OCS Study
MMS 2000-008

EXECUTIVE SUMMARY
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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Dean Hargis

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EXECUTIVE SUMMARY

1.0 INTRODUCTION

1.1 GENERAL BACKGROUND

The California Offshore Oil and Gas Energy Resources (COOGER) study was designed by a joint government/industry working 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. The onshore industrial infrastructure addressed by this study includes facilities to process, store, and transport crude oil, natural gas, liquefied petroleum, and other by-products. It also addresses public infrastructure that could be used by the oil industry, including port and harbor facilities, airports, railways, and local highways and roads. A description of the capacity of each infrastructure component is presented to the extent allowed by available information. The demand associated with future oil and gas development is then presented in relation to capacity to identify potential conflicts or expansion requirements.

The geographic focus of the study is the coastal areas of Ventura, Santa Barbara, and San Luis Obispo Counties (the Tri-County area), and the time period addressed is 1995 through 2015. Until very recently, there were 63 undeveloped offshore leases in this area, including 40 in the federal OCS and 23 in State tide and submerged lands. 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 potentially available for future development. 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. Projections of potential future oil and gas production presented in the COOGER study are limited to development from existing leases, and do not include any production from the recently expired leases.

The COOGER Study process was initiated in 1993 at the request of the State of California and Ventura, Santa Barbara, and San Luis Obispo Counties. These jurisdictions requested that Minerals Management Service (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 MMS administered the COOGER study contract. The MMS and the oil industry jointly funded the study. A Steering Committee provided management oversight of the study to enhance its accuracy and functional use. This committee comprised of representatives from county government (Ventura, Santa Barbara, and San Luis Obispo), State of California (Coastal Commission, State Lands Commission, Division of Oil, Gas and Geothermal Resources), oil and gas industry, local non-energy businesses, and environmental groups. The Steering Committee (with the exception of representatives from 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. The study is the result of a unique collaboration of government and non-government interest.

1.2 STUDY RELATIONSHIP TO AGENCY DECISIONMAKING

The study is an information document and does not advocate or recommend any particular development 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/or 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 addressing socioeconomic topics; comprehensive safety audits of 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 leases. A Presidential Executive Order issued in June 1998 prohibits new leasing of federal offshore oil and gas tracts until after 2012. New leasing in State of California tide and submerged lands is prohibited unless special circumstances are identified (such as the extension of a field under an existing lease into an unleased area). There are presently no approved plans for new leasing in federal or State waters.

2.0 SCOPE OF INVESTIGATION

2.1 PRINCIPAL STUDY REGION AND SUBREGIONS

The principal study region addressed by the COOGER study is the near-coastal areas of Ventura, Santa Barbara, and San Luis Obispo Counties illustrated on Figure 1. This geographic area includes all primary processing and storage facilities used to support offshore oil and gas development and production in the Santa Barbara Channel and Santa Maria Basin. The principal region is further divided into three subregions, also depicted in Figure 1. The subregions include:

- Eastern Subregion: from the Ventura/Los Angeles county line to the northern (western) boundary of Carpinteria.

- Central Subregion: from the northern (western) boundary of Carpinteria to the Santa Ynez River.

- Northern Subregion: from the Santa Ynez River to Point Estero.

2.2 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 from 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 COOGER study Steering Committee defined specific guidelines concerning offshore development scenarios to be evaluated.

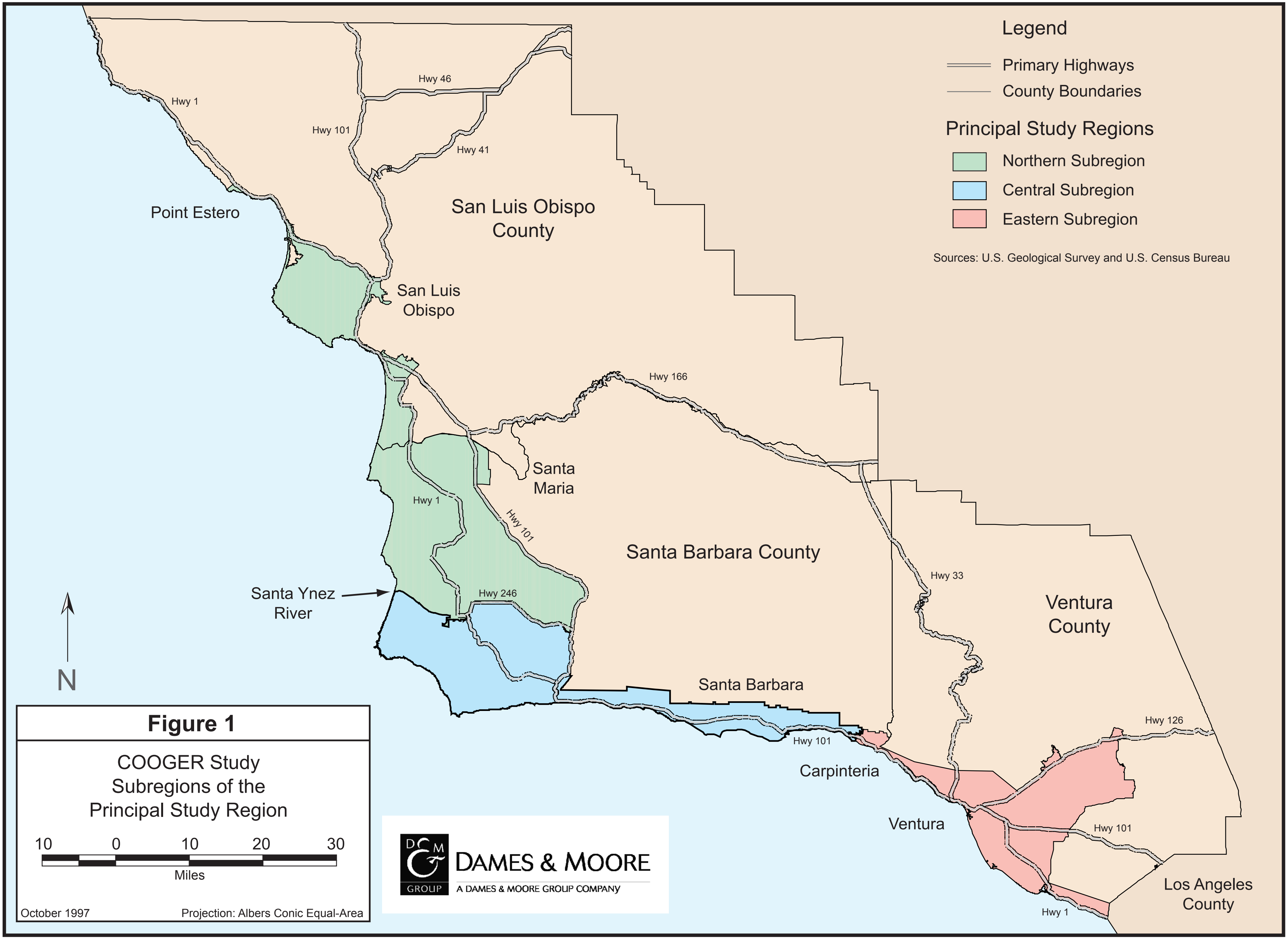


Figure 1

COOGER Study Subregions of the Principal Study Region

These guidelines define the principal differences between the scenarios addressed in the COOGER study and in this summary, and are as follows:

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.

The guidelines described above were used to develop detailed scenarios of offshore development and related onshore activity. These scenarios were used to quantify onshore facility requirements, oil production rates, and demand on local infrastructure. By comparing this information to current conditions and projected future conditions in the absence of new development, readers of the COOGER study can develop an understanding of local onshore infrastructure demand associated with each development scenario.

3.0 EXISTING OIL AND GAS OPERATIONS AND RELATED INFRASTRUCTURE

3.1 EXISTING OFFSHORE PRODUCTION AND RELATED ONSHORE FACILITIES

Ventura and Santa Barbara counties have a long history of offshore oil and gas operations. There are currently 20 offshore production platforms, one offshore production island, and 12 onshore processing facilities associated with offshore development in this region. To evaluate potential future demand for new onshore facility capacity, the COOGER study addresses the capacities of existing onshore facilities. Current oil and gas production rates, and future production rates in the absence of new development provide an estimate of onshore facility capacity which could be available to support new offshore development without initiating new onshore development. In 1995 (the base year for the COOGER study) a total of 73.99 million stock tank barrels of dry oil and 57.69 billion standard cubic feet of natural gas were produced from offshore leases and processed at onshore facilities within the COOGER study area. Details of base year production rates of total fluids (a mixture of crude oil and produced water) and natural gas are presented in Table 1, along with information concerning the processing capacity at each onshore facility. Figure 2 shows the locations of existing oil and gas facilities in the COOGER study region.

The COOGER study presumes that existing facilities will continue to be available to process production from new offshore development to the extent legally allowed. This assumption is not intended to imply that such use is guaranteed. Safety audits may be required in connection with County decisions that could extend the life of an onshore facility.

TABLE 1
EXISTING PRODUCTION AND FACILITY CAPACITY

Onshore Facility	Platform(s)	Field/Unit[2]	Onshore Facility Design Capacity		1995 Production Rate	
			Oil/Water Mixture (BPD)[1]	Gas (MCFD)	Oil/Water Mixture (BPD)[1]	Gas (MCFD)
EASTERN SUBREGION						
Mandalay	Gina Gilda	Hueneme Santa Clara	25,000	18,000	15,753	2,996
West Montalvo	Onshore	West Montalvo	1,197	314	948	422
Rincon Island/State Leases 145/410	Rincon Island	Rincon	3,795	1,000	1,046	208
Rincon Oil & Gas Facility	Henry Hillhouse A B C	Carpinteria Dos Cuadras Dos Cuadras Dos Cuadras Dos Cuadras	110,000	15,000	12,058	8,449
La Conchita	Hogan Houchin	Carpinteria Carpinteria	27,000	22,000	6,339	1,562
Carpinteria Oil & Gas Processing Facility	Gail Grace	Sockeye Santa Clara	40,000	28,000	9,996	20,112
Carpinteria Gas Terminal	Habitat	Pitas Point	0	110,000	14	18,485
Subtotal - Eastern Subregion			206,992	194,314	46,155	52,234
CENTRAL SUBREGION						
Ellwood	Holly	South Ellwood	28,200	20,000	10,002	2,882
Las Flores Canyon	Hondo Harmony Heritage	Hondo Hondo Pescado	160,000	96,000	115,553	57,534
Gaviota	Hermosa Harvest Hidalgo	Point Arguello Point Arguello Point Arguello	125,000	60,000	79,572	41,819
Molino	Onshore	Molino	0	60,000	0	0
Subtotal - Central Subregion			313,200	236,000	205,128	102,236
NORTHERN SUBREGION						
Lompoc	Irene	Point Pedernales	80,000	15,000	62,400	3,589
Subtotal - Northern Subregion			80,000	15,000	62,400	3,589
TOTAL COOGER STUDY REGION			600,192	445,314	313,683	158,059

[1]Indicates wet oil processing capacity and wet oil processed onshore. The total 1995 production for the COOGER study area indicated in this table includes 202,719 barrels per day of dry oil and 110,964 barrels per day of water.

