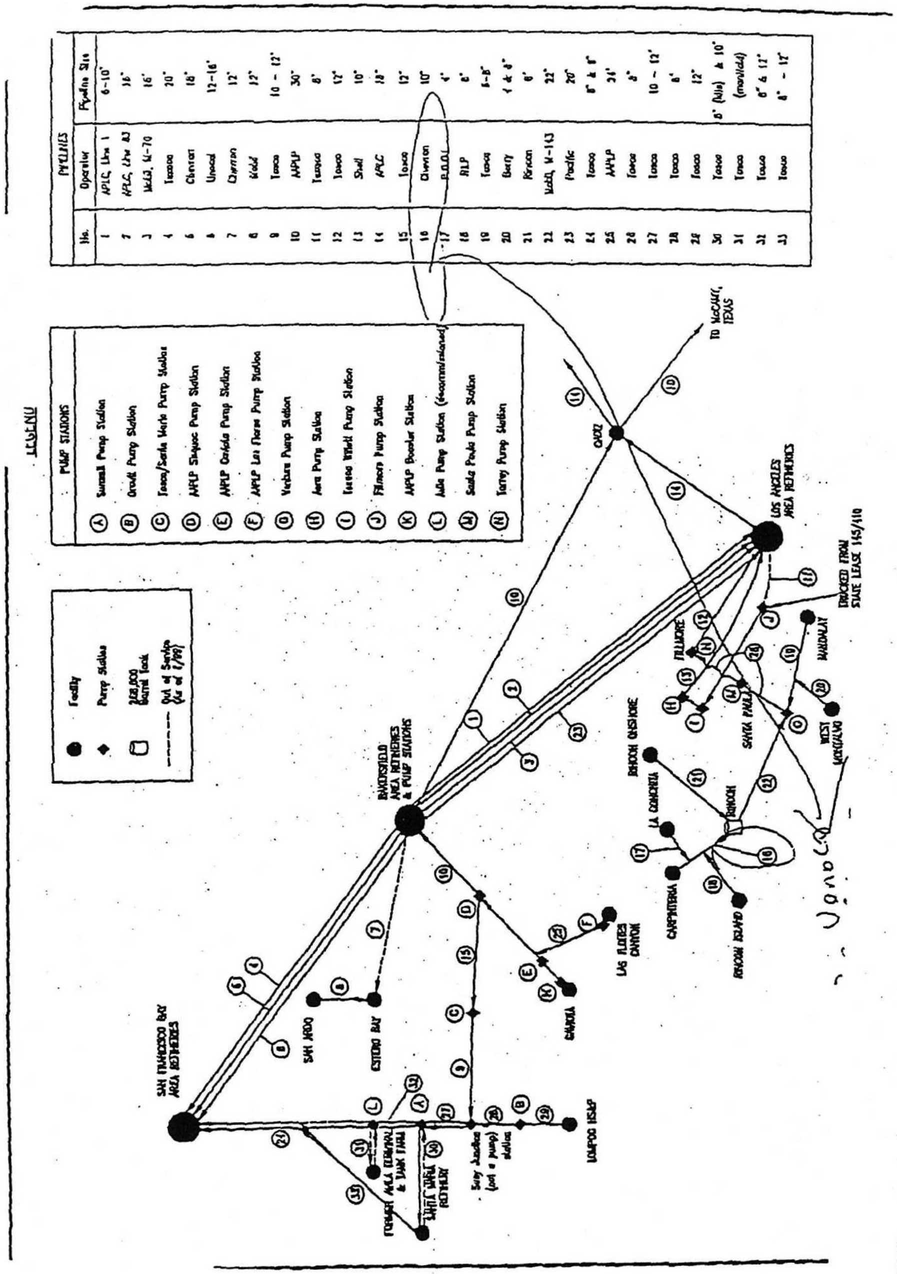
The Central Subregion onshore crude oil pipeline system consists of local gathering lines and connections to the interstate All American Pipeline, L.P. (AAPLP) and intrastate Tosco Pipeline (Northern Pipeline System). Two of the four primary facilities in the Central Subregion (Las Flores Canyon SYU and Gaviota Oil & Gas Processing Facilities) can send crude oil out of the Subregion by pipeline. One facility, the Ellwood Oil & Gas Processing Facility, is only connected to a pipeline to the Ellwood Marine Terminal. The Central Subregion pipelines are discussed in Section 2.4.3.8 as the "AAPLP Pipeline System".

Shell?

Venoco

Table 2.5-1
Existing California Crude Pipelines

No.	Operator Line - Name (type[1])	Pipeline Diameter inches	Origin	Destination	Capacity (MBD[2])	Crude Source
1	APLC, Line 1 (c)	6 - 10	Bakersfield	Los Angeles	Idle	SJV[3] Blend
2	APLC, Line 63 (c)	16	Bakersfield	Los Angeles	115	SJV/OCS[4]
3	Mobil, M-70 (p)	16	Bakersfield	Los Angeles	95	SJV Heavy
4	Texaco (p)	20	Bakersfield	San Francisco	215	SJV Heavy
5	Chevron (p)	18	Bakersfield	San Francisco	95	SJV Blend
6	Tosco (p)	12 - 16	Bakersfield	San Francisco	72	SJV/OCS
7	Chevron (p)	12	Bakersfield	Estero Bay	60	SJV
8	Mobil (p)	12	San Ardo	Estero Bay	28	San Ardo
9	Tosco (p)	10 - 12	Santa Maria P/S	Suey Junction	120	OCS/Local/SJ
10	AAPLP (c)	30	Gaviota	Bakersfield	300	OCS/SJV
11	Texaco (p)	8	Fillmore	Ventura	NA	Local[5]
12	Tosco (p*)	12	Torrey P/S	Los Angeles	20/40	Local/OCS
13	Shell (c)	10	Shell P/S	Los Angeles	35	Local
14	APLC (c)	16	Los Angeles	McCamy (TX)	45/75	OCS/ANS[7]
15	Tosco (p)	12	Sisquoc P/S	Santa Maria P/S	50.4	OCS
16	Chevron (p*)	10	Carpinteria	Rincon 268,000 Tk.	42	OCS
17	POOI (p)	4	La Conchita	Rincon 268,000 Tk.	>0.6	OCS
18	RILP (p)	6	Rincon Island	Rincon 268,000 Tk.	>0.2	SW[8]
19	Tosco (p*)	6-8	Mandalay	Ventura P/S	20	OCS
20	Berry (p)	4 & 6	W. Montalvo	Ventura P/S	NA	SW/Local
21	Torch (p)	6	Rincon Fac.	Rincon 268,000 Tk.	8.5	OCS
22	Mobil, M-143 (p*)	22	Rincon 268,000 Tk.	Ventura P/S	72	OCS/Local
23	Pacific Pipeline (c)	20	Bakersfield	Los Angeles	130	SJV/OCS
24	Tosco (p*)	8 & 8	Avila P/S	San Francisco	57.6	OCS/Local
25	AAPLP (c)	24	Las Flores	AAPLP Main Line	150	OCS
26	Tosco (p*)	8	Ventura P/S	Fillmore P/S	24	OCS/Local
27	Tosco (p*)	10 - 12 8	Suey Junction Suey Junction	Summit P/S Summit P/S	84 24	OCS/Local Local/SJV



database. This database contains historical monthly oil, gas and water production on a well-by-well basis for both the federal offshore and state waters areas. This data was purchased in its entirety from PI and loaded to Scotia's reserves and economics database software. This software allowed a well-by-well projection of production and pressure history performance, allowing the reserves scenarios to be developed. In addition, the software was used to perform and economic analysis allowing the calculation of economic limits based on ~~input of relevant~~ controlling parameters. Other public domain data sources included PI's Well History Control System (WHCS which was in obtained in hard copy form.

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- **Publications** - Literature searches were performed on major sources of publications includin the AAPG, SPE and other technical literature to assemble a bibliography of publishe information on the study area. This bibliography was then reviewed and relevant paramete added to the databases on each field or unit.

A.1.3 Data Analysis

The quantity of technical data available in the study area is immense. All available information h relevance to the construction of realistic profiles of future oil and gas production and the review such information represents and extremely complicated and time-consuming task. To analyze data within the time and manpower constraints of the project, an audit procedure, having following characteristics, was used:

an

- Assembly of basic technical information and previous estimates. This exercise consiste reviewing available documents and previous estimates made by others and summarizin key technical parameters that effect the estimate and its backup.

- Review of estimates with current operators. Since a reservoir and production foreca commonly revised as additional data is collected during production, the most recent avai forecasts and estimates were reviewed with each individual operator and the opera current opinions were recorded. In addition, aspects of current constraints to increas future production were discussed and documented with each operator. Where acce operator data was not available, the projections were performed using decline techniques in conjunction with volumetric estimates.

- Based on the completed interview, existing profiles were adjusted and the basis t estimate documented. In certain cases, this necessitated an adjustment to the profile to honor the available data.

- Documentation of economic limits. The controlling parameters with respect to overall platform economics were researched and documented and the minimum economic rate established on a platform-by-platform basis.

- Interaction of platform production with processing capability. Individual platform projections were combined so that platforms producing into a common facility were handled as a combined unit to ensure that a proper interaction of all capacity considerations was achieved.

A.1.4 Reserves Estimates and Production Profile Construction

The two principal methods for estimation of reserves were volumetrics and decline curve analysis. The volumetric method consists of mapping each hydrocarbon-bearing reservoir and performing Such estimates of net rock volume, porosity and water saturation, and then combining ~~these~~ data ~~with the~~ appropriate formation volume factor to obtain an in-place oil or gas volume. such volumes are calculated down to known fluid contacts or, in the absence of information on fluid contacts, down to the lowest known level of hydrocarbon occurrence in the reservoir. Hydrocarbons below the lowest known occurrence may be classified under the SPE scheme as probable or possible. The recovery of in-place oil and gas reserves is dependent upon an assessment of drive mechanism in the reservoir, well spacing and the location of wellbores in the reservoir, as well as other factors. The ability of wells to produce at their maximum rate is dependent upon the existence of adequate processing and sales facilities.

The scheduling of volumetrically estimated recoverable reserves to generate a production profile is estimated via a variety of techniques ranging from the application of analogs, evaluation of well test results, and development of reservoir simulations.

The decline curve analysis method for estimating reserves consists of projecting established trends in oil, gas or water production and extrapolating these trends to an economic limit. This provides a profile for future production and, via integration of the profile, recoverable reserves. The decline curve method as a stand-alone methodology does not provide information on original in-place volumes or the recovery efficiency of such in-place reserves. Such recovery will be dependent upon existing well spacing and production practices.

A.2 EXISTING FACILITY INVENTORY AND CAPACITY DETERMINATI

A.2.1 FACILITY IDENTIFICATION AND INITIAL CONTACTS

At the beginning of the COOGER Study, the COOGER Technical Management Team (TMT) identified those onshore facilities, associated with offshore oil and gas development, that were to be included in the Study. To initiate the data collection activities in 1995, Worley contacted each of the subject facilities to identify a facility representative and to introduce the purpose of the Study.

Worley then prepared data collection questionnaires specific to various types of onshore facilities (e.g., onshore processing facilities, marine terminals, etc.) and for the platforms that were connected to the onshore facilities. These questionnaires were sent to the facility contacts who were asked to complete them.

After the questionnaires were submitted, Worley scheduled a site visit for each facility, subject to approval from the facilities' operators. During the site visits, a Worley representative met with facility personnel to review the information on the questionnaire, to ask questions about facility equipment and operations, and to make visual observations of the facility. As appropriate, Worley obtained maps, plot plans, or other helpful documents and took photographs where allowed.

In addition to obtaining information from the facility operators, Worley reviewed selected publicly available reports (e.g., EIRs, Development Plans, etc.), agency reports and newsletters, and other related documents to obtain additional facility information.

Worley then prepared a draft report summarizing the facilities ~~and~~ there their operations and submitted the appropriate section of the report to each operator to review ~~and verify~~ the data collected. Worley incorporated the operators' comments, as appropriate, and ~~provided~~ the final report to Dames & Moore. Dames & Moore used the information from Worley, as appropriate, to prepare the TMT-internal draft Task II/III report issued in January 1997. Although much of this information has been updated since the January 1997 draft, plot plans, facility schematics, and facility operational descriptions based on information collected during Worley's efforts are presented in the general facility descriptions in this study.

time period. These employment reductions represent a major portion of the total oil and gas sector employment, and are likely to be highly visible to those directly involved in the offshore industry. Nonetheless, bot the short-term and long-term employment changes indicated by Table A.3-5 are well within the employment variability indicated on Figure A.3-2. These job losses also represent a small component of the local employment, and are unlikely to result in a noticeable effect on the overall County employment, regardless of the specific offshore development scenarios which actually occur.

both

A.3.2 Santa Barbara County

A.3.2.1 Overall Employment

Total employment in Santa Barbara County was 169,800 jobs in October 1998 (Californi Employment Development Department, 1998B). This represents a total civilian unemployment rat of 3.9%, which is slightly lower than the national average unemployment rate of 4.2%. The share c employment by industry sector for 1998 is presented in Figure A.3-3 based on data from th California Employment Development Department (1998B). The share of employment by sectors ar very similar between Ventura and Santa Barbara. Services comprise the single largest sector wit 28.8 percent of total employment. Retail and wholesale trade combined accounted for 21.9 percer of employment while the government sector, including federal, state and local direct employees ar military represents 18.8 percent of the total. With 69.5 percent of the employment from service trade or government, the remaining sectors ranked by their share of employment are (with the sha in parentheses): manufacturing (10%), agriculture (8%), finance, insurance and real estate (4.4% construction (4.1%), transportation, communications and utilities (3.5%), and oil and gas and mini (0.5%).

Although Santa Barbara County has a long history of both onshore and offshore oil and g production operations, employment related to oil field service companies is less than that in Ventu County. Several offices of independent oil and gas producers are located in Santa Barbara Cour County. These include companies such as Torch, Venoco, Ogle Petroleum, and Benton (however. These include companies such as Torch, Venoco, Ogle Petroleum, and Benton Employment associated with company offices involved in local offshore oil and gas producti construction employment associated with facility installation and removal, and service contract directly involved in these activities are included in the COOGER study employment estima Indirect employment resulting from the household expenditures of local workers, agency employn related to the regulation of offshore activities, and industry services which are not directly associ with the operation, construction, or decommissioning of individual offshore facilities or rel onshore facilities is not included.

A.6.3 Supply Vessel Activity at Port Hueneme

Projections of supply vessel activity associated with different offshore development scenarios were developed by analysis of recent supply vessel activity in relation to the offshore activities supported by these operations. Actual vessel activity data were collected from Tidewater Marine and C&C Boats, two companies providing most of the offshore supply vessel service to the offshore industry. In addition, the Oxnard Harbor District "Year to Year Cargo Summary" for fiscal year ending June 20, 1998 and their "Vessel Call Report for FY 1997/1998" were used to identify annual cargo tonnage for different years, and monthly vessel calls during fiscal year 1998. These data were used to define supply vessel activities associated with normal platform operations. A summary of the supply vessel activity data collected is presented in Table A.6-23.

In addition to data addressing routine operations, industry estimates of supply vessel activity associated with past proposals for development well drilling, platform installation, and platform decommissioning and removal were used. Principal references used in this effort included the Santa Barbara County/MMS Point Arguello Field EIR/EIS (A.D. Little, 1984) and the MMS OCS Leases P-0523 and P-0524 exploration and drilling plan (Dames & Moore, 1989). These data indicated supply vessel activity of one supply vessel per day over a 6.5 month platform installation and hookup period, and one supply vessel per day associated with development well drilling (over an average of 75 days per well). Platform decommissioning activities were separated into well plugging and abandonment and equipment and structure removal activities. These activities were assumed to require comparable short-term supply vessel support as corresponding platform installation and development drilling, but were estimated to require approximately one-half the total time to complete.

To develop supply boat activity projections associated with different offshore development scenarios that could be readily updated to reflect future scenario revisions, existing vessel activity records were evaluated in relation to available offshore employment data. Employment data are considered a reasonable measure of the level of activity at a specific facility, and have been substantially documented by operator inputs to this study and by data collection associated with the Tri-Counties Socioeconomic Monitoring Program (SEMP) in connection with specific offshore projects. Employment data for each existing offshore platform and for platform installation and well drilling activity were used to define a series of factors that may be used to estimate weekly supply vessel activity based on total Full-Time-Equivalent employment for that facility or activity. Where individual facility data were not available (as in the case of potential future platforms associated with some

Table A.6-28 lists the facility-specific and composite factors used to develop crew vessel activity projections in this study. These factors were combined with scenario-specific employment estimates (Appendix A.3) to determine average weekly crew vessel activity associated with each five-year time period addressed in the COOGER study. Because crew vessels originate from three locations in the study region (Port Hueneme, Carpinteria/~~Casitas Pier, and Ellwood Pier~~), the origin of crew vessels serving each offshore facility is also tabulated on Table A.6-28. Total crew vessel traffic associated with each scenario addressed in the COOGER study is indicated in Table A.6-29, and this information is summarized by the originating location of vessel trips in Table A.6-30. Table A.6-31 presents composite results for each possible combination of subregional scenarios.

A.6.5 Helicopter Activity

Projections of helicopter activity associated with different offshore development scenarios were developed by analysis of recent helicopter activity in relation to the offshore activities supported. Actual helicopter activity data were collected from offshore operators and published reports (A.D. Little, 1984 and Dames & Moore, 1989). These data were used to define helicopter activity associated with routine platform operations, and with specific activities (well drilling, platform installation, and platform decommissioning and removal).

Existing helicopter activity records were evaluated in relation to available offshore employment data to develop helicopter activity projections that could be readily updated to reflect future scenario revisions. Employment data are expected to provide a reasonable indicator of the demand for helicopter activity, since the two are directly related. Employment data for offshore platforms using helicopter service were combined with helicopter activity factors based on total Full-Time-Equivalent employment for each platform. These factors were used to estimate routine operational helicopter activity and helicopter flights associated with well drilling, platform installation, and platform decommissioning. The estimates developed in this study do not include agency inspection flights, since these are not directly related to individual facilities or the level of development. The Minerals Management Service currently operates five flights per week from the Camarillo Airport and five flights per week from the Santa Maria Airport. These flights would continue under all scenarios as long as offshore production facilities remain on the federal OCS. The calculation of helicopter activity factors was accomplished as indicated by the following example:

Total FTE, Platform Irene:	23
Total weekly helicopter traffic, Platform Irene:	4
Average weekly helicopter traffic per FTE (4/23):	0.1739

Table A.6-32 lists the facility-specific and composite factors used to develop helicopter activity projections in this study. These factors were combined with scenario-specific employment estimates (Appendix A.3) to determine average weekly helicopter activity associated with each five year time period addressed in the COOGER study. Because helicopter flights originate from three locations in the study region (Santa Barbara Airport, ~~Lompoc Airport, and Santa Maria Airport~~), the origin of helicopter flights serving each offshore facility is also tabulated on Table A.6-32. Total helicopter traffic associated with each scenario addressed in the COOGER study is indicated in Table A.6-33,

APPENDIX G

GLOSSARY

APPENDIX G
GLOSSARY

AAPLP	All American Pipeline, L.P.
ANS	Alaskan North Slope
APCD	Air Pollution Control District
API	American Petroleum Institute
EAPI (degrees API)	A unit of measurement which describes oil characteristics related to viscosity and flow properties. In general, oil with a *low gravity* (expressed as EAPI) is heavier and more viscous than oil with a high gravity (EAPI).
APLC	Arco Pipe Line Company
Barrel	A unit of volume commonly applied to crude oil equivalent to 42 U.S. gallons.
BCF	Billion Cubic Feet (of gas)
BOPD	barrels of oil per day
BPD	barrels per day
BPH	barrels per hour
BWPD	barrels of water per day
CEQA	California Environmental Quality Act
CO	Carbon monoxide
CO_2	Carbon dioxide
Commingled	Mixed. As used in this study, commingled oil refers to the mixture of oil from different sources into a common stream.
COOGER	California Offshore Oil and Gas Energy Resources
Crude Oil	Produced oil prior to the separation or chemical processing to produce different hydrocarbon fractions.
CUP	Conditional Use Permit

Decline Curve	An analysis of established trends of oil and gas production and analogous production data from other sources to project future production.
Design Capacity	The maximum sustained rate of operation of a processing facility, refinery, or pipeline system (or pipeline component) based on the engineering design and operating specifications of the installed equipment. This is typically expressed in terms of a volume per unit time.
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
DPP	Development and Production Plan
Dry Oil	Crude oil with little or no water content. Oil transported out of the COOGER study region by pipeline is dry oil.
Economic Limit	The production level at which a producing facility no longer generates sufficient revenue to represent an acceptable rate of return to the owner/operator of that facility.
EIR	Environmental Impact Report
EIS	Environmental Impact Statement
ERC	Emission Reduction Credit
Feedstock	Crude oil (wet or dry) and/or natural gas input to a processing facility.
Future Baseline	Future levels of development and oil and gas production without the installation of new wells or development of any currently undeveloped oil and gas resources. This could include routine maintenance and enhancement of existing wells, however.
Gas lift	A petroleum production technique.
Gas oil	A refined petroleum product somewhat heavier than kerosene which may be used directly as a fuel oil or further refined into other products.
Geographic Information System (GIS)	A computer database designed to display information in graphic form on a geographic base. In the COOGER study, the software package ArcInfo was used for all GIS applications.

H_2S	Hydrogen sulfide
hp	horsepower
HS&P	(Lompoc) Heating, Separation and Pumping Facility, also referred to as the Lompoc Oil & Gas Processing Facility
HVHS	high viscosity, high sulfur
Infrastructure	A basic network, structure, or procedural system supportive of, or required for, further development. This may include physical facilities such as roadways, water supply facilities, harbors, airports, etc. It may also include a framework which facilitates development in a specific manner, such as a regulatory structure, planning guidelines, permit procedures, agency standards and review requirements, etc.
JRP	Joint Review Panel
LCP	Local Coastal Plan
LPG	Liquefied Petroleum Gas
MCF	thousand cubic feet (of gas)
MCFD	thousand cubic feet per day (of gas)
MMBBL	million barrels
MMCFD	million cubic feet per day (of gas)
MMS	U.S. Minerals Management Service
MMSTB	million stock tank barrels (of oil)
NEPA	National Environmental Protection Act
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NGL	Natural Gas Liquids
NO_x	oxides of nitrogen
O_3	ozone
OCS	Outer Continental Shelf

OCSLA	Outer Continental Shelf Lands Act
Offshore Lease	An area designated by an authorized management agency (MMS or California State Lands Commission) for the exploration and potential development of mineral resources such as oil and gas. Leases are sold by competitive bid processes, and have specific conditions regarding their term and activity required to maintain lease rights. They do not convey an ownership interest in the land itself, and do not include a right to develop.
Oil Field	An area within which hydrocarbons have been trapped and concentrated into one or more reservoirs in economically producible quantities.
Operator	Company designated by the owners of an offshore lease to act on the owners' behalf in the management of lease operations, including exploration, development, and production activities. Operator assignments are subject to the review and approval of the Minerals Management Service or California State Lands Commission.
P(50) reserves	An estimated volume of oil and/or gas reserves which is considered equally likely to over- or understate the actual reserve volume.
Permit Capacity	A specified maximum rate of operation expressed as a limitation in an operating permit applicable to a specific facility, pipeline, or piece of equipment. This is typically expressed in terms of a volume per unit time.
PM	Particulate Matter
PM_{10}	Particulate Matter # 10 microns in diameter
$PM_{2.5}$	Particulate Matter # 2.5 micron in diameter
POPCO	Pacific Offshore Pipeline Company
ppm	parts per million
PRC	Public Resources Code
Private Infrastructure	A developed network to which access is limited to individuals with direct ownership interest or others subject to owners' approval. A system of industrial facilities and interconnecting pipelines is an example of private infrastructure.

Produced Water	Water mixed with crude oil and/or natural gas as part of the fluid produced by an oil (or gas) well.
Product	The resulting components of chemical or physical processes implemented to produce different hydrocarbon fractions. These products may be directly marketable (such as asphalt pitch, fuel oil, propane, etc.), or may be marketed primarily to refineries for further processing (such as gas oil).
psig	Pounds per square inch
Public Infrastructure	A developed network which is accessible to the public and exists primarily for the use by, and development of, the community as a whole. Roadways are an example of an element of public infrastructure.
Reserves	Oil and/or natural gas in producible quantities within an identified oil field. References to reserves are typically clarified by referring to the certainty level of the reserve estimate (such as proved reserves, proved developed reserves, and unproved reserves). Reserve estimates used in the COOGER study include all these formal reserve categories, as well as estimates that would be classified as discovered resources or undiscovered resources based on the level of data available concerning the fields addressed.
ROC	Reactive Organic Carbons
SBCAPCD	Santa Barbara County Air Pollution Control District
Scenario	A hypothetical combination of conditions and/or activities expressed as a description of a potential future development level.
SEMP	Socioeconomic Monitoring Program
SJV	San Joaquin Valley
SLC	State Lands Commission
SLOCAPCD	San Luis Obispo County Air Pollution Control District
SO_2	sulfur dioxide
Sour Gas	Natural gas containing hydrogen sulfide (H_2S).
SO_x	oxides of sulfur

Spare Capacity	The difference between the volume processed or handled at a facility (or pipeline) and the capacity of that facility (based on permit capacity or design capacity, whichever is less). This is typically expressed in the same terms of volume per unit time as the controlling capacity.
Steering Committee	The senior management and decisionmaking body responsible for the development of the COOGER study scope and recommendations to the MMS concerning study approach.
Sweet Gas	Natural gas that does not contain hydrogen sulfide (H_2S), or only contains trace amounts of H_2S.
SYU	Santa Ynez Unit
Technical Management Team	A management committee composed of appointed representatives of the COOGER study Steering Committee. This group included individuals with specific technical backgrounds appropriate to the day-to-day direction of COOGER technical investigations.
TPD	tons per day
TPY	tons per year
Tri-Counties	The counties of Ventura, Santa Barbara, and San Luis Obispo.
UCSB	University of California at Santa Barbara
VAFB	Vandenberg Air Force Base
Wet gas	Natural gas prior to the removal of water.
Wet oil	A mixture of crude oil and water which requires further processing to remove water.

FIGURES

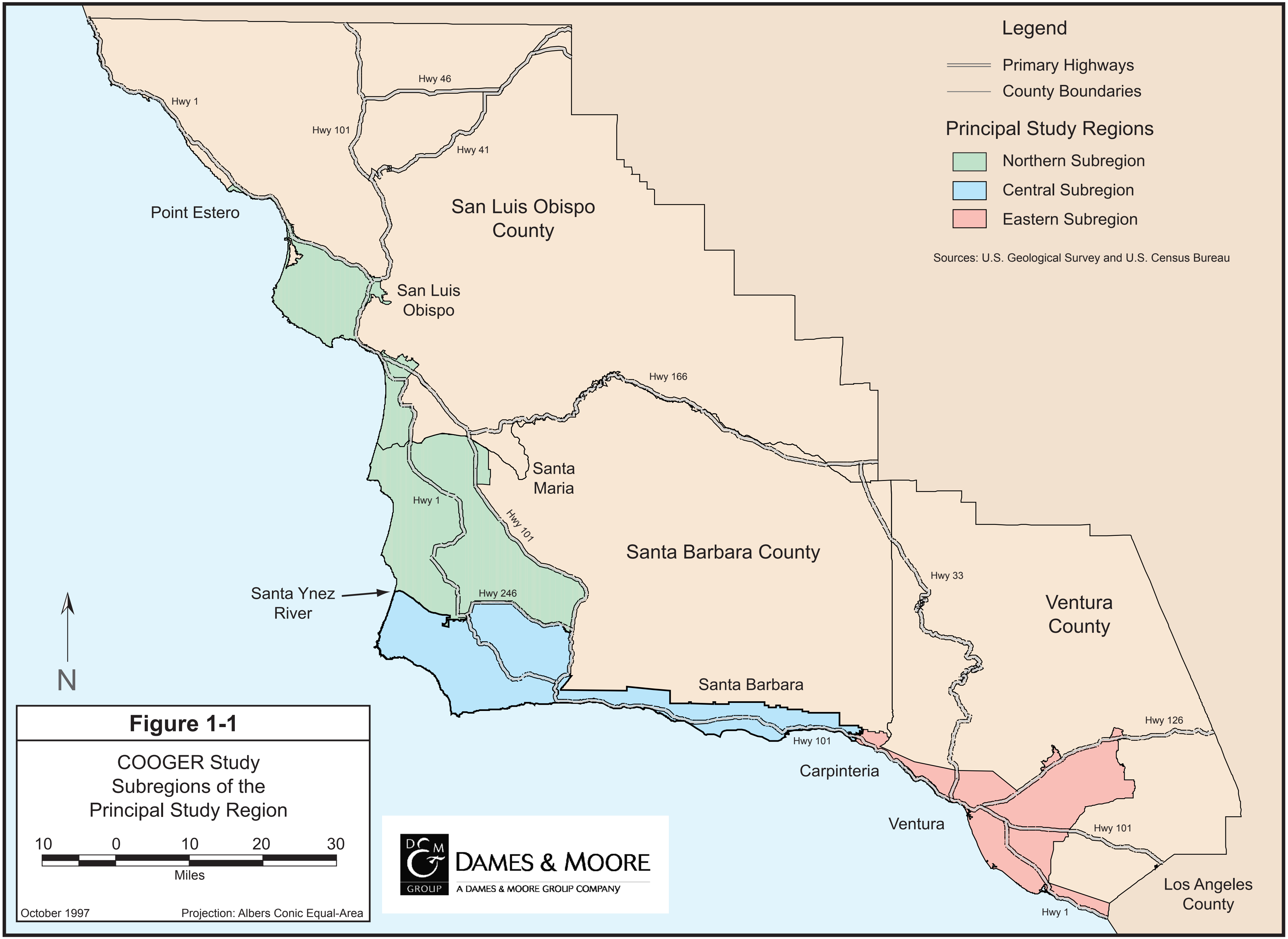
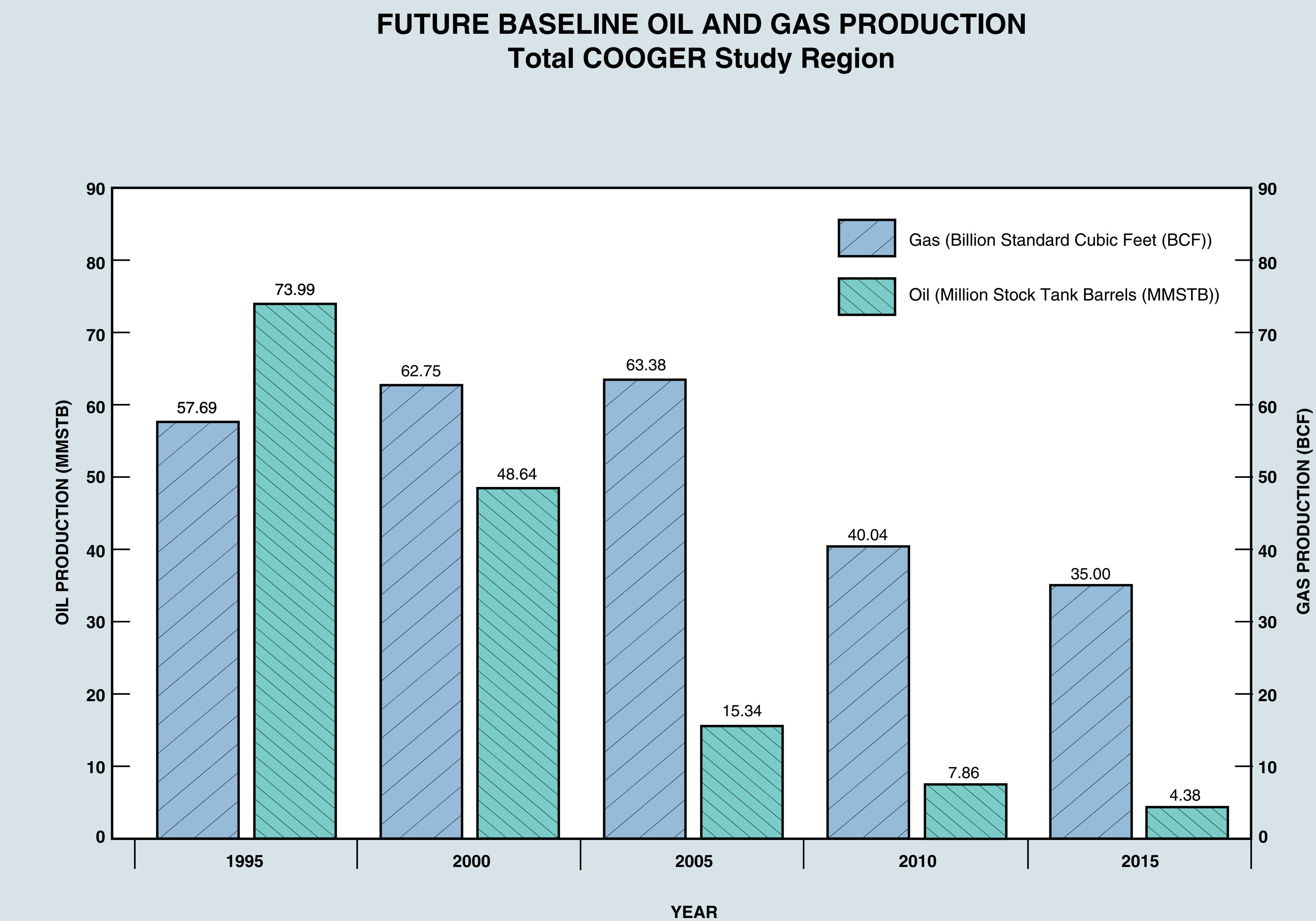