[2]Refer to Figures 8 and 9 on pages 21 and 22 of this summary for the location of offshore fields and units.

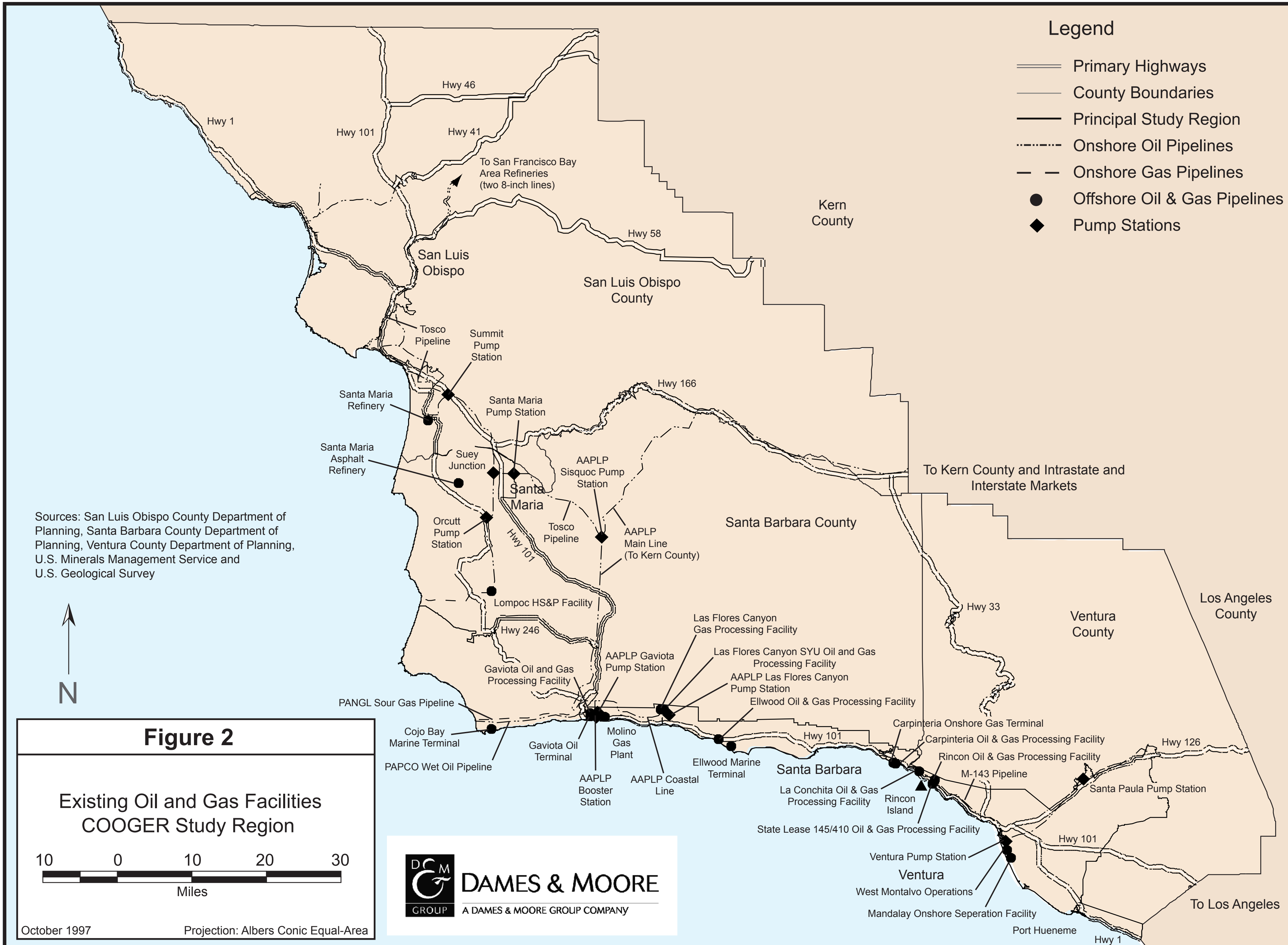


Figure 2

Existing Oil and Gas Facilities
COOGER Study Region

3.2 EXISTING INDUSTRIAL AND PUBLIC INFRASTRUCTURE

Offshore oil activities are supported by an onshore infrastructure of pipelines, roadways, ports and piers, railroads, airports, and one operational marine terminal. This infrastructure is used to transport oil, natural gas, and other products of offshore development. It is also used to transport personnel, materials, supplies, and solid wastes related to the oil and gas activity. Figures 3, 4, and 5 illustrate the locations of the principal elements of the industrial infrastructure in each COOGER study subregion. Figure 6 shows the regional public infrastructure.

3.2.1 Oil Pipeline Systems

Several existing pipeline systems are used to transport crude oil in the COOGER study region. These pipelines are operated by several different companies. A connection between the All American Pipeline (used to transport Central Subregion crude oil) and the Tosco northern pipeline system (used to transport Northern Subregion and onshore produced oil to the Santa Maria Refinery) is the only pipeline system connection between study subregions. Figure 7 presents a diagram of the principal components of the pipeline infrastructure in the COOGER study region, and illustrates the general lack of interconnection between subregions. This lack of interconnection limits the oil distribution options available to many processing facilities and requires consideration of oil transport capacity and demand on a subregion-specific basis.

In the Eastern Subregion, most of the offshore oil production is transported to refineries outside the COOGER study area by the Tosco pipeline system. This system typically operates at a rate of 24,000 barrels per day, and originates at the Ventura Pump Station. The Mandalay Onshore Separation Facility and West Montalvo Operations connect to the Ventura Pump Station via a common 6-inch to 8-inch diameter pipeline. Facilities located north of the Ventura Pump Station (Carpinteria, La Conchita, Rincon Island, and Rincon) send oil to the Ventura Pump Station via the 22-inch diameter Venoco M-143 pipeline. From the Ventura Pump Station, an 8-inch diameter Tosco pipeline transports oil to Santa Paula and Fillmore, and a 12-inch diameter Tosco pipeline connects the Fillmore pump station to Los Angeles area refineries.

Central Subregion oil production is transported out of the study region by marine barges and by pipeline. Production processed at the Ellwood Facility is transported by marine barge, and is discussed in Section 3.2.2. Production from the Las Flores Canyon and Gaviota facilities is transported by the All American Pipeline, L.P. system (AAPLP). The All American Pipeline, L.P. system includes a 150,000 barrel per day capacity pipeline from the Las Flores Canyon Facility to