Figure 1-1

COOGER Study Subregions of the Principal Study Region

1296/191C



DAMES & MOORE
A DAMES & MOORE GROUP COMPANY

Figure 2.3-1
COOGER STUDY

1296/188A

FUTURE BASELINE OIL AND GAS PRODUCTION
Eastern Subregion

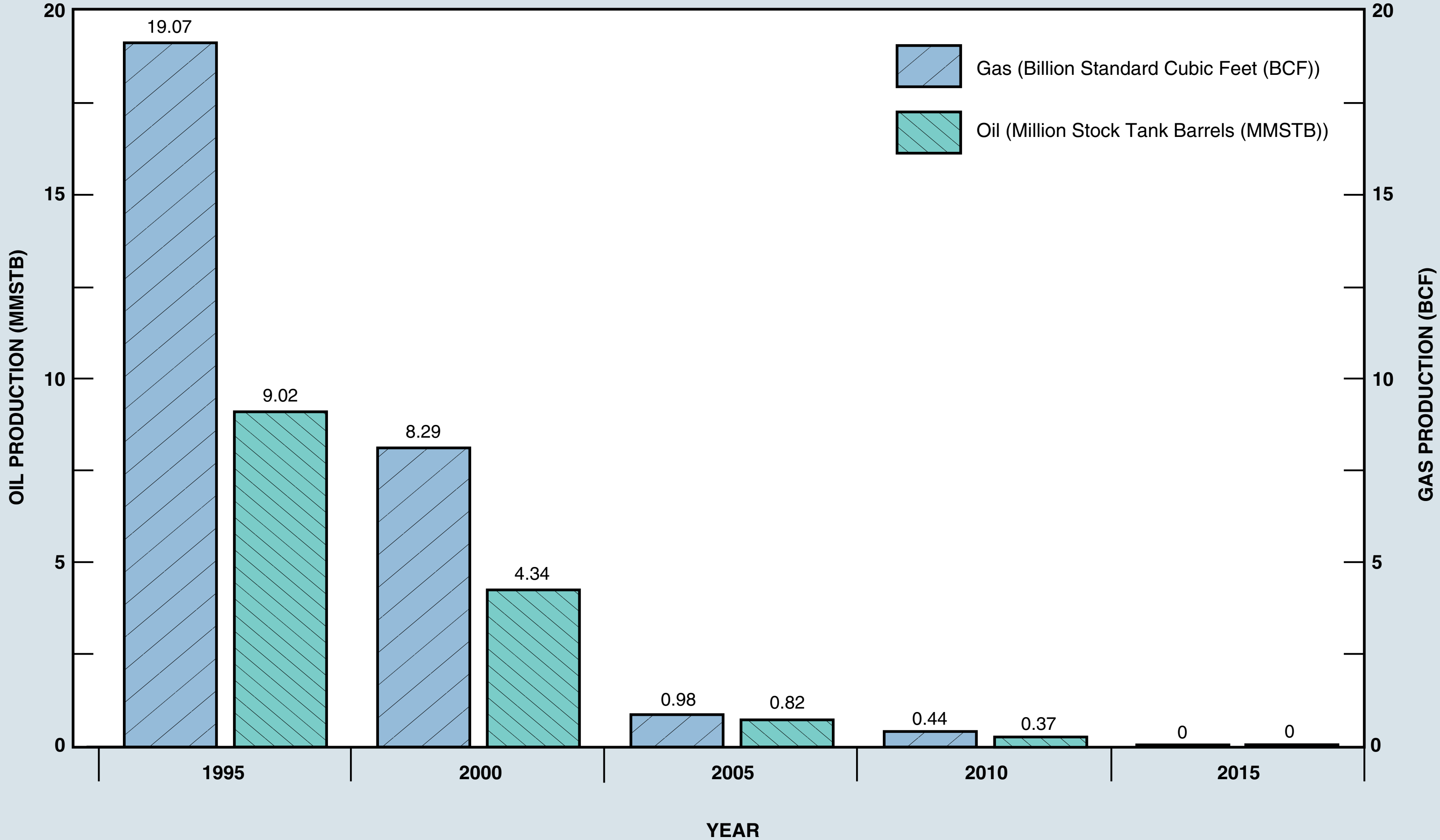


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Figure 2.3-2
COOGER STUDY

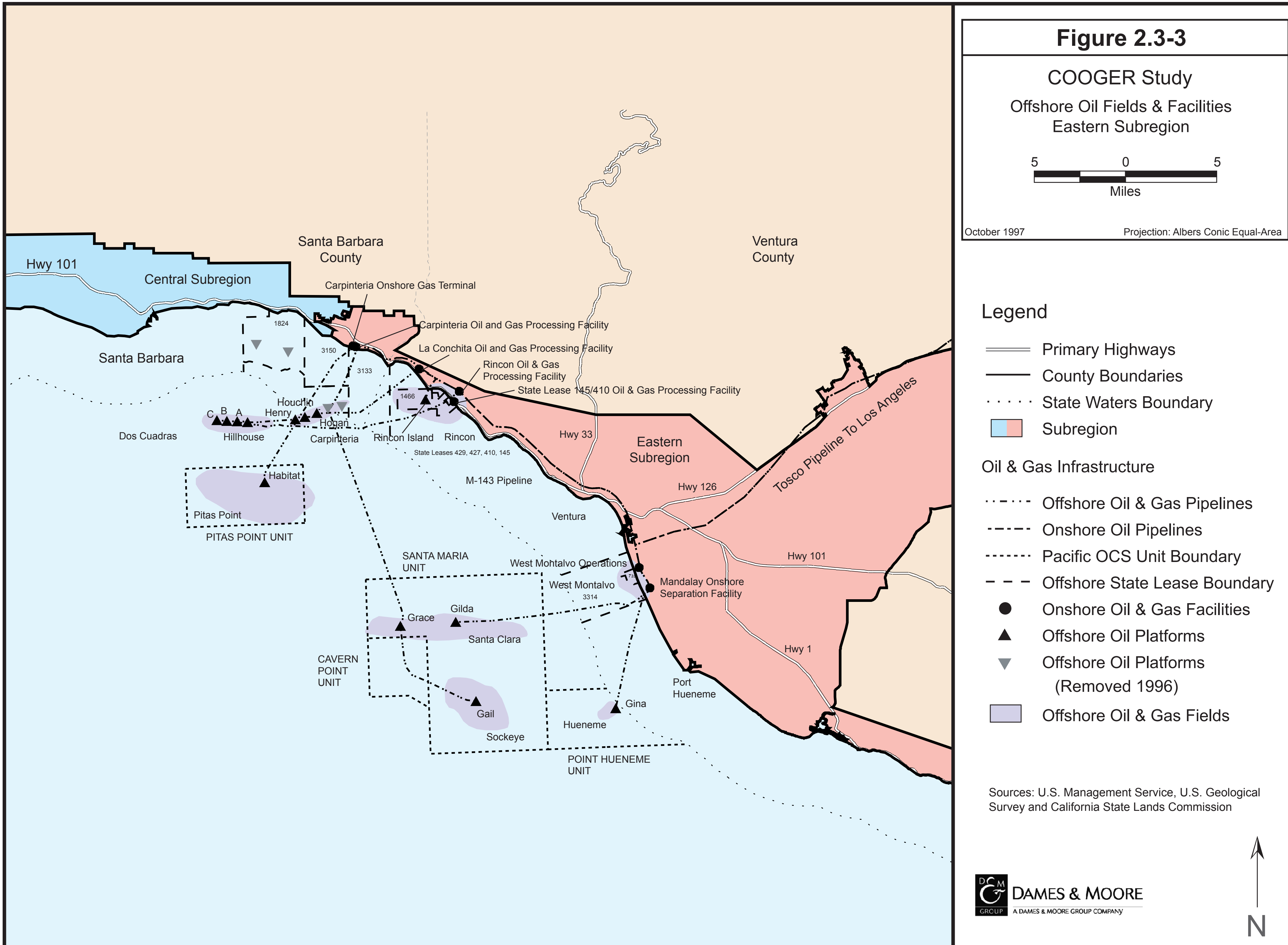

Figure 2.3-3

COOGER Study

Offshore Oil Fields & Facilities
Eastern Subregion

October 1997

Projection: Albers Conic Equal-Area

1296/189C

FUTURE BASELINE OIL AND GAS PRODUCTION
Central Subregion

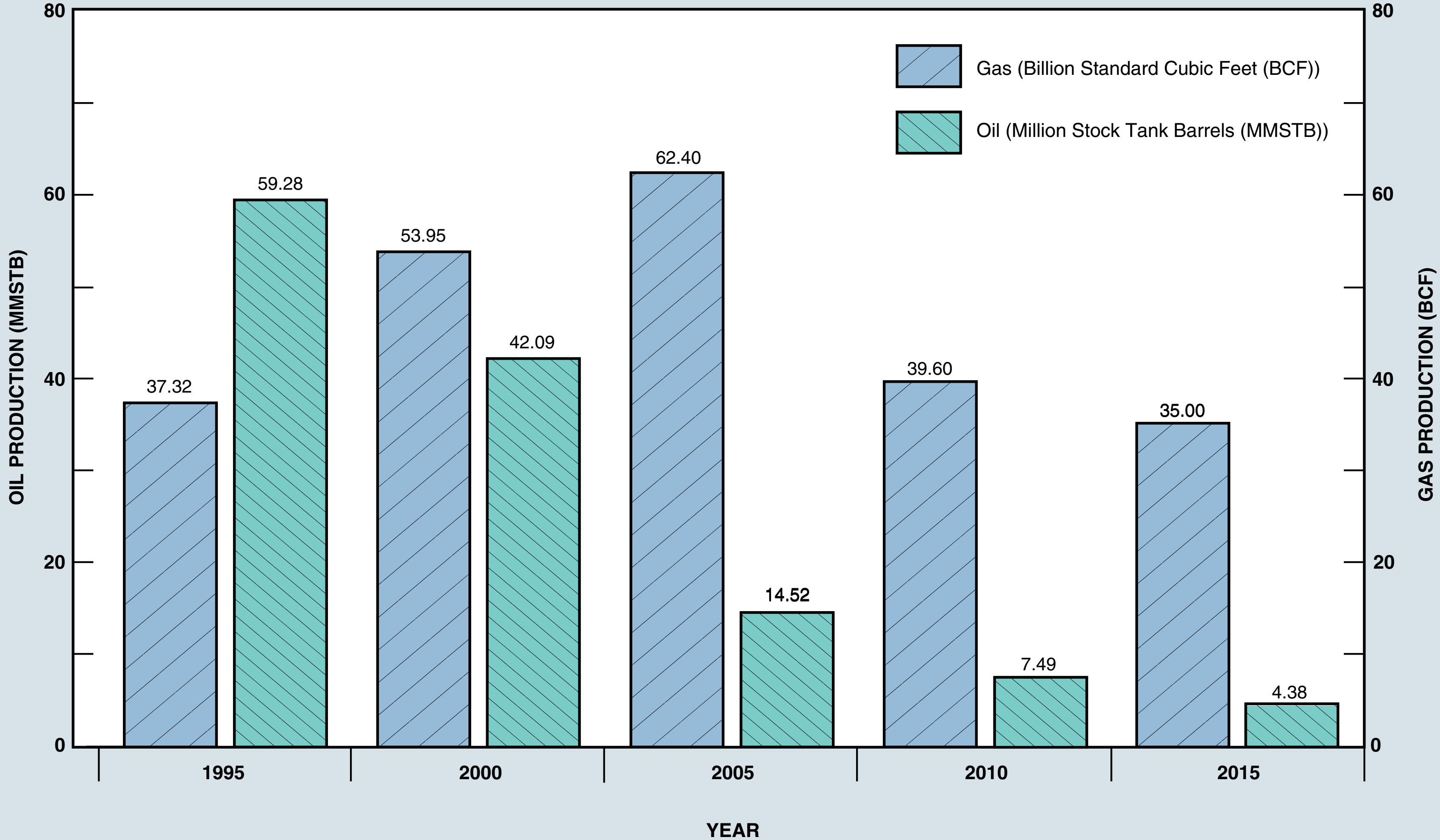

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Figure 2.3-4
COOGER STUDY

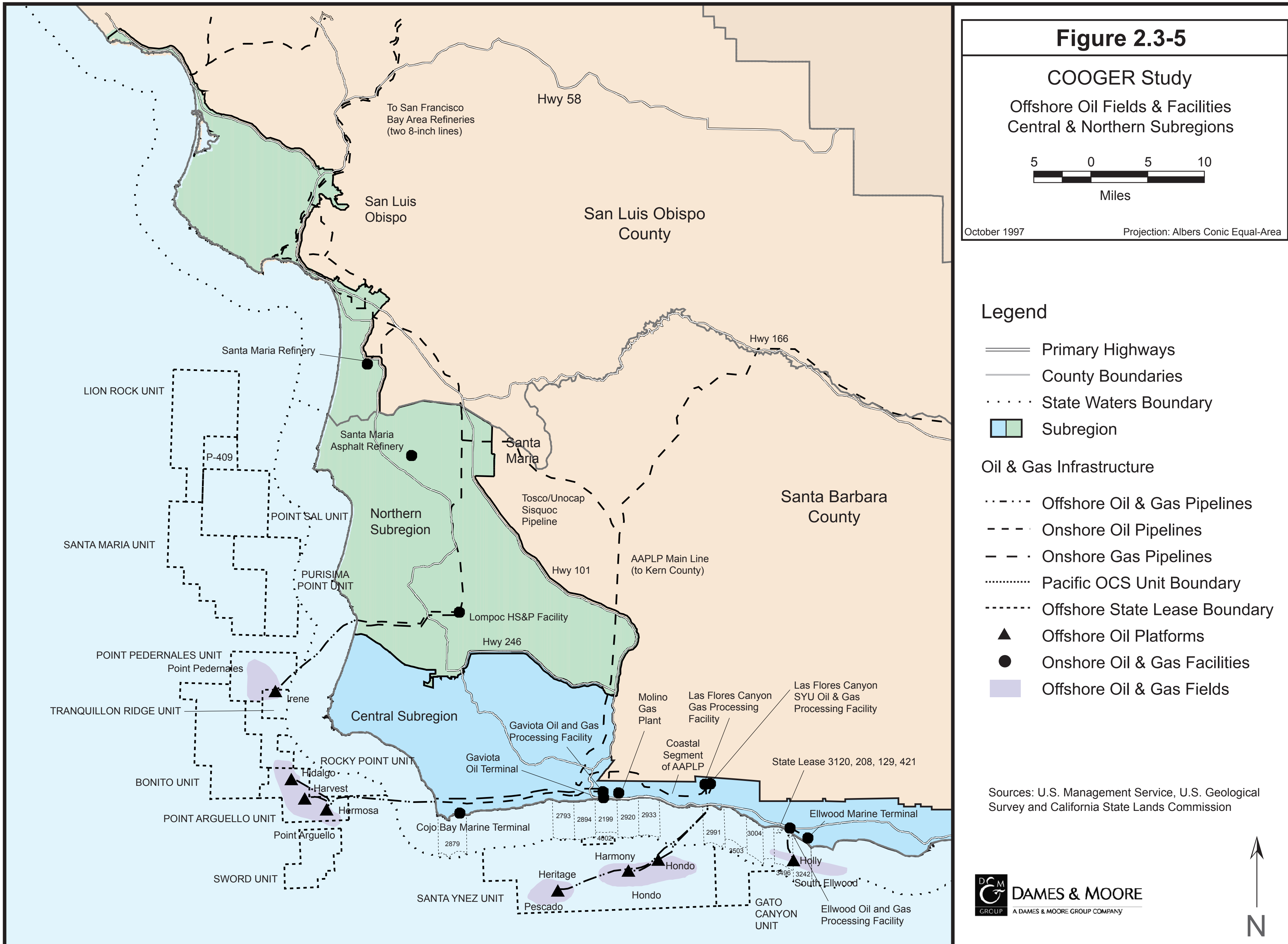

Figure 2.3-5

COOGER Study

Offshore Oil Fields & Facilities
Central & Northern Subregions

FUTURE BASELINE OIL AND GAS PRODUCTION
Northern Subregion

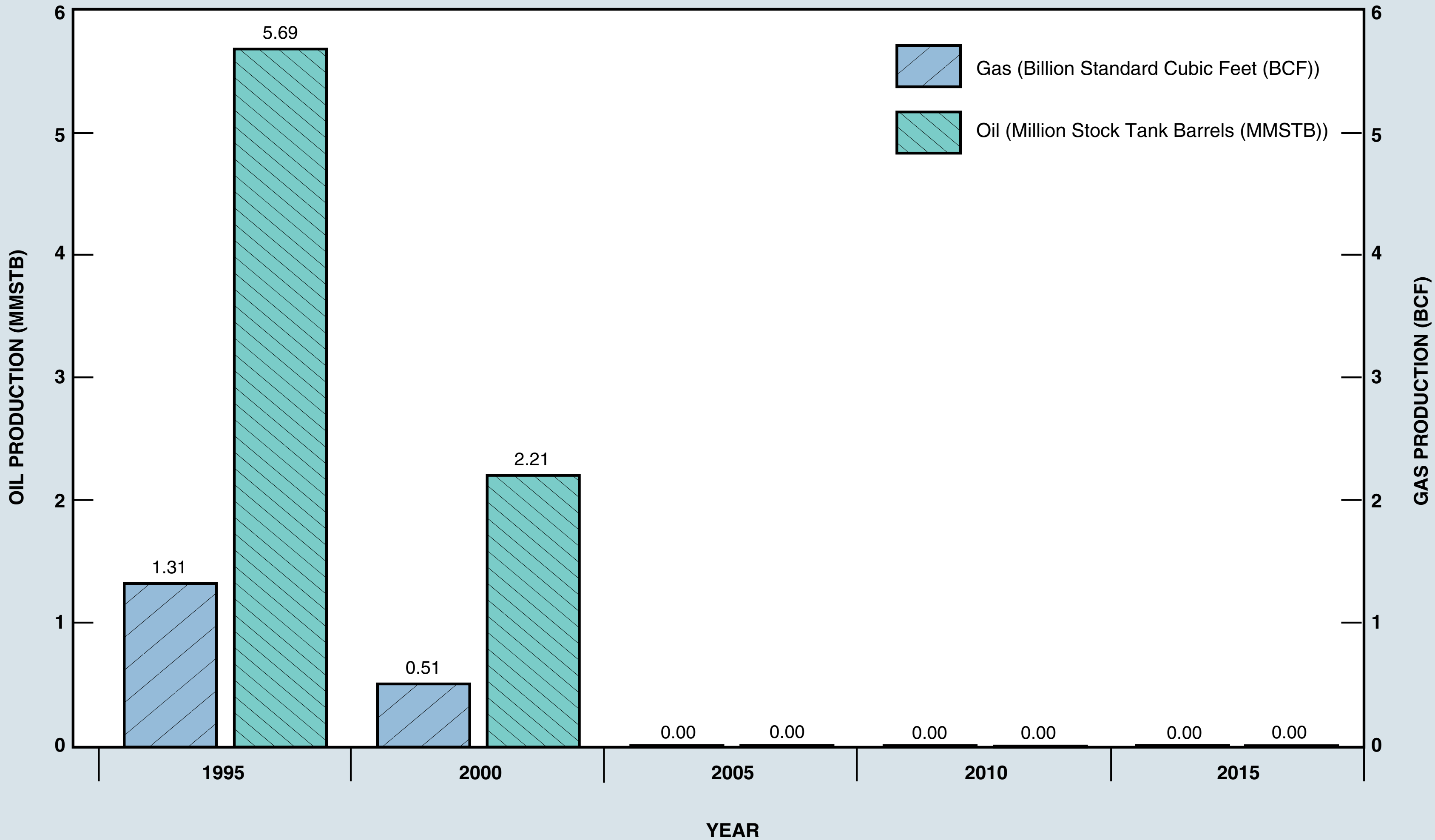

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Figure 2.3-6
COOGER STUDY

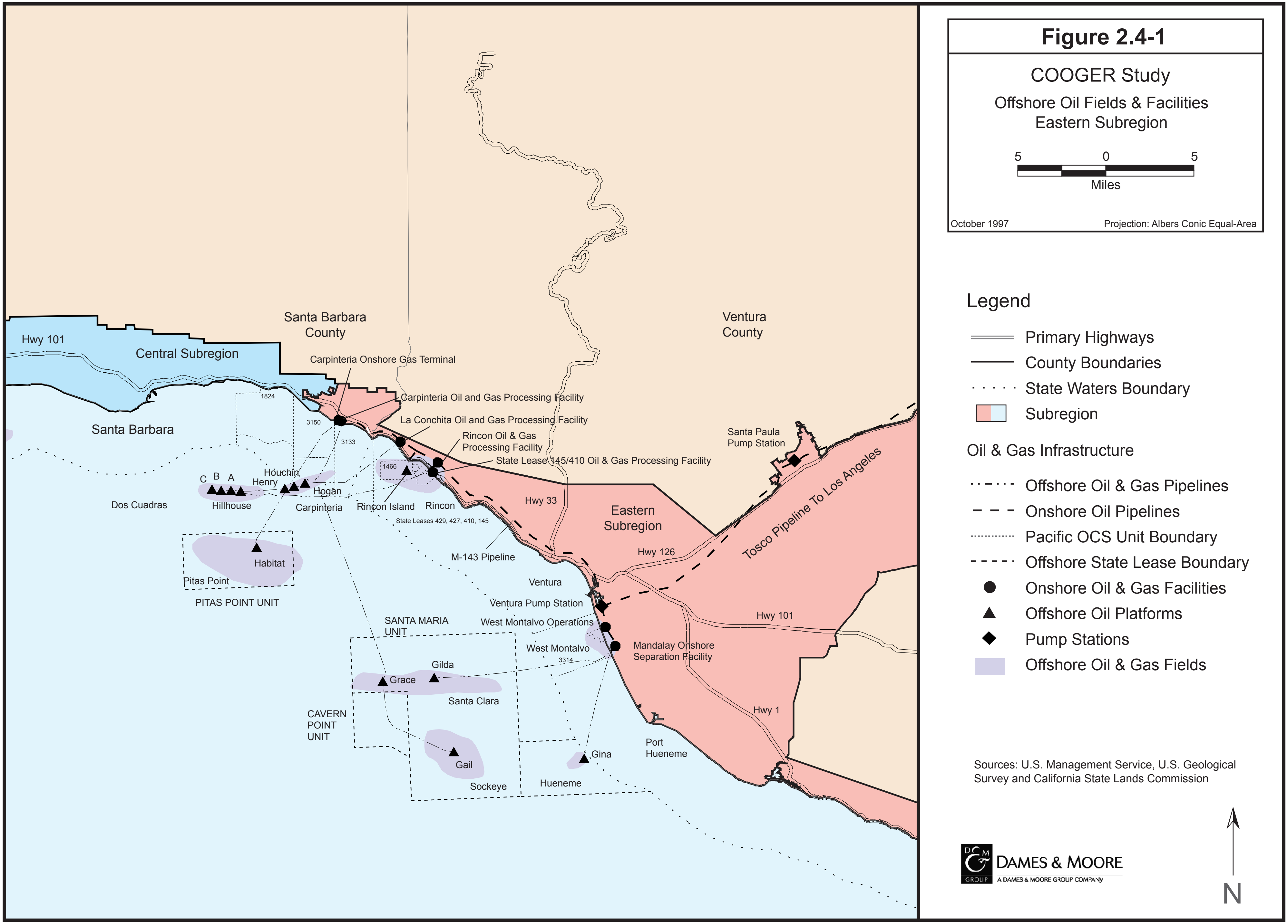
Figure 2.4-1
COOGER Study
Offshore Oil Fields & Facilities
Eastern Subregion
5 0 5
Miles
October 1997
Projection: Albers Conic Equal-Area
Legend
Primary Highways
County Boundaries
State Waters Boundary
Subregion
Oil & Gas Infrastructure
Offshore Oil & Gas Pipelines
Onshore Oil Pipelines
Pacific OCS Unit Boundary
Offshore State Lease Boundary
Onshore Oil & Gas Facilities
Offshore Oil Platforms
Pump Stations
Offshore Oil & Gas Fields
Sources: U.S. Management Service, U.S. Geological Survey and California State Lands Commission
DAMES & MOORE
A DAMES & MOORE GROUP COMPANY
N
Hwy 101
Central Subregion
Santa Barbara County
Ventura County
Carpinteria Onshore Gas Terminal
Carpinteria Oil and Gas Processing Facility
La Conchita Oil and Gas Processing Facility
Rincon Oil & Gas Processing Facility
State Lease 145/410 Oil & Gas Processing Facility
Santa Paula Pump Station
Tosco Pipeline To Los Angeles
Santa Barbara
1824
3150
3133
1466
C B A
Houchin
Henry
Hogan
Hillhouse
Dos Cuadras
Carpinteria
Rincon Island
Rincon
State Leases 429, 427, 410, 145
Hwy 33
Eastern Subregion
Hwy 126
M-143 Pipeline
Habitat
Pitas Point
PITAS POINT UNIT
Ventura
Ventura Pump Station
West Montalvo Operations
SANTA MARIA UNIT
West Montalvo
3314
Mandalay Onshore Separation Facility
Hwy 101
Gilda
Grace
Santa Clara
CAVERN POINT UNIT
Hwy 1
Gail
Sockeye
Gina
Hueneme
Port Hueneme

897/088A

WET OIL PROCESSING FACILITIES SPARE CAPACITY
Eastern Subregion

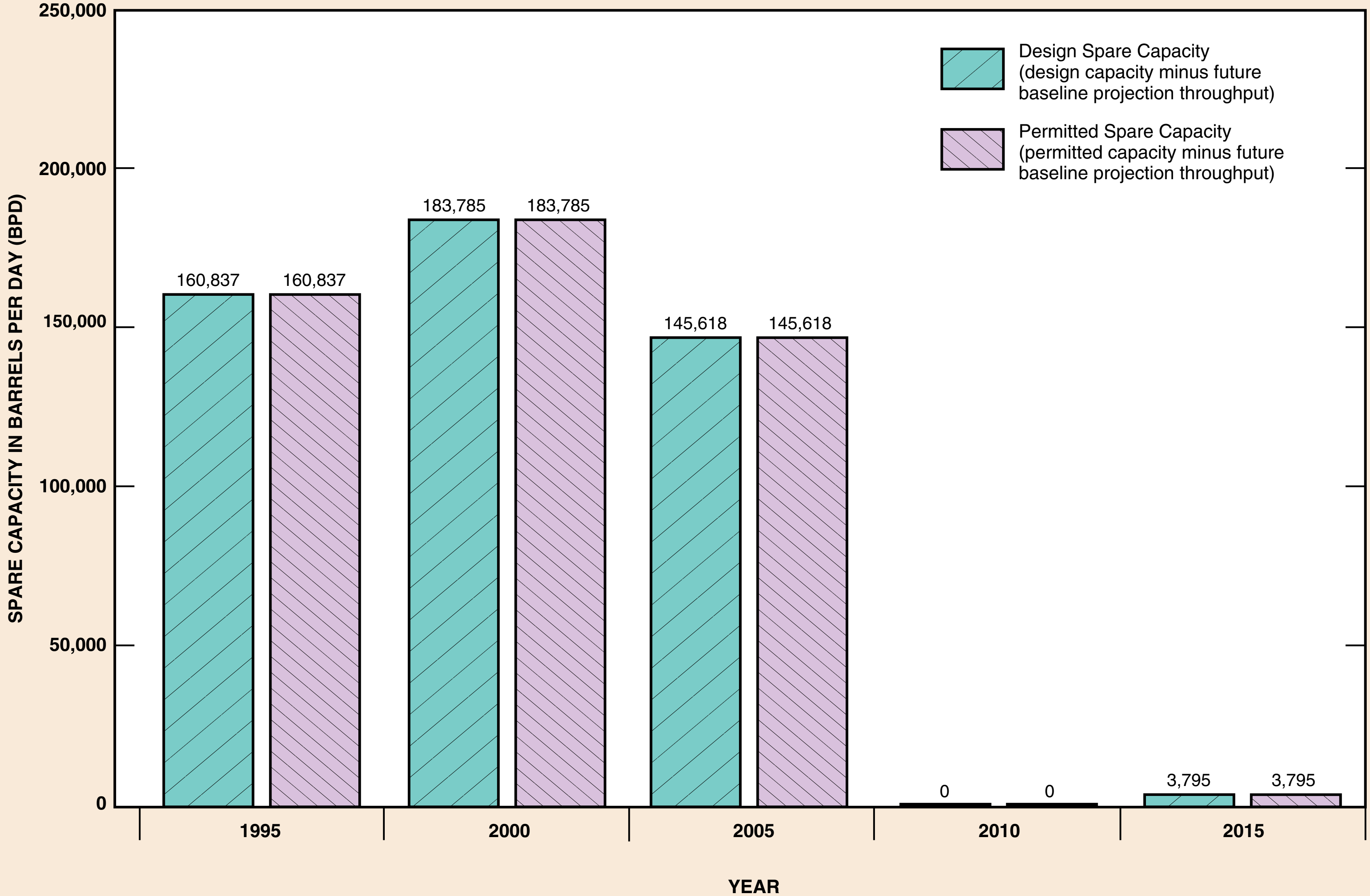

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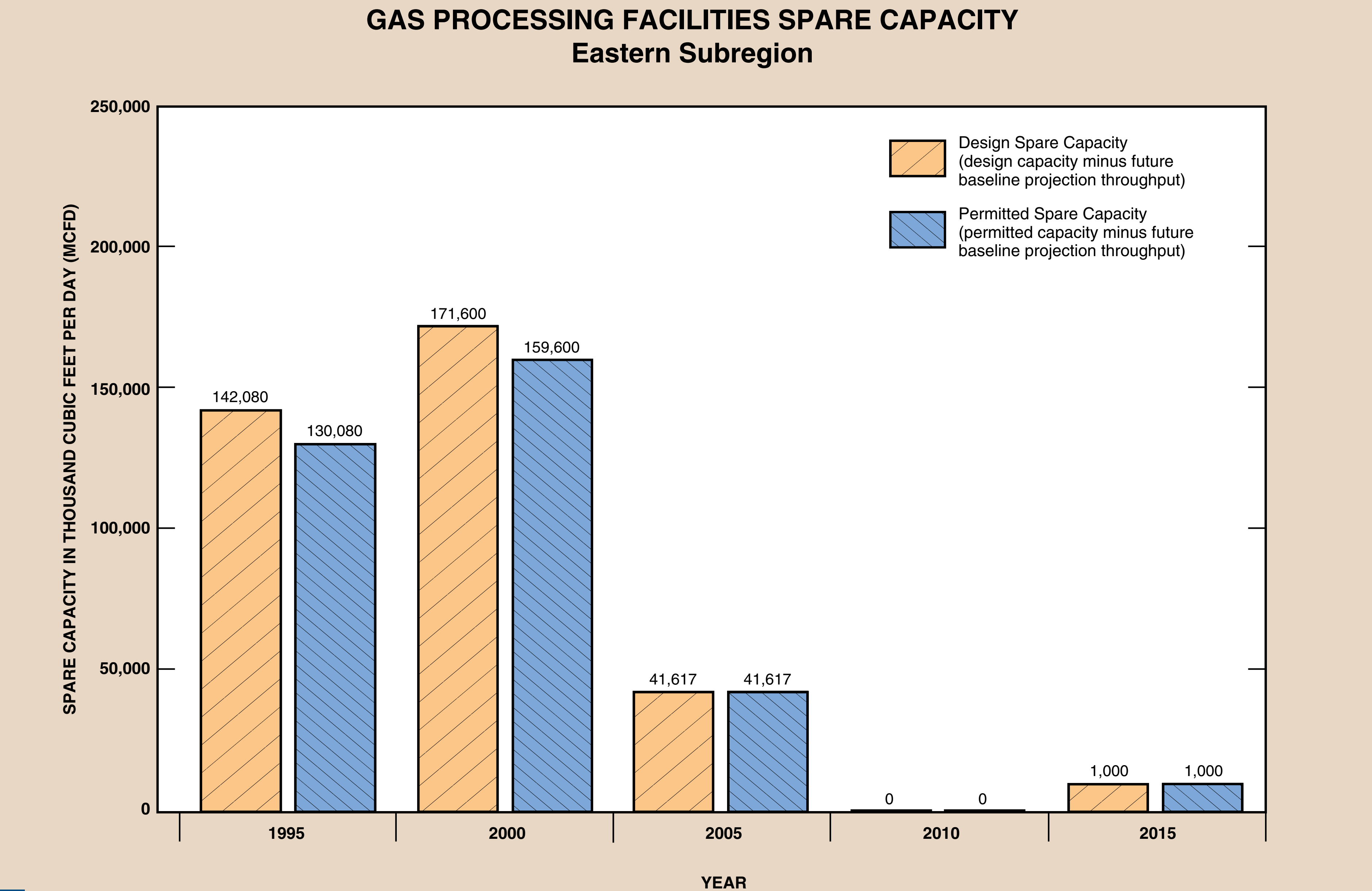
Figure 2.4-2

COOGER STUDY



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GROUP
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Figure 2.4-3
COOGER STUDY

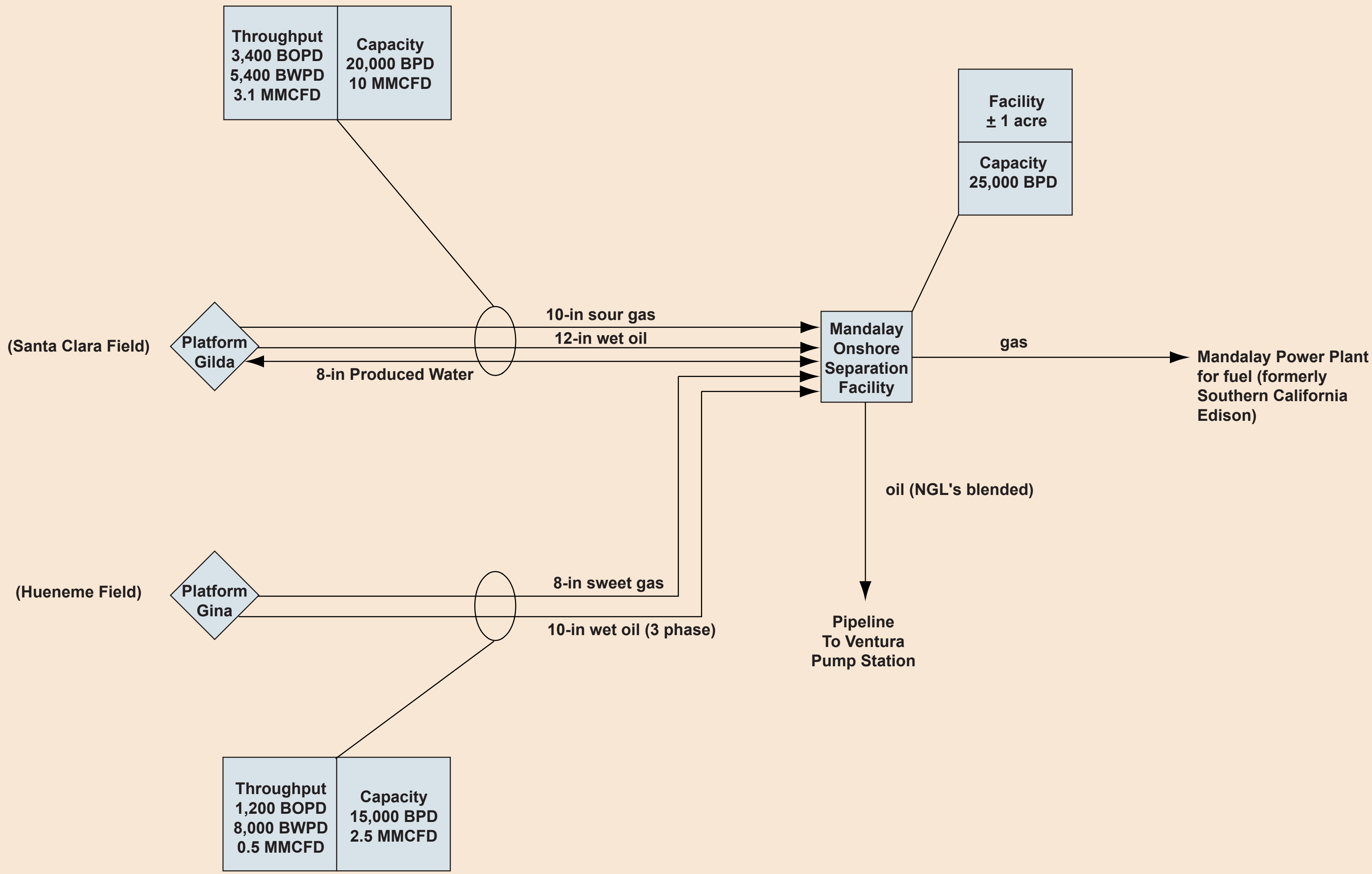
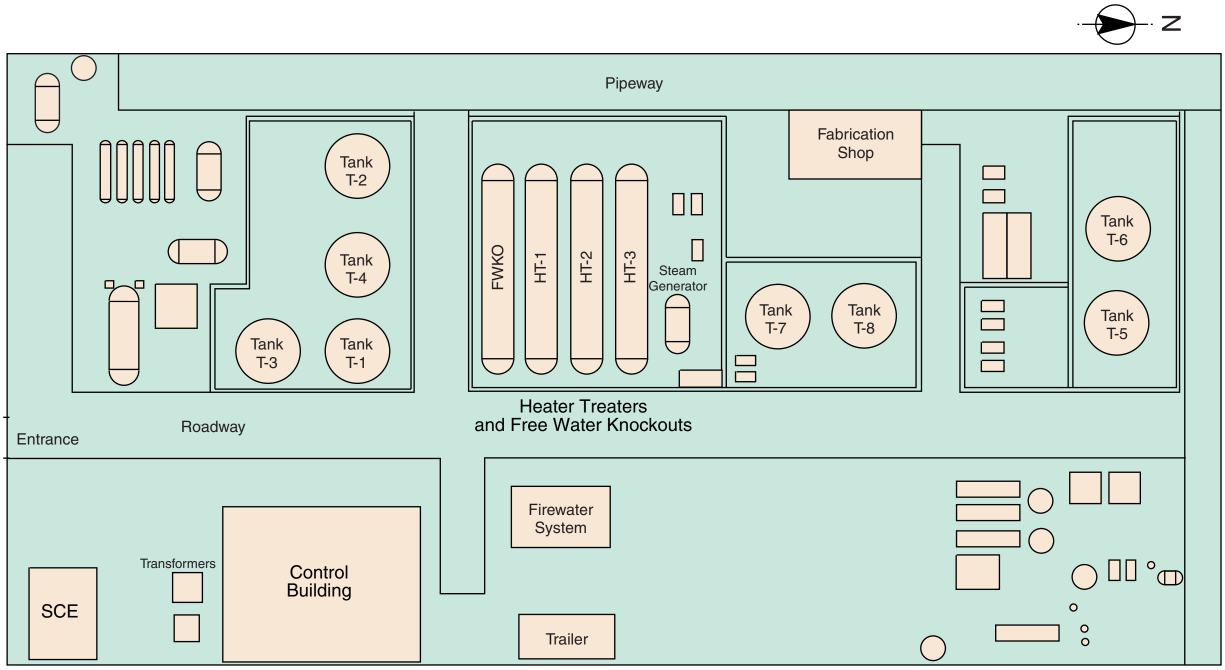


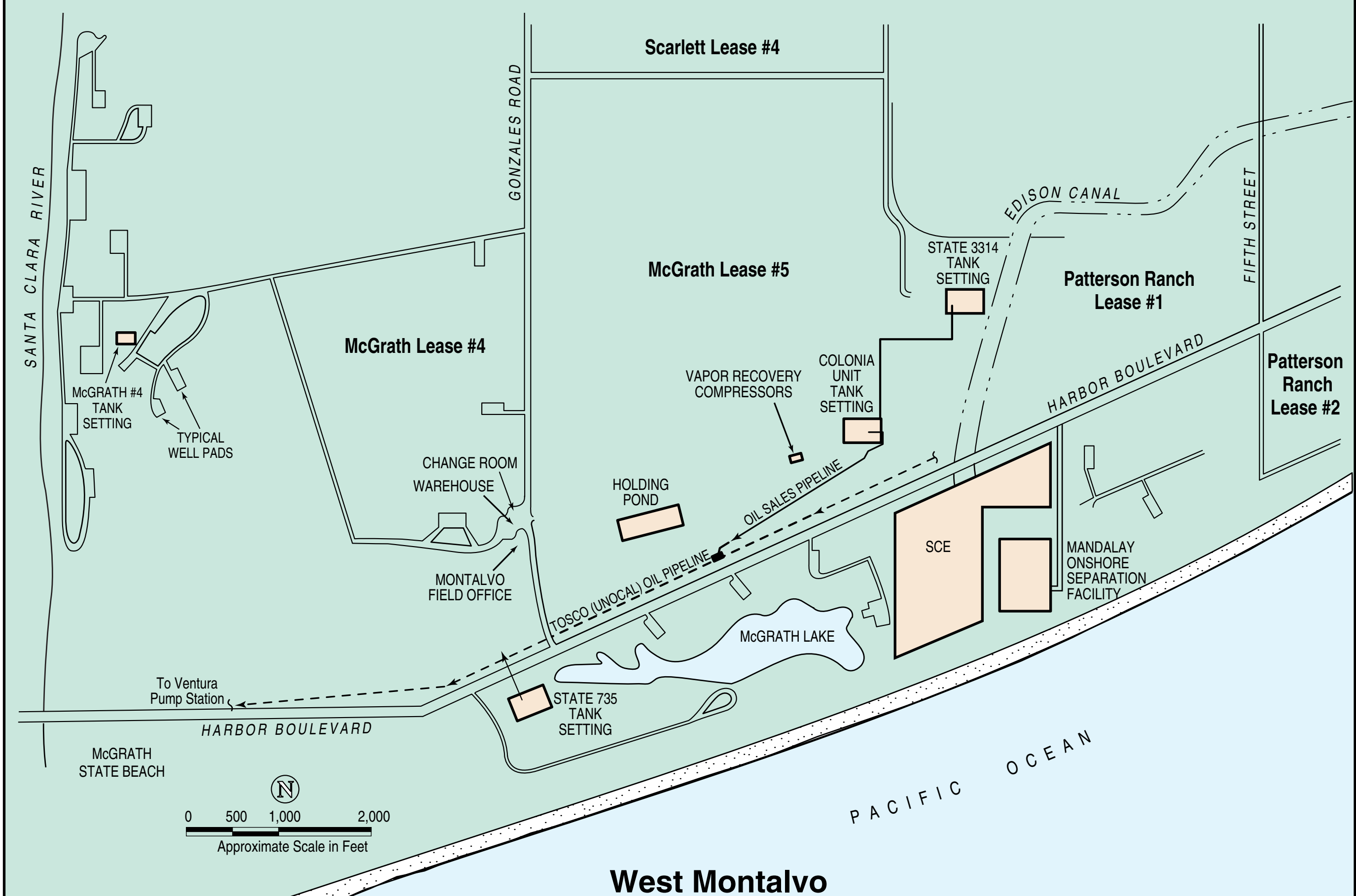
Figure 2.4-4 Mandalay Onshore Seperation Facility System Schematic

NOT TO SCALE
Locations approximate
Source: Worley, 1995, Figure 2.52, Page 2-82

MANDALAY ONSHORE SEPARATION FACILITY AND WEST MONTALVO OPERATIONS PLOT PLANS



Mandalay



West Montalvo

DAMES & MOORE
GROUP
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Figure 2.4-5

COOGER STUDY

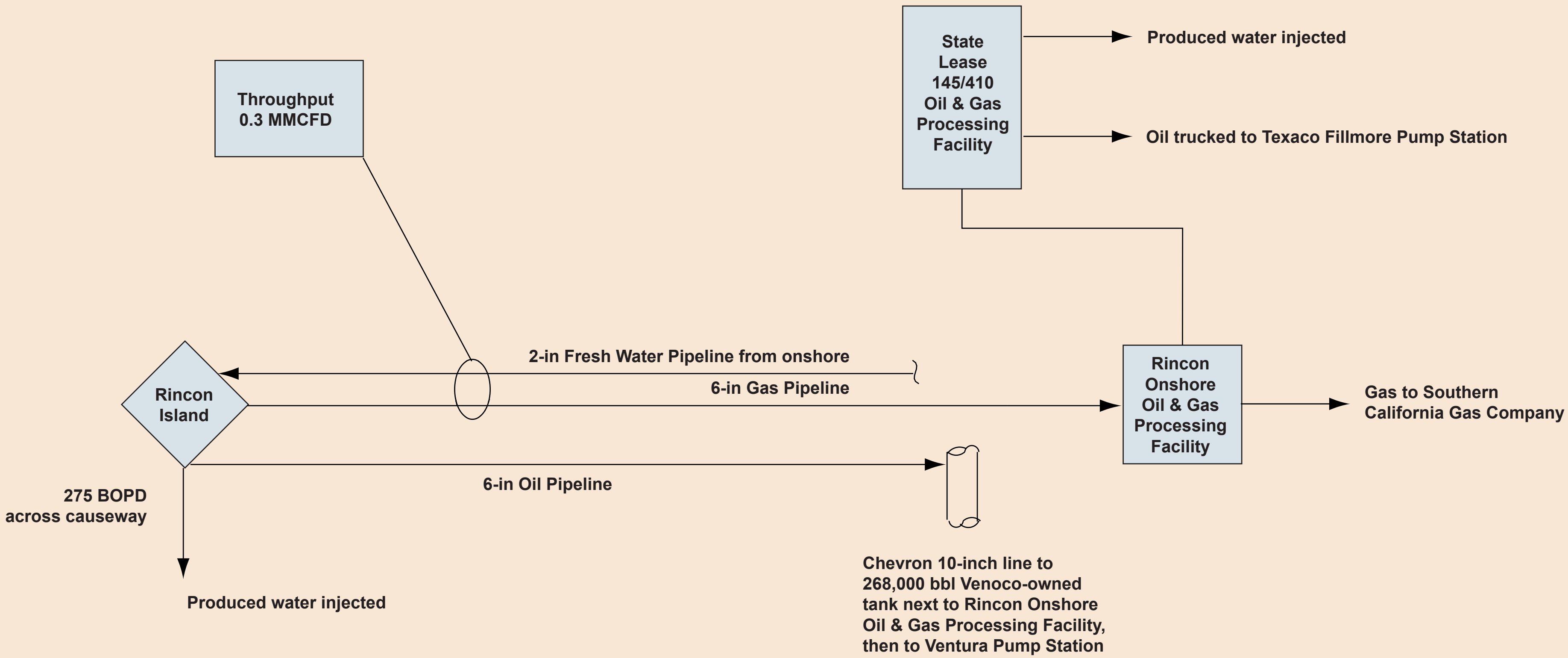


Figure 2.4-6 Rincon Island and State Lease 145/410 Oil & Gas Processing Facility System Schematic

Source: Worley, 1995, Figure 2.67, Page 2-107

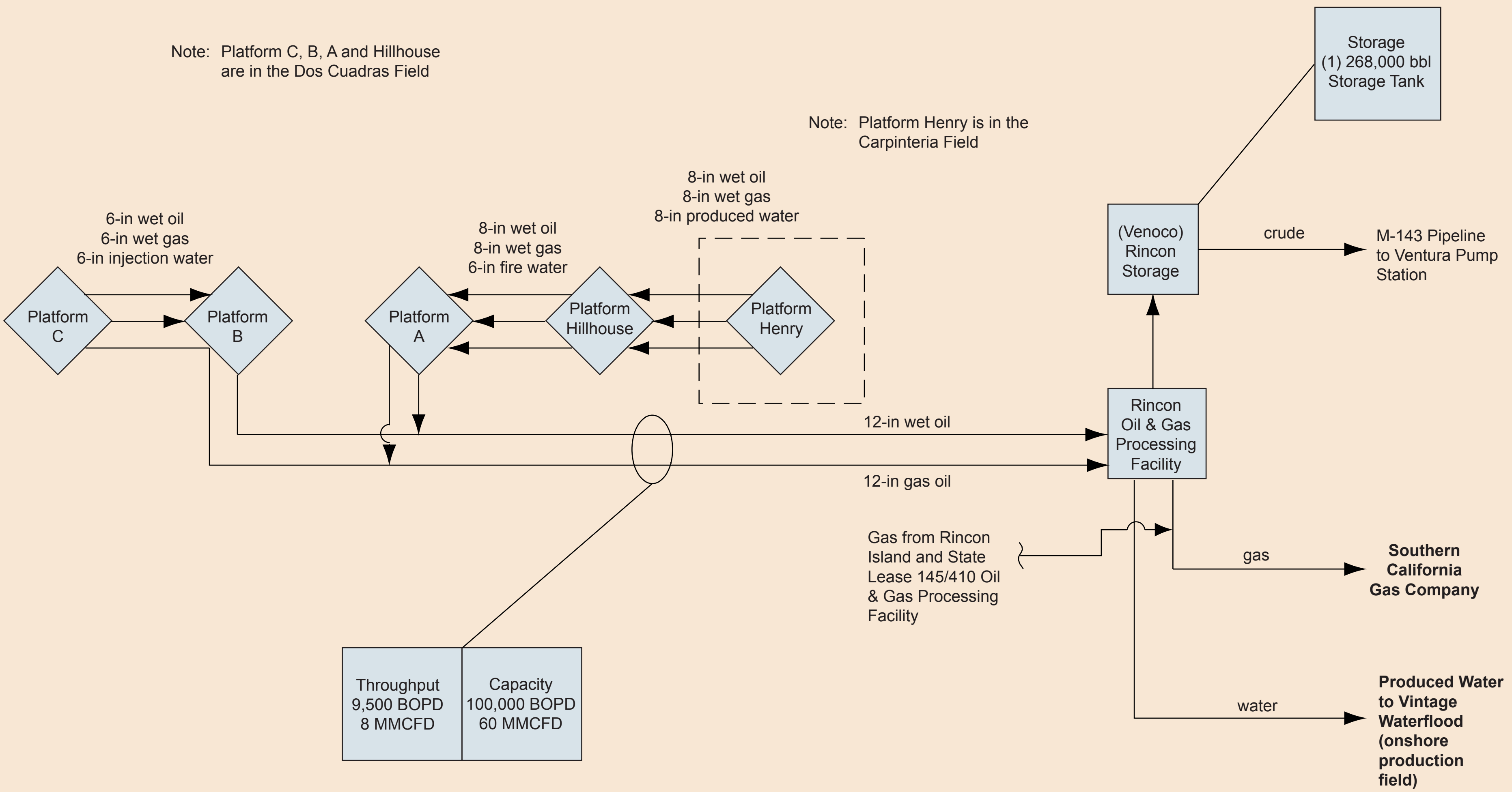


Figure 2.4-7 Rincon Oil & Gas Processing Facility System Schematic

NOT TO SCALE
Locations approximate
Source: Worley, 1995, Figure 2.36, Page 2-61

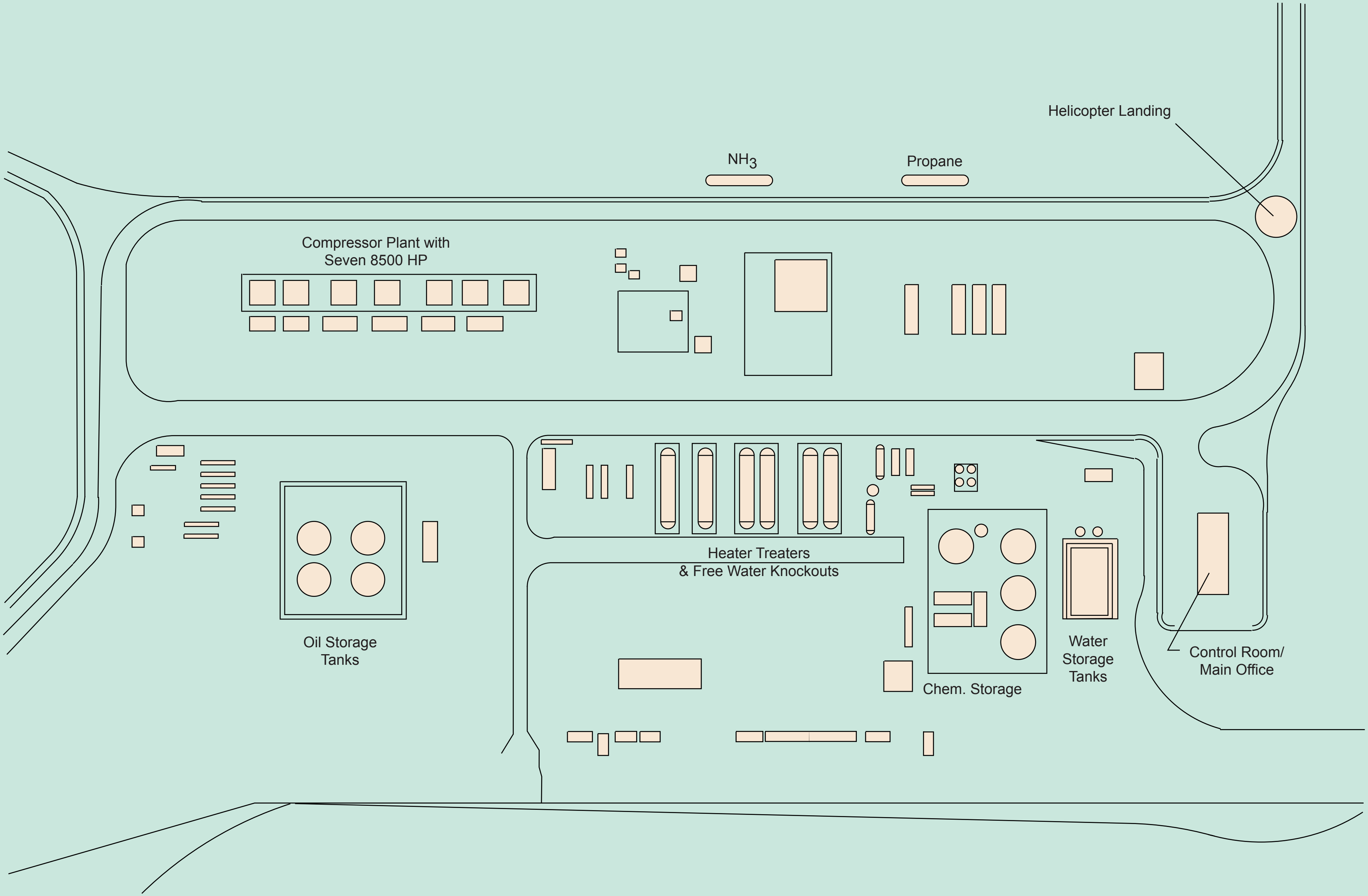


Figure 2.4-8 Rincon Oil & Gas Processing Facility Plot Plan

NOT TO SCALE
Locations approximate
Source: Worley, 1995, Figure 2.37, Page 2-62; Torch, 1997