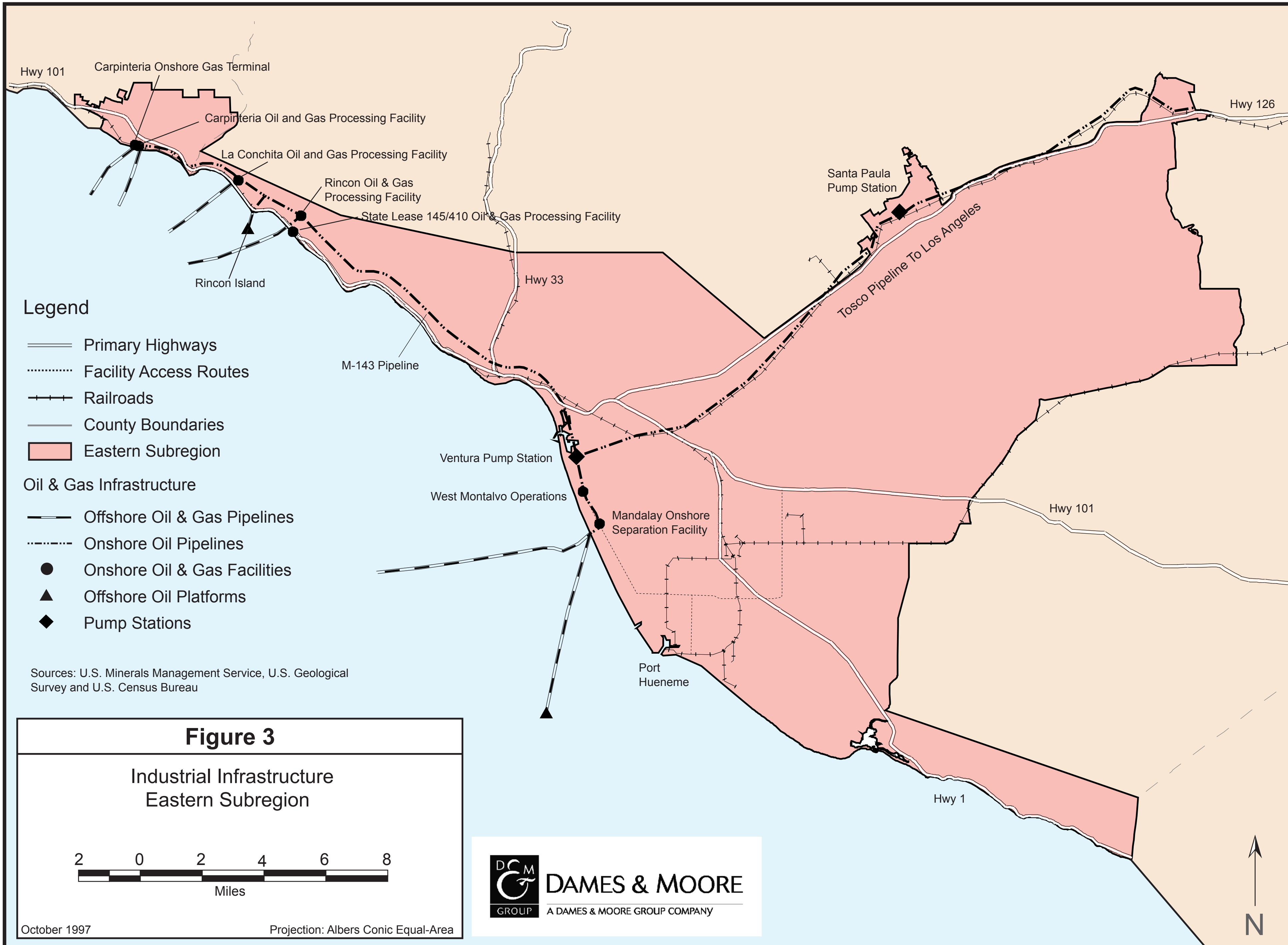


Figure 3

Industrial Infrastructure
Eastern Subregion

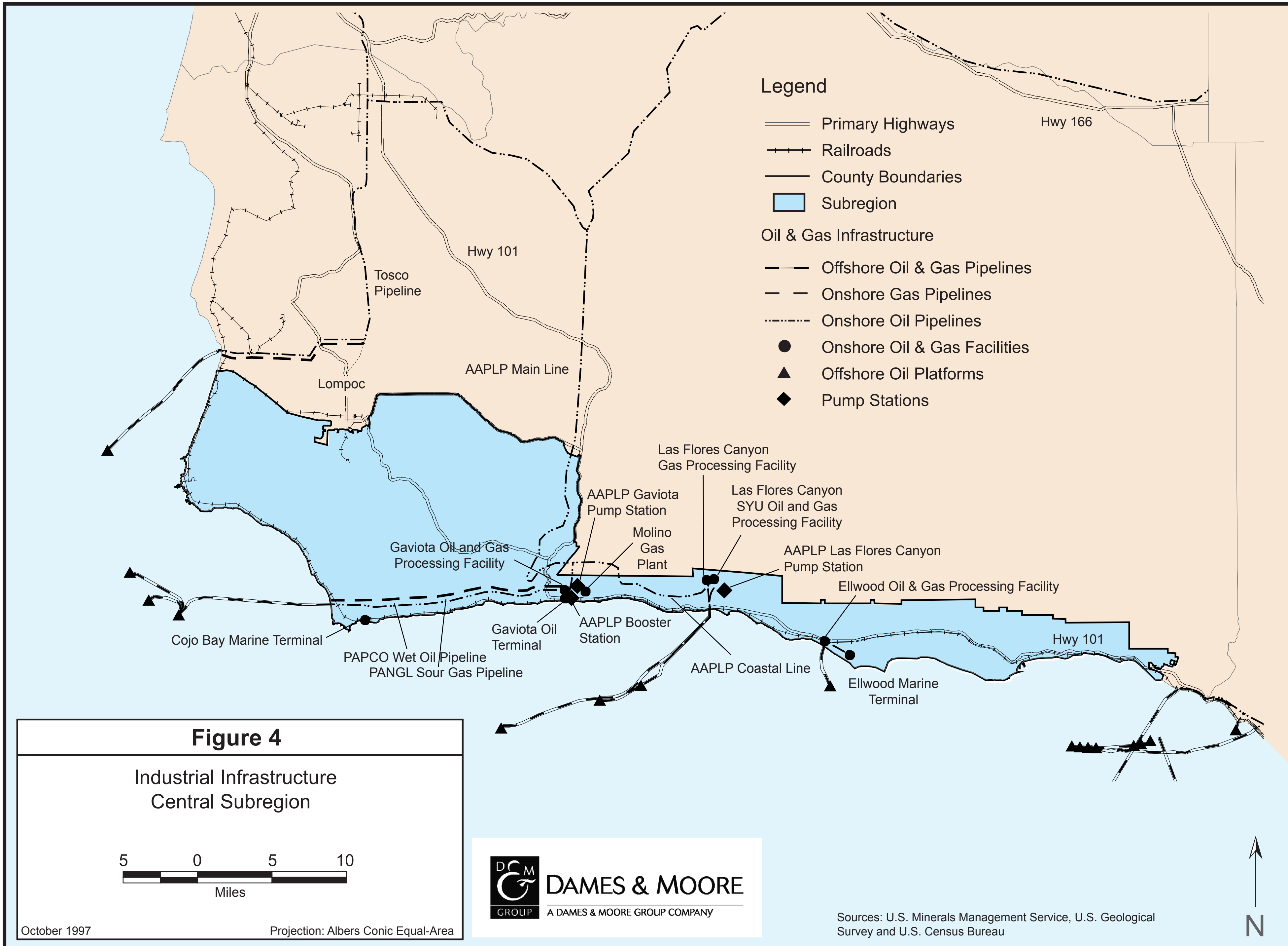


Figure 4

Industrial Infrastructure
Central Subregion

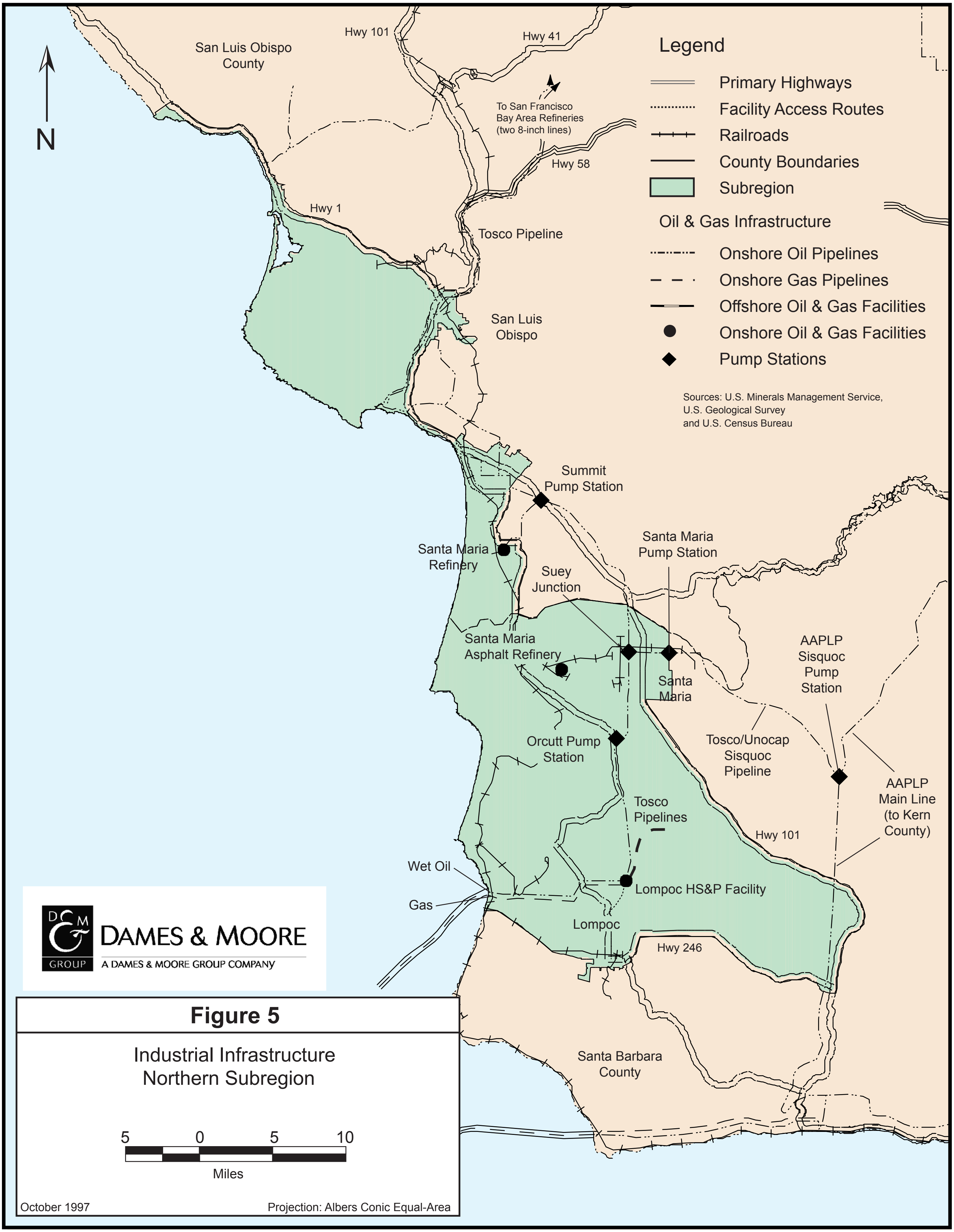


Figure 5

Industrial Infrastructure
Northern Subregion

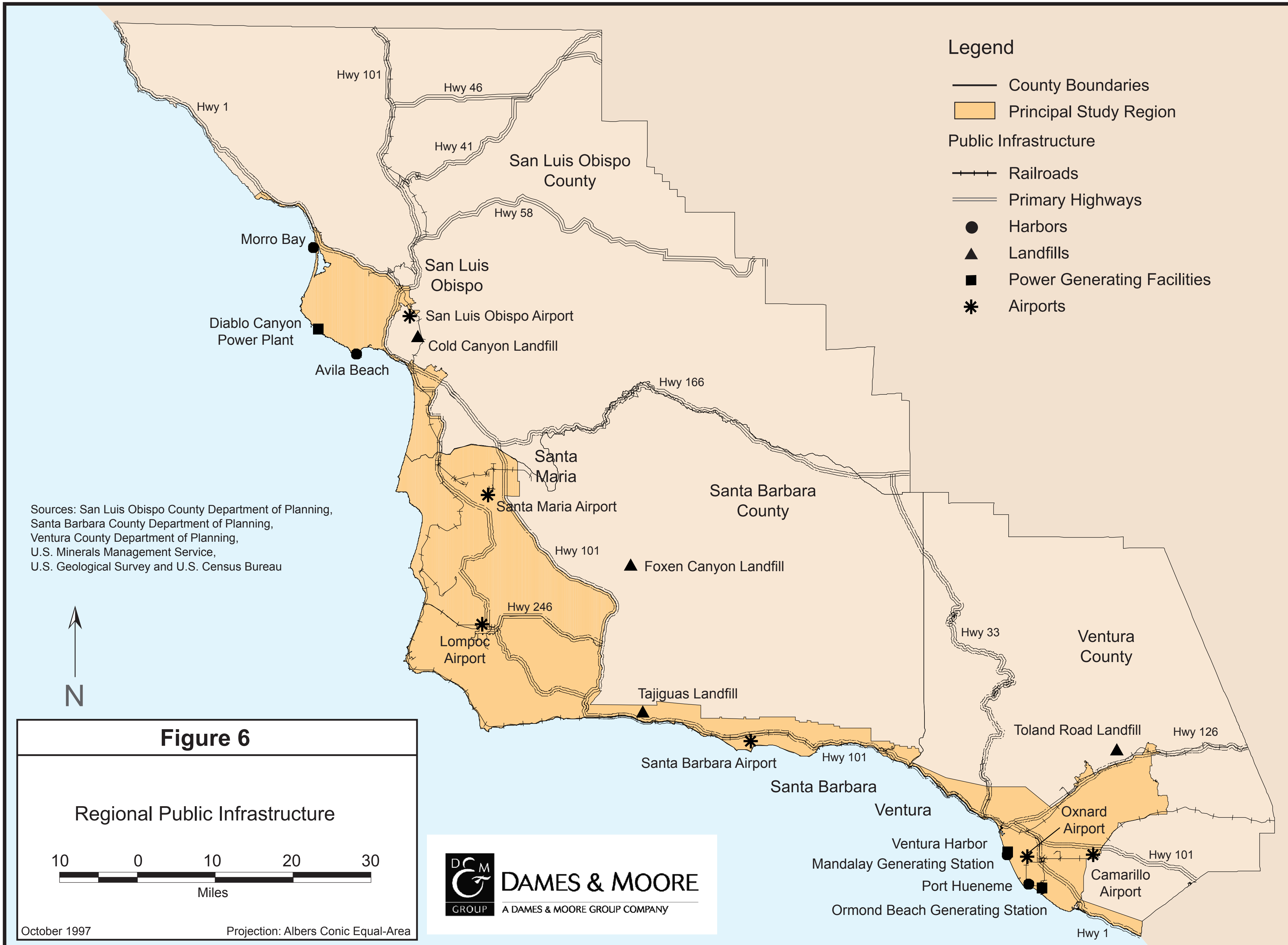
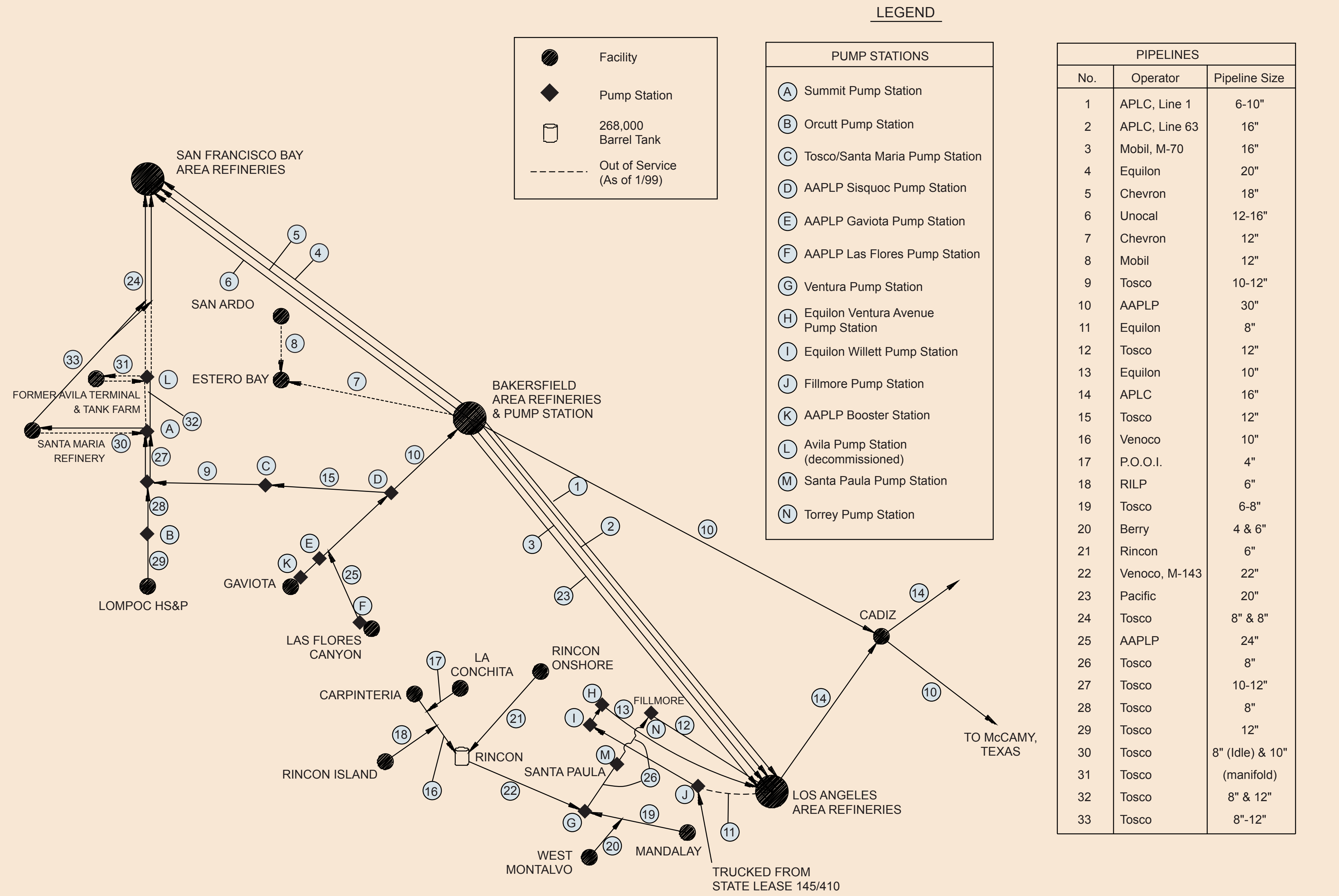


Figure 6

Regional Public Infrastructure



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 7 Regional Oil Transport Pipeline Infrastructure Schematic Diagram

NOT TO SCALE
Locations approximate

the Gaviota Pump Station site, another 150,000 barrels per day capacity line from the Gaviota Oil Terminal to the Gaviota Pump Station, and a 300,000 barrels per day capacity pipeline from the Gaviota Pump Station to the Sisquoc Pump Station and on to the Pentland Pump Station in Kern County. A portion of the oil transported in the All American Pipeline L.P. system can be sent to the Santa Maria Refinery via an existing Tosco pipeline system that connects the Sisquoc Pump Station to the Santa Maria Pump Station and Suey Junction (described in the Northern Subregion paragraph, below).

Northern Subregion offshore production is currently processed at the Lompoc Oil and Gas Processing Facility, and transported to the Santa Maria Refinery in San Luis Obispo County via a Tosco pipeline system. The Santa Maria Refinery processes up to 44,400 barrels per day. Some of the Santa Maria Refinery products are transported by other Tosco pipelines to refineries outside the study region for further refining or sale. Transport of oil from the Lompoc Facility to the Santa Maria Refinery is limited to 36,000 barrels per day by Santa Barbara County permit conditions, although the design capacity of this system is somewhat greater. From Lompoc to Suey Junction, the Tosco pipeline system capacity is at least 43,200 barrels per day. From Suey Junction to the Santa Maria Refinery, existing pipeline system capacity is 72,000 barrels per day (this portion of the pipeline system could transport oil from the All American Pipeline, L.P. system in addition to Northern Subregion production). The pipeline system connecting the AAPLP system to Suey Junction has a total capacity of 36,000 barrels per day from the Sisquoc Station and up to 74,400 barrels per day downstream of the Santa Maria Station (including oil from the Sisquoc Station). Products from the Santa Maria Refinery (pressure distillate or “gas oil”) are transported by an 8-inch to 12-inch diameter Tosco pipeline system with a 36,000 barrels per day capacity, which connects to two 8-inch diameter pipelines near the City of San Luis Obispo. The dual 8-inch pipelines have a total capacity of 57,600 barrels per day, and are connected to the Tosco Rodeo Refinery in the San Francisco Bay area.