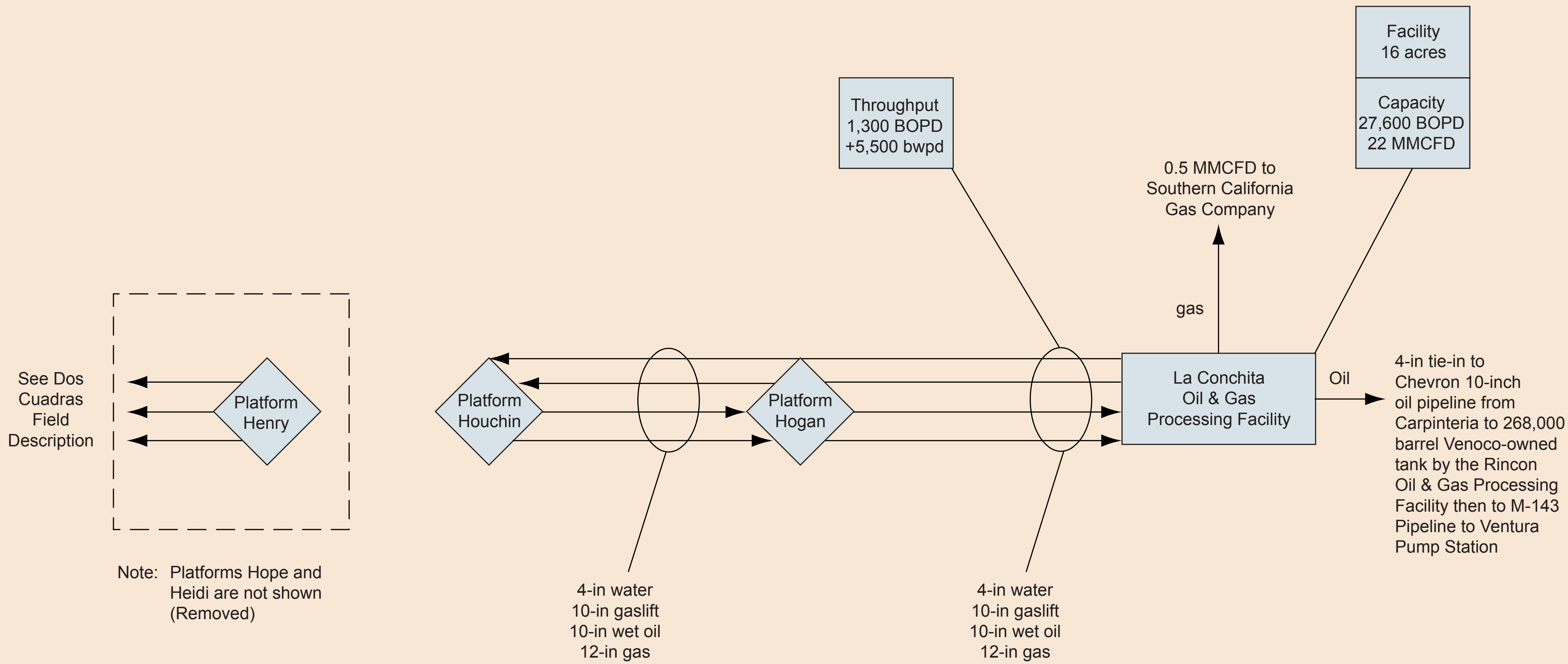


Figure 2.4-9 La Conchita Oil & Gas Processing Facility System Schematic

NOT TO SCALE
Locations approximate
Source: Worley, 1995, Figure 2.46, Page 2-75

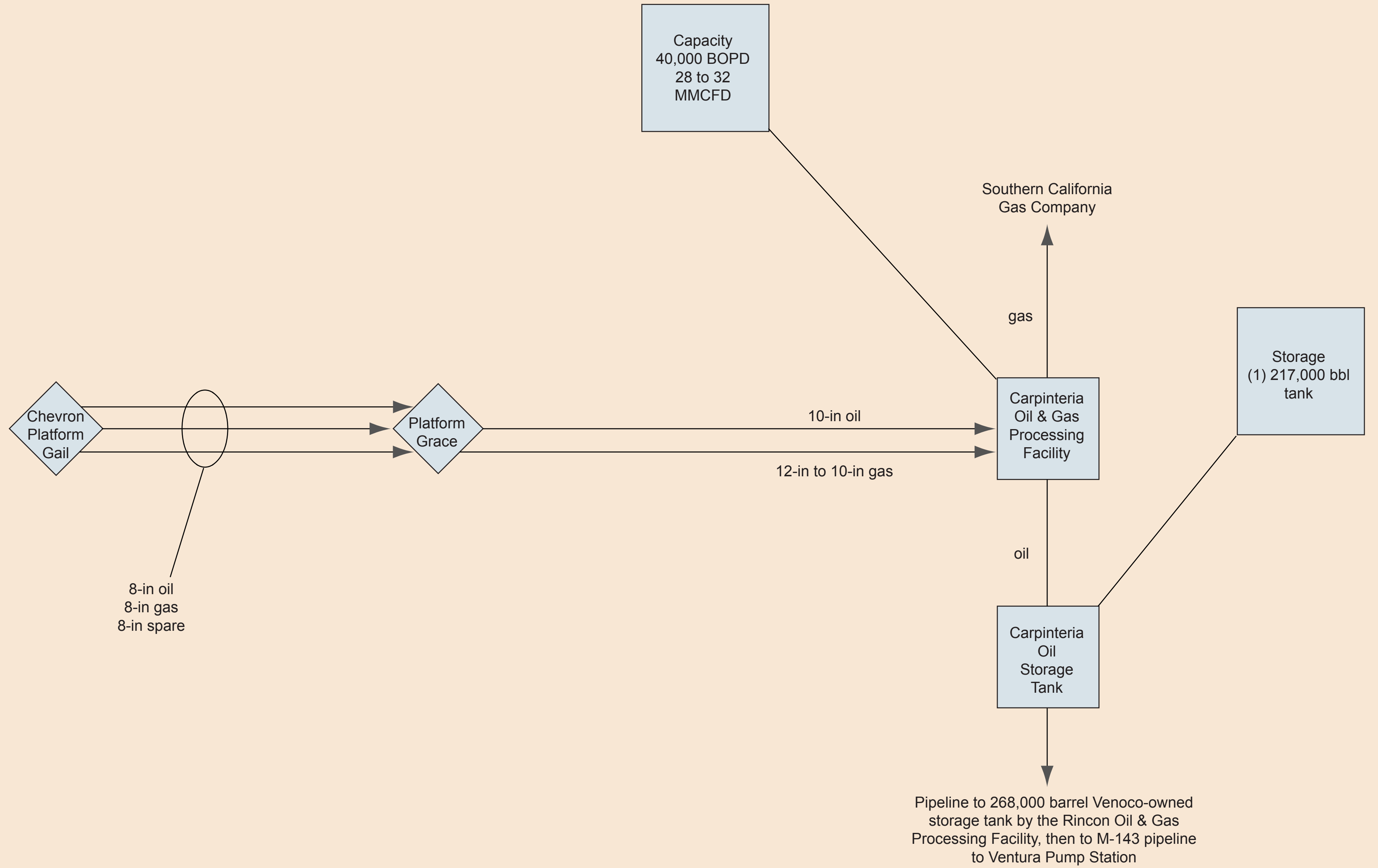


Figure 2.4-10 Carpinteria Oil & Gas Processing Facility System Schematic

NOT TO SCALE
Source: Worley, 1995, Figure 2.60, Page 2-96

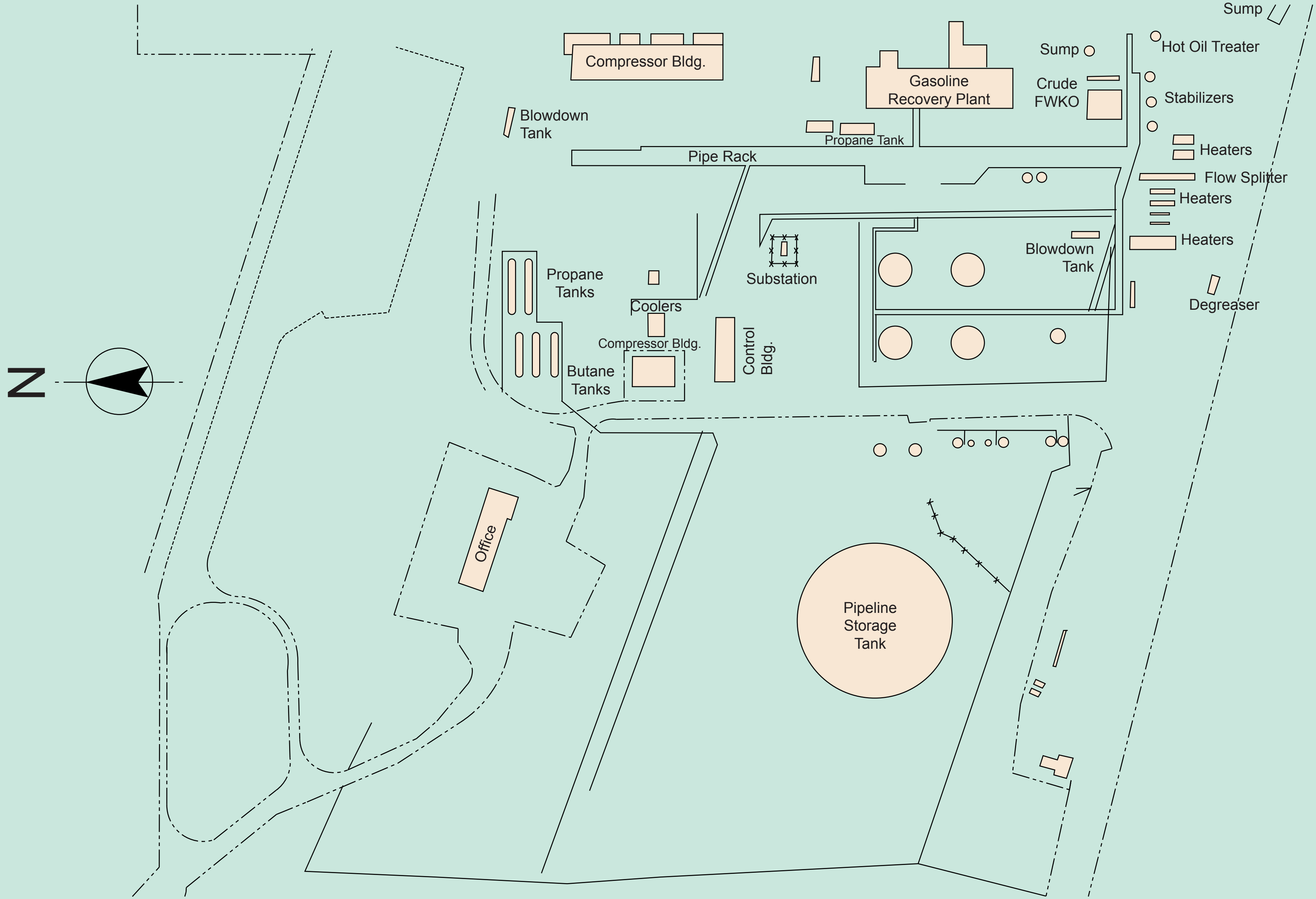


Figure 2.4-11 Carpinteria Oil & Gas Processing Facility Plot Plan

Locations approximate
Source: Worley, 1995, Figure 2.61, Page 2-97

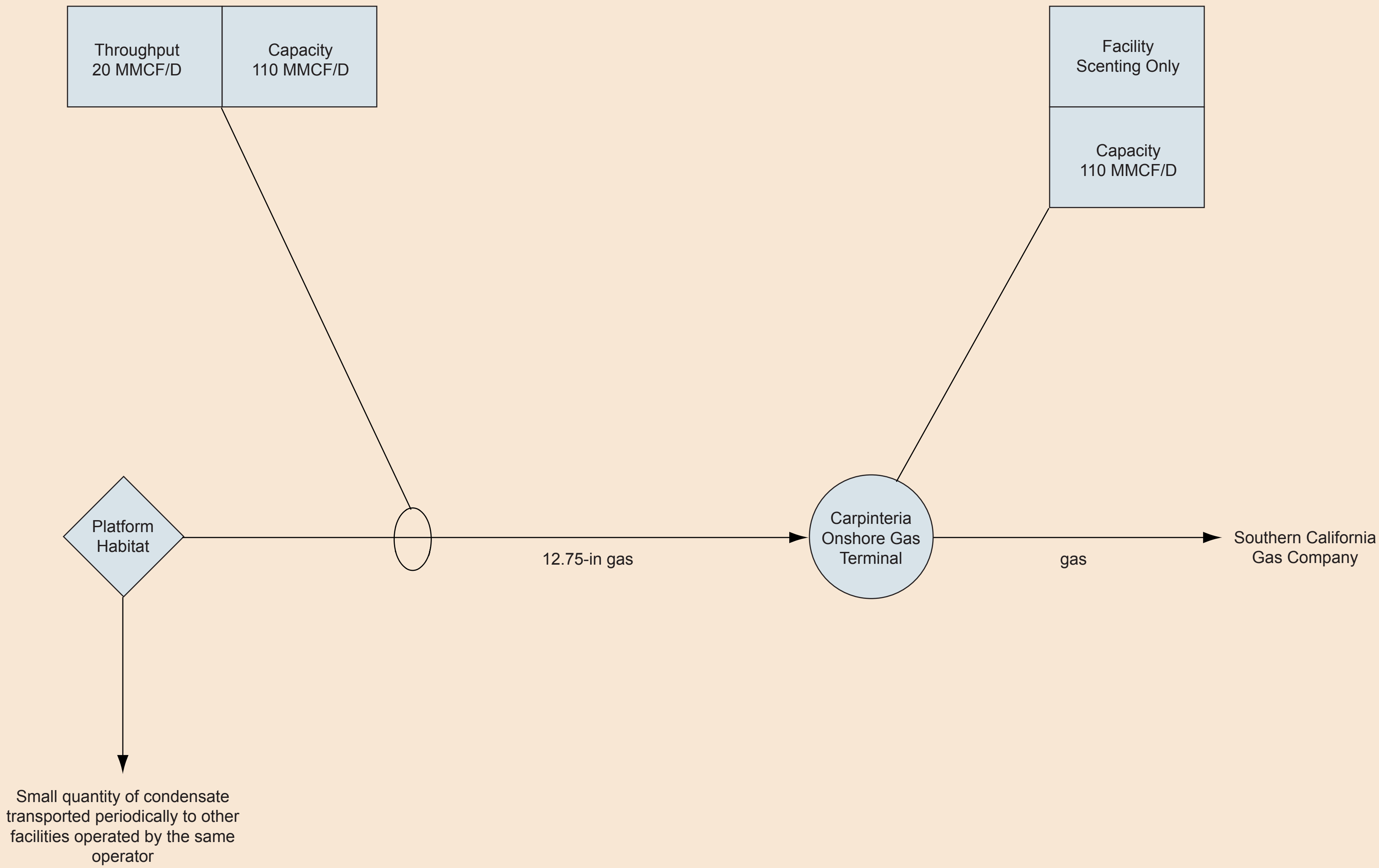


Figure 2.4-12 Carpinteria Onshore Gas Terminal System Schematic

NOT TO SCALE
Locations approximate
Source: Worley, 1995, Figure 2.58, Page 2-89

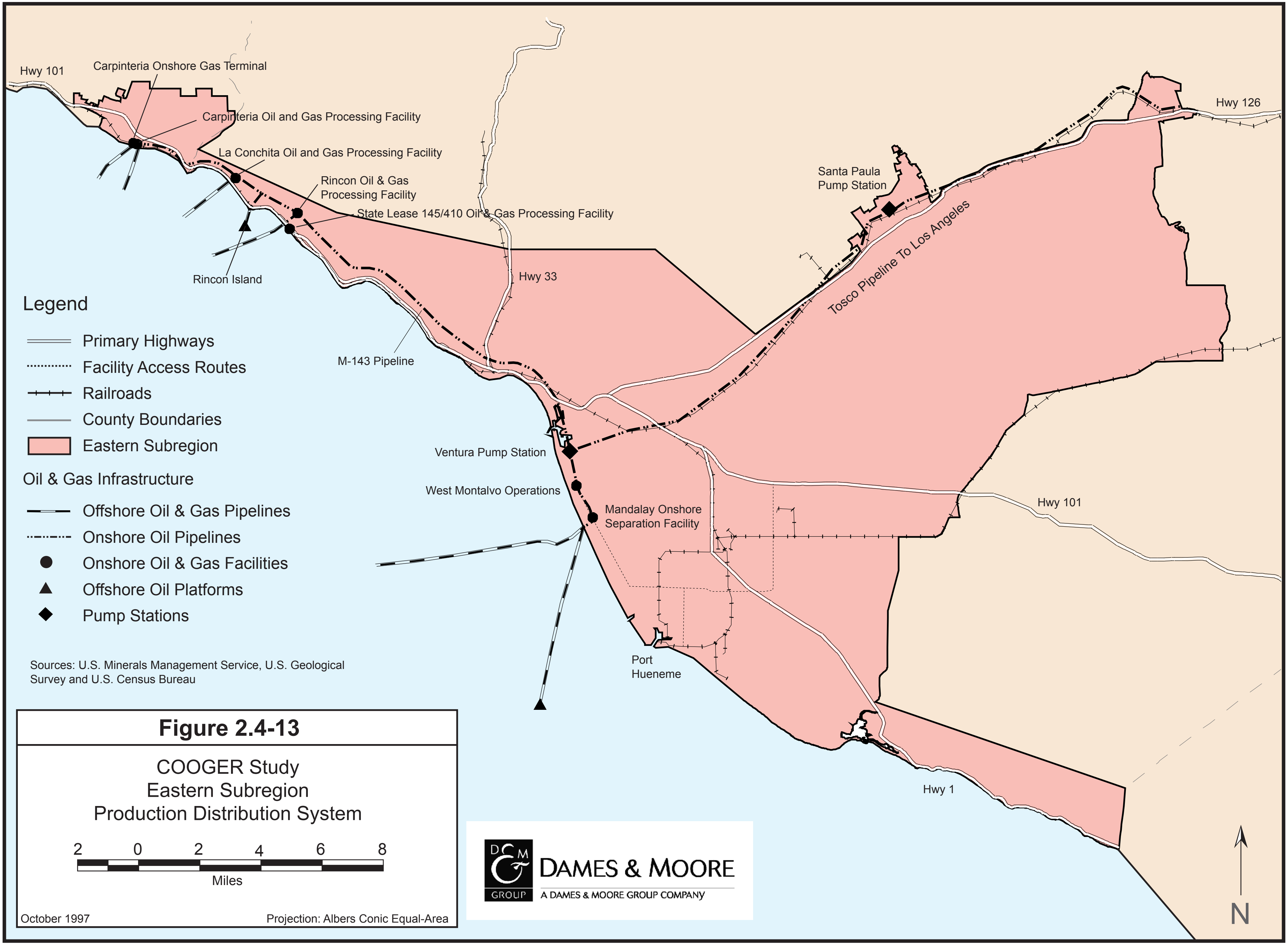
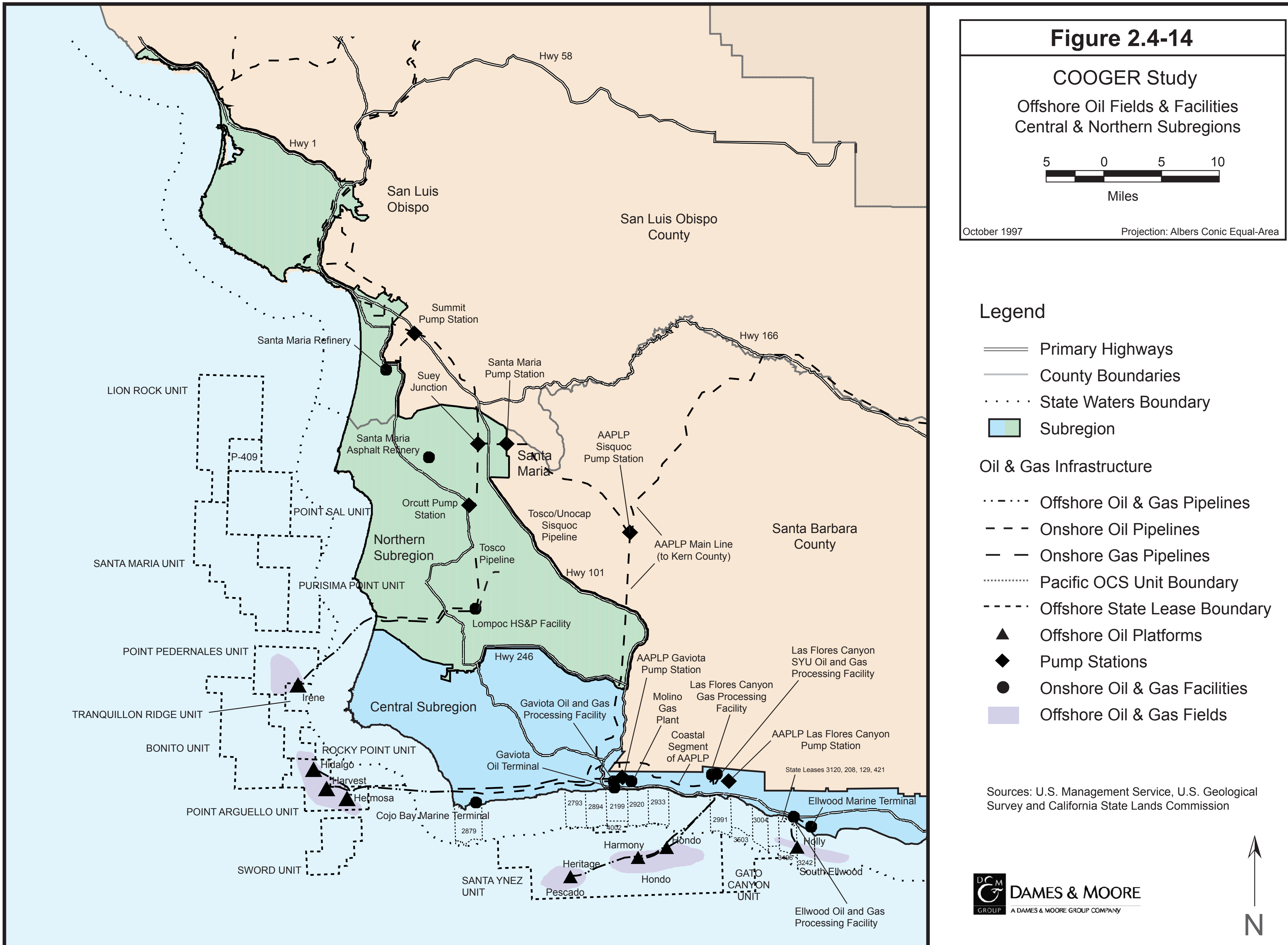


Figure 2.4-13

COOGER Study
Eastern Subregion
Production Distribution System

October 1997

Projection: Albers Conic Equal-Area

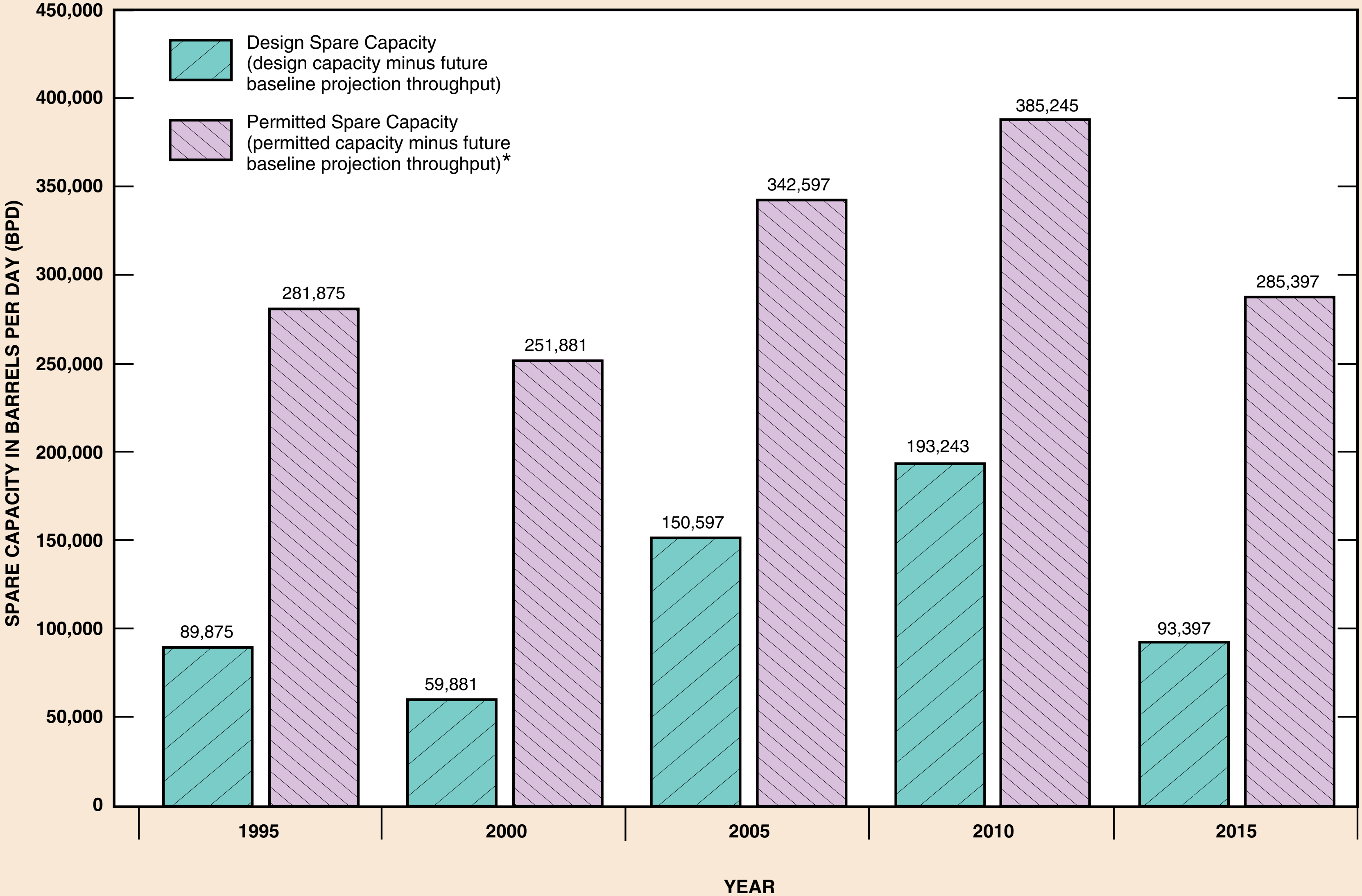


Hwy 58
Hwy 1
San Luis
Obispo
San Luis Obispo
County
Summit
Pump Station
Santa Maria Refinery
Hwy 166
Santa Maria
Pump Station
Suey
Junction
LION ROCK UNIT
P-409
Santa Maria
Asphalt Refinery
Santa
Maria
AAPLP
Sisquoc
Pump Station
Orcutt Pump
Station
POINT SAL UNIT
Tosco/Unocap
Sisquoc
Pipeline
Northern
Subregion
Tosco
Pipeline
AAPLP Main Line
(to Kern County)
Santa Barbara
County
SANTA MARIA UNIT
Hwy 101
PURISIMA POINT UNIT
Lompoc HS&P Facility
POINT PEDERNALES UNIT
Hwy 246
AAPLP Gaviota
Pump Station
Las Flores Canyon
SYU Oil and Gas
Processing Facility
Irene
Central Subregion
Gaviota Oil and Gas
Processing Facility
Molino
Gas
Plant
Las Flores Canyon
Gas Processing
Facility
TRANQUILLON RIDGE UNIT
BONITO UNIT
ROCKY POINT UNIT
Hidalgo
Harvest
Hermosa
Gaviota
Oil Terminal
Coastal
Segment
of AAPLP
AAPLP Las Flores Canyon
Pump Station
State Leases 3120, 208, 129, 421
POINT ARGUELLO UNIT
Cojo Bay Marine Terminal
2793
2894
2199
2920
2933
4002
2879
2991
3004
3603
3406
3242
Ellwood Marine Terminal
Harmony
Hondo
Holly
Heritage
Hondo
South Ellwood
SWORD UNIT
SANTA YNEZ
UNIT
Pescado
GATO
CANYON
UNIT
Ellwood Oil and Gas
Processing Facility
COOGER Study
Offshore Oil Fields & Facilities
Central & Northern Subregions
5
0
5
10
Miles
October 1997
Projection: Albers Conic Equal-Area
Legend
Primary Highways
County Boundaries
State Waters Boundary
Subregion
Oil & Gas Infrastructure
Offshore Oil & Gas Pipelines
Onshore Oil Pipelines
Onshore Gas Pipelines
Pacific OCS Unit Boundary
Offshore State Lease Boundary
Offshore Oil Platforms
Pump Stations
Onshore Oil & Gas Facilities
Offshore Oil & Gas Fields
Sources: U.S. Management Service, U.S. Geological Survey and California State Lands Commission
DAMES & MOORE
A DAMES & MOORE GROUP COMPANY
N

Figure 2.4-14

997/097C

WET OIL PROCESSING FACILITIES SPARE CAPACITY
Central Subregion



DAMES & MOORE
GROUP
A DAMES & MOORE GROUP COMPANY

Baseline throughput in this analysis is limited by Las Flores Canyon design capacity. If permitted capacity is available, actual baseline throughput would increase without any additional development, and available spare capacity could be less than the estimate shown here for some years.

Figure 2.4-15

COOGER STUDY

1097/104B

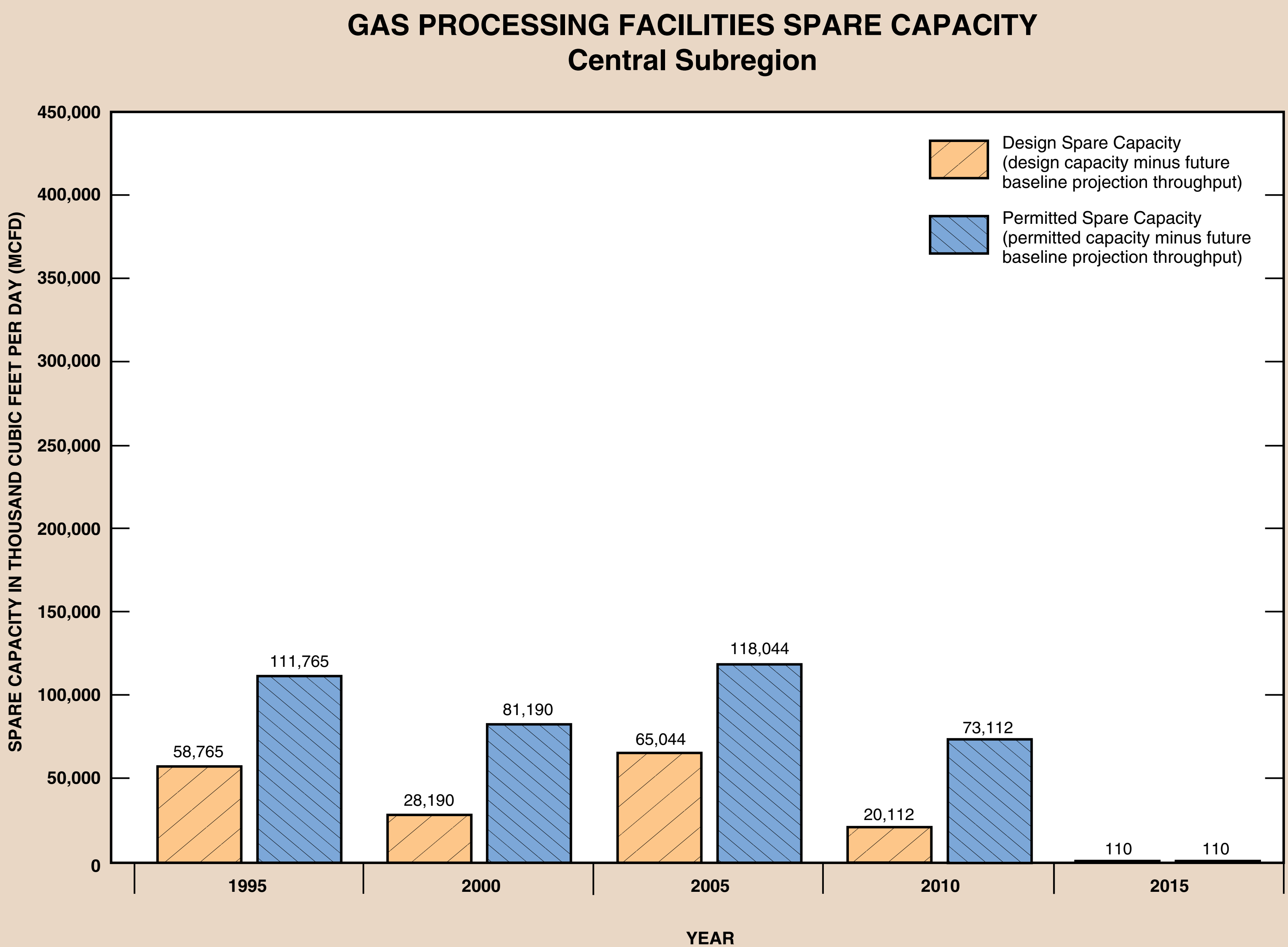


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Figure 2.4-16

COOGER STUDY

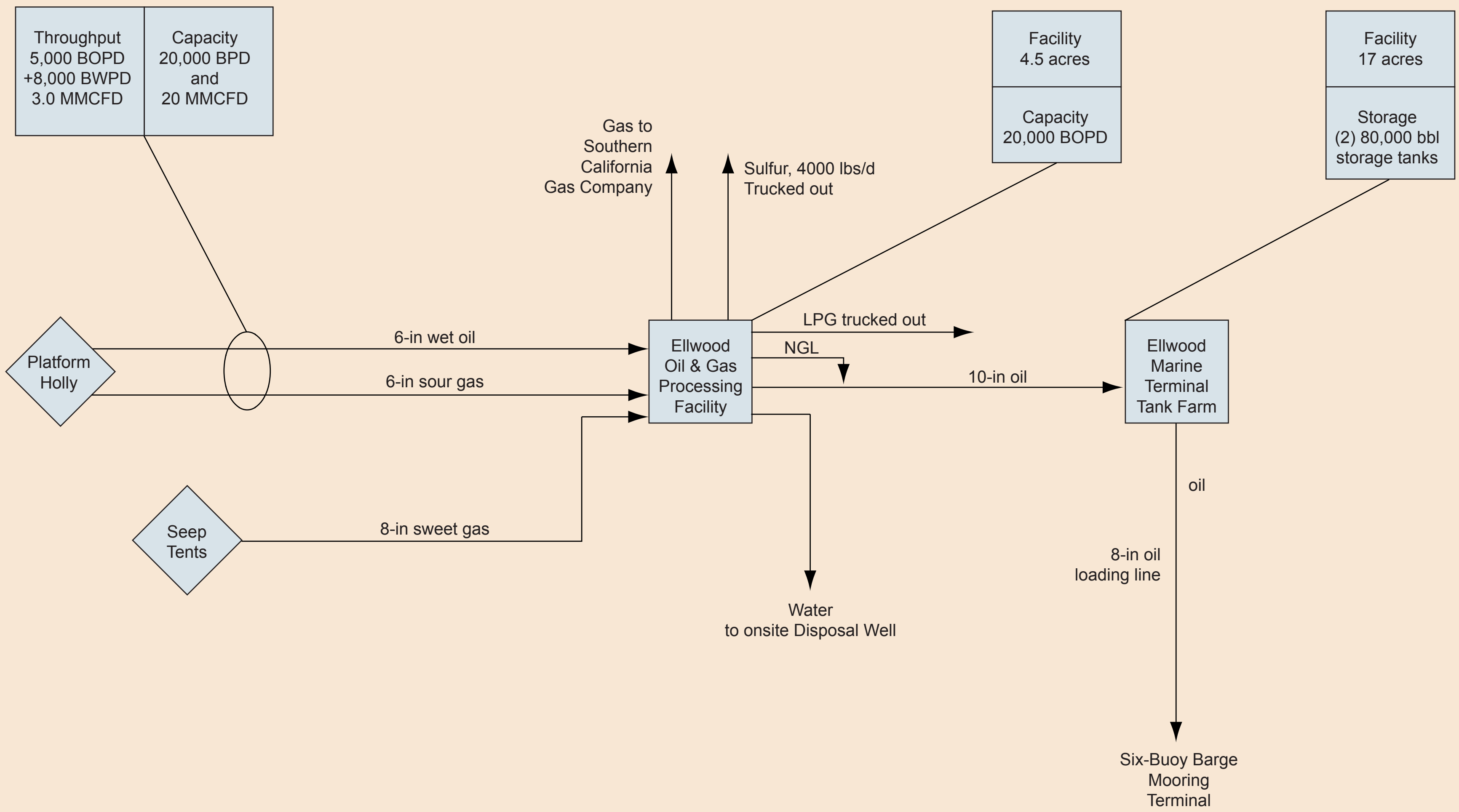


Figure 2.4-17 Ellwood Oil & Gas Processing Facility and Ellwood Marine Terminal System Schematic

Source: Worley, 1995, Figure 2.28, Page 2-47

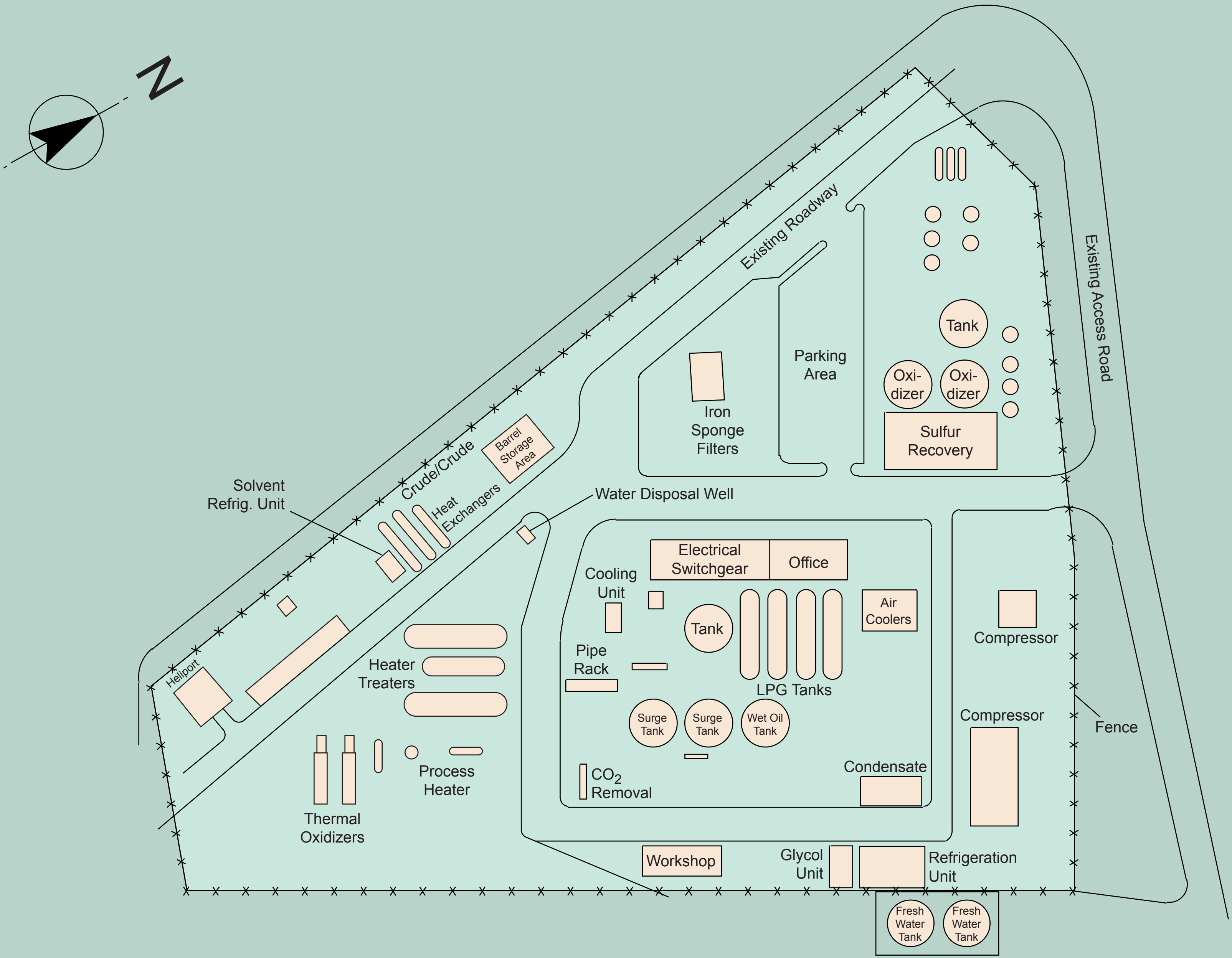


Figure 2.4-18 Ellwood Oil & Gas Processing Facility Plot Plan

NOT TO SCALE
Locations approximate
Source: Worley, 1995, Figure 2.29, Page 2-48

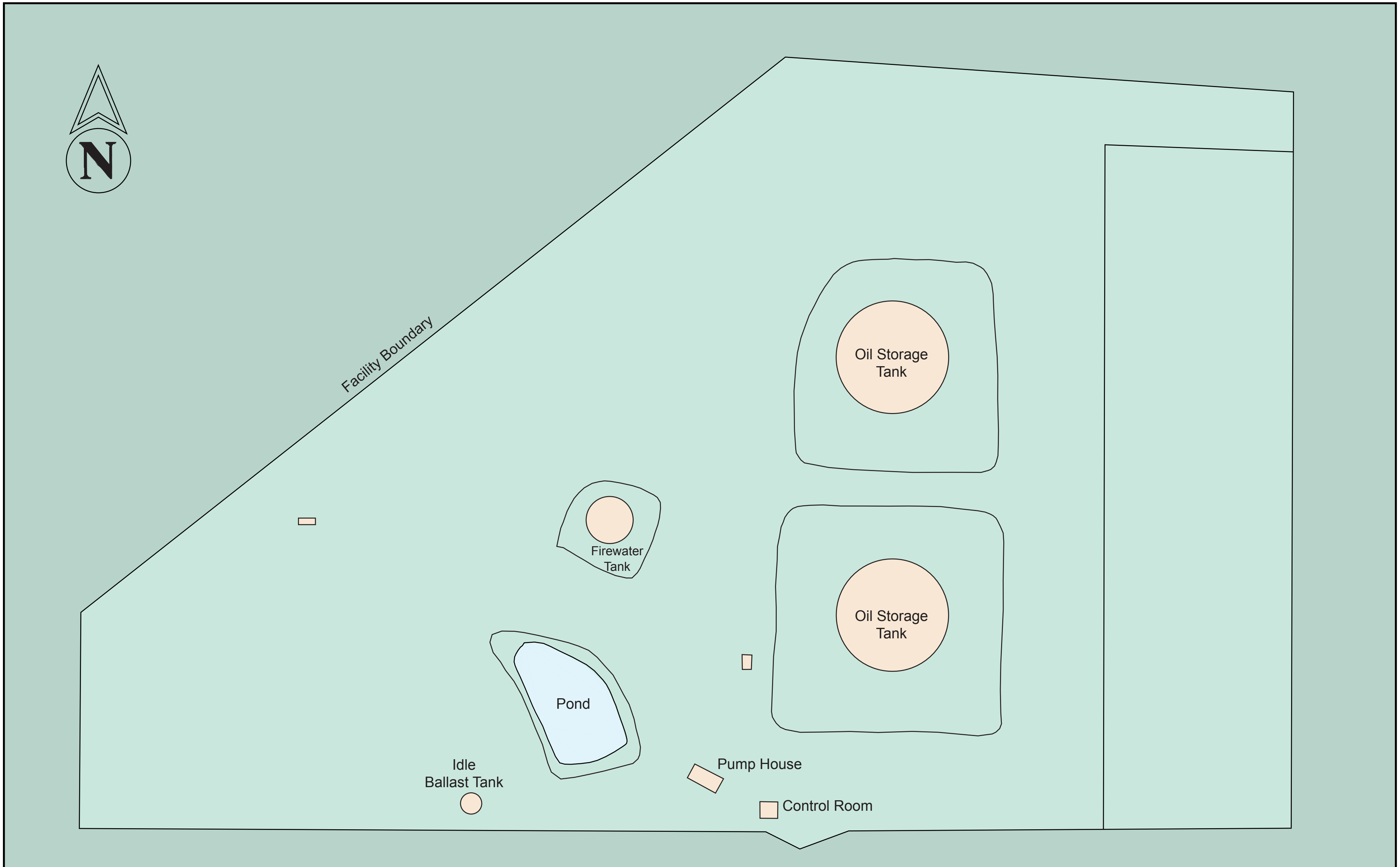


Figure 2.4-19 Ellwood Marine Terminal Tank Farm Plot Plan

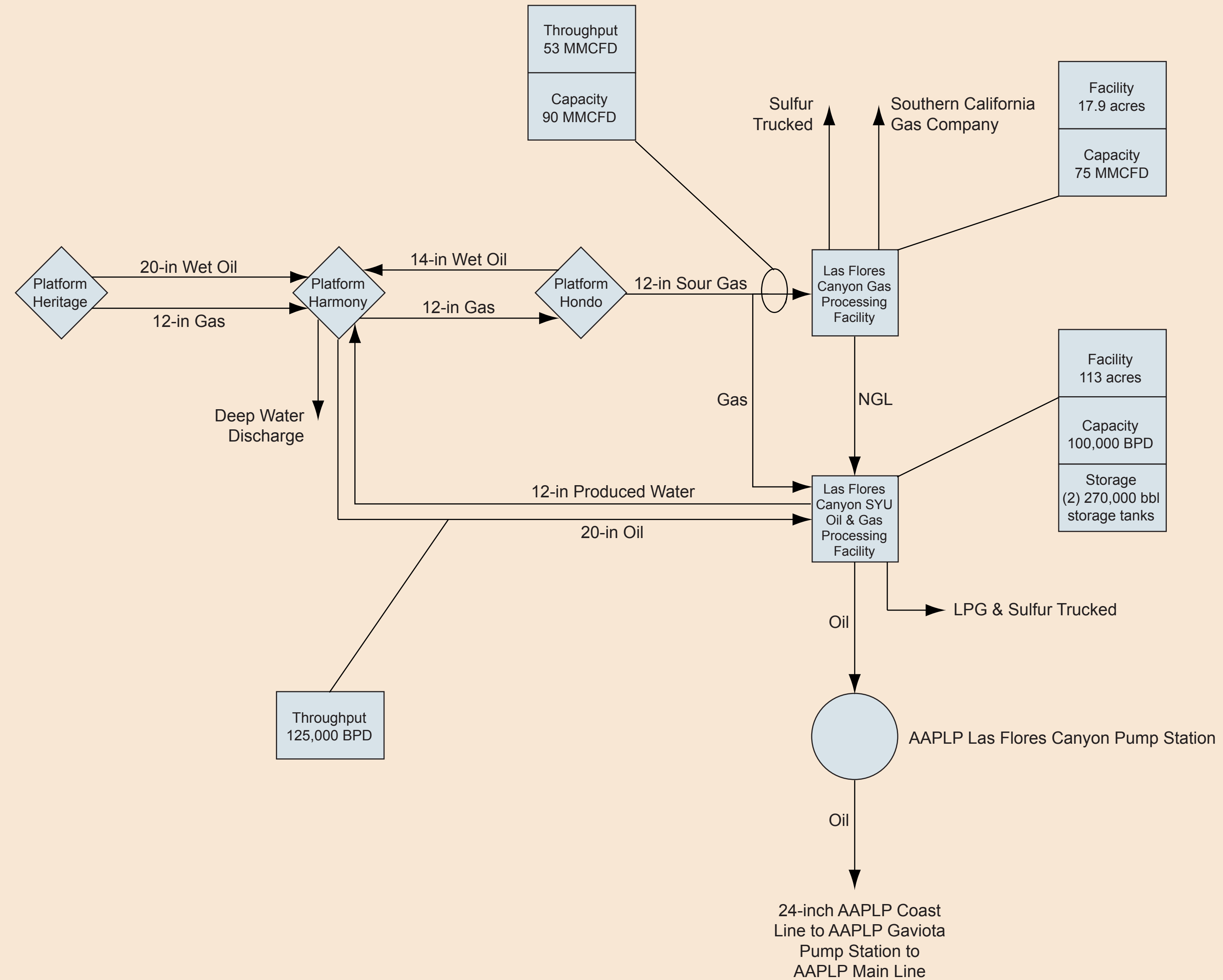


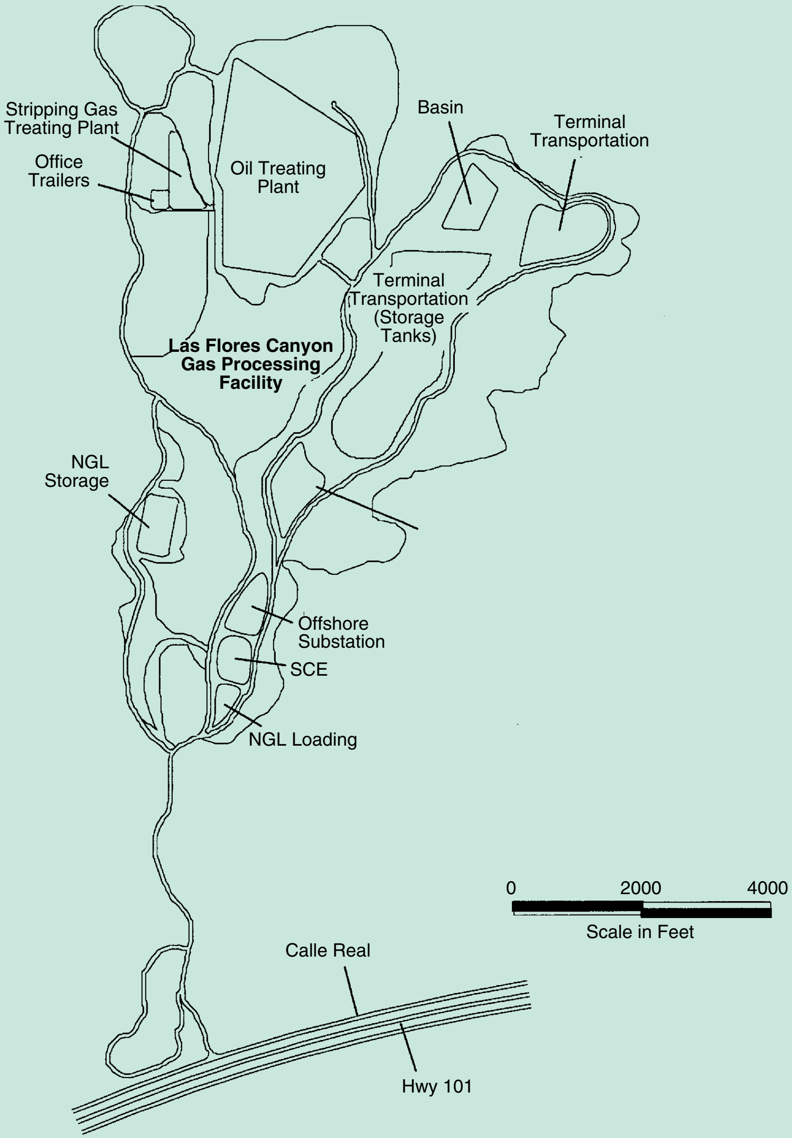
Figure 2.4-20 Las Flores Canyon SYU Oil & Gas Processing Facility and Las Flores Canyon Gas Processing Facility System Schematic