3.2.2 Marine Terminals

There is currently only one active marine terminal in use in the study region. The Ellwood Marine Terminal, located in the Central Subregion, is used to load marine barges with oil processed at the Ellwood Oil and Gas Processing Facility. The Ellwood Marine Terminal is currently designated as a legal, non-conforming use by Santa Barbara County. Based on records from January 1997 through July 1998, this facility loads approximately one barge every two weeks (one barge has a capacity of 56,000 barrels). Once a barge is moored and connected to the marine terminal, the loading operation is completed in 13 to 14 hours.

3.2.3 Public Roadways

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, such as propane and butane, are removed from gas and oil streams. Propane is transported to market in high-pressure tanker trucks. Butane is often blended with crude oil for shipment by pipeline, but may also be 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.

Because many of the facilities in three subregions use the same highways to transport the products they produce, the overall assessment of highway use considers that trucks generated by a facility in one subregion may travel on highways in a different subregion. The following highway 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

In addition to the use of regional highways, surface streets are used for access to oil and gas facilities. Access routes to individual facilities on surface streets are discussed in detail in the COOGER report.

3.2.4 Ports and Industrial Piers

Vessel activity associated with offshore oil and gas operations in the study region is supported at Port Hueneme, Carpinteria (Casitas) Pier, and Ellwood Pier. Other harbors and piers in the study region are not used for daily support activity, although some crew and supply vessels are berthed at Ventura Harbor and a Clean Seas oil spill response vessel is commonly moored outside Santa Barbara Harbor.

Port Hueneme is the only deep water port in the study region. Port Hueneme is used by both supply (work) vessels and crew vessels serving offshore platforms throughout the COOGER study region. This activity includes the transfer of supplies and heavy equipment associated with offshore activities as well as personnel. No other location in the study region is currently available for this use. Recent (1997) records of this activity indicate that Port Hueneme offshore oil related vessel traffic includes approximately 52 supply vessels and 42 crew vessels each week. Port management personnel indicated that this level of activity is well within the Port's capacity, and substantial increases could be readily accommodated.

The Carpinteria (Casitas) Pier is located south of the Carpinteria Oil and Gas Processing Facility. This pier is privately owned, and is not available for public use. The pier is used to transfer personnel and light supplies onto crewboats and supply (work) boats, and serves platforms in the Eastern Subregion. An onshore supply storage area and parking lot is located adjacent to the Carpinteria pier. Activity at the Carpinteria Pier averaged 42 vessel calls per week in 1997.

The Ellwood Pier is located west of the Ellwood Oil and Gas Processing Facility. This pier is privately owned, and is not available for public use. The pier is used to transfer personnel and light supplies onto crew boats and supply (work) boats, and serves platforms in the Central Subregion. A small supply storage and parking area is located adjacent to the pier. Activity at the Ellwood Pier averaged 55 vessel calls per week in 1997.

3.2.5 Railroads

The Coastal Line of the Union Pacific Railroad traverses the length of the COOGER study region, and is located adjacent to or near many of the onshore processing facilities. None of the facilities that receive oil directly from offshore platforms transport crude oil or products by rail. The Santa Maria Refinery, which receives processed offshore oil from the Lompoc Oil and Gas Processing Facility, has a dedicated rail spur and rail loading facility, which is used to transport petroleum coke and sulfur from the refinery.

3.2.6 Airports

Helicopters are used to transport employees and light supplies to platforms, most commonly those platforms located farthest from the ports and piers described in Section 3.2.4. Helicopter services are typically based at public airports in the Tri-Counties area, although some of the onshore facilities (such as the Las Flores Canyon Oil and Gas Processing Facility) also have helicopter landing pads. Public airports used in support of offshore oil and gas activities and recent (1997) levels of activity include:

- Eastern Subregion Airports:
  Camarillo Airport - 5 flights per week (MMS inspection flights)

- Central Subregion Airports:
  Santa Barbara Airport - 39 flights per week (offshore personnel and light supply transport)

- Northern Subregion Airports:
  Lompoc Airport - 4 flights per week (offshore personnel and light supply transport)
  Santa Maria Airport - 5 flights per week (MMS inspection flights)

4.0 OFFSHORE DEVELOPMENT SCENARIOS

4.1 OVERVIEW

The COOGER study presents a range of potential future development of existing offshore leases. This range is defined by the scenario guidelines presented in Section 2.2 of this summary. Each scenario guideline was used to define limiting conditions applicable to potential offshore development.

The production rates and associated development activity presented in the COOGER 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 potential schedule of development and initial production 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 include the specific guidelines applicable to each development scenario described in Section 2.2 and additional details directed by the Steering Committee. 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.

4.2 POTENTIAL FUTURE OFFSHORE DEVELOPMENT

The COOGER study analysis resulted in the identification of eighteen economically viable offshore oil fields on existing leases which were not developed at the time the analysis was conducted. The locations of these oil fields are shown on Figures 8 and 9. The results of the COOGER study determination of development and production schedules for each offshore oil field is summarized on Table 2. The COOGER study analysis of the oil and gas resource, potential development schedule, offshore operator plans, and Steering Committee scenario guidelines were combined to develop projections of new offshore facilities, related onshore facilities, and oil and gas production rates associated with each development scenario. An overview comparison of offshore and onshore facilities associated with different scenarios is presented in Table 3.

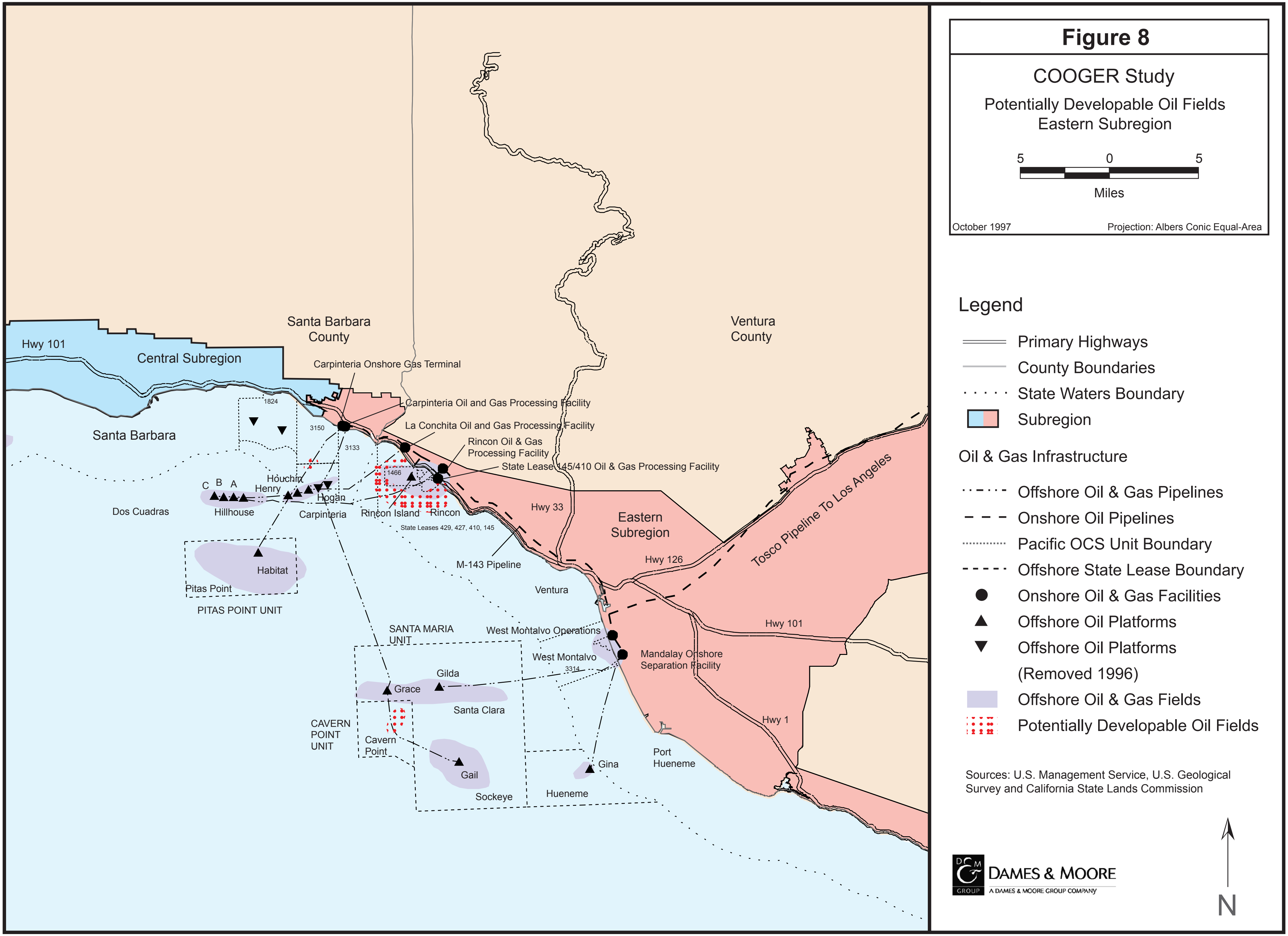


Figure 8
COOGER Study
Potentially Developable Oil Fields
Eastern Subregion
5 0 5
Miles
October 1997
Projection: Albers Conic Equal-Area
Legend
Primary Highways
County Boundaries
State Waters Boundary
Subregion
Oil & Gas Infrastructure
Offshore Oil & Gas Pipelines
Onshore Oil Pipelines
Pacific OCS Unit 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
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
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
Tosco Pipeline To Los Angeles
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
Gilda
Grace
Santa Clara
CAVERN POINT UNIT
Cavern Point
Gail
Sockeye
Hueneme
Gina
Port Hueneme
Hwy 1

Figure 9

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

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TABLE 2
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.

TABLE 3
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

The analysis of future production in the absence of new offshore development is presented as Scenario 1 in each subregion. As indicated by Figure 10, offshore production from currently developed fields is expected to steadily decline through the COOGER study time frame under this scenario. Offshore production in the Eastern and Northern Subregions would be exhausted by the year 2015, and Central Subregion production would decline to 12,000 barrels of oil per day and 95.9 million standard cubic feet of gas per day.

The analysis of expanded development reflected by Scenario 3 provides a reasonable estimate of the upper limit of offshore development potential during the COOGER study time frame. As shown on Figure 11, this scenario would stabilize total production rates in the Central Subregion, and substantially increase production rates in the Northern Subregion. Eastern Subregion production would still be exhausted by 2015, however. Total oil production within the COOGER study region would not exceed 1995 base year production rates from 2000 through 2015. Even if the Northern Subregion Scenario 4 (a maximum case production rate without consideration of market limitations) was added to Scenario 3 in the Central and Eastern Subregions, oil production in the year 2015 would still be less than that experienced in 1995. Substantial new development would be required to generate the production necessary to offset production declines associated with existing developed oil fields. This development would create demands on local infrastructure which are described in Section 5.0.

In addition to the two extremes discussed above, the COOGER study addresses several other scenarios to help refine our understanding of the demand for onshore infrastructure associated with different levels of offshore development. Tables 4 through 9 present the detailed results of production projections developed for each scenario. One notable result of this exercise is the identification that Scenario 2 (development within the capacity of existing facilities) results in nearly the same overall production rates as scenarios which involve new onshore facilities in the Eastern and Central Subregions. This suggests that demand for new onshore processing facilities is likely to be limited to the Northern Subregion.

Another interesting result of the COOGER study is related to the accelerated decommissioning scenario (Scenario 4) in the Central Subregion. Under this scenario, the Gaviota Oil and Gas Processing Facility would be decommissioned between 2001 and 2005. Evaluation of undeveloped offshore resources on existing leases indicated that most would be economically viable even if they were to be connected to the Las Flores Canyon or Northern Subregion processing facilities. As a result, several Northern Subregion development scenarios were added to the COOGER study (Scenarios 2A, 3A, and 4A) to reflect the development that could be displaced to the Northern

Subregion in the event of an accelerated decommissioning of the Gaviota Oil and Gas Processing Facility. The net effect of this activity would be a slight reduction of total oil and gas production and an increase in onshore infrastructure demand and related activity (associated with the development of new onshore facilities). Onshore infrastructure demand associated with all scenarios addressed by the COOGER study is discussed in Section 5.0 of this summary.