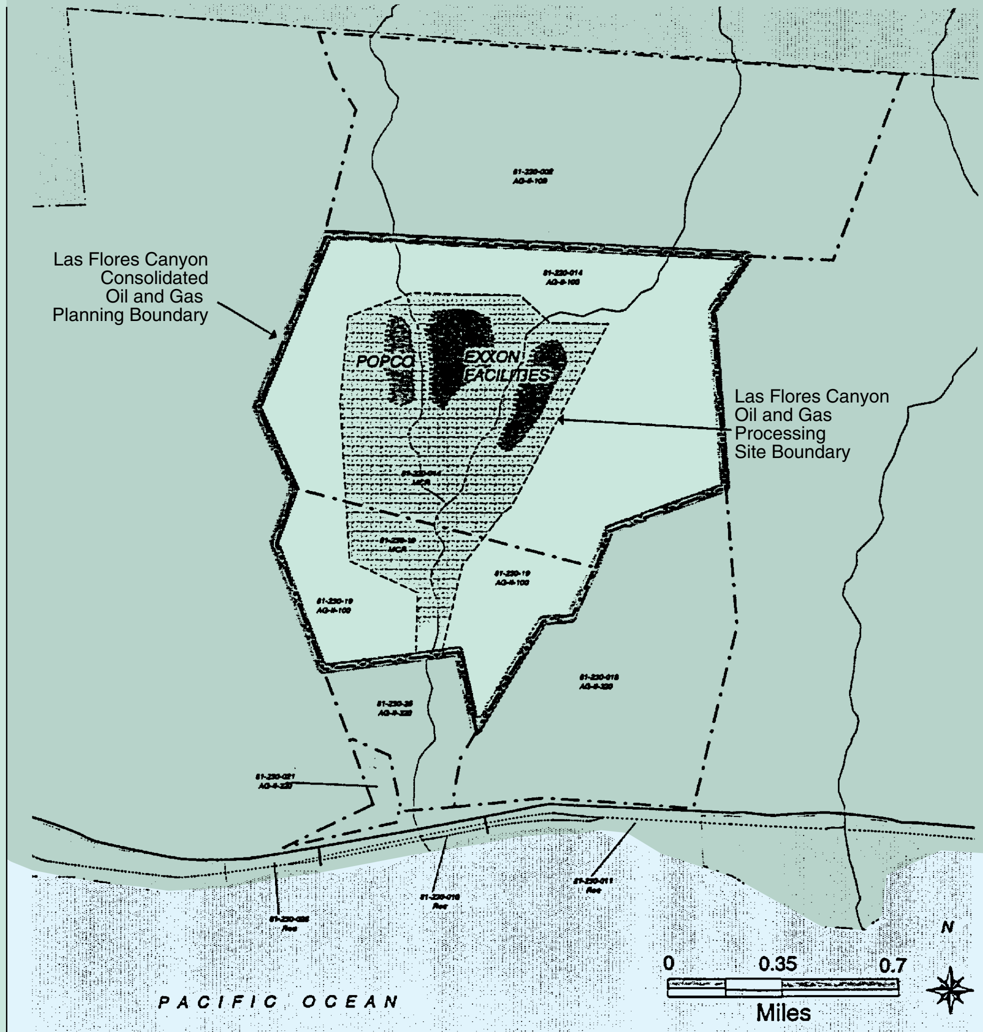
NOT TO SCALE

Source: Worley, 1995, Figure 2.20, Page 2-37

699/064A

LAS FLORES CANYON FACILITIES PLOT PLAN AND CONSOLIDATED SITE BOUNDARY





Source: Santa Barbara County Planning & Development

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GROUP
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Figure 2.4-21

COOGER STUDY

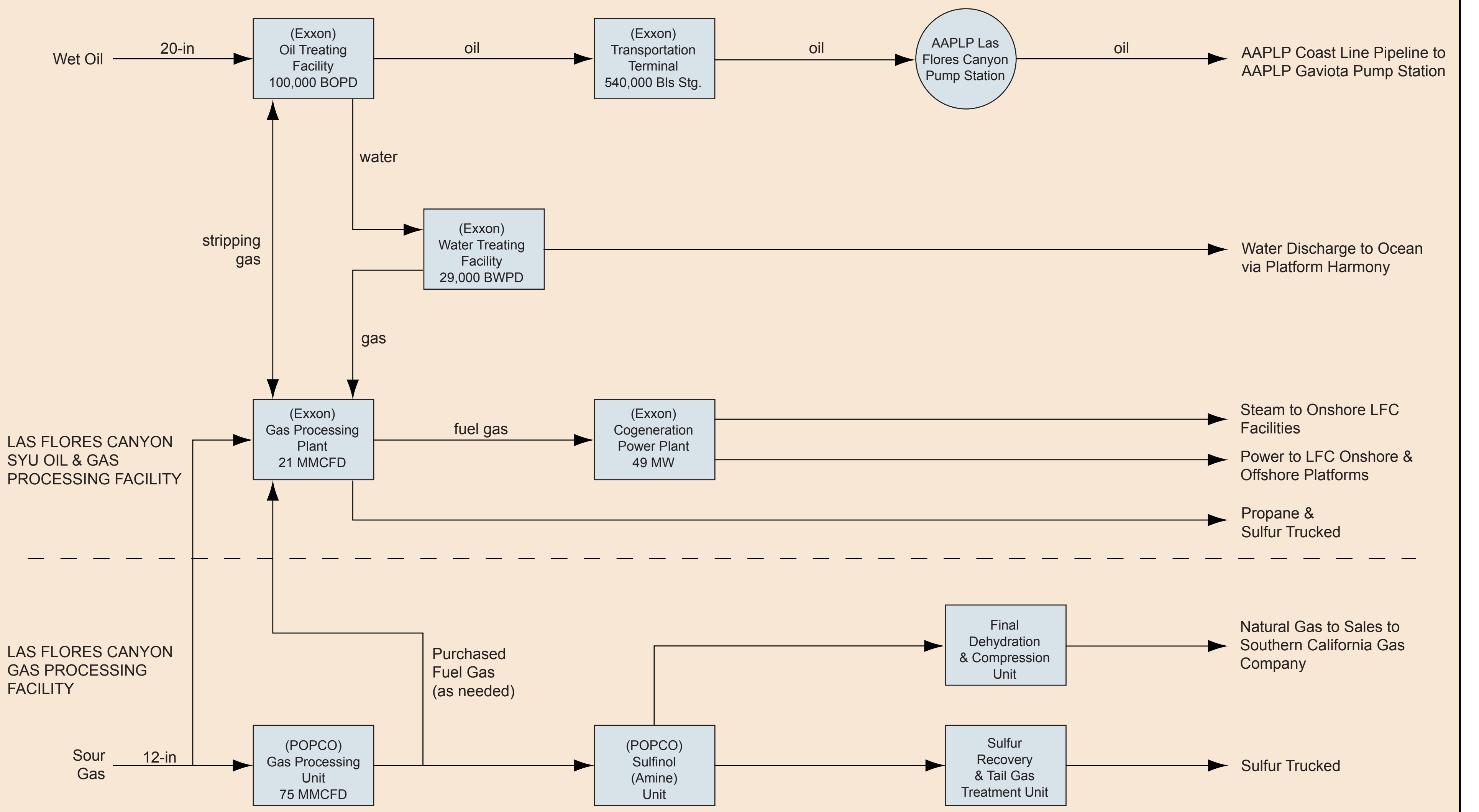


Figure 2.4-22 Las Flores Canyon Facilities Block Flow Diagram

NOT TO SCALE
Source: Worley, 1995, Figure 2.22, Page 2-39

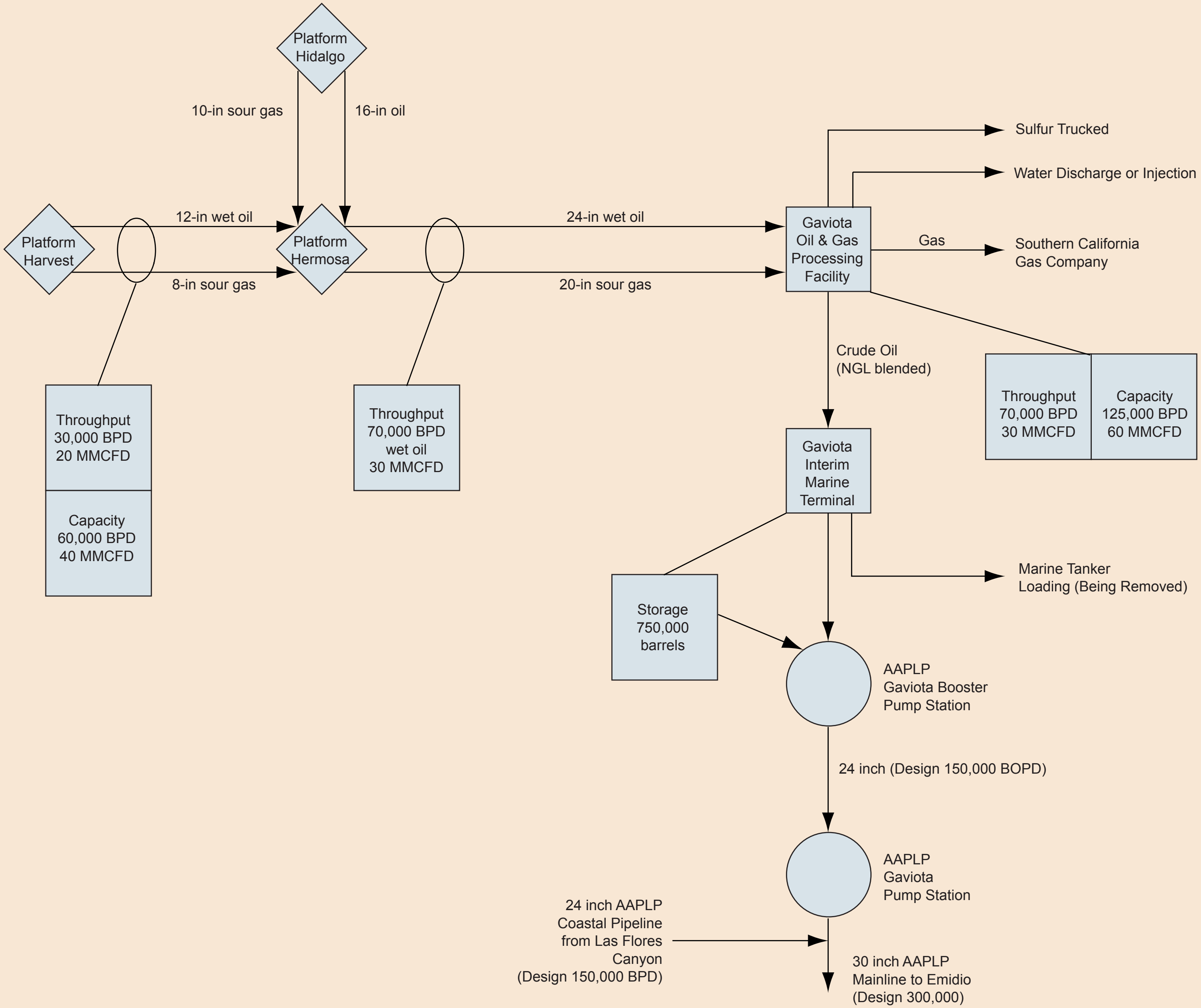
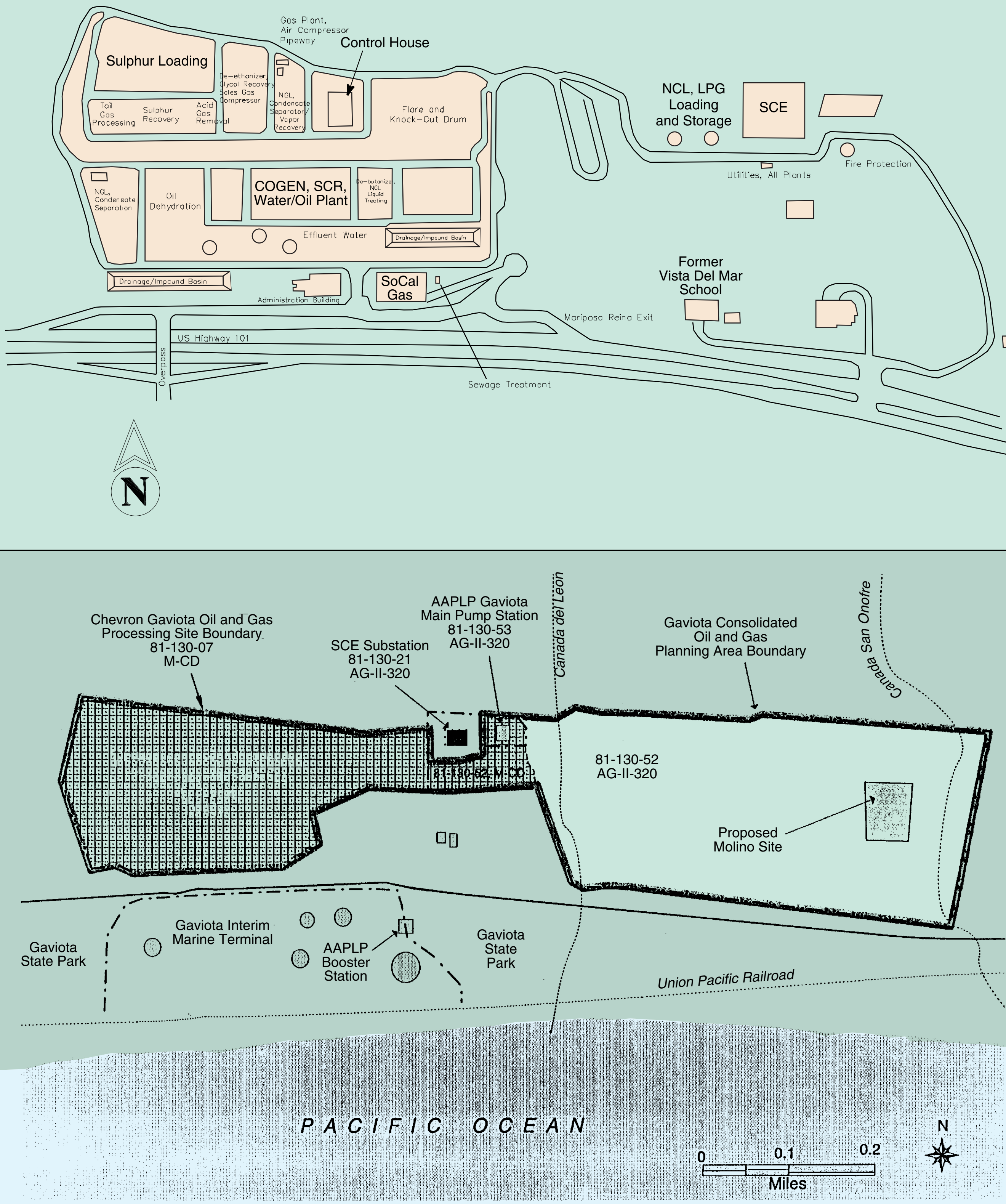


Figure 2.4-23 Gaviota Oil & Gas Processing Facility

NOT TO SCALE
Locations approximate
Source: Worley, 1995, Figure 2.9, Page 2-21

199/007A

GAVIOTA OIL AND GAS PROCESSING FACILITY PLOT PLAN AND CONSOLIDATED SITE BOUNDARY



Source: Santa Barbara County Planning & Development

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Figure 2.4-24

COOGER STUDY

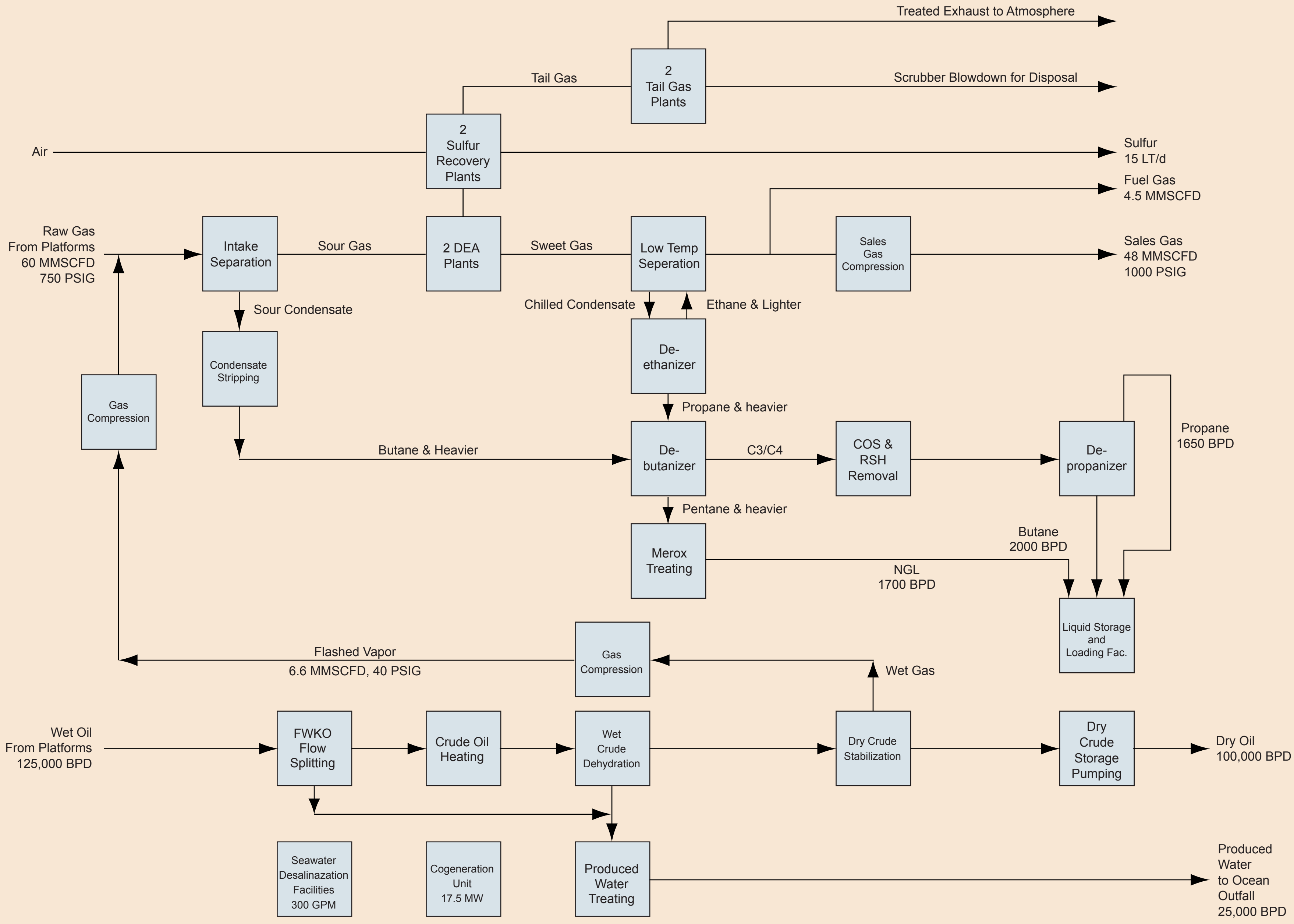


Figure 2.4-25 Gaviota Oil & Gas Processing Facility Block Flow Diagram

NOT TO SCALE
Source: Worley, 1995, Figure 2.10, Page 2-22

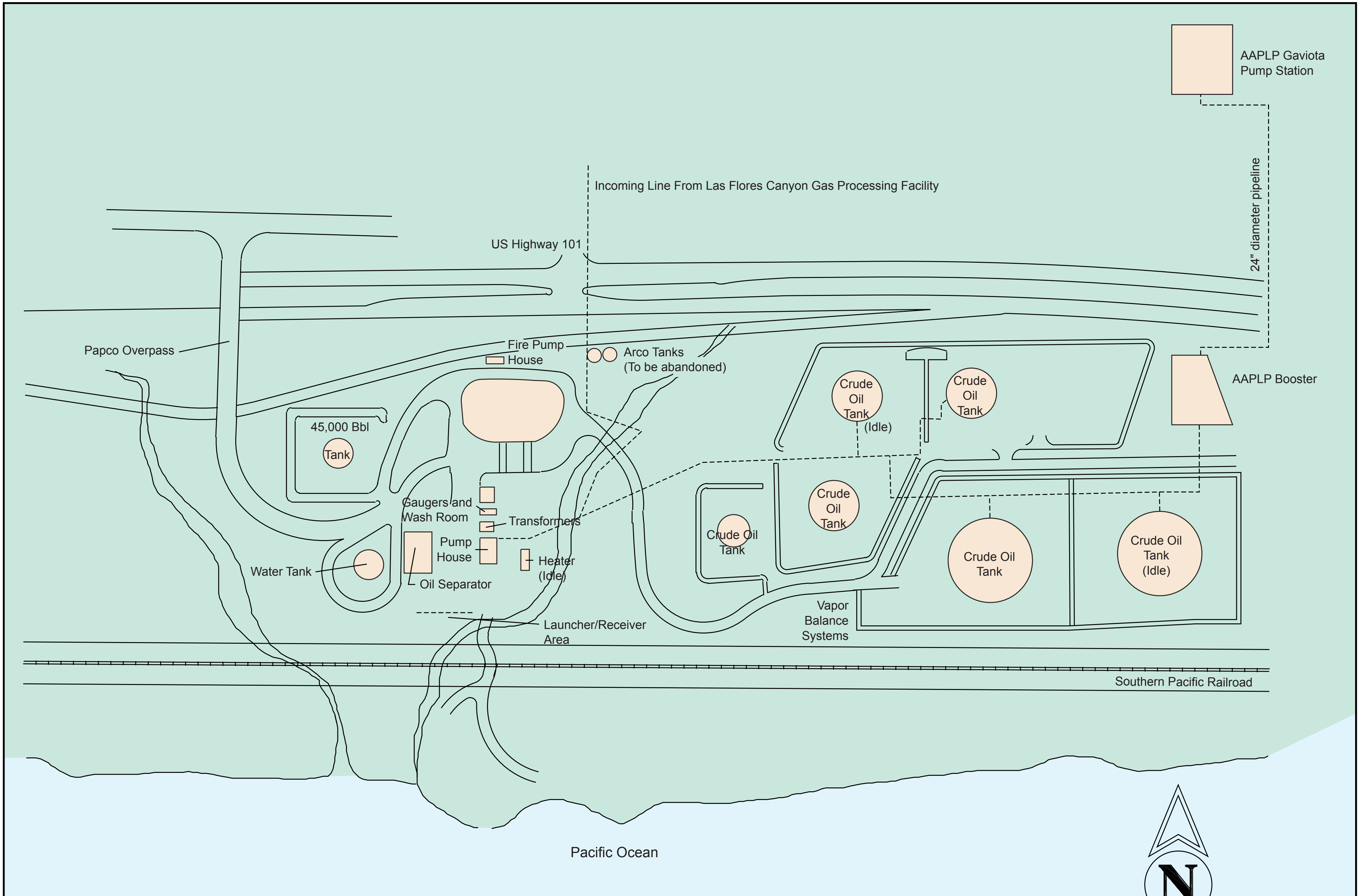


Figure 2.4-26 Gaviota Interim Marine Terminal Plot Plan

Source: Worley, 1995, Figure 2.15, Page 2-25

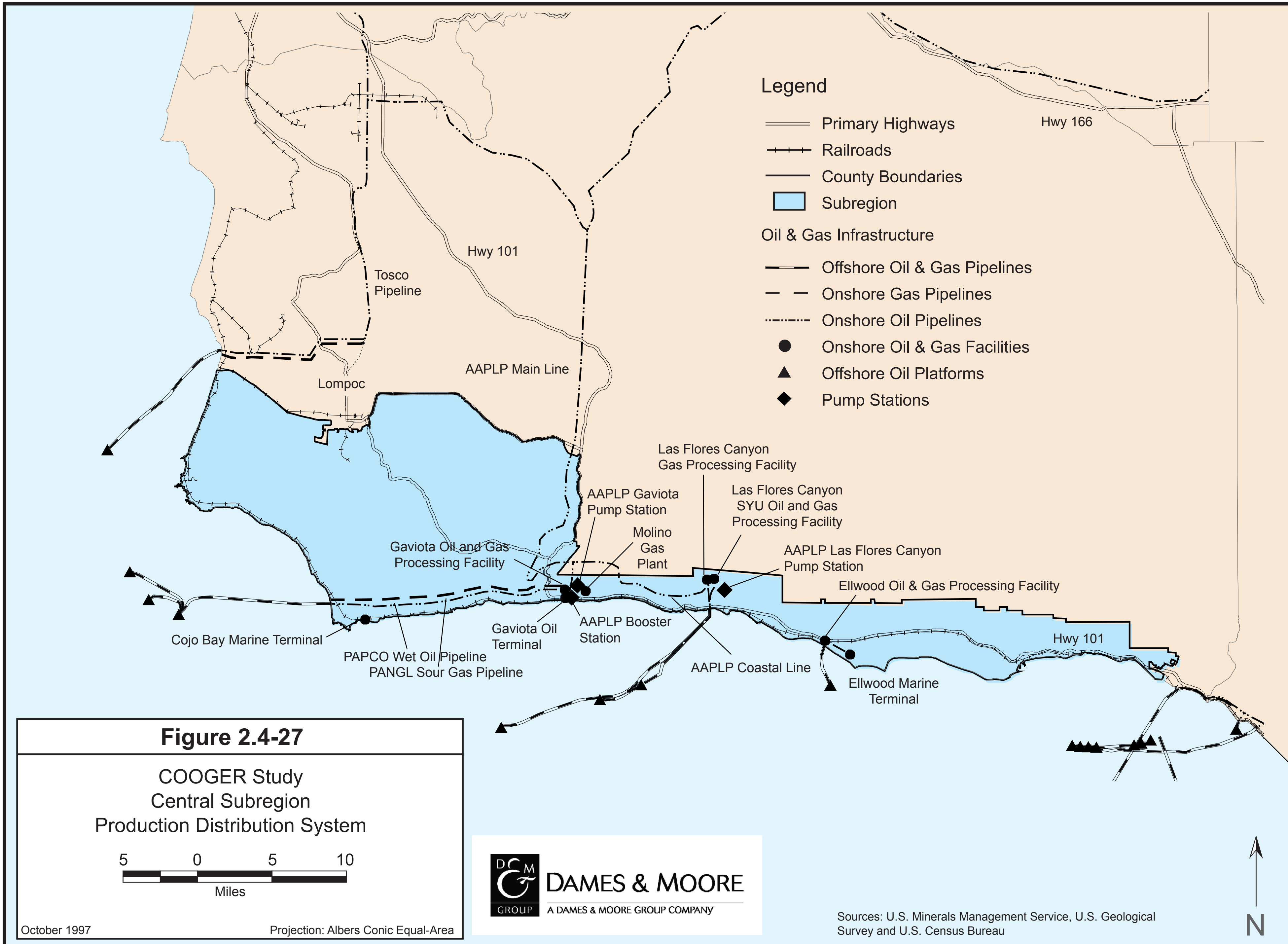


Figure 2.4-27

COOGER Study
Central Subregion
Production Distribution System

October 1997

Projection: Albers Conic Equal-Area

Sources: U.S. Minerals Management Service, U.S. Geological Survey and U.S. Census Bureau

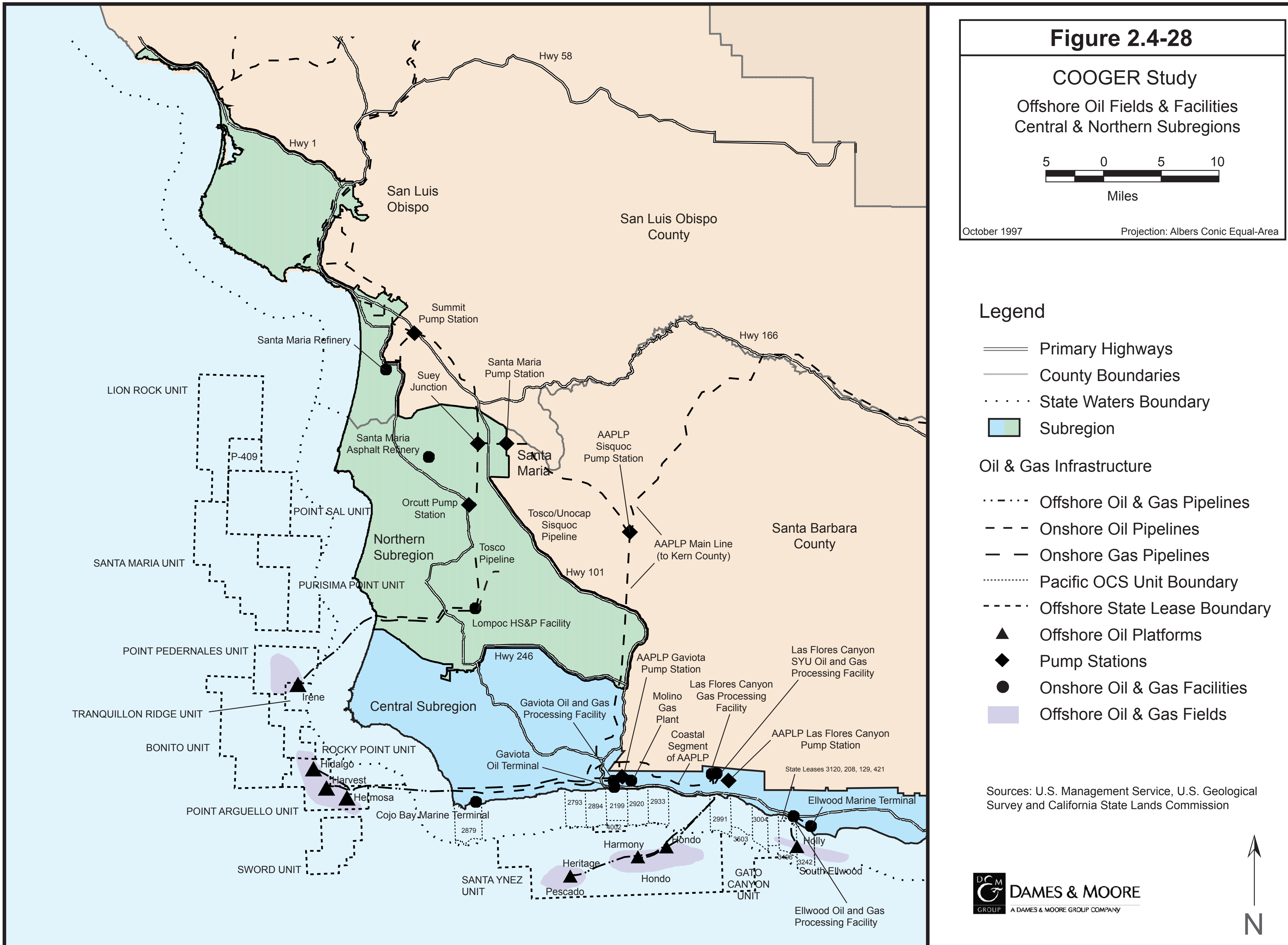


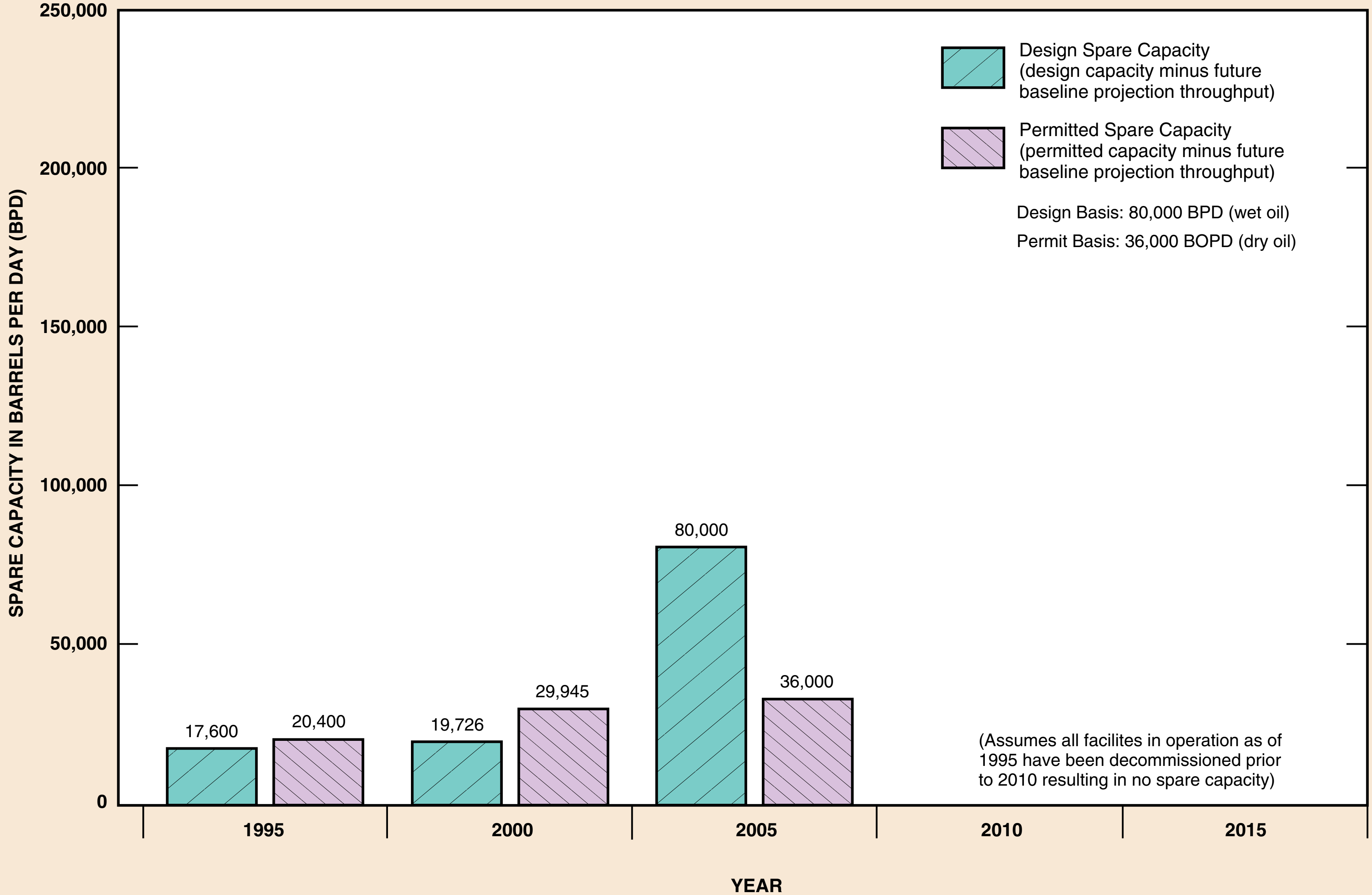
Figure 2.4-28

COOGER Study
Offshore Oil Fields & Facilities
Central & Northern Subregions

October 1997 Projection: Albers Conic Equal-Area

997/096B

WET OIL PROCESSING FACILITIES SPARE CAPACITY
Northern Subregion



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GROUP
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Figure 2.4-29
COOGER STUDY

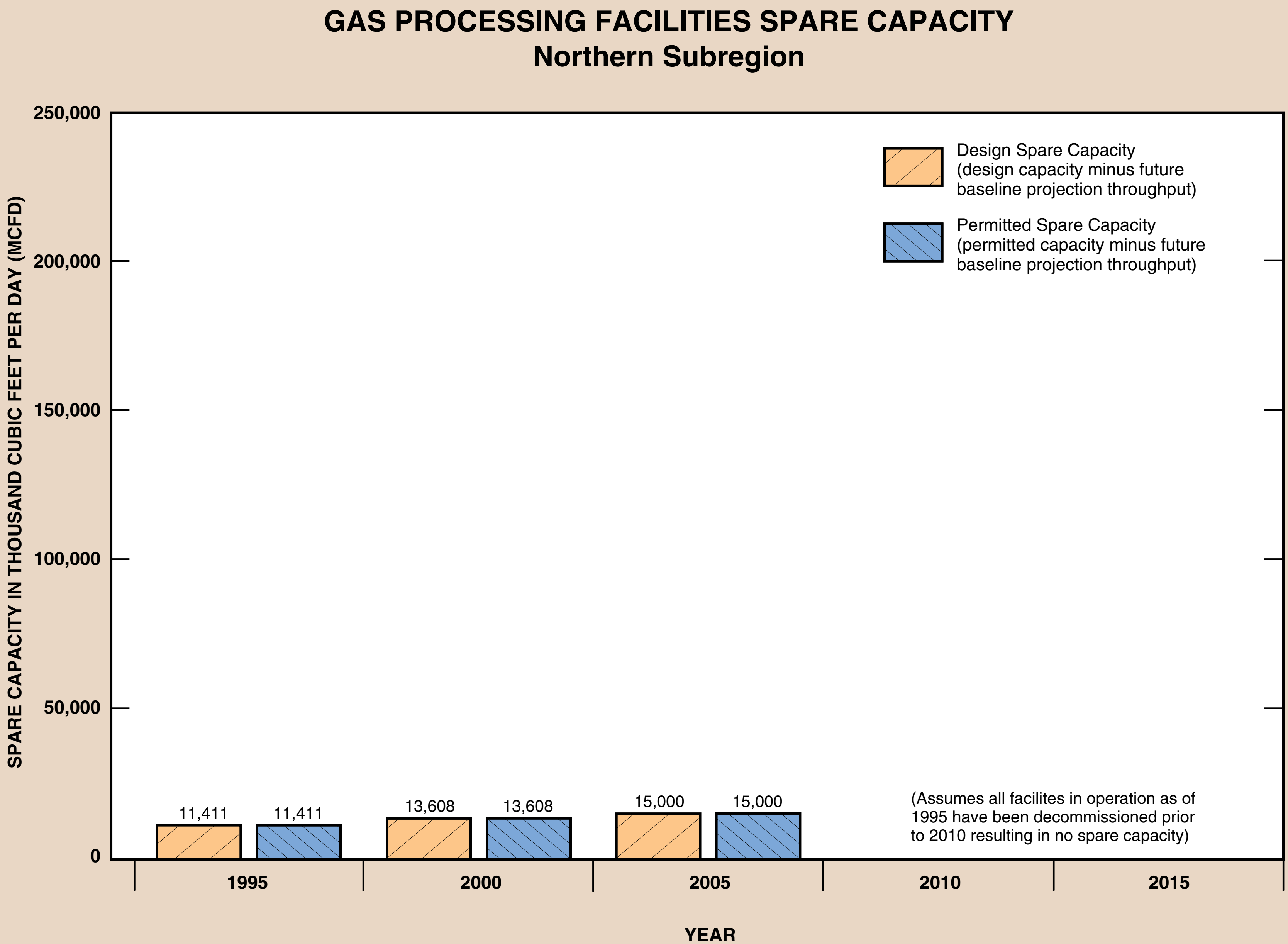

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Figure 2.4-30

COOGER STUDY

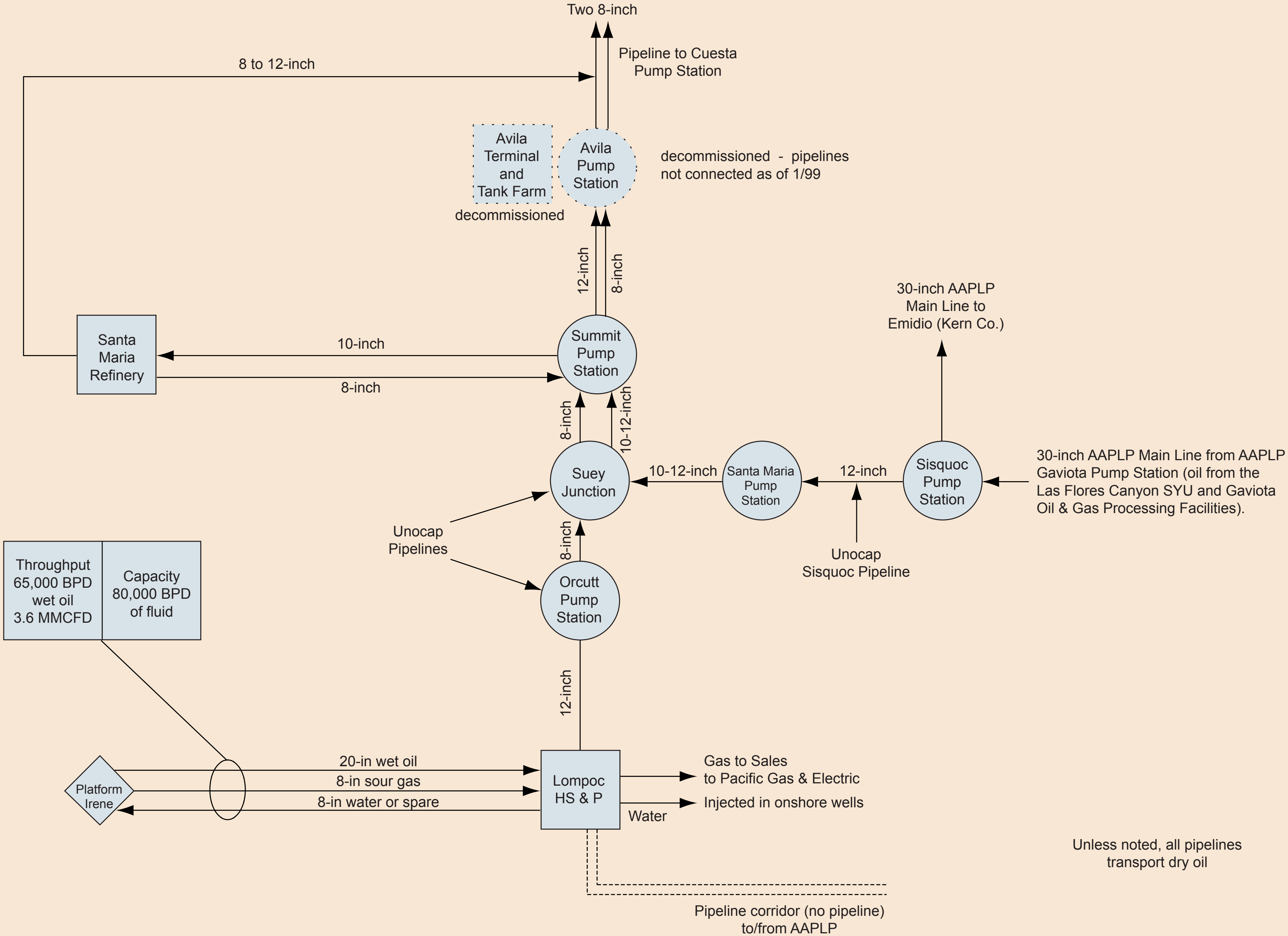


Figure 2.4-31 Lompoc HS&P Facility and Northern Pacific System Schematic

Locations approximate
NOT TO SCALE
Source: Worley, 1995, Figure 2.2, Page 2-7

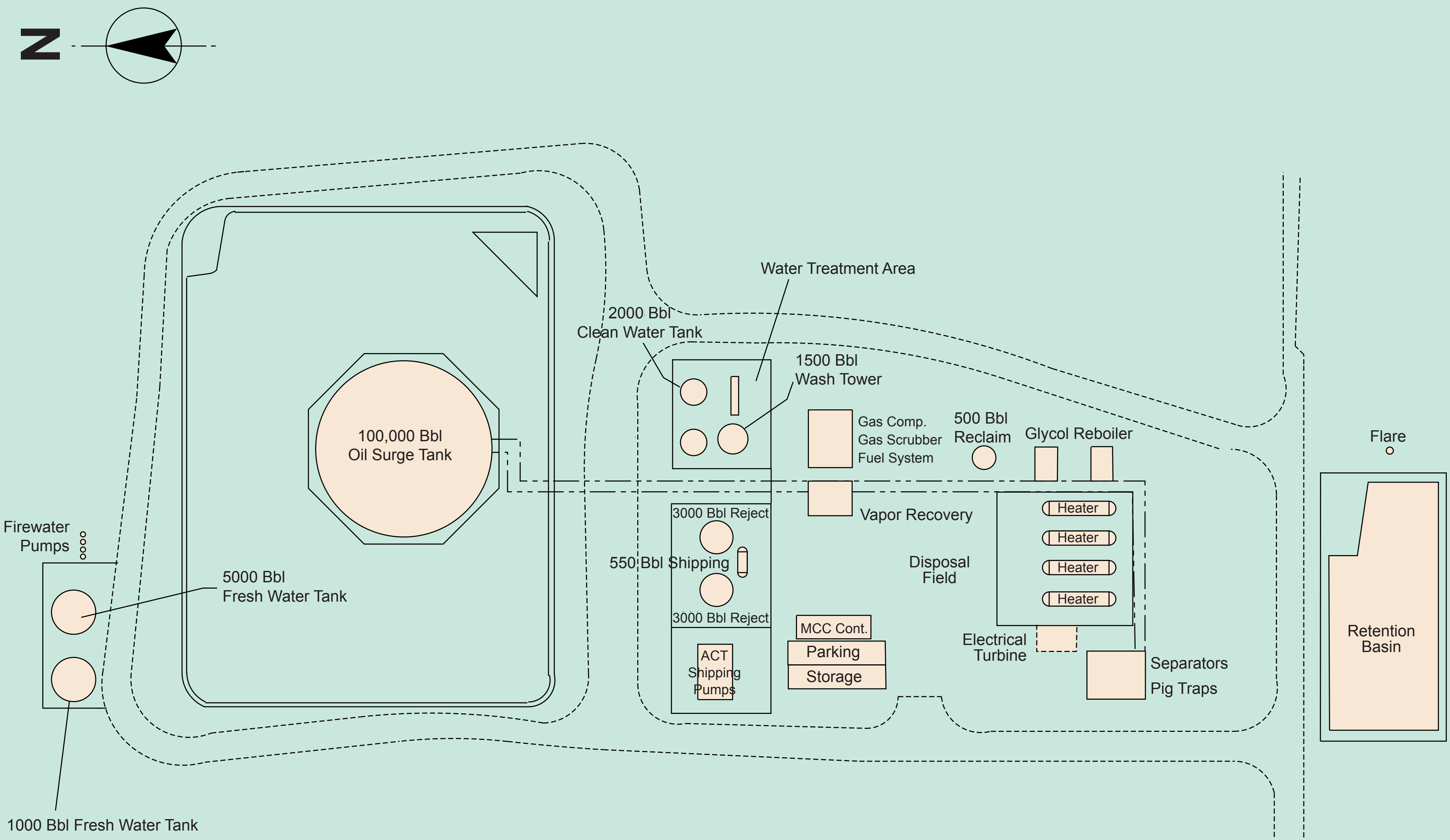


Figure 2.4-32 Lompoc HS&P Facility Plot Plan

NOT TO SCALE
Locations approximate
Source: Worley, 1995, Figure 2.3, Page 2-8; Torch 1997

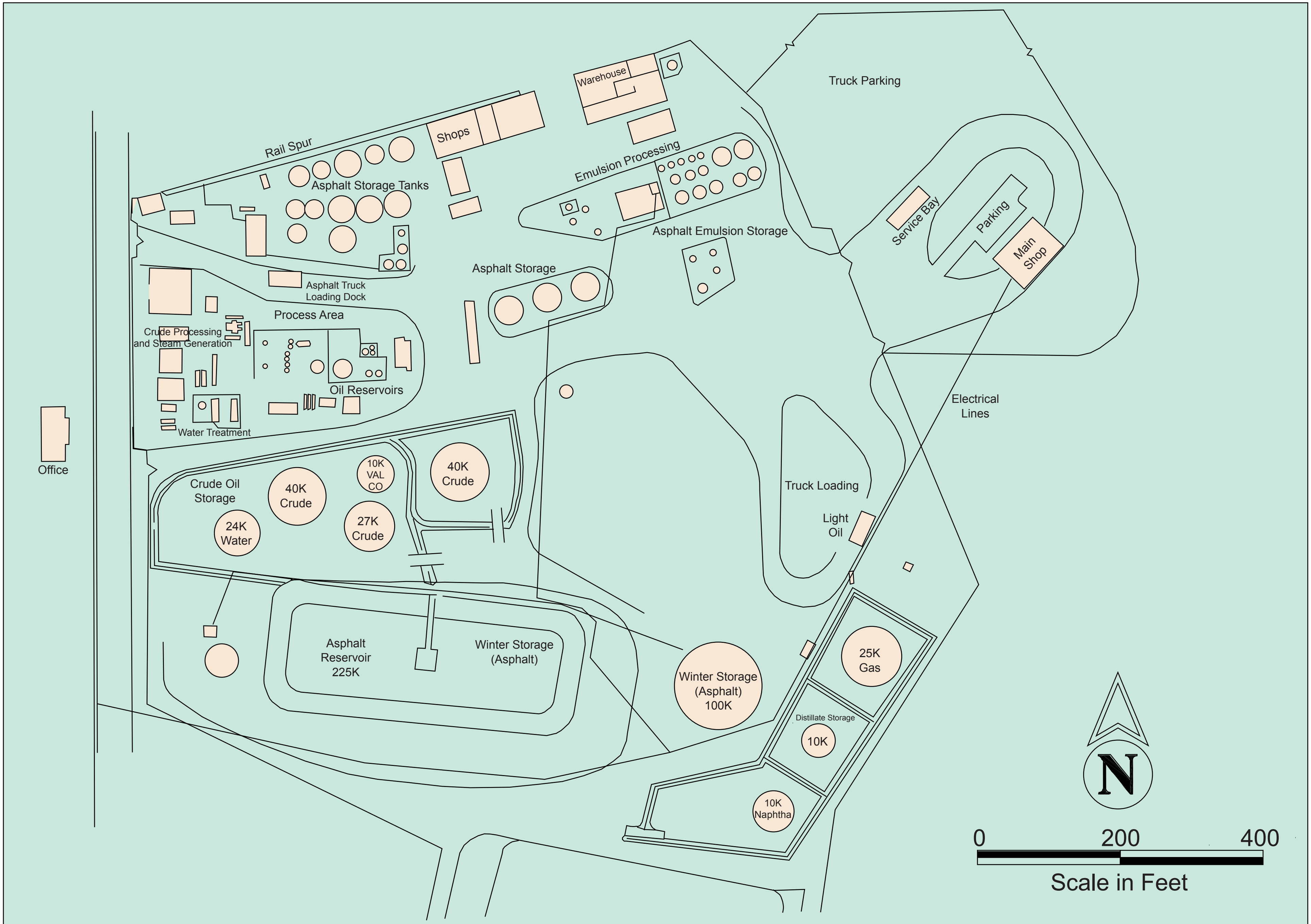


Figure 2.4-33 Santa Maria Asphalt Refinery Plot Plan

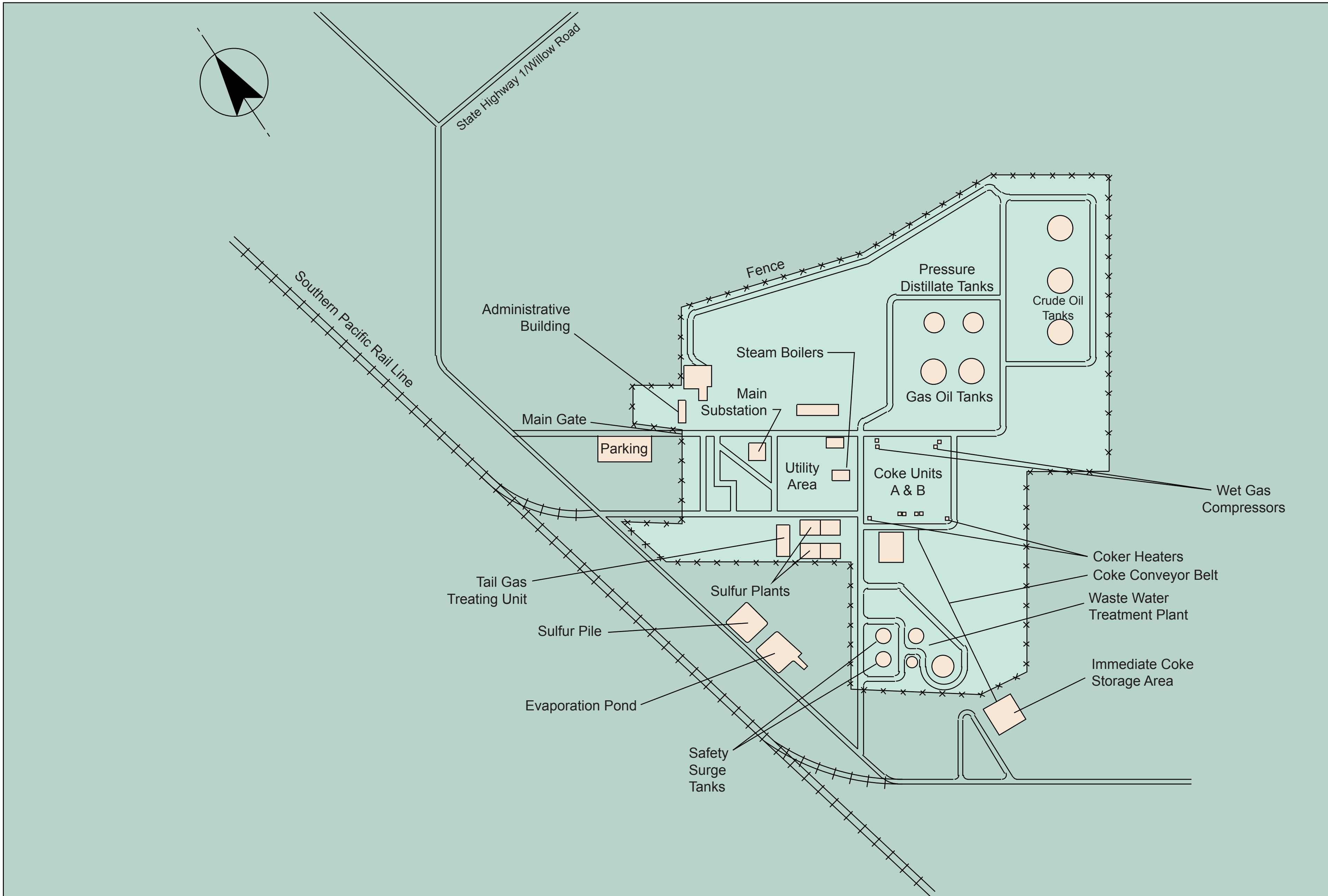


Figure 2.4-34 Santa Maria Refinery Plot Plan

NOT TO SCALE
Locations approximate
Source: Worley, 1995, Figure 2.6, Page 2-10

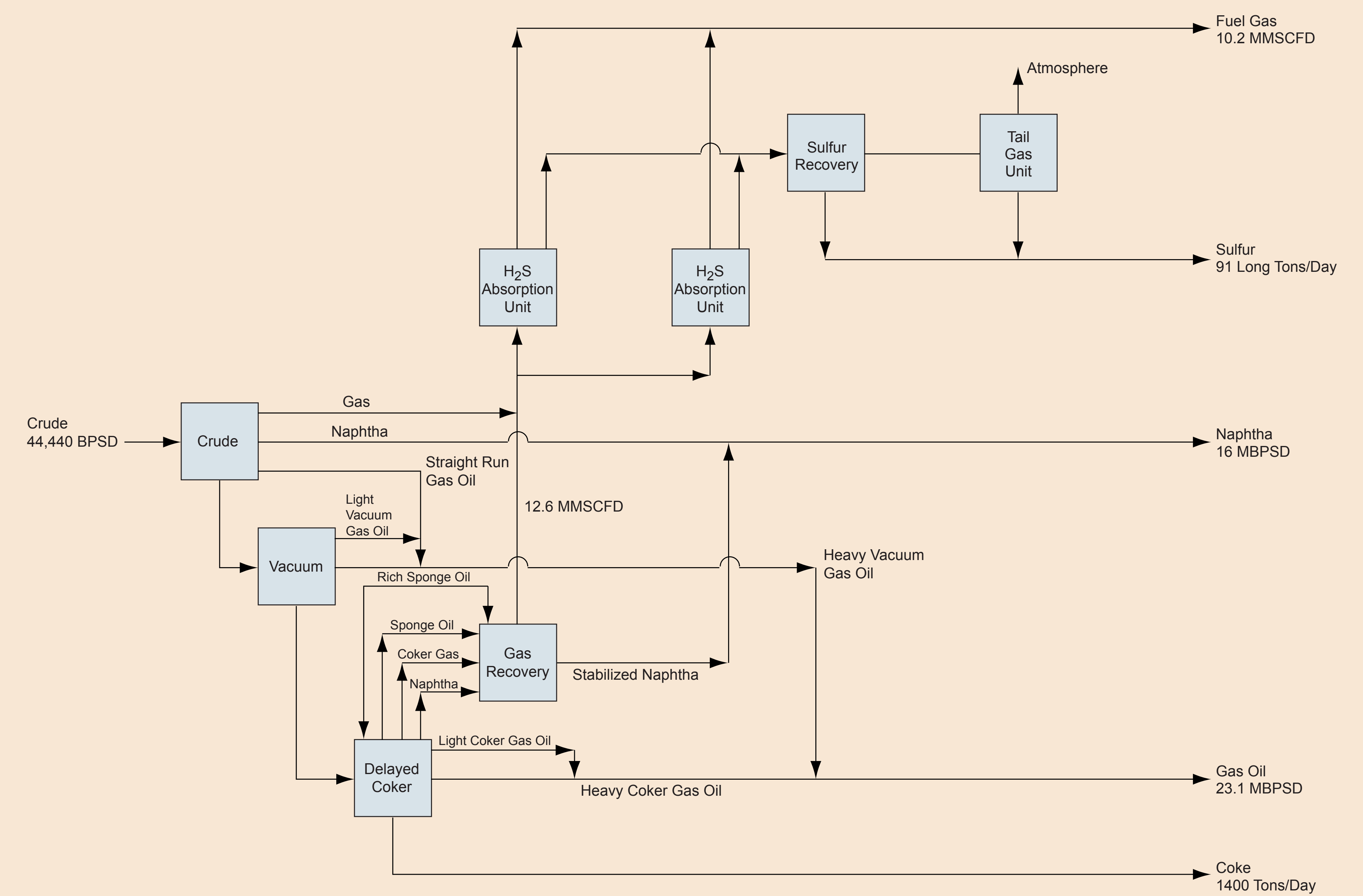


Figure 2.4-35 Santa Maria Refinery Block Flow Diagram

NOT TO SCALE
Locations approximate
Source: Worley, 1995, Figure 2.7, Page 2-11

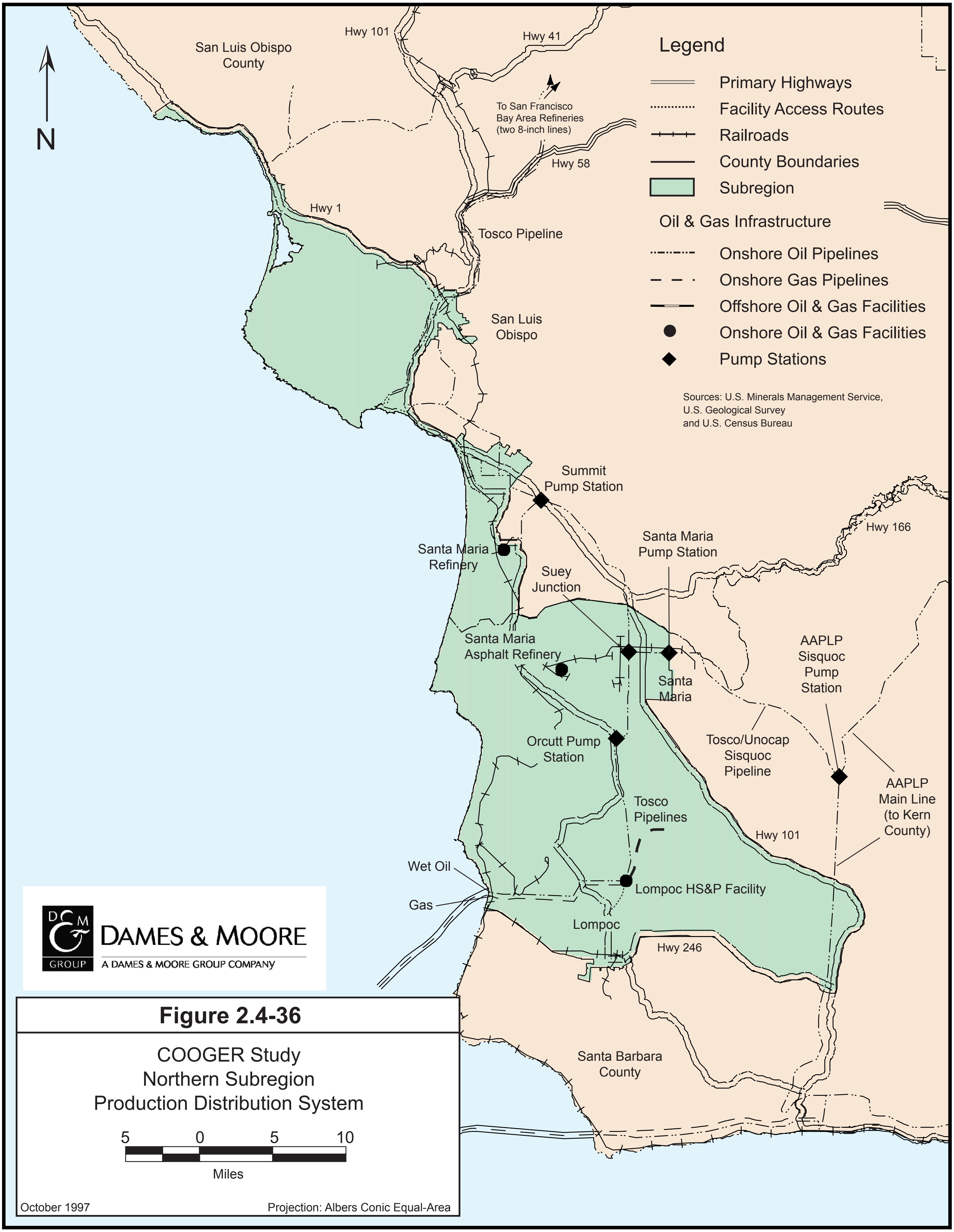


Figure 2.4-36

COOGER Study
Northern Subregion
Production Distribution System

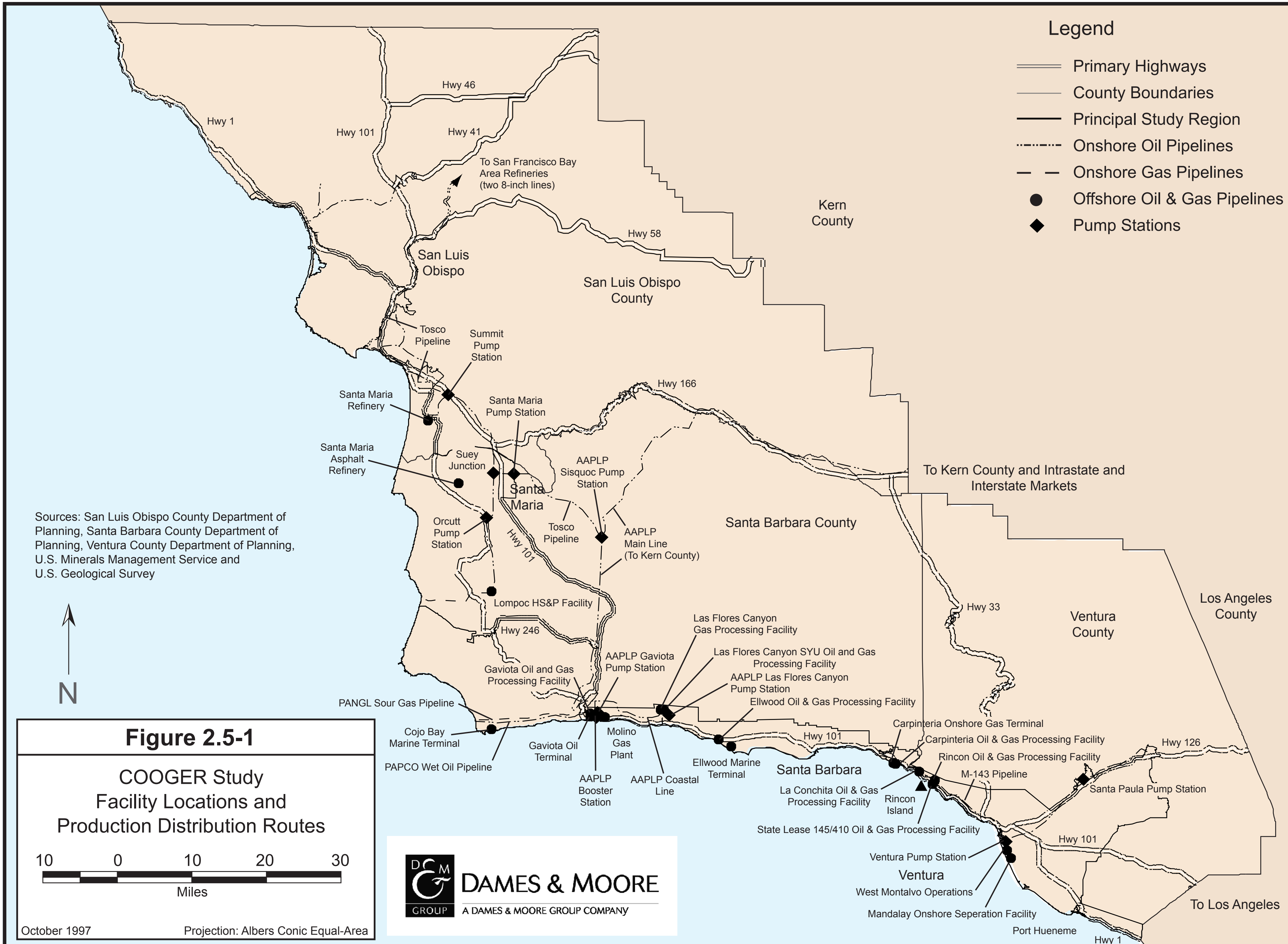


Figure 2.5-1

COOGER Study
Facility Locations and
Production Distribution Routes

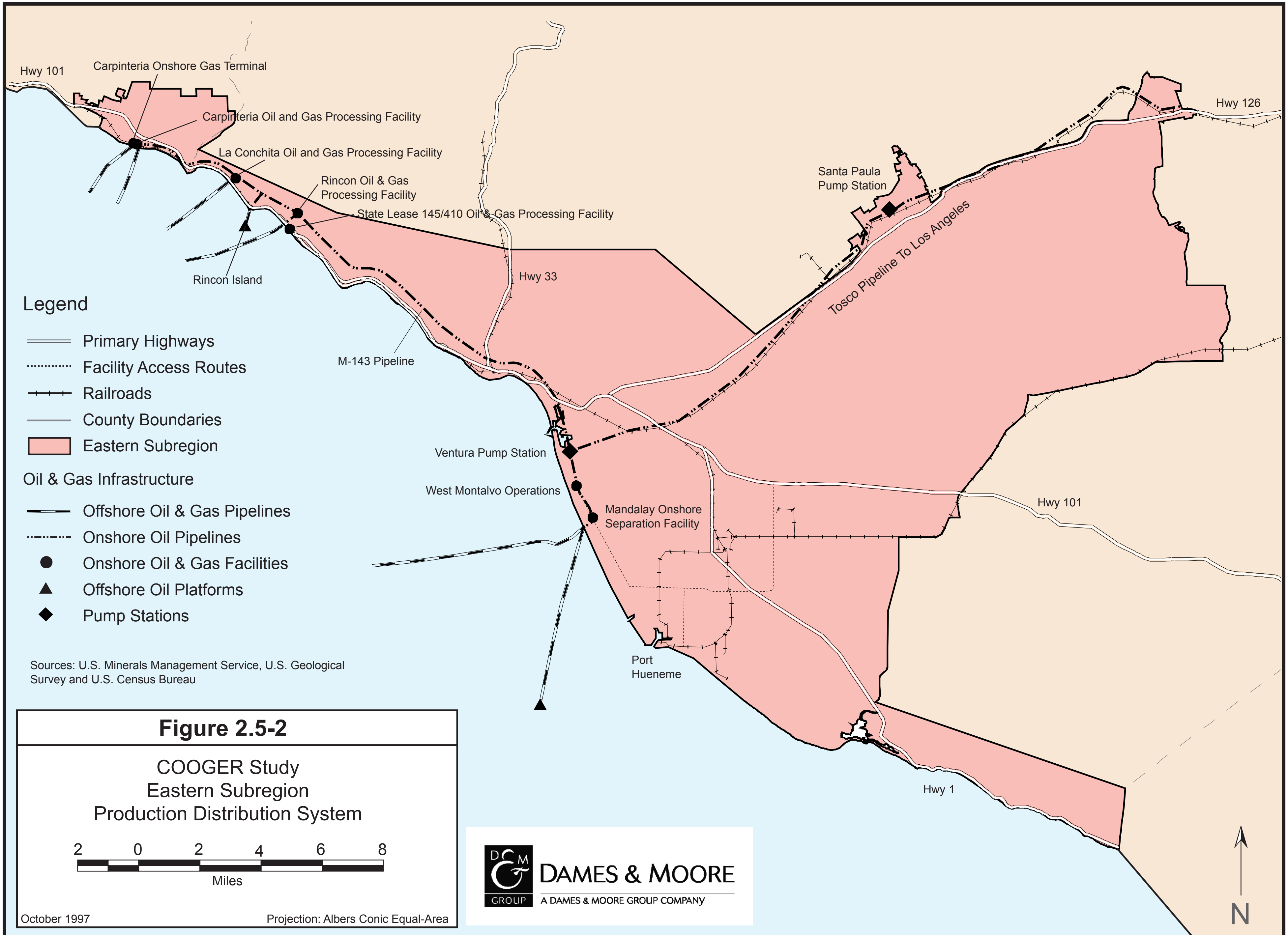


Figure 2.5-2

COOGER Study
Eastern Subregion
Production Distribution System

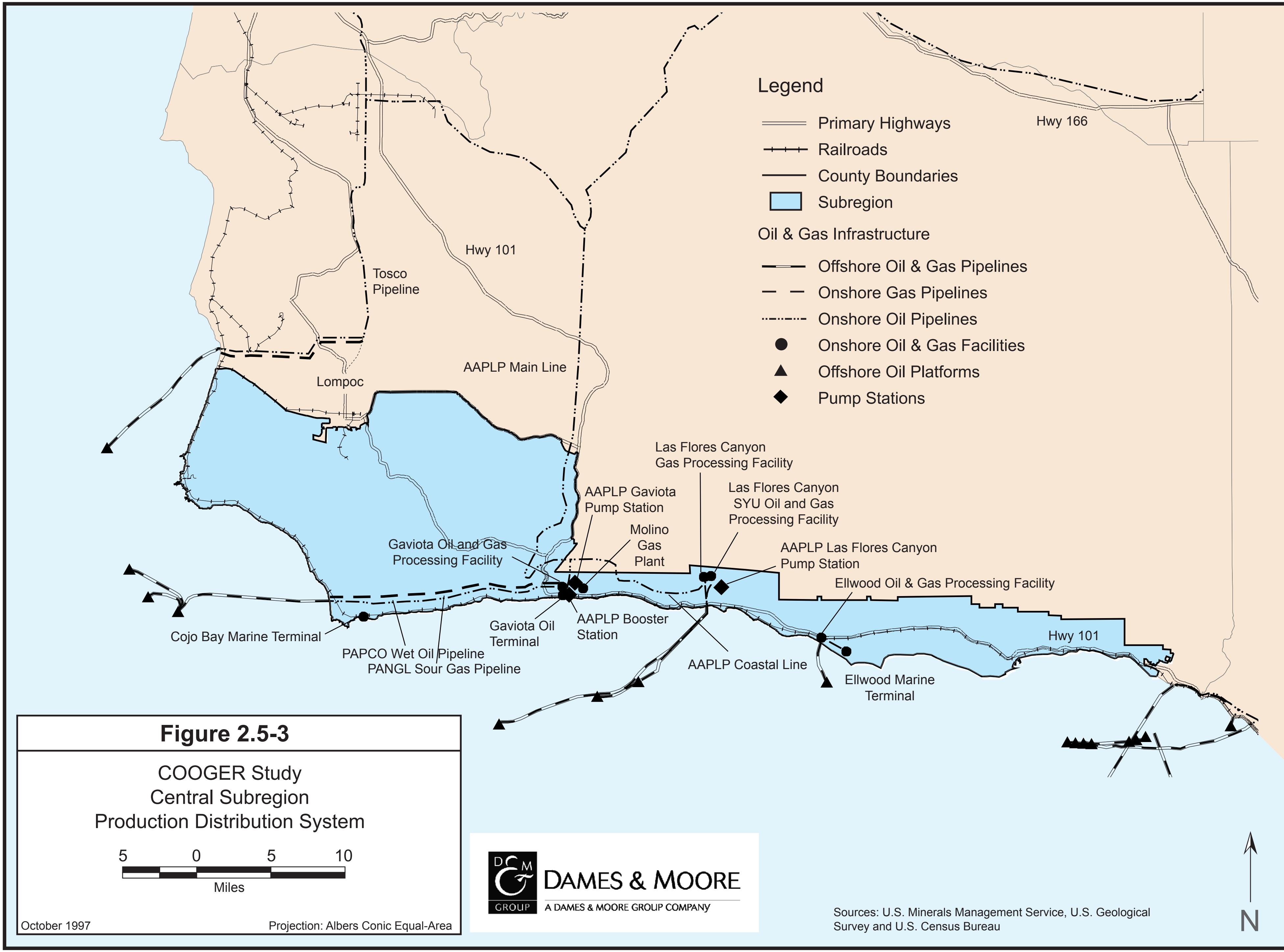


Figure 2.5-3

COOGER Study
Central Subregion
Production Distribution System

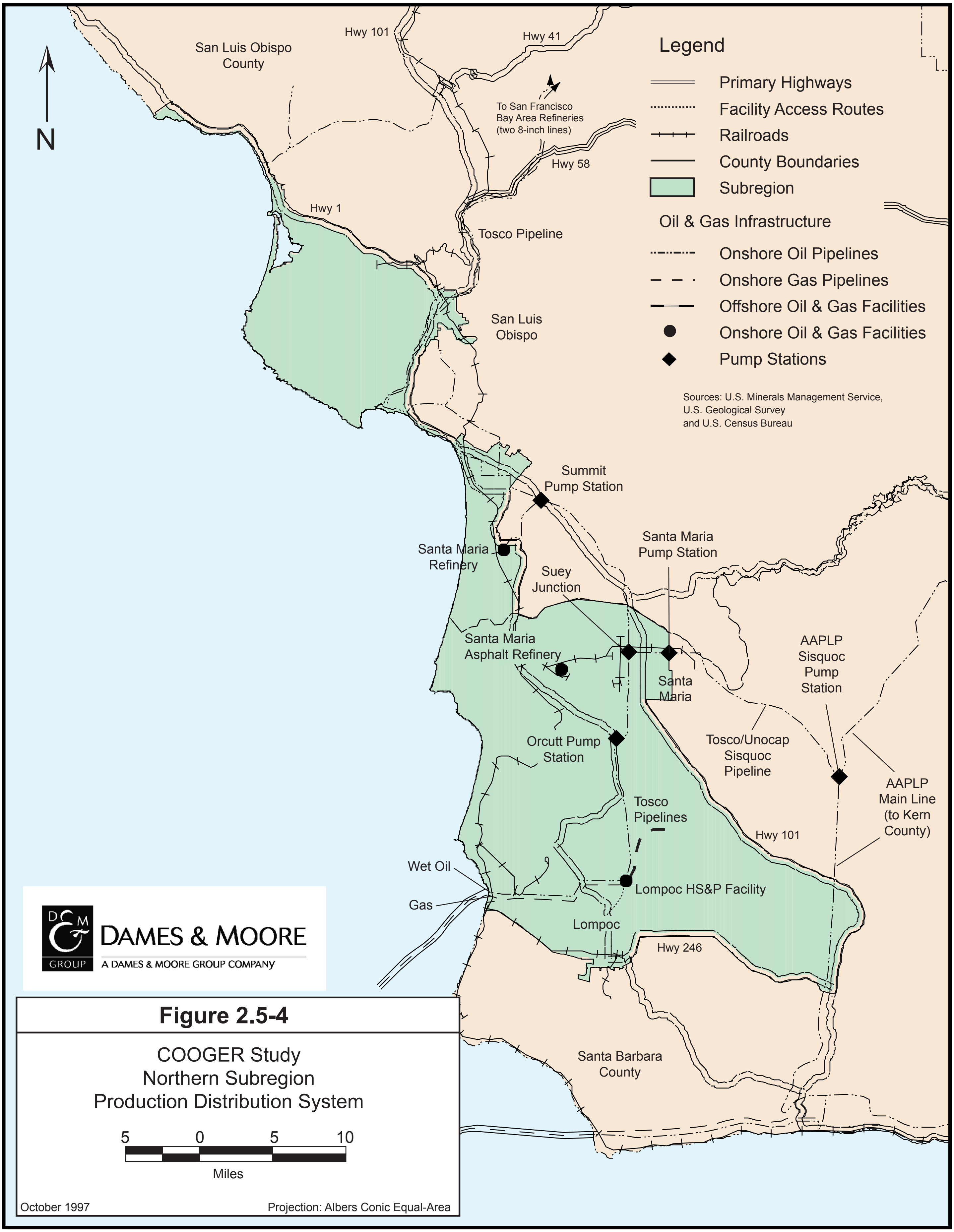
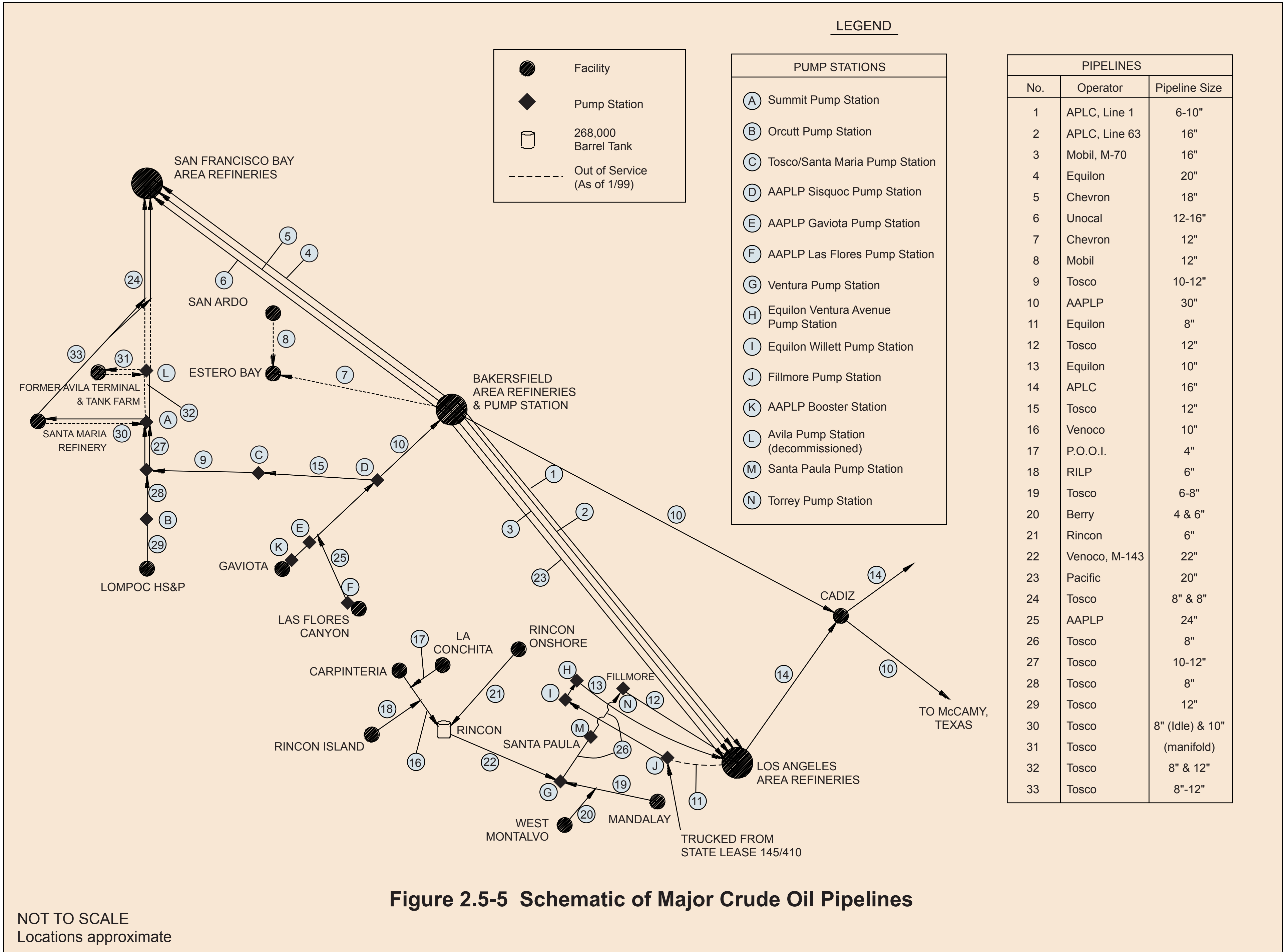


Figure 2.5-4

COOGER Study
Northern Subregion
Production Distribution System



PUMP STATIONS
A Summit Pump Station
B Orcutt Pump Station
C Tosco/Santa Maria Pump Station
D AAPLP Sisquoc Pump Station
E AAPLP Gaviota Pump Station
F AAPLP Las Flores Pump Station
G Ventura Pump Station
H Equilon Ventura Avenue Pump Station
I Equilon Willett Pump Station
J Fillmore Pump Station
K AAPLP Booster Station
L Avila Pump Station (decommissioned)
M Santa Paula Pump Station
N Torrey Pump Station

PIPELINES

No.	Operator	Pipeline Size
1	APLC, Line 1	6-10"
2	APLC, Line 63	16"
3	Mobil, M-70	16"
4	Equilon	20"
5	Chevron	18"
6	Unocal	12-16"
7	Chevron	12"
8	Mobil	12"
9	Tosco	10-12"
10	AAPLP	30"
11	Equilon	8"
12	Tosco	12"
13	Equilon	10"
14	APLC	16"
15	Tosco	12"
16	Venoco	10"
17	P.O.O.I.	4"
18	RILP	6"
19	Tosco	6-8"
20	Berry	4 & 6"
21	Rincon	6"
22	Venoco, M-143	22"
23	Pacific	20"
24	Tosco	8" & 8"
25	AAPLP	24"
26	Tosco	8"
27	Tosco	10-12"
28	Tosco	8"
29	Tosco	12"
30	Tosco	8" (Idle) & 10"
31	Tosco	(manifold)
32	Tosco	8" & 12"
33	Tosco	8"-12"