Figure 10

SCENARIO 1 - NO FURTHER DEVELOPMENT
COMPARISON OF OIL PRODUCTION BY SUBREGION

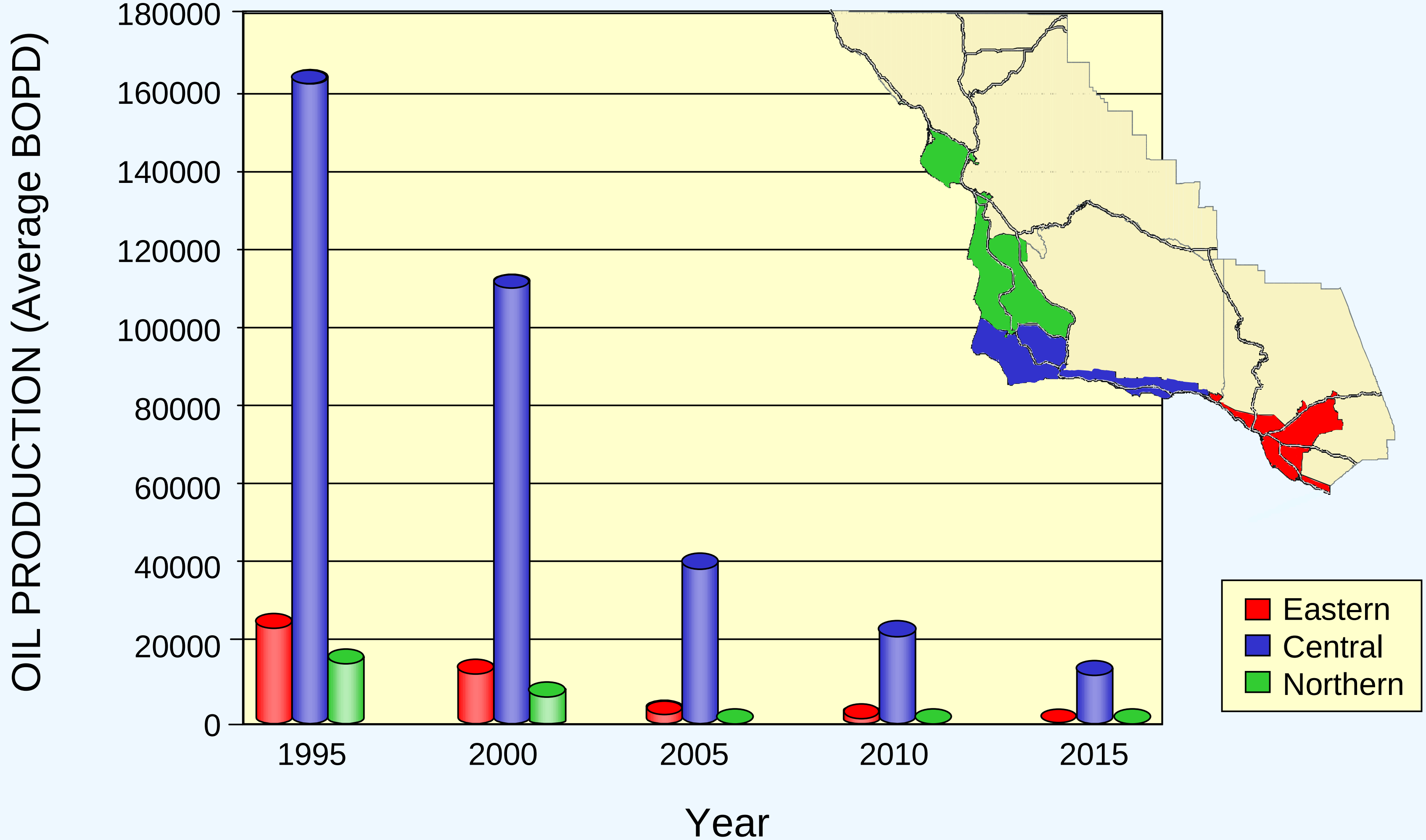

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Figure 11

SCENARIO 3 - CONTINUED OFFSHORE DEVELOPMENT WITH ONSHORE FACILITY EXPANSION COMPARISON OF OIL PRODUCTION BY SUBREGION

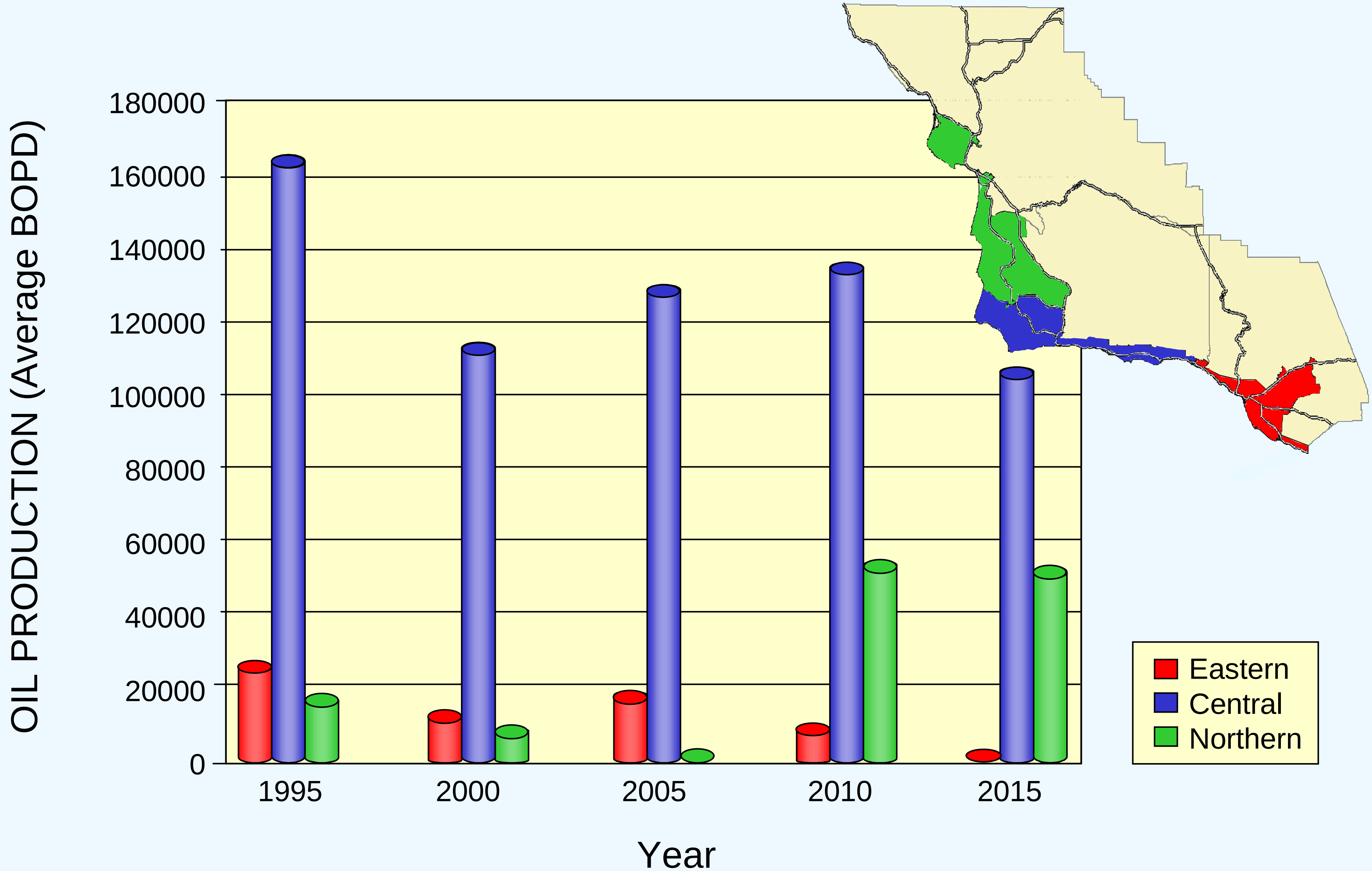

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TABLE 4
EASTERN SUBREGION
SUMMARY OF OIL PRODUCTION BY SCENARIO

	Oil Production (Barrels Per Day, Average)				TOTAL 1995-2015 (MMSTB)
	2000	2005	2010	2015	
Scenario 1 No new development on existing leases	11895	2247	1005	0	52
Scenario 2 Development of existing leases within the capacity of existing onshore facilities	11895	16749	6692	0	90
Scenario 3 Maximum development of existing leases including the expansion of capacity at existing onshore facilities	11895	16749	6692	0	90
Scenario 4 Development of existing leases considering the abandonment of existing facilities	11895	2247	1005	0	51

TABLE 5
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	22714	2697	1206	0	101864
Scenario 2 Development of existing leases within the capacity of existing onshore facilities	22714	49711	25720	0	215695
Scenario 3 Maximum development of existing leases including the expansion of capacity at existing onshore facilities	22714	49711	25720	0	215698
Scenario 4 Development of existing leases considering the abandonment of existing facilities	22714	2697	1206	0	100586

TABLE 6
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	115317	39678	20521	12000	489
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	115317	127649	133602	105415	964
Scenario 4 Development of existing leases considering the abandonment of existing facilities	115317	96865	91340	52915	759

TABLE 7
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	147811	170956	108482	95890	1003341
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	147811	233859	181982	151390	1318013
Scenario 4 Development of existing leases considering the abandonment of existing facilities	147811	209815	160882	125090	1167407

TABLE 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	6055	0	0	0	27
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	53500	50029	163
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	86500	100029	271
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.	6055	19500	95762	102529	334
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.	6055	19500	128762	152529	442

TABLE 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	1392	0	0	0	6104
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	21017	35848	74999
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	29950	82515	140343
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.	1392	9800	42117	62148	160518
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.	1392	9800	51050	108815	225862

5.0 PHYSICAL INFRASTRUCTURE DEMAND

5.1 INDUSTRIAL PROCESSING FACILITY DEMAND

5.1.1 Eastern Subregion

As explained in Section 4.2, 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.