Figure 2.5-5 Schematic of Major Crude Oil Pipelines

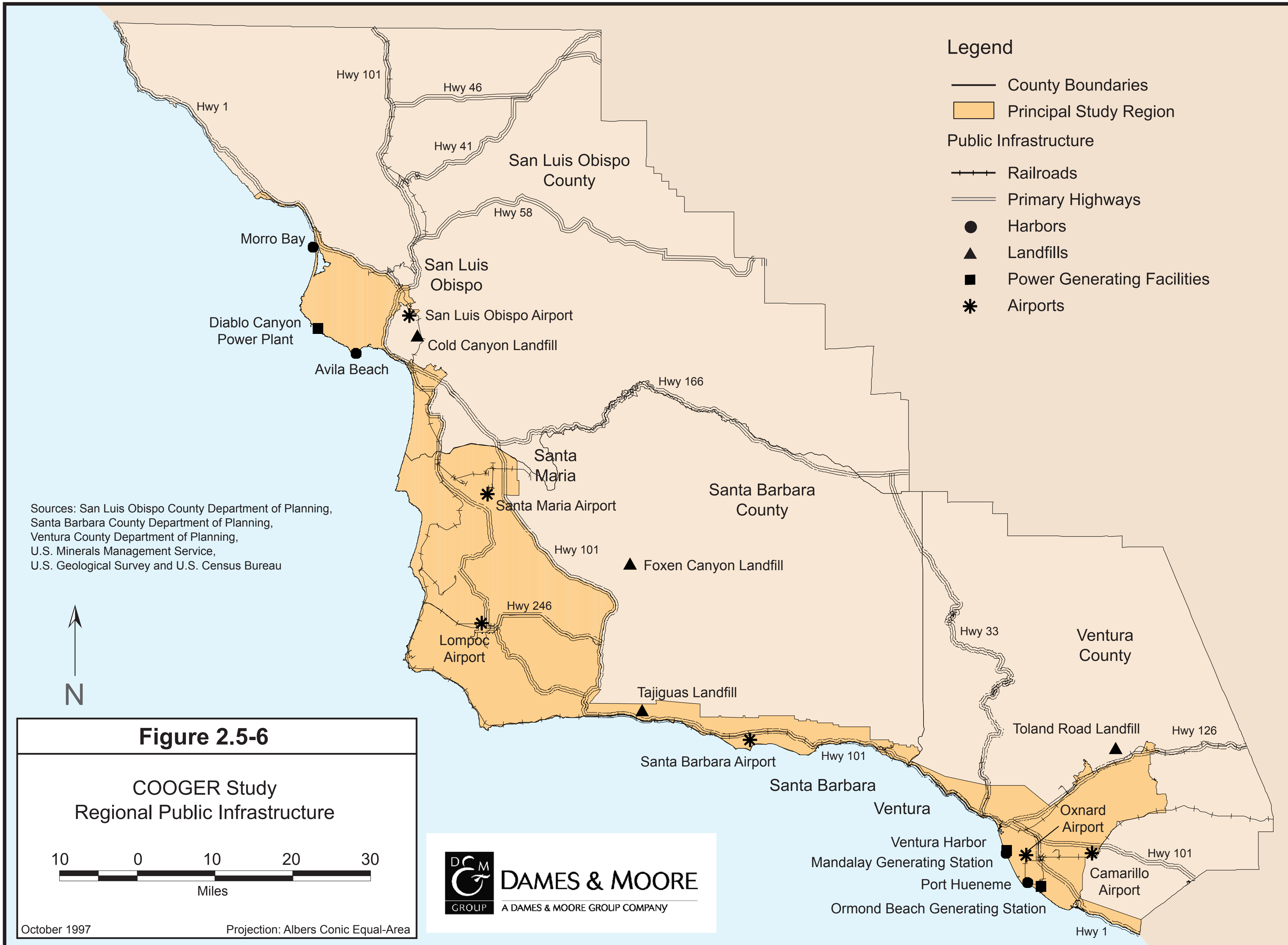


Figure 2.5-6

COOGER Study
Regional Public Infrastructure

October 1997

Projection: Albers Conic Equal-Area

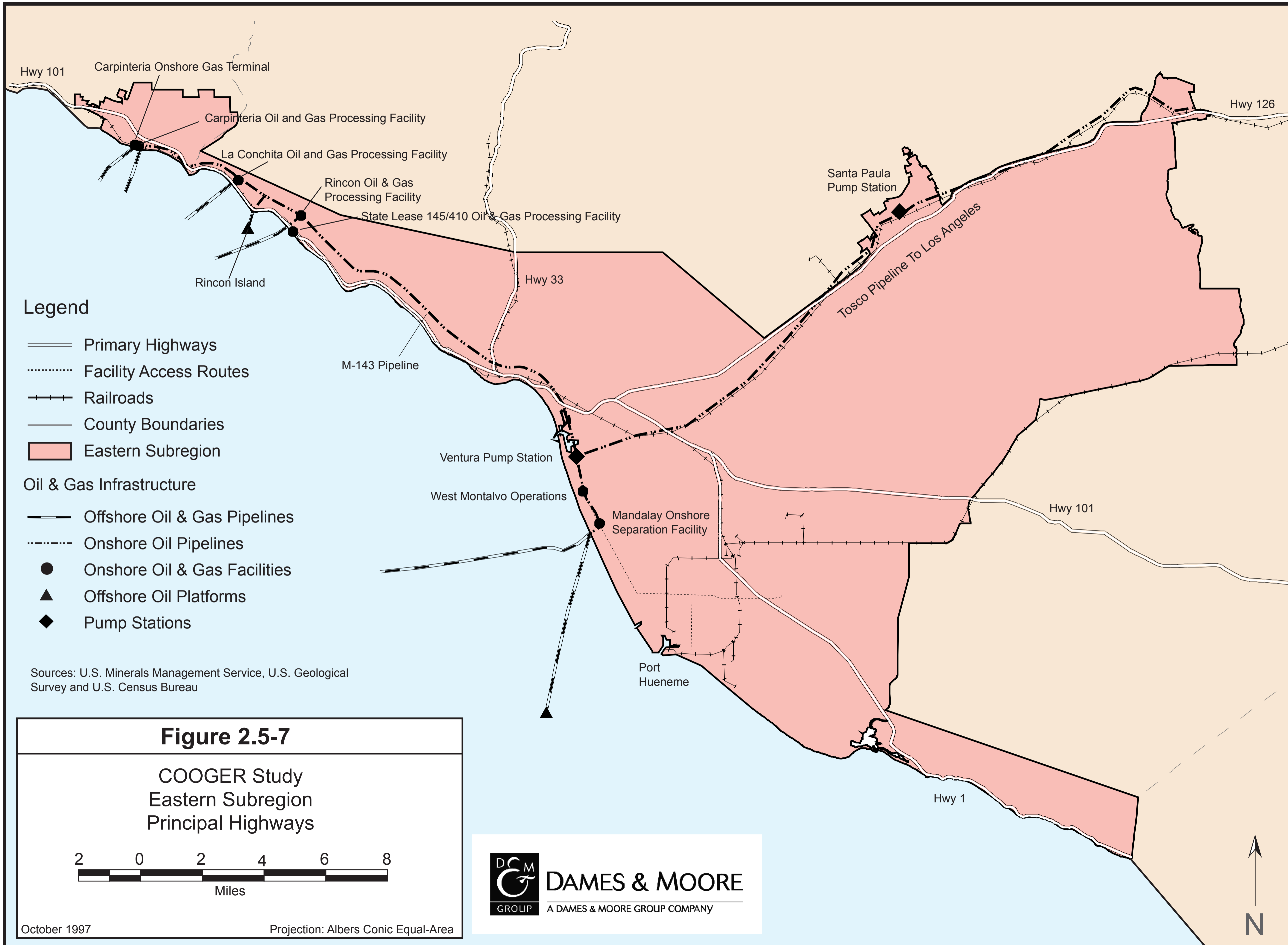


Figure 2.5-7

COOGER Study
Eastern Subregion
Principal Highways

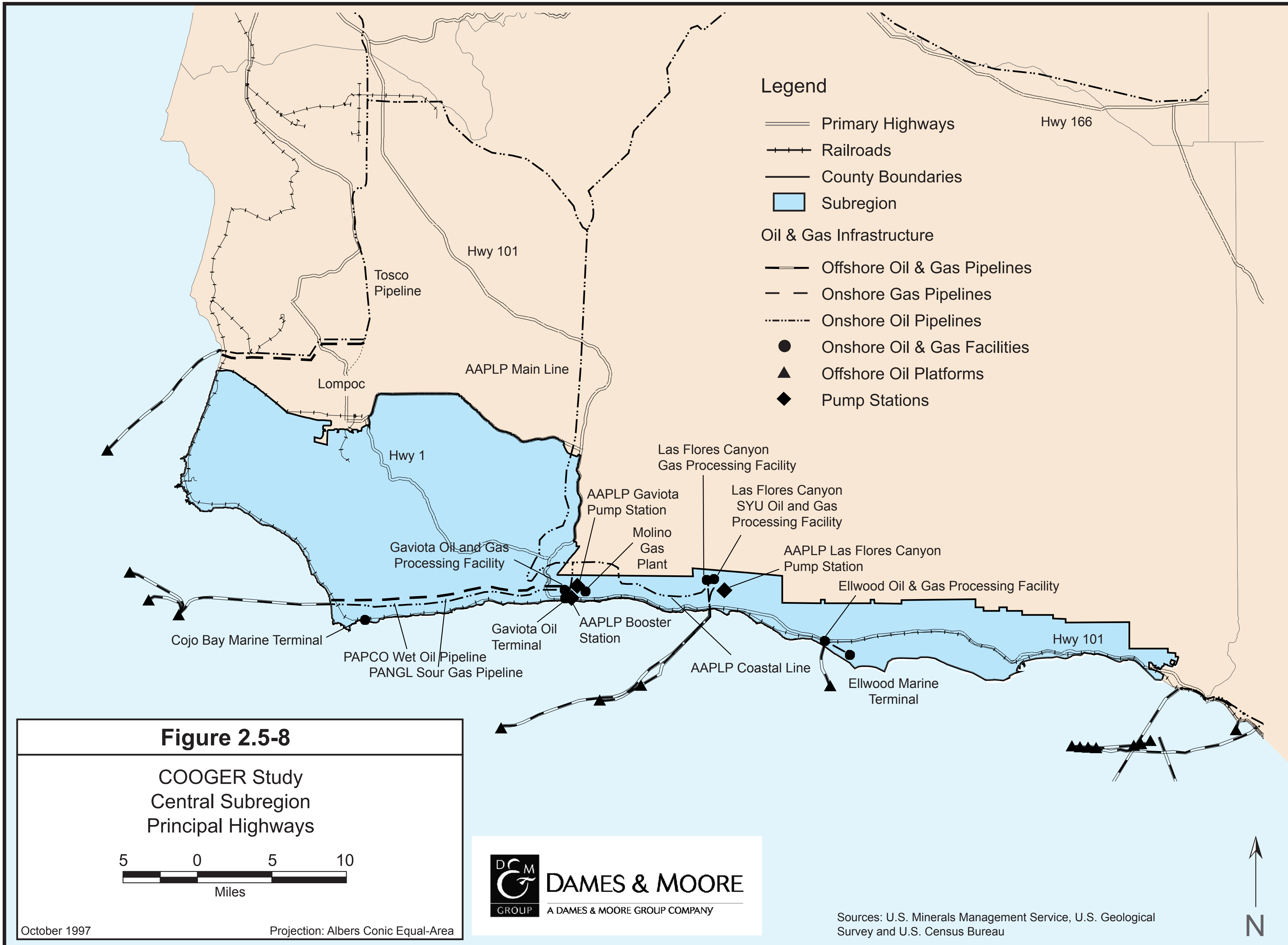


Figure 2.5-8

COOGER Study
Central Subregion
Principal Highways

October 1997

Projection: Albers Conic Equal-Area

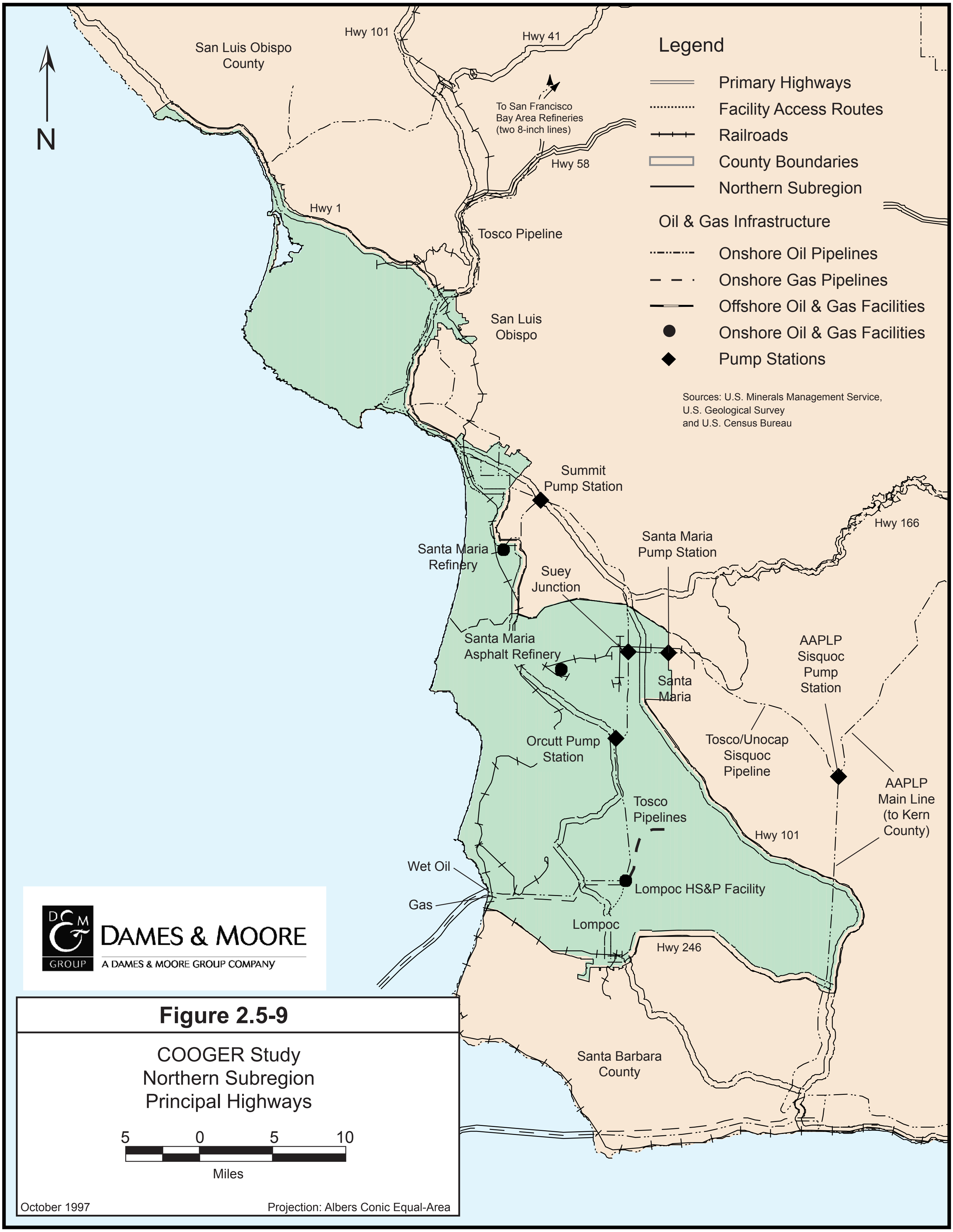


Figure 2.5-9

COOGER Study
Northern Subregion
Principal Highways

299/014

VARIATION IN POSTED OIL PRICES WITH API GRAVITY

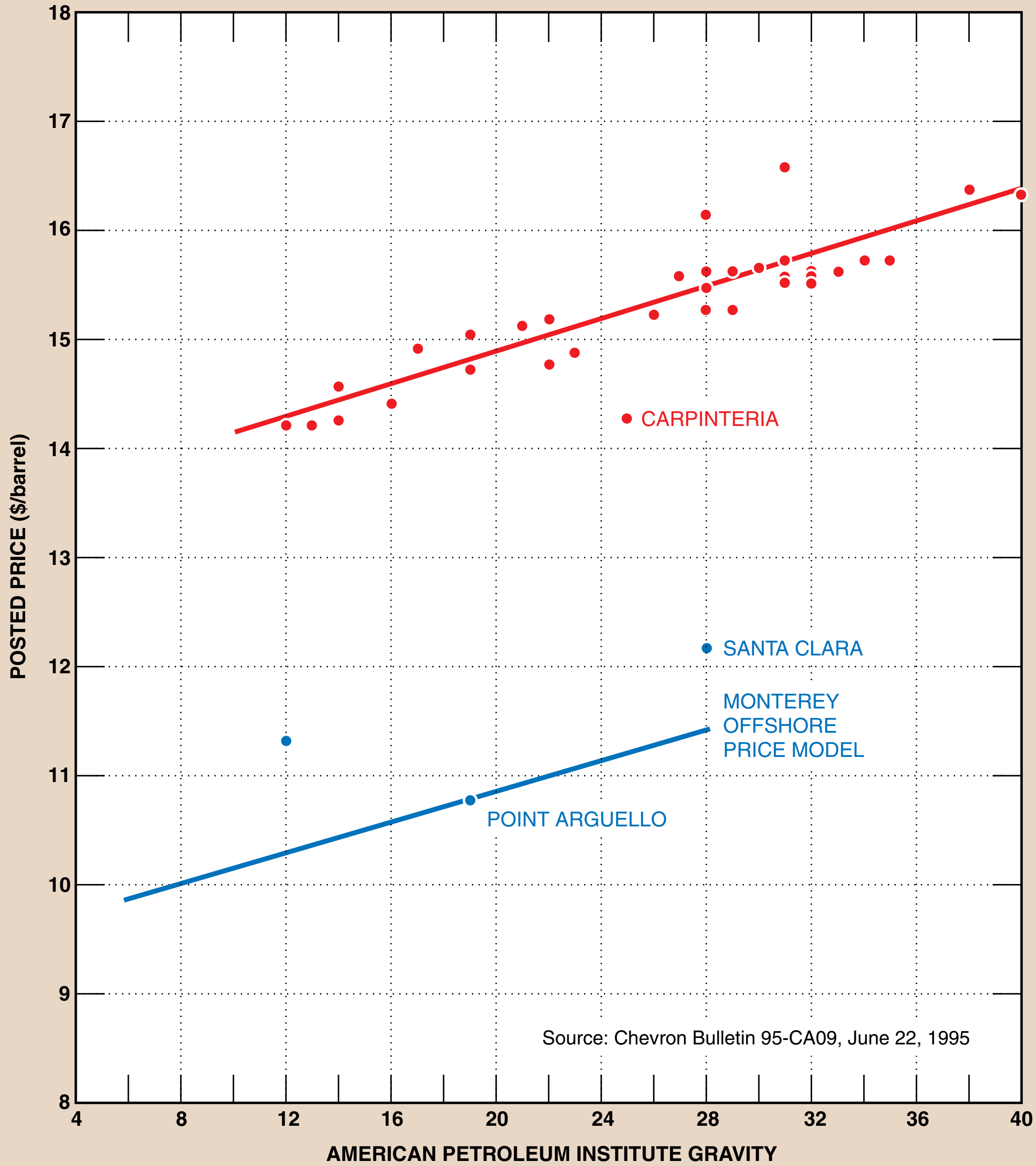


Figure 3.2-1

COOGER STUDY

DAMES & MOORE GROUP

Figure 3.2-2

COOGER Study

Potentially Developable Oil Fields
Eastern Subregion

5 0 5
Miles

October 1997
Projection: Albers Conic Equal-Area

Legend

- Primary Highways
- County Boundaries
- State Waters Boundary
- Subregion

Oil & Gas Infrastructure

- Offshore Oil & Gas Pipelines
- Onshore Oil Pipelines
- Pacific OCS Unit Boundary
- Offshore State Lease Boundary
- Onshore Oil & Gas Facilities
- Offshore Oil Platforms
- Offshore Oil Platforms (Removed 1996)
- Offshore Oil & Gas Fields
- Potentially Developable Oil Fields

Sources: U.S. Management Service, U.S. Geological Survey and California State Lands Commission

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N

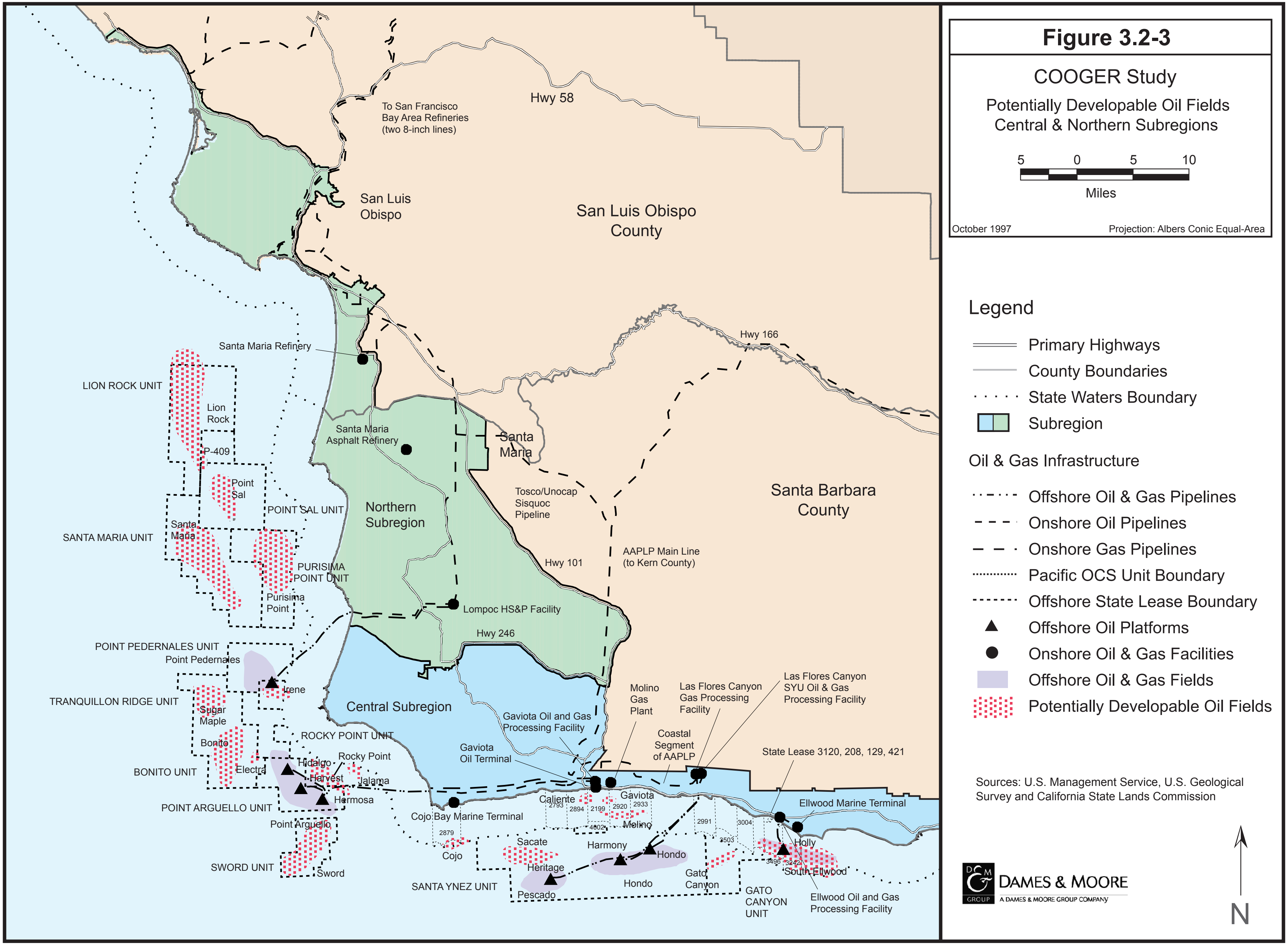
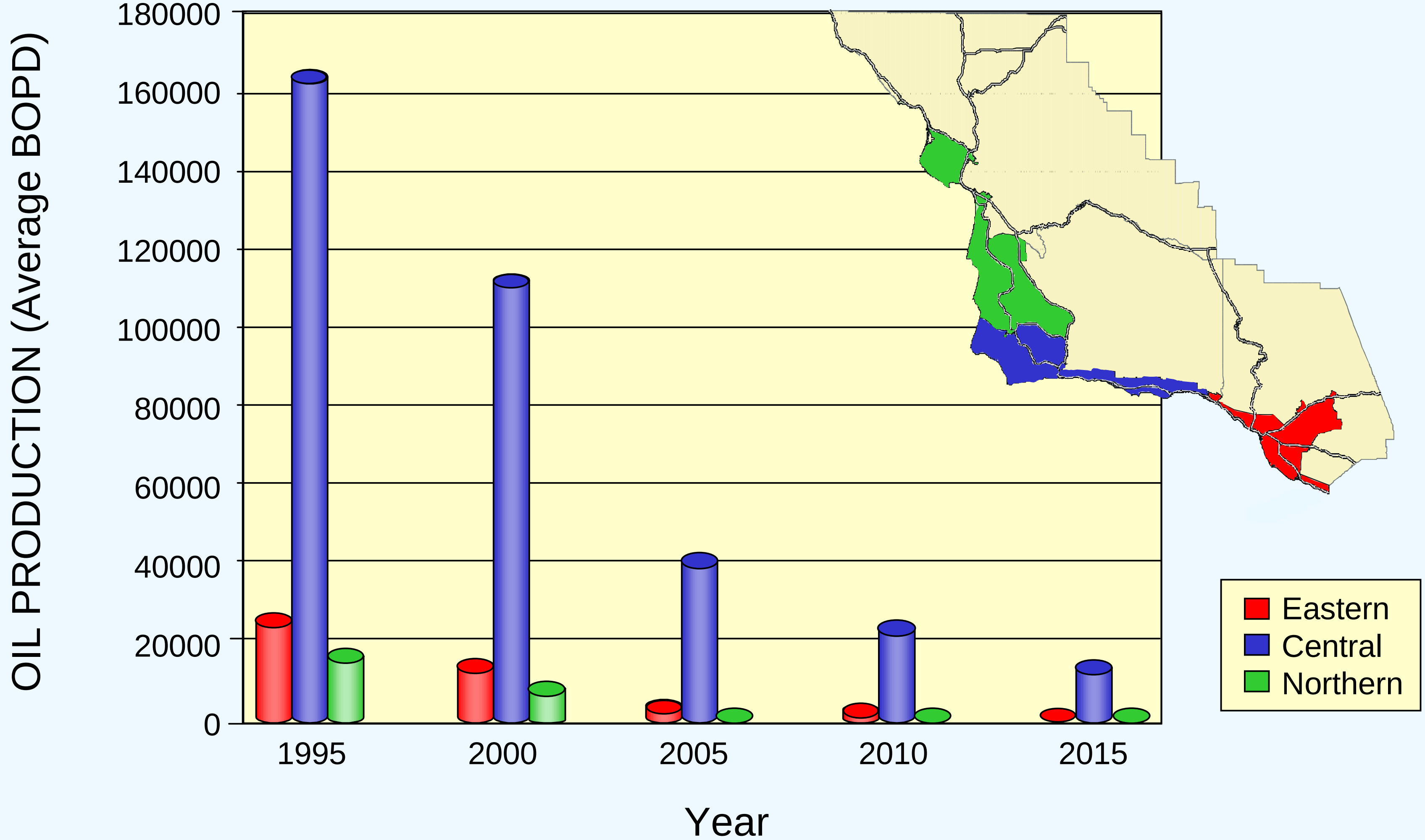


Figure 3.2-3
COOGER Study
Potentially Developable Oil Fields
Central & Northern Subregions
5 0 5 10
Miles
October 1997
Projection: Albers Conic Equal-Area
Legend
Primary Highways
County Boundaries
State Waters Boundary
Subregion
Oil & Gas Infrastructure
Offshore Oil & Gas Pipelines
Onshore Oil Pipelines
Onshore Gas Pipelines
Pacific OCS Unit Boundary
Offshore State Lease Boundary
Offshore Oil Platforms
Onshore Oil & Gas Facilities
Offshore Oil & Gas Fields
Potentially Developable Oil Fields
Sources: U.S. Management Service, U.S. Geological Survey and California State Lands Commission
DAMES & MOORE
A DAMES & MOORE GROUP COMPANY
N
To San Francisco Bay Area Refineries (two 8-inch lines)
Hwy 58
San Luis Obispo
San Luis Obispo County
Hwy 166
Santa Maria Refinery
LION ROCK UNIT
Lion Rock
P-409
Santa Maria Asphalt Refinery
Santa Maria
Point Sal
POINT SAL UNIT
Northern Subregion
Tosco/Unocap Sisquoc Pipeline
Santa Barbara County
SANTA MARIA UNIT
Santa Maria
PURISIMA POINT UNIT
Purisima Point
Hwy 101
AAPLP Main Line (to Kern County)
Lompoc HS&P Facility
Hwy 246
POINT PEDERNALES UNIT
Point Pedernales
Irene
TRANQUILLON RIDGE UNIT
Sugar Maple
Central Subregion
Gaviota Oil and Gas Processing Facility
Molino Gas Plant
Las Flores Canyon Gas Processing Facility
Las Flores Canyon SYU Oil & Gas Processing Facility
ROCKY POINT UNIT
Bonito
Coastal Segment of AAPLP
Rocky Point
Gaviota Oil Terminal
State Lease 3120, 208, 129, 421
BONITO UNIT
Hidalgo
Electra
Harvest
Jalama
Hermosa
POINT ARGUELLO UNIT
Caliente
Gaviota
Cojo Bay Marine Terminal
Molino
Ellwood Marine Terminal
Point Arguello
Cojo
Sacate
Harmony
Hondo
Holly
SWORD UNIT
Sword
Heritage
Gato Canyon
South Ellwood
SANTA YNEZ UNIT
Hondo
Pescado
GATO CANYON UNIT
Ellwood Oil and Gas Processing Facility

Figure 3.5-1

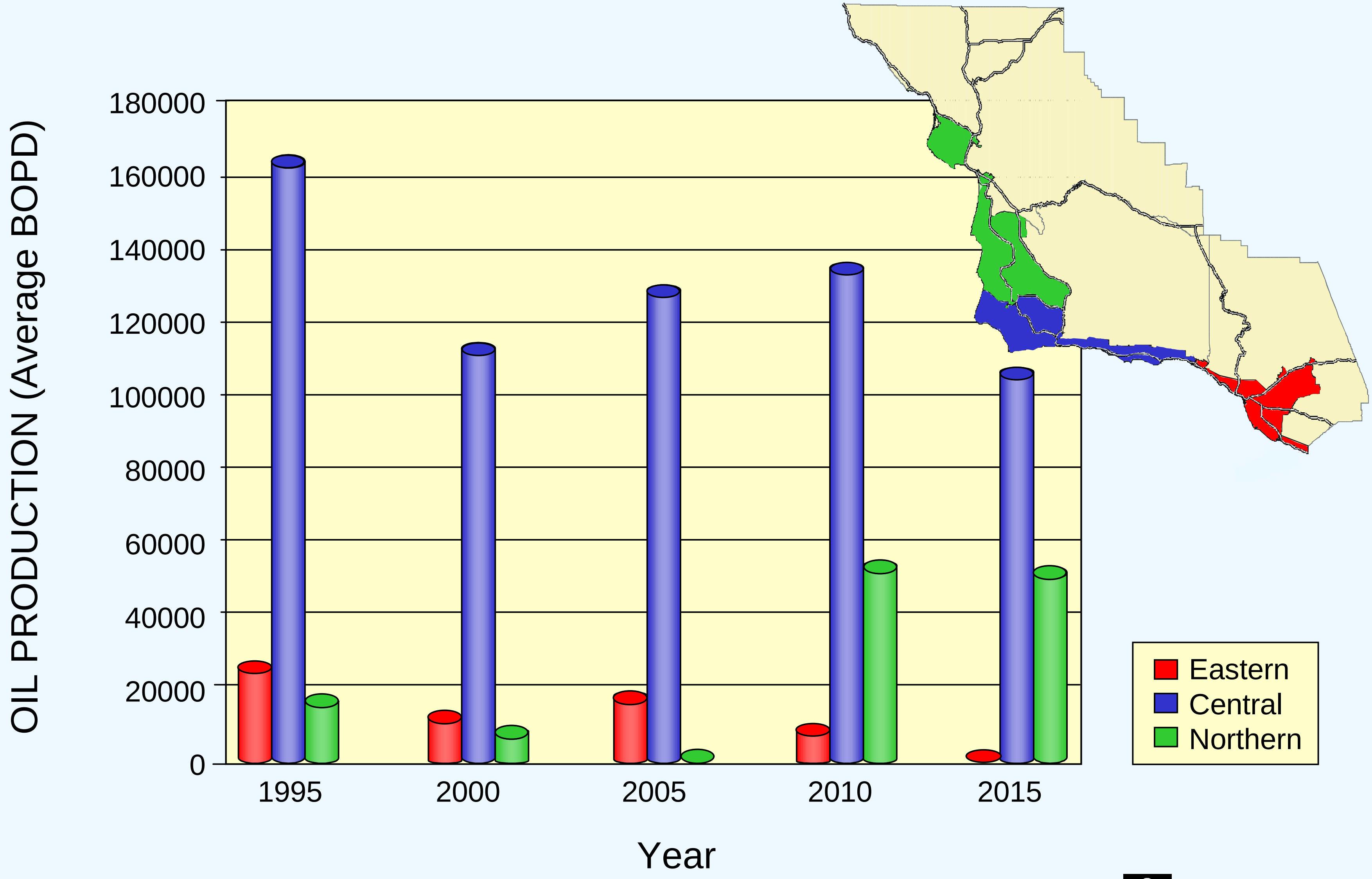
SCENARIO 1 - NO FURTHER DEVELOPMENT
COMPARISON OF OIL PRODUCTION BY SUBREGION



DAMES & MOORE GROUP

Figure 3.5-2

SCENARIO 3 - CONTINUED OFFSHORE DEVELOPMENT WITH ONSHORE FACILITY EXPANSION COMPARISON OF OIL PRODUCTION BY SUBREGION



DAMES & MOORE GROUP

FIGURE 3.5-3

EASTERN SUBREGION
EXISTING ACTIVE OIL & GAS FACILITIES

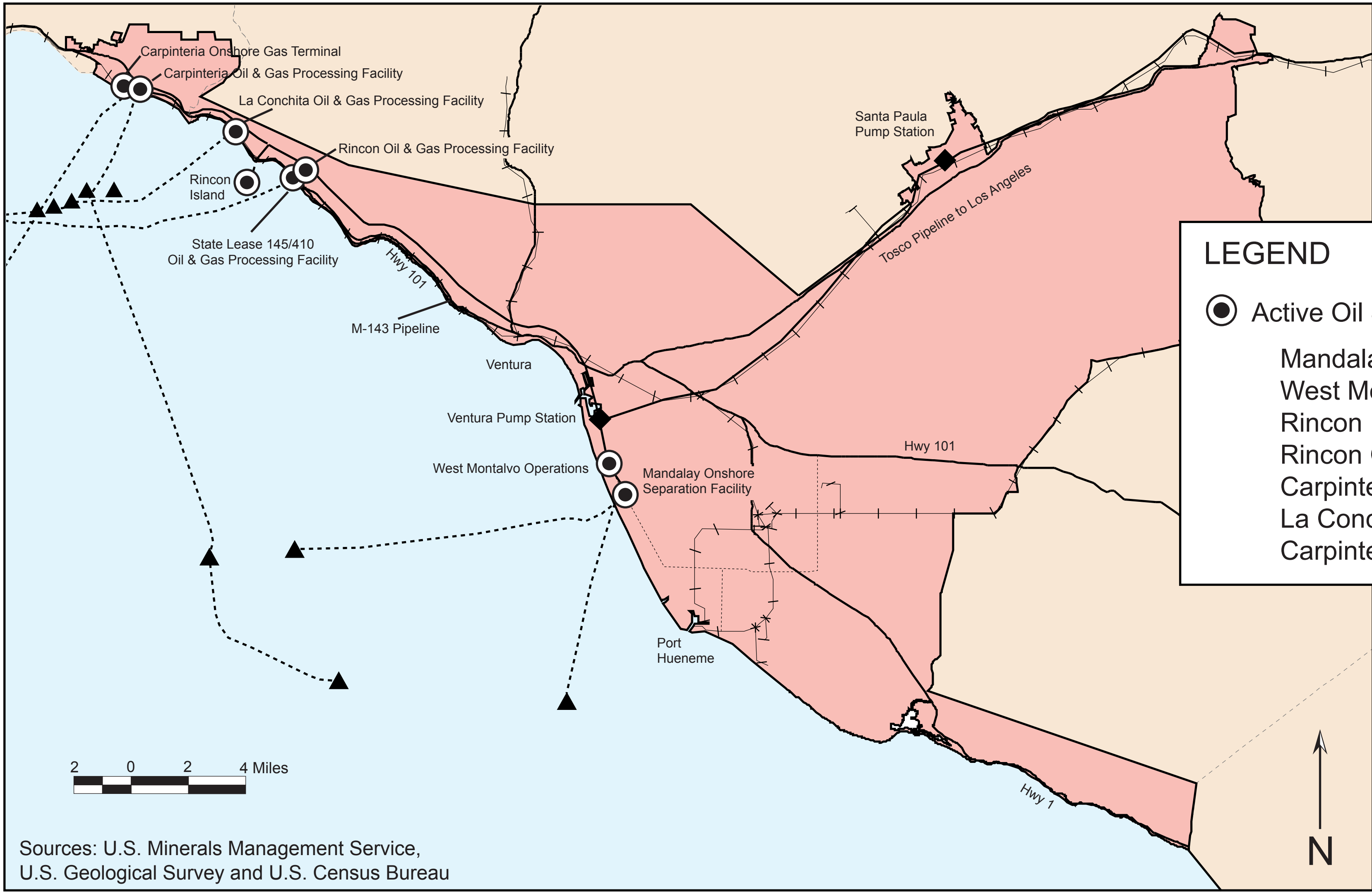


FIGURE 3.5-4

EASTERN SUBREGION
ACTIVE OIL & GAS FACILITIES - 2010
SCENARIO 1 - NO FURTHER OFFSHORE DEVELOPMENT

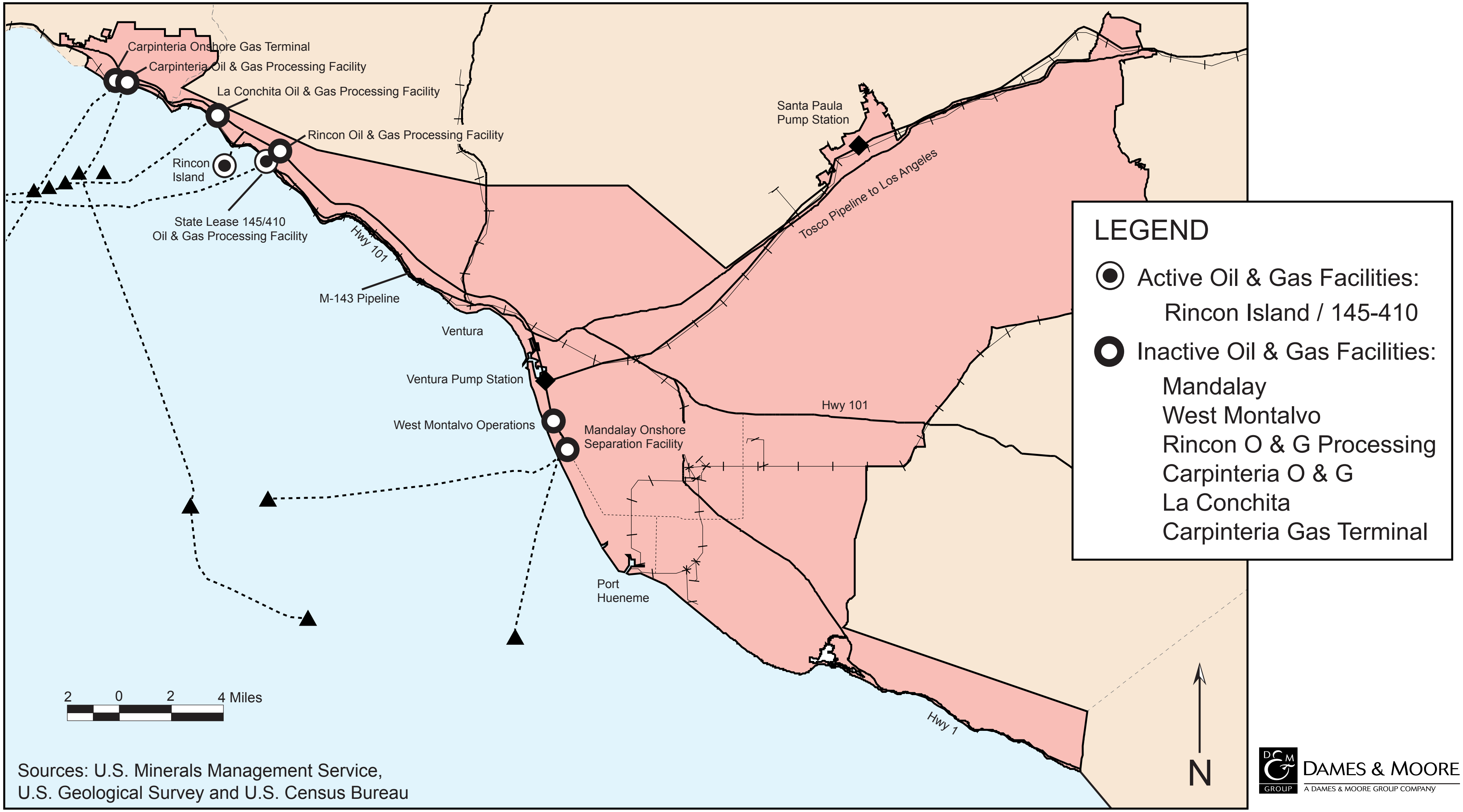


FIGURE 3.5-5

EASTERN SUBREGION
ACTIVE OIL & GAS FACILITIES - 2010
SCENARIOS 2 & 3 - CONTINUED OFFSHORE DEVELOPMENT

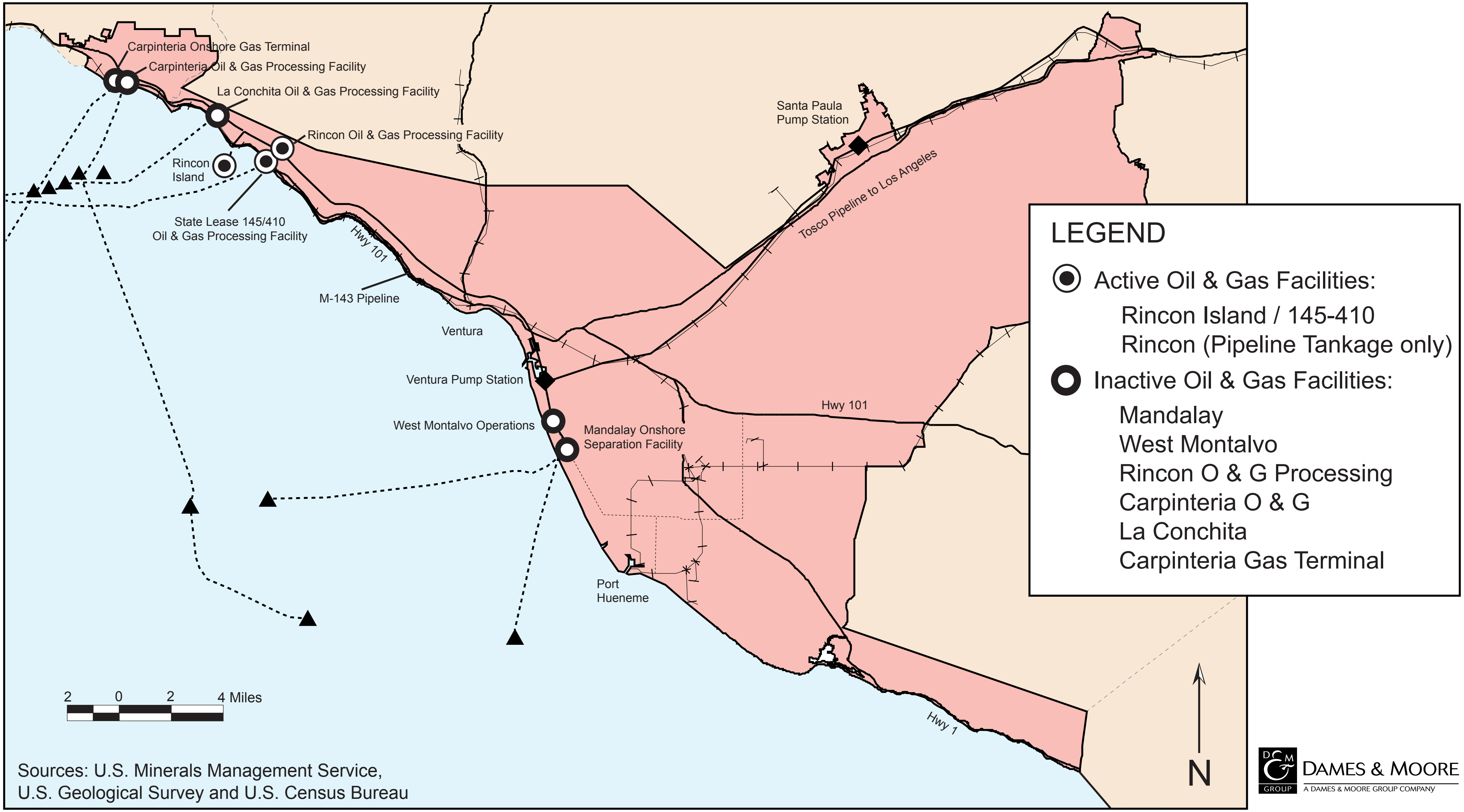
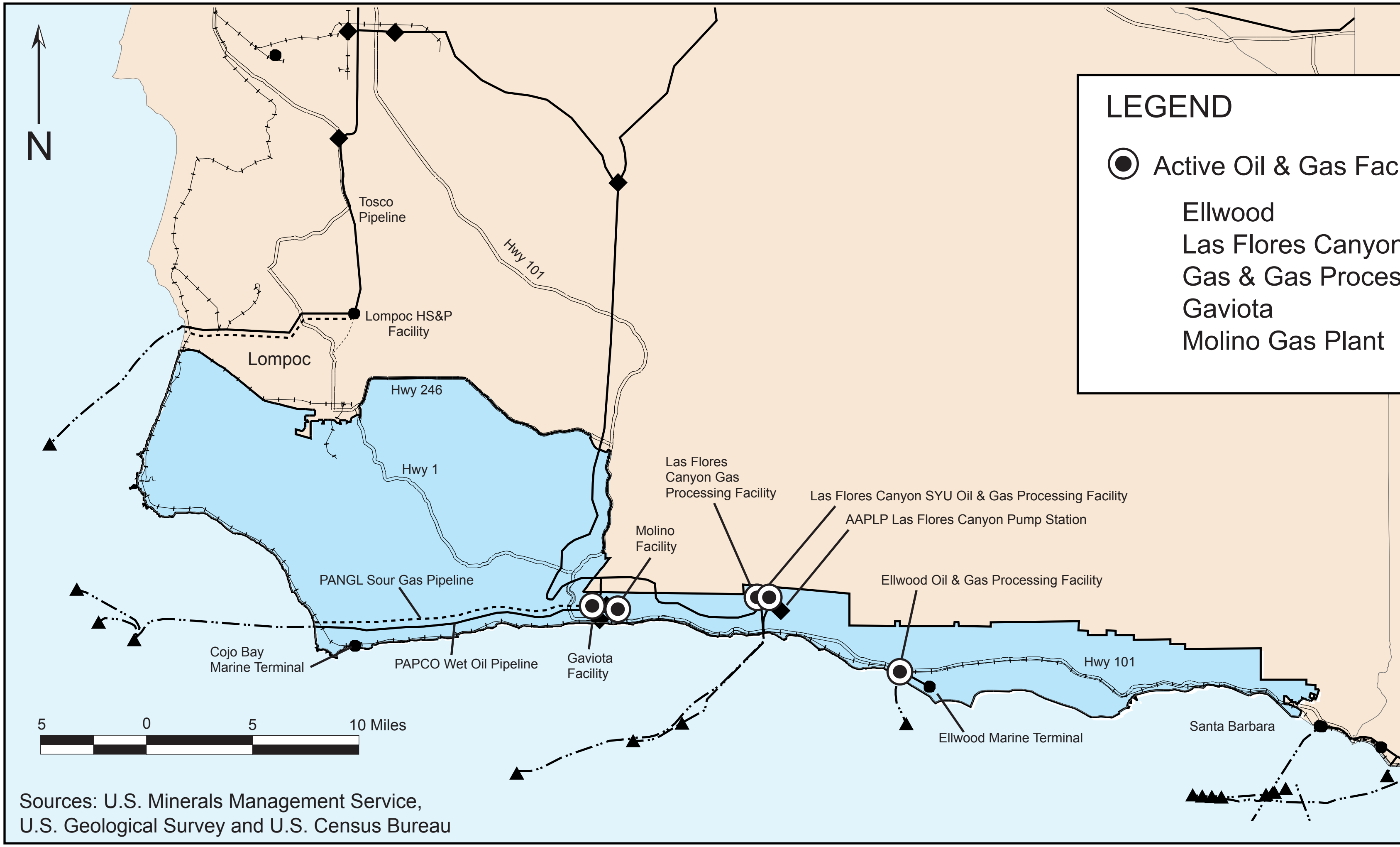


FIGURE 3.5-6

CENTRAL SUBREGION
EXISTING ACTIVE OIL & GAS FACILITIES



Sources: U.S. Minerals Management Service,
U.S. Geological Survey and U.S. Census Bureau

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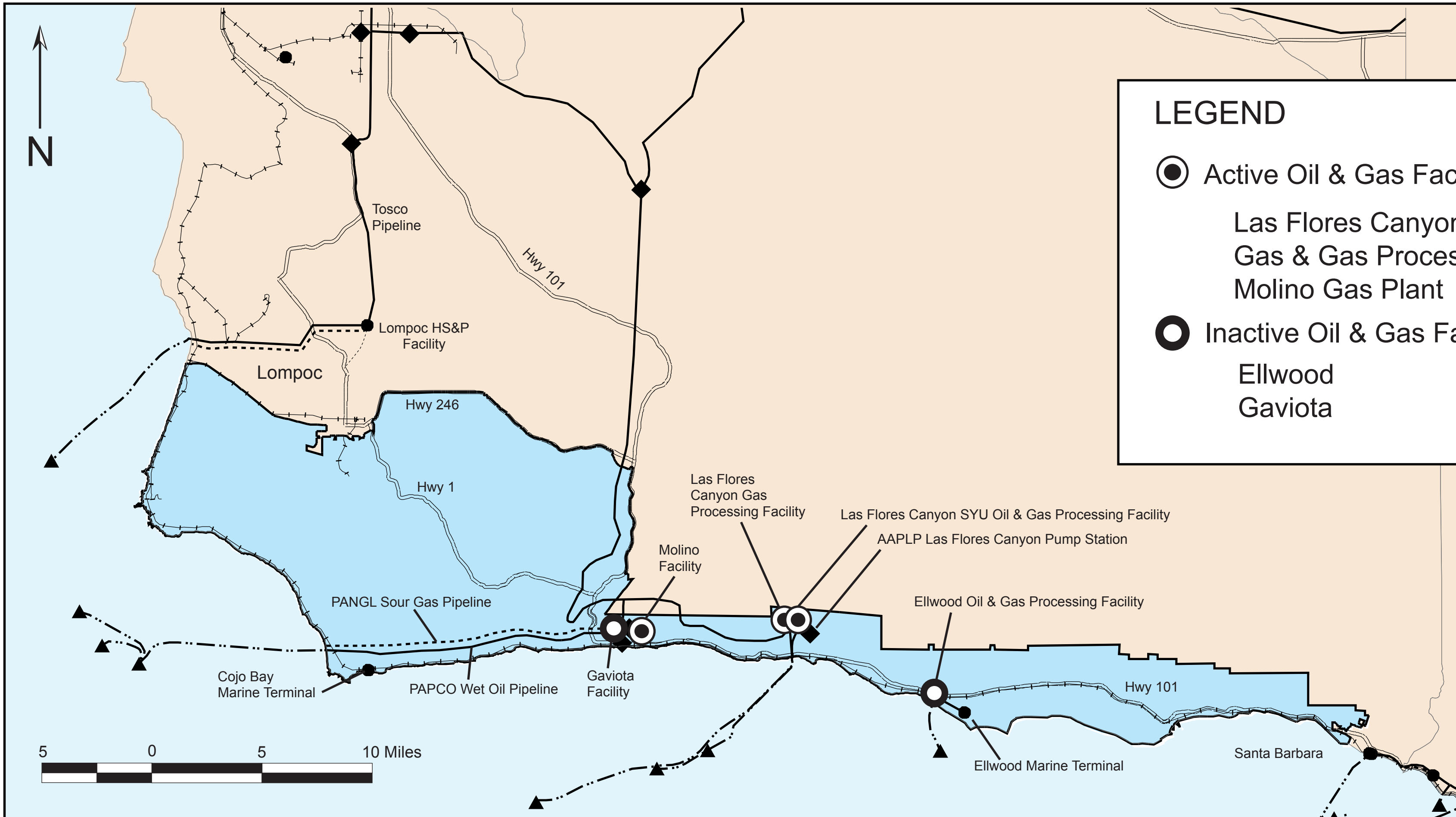
FIGURE 3.5-7

CENTRAL SUBREGION
ACTIVE OIL & GAS FACILITIES - 2010
SCENARIO 1 - NO FURTHER OFFSHORE DEVELOPMENT



Sources: U.S. Minerals Management Service, U.S. Geological Survey and U.S. Census Bureau

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FIGURE 3.5-8

CENTRAL SUBREGION
ACTIVE OIL & GAS FACILITIES - 2010
SCENARIOS 2 & 3 - CONTINUED OFFSHORE DEVELOPMENT

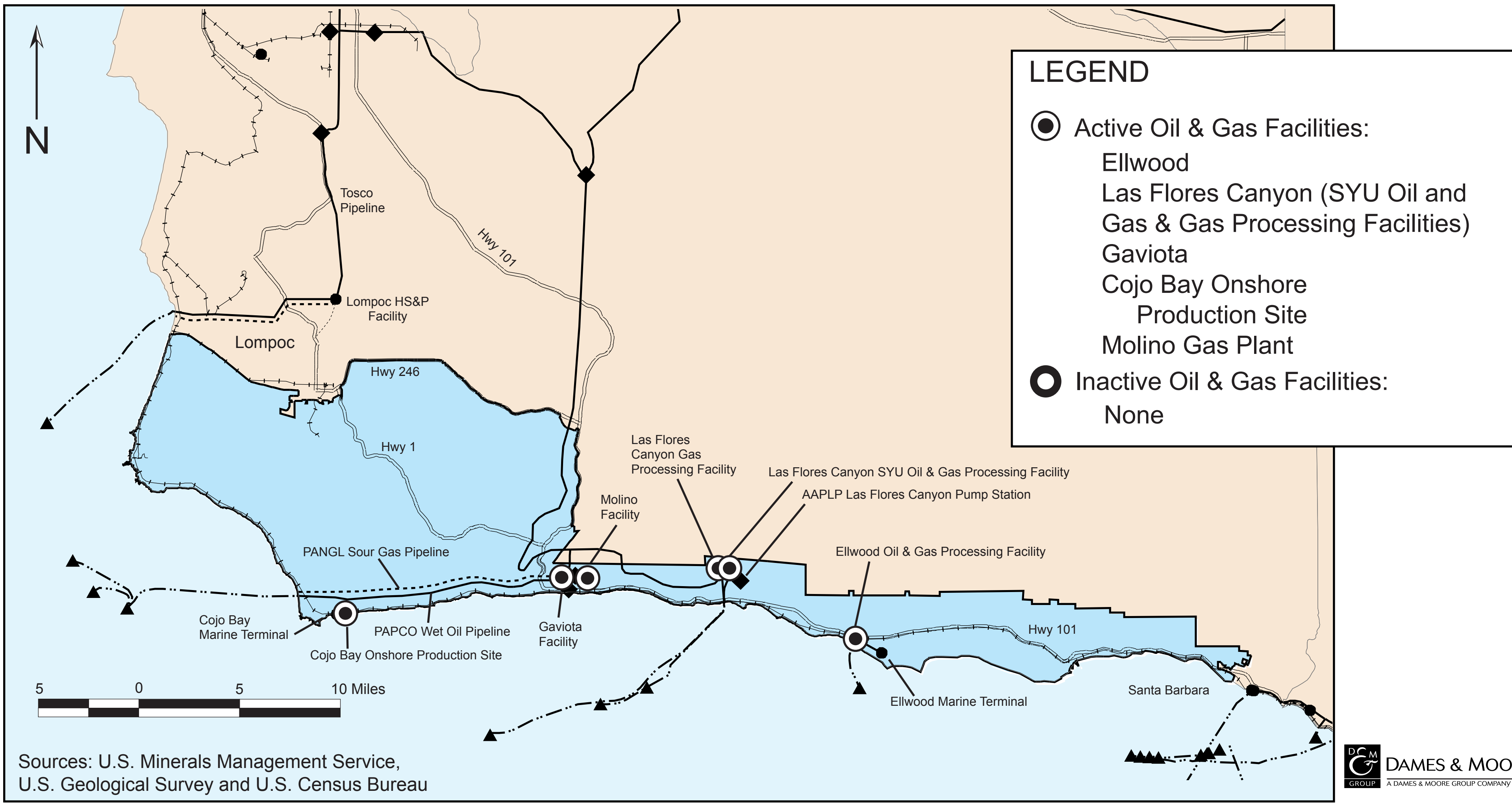

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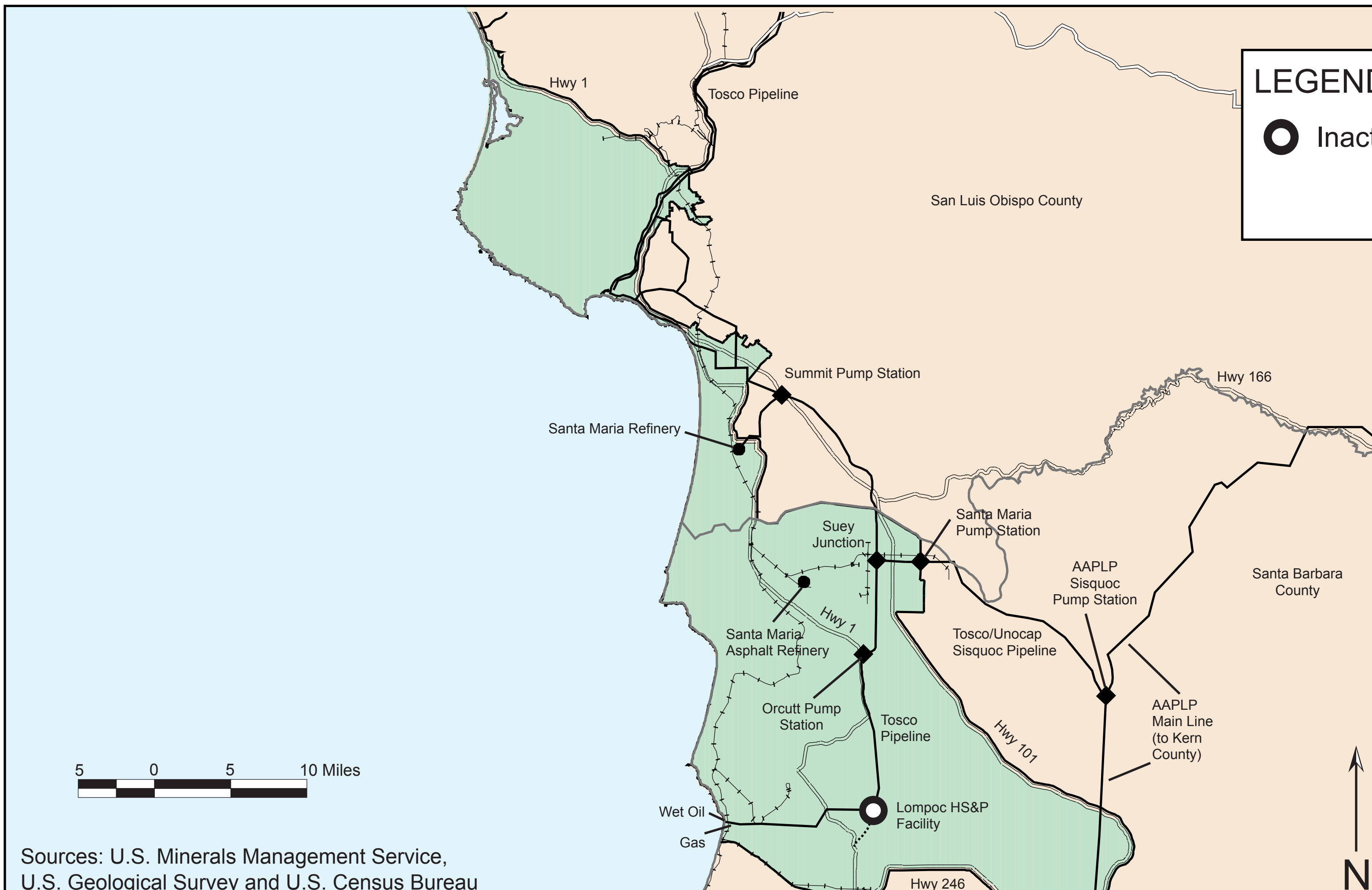
FIGURE 3.5-9

NORTHERN SUBREGION
EXISTING ACTIVE OIL & GAS FACILITIES

FIGURE 3.5-10

NORTHERN SUBREGION
ACTIVE OIL & GAS FACILITIES - 2010
SCENARIO 1 - NO FURTHER OFFSHORE DEVELOPMENT



Sources: U.S. Minerals Management Service,
U.S. Geological Survey and U.S. Census Bureau

LEGEND

Inactive Oil & Gas Facilities:
Lompoc HS&P

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FIGURE 3.5-11

NORTHERN SUBREGION
ACTIVE OIL & GAS FACILITIES - 2010
SCENARIOS 2, 3, 4, 2A, 3A & 4A - CONTINUED OFFSHORE DEVELOPMENT

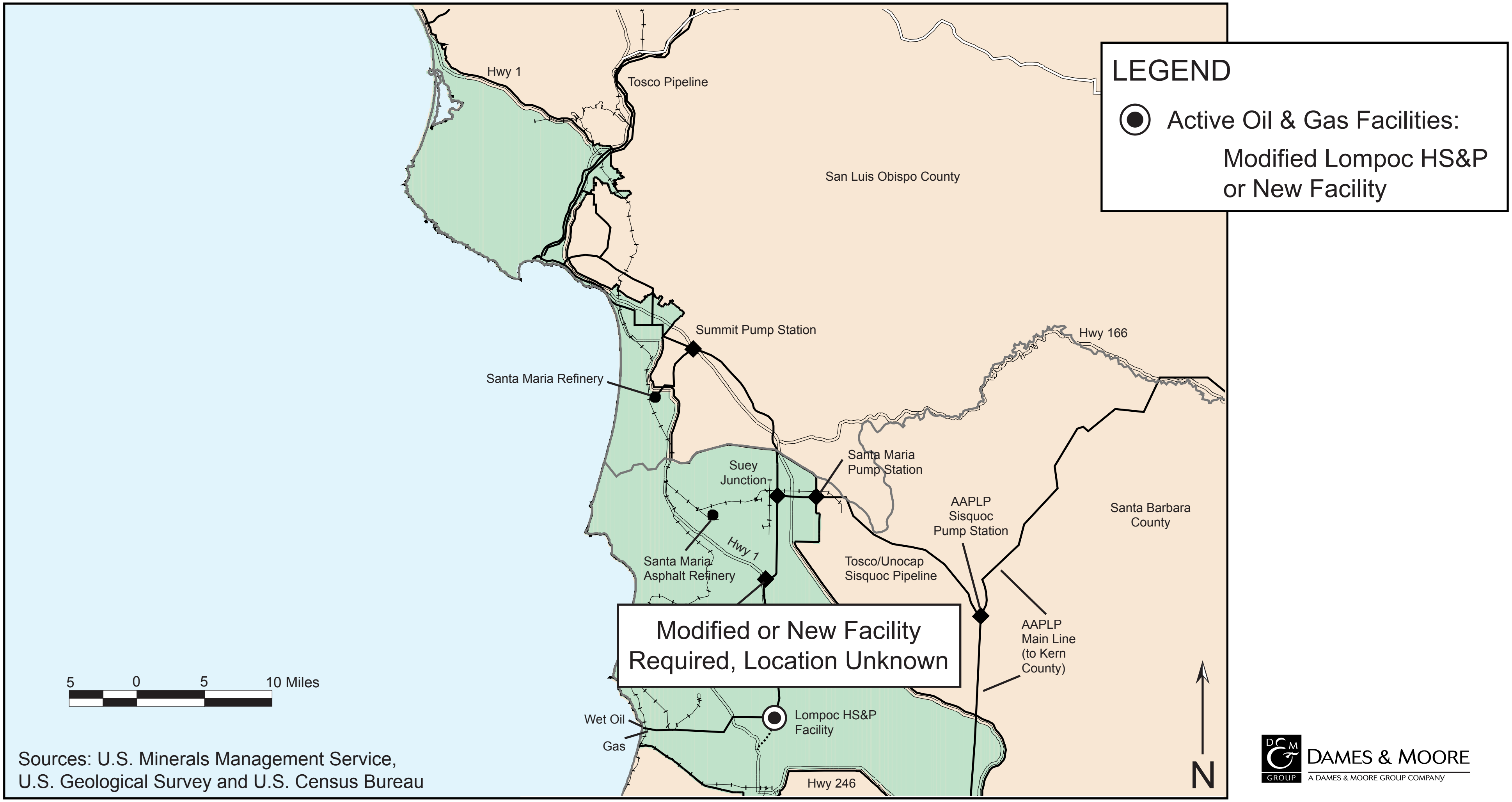

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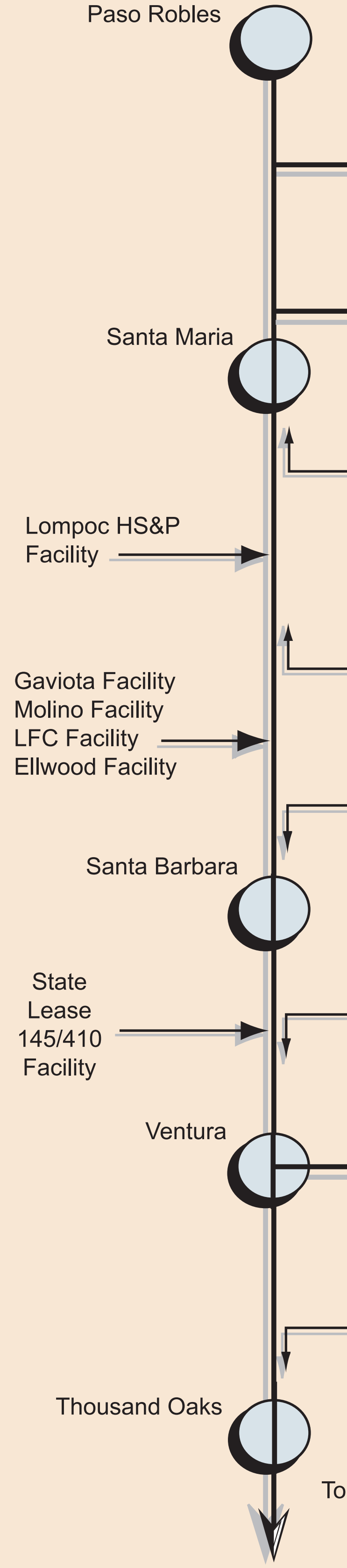
Figure 4.4-1

COOGER Study
Facility Locations and
Production Distribution Routes



Consumed Locally Within the Northern Subregion				
1998	2000	2005	2010	2015
6	6	5	4	4

Highway 166 East Into Kern County				
1998	2000	2005	2010	2015
11	4	26	6	0

Highway 101 North of Lompoc HS&P Facility				
1998	2000	2005	2010	2015
17	10	31	10	4

Highway 101 North of Gaviota-Ellwood Corridor				
1998	2000	2005	2010	2015
12	8	31	10	4

Highway 101 South of Gaviota-Ellwood Corridor				
1998	2000	2005	2010	2015
33	39	39	39	39

Highway 101 South of State Lease 145/410				
1998	2000	2005	2010	2015
42	48	48	48	39

Highway 126 East to Fillmore & L.A. County				
1998	2000	2005	2010	2015
12	13	13	13	4

Highway 101 South to L.A. County				
1998	2000	2005	2010	2015
30	35	35	35	35

FIGURE 4.4-2

Low-Case Truck Traffic
Sulfur, LPG, and Crude Oil Transport
(Average Truck Round Trips Per Week)
Scenario Combination: East: 1/Central: 1/North: 1

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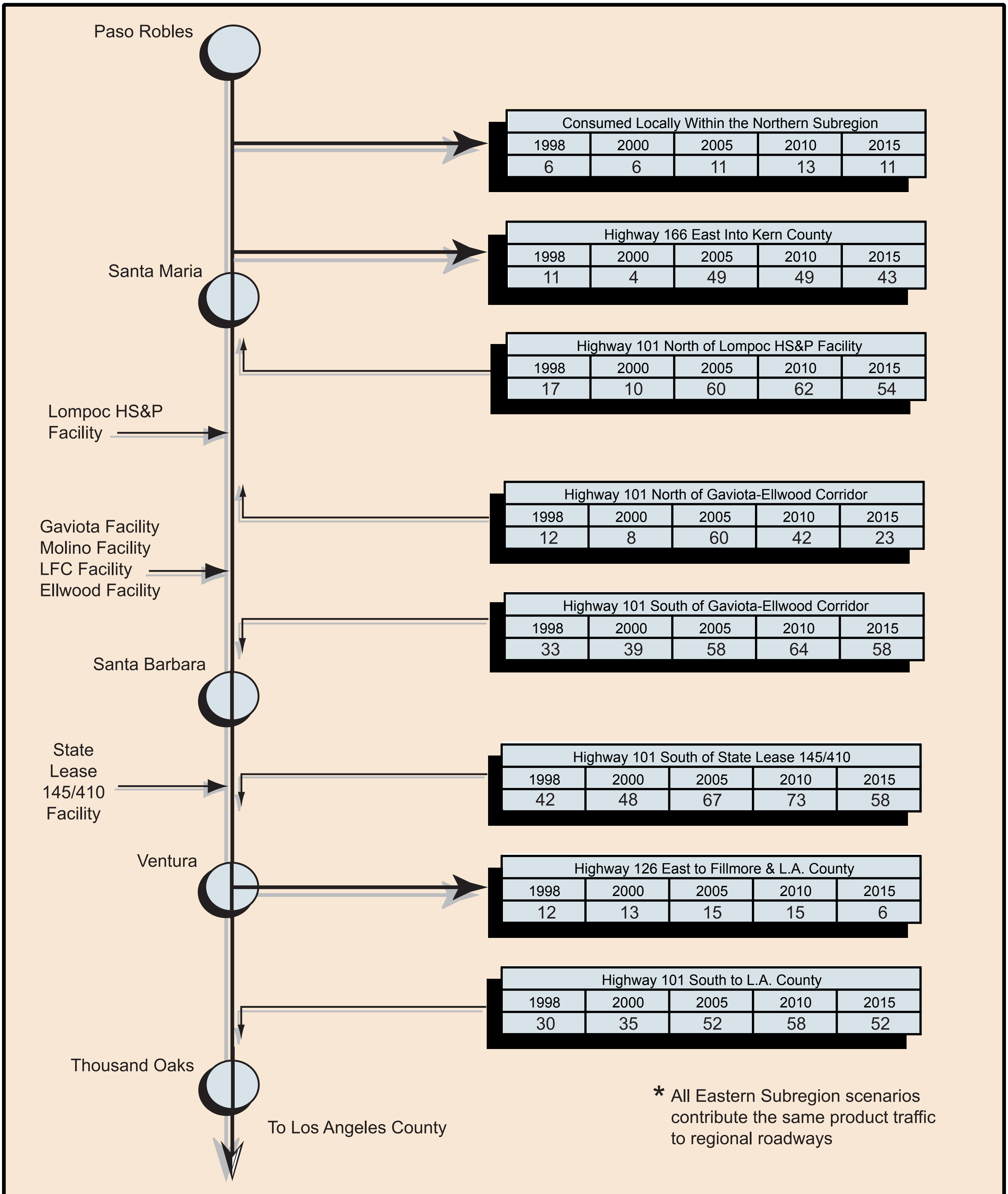

Consumed Locally Within the Northern Subregion				
1998	2000	2005	2010	2015
6	6	11	13	11

Highway 166 East Into Kern County				
1998	2000	2005	2010	2015
11	4	49	49	43

Highway 101 North of Lompoc HS&P Facility				
1998	2000	2005	2010	2015
17	10	60	62	54

Highway 101 North of Gaviota-Ellwood Corridor				
1998	2000	2005	2010	2015
12	8	60	42	23

Highway 101 South of Gaviota-Ellwood Corridor				
1998	2000	2005	2010	2015
33	39	58	64	58

Highway 101 South of State Lease 145/410				
1998	2000	2005	2010	2015
42	48	67	73	58

Highway 126 East to Fillmore & L.A. County				
1998	2000	2005	2010	2015
12	13	15	15	6

Highway 101 South to L.A. County				
1998	2000	2005	2010	2015
30	35	52	58	52

FIGURE 4.4-3

High-Case Truck Traffic

Sulfur, LPG, and Crude Oil Transport

(Average Truck Round Trips Per Week)

Scenario Combination: East: */Central: 3/North: 3

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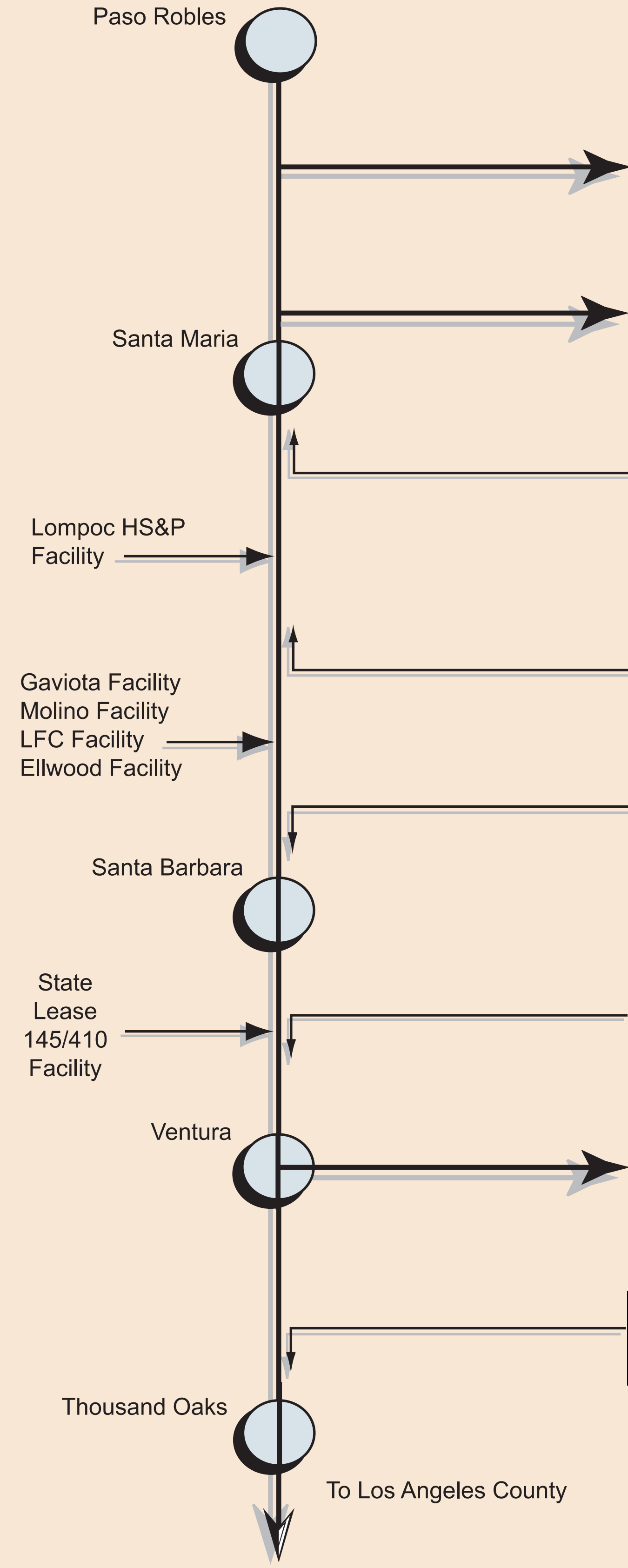

Consumed Locally Within the Northern Subregion

1998	2000	2005	2010	2015
6	6	11	13	13

Highway 166 East Into Kern County

1998	2000	2005	2010	2015
11	4	49	56	82

Highway 101 North of Lompoc HS&P Facility

1998	2000	2005	2010	2015
17	10	60	69	95

Highway 101 North of Gaviota-Ellwood Corridor

1998	2000	2005	2010	2015
12	8	60	42	23

Highway 101 South of Gaviota-Ellwood Corridor

1998	2000	2005	2010	2015
33	39	58	64	58

Highway 101 South of State Lease 145/410

1998	2000	2005	2010	2015
42	48	67	73	58

Highway 126 East to Fillmore & L.A. County

1998	2000	2005	2010	2015
12	13	15	15	6

Highway 101 South to L.A. County

1998	2000	2005	2010	2015
30	35	52	58	52

* All Eastern Subregion scenarios contribute the same product traffic to regional roadways

FIGURE 4.4-4

High-Case Truck Traffic
Sulfur, LPG, and Crude Oil Transport
(Average Truck Round Trips Per Week)
Scenario Combination: East: */Central: 3/North: 4

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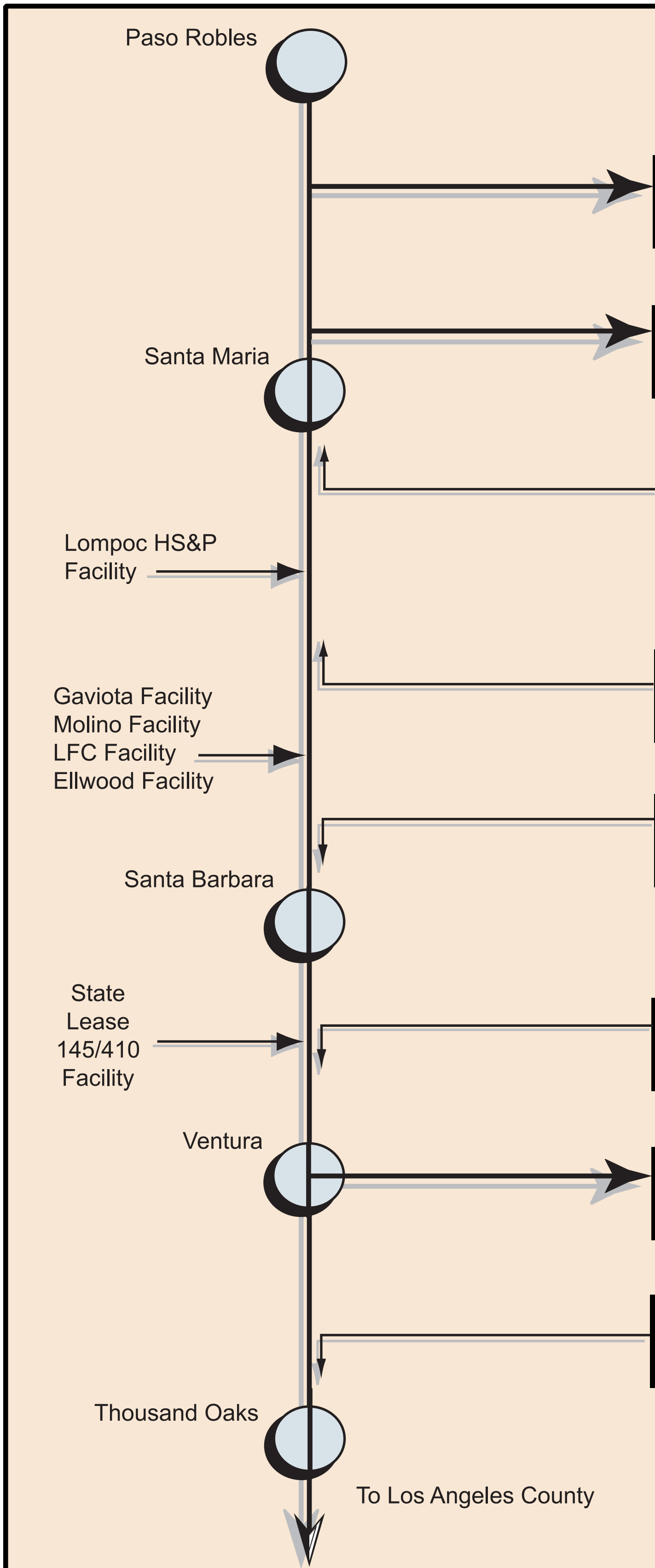

Consumed Locally Within the Northern Subregion

1998	2000	2005	2010	2015
6	6	12	14	14

Highway 166 East Into Kern County

1998	2000	2005	2010	2015
11	4	57	67	65

Highway 101 North of Lompoc HS&P Facility

1998	2000	2005	2010	2015
17	10	69	81	79

Highway 101 North of Gaviota-Ellwood Corridor

1998	2000	2005	2010	2015
12	8	59	41	22

Highway 101 South of Gaviota-Ellwood Corridor

1998	2000	2005	2010	2015
33	39	56	55	48

Highway 101 South of State Lease 145/410

1998	2000	2005	2010	2015
42	48	65	64	48

Highway 126 East to Fillmore & L.A. County

1998	2000	2005	2010	2015
12	13	14	14	5

Highway 101 South to L.A. County

1998	2000	2005	2010	2015
30	35	51	50	43

* All Eastern Subregion scenarios contribute the same product traffic to regional roadways

FIGURE 4.4-5

High-Case Truck Traffic
Sulfur, LPG, and Crude Oil Transport
(Average Truck Round Trips Per Week)
Scenario Combination: East: */Central: 4/North: 3A

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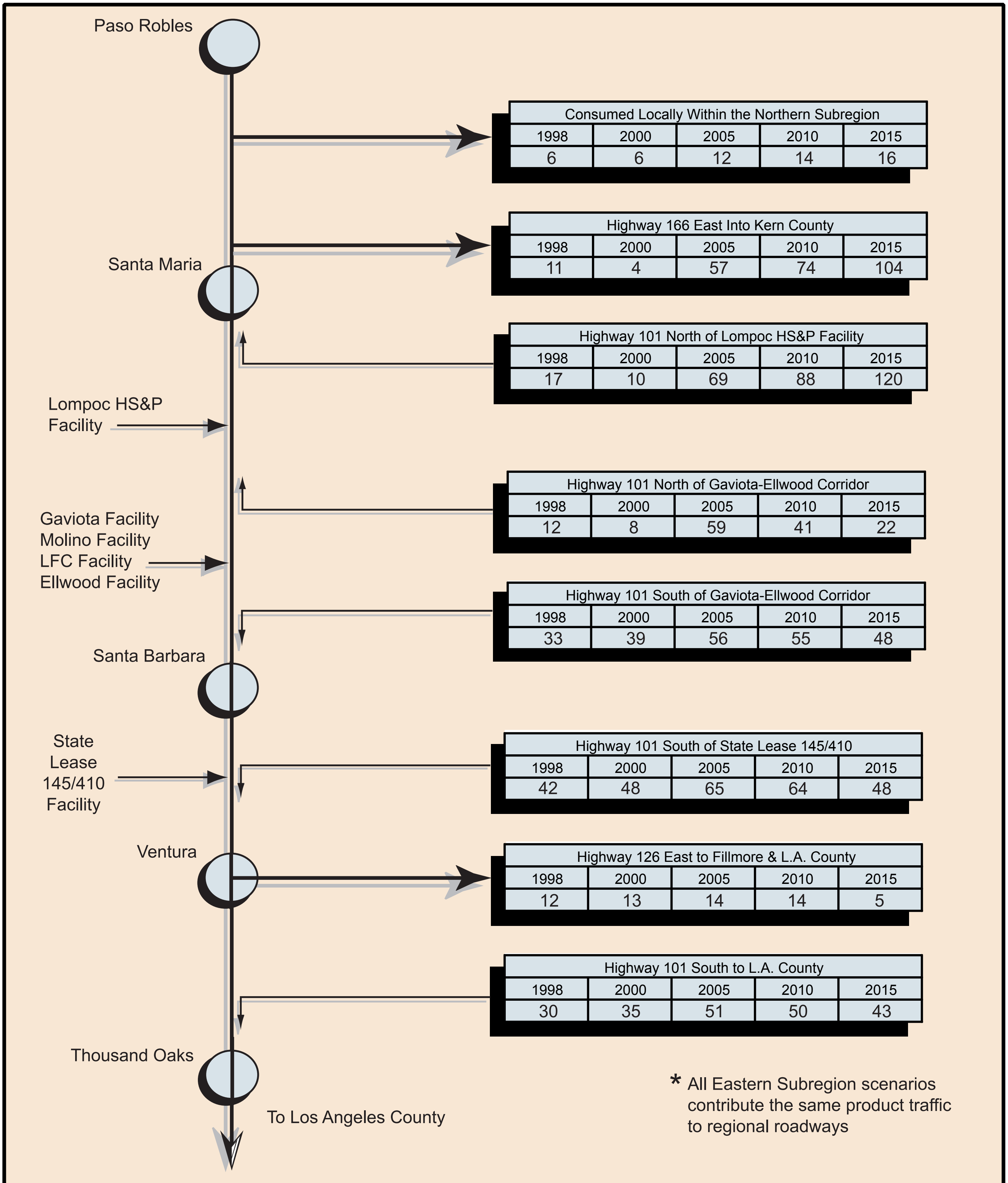

Consumed Locally Within the Northern Subregion

1998	2000	2005	2010	2015
6	6	12	14	16

Highway 166 East Into Kern County

1998	2000	2005	2010	2015
11	4	57	74	104

Highway 101 North of Lompoc HS&P Facility

1998	2000	2005	2010	2015
17	10	69	88	120

Highway 101 North of Gaviota-Ellwood Corridor

1998	2000	2005	2010	2015
12	8	59	41	22

Highway 101 South of Gaviota-Ellwood Corridor

1998	2000	2005	2010	2015
33	39	56	55	48

Highway 101 South of State Lease 145/410

1998	2000	2005	2010	2015
42	48	65	64	48

Highway 126 East to Fillmore & L.A. County

1998	2000	2005	2010	2015
12	13	14	14	5

Highway 101 South to L.A. County

1998	2000	2005	2010	2015
30	35	51	50	43

FIGURE 4.4-6
High-Case Truck Traffic
Sulfur, LPG, and Crude Oil Transport
(Average Truck Round Trips Per Week)
Scenario Combination: East: */Central: 4/North: 4A

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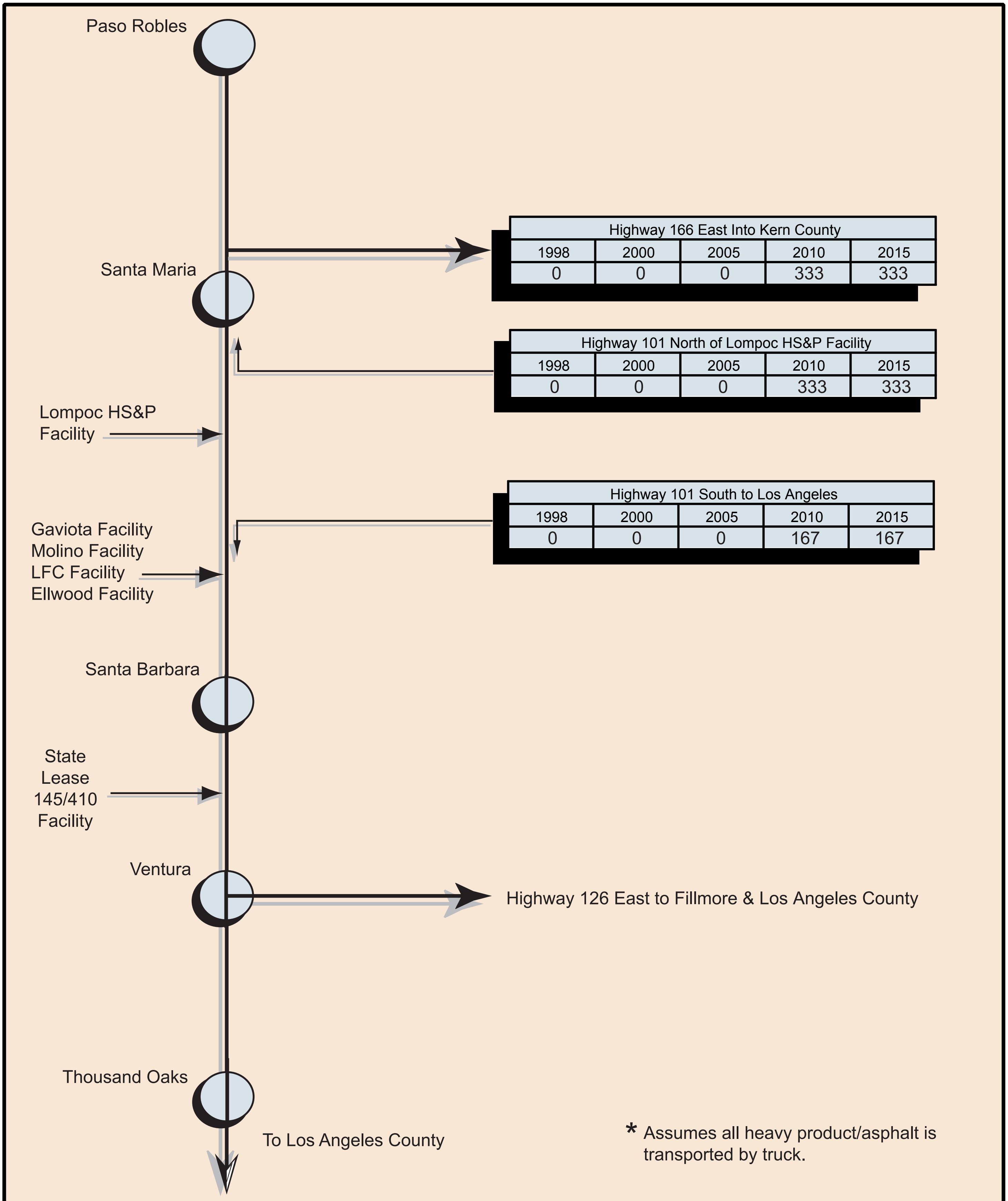

Highway 166 East Into Kern County				
1998	2000	2005	2010	2015
0	0	0	333	333

Highway 101 North of Lompoc HS&P Facility				
1998	2000	2005	2010	2015
0	0	0	333	333

Highway 101 South to Los Angeles				
1998	2000	2005	2010	2015
0	0	0	167	167

FIGURE 4.4-7
Heavy Product Truck Traffic
(Average Truck Round Trips Per Week)
Northern Subregion - Scenarios 3 and 3A

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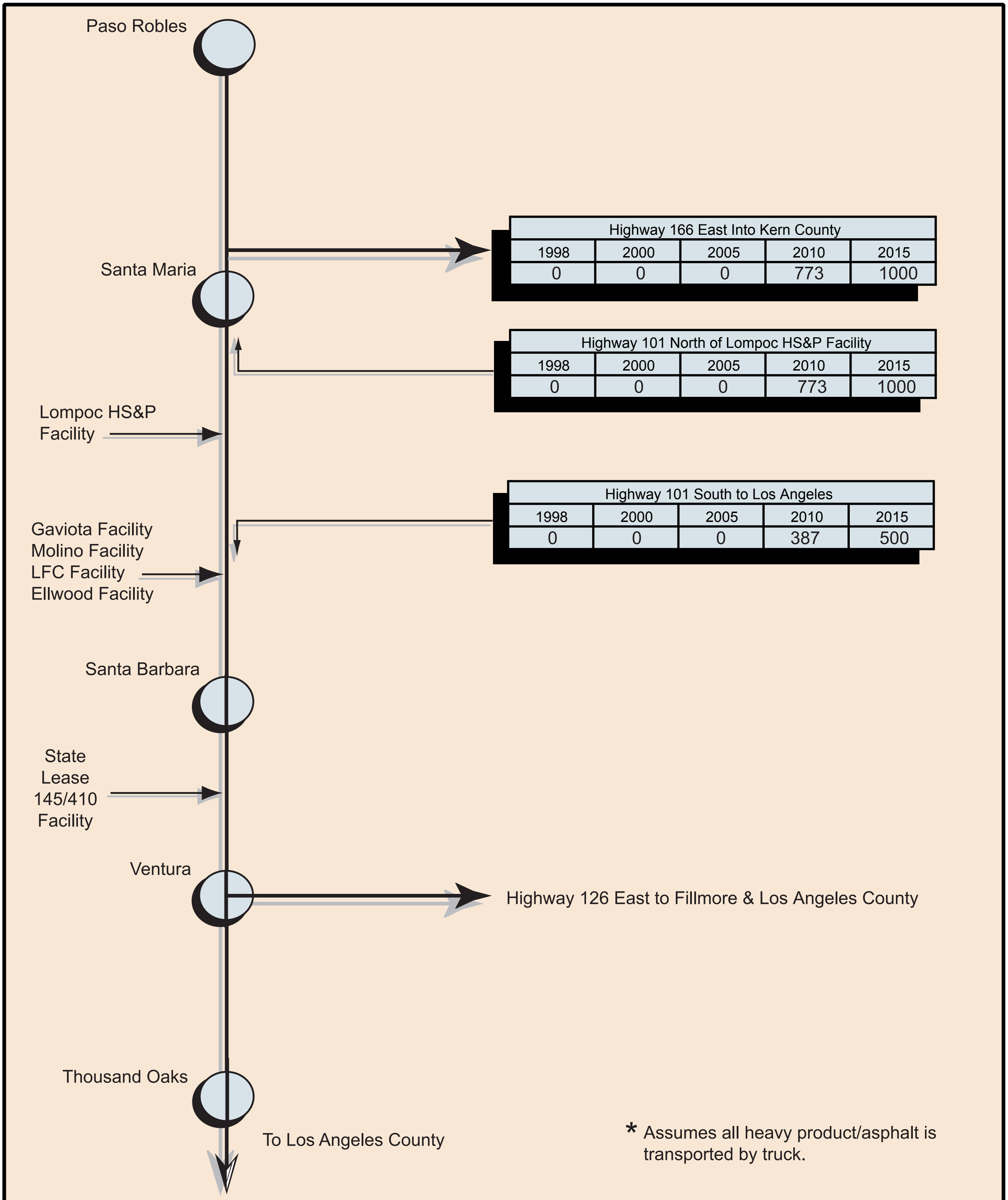