5.1.2 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 4.2. 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. 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 5.1.3 (below) under Scenarios 2A, 3A, and 4A.

5.1.3 Northern Subregion

Only one offshore platform currently produces oil and gas handled at a Northern Subregion onshore processing facility, and that platform would cease production before 2005 in the absence of new development. 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.

Full development of Northern Subregion oil and gas resources is closely related to oil characteristics and potential markets. The heavy crude oil in this study subregion is of a composition and character that one of its potential products is asphalt. The ultimate use of this crude may be influenced by changes in heavy oil technology, however. Currently identified market limitations are considered in Northern Subregion Scenarios 3, 4, 3A, and 4A.

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 Scenario 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.

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, which includes California, Nevada, Arizona, Oregon, and Washington) or markets for other heavy products. This scenario would result in substantially greater production than Northern Subregion Scenarios 1, 2, or 3, and peak dry oil production in 2015 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.

5.2 PIPELINE SYSTEM CAPACITY AND DEMAND

Based on a review of pipeline system capacities and scenario-specific production rates, existing pipeline systems are expected to accommodate any of the Eastern and Central Subregion development scenarios without expansion. A new pipeline would be required to connect South Ellwood Field production to the existing All American Pipeline, L.P. (AAPLP) system under Central Subregion Scenarios 3 and 4, however.

In the Northern Subregion, existing pipeline system capacities are adequate to accommodate production associated with Scenarios 1, 2, and 2A. Scenarios involving expanded production, including Scenarios 3, 4, 3A, and 4A would require expansion of the Tosco pipeline system or construction of a new onshore pipeline to deliver Northern Subregion production to the AAPLP system. The existing capacity of the AAPLP system could accommodate the combined production inputs from both the Central and Northern Subregions without expansion.

5.3 MARINE TRANSPORT

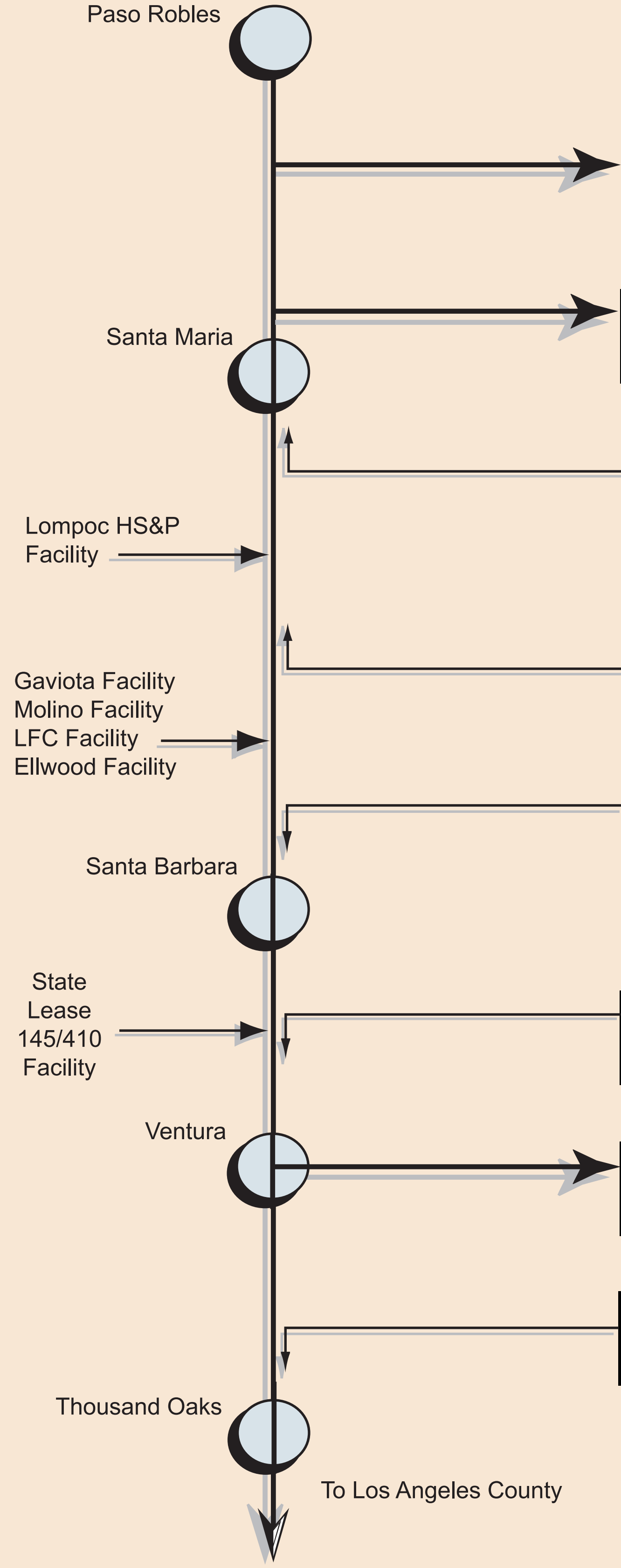
The Ellwood Marine Terminal is the only active marine terminal in the COOGER study region. This facility receives oil from the Ellwood Oil and Gas Processing Facility. Both of these facilities are legal, non-conforming uses and no expansion of either facility is projected under any COOGER study scenario. The Ellwood Marine Terminal is physically capable of barge loading operations that would substantially exceed the permit and design capacities of the Ellwood Oil and Gas Processing Facilities. As such, the Ellwood Marine Terminal does not represent a capacity constraint on any COOGER study scenario.

5.4 DEVELOPMENT-RELATED TRAFFIC ON LOCAL ROADS AND HIGHWAYS

The COOGER study addresses several aspects of traffic on local roadways. Heavy truck traffic on regional highways associated with product transport is evaluated in detail. This analysis addresses potential asphalt/heavy product transport associated with the Northern Subregion offshore fields (projected to produce very heavy, asphaltic crude oil) separate from other product transport to provide useful detail. Because product transport involves truck traffic on regional highways throughout the COOGER study region, this analysis addresses all possible combinations of subregional scenarios. Details of the results of this analysis are presented in the COOGER study report, and selected scenario combinations that reflect the range of traffic generation are presented in this summary. Local traffic associated with supply and personnel transport in the vicinity of Port Hueneme and industrial piers is also addressed.

5.4.1 Product Transport

Figure 12 represents a schematic diagram of 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.



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 12

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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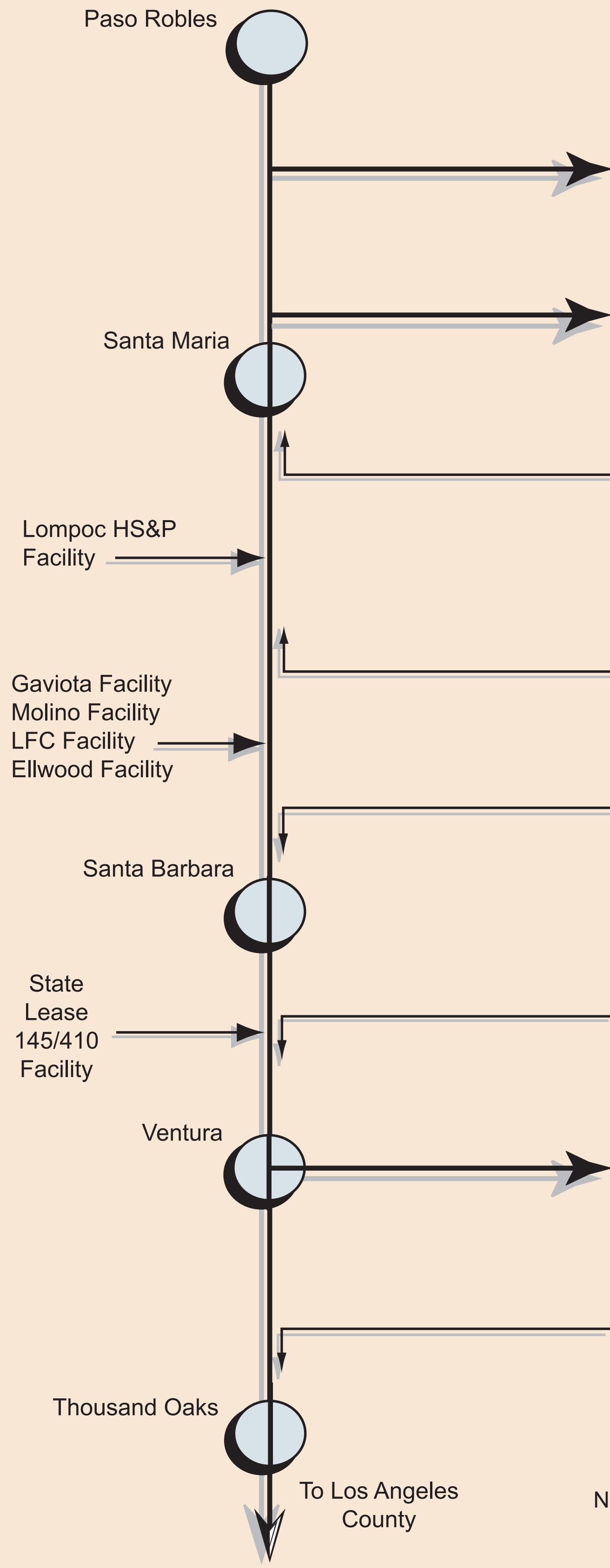
Figure 13 represents the combined LPG, sulfur and crude oil product traffic from the facilities under the scenario combination of any Eastern Subregion scenario, Central Subregion Scenario 3, and Northern Subregion Scenario 3 (excluding heavy product transport associated with Northern Subregion production, which is discussed separately below). The maximum product truck traffic associated with this combination of scenarios would occur in 2010. This combination of scenarios 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 by 2010. 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/New Northern Subregion 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 14 illustrates the effect of the accelerated decommissioning of the Gaviota Facility (Central Subregion Scenario 4) on regional truck traffic. The combination of scenarios represented on this figure includes any Eastern Subregion scenario, Central Subregion Scenario 4, and Northern Subregion Scenario 3A (excluding Northern Subregion heavy product transport which is discussed separately below). This combination of scenarios is comparable to the combination illustrated on Figure 13, with the exception that the Gaviota Oil and Gas Processing Facility is presumed to be decommissioned before 2005 (as specified by Central Subregion Scenario 4), and commercially viable Central Subregion development would be accommodated at the Las Flores Canyon Oil and Gas Processing Facility or at a facility in the Northern Subregion (Northern Subregion Scenario 3A). Under this combination of scenarios, peak product truck traffic would occur by 2010, and would result in up to 64 truck trips per week southbound on Highway 101, about 12 percent less than the southbound traffic projected for the scenario combination represented on Figure 13. Northbound traffic in northern Santa Barbara County would increase under this accelerated decommissioning



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

* All Eastern Subregion scenarios contribute the same product traffic to regional roadways

Note: Potential heavy product transport associated with Northern Subregion production is not included on this figure. Refer to Table 10 (page 45) for information concerning heavy product transport.