Highway 166 East Into Kern County

1998	2000	2005	2010	2015
0	0	0	773	1000

Highway 101 North of Lompoc HS&P Facility

1998	2000	2005	2010	2015
0	0	0	773	1000

Highway 101 South to Los Angeles

1998	2000	2005	2010	2015
0	0	0	387	500

FIGURE 4.4-8
Heavy Product Truck Traffic
(Average Truck Round Trips Per Week)
Northern Subregion - Scenarios 4 and 4A

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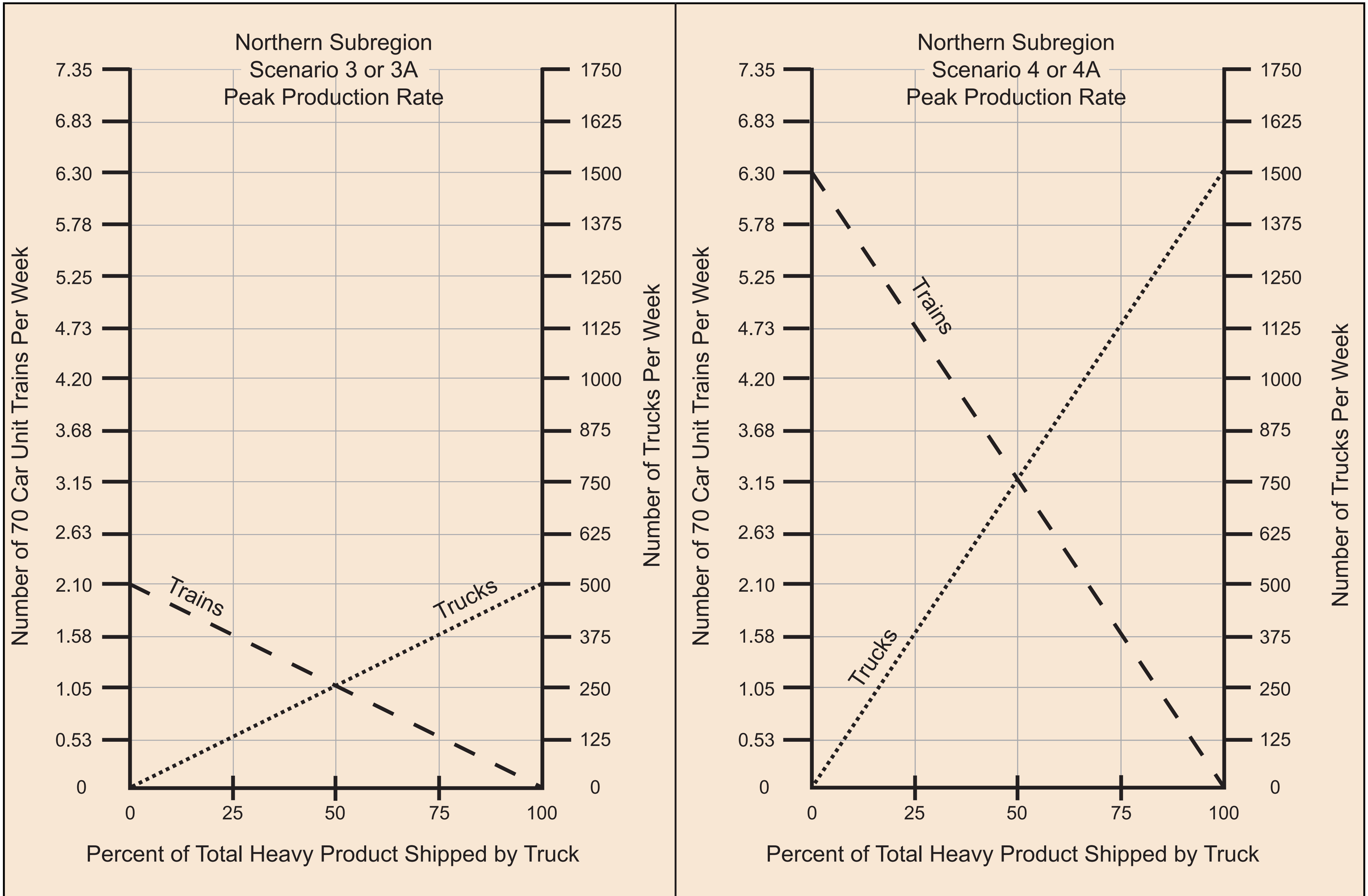

Figure 4.4-9

Potential Combinations of Truck and Rail Transport
Offshore Santa Maria Basin Heavy Product

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1196/141A

EMPLOYMENT BY SECTOR: 1993-2004
Ventura County

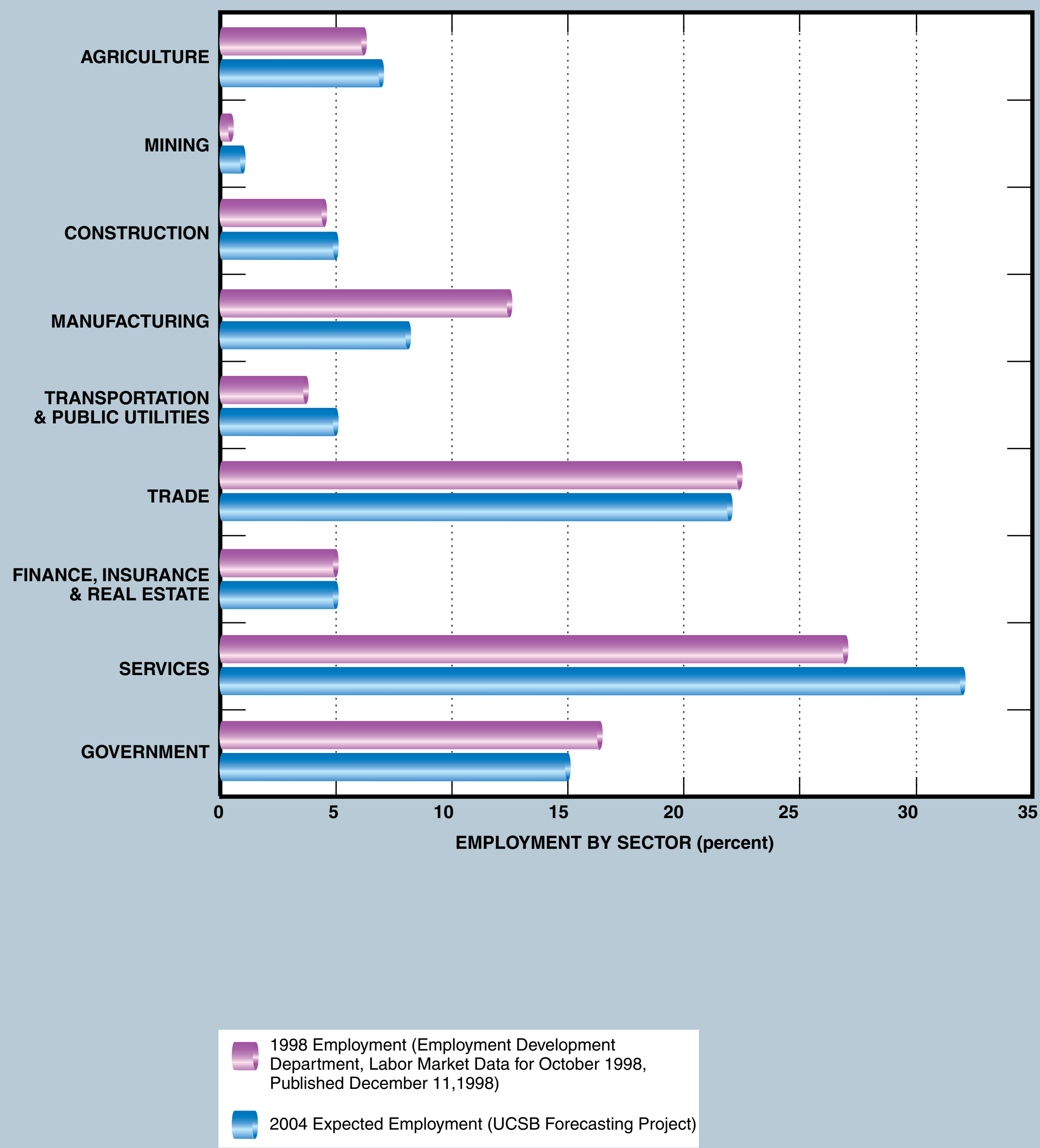

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Figure A.3-1

COOGER STUDY

CHANGES IN EMPLOYMENT, 1981-1995
Ventura County

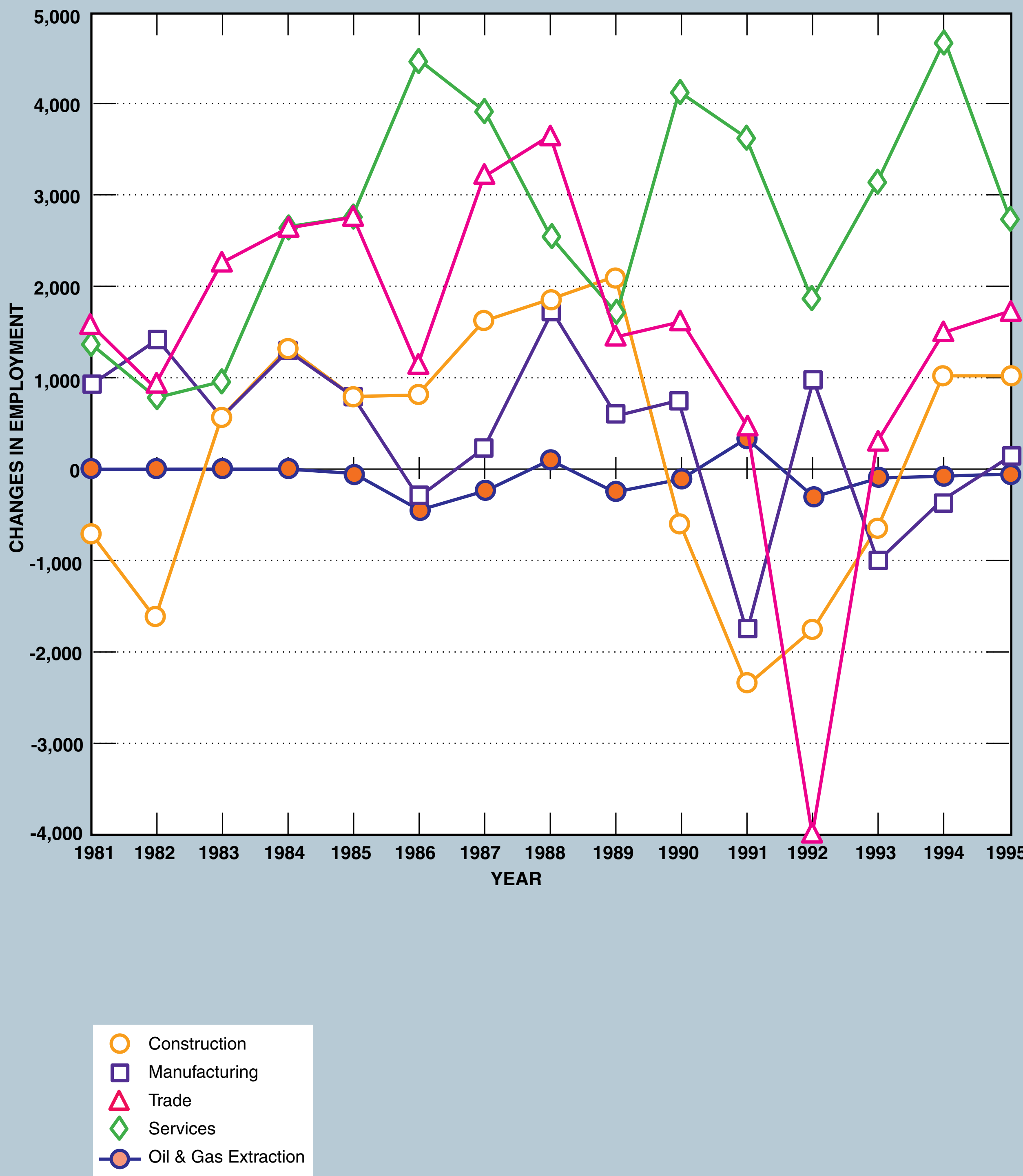
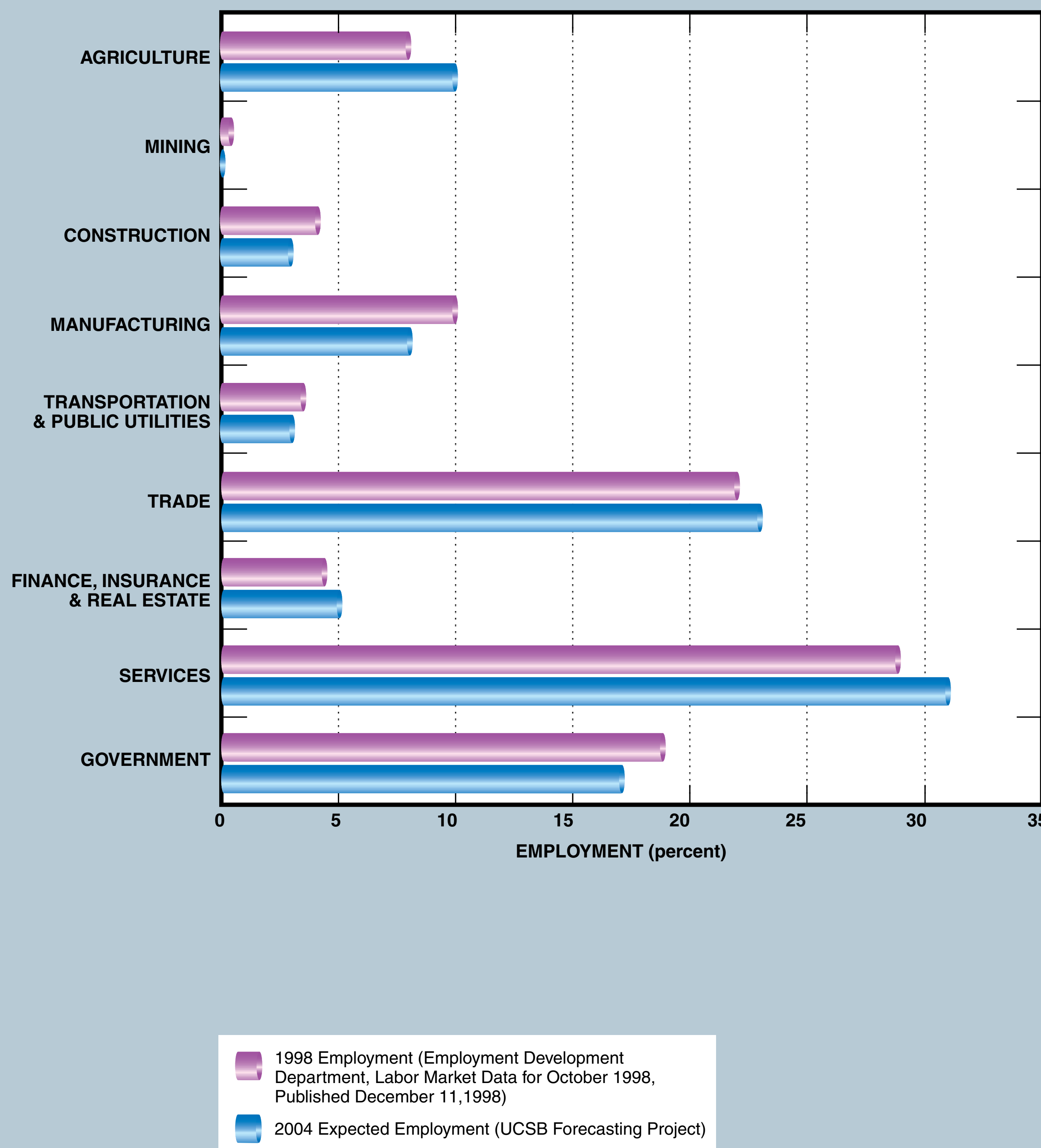


Figure A.3-2
COOGER STUDY

1196/142A

EMPLOYMENT BY SECTOR: 1998-2004
Santa Barbara County



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A DAMES & MOORE GROUP COMPANY

Figure A.3-3

COOGER STUDY

1196/154

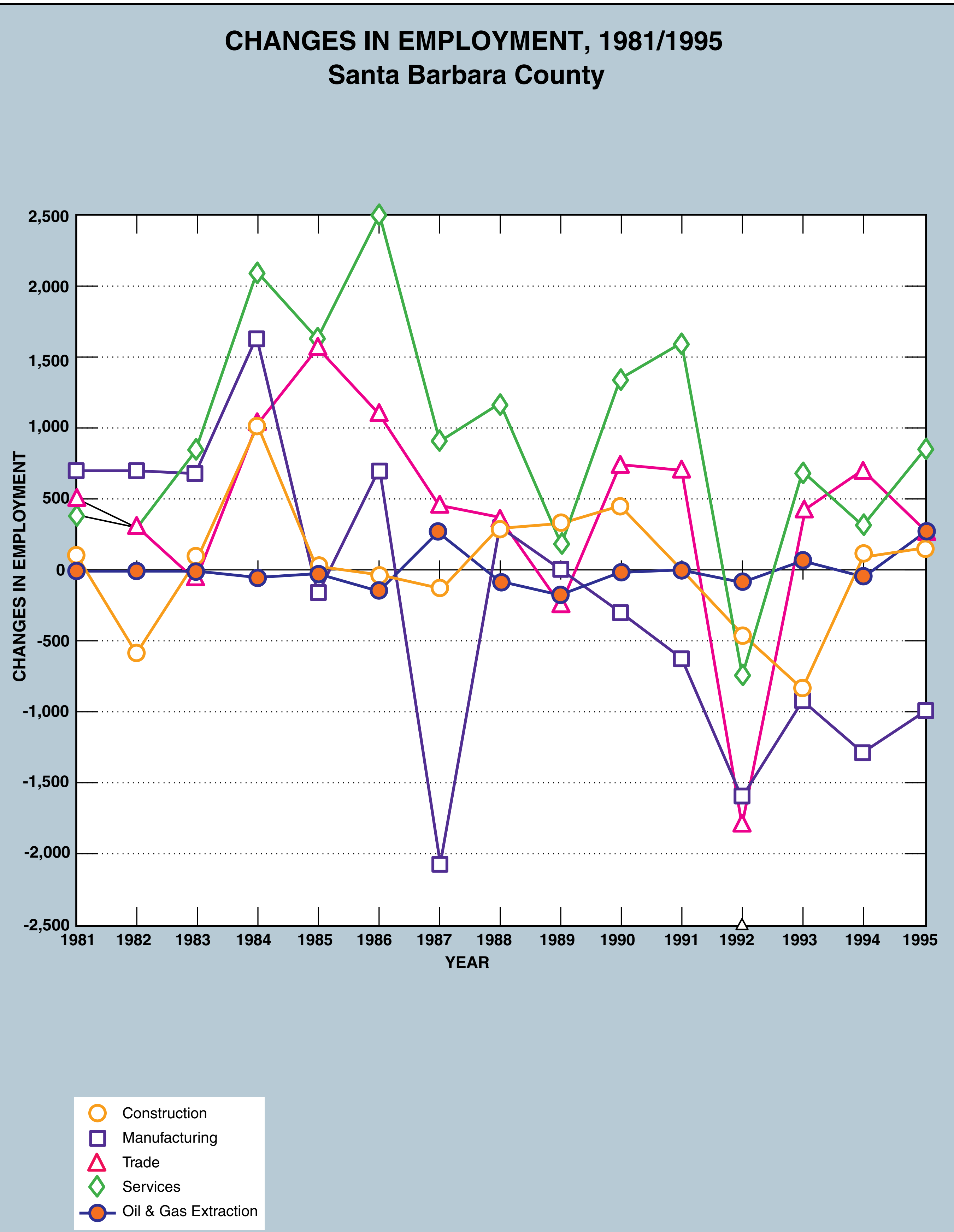

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Figure A.3-4

COOGER STUDY

EMPLOYMENT BY SECTOR: 1993-2004
San Luis Obispo County

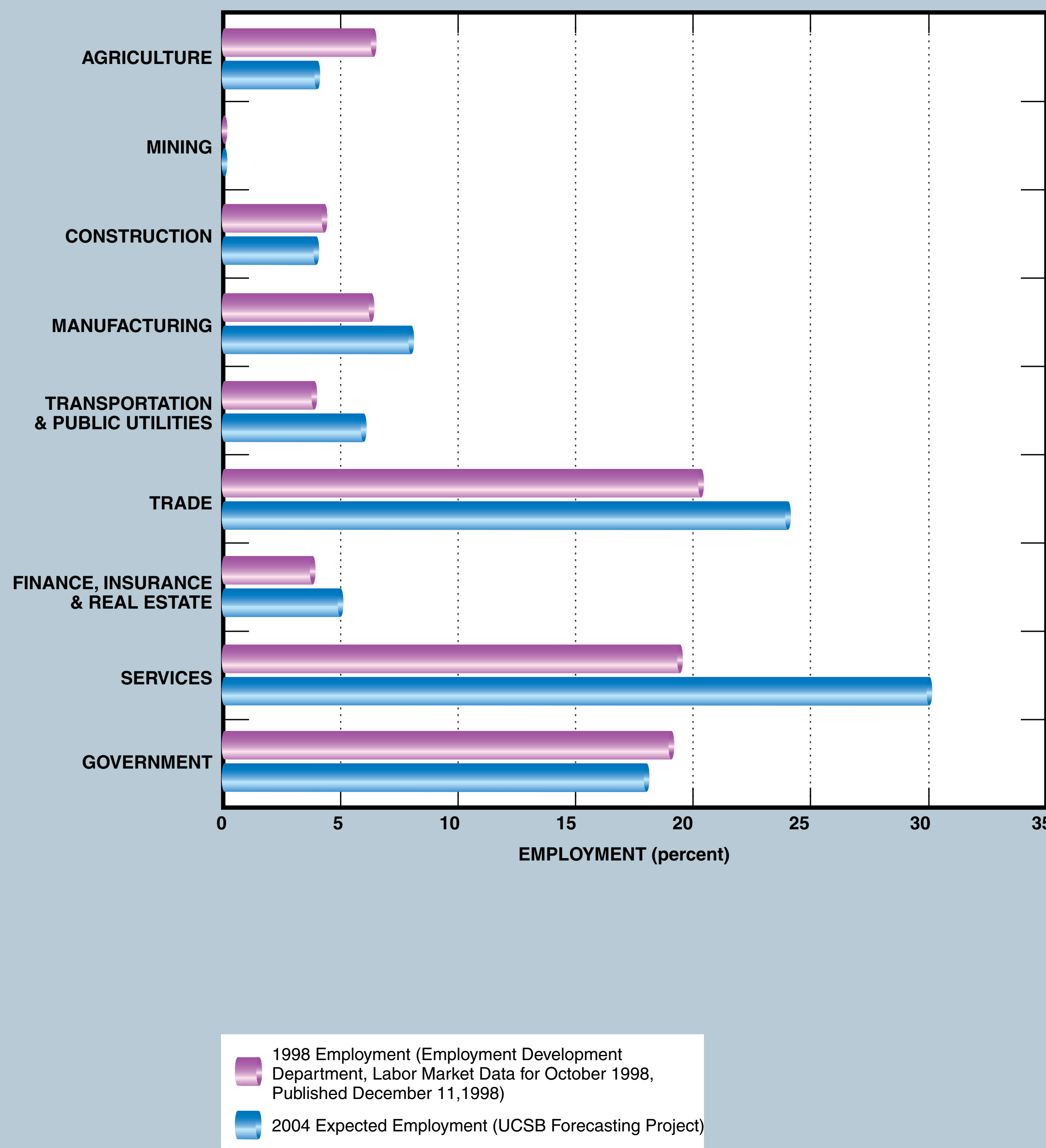

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Figure A.3-5

COOGER STUDY

CHANGES IN EMPLOYMENT, 1981-1995
San Luis Obispo County

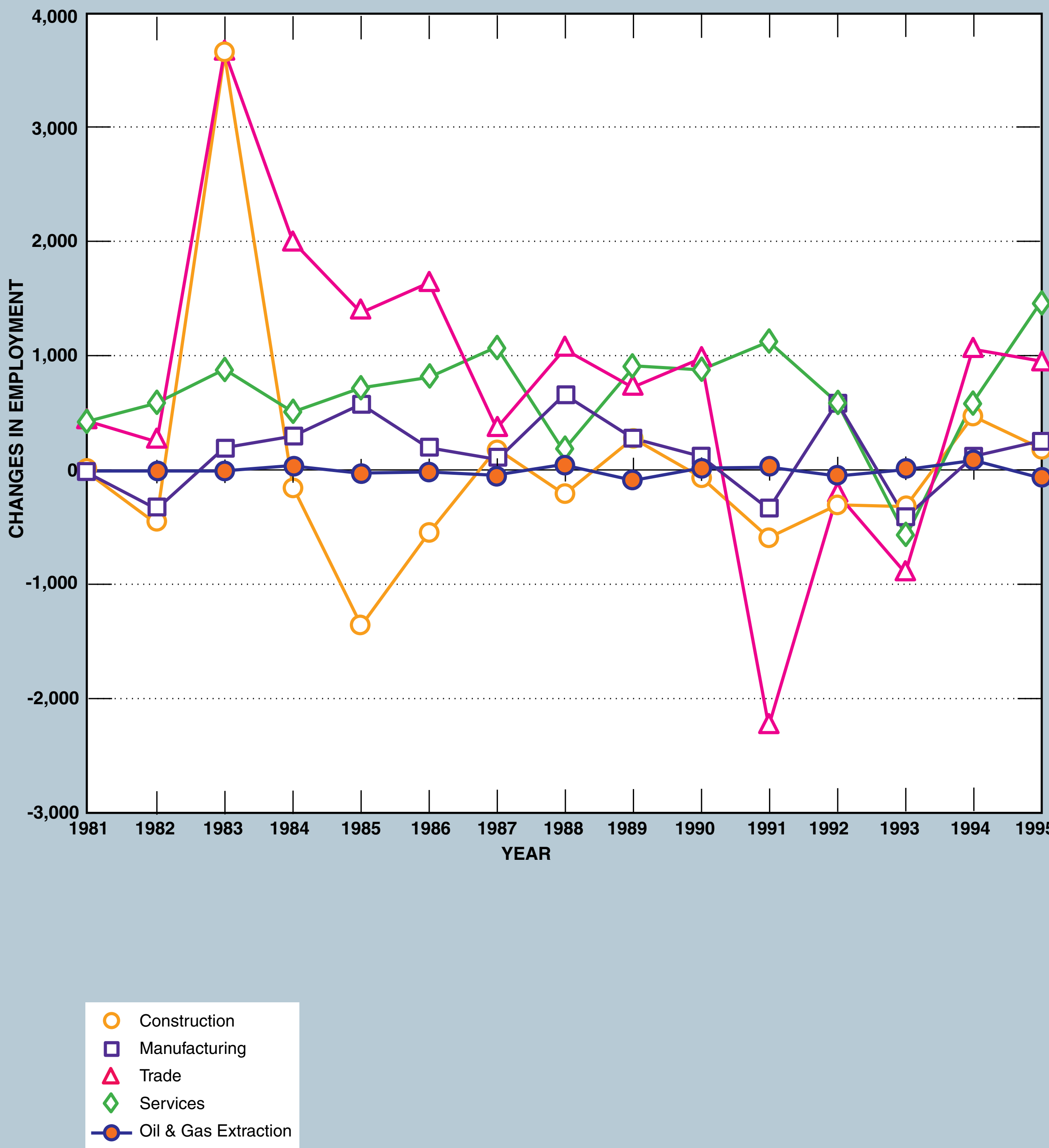

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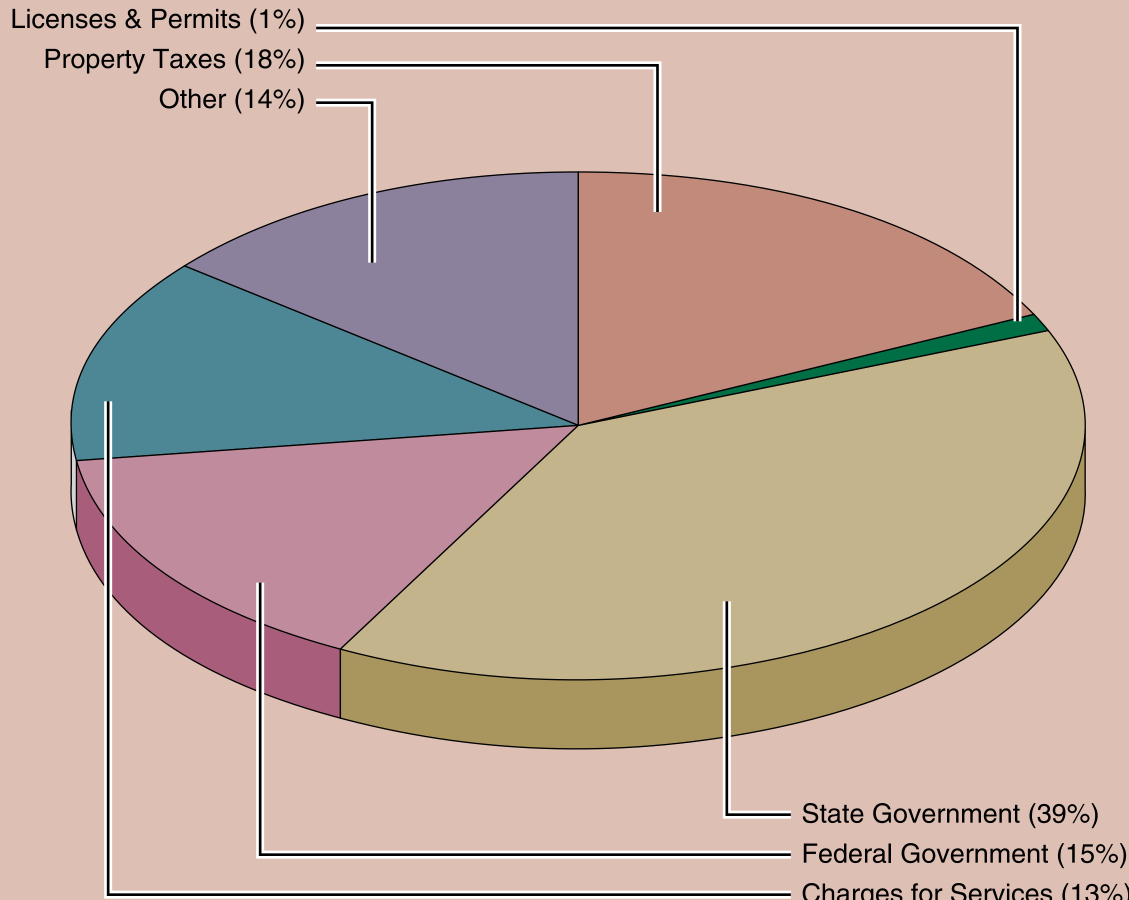
Figure A.3-6

COOGER STUDY

1196/136A

REVENUE SOURCES FY 1994
Ventura County Government



Source:
California Office of the Comptroller

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Figure A.4-1

COOGER STUDY

1196/137A

REVENUE SOURCES: 1980-1995
Santa Barbara County Government

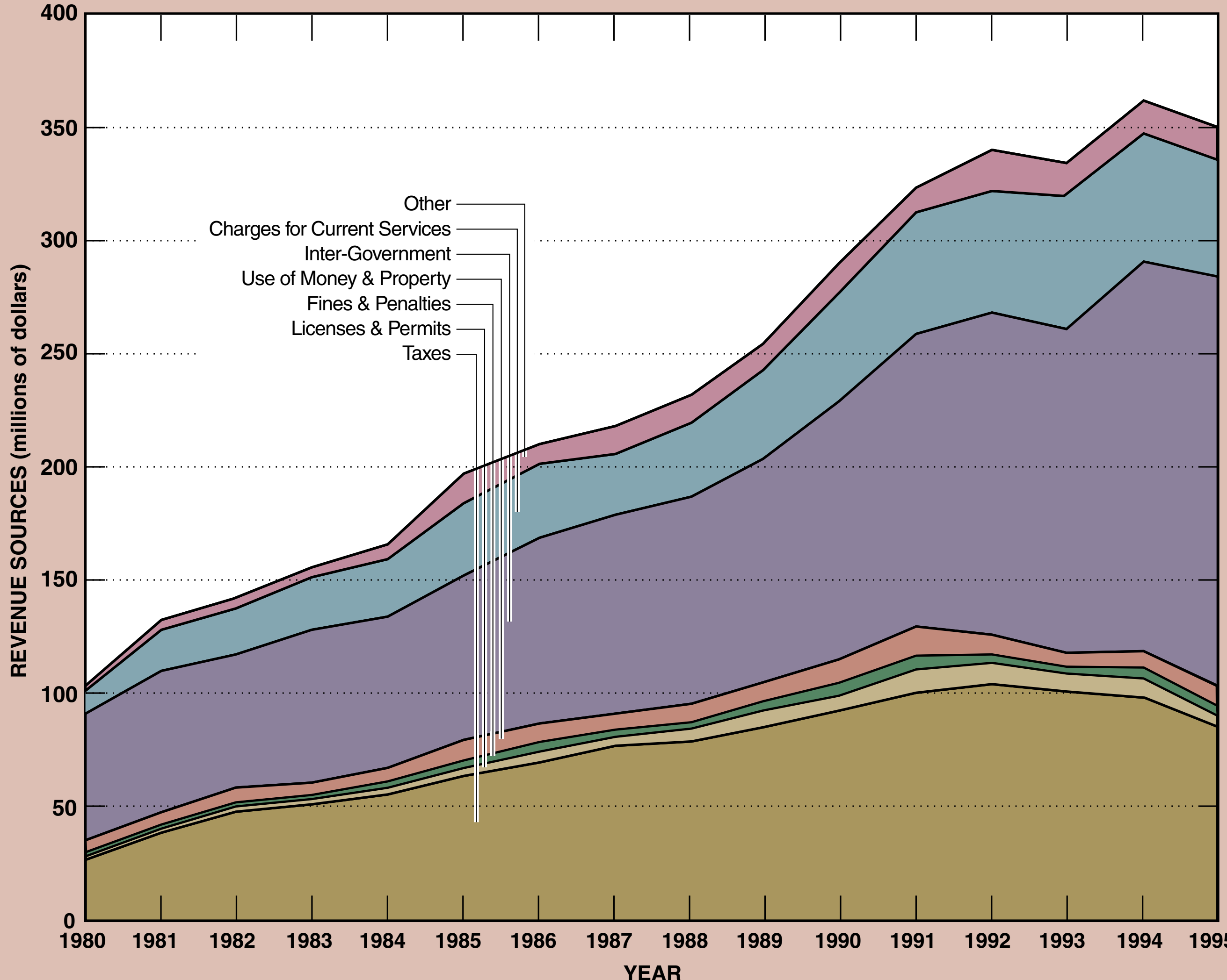

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Figure A.4-2

COOGER STUDY

1196/138A

REVENUE SOURCES: 1980-1995
San Luis Obispo County Government

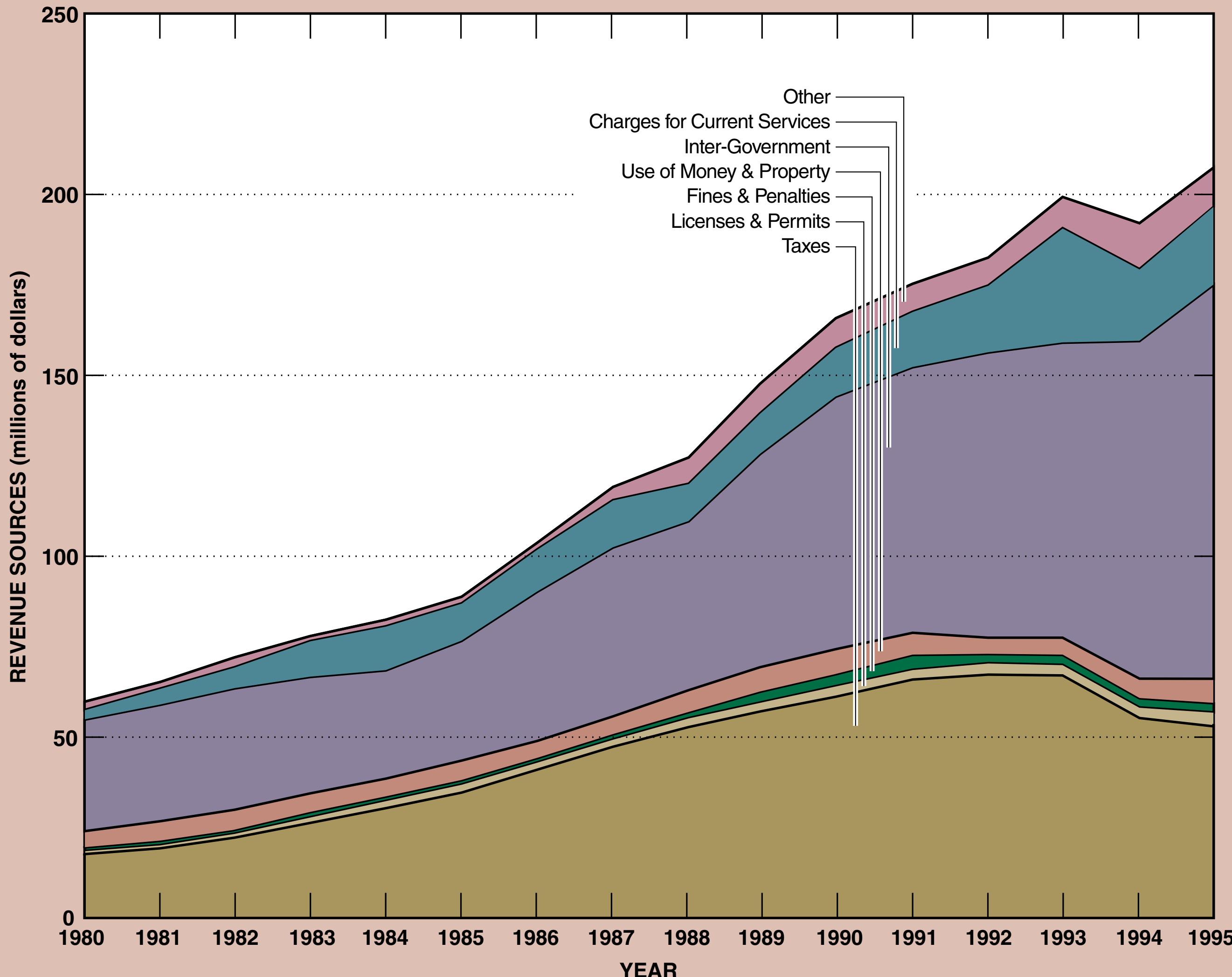

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Figure A.4-3

COOGER STUDY

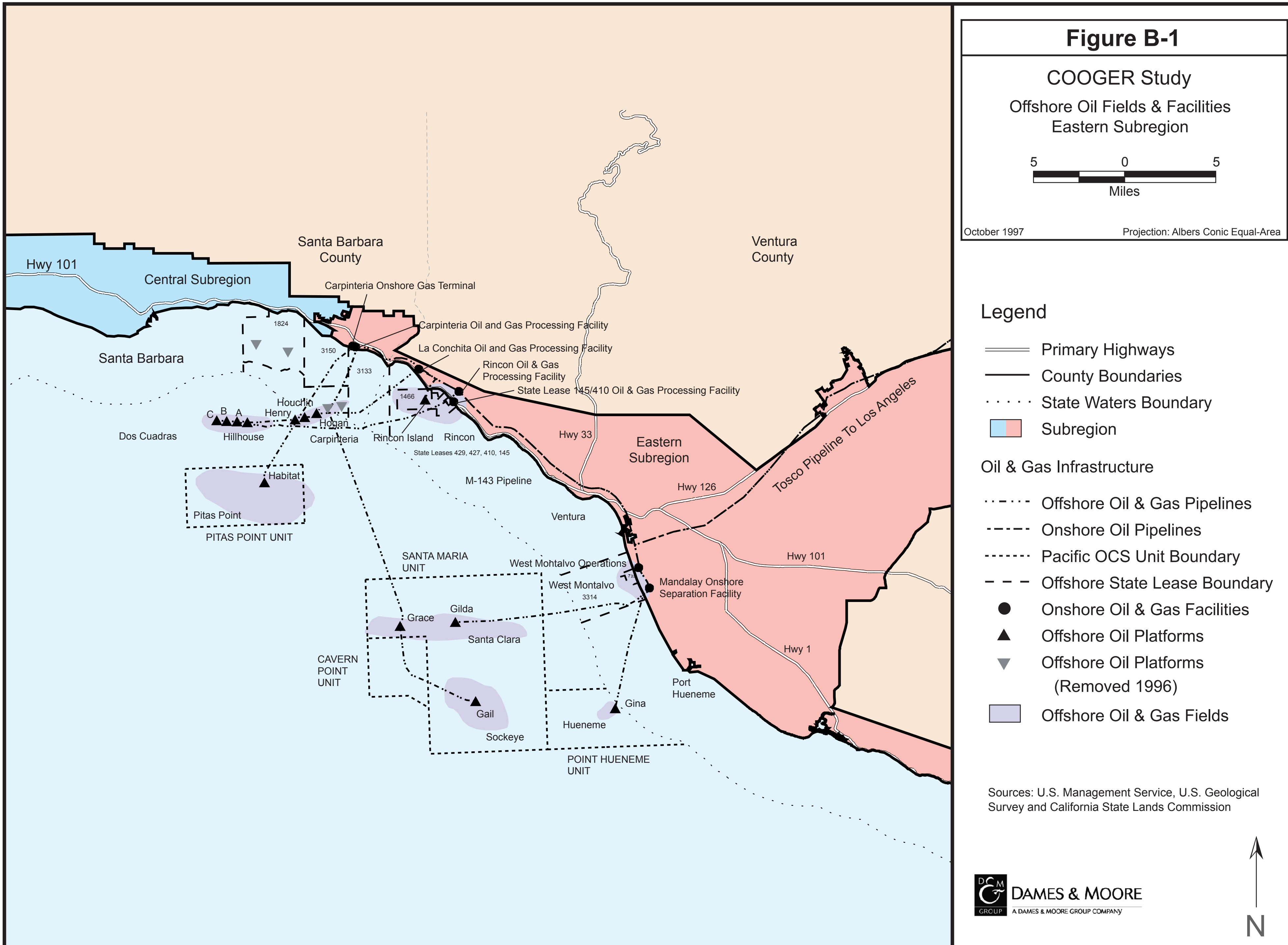
Figure B-1
COOGER Study
Offshore Oil Fields & Facilities
Eastern Subregion
5 0 5
Miles
October 1997
Projection: Albers Conic Equal-Area
Legend
Primary Highways
County Boundaries
State Waters Boundary
Subregion
Oil & Gas Infrastructure
Offshore Oil & Gas Pipelines
Onshore Oil Pipelines
Pacific OCS Unit Boundary
Offshore State Lease Boundary
Onshore Oil & Gas Facilities
Offshore Oil Platforms
Offshore Oil Platforms (Removed 1996)
Offshore Oil & Gas Fields
Sources: U.S. Management Service, U.S. Geological Survey and California State Lands Commission
DAMES & MOORE
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N
Hwy 101
Central Subregion
Santa Barbara County
Ventura County
Santa Barbara
Carpinteria Onshore Gas Terminal
Carpinteria Oil and Gas Processing Facility
La Conchita Oil and Gas Processing Facility
Rincon Oil & Gas Processing Facility
State Lease 145/410 Oil & Gas Processing Facility
1824
3150
3133
1466
Houchin
Henry
C B A
Hogan
Hillhouse
Dos Cuadras
Carpinteria
Rincon Island
Rincon
State Leases 429, 427, 410, 145
Hwy 33
Eastern Subregion
Tosco Pipeline To Los Angeles
Hwy 126
M-143 Pipeline
Habitat
Pitas Point
PITAS POINT UNIT
Ventura
SANTA MARIA UNIT
West Montalvo Operations
West Montalvo
3314
Mandalay Onshore Separation Facility
Hwy 101
Grace
Gilda
Santa Clara
CAVERN POINT UNIT
Hwy 1
Port Hueneme
Gail
Gina
Hueneme
Sockeye
POINT HUENEME UNIT

Figure B-2

COOGER Study

Offshore Oil Fields & Facilities
Central & Northern Subregions

5 0 5 10

Miles

October 1997

Projection: Albers Conic Equal-Area

Legend

- Primary Highways
- County Boundaries
- State Waters Boundary
- Subregion

Oil & Gas Infrastructure

- Offshore Oil & Gas Pipelines
- Onshore Oil Pipelines
- Onshore Gas Pipelines
- Pacific OCS Unit Boundary
- Offshore State Lease Boundary
- Offshore Oil Platforms
- Onshore Oil & Gas Facilities
- Offshore Oil & Gas Fields

Sources: U.S. Management Service, U.S. Geological Survey and California State Lands Commission

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N

PHOTOGRAPHS