FIGURE 13

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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Paso Robles

Santa Maria

Lompoc HS&P Facility

Gaviota Facility
Molino Facility
LFC Facility
Ellwood Facility

Santa Barbara

State Lease 145/410 Facility

Ventura

Thousand Oaks

To Los Angeles County

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

Note: Potential heavy product transport associated with Northern Subregion production is not included on this figure. Refer to Table 10 (page 45) for information concerning heavy product transport.

FIGURE 14

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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scenario combination, including 81 truck trips per week on Highway 101 north of the Lompoc Facility and 67 truck trips per week east on Highway 166 by the year 2010. This represents a nearly 31 percent increase in northbound traffic as compared to the scenario combination represented by Figure 13.

In addition to the LPG and sulfur product transport described above, crude oil characteristics associated with Northern Subregion offshore fields suggest that production from these fields could generate substantial volumes of heavy product, such as asphalt, that may not be suitable for transport by pipeline. This heavy product would most likely be transported by a combination of truck and rail. The projection of potential truck traffic associated with Northern Subregion heavy product is complicated by the fact that a location of its processing facility is not yet known, the proportion of heavy product to be transported by truck versus rail is not known, and the proportion of total product suitable for pipeline transport can only be roughly estimated. Based on a review of expected crude characteristics and discussions with Northern Subregion leaseholders, it was projected that heavy product considered unsuitable for pipeline transport would amount to approximately 40 percent of the total production. This information was combined with field production projections to determine the potential heavy product truck traffic projections shown on Table 10. As indicated by this table, heavy product transport could generate up to 500 truck trips per week by 2010 under Northern Subregion Scenarios 3 or 3A, and up to 1500 truck trips per week by 2015 under Northern Subregion Scenarios 4 or 4A. This truck traffic could be reduced or eliminated by the use of rail transport. As indicated by Table 10, approximately two unit trains per week would accommodate all heavy product transport associated with Northern Subregion Scenarios 3 or 3A. Six unit trains per week would accommodate all heavy product transport associated with Northern Subregion Scenarios 4 or 4A.

5.4.2 Personnel and Supply-Related Traffic

The COOGER study evaluation of local traffic associated with personnel and supply transport focused on activity at industrial ports and piers. This analysis identified declining offshore industry-related traffic in the vicinity of Port Hueneme, Carpinteria Pier, and Ellwood Pier in the absence of new offshore development. Eastern Subregion Scenarios 2 and 3 would result in an approximate 14 percent increase in local traffic in the vicinity of the Carpinteria Pier by 2005 as compared to 1997 traffic levels (528 vehicles per week by 2005 as compared to 462 vehicles per week in 1997). At the Ellwood Pier, Central Subregion Scenarios 2, 3, or 4 would result in a 44 percent increase in local traffic by 2005 (847 vehicles per week by 2005 as compared to 605 vehicles per week in 1997). In all cases, traffic levels at the Carpinteria Pier and Ellwood Pier are projected to be less than 1997 traffic levels by the year 2010.

TABLE 10
EXAMPLES OF POTENTIAL COMBINATIONS
OF TRUCK AND RAIL TRANSPORT OF HEAVY PRODUCT

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

Traffic in the vicinity of Port Hueneme is affected by offshore operations in every COOGER study subregion. Because local traffic in the vicinity of Port Hueneme is already a concern to Ventura County, special attention was given to port-related traffic. Review of onshore traffic at Port Hueneme associated with different offshore development scenarios indicated that traffic associated with Eastern Subregion offshore activity would decline under all development scenarios. In other words, potential offshore oil-related traffic increases at Port Hueneme are entirely related to offshore activities in the Central and Northern Subregions. In the absence of new offshore development (Central and Northern Subregions Scenario 1), offshore oil-related traffic at Port Hueneme would steadily decline to less than 12 percent of 1997 levels by 2010. Combinations of offshore development scenarios that involve continued development in the Central and Northern Subregions (Central Subregion Scenarios 2 or 3 and Northern Subregion Scenarios 2, 3, or 4) are projected to result in a nearly 38 percent increase in offshore oil-related traffic by 2005 (1207 vehicles per week as compared to 876 vehicles per week in 1997). Traffic associated with these development scenarios would generally return to levels comparable to 1997 by the year 2010, and all would result in substantially less traffic by the year 2015.

5.5 INDUSTRIAL USE OF RAILROADS

Existing use of railroads within the COOGER study region to transport products associated with offshore oil production is currently limited to product transport from the Santa Maria Refinery, as indicated in Section 3.2.5. This activity is projected to remain constant or decline under all future development scenarios evaluated in the COOGER study. Rail transport of heavy product associated with Lion Rock Field production could be generated by Northern Subregion Scenarios 3, 4, 3A, or 4A. If all heavy product associated with these scenarios was shipped by rail (thereby eliminating all heavy product truck transport), Scenarios 3 or 3A would result in approximately two 70-car unit trains per week by the year 2010. Under the same circumstances, Scenarios 4 and 4A would result in approximately five unit trains per week by 2010, and six unit trains per week by 2015.

5.6 VESSEL ACTIVITY AT INDUSTRIAL PORTS AND PIERS

As discussed in Section 3.2.4, industrial ports and piers used in support of offshore oil and gas activities include Port Hueneme, Carpinteria (Casitas) Pier, and Ellwood Pier. Port Hueneme is the only industrial port in the COOGER study region that is available for the transport of equipment and heavy supplies to offshore facilities. As a result, offshore activities in all three subregions affect vessel activity at Port Hueneme. The other industrial piers are closely associated with offshore activity nearby; the Carpinteria Pier serving activities in the Eastern Subregion, and the Ellwood Pier serving activities in the Central Subregion.

Offshore oil-related vessel activity at Port Hueneme would generally decrease in the absence of new development, with the exception of periods of increased activity associated with offshore decommissioning activity. Combinations of scenarios involving further offshore development in all three subregions could increase vessel activity to 140 vessel calls per week by 2005, an increase of 49 percent above 1997 vessel traffic levels. Under these scenarios, vessel traffic would decrease between 2005 and 2010, but would still remain above 1997 levels. Under all future development scenarios, vessel activity at Port Hueneme would be substantially less (at least 53 percent less) than 1997 levels by 2015. Oxnard Harbor District management personnel responsible for Port Hueneme operations indicated that the peak vessel activity associated with further offshore development activity would be well within the Port Hueneme wharf capacity.

Vessel activity at the Carpinteria Pier would be similar under all Eastern Subregion scenarios through 2005. Use of the Carpinteria Pier for offshore oil industry activity would be discontinued by 2010 under Scenarios 1 and 4. Under Eastern Subregion Scenarios 2 and 3, industrial use would continue at a low level (4 to 6 vessel calls per week as compared to 1997 levels of 42 vessel calls per week) by 2010 through 2015.

Vessel activity at the Ellwood Pier would remain relatively constant through the year 2010 in the absence of new offshore development, and then would decline substantially by the year 2015. Under scenarios involving new offshore development and accelerated decommissioning of offshore structures (Central Subregion Scenarios 2, 3, and 4), Ellwood Pier vessel activity would increase by 40 percent above 1997 levels by 2005 (to 77 vessel calls per week as compared to 55 vessel calls per week in 1997). Under these scenarios, vessel activity at the Ellwood Pier would return to levels comparable to 1997 by the year 2010, and would remain there through 2015.

5.7 INDUSTRIAL USE OF AIRPORTS

Projected industrial use of airports in the Eastern and Central Subregions would remain relatively constant or decline through the COOGER study period for all combinations of scenarios. MMS use of the Camarillo Airport for inspection flights in the Eastern Subregion is expected to decline as the number of offshore facilities declines. The use of the Santa Barbara Airport for industrial support helicopter flights would increase slightly (about 10%) by 2010 under Central Subregion Scenarios 2 or 3, or decline to less than 40 percent of 1997 levels under Central Subregion Scenario 1. Some increased Santa Barbara Airport helicopter traffic would be associated with Northern Subregion Scenarios 2A, 3A, or 4A (which are associated with Central Subregion Scenario 4), with a net effect of Central Subregion Scenario 4 of stable to decreasing helicopter traffic at the Santa Barbara Airport.

Continued use of Northern Subregion airports in support of offshore oil and gas activity is closely associated with specific development scenarios. In the absence of new offshore development (Northern Subregion Scenario 1), industry use of the Lompoc Airport would be eliminated by 2010, and MMS use of the Santa Maria Airport would likely decrease by the same year. All Northern Subregion scenarios involving further offshore development would generate comparable helicopter traffic at the Lompoc Airport (up to 11 flights per week by 2010 as compared to 4 flights per week in 1997). Industrial helicopter activity would also occur at the Santa Maria Airport (which is presently not used for these flights), including from 3 to 20 flights per week by 2010 depending on the specific Northern Subregion development scenario. This peak of activity at the Santa Maria Airport is partially associated with offshore construction activity. By 2015, helicopter traffic from the Santa Maria Airport associated with Northern Subregion development scenarios would range from 2 to 6 flights per week.

COPIES OF THE COMPLETE COOGER STUDY ARE ON FILE AT LOCAL LIBRARIES, AND WILL BE AVAILABLE FOR A LIMITED TIME ON CD-ROM OR HARD COPY DOCUMENT.

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THANK YOU FOR YOUR INTEREST IN THE COOGER STUDY.

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